The Full Costs of Electricity Provision

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The Full Costs of Electricity Provision

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Foreword

Electricity production, transport and consumption affect every facet of life in the advanced market economies of countries making up the Nuclear Energy Agency (NEA) and Organisation of Economic Co-operation and Development (OECD). Market prices and production costs account for an important share of the overall economic impacts of electricity. However, over at least the past two decades, there has been a growing recognition that this market value of electricity is not the whole story and that the social and environmental impacts of electricity provision are affecting individuals, economies and societies in ways that are not captured in market prices, but yet are too important to be neglected. Concerns about anthropogenic climate change have strongly reinforced such a stance. In addition, the impacts of local pollution from electricity generation on health and longevity, or the fear of major accidents on lives and ecosystems, have troubled policy makers and the public for many years. Employment and technological developments are additional issues.

Such impacts are called external effects, externalities or social costs. While not reflected in market prices, researchers can nevertheless fairly well identify the external impacts of electricity generation and provision, often measuring them and sometimes even monetising them partially or tentatively. The full costs of the electricity generated by a given technology are thus the sum of the technology's private, market-based costs plus its social costs. Since at least the early 1990s, when a raft of major studies on energy externalities was launched, accounting for the full costs has become part of the work of a large constituency of researchers.

Suddenly, public attention moved away from the full costs of electricity, partly because of concerns about climate change with its particular processes and methodological conventions. However, the issues associated with externalities did not disappear. One particularly stark example is provided by the World Health Organization (WHO), whose research indicates that globally, every year three million deaths are caused by ambient air pollution and by particulate matter released mainly through the burning of coal or biomass. Add to this the impact of household air pollution, much of which could be avoided by the provision of clean electricity, and the number of deaths per year rises to over seven million. Clearly, all sources of electricity have advantages and drawbacks. However, it would be wrong to think that no distinctions should be made in terms of social costs, and the present report highlights the most important ones.

Despite the evident importance of full costs, accounting for them remains difficult. From researching biophysical dose-response function, calibrating dispersion models and probabilistic assessments to the contentious issue of monetary valuation, different groups of experts need to be co-ordinated in large-scale multi-year efforts to arrive at robust results. Such a large, systematic effort is, however, beyond the scope of this report.

Nevertheless, the issue is too important to be disregarded any longer. The NEA has therefore decided to produce the present study on the *Full Costs of Electricity Provision* in order to summarise and synthesise the most recent research in this area.

That an agency dedicated to nuclear energy would decide to publish a report on the full costs of electricity provision including all major generation technologies may easily invite questions about even-handedness. However, the authors of this report have shown a strong commitment to synthesising well-documented information from a wide range of

sources. Such questions should, more importantly, be a starting point for more comprehensive research on the full costs of electricity provision, supported by a broad range of stakeholders in the electricity sector. If anything, the present report helps to identify priority areas – such as limiting air pollution, reducing greenhouse gas emissions and properly allocating system costs – that warrant specific, new research.

Research on the full costs of energy and electricity is an ongoing effort. This report highlights the importance of full cost accounting, in particular in the context of the energy transitions under way in many countries. Ideally, it will contribute to generating new and more comprehensive research in the area of the full costs of electricity to allow policy makers and the public to make better informed decisions along the path towards fully sustainable electricity systems.

Acknowledgements

The Full Costs of Electricity Provision is a collaborative effort by the Nuclear Energy Agency Division of Nuclear Technology Development and Economics, under the oversight of the Working Party of Nuclear Energy Economics (WPNE) chaired by Matt Crozat and Professor Dr Alfred Voss. The study has been approved by the parent committee of the WPNE, the NEA Nuclear Development Committee (NDC).

Dr Jan Horst Keppler, Senior Economic Advisor at the NEA, co-ordinated the study and contributed Chapter 1 (Full costs: Key concepts, measurement and internalisation), Chapter 4 (Climate change impacts), Chapter 5 (Air pollution, together with Karl Aspelund, Harvard University), Chapter 7 (Land-use change and natural resource depletion, together with Karl Aspelund), Chapter 8 (The security of energy and electricity supply) as well as the policy conclusions (The policy implications of full cost accounting in the electricity sector). Dr Geoffrey Rothwell, Principal Economist at the NEA, contributed Chapter 2 (Plant-level production costs) and Chapter 9 (Employment generated in the electricity sector). Dr Marco Cometto, Nuclear Energy Analyst from the NEA, contributed Chapter 3 (Grid-level system costs) and Chapter 6 (The costs of major accidents). Dr Marc Deffrennes contributed Chapter 10 (The impact of energy innovation on economic performance and growth). Managerial oversight was provided by Dr Daniel Iracane, Deputy Director-General and Chief Nuclear Officer; Dr Jaejoo Ha and Dr Henri Paillère, the former and Acting Head of the NEA Division of Nuclear Technology Development and Economics, respectively.

Participants in the International WPNE Workshop on The Full Costs of Electricity Provision on 20 January 2016 helped frame the structure and content of this report. The NEA also received a large number of detailed comments from its member countries, including Austria, Canada, France, Germany, Japan, Poland, Russia, and Switzerland, as well as from WPNE delegates. Experts at the International Energy Agency (IEA) also provided valuable comments. These knowledgeable and highly technical comments, very much improved the final version. They speak to the policy relevance of the full costs of electricity provision, as well as to the need for further study, carefully targeted on the most significant aspects of this important subject.

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Abbreviations and acronyms

2DS	Two-degree Celsius scenario
BAU	Business-as-usual
CAA	Clean Air Act
CASES	Costs assessment for sustainable energy systems
CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage
CfD	Contracts-for-difference
CRF	Concentration-response functions
CRP	Conservation Reserve Program
CSP	Concentrated solar power
DALY	Disability-adjusted life-years
DICE	Dynamic Integrated Model of Climate and the Economy
DOE	Department of Energy (United States)
EEA	European Environment Agency
EGC	Expert Group on the Projected Costs of Generating Electricity (NEA)
EGS	Enhanced geothermal systems
ENV	OECD Environment Directorate
EPA	Environmental Protection Agency (United States)
EPR	European pressurised water reactor
EPRI	Electric Power Research Institute
EU	European Union
ETS	Emissions trading scheme
FEEM	Italian Fondazione Enrico Mattei
FIP	Feed-in premiums
FITs	Feed-in-tariffs
F-N	Frequency/consequence
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatt
GWh	Gigawatt-hour
GWP	Global warming potential
IAM	Integrated assessment model
IEA	International Energy Agency

IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
kWh	kilowatt-hour
LCOE	Levelised cost of electricity
MAC	Marginal abatement costs
MW	Megawatt
MWh	Megawatt-hour
NEA	Nuclear Energy Agency
NEEDS	New energy externalities developments for sustainability
NGOs	Non-governmental organisations
NOAA	National Oceanic and Atmospheric Association
NPP	Nuclear power plant
OCGT	Open cycle gas (or oil) turbines
OECD	Organisation for Economic Co-operation and Development
ORNL	Oak Ridge National Laboratory (United States)
O&M	Operation and maintenance
PM	Particulate matter
ppm	Parts per million
PSA	Probabilistic safety assessment
PSI	Paul Scherrer Institute
PV	Photovoltaic
PWR	Pressurised water reactor
QALYs	Quality-adjusted life years
R&D	Research and development
RD&D	Research, development and demonstration
R/P	Reserves-to-production
SCC	Social cost of carbon
SSDI	Simplified supply and demand index
T&D	Transmission and distribution
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
VOC	Volatile organic compounds
VREs	Variable renewable energy sources
VSL	Value of a statistical life
WEO	*World Economic Outlook*
WHO	World Health Organization
WPNE	Working Party of Nuclear Energy Economics (NEA)
WTP	Willingness to pay
YOLLs	Years of life lost

Executive summary

Electricity production, transport and consumption affect every facet of life in the advanced market economies of countries such as those which are members of the Organisation of Economic Co-operation and Development (OECD) and the Nuclear Energy Agency (NEA). Market prices and production costs are important measures of the economics of electricity. However, over at least the past two decades, there has been a growing recognition that these values do not represent the whole story; the social and environmental impacts of electricity provision affect individuals, economies and countries in ways that are not captured in market prices, but yet are too important to be neglected.

Despite their importance, full accounting for these costs remains difficult. From researching biophysical dose-response function, calibrating dispersion models and probabilistic assessments to the contentious issue of monetary valuation, different groups of experts need to be co-ordinated in large-scale multi-year efforts to arrive at robust results. Such a large, systematic effort is, however, beyond the scope of this report.

Nevertheless, the issue is too important to be disregarded. The NEA has therefore decided to produce the present study on *The Full Costs of Electricity Provision* in order to summarise and synthesise the most recent research in this area. Research on the full costs of energy and electricity is an ongoing effort. The report highlights the importance of full cost accounting, in particular in the context of the energy transitions under way in several countries. Ideally, it will contribute to spawning new and more comprehensive research in the area of the full costs of electricity to allow policy makers and the public to take better informed decisions along the path towards fully sustainable electricity systems.

For a number of years, the NEA has been analysing and researching different aspects of the full costs of electricity. The results of this work have found their expression in a number of publications that have already appeared or are forthcoming. While most of these publications centred on nuclear energy, others included different sources of power generation. They include:

- *Risks and Benefits of Nuclear Energy* (2007).
- *Comparing Nuclear Accident Risks with Those from Other Energy Sources* (2010).
- *The Security of Energy Supply and the Contribution of Nuclear Energy* (2010).
- *Projected Costs of Generating Electricity: 2010 Update* (2010), with the International Energy Agency (IEA).
- *Economics of Long-term Operations of Nuclear Power Plants* (2012).
- *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems* (2012).
- *The Economics of the Back End of the Nuclear Fuel Cycle* (2013).
- *Projected Costs of Generating Electricity: 2015 Update* (2015), with the IEA.
- *Nuclear Energy: Combating Climate Change* (2015).
- *Costs of Decommissioning Nuclear Power Plants* (2016).

The NEA is also currently working on a number of publications with relevance to the discussion on full costs and that will be forthcoming in the coming months. These include *Climate Change: Assessment of the Vulnerability of Nuclear Power Plants and Adaptation Costs*, *Estimation of Potential Losses Due to Nuclear Accidents*, *Measuring Employment Generated by the Nuclear Power Sector* and *System Costs in Deep Decarbonisation Scenarios: The Contributions of Nuclear Energy and Renewables*.

A significant number of studies have also been published by other institutions, including the OECD Environment Directorate (see, for instance, *The Economic Consequences of Outdoor Air Pollution*, *The Cost of Air Pollution: Health Impacts of Road Transport* or *Mortality Risk Evaluation in Environment, Health and Transport Policies*) and the IEA (see, for instance, *World Energy Outlook Special Report 2016: Energy and Air Pollution* or *Harnessing Variable Renewables: A Guide to the Balancing Challenge*) alongside a rich academic literature on the full costs of energy, some of which is summarised in the different chapters of this report.

Full costs: Key concepts, measurement and internalisation

The costs of electricity provision fall into three different, comprehensible categories. The first category is constituted of plant-level costs, which include the concrete and steel used to build the plant, and the fuel and the manpower to run it. The NEA and the IEA publish a survey of the plant-level costs in OECD countries every five years in the *Projected Costs of Generating Electricity* series (see IEA/NEA, 2010 and IEA/NEA, 2015; IEA/NEA, 2020 is currently in preparation).

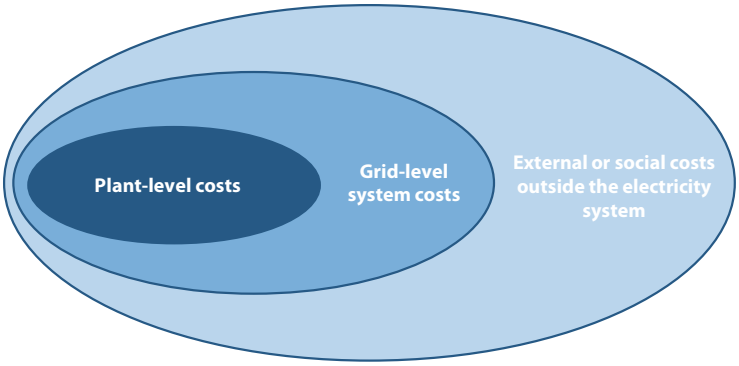
The second category concerns the costs at the level of the electricity system, linked through the transmission and distribution grid. It includes the costs that plants impose on the system in terms of extending, reinforcing or connecting to the grid, but also the costs for maintaining spinning reserves or additional dispatchable capacity when the output of some technologies – typically wind and solar photovoltaic (PV) – is uncertain or variable.

The third, even broader, category includes items that impact the well-being of individuals and communities outside the electricity sector. Known as external or social costs, such costs include the impacts of local and regional air pollution, climate change, the costs of major, frequently not fully insurable, accidents, and land use or resource depletion. Social costs also include the impacts of different power technology choices on the security of energy and electricity supply, employment and regional cohesion or on innovation and economic development. If these impacts are negative, they add to the full costs of a technology; if they are positive, in principle, they need to be deducted as a social benefit.

The full costs of energy provision now include the totality of the three categories: plant-level costs of generation, grid-level system costs and the external social and environmental costs (see Figure ES.1).

In the case of both grid-level system costs and external costs, the actors who cause them are not those who are primarily affected by them. Grid-level system costs thus have an "external" or "social" component as well. In essence, this means that an outside actor, the government, the regulator or the system operator, needs to step in to ensure that such external costs are not overproduced and are correctly internalised. Economic theory has devised a number of corresponding instruments, including standards and technical regulations, pollution taxes, new markets such as emissions trading, better information and research, as well as an overall strengthening of the legal system. Overcoming the knowledge gap is also part of moving towards sustainable electricity systems.

Figure ES.1: **Different cost categories composing the full costs of electricity provision**



Source: NEA, 2012b.

Concerns about higher electricity prices have regularly stunted internalisation efforts. However, it is the responsibility of experts and informed policy makers to insist on internalising social costs, since a reasonable degree of confidence exists that cost internalisation will improve the well-being of society as a whole, meaning that the pie will only become larger. Such internalisation will need to take place at the level of the individual technology in order to induce the relevant substitution effects that will lead to an overall system that minimises the full costs of electricity provision. Where necessary, appropriate compensation mechanisms can be devised to overcome unwelcome distributional consequences.

Accounting for full costs based on the measurement of external costs is not an uncontroversial topic. The monetisation of social costs outside a market framework can be misunderstood as an attempt to reduce human well-being to a question of dollars and cents. The large uncertainties involved, which can produce results that change considerably over time or between comparable projects, are also easy targets for detractors. Others have pointed to social factors as one of the impacts that will remain outside the scope of even very comprehensive efforts.

Most of these criticisms are based on a misunderstanding of what full cost accounting is trying to achieve. Estimates established for the social cost portion of the full costs of electricity provision will never be able to mimic the more reliable information about individual and social preferences conveyed by market prices. The objective is to provide order-of magnitude estimates that allow public discussion and policy making to integrate the most pressing issues in a meaningful way into the inevitable trade-offs that characterise all policy making. In doing so, full cost accounting will unavoidably mix hard market data, reasonably reliable estimates and less reliable estimates. The latter estimates may best be considered, even when undertaken by well-intentioned and experienced practitioners, as intelligent and informed guesswork.

A certain level of social costs due to air pollution, for example, or the impacts of a major accident, are often associated with a representative technology as they are in the present report. The presence or absence of specific pollution control equipment or certain physical barriers, could reduce or increase such impacts. In such cases, pragmatic good judgement needs to be applied to the decision on which reference technology to use. It is primarily for this reason that this report is organised according to subject area rather than according to technology. The goal is not to establish rankings but to draw attention to understudied issues that should be better internalised into the policy process.

Does this mean that any number is no better than the absence of a number as is sometimes advanced? For policy-making purposes, a number advanced by a responsible researcher on the basis of the best available information with the appropriate sources, uncertainties and *caveats* would certainly be better than no number, despite the uncertainties and the *caveats*. The purpose of full cost accounting is not to engage in economic imperialism, nor is it to establish futile oppositions between market prices and social costs. Its sole purpose is to allow for better policy making in the electricity sector.

Overall, this study takes a pragmatic, partial equilibrium approach. The externalities of energy provision in different policy areas such as grid-level system costs, atmospheric pollution or climate change are thus considered one by one. The alternative of considering them together, with the help of a computable general equilibrium (CGE) model, economy-wide input-output models or a macro-econometric model, would have diminished the transparency and readability of findings which are first and foremost addressed to policy makers. Facilitating a more comprehensive and structured discussion of such issues at the policy-making level, rather than at the research level, is the primary purpose of this report.

Plant-level production costs

Plant-level production costs limit themselves to the first and the smallest of the three categories indicated above in Figure ES.1. The NEA began reporting plant-level costs in the *Projected Costs of Generating Electricity* series in 1983, comparing nuclear power plant (NPP) and coal-fired power plant costs. The IEA joined the NEA in publishing this report in 1989. Together, the two agencies updated the study in 1992, 1998, 2005, 2010 and 2015 to evaluate the levelised cost of electricity (LCOE) for a variety of technologies.

The LCOE indicates the discounted lifetime costs for different baseload technologies, averaged over the electricity generated. It has its purpose for informing the investment choices of electric utilities in regulated electricity systems, but it is less pertinent in deregulated electricity systems where revenues vary from period to period over an electricity generator's lifetime. LCOE is also unable to capture the system costs of certain technologies (see Figure ES.2 below). Despite these limitations, it often remains an attractive first reference because of its simplicity and transparency.

Figure ES.2: **Plant-level costs for different power generation technologies**

(USD per MWh)

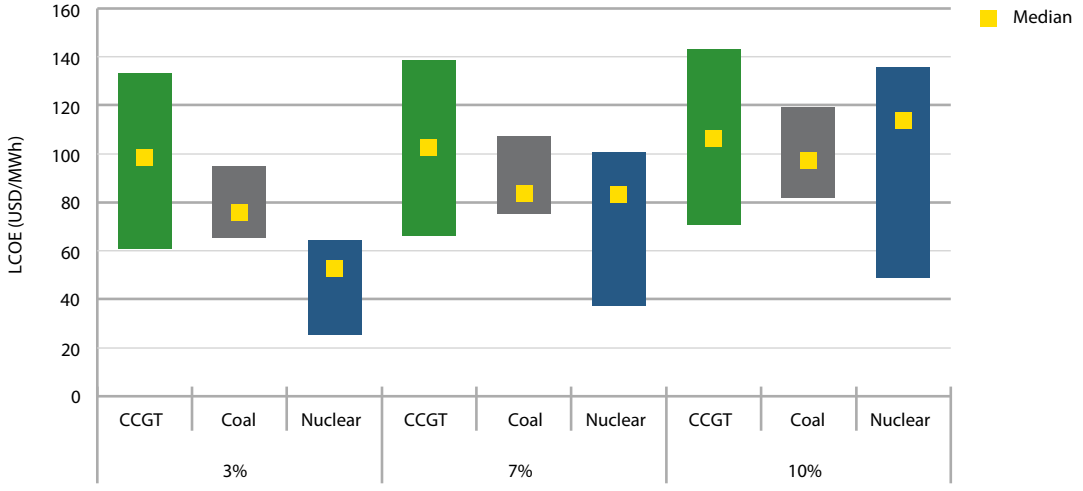
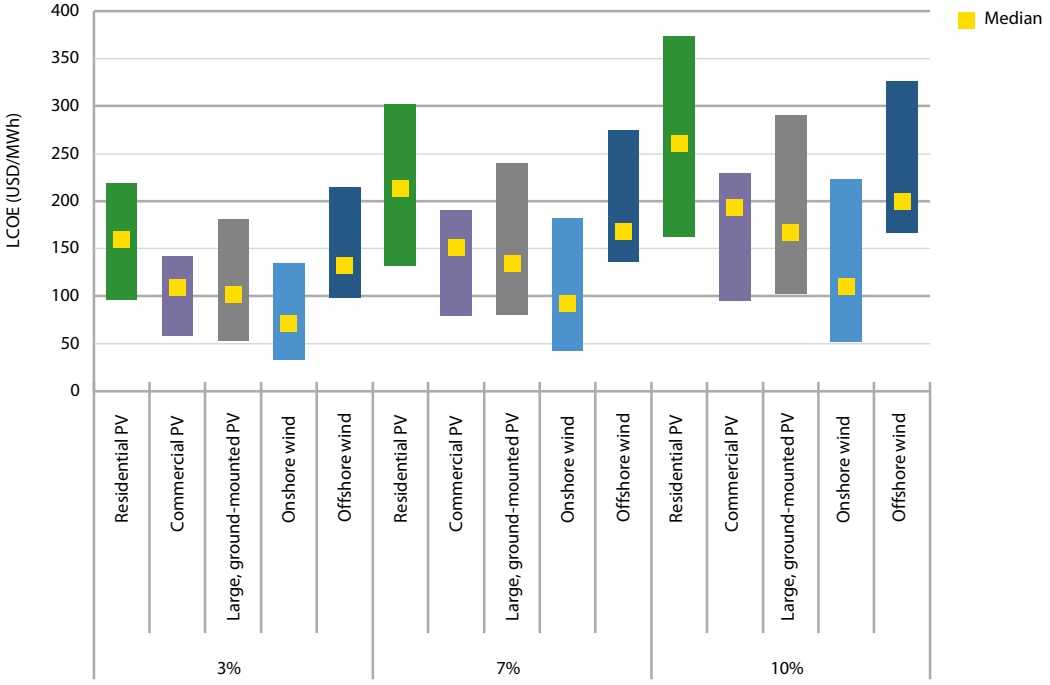


Figure ES.2: **Plant-level costs for different power generation technologies** *(cont'd)*

(USD per MWh)



Source: IEA/NEA, 2015.

Figure ES.2 provides estimates of plant-level costs for dispatchable and renewable power generation technologies at capital costs of 3%, 7% and 10%, assuming region-specific fuel prices, an 85% load factor for nuclear, coal and gas, as well as a carbon price of USD 30 per tonne of CO_2. The latter assumes that the social costs of climate change due to carbon emissions are at least partially internalised in the policy provisions of OECD countries (IEA/NEA, 2015, Figure ES.1, p. 14 and Figure ES.2, p. 15). With the direct carbon emissions of coal being around one tonne per MWh and those of gas around 400 kg per MWh, their respective median values would be around USD 30 and USD 12 lower, if strictly no efforts to reduce CO_2 emissions were made.

Grid-level system costs

While system costs have always existed in unbundled electricity systems, the topic has moved into focus over the last few years with the deployment of significant amounts of variable renewable energy (VRE) sources in many OECD countries. Such system effects are often divided into the following three broad categories:

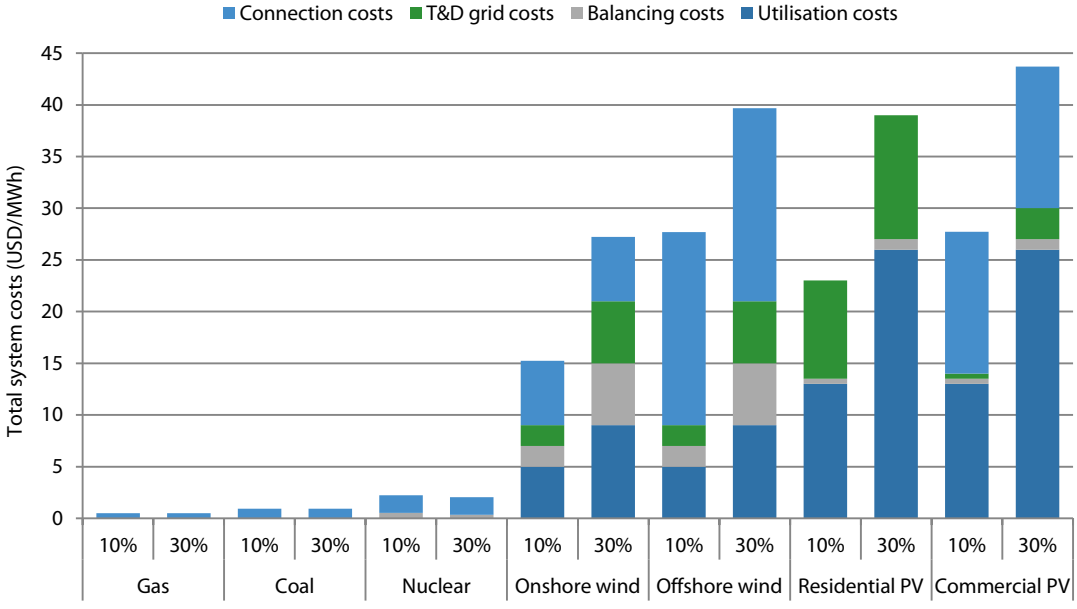
- *Profile costs* are related to the variability of VRE output, and they are able to demonstrate that in the presence of VRE generation it is generally more expensive to provide the residual load. The overall system thus becomes more expensive even if the plant-level costs of VRE are comparable to those of dispatchable technologies.
- *Balancing costs* are related to the uncertainty of power production due to unforeseen plant outages or to forecasting errors in relation to production. Unforeseen plant outages or forecasting errors related to electricity generation require that a higher amount of spinning reserves be carried out. Uncertainties in VRE power production may also lead to an increase in ramping and cycling of conventional power plants, to inefficiencies in plant scheduling and, overall, to higher costs for the system.
- *Grid and connection costs* reflect the effects on the transmission and distribution grid infrastructure due to the locational constraint of generation plants. While all generation plants may have some siting restrictions, the impacts are more significant for VRE. Because of their geographic location constraint, it could be

necessary to build new transmission lines or to increase the capacity of existing infrastructure (grid reinforcement) in order to transport the electricity from centres of production to load. Also, high shares of distributed PV resources may require sizeable investment into the distribution network, in particular to allow the inflow of electricity from the producer to the grid when the electricity generated exceeds demand. Connection costs (i.e. the costs of connecting the power plant to the nearest connecting point of the transmission grid) can also be significant, especially if distant resources have to be connected, as is sometimes the case for offshore wind.

Any quantification of system effects is challenging, not only because of the intrinsic complexity of the phenomena involved, but also because system costs depend strongly on the individual characteristics of the system analysed, on the time frame considered, as well as on the characteristics of the technology assessed and its share in the generation mix. In addition, the composition of the generation mix and the assumptions on the availability and costs of future technologies play a key role in system cost assessments. Innovation and technological progress can further change the system over time. Any estimate of system costs is therefore bound by significant uncertainty and cannot be easily extrapolated to a different system or to a different context.

Figure ES.3 provides an example of the reconstruction of grid-level system costs for different dispatchable and renewable technologies, based on a survey of the literature and the NEA study *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems* (NEA, 2012), whose results continue to hold up well despite the evidence provided by the growth of variable renewables since then. The purpose of this illustrative figure is not to provide an estimate of system costs for a specific system, but rather to help visualise these effects and give an order of magnitude to their value. While uncertainties are considerable, most estimates recognise that the grid-level system costs associated with VRE integration are large and increase over-proportionally with the share in electricity generated (i.e. the penetration level). In comparison, system costs of dispatchable technologies, such as coal, gas, nuclear power or hydro, are at least one order of magnitude lower.

Figure ES.3: **Grid-level system costs of selected generation technologies for shares of 10% and 30% of VRE generation**



Given the extent of system effects and the impacts on electricity markets, governments and policy makers should introduce policies aimed as much as possible at their internalisation. More specifically, it is urgent that all technologies be exposed to the market price and bear the full cost of connecting the plant to the transmission and distribution (T&D) infrastructure.

Climate change impacts

The desire to reduce greenhouse gas (GHG) emissions in order to prevent or mitigate the impacts of anthropogenic climate change has been a high priority for policy makers in many countries for the past two decades. However, this priority has not translated into an ability to quantify and monetise the impacts of fossil fuel combustion. There are three major issues in this context: i) different dimensions of uncertainty; ii) discounting future impacts and; iii) equity issues between different stakeholders.

The multilateral process has thus chosen a different approach because of the factors mentioned above. Rather than estimating the marginal social costs, the amount of emissions considered socially optimal has been the target. Such quantitative targets can be formulated in terms of annual GHG emissions, their resulting concentration in the earth's atmosphere or in terms of the global temperature increase that the latter would cause. In the end, it was this metric that best synthesised the range and probability of different climate change impacts for policy makers and the public – the increase of the global mean temperature compared to the global mean temperature prevailing before the industrial revolution. A consensus has emerged in international fora that a temperature rise of more than 2°C should be avoided.

Table ES.1: **Marginal abatement costs for scenarios with 500 ppm and 450 ppm**

(2005 euros per tCO_2)

	2025		2050	
	Range	Mean	Range	Mean
500 ppm	37-119	60	79-226	130
450 ppm (2DS)	69-241	129	128-396	225

The marginal cost of attaining the 2DS with 450 ppm in 2050 would thus amount to EUR 225 per tCO_2-equivalent. In principle, this would correspond to the level of the carbon tax required. Ppm: parts per million.

Source: Based on Kuik et al., 2009.

A comprehensive analysis of the marginal costs corresponding to the 2DS established in a large number of different climate and energy models have obtained values for marginal abatement costs (MAC) for concentration targets of 450 and 500 ppm in 2025 and 2050 (see Table ES.1). These values imply a cost per tonne of CO_2 of at least USD 100 by 2025 and of at least USD 200 by 2050.

Air pollution

Air pollution constitutes the biggest uninternalised cost of electricity generation. According to the World Health Organization (WHO), it is the world's largest single environmental health risk. WHO studies from 2014 and 2016 find that in 2012 more than 7 million deaths were caused by air pollution (WHO, 2014a, 2014b and 2016). About 3 million deaths are due to outdoor air pollution, to which electricity is a significant contributor, and 4.3 million deaths are due to household air pollution. Even if air pollution is mainly an issue in developing countries, OECD countries are also affected. A recent study estimated the social welfare loss in OECD countries due to air pollution is far above one trillion USD, corresponding to about 3% of the gross domestic product (GDP) (OECD, 2016).

The most carefully studied sources of air pollution are particulate matter (PM) of different sizes, ground-level ozone (O_3), sulphur oxides (SO_x), nitrogen oxides (NO_x) and lead. These emissions arise during the combustion of fossil fuels, coal, oil, gas or biomass, and impact primarily the respiratory system leading to bad health (morbidity) or premature death (mortality). In both cases, large uncertainties remain. The 2012 meta-study by Burtraw, Krupnick and Sampson (2012) provides an overview of the results of four important studies that have been undertaken in the past 20 years (see Table ES.2).

Table ES.2: **Summary of estimates from four external cost studies**

(Mills* per kWh or USD per MWh)

	Coal	Peat	Oil	Gas	Nuclear	Biomass	Hydro	PV	Wind
ORNL/RFF	2.3	–	0.35-2.11	0.35	0.53	3	–	–	–
Rowe et al.	1.3-4.1	–	2.2	0.33	0.18	4.8	–	–	0.02
EC ExternE	27-202	27-67	40.3-148	13.4-53.8	3.4-9.4	0-67	0-13	8.1	0-3.4
NRC	2-126	–	–	0.01-5.78	–	–	–	–	–

* A mill is one-tenth of a cent or one-thousandth of a dollar; PV is photovoltaic.

Source: Burtraw et al., 2012.

While much remains to be said about uncertainties, population densities and wind dispersion modelling, existing work has led to some preliminary conclusions. Burtraw, Krupnick and Sampson have stated, for example, that:

> In general, the results in Table 1 [here Table ES.2] and from the literature support a rank order of fossil fuels wherein the coal fuel cycle is more damaging than the oil fuel cycle, which is more damaging than the natural gas fuel cycle. This difference would be magnified with consideration of climate change impacts… The nuclear fuel cycle has low external costs in general, although the remote probability of accidents adds a very high consequence factor into the estimates. Photovoltaics and wind are essentially emission-free energy sources at the use stage, but impacts over the life cycle occur. (Burtraw et al., 2012: pp. 13-14)

Table ES.2 does not include climate change impacts. Since fossil fuel combustion is the primary source of both GHG, and local and regional air pollution, there are obvious synergies between these two areas. While policies mitigating air pollution *can*, but do not necessarily, reduce GHG emissions, reducing GHG emissions always lowers air pollution.

The costs of major accidents

The reported number of damages – not necessarily the number of fatalities – caused by both natural catastrophes and human-made accidents has continuously increased in the last three decades. Many factors have contributed to this trend and have increased the vulnerability of societies to accidents and catastrophe hazards: growth of the population and the global economy, industrialisation, urbanisation and development of coastal and other risk-prone areas, as well as the growth of more complex and interrelated infrastructures. Better reporting may also have contributed to such vulnerability. Natural catastrophes impose the largest toll in terms of human fatalities and economic consequences. If only human-made accidents are considered, the energy sector is the second-largest contributor, with transportation causing about 60% of all mortalities (EC, 1995).

For all energy technologies, however, the external costs associated with severe accidents are several orders of magnitude lower than those caused during normal operation from pollution and carbon emissions. Risks of severe accidents in all energy chains should not be neglected, however, as they have the potential to cause large-scale and long-term impacts to human health, to the environment and to the whole of society. Severe accidents also tend to have broad media coverage and to attract the attention of the population and different stakeholders. Many studies have pointed out that such extensive media coverage may lead to an overestimation of the probability and of the perceived risk of severe accidents. The likelihood of deaths from widely reported disasters is thus perceived to be higher than that from events, which are less extensively reported in the media but have a higher mortality rate. Risk aversion also plays a role. Overall, additional scientific and economic research and more factual information on the impact of severe accidents should be undertaken and brought to the attention of the public and policy makers.

Land-use change and natural resource depletion

Different forms of electricity generation can have large and lasting impacts on the land they use, the availability of the resources they consume and the ecosystems they affect. While such impacts can be dramatic, the exact nature of land-use change is largely site- and technology-specific. Studying impacts on land-use change also poses a fundamental methodological challenge for full cost accounting: since most land is in fact privately traded, and public land falls under strict regulations in OECD countries.

The most significant external cost of land-use changes are the effects on the ecosystems of natural areas. Most electricity sources have significant land requirements when the whole fuel cycle is considered, including fuel extraction, generation and waste disposal. The fuel that has the highest land-use requirements is by far biomass.

Land use is part of the larger category of natural resource use, which includes water pollution and natural resource depletion. While the impact of power generation on water quality is limited outside mining, the depletion of non-renewable energy resources is frequently mentioned as an issue that deserves policy attention. Despite these concerns, the depletion of non-renewable resources, such as fossil fuels and uranium, should not be a major issue of consideration in policy making. As commodities with high private and little additional social value, oil, coal, gas and uranium are traded on large and liquid international markets, where information about long-term scarcity is widely known and would be priced in immediately if it ever became a genuine cause for concern. From a policy-making point of view, the best response to resource depletion concerns is to ensure that existing markets remain as open and competitive as possible and that information about resource availability is shared widely.

The security of energy and electricity supply

The continuous availability and affordability of energy and, in particular, electricity is an indispensable condition for modern societies. Unsurprisingly, governments of many countries are concerned with understanding the factors influencing the security of energy and electricity supplies and are seeking to develop policy frameworks and strategies to enhance them.

Discussions about energy supply security have for a long time lacked meaningful quantification. An indicator of the security of supply for OECD countries over 40 years was thus developed by the NEA – the simplified supply and demand index or SSDI (see Chapter 8 for further details). The SSDI shows a remarkable improvement of the security of energy supplies for the great majority of OECD countries over the 40-year time frame of the study.

The value of the SSDI significantly increased between 1970 and 2007 in most economies in the study: Australia, Canada, Finland, France, Japan, the Netherlands, Sweden, the United Kingdom and the United States. This improvement resulted from the introduction of nuclear power for electricity generation, decreasing energy intensity and increased diversification of imported fuels such as coal, oil and gas. In general, all low-carbon technologies such as nuclear energy, hydro, wind and solar possess a number of attractive characteristics in terms of external energy supply security. They differ, however, with respect to the contribution to the internal or technical security of supply, in particular in electricity systems. Governments should thus create frameworks that allow all low-carbon technologies to make their contribution to the security of energy supplies and work towards the full internalisation of system costs to further differentiate between dispatchable and non-dispatchable sources of low-carbon power.

Employment generated in the electricity sector

Since the employment required for different technologies in competitive labour markets is the result of competitive, firm cost minimisation, one might ask why employment should be considered as a positive externality. In addition to constituting an economic cost, it is because high employment rates can contribute to social cohesion and general well-being at the societal level. From this perspective, not only the quantity but also the quality of the labour that is required by different technologies should be taken into consideration. Other things being equal, the higher the qualifications of the workforce and the longer the duration of the employment contract, the greater are the positive externalities to social cohesion at the level of local, regional and national economies.

If operations and manufacturing are included, indications are that nuclear power is more labour-intensive than other forms of electricity generation. It also has higher education requirements than renewable electricity generators, which may relate positively to spillovers in terms of social cohesion and regional development. From available evidence, educational requirements (as well as salaries) appear to be higher in the NPP construction and operating sectors (although not as high as in the decommissioning and waste management sectors) than in onshore wind, and in both PV and concentrated solar power (CSP).

The impact of energy innovation on economic performance and growth

Technological change in the energy sector contributes to the macroeconomy in terms of i) value added, income and employment, ii) the functioning of the economy, firms and households that are dependent on cheap and reliable energy supply, iii) the waves of innovation and the spillovers that are generated on both the supply and demand sides,

which constitute the principal reason why governments fund basic research and development (R&D) in energy. Trends in R&D funding have changed remarkably. Since 2000, the public budget for R&D on renewables has been multiplied by five, and for energy efficiency by two. For nuclear energy, there has been a sharp decrease from about USD 8 billion per year in 1980, largely for fission, to less than 3 billion today, with fusion now taking the bigger part (EC, 2016a).

R&D funding is often most successful if combined with other instruments. In climate change policy, for instance, pollution pricing should be complemented with specific support for clean innovation (e.g. through additional R&D subsidies). Promising new clean technologies deserve the highest possible attention in terms of policy support, even if this would mean reducing R&D support targeted on improving existing dirty technologies. Policies should thus support a wide range of low-carbon technologies, as no one, single silver bullet exists. Innovation policies also need to be consistent over time by using a portfolio approach with a long-term perspective.

The policy implications of full cost accounting in the electricity sector

Production and consumption of electricity are not only a major economic issue but also a large contributor to adverse impacts on human health, longevity and the natural environment. Driven by this insight, applied economic research on external effects, externalities or social costs have frequently taken the electricity sector as a starting point. In the 1990s and early 2000s, a series of broad, well-funded studies with dozens of high-level experts from different fields took on the full costs of electricity. Many of the results produced from these studies remain relevant today. While estimates of social costs inevitably display large uncertainties, the studies converged in the identification of key problem areas. However, decision makers never properly implemented the policy conclusions from these studies. It appeared that converging results from several unbiased studies would have implied, at least in qualitative terms, much stronger action on air pollution and climate change than countries around the world were willing to contemplate.

Air pollution, climate change and system costs constitute the largest uninternalised costs

The different chapters in this report converge on one single insight: the external costs of the normal operations of electricity generation exceed the costs of other phases of the life cycle of electricity generation – upstream or downstream of operations – as well as the costs of major accidents by at least one order of magnitude. Mining and transport for the primary fuels of electricity generation (e.g. coal, oil, gas or uranium) do have social costs, but the latter are locally well circumscribed and pale when compared, for example, against the costs of air pollution. In terms of the back end of the life cycle, decommissioning and the storage of waste constitute significant costs for nuclear power indeed. However, these are economic costs, for which provisions exist to be internalised through the funds that are constituted by electricity producers and that are passed on in customer prices and tariffs.

Major accidents of energy structures, be they oil spills, gas pipeline explosions, dam breaks, mining disasters or nuclear accidents, dreadful as these may be for those concerned, are fortunately rare during the life cycle of all power generation technologies and thus do not figure heavily in the accounting of full costs. The problem for policy making is, of course, that such accidents receive an extraordinary amount of attention from the media and the general public. The greatest number of fatalities is recorded in coal mining and hydroelectricity, two technologies which do not generate widespread public concerns. Oil spills and nuclear accidents, in particular, receive an amount of

media and policy attention that is extraordinary compared to the damages and human casualties for which they are responsible.

Individual human suffering induced by any sort of accident or external effect, whether it captures public attention or not, cannot be reduced to statistics. Policy makers have the difficult task to balance both aspects, the legitimate public concern of the moment and the need for a longer-term structure of an energy system constituting the best available option to minimise accidents and hardship in a 360° perspective. The enormous impacts of air pollution and the greenhouse gas emissions associated with climate change, or even the multi-billion system costs of the variability of certain renewable technologies, have thus been unable to make an impact on public perceptions. Air pollution constitutes the biggest uninternalised cost of electricity generation. It is also an intensively studied area with stable research protocols, consistent methodologies and converging results. Worldwide, the deaths of 3 million people per year are attributed to ambient air pollution, of which power generation contributes a significant share.

The full costs of climate change come with high uncertainties but are routinely characterised by analysts to be in the trillions of US dollars or euros. Climate change action has a unique role in this context. Public awareness, media focus and political attention are intense, but have failed thus far to translate into effective GHG emission reductions. The under-reported subset of full costs constituted by system costs are also bound to increase further. Yet outside the circle of electricity market experts, the issue is virtually unknown.

Security of supply, employment effects and the impacts of technology innovation are rather technical issues. Contrary to system costs, however, they do possess their own, if rather limited, constituencies that ensure that they are taken into account at least in a partial, if imperfect internalisation process.

Policy makers must internalise full costs where it matters most

Public attention does not focus extensively on an issue such as air pollution, where a steady stress builds up over years to combine with genetic and other factors to cause respiratory illness and heart failure. The complexity and duration of the process makes covering, reporting, disseminating and absorbing the relevant information much more difficult.

In such cases, the public, the media and policy makers are prone to *attention bias*. An accident with 50 fatalities once every ten years will get infinitely more media and policy attention than 1 000 premature deaths coupled with increased morbidity in a large population because of a constant level of pollution over the same time span. While individual human suffering cannot be calculated and compared, dispassionate reflection with an aim to improve general welfare would suggest that the far larger number of casualties due to air pollution would demand at least as much attention as rare accidents. However, public opinion, social forces and political pressures have ensured that policy attention and resources disproportionately favour the latter.

It is the role of publications such as the present report to mitigate or to reverse attention bias. Once the relevant subsets of full costs receive appropriate attention from the public, the media and policy makers, the different manners to proceed towards internalisation can be better understood. Practical policy instruments that should be considered fall into three broad categories:

1. Price- and market-based measures such as taxes, prices, subsidies, the allocation of property rights and market creation.
2. Norms, standards and regulations, which are the default measure of policy making.

3. Information-based measures, including R&D support, are not minor add-ons but are at the heart of internalisation.

Whatever the chosen instrument, governments must be the primary driver behind implementation. When the lives of millions of people are at stake, governments have an obligation to put into place incentive structures that reduce transaction costs and enable new allocations that allow for large welfare improvements so as to address key issues such as air pollution.

In parallel, work on better information should be ongoing. It is vital that governments resuscitate the important debate and large-scale work on external effects in the energy sectors of the 1980s and 1990s. Measured against the scale of the externalities discussed, the required funds for research are negligible. At the same time, such work needs to be managed tightly and focus on key issues with a view to contributing to better policy making in the context of the energy transitions under way. Disseminating and synthesising knowledge on some of the most salient features of the full costs of electricity provision is key to arriving, through the progressive internalisation of social costs, at better policies and more sustainable electricity mixes.

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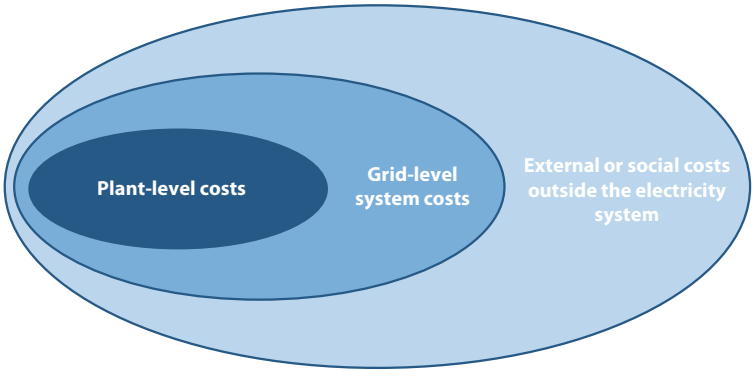
Chapter 1. **Full costs: Key concepts, measurement and internalisation**

1.1. Key concepts

Life and lifestyle in today's developed societies depend on the continuous supply of large amounts of affordable electricity. Private consumers or public entities will finance the cost of power generation that is composed of fixed costs such as the capital investments for power plants and grids, variable costs such as fuel, operations and maintenance, as well as the costs for transmission and distribution. Citizens and policy makers are, however, increasingly concerned about the impacts that are not captured in the straightforward financial plant-level costs of electricity generation. Those impacts include the costs that a given technology imposes on the electricity system as a whole as well as the impacts on the natural environment and the wider economy.

Such external costs beyond plant-level costs fall into two broad categories (Figure 1.1). The first category concerns the system costs at the level of the electricity system as it is linked through the electricity grid. They include the additional costs that plants impose on the system in terms of extending, reinforcing or connecting to the grid, but also the costs for additional reserves and cycling of dispatchable capacity when the output of some technologies, typically wind and solar photovoltaic (PV), is uncertain or variable. The second, even broader, category includes items that impact the well-being of individuals and communities outside the electricity sector. Such social costs include the impacts of local and regional air pollution, climate change, the costs of major, frequently not fully insurable, accidents, land use or resource depletion. They may also include the positive or negative impacts of different power technology choices on the security of energy and electricity supply, employment and regional cohesion or on innovation and economic development.

Figure 1.1: **Different cost categories composing the full costs of electricity provision**



Source: NEA, 2012b.

The full costs of energy provision include the totality of the three categories: commercial plant-level costs of generation, grid-level system costs and external and environmental costs (see Figure 1.1). In principle, an assessment of the full costs of energy provision would integrate these three categories over the whole life cycle of electricity, i.e. from fuel extraction and conditioning, over construction, operations, generation, transport and distribution to decommissioning and waste disposal. Practical considerations will, of course, put a limit to the complete representation of *all* costs and suggest a concentration on the most important cost categories.

As indicated in Figure 1.1, the full costs of electricity provision can be divided into plant-level costs, grid-level system costs and external or social costs [1] If not addressed by specific policy actions, such external costs will be produced at inefficiently high levels and be borne by the system or society as a whole rather than by those who generate them.

One should also note the specific nature of the three categories to the extent that the different phenomena that are included in them vary considerably in the firmness of their economic and financial evaluation. Plant-level costs are, of course, those costs that come most naturally to mind when thinking about the costs of electricity provision. The "bricks, mortar and steel" to build the plant, the fuel and the manpower to run it are easily comprehensible cost items. The Nuclear Energy Agency (NEA) and the International Energy Agency (IEA) publish a survey of the plant-level costs in OECD countries every five years in the *Projected Costs of Generating Electricity* (see IEA/NEA, 2010 and IEA/NEA, 2015; IEA/NEA, 2020 is currently in preparation). While concrete work reveals also a number of difficulties in assessing plant-level costs, e.g. which discount rate to use to reflect the cost of capital, at least the basic concepts are well understood. Plant-level costs of production are financial and economic realities that are straightforwardly monetised and integrated into the decision-making processes of private and public actors.

Things are slightly more complicated for grid-level system costs. In an interconnected electricity system, each plant interacts with all other plants, on both physical and economic levels. In addition, different plants impose different costs in terms of their connection or the distribution and transmission system. While such grid-level system costs have always existed, they have only gained widespread attention in recent years because of the integration of significant amounts of variable renewable energies (VREs). The latter have three major characteristics, which cause their grid-level system costs to be of a higher level of magnitude than those of other technologies. First, their dependence on locations with favourable meteorological conditions, in particular for wind, can place them far apart from urban and industrial load centres, thus increasing the costs for electricity transportation. Second, their limited predictability requires a greater share of dispatchable plants to provide reserves, i.e. to operate at less than full capacity, to be able to respond to sudden imbalances in the equilibrium between demand and supply. Third, their variability implies that the residual generation system needs to be maintained to ensure the security of supply during hours of low VRE generation. Dispatchable technologies such as nuclear, hydro, gas or coal have thus to stay in the market at a reduced number of hours of operation, which causes revenue shortfalls. In the absence of additional sources of revenue such as capacity payments, dispatchable technologies may leave the market, reducing the security of supply in the process.

1. To ensure readability and avoid economic jargon, this report employs the term social costs as a synonym for external costs. Strictly speaking, the latter correspond to marginal social costs, in which case total social costs would refer to the sum of private, market-based costs and external costs. Total social costs are identical with full costs. An analogous convention is applied to grid-level system costs. In the absence of any further qualification, grid-level system costs refer to the increased costs above plant-level costs. Total system costs instead refer to the sum of plant-level costs and grid-level system costs.

In principle, grid-level system costs are real economic costs that are directly reflected in the balance sheets of companies and system operators or in the monthly bills of electricity consumers. Formally, they could be defined as the total costs above plant-level costs to supply electricity at a given load and given level of security of supply. While grid-level system costs have always existed, they have gained dramatically in importance because of the deployment of significant amounts of VRE sources, such as wind and solar PV. This has spawned much new research and a lively discussion on their nature and extent. It is often difficult to allocate system costs with precision as they interact with virtually all parameters of the electricity system. For instance, is the decline in the share price of a traditional utility due to inefficient management, errors in the forecast of electricity demand or to the system effects induced by a myriad of decentralised wind and solar plants? There are also difficult distributional questions to be considered that are only now beginning to emerge. For instance, should the increased costs for connection, distribution and transportation be allocated to the plants that are directly or indirectly responsible for them, or should they be socialised through the network tariffs paid by consumers, independent of their origin? For these reasons, grid-level system costs, in particular the impacts of the variability of VREs, although very real for those concerned, are usually more difficult to assess than plant-level costs.

The third cost category that is included in the full costs of energy provision is at the conceptual level well established but is at the practical level the most difficult to assess with precision. These are the external or social costs that reflect the impacts of different energy technology choices on the environment, security of supply and other social issues. Such social costs have two characteristics, which seem distinct but are indeed the two sides of the same coin, once looked at from a structural or methodological point of view and once looked at from a policy-making perspective. Social costs arise where issues are too complex, too new or too indefinite in nature in order to be given a monetary value that would allow for market transactions. Economics has coined the notion of "transaction costs", which include the costs of generating, codifying and transmitting information, as a catch-all term for all the factors that are preventing decision making on the optimal level of a good, say the level of security of supply, by way of the price mechanism determined by the forces of supply and demand. In other words, without alternative forms of intervention, e.g. political decisions or the legal system, such external impacts will not be taken into account by producers and consumers with the result that positive externalities will be undersupplied and negative externalities oversupplied (see Section 1.3 for more details).

Social costs highlight the distinction between a form of welfare routinely measured in monetary units and a broader form of welfare including in some preliminary form also non-monetised impacts. The gross domestic product (GDP) is the classic metric measuring the value of the goods and services produced and consumed by the private and public sectors in monetary form. Typically, plant-level costs are part of GDP. Also grid-level system costs will eventually show up in the GDP although they will be borne by parties other than those who caused them. Social costs such as environmental externalities will not show up in GDP figures as they affect public rather than private goods supplied by the market. Employing the term "welfare" in a study about the full costs of electricity provision thus implies a notion of well-being that includes but goes beyond the monetised measurements of GDP. Quite obviously, such a broader notion of welfare, which includes public goods, does not allow for the construction of well-defined individual and social utility functions. If the latter are already difficult to determine for marketed goods, the intrinsic complexity of external costs prevents the establishment of social welfare functions adopting a broader notion of welfare.

The issue lends itself to interesting conceptual discussions which, however, ultimately have little practical bearing. To a large extent social costs are external, i.e. not internalised, precisely because no well-defined utility functions exist. At the same time, the standard environmental economics that originate with Pigou's work (1932) postulates

the necessity to identify, measure and internalise social costs and promotes the measurement of utility functions also for social costs. Discussion quickly shows that any framework based solely on static optimisation will run into internal contradictions. Social costs need to be approached in a dynamic perspective, in which decision makers advance from larger to smaller imperfections in a process of continuous learning about the impacts of social costs. It also means pragmatically basing decisions on a mix of information that is partly generated on the basis of market prices and partly by alternative methods employed to reveal social costs (see below).

If complexity is one characteristic of issues causing social costs or benefits, one-sidedness is another. A classic, technical externality arises if the action of one party, say a power plant with pollutant emissions, has an impact on the well-being of another party without this second party being able to communicate its reaction to the first party. This lack of reciprocity or feedback is the defining criterion of an external effect. Again, such feedback is prevented by transaction costs and requires intervention by third parties, such as governments, to internalise the issue. This is particularly relevant for externalities that affect a large number of people or result from a large number of sources such as atmospheric pollution or climate change. Dealing with the issue at a centralised level is in such cases more efficient than multilateral negotiations between all stakeholders. That said, markets in which a good or a service is fully defined achieve, through the price mechanisms, precisely such multilateral negotiations at very low transaction costs to arrive at optimal outcomes. The division of labour between governments and markets is thus a key issue in the internalisation of external effects.

Beyond the well-publicised and broadly discussed notion of environmental externalities, in particular to the extent that they relate to air pollution and climate change inducing GHG emissions, external effects or social costs may affect other areas. These can be as diverse as the impacts of a given form of electricity generation on the security of energy supply and on a country's strategic position, the costs of waste disposal or industrial accidents to the extent that costs are not included in end-user prices; the benefits of basic and applied research on different technologies or even the spillovers that the development of a given technology can have for economic development, industrial competitiveness or the trade balance. In this study, chapters on the security of supply, employment and the economy through dynamic technological spillovers all study how electricity provision impacts different public goods at the level of the economy. These impacts are absent in the decision-making processes of private actors. Political or regulatory authorities thus need to put in place complementary incentives to strive for overall welfare maximisation. This is why these economy-wide external effects are part of the full costs of electricity provision.

However, even a study on the full costs of electricity provision will not cover all aspects pertaining to electricity. In other words, even the most comprehensive category of external or social costs will be bounded. In addition, they are considered in this study with the help of a pragmatic partial equilibrium approach. The externalities of energy provision in different policy areas such as grid-level system costs, atmospheric pollution or climate change are thus considered one by one. Also the chapters considering economy-wide impacts ultimately pursue a partial equilibrium approach. The alternative of considering all impacts or a subset of them together with the help of a computable general equilibrium (CGE) models, economy-wide input-output models or macro-econometric model would have diminished the transparency and readability of its findings which are first and foremost addressed to policy makers. [2]

2. On the use of integrated macro-models models in climate and energy policy see Pollitt and Mercure (2015), Berg et al. (2015) or Jackson et al. (2015).

This study takes a similarly pragmatic approach to questions regarding competition and regulation in electricity markets. Social costs are external costs imposed on society per MWh of electricity. They can thus arise in all forms of electricity markets, whether they are rate-regulated or liberalised with marginal cost pricing, whether monopoly power exists or not. For institutional reasons, regulated markets may in some instances have an advantage in terms of being able to *implicitly* internalise social costs in their rate-making decisions, while deregulated markets need to resort to the *explicit* pricing of externalities. The latter may in some cases be politically more difficult to achieve; however, the fundamental problem of identifying, measuring and internalising external costs applies equally in both regulated and deregulated markets.

Accounting for full costs based on the measurement of external costs is not uncontroversial. The monetisation of social costs outside a market framework can be misunderstood as a fanatical attempt to reduce all aspects of human well-being to a question of dollars and cents. The large uncertainties involved, which can produce results that change considerably over time or between comparable projects, are also an easy target for detractors. Others have pointed out that certain impacts such as social factors will remain out of scope even in very comprehensive efforts.

Most of these criticisms are based on a misunderstanding of what full cost accounting is trying to achieve. Estimates established for the social cost portion of the full costs of electricity provision will never be able to mimic the reliable information about individual and social preferences conveyed by market prices. Its objective is to provide order-of-magnitude estimates that allow public discussion and policy making to integrate the most pressing issues in a meaningful way into the inevitable trade-offs that characterise all policy making. In doing so, full cost accounting inevitably mixes hard market data, reasonably reliable and less reliable estimates even when undertaken by well-intentioned and experienced practitioners that might best be thought of as intelligent and informed guesswork.

Reports such as this one also inevitably associate a certain level of social costs due to, say, air pollution or the impacts of a major accident, with a representative technology. It is quite obvious that the presence or absence, as the case may be, of specific pollution control equipment or certain physical barriers could reduce or increase such impacts. In those cases, pragmatic good judgement needs to be applied to the decision on which reference technology to use. This is one of the reasons why this report is organised according to subject areas rather than according to technologies. The point is not to establish rankings but to draw attention to understudied issues which require better internalisation into the policy process.

Does this mean than any number is not better than no number, as it is sometimes advanced? Certainly not. However for policy-making purposes, a number advanced by a responsible researcher on the basis of the best available information with the appropriate sources, uncertainties and *caveats* is much better than no number, despite the uncertainties and the *caveats*. The purpose of full cost accounting is not engaging in economic imperialism, nor is it establishing futile oppositions between market prices and social costs. Its sole purpose is to allow for better policy making in the electricity sector.

Looking at full costs in the energy sector: The role of the Nuclear Energy Agency

Historically, energy and, in particular, electricity production have frequently been at the heart of concerns about external costs. As a large, frequently centralised activity producing an output that is fundamentally important to human well-being, industrial development and economic growth, electricity production is also the most broadly studied sector in this respect. From acid rain and tanker spills to cancer scares from electric power lines, respiratory diseases due to coal-fired power generation, gas supply crunches and the fear of nuclear accidents – all through the energy cycle the energy

sector is faced with impacts it never intended to create and for which it is nevertheless increasingly held accountable.

In the energy field, the electricity sector has always played a particularly important role because of concerns about air pollution and climate change, both resulting from fossil fuel combustion during electric power generation. The risks stemming from nuclear accidents and the disposal of spent nuclear fuel have also always loomed large in public perception. Traditionally, concerns about social costs have focused on electricity production at the plant level. In recent years, however, the advent of significant amounts of wind and solar PV capacity has required, for the reasons explained above, a shift from a plant-level perspective to a systems perspective. Consistent with a general shift of focus in the energy sector, this is also why the present effort aims at providing a policy-relevant synthesis of the full costs of electricity provision at the level of the consumer rather than just at the level of the costs of electricity generation at the individual plant.

Box 1.1: **Energy-related externalities and the lack of feedback mechanisms**

Imagine the simplified example of a coal-fired power plant. Its input (coal) and its marketed output (electricity) are paid for in monetary units. Buyers and sellers, producers and consumers, all have their say through the market mechanism. As long as markets are competitive, the quantities that are produced and the prices that are paid for them will be exactly at the optimal level. This is different for the outputs that are not accounted for in monetary terms. Particulate matter, sulphur dioxide, carbon monoxide, nitrogen oxides and, in particular large quantities of carbon dioxide all impact the well-being of individuals and social groups through decreased air quality, acid rain, diminished health, shorter lives and increased climate risks.

Yet those individuals or social groups have little possibility to express their dissatisfaction effectively in order to trigger pressure for reducing those impacts either by way of technical change (scrubbers, filters, capture, higher thermal efficiencies, etc.) or by way of output reductions (less electricity from coal-fired power plants). The emitter, the coal-fired power plant, will thus continue production at full throttle and without any emission abatement. This lack of any feedback mechanism is the defining hallmark of an externality causing social rather than private, market-based costs. Markets for private goods establish bilateral links that allow for optimising trade-offs. If an individual wants to have less electricity, he or she will stop buying it. If the same individual would like to have less particulate matter emitted, there exists no possibility to ensure that this wish is being heard. In the famous words of Kenneth Arrow (1970), "externalities are goods for which no markets exist".

Economic theory proposes instruments that establish feedback mechanisms either by creating markets or by substituting for them. Such alternative economic measures, for instance taxes, subsidies or standards, would *internalise* the externality in question and ensure a level of pollution that balances economic and public health impacts. Such feedback mechanisms do need not to be constituted by direct government interventions. For instance, an obligation for the top managers of a plant to live in a 5 km radius of the plant could constitute an effective means of internalisation. In particular Ronald Coase (1960) developed a framework that allows thinking about internalisation in a creative manner. The key principle is always that those determining the level of pollution or of risk must be exposed directly or indirectly to the impacts they cause. In this manner, they will proceed to integrate harmful or unwanted side-effects into the full costs of producing and providing electricity, energy or any other marketable commodity.

For a number of years, the NEA has been following, analysing and researching different aspects of the full costs of electricity provision. The result of this work has found its expression in a number of publications that have already appeared or are under way. A number of these publications centred on nuclear energy, others however also included different sources of electric power generation. They include:

- *Risks and Benefits of Nuclear Energy* (2007).
- *Comparing Nuclear Accident Risks with Those from Other Energy Sources* (2010a).

- *The Security of Energy Supply and the Contribution of Nuclear Energy* (2010b).
- *Projected Costs of Generating Electricity: 2010 Update* (IEA/NEA, 2010).
- *The Economics of Long-term Operations of Nuclear Power Plants* (2012a).
- *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems* (2012b).
- *The Economics of the Back end of the Nuclear Fuel Cycle* (2013).
- *Projected Costs of Generating Electricity: 2015 Update* (IEA/NEA, 2015.
- *Nuclear Energy: Combating Climate Change* (2015).
- *Costs of Decommissioning Nuclear Power Plants* (2016).

The NEA is currently also working on a number of publications that are relevant to the discussion on full costs and will be forthcoming in the coming months. These include *Climate Change: Assessment of the Vulnerability of Nuclear Power Plants and Adaptation Costs*, *Estimation of Potential Losses Due to Nuclear Accidents*, *Measuring Employment Generated by the Nuclear Power Sector* and *System Costs in Deep Decarbonisation Scenarios: The Contributions of Nuclear Energy and Renewables*.

There also exist a significant number of studies published by other institutions that contain substantive work on the full costs of electricity. Both the OECD Environment Directorate (ENV) and the IEA have previously worked on external costs (see Chapter 5 for a detailed bibliography). Over the past 20 years, the European Commission (EC ExternE up to 2005, and the New Energy Externalities Developments for Sustainability, the NEEDS studies, between 2004 and 2008) and the Paul Scherrer Institute (PSI, Switzerland) have been among the most active institutions in the field of externality measurement and are important sources of information and methodological competence. More recently, the European Commission ordered a study on energy costs and subsidies in the Union that provide some additional insight on methodology and data for 28 European countries (Ecofys, 2014). However, energy externalities are far from being an exclusively European concern. Relevant work has also been performed both in Japan and in the United States.

There exists also a rich academic literature on the external costs of energy. However this literature had its high point during the 1990s and has since lost some of its dynamism. In addition, many of its conclusions were quite location-specific or tied to specific technical assumptions, which limited their policy relevance. Recent exceptions are constituted by the work of the World Health Organization (WHO, 2016), the OECD Environment Directorate (OECD, 2016) and the IEA (2016). All three deal with outdoor air pollution due to fossil fuel combustion and focus on policy-relevant, global headline figures. The WHO report, for instance, states: "Air pollution represents the biggest environmental risk to health. In 2012, one out of every nine deaths was the result of air pollution-related conditions. Of those deaths, around 3 million are attributable solely to ambient (outdoor) air pollution" (WHO, 2016: p. 15).

The OECD report, which constitutes a prospective modelling effort, estimates that the number of annual premature deaths due to ambient air pollution could be six to nine million by the year 2060. The IEA report provides some factual information on emissions from power generation in OECD countries. While valuable, these efforts remain limited to the issue of air pollution. The objective of this study on *The Full Costs of Electricity Provision* is to synthesise and to broaden these attempts by including most or all policy-relevant categories of social costs linked to the production, transformation and consumption of energy in a manner that is sound, concise and policy-relevant.

This study is structured by cost categories rather than by energy sources. The purpose is thus not to identify the generation technology with the overall lowest full costs. That will depend in many instances on local and regional circumstances as well as the structure of the generation mix and patterns of electricity demand. In addition, subjective, cultural, societal and political factors inevitably come into play as soon as one moves away from costs based on the indisputable interpersonal consensus established in

competitive markets and expressed in market prices. As indicated above, by definition, there exist no market prices for external social costs.

Despite these obvious methodological limitations, economic policy making is obliged to take into account the impacts on human well-being that go beyond what markets are capable of valuing. Air pollution, the risks associated with climate change and system costs are the most important issues in this context. This report aims precisely at providing policy makers with key facts, both in monetised and non-monetised forms, about the external costs of energy provision in the most relevant cost categories.

The next sections will begin with introducing the main conceptual and methodological issues surrounding both grid-level system costs and external social costs. A summary of recent quantitative research on grid-level system costs will also be contained in relevant topical chapters, but the specific methodological issues concerning system costs are best appreciated in the context of this introductory chapter and in confrontation with traditional notions of external costs. Subsequently, each cost category will be dealt with in a dedicated chapter, before a policy-oriented conclusion will round out the report.

1.2. Assessing and internalising grid-level system costs [3]

The subset of costs that are external to the perimeter of the single plant but that are still mediated by the electricity grid are referred to as grid-level system costs. Such system costs reflect the fact that power plants do not exist in isolation but that they interact with each other and their customers through the electricity grid. This means that electricity provision generates costs beyond the perimeter of the individual plant or the individual consumer, even without taking into account impacts on the wider natural, economic and social environment. Such system effects can take the form of variability, network congestion or greater grid instability. Accounting for such system costs can make significant differences to the private, market-based and social costs of different power generation technologies.

