VME Energy Transition Strategy

External Costs and Benefits of Electricity Generation

Report
Delft, January 2010

Author(s):
Dorien Bennink
Frans Rooijers
Harry Croezen
Femke de Jong
Agnieszka Markowska

Publication Data

Bibliographical data:
Dorien Bennink, Frans Rooijers, Harry Croezen, Femke de Jong, Agnieszka Markowska
VME Energy Transition Strategy
External Costs and Benefits of Electricity Generation
Delft, CE Delft, January 2010

Keywords: Power generation / Electricity generation / Production / Costs / Benefits / Environment / Accidents / Land use / LCA / Effects / Analysis / External costs

Publication number: 10.3942.02

CE publications are available from www.ce.nl

Commissioned by: the Dutch Association for Energy Markets, VME.
Further information on this study can be obtained from the contact person Dorien Bennink.

CE Delft
Committed to the Environment

CE Delft is an independent research and consultancy organisation specialised in developing structural and innovative solutions to environmental problems.
CE Delfts solutions are characterised in being politically feasible, technologically sound, economically prudent and socially equitable.

Preface

This report is a follow-up to previous work by CE Delft supporting VME (Dutch Association for Energy Markets) in drafting their Transition Strategy and providing the necessary background information to do so. To bring the discussion on direct and indirect production costs another step further in the context of comparing different types of power plant, VME asked CE Delft to analyse the external costs of electricity generation in greater detail. The present report is the result of this additional analysis and goes into the external costs associated with environmental impacts and accidents, land use, security of supply and flexibility issues over a large part of the power generation life cycle, viz. the mining, transport and combustion phases.

Contents

	Conclusions in tables & figures	**7**
	Management summary and conclusions	**15**
1	**Introduction**	**25**
1.1	Introduction and goal of this study	25
1.2	External costs (and benefits) and study scope	26
2	**Direct production costs**	**29**
2.1	Introduction	29
3	**Environmental damage costs**	**31**
3.1	Introduction	31
3.2	Shadow pricing in general	32
4	**Environmental costs associated with different power plants**	**37**
4.1	Introduction	37
4.2	Shadow prices of accidents	37
4.3	External costs of emissions and accidents per plant type	40
4.4	Comparing total production costs, including environmental costs and accidents	41
5	**Land use**	**45**
5.1	Introduction	45
6	**Security of supply**	**49**
6.1	Introduction	49
6.2	Energy price fluctuations	49
6.3	Value of Lost Load	55
6.4	Conclusions	58
7	**Flexibility of electricity supply**	**61**
7.1	Introduction	61
7.2	Lower operating times of alternative production capacity	63
7.3	(Additional) storage facilities	63
7.4	Conclusions	64
	References	**65**
Annex A	**Shadow prices: backround and methodology**	**69**
A.1	Damage costs versus avoidance costs	69
A.2	Methodology for estimating damage costs	69
A.3	Global warming	72

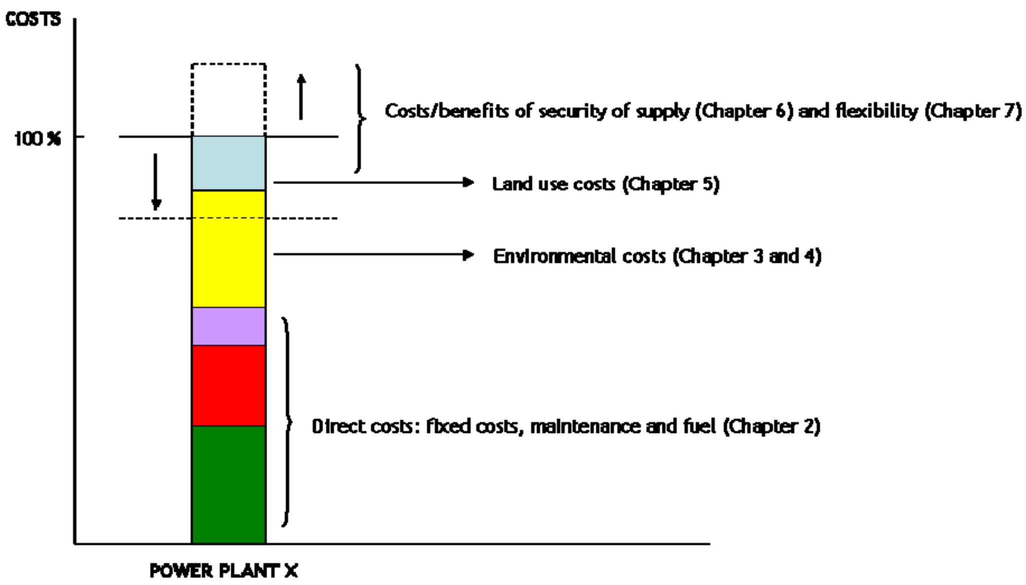
Annex B	**Detailed tables of emissions and power plant characteristics**	**79**
B.1	Fuels	79
B.2	Power plants	80
B.3	Coal-fired power plant burning 50% biomass	82
B.4	Third-generation nuclear power plant	84
B.5	CCGT with/without CCS	85
B.6	Multi-fuel CCGT with/without CCS (coal gasification)	87
B.7	Decentralised CHP	88
B.8	Biomass gasification (CFBC) with/without CCS	89

Conclusions in tables & figures

Introduction
When comparing the costs and benefits of different types of power plant it is important to take into account not only direct production costs (including the fixed costs of investments and depreciation, maintenance and fuel) but also indirect, i.e. external, costs and benefits. These external costs and benefits consist of:
– Costs related to environmental damages.
– Costs related to accidents in the fuel chain.
– Costs related to land use.
– Costs and benefits related to security of supply in terms of fuel mix diversification.
– Costs related to increased flexibility of the energy system, to facilitate greater use of intermittent sources like wind.

Figure 1 provides a schematic breakdown of total production costs for a hypothetical power plant.