While such grid-level system costs have always existed in unbundled electricity systems, the topic has assumed a growing relevance in the recent years with the deployment of VREs, such as wind and solar PV in the electricity systems of OECD countries. The integration of VREs profoundly affects the structure, financing and operational mode of electricity systems in both the short and long terms. The three most significant effects are the increased costs for providing the residual load, for short-term balancing and for the extension and reinforcement of the transmission and distribution grids. This is due to three characteristics that are by and large unique to VREs such as wind and solar PV:

1. Their output is variable. This means that during hours when the wind is not blowing and the sun is not shining dispatchable capacity that is otherwise idle needs to be available in sufficient quantities. This causes a reduction in the load factors of dispatchable generation plants and a shift towards technologies with lower capital costs and higher variable costs, which increases the costs of the overall system. This effect is referred to as utilisation costs or profile costs. It is usually the most costly system effect of VREs.

3. This section has drawn on material provided in *Nuclear Energy and Renewables: System Costs in Decarbonising Electricity Systems* (NEA, 2012b).

2. Their output is difficult to predict. This means that in order to balance demand and supply at all moments the electricity systems needs to provide greater amounts of operational reserves, also referred to as spinning reserves. The latter consist of generators that are operating below capacity or are on stand-by to be able to ramp up quickly but which do not inject electricity into the grid.
3. Wind and solar plants are built where the wind blows, e.g. offshore or on the coast, and the sun shines, and not where the centres of demand are. This increases demands on the transmission system. Distributed resources such as solar PV also require stronger and more expensive distribution systems.

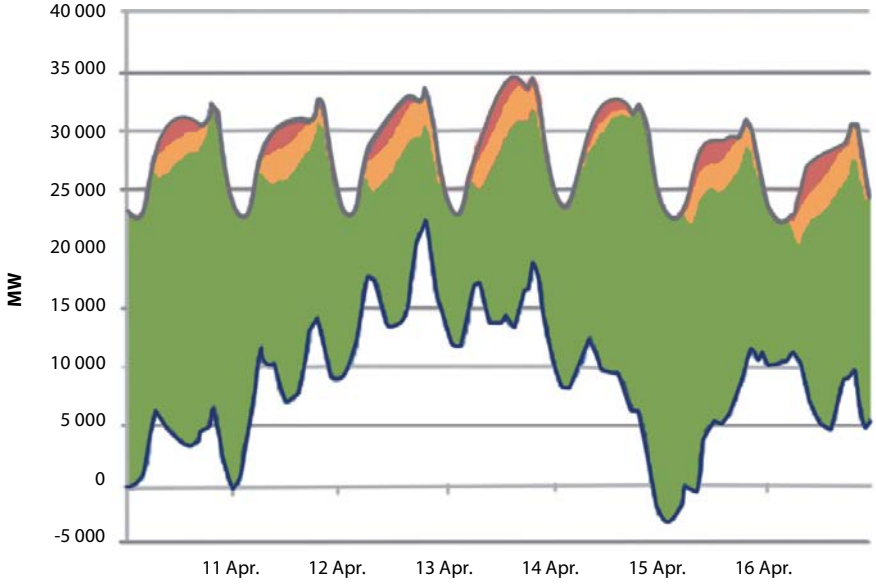
The magnitude of all system effects depends strongly on local conditions, the outlay of the existing grid as well as the overall structure of the energy mix and the demand for electricity. However the grid-level system costs of VREs such as wind and solar PV, contrary to those of dispatchable generation, will increase significantly with their overall share. This effect, combined with the forecasted increase in the share of VRE, means that system costs are therefore likely to increase considerably in the years to come, as long as no new, cheap solutions for flexibility provision in the form of storage or demand response are found. For instance, the IEA's *World Energy Outlook 2016* (WEO) indicates in its central New Policy Scenario an increase in the share of wind power in the electricity generation of OECD countries from 4% in 2014 to 14% in 2040. The increase for solar PV would be from 1% in 2014 to 6% in 2040. In order to limit the rise in global mean temperatures to 2°C, the WEO Scenario forecasts an increase of the wind and solar PV power to 23% and 9% of electricity generation (450 ppm scenario).

The most important contribution to system costs comes from the variability of wind and solar PV which induces a significant change in the structure of the conventional generation mix, with a larger overall capacity needed and a shift from baseload technologies towards more expensive peakers and mid-load capacity. While the diversification of renewable supply, interconnections with adjacent regions, storage and demand management can all play helpful roles in mitigating variability, the most cost-efficient solution at least in the medium term remains the use of dispatchable capacity, i.e. nuclear, coal, gas, hydro and biomass, for electricity generation.

Figure 1.2 shows the impact of VRE variability on the residual load and hence on dispatchable power plants. A modelling effort by GE Energy for the US Department of Energy shows the impact of a 35% share of renewable energy (wind in green, concentrated solar power in orange and photovoltaics in red) in the WestConnect area in the Western United States, which comprises Arizona, Colorado, Nevada, New Mexico and Wyoming. In a week mimicking the most volatile meteorological conditions of the past three years, the net demand for dispatchable capacity, the blue line above the white area, varies between -3 GW to more than 20 GW, while the total demand, the upper line of the graph, varies between 22 GW and 35 GW. The variations in net demand are clearly larger and less predictable than those in total demand.

The production of electricity from variable renewables thus significantly affects the economics of dispatchable power generation technologies. In the short run, with the structure of the existing power generation mix remaining unchanged, dispatchable technologies, such as nuclear, coal, gas or hydro, will have to cope with lower average electricity prices and reduced load factors. Thanks to their relatively low variable costs, existing nuclear power plants will usually do better than gas and coal plants. In the long run, however, high fixed cost technologies such as nuclear will be affected disproportionately by the increased difficulties in financing further investments in volatile low-price environments. The precise outcome of these competing factors will depend on the amount of variable renewables being introduced, the level of carbon prices as well as local conditions such as the availability of hydroelectric resources, interconnections or storage.

Figure 1.2: **An example of the impact of VRE production on the residual load of dispatchable producers**



Note: The figure shows the total load curve in MW (upper blue line) including the contribution of solar PV (mauve area), the contribution of concentrated solar power (CSP, pink area) and the contribution of wind power (green area). The lower blue line shows the residual load that needs to be covered by conventional power producers (white area).

Source: USDOE/NREL and GE Energy, 2010.

All power generation technologies cause system effects. By virtue of being connected to the same physical grid and delivering into the same market, they exert impacts on each other as well as on their load available to satisfy demand at any given time. The interdependencies are heightened by the fact that currently only small amounts of cost-efficient electricity storage are available. For example, the system effects of nuclear power relate to its large size, to its specific siting requirements as well as to the conditions that it poses for the outlay and technical characteristics of the surrounding grid. The comparatively large size of nuclear power plants requires increasing the amount of available reserves to offset, according to the N-1 criterion, the risk of a frequency drop in the case that a nuclear plant would trip. These nuclear system costs are real and were estimated as being in the range of USD 2 to 3 per MWh, slightly above those of other dispatchable technologies. Variable renewables such as wind and solar, however, generate system effects that are, according to the results reported in Chapter 3, at least an order of magnitude greater than those caused by dispatchable technologies.

Grid-level system costs resulting from limited predictability, variability and spatial dispersion of VRE already today constitute significant monetary costs for different economic actors. They are incurred in the form of present outlays or future liabilities of producers, consumers, taxpayers or transmission grid operators. Related to grid-level system costs, but not precisely of the same kind, are the pecuniary and dynamic effects of variable renewables. These are difficult to conceptualise in standard economic terms as they do not constitute externalities in the traditional sense of the term and are difficult to measure at the current state of research. However, they may well constitute the impacts most acutely felt by electricity producers and may in the long run have the most profound effect on the operations and structure of electricity markets. The four principal effects falling into this category are:

a) Lower and more volatile electricity prices in wholesale markets due to the influx of variable renewables with low-marginal costs.

b) The reduction of the load factors of dispatchable power generators (compression effect) as low-marginal cost renewables are prioritised in power markets over dispatchable supply because of regulation or more favourable marginal costs.

c) The de-optimisation of the generation mix, coupled with the influx of VRE with out-of-market finance, creates a wedge between electricity generating costs and market prices, thus impeding long-term investment based on market prices.

d) The auto-correlation of electricity production from VRE during a comparatively small number of hours coupled with out-of-market finance further distorts economic incentives as less and less value is created for any additional MW of VRE.

The impacts on prices and profitability can be quite large. Table 1.1 provides a first indication of the losses in load factors. It shows that those most heavily affected in the short run are the technologies with the highest variable costs, which are hit hard by the unavoidable decline in electricity prices due to the influx of 10% or 30% of electricity with zero marginal cost that will push the supply curve towards the right. In the long run (not included in Table 1.1), the situation changes as high fixed cost technologies will leave the market because of reduced numbers of full load hours. While average electricity prices will tend to remain stable as low variable cost baseload providers will leave the market, their volatility will increase strongly.

Table 1.1: **Losses of dispatchable operators due to the influx of wind and solar**

		10% penetration level		30% penetration level	
		Wind	Solar	Wind	Solar
Load losses	Gas turbine (OCGT)	-54%	-40%	-87%	-51%
	Gas turbine (CCGT)	-34%	-26%	-71%	-43%
	Coal	-27%	-28%	-62%	-44%
	Nuclear	-4%	-5%	-20%	-23%
Profitability losses	Gas turbine (OCGT)	-54%	-40%	-87%	-51%
	Gas turbine (CCGT)	-42%	-31%	-79%	-46%
	Coal	-35%	-30%	-69%	-46%
	Nuclear	-24%	-23%	-55%	-39%
Electricity price variation		-14%	-13%	-33%	-23%

Source: NEA, 2012b.

The variability of wind and solar also demands providers of dispatchable generation, nuclear, coal, gas, hydro or biomass, to vary substantial portions of their load in short time frames. The ability to follow load is thus an increasingly important criterion to choose between different backup technologies, in particular dispatchable low-carbon technologies. Most plants prefer to operate at stable levels close to full capacity in order to supply baseload electricity. This is not only the simplest operational mode but also economically the most advantageous as long as prices are stable and cover average costs. It is thus the operational mode that is preferred in most OECD countries. VREs force dispatchable producers into a less profitable and technically more demanding mode of production with numerous, steep up- and down-ramps throughout the year.

Grid-level system costs, at least at a level that makes them a policy-relevant issue, are a relatively new phenomenon. Research is still ongoing. Current results and even methodologies are thus likely to be refined in the future.

Do grid-level system effects always constitute welfare-relevant economic externalities?

Grid-level system costs constitute real monetary costs today. They are incurred now as present and future liabilities by producers of existing generation assets, taxpayers and electricity consumers. Some of these costs are increasing the overall cost of the electricity system and thus constitute unaccounted for social or external costs in the sense discussed above. Some system effects, however, correspond to rearranging monetary transfer payments between different constituents of the electricity systems. For instance, the decline in electricity prices that is triggered by wind and solar PV production with low variable costs implies a cost to producers, in particular producers of electricity with conventional, dispatchable assets. At the same time, it constitutes a benefit for consumers.

From the point of view of general economic welfare, having the energy transition financed by the shareholders of incumbent utilities is a problem only if this readjustment leads to inefficiencies and suboptimal economic outcomes at the overall level. By and large, withdrawing dispatchable assets that are no longer profitable owing to VRE production benefiting from out-of-market financing is unlikely to constitute a socially optimal outcome. Proponents of such policies, however, argue that the dynamic effects in the very long run, most notably cost reductions for wind turbines and solar panels, outweigh any concerns about adjustment costs in the short run.

Such distributional considerations are even more necessary during times of rapid dynamic change, where events can be considered very differently depending on the point of view. The financial decline of traditional utilities due to the influx of VREs with out-of-market finance is a case in point. This massive new phenomenon allows different readings. From one perspective, the sudden depreciation of the value of existing assets due to the political decision to introduce subsidised VRE may be considered a form of expropriation. From another perspective, the very same process may be considered a welcome manifestation of the necessary "creative destruction" during the transition towards a new energy system based largely on VREs. The real transfer of income and wealth from conventional producers whose only revenues are market prices on the one hand and consumers as well as producers with assets benefiting from out-of-market finance in the form of feed-in tariffs (FITs) can thus be interpreted very differently depending on the normative reference framework of the observer.

In order to allow a better conceptualisation of such issues, economists, following Scitovsky (1954), have introduced the distinction between technical and pecuniary external effects. Technical externalities are the classic external or social costs already identified by Pigou (1932), which, if not internalised, will lead to suboptimal outcomes for society as a whole. This is, for instance, the case of environmental externalities, where pollution or ecosystem destruction results from the inability of the affected party to make its voice count. Next to negative environmental externalities, the most significant in economic terms are positive network externalities. Connecting an individual consumer to a power plant would be prohibitively expensive. However, each additional customer in the area reduces the average cost for all involved since the cost for connecting the additional customer is small. The physical link through the grid not only links customers to a producer but also links all producers with one another. This is why in the electricity system changes in the level of production of one company immediately have impacts on the production and profitability of another company.

Other than in electricity, network externalities are important in the information and communications industry. They need not necessarily be mediated by a physical grid. The adoption of particular software, the "buzz" created by viral marketing around a particular product, the positive spillovers of a company's research and development (R&D) spending or a "cluster" of like-minded researchers pushing each other are all examples where positive externalities ensure that the final result is greater than the sum of the individual contributions. Whether negative or positive, technical externalities lead to suboptimal situations as their unconstrained production is either too high or too low. When VREs

increase the cost of the total system, even in a long-term equilibrium perspective when all actors have optimally adjusted, they impose such technical externalities or social costs through increased balancing costs, more costly transport and distribution networks and the need for more costly residual systems to provide security of supply around the clock.

From the point of view of economic theory, VREs should be taxed for these surplus costs in order to achieve their economically optimal deployment. There is an interesting technical side-argument here regarding the de-optimisation of the residual system. If VREs had to earn their revenue on the market rather than receive fixed remuneration, the revenue they would earn would be lower than the average of all the prices during the 8 760 hours of the year. This is because VRE production is self-correlated and concentrated during a limited number of hours of the year during which processes are particularly low, precisely because of high VRE production. Since this effect is precisely proportional to the variability of the VREs, the negative externality of system de-optimisation would, in fact, be directly internalised through the price system (see NEA, 2012a). However, as long as VRE receive fixed FITs, which protect them against this effect, the system de-optimisation due to over-deployment of VREs, from the point of view of economic efficiency, continues to impose an uninternalised social cost or "technical externality" on the electricity system.

Pecuniary externalities are of a different kind. While they can impose highly unwelcome impacts on certain parties, e.g. traditional utilities, which may raise issues from a distributional or political point of view, they do not as such constitute social costs and rationales for public intervention. They are thus of a different nature from technical externalities, which are usually implied when the term externality is used. This is due to the fact that pecuniary externalities operate through the price mechanism, which implies reciprocity. For instance, the entry of a new, lower-cost power producer into the market will reduce electricity prices and profits for incumbent producers. Pecuniary externalities thus have very real effects on the well-being of other parties. Nevertheless, they do not constitute an economic inefficiency per se but are part of the usual dynamic adjustments in a market economy. As mentioned above, the price mechanism allows a reaction by the affected parties and thus avoids the absence of a possibility to respond to a one-side impact that is typical for external or social costs. Taking the example described above, the deployment of a same amount of VRE on a pure market basis would impose the same revenue shortfall to incumbent power generation, but in this case, this would constitute a pecuniary externality and not constitute an economic inefficiency.

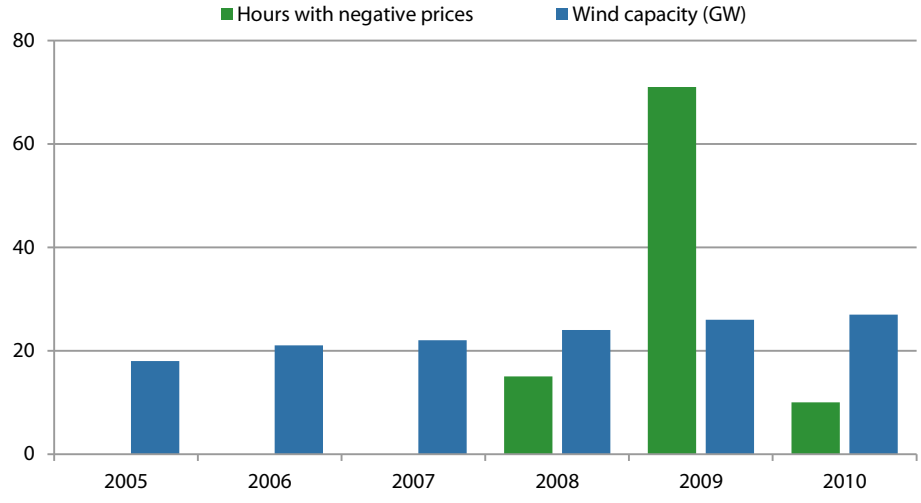
The conceptual problem in the present context of energy transitions towards low-carbon electricity systems is, of course, that technical and pecuniary externalities are mixed. While subsidies for low-carbon technologies in order to internalise the externality of climate change can be justified from an economic point of view, doing so in a manner that is not attaining reduction objectives at least cost constitutes a waste of social resources. The fact that subsidies for VRE are attributed on the basis of a large political and societal consensus does not invalidate the fact that this is a highly inefficient, at times even counter-productive, manner from an economic point of view. Even democratically legitimated policies can be economically costly.

In addition, pecuniary externalities may themselves generate technical externalities when dynamic changes, if not sufficiently quickly attended to, may bring unwelcome side-effects. The decline of traditional utilities based on dispatchable generation assets can thus degrade the security of electricity supply. Of course, countervailing measures such as capacity mechanisms or long-term support for dispatchable assets, in particular if they are low-carbon such as hydro or nuclear, can internalise any newly arising external effects.

A particularly striking example of this interaction of technical and pecuniary externalities is constituted by the negative electricity prices observed in several European countries, in particular Germany, following the introduction of large amounts of VRE.

It does not require elaborate economic theory to show that negative prices constitute a commercially very awkward reality. This holds, in particular, for baseload producers such as nuclear which rely on high load factors and predictable prices in order to recoup their high fixed costs. Figure 1.3 shows the emergence of the phenomenon of negative prices following the requirement that all output of wind and solar PV installations had to be sold through the wholesale market in 2009. The decline in negative hours between 2009 and 2010 is due to improvements in the accuracy of weather forecasts as well as the practice of load-following by operators, including the operators of nuclear power plants, introduced to soften the price impacts of sudden surges in wind and solar power.

Figure 1.3: **Wind power and negative prices on the German electricity wholesale market**



Source: EPEX Spot (www.epexspot.com).

The counter-intuitive phenomenon of negative prices in the electricity markets of OECD countries with significant amounts of variable renewables is not a uniquely German or European phenomenon. The Canadian province of Ontario thus disbursed CAD 35 million in the first six months of 2011 for the right to export electricity produced in Ontario to Quebec or the United States during the 95 hours when prices were negative (Enerpresse, 2011). In Southern California, the annual distribution of electricity prices also contains a substantial tail with negative prices (Forsberg, 2012: p. 12). Other things equal, zero or negative prices will become more commonplace as larger VRE capacities are being installed. However, in parallel, electricity system managers and flexibility providers, whether in the form of demand response, storage, curtailment or dispatchable backup power, are becoming more adept at managing variability. The final outcome will thus depend on a kind of race between VRE deployment and efforts to render the system more flexible.

However, not even in the extreme circumstance of negative electricity prices is it entirely clear whether this is exclusively a negative externality due to VREs with zero variable cost or a natural economic phenomenon due to the inflexibility of existing operators, who prefer to pay their customers to take off load rather than to engage in costly ramping. Again, as long as VREs are financed out of the market, the establishment of a normative reference framework that would allow distinguishing between welfare-relevant technical externalities and acceptable pecuniary externalities is impossible.

Overall, the introduction of significant amounts of VRE has set into motion several important structural changes. While some inefficiencies, e.g. the insulation of VREs from the market prices that they themselves influence heavily, can be clearly indicated, others are more difficult to assess. Chapter 3 nevertheless provides a first estimate of those grid-level costs that, under the current circumstances, do constitute welfare-relevant externalities and must thus be counted towards the full costs of energy provision. In addition, pecuniary effects are listed for information but the two categories are being reported separated.

Internalising grid-level system effects

Not all forms of support for low-carbon electricity will lead to suboptimal economic configurations. The original idea behind the support for renewables energies, for instance, was motivated by justifiable public policy objectives such as the reduction of climate change-inducing GHG emissions and the support for domestically produced rather than imported forms of energy. In other words, the objective was to internalise the perceived external costs of climate change and import dependence. However, the intellectually coherent manner to proceed towards this internalisation would have been to tax the externality itself, i.e. to impose taxes on GHG emissions and the use of imported fuels, rather than to impose certain technologies on the market. Guaranteeing long-term revenues to VREs only, whether through feed-in tariffs or other instruments, is thus at the origin of the technical and pecuniary externalities that are created by the variability of wind and solar PV.

Feed-in tariffs also drive a wedge between the wholesale market price and the price paid by consumers through higher payments to the network operators who recuperate the cost of the feed-in tariffs. This reduces the profitability of alternative means of electricity production, which nevertheless remain indispensable to ensure the security of supply and thus will require additional revenues through capacity mechanisms. Independently of social preferences for one technology over another, the current trend of superposing market outcomes with different layers of policy instruments to achieve certain outcomes poses serious questions concerning the transparency and ultimately the sustainability of electricity sectors in OECD countries. Currently, dispatchable producers that are exposed to lower wholesale electricity prices and reduced load factors resulting from the influx of large amounts of VRE are expected to provide the backup for variable renewables to cover demand when the latter are unavailable. This service is costly but currently not remunerated. At low levels, such implicit redistributions can be borne by the system. However, the increasing magnitude of grid-level system costs requires: i) fair and transparent allocation mechanisms to maintain economically sustainable electricity markets; and ii) new regulatory frameworks to ensure that balancing and long-term capacity provision can be provided at least cost.

The introduction of large amounts of variable renewables creates in many ways a radically new situation in electricity wholesale markets that requires rapid adaptation from all actors. This requires the creation of new and innovative institutional, regulatory and financial frameworks that allow the adequate remuneration of system and flexibility services, which include short-term balancing services as well as the provision of sufficient amounts of dispatchable long-term capacity.

There are essentially four dimensions, in which one may consider providing the necessary services to ensure the balance between demand and supply in electricity systems with a significant share of VRE and to minimise the grid-level system costs they generate:

1. short-term spinning reserves and long-term capacity provided by dispatchable power generators such as nuclear, coal or gas;

2. the extension of market interconnections to smooth demand and supply imbalances over larger areas;
3. storage in order to have short-term power reserves available in time of need;
4. demand-side management (DSM) to curb demand in case of supply shortfalls.

A crucial question in this context is who will bear the costs of these flexibility measures. Full internalisation supposes that VREs would bear these costs. This would actually be the case if out-of-market financing was abolished and VREs had to sell their production at market prices. VRE producers would then invest themselves in flexibility measures up to the point where smoother production profiles would produce a higher system value of their output and command better prices.

So far, however, explicit and implicit distributional arrangements allocate the cost of VRE integration to all electricity customers, regardless of whether the origin of their electricity comes from VREs or dispatchable sources. Of particular importance in this context are capacity mechanisms remunerating dispatchable capacity for its availability in time of need. The decline in prices, revenues and profits of dispatchable technologies requires that a portion of their revenues be derived from other sources if they are to stay in the market to provide the necessary backup services. There exist two major forms in which such additional revenue generation could be provided:

1. Capacity payments or markets with capacity obligations, in which variable producers are obliged to acquire the adequacy services from dispatchable providers, which thus would earn additional revenue.
2. Long-term fixed-price contracts attributed by governments (perhaps through auction mechanisms) either for guaranteed amounts of output from dispatchable plants or for their round-the-clock availability.

Governments and regulators in OECD countries have started the necessary processes of education, consultation and consistent policy formulation facilitating the introduction of such mechanisms. This is not an easy task. However, given their magnitude, technical and pecuniary system costs can no longer be borne in a diffuse and unacknowledged manner by operators of dispatchable technologies. The inclusion of grid-level system costs in the assessment of generating costs to prepare choices on different technology options is vital for informed decision making. There can be no cost transparency without considering system costs. Otherwise, implicit subsidisation will be added to explicit subsidisation and substantial hidden costs can lead to unpleasant surprises further down the road.

1.3. Assessing and internalising external social costs

As explained in Section 1.1, external or social costs transcend the perimeter of the electricity grid. While they encompass many different areas reaching from climate change risks and air pollution to security supply and economic development, historically the issue has always been closely related to the natural environment. A focus on the environment also allows a rather intuitive treatment of a number of conceptual issues.

The close association of external effects with an unaccounted for and inefficient consumption of the environment explains also the prevalent concern with negative externalities. In principle, market-based activities provide as many positive as negative externalities. Positive network externalities and spillovers from research and technology development have already been mentioned. In today's energy sector, however, negative externalities dominate the discussion.

Economists have long realised the existence of effects of economic activity on well-being that were mediated by the market. Arthur C. Pigou in *Wealth and Welfare* (1912) first developed the concept of social costs. His classic example was the sparks flying from the chimneys of coal-fired locomotives that set the fields adjacent to the railroad tracks on fire, thus causing damage to the farmers exploiting those fields. His foray was taken a decisive step forward by Kenneth Arrow who concluded in *The Organization of Economic Activity: Issues Pertinent to the Choice of Market versus Non-market Allocation* (1970) that the existence of externalities was equivalent to the non-existence of a market for the good in question. Put simply, emissions of fossil fuel-based power plants are too high because there is no market for fresh air.

This is not equivalent to saying there should be a market for fresh air. It rather focuses attention on the question "why is there no market for fresh air?" The answer, "because it is near-impossible to assign property rights over fresh air", helps to understand why social costs exist. The link between externalities and the non-existence of markets is connected to the initial definition of externalities as effects whose creation lies outside the intention or concern of those who control the originating activity and outside the control or influence of those who are affected by them. In a market, there is always a feedback mechanism between producers and consumers, which runs obviously through the payment of money. By indicating the price they are willing to pay, consumers signal to producers the quantity of the good they wish to have supplied, and producers happily concur, since through the transfer of money the interests of the consumers have become their own.

Identifying reasons for the non-existence of markets is thus equivalent to identifying reasons for the existence of externalities. Ronald Coase (1960) in *The Problem of Social Cost* showed that all externality issues can be reduced to market transaction costs. The higher these costs, the higher will be the level of external or social costs. While this was undoubtedly a major conceptual insight, stating that transaction costs cause social costs does not say all that much. This is because transaction costs are a residual category that includes all those effects that economists are unable to define properly. Going a step further, one can identify two major sub-categories of transaction costs that can help to understand the non-existence of markets and the existence of external costs.

The first category concerns the absence of property rights over the goods in question. The absence of property rights is due to either the physical nature of the good (such as clean air) or due to ethically motivated decisions (such as maintenance of beaches as common properties). Obviously, the costs and difficulties involved in defining property rights can be defined as a transactions cost. It is also clear that transaction costs do not constitute a once-and-for-all barrier to exchange and the existence of markets. Technological advances, for instance, could make the collection and transmission of information easier and may thus contribute to the creation of new markets. A case in point is the market for sulphur emissions, which has been working well under the "Acid Rain Program" in the United States since 1993. It would be unthinkable without the possibility to measure each participant's emissions and to verify, share and process the information at a reasonable cost.

The second category is of a less economic nature, yet contributes largely to the existence of externalities, in particular in connection with environmental questions. It concerns the formation of people's preferences and the form they choose to articulate them. The existence of a market allowing for monetary evaluation requires that people have well-defined preferences over clearly identified and codified goods. However, in the case of externalities, people have concerns, fears, hopes, lacunae of information which all influence their well-being. Attitudes towards nuclear power are a good example. The vagueness of these "opinions", whether they are positive or negative, often prevents optimal internalisation, as they do not allow the formulation of clear choices between distinct possibilities, a precondition for the existence of markets.

External effects often have a dynamic quality as they start out as new phenomena championed by cranks and fringe groups. Concerns about climate change and global warming competed at the beginning of the 1970s with fears of global cooling due to the widespread use of aerosols and a new ice age for policy attention. Only progressive research, public discussion and societal processes codify the issues up to the point that they can be properly evaluated and internalised. In the production, procurement and consumption of energy, many external dimensions exist and new ones are coming up. Think about the impacts, real or imagined, of the magnetic fields around overland power lines. Energy systems are at the heart of modern societies and their structure and performance reflect deeply held policy objectives and beliefs, both explicit and implicit. This still allows the identification and sometimes the measurement of external costs. Nevertheless, it is obvious that, also inside the category of social costs, there exists a large range of issues of different conceptual, economic and political firmness that require an equally large variety of instruments to deal with them.

Dealing with social costs

Since Pigou, economists have attempted to properly frame the issue of social cost and to find appropriate instruments to internalise externalities into economic decision making. A frequently voiced criticism of the economic approach is that it proceeds in a framework of static optimisation and does not take into account dynamic change. This is not the place to go into an extended methodological discussion. Economics in general is more comfortable in analysing static optima than dynamic change. However, the economic approach allows at the very least to provide a conceptual benchmark and a rigorous starting point for discussions about policy instruments. Dynamic considerations must then be integrated in a second step.

Counter to intuition, the optimal level of social costs in an economic framework is *not* a zero level. While this may be surprising, it is actually quite intuitive as there are economic costs to avoiding externalities. These latter costs are referred to as the abatement costs or costs of control that would need to be incurred by polluting installations to reduce the level of pollution. Economics shows that costs of abatement, *when they are not undertaken*, are precisely equal to the economic benefits of pollution. In other words, a dollar saved on pollution control is considered a dollar earned.

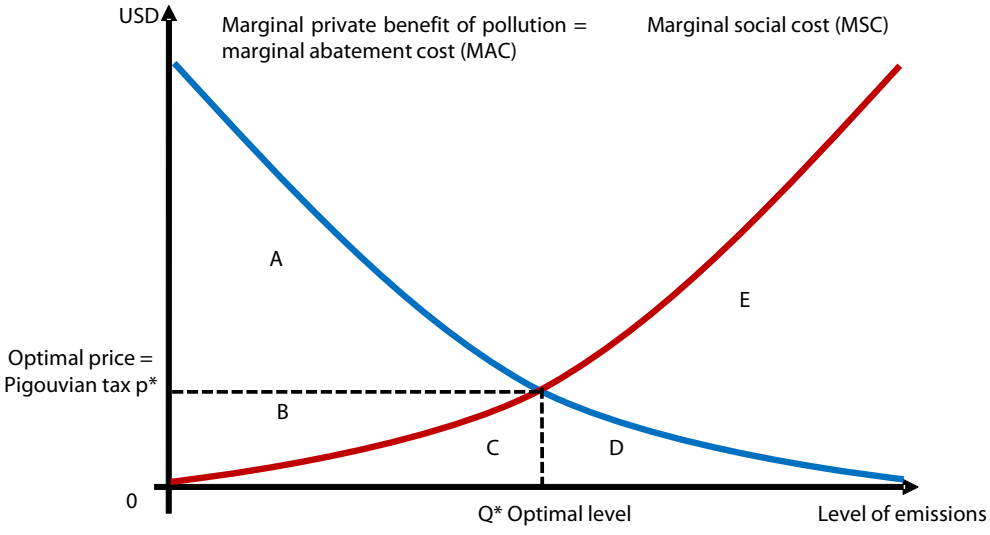
In an economic framework, the optimal level of externalities or the optimal level of production is defined by the equality of the marginal social cost of the externality, and the marginal cost of abatement, which is, of course, equal to the marginal private benefit. In an optimum situation, the last unit of emissions would thus cause exactly as much harm (expressed in monetary terms) as it would cost to reduce it. This corresponds to the private, commercial benefit a producer would obtain from an additional unit of pollution. Figure 1.4, a well-known graph, illustrates this statement.

Let us take the example of a coal-based electricity generator. As long as the marginal social damage from an additional unit of particulate and GHG emissions is higher than the marginal economic benefit to the generator, emissions should be reduced, i.e. from any point to the right of the optimal point Q^* one should move left-wards. Conversely as long as the marginal benefit (avoiding the marginal cost of abatement) to the generator from an additional unit of emissions is higher than its marginal damage, then more emission should be allowed to, i.e. from a point to the left of the optimal point Q^* one should move rightwards. The optimal level of emission is reached where the marginal social costs equate to the marginal private costs of abatement.

To arrive at the optimal level of emissions Q^*, there exist four principal approaches in economic theory (see below the detailed discussion of different policy instruments). The first two are based on the idea to *supplement existing markets* or to *create new markets* and could be categorised as "market simulation". A third approach sets *quantitative limits through regulation*. A fourth approach, finally, deals through qualitative *institutional*

mechanisms with the social costs created by phenomena that are too complex and not sufficiently defined to be amenable to static optimisation, since the process of preference formulation and articulation is still under discussion.

Figure 1.4: **Optimal static internalisation**



The *first approach* to achieve the equalisation of marginal benefit and marginal damage was developed by A.C. Pigou himself. In order to force British Rail to reduce the emissions of sparks from its locomotives he proposed a tax, later called Pigouvian tax, to be levied by the government on each unit of emissions. This tax should be equal to the marginal societal damage at the point of optimality, which implies that it is also equal to the marginal private benefit at that point. In a world with no further disturbances, this would force a profit-maximising producer to restrict his emissions exactly at the optimal point.

Considering the above-mentioned link between externalities and the non-existence of markets, Pigou's proposal essentially creates the market that was hitherto missing. Governments, in the interest of maximising the total welfare of society, act here as the caretakers of social resources and set the socially optimal price. The incentive for the producer to reduce his emissions is now the price he has to pay for emitting sparks, particulates or greenhouse gases.

While perfectly consistent and economically efficient, the Pigouvian approach comes with a major handicap: the information that is necessary to determine the optimal level of the tax is very hard to come by. At a political level, a Pigouvian tax also introduces significant shifts in the allocation of environmental use rights, which can translate into real economic losses or gains for different groups of users or producers worth billions of dollars. This often explains the ferocious resistance to environmental taxes, for instance carbon taxes, by those who would need to pay them.

Distributional conflicts between different lobbies are not as such an argument against a policy instrument that is designed to maximise overall social welfare. On a conceptual level, it is the information problem that constitutes the true Achilles heel of the Pigouvian approach centring on the optimal pricing of externalities. In order to set an optimising tax, governments need to possess information not only about the costs of abatement, but also about the damage costs to society, including dirty laundry, damages

to buildings and bridges, discomfort due to itching eyes, increased mortality rates as well as sea level rises and desertification. The examples chosen indicate that precise numbers are difficult to compute. In practice, however, lower bounds of the damage costs could quite easily be defined and translated into emission taxes.

Nevertheless, the information problem goes to the heart of the Pigouvian approach. Let us recall that social costs or externalities are due to the transaction costs that prevent their internalisation in the first place. The difficulty of obtaining comprehensive and pertinent information is a key part of transaction costs. In other words, if private actors had all the necessary information available, they would have already internalised the externalities in question through the legal system.

This argument was developed by Ronald Coase, another British economist, yet one closely associated with the University of Chicago. In his famous article "The Problem of Social Cost" (1960), he stated the fundamental insight that the level of social costs is determined by the level of transaction costs. If private actors, who are perfectly capable of arriving at socially optimal outcomes in other cases, eschew to do so in the case of externalities, then this is due to the real costs of improving over the existing situation. In essence, his argument says that we are already living in the best of all possible worlds. Since government bureaucrats have no easier access to information about social costs than those principally concerned, it is a costly folly wanting to improve on existing social costs. Coase did not deny that those social costs exist. He only denied that they can be reduced in a manner that would lead to economically superior outcomes.

His followers developed his arguments in the direction that, if property or use rights over environmental resources were unequivocally assigned to one party or another, this would reduce transaction costs considerably and would allow the internalisation of externalities through bilateral negotiations. This holds, in particular, for local resources that are shared between neighbours. One might, for instance, think about a lake, where on one shore a camp site caters to tourists and on the other shore a timber processor discharges wood wastes into the lake. Recalling Figure 1.4 above, whenever a point to the right of the optimum is considered, with the costs to the camping site being higher than the benefits to the timber processor, it would make sense for the operator of the camping site to pay the timber processor an amount lower than its own marginal damage but higher than the latter's marginal benefits to reduce its discharges. Vice versa, at any point to the left of the optimum, it would make sense for the timber processor to pay for the right to increase its discharges and for the camping site to grant it, as long as the agreed-upon sum was higher than the marginal cost and lower than the marginal benefit. Either one of the two processes would go on until the optimum was reached.

A striking result of the Coasean approach is that the same optimal point would be reached regardless of the initial distribution of property or use rights, i.e. whether the timber processor or the camp site operator possessed the right to enjoy the benefits of the clean water of the lake. The process towards optimality through private negotiation would only be limited by transaction costs, whose existence would in return justify the continued existence of suboptimal levels of social costs.

While fascinating and intellectually stimulating, the Coasean approach, both in general terms and with respect to the property rights approach, needs to be put very firmly in perspective. First, with respect to the property rights approach, it is quite obvious that private transaction costs increase with the number of participants. While the allocation of clearly defined use rights constitutes an interesting perspective for bilateral negotiations between two parties using the same lake, it does not constitute a viable option for issues of atmospheric pollution or climate change with thousands or millions of parties affected on both sides. In such cases, collective action organised by non-governmental organisations (NGOs), institutions or governments is far more effective in achieving progress towards a meaningful reduction of inefficiently high social costs than private negotiation. This, however, leads back to some form of the Pigouvian approach.

In fact, the central Coasean argument that we are already living in the best of all possible worlds since the level of transaction costs determines the level of external costs is ultimately a tautology that applies only when adhering to a very strict interpretation of static optimality. It thus fails to account for any meaningful, dynamic, future-oriented policy action. The Coasean approach disregards that it is precisely the ambition of policy action to lower transaction costs, for example by providing for better research, better information, more compelling incentives or clearer responsibilities, in order to allow for new ways of internalisation that will allow for lower levels of social costs and overall higher levels of welfare.

The Coasean approach becomes most valuable for public policy making if interpreted in such a dynamic perspective. It then teaches governments and decision makers not to substitute themselves for the outcomes of private actions but to create the conditions under which private actors can best advance towards overall optimality by lowering transaction costs. Such a neo-Coasean approach implies four distinct strategies for dealing with social costs, including the full costs of energy provision:

1. The funding of research and the distribution of information about different dimensions of full costs;
2. The organisation of societal and institutional processes that allow progressing from diffuse and vaguely held opinions, intuitions and prejudices towards meaningful societal preferences that can be translated into concrete policy objectives;
3. Clarifying the allocation of use and property rights over environmental resources as well as responsibilities regarding other public policy objectives (e.g. security of supply);
4. Creating markets, such as emissions trading systems, by defining tradable products and allocating property rights, which allow private actors to engage in achieving efficient outcomes over parameters that previously had impossibly high transaction costs.

Allocating use and property rights are particularly thorny issues. Climate policy is a case in point. Efforts to reduce GHG emissions are impacted by an unacknowledged struggle about who should possess the use rights over the earth's atmosphere. While historical use rights were on the side of carbon emitters, current policy prescriptions somewhat breezily assume on the basis of a "polluter pays principle", whose real-world application is often more difficult than the casual observer might assume, that current use rights belong to the general public. There is nothing fundamentally wrong with this. The problem is only that the hidden distributional issue, which is of considerable magnitude measured in billions of dollars, is defining the strategies of the different actors and blocks any overall progress towards meaningful GHG emissions reductions. It is true that, at some general level that includes currently not monetised externalities, climate change action could be viewed as paying for itself. However, stating this overlooks the massive *negative* distributional impacts of climate action on industrial sectors, regions and, in fact, whole countries. As long as externalities are unpriced, climate action will also *ceteris paribus* somewhat reduce overall economic wealth in pure GDP terms, although dynamic effects may ensure also some positive economic spillovers. As long as these distributional impacts remain unaddressed, the losers as the result of climate action are incentivised to prevent meaningful emissions reductions. Sometimes, even potential net beneficiaries of climate action will block it, such as consumers located in low-laying areas who are resisting higher electricity tariffs as a consequence of carbon pricing.

The question of distribution frequently also influences discussions on the choice among policy instruments, which, in principle, all aim at the same optimising internalisation of social costs. Technically speaking, different instruments imply different allocations of environmental rent. The environment, which is provided free of charge by nature itself, and its use constitute a real economic value. Ensuring the optimal level of

external costs is equivalent to maximising the value of the environmental rent given competing uses. Take the example of the coal-based electricity generator. The optimal level of emissions can be achieved either by environmental taxes or by a governmental regulation setting a standard of the total amount of emissions at Q^*. For an impartial observer interested only in maximising total welfare it does not matter which instrument is chosen. Yet for the generator, the public or the government, the choice of the instrument that is chosen matters tremendously, as their income depends on it. See Table 1.2 that makes reference to the Figure 1.4 above. The income for different parties in terms of environmental rent will depend on the instrument that is chosen for internalisation. The choice of instrument thus inevitably implies a political choice in terms of distribution.

Table 1.2: **The distributional impacts of different internalisation strategies**

(The shares of environmental rent A, B, C, D and E correspond to the surfaces in Figure 1.4)

	Status quo (no action)	Tax (Pigou)	Standard	Permit trading (generator)	Permit trading (public)
Generator	A+B+C+D	A	A+B+C	A+B+C	A
Public	-C-D-E	-C	-C	-C	-C
Government	0	B+C	0	0	B+C
Total rent	A+B-E	A+B	A+B	A+B	A+B

Note: A highly technical argument pertains to a slight disadvantage in economic terms of quantity-based standards. Their sub-optimality does not pertain to the dimension of social costs themselves as, with perfect information, both a tax and a standard would achieve the socially optimal level of emissions. It refers instead to the means employed to reduce pollution to the optimal point. Take the example of carbon emissions reductions from coal-fired power generation: with a carbon tax, the generator would choose an efficient least-cost mix of technical abatement, e.g. more efficient boilers, and reductions in the output of electricity to achieve the intended level of emissions. With a quantity-based standard instead, generators would overinvest in technical abatement and underinvest in output reductions, thus selling more electricity than with a carbon tax. This is because, in the example of the standard case, infra-marginal emissions are costless and only the last unit of emissions elicits compliance. What looks like an advantage, i.e. more electricity sold at the same amount of emissions, is in fact an economic disadvantage. By levying a Pigouvian tax, the government could have generated a *higher* value for the overall economy than the added surplus for the electricity customers resulting from the standard. Clearly, this is a second-order effect that in practice is quickly superseded by distributional or political considerations. It also does not apply to emissions trading schemes which, despite being based on an overall quantitative limit, do price infra-marginal emissions. The argument presented here however explains why economists do prefer price-based instruments under almost all circumstances.

In a Pigouvian solution, a significant share of the environmental rent is captured by the government by way of an emissions tax. The share remaining to the generator will be smaller than in all other solutions and in particular much smaller than in a situation with a hands-off policy of doing nothing. A Coasean solution could be either associated with the *status quo* of doing nothing, in case that the transaction costs are considered too high, or with permit trading as a particular form of the property rights approach.[4] It is obvious that doing nothing or leaving the use rights to the generator and his customers is far more advantageous to the latter than a tax on emissions. Only permit trading with an allocation of use rights to the general public would replicate the distributional consequences of a carbon tax. In this case, the generator would acquire the permits required to continue his business through either an auction or the open market. In both cases, the receipts would presumably fall to the government. Thus, different policy

4. Strictly speaking a pure Coasean property rights approach would need to work without any government intervention. However, in the case of airborne emissions, it seems obvious that some form of institutional agent, the government, an NGO, an association, would need to defend the use rights of the general public because of the large number of individuals affected.

instruments have different distributional implications. Last but not least, it should be noted that all policy instruments have far superior overall welfare impacts than the option of doing nothing, i.e. maintaining the *status quo*, which inevitably generates the highest social costs.

Environmental taxes, subsidies and emissions trading

Because of their importance as policy instruments for dealing with the external social costs of energy, the three instruments of environmental taxes and standards, subsidies and emissions trading will be presented in slightly more detail. One or more of these instruments are likely to play key roles in shaping policies in the energy sector aiming at taking into account the full costs of energy provision.

a) Environmental taxes and standards

Environmental taxes result straight from Pigou's reasoning that you need to make the production of an externality so expensive that its level will be restricted to the optimal one. An environmental tax can also be considered as a tax on the use of an input factor, which in this case would be the environmental good in question, e.g. fresh air. This will cause, like any tax or price rise on inputs, an output and a substitution effect, i.e. less of the final product will be produced (as demand falls as a result of the total price rise following the rise in an input) and production will substitute other factors (capital, labour) for the taxed input, i.e. the environment. In practice this means the investment into equipment with less environmental effects.

As shown above, an environmental tax affects the distribution of environmental rents as the government appropriates a substantial portion of the environmental rent. Of course, it is possible to maintain budgetary neutrality, i.e. to give back the rent. It is essential though that this redistribution is independent of the amount of environmental tax paid by any individual, which would neutralise any incentive effects. Ideally, the tax should be redistributed in the form of a flat rate per capita. Earmarking environmental taxes can lead to new inefficiencies.

A great advantage of environmental taxes is the pressure they exert on technological developments not only in a static, but also in a dynamic fashion. With an environmental tax, it pays firms to invest in research for new technologies even with uncertain outcomes, as the potential payoff from new inventions is greater than without the tax.

Frequently, decisions on environmental policy instruments need to be taken under uncertainty about the precise welfare-maximising level of pollution. In such cases, attention must be given to the relative elasticities of the marginal social cost curve and the marginal benefit curve. If the former is more inelastic, a quantity instrument such as a standard should be chosen, as it would limit the impact of an error on the social cost side; if the latter is more inelastic, a price instrument should be chosen as it would limit the error on the side of the economic costs.

b) Subsidies

Theoretically, subsidies function like a Coasean internalisation mechanism, in which the property rights lie with the firm and in which the government (as the agent of those affected) pays for a reduction of the externality. It can be shown that, depending on the precise form of the subsidy, this can be economically efficient in a framework of static optimisation. The payment of subsidies can take various forms. Grants are direct lump-sum financial transfers and can, in fact, be paid for output reduction as well as for new abatement technology. Soft loans at below-market interest rates can be assumed to pertain only to the investment in new abatement technology. Tax allowances, finally, can take two forms: they can be granted for investment in new technology or for environmentally cleaner goods. In the first case, they work like soft loans; in the second

case they work exactly like product charges (obviously with a reversed rent distribution between government and producers), in as much as they make it relatively more expensive to produce goods with a high level of externalities.

Subsidies have two unwelcome side-effects. First they need to be financed by levying taxes on other goods and services, which leads to the well-known economic efficiency losses that the literature on public finance deals with. Second, they have very ambiguous dynamic effects. If the payment of subsidies is linked to the adoption of new technologies, firms may indeed improve their efficiency but only up to the point that these improvements are stipulated *ex ante*. On the other hand, if subsidies are conditional on some threshold in terms of the production of external costs, think of "energy-intensive companies", then subsidies could actually spur perverse behaviour as firms struggle to become part of the subsidised category.

c) Emissions trading

Creating markets for trading emissions, such as carbon markets, are the economic instrument *par excellence* and has some attractive features for internalisation. Yet, it is helpful to return to the initial definition of externalities as goods for which no markets exist. Thus, market creation as a means to internalise externalities always is a difficult endeavour. At the same time, new technological developments, particular in the field of information gathering and processing may lower transactions costs to a point where market activity in new commodities becomes advantageous. In any case, the creation of a new market for emissions trading will always entail substantial government intervention in order to set up the institutions, payment and monitoring facilities necessary to enable private traders to engage in them.

For emissions trading to work, the government has to specify first the maximum admissible amount of total pollution. This amount is then subdivided into smaller units for which so-called emission certificates or quotas are created. These certificates will then be given away or sold to the interested firms. Any firm possessing certificates can now pollute up to the quantity corresponding to the number of its certificates. Any firm wishing to increase its emissions or any new firm entering the market is now obliged to acquire new certificates from existing firms at a price.

Emissions trading combines the dynamic incentive of a tax with the clarity of a quantitative standard and the transparency of an explicit allocation of use rights. It has the added advantage that the redistribution of environmental rent can be easily fine-tuned by the share of emission quotas that is allocated for free to existing firms ("grand-fathering") or sold off by government at an auction. The amount of rent transferred from the firms to the government is thus determined through the original price of the emission certificates. By the way, the final price in the market is determined by relative scarcity and is independent of the initial transfer price to firms.

Since emission certificates always generate value, either as an input into production or as a financial asset on the market, firms also have the incentive to use as few certificates as possible. They will invest in additional abatement wherever possible, thus creating a positive dynamic effect towards less pollution per unit of output, even though the absolute levels of pollution will remain fixed.

Emissions trading may be considered a hybrid instrument that includes aspects of both a Pigouvian and a Coasean approach. From the former it takes the pricing of all units of emissions; from the latter it takes the idea of creating markets through the allocation of property rights. Last but not least, from the neo-Coasean approach it takes the idea that government's role is primarily to reduce transaction costs in order to allow for new and more efficient forms of internalisation.

The best known emissions trading system, the European Union Emissions Trading Scheme (EU-ETS) for CO_2 allowances is working well on a technical level. For distributional

considerations, however, decision makers have chosen a level of quotas that is too low to allow for prices that could significantly alter investment and dispatch decisions. Switching from a free allocation of quotas consistent with historical use rights to an allocation by auction has increased the need to pay attention to the plight of historic CO_2 emitters, which previously had been able to cushion the choc. The EU-ETS, for all its sophistication, currently fails to contribute decisively to the deployment of low-carbon technologies in European electricity markets.

Measuring full costs

The previous section presented the most important policy instruments aimed at the static optimisation of the level of externalities in order to maximise total welfare. The idea is thus to internalise full costs, including plant-level production costs, grid-level system costs and social costs, in a comprehensive manner. In an ideal setting, this would demand knowledge not only of all pertinent economic cost factors that go into the marginal private benefit curve, but also of the marginal social cost curve. As formulated in the Coasean critique of the Pigouvian approach, this information is particularly difficult to come by. If it was easily solicited and generally accepted, much internalisation would already have taken place through the legal system. The definition of property rights, if it could be done at reasonable transaction costs, would further advance that process.

As has been pointed out above, this intrinsic contradiction of the Pigouvian approach is valid only in a static perspective. In a dynamic perspective, in which stakeholders, experts and governments progressively develop ever-clearer notions of private, market-based costs, grid-level costs and social costs, internalisation through economic instruments such as Pigouvian taxes, emissions trading or quantity-based standards do advance economic welfare. Transaction costs and, in particular informational transaction costs, have a tendency to be absorbed by economic, social and political change. The work of stakeholders and NGOs or publicly sponsored research programmes will thus elicit previously unavailable information about biophysical relationships, private and social preferences and, ultimately, economic costs in different dimensions. In the following are briefly presented some of the techniques that are employed by environmental economists to walk the fine line of converting external social costs, which to some extent are external because difficult to assess, into the monetary evaluations that form the basis for most economic instruments of internalisation.

While the establishment of the social marginal cost curve is a fundamental challenge for environmental economists, the establishment of the marginal benefit or marginal abatement cost curve is a cumbersome but methodologically straightforward problem since all the necessary information regards marketed goods with known prices. Different technologies have different costs, as well as different emission coefficients. Under the assumption of a fixed level of output, different technologies are then associated with percentage reductions in emissions. Thus one obtains step functions which fall towards the right, as emissions reductions are plotted from 100 to zero. The costs thus derived are average cost at the level of production. Given that these average costs change in discrete steps with increasing emissions, they can be considered individually as ranges of marginal costs. [5]

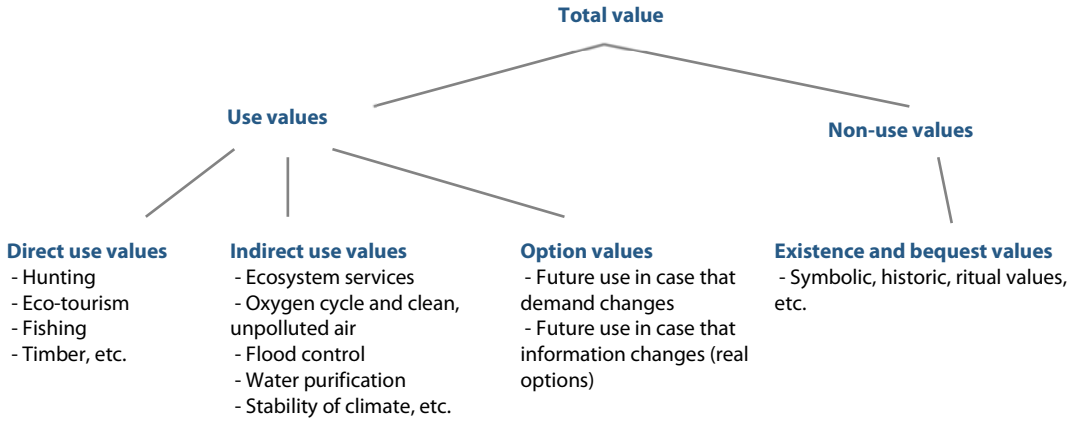
5. It is sometimes argued that this is the only information required to determine the height of an optimal tax or standard. On the basis of the shape of the marginal abatement cost curve, public authorities would then decide on a desired percentage reduction. This would assume that information about damage costs is implicit in the government decision-making process. This circular reasoning is, however, naïve and short-sighted. In particular, it skirts the question on which facts the optimising political process will be based on.

As indicated, the quantification and monetisation of damage costs is at the heart of environmental economics. Opponents point out the cynicism of putting monetary values on human health and lives, while supporters point out that implicitly this calculation is done every day when the government weighs, for instance, the life-saving potential of seat-belts against their costs for consumers and the car industry. In practice, some monetisation is frequently helpful to provide at least a lower bound for the damage costs. The techniques employed to reveal monetisable social costs offer steps on the way to arrive at solutions superior to the *status quo*. By establishing a lower limit for the order of magnitude of the damages, they thus provide inputs into the political bargaining process.

In discussions of the different techniques employed to solicit information about external social costs, the natural environment, understood here in the broadest possible sense, constitutes a paradigmatic example. While most of these techniques could in principle be employed to assess social costs also in other areas, this is rarely done. In fact, most of these techniques have been developed with direct reference to the assessment of damages to the natural environment. One explanation for this fact is that the social codification of environmental damages has advanced during the last few decades to a point where the application of quantifying measures becomes possible. This is not the case in areas such as the security of energy supply or the impact of different generation technologies on economic growth or employment. As discussed in the next section on the dynamic nature of externalities, such impacts must be internalised through implicit institutional mechanisms that owe as much to politics and the legal system as to economics understood as a system of market transactions based on explicit prices.

In the environmental field, total damage costs are composed of the different constituent parts of total environmental value as indicated in Figure 1.5. Similarly to what has just been remarked with regard to the diverse nature of external effects in different spheres, also internally to the natural environment, there exists a range of values of very different quality. Some, such as direct use values in agriculture, forestry or fishing are quite naturally prone to monetisation, others such as bequest and existence values are not. It is the third category, indirect use values and option values, that are the most interesting to environmental economists as they allow the application of techniques that draw so far unpriced aspects of the environment into the sphere of explicit value formulation where the goods in question can perhaps not yet be traded in all cases but are amenable to policy actions such as Pigouvian taxes that rely on explicit damage estimates.

Figure 1.5: **An overview of environmental values**



In order to arrive at indications of total values of environment damage costs, there exist five basic approaches. Four of them are technical economic techniques, while one proceeds directly from existing market prices. The discussion of these techniques will be short, since extensive discussions can be found elsewhere (see, for instance, Freeman (1979) or OECD (1994).

The *first approach* proceeds directly from observable prices and concerns damages through energy production and consumption to marketed goods, or, in other words, goods for which monetary valuations do exist. This would include material damages to buildings and bridges, the losses of farmers due to environmental degradation and the damages to commercially used woods. The regular and costly *ravalements* to which apartment buildings in Paris are subjected in order to sandblast away the accumulated soot from air pollution is a typical example. Health costs, of which at least a portion is easily measurable through medical bills, would be another. Strictly speaking, these damages do not constitute a public goods problem, but concern gaps in the liability system of the existing legal framework or arise from a failure to detect relevant causal relationships or to identify those responsible for the causes. With increased information and tighter legal regulations, these externalities would not need to exist. At the same time, these externalities are the most easily quantified and are often those which are used to most effect in public discussion.

The *remaining four techniques* fall into two groups. The first three are indirect valuation techniques which try to derive the damage in terms of external costs from the observed behaviour of those affected in actual markets. The fourth is a direct valuation technique and attempts to derive preferences concerning public goods through questionnaires. Indirect valuation techniques have the advantage of relying on actually observed behaviour (revealed preferences) and are thus immune to strategic behaviour; at the same time they primarily provide information about public goods that have close relationships with marketed goods and have to make strong assumptions about these relationships.

The direct valuation through a questionnaire (also called contingent valuation) has the enormous advantage that any information desired can – at least in principle – directly be looked for. This concerns, in particular, bequest and existence values, i.e. the desire to preserve parts of the environment for future generations with no advantage in terms of direct or indirect use values. The great disadvantage of contingent valuation is that the information thus solicited could be biased (as people expect advantages from giving false information), or that people themselves do not have sufficiently formed preferences to provide usable information. As mentioned earlier, this can be a problem connected with the nature of an externality itself.

A well-known bias is the over estimation of the willingness to pay for environmental values when people are questioned about their preferences in hypothetical situations of the type "How much is it worth to you to ensure the long-term survival of a substantial elephant population in Africa?" Many respondents will indicate amounts far greater than those they would actually commit in real life. It is also easy to see, for instance, that by enumerating a large number of charismatic mega-species, total sums can easily exceed available budgets. Also, laboratory experiments with preselected interviewees (mostly students in economics) have led to a much higher level of strategic behaviour than that actually met with in the real world (see Diamond and Hausman, 1994, for a more detailed description of many criticisms of contingent valuation). Advanced questionnaires that frequently recall total budget constraints and alternative spending categories (e.g. housing, food, transport and leisure) can help. So does switching from direct questions asking for absolute values to step-wise Yes-No answers. This may even evolve into full-scale choice modelling, where researchers present different well-defined alternatives, including the *status quo*, among which the respondents are asked to choose.

Nevertheless, the use of questionnaire-based, stated preference or contingent valuation techniques has declined in recent years. These techniques run up against the fundamental issue that economic behaviour and economic analysis are not based on what people think they are doing or on what they would like themselves to be doing, but on what they are *actually* doing, perhaps unwittingly and without much reflection, but in the form of fully executed monetary trades. For a comprehensive overview of the advantages and drawbacks of contingent valuation, see the 1993 report of the NOAA Blue Ribbon panel (Arrow et al., 1993).

The three indirect valuation techniques are hedonic pricing, the travel-cost method and the identification of cross-price elasticities between public and private goods. Because of their reliance on existing markets for private goods, they are also referred to as "surrogate markets" methods. The hedonic pricing method assumes that certain public goods such as silence, a good view, proximity to green spaces or air quality are directly imputed into the value of privately traded goods such as houses or property (hence the name). Thus the value of a house is in the simplest case a function of its size, year of construction and the absence of social costs such as noise or pollution. The latter factors can nowadays be measured quite comprehensively. If the external question is, for instance, the construction of a regional airport, then distance to the airport is quite an adequate proxy for the real nuisance without requiring sophisticated measurements. Once an appropriate system of indicators has been defined and a large enough sample has been assembled, all that needs to be done is to regress house prices on the different explanatory variables (e.g. size, age and distance from airport), to obtain the coefficient that relates a variation in, say, noise or air quality to a change in house prices. Thus, averaging results and multiplying them by the relevant number of people affected, provides indicative values for the losses inflicted by certain kinds of social costs.

Theoretically elegant, the hedonic property price method needs to overcome difficulties in data collection. Because of data issues, it is frequently limited to assessments of energy production and consumption on house prices in the real estate market. Needless to say, hedonic pricing will only ever capture the subset of social costs that manifest itself in house pricing and not the larger impacts on the population living further away or not participating in the housing market. In addition, it needs to separate income effects from public good effects, e.g. taking account of the fact that houses in good locations with respect to the external costs in question also tend to be bigger and of higher quality. Yet, for a limited number of clearly identified and measurable public goods it can provide a lower bound for the total social costs. Analytically identical is the calculation of the implied cost of risks to life and health for workers derived from wage differentials (see Box 1.2).

The travel-cost method tries to value public goods on the basis of the differential prices people in different geographic zones are willing to pay in order to gain access to it. The price of the public good is thus the time and the monetary cost spent by people living in different zones at different distances from the public good. An average cost for each zone is calculated. The number of visits from each zone and their respective costs constitute a point on the demand curve. The area under the demand curve is the consumer surplus and thus the value of the public good. Obviously, this method can only be used for locally very precisely confined public goods such as tourist sites, recreational facilities, national parks and the like, yet in those cases it has established itself as a frequently used and quite reliable instrument.

Box 1.2: **An issue of contention – The value of a statistical life**

One of the most high-profile issues in the assessment of social costs is the estimation of the increased costs of morbidity and mortality. This does not concern the value of an individual's life either to himself or to those close to him, but the value of a marginal reduction in the risk of falling ill or dying. This is quite different as it introduces a notion of substitutability at the margin, which does not exist for an individual faced with a life-or-death situation. The willingness to pay (WTP) of an individual in immediate mortal danger is grounded on entirely different motivations from the WTP of a car buyer contemplating whether to pay for an additional set of air bags that would reduce the risk of death and injury in the case of a certain type of accident. Technically speaking, a value of a statistical life (VSL) indicates a person's WTP to ensure a marginal reduction in mortality or morbidity risk.

VSL may also be conceived as the monetary value that a group of people would be willing to contribute together to prevent the death of one of its members at random. They are frequently based on estimates from labour markets where studies assume that occupational health hazards are internalised through marginal wage increases (OECD, 2012). VSL estimations are usually working with revealed preferences based on people's actual economic behaviour and are closely linked to the hedonic pricing method. The estimated coefficients in the regression for each attribute, e.g. accident risk in a certain kind of profession, would indicate the marginal WTP for each attribute. Of course, subjective risk perception may not correspond to actual risk. For instance, a devastating, highly evocative singularity like an earthquake and a more diffuse and constantly present phenomenon such as air pollution, may have the same mortality rates, but people would not necessarily accept the same marginal increase in income for the mortality risk in being exposed to each. Cameron (2010) thus rightly remarks: "'The VSL' is not some true-but-unknown fundamental constant of nature that we merely need to measure more accurately. Instead, 'the VSL' is the result of attempts to find a convenient one-size-fits-all measure of demand for risk reductions – a number that may or may not be appropriate across all different types of risks or all different affected populations."

The question is, of course, whether there exists a better alternative. Some studies do not use revealed preference methods and return to stated preferences, i.e. contingent valuation, with all the known *caveats*. Ultimately, the premise of a WTP as society's marginal benefit for reducing a given social cost is solidly grounded in economic theory. The VSL, the extension of WTP into the area of mortality cost estimations, is also covered by economic theory. However, the notion of a single "true VSL" must be avoided to recognise the vastly different contexts and risk perceptions of damages. Willingness to pay for risk reduction is neither evenly spread across the population, nor are all individuals' marginal WTP for risk reductions necessarily similar. The literature contains many examples that show, for instance, that workers in high-risk jobs have lower VSLs on average. Individuals' WTP to preserve health also increases with income. Viscusi and Aldy (2003) estimate that VSL has an income elasticity of 0.5 to 0.6. Empirical estimates also suggest an inverted U-shaped relation between age and VSL; in other words, they increase until middle age and then begin to decline (OECD, 2012). Despite the uncertainties and caveats, a meta-study of VSL estimates by the OECD established a range for an average adult VSL of USD 1.5 to 4.5 million. The recommended base value is USD 3 million (OECD, 2012).

Issues can be even more complicated when it comes to morbidity. As OECD (2014) notes, "economics today does not possess a … standard method by which to measure the cost of morbidity from a given source". While a subset of the costs of morbidity such as loss of working capacity or the cost of hospitalisation can be reliably measured on the basis of available data, other notions such as disability-adjusted life years (DALY) or the value of a life year lost (VOLY), a composite of the economic cost of morbidity and of mortality, are more fragile. There is also the risk of doubly penalising people exposed to social costs, e.g. air pollution, by treating their subsequent deaths as less valuable, as a DALY method yields a lower value on reductions in mortality risk for older populations with lower quality of life. These are ongoing issues where current economic research on costs of morbidity still needs to converge on a widely accepted metric for morbidity that would be comparable to the VSL established for measuring the social costs of increased mortality risk in the context of full cost accounting.

A final form of indirectly estimating the value of public goods is the use of known substitution relationships between private and public goods. Assuming a public good safety for a given community and assuming that doubling the number of policemen will have the same reduction in the crime rate as the installation of private burglar alarms, the price for the public good can be derived. Of course, any private good will only capture certain aspects of the public goods, but with this (heavy) caveat in mind, the relation to private goods could provide valuable input into the final valuation.

The preceding paragraphs have emphasised the difficulties of arriving at meaningful information about the value of public goods affected by energy externalities. Yet, this should not lead to an overly critical attitude towards the estimations derived at by these instruments. In many policy-relevant cases, rough indications of orders of magnitude are sufficient to decide on the appropriate form of government intervention. The existence of step functions in environmental investments on the firm side and in biophysical relationships with possible threshold values on the damage side also frequently leads to situations where consensus only has to be achieved about whether a value lies under or above the relevant threshold value. The information problem in connection with externalities and their effects on public goods certainly exists and presents a formidable challenge to their internalisation. Yet, in the end, potential misallocations due to incomplete information have to be weighed against the costs of doing nothing.

The heyday of the monetary measurement of environmental externalities was in the 1990s when a large number of researchers became active in this field. Partly owing to the invention of the techniques described above, partly owing to renewed concerns about the social costs of energy production and consumption ranging from local air pollution over climate change to security of supply, a number of large-scale studies on the external costs of energy were thus funded and undertaken. Year 1995 saw thus the publication of three major studies on the measurement of the social costs due to the external effects of electricity generation:

1. *ExternE: The External Costs of Energy*, co-ordinated and funded by the European Commission.
2. *Estimating Fuel Cycle Externalities*, co-ordinated by the Oak Ridge National Laboratory (ORNL) and funded by the United States Department of Energy (USDOE).
3. *New York State Environmental Externalities Cost Study*, co-ordinated by RCG/Hagler Bailly and funded by the New York State Energy Research and Development Authority, the Empire State Electric Energy Research Corp. and the Electric Power Research Institute (EPRI).