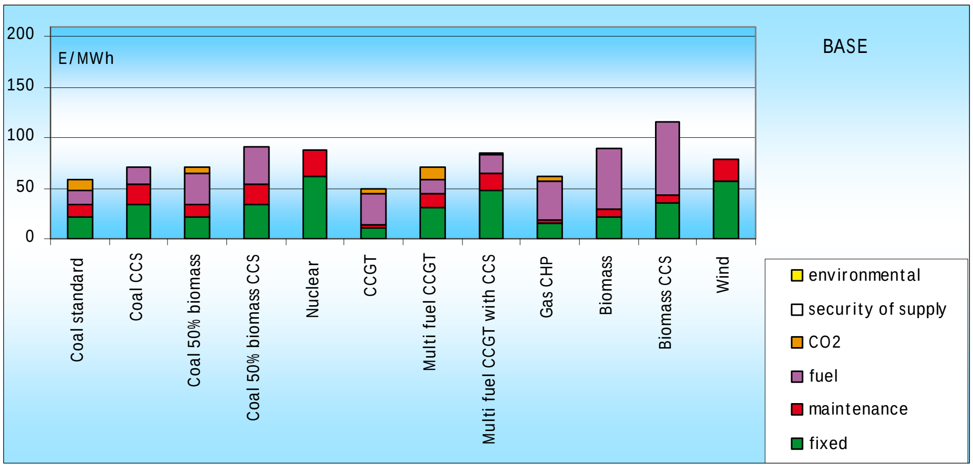
Figure 1 Graphical presentation of types of external costs



Conclusions
Our analysis shows that CO_2 emissions account for the vast bulk of the external costs of power generation reviewed in this study, contributing significantly more than all other environmental costs together. In the case of coal-fired power plants, for example, CO_2 emissions account for some 70-85% of total external environmental costs (if no carbon capture and storage, CCS, is assumed). For power plants burning biomass, the external costs associated with land use are also important: about 50% of total external costs (land use, environmental damage and accidents). If energy systems are to accommodate a growing share of intermittent sources (mainly wind), they must be made more flexible and/or redesigned to incorporate some form of energy storage. If all the costs associated with such steps were attributed to wind energy, this would push the total production costs of wind power by up to **120 € per MWh.**

Direct production costs (chapter 2)
Figure 2 provides a comparison of the direct production costs of the various different power plants studied. These are the fixed costs associated with (depreciating) investments, maintenance and fuel of a power plant with an installed capacity of 1,000 MW and an annual output of 6,000 GWh (6,000 full-load hours per year)[1]. The internalised CO_2 price, currently about 15 € per tonne, has been included. The costs are expressed in € per MWh. Further details of the assumptions made in deriving these costs are provided in chapter 2 and annex B.

Figure 2 Comparison of direct production costs of different power plants (in € per MWh), incorporating a CO_2 price of 15 € per tonne



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

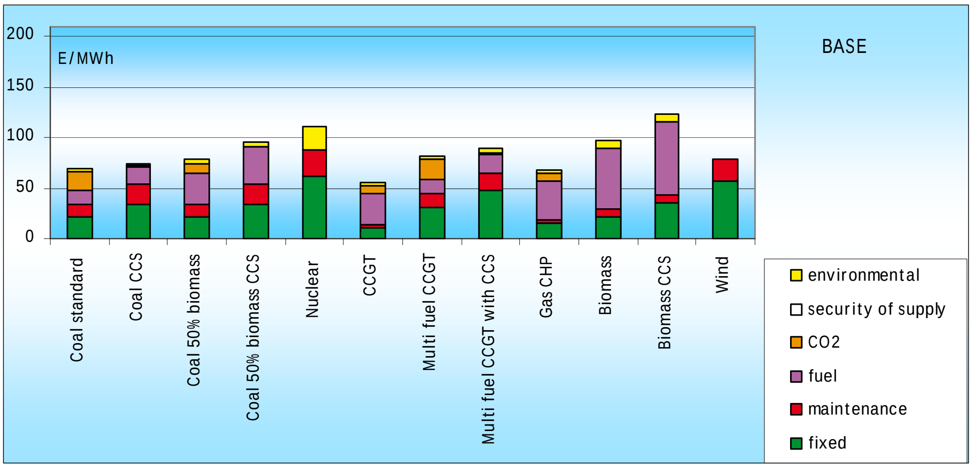
Source: Calculations by CE Delft based on (an update of) CE, 2007.

Environmental costs and accident costs (chapters 3 and 4)
On top of these direct production costs come the various external costs associated with environmental pollution (including radioactivity) and accidents down the fuel chain. These are presented in Figure 3 to Figure 5. In each figure a successively higher CO_2 price is assumed, reflecting an expected rise in the value attributed to (accumulating) environmental damages due to CO_2 emissions[2].

[1] Source for assumed (average) figure of 6,000 annual full-load hours for a 1,000 MW power plant: http://statline.cbs.nl/statweb/?LA=en.

[2] These correspond to the estimated value of CO_2 damages in 2008, 2030 and 2050 (based on CASES, 2007).

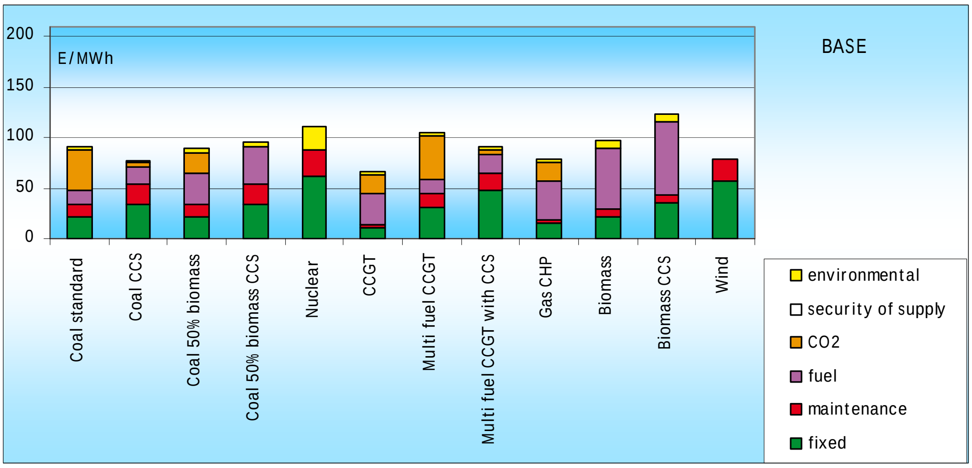
Figure 3 **Comparison of production costs of different power plants (in € per MWh), including environmental costs and accidents and assuming a CO_2 price of 25 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

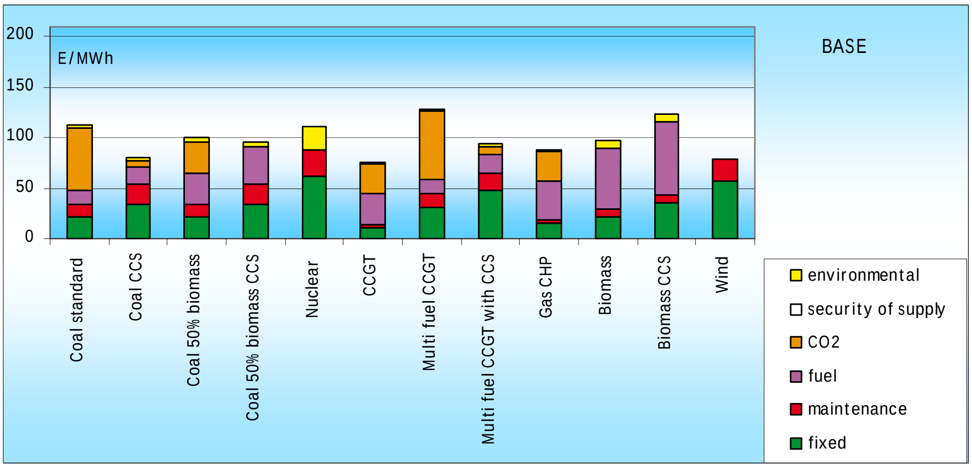
Figure 4 **Comparison of production costs of different power plants (in € per MWh), including environmental costs and accidents and assuming a CO_2 price of 55 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE(2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

Figure 5 **Comparison of production costs of different power plants (in € per MWh), including environmental costs and accidents and assuming a CO_2 price of 85 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

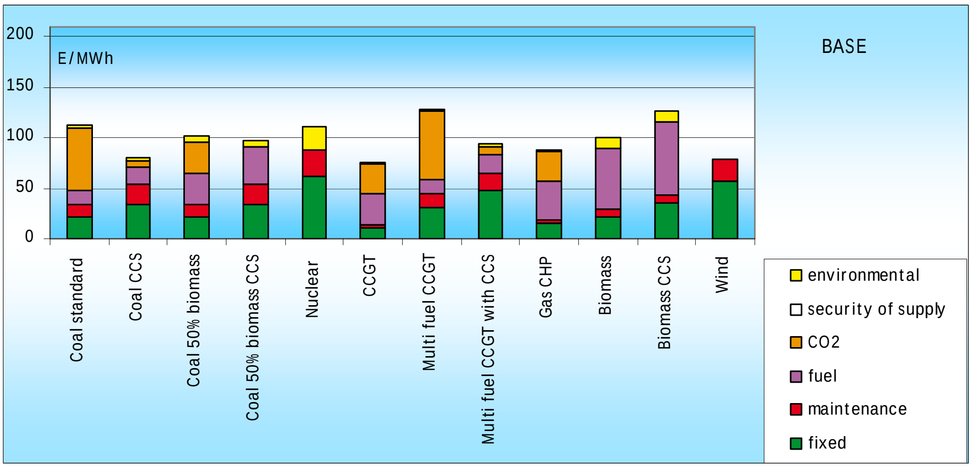
Land use costs (chapter 5)

In this report the costs of land use associated with biomass cultivation have also been assessed[3]. The main impact of land use is damage to ecosystems due to the effects of land occupation and conversion. It has been assumed that demand for biomass (from Canada) leads to only negligible conversion of land . In this report, therefore, only the external costs attributable to biodiversity loss associated with land occupation have been calculated. It was thus estimated that the external costs of Canadian-sourced biomass due to land use equal **€ 3.43 per MWh**[4]. Adding this figure to the external production costs of a coal-fired power plant running on 50% biomass and a 100% biomass-fueled plant yields the results shown in Figure 6.

[3] The land use costs of wind energy are estimated to be either limited, already (partly) incorporated in land prices and therefore not external, or very hard to assess (see chapter 5).

[4] Assuming power generation in a 100% biomass-fueled plant.

Figure 6 **Comparison of production costs of different power plants (in € per MWh), including environmental costs, accidents and land use costs (biomass) and assuming a CO_2 price of 85 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008), Goedkoop et al. (2009) and Kuik et al. (2008).

Costs and benefits of security of supply (chapter 6)

The Costs and benefits of energy security have been studied in two ways, by examining:

- The costs related to (the risk of) energy price fluctuations.
- The costs related to damages due to power supply interruptions (Value of Lost Load, VOLL).

The external costs associated with energy price fluctuations and VOLL can provide an indication of the value (benefits) that society associates with having a more diverse fuel mix and being less reliant on one particular fuel source (generally oil). In Table 1 an estimate is given of the value attributable to each factor.

Table 1 **Value (benefits) of security of supply**

	Estimated value in € per MWh
Source: CASES, 2007	
Energy price fluctuations	**0.004**
Value of Lost Load (VOLL)	**7,000**
Source: other	
Energy price fluctuations and VOLL (total)	**2-6**

Source: CASES, 2007 a.o.