Some years earlier, in 1990, the Pace University Centre for Environmental Legal Studies (1990) had already produced its study on the *Environmental Costs of Electricity*. All these studies are part of a first wave of social cost accounting that had united a sizeable community of competent and committed researchers.

While public and political concerns about the external and full costs of energy and electricity have, if anything, increased since then, little has been added in terms of methodological sophistication or systematic empirical analysis. Recent efforts to provide comprehensive assessments of the external costs of energy are the NEEDS and Costs Assessment for Sustainable Energy Systems (CASES) projects funded by the European Commission (see also Markandya et al., 2011). The CASES project, in particular, publishes detailed external cost estimates for different generation power technologies on a website maintained by the Italian Fondazione Enrico Mattei (FEEM). A summary of these results are reproduced in Table 1.3. They synthesise many recent external cost estimates of different sources of electricity generation based on a comprehensive international effort.

Table 1.3: **A summary of external cost estimates from the European CASES Project***

(2005-2010, euros per MWh)

	Nuclear	Coal IGCC	Lignite IGCC	Gas CCGT	Hydro (dam)	Wind ON	Wind OFF	Solar PV	Biomass (straw)	Biomass (wood)
Human health	1.55	8.35	3.84	4.24	0.57	0.75	0.72	6.58	15.55	4.64
Loss of biodiversity	0.09	0.79	0.32	0.52	0.02	0.04	0.03	0.34	2.94	0.49
Crops (N, O_3, SO_2)	0.02	0.15	0.04	0.12	0.01	0.01	0.01	0.07	0.10	0.13
Materials (SO_2, NO_x)	0.03	0.11	0.03	0.07	0.01	0.01	0.01	0.09	0.12	0.07
Radionuclides	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Climate change	0.43	17.6	19.57	8.97	0.16	0.21	0.17	1.81	1.46	1.20
Total	**2.14**	**26.96**	**23.80**	**13.93**	**0.76**	**1.03**	**0.94**	**8.88**	**20.17**	**6.54**

N: nitrogen; NO_x: nitrogen oxides; O_3: ozone; SO_2: sulphur dioxide.

* This table should not be construed to reflect a definite consensus view on the external costs of electricity. External cost accounting, by its very nature, will always allow for alternative viewpoints. Coal, for instance, does emit a higher level of radionuclides than nuclear energy. The estimate of the impacts of hydroelectricity on biodiversity seems small when compared to anecdotal evidence. Such uncertainties show that more systematic as well as policy-relevant research on the external costs of power generation is needed.

Source: Adapted from FEEM, 2011.

Of course, such average numbers based on dose-response functions have indicative value only. In particular, they do not account for the different levels of risk aversion that individuals associate with different types of risk. Studies have shown that people are far more risk-averse when facing risks that they do not themselves control than when they themselves have some influence about probabilities, e.g. driving a car.

Risk aversion also has implications for the choice between risk structures. The costs of risk are usually calculated as the product of damage costs times the probability of its realisation. Risk aversion now implies that people would prefer the same cost of risk, if it was composed of relatively high probabilities of realisation, and relatively low damage costs rather than the opposite. In other words, at equal total cost people would prefer the constant nuisance and adverse health effects of particulate matter emissions to the low probability of a catastrophic accident such as a nuclear accident or a fire in an oil refinery. This would change, of course, the moment that particulate emissions would lead to serious illness and increasing mortality.

The dynamic nature of externalities

The previous section has provided some evidence for the creativity and ingeniousness with which economists address the information problem that needs to be overcome in order to realise the Pigouvian paradigm either through price-based or quantity-based measures. However, there exist forms of social costs that are impenetrable to attempts to quantify and to monetise them. As mentioned, external or social costs are "external", i.e. not internalised, unpriced, and hence provided in suboptimal quantities, because no markets for them exist. This absence of markets is precisely due to their lack of codification with respect to both biophysical relationships and economic preference formation. The information problem is thus intrinsic to the very notion of external effects.

This is altogether not so surprising. In many cases, externalities exist because they have just recently developed as new and policy-relevant phenomena. As such, they are considered to have an impact on human well-being but it is impossible to assess its magnitude. Sometimes, it is not even understood whether this impact is positive or negative. The impact of the magnetic fields around electric overland lines, or the ability to import cheap electricity from a given country, may serve as examples. Any attempt to give expression to these impacts is necessarily imprecise and any attempt to quantify or monetise them will be useless.

Despite the elusiveness of these issues for standard economic reasoning, they do nevertheless create effects on the perceptions and emotions of human beings, influence their well-being, and thus have to be considered as externalities. Such awareness creation, frequently by cranks or groups at the margins of the going societal discourse, is the first step of the process of internalisation. It identifies the external effect as something which was not there before, which is inadequately understood and which now has to be discussed in order to arrive at a consensus over which information has to be gathered, and which internalisation strategies should be pursued. The system effects of variable renewables, although discussed here under a separate category, are a fine example of this progressive organisation of the search for conceptual and organisational responses.

This temporal aspect of externalities explains why they are so closely linked to discussions about technological progress. New technologies create new effects and new impacts, many of which are not foreseeable and can thus not be taken into account in their conception and implementation. An externality is then the impact of a new process on aspects of life which has had no prior consideration. Obviously, new impacts of existing technologies, e.g. the accumulation of well-known effects which leads to qualitatively new impacts, generate analogous effects.

Similarly, changes in preferences can create "new" impacts. Even if they are not physically new, they constitute new phenomena with respect to public perception and individual well-being. The rise in living standards in industrialised countries has undoubtedly contributed to a higher concern for the environment, over and above measurable physical, chemical or biological impacts. Even if nature as such belongs to all humans in equal measure, econometrically speaking, environmental quality is a luxury good, demand for which rises over-proportionally with income. This should not lead to considering these concerns as less real.

The first identification of a new externality is frequently promoted by groups outside the societal mainstream. If it turns out to be of genuine concern to important groups in society, these first statements will be taken up, information about the externality will be requested and individual and social preferences over certain parameters will be formed. Subsequently, pressure towards its internalisation will build up in public opinion, the political process or the legal system. This pressure will lead to more specific research and ultimately to the implementation of appropriate incentives for internalisation.

In a sufficiently long-term view, externalities can be considered temporal phenomena. By no means all, probably not even a majority, externalities identified by individuals or small groups are being taken up by the mainstream, but only those which in fact affect the well-being of a sufficient number of people in a strong enough fashion to warrant wider concern. If this is not the case, interest will fade quickly.

A case in point is the international effort to reduce carbon dioxide emissions so as to reduce climate change risks. Carbon dioxide as a non-poisonous, odourless gas had until a few decades ago no negative connotations attached to it. Fringe groups were the first to be concerned and pressured for more research. More research confirmed that there was at least some justification for concern. This prompted more research, a discussion about risks, damage probabilities and costs and, finally, first tentative steps towards internalisation. Institutions such as the United Nations Framework Convention on Climate Change (UNFCCC) and the Intergovernmental Panel on Climate Change (IPCC), but also dozens of national research institutes, advanced this process. In 2015, 194 countries signed the Paris Treaty with pledges aiming at maintaining global carbon emissions at a level consistent with a rise in global mean temperatures of no more than 2°C. Compared with other instances of social costs, one may think of tobacco smoking or lead concentration in drinking water, this process has developed reasonably quickly.

The debate about carbon dioxide emissions has also assembled the three major elements of any "internalisation" of effects over which fixed preferences do not yet exist, i.e. the media, the legal system and the political process. The legal system is in this

context understood in a very wide sense encompassing efficiency goals and technical regulations. First, there is public awareness and opinion creation by means of public communication. These may be commercial means of communication, such as television or newspapers, but also non-commercial means of public awareness creation such as demonstrations, sit-ins, public speeches and the like. Again, information is the first step in internalising external costs.

Second, there is the possibility to internalise through court action, which may impose liability or added abatement features. This way, the set of choices is transformed into new choices that integrate a higher share of public concerns. The legal approach to internalisation bears an interesting parallel to the Coase approach mentioned above. Any internalising court action can only be undertaken as long as there is a complete legal system defining rights and responsibilities on the basis of which recommendations or court orders can be formulated. Legally not defined spheres make internalisation through the legislative system impossible. In many cases, a necessary first step of internalisation is a definition of the legal responsibilities.

The third way of internalisation is the political process. Obviously, this sphere is closely linked to the former two. In the social choice literature, voting mechanisms have been discussed at length, usually under the assumption of existing static preferences. In this context, the term "political process" is to be understood in a wider sense, encompassing those processes of opinion formation, scientific expertise, decision making, of which the actual vote is only a relatively small part. The political process can also serve as a means of internalisation when, for instance, political parties run through transformations, or, in other words, deem it necessary to internalise some public concerns (e.g. the environment) into their platforms.

Thus, also the two preceding internalisation strategies discussed under the names of their initial proponents, Pigou and Coase, become part of a wider process. In this context the development and implementation of an economic instrument such as a "green tax" can be seen as the end-point of an expression of newly developed preferences. Equally, the development of property rights, or the perceived need for it, is the result of a perception of the good over which property rights are to be implemented as valuable. Thus, any internalisation is just the outcome of the continuing process to harmonise the preferences of different societal groups.

1.4. Conclusion

The costs of energy and, in particular, electricity provision are composed of three cost categories of decreasing economic and conceptual firmness – plant-level costs, grid-level system costs and external social and environmental costs. This does, of course, not imply any decrease in importance. The social costs of atmospheric pollution may one day dwarf any differences in generation costs. In some cases, grid-level system costs are already today large enough to overcome differences in plant-level costs (see Figure 3.3 in Chapter 3).

Energy policy makers trying to optimise energy systems on a full cost basis must thus act on all three categories at once. The instruments that are appropriate for each category are, however, very different (see policy conclusions on page 201). With respect to plant-level costs, the task is to provide the appropriate market framework in which private actors decide on the economically efficient mix of technologies. In the area of grid-level system costs, a rather new area of research and policy concern, the challenge is to devise metrics for assessing grid-level system costs and to internalise them through measures that minimise the costs of the total system under given security of supply and carbon constraints. This implies taking into account profile costs, balancing costs as well as increased outlays for transport and distribution grids. Depending on the accompanying measures chosen, e.g. the form of support for variable renewables such as wind and solar

PV, the scope for decentralised private decisions varies. Some decisions, however, will inevitably need to be taken at the system level in a centralised fashion.

External social costs are both the least codified and the most passionately debated elements in the full costs of energy systems. The previous sections have discussed at length the fundamental challenges that they pose for codification and monetisation. Needless to say, these difficulties diminish neither their economic relevance nor the high priority that they often have in policy discussions. While economists have developed a fully stocked tool-box to deal with different kinds of social costs in the energy sector, their most important quality could well be their dynamic nature. In other words, often it is more important to create the institutional settings and rules that will frame the process of internalisation rather than to come up with fully fleshed-out policy prescriptions.

The purpose of this report is thus not to provide ready-made answers to complex issues that inevitably will be resolved in different countries in different manners. Its purpose is to bring together in one single publication, the latest information on the orders of magnitude of the level of costs in different categories, together with their main challenges and most promising prospects for effective internalisation. It presents an overview of the most recent research on the full costs of electricity provision assessed by the NEA, which was supported in this effort by experts from OECD and IEA member countries. The following chapters will succinctly present this information for the following costs categories:

Direct economic impacts

- plant-level production costs;
- grid-level system costs.

Impacts on the environment and human health

- climate change;
- air pollution;
- the costs of major accidents;
- land-use and resource depletion.

Social and indirect economic impacts

- security of energy supply;
- impacts on employment and regional cohesion;
- positive spillovers for innovation and growth.

It has been repeatedly pointed out that the problem of externalities is closely related to barriers in communication between the different parties involved. All economic instruments ultimately attempt to achieve the double objective of transmitting the information on full costs to those able to control their level in order to achieve optimal outcomes in terms of the choice and mix of different technologies.

All that scientific, economic and technical discussion can do is to introduce and discuss the relevant parameters. Since research on the social and full costs of energy provision itself points out the difficulties of precisely achieving optimal outcomes, it would be odd if this report claimed to be able to provide definite answers. Decisions on when and how to internalise externalities will have to be taken by the relevant actors themselves on the basis of circumstance, available knowledge and best effort.

The energy sector plays an important role in this field. Not only because it contributes through its impacts on full costs, but also because of its positioning at the centre of the

economic activity in industrialised societies, it will always be the subject of value judgements beyond its measurable physical effects. For its own sake and the sake of society at large, the energy sector needs to engage with all of its stakeholders to find solutions that are sustainable not only in an environmental dimension but also in an economic and political dimension. Credible information is an indispensable first step in this process.

An important question is then whether it is private actors or governments which take the decisive steps. The preceding sections indicated under which conditions private or public action will be most effective. However, it is useful to emphasise the complementarity of the two modes rather than their opposition. Private action, such as envisioned by Coase, has to be supported by a government delimiting and enforcing private property rights in new spheres. Vice versa, a government, in its efforts to control emissions, has to rely on the information provided by private parties in order to optimise its policy.

One also needs to be aware of the link between static and dynamic optimisation. The above presentation of the economic theory of externalities necessarily had its emphasis on static optimisation. Instruments for static optimisation are most useful when dealing with goods over which fixed preferences are formulated and which are closely related to identifiable industrial processes. Yet, for many externalities this degree of informational preciseness is elusive. Static optimisation is also always an *ex post* internalisation. It is incapable of dealing with externalities at the early stages of their existence.

Thus additional institutional instruments need to be created that not just correct in hindsight but that include certain concerns *ex ante*. Consultation with stakeholders in the planning phase, round tables, exchange of data, government-sponsored voluntary agreements, public hearings, modifications in the legal and corporate procedural rules to allow for more outside input are all possibilities to tackle the problem of externalities *before* they have major effects on welfare.

Coming back to static optimisation, an important point is the comparison of "economic instruments" with "command-and-control measures". Again, they should be viewed as complementary rather than opposed, each useful in specific circumstances. Economic instruments enjoy a reputation of high efficiency, yet sometimes this is true also for optimal command-and-control measures (such as standards or technical regulations). On the other hand, economic instruments are often more transparent with respect to costs, as the latter are not hidden in technical manuals.

Once externalities are understood as communication failures, the triad "information, communication, implementation" becomes the guiding principle for the internalisation of externalities. Information includes identifying externalities as negative impacts on welfare. It includes the measurement of physical impacts and the documentation of scientific evidence. Good information separates hysteric worries from genuine problems and can proceed towards the measurement of the damage costs through an analysis of the preferences of those affected.

It is precisely in this dynamic logic that this report inscribes itself. In the field of full costs, good research does not substitute itself for the solution but facilitates it. Highlighting the critical points in each area and providing the sources for more in-depth detailed studies, this report wants to relaunch the discussion on full costs that after its heyday in the 1990s has, with the exception of climate change, somewhat slipped from the radar of policy discussion. Issues such as system costs, atmospheric pollution, security of energy supply and technology developments remain however large and pressing; and must remain firmly on the radar of policy makers.

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Chapter 2. **Plant-level production costs**

2.1. Introduction

The Nuclear Energy Agency (NEA) began publishing the *Projected Costs of Generating Electricity* in 1983 comparing nuclear power plant (NPP) and coal-fired power plant costs. This was updated in 1986. The International Energy Agency (IEA) joined the NEA in publishing this report in 1989. These two agencies of the OECD updated the report in 1992, 1998, 2005, 2010 and 2015 to evaluate the costs of electricity generation for a variety of technologies. These reports use input data provided by participating countries through a survey by electricity technology experts nominated by member countries (the Expert Group on the Projected Costs of Generating Electricity – EGC Expert Group).

The objective of the *Projected Cost* series of studies is to provide a reliable benchmark for the costs of electricity generation in different OECD member countries and selected non-member countries. Its intended audience are policy makers and electricity system experts and modellers, who depend on meaningful cost figures and models of national and regional electricity sectors. These two audiences can have slightly different objectives. Policy makers are trying to recommend policies that support the overall socially optimal selection of generation technologies, occasionally including the "full" costs of electricity. While some energy models pursue precisely the same objective, other models are trying to project how electric utilities make choices among these technologies as they minimise costs subject to satisfying all electricity demand or as they maximise profits subject to electricity market constraints. Other things equal, the methodology developed for the *Projected Costs of Generating Electricity* is geared towards providing more pertinent information for the first set of questions rather than for the second one. Overall, the *Projected Costs* series is one of the few sources of plant-level electricity generation cost information across a variety of technologies across a variety of countries.

The series evaluates the levelised cost of electricity (LCOE, in some editions also known as the EGC Expert Group, Electricity Generation Cost) which represents the cost of electricity generation at the busbar of the plant for a technology operated as baseload. The LCOE indicates the discounted lifetime costs averaged over the electricity generated. The LCOE thus provides a handy and transparent tool for assessing and comparing different technologies. It was originally developed for informing the investment choices of electric utilities in regulated electricity systems. Since it does not capture technology-specific quantity or price risks nor bankruptcy risk, it is less pertinent in deregulated electricity systems where the revenues and risks of different operators can vary substantially both among different technologies and from period to period over an electricity generator's lifetime.

One of the attractions of the LCOE methodology is its transparency and straightforward computation. As described in IEA/NEA (2015: p. 28):

> [T]he LCOE calculation begins with equation (1) expressing the equality between the present value of the sum of discounted revenues and the present value of the sum of discounted costs, including payments to capital providers. The subscript *t* denotes the year in which the sale of production or the cost disbursement takes place. The summation extends from the start of construction preparation to the end of dismantling, which includes the discounted value at that time of future

waste management costs. All variables are real, i.e. net of inflation. On the left-hand side one finds the discounted sum of benefits and on the right-hand side the discounted sum of costs:

$$\Sigma P_{MWh} * MWh_t * (1 + r)^{-t} = \Sigma(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t)\ (1 + r)^{-t} \quad (1)$$

where the different variables indicate:

P_{MWh}	=	the constant lifetime remuneration to the supplier for electricity;
MWh_t	=	the amount of electricity produced in year *t* in MWh;
$(1 + r)^{-t}$	=	the discount factor for year *t* (reflecting payments to capital);
$Capital_t$	=	total capital construction costs in year *t*;
$O\&M_t$	=	operation and maintenance costs in year *t*;
$Fuel_t$	=	fuel costs in year *t*;
$Carbon_t$	=	carbon costs in year t;
D_t	=	decommissioning and waste management costs in year *t*.

Because P_{MWh} is a constant over time, it can be brought out of the summation, and equation (1) can be transformed into

$$LCOE = P_{MWh} =$$

$$\Sigma\ [(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t)(1 + r)^{-t} / MWh_t (1 + r)^t] \quad (2)$$

where this constant, P_{MWh}, is defined as the LCOE (IEA/NEA, 2015: p. 28).

The methodology has been regularly vetted and, where appropriate, updated with each edition by the EGC experts. For example, since the 2010 editions, the cost estimates of fossil fuel technologies integrate a carbon price of USD 30 per tonne of CO_2. The LCOE is essentially calculated using a cash-flow model. The results of this model can be verified by calculating annual cash flows and dividing by annual output under the assumption that annual cost flows during operation are equal. On the equivalence of these methods, see Rothwell (2016; Appendix 2A).

Figure 2.1: **Plant-level costs for different power generation technologies**

(USD per MWh)

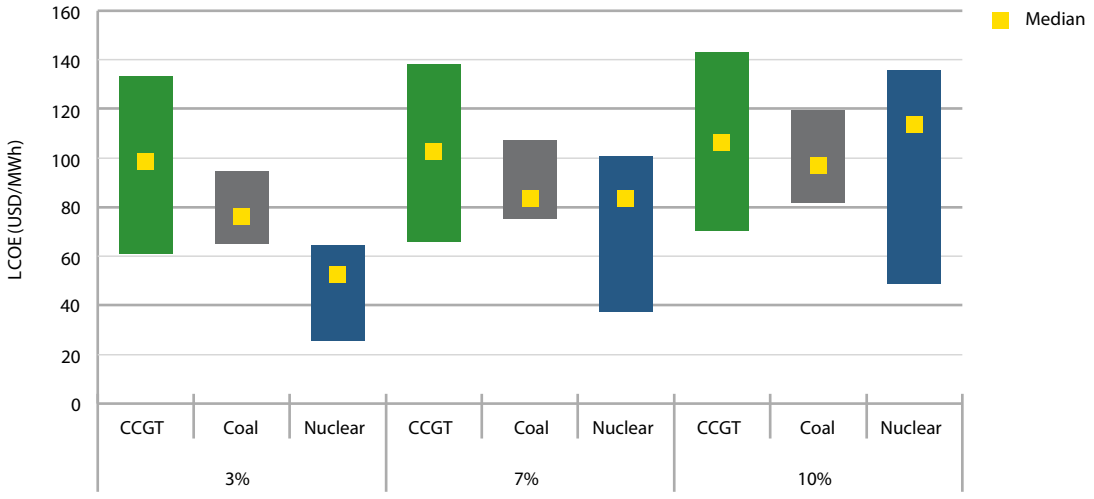
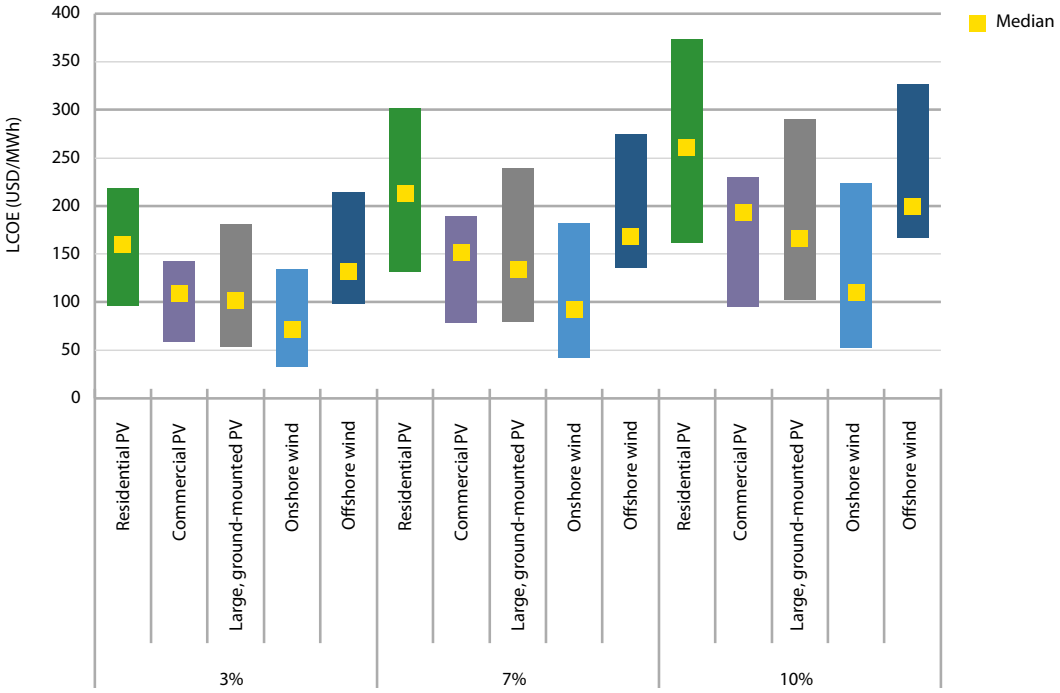


Figure 2.1: **Plant-level costs for different power generation technologies** *(cont'd)*



Source: IEA/NEA, 2015.

A key input in LCOE calculations is the discount rate. Having included for many years discount rates of 5% and 10%, the latest edition of the series, *Projected Costs of Generating Electricity 2015*, has provided results for discount rates of 3, 7 and 10%. Figure 2.1 presents the results for thermal technologies with a load factor of 85% on the left and renewable technologies with their country-specific load factors on the right. The figures for dispatchable thermal technologies also include a carbon price of USD 30 per tonne of CO_2. The latter assumes that the social costs of a changing climate due to greenhouse gas emissions are at least partially internalised in the policy provisions of OECD countries (IEA/NEA, 2015: Figure ES.1, p. 14 and Figure ES.2, p. 15). With the direct carbon emissions of coal being around one tonne per MWh and those of gas around 400 kg per MWh, their respective median values would be around USD 30 and USD 12 lower, if strictly no efforts to reduce CO_2 emissions were made.

A key parameter, however, remains the discount rate. Logically, the LCOE of nuclear as the most capital-intensive baseload technology depends more heavily on the discount rate that the LCOE of gas or coal, a feature that it shares with renewable technologies such as wind and solar. At 3%, nuclear is thus easily the least costly choice, whereas at 10% it is competitive only in a very few countries.

The LCOE figures are the result of a number of complex methodological conventions and assumptions concerning the different cost components that will be discussed in the following. The next two sections of this chapter consider capital costs and financing[1] Section 4 discusses variable costs. Section 5 concludes.

1. Decommissioning costs in this context are considered a capital expense, the funds for which are collected annually. Hence decommissioning and waste management costs in year t in Equations (1) and (2) can be modelled as annual (variable) costs. See NEA (2016) on the cost of decontamination and dismantling.

2.2. Plant-level overnight costs in levelised costs

One of the primary plant-level costs is the total capital investment cost (TCIC) of the generating facility (see, for instance, Economic Modelling Working Group (EMWG, 2007). This includes both the overnight (capital) cost and the costs of financing, which depend on the duration of construction, the construction expenditure flow, and the cost of capital. Overnight costs are supplied in the country surveys.

The capital cost values in IEA/NEA (2015) require some explanation, since the cost figures provided in Table 2.1 are estimates of costs in 2020. This is no big deal if costs are stable. It is however a crucial issue for technologies expecting further cost declines such as renewable energy technologies, in particular solar photovoltaic (PV). While it is true that the cost of renewable technologies – in particular solar PV – have declined significantly over the past five years, *Projected Costs of Generating Electricity, 2015 Edition* actually integrates further projected cost declines between 2015 and 2020, as reported by experts from member countries on the EGC. A number of publications such as *VGB* (2015: p. 10), *PV Magazine* (2015) or the *Ecologist* website actually confused values for 2015 and 2020, and thus oversold the historical decline of the costs of solar PV, which remain considerable by any historical standard. Table 2.1 provides the essential capital cost figures for 2020.

Table 2.1: **Net capacity and overnight costs for different technologies**

Technology	Input received	Net capacity (MW)[1]				Overnight cost (USD/kWe)[2]			
		Min	Mean	Median	Max	Min	Mean	Median	Max
Natural gas – CCGT	13	350	551	475	900	627	1 021	1 014	1 289
Natural gas – OCGT	4	50	274	240	565	500	708	699	933
Coal	14	605	1 131	772	4 693	813	2 080	2 264	3 067
Nuclear	11	535	1 434	1 300	3 300	1 807	4 249	4 896	6 215
Solar PV – residential	12	0.003	0.007	0.005	0.02	1 867	2 379	2 297	3 366
Solar PV – commercial	14	0.05	0.34	0.22	1.0	728	1 583	1 696	1 977
Solar PV – large	12	1	19.3	2.5	200	937	1 555	1 436	2 563
Solar thermal (CSP)	4	50	135	146	200	3 571	5 964	6 072	8 142
Onshore wind	21	2	38	20	200	1 200	1 911	1 804	2 999
Offshore wind	12	2	275	223	833	3 703	4 985	4 998	5 933
Hydro – small	12	0.4	3.1	2	10	1 369	5 127	5 281	9 400
Hydro – large	16	11	1 093	50	13 050	598	3 492	2 493	8 687
Geothermal	6	6.8	62	27	250	1 493	4 898	5 823	6 625
Biomass and biogas	11	0.2	154	10	900	587	4 447	4 060	8 667
CHP (all types)	19	0.2	5.3	1.1	62	926	4 526	2 926	15 988

1. Net capacity may refer to the unit capacity or to the combined capacity of multiple units on the same site.

2. Overnight cost includes pre-construction, construction (engineering, procurement, owner's and construction) and contingency costs, but not interest during construction (IDC).

Source: IEA/NEA, 2015.

2.3. Plant-level financing costs

Investment costs of the generating facility include both the overnight (capital) cost and the costs of financing, which depend on the duration of construction, the construction expenditure flow, and the cost of capital. The financing costs are calculated by the NEA under the direction of the EGC Expert Group. However, the appropriate discount rate is not obvious. Because of the different possible assumptions about discount rates, two or three different rates have been used in the previous reports. IEA/NEA (2015) breaks with previous editions by not calculating a 5% discount rate case.

> The real discount rate *r* used for discounting costs and benefits is stable and does not vary during the lifetime of the project under consideration. Also, this edition uses a 3% discount rate (corresponding approximately to the "social cost of capital"), a 7% discount rate (corresponding approximately to the market rate in deregulated or restructured markets), and a 10% discount rate (corresponding approximately to an investment in a high-risk environment). Nominal discount rates would be higher, reflecting inflation (see Chapter 8). These rates should not be seen as being applicable to particular projects but as a method to compare the costs of various technologies across regions. (IEA/NEA, 2015: p. 26)

A rather complete discussion of the different meanings that the notion of discount rate can assume can be found in NEA (1989: p. 123).

> Thus discount rates can be based on:
>
> i. The costs of investment funds (frequently the interest rate on bonds for an electric utility, but can also include the dividend on equity finance) over the timescale of the project.
>
> ii. The opportunity cost of capital at the time of investment as determined by the income it could potentially generate in alternative uses.
>
> iii. Social time preference reflecting wider benefits and society's desire to protect the interests of future generations.
>
> iv. Some mixture of these concepts.
>
> In general, the opportunity cost rate ii) is likely to be higher than the long-term borrowing rate i) which in turn is likely to be higher than the social time preference rate iii). Both the borrowing rate (or dividend or composite rate) and the opportunity cost rate are likely to be higher for investments perceived to have uncertain outcomes. In analytical terms, it can be convenient to distinguish the concept of time preference from that of risk. The risks of high or low outcomes for important items (such as the price of coal and other fuel inputs, capital costs, building times, load factors, efficiencies, availabilities for the generating plant) are most clearly described by the use of suitable sensitivity ranges combined with a purely time-preference discount rate. However, investors are on balance risk-averse and seek to avoid losses in more risky projects (or companies) by seeking higher rates of return. (NEA/IEA, 1989: p. 123)

It should be mentioned, however, that in the environment free of financial risk of regulated electric utilities for which LCOE was first developed, the four definitions converge towards a single cost of capital agreed to between utilities and the regulator that includes information from the private sector and social time preference. It should also be mentioned that the IEA/NEA reports do not consider any tax implications. In all but the first edition, a 10% discount rate was used. In all but the 2015 edition, a 5% discount rate was used. The 1989 edition used 3% and 7% for sensitivity analysis (along with the 5% and 10% values). As pointed out in the 1992 edition (p. 24):

> In earlier studies generation costs were calculated at real discount rates of 5 per cent p.a. and 10 per cent p.a. with sensitivity analyses in the 1989 study at 3 per cent and 7 per cent p.a. Five per cent was previously adopted as the reference value because it was consistent with the values adopted in the majority of OECD countries. Ten per cent was included to demonstrate sensitivity and because it was consistent with the highest rate used in participating countries (including non-OECD countries for their own analyses. (NEA/IEA, 1992: p. 24)

In the 1992, 1998, 2005 and 2010 editions, discount rates of 5% and 10% were used exclusively. As noted in IEA/NEA (2010: p. 34), "In keeping with tradition, also this edition of the *Projected Costs of Generating Electricity* has worked both with a 5% and a 10% discount rate." Although there has been a tradition of using discount rates of 5% and 10%, there has been some confusion regarding the determination of the discount rate.

IEA/NEA (2010: p. 151) deals with the difficult issue of distinguishing social and private investment costs, and states:

> Social resource cost is the opportunity cost a society has to forego when it undertakes an investment in a specific technology. The key aspect here is the assumption that all risk is captured in the discount rates. The additional uncertainty that goes beyond the risk captured in the discount rates and needs to be faced by an investor operating in competitive markets, in particular private investors, is not the subject of this study… In practice, private investors face higher financing costs than public investors since creditors demand extra insurance for the risk of default. For the purposes of this study, it means that when using the term "social resource cost", we treat the investment in question as if there was no price risk. The very notion of the levelised cost methodology implies the existence of stable electricity prices over the whole lifetime of the project. Nevertheless, the two discount rates used in this study (5% and 10%) provide rough indications of different levels of intrinsic risk. (IEA/NEA, 2010: p. 151)

The essential point here is that private, market-based discount rates include risks that are not uniform across technologies and depend on different market environments. They are hence not captured in the discount rates used in LCOE calculations. Also, for all technologies, the level of risk (and hence the discount rate that should be used to discount cash flows) depends on the stage of the project and thus varies with time. Instead, the LCOE methodology uses a constant discount rate over the lifetime of the project.

Therefore, while the EGC Expert Group, NEA and IEA consistently used similar discount rates from 1983 to 2015, the rationale for selecting these rates has changed over time.

2.4. Plant-level variable and levelised costs

Generally, the EGC assumes the price of fuel (IEA/NEA, 2015: p. 32). On the other hand, member country experts provide technology-specific operation and maintenance (O&M) costs. These costs were provided for coal and nuclear plants in all editions of *Projected Costs* in the 1980s; for natural gas (combined-cycle gas turbines – CCGT), coal and nuclear in all editions since 1992; and for onshore wind and ground-mounted solar PV in all editions since 2005.

In the 2005 edition:

> Like each study in the series, the present one aimed at covering state-of-the-art technologies for electricity generation commercially available at the time of publication. Accordingly, emphasis was placed in the present update on including a broad range of generation sources and technologies covering the span of

> alternatives considered in participating countries for power plants under construction in 2003-2004 and/or planned to be connected to the grids within a decade or so… However, some participating experts included plants recently connected to the grid that they considered representative of state-of-the-art technologies in their respective countries. Also, for some newer technologies with relatively steep learning curves, state-of-the-art technology today may have improved by 2010-2015. (NEA/IEA, 2005: p. 11)

Therefore, respondents for renewables could have projected costs to 2010. Compare this discussion with those in the 2010 and 2015 editions.

In the 2010 edition: "The study focuses on the expected plant-level costs of baseload electricity generation by power plants that could be commissioned by 2015" (IEA/NEA, 2010: p. 17).

In the 2015 edition:

> This report presents the results of work performed in 2014 and early 2015 to calculate the cost of generating electricity for both baseload electricity generated from fossil fuel thermal and nuclear power stations, and a range of renewable generation, including variable sources such as wind and solar. It is a forward-looking study, based on the expected cost of commissioning these plants in 2020. (IEA/NEA, 2015: p. 17)

However, the IEA/NEA 2015 edition (p. 11) raises issues regarding possible changes in renewables costs between 2014 (the date of the survey) and 2020:

> What is the representative cost of renewable energy? Answering this question is a particular challenge, given the dynamic evolution of some technologies, such as solar PV and wind… Moreover, rapid price declines in some technologies mean that data points can quickly become obsolete. For example, despite significant declines in solar PV module costs in recent years, prices for entire PV installations vary significantly among countries for similar system types. Most of the gap comes from differences in "soft costs", which include customer acquisition; permitting, inspection and interconnection; installation labour; and financing costs, especially for small systems… *The Medium-term Renewable Energy Market Report* (IEA, 2014), or MTRMR, goes one step forward towards displaying more representative costs. Though not a cost study per se, the MTRMR tries to identify the most dynamic markets for solar PV deployment over the medium term and focuses cost evaluation efforts on these areas (IEA, 2014). Unlike EGC 2015, the MTRMR also tries to apply market-specific discount rates to its LCOE calculations, though such values can carry a degree of uncertainty. The upshot of such an approach is that the MTRMR cost analysis better reflects the expected trend of deployment. (IEA/NEA, 2015: p. 113)

The MTRMR differs from the methodology in *Projected Costs*, as it uses "market-specific discount rates". Therefore, it is difficult to reconcile the MTRMR 2014 sample of utility-scale solar PV LCOEs projected in 2020 (see Figure 6.2) where the median and mean LCOEs are below USD 100 per MWh with: (1) EGC calculations where the median and mean LCOEs are above USD 150 per MWh; and (2) EGC calculations where the median for solar and wind technologies is at USD 200 per MWh.

To investigate the origin of the plunge cost values for onshore wind and ground-mounted PV from NEA/IEA (2005), IEA/NEA (2010), and IEA/NEA (2015) are translated into 2013 USD (the currency used in IEA/NEA, 2015) and compared in Tables 2.2 and 2.3.

In Table 2.2 regarding onshore wind, the mean size increased from 36 MW in 2005 (projected to 2010) to 56 MW in 2010 (projected to 2015), then decreased to 38 MW in 2015 (projected to 2020). In other words, there was little anticipated change in the size of onshore wind projects. The mean load or capacity factor increased from 24% in 2005 to

27% in 2010, and to 31% in 2015. In other words, the onshore wind load factor increased by more than 10% over each five-year period, thus decreasing the fixed cost component of its LCOE. Strangely, the mean overnight cost increased from USD 1 605 per kW_e in 2005 to USD 2 622 per kW_e in 2010, then decreased to USD 1 911 per kW_e in 2015. In other words, expected average overnight costs increased by 63% from 2010 to 2015, then decrease by 27% from 2015 to 2020, but were still 19% higher in 2020 than in 2010.

Regarding O&M costs, anticipated 2010 mean 0&M costs rose from USD 12.92 to USD 25.75 for 2015, then fell to USD 22.46 in 2020. In other words, expected average O&M costs doubled from 2010 to 2015, then decrease by 13% from 2015 to 2020, but were still 74% higher in 2020 than in 2010. Finally, looking at the LCOE at a 10% discount rate (which is the only one calculated in all three editions), the LCOE for onshore wind increased from USD 90 per MWh to USD 148 per MWh and then declined to USD 110 per MWh, i.e. it increased by two-thirds from 2010 to 2015, then declined by 26% for 2020, but was still 23% higher in 2020 than in 2010.

Table 2.2: **The costs of onshore wind**

(in USD 2013)

	Site capacity (MW)	Load factor (%)	Overnight cost (USD/kW_e)	O&M costs (3% or 5%) (USD/MWh)	LCOE 3% (USD/MWh)	LCOE 5% (USD/MWh)	LCOE 7% (USD/MWh)	LCOE 10% (USD/MWh)
IEA/NEA (2015: Table 6.7)					IEA/NEA (2015: Table 3.13)			
Count	20	20	20	18	18		18	18
Maximum	200	49%	2 999	36.24	135		182	223
Minimum	2	20%	1 200	11.37	33		43	52
Mean	38	31%	1 911	22.46	71		91	110
Median	20	28%	1 804	21.38	68		85	99
IEA/NEA (2010: Table 5.1)					IEA/NEA (2010: Table 5.2)			
Count	13	13	13	13		13		13
Maximum	150	41%	4 022	46.30				
Minimum	2	21%	1 997	9.34				
Mean	56	27%	2 622	25.75		105		148
Median	45	26%	2 542	23.72				
NEA/IEA (2005: Table 4.4)					NEA/IEA (2005: Table 4.5, 4.6)			
Count	8		8	8		8		8
Maximum	60		1 836	18.75		96		134
Minimum	14		1 297	6.21		39		61
Mean	36	24%	1 605	12.92		63		90
Median	35		1 644	13.36		59		82

Sources: IEA/NEA, 2015; IEA/NEA, 2010; NEA/IEA, 2005.

In Table 2.3 regarding large ground-mounted solar PV, the mean size increased from 1.51 MW in 2005 (projected to 2010) to 3 MW in 2010 (projected to 2015) and to 19 MW in 2015 (projected to 2020). However, the expected median size increased from 0.5 MW in 2010 to 1 MW in 2015 to 3 MW in 2020. In other words, the Chinese project of 200 MW skewed the mean in IEA/NEA (2015: p. 50). There appear to be many small, "large" PV projects and a few large "large" projects, most of which are being built outside OECD countries. The anticipated mean load factor increased 40% from 11% in 2010 to 15% in

2015. In other words, PV capacity factors seem to have approached an upper boundary although concentrated solar power (CSP) facilities have higher capacity factor (see discussion and data in IEA/NEA, 2015: pp. 42-43). Surprisingly, the anticipated mean overnight cost decreased from USD 7 261 per kW_e in 2010 to USD 6 000 per kW_e in 2015 and to USD 1 555 per kW_e in 2020. In other words, expected average overnight costs decreased by 17% from 2010 to 2015, then decrease by 74% from 2015 to 2020. These, of course, are anticipated declines, not actual declines.

Table 2.3: **The costs of ground-mounted PV**

(in USD 2013)

	Site capacity (MW)	Load factor (%)	Overnight cost (USD/kW_e)	O&M costs (3% or 5%) (USD/MWh)	LCOE 3% (USD/MWh)	LCOE 5% (USD/MWh)	LCOE 7% (USD/MWh)	LCOE 10% (USD/MWh)
IEA/NEA (2015: Table 6.6)					IEA/NEA (2015: Table 3.12)			
Count	12	12	12	10	11		11	11
Maximum	200	21%	2 563	54.09	181		239	290
Minimum	1	11%	937	2.65	54		80	103
Mean	19	15%	1 555	30.45	107		144	175
Median	3	15%	1 436	37.40	102		135	166
IEA/NEA (2010: Table 5.1)					IEA/NEA (2010: Table 5.2)			
Count	13	13	13	13		13		13
Maximum	10	25%	7 988	87.60				
Minimum	0	10%	3 536	6.20				
Mean	3	15%	6 000	37.90		445		667
Median	1	13%	6 499	81.40				
NEA/IEA (2005: Table 4.4)					NEA/IEA (2005: Table 4.5, 4.6)			
Count	4	4	4	4		4		
Maximum	5.00		12 876	174.69		1 926		2 377
Minimum	0.03		4 260	6.08		153		265
Mean	1.51	11%	7 261	75.29		764		1 031
Median	0.50		5 953	45.10		489		741

Sources: IEA/NEA, 2015; IEA/NEA, 2010; NEA/IEA, 2005.

Regarding O&M costs, anticipated 2010 mean 0&M costs fell from USD 75.3 to USD 37.90 for 2015, and then fell to USD 30.45 in 2020. In other words, expected average O&M costs fell by 50% from 2010 to 2015, and again by 20% from 2015 to 2020. Finally, looking at the LCOE at a 10% discount rate, the LCOE for large solar PV decreased from USD 1 031 per MWh to USD 667 per MWh and then to USD 175 per MWh, i.e. it decreased by one-third from 2010 to 2015, then by three-quarters to 2020. Therefore, the anticipated costs of large solar PV have "plunged" by more than 80% from 2005 (see NEA/IEA, 2005) to 2015 (see NEA/IEA, 2015).

2.5. Summary and key issues for policy makers

This chapter has examined some of the key methodological issues in the calculation of LCOE in the *Projected Costs* series up to its last edition in 2015. While there appears to be a general consensus that the LCOE methodology is still useful as a cost concept limited to

the workings of an individual plant, it includes, by definition, neither the complete system costs of electricity provision (see Chapter 3) nor *a fortiori* the full costs of electricity provision. LCOE costs are however an important element of both system costs and full costs, and thus fully deserve to figure in this report.

An important fact to keep in mind in all *Projected Costs* studies is that reported costs are not actual costs but anticipated costs of new projects as communicated by member country experts and validated by their respective governments. Changes in LCOE are thus anticipated changes rather than actually verified changes. Both the *Projected Costs of Generating Electricity* series by the IEA and NEA as well as LCOE accounting, in general, have their limits and any results need to be adequately framed. However, thus far, their inconveniencies are still more than outweighed by their usefulness for energy experts, modellers and policy makers.

Considering the latest issue of the *Projected Costs* series, the 2015 edition, and, in particular, comparing it with earlier issues, two striking facts appear. The first fact is the substantial decline in the costs of renewable energies, in particular solar PV. The overnight investment costs of ground-mounted PV installations as reported by OECD member countries in 2015 (for installation in 2020) have thus declined on average by 75%, when compared with the figures reported in 2010 (for installation in 2015). The second important fact is the decisive influence of the discount rate or discount factor. Because of the capital-intensity of all low carbon technologies, nuclear, hydro and renewables, this influence is bound to increase as OECD countries decarbonise their electricity sectors. Nuclear energy as the only large dispatchable source of low-carbon baseload power is particularly affected. At a discount rate of 3%, nuclear is easily the least costly choice, whereas at 10% or even 7% it is competitive only in a very few countries. Nuclear power will not be able to rely on the advantages of the current low interest-rate environment for ever. Efforts on reducing the capital costs of nuclear power, through incremental improvements at the industrial level, as well as through innovation through new research and development, are thus an indispensable part of credible strategies to decarbonise the power sector.

A frequent source of misunderstandings is the discount factor in the levelised cost equation and its relationship to the cost of capital. This chapter has reviewed the discussion of this relationship in the various editions of the report. It is beyond the scope of the present study to determine the "correct" discount factor. The relationship of the discount factor to concerns regarding "sustainability" must however be discussed elsewhere and, ideally, before the next edition of *Projected Costs*.

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Chapter 3. **Grid-level system costs**

3.1. Introduction

As defined in the International Energy Agency (IEA)/Nuclear Energy Agency (NEA) methodology described in the previous chapter, the levelised costs of electricity (LCOE) represent the average lifetime cost of producing a MWh of electricity, obtained by summing all the various expenses (investment, fuel, operation and maintenance, dismantling and, when appropriate, carbon emissions) over the lifetime of the power plant and dividing them by the electricity generated, after an appropriate discounting factor is taken into account. Plant-level costs therefore integrate all different expenses needed to generate a given amount of electricity at the busbar of the plant but do not consider all the infrastructure and associated costs needed to provide the electricity to each customer. By construction, plant-level costs also consider each power plant in isolation, without considering how they interact with each other.

Contrary to other goods and services for which production costs constitute the large majority of providing the good or service to a client, in the case of electricity generation, costs represent only a part, albeit an important one, of the costs to provide electricity to a customer. Many components and systems other than generating plants are needed to transport the electricity from the production site to the final consumers, to ensure that power supply continuously matches demand and that the electricity system is able to withstand the potential failure of one of its components without disrupting the security of electricity supply (the N-1 criterion). While a customer perceives only one defined good in terms of kWh, each component of the power system provides many other services and interacts with all the others to guarantee that the system operates efficiently and guarantees the required level of security of electricity supply.

The concept of system costs has been recently developed to describe and take into account the interactions between different generation technologies and the infrastructure which constitute the power system, and to capture the impacts of the introduction of each technology on the whole system. System effect analysis also provides a framework for characterising the contribution of a given generation technology to the overall power system. In other words, if plant-level costs characterise the cost of generating a kWh of electricity, system costs capture the additional costs of providing the kWh to the customer in the context of the system as a whole. While grid-level system costs have always existed in unbundled electricity systems and competitive generation, this concept has been developed extensively and framed by the IEA and the NEA in the recent years (IEA, 2011 and 2014, NEA, 2012 and IEA/NEA, 2015) and has benefitted from a significant amount of new research from academia, industry and governments.

If the analysis is limited to generators, each power plant has its specificities and characteristics: it is able to provide certain services to the system other than pure electricity generation and imposes some constraints and additional requirements to the system. Broadly speaking, despite their individual differences, dispatchable technologies, including nuclear, share similar features and cause a relatively limited impact on the overall electricity system. Impacts are mainly due to the large size of hydroelectric and nuclear facilities, which require somewhat higher amounts of balancing reserves to satisfy the N-1 criterion as well as special outlays for connection to the transmission grids. However, because of their large output, the additional costs per MWh remain limited.

On the contrary, variable renewable energies (VREs), more specifically wind and solar photovoltaic (PV) technologies, share some specific characteristics that make their integration into the electricity system more challenging and affect both their capability to provide services to the system and the economic value of their production. This is why the topic of system effects has attracted much interest since VRE technologies have reached significant penetration levels in many OECD countries.

The IEA (2014) has identified six technical and economic characteristics that are specific to VRE and differentiate them from dispatchable generation technologies. These characteristics, which are intrinsically linked to their nature, affect the VRE contribution to the power system and are a key element to explain and understand the associated system costs. It should be kept in mind, however, that the precise impact of each one of these characteristics strongly depends on the surrounding electricity systems, the composition of the generation mix, the carbon pricing regime, the form of renewables support and, in particular, the availability of flexible resources on the supply and the demand sides. The output of VRE is:

1. Variable: the power output fluctuates with the availability of the resource. VRE are non-dispatchable as the power output cannot be adapted to the system's needs. [1]
2. Uncertain: the amount of power produced cannot be predicted with precision. The accuracy of production forecast increases when approaching the time of delivery.
3. Location-constrained: the available resources are not equally good in all locations and cannot be transported. Often good sites are in a same region and far from load centres.
4. Non-synchronous: VRE plants are connected to the grid via power electronics, while conventional generators are synchronised to the grid.
5. Multi-scale: the scale of an individual VRE unit is much smaller than other conventional generators.
6. With low variable costs: once constructed, VRE can generate power at little cost. In particular, variable production costs (marginal costs) are close to zero for wind and solar units.

Recent analysis performed at the NEA (2012) nevertheless shows that, while all generation technologies have some system costs, the costs imposed to the system by variable renewables are of at least one order of magnitude larger than those of dispatchable technologies. In addition, the introduction of subsidised VRE creates a market environment in which conventional technologies are unable to be financed through revenues in "energy-only" markets, which may have serious implications for the security of electricity supply. With the increased share of VRE in the electricity mix of many OECD countries, their impact on the system is becoming more and more apparent, calling for a recognition of the existence of system effects and for putting in place adequate frameworks to minimise them and, to the extent possible, to internalise them.

1. Wind generation could be curtailed in case of need and thus could provide some downward services to the system.

3.2. Definition of system effects, methodological issues, difficulties and uncertainties

Despite increasing research performed in this area and progress achieved, a rigorous and universally accepted definition of system effects and a well codified methodology for their quantification are still lacking. This is a direct consequence of the underlying nature of system effects, the complexity of the phenomena involved and the challenges of performing a detailed modelling of the power system. By their nature, system effects cannot be defined nor observed by looking at a single system, but can be understood and quantified only by comparing two or more systems, and their quantitative estimation depends on the choice of the reference system ("benchmark"). As an example, the introduction of a given amount of VRE capacity in a given system, let us say 10 GW of onshore wind, would cause in the long term a change in the electricity system: more transmission would be needed (or a different structure of the transmission grid) as well as a different generation mix, more adapted to accommodate the characteristics of wind production. The quantification of system effects due to the introduction of these 10 GW is possible only by comparing the new generation system with the reference system, in which the 10 GW of wind energy has not been exogenously imposed. How the reference system is defined and how the system with wind energy is constructed and optimised are key aspects in any quantitative evaluation of system effects. These are often divided into the following three broad categories:

a) utilisation costs, sometimes referred to as profile costs;

b) balancing costs;

c) grid costs, which may include connection costs.

Utilisation costs (or profile costs) refer to the increase in the costs of the electricity system in response to the variability of VRE output. They capture the fact that in a system with VRE, it is generally more expensive to provide the residual load than in a system with a technology that is dispatchable but otherwise equivalent in terms of LCOE. Utilisation costs are the opportunity cost of not having, in the long term, a cheaper conventional generation mix for the residual load (see Figure 3.1 for an illustration).

Another way of looking at the utilisation costs of VRE is to consider that the electricity production of wind or solar PV is concentrated during a limited number of hours with favourable meteorological conditions. This autocorrelation reduces the average value of each MWh of VRE output. Especially at high penetration levels, a given VRE plant is more likely to generate when other VRE plants are also generating, which reduces the market value of the electricity produced as well its contribution to the system. Finally, utilisation costs should also include the effect associated with the low capacity credit of VRE as well as the increased burden to other plants in terms of more frequent cycling and steeper ramping requirements.

If electricity markets are complete and perfectly competitive, there is a direct link between utilisation costs and the market revenues obtained by a given VRE technology. Several studies (Fripp and Wiser, 2008; Joskow, 2011; Hirth, 2013 and 2015a) have shown on the basis of using empirical market data or numerical simulations that the market remuneration of electricity generated by VREs indeed decreases with the latter's share in electricity production. This phenomenon reflects the lower value for the system of each additional unit of VRE production and corresponds to an equivalent increase in utilisation costs. This observation is important since utilisation costs could be internalised if all technologies were exposed to market signals. [2]

2. Exposing all technologies to market prices in an energy-only market could internalise a large fraction of utilisation costs.

Balancing costs are related to the uncertainty of the power production due to unforeseen plant outages or forecasting errors of production. In case of dispatchable plants, the cost of operating reserves are generally given by the larger contingency, in terms of the larger unit (or the two largest units) connected to the grid. In case of VRE, balancing costs are essentially related to the uncertainty of their output, which may become important when aggregated over a large capacity. Because of the uncertainties in VRE power output, the schedule of other power plants in the system has to be changed more frequently and closer to the real time. Also, forecasting errors may require carrying on higher amounts of spinning reserves in the system. This may lead to increasing ramping and cycling of conventional power plants, to inefficiencies in plant scheduling and, overall, to higher costs for the system. Sometimes, the variability of VRE within the scheduling interval of power systems (one hour or less) is also accounted for balancing costs.

Grid costs reflect the effects on the transmission and distribution grid due to the locational constraint of generation plants. While all generation plants may have some siting restrictions, the impacts are more significant for VRE. Because of their geographic location constraint, it may be needed to build new transmission lines or to increase the capacity of existing infrastructure (grid reinforcement) in order to transport the electricity from production centres to load. In addition, transmission losses tend to increase when electricity has to be moved over long distances. Also, high shares of distributed PV resources may require sizeable investments into the distribution network, in particular to allow the inflow of electricity from producer to the grid when the electricity generated exceeds demand.

Connection costs are defined as the costs of connecting the power plant to the nearest connecting point of the existing transmission grid. They can be significant especially if distant resources have to be connected as can be the case for offshore wind, if load factors are low or if the technology has more stringent connection requirements than for nuclear power. Connection costs are sometimes integrated within the system costs (NEA, 2012), but more often are not considered as system costs and implicitly included in the LCOE as plant-level costs. The difficulty in this assessment is that connection costs are sometimes borne by the plant developer and sometimes paid for by the transmission grid operator. In the former case, they are part of the plant-level costs and thus fully internalised, while in the latter case they become part of the system costs.

The above characterisation is not fully exhaustive, as there are other aspects that may have a noticeable impact on the electricity system, especially at high shares of renewables. For example, the fact that VREs are connected to the grid via power electronics and thus are non-synchronous will reduce the inertia of the system, although advanced power electronics can mitigate some of this effect. This reduction impacts the ability of the system to restore the target frequency levels after an incident, and thus undermines the overall robustness of the system. However, to the knowledge of the authors, there has not been a systematic attempt to quantify its economic impact and thus other effects will not be discussed further in this chapter.

It is important to note that the different categories are not independent from one another, but costs can be "shifted" from a category to another. For example, additional investments in the transmission and distribution infrastructure, and thus higher transmission costs, may lead to a cheaper generation mix and lower balancing costs, thus reducing the two other cost components. Similarly, having a more flexible generation is generally more expensive, but allows for a reduction in balancing costs.

These conceptual difficulties are compounded by the challenge of modelling a complex system such as a large interconnected electricity grid. System effects calculations would require the simultaneous optimisation of the transmission and distribution networks together with that of the generation system, with a time frame going from the short-term operational constraints in the range of few tens of minutes to

the long-term investment planning on new generating capacities and on transmission and distribution (T&D) infrastructure. The numerical capabilities of existing tools do not allow such comprehensive calculations and existing power system models can represent only some aspects of the whole system and are therefore able to capture only limited impact groups at once. For instance, some models are able to assess impacts on the transmission or distribution grid, while others may be able only to assess the impact on balancing, on reserve requirements or on utilisation costs.

System costs depend strongly on the characteristics of the system analysed, on the type of generating technology considered and on its share in generation. While these considerations hold for every technology, their impact is particularly pronounced for variable renewables. Characteristics specific to each power system, such as the shape of electricity demand, the correlation between load and generation profile of VREs, the composition of the existing generation mix and the geographical distribution of VRE resources and load, have a major impact on system costs and on VRE integration potential. For example, system costs are lower if there is a good match between VRE production and demand or if distributed resources are closer to the main load centres. Similarly, systems with a large amount of flexible resources and storage capacity experience much lower system costs than more inflexible systems. Also, numerical analyses and empirical experience show that all components of system costs, and in particular utilisation costs, increase substantially with the share of VREs in electricity generation.

Each result is therefore specific to the system and to the level of VRE penetration for which it has been derived and, in general, cannot be easily extrapolated or adapted to other systems and other conditions. However, while numerical results can differ, the main trends and effects observed are common to all system and penetration levels.

A last important aspect is the importance of the time frame chosen for the economic analysis of system effects: the overall economic impacts on the system arising from the introduction of new generation capacity as well as the impacts on the operation mode and economic profitability of existing assets depend strongly on the time horizon chosen for their assessment. In the short term, the electricity system is locked in with the existing generation mix and infrastructure and cannot adapt quickly to the introduction of the new technology. On the contrary, in the long term, both the infrastructure and generation capacity can evolve and adapt to the new market conditions resulting from the introduction of the new generation capacity. Thus, system costs are different if assessed in a short-term perspective with numerous dynamic processes or in a long-term equilibrium perspective.

For example, the recent fast deployment of a large share of VRE resources in many OECD countries had a significant impact on electricity market conditions, with a large decrease of the average electricity prices combined with an increase in their volatility. This had a profound consequence on the operations and the revenues of existing power plants. Also, if looked at in a long-term perspective, the introduction of VREs would cause a shift of the generation mix, with a shift towards more mid-load and peak power plants and a decrease in baseload capacity. Because prices are set by the variable costs of the marginal technology in competitive electricity systems, *prices* in long-run equilibrium would actually be the same as before, as long as VREs do not become the marginal technology with episodes of zero- or negative prices. Nevertheless, *costs* would go up as larger capacities of peaking plants would substitute for baseload capacity, which is no longer called upon for a sufficiently large number of running hours. Episodes of zero or negative prices would, of course, further contribute to the latter's hardship.

Box 3.1: **Short-term impacts of VRE deployment**

For the present study, system costs and in particular utilisation costs have been estimated in a long-term perspective, i.e. adopting a greenfield approach. While this does not account for all the costs incurred today by the system, it allows performing an unbiased comparison among technologies without implicitly favouring incumbent generators at the expense of newcomers.

However, it should be recognised that the recent rapid deployment of subsidised VRE in many OECD countries had a profound impact on the electricity market, in particular contributing to a sharp decrease of wholesale electricity prices and to an increase of their volatility.* This, in turn, has severely affected the revenue stream and the profitability of incumbent utilities, thus jeopardising their financial stability and their ability to take on new investments. The short-term impact on market prices has been, by far, the most acutely felt by the industry.

As already mentioned in the introduction, a decrease in electricity market prices does not constitute necessarily an externality per se: the introduction of a cheaper and more efficient technology under market conditions, a decrease in electricity demand or in fuel costs would all cause a decline in electricity prices and thus have a financial impact on incumbent generators/utilities. However, all these causes are part of the industrial risk of generating electricity and should not be considered an externality. The fact that VREs have been deployed outside market mechanisms and that they are not exposed to a price feedback is the reason why these effects should be considered as "pecuniary" externalities, even if this is still controversial. However, in the following, we will simply describe the short-term impact of introducing new VRE capacity into the market, without further discussing whether these effects are an externality.

In the short term, the addition of new VRE capacity into a system causes two different effects in the electricity market:

i) Reduction in the capacity factors of existing generators, in particular for those with the highest marginal cost (*compression effect*).

ii) Reduction of the electricity market price when VREs are generating (*merit order effect*), since plants with higher marginal costs are put out of the market, which results in lower spot and average electricity market prices and in a reduction of infra-marginal rent for baseload and mid-load technologies.

The combination of a reduced capacity factor and reduced electricity prices may have a severe impact on the revenues of existing generating plants. Quantitative estimates performed by the NEA (2012) show that this phenomenon affects all existing generators, but the effect is more significant for peak- and mid-load plants, as shown in the table.

Short-term electrical load and profitability losses

Penetration level		10%		30%	
Technology		Wind	Solar	Wind	Solar
Load losses	Gas turbine (OCGT)	-54%	-40%	-87%	-51%
	Gas turbine (CCGT)	-34%	-26%	-71%	-43%
	Coal	-27%	-28%	-62%	-44%
	Nuclear	-4%	-5%	-20%	-23%
Profitability losses	Gas turbine (OCGT)	-54%	-40%	-87%	-51%
	Gas turbine (CCGT)	-42%	-31%	-79%	-46%
	Coal	-35%	-30%	-69%	-46%
	Nuclear	-24%	-23%	-55%	-39%
Electricity price variation		-14%	-13%	-33%	-23%

These findings, based on a simplified modelling exercise, are backed up by an analysis of the electricity drop in Germany and Sweden between 2008 and 2015 (Hirth, 2016b). In this time horizon, the average electricity market price has decreased by 59% in Germany and by 57% in Sweden. Among the different individual factors considered (market prices of coal, gas and CO_2, change in electricity demand, electricity import/exports, investments in new conventional plants and phase-out of nuclear units in Germany, availability factors of nuclear and hydro plants), the deployment of variable renewable energy has been the largest individual contributor to the price drop: -24% in Germany and -35% in Sweden.

* Many other elements have contributed to the sharp decline in electricity prices, such as the unanticipated reduction in electricity demand, the decline in fossil fuels and in carbon prices, as well as additional investments in conventional capacities.

+ Note that, in the same time, electricity prices for households (all taxes and levies included) have increased by 37% in Germany and by 10% in Sweden (source: Eurostat).

3.3. State of research, main studies and quantitative estimates

Although the studies on system effects are relatively recent, a sufficiently rich literature is building on this topic. However, because of the intrinsic complexity of such analysis, most of the studies focus only on one or two components of system costs and, to the knowledge of the authors, a complete and comprehensive analysis of the system effects has yet to be performed. Also, many studies analyse and describe the impacts of large VRE penetration on the system, but do not explicitly calculate the system costs.

Almost the totality of studies focus on the system cost associated with the introduction of VRE, and only minimal attention has been given to conventional dispatchable technologies. The only attempt in this respect has been performed by the NEA publication (2012) in which the system costs of different conventional power plants have been compared with those of VREs. Also, the large majority of recent studies focus on the impacts on the generation mix (utilisation cost) or on the value of VRE generation, while the amount of research on impacts on transmission and distribution infrastructure or on balancing costs is more limited.

A survey of results from the literature shows a wide range of results, which underlines the difficulties of such undertakings. In particular, it should be kept in mind that quantitative results are influenced by many factors and assumptions, which may significantly differ among studies:

i. different power systems are assessed, and for different levels of VRE penetration;

ii. different assumptions for the availability and cost of technologies in the future, in particular for storage capacity, smart grid and demand side response;

iii. costs assessments are made in a long-term or on a short-term perspective;

iv. different definitions for each system cost component;

v. different models which have a different degree of complexity and different predictive capacity;

vi. different frameworks for the analysis.

However, despite these difficulties, the most recent estimates of the different categories of system effects are provided in the following paragraphs.

Utilisation costs and the value of VRE generation

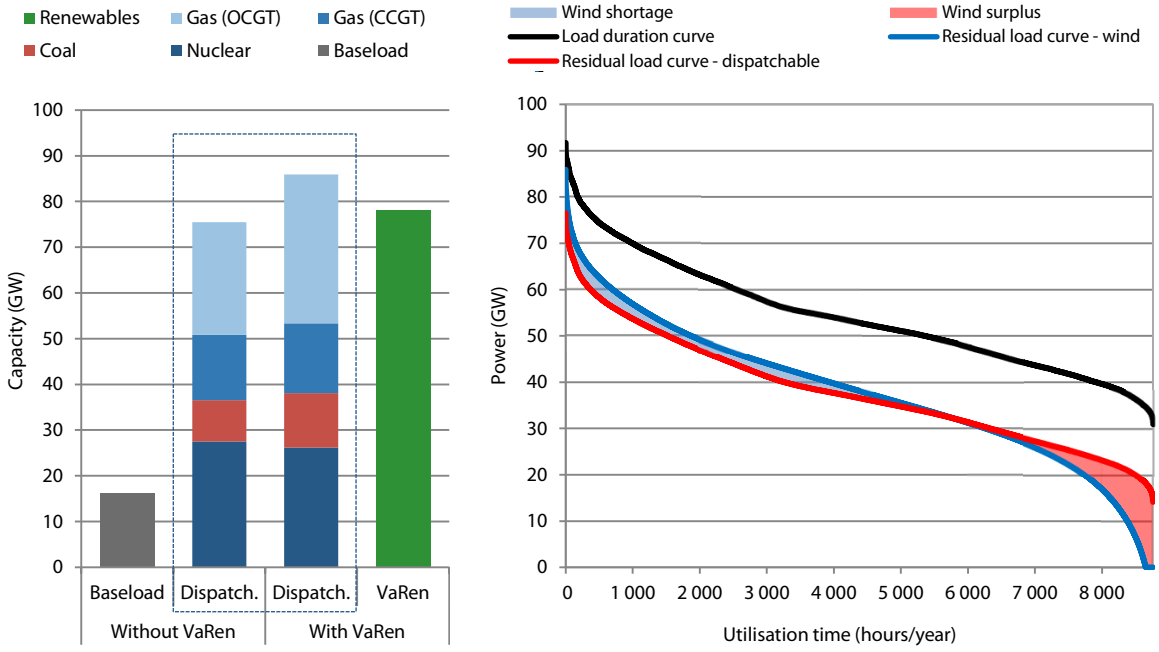
In recent years there has been a significant effort to understand, capture and quantify the impacts that the introduction of VREs has on the residual load and on the generation mix. In the long term, the deployment of VREs induces a significant change in the structure of the conventional generation mix, with a larger overall capacity needed [3] and a shift from baseload technology towards peakers and mid-load capacity. In term of electricity generated, the share of baseload generation is reduced and replaced by peak and mid-merit plants. This effect is illustrated in Figure 3.1, where the residual load for a system with a given capacity of VRE (wind at 30% share in blue) is compared with that of system where the same amount of energy is provided by baseload capacity (30% of demand, in red): the difference between those two curves constitutes the essence of utilisation costs. In most of the cases, the cost for providing the residual load is higher in a system with VRE than in a system without, and this cost increases markedly with their penetration level.