With regard to energy security, it can be concluded that VOLL is by far the most important cost component. For the Netherlands, VOLL has been estimated at up to **7,000 € per MWh**, with the costs of price fluctuations found to be rather negligible: **0.004 € per MWh**. It seems reasonable to assume, however, that VOLL benefits are not (entirely) external, since one might anticipate these being internalised to some extent in transportation charges from network operators and financial power interruption compensation schemes. Also, one might in general argue that it is somewhat counterintuitive to regard the costs of power interruptions (VOLL) as an estimate of the benefits accruing from a more diverse energy supply. This is because a *technical* interruption due to grid problems in itself is unrelated to the source of the electricity being transported[5].

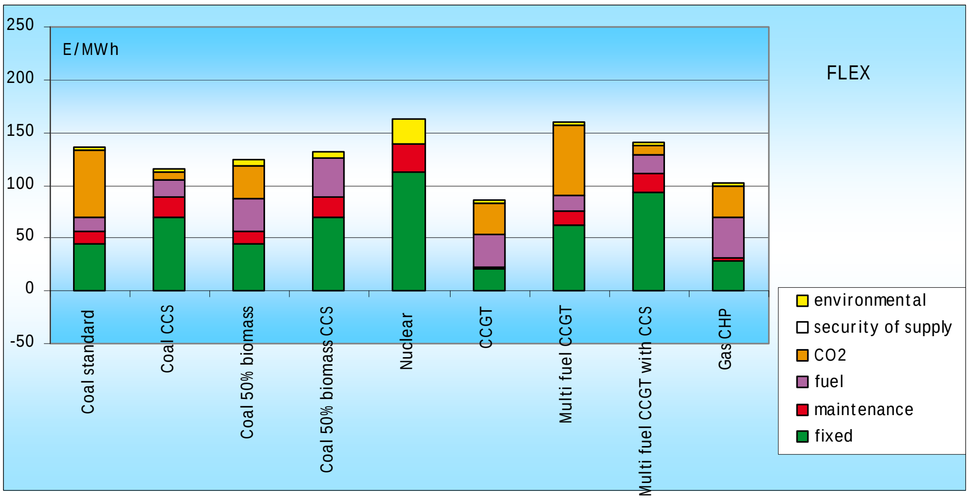
In summary: the external costs of price fluctuations are negligible. On the information available, moreover, it does not seem reasonable to attribute an uncertain fraction of the external costs associated with VOLL as benefits of a more diverse energy supply. CE Delft is of the opinion that it is not to be expected that the benefits relating to security of supply issues influence the costs associated with (different types of) electricity production to any substantial extent.

Costs of flexibility (chapter 7)
The introduction of significant amounts of intermittent generating capacity, like wind energy, will affect the way the electricity system operates. Available wind energy (as well as solar and, to an extent, combined-cycle gas-fired power plant) is considered 'must-run' capacity[6]. Since renewable sources have priority access to the grid, whenever renewable power is fed in, other power plants will have to ramp down, causing their average annual (base-load) operating time to decline. As a result their (fixed) costs per MWh output will rise.
The effect of a decline in output from 6,000 to 3,500 GWh and an increased number of operating hours for intermittent sources on the direct, fixed production costs of different conventional power plants is shown in Figure 7.

5 Although the extent to which electricity comes from distributed generation (e.g. wind turbines, CHP) might, in theory, influence the frequency of power interruptions. This might perhaps offset the benefits associated with a more diversified fuel mix. CE Delft did not look into this issue in detail, though.

6 Electricity cannot be stored to any substantial degree, at least not in the Netherlands itself, where there is hardly any pumped hydro storage capacity available. This option could be made available via interconnection, though.

Figure 7 **Comparison of production costs of different conventional power plants (in € per MWh), including environmental costs, accidents and land use costs (biomass) and assuming a CO_2 price of 85 € per tonne and 3,500 operating hours per year**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008), Goedkoop et al. (2009) and Kuik et al. (2008).

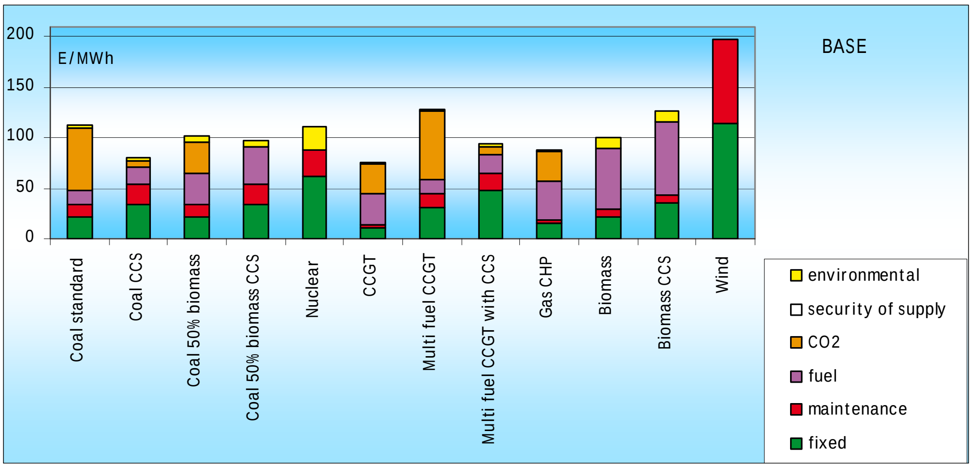
Reduced operating times will cause the fixed costs of conventional coal-fired and nuclear power plants to increase by up to about **50 € per MWh.** This may serve as an indication of the costs associated with the flexibility required to facilitate greater use of intermittent energy sources in the power supply.

Another way to approximate the costs associated with flexibility is to assume that an intermittent source like wind energy should be able to provide base-load electricity[7]. For this to be feasible requires the use of storage facilities[8] to flatten out the fluctuations in wind energy supply in relation to demand. The results of adding the estimated costs associated with these storage facilities to the production costs of wind energy leads to the picture shown in Figure 8.

[7] In other words: wind energy becomes demand-driven rather than supply-driven (must-run) production capacity.

[8] Pumped hydro storage in Norway (via interconnection), for example, or in the future perhaps the batteries of electric vehicles.

Figure 8 **Comparison of production costs of different power plants (in € per MWh), including environmental costs, accidents and land use costs (biomass) and assuming a CO_2 price of 85 € per tonne and attributing all energy storage costs to wind energy**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas source: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008), Goedkoop et al. (2009) and Kuik et al. (2008).

This method of estimating flexibility-related costs leads to an additional figure of around **120 € per MWh,** which in Figure 8, is attributed entirely to wind energy as an intermittent source. In conclusion: the estimated costs associated with the need for a more flexible energy supply amount to **120 € per MWh**. It seems reasonable to attribute these to the total production costs of wind energy as the main intermittent energy source, which is why the production costs of wind energy are considerably higher in Figure 8 than in Figure 6.

Management summary and conclusions

Introduction
As things stand today, investment decisions on new generating capacity are generally based mainly on the perceived direct costs of power production, which may readily lead to the conclusion that electricity from coal-fired plant, say, is relatively cheap. When indirect or external costs are also taken into account, though, the picture radically changes. Examples of these costs are those associated with climate change, air pollution and potential accidents at the power plant itself, as well as the environmental and other impacts of mining, land use, transportation and other upstream processes. On top of these come several new factors that also need to be factored in, such as the costs of integrating more intermittent power sources like wind into the supply system.

This report explores the extent to which investment decisions are influenced by choices regarding which kinds of external costs are taken into account. Today an analysis of this influence is especially relevant, as it is more than likely that energy companies will soon be explicitly confronted with these costs as policy-making on energy issues becomes more future-oriented. The project results will help to anticipate this development.

The assessment leads to the conclusion that the costs associated with CO_2 emissions are substantial, amounting to 70-85% of the total external environmental costs of coal-fired power plants (without carbon capture and storage, CCS). For biomass-fueled power plants the external costs associated with land use are also substantial. The country of origin of the fuels does not significantly influence the results, except for the biomass scenario in which a (substantial) amount of the biomass is coming from Brazil instead of Canada[9]. Another major lesson is that substantial costs are involved in the integration of intermittent energy sources, because of the required flexibility and the need for storage systems. If these costs are fully attributed to the intermittent sources, their production costs increase by up to 120 € per MWh.

The following paragraphs elaborate on these results.

Starting points and approach
In this study the following power generating options have been examined:
- A regular coal-fired power plant, with and without CCS; the option of co-firing biomass (50%) was also analysed.
- A third-generation nuclear power plant.
- A combined-cycle gas turbine plant (CCGT), with and without CCS.
- A multi-fuel CCGT, with and without CCS.
- A decentralised combined heat and power plant (CHP).
- A 100% biomass-fired power plant (CFBC), with and without CCS.
- A wind farm, both offshore and onshore.

9 See Table 29 and Table 30 in annex B.

The coal for the coal-fired plants was assumed to be imported from South Africa or Australia, and the biomass from Canada or Brazil. Natural gas was assumed to be from The Netherlands, Norway or Russia, possibly with LNG from Algeria. There are various potential sources of uranium, including Canada and Kazakhstan, and no precise assumptions were made on this point.

For each generating option, the cost assessments in this report are based on a base-load capacity of 1,000 MW and, for all the power plants except wind turbines, an annual output of 6,000 GWh (6,000 full-load hours).

First of all, for each option the initial direct production costs were determined. In these costs a standard CO_2 price of 15 € per tonne has already been incorporated, as a consequence of the EU Emission Trading Scheme (EU ETS). The various categories of external costs were then analysed and assessed.

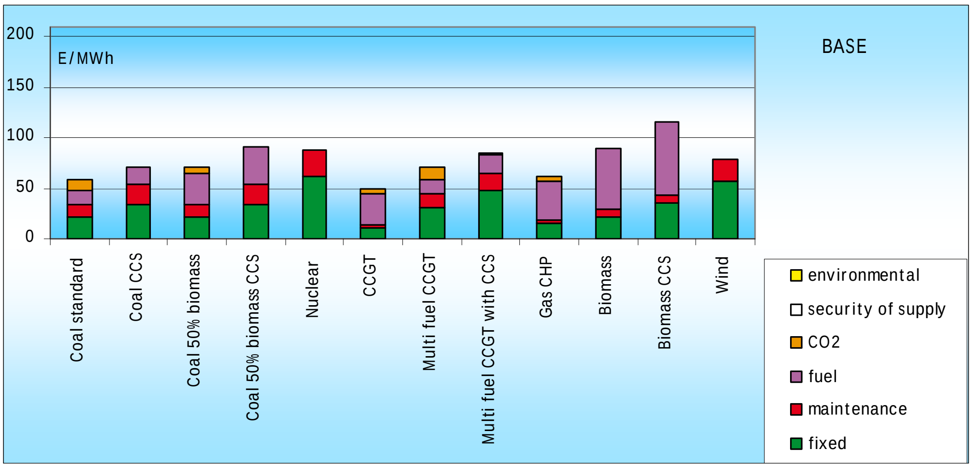
Next, the costs associated with environmental pollution and potential accidents were calculated using the shadow price methodology. Shadow prices provide an indication of the overall change in welfare resulting from a given economic activity. The shadow prices of pollutants are expressed in Euro per tonne of emission, with the exact value depending on emission location and other relevant conditions.

Finally, the costs of land use, flexibility and security of supply were assessed in a more direct manner, taking into account precise plant locations and required provisions (buildings, installations, and so on).

Direct production costs

In Figure 9 the direct production costs of the various types of power plant are compared.

Figure 9 **Comparison of direct production costs of different power plants (in € per MWh), incorporating a CO_2 price of 15 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE, 2007.

As can be seen from the figure, in terms of direct production costs conventional coal-fired plants are the most competitive.