3. Because of the generally lower capacity credit of VREs, a larger capacity of dispatchable plants is needed to meet the residual load (in the absence of storage and demand-side management).

While there is a broad consensus about the impact of VRE introduction, the quantification of utilisation costs requires a significant modelling effort and results are sensitive to the establishment of a large number of parameters and assumptions. Also, the quality and precision of computational tools used have an impact on the results. For example, methods based on residual load duration curves are unable to adequately take into account the storage capacity present in the system and the potentials for demand-side management, thus implicitly overestimating utilisation costs. Furthermore, these models cannot correctly describe the technical limitations on flexibility of all conventional power plants nor take into account the associated costs, which lead to an underestimation of utilisation costs. These limitations are overcome, at least partially, by using more complex modelling tools, based on dispatch and unit commitment models.

Also, most studies attempt to evaluate the declining value of VRE generation with an increasing share of VRE production, expressed often as a fraction of the value of baseload production, while only few authors assess directly utilisation costs. As previously indicated, these two metrics essentially describe the same effect, and the findings of the different studies are coherent in this respect; it is however not straightforward to translate an estimate of "value" of VRE generation in terms of "utilisation costs" and vice versa.

Figure 3.1: **Comparison of residual load duration curves with and without VRE**



Source: Based on NEA, 2012.

Few estimates of utilisation costs are available in the literature, but all suggest that they are considerable, especially at high VRE penetration levels: NEA and IEA provided very similar estimates for wind power using a model based on residual load duration curve; values lie in a range of USD 4 and 10 per MWh at 10% and 30% penetration levels (IEA, 2014 and NEA, 2012). The results for solar PV show a wider range, maybe reflecting the analysis of different systems: for the two penetration levels of 10% and 30%, IEA estimates are in the range of USD 4 and 15 per MWh, while NEA's results lie in a range of USD 13 to 26 per MWh. These disparities arise as a result of differences in the systems being analysed. One key parameter in this context is the correlation between solar

production and demand, which varies strongly between countries. Other estimates of utilisation costs have been obtained by Hirth using a dispatch and commitment model or derived by a literature survey (Ueckerdt et al., 2013). [4] At very low penetration levels (few percent of demand) marginal utilisation costs are small and could be positive or negative depending on the correlation between wind production and demand. For wind power at 30% penetration level, marginal utilisation costs are estimated at about EUR 30 per MWh for Germany, and between EUR 14 and 35 per MWh for North Western Europe. Overall, a broad survey of about 30 studies on utilisation costs estimates long-term utilisation costs at between EUR 15 and 25 per MWh, for wind at 30% penetration level (Hirth, 2013). In case of solar PV, most of the studies directly calculated the value of solar production without directly assessing the utilisation costs (see the following paragraph). The Catholic University of Leuven (Delarue et al., 2016) has estimated utilisation costs in a range of EUR 3.3 and 8.4 per MWh for Belgium and between EUR 6.5 and 12.6 per MWh for Central Western Europe, assuming a combined solar PV and wind penetration rate between 19% and 35%.

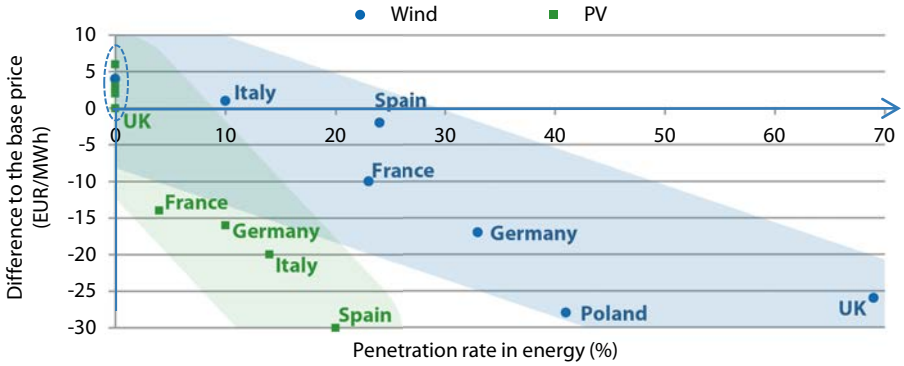
Many studies express similar findings by introducing the concept of the "value of VRE energy" relative to a baseload technology: it is expressed either in relative terms, as the ratio of the market price seen by VRE and the average price seen by a baseload technology; or in absolute terms, as the difference between these two prices (an example of the latter is shown in Figure 3.2). The market value of VRE represents the total remuneration that a VRE power plant receives from the market assuming that the electricity price is the cost of the marginal technology called upon. Under the hypothesis of a perfect market, this price represents the value to the system of the electricity generated. For the first unit of electricity produced from VRE sources, the market value can be higher or lower than the electricity base price, depending on the correlation between VRE generation and demand; it is in general positive for solar PV, since normally electricity demand is higher during the day, when solar PV is generating, especially in countries with large amounts of air conditioning. However, the market value of VREs decreases quickly with the scale of their deployment. This effect is caused by the fact that a VRE generator is likely to produce when other VRE generators are also generating, thus reducing the value of electricity. Conversely, electricity prices tend to be higher when VREs are not producing, since there is less electricity supply in the market. All studies surveyed show that the market value of VRE decreases significantly with penetration level and such decrease is more significant for solar PV than for wind power, since solar PV generation is concentrated around few hours in the day.

A thorough study has been performed by the French utility EDF to analyse the technical and economic implications of introducing 40% of VREs at the scale of Europe (EDF, 2015). Results confirm that the difference with baseload price is low for the first MW of wind energy or solar PV installed, ranging between EUR +6 and -1 per MWh depending on individual countries characteristics. On the contrary this gap becomes important if a broad European target of 40% of VRE is achieved. Country-specific trends for solar PV and wind are illustrated in Figure 3.2. Similar results have been shown in Hirth (2013) by modelling several countries in Continental Europe (Belgium, France, Germany, the Netherlands and Poland). The value factor for wind power, initially about 10% above the market price, decreases significantly, reaching 65% of the baseload price at 30% penetration level. These numerical findings are backed by a review of studies and by an analysis of historical data in different European markets. More recent analysis shows that the value factor loss is slightly less pronounced for more flexible systems, with

4. It should be mentioned that the authors have calculated the marginal utilisation cost, i.e. the utilisation cost of the last unit of power introduced in the system, while IEA and NEA have calculated average utilisation costs. In this framework, marginal utilisation costs are, by construction, higher than average utilisation costs.

significant hydro resources (Hirth, 2016a). Higher drops are featured for solar PV, for which the value factor decreases more dramatically, reaching about 60% of baseload costs at a penetration level of 15% (Hirth, 2015b). Recent quantitative analysis at the NEA also confirms such trends (NEA, forthcoming): in a highly flexible system, the value factor for wind onshore reaches about 80% and 70% of baseload at 30% and 40% penetration level. Solar PV reaches 60% of baseload price at 12.5% penetration and the value sharply drops at only 30% when a 20% penetration level is reached.

Figure 3.2: **VRE value in comparison to base price per country**



Source: Adapted from EDF, 2015.

Balancing costs

While the definition of balancing costs is relatively straightforward, there are differences across different studies with respect to the elements that are accounted for and the methodologies used: i) some studies include the cost of holding balancing reserves, while others do not; ii) the definition of "short term" varies across the studies; and iii) some studies use the current market price for imbalances, while other rely on modelling data. Only few studies have assessed the costs associated with the increased wear and tear of conventional power plants due to additional cycling.

Literature estimates of balancing costs for wind power range from USD 1 to 7 per MWh, depending on penetration level and system context (Hirth, 2013 and Holttinen et al., 2011). In thermal-based systems, more recent estimates of balancing costs are in the range of 2 to 6 EUR/MWh (Hirth et al., 2015 and Holttinen, 2013), while these costs are significantly lower, i.e. less than EUR 1 per MWh, in systems with high hydro capacity. However, AGORA (2015) notes that studies that assess balancing costs based on market data find in general higher balancing costs than those that are based on models; this reflects the fact that the price that generators pay today for imbalances are often not reflective of costs. For example, balancing costs for wind in Austria were estimated at EUR 11 per MWh, based on market data (e3 consult, 2014). The Catholic University of Leuven has assessed balancing costs in Belgium and Central Western Europe (CWE) for different VRE penetration levels (from 19% to 35% of solar PV and wind energy). Estimates of balancing costs lie in a range of EUR 2.1 and 4.7 per MWh in Belgium and between EUR 1.4 and 3.6 per MWh in CWE (Delarue et al., 2016).

There is a much less common literature with respect to solar PV balancing costs, but current estimates are much lower than for wind because of the better predictability of solar: PV Parity (2013) estimates the balancing costs for solar PV in the range of EUR 0.5 to 1 per MWh. Finally, the increased wear and tear associated with more frequent and deeper conventional power plant cycling was the focus of an integration study conducted by the National Renewable Energy Laboratory, in the United States (Lew et al., 2013). The

study concluded that increased plant cycling contributed a very low additional cost, between USD 0.1 and 0.7 per MWh of VRE generation at a penetration level of 33%.

Despite being a dispatchable technology, whose output is, short of a technical accident, predictable, some balancing costs must also be attributed to nuclear energy. These costs, which are below EUR 1 per MWh, are explained by the fact that nuclear power plants constitute the installations with the largest capacity. Electricity systems must always maintain cycling reserves according to the N-1 criterion, which means that the system must be able to continue supplying the full load, even if one plant trips. Logically, these cycling reserves are calibrated on the largest plant in the system, which happens to be nuclear. With smaller reactors, the balancing costs of nuclear, not very high to being with, would be even smaller.

In conclusion, the most recent estimates for balancing costs lie in a range of EUR 2 to 6 per MWh for wind power in thermal systems, while costs for solar PV, wind power in hydro-based systems or nuclear are much lower, less than EUR 1 per MWh.

Grid costs (transmission and distribution) and connection costs

A major analytical effort has recently been performed in the United States and in several European countries to estimate the costs of transmission and distribution expansion associated with the deployment of VRE with a particular focus on onshore wind.

Integration studies have been performed for the three interconnected systems in the United States, for a penetration level of VRE of about 30% (NREL, 2015). Additional grid costs are estimated within a range of USD 2 to 6 per MWh for PJM (GE Energy, 2014), at about USD 9 per MWh for the Eastern electricity system (Corbus et al., 2011), and at about USD 2 per MWh for the Western electricity system (Lew et al., 2013).

AGORA (2015) has quantified the additional costs for transmission and distribution in Germany, based on three studies performed by the German network operator, Consentec, and a consulting company under the German Ministry of the Economy. According to these three studies, transmission costs increase by about EUR 5 per MWh for onshore wind and solar PV and by about USD 30 per MWh for offshore wind. Additional distribution costs have been evaluated in a range of EUR 6 to 14 per MWh.

Other studies have been performed for individual countries in the European Union: in Ireland, additional costs for transmission have been evaluated in a range of EUR 2 to 10 per MWh for penetration rates of 16% and 59% (IEA, 2011), Holttinen et al. (2011) report values between EUR 2 and 7 per MWh for penetration levels below 40%. Costs from several European countries show an average value of EUR 7 per MWh, with large differences between the countries analysed (KEMA, 2014). Grid costs for Belgium have been estimated at about EUR 3 per MWh by the Catholic University Leuven for VRE penetration levels between 19% and 35% (Delarue et al., 2016).

With respect to solar PV, the PV Parity Project assessed additional transmission costs at EUR 0.5 per MWh for 2020 that will increase to EUR 3 per MWh by 2030 with the increased penetration level. Reinforcing the distribution network for accommodating more distributed PV resources would cost about EUR 9 per MWh by 2030 (PV Parity, 2013).

In conclusion, quantitative estimates available on grid costs are characterised by large variations, reflecting the specific features of each individual system, different penetration levels analysed and whether distribution costs have been included, as well as specific methodological assumptions. However, available estimates lie in a broad range from few USD/MWh to EUR 10 to 20 per MWh.

Connection costs, i.e. the cost of connecting a power plant to the nearest connecting point of the existing high-voltage power grid, are only seldom considered in the studies on system costs, as these costs are often borne by the plant developer and thus pertain to

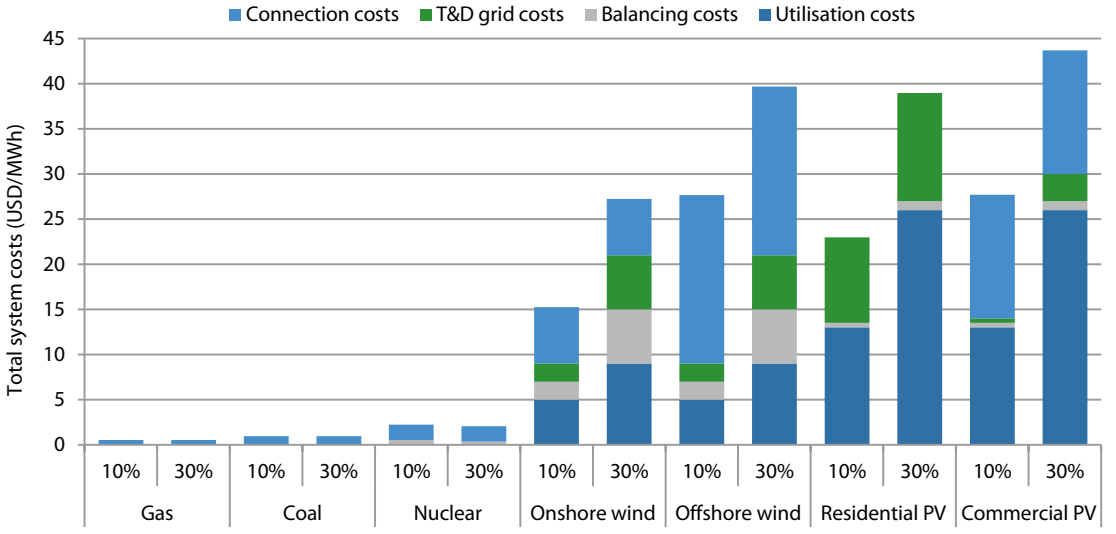
plant-level costs. However, there are situations in which connection costs are paid by the transmission operator and thus become part of system costs. Also, connection costs are not integrated in the LCOE methodology developed by NEA and IEA. For completeness, estimations of NEA (2012) are reported and discussed in the following paragraphs.

Connection costs are strongly project-specific and therefore exhibit a big variability across countries and among different projects within a country; however, their impact may be substantial, especially if distant resources have to be connected to the grid. In general, connection costs are higher for wind and solar PV projects, [5] owing to their lower load factors and the distance of their resources to the grid network. Higher costs are expected for offshore wind, reflecting the additional complexity of connecting resources by underground cables. With respect to dispatchable technologies, nuclear power features the highest costs, mainly due to the need of having two physically independent connections to the grid for safety reasons. Estimates of the NEA study, averaged over the different countries, are of EUR 0.5 per MWh for gas power, USD 1 per MWh for coal, USD 2 per MWh for nuclear, USD 6 per MWh for onshore wind, USD 14 per MWh for solar PV and about USD 20 per MWh for offshore wind.

Long-term system costs: A synthesis

Figure 3.3 provides an example of reconstruction of the total system costs for different conventional and renewable technologies, based on the literature results presented in this chapter for two representative penetration rates. These estimates do not reflect results for a specific country but rather represent an "average" of different estimates found in the literature. As indicated throughout this chapter, system effects are strongly country-specific and their different components are strongly interrelated, which limits the validity of adding together components obtained from different modelling exercises. The purpose of this exercise is therefore not to come up with an estimate of system effects for a specific situation, but rather to help visualise and give an order of magnitude of their value for different technologies.

Figure 3.3: **System cost of different generation technologies**



5. Connection cost does not apply to distributed residential solar PV but only to large solar infrastructure.

Again, precise impacts depend on the composition of the generation mix, the carbon pricing regime, the form of renewables support and, in particular, the availability of flexible resources on the supply and on the demand side. A particular role in this context is played by the correlation of electricity production with demand. If the two are well correlated, as happens when peak solar production coincides with peak demand due to air conditioning, profile costs are dramatically reduced, at least at modest levels of penetration. Despite these qualifications, one can summarise that the system costs for variable technologies (wind and solar PV) are about one order of magnitude higher than those of dispatchable technologies.

3.4. Perspectives of internalisation

The large-scale development of renewable energies, such as wind and solar PV, which has occurred over the last years, was favoured by generous ad hoc support schemes, frequently based on feed-in tariffs, put in place in many OECD countries. The rationale for this choice was to integrate a new low-carbon source in the electricity mix, to reduce the dependence on energy imports, to develop a competitive sector that would bring positive spillovers in terms of employment and industrial development, and to allow for an effective cost reduction in generating electricity by VRE. These policies have certainly been effective in promoting the deployment of VRE and have allowed an impressive reduction on their plant-level costs: wind and solar PV have already passed the development stage and have acquired the industrial maturity that allows them already now to compete with conventional technologies in some OECD markets. However, by insulating these technologies from market mechanisms, they have also had unintended consequences on the electricity markets and on the economy of existing generators and incumbent utilities. The scale of system costs associated with the deployment of variable renewable energy and the impacts that they impose to the electricity systems call for a revision of the existing support schemes and the establishment of carefully designed market mechanisms for allowing their efficient economic development. More specifically, it is of importance that system costs are recognised by governments and, to the extent possible, internalised in the electricity markets of the future. For some of the costs categories defined above, such as connection and utilisation costs, the internalisation could be achieved in a relatively simple way, while for other components, the task is more challenging.

It is of paramount importance that all technologies be exposed to market prices in order to realign the remuneration with the value of the electricity provided to the system. This is particularly important for technologies for which the value of electricity generation for the system varies considerably with the penetration rate. In this respect, feed-in tariffs (FIT) or any other market mechanism that *de facto* insulates a generator from the market price, which includes contracts-for-difference (CfDs), should be replaced by other mechanisms that would provide some certainty of income but would also maintain some exposure to market prices. Feed-in premiums (FIPs, which guarantee a remuneration on top of the revenues from the electricity market) or other mechanisms that remunerate the fixed capacity of generating plants are possible options. Similar results could be achieved by allowing long-term contracts for the delivery of a certain amount of power over the year in a continuous way. To a large extent, the exposure of every technology to the market price, would be sufficient to internalise a large part of the utilisation cost, limit the pecuniary externalities on incumbent generators and would avoid some of the unintended consequences of providing a fixed remuneration of technologies, such as the emergence of negative electricity prices into the market.

Similarly, it is important that connection costs be internalised by exposing every power plant to the cost of connecting it to the transmission or distribution grid. Hiding the connection cost from the plant developer by, for example, making the transmission

system operator (TSO) fully or partially liable for these costs, and then reallocating them to all the customers' results in suboptimal outcomes.[6] For example, a power plant developer would be inclined to favour the maximal achievable load factor in spite of potentially higher connection costs when these are borne by a third party. This choice would minimise the private plant-level costs for the plant developer, but will result in higher overall costs for the electricity provision.

While the attribution and internalisation of connection and utilisation costs is straightforward and, to a certain extent, easily achievable, the situation is more complex for the other components of system costs: balancing and transmission and distribution costs. In particular, it is challenging to directly attribute these costs to each market participant. For example, reinforcing an existing (or building a new) interconnection capacity between two regions may be motivated by the integration of new VRE capacity and thus serves primarily this objective. However, this provides other benefits for the whole system, such as for example reducing network congestion or reducing overall balancing requirements. The exact attribution of costs and benefits among different components of the system is virtually impossible in most practical cases.

With respect to balancing costs, and more generally to the provision of system services, it is important that those providing the services are effectively remunerated. The creation of a market for these services would be a first necessary step to ensure that such services can be economically provided in the long term. However, strictly speaking, such mechanisms do not allow for an attribution of these additional costs to those that have generated them and thus are not effective for internalisation purposes. An alternative mechanism would be to require from all generators the provision of a certain service: for example, requiring from all generators the provision of firm capacity, based on the amount of yearly production of electricity. For the suppliers under such a constraint, this service could be either provided directly by the generator or bought from the market.

Similarly, attribution of additional grid costs to each generator is quite challenging, and therefore the internalisation of such costs is difficult. It is however possible to design mechanisms that allow a partial internalisation of geographical constraints. An example is the adoption of locational pricing, where differentiated wholesale market pricing reflects the different locational value of electricity generated and implicitly accounts for grid costs. In principle, symmetrical provisions could be conceived for the demand side. But computational difficulties, transaction costs and social considerations have so far limited price differentiation according to the location of consumers.

3.5. Summary and key issues for policy makers

The topic of system effects has emerged in the last few years in the policy debate concurrently with the deployment of large variable renewable energy sources in many OECD countries. Despite its novelty, a rich literature is quickly building on this topic and a robust framework has developed to define, understand and quantify these effects. However, the quantification of system costs is a complex undertaking and requires extended modelling capabilities. In addition, results are country- and technology-specific, depend on the penetration level assumed and are strongly dependent on many subjective

6. Very fine calculations of grid costs would need to take into account different lifetimes for transmission and distribution equipment on the one hand and generation equipment on the other. If the lifetime for the former is considerably longer, original expenditures for grid equipment could be spread over more than one generation of generating equipment. Since the orders of magnitude are similar, no such distinctions were introduced in NEA calculations.

assumptions on the availability and cost of different flexibility sources in the future. Thus, quantitative estimates of system costs differ strongly among studies and are inherently subject to large uncertainties.

However, most of the available estimates recognise that the system costs associated with VRE integration are large and increase over-proportionally with the penetration level. Median estimates of total system costs show a range of costs of USD 15 per MWh for onshore wind, USD 20 per MWh for solar PV and about USD 25 per MWh for offshore wind at a penetration level of 10%. At 30% penetration level, system costs increase significantly, reaching about USD 25 per MWh for onshore wind and about USD 40 per MWh for solar PV and offshore wind. In comparison, system costs of dispatchable technologies, such as coal, gas, nuclear or hydro, are at least one order of magnitude lower.

The rapid deployment of VRE in OECD markets, favoured by targeted policies that have *de facto* insulated these technologies from market mechanisms, has created important short-term effects. Recent experience in the electricity markets has shown that the introduction of VRE, even at modest penetration levels, has had large impacts on the level and volatility of electricity prices and has jeopardised the economics of existing generators and incumbent utilities.

Given the extent of system effects and the impacts on the electricity markets, governments and policy makers should introduce policies aimed at their internalisation, as much as possible. More specifically, it is urgent that all technologies be exposed to the market price and bear the full cost of connecting the plant to the T&D infrastructure. If policies are sought to promote the development of low-carbon technologies, they should primarily focus on the establishment of an adequate and credible carbon price, and could be possibly combined with other forms of technologically neutral incentives to low-carbon technologies. However, such incentives must leave each generator exposed to the market price and thus link the remuneration with the value of the electricity provided to the system. Mechanisms such as feed-in premiums on the basis of free auctions or market-based long-term contracts seem well-suited options.

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Chapter 4. **Climate change impacts**

4.1. Introduction

Reducing greenhouse gas (GHG) emissions in order to prevent or mitigate the risks from anthropogenic climate change has been a top priority for the policy makers in many countries for the past two decades. The Paris Agreement concluded at the twenty-first Conference of the Parties (COP 21) in December 2015 proclaims that "climate change represents an urgent and potentially irreversible threat to human societies and the planet" (UNFCCC, 2015: p. 1). Validating the declaration of policy makers, the Intergovernmental Panel on Climate Change (IPCC), the United Nations body co-ordinating scientific research on climate change, states in its 5th Assessment Report:

> Total anthropogenic GHG emissions have continued to increase over 1970 to 2010 with larger absolute increases between 2000 and 2010… Anthropogenic GHG emissions in 2010 have reached 49 ± 4.5 gigatonnes of carbon dioxide-equivalent per year ($GtCO_2$ eq/yr). Emissions of CO_2 from fossil fuel combustion and industrial processes contributed about 78% of the total GHG emissions increase from 1970 to 2010, with a similar percentage contribution for the increase during the period 2000 to 2010. (IPCC, 2014: p. 5)

The report continues by listing some of the major impacts of these emissions during the past 50 years. According to the IPCC, "… evidence for human influence on the climate system has grown since the IPCC Fourth Assessment Report (AR4)…" It believes that "anthropogenic influences have likely affected the global water cycle since 1960 and contributed to the retreat of glaciers since the 1960s and to the increased surface melting of the Greenland ice sheet since 1993." IPCC climate scientists have also reported that "anthropogenic influences have very likely contributed to Arctic sea-ice loss since 1979 and have very likely made a substantial contribution to increases in global upper ocean heat content (0-700 m) and to global mean sea level rise observed since the 1970s." (ibid.: p. 5)

Converging research suggests that future impacts of climate change, especially after 2050, will primarily depend on the trajectories of CO_2 emissions and concentrations in the atmosphere and thus on the specific scenario chosen. Independent of the specific scenario chosen, however, the IPCC states that it is "virtually certain" that hot temperature extremes will occur more frequently and that global mean surface temperatures will increase. Precipitation is likely to fall in a much more uneven manner, increasing, for instance, in the polar regions and decreasing in what today are the earth's temperate regions, exposing them to the risk of desertification.

The global distribution of the estimated changes in heat and precipitation in two IPCC climate scenarios are vividly represented in Figure 4.1. As in all climate research, there are inevitably large uncertainties attached to such scenarios. A summary of the published research suggests:

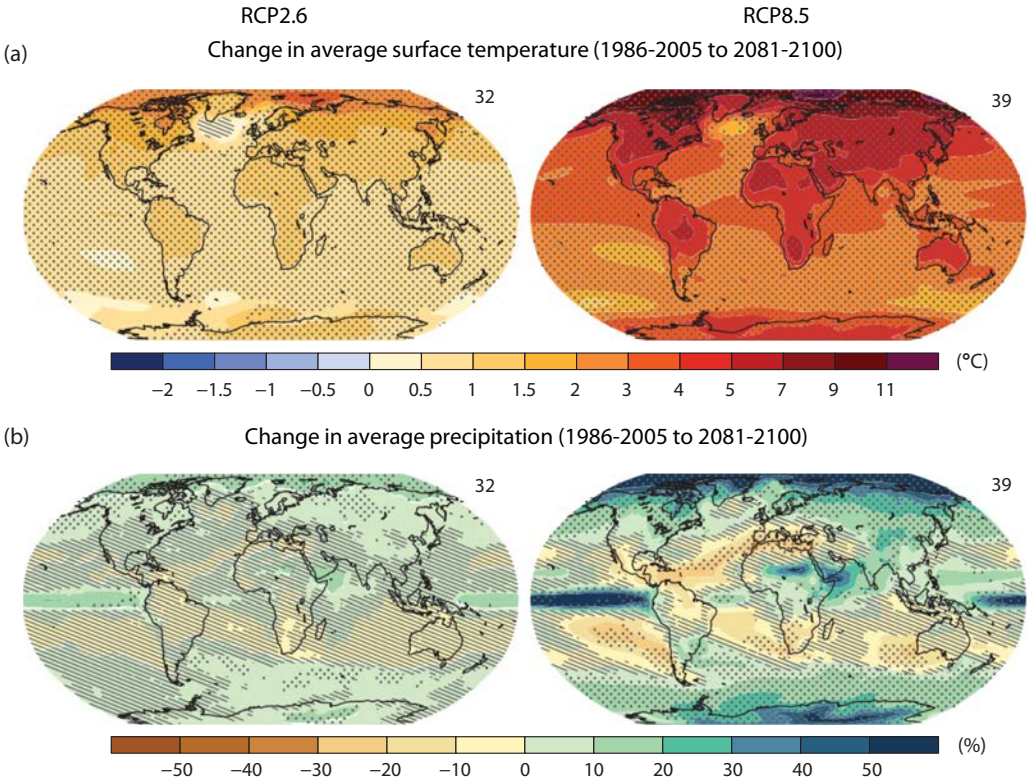
- Emissions of anthropogenic greenhouse gases have been rising since the industrial revolution. The last two years have seen a stabilisation of annual emissions, albeit

at a level still far too high to reduce atmospheric concentrations of GHGs that are ultimately responsible for the greenhouse effect and rising temperatures.

- According to the evidence assembled by the IPCC, climate change is already under way and can be measured in terms of rising global mean temperatures, increased numbers of tropical storms and changes in precipitation patterns. While current changes can by and large still be absorbed through the adaptation of existing socio-economic systems, climate scientists warn that there are risks that further temperature increases could trigger tipping points where this is no longer the case.

Figure 4.1: **Temperature and precipitation in two IPCC scenarios**

(RCP2.6 corresponds to zero global annual GHG emissions by 2100, while RCP8.5 corresponds to global annual GHG emissions of roughly 100 $GtCO_2$-eq by 2100. Current emissions are about 50 $GtCO_2$-eq)



Change in average surface temperature (a) and in average precipitation (b) based on multi-model mean projections for 2081-2100 relative to 1986-2005 under the RCP2.6 (left) and RCP8.5 (right) scenarios. The number of models used to calculate the multi-model mean is indicated in the upper right corner of each panel. Dotted areas indicate regions where the projected change is large compared to natural internal variability and where at least 90% of models agree on the sign of change. Hatched areas indicate regions where the projected change is less than one standard deviation of the natural internal variability.

Note: CO_2-equivalents are used to convert greenhouse gases with different degrees of "global warming potential (GWP)", their impact in terms of climate change, into a single metric. Over a 100-year time frame, the IPCC sets the GWP of a tonne of CO2 at 1 and estimates the GWP of a tonne of methane (CH_4) at 25 and the GWP of a tonne of nitrous oxide (N20) at 298. GWPs for industrial gases such as CFCs and HCFC can run into the thousands (IPCC, 2007b: Table 2.14). Despite their relatively low GWP, CO_2 emissions still account, because of their sheer magnitude, for about 70% of the GWP of total annual greenhouse gas emissions.

Source: IPCC, 2014.

4.2. Methodological issues, quantitative estimates and state of research

A large majority of climate scientists expect the climate impacts of anthropogenic GHG emissions to be massive. However, this does not automatically translate into an ability to quantify and monetise the impacts of fossil fuel combustion on a per MWh basis. In fact, the underlying assumptions and approaches used will largely determine results. In addition, this is a highly politicised area of scientific inquiry where well-funded, high-quality research endeavours were undertaken in numerous places but without reaching broad convergence towards a generally accepted set of assumptions and methodologies. Hence, when assessing the full costs of GHG emissions, it is impossible to separate the methodological questions from the results.

The link between an individual tonne of CO_2 and its impact on the climate is tenuous. A tonne of carbon emitted anywhere in the world will create an effect on the climate by increasing the concentration of GHGs in the atmosphere, which in turn influences global mean temperatures and, in conjunction with a myriad of other factors, will generate local impacts such as floods or droughts. Impacts will be very different in different areas of the world. If land-locked regions in colder areas such as Siberia or Canada would benefit from a warmer climate, lower-lying countries with extended shorelines or smaller islands would be existentially threatened by more frequent storms and a sea level rising as a result of melting polar ice caps and the thermal expansion of oceans. Desertification, epidemics of tropical diseases as well as mass migration of both humans and animal species are additional impacts that a rising climate will inflict. All of them, however, are somehow part of the social costs of GHG emitted by using fossil fuels in both transport and electricity generation (see the OECD 2015 report on *Monetary Carbon Values in Policy Appraisal* for more details).

It is quite obvious that assessing these impacts, many of which will only manifest themselves with important lags, is a complex undertaking fraught with huge uncertainties. At the same time, climate change, once underway, is largely irreversible. Waiting too long to mitigate its potential impacts could reduce the number of possibilities to adjust policies and behaviour. However, any kind of policy needs to take into account at least the rough contours of the matrix of the outcomes resulting from the interaction of policy responses and the possible reactions of the climate system. The OECD identifies three key issues in this context: 1) different dimensions of uncertainty; 2) discounting future impacts; and 3) equity between different stakeholders (OECD, 2015: pp. 12-16). Their key points, augmented with some further considerations, are:

1. Uncertainty is subdivided quite straightforwardly into uncertainty about future GHG emissions; uncertainty about the impact of these emissions on the stock of GHGs in the atmosphere and the resulting climate effects; uncertainty about the climate system's impact on the physical and biological environment; and uncertainty about the social and economic valuations of these impacts.

2. Discounting future impacts refers to the arbitrage between the present and the future. It can conceptually be derived on the basis of a preference for present consumption over future consumption because of uncertainty and limited lifespans. OECD (2015) mentions the opportunity cost of capital as an alternative, the two however equalise as long as there are no restrictions on either savings or investment. The choice of discount rate is crucial when considering impacts far out in the future. While many, not all, actions to reduce emissions may be costly today, their benefits will only accrue several decades from now. If the discount rate is zero, a benefit of USD 1 billion in 2050 would justify an equivalent investment in emissions reductions today of USD 1 billion. However, if the discount rate is 5% per year, today only an investment of USD 200 million would be justifiable. It would fall to USD 43 million at an, admittedly very high, discount rate of 10%. If benefits accrued only in 2100, even with a 5% discount rate, not more than USD 17 million of

investments could be justified. Settling on the right discount rate is fiendishly complex and the subject of much debate. This debate has three major dimensions:

a. *Intergenerational equity* refers to the trade-off in well-being between current and future generations. If the well-being of future generations is considered important, then the discount rate must be low and vice versa.

b. *Private vs. social discount rates* indicates that societies as a whole, with longer lifespans and the ability to diversify and spread risks have lower discount rates than private individuals. However, markets, which would need to be the drivers of effective climate action, use private discount rates. Should governments then intervene to lower the costs, i.e. subsidise investments into emissions reduction such as carbon-free electricity generation?

c. *The current low interest rate environment* is seriously shaking many assumptions about the formation of interest and discount rates. Is this a passing phenomenon due to a temporary slump in aggregate demand or is it the sign of a profound structural change that would demand a recalculation of the costs of long-term investments? The point is central for the relative costs of high-capital low-carbon investments such as nuclear, hydro or renewables.

3. Equity regards not only intergenerational equity but also distributional questions between emitters on the one hand and those affected or likely to be affected by climate change on the other. The dividing lines here run between but also across countries. This is not only an ethical issue. Environmental economics has shown that the distribution of environmental costs and benefits impacts marginal values, i.e. the full costs of energy provision as such.[1] However, considering that estimating the cost of climate change constituted an enormous challenge for a number of reasons, the added effects of distribution may be considered second order.

Despite these challenges, researchers regularly take on the task of providing order-of-magnitude estimates for the cost of climate change, often referred to as the social cost of carbon (SCC) in its totality. Some recent studies may serve as, very imperfect, examples for this herculean task. A large-scale 2016 study by the United Nations Development Programme (UNDP), *Pursuing the 1.5°C Limit: Benefits & Opportunities*, thus estimates that climate change will lop off about USD 33 trillion from global annual gross domestic product (GDP). Assuming annual global GDP to amount to USD 130 trillion in 2050, this would amount to a very sizeable reduction of 25% of global GDP (UNDP, 2016: p. 18). With global CO_2 emissions currently amounting to roughly 50 billion tonnes of CO_2-equivalents, this amounts to a cost per tonne of carbon of about USD 660.

While the UNDP report makes, in the limits of the exercise, a credible attempt to assess climate costs, it may not be the most didactic one since it assumes climate costs of USD 21 trillion to arise even *with* aggressive policy changes. Such policy changes, in essence achieving the ambitious objectives of the Paris Agreement of keeping global mean temperatures from rising significantly above 1.5°C, would thus generate benefits of only USD 12 trillion, or roughly 10% of global GDP.

1. The argument is based on the fact that different stakeholders have different income elasticities with respect to their demand for environmental goods. Think of Group A consisting of coal miners with a high tolerance for climate change and Group B consisting of fishermen in a small island country very sensitive to climate change. Leaving environmental use rights, i.e. the right to emit CO_2, with members of Group A will increase their relative income and their willingness to pay and hence climate change impacts must be economically valued in a rather modest manner. Instead, giving environmental use rights, i.e. the right to demand an end to CO_2 emissions, to members of Group B will increase their income and their willingness to pay, and hence climate change impacts will need to be valued in a more substantive manner.

A scientific paper by Dietz et al., published also in 2016 in *Nature Climate Change,* estimates somewhat more conservatively that by 2100, climate change would destroy USD 2.5 trillion or 1.8% of global financial assets given their current level. This is the representative value of the probability distribution. Tail risk can be as high as USD 24 trillion or 17% of global assets (Dietz et al., 2016: p. 676). However, also here part of the damage is already done. Keeping the increase of the global mean temperature to 2°C would reduce damages by roughly one-third but no more.

In some ways, these results are surprising inasmuch as one would expect an exponential increase in climate damages as a function of large temperature increases. In particular, mutually reinforcing feedbacks in the climate system, e.g. warmer climates releasing the methane trapped in permafrost soils could lead to discontinuities with at least some risk of catastrophic change, e.g. a breakdown in the global oxygen cycle, rather than the by and large linear damage functions assumed in these representative studies.

Respected Yale economist William Nordhaus recently provided updated estimates from his Dynamic Integrated Model of Climate and the Economy (DICE) part of the so-called Integrated Assessment Model (IAM) group of models. His latest study thus settles on a level of USD 31 per tonne of CO_2 (tCO_2) as the social cost of carbon in an emissions trajectory that would take the world to an increase of 4°C by 2100. The costs themselves would rise until 2050 up to USD 103 per tCO_2. These costs result to a large extent from the assumed discount rate of 4.25%. This may be considered high, in particular as Nordhaus does not make any distinction between the private, market-based rates and the social rates of discount. The latter is, however, absolutely crucial as shown in the computation in Table 4.1 provided by Nordhaus himself.

Table 4.1: **The social costs of carbon as a function of the discount rate**

(2010 USD per tCO_2)

	2015	2050
2.5%	129	236
3.0%	79	157
4.0%	36	82
5.0%	20	49

Source: Nordhaus, 2017.

IAMs yield top-down scenarios built on a number of dynamic equations constantly recalibrated on past relationships between different parameters, e.g. economic growth and emissions. Despite their technical sophistication, their equations are also subject to much criticism. Samadi (2017) reports in his broad review of the social costs of electricity that a number of researchers contend that IAMs typically provide estimates on the low side of the true social costs of carbon. The three key points are the exclusion of non-market goods such as biodiversity, of risk aversion as well as of the potentially devastating impacts of "tipping points" in the climate system. On the basis of studies by Van den Bergh and Botzen (2014) and a sensitivity study by Kopp et al. (2012), he then settles on a median value of EUR 114 per tCO_2 with EUR 11 as a lower and EUR 626 as an upper bound (Samadi, 2017: pp. 14-15). Harvard economist Robert Pindyck goes much further in his criticism:

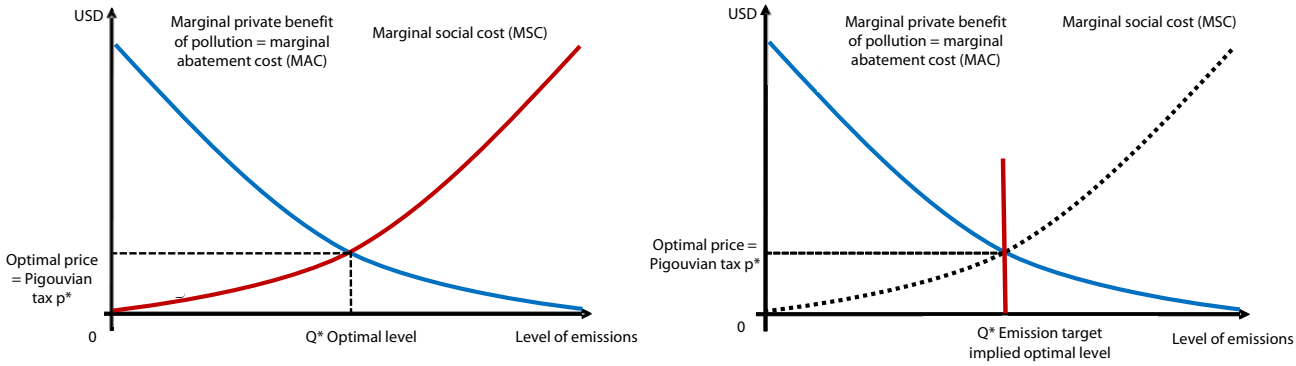
> These models have crucial flaws that make them close to useless as tools for policy analysis: certain inputs (e.g. the discount rate) are arbitrary, but have huge effects on the SCC [social costs of carbon] estimates the models produce; the models' descriptions of the impact of climate change are completely ad hoc, with

> no theoretical or empirical foundation… IAM-based analyses of climate policy create a perception of knowledge and precision, but that perception is illusory and misleading. (Pindyck, 2013: p. 860)

The criticism is subsequently backed up by detailed arguments. However, Pindyck also holds IAMs to a methodological standard they were never designed to satisfy. IAMs were never meant to be accurate scientific estimates of future costs but rather an order of magnitude indication of vague social perceptions of costs under different assumptions.

Nevertheless, the global policy-making process has largely abandoned the explicit assessment of the full costs of climate change, and rightly so. Uncertainties are such that explicit numbers cannot function as relevant focal points for policy making (see also Weitzman, 2011, on this point). This does not mean abandoning the monetisation of the costs of the emissions of GHGs and CO_2, only the logic changes. Assessments of climate change damages thus proceed in a logic that is precisely the reverse of traditional full cost accounting. As explained in Chapter 1, traditional full cost has the objective of establishing a marginal social damage function and of equating those with the marginal private cost of abatement. Their intersection will determine the optimal quantity of emissions. Instead of equalising the marginal social costs with the marginal private costs of abatement, one sets the amount of emissions that is considered socially optimal or acceptable and infers from there the corresponding marginal costs of abatement. The latter will then correspond implicitly to the marginal social costs. Figure 4.2 shows the two logics side by side. Clearly, an explicit determination is methodologically preferable. However, in terms of policy making, the quantitative targets used in the implicit determination of social costs allow for far easier integration into social decision-making processes and ultimately for more sustainable decisions.

Figure 4.2: **Explicit and implicit determination of the full costs of CO_2 emissions**



Such quantitative targets can be formulated in terms of annual GHG emissions, their resulting concentration in the earth's atmosphere or in terms of the temperature increase the latter would cause. It turned out that the metric that best synthesised the range and probability of different climate change impacts for policy makers and the public was the increase of the global mean temperature compared to the global mean temperature prevailing before the industrial revolution. On the basis of the IPCC studies referred to above, there is a widespread consensus that a temperature rise of more than 2°C would cause an unacceptable amount of damages and distress. Everybody understands that the global mean temperature is a very imperfect metric, but its attractiveness lies in its simplicity and its ability to serve as a reference to derive politically and economically meaningful objectives in terms of GHG emissions reductions.

It is to the credit of the complex and time-consuming process of global climate policy making that it has been able to converge towards a widely accepted global target. Adopting a sensible, easily understood and policy-relevant objective such as the 2°C goal was thus an important step forward.

Climate modellers suppose that in order to have at least a 50% chance of holding the increase of the global mean temperature to the 2°C objective, the concentration of GHGs in the earth's atmosphere must not exceed 450 parts per million (ppm) of CO_2-equivalent emissions (see Table 4.2). The concentration objective can then be translated into annual global GHG emissions as well as CO_2 emissions in both the overall energy sector and the electricity sector. The International Energy Agency (IEA) *World Energy Outlook 2016* thus calculates that energy-sector emissions from fossil fuel combustion would need to decline from 32.2 Gt of CO_2 in 2014 to 18.4 Gt in 2040, while emissions from the electricity sector would need to decline even more dramatically from 13.5 Gt to 3.6 Gt over the same period.

Table 4.2: **Greenhouse gas concentrations and expected temperature increases**

Concentrations in CO_2 equivalents (ppm)	Global mean temperature increase (°C)
445-490	2.0-2.4
490-535	2.4-2.8
535-590	2.8-3.2
590-710	3.2-4.0
710-855	4.0-4.9
855-1 130	4.9-6.1

Source: IPCC, 2007b.

A very comprehensive analysis of the marginal abatement cost curves established in a large number of different climate and energy models was undertaken in by Kuik, Brander and Tol (2009). Their results are summarised in Table 4.3. All but one of the models analysed (25 out of 26) assumed atmospheric concentrations of GHGs between 525 and 650 ppm in 2050, which is, of course, considerably higher than the 450 ppm or lower implied in the Paris Agreement. This may be taken as an indicator of the extent to which the policy debate has abandoned any link with modelling efforts attempting to estimate realistic medium-range scenarios.

Table 4.3: **Summary statistics of marginal abatement costs of 26 models**

(Values normalised to 2005 euros)

Statistic	MAC 2025 (Euros per tCO_2-equivalent)	MAC 2050 (Euros per tCO_2-equivalent)
Mean	25	56
Median	16	32
Maximum	120	209
Minimum	0	1.4
Standard deviation	28	53

Source: Based on Kuik et al., 2009.

On the basis of the assembled literature, the authors performed a meta-analysis, essentially plugging the obtained values into a non-linear regression analysis, in order to derive marginal abatement costs (MACs) for 2025 and 2050 also for concentration targets of 450 and 500 ppm (see Table 4.4). It should also be noted that the models considered calculate abatement costs for the energy sector rather than for the electricity sector.

Table 4.4: **Marginal abatement costs for scenarios with 500 ppm and 450 ppm**

(2005 euros per tCO_2-eq)

	2025		2050	
	Range	Mean	Range	Mean
500 ppm	37-119	60	79-226	130
450 ppm (2DS)	**69-241**	**129**	**128-396**	**225**

The marginal cost of attaining the 2DS with 450 ppm in 2050 would thus amount to EUR 225 per tCO_2-equivalent. In principle, this would correspond to the level of the carbon tax required. Ppm: parts per million.

Source: Based on Kuik et al., 2009.

This latter result needs, however, to be treated with great caution and an understanding of the limits of energy modelling. The USD 35 per tCO_2 figure is the result of specific modelling assumptions regarding the relative costs of different technologies. If the cost assumptions for coal and gas, on the one side, and for nuclear power on the other side are in a comparative range, even a relatively modest carbon tax can be sufficient to tilt decisions in one way or another in the frictionless world of models. In the real world, important issues of credibility and political uncertainty would need to be surmounted in order to nudge decision makers towards the kind of behaviour implied by models.

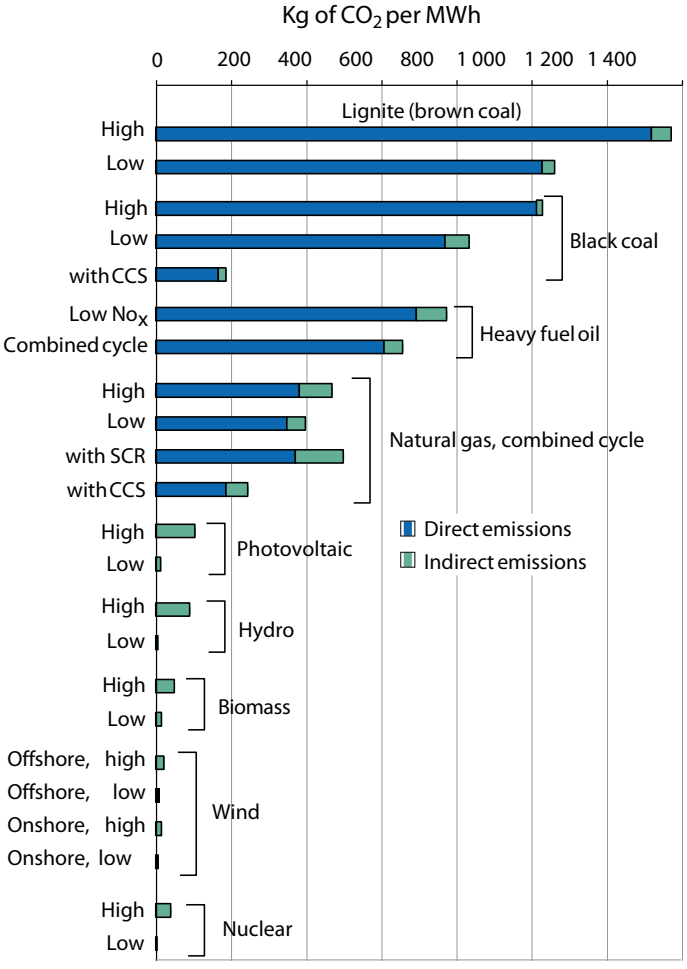
An additional issue to be considered is financial risk, which in unregulated markets differs from technology to technology. In the rough and tumble of the marketplace, carbon prices would also have to be considerably higher than those implied by the average cost determined by levelised costs of electricity (LCOE) calculations. This results from the fact that in deregulated markets with price volatility low-carbon technologies with high fixed costs always have higher capital cost than fossil fuel-based technologies with lower fixed costs because of long-term price risk. Carbon taxes would need to be high enough to overcome this competitive disadvantage of low-carbon generators with fossil fuel technologies.

An additional distinction needs to be made between the electricity sector, which is modelled in the NEA effort, and the economy at large. Of course, the electricity sector is supposed to carry an important share of the effort to reach the objective of limiting the rise in temperatures to 2°C. According the IEA's *World Energy Outlook*, the electricity sector would contribute 71% of the global effort to bring the energy sector in line with the 2DS and 55% at the level of OECD countries. The figures cited by Kuik et al. (2009) refer to the marginal values for the energy sector as a whole. The latter are higher than those found in electricity sector modelling, since abatement costs outside the electricity sector will be significantly higher. The question is, however, whether they can be more than four times higher since electrification remains an option for the majority of uses of fossil fuel combustion. Here, future modelling work and empirical studies will be required to bridge the gap. Neither the discussions about the social cost of carbon, nor the discussions about the marginal cost of abatement according to a politically chosen quantity target are anywhere near to conclusion.

4.3. Perspectives for internalisation

While the impact of the full costs of CO_2 emissions from fuel combustion on atmospheric concentrations, on the climate and on human well-being are difficult to assess, their internalisation is actually quite straightforward. CO_2 emissions from fuel combustion in electricity generation are a function of the carbon content of the underlying fuel, mainly gas and coal, as well as a function of the thermal efficiency of the plant in converting chemical energy to electricity. These two factors can be measured with precision and converted into the metric of tonnes of CO_2 per MWh of electricity. Figure 4.3 provides an overview of the emission intensity of a large range of power generation technologies measured in kg per MWh, reaching from zero direct emissions for nuclear and renewables to around 1 tonne per MWh for coal-fired power generation.

Figure 4.3: **Direct and indirect CO_2 emissions of different power generation technologies**



CCS: carbon capture and storage; NGCC: natural gas combined-cycle; SCR: selective catalytic reduction.

Source: IPCC, 2007b.

At this point, economic theory holds that the costs-minimising solution to achieve a given reduction objective is to impute an appropriate carbon price to each tonne of CO_2. Following the Pigouvian paradigm presented in Chapter 1, such a carbon price would be most straightforwardly administered in the form of a carbon tax imposed on the emitting producers. The carbon tax would then render carbon-intensive technology more expensive, would lead to a reduction of fossil fuel-based electricity in the power mix and, ultimately, to a reduction of carbon emissions themselves.

Table 4.5 shows how the imputation of a carbon price would increase the per-MWh costs of gas- and coal-fired power plants, while the costs of low-carbon technologies such as nuclear, hydro and renewables would remain unchanged.

Table 4.5: **Increase in variable costs of coal- and gas-fired power plants according to different carbon values**

(USD per MWh, carbon intensity is median value for OECD countries)

	Carbon intensity (tCO_2/MWh)	Level of carbon price (USD per t CO_2)			
		10	30	50	100
Gas	0.34	3	10	17	34
Coal	0.74	7	22	37	74

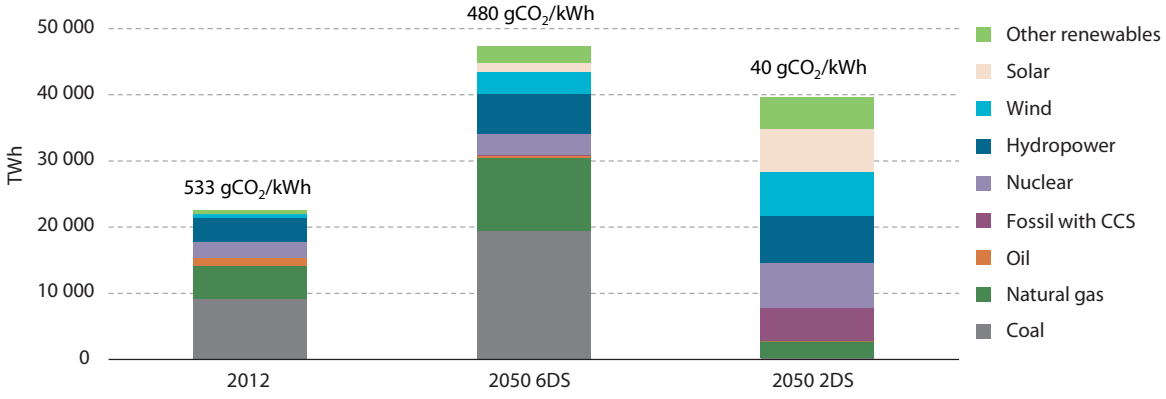
Source: Adapted from IEA/NEA, 2015a.

These added costs due to carbon pricing need to be put into perspective considering that the median LCOE of a nuclear plant according to IEA/NEA (2015a) is USD 83 per MWh, compared to USD 93 per MWh for a gas plant and USD 68 per MWh for a coal plant (all numbers for 85% capacity factor and 7% cost of capital). In all fairness, it must be added that the costs for gas-fired power generation are hugely dependent on the location and that its LCOE can fall as low as USD 60 per MWh in the United States.

The immediate impact of CO_2 emissions from electricity generation in the OECD area, and the huge amounts involved, corresponded to slightly less than 12 billion tonnes in 2015, making carbon taxes a very contentious issue. Fossil fuel producers and power-intensive industries are opposed, as may be consumer organisations concerned about higher electricity prices. Others are concerned about the magnitude of the challenge to reconfigure the structure of the global power supply. Indeed, the challenge is huge. Figure 4.4 shows how the electricity generation mix would need to reduce its carbon emissions from 0.5 gCO_2 per kWh today to 0.04 gCO_2 per kWh in 2050 in order to limit the rise in global mean temperatures to less than 2°C. This corresponds to a reduction of carbon intensity of more than 90%. Changes required in sectors other than electricity could be even more challenging.

Economic theory insists that carbon taxes are the quickest, most cost-efficient and, at least at first sight, also the most equitable instruments to bring about this change. Equity is ensured by the fact that carbon taxes correspond to the polluter pays principle (PPP). Why are they then equitable only at first sight? Because one could argue that fossil fuel producers and their customers had established since the industrial revolution a sort of historic "use right" that would allow them to emit CO_2 s into the atmosphere at no cost. Changing that right would mean that they alone would pay for society's benefit of reduced emissions and a stable climate. On the other hand, carbon taxes will allow, at the level of the general budget, to reduce other taxes and levies, especially corporate and income taxes, thus generating added economic activity and employment.

Figure 4.4: **The change required in the global electricity system to achieve the 2DS**



Source: IEA/NEA, 2015b.

It is quite obvious that with tens of billions of euros or dollars at stake, the debate over carbon taxes is intense. One point repeatedly mentioned is the credibility of a carbon tax. A nuclear investment commits an investor for at least 30 or 40 years (theoretically the time frame is even longer, but from a financial point of view, what happens beyond 40 years is of only limited interest), and an investment in variable renewable energies (VREs) for at least 20. Can an investor count with reasonably high probability on the continued existence of a sufficiently high-carbon tax? While a carbon tax has a number of advantages, in terms of ease of implementation and administration, other options exist.

In particular, a carbon price must not necessarily come in the form of a carbon tax. Emission markets such as the European EU-ETS are an obvious alternative in which overall emissions are capped and in which different parties, not only electricity producers, can buy and sell emission allowances or quotas. If quotas are sold by governments, typically through auctions, the distributional impacts are identical to those of a carbon tax. The only difference is that, with a tax, one obtains price stability, while quantities may vary somewhat according to electricity demand, and that with an emission market, quantities will be fixed but prices can vary strongly. The key condition for an emissions trading system to make a difference is, of course, that the sum of quotas given out by governments is sufficiently low.

Other measures to value emissions reductions are feed-in premiums (FIPs), production tax credits (PTCs) or zero-emission credits (ZECs) for low-carbon electricity. Such support could be seen as remunerating the provision of the public good of GHG emissions reduction. Similar to a carbon tax, it would drive a wedge between the profitability of low-carbon and fossil fuel-based producers. However, the distributional implications and the impacts on the security of supply would be different. A carbon tax draws money from electricity producers into government coffers. FIPs, PTCs or ZECs instead provide added revenue to producers. This may be an important difference. One of the reasons for not introducing higher carbon taxes or prices in Europe and the United States is that they would risk driving some of the largest utilities out of the market.

From an electricity sector perspective, such support measures have many advantages. Their biggest drawback is that ZECs could be considered a subsidy for low-carbon production, especially if they are not allocated through competitive auctions. However, any justified subsidy is the remuneration of contributions towards a positive externality or a public good. In this sense, a transparent per-unit subsidy for all low-carbon technologies, including dispatchable ones such as nuclear and hydro, which would work

like a FIP and would continue to expose recipients to market signals would be far more efficient in both economic and emission terms than the current system of selective out-of-market financing.

A third option would consist in authorities offering long-term supply contracts to low-carbon producers, thus mitigating their price risk and providing revenue security. Again, such long-term contracts would need to be allocated through competitive auctions. Competition would then take place *for* the markets rather than *in* the market. Such stability can be provided through a variety of means, including:

- feed-in-tariffs (FITs);
- contracts-for-difference (CfDs);
- long-term power purchase agreements (PPAs);
- auto-generation or Mankala model under appropriate circumstances;
- regulated tariffs.

These different measures all have the same desired effect of providing price stability and visibility for investors in projects with high fixed costs and long lifetimes. Feed-in tariffs have been the preferred instrument to promote renewables in European OECD countries. Providing such long-term price guarantees does not automatically imply the provision of a subsidy. Auctioning could ensure competition for a share of the market rather than in the market. In addition, short-term markets would organise dispatch and adjustment on the basis of competition.

Finally, non-price instruments such as public investment in research and development or appeals to consume less carbon-intensive goods may be considered as well. However, such non-price measures will not be sufficient to make a decisive difference in emission trajectories. If countries are serious about reducing CO_2 emissions to reduce climate change risks, then internalising the latter's perceived cost at the appropriate level in market prices is indispensable. This statement does not imply that the distribution of costs cannot be discussed. Relative costs may be changed through a carbon tax or through a zero-emission credit. In the first instance, costs will be borne by electricity consumers, in the second by taxpayers. In both cases, there will be compensating economic impacts such as increased tax revenues in the first case and lower electricity prices in the second. The relative costs of fossil and low-carbon generators may be changed through a number of instruments, but change they must.

4.4. Summary and key issues for policy makers

The efforts by many countries to address climate change is one of the defining energy policy issues of our times. Many countries are implementing policies to promote the transition towards less carbon-intensive energy and electricity sectors.

While climate researchers have stated that emissions of CO_2 and other GHGs have been rising and that atmospheric concentrations as well as global mean temperatures are increasing, predicting precise causalities, future emissions pathways and climate change impacts is a complex task with many uncertainties. What one must note on a qualitative level is that based on published research, the costs are projected to be measured in the tens of trillions of dollars. Even more important is that the uncertainties are significant and cannot be fit into standard probability distributions. This makes private insurance problematic and makes the involvement of governments indispensable. Any estimates of future costs will also vary widely as a function of the discount rate chosen. Estimates of the social cost of carbon thus inevitable are highly uncertain. Nevertheless, an order of magnitude of USD 100 per tCO_2 would be included inside the range of possible values of

the great majority of estimates, even though all of them have their distinct shortcomings. Needless to say, the latter do not result from the incompetence or the lack of resources of researchers but are inherent to the subject matter.

This is why the policy-making process has settled on a process, in which the full costs of carbon emissions are taken into account in an implicit rather than an explicit manner through a quantitative emission target. This target is derived on the basis of the goal to not allow global mean temperatures to rise by more than 2°C by the end of the century, which translates into limiting the atmospheric concentrations of GHGs to 450 ppm of CO_2-equivalent. This in return translates into emission pathways for the world as a whole as well as for different regions and countries.

These quantitative targets imply a certain level for the marginal abatement costs, which again are a subject of much research and discussion. A meta-analysis of a large number of climate models came up with a mean estimate of USD 129 per tCO_2 for 2025. Again, such numbers resulting from very high-level top-down models must be taken with great caution. Let it just be said that their order of magnitude is comparable to that of estimates of the social costs of carbon, which supports the 2°C objective.

If understanding and measuring the impacts of climate change and the setting of appropriate targets is complex and difficult, the internalisation of the external effects of carbon emissions, because of the easy measurability of anthropogenic GHGs at the point of emission, is in principle straightforward. The appropriate price of CO_2 emissions must drive a wedge between the costs of fossil fuel-based power generation and generation with low-carbon technologies such as nuclear, hydro and renewables.

While conceptually straightforward, carbon taxes have been vigorously resisted by fossil fuel producers and, to a lesser extent, by electricity consumers, who resent the increases in electricity tariffs that are the inevitable consequence of carbon pricing. In this situation, supporting low-carbon electricity generation rather than taxing carbon-intensive generation can be an economically sound alternative for countries seeking to reduce GHG emissions. From an economic point of view, it is important that such support is provided as a unit subsidy for each MWh of low-carbon electricity. While not complying with a narrow reading of the "polluter pays principle", shifting the burden of reducing GHGs from the electricity sector to taxpayers can be justified on the basis of historic use rights. In order to make progress in reducing GHGs and reconfiguring the electricity sector towards low-carbon generation, it is, however, indispensable that the relative costs of different technology options include a socially and politically sustainable estimate of their respective impacts on emissions and the climate.

From an economic point of view, carbon taxes remain a first best instrument, also because it is easily implemented across all sectors of the economy. However, if political realities do not allow for it, generalised per-unit support for low-carbon generation can be a second-best alternative.

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Chapter 5. **Air pollution**

5.1. Introduction

Atmospheric pollution arises primarily during the generation stage of electricity and arguably constitutes the most important social cost issue in electricity provision, possibly even greater than climate change risks. While major accidents are an issue closely followed by policy makers and the general public alike, actual costs are comparatively low as Chapter 6 shows. System costs (see Chapter 3) are relatively high but since they remain confined to the economic sphere, they fail to arouse the passions of the media, the public and policy-making circles. There is little room instead for looking the other way when it comes to atmospheric pollution.

Recent research confirms that the tally of air pollution in terms of morbidity and mortality may well be the biggest uninternalised burden of electricity generation. The World Health Organization (WHO) refers to it as the world's largest single environmental health risk. WHO studies from 2014 and 2016 find that in 2012 around 3 million people died due to ambient air pollution, to which electricity generation is a major contributor (WHO, 2014a, 2014b and 2016). Household air pollution causes an additional 4.3 million deaths. The leading cause of mortality and morbidity caused by air pollution are strokes, ischaemic heart disease, chronic obstructive pulmonary disease and lung cancers (WHO, 2016: p. 44). "Few risks have a greater impact on global health today than air pollution; the evidence signals the need for concerted action to clean up the air we all breathe", says Maria Neira, director of the WHO's Department of Public Health. Whereas ambient air pollution is caused by power generation, transport and industrial production, household air pollution is caused by the indoor use of coal, petroleum products, wood or biomass for cooking, lighting and heating. While indoor air pollution is almost exclusively an issue for non-OECD countries, the latter also carry the principal burden of ambient air pollution. The WHO estimates that 87% of deaths due to ambient air pollution occur in low- and middle-income countries. Nevertheless, a considerable number of people are exposed to ambient air pollution in OECD countries. The OECD estimates the welfare costs of lives lost due to ambient air pollution in 2015 to be as high as USD 1.4 trillion per year in OECD countries and USD 3.2 trillion per year at the global level (OECD, 2016: p. 91).

As far as outdoor air pollution is concerned, the International Energy Agency (IEA) in its *World Energy Outlook* (WEO) *Special Report on Energy and Air Pollution* indicates that fossil fuel-based power generation is a major contributor to the issue but not the only one. The power sector is thus responsible for one-third of the emissions of sulphur dioxide (SO_2), which causes acid rain, 14% of emissions of nitrogen oxides (NO_x), a precursor pollutant for particulate matter (PM) and ground-level ozone, and 5% of particulate matter ($PM_{2.5}$). Whereas power generation and industry are mainly responsible for SO_2 emissions, transport is the largest source of NO_x and biomass is by far the largest single contributor to pollution by $PM_{2.5}$. Inside the power sector, coal combustion generates between 70% and 90% of the sectors contribution to the three key pollutants (IEA, 2016a: pp. 26-44).

These estimates carry added weight due because the emissions, impacts and costs from electricity generation are since 40 years part of a well-developed research subject with several high-quality studies converging on methodologies and magnitudes. To some extent the perception that the full costs of electricity generation significantly exceed the accounted for plant-level costs of production was shaped by concerns about the health

impacts of air pollution. Pollution from factories and power plants has been the classic example for the concepts of external or social cost.