Environmental costs and accidents

In this report the external costs of a range of pollutant emissions (CO_2, CH_4, N_2O, SO_2, NO_x, PM_{10}, $PM_{2.5}$ and radioactivity have been calculated. Table 2 provides an overview of the shadow prices calculated for CO_2, CH_4, N_2O, SO_2, NO_x, PM_{10} and $PM_{2.5}$.

Table 2 External costs of emissions analysed (€ per tonne)

Pollutant	External cost 2008 at low height of release							
	Combustion	*Precombustion*						
	Netherlands	Algeria	Australia	Brazil	Canada	Norway	Russia	South Africa
NO_x	8,647	2,821	7,695	3,122	10,026	3,773	2,692	3,421
PM_{10}	1,961	247	950	346	975	352	2,263	403
$PM_{2.5}$	29,925	1,652	16,885	2,237	6,298	7,997	32,196	2,615
SO_2	12,428	2,589	7,273	3,114	10,035	4,128	5,584	3,357
CO_2	25	25	25	25	25	25	25	25
CH_4	630	630	630	630	630	630	630	630
N_2O	7,450	7,450	7,450	7,450	7,450	7,450	7,450	7,450

Source: Based on CASES, 2008. For Norway and Russia the values have been taken directly from the spreadsheet tool developed in the NEEDS and CASES projects (CASES, 2008).

In Table 2 a shadow price of 25 € per tonne of CO_2 has been taken to reflect future damage costs related to CO_2 emissions, expressed in today's prices. Since these future costs are uncertain and expected to increase in real terms, in this study sensitivity analyses have also been performed using values of 55 and 85 € per tonne CO_2 (estimated values in 2030 and 2050, respectively). The CO_2 price has a major impact on aggregate costs, as will become clear below.

The actual external costs of one MWh of electricity will depend on the type and magnitude of emissions and other external effects of the production option involved. Table 3 summarises the emissions that have been assumed for each of the generating options, expressed in tonnes per year.

Table 3 **Total emissions (precombustion and combustion) per power plant type, assuming 6,000 GWh/yr output (tonne per year)**

	CO_2	CH_4	N_2O	SO_2	NO_x	PM_{10}
Coal	4,404,528	5,358	0	441	1,095	56
Coal CCS	605,977	6,457	0	131	1,042	46
Coal/50% biomass	2,248,662	2,772	10	626	1,614	531
Coal/50% biomass CCS	-2,136,887	3,341	12	493	1,668	627
Nuclear	very low					
CCGT	2,136,410	224	0	53	1,528	7
CCGT CCS	291,990	249	0	59	1,705	7
Multi-fuel CCGT	250,222	5,724	0	121	1,415	41
Multi-fuel CCGT CCS	657,770	6,996	0	141	1,730	39
Gas CHP	2,173,890	228	0	54	1,555	7
Biomass (CFBC)	11,038	208	22	906	2,387	1,126
Biomass (CFBC) CCS	-5,529,950	254	27	969	2,601	1,368
Wind	0	0	0	0	0	0

Source: CE, 2007 and calculations by CE Delft (update).

In this report the external costs of potential accidents in the respective fuel life cycles have also been assessed, based on a series of international studies. These costs are reported in Table 4.

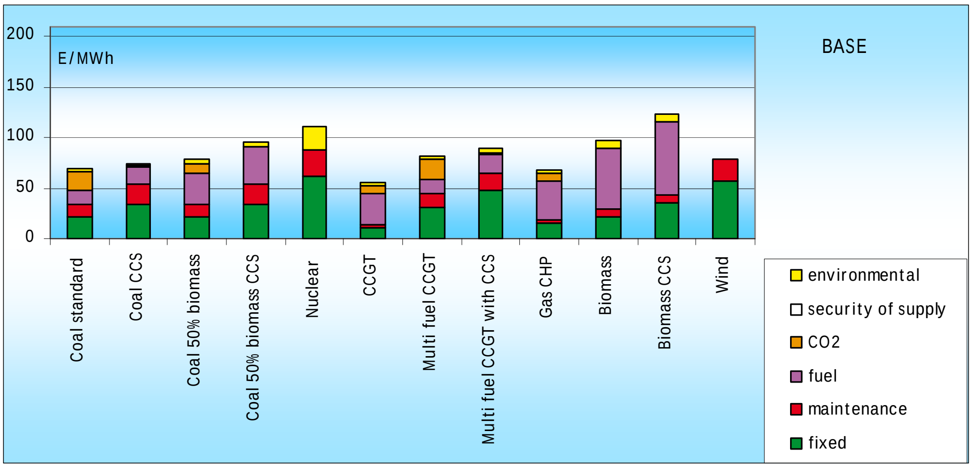
Table 4 **Total external costs with risk aversion for accidents (in € per MWh), 2008 prices**

	OECD countries	Non-OECD countries
Coal	0.057	0.53
Gas	0.087	0.21
Nuclear	23	23
Biomass	≈0	-
Wind	≈0	-

Source: Hirschberg et al., 2004 and calculations from CE Delft; based on Jonkman et al., 2003.

When the environmental costs, including accidents and radioactivity, are added to the direct production costs, the following cost overview results.

Figure 10 Comparison of production costs of different power plants (in € per MWh), including environmental costs and accidents and assuming a CO_2 price of 25 € per tonne



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

As can be seen, when environmental damages and the effects of accidents in the fuel life cycle are taken into account, some of the generating options that originally had relatively low costs, based on direct production costs alone, become more expensive.

Costs of land use

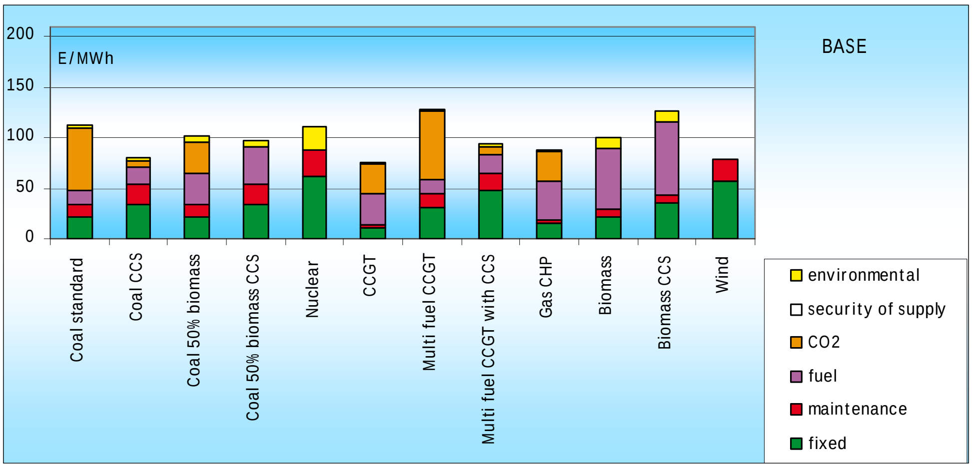
The main impact of land use is damage to ecosystems due to the effects of land occupation and conversion. These effects have been analysed for a scenario in which biomass is sourced in Canada, where it has been assumed that demand for biomass leads to only negligible conversion of land. In this report, therefore, only the external costs attributable to biodiversity loss associoated with land occupation have been calculated. It was thus estimated that the external costs due to land use for biomass production equal 3.43 € per MWh[10]. Adding these costs to the other production costs of a coal-fired power plan running on 50% biomass and to the production costs of a 100% biomass-fueled power plant yields the picture reported below in Figure 11 for the various generating options.

The costs of land use are included in the 'environmental' part of the cost bars. This shows that these costs are relatively marginal in the sense that they have no substantial impact on the relative competitiveness of power plants running wholly or partly on biomass.

The impact of anticipated damages due to CO_2 emissions is much more substantial. For 2050 the estimated shadow price of CO_2 price is 85 € per tonne. Incorporating this figure in the total cost overview yields a completely different picture compared with that presented earlier for the direct production costs only.

[10] Assuming power generation in a 100% biomass-fueled plant.

Figure 11 **Comparison of production costs of different power plants (in € per MWh), including environmental costs, accidents and land use costs (biomass) and assuming a CO_2 price of 85 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008), Goedkoop et al. (2009) and Kuik et al. (2008).

Costs and benefits of security of supply

The costs and benefits of energy security include:

- The costs related to (the risk of) energy price fluctuations.
- The costs related to damages due to power supply interruptions (Value of Lost Load, VOLL).

The external costs associated with energy price fluctuations and VOLL reflect the value (benefits) that society attributes to being less dependent on one or just a few fuel sources and less susceptible to interruptions. Table 5 provides an estimate of these values.

Table 5 **Value (benefits) of security of supply (in € per MWh)**

	Estimated value in €/MWh
Source: CASES, 2007	
Energy price fluctuations	**0.004**
Value of Lost Load (VOLL)	**7,000**
Source: other	
Energy price fluctuations and VOLL (total)	**2-6**

Source: CASES, 2007, a.o.

With regard to energy security, VOLL proves to be by far the most important cost component. For the Netherlands, VOLL has been estimated at up to 7,000 € per MWh, with the costs of price fluctuations found to be rather negligible. I all likelihood the VOLL benefits are not entirely external, as one might anticipate these being internalised in transportation charges by network operators or by way of power interruption compensation schemes.

In summary: the external costs of price fluctuations are negligible and it seems hardly reasonable to attribute the costs associated with VOLL as benefits of a more diverse energy supply. CE Delft is of the opinion that the benefits related to security of supply will not influence the costs associated with (different types of) electricity production to any substantial extent.

Costs of flexibility

The growing input of renewable energy to the grid will give rise to (external) costs related to the need for a more flexible power supply to satisfactorily incorporate these intermittent energy sources. Market circumstances are complex, though, and will change over time as the contribution of wind power increases. This makes it impossible to come up with a single quantitative figure providing a reasonable overall indication of the costs associated with flexibility demands on the energy system due to (a rising share of) wind energy. To get some feel for the upper bound of a bandwidth of these costs, though, i.e. a maximum figure, we consider two rather extreme ways to estimate the flexibility costs associated with wind power:

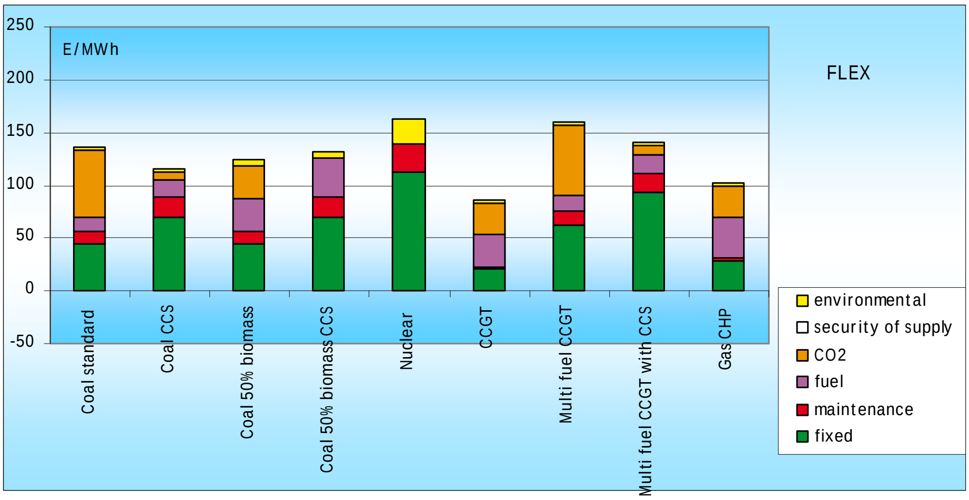
1. Assuming lower operating times of conventional power plants.
2. Assuming that wind energy should be able to meet base-load electricity demand, so that storage capacity is needed.