Policies to mitigate local air pollution can also lower carbon dioxide CO_2 emissions from power plants, a pattern observed in many OECD countries (see IEA, 2014b). While long considered a beneficial side-effect of decarbonisation, pollution control efforts are increasingly the primary policy driver for reducing fossil fuel use in power generation, with the reduction of greenhouse gas (GHG) being a welcome side-effect. Indeed, in most climate change mitigation studies, the benefits from reducing human exposure to PM, SO_2 and NO_x outweigh the benefits of reducing GHG emissions and the resulting climate change mitigation, which offers new perspectives for internalisation. While it is notoriously difficult to build the coalitions necessary for effective action on global issues such as climate change, local and regional issues frequently have lower transaction costs and allow for quicker internalisation, which would also benefit the efforts of OECD countries to reduce greenhouse gas emissions.

5.2. Main studies and quantitative estimates

Most atmospheric emissions accrue at the stage of electricity generation from burning fossil fuels. In recent years, a vast amount of epidemiological research has contributed to an increased understanding of the varied health impacts of air pollutants and to a considerable rise in the estimates of mortality (death) and morbidity (bad health) attributed to air pollution.

The major groups of air pollutants are PM, SO_x, NO_x, ozone (O_3) and toxic metals. Particulate matter is a complex mixture of small particles and liquid droplets that include organic chemicals, metals, and soil or dust particles. The particles are normally grouped into coarse particulate matter with a diameter around 10 µm (PM_{10}), which are emitted directly from the sources, and fine particulate matter with a diameter less than 2.5 µm ($PM_{2.5}$), which are formed during chemical reactions of other gases emitted during electricity provision, including SO_2, NO_x, and others. Both types lead to a variety of respiratory problems, such as aggravated asthma, chronic bronchitis and irritation, but also irregular heartbeat, other heart problems and premature death (EPA, 2012; EC, 2005a). $PM_{2.5}$ is considered especially dangerous as the particles can penetrate deep into the lungs (EPA, 2012), and an extensive epidemiological literature shows that it is a leading contributor to health damages.

SO_2 is the major gas in the group of highly reactive oxides of sulphur that contributes to the formation of $PM_{2.5}$ but also to various cancers, adverse effects on the respiratory system and, as mentioned, acid rain (EPA, 2012). NO_x, which are also highly reactive, include nitrogen dioxide (NO_2), nitrous acid (HNO_2) and nitric acid (HNO_3) (EPA, 2012). These gases, especially NO_2, can directly cause pulmonary inflammation and react with ammonia (NH_3) and other particles to form $PM_{2.5}$. In the presence of sunlight, they also react with volatile organic compounds (VOCs) of various kinds to create ground-level O_3, a secondary particle that causes inflammation and exacerbates other respiratory problems (EPA, 2012). Electricity generation, in particular from waste and, to a lesser degree, from coal, can also lead to the atmospheric emission of toxic metals. Some are cancerous, such as arsenic (As), cadmium (Cd), chromium (Cr) and nickel (Ni), while mercury (Hg) and lead (Pb) are dangerous neurotoxins (EC, 2005a).

Radionuclides or radioisotopes (atoms emitting radiation) are the primary air pollutant associated with nuclear energy and are released in a regulated fashion during normal operation, or in an uncontrolled fashion during an accident situation. Radioisotopes in the body affect different organs in different ways. At very high levels, this can lead to severe cell and organ damage that can cause death. At lower levels, cells can be damaged and successfully repaired, or can be unsuccessfully repaired and become cancerous. However,

the probability of cancer being caused by regularly working in a nuclear power plant is numerically exceedingly low. On average, each individual on earth receives 2.4 millisievert (mSv) of dose per year, although there is a wide variation. This exposure comes from natural background radiation, which is everywhere on earth although it varies greatly with geography and altitude. In addition to dose from natural background radiation, humans are also increasingly exposed to human-made ionising radiation, mainly coming from medical diagnostic and therapeutic procedures. Radiation dose from radioactivity released from power generation during normal operations is roughly two orders of magnitude less than radiation dose from natural background and medical procedures.

Air pollution has long been of concern to policy makers in OECD countries. Yet, while the damage by acid rain created from SO_2 emissions was known for decades, researchers did not begin to understand the adverse effects on human health from other chemical air pollutants until the 1990s. Understanding the mortality and morbidity effects of local air pollutants has been vital in promoting abatement policies in the electricity sector, most notably the transition of electricity systems to low- or zero-carbon sources.

Electricity sources can be split into two groups in terms of air pollution damages. Carbon-based sources (coal, natural gas, oil and biomass) emit local air pollutants during electricity generation, while non-carbon-based sources (nuclear, wind, solar, hydro, geothermal and tidal) emit either few or no air pollutants during generation, with some indirect emissions resulting from the manufacture of steel and concrete for the power plant construction. Overall, costs of air pollution from carbon-based sources are orders of magnitude higher than those from non-carbon-based ones, and the air pollution costs of coal-based electricity are much higher than those from other carbon-based fuels (see Table 5.1 below).

Table 5.1: **Overview of key emissions by different generation technologies**

	mg/kWh	SO_2	NO_x	PM	Hg
Coal	Hard coal	530-7 680	540-4 230	17-9 780	0.01-0.037
	Lignite	425-27 250	790-2 130	113-947	Insufficient data
Natural gas	Combined-cycle	1-324	100-1 400	18-133	Insufficient data
	Steam turbine	0-5 830	340-1 020	Insufficient data	Insufficient data
Nuclear		11-157	9-240	0-7	Insufficient data
Bioenergy		40-490	290-820	29-79	Insufficient data
Solar	Photovoltaic	73-540	16-340	6-610	~0
	CSP	35-48	54-160	7-26	Insufficient data
Geothermal		0-160	0-50	1.3-50	~0
Hydropower	Reservoir	9-60	3-13	0.1-25	Insufficient data
	River	1-6	4-6		Insufficient data
Ocean/tidal		64-200	49	15-36	Insufficient data
Wind		3-88	10-75	1-14	~0

Source: Based on Masanet et al., 2013.

Emission rates for all air pollutants have fallen remarkably over the last few decades in all OECD countries, including emissions from electricity production. This was brought about by a combination of stricter emission limits and accompanying air quality standards as well as switching to less polluting forms of energy away from coal

towards nuclear, wind, solar, natural gas and less sulphurous coal. From 2005 until 2014, SO_2 emissions from electricity generators under the US Environmental Protection Agency's trading programmes have thus fallen by 69% from approximately 10 million tonnes to 3 Mt and NO_x emissions by 55% from approximately 3.6 Mt to 1.6 Mt in the same time frame.

Still, impacts remain significant. Caiazzo et al. (2013) for instance find for the United States that electric power generation accounts for $PM_{2.5}$ concentrations of 2.27 µg per cubic metre that cause about 52 000 early deaths per year. In comparison, road transport accounts for 53 000 deaths per year. The electricity sector also accounts for 38% of NH_3 (ammonia) emissions and 70% of SO_2 (sulphur dioxide) emissions. Meanwhile, power generation contributes 2.15 ppb of ozone per year, less than a third of that of road transportation and only 16% of NO_x emissions. In fact, diesel engines emit large amounts of NO_x and are therefore the major source of ground-level ozone.

Location remains a major determinant of damages. Electricity generation thus causes major impacts in the Mid-Atlantic, Central-eastern and Midwestern regions of the United States that are downwind of power plants relying on high-sulphur coal from the Appalachians. Mortality rates measured in annual deaths per 100 000 people, are in the 20s and 30s and reach nearly 40 in Kentucky (Caiazzo et al., 2013). Since sulphur content significantly affects damage estimates from coal-fired generation, health damages are considerably lower in regions that rely on low-sulphur coal from the Powder River Basin in Wyoming and Montana. In the following, we will present briefly the key impacts of different electricity sources.

Fossil fuels

Coal

Electricity generation from coal and lignite is the largest contributor to damage estimates from air pollution. Coal is also the dominant source of electricity worldwide, accounting for 41% of global power generation in 2014, by far the largest share of any fuel source, and for 32% of power generation in the OECD (IEA, 2016b). The amount of air pollution, essentially particulate matter and SO_2, emitted by the coal fuel cycle compared to other sources is striking. Ranges for other sources of electricity, including natural gas, do not even come close to those from coal.

Of the 9.46 Mt SO_2 emitted in the United States in 2005, about 95% comes from coal-fired power plants (Caiazzo et al., 2013). Other than direct health impacts, SO_2 causes corrosion of both metal and non-metal building materials. Non-metal materials such as stones containing calcium carbonate have straightforward dose-response functions, while those for metals are slightly more complex. Together with ozone and NOx, SO_2 causes damage to forests, fisheries and other ecosystems through "acid rain".

Apart from PM and SO_2 emissions, coal plants also emit non-negligible levels of radiation. Natural coal has trace amounts of uranium and thorium, and radiation levels become noticeable when these radioactive materials are concentrated in the fly ash (PM_{10}) emissions from combustion. Indeed, a series of studies since the initial report in *Science* (McBride et al., 1978) show that while radiation levels are still small, coal plants emit considerably more radiation than nuclear power plants during normal operations (see also UNSCEAR, 2016). Disposal sites for coal waste also emit non-negligible levels of radiation, owing to the presence of fly ash. Yet even at those levels, the damages of radiation are several orders of magnitude lower than other external effects of using coal in power generation.

Coal is also associated with damages from the release of toxic metals, e.g. with an impact in agriculture, but these are not always quantified. Last but not least, occupational injuries and fatalities in coal mining and transport, including respiratory

damage, are also large compared to other energy resources (see Chapter 6). Exposure to both radon and dust, which provoke similar damages, is high especially for underground coal mining (EC, 1995). Coal mining operations reported 159 occupational illnesses in the United States in 2007, 40 of which were dust-related respiratory diseases (NRC, 2010).

Oil and natural gas

Oil and natural gas are often grouped together in external cost analyses even though gas has lower impacts than oil. In both cases, however, the health effects are much lower than those of coal-powered electricity systems. It should be noted, however, that oil contributes only a small share of power generation both globally (4%) and in OECD countries (3%). Natural gas, meanwhile, is a major source of electricity, accounting in 2014 for 22% of electricity generation globally and 24% in the OECD (IEA, 2016b).

Refining, exploration and drilling activities are similar for oil and natural gas. Powered by large diesel engines that emit large quantities of PM, SO_x and NO_x, drilling equipment can be a significant source of air pollution. Extraction can also produce hydrogen sulphide (H_2S) in what is known as "sour" gas. PM emissions also occur in the hydraulic fracturing process, and there is a risk of gas leaks from storage tanks and pipelines in the case of natural gas. These leaks are mostly composed of methane, the primary component of natural gas, which is a potent greenhouse gas and a potential precursor gas of VOCs that can interact with NO_x to form ozone. Dones et al. (2005) estimate in their life-cycle analysis that half of all non-methane VOCs, 40% of PM, 20% of NO_x, and 80% of SO_2 emissions for the natural gas fuel cycle come from drilling and extraction (NRC, 2010). The same study also found that only 4% of natural gas damages were from SO_2 emissions, compared to 85% for coal. Since SO_2 has high damage costs, this contributes to lower overall damages. On average, the overall costs per kWh associated with coal plants were 20 times higher than the damages associated with gas plants (NRC, 2010).

Biomass

Analysing the external costs of biomass is difficult, given that biomass itself is a broad category that lumps together many different resources and is highly localised. To create electricity, biomass can be converted into a liquid or gas or be combusted directly. It is unique among renewable energies in that it is used in all sectors, including transport and industry. While biomass is considered a renewable energy and does not emit large levels of GHGs in its life cycle, pollutant emissions per MWh of bioelectricity production can be substantial. Its massive contribution to indoor air pollution has already been mentioned in Section 5.1.

Biomass power plants are often small and located closely to where the fuel crops are grown since transportation costs are high. They are thus often found in rural areas where damages from air pollution are lower. The major source of damage in the biomass fuel cycle is constituted by health damages from PM and ozone formed by NO_x. Like for like, the costs of air pollution from biomass combustors are in the same order of magnitude as those from coal.

Low-carbon sources

Nuclear

In 2014, nuclear power plants (NPPs) generated 11% of electricity globally and 18% in OECD countries (IEA, 2016b). Nuclear energy emits no air pollutants other than very small amounts of radionuclides during normal operation. Upstream costs of air pollution from nuclear power can be more significant. As in the case of coal mining, uranium mining can occur on the surface or underground. Radiological exposure can occur through the inhalation of radioactive dust, ingestion of radionuclides through food and water, or

direct irradiation. The last occurrence is an occupational risk for workers in underground uranium mines. For the public, the most significant source of health damages from uranium mining is naturally occurring radon leakage into surface water or the groundwater. Small amounts of radon and radioactive dust are, however, also emitted into the air during mining. Uranium conversion and enrichment do not emit air pollutants on their own, but consume large amounts of electricity. Depending on the structure of the electricity supply, this may generates indirect impacts but these are not inherent to nuclear power itself.

As for power generation itself, routine radionuclide emissions, which are considerably smaller than those from fly-ash emissions from coal plants (McBride et al., 1978; UNSCEAR, 2016) were not considered a priority impact by large studies such as ExternE (EC, 1995) or NRC (2010). While radioactive substances are proven to cause cancer at high concentrations, these are far above the concentrations from regular plant operation. Indeed, the morbidity effects through fatal and non-fatal cancers and hereditary effects are "extremely small" (Markandya and Wilkinson, 2007). Indeed, the predicted mortality rates from radiation are already fairly small for coal-fired power plants. They are smaller still for radiation from NPPs. Statistically significant risk of cancer has only been observed at doses significantly higher than those resulting from normal atmospheric emissions of NPPs.

Wind

In 2014, wind plants generated 3% of electricity globally and 5% in OECD countries (IEA, 2016b), shares that are expected to increase rapidly. As for nuclear power, there are effectively no emissions of local and regional air pollutants in wind power generation, with most emissions and accompanying health effects occurring upstream of generation, particularly during the manufacture of the turbines, which is again a function of the structure of the electricity supply. The costs of air pollution from wind power are thus negligible. Studies on external costs focus instead on the potential ecological and noise effects of wind power.

Wind turbines consist of nearly 90% metal and the transportation requirements for setting up wind farms, especially offshore, can be large (NRC, 2010). Mining and transportation result in emissions similar to those that have been described for coal and uranium mining, most notably PM. Steel production as such emits some PM such as black carbon over and above the emissions resulting from electricity generation.

Hydro

Hydroelectricity is the largest renewable source of electricity in the world, accounting for 16% of global electricity generation in 2014 and for 13% in OECD countries (IEA, 2016b). Further hydropower capacity in OECD countries however is limited, with the best resources already tapped and the emergence of significant environmental concerns. Like wind or nuclear, electricity generation from hydropower does not involve any direct atmospheric emissions. As with other renewables, the only sources of air emissions result from manufacturing and construction such as the steel and cement used in the construction of hydroelectric dams. The direct impact of hydroelectricity on air pollution, however, is negligible, compared with both the impact on air pollution of carbon-based sources, and with the external costs of hydroelectricity itself on ecosystems and the destruction of landscapes with amenity value.

Solar photovoltaic

In 2014, solar photovoltaic (PV) plants generated 1% of electricity both globally and in OECD countries (IEA, 2016b). Again, these shares are expected to increase rapidly. Since solar power was not a widely used electricity source before the last decade, impact pathway analyses for solar power are more limited. Widely-cited older studies like ORNL-

RFF and EC ExternE did not include solar power in their analyses at all. In addition, solar power is the only electricity source whose underlying technology has changed rapidly in the past 30 years. Indeed, the production of PV panels is the main source of atmospheric emissions in the solar fuel cycle, which involves zero-emission during generation. Changes in manufacturing processes thus have significant implications in determining the costs of air pollution from solar power.

The solar power life cycle emits air pollutants at a much lower rate than fossil fuels, although at higher rates than nuclear, wind and hydroelectricity. Toxic metal emissions from mining and smelting during PV panel manufacturing have received a considerable amount of attention. Total direct emissions of cadmium, a key component of certain PV technologies, are estimated to be about 0.015 g per GWh, but remain orders of magnitude lower than Cd emissions from fossil fuels (Fthenakis et al., 2008). Other metals include chromium and arsenic from copper, lead and steel alloying. There are no substantial differences in emissions between different kinds of PV technology, such as single- or multi-crystalline silicon (Fthenakis et al., 2011; EC, 2005b). Studies also point to the waste from worn-out solar panels as a matter of concern. Air emissions from these wastes are minimal but toxic chemicals may leach into water and soil.

Geothermal

Geothermal electricity generation, utilising the heat radiating from the earth's crust to heat water, makes up less than 1% of electricity production. The power source has very high siting restrictions, with only certain areas having the suitable near-to-surface temperature ranges for the large-scale use required for a power plant.

However, geothermal plants do release some local air pollutants during generation, the only non-carbon-based electricity source to do so. Small amounts of airborne emissions are made up of CO_2 and hydrogen sulphide (H_2S, the source of the "rotten eggs" smell). While concentration-response functions (CRFs) have not been conclusively determined for H_2S, it is potentially toxic. However, concentrations are rarely sufficient to be harmful and vents are usually scrubbed to remove it. There can also be small releases of SO_2, methane, nitrogen, hydrogen, and ammonia (Goldstein et al., 2011). The exact make-up of the emissions is heavily dependent on the water used at individual geothermal sites. These emissions are tiny and often negligible, since geothermal plants are often built far from heavily populated areas, and filters are highly effective.

Tidal

The use of kinetic energy from tides and waves to generate electricity is an energy source that is still at an experimental stage. Again, electricity generation itself does not cause any atmospheric emissions. For indirect emissions, the remarks made above with respect to nuclear, wind and solar PV apply. Transportation costs could perhaps be important if the optimal sources are located far from production areas. Overall, though, tidal electricity production is likely to cause no impacts on air quality. More important are the ecosystem impacts on the estuaries where tidal power plants are built.

5.3. Estimating damages

Since the middle of the 1990s, several major studies have compiled data on the social costs of energy, all of which indicate the costs of local and regional air pollution. They include the study by Hagler Bailly Consulting (1995) for New York State, those by Oak Ridge National Laboratory and Resources for the Future (ORNL and RFF, 1995) as well as by the NRC (2010) in the United States and the reports following the projects ExternE (EC, 1995; EC, 2005a) and New Energy Externalities Developments for Sustainability (NEEDS) (EC, 2005b) in Europe. Of these, the ORNL-RFF and ExternE studies are the most comprehensive.

Burtraw et al. (2012) list these as the best primary studies on the full costs of electricity. While specifics to analyse the costs of air pollution as part of the life-cycle analysis (LCA) of different technologies vary across studies, they share the basic methodology:

1) emissions must be linked to concentrations in ambient air;
2) health effects, known as "burdens" in many studies, must be drawn from the ambient concentrations;
3) costs or damages must be estimated on the basis of the health effects.

Environmental agencies in most OECD countries have set up inventories to measure the emissions of major ambient air pollutants. In the United States, for instance, the US Environmental Protection Agency (EPA) maintains the National Emissions Inventory (NEI), which contains estimates of emissions of 187 hazardous air pollutants, with information collected from state and local agencies down to the facility level (see EPA website: www.epa.gov/ttn/chief/net/2011inventory.html). The European Environment Agency (EEA) maintains the European Pollutant Release and Transfer Register (E-PRTR), which collects emissions data for 91 pollutants and also down to the facility level (http://prtr.ec.europa.eu/#/home). Other countries have similar emissions inventories, though there exists at present no global inventory for local air pollutants (Amann et al., 2013).

The EEA has released estimates of the cost of air pollution in Europe from 2005 to 2012, utilising new emissions figures for air pollutants in damage functions (damage cost per tonne) determined by methods in the European Commission's Clean Air for Europe programme (EEA, 2014b). It determined that the aggregated damage costs from the main air pollutants NH_3, NO_x, PM_{10}, SO_2 and VOCs for the period 2008-2012 amounted to between EUR 40 to EUR 115 billion, depending on methodological conventions for the value of a statistical life. The report showed a decreasing trend for the agency's damage estimates in Europe from 2005 to 2012, which it attributes to progressively strengthening environmental legislation as well as lower industrial output after the economic recession.

If the measurement of emissions, although still incomplete, is a comparatively straightforward process, modelling the dispersion of air pollutants from emitters is a far more complicated process. This includes the movement of pollutants directly from the source into the wider region as well as the formation of other particles such as ozone from primary pollutants. The aim is to model ambient air concentrations for various substances. ExternE, ORNL-RFF and Hagler Bailly used variants of the industrial source complex long-term (ISCLT) dispersion model for short-range air quality modelling. NRC (2010), meanwhile, used the newer Air Pollution Emissions Experiments and Policy (APEEP) model (Burtraw et al., 2012). Both make use of Gaussian plume models that assume that pollutants are carried in a straight line by the wind, mixing both horizontally and vertically to form concentrations with a normal (Gaussian) distribution (EC, 2005a). ExternE and ORNL-RFF also included separate models to estimate ozone concentrations from sources based on the NO_x and VOC emissions that contribute to its formation. ExternE also links regional air quality with a soil and water model, as damages from air pollutants are not restricted to inhalation. In particular, toxic metals can be ingested through food and drink.

While uncertainties remain large and data are still lacking on the precise effects of many chemicals on human health, there is continuous progress. In recent years, remote-sensing techniques through satellite observations and inverse-modelling methods have been developed to validate emissions inventories. This top-down approach mostly confirms trends in bottom-up estimates. While being far from an exact science, a comprehensive body of knowledge about airborne pollutants and their health impacts has now been assembled and continues to improve.

Translating emissions into damages

The association between air pollutant concentrations and health damage can be divided into two categories, mortality (premature deaths) and morbidity (disability and disease). Economists and public health researchers have long focused on mortality when investigating the costs of air pollution. The basic methodology to estimate mortality from air pollution is the formulation of CRFs, also referred to as dose-response functions (Caiazzo et al., 2013).

Assumed to be linear in most studies, CRFs are described in EC (2005a) as "a central ingredient in the impact pathway approach". The United States EPA keeps a reference of health impacts in its IRIS database, which includes CRFs for many major pollutants. Yet, CRFs for many minor pollutants, especially toxic metals, are still missing. However, all studies converge on the point that the largest source of premature mortality is due to PM exposure, with ozone in second place. It should be kept in mind, however, that new information on the health effects of SO_2, NO_x, and toxic metals is appearing constantly.

In general, CRFs for the six main air pollutants – particulate matter, ground-level ozone, carbon monoxide, sulphur oxides, nitrogen oxides and lead – are assumed to be linear and without threshold, the linear-no threshold (LNT) model. This presents a serious methodological problem. The ExternE study, for instance, states that in investigating the health effects of air pollutants, "one needs relatively high doses in order to obtain observable non-zero responses unless the sample is very large" (EC, 2005a). Such doses, however, significantly exceed typical concentrations in the European Union and North America. Extrapolating data linearly to low doses is thus problematic, with uncertainty compounded if laboratory studies on animals are utilised as opposed to epidemiological studies drawing on large groups of people (EC, 2005a; Burtraw et al., 2012). Many studies, notably ORNL-RFF (1995) and EC (1995), have nevertheless relied on the LNT model in the past. The reason is that it is unclear what assumption could take the place of the LNT model, as the existence of thresholds and the general shape of the dose-response function at these low doses are unknown.

Meanwhile, measuring impacts on morbidity is even more difficult. Whereas mortality has only one end point, morbidity has many. ExternE cites, for instance, impacts as diverse as chronic bronchitis, new cases of chronic cardiovascular disease, respiratory hospital admissions, consultations with primary care physicians for respiratory illness, medication usage for respiratory illnesses like asthma, and cancer rates in the case of toxic metals. These values are combined to create a unit of number of new cases, events or days per unit population per 1 $\mu g\ m^{-3}$ pollutant.

Similar categories and cases are also used in ORNL-RFF (1995) and NRC (2010). The NEEDS study (EC, 2007) included an indicator for morbidity measured in disability-affected life years (DALYs), a unit from epidemiological literature that is also known as quality-adjusted life years lost (QALYs). Just as epidemiological research can measure mortality in terms of deaths or life-years lost, morbidity can be measured in terms of end-points like in ExternE or with QALY or DALY, which, while slightly different methodologically, end up quantifying the number of healthy years lost because of disease. While both are considered adequate units for measuring morbidity, questions concern the extent to which they can be associated with monetary damages.

Few are the studies that dare to synthesise and compare the overall impacts on morbidity and mortality of different power generation sources. One laudable, and authoritative, exception is the 2007 meta-study by Anil Markandya and Wilkinson published in the medical journal *The Lancet*, whose key table is reproduced as Table 5.2.

Undoubtedly, the uncertainties in this and similar exercises are huge. Nevertheless, it should be noted that the social costs of airborne pollution during electricity generation is today benefiting from more than 50 years of research on the subject as well as from

major advances in epidemiological research techniques. The same sort of historical arch is not present in other fields of external costs, including climate change.

Epidemiological research into those health damages continues to grow and with it cost estimates from those damages. While this history of research and regulation makes local and regional air pollution one of the most recognisable types of external costs from electricity provision, research continues. In particular, epidemiologists have begun looking at the various components of PM_{10} and $PM_{2.5}$ as these components have been shown to have differential health damages and lifetimes in the atmosphere.

Table 5.2: **Health effects of electricity generation by primary energy source**

(Europe, deaths/cases per TWh)

	Deaths from accidents		Air pollution-related effects		
	Among the public	Occupational	Deaths*	Serious illness†	Minor illness‡
Lignite	0.02 (0.005-0.08)	0.10 (0.025-0.4)	32.6 (8.2-130)	298 (74.6-1 193)	17 676 (4 419-70 704)
Coal	0.02 (0.005-0.08)	0.10 (0.025-0.4)	24.5 (6.1-98.0)	225 (56.2-899)	13 288 (3 322-53 150)
Gas	0.02 (0.005-0.08)	0.001 (0.0003-0.004)	2.8 (0.70-11.2)	30 (7.48-120)	703 (176-2 813)
Oil	0.03 (0.008-0.12)	..	18.4 (4.6-73.6)	161 (40.4-645.6)	9 551 (2 388-38 204)
Biomass	..	..	4.63 (1.16-18.5)	43 (10.8-172.6)	2 276 (569-9 104)
Nuclear	0.003	0.019	0.052	0.22	..

Data are mean estimate (95% CI).

* Includes acute and chronic effects. Chronic effect deaths are between 88% and 99% of the total. For nuclear power, they include all cancer-related deaths, including accident and long-term effects.

† Includes respiratory and cerebrovascular hospital admissions, congestive heart failure, and chronic bronchitis. For nuclear power, they include all non-fatal cancers and hereditary effects.

‡ Includes restricted activity days, bronchodilator use cases, cough, and lower-respiratory symptom days in patients with asthma, and chronic cough episodes. TWh-1012 watt hours.

Source: Based on Markandya and Wilkinson, 2007.

Converting damages into monetary damages is yet another challenge. The basic techniques, challenges and controversies have been presented in Chapter 1. Section 5.5 in this chapter provides a summary table (5.3) of the damage cost estimates of four major studies. Unsurprisingly, the social costs of air pollution are highest for coal-fired power generation, which can generate in certain regions and under certain assumptions damages that exceed the level of USD 100 per MWh.

5.4. Perspectives of internalisation

Since the late 1960s, regulating local and regional air pollutants has been a cornerstone of environmental policies in OECD countries. While pollutant categories, emission levels and other regulatory details vary from country to country, all governments address them through command-and-control policies that focus on the power plants themselves, where they set emission limits and ambient air quality standards. At the onset, governments undertook such programmes primarily out of a concern for ecosystem loss and habitat damage. However, in recent decades, policy makers have become increasingly aware of air pollution's significant detrimental impact on public health, particularly that of particulate matter.

Command-and-control mechanisms for local and regional air pollution are often fairly similar across the OECD. Usually, policies enact emission limits on various pollutants, called ambient air quality standards, and set requirements for emitters such as the adoption of certain kinds of abatement technology. In the United States, most air pollution policy is undertaken under the authority of the Clean Air Act (CAA), first passed by the US Congress in 1963 with amendments in 1970 and 1990 that significantly expanded its purview. EPA sets national ambient air quality standards (NAAQS) for pollutants considered harmful to public health and the environment. The CAA sets out two types of NAAQS: primary standards that provide public health protection and secondary ones that provide public welfare protection against decreased visibility and damage to animals, crops and buildings.

In the European Union, air pollution emission regulation is underpinned by the European Commission's Strategy on Air Pollution, which was last reviewed in 2011 and led to a new Clean Air Policy Package in 2013 that formulated more stringent emissions ceilings. In the power sector, the hugely influential Large Combustion Plant Directive required member states to limit emissions of particulate matter, SO_2 and NO_x from combustion plants having thermal capacity of 50 MW or more. Plants that did not comply with new limits had to close completely by the end of 2015. The 2004 Ambient Air Quality Directive regulates concentrations of As, Cd, Hg, Ni and polycyclic aromatic hydrocarbons, while a 2008 directive regulates ambient air concentrations of SO_2, NO_2, PM_{10}, $PM_{2.5}$, Pb, benzene, CO, and ozone O_3.

Other countries have comparable systems. The Canadian Environmental Protection Act of 1999 is similar in structure to the Clean Air Act (CAA) in the United States, with a set of criteria air pollutants (SO_x, NO_x, PM, VOC, CO, NH_3 and O_3) and addressing heavy metals and toxic pollutants. Canada has ambient air quality standards for $PM_{2.5}$ and ozone and is developing ones for NO_2 and SO_2, although these are voluntary objectives for provinces and territories, unlike in the United States. Japan's policy instruments to address air pollution are also based on regulation, such as quality standards, non-compliance responses and pollution limits (OECD, 2012).

Despite the dominance of command-and-control regulation, the economic analysis of environmental policy instruments has built a strong case for market-based policies to ensure the most cost-effective internalisation of air pollution.

The efficiency gains from market-based mechanisms result from the fact that the marginal abatement cost for a given pollutant is equalised across all sources. The latter is, in return, equalised to the marginal social cost of pollution according to the Pigouvian paradigm outlined in the introductory chapter. This desirable state of affairs can be achieved either through appropriate taxes or through emissions trading schemes that replicate their effect by setting appropriate caps. Economic analyses of cap-and-trade schemes have been rather favourable.

A famous example for market-based internalisation is provided by the US SO_2 Allowance Trading System. This SO_2 cap-and-trade mechanism is the only major market-based scheme addressing local air pollutants. It was introduced in the 1990 amendments to the CAA. Seeking to reduce total annual SO_2 emissions by approximately 10 Mt relative to 1980, the first phase of the US programme required emissions reductions from the 263 most polluting coal power plants east of the Mississippi River. The second phase set an aggregate national emissions cap on almost the entire fleet of fossil fuel-power plants in the United States, representing a 50% reduction from 1980 levels. The government then gave out allowances to power plants in the second phase, and utilities could either buy allowances from others or reduce emissions in order to return enough allowances to cover their emissions, with a fine of USD 2 000 per US tonne for emissions exceeding allowance holdings. The national emissions goal of 8.95 million US tonnes annually was achieved in 2007. The costs of achieving that objective were up to 90% less than they would have been for a command-and-control programme according to a study by

Schmalensee and Stavins (2013). The switch to low-sulphur coal from Wyoming made possible through the deregulation of freight rail rates in the 1970s contributed to the cost-effectiveness of the programme. On the basis of this successful experience, a NO_x Budget Trading Program was also instituted by state governments in 2003 with EPA support in order to reduce NO_x emissions during the summer months.

5.5. Summary and key issues for policy makers

Air pollution constitutes the biggest uninternalised cost of electricity generation. According to the WHO it is the world's largest single environmental health risk. WHO studies from 2014 and 2016 find that in 2012 around 3 million people died due to ambient air pollution to which electricity generation is a major contributor (WHO, 2014a, 2014b and 2016). Household air pollution, much of it due to a lack of electricity, causes an additional 4.3 million deaths. Roughly half this pollution can be attributed to outdoor air pollution. This corresponds to an estimated loss in welfare in OECD countries that is far above one trillion USD, corresponding to roughly 3% of GDP (OECD, 2014).

For more than 40 years, the costs of air pollution are also a well-researched area with widely used methodologies. While the range of uncertainty over impacts and their monetised values remains considerable, methodologies are now firmly established and ranges of reasonable values exist. The perception that there was a need for the study of the full or external costs of electricity generation beyond its plant-level production costs was very much motivated by concerns about the external cost of air pollution. While in the meantime climate change risks have assumed comparable importance, the costs of air pollution remain a top priority in the planning and regulation of sustainable electricity systems.

The most carefully studied sources of air pollution are particles of different sizes, ground-level O_3, SO_x, NO_x and lead. These emissions arise during the combustion of fossil fuels (coal, oil, gas or biomass) that impact primarily the respiratory system leading to bad health (morbidity) or premature death (mortality). Economics has long attempted to monetise these impacts by assessing an individual's marginal willingness to pay for marginal changes in the probability of incurring mortality risk, from which the notion of the value of a statistical life (VSL) can be derived. Methodologies for monetising morbidity damages also exist but are less stabilised. In both cases, large uncertainties remain.

Sometimes these differences are due to objective factors such as location, population density and wind speeds and directions. Sometimes they are due to methodological differences or different estimations for the value of a statistical life. The 2012 meta-study by Burtraw et al. (2012) provides an overview of the results of four important studies that have been undertaken in the past 20 years (see Table 5.3).

Table 5.3: **Summary of estimates from four external cost studies**

(Mills* per kWh or USD per MWh)

	Coal	Peat	Oil	Gas	Nuclear	Biomass	Hydro	PV	Wind
ORNL/RFF	2.3	–	0.35-2.11	0.35	0.53	3	–	–	–
Rowe et al.	1.3-4.1	–	2.2	0.33	0.18	4.8	–	–	0.02
EC ExternE	27-202	27-67	40.3-148	13.4-53.8	3.4-9.4	0-67	0-13	8.1	0-3.4
NRC	2-126	–	–	0.01-5.78	–	–	–	–	–

* A mill is one-tenth of a cent or one-thousandth of a dollar; PV is photovoltaic.

Source: Burtraw et al., 2012.

On the basis of these studies, orders of magnitude of the damage from various air pollutants and of the costs of air pollution from major sources of electricity have been determined. As far as air pollution is concerned, power sources can largely be split into two groups: i) carbon-based electricity sources, including fossil fuels and biomass, with coal-fired plants causing damages that are considerably higher than those from natural gas, oil, or biomass; ii) sources that have impacts on air pollution from low-carbon electricity sources – nuclear, wind, solar, hydro, geothermal and tidal – are either negligible or zero, although some indirect emissions could arise during production. Such indirect emissions, however, are a function of the structure of the existing electricity system, not of the individual technology being produced. The only local air-polluting emissions from the generation stage of the nuclear fuel cycle are minor operational radionuclide emissions. The contributions to background radiation from these operation emissions are numerically minute, and thus the radiological risks that such emissions might cause (possibly fatal and non-fatal cancers, genetic effects, etc.) would also be numerically very small (NEA, 2016).

Indeed, coal-fired generation releases 100 times more radioactivity per MWh than nuclear power generation, through fly-ash emissions. This is compounded by the emission of large amounts of PM, SO_2, NO_x, and toxic metals, common throughout all carbon-based sources, with significant damages to public health and ecosystems. When compared to any carbon-based source, air-polluting emissions from nuclear power generation are numerically extremely small. The life cycle of nuclear power generation, however, causes some upstream emissions of radon and radioactive dust. Such air emissions are released during uranium mining, with most of the risk being to miners. Burtraw et al. produce a useful summary of their study:

> In general, the results in Table 1 [5.3] and from the literature support a rank order of fossil fuels wherein the coal fuel cycle is more damaging than the oil fuel cycle, which is more damaging than the natural gas fuel cycle. This difference would be magnified with consideration of climate change impacts. The estimates also suggest that damages from the biomass fuel cycle are of the same order of magnitude as the coal or oil fuel cycles when climate change is not taken into account… The nuclear fuel cycle has low external costs in general, although the remote probability of accidents adds a very high consequence factor into the estimates. Photovoltaics and wind are essentially emissions-free energy sources at the use stage, but impacts over the life cycle occur. (Burtraw et al., 2012: pp. 13-14)

Table 5.3 does not include climate change impacts. Since fossil fuel combustion is the primary source of both GHG and local and regional air pollution, there are obvious synergies between these two areas. While policies mitigating air pollution *can*, although do not necessarily, reduce GHG emissions, reducing them always lowers air pollution.

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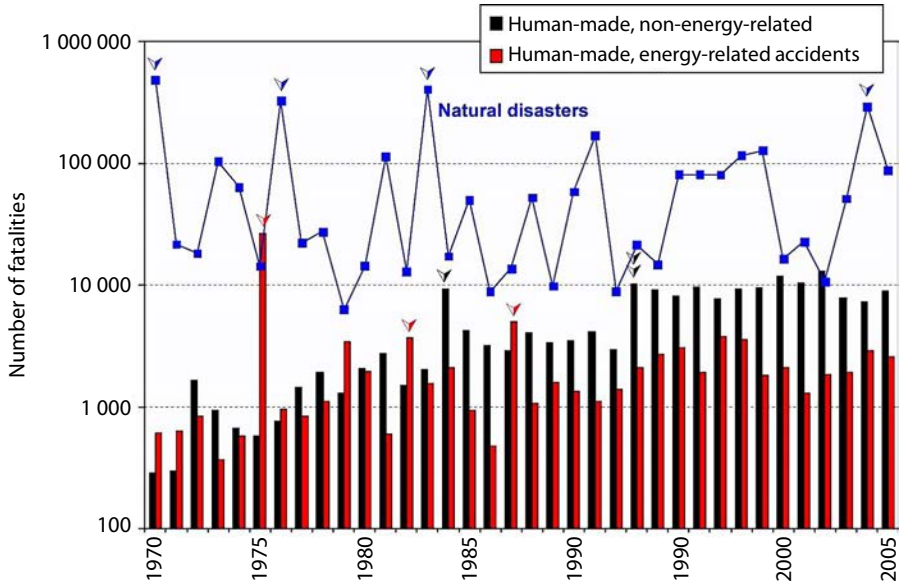
Chapter 6. **The costs of major accidents**

6.1. Introduction

In the last decades, the damages caused by both natural catastrophes and human-made accidents have continuously increased. Many factors have contributed to this trend and have increased the societal vulnerability towards accidents and catastrophe hazards: growth of the population and global economy, industrialisation, urbanisation and development of coastal and other risk-prone areas, as well as the growth of more complex and interrelated infrastructures.[1] Natural catastrophes impose the largest toll in terms of human fatalities and economic consequences: as illustrated in Figure 6.1, natural catastrophes caused about 90% of the 3.4 million fatalities that occurred worldwide in the period 1969-2005, while the remaining 10% are due to human-made accidents (Burgherr et al., 2008c). If only human-made accidents are considered, transport causes about 60% of all mortalities; the energy sector is the second-largest contributor (ExternE, 1995).

Figure 6.1: **Number of fatalities due to natural disasters and human-made accidents**



Source: Burgherr et al., 2008c.

1. Better reporting may also have contributed to this trend.

Although the external costs of severe accidents are considerably smaller than other externalities associated with power generation (air pollution, carbon emissions or system effects, for example), severe accidents in the energy sector can have disastrous and far-reaching impacts on the well-being of populations and the economy of modern societies. Human-made accidents and natural disasters affect directly people's health (immediate and latent fatalities, injuries and morbidity), property and direct economic losses, and may have long-term impacts on the natural environment and ecosystems (as an example, a spill of hydrocarbons or a release of radioactive material). Beside these direct effects, severe accidents may also have adverse consequences for the security of energy supply or the global supply chain of goods and services. Indeed, the project New Energy Externalities Developments for Sustainability (NEEDS) has identified that severe accidents on energy chains may impact several criteria and dimensions of sustainability (Hirschberg et al., 2008).

Recent years have witnessed a growing interest and demand for accurate data and analysis on the consequences and risks of potential severe accidents in the energy sector by decision makers, government authorities, different stakeholders' groups such as industry, insurance and reinsurance companies, as well as by the general public. Recent disasters in the energy sector, such as the Deepwater Horizon oil spill in the Gulf of Mexico, the accident in the Fukushima Daiichi nuclear power plant, several accidents to the gas and oil transmission infrastructure in Europe and Africa or accidents in coal mines in China received broad media coverage and raised a large debate within the energy community as well as among the public.

However, despite the growing public interest and the importance of this subject, the information publicly available on past accidents and on potential consequences of accidents in the energy sector is fragmented, mostly incomplete and, with few exceptions, does not allow for a comparison of different energy technologies.

6.2. Methodological issues, difficulties in measurement and uncertainties

The establishment of a comprehensive analysis of accident risk in the energy sector faces large conceptual, technical and practical challenges. The wide range of technology used in energy production, their different level of technological maturity and market deployment, as well as significantly different risk profiles among technologies and the wide range of potential consequences makes the analysis and direct comparison of accident risks very challenging.

In principle, a statistical analysis of past accidents could provide sufficient information to assess the frequency and impacts of accidents for different energy technologies. This approach appears to be well suited for the analysis of certain technologies, although it presents some practical difficulties that will be discussed in the following paragraphs. For example, the extensive historical experience of severe accidents in the fossil chain and, at least for non-OECD countries, in hydropower provides a strong analytical basis to quantitatively assess the accident risk and to provide a reliable estimate of the range of potential consequences. On the contrary, this approach has certain weaknesses when applied to energy technologies for which the accumulated historical experience is outdated or too limited to draw sufficiently robust quantitative conclusions. This applies to nuclear energy, where only three major accidents occurred worldwide, to hydroelectricity, at least for the OECD countries where recent accidental occurrences are limited, as well as to some renewables technologies for which the deployment is too limited or too recent. For these technologies, the historical evidence must be complemented by expert judgement and/or quantitative analysis of simulated accidental events. In the analysis of nuclear energy level-III Probabilistic Safety Assessment provides insights on the likelihood and impacts of potential accidents.

The use of historical data presents also some issues related to the time period used for the statistical evaluation of accidental events and the level of geographical aggregation of the results. With respect to the time dimension, technological progress has continuously improved over time, contributing to an increase of the safety level of all installations in the energy sector. In all countries, more modern and safer plants have replaced older and less technically advanced ones. Major improvements in safety standards and in safety culture have also contributed to a decrease of the rate of accidents in all advanced and emerging economies. Therefore, historical accidents may no longer be representative of facilities and working policies in operation today. An additional conceptual difficulty arises as the operational lifetime (and thus the average lifetime) of power plants and other energy infrastructure varies significantly across energy technologies: a modern nuclear plant has an operational life exceeding 60 years, hydropower infrastructure can operate for even longer, while the expected lifetime of other energy infrastructure is much shorter (for example the lifetimes of a solar photovoltaic panel, a windmill or a gas power plant are expected to be shorter than 30 years, because of technical limitations or the expected efficiency improvements in future plants). The choice of the appropriate time length of the database of accidents considered is therefore subjective and technology-specific: it should be sufficiently long to provide a number of entries statistically significant but also contain data representative of the existing energy infrastructure in terms of technology development and safety and regulatory standards.

With respect to the geographical component, detailed analysis of accident history shows that accident and fatality rates are very heterogeneous across the world, reflecting different levels of technological development, regulatory frameworks and safety culture among countries. An appropriate aggregation level of the results is therefore needed to reflect these differences. For example, researchers from the Paul Scherrer Institute (PSI, Switzerland) aggregate the results in three major groups – European Union member states (27), OECD and non-OECD countries [1], but the latter group is further disaggregated to reflect specific situations for certain energy technologies (for instance the data for coal in China have been reported separately, since they are significantly higher than those of other countries). In the literature, different approaches have been used with respect to the time frame considered and to the geographical segmentation used: a comparative study (Felder, 2009) pointed out that two major accident-related studies from PSI and Sovacool (Sovacool, 2008 and Hirschberg et al., 1998) used a very different aggregation level both in a temporal dimension and on the aggregation level of countries considered.

Before looking at quantitative estimates of the impacts of severe accidents in the energy sector, it is useful to further discuss other practical aspects that make this analysis challenging. A first challenge is related to the type of accidents that should be included in the analysis. Ideally, all accidents should be integrated in the risk assessment, regardless of their severity. However, such an approach is not practically feasible; preparing and maintaining a complete, reliable and up-to-date database of all worldwide accidents in the energy sector would be extremely resource-intensive and almost impossible in practice. In addition, researchers from the PSI point out that relatively scarce major accidents have a greater chance to be accurately reported than much more frequent, smaller accidents with only minor consequences. Also, when reported, the information on indicators other than fatalities is lacking and they appear even more incomplete than in case of severe accidents. PSI researchers conclude that small accidents are *de facto* strongly under-represented in available databases because of under-reporting. This may have an important impact on the overall results, as it is recognised that, for some technologies, the aggregate cost of small accidents can be large and may have a substantial impact in terms

1. The first two sets of countries are partly overlapping. The choice performed by PSI may also reflect the need to provide results for Europe alone, since most of the work was conducted under an EU framework.

of human fatalities (Burgherr and Hirschberg, 2008a and 2008b). On the other hand, severe accidents are viewed more controversially by the public and in the energy-policy debate, and also the degree of internalisation of damages is more likely to be significantly lower than for smaller accidents. This is why this chapter is focused only on severe accidents,[2] thus neglecting the large majority which have more limited consequences. While concentrating the analysis on severe accidents is the only practicable way forward, it should be borne in mind that this is one of the factors that contribute to an overall underestimation of accident impacts and economic costs.

Secondly, historical experience shows that the analysis and assessment of energy-related accidents and risks requires considering the full energy chains because accidents do not occur only during electricity generation but at every stage of the energy chain: exploration, extraction, refining, transportation, power production, distribution, storage and waste disposal. For example, in the fossil fuel chains, the upstream stage dominates the severe accident risks. For hydro and nuclear power instead the corresponding risks are predominantly concentrated on power plants. Limiting the analysis to the sole stage of power production would therefore severely underestimate some results and bias the comparison across technologies.

There are two other methodological difficulties that need to be discussed in the context of this analysis: how to consider the import/export of primary resources across countries and the different levels of internalisation of accident cost. These levels vary significantly across countries, with more developed countries generally being able to internalise costs to a greater extent, and across energy technologies. For example, an accident in a coal mine is mostly limited to the facility itself: almost all the fatalities occur among the mine workers, and the economic damages are almost exclusively restricted to the facility itself. Most of the accident costs are therefore fully or partially internalised. In contrast, an accident in a hydro facility or in a nuclear power plant (NPP) may have far-reaching impacts and are most likely to affect the residents in the vicinity or downstream of the plant, while the impact on workers is much more limited. Similarly, only a fraction of the economic impacts occurs within the plant boundaries. The degree of internalisation of economic impacts in these energy chains is therefore much more limited. The distinction between occupational and public consequences is important, as the degree of internalisation of consequences differ considerably for the two groups and thus influences the transfer from damages to external costs.

Some energy technologies are characterised by significant trade of primary fuel sources between OECD and non-OECD countries. For instance OECD countries import from non-OECD countries a large share of their crude oil and a small portion of natural gas needs, while the import/export balance of coal is negligible. The reallocation between OECD and non-OECD countries of the damages occurring in the extraction and transportation parts of the energy chains poses some methodological challenges. Some studies (Hirschberg et al., 1998) have developed a methodology for reallocating the consequences of accidents occurring in an exporting country based on the net amount of energy exchanged and have performed a comparison with calculations where no reallocation is considered. Comparative results are also presented in Friedrich (2004a). However, for simplicity, the analysis and results presented in this chapter assume that no reallocation of accident impacts is considered.

Finally, a particular challenge arises when assessing the potential impacts, economic consequences and risks of severe accidents in nuclear energy. This is due to the specificity of nuclear accidents in terms of timescale of potential consequences and the lack of a clear causality link between the long-term consequences observed and the accident itself. Contrary to accidents in other energy chains, where most of the economic

2. A formal definition of a severe accident is provided in Section 6.3.

damages and health consequences are immediate and where effects are limited to a well-defined area, impacts of a nuclear accident may last for several years or decades, may affect a large region beyond the "contaminated" area and are dominated by indirect or induced effects on the economy[3]. Also, it is recognised that the response and decisions taken by governments and safety authorities in the aftermath of the event may have an important impact on the overall consequences of the accident. All these features add yet another layer of uncertainty and subjectivity when assessing economic impacts of past or potential accidents in the nuclear energy chain.

With respect to the health consequence on the exposed population, most recent studies agree that it is extremely unlikely that a severe nuclear accident occurring in a modern plant could cause immediate fatalities or deterministic health effects in the population. The totality or the large majority of such health effects would be expected to occur several years after the exposure as, at most, a (small) increase of the cancer rate across the exposed population; radiation-induced cancers are not physically discernible from other unrelated pathologies, and the increase may not be statistically discernible from the mortality and morbidity rates normally occurring in a population. Moreover, the estimates of additional morbidity and mortality in the exposed population will be highly uncertain at low individual exposures. This uncertainty results from, *inter alia*, an incomplete scientific understanding of low-dose radiological risks, such that the range of possible low-dose risks is fairly large, and includes zero. Such difficulties also help to explain the diverging estimates on future fatalities resulting from the Chernobyl accident, which often differ by more than one order of magnitude. In addition, when analysing hypothetical accidents, countermeasures effectively taken to mitigate radiation exposure have a strong impact on the total dose received by the population and therefore add further uncertainty on the *a priori* estimates (for example, effective evacuation minimised the collective dose after the Fukushima Daiichi accident in comparison with the Chernobyl event). While radiological effects are generally characterised as cancers and leukaemia, recent focus has been on the psychological effects caused directly or indirectly by the accident and by radiological protection choices.

To an even higher degree, the evaluation of economic impacts of a nuclear accident is controversial and strongly dependent on subjective assumptions with respect to the types of losses included in the analysis, the resilience of the economy to the event, and to the behaviour of authorities and population after the accident. Dealing with these effects has a strong subjective component, including the establishment of scope and boundaries for the analysis. As a result, existing studies on the economic impacts of a nuclear accident, and *a fortiori* on the risk of nuclear, can show differences of several orders of magnitude in terms of their outcomes.

6.3. State of research, main studies and quantitative estimates

Despite the large impacts of severe accidents on modern society and of the growing awareness of the public on this topic, there have been few attempts to systematically categorise, analyse and compare accidents in the energy sector. Most of the published work and quantitative analyses on this area have been carried out in the last decades at the PSI. In particular, PSI has been the main contributor to the comparative analysis of externalities due to severe accidents performed within the EU NEEDS project, New Ext and SECURE, which constitute to date the most comprehensive and detailed effort to characterise and quantify externalities in the energy sector. The present section relies

3. It should be noted that large accidents in the non-nuclear energy sector, such as petrochemical, can release cancer causing chemical contaminants that may have long latency periods.

mainly on the results published in these major studies and on more recent research findings of PSI, which focus specifically on the risk assessment of terrorist attacks on large energy infrastructures. However, evidence from other studies is also discussed and, where possible, integrated into the final quantitative assessment.

ENSAD database and methodology

At the beginning of the 1990s, PSI initiated a research activity to collect, verify and integrate information on severe accidents by creating the ENSAD database (Energy-related Severe Accidents Database). To ensure better quality and completeness of the data, ENSAD focuses mainly on human-made severe accidents, but it includes also data on natural disasters, other non-energy-related accidents as well as on less severe human-made accidents, although with a lesser degree of completeness. Since at that time there was no commonly shared definition of severe accident in the literature, PSI considers as "severe" an accident that is characterised by at least one of the following consequences:

- at least 5 fatalities;
- at least 10 injured;
- at least 200 evacuees;
- extensive ban on consumption of food;
- release of hydrocarbons exceeding 10 000 metric tonnes;
- enforced clean-up of land and water over an area of at least 25 km^2;
- economic losses of at least 5 million USD_{2000}.

The ENSAD database has been continuously updated since its creation by integrating several databases and information sources, and by increasing its geographical breadth. Currently, it is considered the most complete and reliable source of information on human-made severe accidents in the energy sector. In total, ENSAD comprises over 32 000 accidental events, 83% of which are categorised as human-made, 16% as natural disasters and the remaining as conflicts. Among human-made accidents, more than 20 000 are attributable to the energy sector. In recent years, additional effort has been devoted to the vulnerability of energy chains to intentional human actions, such as vandalism, sabotage and terrorist threat (Burgherr et al., 2011; Hirschberg et al., 2016).

Unless indicated otherwise, results reported here cover almost four decades of historical experience worldwide, from 1970 to 2008.[4] This constitutes a sufficiently long time frame to achieve a sound statistical base without integrating inputs that are too outdated and may no longer adequately reflect the improvements on technology and on safety standards that have occurred in every energy chain. ENSAD provides data for individual countries; however, results are aggregated for three major groups of countries[5] (OECD countries, non-OECD countries and EU 27) to reflect the differences in technological development, management, regulatory frameworks and safety culture between highly developed and emerging or developing economies. Table 6.1 provides an overview of the number of severe accidents and related fatalities per energy chain for the different macro-regions considered.

4. This time frame corresponds to the last consolidated version of the database, at the end of the SECURE project. Updated data for fossil chains are available until 2014 and are currently undergoing the final validation and verification process.

5. A more disaggregated level is also provided for some specific energy chains.

While ENSAD provides a comprehensive coverage of accidents in the fossil fuel chains in both OECD and non-OECD regions and, in the hydropower in non-OECD countries, available data are more limited for the other energy chains and in particular for new renewables. In PSI's most recent analysis, the empirical evidence for nuclear and hydro chains has been complemented by site-specific consequence modelling of hypothetical severe accidents. For new renewables, available accident data are combined with chain-specific modelling and expert judgement.

Table 6.1: **Summary of accidents with more than five fatalities in the ENSAD database** (1970-2008)

Energy chain	OECD		EU27		Non-OECD	
	Accidents	Fatalities	Accidents	Fatalities	Accidents	Fatalities
Coal	87	2 259	45	989	2 394[a] 162 818 1 214	38 672 5 788 11 302 15 750
Oil	187	3 495	65	1 243	358	19 516
Natural gas	109	1 258	37	367	78	1 556
Liquefied petroleum gas	58	1 856	22	571	70	2 789
Hydroelectric	1	14	1	116	9[b] 12	3 961 26 108
Nuclear	–	–	–	–	1	31[c]
Biofuel	–	–	–	–	–	-
Biogas	–	–	–	–	2	18
Geothermal	–	–	–	–	1	21
Wind[d]	54	60	24	24	6	6

a. Coal: first line non-OECD total; second line non-OECD without China; third line China 1994-1999; fourth line China 2000-2008. b. Hydro: first line non-OECD without China; second line China. c. Nuclear: only immediate fatalities. d. Wind: only small accidents.

Note: Quantitative estimates of delayed fatalities from the major nuclear accidents are provided in the next section.

Source: Burgherr and Hirschberg, 2014.

With respect to the economic indicators considered within ENSAD, researchers from PSI indicate that data on fatalities are the most homogeneous, complete and reliable. For reasons of coherence, comparability and robustness, results on accidents consequences are often presented in terms of number of fatalities per energy produced or in terms of economic costs associated only to the fatalities. Data on injuries and evacuees are often missing or incomplete and their reporting is in general more subjective. The least complete and most uncertain information concerns economic losses. First, the estimation of monetary losses is not available for the majority of non-nuclear accidents. When reported, the cost elements covered are not well documented and vary significantly from case to case, depending on the purpose and scope of each database (i.e. claims, settled losses vs. real costs). More importantly, the perimeter of losses considered may vary significantly across sources, from covering only direct losses (or a subset of them) to including also indirect and induced effects on the broad economy.

Analysis of different energy chains

The statistical analysis of severe accidents can identify some important global trends common to most energy technologies. With respect to geographical distribution, rates of both accident frequency and fatality related to severe accidents in non-OECD countries are substantially higher than those in OECD countries; on the other hand, non-OECD countries have also experienced a number of accidents with very heavy consequences that have not been observed in the OECD countries. As expected, results for non-OECD countries show a much higher variability than for more homogeneous OECD and EU countries. Despite substantial variation in fatality rates across individual countries and technologies, the rank of regions was consistent across the fossil fuel technologies analysed (Burgherr and Hirschberg, 2008a and 2014). This indicates that the level of economic development, the safety culture and the capacity to enforce effective regulation procedures have a large impact on the severe accident risk.

When looking at the development in time over the period 1970-2008, the frequency of severe accidents per unit of energy consumed is decreasing in the OECD countries, for all fossil technologies analysed. The opposite trend is visible in non-OECD countries, where the number of severe accidents continues to rise. However, no statistically significant trend could be observed with respect to the severity distribution of accidents over the period analysed (Burgherr et al., 2011).

Coal

The severe accidents and the associated fatalities in the coal chain are dominated by extraction and exploration, where 99% of the accidents and 98% of the fatalities reported occurred. The most frequent causes of accidents in mining have been the explosions of methane gas, fires, collapses of the roof and, in China, water hazards. As already mentioned, accidents in the coal chain are dominated by mining activities and only seldom affect the public. The degree of internalisation of accident costs is therefore higher for coal than for most other energy technologies.

In the last two decades, the number of fatalities has significantly decreased in OECD countries, despite an increase in coal production. The implementation of stricter regulations, advanced research concerning the prevention of gas explosions and the closure of old and unsafe mines have all contributed to this trend. When looking at non-OECD countries, researchers from PSI underline that the fatality rate in China is one order of magnitude higher than in the other non-OECD countries and therefore should be analysed and reported separately. The comparison between data for 1994-1999 and these from 2000-2008 shows that the fatality rate is steadily declining, indicating that safety levels in the Chinese coal industry are improving and approaching that of other non-OECD countries. Instead, the number of fatalities appears to have increased in non-OECD countries other than China.

Oil

The transportation stage, which involves the transport to the refinery and the regional distribution, is the most accident-prone in the oil chain, accounting for more than 70% of the fatalities in OECD countries and almost 90% in non-OECD countries. Furthermore, the most severe accidents have occurred in these stages. Most of the severe accidents involved tankers (collisions, explosions, fires and impact with the ground) and road accidents during regional distribution. In the oil chain, fatalities are fairly evenly distributed among workers and the public (Burgherr and Hirschberg, 2008a).

Accidents in the oil sector may cause significant environmental damages by releasing hydrocarbons in the ecosystem; it is estimated that accidents account for about half the oil releases on sea, while the remaining 50% occurs naturally and at a very slow rate from oilfields. The majority of human-made oil spills occurs during transportation and

involves tankers. The most accident-prone areas are the Gulf of Mexico, the north-eastern coast of the United States, the Mediterranean Sea and the Persian Gulf.

As for other energy chains, OECD and non-OECD countries show opposite trends in a number of accidents in the oil chain, with a decrease in the former and a strong increase in the latter.

Natural gas and liquefied petroleum gas

In the gas chain, the majority of severe accidents and fatalities occur during transport and storage; most of the accidents involved pipelines for natural gas and road tankers for liquefied petroleum gas (LPG). The second common cause of accidents is the heating process for natural gas and regional distribution for LPG. Overall, ENSED data suggest that occupational fatalities constitute 10% to 25% of fatalities in the natural gas and LPG chains, indicating that the degree of internalisation of severe accidents is lower than that for oil and coal (Burgherr and Hirschberg, 2008a).

Contrary to other fossil fuel energy technologies, there is less difference in accident and fatality rates between OECD and non-OECD countries. However, the yearly number of severe accidents substantially increased in non-OECD countries whereas it remained stable or decreased within OECD member countries.

Nuclear power

Three severe accidents dominate the history of NPPs: the Three Mile Island Accident (United States, 1979), Chernobyl (Ukraine, 1986) and Fukushima Daiichi (Japan, 2011). While the first had practically negligible radiation-exposure related health and environmental consequences, the two others had significant radiation-exposure related health and environmental consequences, and all three had from small to very large social and economic impacts. The Chernobyl accident, for instance, caused 31 immediate fatalities, and approximately 6 000 thyroid cancers (fatal in 15 cases). In the case of nuclear accidents, the causes of predicted fatalities are dominated by cancers that could appear anywhere from 5 to 10 years post-accident, and up to 30 years or more after radiation exposure. As already mentioned, estimates of latent fatalities are calculated based on ICRP risk values, which are based on assumptions, as a result of our current knowledge gap regarding the effects at low doses, and therefore are bound by significant uncertainties[6]. Large uncertainties may also result from the choice of geographical range (e.g. within a radius of 50 km, or over the entire northern hemisphere), and temporal range (e.g. over the next generation, or over the next 10 000 years). An authoritative report from the United Nations (IAEA, 2005) indicates that: "It is impossible to assess reliably, with any precision, numbers of fatal cancers caused by radiation exposure due to Chernobyl accident. Further, radiation-induced cancers are at present indistinguishable from those due to other causes." However the IAEA International Expert Group "predicts that among the 600 000 persons receiving more significant exposures (liquidators working in 1986-1987, evacuees and residents in the most "contaminated" areas), the possible increase in cancer mortality due to this radiation exposure could be up to a few per cent. This eventually represents up to

6. Individual doses of less than about 100 mSv are assumed, for regulatory and optimisation purposes, rather than observed. So while such latent fatality values are useful for protection planning and preparation purposes, their use should be qualified in several ways: first, that ICRP risk values are selected based on the practical assumption that all exposures carry some risk; second, that risk can be represented by a linear non-threshold (LNT) risk/dose relationship, extrapolated from where excess risk is epidemiologically statistically significant (about 100 mSv), to zero; and third, that estimates of latent fatalities using risks estimated assuming LNT represent a range (e.g. from 0 up to the number of latent fatalities calculated assuming LNT) of possible latent fatality outcomes.

4 000 fatal cancers in addition to the approximately 100 000 fatal cancers to be expected due to all other causes in this population."[7] Other reports provide an even larger range of expected fatalities due to the Chernobyl accident. Many fewer fatalities are expected in Japan from the Fukushima Daiichi accident, despite the higher population density in the Fukushima region than in Chernobyl, which is thanks to the lower total release of radioactive material on land and to a very effective and precautionary adoption of protective countermeasures.

Because of the large differences in plant design (e.g. the lack of a containment building) and both the operational and regulatory environment, the Chernobyl accident is not considered representative of the safety level of power plants operated in the OECD and in most non-OECD countries. Therefore, researchers from PSI suggest adopting a probabilistic analysis, preferably via a complete level III probabilistic safety assessment (PSA), to estimate the frequency and potential consequences of a nuclear accident. However, it should be borne in mind that the outcomes of a PSA assessment are strongly plant- and site-dependent; their extrapolation to other plants and locations should be carried out with great care.

Hydro

Accidents in hydro facilities generally occur at dam or reservoir sites, and have the potential to cause a large number of fatalities, predominantly among the public; for instance, the two largest accidents in the energy sector occurred at the Banqiao and Shimantan hydro plants, causing together 26 000 direct fatalities.However, there are some documented accidents during the construction of dams. With few exceptions, dam failure rates have decreased significantly over time, thanks to technological development since the early projects at the beginning of last century, progress in geological analysis and the impact of regulatory requirements. The PSI analysis also shows a significant decrease in the failure rate after five years of operation of hydropower; this observation has important consequences for risk assessment since the majority of existing dams, at least in OECD countries, has very long operation experience and should therefore present a lower risk.

Severe accidents in hydropower are few, most occurring in non-OECD countries, but with very large consequences. On the contrary, recent experience in OECD countries is very limited, with only a single severe accident in the last 40 years: for OECD countries, the analysis has therefore been complemented by a risk assessment performed for Swiss plants.

Hydroelectric power share several similarities with nuclear power: both technologies have a very low accident rate, at least in OECD countries, but accidents may potentially affect very large areas, impact many individuals and have very broad economic consequences. Also, occupational fatality rates of both technologies are quite low. The degree of internalisation of accident costs in these two energy chains is therefore lower than for the other power generating options. Risk assessment based on probabilistic analysis is strongly site-specific, depending on the type of dam analysed, on the population distribution downstream and on the assumed warning time for efficient evacuation. Overall, theoretical risk assessments tend to result in significantly higher potential consequences than experience-based models.

7. The study indicates that among the 5 million persons residing in other contaminated areas and subject to much lower doses, "any projected increases are more speculative, but are expected to make a difference of less than 1% in cancer mortality".

Wind, solar and other new renewables

Because of their decentralised nature, wind and solar energy chains have a limited potential to cause catastrophic damages. In general, the availability of data on severe accidents for new renewables is quite limited and depends on the technology. In the case of wind power, an extensive collection of accidental events is available but it is limited to certain regions. For solar photovoltaics (PV), the main concern is the manufacturing stage that involves numerous explosive and toxic chemicals, whereas the potential for large accidents during actual operation and maintenance is quite limited. Some of the accidents reported for solar PV and wind chains have led to fatalities. While no accident has resulted in five or more victims, the death rate is persistent. Nevertheless, for their risk assessment, the limited historical experience has therefore been integrated with quantitative analysis based on expert judgement. Finally, for some renewable technologies such as solar thermal, tidal and wave power, there are practically no data available and results are based solely on expert judgement.

Comparative analysis

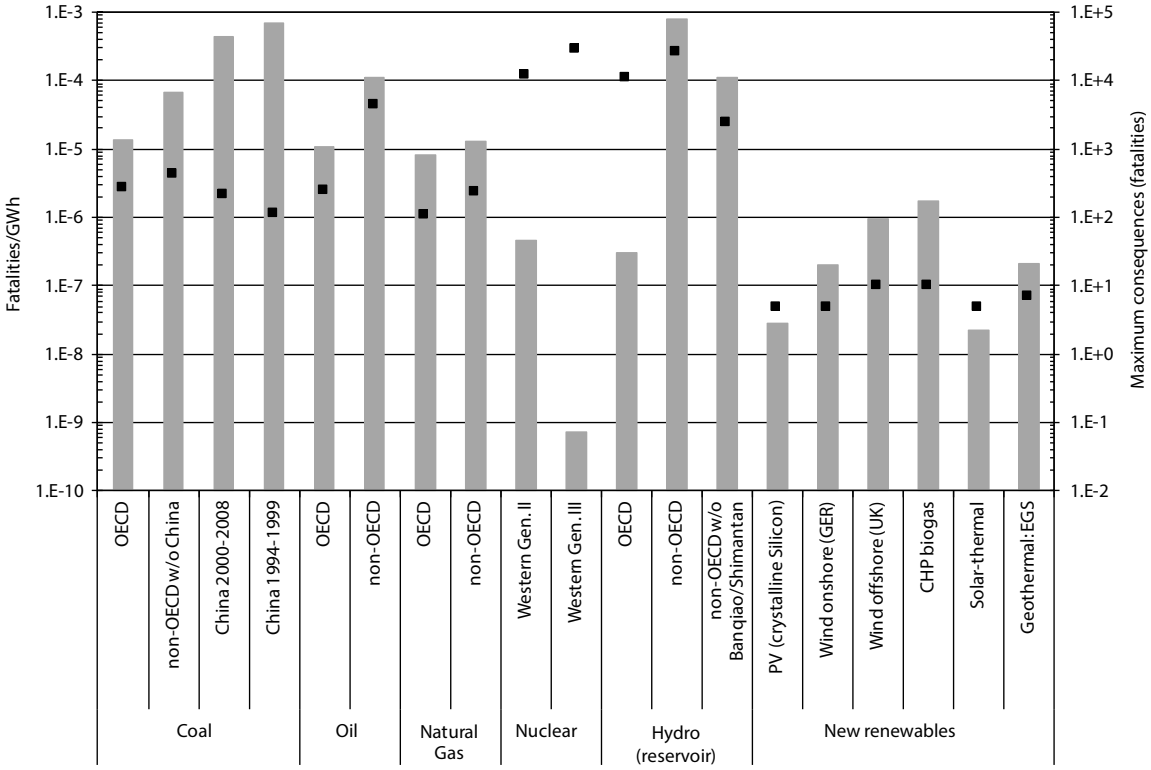
In most of the studies focusing on the externalities of electricity generation, the comparison of severe accident risk is centred on fatalities and on their associated economic costs. The rationale for this choice is that reporting on fatalities is the most complete, consistent and reliable among the main consequence indicators considered, and thus allows for a more coherent comparison across energy chains. However, if fatalities are the most important indicator for policy makers and the general public, they constitute only one of the multiple impacts of a severe accident. Limiting the economic analysis only to this aspect results therefore in an underestimation of the overall economic impacts of accidents. In addition, depending on the energy chain, fatalities are likely to represent a different fraction of the total economic impacts of an accident: looking only at this aspect therefore introduces a bias in the comparative assessment. For instance, it is expected that accidents in nuclear or hydroelectric power may have significant economic impacts beyond pure fatalities, while in other energy technologies the economic impacts of fatalities are dominant.

For every energy chain, results are provided in the form of two separate indicators that convey different important information. A first aggregate indicator shows the number of fatalities per unit of energy produced: this allows for a direct and straightforward comparison of severe accident consequences among different energy chains and country groups. Aggregated results are provided in Figure 6.2, which shows the expected fatalities together with the maximum number of fatalities occurred (or expected to occur) per unit of electricity output, as well as in Figure 6.3, which provides an estimate of the aggregated economic costs due to fatalities. Additional information is conveyed by using frequency/consequence (F-N) curves. This method offers additional valuable insights that remain hidden in more aggregate indicators, as it provides information on the potential maximum damages as well as the probability of an accident exceeding a specified threshold of fatalities. The evaluation of historical experience on severe accidents shows significant differences between various technologies as well as between individual countries and group of countries. With the exception of renewable energy, energy-related accident risks are markedly higher in non-OECD countries than in OECD countries, and this applies to all energy chains considered. The frequency of accidents is generally higher for non-OECD countries for all energy chain. Also, the maximal consequences observed are significantly more severe in non-OECD countries. Finally, results within OECD countries are generally more homogeneous, while those in non-OECD countries show a larger dispersion.

Among centralised large-scale technologies, hydropower in OECD countries and nuclear power feature the lowest expected fatality rates and thus the lowest corresponding accident and external costs. Fossil energy chains are more accident-prone

and, together with hydropower in non-OECD countries, show a distinctively higher fatality rate, as shown in Figure 6.2. Among fossil fuel technologies, gas features the lowest fatality rate and the lowest associated economic costs. With respect to other renewable technologies (solar, wind and new technologies) the available experience and analysis shows that they have a very low risk, featuring fatality rates comparable with those on nuclear and hydro in OECD countries.

Figure 6.2: **Severe accident fatality rates and maximum consequences (black points)**



Note: Data are based only on historical experience in the period from 1970 and 2008. For nuclear, results are based on a PSA assessment, while for new renewables on a combination of historical data, expert judgement and modelling.

Source: Adapted from Hirschberg et al., 2016.

On the other hand, hypothetical extreme accidents occurring in both nuclear and hydroelectric power chains have the potential to cause much larger economic damages and fatalities than accidents occurring in all the other technologies In addition, because of their limited size and decentralised mode of production, maximal potential consequences of an accident in new renewable technologies are low in comparison to that of all other technologies. Information on maximal potential consequences of an accident is important as society and individuals are reluctant to accept options bearing potentially large negative outcomes or large uncertainties. Simply multiplying probability by potential outcomes does not address this issue. Some authors and studies have thus applied a risk-aversion factor (larger than one) to low-probability/high-consequence events, but the choice of the coefficient is subjective and controversial. The valuation of this subjective aspect can be appropriately assessed in a multi-criteria analysis: the SECURE project identifies three separate risk indicators to characterise the risk of severe accidents and to be used in a multi-criteria decision analysis framework (Eckle et al., 2011).

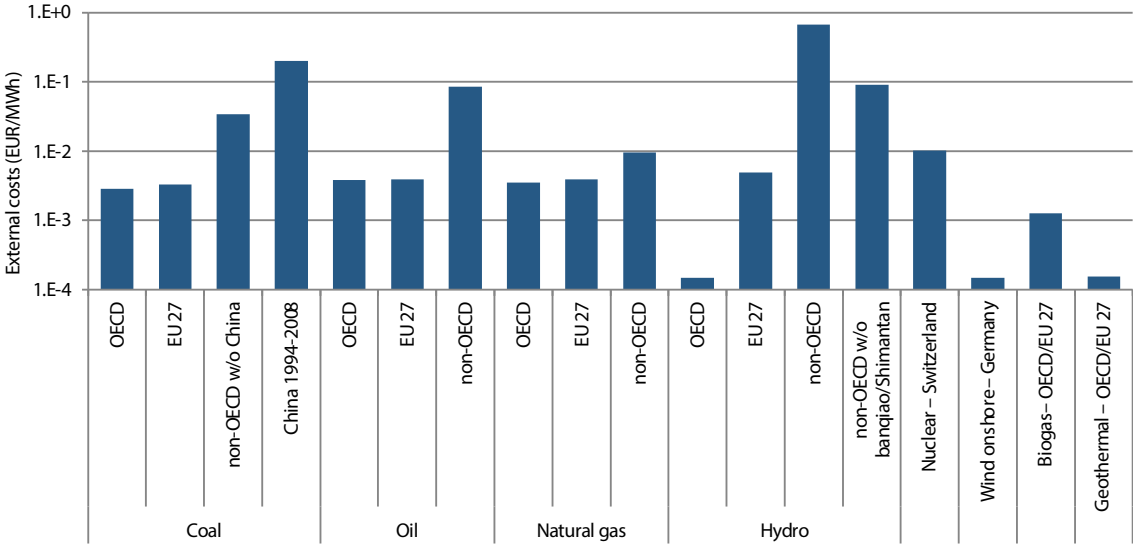
As discussed in the previous section, the evaluation of economic losses due to severe accidents is a complex undertaking and involves strong subjective components: the results provided in what follows thus have a large degree of uncertainty and, especially

when obtained from analysis of past accidents, may contain systematic underestimations. Also, differences in collecting and reporting the data, choice of cost categories to be included and the perimeter of the analysis may introduce a bias in the comparison of technologies. To allow better comparability across technologies, the external costs presented in Figure 6.3 are only those related to fatalities, as this is the most reliable indicator. Results are based on ENSAD data in the period 1970-2008 and represent the synthesis of the most recent published data on the external cost of severe accidents for several energy technologies. It should be noted that data for nuclear energy have been obtained with a probabilistic safety assessment of a NPP in Switzerland, and include both immediate and latent fatalities. Overall, fatality-related external costs due to severe accidents tend to be low, well below EUR 1 per MWh for all technologies and regions analysed. In particular, accident costs in OECD countries lie in a range of EUR 10^{-2} to 10^{-3} per MWh for most of the conventional generation technologies, while they are about one order of magnitude lower for wind, hydropower and geothermal energy.

In the framework of the NewExt project (Friedrich, 2004a), researchers from PSI have provided cost estimates for a broader range of cost categories (fatalities, injuries, evacuation and impacts of oil spills) based on the main large-scale technologies. Total accident costs have been obtained by integrating four cost components. Table 6.2 provides the contribution of each of the four categories to the total accident costs as well as the fraction of total cost that is internalised. Results show that fatality rates form a large share of costs in the coal and natural gas energy chains, while other cost components give a significant contribution in other energy chains. In particular, in OECD countries the environmental costs of oil spills and the evacuation cost of nuclear accidents appear to be dominant in the respective energy chains. However, given the large uncertainties, these results are intended simply as a complement of the data provided in Figure 6.3 and should be simply considered as order-of-magnitude indications of the different weight of cost across technologies.

Figure 6.3: **Estimates of external costs for different energy technologies resulting from major accidents**

(EUR/MWh, logarithmic scale)



Note: Data for nuclear energy have been obtained with a probabilistic safety assessment of a NPP in Switzerland, and include both immediate and latent fatalities. Data for wind onshore was available only for Germany. Broader data sets were available for all other technologies.
Source: Based on data from Burgherr and Hirschberg, 2014.

Table 6.2: **Total damage costs of severe accidents for different economic indicators**

		Total damage costs of severe accidents (EUR_{2002}/MWh)					Fraction of cost internalised
		Total	Fatalities	Injured	Evacuees	Oil spills	
Coal	OECD	1.73E-02	98.7%	1.3%	N/A	N/A	80%
	Non-OECD	6.58E-02	99.2%	0.8%	N/A	N/A	50%
	China	1.22E-01	99.7%	0.3%	N/A	N/A	50%
Oil	OECD	5.90E-02	32.2%	5.0%	0.1%	62.7%	65%
	Non-OECD	1.87E-01	67.3%	3.3%	0.0%	29.4%	24%
Natural gas	OECD	8.13E-03	81.1%	18.3%	0.6%	N/A	60%
	Non-OECD	9.98E-03	91.7%	8.3%	0.0%	N/A	30%
Hydro	OECD	2.02E-03	20.1%	77.2%	2.8%	N/A	50%
	Non-OECD	1.23E+00	100.0%	0.0%	0.0%	N/A	20%
	Non-OECD without Banqiao/Shimanton	1.61E-01	99.8%	0.1%	0.1%	N/A	20%
Nuclear	OECD	5.14E-04	N/A	38.5%	61.5%	N/A	62%
	Non-OECD	1.11E-02	51.7%	41.3%	7.0%	N/A	48%

Source: Based on data from Friedrich, 2004a.

Other results/studies

There have been few attempts in the literature to assess the economic costs of accidents in the energy sector. Whenever they were undertaken, they were of a very narrow scope in terms of the technology considered. Also, each study had a different focus and adopted different methodologies, which limited the comparability of results. Nevertheless, for completeness sake, the main results are reported here.

Sovacool (2008) published detailed information on the number of victims and property damages for 208 accidents that occurred in the period 1907-2007 in the main energy chains. However, no attempt has been made to compute the expected cost per unit of energy produced. In a recent paper by Sovacool (2016), accident risk was calculated for several low-carbon technologies, on the basis of a statistical sample of accidents that occurred between 1990 and 2013 and taking into account a broader range of cost components than simple fatalities. This yielded normalised costs of EUR 3 per MWh for nuclear, EUR 0.23 per MWh for wind, EUR 0.1 per MWh for hydro, EUR 0.15 per MWh for biomass, and EUR 0.03 per MWh for solar.

There have been several other studies that focused only on severe accidents in the nuclear sector. Again, the very different scope of these studies, their different methodologies for assessing the expected accidents frequency and the different cost categories included make a comparison among them very challenging. Laes et al. (2011) and IER (2013) report costs of severe nuclear accidents in the range of EUR 0.1-0.15 per MWh, respectively. Estimates of Lévêque (2013a and 2013b) and Rabl and Rabl (2013) are about one order of magnitude higher, EUR 1 and 3.8 per MWh, respectively, while Torfs (2001) reports an external cost due to nuclear accidents in the range of EUR 8 10^{-4} and 0.35 per MWh.

6.4. Perspectives of internalisation

Accidents in the energy chain may cause a wide range of impacts on the local and global economy, such as direct impacts on the health of workers and members of the public in terms of increased mortality or morbidity; the need to evacuate and relocate people for potentially long periods; direct impacts on the energy infrastructure; and other direct private losses. Accidents in some specific energy chains may also cause extensive and long-term impacts on the natural environment and ecosystems, as well as wider impacts on the security of energy supply and the national economy. However, when weighted with the expected frequency of occurrence, the risk associated with severe accidents in the energy chain is relatively low. The EU NewExt study shows that overall the degree of internalisation of damage [8] ranges between 50% and 80% in OECD countries, depending on the technology considered. In non-OECD countries, the degree of internalisation of accident costs is considerably lower, lying in a range of 20% to 50% (see Table 6.2 for details).

Some of the economic losses are borne directly by the owner of the facility where the accident occurred and hence do not constitute an externality. One example is the loss in value of the damaged facility and the additional costs for the replacement of the production lost. Other economic losses, such as the consequences on workers' health, are partially internalised into the cost of labour. The degree of internalisation varies across countries and is, in general, higher within OECD member countries. There are, however, many other potential impacts of accidents that are borne by the society as a whole and for which the internalisation is less straightforward and more complex. This is the case for the economic consequences on health and on the business property of a third party or on the environment. The entity liable for the accident is held responsible for the victims' compensation, which ensures a certain internalisation of accident costs. For example, the BP oil and gas company had to pay several billions of US dollars as compensation to individuals for damages caused by the accident at the Deepwater Horizon drilling unit, as well as to businesses and to the US government for damages to the environment and the ecosystem. However, the ability of effectively paying such compensation depends upon the financial strength of the company held liable for the accident.

The potential impacts that severe accidents may have on society as a whole and the effective degree of internalisation of severe accident costs are a fiercely debated topic, especially for power generating technologies where low-probability events can cause extensive damage. This concerns hydropower, nuclear power and, to a lesser extent, the oil industry. A severe accident at a nuclear power or hydropower plant in particular may cause damage for which compensation may exceed the financial capacity of the operator that shall have to bear the claims. These concerns were already raised at the early stages of nuclear energy development and have contributed to the creation of special liability regimes and international conventions applicable in the case of a nuclear accident.

Special international liability regimes have been developed with regard to oil transport and nuclear industries so as to ensure an adequate compensation of victims in case of damage caused by spills from oil tankers [9] and by ionising radiation in the event of

8. The analysis is limited to a subset of damage, i.e. fatalities, morbidity, evacuation costs and economic consequences of oil spills.

9. Conventions: the International Convention on Civil Liability for Oil Pollution Damage, 1992 (1992 Civil Liability Convention) and the International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage, 1992 (1992 Fund Convention), together with the Protocol of 2003 to the 1992 Fund Convention (Supplementary Fund Protocol).

an accident occurring at a nuclear installation.[10] These regimes have certain similarities, such as the strict and usually limited liability of the tanker owner or the nuclear operator, compulsory financial security to cover its liability and provisions to determine the competent court(s). With respect to oil pollution, the relevant conventions establish international funds to ensure supplementary funding to compensate the victims. The States parties to this system may adhere to cumulative funds: the first tier is guaranteed by the ship owner, while funding for the two other tiers is provided by the International Oil Pollution Compensation Funds, based on a contribution levied on each oil delivery to individuals or entities. In the case of nuclear power, in most cases operator liability is limited to a certain amount, which depends on the country and on the international convention to which the country adheres, and may be supplemented by additional amounts provided by the country where the accident occurred and/or by the countries adhering to the same supplementary convention.[11] The operator is compelled to have and maintain financial security to cover its liability via commercial insurance, operators' pool schemes, mutuals, corporate finance or other financial alternatives. Some countries, such as Germany, Japan and the United States have provided for nuclear operators' pools schemes.[12] In the United States for example, the Price Anderson Act provides that once a nuclear operator has paid (via its insurance) USD 450 million, each licensee will contribute into a fund on a prorated share of the excess compensation amount, up to USD 121.255 million per reactor. With 102 reactors currently in the insurance pool, this secondary tier of funds would contain about USD 12.4 billion.

International conventions and liability regimes provide an effective legal framework in case of accidents, require compulsory financial security, ensure a relatively swift and non-discriminatory compensation process among victims within the country where the nuclear accident occurred or among victims of countries parties to the same international conventions. From an economic standpoint, they allow for the internalisation of part of the damage suffered by third parties. However, funds provided under the liability regimes are in practice limited (either because the liability amount is capped or, if not, because amounts available are limited to the company's assets) and the different types of damage to be compensated are defined by law, by the courts and/or by special committees. Also, it is often argued that only the shares of costs provided by the operator or pooled among the nuclear operators are effectively internalised, while this does not apply to the share provided by governments.

When considering nuclear power more specifically, the key questions are what is the entity best positioned to cover the risk of a nuclear accident and, in particular, the residual risk, and to what extent it is possible (or advisable) to internalise it. From the viewpoint of an insurer, nuclear accident risks pose many difficulties, because: i) they are a low-frequency/high-impact event for which both expected frequency and potential claims are unknown or difficult to evaluate; ii) they are not diversifiable and there is a

10. The 1960 Paris Convention on Third Party Liability in the Field of Nuclear Energy and the 1963 Brussels Supplementary Convention; the 1963 Vienna Convention on Civil Liability for Nuclear Damage and the 1997 Protocol to amend the Vienna Convention; and the 1997 Convention on Supplementary Compensation for Nuclear Damage.

11 Some countries have provided for unlimited liability for the operator. However, in practice, the liability of a private company is limited to its financial resources available after the accident occurred.

12 For more information on the German and US pooling systems, see "Operators' pooling arrangement: a national and international perspective", Norbert Pelzer, University of Göttingen, Germany (2013) at www.oecd-nea.org/ndd/workshops/nuclearcomp/presentations; for more information on the Japanese pooling system, see "Japan's Compensation System for Nuclear Damage as related to the TEPCO Fukushima Daiichi Nuclear Accident" (2012) available at www.oecd-nea.org/ndd/workshops/nuclearcomp/presentations.

risk of claim accumulation from a single event; and iii) there are few nuclear installations, thus making it difficult to spread the risks. As for other catastrophic risks, insurers must charge a premium that may be several times higher than the annual expected losses in order to meet their solvency constraints. In addition, some of the potential losses are not insurable or difficult to be covered by insurance (to date). Insurers are reluctant in particular to provide coverage for loss of life or personal injury occurring between ten and thirty years after the nuclear accident occurred, while only some would refuse full coverage for costs of measures of reinstatement for impaired environment or for cost of preventive measures. Beyond a certain level, the state is the sole entity able to bear the accident risk, and socialisation of such residual risk is the most efficient economic solution.

Whether governments should be compensated for the funding provided beyond the share of compensation to be provided by the liable nuclear operator, thus fully internalising nuclear accident costs, is a topic of debate. As seen in this chapter, any estimate of the expected frequency and costs from a severe nuclear accident is extremely challenging and highly controversial. The major difficulty would therefore be to provide a valid estimate of the risk from a nuclear accident and of the residual risk that is borne by the state. However, despite the large differences observed, most of the estimations available indicate that nuclear risk is expected to be low, and therefore the residual risk is expected to be even lower.

6.5. Summary and key issues for policy makers

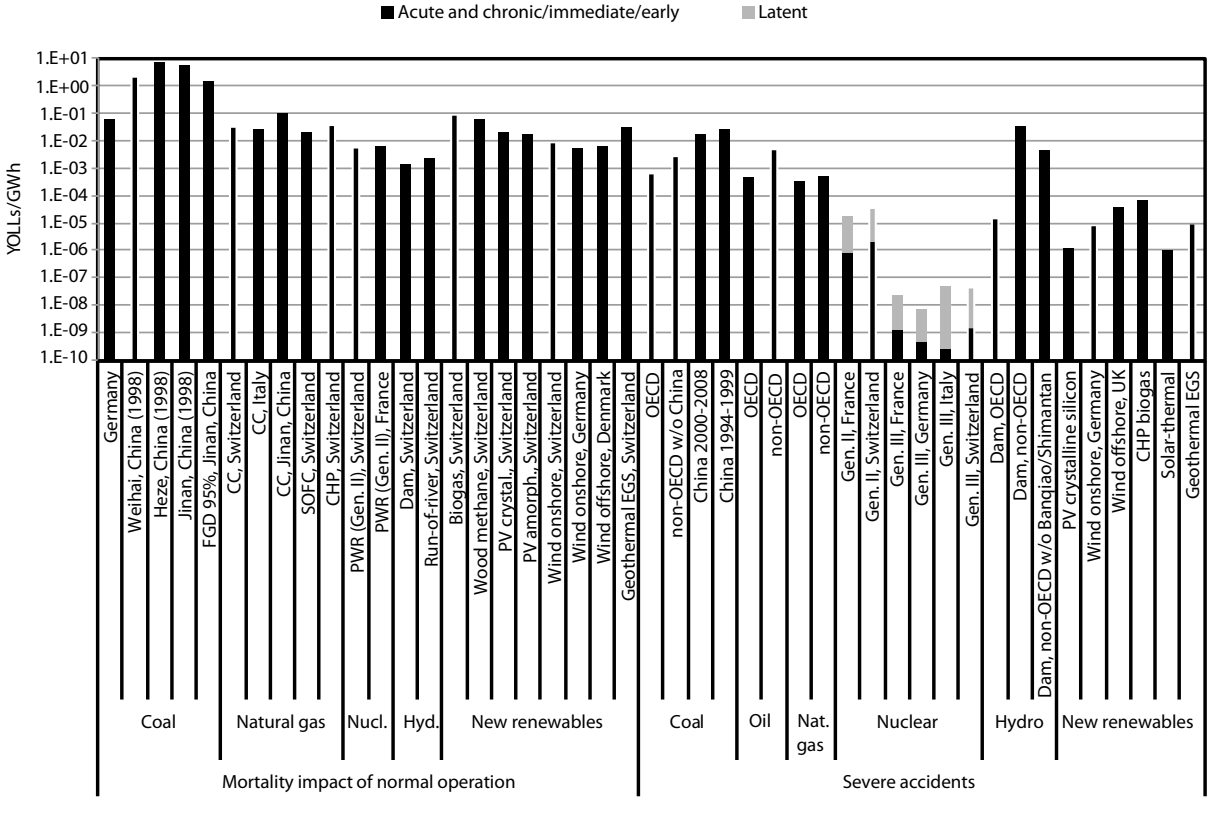
Damages caused by severe accidents in the energy sector are substantial, but remain quite small compared with those caused by natural disasters or by human-made accidents in the transport sector. Available estimates of accident consequences and associated external costs are subject to large uncertainties and are inherently conservative. Consequence analysis is limited to a subset of accidents (only severe accidents are considered), is based on incomplete information and accounts only for a limited subset of possible losses. In particular, the economic assessment of accident impacts is highly uncertain and most likely to be underestimated. However, for all energy technologies, total and external costs associated with severe accidents are several orders of magnitude lower than those costs caused during normal operation by pollution and carbon emissions. This is shown in Figure 6.4, which compares the accident due to normal operations with the main accidents occurring in all the main energy chains.

Additional research in this field is needed and should be encouraged by governments and policy makers. This would contribute to improving the completeness, coherence and breadth of data collection, and would increase the number of impacts included in the analysis. However, even if this would most likely lead to an upwards revision of the figures currently available, it is not expected to change significantly the conclusions presented above.

Despite these conclusions, the risk of severe accidents should not be neglected as accidents have the potential to cause large-scale and long-term impacts on human well-being, on the environment and on society as a whole. Severe accidents tend to have broad media coverage and to attract the attention of the population and different stakeholders. Many studies point out that such extensive media coverage may lead to an overestimation of the probability and of the perceived risk of severe accidents. Friedrich (2004a) notes that the likelihood of deaths in widely reported disasters is perceived to be higher than the probability of events such as breast cancers or diabetes that are not covered extensively in the media. Risk aversion also plays a role here. D'haeseleer (2013), by comparing the perceived risk of plane and car accidents, concludes that occurrences that happen frequently with only a few victims at a time are perceived less risky than rare events with a higher number of fatalities at one single instance. Additional scientific and economic

research and more factual information on the impacts of severe accidents should be performed and brought to the attention of the public and policy makers. Better knowledge and understanding of the risks involved would support better informed economic choices.

Figure 6.4: **Mortality due to normal operation and severe accidents in the main energy chains**



CC: carbon capture; CHP: combined heat and power

Source: Adapted by NEA from Hirschberg et al., 2016.

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Chapter 7. **Land-use change and natural resource depletion**

7.1. Introduction

Different forms of electricity generation can have large and lasting impacts on the land they use, the availability of the resources they consume and the ecosystems they affect. At first sight, it seems obvious that these impacts should be straightforwardly included in the full costs of electricity provision as additional external costs on top of plant-level and system costs. However, at second sight, land-use change and the use of natural resources during electricity provision are one of the most elusive aspects of full cost accounting. The reasons are fourfold.

First, while impacts can be dramatic, the exact nature of the land-use change is very site- and technology-specific. Second, studying the impacts on land-use change poses a fundamental methodological challenge for full cost accounting: much land is, in fact, privately traded and public land falls under strict regulations in OECD countries. Many land-use changes are thus already effectively internalised through changing property values in real estate markets or through existing land-use regulations. However, land has a social as well as a private value. As soon as changes in ecosystems and the resulting loss of social value are ignored in the prices for private transactions, land-use impacts do become an external cost of electricity provision and hence a public policy issue.

Third, some external costs of land use fall into other full cost categories. For instance, climate change is likely to heavily impact land use and ecosystems. These effects, however, are dealt with in Chapter 4 on the external costs of climate change. Also some of the greatest damages in terms of land-use change result from accidents and are dealt with in Chapter 6. Oil spills, dam breakages or nuclear accidents all devastate ecosystems and developed land. Recently, the nuclear accident at Fukushima Daiichi and the Deepwater Horizon oil spill have shown the large impacts of accidents in the energy field on land use.

Fourth, land use is part of the larger category of non-atmospheric ecosystem that impacts natural resource use, which refers primarily to environmental externalities other than those transmitted by the atmosphere (i.e. greenhouse gas emissions and air pollution, which are dealt with in Chapters 4 and 5, respectively). The most important impacts in this category, other than land use, are water pollution and natural resource depletion. While the impact of power generation on water quality is very limited outside mining (see below), the depletion of non-renewable energy resources is frequently mentioned as an issue that deserves policy attention. However, also here it is unclear to which extent natural resource depletion constitutes a genuine externality or to which extent it is already internalised in market prices.

For these four reasons, assessing the full costs of land-use change and resource depletion will, in general, produce results that are somewhat broader and less precise than those regarding the health impacts of atmospheric pollution or major accidents. In order to allow for a transparent presentation, the issues of land use and natural resource depletion, although related at some deeper level, are considered in two separate sections.

7.2. State of research, main studies and quantitative estimates: Land use

Assessing the costs of land-use change is difficult. At all stages of the impact pathways, a good understanding of the costs of land-use change is currently still lacking. Often it is even difficult to characterise damages to ecosystems qualitatively, let alone measure and monetise them. No study claims that it has a conclusive monetised value for the full costs of a certain change in land use. However, taking a closer look, it becomes quickly apparent that geographic footprint, i.e. the land-use requirements of different technologies measured in square metres, is a useful but very imperfect proxy for the severity of the public policy issues raised by them.

Land requirement is an important marker of the burden of an electricity source, but it does not on its own represent a social cost. Different kinds of land in different places have very different value for society. Theoretically, a proper social value of land would be the monetary value of society's willingness to pay for or willingness to accept a certain change in the function of the land use. Types of land-use changes are of great variety and their costs are tied closely to the nature of the population and of the surrounding area. An additional public policy issue is that at least in some European countries generous feed-in tariffs (FITs) for wind farms and solar parks function also as indirect subsidies for an agricultural sector, whose land otherwise no longer produces the financial yields deemed appropriate.

As mentioned, much land-use change is dealt with on the basis of private transactions in the property market. Replacing a wheat field with a coal mine is not necessarily creating external costs. If property rights are clearly delineated, then the owner of the wheat field will consider the change in the land's value in the real estate market when determining whether to grow wheat, construct apartment buildings or sell the land to the mining company. In practice, of course, it is more accurate to say that the owner will internalise only *some* of the costs. For instance, the land owner will not consider the costs of a road that will be built to the plant that will subsequently destroy a breeding ground for an endangered forest bird. He or she will not consider the costs of water leakage during construction damaging a fragile wetland, nor the loss of amenity value for tourists who prefer to look at a sheer wheat field than at a coal mine or a wind farm. These are indeed examples of land-use change, but they are not reflected in a real estate market. It is best to think of land as offering a set of services, whose value changes when the use of the land changes, and who are referred to as "ecosystem services".

Box 7.1: **A note on aesthetic value**

A specific area of concern in the placing of energy facilities is the loss of the aesthetic value of the land. Wind (both onshore and offshore, rooftop solar and tidal electricity generation, for instance) is very location-dependent and may thus impinge on the views of valued natural landscapes and affect the utility of residents and visitors. In a world without transaction costs, social costs to changes in aesthetic value can be considered internalised into the market through the subsequent changes in property values from the placement of the wind farm, solar panels or tidal power station. Hedonic pricing studies may be able to shed some light on the impact of generation sites on property values. However, this only refers to residents. The preferences of tourists, occasional visitors and nature conservationists, to the extent that their displeasure about the aesthetic degradation is not monetised through impacts on the local economy, remain unconsidered in this context.

Aesthetic concerns are not limited to renewable electricity sources. However, electricity generation that is not location-dependent, like fossil fuels and nuclear power, is sited in areas where they will not impinge too heavily on property values or natural views. Separately, one study on hedonic property price found that vicinity to nuclear power plants in the wake of the 1979 nuclear accident at Three Mile Island had no positive or negative effects on property values (Gamble and Downing, 1982).

In assessing the value of ecosystem services, environmental economists concentrate on the marginal willingness to pay (to accept) for a positive (negative) change in the value of ecosystem services. There is little sense in trying to assess the absolute value of ecosystems. A famous study by Costanza et al. (1997) estimated the worth of total global ecosystem services at USD 33 trillion per year. Given that these include indispensable life-supporting elements such as clean drinking water, the economist Michael Toman (1997) famously quipped that this constituted "a serious underestimate of infinity". Any analysis of ecosystem valuation thus needs to focus on marginal changes in ecological functions. OECD (2006) recommends identifying key services and products, determining the degree of irreversibility and geographical scope, establishing property rights, valuing services and products as if they were independent of each other, and finally analysing any obvious interactions between services to modify conclusions from there. The methods to determine willingness to pay or to accept are those presented in Chapter 1 such as the travel-cost method, contingent valuation and hedonic pricing. The latter method is particularly interesting in this context as it can be used to identify interlinkages between prices in the real estate market and certain markers for the level of ecosystem services. Overall, however, changes in the level of ecosystem services are less defined, more diffuse and less studied than, say, the costs of air pollution on human morbidity and mortality. Where monetary comparisons are possible, the latter, it must be said, are also an order of magnitude larger.

While the evaluation of marginal changes in ecosystem services remains the methodologically appropriate manner to assess land-use change, headline numbers about geographic footprint still hold great appeal for policy makers and for the general public. While not providing a measure of social value, metrics for land requirements such as per-capita land footprint, land transformation or land occupation per year and per GWh, provide straightforward and easily quantifiable assessments. The concept of land occupation brings up an important dynamic consideration: a fuel cycle's land requirements could change over time. This is a key difference between electricity sources that rely on extracted substances (fossil fuels, nuclear, biomass) and those that do not (wind, solar, tidal, hydro, geothermal). Over time, the former must continue to mine or cultivate their fuel source to provide electricity, whereas once infrastructure for the latter is built, there is no need for further land transformations (Fthenakis and Kim, 2009).

In land-use studies of the electricity sector, an oft-cited study for raw numbers is that of Fthenakis and Kim (2009). The study conducted life cycle land-use estimates for renewable fuel cycles as well as for coal, nuclear and natural gas. Although applying a life-cycle approach is important, framing the analysis is also vital so that the study's scope does not get out of hand.

Land use patterns of different power sources

In general, it makes sense to distinguish the land-use patterns of renewable sources from those of non-renewable sources, especially in a dynamic perspective. The land occupation rate for non-renewable sources, in particular fossil fuels, is thus dependent on the fuel extraction rate relative to the ecological recovery rate of the land on which the mine was built. Land use thus increases with electricity production. For renewable sources, such as wind, solar and biomass, once capacity is installed, land use no longer increases. The more hours of the year one of these sources runs to generate electricity, the smaller is the land requirement per MWh (Fthenakis and Kim, 2009). While all renewable sources share the quality of having a constant land occupation over the time of generation, the variation in land requirements is greater both quantitatively and qualitatively than among non-renewable sources. Wind and solar are unique in that the land on which they are located can sometimes be employed for other uses alongside electricity generation. Key features of different technologies are presented in the following.

Coal

As coal is with 40% of production the world's largest single source of electricity, coal mining is a large industry with significant land requirements and ecological effects. These outweigh those of other fuels mainly because of the large-scale surface mining of coal, also known as strip mining. Underground coal mining, while encountered more often has a smaller land burden.

Strip mining often destroys the top layer of soil, removes all vegetation, and alters the landscape. Mountain-top mining is a method common in steep terrains, like in the Appalachian region of the United States, where mountain tops are stripped by using large amounts of explosives and the volume of excess rock is then placed in adjacent valleys. Environmental studies have shown that mountain-top mining increases mineral levels in water, covers streams, divides forests, decreases soil quality, and degrades overall biotic communities in the river basins around the mining area (NRC, 2010). In most countries, firms are required to reclaim the land after mining is completed (e.g. the 1977 Surface Mining Control and Reclamation Act in the United States), requiring sites to be returned to their previous condition or to one that supports a better use (i.e. more and better-functioning ecosystem services). However, Fthenakis and Kim (2009) point out that the original landscapes of many mountain-top mining areas were native forests, whose rehabilitation will take 200-300 years. Recovery in other areas can be much faster, such as in Wyoming and parts of Germany.

Most of the ecological damage risk in underground mining is mine collapse and gradual subsidence, which can affect ground-level and subsurface water flows and thus the ecosystem functions in the region. Mine fires are a danger, and acid draining and waste disposal remain significant environmental concerns. In comparison, the land requirements of an actual coal plant are instead rather limited.

Oil and natural gas

For both oil and gas, the land requirements are lower than for coal-powered electricity systems, since drilling does not have the same land burden as mining. In addition, there is significant offshore extraction, which has no direct land requirement even though it generates ecological impacts of its own. It should also be noted that oil-fired electricity generation is small and declining.

Overall, the geographic footprint for gas is smaller than for oil. A gas well uses about 5 acres (0.02 km^2) of land, while the equivalent surface for oil would be about 50 acres (0.2 km^2) per well (NRC, 2010). While significant, this is much smaller than the land requirements of coal mining. Technologies for the exploration and extraction of oil and gas are comparable. There is soil erosion during well construction, and preparing the well casing can sometimes cause leaks into the groundwater or surface. Indeed, wastewater from all points upstream of generation can leak into ground or surface water. Seismic impacts are also an issue.

Much oil and gas extraction takes place offshore, where production wastes and drainage can create serious harm to ocean ecosystems. Both fish, including commercially harvested species, and birds are affected by the toxic metals and oils contained in these wastes. While direct land requirements are small, the deterioration of onshore land has been linked to offshore operations, thus creating a significant indirect land burden (NRC, 2010).

Pipelines for the transport of oil and gas also have significant land use. While much of it is underground, development is often seriously curtailed on the land above those pipelines (Fthenakis and Kim, 2009).

Nuclear

Although nuclear is a non-renewable source, it is very different from fossil fuels in that uranium mining is not nearly as large an endeavour as coal mining or oil and gas extraction. Often uranium mining is not even factored into the land requirements for nuclear power, since most of the world's uranium supply comes from only a few, very large and thinly populated countries such as Australia, Canada and Kazakhstan. The magnitudes are of a very different order. Whereas 58 816 tonnes of uranium were produced in 2012 (NEA, 2014b), the world produced 6.9 billion tonnes of steam and coking coal and 890 million tonnes of lignite in that year (IEA, 2014a).

Uranium mining is dominated by a technology referred to as in situ leaching (ISL), where a solution is pumped through the well to leach out uranium which is then pumped back out. The two other major extraction processes are classic underground mining and opencast mining. The latter generates considerable amounts of waste rock and thus has a significant surface impact. For ISL, groundwater impacts from potential leaks or spills, as well as the deep-well injection of processing waste, is the primary environmental concern (NRC, 2010; NEA, 2014b).

Waste storage can take place in land with few ecosystem services where ecological damage can be kept to a minimum. Deep geological storage disposal also implies that the actual surface area that is lost to alternative uses is considerably smaller than the storage area. Nevertheless, the Yucca Mountain repository would require an area of 60 700 hectares (607 km^2) isolated from the public, effectively forever, to meet licensing requirements (Fthenakis and Kim, 2009). Maintaining long-term radioactive waste facilities would indeed increase the land requirements somewhat for nuclear power.

Wind

Wind power, predicted to achieve the largest increases in share of global electricity production in coming decades, is already being deployed widely across the world, particularly on land (IEA, 2014a). Unlike other electricity sources, wind power never uses up all the land which a wind farm occupies. Only about 1% to 10% of land is used, depending on the characteristics of the wind farm area. In addition, the land a wind farm occupies can often be used by and large just as it had been before, e.g. for grazing or agriculture.

The aesthetic effects of wind turbines area are a major issue in that they lower property values, both for onshore and offshore wind parks. Indeed, it can be considered the major land-use change for offshore wind farms, which critics say detract from landscape and coastal views and lower the value of homes in areas with recreational value and, in particular, on the seaside.

Solar

There are two major solar power technologies: photovoltaic (PV) panels and concentrated solar power (CSP). The first is the dominant source of solar power (139 GW of installed capacity compared to 3.4 GW of the latter) and has been the focus of studies on land requirements (REN21, 2014). Most solar power capacity has been built within the last decade, with a boom in PV deployment in recent years thanks to a steep decline in unit costs. Land requirements are substantial for both PV panel arrays and CSP sites, accommodating modules, access for maintenance, and prevention of shading. The land use requirement per GWh is similar for both PV panel arrays and CSP sites (Fthenakis and Kim, 2009; Ong et al., 2013). In addition, studies have not found a significant relationship between the land-use efficiency of utility-sized solar power plants, either capacity-based (e.g. watts per square metre) or generation-based (e.g. kWh per square metre), and the size of the power plants (Hernandez et al., 2014; Ong et al., 2013).

However, land use is generally less per GWh than for wind turbines, although solar arrays have a much more concentrated impact. In addition, large-scale solar power arrays are limited to certain high-insolation regions, like the American Southwest and Spain. Frequently, land-use values are low in regions witnessing the highest solar power development, i.e. arid regions with comparatively little agriculture and vegetation. The development of rooftop solar PV panels is also growing fast. It has the advantage of not having any unique land requirements. Aesthetic effects do exist for rooftop PV panels, but are considered minor.

Worn-out PV panels have the potential to create large amounts of waste, mostly made up of toxic metals like cadmium, which can leach into soil and water and cause damage to ecosystem functions and water supplies for nearby population centres. Panels can be recycled, which would reduce their ecological impact, but which adds to their lifetime costs (NRC, 2010).

Hydroelectricity

Hydroelectricity, the largest renewable source of electricity, is unlikely to undergo significant development in the future in OECD countries, for two reasons. First, the best sites have already been developed and, second, there is now significant public concern over the large-scale land-use changes wrought by hydroelectric dams. Indeed, the significant impacts on land use and ecosystems by the creation of reservoirs for hydroelectric dams are the major external cost. However, not all hydroelectric plants are reservoir-based. Run-of-the-river dams, although usually much smaller, often have tiny land occupation rates, since they do not require the creation of a reservoir. While they allow the river to constantly run and spin a turbine, there may be ecosystem impacts due to a reduction in the flow rate of the water and the risk of eutrophication (oversaturation with fertilisers and other plant nutrients leading to excessive algae bloom).

There is even considerable variation among reservoir-type hydroelectric dams. While all are based on the potential energy in the water of the reservoir, some are long and wide, flooding large areas, while others, especially those in mountainous areas, are often deeper and shorter, requiring less land in the process (Fthenakis and Kim, 2009). The effects of reservoir creation can be quite dramatic as it impedes any alternative forms of land use. It also alters river flows, creates huge rock waste and may obliterate cultural objects, historical landscapes as well as aquatic and terrestrial ecosystems (EC, 1995). Increases in the full cost of power generation due to land-use changes are always site-specific and local. For no technology does this apply more than for hydroelectric power plants.

Biomass

Biomass feedstock is a broad term that lumps together many different resources and is again highly localised. To generate electricity, biomass can either be converted into a liquid or gas, usually from food crops like corn or soybean, or combusted directly when dealing with woody crops like willow or poplar. Although the proportion is expected to rise in coming decades, it should be noted that only 2.8% of the primary energy demand from biomass was for electric power generation in 2012 (IEA, 2014). It also plays a fairly small role in the electricity sector: biomass contributed only 1.9% of the world's electricity generation in 2012 (IEA, 2014b). Most demand today is for solid biomass-wood, agricultural residues and waste for heating. A significant portion of more sophisticated biofuels, meanwhile, is used in transportation. Land-use impacts of biomass thus transcend the electricity sector.

Land-use change is a major contributor to the full costs of biomass. It is singular among renewable sources in that these impacts largely occur before rather than during the generation stage. The land-use change for commercial energy crops in most cases can be considered internalised. Farmers will cultivate energy crops instead of food crops on dedicated agricultural land, according to their own cost-benefit calculation. There are,

however, concerns that land use for subsidised biomass could reduce land dedicated to growing food crops and thus endanger food security. Policies supporting biofuels, which are mainly used in transportation, were thus blamed for spikes in food prices in 2007 and 2008 (OECD, 2015).

Land requirements for a given unit of bioelectricity generation depend on the growth rate of the crop, which itself depends on the soil, climate, species in the area, and other factors. Growing food crops for conversion into a biofuel (e.g. ethanol) in a refinery (for subsequent combustion in a power plant) will have different land-use impacts from growing woody crops for direct combustion. In addition, the efficiency of bioelectricity processes vary: while woody crops yield more biomass per unit area than a food crop like corn or soybean, biofuel-related processes like ethanol combustion usually convert a higher percentage of biomass energy content into electricity (Fthenakis and Kim, 2009).

The cultivation of commercial biomass for electricity generation can also replace landscapes with slower recovery rates, such as forests. In such cases, ecosystem services and external costs decline. While the total area covered by forests and wooded land has remained roughly stable in OECD countries over the last 50 years, forest cover continues to decrease at a global level because of persistent deforestation. Worryingly, this concerns in particular the world's most sophisticated ecosystems, tropical rainforests. With a combination of fast economic growth and lax environmental regulation, countries like Brazil, Indonesia and Malaysia are meeting increased food and energy demand by converting their forests to agricultural land (OECD, 2015). Deforestation for cropland is one of the major driving forces of ecosystem degradation and habitat loss across the world. By destroying carbon sinks, deforestation also amplifies the impacts of anthropogenic climate change (OECD, 2012 and 2015).

Geothermal

Geothermal electricity is today a minor form of electricity generation, contributing only 0.3% of global electricity production in 2012 (IEA, 2014b). This is due to siting restrictions and the scarcity of locations with near-surface level temperatures suitable for power generation. Enhanced geothermal systems (EGS), where water is pumped into the ground to be heated in low permeability locations, could expand that scope, but the increase cost of deep drilling are likely to limit the contribution of geothermal power to electricity generation. Nevertheless, it can be an important local source of power. Compared to other renewable and non-renewable sources, the land requirements for geothermal electricity are fairly minor.

The land footprint for a traditional hydrothermal plant that uses hot water trapped in the earth to run a turbine is very site-specific and depends, in particular, on the process used for discharging the waste stream, e.g. reinjection into the ground. While power plants are built close to the heat source, since distance would decrease the temperature of the fluid and hence efficiency, drilling fields can cover a wide area. Multiple wells are thus often drilled from the same source. The power plant itself, with cooling towers and the substation, is relatively small, and pipelines are normally mounted so that the land underneath can still be used for grazing or crop cultivation. Indeed, land above many geothermal reservoirs has remained in service for its previous use, apart from the surface covered by the plant itself (Mock et al., 1997). Wells and pipes are very significant; accounting for them can increase land use by three times (Tester et al., 2006).

Land-use changes can be dramatic where fluid withdrawal exceeds replenishment, which can cause landslides and seismic activity. The precise impacts on land use and ecosystems are difficult to attribute, however, as areas with hydrothermal potential are often prone to high levels of natural seismic activity. Hydrothermal plants have disturbed or destroyed some natural hydrothermal regions like geysers or hot springs (Kristmannsdóttir and Ármannsson, 2003). Land impacts from drilling operations can largely be mitigated once generation has begun.

Waste water is a major environmental concern with geothermal power, as it can leak into natural waterbeds, increase water temperature and affect wildlife. However, in more sophisticated settings, waste water can also be utilised for home heating or industrial uses (Kristmannsdóttir and Ármannsson, 2003). Other strategies for minimising the ecological damage from geothermal waste water include reinjection and closed-loop cycles (Mock et al., 1997).

Tidal

The use of kinetic energy from tides and wave to generate electricity has great potential in certain regions but little current development. There are both offshore and shoreline devices currently being tested, but in any case the land use is either minimal or negligible (EC, 2008). Installation would also require little land, and any construction-related impacts would be temporary and reversible. Research into tidal energy's potential impacts on ocean flora and fauna is limited, but shoreline plants could damage sensitive ecosystems like bird-nesting grounds. Development in such areas would be avoided, though. There may also be aesthetic concerns like those with wind power, which may be reflected in changes in property values. Quite intuitively, tidal power will have the smallest land burden of any renewable source.

7.3. State of research, main studies and quantitative estimates: Resource depletion

The depletion of non-renewable natural resources is a recurring theme in discussion about the sustainability of economic growth in general and about the sustainability of different energy choices in particular. The key question is whether market prices adequately reflect the scarcity of non-renewable resources, which include land, but also metals and minerals and, most importantly in the context of the full costs of electricity provision, energy resources such as oil, gas, coal and uranium.

Concerns about resource exhaustion have an illustrious pedigree. As early as 1803, the Reverend Robert Malthus, who was to become two years later the first professor of political economy, wrote in his *Essay on the Principle of Population* that economic growth and population growth were constrained by the availability of arable land. His concerns were spawned by the rapid increase of population and hence demand for bread and corn that accompanied the early stages of the industrial revolution in England. The result would be a steady-state economy, where periodic famines would limit the population at a level that the available land could sustain. It is obvious that his concerns came to nought and that throughout the 19th century England enjoyed higher rates of growth in economic wealth and population than ever before. A key factor was increasing productivity in agriculture with the use of chemical fertilisers. Grain imports also contributed.

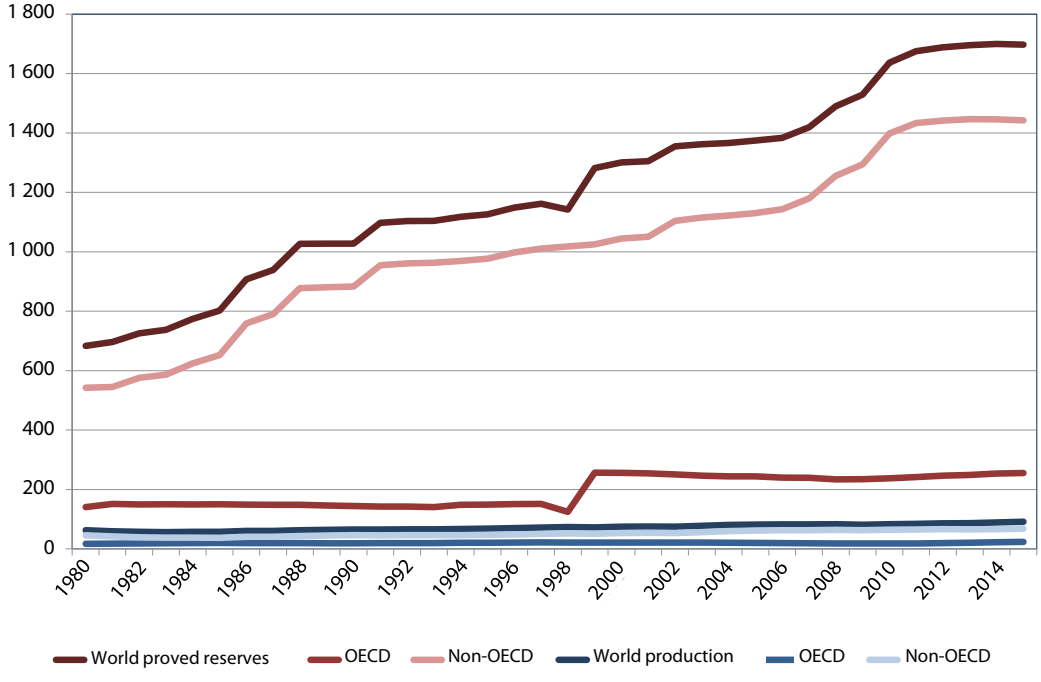
Nevertheless, Malthusian predictions of gloom, which already at its time earned economics the moniker of the "dismal science" (Thomas Carlyle), have been popular ever since. A particular influential example was the report by the Club of Rome (Meadows et al., 1972) with the programmatic title *The Limits to Growth*. Extrapolating existing trends with an early use of computer modelling, the Club of Rome predicted *inter alia* an exhaustion of petroleum reserves by 2003 under pessimistic assumptions and by 2022 under optimistic assumptions. It is safe to say that also their second prediction will not be realised, see Figure 7.1, which traces proved resources and the production of oil, the most emblematic of natural resources over the past 35 years.

Figure 7.1 shows that over the past 35 years proved reserves have increased considerably more than production and consumption. This means that the reserves-to-production (R/P) ratio, i.e. the reserves of a given year divided by the production in that year – which gives the length of time that reserves would last with constant production –

also increased. In other words, the security of oil supplies has strongly increased rather than decreased over the past decades. The situation is even more favourable for other energy resources (see Figure 7.2).

Figure 7.1: **Proven oil reserves* and oil production 1980-2015**

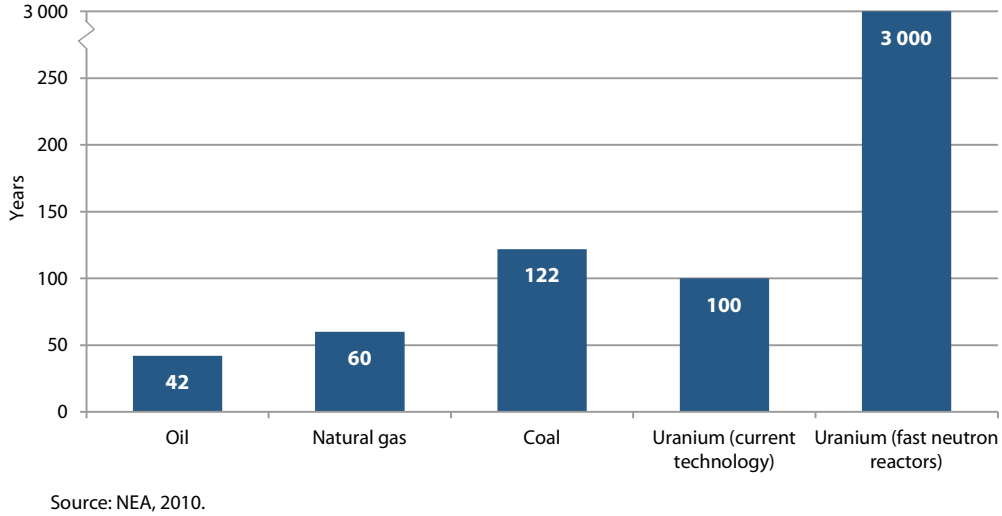
(Billions of barrels)



* Proved reserves of oil are generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions. Numbers do not include oil sands in Canada and Venezuela.

Source: Based on BP, 2017.

Figure 7.2: **Reserve/production ratios for selected energy resources**



Source: NEA, 2010.

Another more recent example of largely unfounded worries about the availability of natural resources is about "rare earth metals", which consist of the 15 elements known as the lanthanides plus scandium and yttrium. The moniker "rare earth" is a misnomer dating from the 19th century long before the interesting industrial properties of these metals became known. The majority of them are earth metals and are actually quite abundant but they are difficult to mine and to separate. This makes their relative scarcity as an industrial resource a short-term economic issue rather than a long-term geological issue.

Doomsayers worrying about the long-term exhaustion of economically relevant natural resources generally disregard two crucial considerations in this context:

1. Economic activity and growth depend not on materially available but on economically recoverable resources. Available resources are, of course, finite in some abstract physical sense; however, they also far exceed what will ever be used. Economic recoverability instead is a function of technology, demand and difficulty of access. In other words, here are economic forces at play and scarcity, which is a function of the difficulty of access, is well internalised.
2. Many, if not most, economically relevant natural resources can either be recycled or substituted. In the energy sector, recycling is limited to uranium for nuclear energy, while fossil fuels are irreversibly combusted. In other industrial sectors, the recycling of metals such as copper or steel plays an important role. For fossil fuels, however, substitution plays an important role. This holds not only for consumption, i.e. switching from combustion engines to batteries, but also for production. The Fischer-Tropsch process is thus able to convert coal, whose reserves are plentiful with R/P ratios stretching into hundreds of years, first into syngas and then into gasoline. Undoubtedly, this will come at a significant cost, but economic growth will not be limited by the scarcity of natural resources with commercial value.

This does not mean that there is no issue at all with resource depletion. However, it is limited to natural resources *without* commercial value. Consistent with what has been said in Chapter 1, to the extent that impacts are external, i.e. not taken into account by market participants, natural resources can be quickly depleted with great losses to societies and individuals. Examples are tropical rain forests and local ecosystems the world over. This comes back to the issue of land-use and the ecosystem services that land provides. Climate change can also be analysed from this perspective, which would require a consideration of the absorptive capacity of the earth's atmosphere as a finite natural resource being depleted by the incessant emission of large amounts of greenhouse gases (GHGs). Once the appropriate cost estimates have been established, governments would then need to internalise the value of such resources into the full costs of the economic activities that deplete them. Quite obviously, issues such as climate change or tropical rainforests, which constitute a vital link in the global oxygen cycle, transcend national boundaries and need to be internalised through cumbersome, but indispensable, international negotiations.

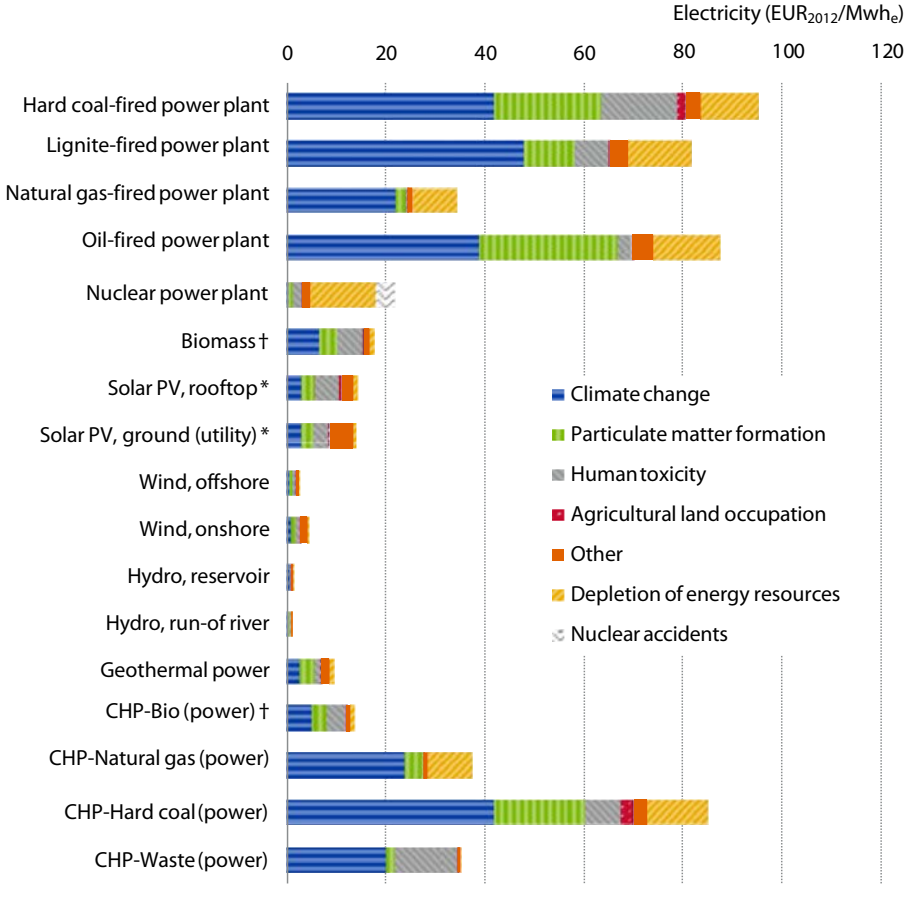
However, for marketable commodities, including energy commodities, it is very hard to make a case that markets overexploit existing resources. A well-known study on the full costs of energy prepared for the European Commission by Ecofys consultants (2014) is a case in point. The study included in its calculations the social costs for non-internalised resource depletion at a level ranging between EUR 9 and EUR 14 for gas, coal, oil and nuclear per MWh produced (Ecofys, 2014: p. 37) – see Figure 7.3. Nuclear power fared actually rather well in this comparison, given its good performance in terms of climate change risks and air quality (particulate matter formation).

The inclusion of sizeable resources depletion externalities is nevertheless surprising. Not only have proved reserves for all four resources been rising rather than decreasing. In addition, with commercially traded commodities, market participants should include any

information into the price. The well-known Hotelling rule (see the detailed discussion below) thus stipulates that in competitive markets, the value of the resource rent which is a key component of the price increases with the discount rate. The authors argue that resource depletion externalities exist since the depletion of gas, coal, oil and uranium progresses faster than socially optimal because "owners of finite stocks of natural resources have higher discount rates than socially optimal" (Ecofys, 2014: p. 38). However, this comes back to the earlier argument. If the commodities in question are fully marketable, then the private, market-based discount rate is the relevant parameter.

Figure 7.3: **External costs including resource depletion for different electricity generation technologies**

(Weighted average of EU countries, EUR/MWh)



Source: Ecofys, 2014, p. 37.

* Ecofys states that the values solar PV are likely to be an overestimation, because of the high pace of technological development for this technology improving efficiencies and reducing upstream impacts.

† Biomass is assumed to be sourced from agricultural/waste wood residues only, i.e. biomass from dedicated energy crops is not included.

Again, a case for social costs unaccounted for by private market participants can only be made if benefits exist from natural resources that are unaccounted for by the markets. This is an enormous area that includes reducing the risks of climate change or preventing the degradation of human health and biodiversity. However, the non-commercial benefits of oil, gas, coal and uranium are negligible compared to their value

in the production of electricity, energy services or in the chemical industry. In addition, there are no informational symmetries involved as markets will be far better informed than governments about the availability of resources and the cost of their extraction.

In the case where no externalities are present and private, market-based costs correspond to full costs, then the optimal price paths for an exhaustible resource is provided by the Hotelling rule, which states that, under competition, the resource rent, i.e. the market price of the resource minus its extraction costs, will rise over time with the rate of discount (see Hotelling, 1931). Discounting takes place starting from the point in time when the last economically valuable unit of the resource is used. This may be due to a suitable back-stop technology, say electric cars instead of petrol-fuelled cars, or due to the final consumption at the highest possible valuation of the resource in question. In the first case, it is the cost of the back-stop technology that is discounted; in the second case, it is the marginal utility of the last unit. In reality, this will not be the last physically available unit in either case since, as prices rise, there will eventually always be substitution either in production or in consumption. "The last barrel of oil will never be lifted", is an important principle to keep in mind.

The intuition behind the Hotelling rule is that an exhaustible natural resource is an interest-earning asset that competes with other assets. If prices rose less than the standard rate of return on capital, then the owners of the exhaustible resource would be advised to sell more of the resource and to reinvest the proceeds at the standard rate of return on capital or, equivalently, to put them in the bank to earn interest. This would lower present prices and bring their relationship with future prices, which are ultimately defined by the cost of the back-stop technology, in line with the standard rate of return on capital. Conversely, if prices rose faster than the standard rate of return on capital, then it would become profitable to buy additional amounts of the resource or to leave it in the ground. This would reduce supply and increase the present price until the latter's relation with future prices came again in line with the standard rate of return on capital.

Clearly, in the real world, no resource has such a smooth price path. Uncertainty, new discoveries, technological changes, geopolitics, variation in demand as well as speculation, storage and monopoly power all heavily influence prices. Most importantly, substitution, which in the Hotelling framework is an all or nothing process at a defined date in the future, is happening all the time in a multitude of different ways. If copper prices rise too far, recycling becomes profitable, if oil prices rise too far, commuters take public transport instead of their cars and so forth. This is why the smoothly rising exponential growth path of prices implied by the Hotelling rule is rarely if ever observed in the real world. However, despite its limited empirical validation, the Hotelling rule provides a sound basis for the general insight that, in the case of natural resources with commercial value, ultimately all economically available information is internalised in market prices.

7.4. Perspectives for internalisation

Managing ecosystems and nature conservation constitute the very beginning of environmental policy making. The earliest modern forms can be traced back to forestry methods implemented in the British Empire in the eighteenth and early nineteenth centuries. Conservation and land-use policies took their current form as a cornerstone of the modern environmental policies that emerged in the 1960s and 1970s, after becoming a major theme in the modern environmental movement that developed in particular in the United States in the wake of Rachel Carson's *Silent Spring*.

Given the well-defined private or public ownership of most land areas, it is in the form of ecosystem impacts that land-use change becomes an external effect that is not properly mediated by changes within the market. Command-and-control measures in the form of strict regulation dominate land-use policies across OECD member countries.

Local and regional governments often hold significant power in zoning and permitting certain kinds of development on land. National governments, meanwhile, often oversee large swathes of public and little-developed land, sometimes in the form of national parks and refuges. However, many endangered species and ecosystems lie on the land of private landowners, who do not bear the full social costs of the lost ecosystem services and thus have no incentive to protect them adequately.

This is where land-use restrictions come in. In the United States, a key measure to enforce land-use restrictions is the Endangered Species Act of 1973. Another measure is the Conservation Reserve Program (CRP), run by the Department of Agriculture, which pays American farmers to retire land from production that is deemed to provide important environmental services. The CRP is a good example of a "payment for ecosystem services" programme, a topic investigated extensively in OECD (2010). It is the largest conservation programme in the United States and considered to be significantly more cost-effective than a uniform price scheme or land-use restrictions. Conservation funds also exist in Canada and Australia to deal with extensive wildlife habitats in those countries.

In Europe, land-use development plans are left to individual countries. However, the European Commission assists in environmental impact analyses and co-ordinating strategies on urban planning and coastal zones. Space is included as resource in the European Union's thematic strategy on the sustainable use of resources (EEA, 2015). The EU has set the goal to halt the loss of biodiversity and degradation of ecosystem services within the EU by 2020, underpinned by the Birds and Habitat Directive, which relies on funds and land-use restrictions to meet its goals. EU agricultural policy also plays a large role in continent-wide land-use decisions.

As a "payment for ecosystem services" programme, the CRP in the United States straddles the border between a command-and-control scheme and a market-based one, since landowners do receive payments that seek to internalise habitat protection in their decision making, rather than banning certain decisions outright. However, those payments come from the federal government, meaning that there is not a true market of habitats where private owners exchange land-protection rights. The best example of an attempt to create a "land-use market" is mitigation banking, which first emerged in the United States but has been implemented in other countries, e.g. in Australia to prevent old-growth forests and in Indonesia to prevent soil erosion (OECD, 2010). In mitigation banking schemes, government agencies determine the various services provided by a wetland or an endangered species' habitat and thereby the number of credits the site can give. These credits can then be sold on the market.

When it comes to the electricity sector, a first step would require the collection and analytical treatment of data on land requirements and geographical footprint of different power generation options in a comprehensive manner. Environmental economics is currently still far from properly evaluating the impacts on land use and ecological systems of electricity generation. The important work on the health impacts of air pollution, for instance, still needs to be replicated in the area of land use.

7.5. Summary and key issues for policy makers

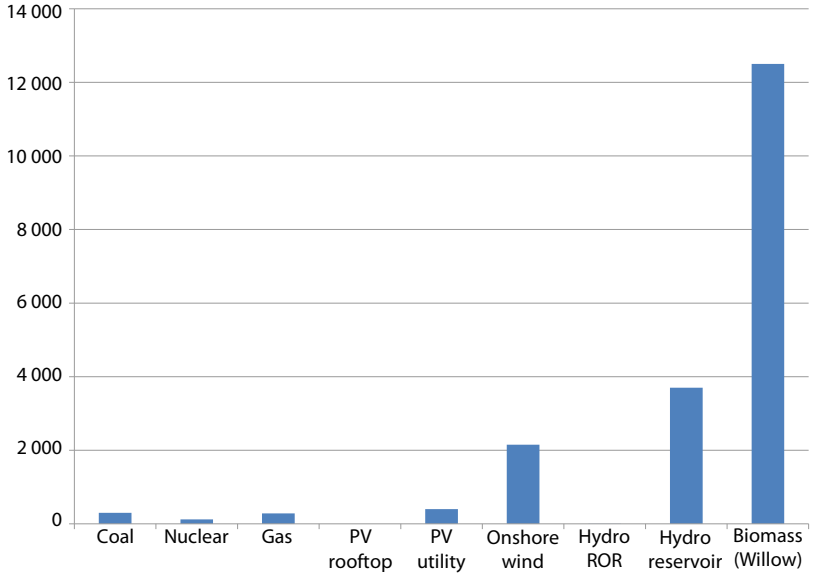
Electricity systems have a large impact on the land and, as major components of modern infrastructure, are a major subject in discussions about land use and impacts on natural sites. Direct land-use regulation, most often through zoning laws at the local and regional levels, are the most common and most widely used form of land-use policy. However, market-based schemes such as mitigation banking have been used in some countries to try to ensure that there is no net loss of sensitive ecosystems like old-growth forests and wetlands.

Valuation of land-use change is a difficult process. There is a clearly internalised component to land-use change in the changes in property values in the real estate market from a change in land use on or near the property. The most significant external cost of land-use change is the effects on the ecosystems of natural areas. Ecosystems can be considered as natural capital offering a flow of services over time. Because human survival and development is inextricably linked to the existence of the biosphere, it is meaningless to speak of the "total value" of the world's ecosystems in the standard economic sense of society's willingness to pay. Marginal changes in the functioning of these ecosystem services from a change in land use, however, and the social valuation of those changes in services would give a measure of the total cost of a land-use change.

Present shortcomings in evaluating ecosystem services have lead land requirements, basically the measure of geographical footprint, to be the common point of measure when considering land use in the electricity system, normally accompanied by a qualitative discussion of the changes in land quality. Most electricity sources have significant land requirements when the whole fuel cycle is considered, including fuel extraction, generation and waste disposal. Literature on life-cycle estimates of land requirements is scarce, but it suggests that the land burden of some non-renewable sources is comparable or higher than that of renewable ones (see Figure 7.4). Each electricity source has different nuances in its effect on the landscape.

Figure 7.4: **Land-use requirements for different power generation technologies**

(Life-cycle assessment including mining and transport, m^2/GWh)



Source: Based on Fthenakis and Kim, 2009.

As for policy improvements, there are significant gaps in land-requirement data and the understanding of how individuals value the land and its services. These must be filled for better internalisation. There are also clear guidelines for establishing cost-effective market-based land-use policies ("payment for ecosystem services" programmes). Lastly, even with the current limits to understanding, governments do not take into account many aspects of the services provided by natural landscapes and ecosystems. Building the capacity within policy-making communities to consider properly environmental qualities in development decisions is vital. In the electricity sector, this involves strategies to build

effective social institutions to ensure communication and the most up-to-date technical and institutional understanding among various government agencies, private firms, and groups in civil society. Considering the environment properly will allow for more balanced decisions in the realm of land use. This is especially prevalent in developing countries, where many of the world's most fragile, imperilled and active ecosystems lie.

Despite periodically voiced concerns, the depletion of non-renewable resources, such as fossil fuels and uranium, is not a major issue for policy making. As commodities with high private and little additional social value, oil, coal, gas and uranium are traded on large and liquid international markets, where information about long-term scarcity is widely known and would be immediately priced in if it ever became a genuine cause for concern. Actual prices vary in response to short-term supply concerns, linked to investment and geopolitical events, rather than in function of long-term availability. From a policy-making point of view, the best response to resource depletion concerns is to ensure that existing markets remain as open and competitive as possible and that information about resource availability is shared widely.

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Chapter 8. **The security of energy and electricity supply** [1]

8.1. Introduction

The continuous availability and affordability of energy and, in particular, electricity are indispensable conditions for the working of modern society. This is especially true for advanced industrial or post-industrial societies, where electricity provides the services essential for production, communication and exchange. Unsurprisingly, governments of OECD countries are thus concerned with understanding the factors influencing the security of energy and electricity supplies and seek to develop policy frameworks and strategies to enhance them.

The positive or negative impact of a given form of energy on the overall security of supply constitutes an external effect that should be accounted for in the full costs of a given source. While there is widespread agreement that the security of energy supply should be a concern for policy making, the issue has so far escaped meaningful quantification and, consequently, monetisation. Concerning the first point, quantification, the publication on which this chapter is based (NEA, 2010) has made a first important contribution by developing not only a meaningful indicator of the security of supply, but also combining it with a consistent set of data for OECD countries over 40 years (see Section 8.3). While indicators for the security of supply had been discussed before, their application to consistent data had so far been lacking. Despite such progress, monetisation remains elusive. Since the security of energy supply is tied closely to broad, high-level policy issues such as national sovereignty as well as to complex social attitudes towards risk, monetisation is currently not a viable option.

The sector in which the security of supply issue poses itself with the greatest insistence is the power sector. The need to balance supply and demand in power markets where electricity is non-storable and demand inelastic has always demanded close co-ordination between suppliers and the operators of electricity transmission grids. However, with the double challenge in many OECD countries of market integration and energy market liberalisation, such co-ordination has come under increasing strains. The principal reasons are: a) the inadequacy of the transmission infrastructure; b) the declining capacity margins, which leaves systems vulnerable to spikes in demand or technical accidents; and c) large amounts of intermittent renewable energy such as wind power (see also Chapter 3 on system costs). It is in the electricity sector where the economies of OECD countries currently face their greatest security of supply issue. It is also here that nuclear energy, together with hydroelectricity, as a stable provider of dispatchable electricity at predictable costs has significant potential to contribute to reinforcing the overall security of energy supplies.

Unfortunately, currently available indicators do not provide a complete picture of the security of supply situation in the electricity sectors of OECD countries. It is fairly straightforward to compile, as for the rest of the energy system, the relative contributions of different domestic and imported energy sources in order to obtain a snapshot of diversification and import dependence. It is also possible, albeit imperfectly, to obtain

1. This chapter is based primarily on NEA (2010) as well as on Cameron and Keppler (2010).

proxies for the state of the transmission and distribution system, and the level of reserve margins. However, it is currently not possible to provide a consistent indicator across countries of the relative contributions of intermittent and dispatchable technologies to the security of electricity supply. Other things being equal, dispatchable technologies make per MW of installed capacity a more reliable contribution to the security of electricity supply than variable ones, a fact that is measured in their respective "capacity credits". However, as pointed out in Chapter 3, the different system costs of variable technologies are highly country specific and depend on the latter's correlation with demand and the availability of flexible resources. In 2010, the issue of system costs was also not yet fully understood, which is why the impact of variability on the security of electricity supply has not yet been reflected in the indicators presented in this chapter.

8.2. Methodological issues, difficulties in measurement and uncertainties

The security of energy supplies is readily invoked in policy discussion but rarely defined with precision. This is partly because it frequently means very different things to different people. A foreign policy expert will look at the issue differently from a network engineer or an economist. Definitions of what is security of energy supply by different experts abound; they try to weld together in a variety of ways concerns linked to geopolitical preferences, strategic technology choices, economic development or social policy. Definitions also change from country to country. Countries with limited access to cross-border energy transport infrastructures but with broad domestic resource bases will think differently about the security of energy supplies from small, open economies that are closely interconnected with their neighbours but have few resources of their own. Even at a closer look, security of energy supply remains a complex concept requiring careful analytical decomposition in order to allow for meaningful quantification and comparisons across countries or through time. A good starting point is the following consensus definition from NEA (2010: p. 9): "Security of energy supply is the resilience of the energy system to unique and unforeseeable events that threaten the physical integrity of energy flows or that lead to discontinuous energy price rises, independent of long-term economic fundamentals."

Once a risk to the security of energy supply has been defined as a vulnerability to unique or unforeseeable events, it is possible to provide a number of examples that do constitute genuine energy supply risks: [1]

1. Long- or medium-term physical interruptions of energy supplies due to:
   a. political decisions such as embargoes (e.g. oil crisis of the early seventies);
   b. geopolitical tensions involving one or more supplier countries (e.g. wars, mid-east tensions);
   c. internal problems of a supplier country or region (e.g. civil war, political tensions, strikes);
   d. limitations of productive capacity due to a lack of investment (e.g. refusal of foreign direct investment, bad management);
   e. limitations of production capacity due to the "sustainable" long-term management of natural resources (e.g. Norway, Qatar);
   f. restrictions of supplies due to the long-term exercise of monopoly power by a single entity or a cartel (e.g. OPEC);

1. This is an adaptation of the list provided by Keppler and Lesourne in Keppler (2007b).

   g. restrictions on the use of certain fuels (e.g. constraints on fossil fuel use owing to limits on CO_2 emissions to combat global warming);
   h. the depletion of natural resources to the extent that it is not adequately taken into account by private actors, or that new information suddenly arrives.
2. Short-term physical interruptions of energy supplies due to isolated and non-predictable events such as:
   a. political and military reasons (e.g. Suez crisis);
   b. commercial disputes (e.g. Byelorussia, Ukraine);
   c. sabotage (e.g. Iraqi oil pipelines);
   d. non-state violence against energy infrastructures (e.g. pirate attacks in the straits of Malaga and Hormuz);
   e. extreme meteorological events (e.g. hurricane Katrina, polar vortex);
   f. technical accidents (e.g. breakdown of European high-voltage system due to strong spikes in variable production or demand, Macondo oil spill);
   g. inadequate domestic generating capacity (e.g. California 2002).
3. Short-term spikes in the price of energy due to:
   a. the sudden exercise of monopoly power by a single entity or a cartel (e.g. OPEC quota revisions);
   b. speculative bubbles and herd behaviour (e.g. oil prices during 2008);
   c. new information concerning the reserves position of a major supplier or likely future demand.

The two key dimensions of energy supply security

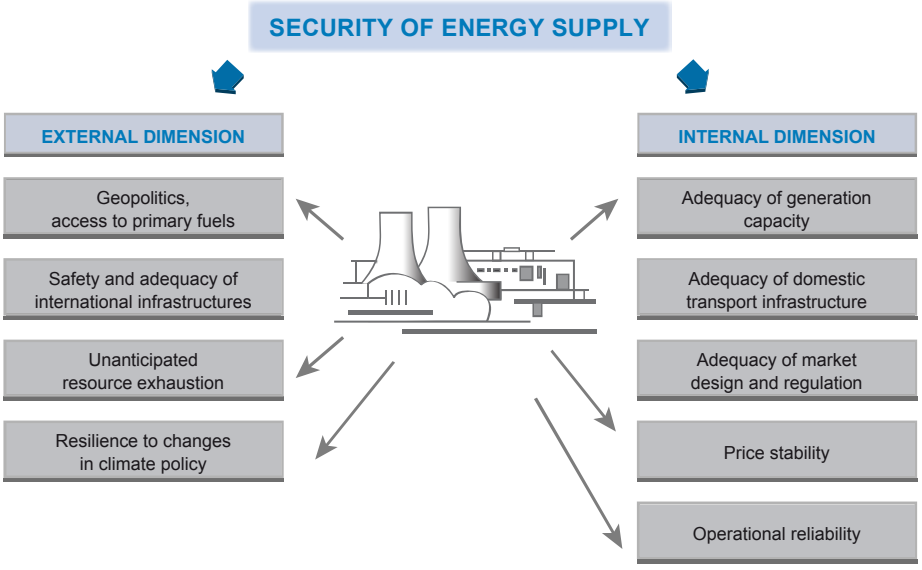
Energy supply security is a classic example of an externality, i.e. of an issue that affects the well-being of individuals and society but that markets are not providing at adequate levels. Being a negative externality, energy supply risk constitutes a policy issue as private individuals cannot cover themselves for such risks because of their informational complexity and unquantifiable nature. As shown in Chapter 1, such complexity is equivalent to the existence of transaction costs and can be due to the absence of established causal relationships, ill-defined or non-existent preferences, or large numbers of individual stakeholders that are difficult to aggregate through institutional processes. In the case of the security of energy supply, considerations of domestic political power, geopolitical strategy and, in some cases even military planning must be added to the list of factors complicating straightforward internalisation and economic optimisation. Even more so than in the case of other categories of externalities, managing the security of energy supply will thus always imply some level of government involvement.

Nevertheless, it would be wrong to think of the security of energy supply as a black box. One can coherently analyse and even quantify it with the help of a number of analytically sound and consistently trackable metrics. While this will never be the whole story, policy makers would be well advised to integrate these metrics into their decision-making processes, as they reflect powerful facts about the underlying economic structure of the energy sector. Two key dimensions are the external or geopolitical dimension and the internal, domestic dimension that includes technical, financial and economic issues (Figure 8.1).

Geopolitical risk refers almost always to primary energy carriers (oil, gas, coal or uranium) since their location depends on the vagaries of geology and climate. The extraction of primary energy carriers and their consumption are thus often physically far apart and take place in countries and regions with different histories, cultures and values. While all other steps of the energy chain such as refinement or enrichment, conversion and distribution can be moved physically closer to the final customer, exploration and production of primary energy cannot.

Given that one major cause of geopolitical supply risks is the physical separation of the centres of production of primary energy and their consumption, it is tempting to address the issue by striving to bring production home ("energy independence"). Whether this is a good approach depends on a country's geographical position, its own energy endowment, the state of its physical infrastructures for transport and storage, the diversification of its supplies, the willingness of its population to accept higher average long-term prices for lower volatility, and a host of other issues.

Figure 8.1: **Dimensions of energy security**



Source: NEA, 2010.

Security of energy supply does not necessarily equate with energy independence or self-sufficiency. Free and global energy trade through smoothly functioning competitive markets can ensure timely delivery of all necessary energy resources. Most countries are relying at least partially on the international trade of energy and will continue to do so. However, the issue of self-sufficiency does assume a particular significance in electricity markets, where a certain amount of domestic generation is required by the fact that electricity can neither be stored nor transported over long distances at reasonable costs. In island countries such as Australia and Japan or *de facto* geographically isolated countries such as Korea, domestic power generation *must* be able to cover demand on its own. This is not the case for storable resources such as coal or oil, where countries can enjoy high levels of security of supply even if they have no domestic production. Of course, the inputs for electricity generation such as uranium or gas can be sourced externally and stored, but generation itself needs to take place domestically.

Box 8.1: **Pitfalls of the geopolitical approach**

Geopolitics and import dependence certainly have a bearing on the security of energy supplies. Yet, one needs to be careful not to privilege this dimension to the exclusion of all others. A cautionary example is provided by an otherwise well-informed presentation by Professor John Gittus, Lloyd's of London, with the title "Keep the Lights Burning". Insisting heavily on the risks of future turmoil in the Middle East and future interruptions of Russian gas, he raises the spectre of a return to a "three-day-week" in absence of drastic action and predicts a blackout in the United Kingdom by 2025 with a 75% loss of electric power lasting more than one day with "2% to 5% probability" (Gittus, 2004: p. 7).

The choice of terminology, however, requires a moment of thought. The infamous term "three-day-week" was coined during the 1984 "winter of discontent" when the UK coal miners went on strike. Gittus thus unwittingly highlights that fact that domestic energy resources do not necessarily outperform imported energy resources with respect to the security of energy supply. His own statistics confirm that the longest significant energy supply interruption in the United Kingdom was precisely due to the 1984 strike (Gittus, 2004: p. 5). What counts is not so much the distinction between domestic and foreign sources but the absence of efficient market signals and the degree of politicisation. Distributional conflicts in the coal industry of the United Kingdom are as detrimental to the security of energy supply as Middle East turmoil.

The security of energy supply always has an important internal dimension. Energy security begins at home. The most important responsibility for OECD governments is setting appropriate frameworks providing incentives for private actors to install domestically an adequate level of facilities for the production, transport, conversion and consumption of energy. Important elements in this strategy are regulatory stability, market organisation, fiscal coherence and predictability of environmental policy. More specifically, the key challenge for policy makers in the electricity sector is to create appropriate frameworks for:

- Investment on domestically producing, low-carbon power sources such as nuclear, hydroelectricity or renewable energies. Low-carbon technologies have verifiable benefits for the security of electricity supply but suffer from high fixed costs in markets with uncertain prices and the absence of a reliable carbon price signal.
- The construction of adequate infrastructures for transport and conversion with appropriate long-term financial arrangements.

OECD governments have thus a responsibility to create market conditions that allow low-carbon technologies with lower supply risks to compete on a level playing field. Governments also have a role to play with regard to the provision of adequate levels of transport, distribution and conversion capacity. Partly, such capacity can be provided by markets themselves, but in other cases it requires regulation and supervision. First and foremost, such regulation must provide sufficiently attractive financial conditions for investment in transport and conversion infrastructure. Second, political backing must support projects that are necessary at the national level against excessive delays, through appropriate regulatory processes and zoning laws, as well as provide effective mechanisms for consultation, mediation and compensation.

8.3. State of research, main studies and quantitative estimates

There is a long history of security of supply indicators (see Box 8.2 and Appendix 8.A1). The challenge is always to combine pertinent indicators with relevant, consistent and comparable data. In 2010, the NEA published *The Security of Energy Supply and the Contribution of Nuclear Energy which* developed a consistent methodology for all forms of energy and electricity to deliver quantitative metrics for the security of supply. The methodology is perfectly transparent and the weights attributed to different parameters

can be adjusted according to national preferences. The originality and importance of the NEA study was its ability to combine a straightforward methodology based on the work by Scheepers et al. (2007) with a large consistent data set on energy and electricity supply in OECD countries over 40 years provided by the International Energy Agency (IEA). It is on this point that the NEA contribution makes a genuine difference.

Box 8.2: **Diversity – A key concept for the development of security of energy supply indicators**

The concept of diversity is being applied in many sciences. It broadly refers to the extent of diversification between categories of different elements in a given system. The essential strength of a well-diversified system is that in the face of uncertainty or even ignorance about future outcomes, it provides resilience. One of the first scientific disciplines where this concept was studied was ecology. Darwin thus already demonstrated that diversification of a species within an ecosystem was a "spontaneous" survival strategy in the face of changing biotope conditions. Yet diversity also has costs such as foregoing the benefits of scale and standardisation.

Andrew Stirling, in particular, has applied the notion of diversity to energy policy differentiating it according to the categories of variety, balance and disparity (see Stirling, 1994 and 1998; and also Jansen et al., 2004). Variety refers to the number of different categories into which a system may be partitioned. Balance refers to the spread of the volume of system elements across the relevant categories. Disparity refers to the degree to which the categories themselves differ from each other. Stirling addressed the question of how diversity can be captured in a simple and robust quantitative index. Ecologist Mark O. Hill demonstrated that most prominent diversity indices relating variety to balance are derivations of the general form (Hill, 1973: p. 428-431):

$$\Delta a = [\sum I\ (pia)]1/(1-a),$$

where pi denotes the share of element i and Δa denotes a measure of diversity according to parameter a. The greater is a, the smaller the sensitivity to the presence of lower-contributing options (Stirlin, 1998: p. 49). In other words, the higher is a, the more importance is paid to the feature whether the different elements are evenly distributed. Letting a go towards one allows in the limit to obtain an exponential expression of the well-known Shannon-Wiener Index (SWI):

$$\Delta 1 = eSWI \text{ with } SWI = - \sum I\ pi*\ln(pi).$$

The minimum diversity value occurs when the system of elements is encompassed by only one category. The maximum value is attained when all system elements are evenly spread among the system categories. Setting parameter a of Hill's general form equal to two, one obtains the reciprocal of the function, referred to in ecology as the Simpson diversity index and in economics as the Hirschman-Herfindahl index (HHI):

$$\Delta 2 = 1/\sum i\ pi2 = 1/HHI \text{ with } HHI = \sum i\ pi2.$$

Diversity indicators can be complicated at will. One interesting extension is the inclusion of disparity, the "distance" between different options. This however easily slips back into qualitative reasoning.

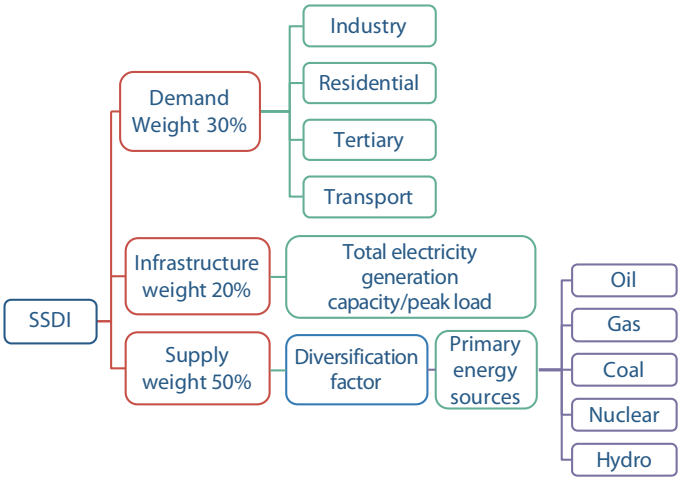
The security of supply indicator developed by the NEA is referred to as the simplified supply and demand index (SSDI). It belongs to the category of resilience-based indicators, which seek to measure the ability of an economy to absorb and moderate the impact of supply incidents by mitigating negative welfare impacts through increased flexibility on the supply and the demand sides (Jansen and Seebregts, 2010; Jansen and van der Welle, 2011). In particular, the supply/demand (S/D) index proposed by Scheepers et al. (2007) on which NEA's SSDI is based, includes both supply-side and demand-side vulnerability and flexibility aspects.

The S/D index is a composite supply security indicator for a defined region in the medium and long run that includes major underlying supply-side and demand-side factors. This index is normalised to range from 0 (extremely low security) to 100 (extremely high security). It covers final energy demand, energy conversion and transport, and primary energy supply (hence, in principle the entire energy system). The difference in the SSDI and the S/D index is that the SSDI was adapted to be able to work with the only available consistent data available for the past 40 years, i.e. the IEA Energy Statistics. The applicability of the scoring rules (see below) has also been simplified and adapted from the European Union and Norway to the whole of the OECD. The SSDI index thus uses four types of inputs:

1. The shares of different supply and demand categories (i.e. for supply: oil, gas, coal, nuclear, renewable energy sources and other; for demand: industrial use, residential use, tertiary use and transport use).
2. Indicators for energy and carbon efficiency as well as for the adequacy of infrastructures for conversion and transport of secondary energy carriers (electricity, heat and transport fuels).
3. Weights determining the contribution of the different components to the SSDI (e.g. the ratio between supply and demand or between OECD imports and non-OECD imports).
4. Scoring rules for determining various SSDI values reflecting different degrees of perceived vulnerabilities for different fuels.

The NEA study applied the SSDI to the only available consistent data set for the energy sectors of OECD countries during the past 40 years, the *IEA Energy Statistics*. The weighted contributions of demand, infrastructure and supply take into account the degree of diversity and supply origin of different energy carriers, the efficiency of energy consumption and the state of the electricity generation infrastructure. Figure 8.2 provides an overview of the shares and weights used for the SSDI in NEA (2010) at level 1 of the analysis. The complete list of detailed scoring rules is available in NEA (2010: pp. 123-124). One limit of the SSDI is the fact that it does not take into account renewable energy sources other than hydro whose contribution to electricity supply over most of the 40 years of analysis was too small to make any difference. This has clearly changed in the past ten years. Any update of the SSDI would need to account for all forms of renewable energy and the impact of variability on the security of electricity supply.

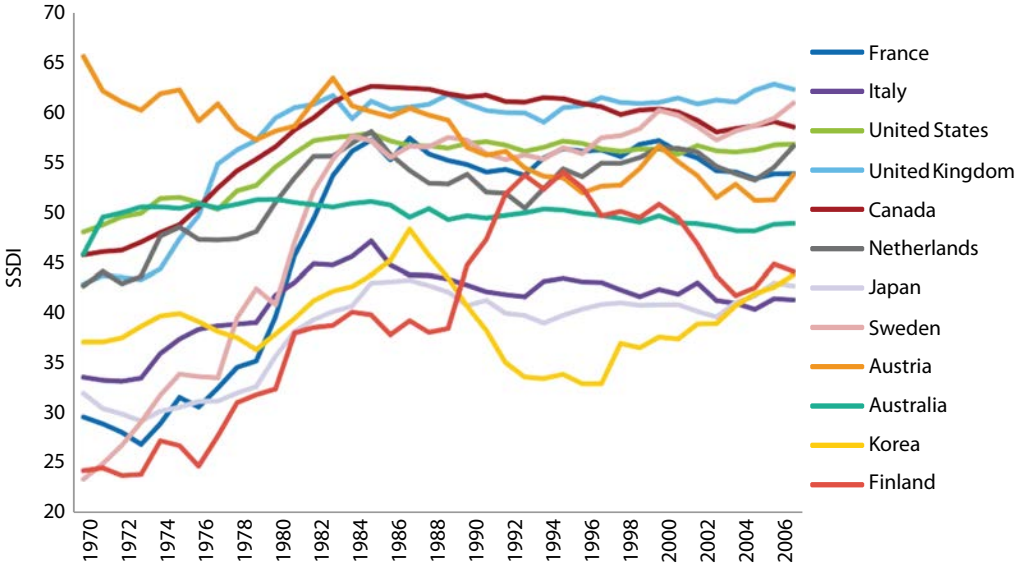
Figure 8.2: **Shares and weights used in the simplified supply and demand index**



Source: NEA, 2010.

Based on data from *IEA Energy Statistics*, the SSDI shows a remarkable improvement of the security of energy supplies for the great majority of OECD countries over the 40 years of the time frame of the study. Key factors in this evolution are the switch from imported sources such as oil, gas and coal to largely domestic sources such as nuclear and renewable, as well as the diversification of supply sources for imported energies. The evolution of the SSDI through the period (1970-2007) was analysed for several OECD countries: Australia, Austria, Canada, Finland, France, Italy, Japan, Korea, the Netherlands, Sweden, the United Kingdom and the United States (see Figure 8.3). It identifies changes in the trend since important policy changes have been implemented such as the United Kingdom's switch from coal to gas or the introduction of nuclear programmes in France and the United States.

Figure 8.3: **Evolution of the SSDI for selected OECD countries**



Source: NEA, 2010.

One can see that the value of SSDI has significantly increased between 1970 and 2007 in the case of most economies under study: Australia, Canada, Finland, France, Japan, the Netherlands, Sweden, the United Kingdom and the United States. On the contrary, the value of SSDI is low or not increasing between 1970 and 2007 for Austria, Italy and Korea. The improvement in the SSDI of countries in the OECD is due to three different factors:

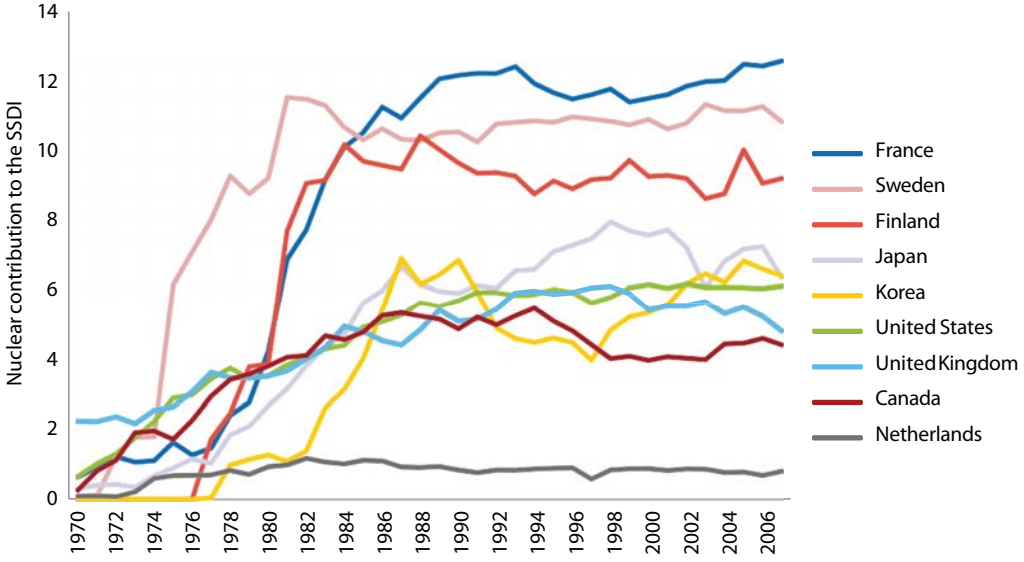
- the introduction of nuclear power for electricity generation;
- the decrease of the energy intensity in OECD countries;
- the increase of diversification of primary energy sources.

Renewable energy sources such as wind and solar are also often mentioned in this context, but their share until 2007 was too low to make any impact on the quantitative indicators. However, the rapid development of wind and solar PV in a number of OECD countries since certainly had an impact on the security of supply. Net effects would depend on the trade-off between the positive impact of domestic production and the negative impact of declining reserve margins of the electricity system (see also Chapter 3 on system costs). However, with the very rough and ready metric for system adequacy used in this exercise, which is the ratio of total generating capacity over peak demand, *ceteris paribus* the SSDI would increase in response to increased renewable production.

The role of nuclear energy in this perspective is even more favourable given its ability to increase the share of domestic production, while maintaining or improving the reserve margins of the electricity system. During their life cycle, nuclear power plants source up to 90% of their inputs in terms of value domestically. Imports of uranium, just as imports of rare earths for the rotors of wind turbines, are not a major concern as they are widely diversified and frequently stem from other OECD countries. In addition, storing uranium, because of its high energy density, is possible at comparatively low cost. Storage costs for uranium are thus far lower than storing equivalent amounts of primary energy in the form of fossil fuels. Last but not least, nuclear energy shares with renewables the advantage, in security of supply terms, that its costs would remain unaffected in the case of a sudden tightening of restrictions on the emissions of GHGs.

In the face of geopolitical supply risks, whether due to import dependence, resource exhaustion or changes in the global carbon regime, nuclear energy and renewable energies hold advantages that other fuels such as oil, coal and gas do not enjoy: wide availability of resources for a long time to come, modest impacts of increases in resource prices and resilience against carbon policy shifts. Doubling the carbon price, for instance, from USD 30 per tonne of CO_2 to USD 60 per tCO_2 would increase the total average cost of coal-produced power by 30%, more than doubling its variable cost in the process. This is not an unrealistic number. Given current commitments to reduce global electricity sector emissions by 2050 by 50% in order to limit the rise of global mean temperatures to 2°C, modelling results imply marginal costs for carbon abatement of at least USD 100 per tCO_2. Electrification of the energy system with the help of low-carbon technologies that have large domestic components thus, in general improves the security of supply.

Figure 8.4: **The contribution of nuclear power to progress in the SSDI**



Source: NEA, 2010.

Many OECD countries invested massively in nuclear power development during the 1970s and 1980s. Figure 8.4 shows the extent to which nuclear energy has contributed to the increase in energy supply security of these countries (Figure 8.4 isolates the nuclear contribution to the SSDI provided in Figure 8.3). By and large, nuclear energy contributed about half the improvement in the security of supply observed since 1970. The contribution of hydroelectricity remained roughly stable during the observed period and the share of non-hydro renewables was, as mentioned, too small to make a difference but

has dramatically increased since then. The variability of non-hydro renewable poses challenges not only for the availability of power at all times but also for grid stability and the technical reliability of the system. Among the low-carbon options, nuclear power is unique as being independent of either the annual fluctuations in the availability of hydropower or the daily variations of wind and solar PV.

8.4. Perspectives for internalisation and key issues for policy makers

Because of its complexity and the dynamic evolution of the many parameters that define the reality, as well as the public demand for a "secure" supply, energy security remains an uninternalised externality or a public good that markets are unable to provide for at the appropriate level. Even in the presence of a globalised marketplace for most energy commodities, energy supply security thus remains a policy issue for which governments need to assume responsibility. In the geopolitical dimension, in addition to ensuring adequate shares of domestically produced energy, governments need to ensure transparent global markets that enable diversification and a mutually beneficial division of labour. In the internal dimension, the focus must be on creating appropriate market conditions and incentive systems that enable all technologies to deliver their potential contribution to the security of supply, in particular high fixed cost, low-carbon technologies.

On a more technical level, one can identify five distinct policy areas, on which governments need to focus in order to respond effectively to security of energy supply challenges:

1. diversification, technical reliability and flexibility in both the energy and the electricity sectors;
2. energy conservation, demand management and storage of energy carriers;
3. regulatory, institutional and fiscal frameworks for adequate infrastructure provision;
4. crisis management mechanisms.

In general, low-carbon technologies such as nuclear, hydro, wind and solar possess a number of attractive characteristics that enable them to contribute to both the geopolitical and the domestic dimension of energy supply security. Cost variations to changes in raw materials or carbon taxes are either absent or minimal, unlike fossil fuel-based technologies. Their costs are thus relatively insensitive to the vagaries of geopolitics or the evolution of the global efforts to reduce greenhouse gas emissions. However, because of their large fixed costs, these low-carbon technologies require frameworks that do not disadvantage them in the competition with fossil fuels in order to make their full contribution to the security of energy supplies of OECD countries.

Last but not least, among different low-carbon options, the difference in the contribution of variable and dispatchable low-carbon technologies to the security of energy and electricity supply needs to be properly recognised. Other things being equal, dispatchable technologies make per MW of installed capacity a more reliable contribution to the security of electricity supply than variable ones. Nevertheless, the different system costs of variable technologies are highly country-specific and depend on the correlation with demand, and the availability of flexible resources. This is why, at the current state of progress, no consistent indicators exist that would enable experts to take into account the difference between variable and dispatchable technologies. Future research on security of supply indicators promises to address this issue.

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Appendix 8.A1. **An overview assessment of security of energy supply indicators**

Indicator	Usefulness	Transparency	Data availability	Relevance for nuclear energy
Import dependence and diversification				
Import dependence	H	H	H	H
Ratio of net fuel import bill to GDP	H	H	M	H
Reserves/production ratio	H	M	H	H
Resources/production ratio	H	L	M	M
Energy and carbon price volatility	H	H	H	H
SWI diversity index	H	H	L	H
HHI market concentration index	H	H	L	H
Resource and carbon intensity				
Recovery factor	H	M	M	M
Energy loss rate during transportation	M	M	M	M
Generation/conversion efficiency	M	H	H	M
Transmission and distribution losses	M	H	M	M
Fuel or power use per unit of GDP	M	L	H	H
GHG emissions per unit of fuel	H	M	H	H
GHG emissions per unit of generation	H	L	M	H
System adequacy				
Power generation capacity margin	H	M	L	H
Energy margin	H	M	L	L
Peak supply shortfall (gas and oil)	H	M	L	L
Must-run baseload power capacity	H	M	L	H
Indicators of investment in supply	L	M	M	M
Adequate transport capacity	H	L	L	M
Storage capacity for fuels	M	M	M/L	M
Share of interruptible contracts	M	M	L	L
Flexibility margin for load balancing	H	M	L	M
Indicators of investment in transport	L	M	M	L
Peak interconnector margin	L	H	M	M/L
Interconnector capacity benchmark	M	M/L	H	M

Source: NEA, 2010.

Chapter 9. **Employment generated in the electricity sector**

9.1. Introduction

During the past decade there have been many reports attracting high-level policy makers' attention by providing estimates of the number of jobs created by various electricity generation technologies. While an important economic indicator, the interest in job creation ebbs and flows with the business cycle. However, since the recession of 2007-2008, employment growth has lagged economic growth more than in previous expansionary periods. This has been particularly true in the electricity sector, which, in addition, has experienced low demand growth in OECD member countries since 2008. The number and quality of jobs generated in the electricity generation sector is thus of considerable political interest ("quality" refers here to educational requirements and the implied level of wages and salaries). This information is also frequently used by different stakeholder groups to promote their preferred technology and, in some circumstances, to present it as eligible for government support.

While the political argument for employment studies in the electricity sector is obvious, the economic argument is far less so. High labour intensity may be of interest to local policy makers, but it could also constitute a disadvantage in economic competition. Standard economic theory would indicate that social welfare is maximised by providing a given level of output of electricity at the least economic cost. Such optimality would be achieved by letting firms in competitive electricity markets choose the appropriate technology under the condition that relevant externalities, such as atmospheric pollution and climate change, have been appropriately internalised.

There exists nevertheless one economic argument that can justify the study of employment effects. This consists of the fact that the quantitative and qualitative characteristics of employment in different power generation technologies can generate positive externalities beyond workers' productivity in the market-driven production of electricity. Just as in the case of technological development (see Chapter 10), it is important here to distinguish standard economic effects from genuine externalities that are not captured by market prices. In a more comprehensive approach, high employment rates generate positive spillovers, contribute to social and regional cohesion as well as to greater levels of well-being. In this perspective, the quality of the labour that is required by different technologies is of particular interest. The higher the qualification of the workforce and the longer the duration of the employment contract, the higher is the likelihood that long-term positive externalities would accrue to local, regional, and national economies.

Another aspect, not explored in the present chapter, is the question of the extent to which parts of the economic life cycle of a generation technology can be delocalised. The construction of a power plant or the production of major components could thus take place outside the country where the electricity is produced. The latter choice could well be the economically optimal one, but any positive externalities of employment would of course be lost. In summary, employment effects in the electricity sector do not allow for simple conclusions and must be considered in a number of different perspectives. Their high policy relevance nevertheless warrants their inclusion in the full costs of electricity.

9.2. Jobs and education in the nuclear power sector

The nuclear sector

This chapter grows out of a forthcoming NEA report entitled *Measuring Employment Generated by the Nuclear Power Sector*, which draws on the work of Cameron and van der Zwaan (2015), *Employment Factors for Wind and Solar Energy Technologies: A Literature Review* and Harker and Hirschboeck (2010), *Green Job Realities: Quantifying the Economic Benefits of Generation Alternatives*. While the chapter does not concentrate exclusively on nuclear power, it takes its starting point from employment effects in the nuclear sector. The above report thus defines direct, indirect and induced employment in the nuclear sector as follows:

> [In] the nuclear power sector… direct employment is defined as employment at NPPs in construction, operation, decommissioning and waste management; indirect employment is employment supplying products and services to these activities at NPPs; and induced employment in an economy associated with direct and indirect plant and labour expenditures. Indirect and induced employment must be calculated with a macroeconomic model of a particular region or country. (NEA, forthcoming)

These definitions grow out of the input-output (I-O) literature (the macroeconomic model of choice), where the "nuclear sector" receives inputs from other (e.g. manufacturing) sectors and sells electricity to other sectors (or simply to the electricity grid). Each sector in an I/O model is assumed to supply a homogeneous product to other sectors. Hence, the supply chain *must be* assigned to sectors that produce the structures, equipment and materials required in the nuclear power sector.

In Table 9.1 values for the construction cost of a generic pressurised water reactor (a PWR-12, similar to units constructed at Tennessee Valley Authority's Watts Bar site, see ORNL 2011, based on ORNL, 1988) are assigned to North American Industrial Classification System (NAICS) industries. For each 6-digit NAICS industry the amount spent to construct a generic PWR is identified i) for labour (in thousands of 2011 dollars) and ii) for other (equipment and materials, a minor portion). (In calculating employment, NEA (forthcoming) implicitly assumes that construction cost increases are matched by increases in labour costs; so the number of jobs remains constant over time.)

In Table 9.2, to approximate first-order indirect jobs, the amounts in Table 9.1 are aggregated to 3-digit NAICS industries. Spending on "other" is multiplied by "industry revenues to jobs multiplier", and this value is divided by annual wages in each industry. This procedure yields both: (1) direct labour per MW of about 12.1; and (2) first-order indirect labour per MW of about 9.2. Other studies of the nuclear power sector find that indirect labour is approximately equal to direct labour (see IAEA, 2009 for Korea), i.e. this method identifies about 75% of the indirect labour with 25% of the indirect labour supplying the needs of the nuclear construction supply chain, e.g. in supplying materials to the machinery manufacturing industry (NAICS 333).

In applying the definition of types of employment, the NEA has calculated the approximate direct, indirect, and induced employment in the nuclear power sector per GW of nuclear capacity in the following manner:

> To summarise the results […], direct employment during site preparation and construction of a single 1 000 MW advanced light-water unit is about 12 000 direct labour-years during construction from Table 2.2. For 50 years of operation, annually there are approximately 600 administrative, operation and maintenance, and permanently contracted staff, or about direct 30 000 labour-years during operation. For 10 years during decommissioning, there are approximately 500 employees annually, or about direct 5 000 labour-years. Finally, for 40 years, there are about

80 employees managing nuclear waste, or about direct 3 000 labour-years (NEA, forthcoming).

Hence, the total is approximately 50 000 direct labour-years per GWe over 60 years.

Table 9.1: **US PWR construction cost breakdown into NAICS industries**

(in USD_{2011} thousands)

NAICS Industry	NAICS CODE	Labour	Other	Total
Water and sewer line and related structures construction	237 110	3 322	3 444	6 766
Power and related structures construction	237 130	36 452	199 812	236 264
Highway, street and bridge construction	237 310	1 761	1 951	3 712
Heavy and other civil engineering construction	237 990	3 653	3 391	7 044
Concrete, poured structure contractors	238 110	51 351	36 973	88 324
Structural steel and precast concrete contractors	238 120	122 698	80 614	203 312
Welding, on-site, contractors	238 190	9 727	1 457	11 184
Electrical and other wiring installation contractors	238 210	45 694	31 508	77 202
Plumbing and HVAC contractors	238 220	17 371	23 144	40 515
Building equipment contractors, other	238 290	7 883	13 371	21 254
Painting of engineered structures	238 320	10 329	2 935	13 264
Site preparation contractors	238 910	25 416	15 411	40 827
Pipe, iron and steel pipe and tube manufacturing	331 210	18 679	40 431	59 110
Structural steel, fabricated, manufacturing	332 312	21 148	32 863	54 011
Power boiler and heat exchanger manufacturing	332 410	29 106	360 507	389 613
Metal tank (heavy gauge) manufacturing	332 420	330	13 387	13 717
Chain link fencing and fence gates	332 618	251	267	518
Metal products, all other misc. fabricated manufacturing	332 999	9 010	3 150	12 160
Other industrial machinery manufacturing	333 249	7 691	37 895	45 586
Water treatment equipment manufacturing	333 318	21 655	53 640	75 295
Heating and cooling industrial equipment manufacturing	333 415	23 238	62 050	85 288
Turbine and turbine generator set manufacturing	333 611	19 632	333 983	353 615
Pump and pumping equipment manufacturing	333 911	48 493	140 558	189 051
Air compressors manufacturing	333 912	3 206	1 549	4 755
Material handling equipment manufacturing	333 920	928	2 463	3 391
Elevator and moving stairway manufacturing	333 921	378	1 222	1 600
Crane, hoist, etc. overhead travelling system manufacturing	333 923	2 111	12 599	14 710
Fire detection and alarm systems manufacturing	334 290	17 654	14 528	32 182
Instruments and related products manufacturing	334 513	18 307	24 258	42 565
Measuring and controlling device manufacturing	334 519	17 601	59 158	76 759
Transformers, power and special, manufacturing	335 311	800	7 105	7 905
Switchgear and switchboard apparatus manufacturing	335 313	3 665	37 911	41 576
Current-carrying wiring device manufacturing	335 931	178	176	354
Non-current-carrying wiring device manufacturing	335 932	59 633	12 944	72 577
Electrical equipment and components, all other, manufacturing	335 999	5 804	4 069	9 873
Office furniture manufacturing	337 214	111	1 124	1 235
Railroad line-haul	482 111	0	13 292	13 292
Insurance funds, other	525 190	0	149 261	149 261
Engineering services	541 330	0	700 212	700 212
Scientific and technical consulting services	541 690	0	27 041	27 041
Labour, contracted	561 320	239 437	0	239 437
Public finance activities (local)	921 130	0	27 156	27 156
Total		904 703	2 588 810	3 493 513

Note: HVAC = Heating, ventilation, and air conditioning.

Table 9.2: **US PWR (1 147 MW) direct and first-order indirect labour in construction**

(in thousands of 2011 USD, excluding local and national public-sector jobs)

General NAICS industries	NAICS CODE	NPP labour payroll	NPP other spend	Industry revenues to jobs multiplier	Sector annual wages (USD)	Direct labour	First-order indirect labour*	Total direct and indirect labour
Heavy and other civil engineering construction	237	45 188	208 598	0.375%	56 915	794	782	1 576
Speciality trade contractors	238	290 469	205 413	0.601%	44 856	6 476	1 235	7 711
Primary metal manufacturing	331	18 679	40 431	0.146%	59 203	316	59	374
Fab. metal product manufacturing	332	97 203	491 036	0.408%	48 758	1 994	2 006	3 999
Machinery manufacturing	333	127 332	645 959	0.262%	56 743	2 244	1 695	3 939
Computer and electronic product manufacturing	334	53 562	97 944	0.273%	73 431	729	268	997
Electrical equipment component manufacturing	335	70 080	62 205	0.273%	52 252	1 341	170	1 511
Furniture and related product manufacturing	337	111	1 124	0.512%	37 822	3	6	9
Transportation and warehousing	48-49	0	13 292	0.589%	42 699	0	78	78
Finance and insurance	52	0	149 261	0.166%	86 668	0	248	248
Professional, scientific and technical services	541	0	727 253	0.554%	70 871	0	4 030	4 030
Labour		853 302			61 405	13 896	10 577	24 473
Labour per MW						12.1	9.2	21.3
Multiplier: (first-order indirect)/direct							0.761	

* First-order indirect labour = NPP other spend x industry revenues to jobs multiplier.

Source: Based on NEA, forthcoming.

To compare these values with employment in other electricity generation sectors, there are about 24 direct and indirect labour-years per MW in nuclear power plant (NPP) construction and the supply chain (i.e. twice 12.1/MW, direct and indirect employment, from Table 9.2) and about 1.2 jobs/MW (i.e. twice 0.6/MW, direct and indirect employment) during the operation, decommissioning, and waste management phases, i.e. over 60 years (600 employees during operation and 580 in decommissioning and waste management, plus indirect labour during these 60 years).

So far for construction, operations are quite a different matter. To understand how these jobs are distributed locally, regionally and nationally, Table 9.3 breaks down the 15 largest categories of spending during the operation of an NPP. Notice that about half the labour is employed at the plant locally (in the county) and the other half is in the regional (state) and national supply chains.

But employment effects are not only about raw numbers but also about the quality of employment. To understand the quality of employment at NPPs, it is helpful to consider the analysis by Peddicord, a professor of nuclear engineering at Texas A&M University (Peddicord, 2010). His breakdown of occupations and degrees required at NPPs is presented in Figure 9.1, where "2-year Associate Degree backgrounds" can also include post-secondary certifications, apprenticeships and military training.

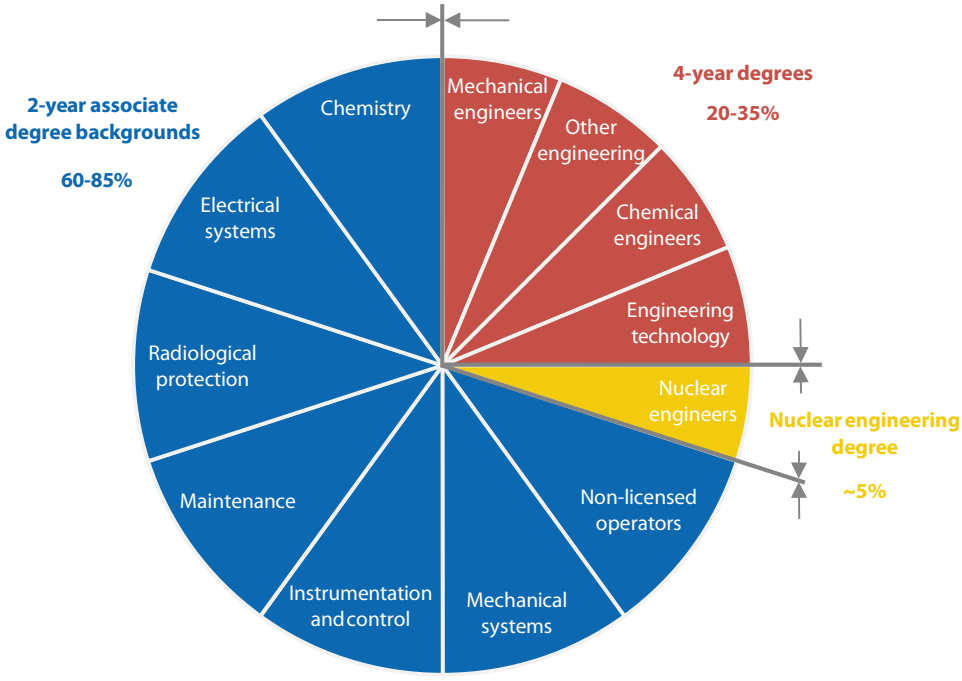
Table 9.3: **Fifteen largest annual operating expenditures in an average US nuclear plant**

(in thousands 2013 USD)

NAICS descriptors	NAICS code	County	State	National
Total (of which 32% is labour)				215 000
Labour	Labour	30 700	64 500	68 900
Indirect taxes	Taxes	6 900	8 500	20 300
Other basic inorganic chemical manufacturing	325 180	0	200	18 300
Engineering services	541 330	0	7 600	15 100
All other non-metallic mineral mining	212 399	0	0	12 000
Federal regulators and administrators	926 130	0	0	14 000
Other maintenance and repair construction	811 310	1 200	6 100	8 800
Support activities for non-metallic mining	213 115	0	0	7 000
Misc. professional and technical services	541 300	100	1 500	5 300
Misc. electrical equipment manufacturing	335 999	100	1 200	4 300
Other state and local government enterprises	921 130	600	2 800	3 600
Scientific research and development services	541 712	0	100	2 700
Environmental consulting services	541 620	0	1 200	2 700
Electric power and transformer manufacturing	335 311	0	700	2 000
Hazardous waste treatment and disposal	562 211	100	800	1 900

Source: Based on NEA, forthcoming.

Figure 9.1: **Distribution of disciplines for the nuclear power workforce**



Source: Peddicord, 2010.

In general, according to the IAEA (2011):

> [W]hen staffing the NPP for the operations phase, the graduate component is generally the minority part of the total workforce, with the majority of the workforce being "technician" level staff (i.e. staff that may only have high school level educational qualifications, coupled with some form of vocational skill certification and/or apprenticeship. These staff will require less "nuclear" knowledge than their graduate counterparts but will need considerable training in order to understand the quality and safety requirements of working in a nuclear environment and why nuclear is different from other engineering and industrial environments. (IAEA, 2011: p. 19)

These educational requirements can be compared with those given in the case studies in IAEA (1999). In 1996 educational levels at the Dukovany NPP in the Czech Republic were 1.1% basic education, 23.6% apprenticeship (in place of secondary education), 47.1% secondary education, and 28.2% university education. In 1996, educational levels at the Blayais NPP in France 25% had a baccalauréat (BAC), 12% had attained BAC + two years, and 4.9% had attained BAC + 4 years (where a BAC indicates the end of secondary education, but is equivalent to an "Associate Degree" in Figure 9.1, i.e. under this interpretation, 25% had an "Associate" Degree, 12% had a "Bachelor" degree, and 5% had a "Graduate" degree). At Wolsong, in Korea, "Most of the employees have university degrees (48.5%) or a junior college education (18.0%); the remainder graduated from high school" (IAEA, 1999: p. 87).

Other power generating sectors

Comparing employment effects in the nuclear industry with those in other electricity generation technologies provides some interesting insights. Since the present chapter compares employment across electricity generation technologies, it does not explicitly discuss induced employment for each generation technology given that it would be difficult to distinguish induced employment for individual electricity generation technologies. This assumption follows the examination of employment in the renewable technologies in Cameron and van der Zwaan (2015: p. 162):

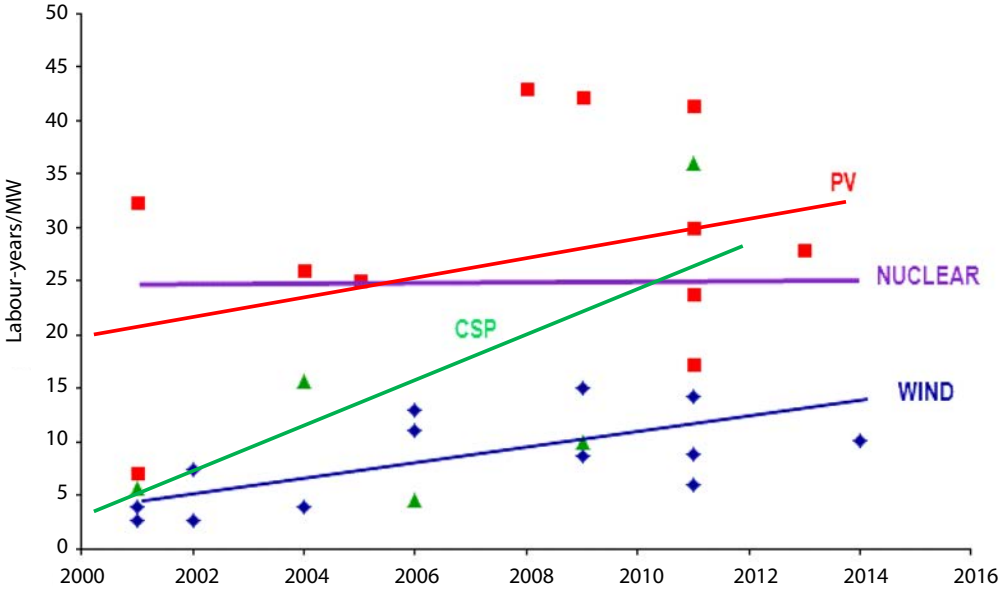
> Another major distinction between studies on employment impacts is the types of jobs they consider. By type, we refer to the "proximity" of a created job vis-à-vis a given technology in terms of how indirectly it can be attributed to a certain investment or, in our case, increase in renewable electricity generation capacity. Although studies consider different types of jobs, nearly all adopt a common language of "direct", "indirect" and "induced" jobs. The International Renewable Energy Agency (IRENA) provides not only a clear and operational definition of these terms, but also elaborates appropriately on the slight but important variations in their interpretation across studies (IRENA, 2011).
>
> *Direct jobs*. Precise definitions vary, but in general these are jobs related to core activities, such as manufacturing/fabrication, construction, site development, installation, and operation and maintenance (O&M). Direct jobs are relatively easy to measure and their absolute number unequivocally correlate to the rate of growth of renewable technologies. All studies we contemplate consider direct renewable energy job impacts.
>
> *Indirect jobs*. These are jobs related to the supply and support of the renewable energy industry at a secondary level… Only a small fraction of available studies explicitly calculate indirect jobs. Some others note that indirect effects can be expected, or explicitly estimate these effects via a simple multiplier.
>
> *Induced jobs*. These jobs arise from the economic activities of direct and indirect employees… In practice, however, induced jobs are often difficult to accurately determine, since tertiary (and quaternary) employment effects of the deployment

of renewables may be hard to isolate. For this reason, and given the paucity of literature in the domain of induced jobs, we do not include induced jobs in the present study. (Note Tourkolias and Mirasgedis, 2011, calculate induced employment "based on an input-output model for the Greek economy"; see Cameron and van der Zwaan, 2015: p. 162.)

A comparison of data used in Cameron and van der Zwaan (2015), is provided in Figures 9.2 and 9.3. Considering the distribution of the observations, one cannot reject the hypothesis that nuclear power provides more "installation/manufacturing" (construction and supply chain) labour-years than wind and concentrated solar power (CSP), and more O&M (operating) jobs/MW than wind, photovoltaic (PV) and CSP. The rejection of this hypothesis would assume that observations are independent. It, however, runs counter to the appearance of regular *increases* in both labour-years/MW and jobs/MW in renewables, during a period when the levelised cost of renewables has been reported to be *declining* (see Chapter 2). This might indicate a correlation with the evolution of the debate on the employment contribution of different technologies, i.e., as political interest has increased, greater efforts to find positive employment effects have yielded the desired results. Such correlations are, of course, an indication that further research is required on the importance of labour in the manufacturing and operating costs of renewables.

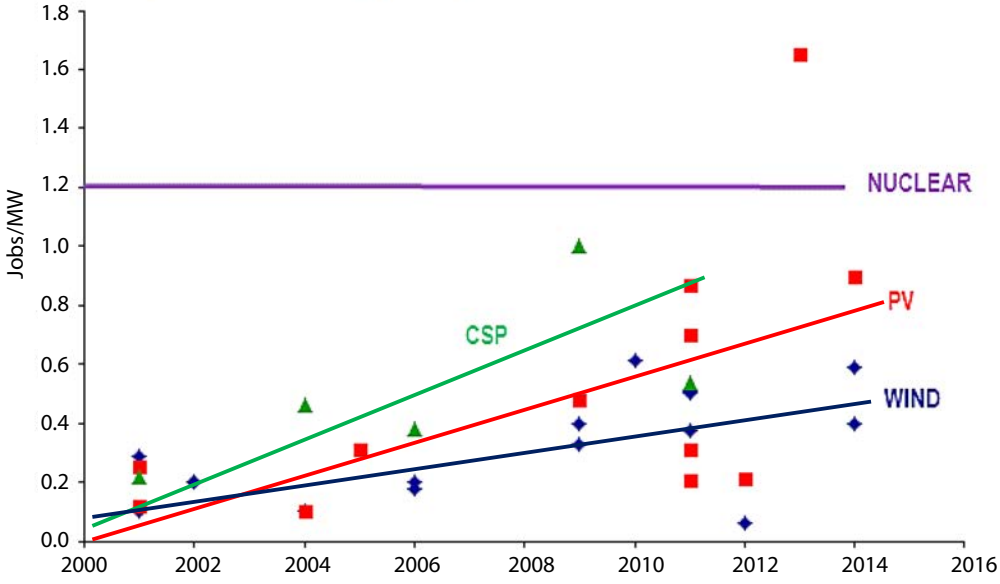
To understand how the job education requirements for NPPs compare to those for renewables, consider the jobs in Table 9.4 for a wind turbine manufacturing facility. As shown in this table, most of the positions (46% of the occupations identified) require an apprenticeship, generally available through craft unions; 31% of the positions require graduation from high school; and 23% require some form of college degree, and 7% require an engineering degree. While not comparable to the operation of NPPs (it would be comparable to a module fabrication factory for a small modular reactor (SMR), however there is little publicly available information on the organisation of an SMR factory; see EPI, 2010: p. 28), the number of engineers required to produce wind turbines is far below the number required to produce and operate nuclear reactors, although it is similar to the number of engineers required to operate a waste management facility (NEA, forthcoming: p. 79).

Figure 9.2: **Labour-years per MW in manufacturing and installation with linear trend lines**



Source: Based on Cameron and van der Zwaan, 2015.

Figure 9.3: **Comparison of direct employment factors for O&M (in jobs/MW) for onshore wind, PV and CSP by year of publication with linear trend lines**



Source: Based on Cameron and van der Zwaan, 2015.

Table 9.4: **Selected occupations at a wind turbine manufacturing company in Ohio in 2006**

Occupation	Education required	Number of employees	Average earnings (USD)	Earnings per hour (USD)	Total payroll (USD)
Clerks and janitors and labourers	High school	16	33 794	16.90	540 700
Assemblers	High school	47	34 189	17.10	1 606 900
Sales, customer service representatives	Associate	2	39 100	19.60	78 200
Machinists and operators	Apprentice	66	39 408	19.70	2 600 900
Drafters	Associate	2	39 900	20.00	79 800
Welders, cutters, solderers and brazers	Apprentice	4	39 900	20.00	159 600
Inspectors, testers, sorters and samplers	Apprentice	8	40 400	20.20	323 200
Administrative assistants	Bachelor	2	43 200	21.60	86 400
Tool makers	Apprentice	6	43 733	21.90	262 400
Maintenance and repair workers	Apprentice	4	44 100	22.10	176 400
Mechanics, electricians and technicians	Apprentice	7	48 429	24.20	339 000
Sales representatives and purchasing agents	Bachelor	5	55 840	27.90	279 200
Supervisors, accountants and auditors	Graduate	12	59 633	29.80	715 600
Engineers	Bachelor	15	71 480	35.70	1 072 200
Managers	Graduate	9	107 333	53.70	966 000
Other employees	Unknown	45	49 700	24.90	2 236 500
Total payroll (with 126 occupations)		**250**	**46 092**	**23.00**	**11 523 000**

Source: Based on National Academy of Sciences, 2010.

Regarding O&M labour at an onshore wind facility, according to PayScale (2017) www.payscale.com (updated 4 May 2017):

"Wind Turbine Technicians in the United States are largely men, earning an average of $21.17 per hour. Wind turbine technicians identify, inspect, maintain and repair wind turbines to ensure proper quality control exists. Their goal is to keep maintenance costs low and quality high."

Regarding solar energy (O&M) technicians, (Chron, 2017) http://work.chron.com/pay-scale-solar-energy-technician-19567.html.

> As of 2012, the average pay reported by solar energy technicians was $19.53 per hour and $40 620 per year. The median-earning 50 percent of solar technicians reported annual incomes ranging from $31 150 to $47 620. According to the U.S. Bureau of Labor Statistics, the lowest-paid 10 percent of solar technicians earned $12.62 or less per hour and $26 250 or less per year, while the highest-paid 10 percent made $27.88 or more an hour and reported annual incomes of $57 980 or above. (Chron, 2017)

These salaries (salaries have changed little between 2012 and 2017 in the United States) can be compared to those in the nuclear power maintenance of USD 26.25/hour or USD 52 000 per year, and nuclear power plant operators at USD 72 000 per year. Available at: www.payscale.com/research/US/Job=Nuclear_Technician/Hourly_Rate.

To compare the number of jobs estimated in Cameron and van der Zwaan (2015) to the number of jobs geographically near the electricity generating facility site, i.e. local, see Table 9.5.

Table 9.5: **Local (county) jobs in the O&M of various electricity generating technologies, ordered by average size of the electricity generating facility**

Technology	Jobs/MW	Average size (MW)	Direct local jobs
Nuclear	0.50	1 000	504
Coal	0.19	1 000	187
Hydro > 500 MW	0.11	1 375	156
Hydro pumped storage	0.10	890	85
Hydro > 20 MW	0.19	450	86
Concentrating solar power	0.47	100	47
Gas combined-cycle (CCGT)	0.05	630	34
Photovoltaic (PV)	1.06	10	11
Micro hydro < 20 MW	0.45	10	5
Wind	0.05	75	4

Source: Harker and Hirschboeck, 2010.

Regarding assumptions and sources of data in Harker and Hirschboeck (2010), Harker was director of Navigant Consulting's energy practice):

> The analysis ignored the indirect and induced jobs used in various models, because from the point of view of a local economic developer, these jobs might be transitory or outside the local area. Also ignored were taxes – for the sake of simplicity – because local taxing entities frequently provide various levels of tax

> relief for projects. In performing the analysis, actual data on various technologies were used for plant staffing and sizes from various information sources. The data were drawn from Navigant Consulting's annual staffing surveys, benchmarking services, plant staffing databases and discussions with industry experts. The first step in the analysis compared direct local permanent jobs per MW of installed capacity for each of the technologies reviewed… The data showed that various technologies produce vastly different levels of employment. Utility-scale PV facilities provide the most jobs per MW of installed capacity, because they generally require a large on-site staff to clean the solar panels and provide plant security. However, there are very few on-site skilled labour jobs for these facilities due to the fact that most PV plants acquire skilled transitory labour through long-term service agreements with original equipment manufacturers. By comparison, nuclear power is a very labour-intensive technology when it comes to permanent direct job creation. (Harker and Hirschboeck, 2010: p. 1-2)

Comparing the data in Figure 9.5 to Figures 9.2 and 9.3, nuclear power has a lower number of jobs/MW than calculated in NEA (forthcoming), 0.5 jobs/MW versus 0.6 jobs/MW (although this does not include jobs off-site at the electric utility or jobs in the operations supply chain). PV, with 1.06 jobs/MW, is higher than what Cameron and van der Zwaan (2015) found in the literature. CSP, with 0.47 jobs/MW, is in the middle of the observed distribution in Cameron and van der Zwaan. However, wind, with 0.05 jobs/MW, is lower than in all the literature reviewed in Cameron and van der Zwaan (2015). The assumption that most of the jobs in wind are not local is reinforced by the finding that there are fewer local maintenance and security jobs in wind than in solar; to be compared with the estimate of 0.06 jobs/MW for wind in Steinberg, Porro and Goldberg, 2012). Therefore, more research is required to determine the number of O&M jobs in onshore wind. However, as pointed out by Cameron and van der Zwaan (2015):

> Although there is generally broad agreement that renewables induce net job creation in comparison to the same capacity of fossil fuel based electricity generation, based on the limited number of studies that investigate and compare the employment impacts of renewables versus those of traditional methods of power production the case for net job creation is arguably not certain. The large range of renewable technology employment factors observed across different studies confirms this uncertainty. We have not been able to identify a rigorous comparison of the employment effects of renewable technologies and those of thermal power generation, let alone one that uses a common and transparent methodology for determining job impacts across distinct technologies. Even the most advanced models are susceptible to being swayed by assumptions. For instance, the detailed input-output model developed by the German government [BMU, 2011] predicts net job creation for most scenarios, but requires export of renewable technologies to achieve net job creation This requirement favours renewable energy (at least compared to other national contexts where exports may not play a role) since for conventional technologies no exports are assumed. (Cameron and van der Zwaan, 2015: p. 164)

Further, Harker and Hirschboeck (2010) provide jobs/MW values for fossil fuel technologies, i.e. coal and combined-cycle gas turbines (CCGT), with, respectively, 0.19 jobs/MW (compare to 0.18 jobs/MW in Singh and Fehrs, 2011: p. 26) and 0.05 jobs/MW (compare to 0.07 jobs/MW for 15 natural gas-fired plants in Heavner and Churchill, 2002: p. 14). Further, unlike Cameron and van der Zwaan (2015), Harker and Hirschboeck (2010) provide the average size of the various technologies and the local direct employment, ranging from 504 jobs at 1 000 MW nuclear units to 10 jobs for PV with an average facility size of 10 MW. Size of facility gives a sense of levels of employment, not simply rates of employment per MW.

9.3. Summary and key issues for policy makers

This chapter has reviewed estimates of employment at NPPs (in NEA, forthcoming), at renewable electricity generation facilities (Cameron and van der Zwaan reviewed estimates in 70 studies), and at fossil fuel electricity generating facilities (in Harker and Hirschboeck, 2010). It found that nuclear power is more labour-intensive than all other forms of electricity generation and has higher education requirements than renewable electricity generators. Regarding educational requirements in electricity generation, there is little discussion of this outside the nuclear power sector where the discussion is prompted by near-term retirements of nuclear sector employees and the necessity of training staff for nuclear new build. From the available evidence, educational requirements (as well as salaries) appear to be higher in the NPP construction and operating sectors, but perhaps not as high in the decommissioning and waste management sectors as in onshore wind, and in both PV and CSP solar.

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Chapter 10. The impact of energy innovation on economic performance and growth

10.1. Introduction

The energy system is deeply embedded with myriads of complex connections in the macroeconomy. The use of energy is so pervasive throughout the economy that major transformations in society and economic performance have been driven by waves of innovation in energy supply and use. In the present context, it is of primary importance for policy makers to anticipate how the low-carbon energy transition will impact the economy, and whether it will help or hinder macroeconomic development. This chapter is therefore of a somewhat wider nature than the others. It was nevertheless considered important to include it here so as to allow policy makers to understand the broader economic impacts of energy policy, beyond cost factors coming first in mind.

Innovation, in general as a driver for economic activity, is a recurrent theme. Investment in low-carbon energy production, and energy efficiency improvements in particular, have potentially important macroeconomic implications through, *inter alia*, their impacts on growth, jobs, competitiveness, economic resilience by increased security of supply… In this context, technological energy innovation plays a crucial role in determining the future changes in the energy supply mix, energy efficiency and demand-side management of energy consumption. Innovation is perceived as a key enabler for the transition to low-carbon energy systems, illustrated, for example, through the launch of the Mission Innovation initiative announced in November 2015, as world leaders were coming together in Paris for the COP21.[1] Innovation that curbs or eliminates emissions with harmful effects on human health and climate, by promoting clean ways of energy production and use, as well as energy efficiency, support the decoupling of economic growth from damages to the environment and hence relax an important long-term constraint on growth.

Determining how and how much growth can be influenced by technology innovation in energy systems, on both the supply and the demand sides, remains an open question. Modelling needs to be improved and enlarged, to provide policy makers with tools allowing them to take informed decisions on energy investment strategies that best promote global growth and competitiveness in a sustainable future.

Innovation needs to be understood here in a broad sense, wider than the narrowly defined energy-related research, development and demonstration (RD&D) process, covering also the uptake of the outcomes of RD&D up to their effective large-scale market

1. Mission Innovation (http://mission-innovation.net) is an initiative of 22 countries and the European Union to "dramatically accelerate global clean energy innovation". As part of the initiative, participating countries have committed to "double" their government's clean energy research and development (R&D) investments over five years, while encouraging greater levels of private-sector investment in transformative clean energy technologies. These additional resources will dramatically accelerate the availability of the advanced technologies that will define a future global energy mix that is clean, affordable and reliable.

deployment and the resulting expected broader benefits for the economy. While there are consolidated sources of information on RD&D budgets provided by the public sector, usually focusing on the lower technology readiness levels, the evaluation of the costs and returns of the market deployment, in economic terms, are more difficult to evaluate because of the multiple ways innovation is financed at higher technological readiness levels and contributes to economic performance and growth.

This chapter is providing a first glimpse of the interactions between energy-related RD&D, the full innovation chain and global wealth. A better understanding of these interactions would indeed help target limited public financing for energy research in the most effective way, and foster the private sector to engage more in innovation, helping best technologies to reach the market in an accelerated way, in time to meet the carbon reduction goals agreed at the COP21 meeting.

10.2. State of research, main studies and selected quantitative estimates

Traditional approach to measure economic contributions

The traditional approach in measuring the contribution of sectors to the economy is by compiling the value added and the employment in firms operating in these sectors. This avoids double counting when applied systematically across all sectors. But this way of measuring the contribution of one sector, here the energy sector, ignores its value added associated with upstream and downstream linkages, since counted as value added of other sectors. This is particularly true for indirect and dynamic innovation spillovers transcending the sectors' barriers.

Table 10.1: **List of studies on the relationship between energy and growth**

Energy-growth causality				
Kraft and Kraft (1978)	United States	1947-1974	Causality runs from growth to energy consumption	Method employed: Granger causality test
Yu and Hwang (1984)	United States	1947-1979	No causality	Method employed: Sim's test
Oh and Lee (2004)	Korea	1970-1999	Causality runs from energy consumption to growth	Method employed: Granger test and Error Correction Model
Wolde-Rufael (2004)	Shanghai	1952-1999	Causality runs from energy consumption to growth	Method employed: Toda-Yamamoto causality test
Soytas and Sari (2009)	Turkey	1960-2000	No causality	Method employed: Toda-Yamamoto causality test
Yang (2000)	Chinese Taipei	1954-1997	Bidirectional causality	Method employed: Granger causality-VAR
Tsani (2010)	Greece	1960-2006	Unidirectional causality from aggregate energy consumption to output	Method employed: Toda-Yamamoto causality test
Menegaki (2011)	27 EU countries	1997-2007	No causality	Method employed: Panel causality test and one-way random effect model
Menegaki and Oztruk (2013)	26 EU countries	1975-2009	Causality runs from energy consumption (fossil) to growth	Method employed: Dynamic error correction model
Ukan et al. (2014)	15 EU countries	1990-2011	Causality runs from non-renewable energy consumption to economic growth	Method employed: Panel integration test

Source: EC, 2016a.

The energy production and energy efficiency sectors generate a demand for the sectors producing the necessary equipment, sustaining value added and employment in these sectors (which may be localised in other countries). Similarly, a reliable and competitively priced energy supply, as well as gains in energy efficiency, support the competitiveness of energy users. Both these added values are not counted in the statistics of the energy sector, but in upstream and downstream sectors.

A number of studies have tried to demonstrate and establish the nexus between energy and growth. A list is given in Table 10.1. It seems that no definite finding is emerging, which may be due to the different econometric techniques used, the specificities of the countries studied, and diverse time periods. Nevertheless, one can observe that a majority of studies point towards some form of causality between energy and growth.

Looking at trade balances

Beyond these traditional ways of looking at the impact of energy on growth, evaluating more specifically the global economic effects and spillovers of innovation in the energy sector, in the broad sense from RD&D up to market uptake and deployment of clean technologies, is a further endeavour which still needs to be done. Some insight could be provided by looking for instance at trade balances in energy sectors where support for innovation has been a driver in the recent boost in market deployment. As an example, the substitution of fossil fuels by renewables and the corresponding global market for renewable power equipment offer opportunities, but also risks, for national or regional trade balances. In the case of the European Union (EU), for instance, there is a trade deficit with China in solar components, China being the largest producer of solar panels with 65% of the global production, 90% of exports of which 80% serve the EU market. Counting the trade benefit coming from export of solar equipment to non-EU countries, such as Japan and the United States, the resulting trade deficit for the EU has been EUR 21 billion in 2010, falling to 9 billion in 2012. Unlike trade in solar components, the EU has a sustained trade surplus in components for wind power, amounting to EUR 2.5 billion in 2012.

At global EU level, the impact on the trade balance, based on this example, has been therefore rather limited. One could therefore look more closely for one country where renewable energy innovation policy was particularly strong. The case of Germany is interesting: looking at the trade balance for solar and wind components in 2012, the trade deficit for solar equipment just balanced the trade surplus for wind components: EUR 1.9 billion. So, there also, the impact has been rather marginal. These being just selected examples, such analysis should be performed for all clean technologies, including nuclear and energy efficiency, and at worldwide level, by region and by country.

Impacts on employment

There have been also a number of studies over the past decades that have identified an effect of energy efficiency and low-carbon technological improvement and investment on employment. In the majority of these studies, the net employment effects are positive. Nevertheless it is very hard to try a comparison between the respective effects of the diverse sources of electricity production and energy efficiency, because studies are relying on scenarios, with different specific underlying assumptions.

As an example, one may refer to a recent study led by Pollitt *et al.* (2015) for the DG Climate Action of the EC that is cited in Stone (2015). The study analyses the effects of three energy scenarios on global employment in the European Union. In the baseline scenario (business-as-usual, BAU) including only measures already adopted), the model predicted a sevenfold increase in carbon price and a loss of 2 million jobs between 2020 and 2030, linked to the associated decline of working-age populations after 2020. In a first decarbonisation scenario (meeting the 40% emissions reduction in 2030), carbon price

increases eightfold and 680 000 jobs are saved compared to the BAU. In a second decarbonisation scenario (with additional strict energy efficiency measures and a 30% energy consumption coming from renewables), the carbon price only doubles and 1.2 million jobs are saved compared to the BAU. It must be noted that the results are sensitive to the way the carbon revenues are returned to the consumers, either as direct payments or by using the revenues to offset income taxes. Offsetting labour taxes leads to better results in terms of saved jobs for Scenario 1 compared to Scenario 2. The study concludes that taking more aggressive renewable and energy efficiency policies (the impact of nuclear is not central in the study) would positively influence employment by creating opportunities for expanded and economically more attractive investments.

Another example, focusing on nuclear energy, can be found in a paper presented in 2013 at the European Nuclear Energy Forum (ENEF) plenary meeting, on the socio-economic benefits for the European Union also, of nuclear energy towards 2050. The study is based on scenarios developed by the European Commission for its Energy Roadmap 2050 communication (Greenpeace, 2011). The so-called "diversified" energy scenario, simulating a balanced mix of electricity production, leads to around 100 GW_e nuclear generating capacity in operation in the EU in 2050. This is close to what is today in operation. Because the large majority of the existing nuclear plants will be shut down by that time, even assuming-long-term operation, the bulk of the contribution of additional "nuclear related activities" in terms of jobs will mainly come from lifetime extension programmes, new built, and decommissioning. These jobs will be supplementary to the "normal operation and maintenance" activities, which will be roughly stable over time if indeed the total capacity is more or less constant. The ENEF paper (2013), extrapolating to the EU members of a PWC study for France, estimates that the direct jobs created are on average, for the given scenario, of the order of 50 000 over the period 2012-2050, with peaks near 100 000 during the times of high new built activities (2030-2040). Looking at the total number of jobs (direct, indirect and induced), the numbers are roughly multiplied by three, around 150 000 on average over the full period, and 350 000 for the peak activities. As mentioned, these are additional jobs over and above the "baseload" of employment within the nuclear industry in Europe, for the "normal operation and maintenance" of the fleet: 250 000 direct jobs and 800 000 total jobs, according to ENEF.

Beyond direct effects on labour in the energy sector per se, as analysed above, low-carbon energy and energy efficiency investment may further support wider employment: if investment reduces the overall energy costs, it improves the competitiveness of industry and reduces the households budget for energy, freeing money to be recycled in the economy, in turn, leading to further increases in employment.

R&D budgets, energy consumption and growth

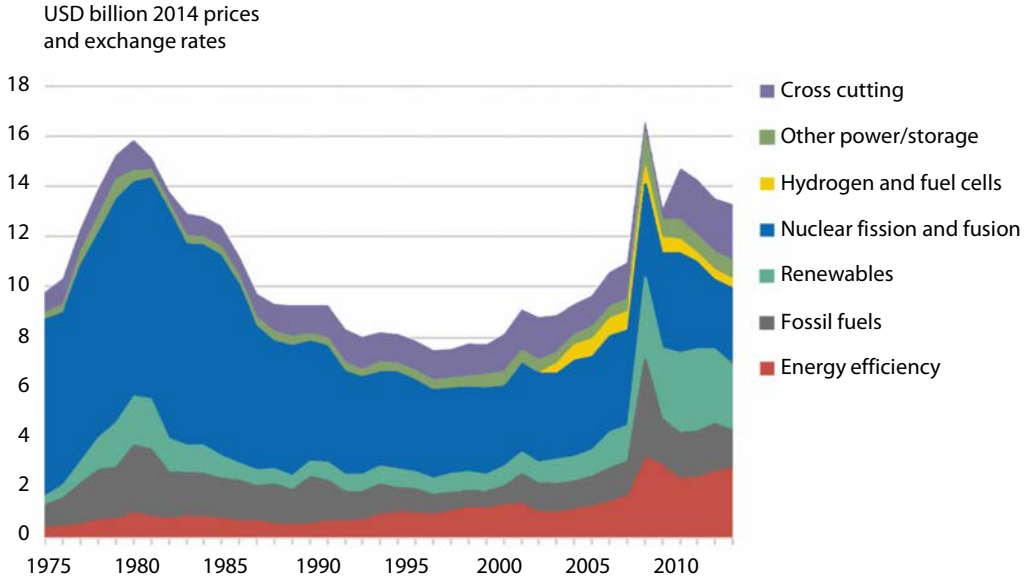
Focusing on the specific aspect of the support given to technology developments which are not yet mature, in the form of a stimulus for innovation before the deployment phase, one could have a look at some figures of past energy-related RD&D budgets and to the perspectives for the future trend, and see if and how it may correlate with energy consumption, energy intensity and global growth.

For the past, consolidated figures may be found from the annual survey of the International Energy Agency (IEA) member countries on publicly financed energy RD&D budgets. In Figure 10.1, showing the evolution of budgets for the diverse sources of energy and energy efficiency, recalculated in 2014 US dollars, one observes: i) a sharp increase in budgets for the first years following 1975, as a reaction to the first oil crisis, peaking in 1980; then ii) a downward trend until 2000; followed by iii) an increase again, reflecting most new concerns, in particular about climate issues, leading to increased efforts in RD&D in renewable energies and energy efficiency. Since 2000, public RD&D budgets for renewables have been multiplied by about five, and for energy efficiency by about two. A sharp peaking point can be observed in 2009, coming mainly from the

United States input data for that year. For nuclear energy, which in the graph integrates RD&D for both fission and fusion, there has been a continued decrease over time from about USD 8 billion per year in 1980, largely for fission, to less than 3 billion today, with fusion now taking comparatively a bigger part.

Figure 10.1: **Energy R&D public expenditures over time in Europe**

(Prices and exchange rates in 2014 billion US dollars)



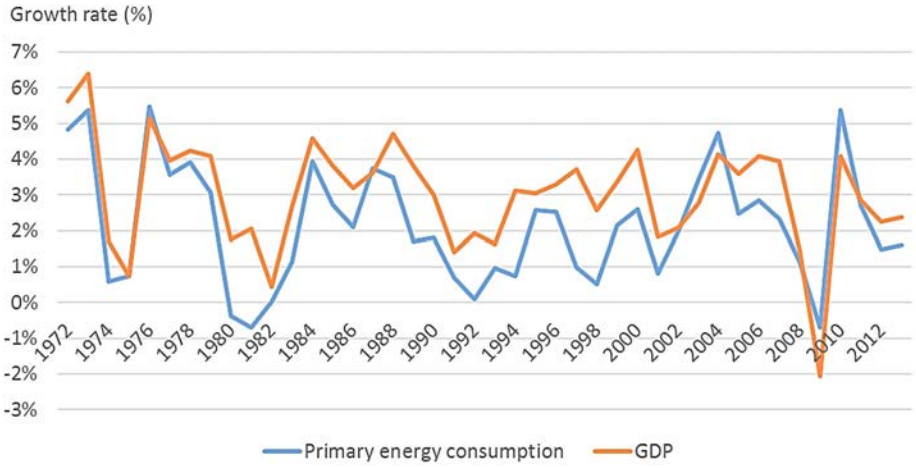
Source: EC, 2016a.

These past contributions by the public sector of IEA member countries for energy RD&D may be put in the perspective of the trends in world gross domestic product (GDP) and primary energy consumption, shown in Figure 10.2.

During the past five decades, there has been a close relation between the evolution of the growth rate of GDP and that one of primary energy consumption. The latter is most of the time slightly lower than the first, reflecting a continued improvement (meaning reduction) in energy intensity and structural changes in the economy. Energy RD&D-driven innovation certainly influences these factors, but, from the curves above in Figure 10.2, one cannot, at first glance, find a link between the evolution of public budgets for energy RD&D on one side and the evolution of GDP on the other side: the global GDP has most of the time been positive, while the RD&D budgets were strongly decreasing between 1980 and 2000, then increasing in the last 15 years.

It would be useful to perform a more refined analysis, separating the two time periods, and considering the same geographical coverage for RD&D budgets and GDP. Indeed, if during the period 1980-2000 most of energy RD&D was performed in IEA countries, since 2000 a number of non-OECD countries, in particular in Asia, have scaled up their contribution. Also, the focus of the research portfolio has strongly evolved between the two periods, with, for IEA countries, a central focus on nuclear in the first period with an average GDP growth rate above 2%, and a more balanced approach between RD&D on nuclear, renewables and energy efficiency, and an average GDP growth rate closer to 1% over the second period.

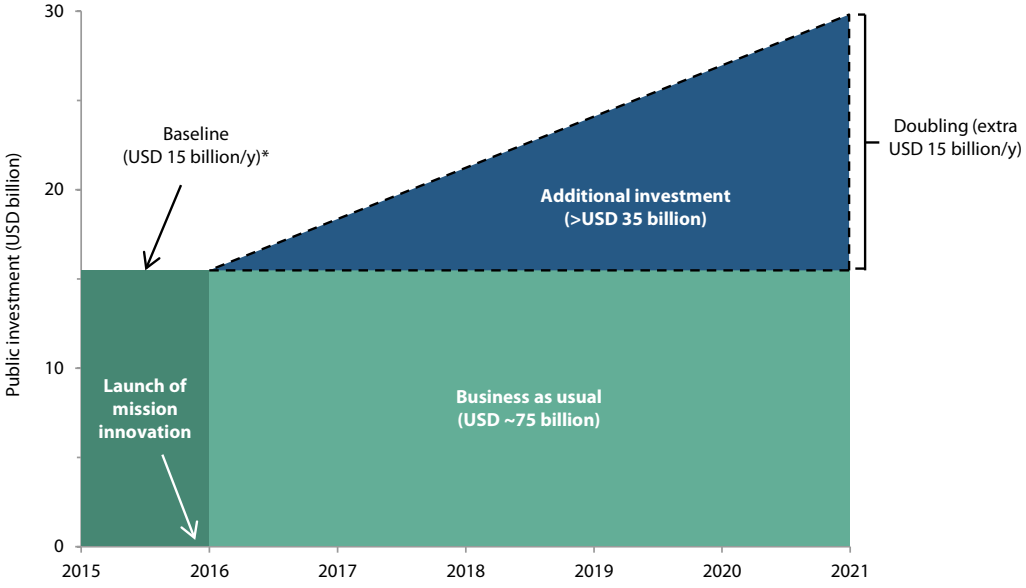
Figure 10.2: **Growth in energy consumption and GDP over time**



Source: EC, 2016a.

Statistics for recent years suggest, for developed countries, a decoupling between primary energy consumption and GDP, thanks to the investments in energy efficiency, decreasing energy intensity. This trend, which is not true for developing countries, remains nevertheless to be verified over a more extended period of time. In addition, as mentioned in Stern (2004), when considering a global perspective – the only one that matters for issues such as climate change – one has to consider the transfer of energy-intensive manufacturing processes from developed to developing countries, shifting energy consumption to these countries, while the final products are still used and accounted for in developed countries. On a global scale, there may be limits to the extent to which developing countries can replicate the structural shift that has occurred in the developed economies. And therefore what needs to be done is to globally shift towards (very) low-carbon energies and energy efficiency.

Figure 10.3: **Clean energy R&D investment chart for Mission Innovation**



* MI baseline of USD 15 billion per year in clean energy R&D is compiled from reports of 21 Mission Innovation members.

Source: Mission Innovation.

For the future trends in public funded energy RD&D, one could look at the commitment taken by 22 countries, and the EU, under the Mission Innovation during the preparation of COP21, to double their efforts by 2020. Table 10.2 and associated Figure 10.3 provide the baseline yearly spending declared in 2016, and the global trend towards 2020. This information is extracted from the website of Mission Innovation (http://mission-innovation.net).

Table 10.2: **Summary of the financial commitments for public funding for energy R&D under Mission Innovation**

Country	Baseline amount declared in June 2016, unless otherwise noted	
	(million currency as declared, per year)	(million USD per year[1])
Australia[2]	AUD 108	81
Brazil	BRL 600	150
Canada	CAD 387	295
Chile	USD 41 856	4
China	RMB 25 000	3 800
Denmark	DKK 292	45
European Union	EUR 989	1 111
Finland	EUR 54.9	58
France	EUR 440	494
Germany	EUR 450	506
India	INR 4 700	72
Indonesia	USD 16.7	17
Italy	EUR 222.6	250
Japan	JPY 45 000	410
Mexico	USD 20.71	21
Netherlands	EUR 100	113
Norway	NOK 1 132	140
Korea	USD 490	490
Saudi Arabia	SAR 281.3	75
Sweden	SEK 134	17
United Arab Emirates	USD 10	10
United Kingdom	GBP 200	290
United States[2]	USD 6 415	6 415
Total		**14 864**

1. Currency conversions are based on exchange rates when the baseline amounts were submitted, between November 2015 and June 2017.

2. Australia updated its baseline amount from AUD 104 million, as reported in June 2016, to AUD 108 million in June 2017.

3. The United States is currently reviewing the funding levels for its Mission Innovation activities.

While most countries have pledged for the doubling of the baseline, a few have indicated that they will go beyond the doubling commitment. This is notably the case for Indonesia pledging an increase from USD 17 million in 2016 to USD 150 million in 2020. The Netherlands indicated a prospect of spending EUR 237 million per year for the period 2016-2020, more than doubling the EUR 100 million of 2015.

Table 10.3 provides an overall perspective on which energy R&D area the Mission Innovation participating countries have decided to put the emphasis.

Table 10.3: **Summary of priority areas for energy R&D under Mission Innovation**

	AUS	BRA	CAN	CHL	CHN	DNK	EU	FIN	FRA	DEU	IND	IDN	ITA	JPN	SAU	MEX	NLD	NOR	KOR	SWE	ARE	GBR	USA
Industry and building	●	●	●	●	●	●	●		●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Vehicles and other transportation	●	●	●	●	●	●	●	●	●	●	●	●		●	●	●		●	●	●	●		●
Bio-based fuels and energy	●	●	●			●	●	●	●	●	●	●	●			●	●	●	●	●	●	●	●
Solar, wind and other renewables	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Nuclear energy	●	●	●		●											●			●		●	●	●
Hydrogen and fuel cells	●	●	●		●	●	●	●	●	●	●			●	●	●	●	●	●			●	●
Cleaner fossil energy		●	●		●	●		●		●	●	●			●		●		●				●
CO_2 capture, utilisation and storage	●	●	●		●	●	●		●	●	●	●		●	●	●	●	●	●		●	●	●
Electricity grid	●	●	●	●	●	●	●	●	●	●	●	●	●	●		●	●	●	●	●	●	●	●
Energy storage	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Basic energy research	●		●			●	●		●	●	●	●	●	●	●		●	●		●	●		●

Indicators are for key areas of R&D investment, but do not imply a comprehensive representation of a country's full R&D portfolio.

Source: Mission Innovation.

Global R&D funding

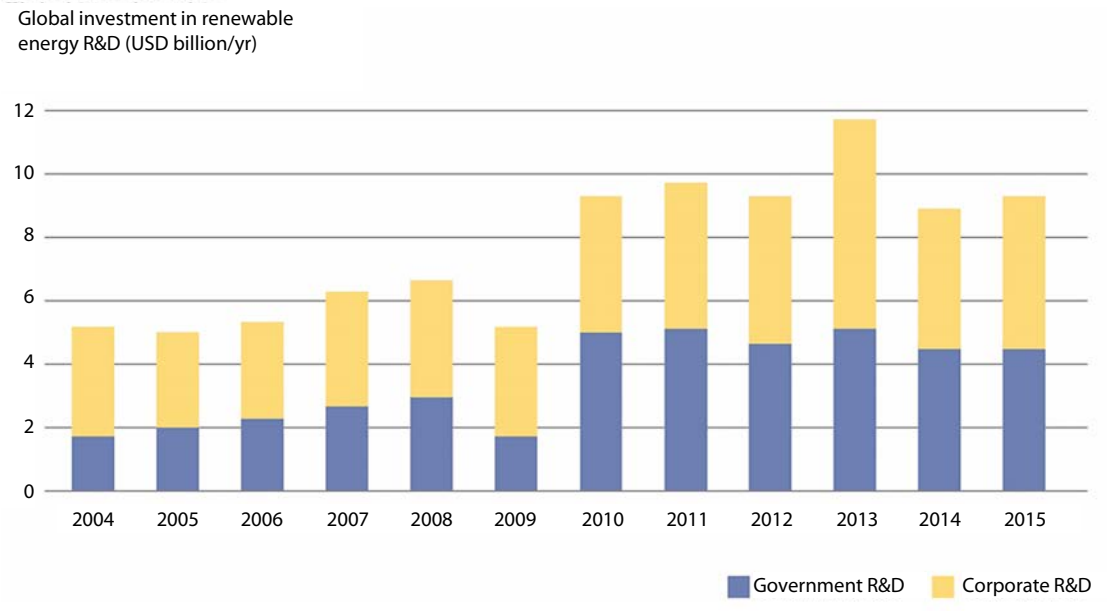
Going beyond publicly funded RD&D is necessary if one wants to picture the cost of the full innovation process – covering also privately financed RD&D, but also market creation and deployment. A first, even if incomplete, Global Energy Assessment launched in 2012, co-ordinated by the International Institute for Applied Systems Analysis (IIASA), of the entire global resource mobilisation, in both energy supply- and demand-side technologies and across different innovation stages, suggests: i) current RD&D investments of some USD 50 billion; ii) market formation investment, mainly relying on directed public policy support, of some USD 150 billion; and iii) an estimated USD 1 to 5 trillion investments in mature energy supply and end-use technologies diffusion.

Major developing economies, first of all China, but also India and Brazil, have become significant players in global energy technology RD&D, with public- and private-sector investments approaching USD 20 billion, almost half the total estimated above. This is significantly above the IEA countries public-sector energy RD&D data, totalling USD 13 billion on average per year over the recent years. There are important data and information gaps for all stages of energy technology innovation investments outside public-sector R&D funding in IEA countries, particularly in the areas of recent technology-specific private-sector R&D and non-IEA R&D expenditures, and of investments in energy end-use diffusion.

The IRENA platform (2017), grouping more than 50 countries engaged in renewable energy R&D, has collected data on the R&D spending on renewable energy for the period 2004-2015, both from government and corporate funding. As it can be seen in Figure 10.4, a spike occurred in 2010, but since then the figure is stable. The public funding figure is rather consistent with the IEA data.

Figure 10.4: **Global investment in renewable energy R&D over time**

(in USD billion per year)



Source: IRENA, 2017 on the basis of figures provided by the desktop database of Bloomberg New Energy Finance.

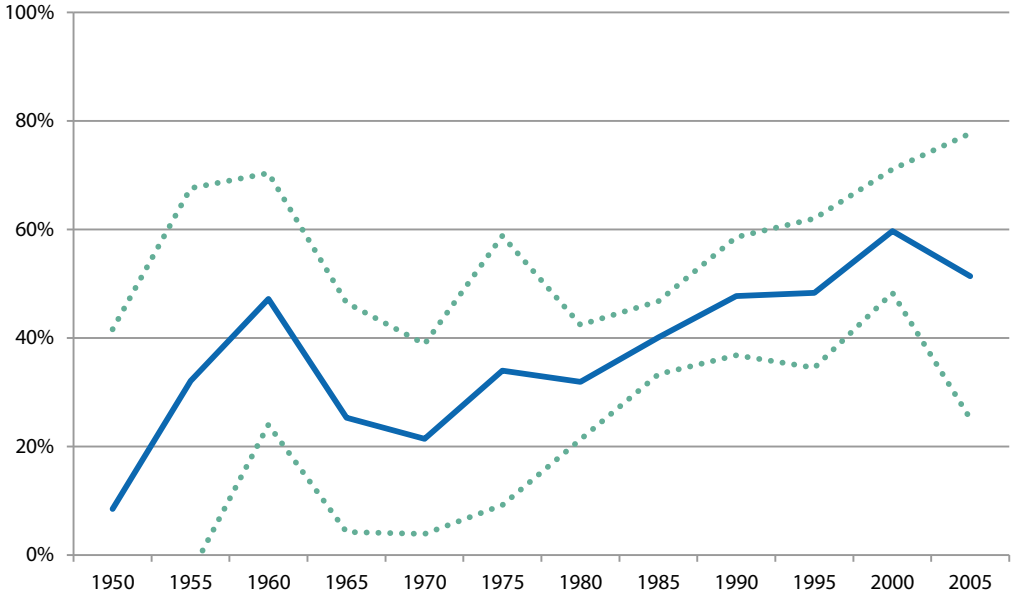
Analysis of investment flows for the different stages of the innovation process reveals a mismatch of resource allocations and needs. Early in the innovation process, public RD&D expenditure is heavily weighted towards large-scale supply-side technologies. Out of the above-mentioned USD 50 billion, less than 10 billion is allocated to end-use technologies and energy efficiency. Later in the innovation process, annual market diffusion investment on the supply side totals roughly USD 0.8 trillion, compared with 1 to 4 trillion on the demand side. These relative proportions are, however, insufficiently reflected in the incentives to invest in the market deployment of technologies, focusing almost exclusively on supply-side options, to the detriment of energy end-use in general and energy efficiency in particular, foregoing associated employment and economic growth stimuli effects.

A recent study (CEP, 2014) tries to analyse if financing in R&D is justified in terms of spillovers to the economy. The study looks in particular at innovation support in "clean" versus "dirty" technologies for electricity production (renewables versus fossil fuels) and transportation sectors. The first one is directly of interest for us, even if the second also has a direct implication on the reduction of greenhouse gas (GHGs). Looking at the number of citations received for "clean" patented inventions in the electricity sector, compared to "dirty" ones, the study finds a gap of nearly 50%, and this gap has been increasing constantly during the past 50 years, as it can be seen in Figure 10.5. This shows a clear evidence of larger spillovers for clean technologies.

Knowledge spillovers from clean technologies appear comparable in scope to those in the information technology (IT) sector, which is considered a driver behind the so-called third industrial revolution. When comparing "clean", "dirty" and "emerging" technologies (IT, nanotechnologies, robotics, 3D, etc.) with all other inventions patented in the economy, there is a clear ranking in terms of knowledge spillovers: "dirty" technologies are lower than the average invention, with "clean" and "emerging" ones exhibiting larger knowledge spillovers. Nevertheless, "emerging" technologies show larger knowledge spillovers over the average invention than "clean" ones. These differences can be

explained by a combination of level of novelty and visibility for the end-users: while IT tools and renewables can both be considered as novelties, the novelty of the first is much more visible for the end-users in their daily life than ways to produce electricity.

Figure 10.5: **The gap in knowledge spillovers between "clean" and "dirty" technologies for electricity production**



Blue curve = gap. Green dotted lines = confidence interval 95%.

Source: Dechezleprêtre, Martin and Mohnen, in CEP, 2014, http://cep.lse.ac.uk/pubs/download/dp1300.pdf.

10.3. Methodological issues, limitations and uncertainties

Few systematic data are available for private-sector innovation and related investments. Information is patchy on innovation spillovers or transfers between technologies, sectors, countries. The pace of depreciation of knowledge generated by innovation investments is also not clearly understood.

Modelling

Analysis carried out to assess the potential cross-sectoral and economy-wide impacts of policies designed to promote a sustainable, secure and competitive energy future typically involves quantitative models using economy-wide macro-sectoral tools. A key lesson is that conclusions about the scale and even sometimes the direction of the economic impacts of policies that encourage the uptake of low-carbon technologies and practices differ considerably across different models, because of their diverse theoretical underpinnings, assumptions, and the corresponding modelling.

In the case of equilibrium models with crowding out, an investment-intensive energy transition would displace resources that would have been used more productively elsewhere in the economy, leading to a suboptimal equilibrium at lower GDP in the short run. In the long run, however, GDP recovers thanks to learning-by-doing, an easing of resource displacement and lower expenses on imported fossil fuels (EC, 2016a and 2016b).

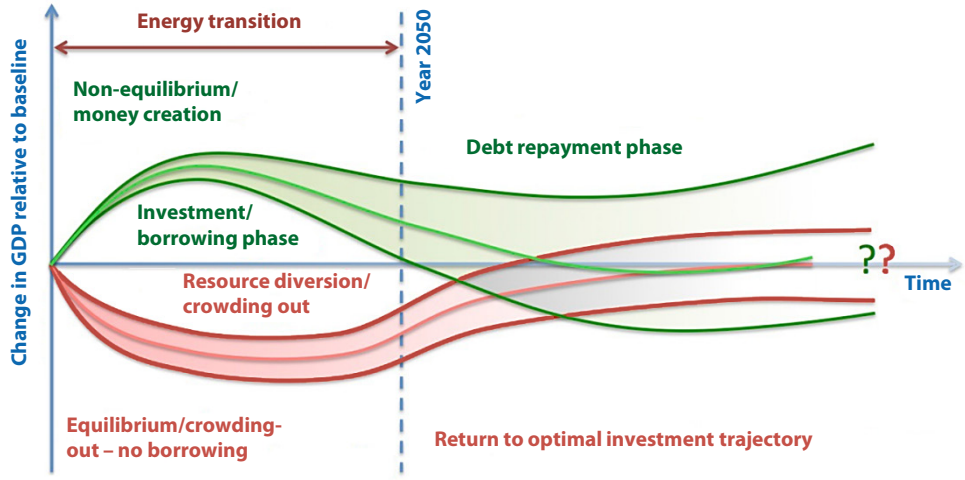
In the case of non-equilibrium models, an investment-intensive energy transition programme results in creating additional employment and boosting GDP in the short to medium run, but a possible reduction in macroeconomic gains or even decline in the long run, depending on debt servicing conditions. This is due to money being created in the early phase, which funds construction and results in activity across the economy, but also increases the debt burden, which remains in the longer term. Once the transition ends, spending declines but debt repayments remain, reducing income again, unless a new impetus is given to the economy and debts are refinanced. Long-lasting productivity increases may remain in the long term, following cumulative investments in new technology and equipment. In the short run, if decarbonisation is carried out faster than capital turnover rates allow, an additional cost is incurred related to scrapping capital earlier than it is able to pay for itself, a cost that can be higher than the income generated by job creation (Ibid.)

This explains, in a simple way, how models exhibit essentially opposite outcomes for the economics of a transition to sustainability. Uncertainty also behaves differently: in equilibrium, uncertainty with solutions is linearly related to the uncertainty in parameters. In non-equilibrium models, uncertainty on parameters leads to scenarios that diverge from each other, such that model outcomes in the far future are much more uncertain than those in the near future.

This is conceptually illustrated in Figure 10.6. It shows the trend in GDP, relative to baseline, of a policy-driven sustainability transition for two types of modelling approaches, equilibrium and non-equilibrium. In this illustration, the low-carbon energy transition is financed, either self-financed or via borrowing, from time zero until the vertical dashed line (here set in 2050), after which the low-carbon finance stops. Upper and lower boundary lines display uncertainty ranges.

It is therefore necessary: i) to provide an exhaustive account of the theoretical origins of the differences in outcomes between models with regards to innovation – how energy innovation, technological change and its financing are represented in theories and models, and what are the implications; ii) to identify missing knowledge on the drivers and barriers to innovation: what constrains the pace of technological change and innovation; and iii) to identify the key gaps in the existing models.

Figure 10.6: **Illustration of trends in GDP associated with the financing of a low-carbon energy transition, for two different economic models**



Source: EC, 2016b.

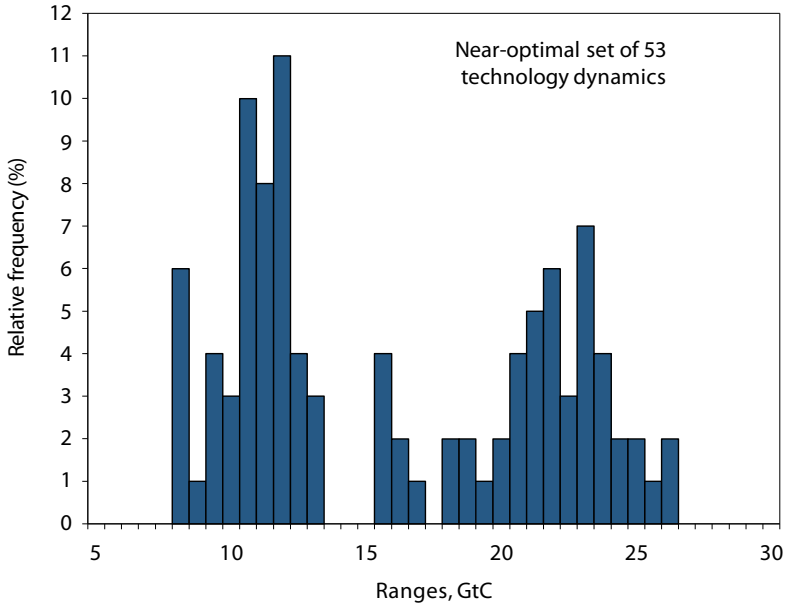
Some results

Several reviews on how energy-related innovation is handled in macroeconomic models have been performed. These reviews reveal a number of shortcomings, as implementation phases are not well covered by existing models. In particular, they do not link to the extensive field of the Energy Technology Innovation System (ETIS), and do not fully touch upon how innovation is financed, adopted and diffused. Technology push and market pull policies need to be properly modelled because it is the proper combination at both ends of the innovation chain which offers the best prospect of accelerating the pace of innovation.

As already mentioned by Grubb (2005), most global energy system models have modelled technology change as an exogenous assumption, with future technology costs simply entered by the modeller, not being affected by the abatement or carbon price assumptions in different control scenarios. This is equivalent to a technology supply-push and contrasts with the accumulating evidence around market-based technology learning. Indeed, innovation is the product of a complex system in which feedbacks from the different stages of the innovation chain and the ability to learn from market experiences are crucial.

Figure 10.7 from Grubb (2005) shows the relative frequency distribution of projected global carbon emissions in 2100 for 53 scenarios developed at the International Institute for System Analysis (IIASA) in which total discounted energy system costs were within 1% of the minimum, derived from a model with learning-by-doing (see also Gritsevsky and Nakicenovic, 2002).

Figure 10.7: **Frequency distribution of global CO_2 emissions in 2100 for 53 least-cost scenarios (within 1% difference) of IIASA**



Source: Grubb, 2005.

According to Figure 10.7, some futures embody learning on a high-carbon energy system, others on a low carbon one, but it cannot be assumed *a priori* that one or the other will be globally cheaper or more expensive, even if fundamentally different in terms of technologies, system, resources and impacts on the environment.

Equivalent results were obtained, in a different format, by Papanathsiou and Anderson (2002) in Grubb (2005), who produced a probability density of net costs of renewable-intensive futures, and found these to be widely distributed about the zero point. In other words, given learning-by-doing at uncertain rates, renewable-intensive futures may be either cheaper or more expensive than carbon-intensive futures, depending on the choice of learning parameters.

Taking note of this, it is interesting to flag that all the European Union energy scenarios used to support the European Commission Energy Roadmap (EC, 2011b) – reference case BAU, high energy-efficiency case, diversified energy mix case, high renewables case, high-carbon capture and storage CCS/low nuclear case, high nuclear/low CCS case – are roughly equivalent in terms of global cost for society: requiring around EUR 1.8 trillion per year in 2011-2020, around EUR 2.45 trillion per year in 2021-2030 and around EUR 3 trillion per year in 2031-2050.

A high-level policy implication is that, even considering all uncertainties associated with assumptions and modelling, the energy mix of the future will require major investments. But also that the decarbonisation path would not be over-expensive compared to the business-as-usual reliance on carbon. And therefore the need for research and studies to improve modelling and reduce uncertainties should not be an argument to delay action on moving proactively towards the energy decarbonisation route, relying on and promoting all low-carbon energy sources, and reflecting on their proper mix, from an energy system perspective. An optimal mix is probably an unreachable grail, but a proper balance of environment protection, economics and reliability of energy supply, would help make sustainable choices.

10.4. Perspective for internalisation

Because the use of energy is pervasive throughout the economy, policies seeking to influence energy demand and the mix of fuels have widespread impacts. These impacts are not limited to headline figures of GDP, but include long-ranging effects and consequences on public budgets, the labour market, wider social indicators, health, environment and the competitiveness of the private sector. Models are needed to integrate all these effects, as a way to internalise them and to provide an insight into trade-offs and complementarities that exist between policy objectives in different domains.

But the approach to internalisation will depend on the model used to evaluate the impact of innovation on the global economy. In equilibrium models, reducing GHG emissions or pollution is always costly as long as the externality has not been internalised in the decisions of economic actors. In non-equilibrium models, policy intervention influences the economic development trajectory. The difference between the two has often been framed as a difference over the extent to which low-carbon investments, promoted by policy intervention, are understood to have an effect of "crowding out" other investments that would have otherwise taken place. Equilibrium model assumes finite resources with low-carbon investments displacing financial resources from other uses leading to an opportunity cost, while non-equilibrium models do not, assuming resource constraints do not apply (EC, 2016a and 2016b).

As mentioned in the CEP study (2014), itself referring to a number of other studies, there is a consensus among economists that market mechanisms alone cannot provide the optimal amount of "green" innovation because of the combination of negative environmental externalities – environmental benefits being not appropriately valued by markets – and positive knowledge externalities – innovators not reaping all benefits of their innovations. However, once some mechanism is in place to internalise the environmental externality, there is no reason *a priori* to implement R&D support policies targeted specifically at low-carbon technologies. Positive externalities in knowledge production may be addressed by generic instruments such as the systematic protection

of intellectual property rights (IPRs). Yet, in theory, subsidies to private R&D activities should reflect the size of the external spillovers from the research. Consequently, the optimal level of subsidies for R&D on low-carbon technologies depends on the magnitude of knowledge spillovers from these technologies, relative to the spillovers generated by other technologies, in particular the fossil technologies they replace.

10.5. Summary and key issues for policy makers

Technological change in the energy sector contributes to the economy in terms of: i) value added, income and employment that it generates from its production, transformation and distribution, including of associated equipment; ii) the functioning of the economy, firms and households that are dependent on cheap and reliable energy supply; and iii) the waves of innovation and the spillovers that it generates on both the supply and the demand sides, which are closely linked with the transformations in society and economic performance.

The collection of data, in particular budgets, on energy technology innovation needs to be improved to cover the full process, from early stages of RD&D to full market deployment. It also needs to cover not only the public sector, but also the private one. The intellectual property argument, while valid in some cases, should not impede the development of standardised mechanisms to collect, compile and publish urgently needed global data on budgets for energy technology innovation.

Capturing the impacts of energy innovation on international economics and growth requires much finer analysis. Energy economic models used in the literature only partially address the treatment of technological changes. There is a need for further research in looking across the innovation value chain (from RD&D to market uptake) in a broad international perspective, assessing the impacts of innovation and energy policy-induced technological changes in terms of growth, while accounting for the diversity of economic actors' behaviours with respect to low-carbon energy, themselves influenced by energy policies which may evolve over time.

Analysis that has sought to account for the change in energy intensity attributes a substantial part of the change to improvements in technological efficiency. Such improvements are the result of decisions by suppliers to innovate with more efficient equipment, and by energy users to invest in this equipment. Policy makers and energy modellers need to consider what drives these decisions: policy regulation, price of energy, financing conditions, but also incentives for RD&D and innovation, and the availability of knowledge and consecutive spillovers.

These last aspects are confirmed by the study CEP (2014) showing that, with respect to climate change policy, pollution pricing should be complemented with specific support for clean innovation, e.g. through additional R&D subsidies, that goes beyond standard policies in place to internalise knowledge externalities. Indeed, higher spillovers from clean technologies, compared with dirty technologies, justify higher subsidies in a best policy setting. Radically new clean technologies should receive more public support than R&D targeted on improving existing dirty technologies, support that could even be refused at a time of public funding scarcity. Redirecting innovation from dirty to clean technologies reduces the cost of environmental policies and can lead to higher economic growth in the short run, if the benefits from higher spillovers exceed these costs.

There has been a partial recovery in publicly financed energy RD&D budgets in IEA countries, with nearly a doubling since the year 2000, reaching a total of USD 14 billion, still lower nevertheless than the figure of USD 16 billion in 1980 following the first oil crisis (both figures are given in 2014 US dollars). There has been a drastic evolution in the portfolio of energy RD&D, with today nearly an equal sharing between energy efficiency, renewable and nuclear energy (fission and fusion altogether), compared with a

predominance of nuclear fission in 1980. This financial effort needs nevertheless to be sustained and accelerated, if indeed the objective of a near-zero-GHG emission electricity production is maintained. The commitment made by the 22 countries (and the EU) under the Mission Innovation, to double their public financing for low-carbon energy RD&D is therefore crucial and may need to be strengthened even further in the future. RD&D programmes should foster innovation, preparing for and accelerating the market uptake of innovative technologies, and serve as triggers to leverage wider investments by the private sector, for the benefit of the global economy.

Beyond the public financing of the early stages of innovation, and noting the increasing importance of electricity for timely meeting the goal of deep decarbonisation, it is necessary to further progress in the explicit modelling of the take-up of low-carbon technologies. The scale of investment required to decarbonise the power sector is very large. For instance, the IEA's Energy Technology Perspectives (ETP) estimates in its 2DS that global nuclear capacity needs to double between now and 2050.

While the required sums are measured in the trillions of dollars, they remain below those projected for investments in renewable capacity over the same period. Nevertheless, energy innovation economic models should integrate the macroeconomic impacts resulting from the diversion of investment away from not only the fossil fuel sector but also other sectors of the economy.

The risks associated with large-scale investments in upfront capital-intensive low-carbon power generation projects are different from those associated with conventional fossil fuelled plants. This supports the conclusion that positive spillovers from R&D support for low-carbon technologies are comparatively larger, simply because the private sector is less prone to take on the financial risks associated with them. Crowding out is thus much lower.

Investment to support the widespread diffusion of efficient end-use technologies, in particular in the phase of market uptake, is necessary as the demand-side generally tends to contribute more in terms of wider global economic impacts and employment. RD&D initiatives which fail to encourage consumers to adopt the outcomes of innovation efforts are not cost-effective.

In conclusion, policies should support a wide range of low-carbon technologies. However seductive they seem, silver bullets do not exist. Innovation policies need to be consistent over time, recognising the inherent risk of failures. These logically outnumber the successes. Experimentation, often for prolonged periods (decades rather than years), is critical to generate the applied knowledge necessary to support the scaling-up of innovations to the mass market, allowing full economic return. Therefore, innovation policies should use a portfolio approach under a risk-hedging and "insurance policy" decision making, with a long-term perspective.

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Chapter 11. **Policy conclusions:**

The policy implications of full cost accounting in the electricity sector

The production and consumption of electricity is not only a major economic issue but also a large contributor to adverse impacts on human health, longevity and the natural environment. Driven by this insight, applied economic research on external effects, externalities or social costs has frequently taken the electricity sector as its starting point. In the 1990s and early 2000s, a series of broad, well-funded studies with dozens of high-level experts from different fields began a more extensive examination of the full costs of electricity. Many of the results produced from these studies remain relevant today. While estimates of social costs inevitably display large uncertainties, the studies converged in the identification of key problem areas and the determination of orders of magnitude for different areas of impact. Despite their intrinsic quality and comparable results, these studies did not receive sufficient attention from policy makers or the general public.

Policy makers, in particular, have never properly implemented the recommendations of experts to fully internalise social costs into private decisions. It may have been optimistic to presume that the frank imposition of fiscal measures, based on precisely monetisable social costs and the resulting tax adjustments that would bring social and private, market-based costs in line, could be routinely implemented in all circumstances. Yet, converging results from a number of broad-based and well-balanced studies have all implied that much stronger action than countries have been willing to contemplate – at the very least on air pollution and the reduction of climate change risks – is required to move towards economic optimality. The widespread lack of a meaningful carbon tax in many countries is a case in point. Stronger technical regulations, market creations, subsidies, improved transparency and reduced legal and institutional transaction costs, however, are all available as part of an arsenal of measures that can be used where the straightforward imposition of Pigouvian taxes remains elusive because of political obstacles resulting from distributional concerns.

The objective of the present report is to recall the principal results of the externality studies of the past two decades, to complement them with more recent research results and to remind decisions makers of their obligations to take these combined insights into account in the formulation and implementation of energy policies. The well-being of their citizens and the welfare generated by their economies depend on it.

The Full Costs of Electricity Provision is part of the growing series of Nuclear Energy Agency (NEA) studies on the costs of nuclear energy and other power generation options. Several of these studies, including those on plant-level costs, system costs and security of supply, have been summarised in the preceding chapters. They reflect a desire to arrive at robust and meaningful cost measures for electricity provision that go beyond the traditional LCOE-measure for the costs of plant-level baseload provision in regulated power systems. Given its simplicity, transparency and easy comparability, the LCOE will continue to be part of the information set required by experts, researchers and policy makers. However, even in future editions of the NEA/IEA flagship publication on *The Projected Costs of Generating Electricity*, the next edition of which is foreseen for 2020, broader, complementary measures are now required, since

the per MWh cost of a generating technology can no longer be assessed independently of the surrounding electricity system. The role of day-ahead dispatch, which was the prevailing paradigm for both regulated and, initially, for liberalised markets, is declining, while the role of payments for capacity, flexibility, stability and system services is increasing. Even at the level of the grid-connected system, an MWh of electricity is no longer a homogeneous good.

It is even less a homogeneous good at the level of the surrounding environment, the citizens who live in it, the security of supply they aspire to, or their existing social and technological dynamics. It is why the notion of full costs is so important. Moving towards improved welfare requires differentiating technologies according to a number of relevant metrics that reflect their full impact on society and on the economy.

The challenges that this implies are evident, both at the level of assessing full costs and of determining widely acceptable ranges of valuation, as well as at the level of overcoming the entrenched interests and the resistance to be held accountable. Full costs are plant-level and system costs, plus uninternalised externalities. If the latter are negative, they need to be added as extra costs; if the latter are positive, in principle, they need to be subtracted. The term "in principle" is used here because positive externalities such as the spillovers of employment in certain technologies or the impact of innovation on economic performance and growth are, usually, of an even more uncertain nature than the negative impacts on human health, longevity and the environment. The internalisation of positive externalities is thus usually best handled in an implicit manner through general policy rather than through the imposition of monetary incentive measures that would adjust market costs.

Air pollution, climate change risks and system costs constitute the largest uninternalised costs

If the ten preceding chapters on the different facets of full costs converge on a single insight, it is that the non-internalised, external costs of normal operations for electricity generation exceed the costs of other phases of the life cycle, both upstream and downstream of operations, as well as the costs of major accidents, by at least one order of magnitude. Mining and transport of the primary fuels from which electricity is generated, such as coal, oil, gas or uranium, do have social costs but they are locally well circumscribed and much lower than, for instance, the costs of air pollution. As far as the back end of the life cycle is concerned, decommissioning and storage of waste constitute significant costs for nuclear power. However, these are economic costs that are internalised through the provisions constituted by electricity producers and passed on via prices and tariffs to customers. One can have a legitimate debate about the question of whether the provisions are adequate. However, Chapter 2 shows that, at least at the level of LCOE accounting, the economic costs of decommissioning and disposal, in the case of nuclear energy as in the case of other technologies, are routinely internalised. This internalisation is matched by detailed provisions in NEA member countries for constituting provisions for decommissioning and waste disposal with every MWh of electricity produced by nuclear power plants.

The same holds for the topic of natural resource depletion (see Chapter 7). As far as commercially valuable primary energy carriers such as coal, oil, gas or uranium are concerned, competitive markets will ensure a path for the exploitation of these resources that is optimal for both present *and future* generations. As soon as one considers commodities that have valuable qualities that are not valued by the market, this observation will needless to say no longer hold. An obvious example is the deforestation of tropical rainforests, where private exploitation proceeds far too quickly without any regard for the overall well-being of present or future generations. However,

primary energy carriers of coal, oil, gas or uranium, for example, hold little value beyond their commercial use, and there are very few uninternalised externalities connected with their exploitation.

Finally, major accidents involving energy structures, whether they be oil spills, gas pipeline explosions, dam breaches, mining disasters or nuclear power plant accidents, are fortunately rare enough during the life cycles of all power generation technologies not to figure prominently in the accounting of full costs. This statement from an economic cost accounting perspective, which is important for decision-making, complements rather than contradicts the fact that such accidents, with their concentrated hardships, receive an extraordinary amount of attention from the media and the general public. Events taking place over a longer time-span than the frequency of individual media outlets are unlikely to fulfil the necessary criteria to become "news" unless they reach "…some kind of dramatic climax". (Galtung & Ruge, 1965: 66)

In other cases, the attention bias, which weighs heavily on policy making, is not linked to the concentrated nature of impacts but depends on the technology under consideration. As shown in Chapter 6, the greatest number of fatalities during major accidents is recorded in coal mining and hydroelectricity, two technologies which do not generate widespread public concerns. Oil spills, and in particular nuclear accidents, instead receive an amount of media and policy attention that is extraordinary when compared to the damage and human casualties for which they are responsible. In the case of nuclear accidents, even minor industrial accidents attract enormous attention.

Even observers that consider themselves well-informed are surprised to learn that at Fukushima not a single casualty was due to radiation. Very clearly, Fukushima was a major accident that revealed inadequate preparation for a rare but not unforeseeable natural disaster. However, it is legitimate to observe that the strategic policy shifts from nuclear power to the utilisation of fossil fuels that it engendered the world over were neither proportionate to the actual hardship caused by the accident nor consistent with the objective to reduce the health impacts and social costs from air pollution.

Some factors can of course explain the dissymmetry between public and policy attention on the one side and the overall severity of impacts on the other. Oil spills and nuclear accidents are characterised by two facts that are particularly uncomfortable for the public. First, their impacts can extend over long time frames, while the vast majority of the damages wrought by a mining accident or the explosion of a gas pipeline are immediate. Second, many of their impacts cannot be discerned visually. Damages due to radiation or the impact of hydrocarbon pollution through the food chain require sophisticated measurements to be properly assessed. The intuitive reaction by a public avid to understand a traumatic accident is frequently that "the true extent of damages is hidden".

It is not the purpose of this publication to explore the reasons for this dissymmetry between the extent of damages from accidents and the extent of the public reaction. Transparency about the extent of the full costs of all energy chains must be the primary strategy to address such dissymmetries. Such transparency requires a dedicated effort from all stakeholders in the energy sector, and it is the objective of this publication to contribute to this task.

That said, individual human suffering induced by any sort of accident or external effect, whether it captures public attention or not, cannot be reduced to statistics. Policymakers have the difficult task of balancing both aspects, the legitimate emotional reaction in the moment and the need for a longer-term structure of an energy-system constituting the best available option to minimise accidents and hardships in a 360° perspective. Dispassionate reflection with an aim to improve general welfare suggests that the large number of casualties caused by air pollution demand at least as much attention as the rare accident. Currently, public opinion, social forces and political pressures will ensure that policy attention and resources will go disproportionately to the

latter. Externalities in this case will be internalised or even over-internalised, while pollution will continue unabated as is currently the case in electricity provision. There is thus a legitimate question to be asked: why the very serious and far greater impacts of air pollution, the potential risks of climate change, or even the multi-billion dollar system costs of the variability of certain renewable technologies, are unable to make a sufficiently forceful impact on public perceptions to be translated into effective policy action? As outlined in Chapter 5, air pollution constitutes the biggest uninternalised cost of electricity generation. It is also an intensively studied area with stable research protocols, consistent methodologies and converging results. According to the World Health Organization, it is the world's largest single environmental health risk, with 3 million deaths annually due to ambient air pollution, to which electricity generation is a major contributor. Household air pollution, much of it resulting from a lack of electricity, causes an additional 4.3 million deaths. While most deaths occur in low- and middle-income countries, welfare losses caused by air pollution amount to an estimated loss in welfare in OECD countries alone far above one trillion USD, or roughly 3% of their gross domestic product (OECD, 2014).

The full costs of climate change, presented in Chapter 4, are difficult to assess with precision but climate scientists routinely estimate them as being in the trillions of US dollars or euros. One of the most difficult issues in this exercise is the very high uncertainty involved, which makes it impossible to fit possible outcomes into a stable probability distribution. It is possible, however, to identify an order of magnitude value of USD 100 per tCO_2 which is included in the ranges provided by the vast majority of studies on the likely costs of climate change. While each single study can be criticised for methodology or data selection, such shortcomings are inherent to a multi-dimensional subject matter that touches upon almost every aspect of human life. In addition, assumptions on discount rates that reflect the implicit cost-sharing arrangements between present and future generations further skew the results of any individual study.

Reducing greenhouse gas emissions to reduce the risk of climate change has a special role in this context. Public awareness, media focus and political attention are intense, but have failed thus far to translate into effective policies on the ground. At international conferences, it has become an article of faith to describe the need to fight climate change in the starkest of possible terms, while baulking at the introduction of all but the most uncontroversial policy measures.

System costs (Chapter 3) are another under-reported subset of full costs, a topic that has emerged in the last few years following the deployment of significant capacities of variable renewable energy sources – primarily wind and solar photovoltaics – in many countries. Consisting of grid cost, balancing costs and utilisation or profile costs, results are country- and technology-specific, and increase over-proportionally with the penetration level. Central estimates of total system costs show a range of costs of USD 15 per MWh for onshore wind, USD 20 per MWh for solar PV and about USD 25 per MWh for offshore wind at a penetration level of 10%. At a 30% penetration level, system costs increase significantly, reaching about USD 25 per MWh for onshore wind and about USD 40 per MWh for solar PV and offshore wind. In comparison, system costs for dispatchable technologies such as nuclear, coal and gas are at least one order of magnitude lower, i.e. below USD 2 per MWh.

These results vary significantly according to the characteristics of the surrounding electricity system. For instance, a significant share of hydroelectric resources would provide some or all of the flexibility required to integrate variable renewables and thus limit the increase in system costs. Depending on their technical characteristics, which differ according to the reactor type, nuclear energy further contributes to the flexibility provision in low-carbon systems. Nevertheless, given that production from wind and solar PV in OECD countries was already more than 600 TWh (one million MWh) in 2014 and is rising fast, it is easy to see that system costs are measured in the billions of US dollars and are bound to increase further. Yet outside the circle of electricity market experts, the issue is virtually unknown.

Again, it is not impossible to indicate factors that explain the limited attention that air pollution and system costs receive. In the case of system costs, the reality is that the subject is technical and that it runs counter to dearly held prejudices about the economic and social desirability of renewables in general, and wind and solar PV in particular. A similar argument holds for security of supply (Chapter 8), employment effects (Chapter 9) and the impacts of technology innovation (Chapter 10). These are specific, rather technical issues. Contrary to system costs, however, they do possess their own, although limited, constituencies that ensure that they are taken into account, and their partial, if imperfect, internalisation. These constituencies change over time. In terms of security of supply, the role of domestically produced coal was reduced as faith in the reliability of an open-market system grew. For employment effects, trade-offs between diffuse effects at the national level and concentrated effects at the local level must be considered. In R&D and innovation, contrary to a common misperception, nuclear fission (i.e. the physical process at the heart of today's nuclear power plants) has faced a significant decrease in funding in OECD countries. In the European Union, for instance, annual support for nuclear energy research has dwindled from EUR 8 billion to EUR 3 billion, with the majority of this support going to research on the long-term option of nuclear fusion.

In the case of air pollution, the public has difficulty identifying with an issue that involves a steady stress build-up over a period of years to combine with genetic and other factors and cause respiratory illness and heart failure. While the human tragedy at the individual level is not any easier to bear, the complexity and the long duration of the process make covering, reporting, disseminating and absorbing the relevant information much more difficult.

It is the role of publications such as these to put the spotlight on attention biases, not to downplay major accidents, which continue to require high scrutiny and appropriate regulation, but to ensure that policy attention is attuned to all areas with large and verifiable costs both in terms of mortality and morbidity, as well as in terms of economic costs.

How to internalise?

Once the different subsets of full costs receive the appropriate attention they deserve, well-understood instruments for internalisation can be applied. Chapter 1 presents the applied economics behind practical policy decisions, which continue to fall into three broad categories:

1. *Price- and market-based measures:* in many circumstances, the simple application of a Pigouvian tax to any externality that can be identified is neither practicable or desirable. Nevertheless, taxes, prices, subsidies, the allocation of property rights and the reduction of transaction costs are key measures in the policy makers' arsenal to reflect the full costs of electricity provision. Such instruments should be used in a qualitative and predictable manner to steer electricity provision into the desired direction over the long term.

2. *Norms, standards and regulations*: these are the default measures of policy making and have already been widely adopted. They have the added advantage of leaving the pollution rent to the polluter. However, in the area of air pollution and greenhouse gas emissions in particular, a review and eventual tightening of emission standards seem warranted.

3. *Information-based measures*: contrary to a frequent misconception, these measures are not minor add-ons to "real" measures but are at the heart of modern internalisation. Support for research and innovation belongs here, as does taking part in the policy-making and rule-setting processes. This publication is a small

but focused effort to overcome some of the informational transaction costs that stand in the way of better policy making in the electricity sector.

Four general points apply in this context. First, successful measures often combine aspects of different categories. An important example in this context is emissions trading, which combines the setting of a quantitative standard with the creation of a market that allows a price for the externality to emerge. Information and education can further improve the effectiveness of such economic incentive measures.

Second, any measure can be tailored so as to be adapted to different normative frameworks concerning distributional arrangements. From the point of view of welfare optimisation, whether a carbon price to reduce greenhouse gas emissions comes in the form of a tax, a quota that has been allocated through an auction, a quota that was given for free or a zero-emission credit (i.e. subsidy for low-carbon production) is secondary. The decisive point is that a price will be set that differentiates incentives for low-carbon and for high-carbon power generation.

Third, synergies exist between measures addressing different social costs of electricity generation. An obvious example is the fact that any measure that will reduce air pollution from fossil fuels will also reduce carbon emissions, and vice versa. In addition, such action will produce beneficial side effects on resource depletion and the security of energy supplies.

Fourth, the distributional impacts of different measures of internalisation are frequently the most significant barrier to the internalisation of external costs. These impacts are real and must be addressed. Appropriate measures of compensation are relatively simple to put in place and are, if well done, fully compatible with efficient internalisation. They can be permanent or temporary, aiming at full or partial compensation. They require, however, that the logic of confrontation be abandoned and that the different actors commit to working in a framework of overall welfare maximisation.

Finally, when discussing full costs, one must underline the role, importance and responsibility of governments in this area. The gap between full costs and private, market-based costs is related to the inability of private actors to take into account all relevant information about welfare effects, as feedback mechanisms between private parties and appropriate incentive structures are lacking. "Transaction costs" is the catch-all term that economists have coined to refer to barriers to arrangements that, in principle, would be mutually advantageous since the gains of winners would be larger than the costs of losers. These transaction costs are not an unavoidable factor of economic life but can be dramatically reduced over time through both information and incentives.

When the lives of millions of people are at stake, governments have the obligation to put into place incentive structures that vastly reduce transaction costs and enable new arrangements that would allow for large welfare improvements. Once again, the key policy areas here are the prevention of air pollution and the reduction of climate change risks.

In parallel, more information on the full costs of energy is required. It is crucial that governments resuscitate the important debate and large-scale work of the 1980s and 1990s on external effects in the energy sectors. Measured against the scale of the externalities discussed, the required funds for research are negligible. At the same time, such work needs to be managed tightly with a view to contributing to better policy making in the context of the energy transitions under way. The European *New Energy Externalities Developments for Sustainability* (NEEDS) project that was completed in 2008 is a fundamental building block for this work, but it is, alas, also an example of how an enormous amount of good work is suboptimally used when managers are incapable of limiting the perimeter and scope of externality accounting. Future research must prioritise key areas of research and focus on intelligent metrics with relevance for policy making. It also needs to freely acknowledge when topics are not yet ripe for quantification and monetisation, and thus

require qualitative approaches. The old adage that any number is better than no number is simply wrong in this case, and it has diminished the role of full cost accounting in policy making.

The present publication is a small pebble in what one would hope to see becoming over time a large and expressive mosaic. Disseminating and synthesising knowledge on some of the most salient features of the full costs of electricity provision is part of the process of arriving, through the progressive internalisation of social costs, at better policies and more sustainable electricity mixes.

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Annex A. List of participants at "The International Workshop on The Full Costs of Electricity Provision"

NEA Working Group on Nuclear Economics (WPNE)
OECD Headquarters, CC20, Paris

Wednesday, 20 January 2016

Ismail Aydil	Permanent Delegation of Turkey to OECD
Michel Berthelemy	Commissariat à l'Énergie Atomique (CEA), France
Alain Burtin	Électricité de France (EDF), France
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William D'Haeseleer	Catholic University of Leuven, Energy Institute, Belgium
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Reiner Friedrich	IER Dep. Technology Assessment and Environment, Germany
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OECD

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The Full Costs of Electricity Provision

Electricity provision touches upon every facet of life in OECD and non-OECD countries alike, and choosing how this electricity is generated – whether from fossil fuels, nuclear energy or renewables – affects not only economic outcomes but individual and social well-being in the broader sense. Research on the overall costs of electricity is an ongoing effort, as only certain costs of electricity provision are perceived directly by producers and consumers. Other costs, such as the health impacts of air pollution, damage from climate change or the effects on the electricity system of small-scale variable production are not reflected in market prices and thus diminish well-being in unaccounted for ways.

Accounting for these social costs in order to establish the full costs of electricity provision is difficult, yet such costs are too important to be disregarded in the context of the energy transitions currently under way in OECD and NEA countries. This report draws on evidence from a large number of studies concerning the social costs of electricity and identifies proven instruments for internalising them so as to improve overall welfare.

The results outlined in the report should lead to new and more comprehensive research on the full costs of electricity, which in turn would allow policy makers and the public to make better informed decisions along the path towards fully sustainable electricity systems.

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