Ad 1. The introduction of significant amounts of intermittent generating capacity, like wind energy, will affect the way the electricity system operates. Available wind energy (as well as solar energy and, to an extent, combined-cycle gas-fired power plant) is considered 'must-run' capacity[11]. Since renewable sources have priority access to the grid, whenever renewable power is fed in, other power plants will have to ramp down, causing their average annual (base-load) operating time to decline. As a result, their (fixed) costs per MWh output will rise.

The effect of a decline in output from, say, 6,000 to 3,500 GWh and an increased number of operating hours for intermittent sources on the direct, fixed production costs of different conventional power plants is shown in Figure 12. In this figure a CO_2 price of 85 € per tonne has again been used. The big differences in fixed costs and maintenance costs, compared to earlier figures, results from the lower annual production volumes for the base-load options.

[11] Electricity cannot be stored to any substantial degree, at least not in the Netherlands itself, where there is hardly any pumped hydro storage capacity available. This option could be made available via interconnection, though.

Figure 12 **Comparison of production costs of different conventional power plants (in € per MWh), including environmental costs, accidents and land use costs (biomass) and assuming a CO_2 price of 85 € per tonne and 3,500 operating hours per year**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008), Goedkoop et al. (2009) and Kuik et al. (2008).

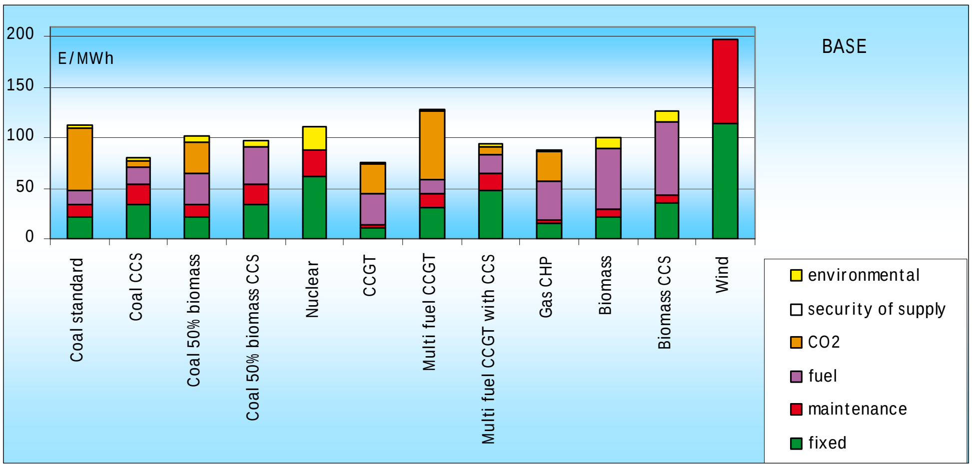
Adding these fixed cost increases due to lower operating times leads to additional fixed production costs of up to about 50 € per MWh. This may serve as an indication of the costs associated with the flexibility required to facilitate greater use of intermittent energy sources in the power supply.

Ad 2. Another way to assess the costs associated with flexibility is to assume that an intermittent source like wind energy should be able to provide base-load electricity[12]. In that case storage facilities[13] will be needed to level out the fluctuations in electricity supply. Adding the estimated costs associated with these storage facilities to the production costs of wind energy leads to the picture shown in Figure 13.

[12] In other words: wind energy becomes demand-driven rather than supply-driven (must-run) production capacity.

[13] Pumped hydro storage in Norway (via interconnection), for example, or in the future perhaps the batteries of electric vehicles.

Figure 13 **Comparison of production costs of different power plants (in € per MWh), including environmental costs, accidents and land use costs (biomass) and assuming a CO_2 price of 85 € per tonne and attributing all energy storage costs to wind energy**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008), Goedkoop et al. (2009) and Kuik et al. (2008).

This method of estimating flexibility-related costs leads to an additional figure of around 120 € per MWh, which in Figure 13, is attributed entirely to wind energy as an intermittent source. In conclusion: the estimated costs associated with the need for a more flexible energy supply amount to € 120 per MWh.

Conclusion

It makes sense to explore the influence of external costs on investment decisions on new generating capacity, as it is more than likely that energy companies will soon be explicitly confronted with these costs as a result of new environmental and energy policies. By including these external costs in the total production costs, long-term investments will be based on the full costs associated with electricity production. It is to be expected that companies will optimise their portfolios differently as a result, taking into due account the required transition of the energy supply.

The effects of the various cost elements are summarised in Table 6 below. This table and the rest of the report show that the costs related to CO_2 emissions have by far the most substantial impact, readily accounting for 70-85% of the total external environmental costs of a coal-fired power plant (without CCS), for example. For plant burning biomass the external costs related to land use are also substantial. The impact of the external costs of potential accidents is relatively high for the nuclear option. The results are not significantly influenced by the country of origin of the fuels, except for the biomass scenario in which a (substantial) amount of the biomass is coming from Brazil instead of Canada[14].

Furthermore, substantial costs are connected to integrating wind energy and other intermittent energy sources into the energy system. These costs are a consequence of the required ramping down of base-load plants as well as

14 See Table 29 and Table 30 in annex B.

requirements vis-à-vis flexibility and/or storage facilities in the supply system. If these costs are attributed entirely to the intermittent sources, the production costs of these options increases by up to 120 € per MWh.

Table 6 Background data for the costs of different power plants (in € per MWh)

	Environmental costs, incl. radioactivity		Accidents		Direct production costs		Total	
Scenario	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Coal	21.72	22.52	0.057	0.53	58.66		80.4	81.7
Coal CCS	5.33	5.02	0.057	0.53	71.62		77.0	77.2
Coal 50% biomass	13.91	24.98	0.057	0.53	70.45		84.4	96.0
Coal 50% biomass CCS	-4.39	8.32	0.057	0.53	85.57		81.2	94.4
Nuclear	0.12	8.4		23	88.25		111.4	119.7
CCGT	11.25	12.71	0.087	0.21	61.73		73.1	74.7
Multi-fuel CCGT	4.27	3.98	0.057	0.53	71.13		75.5	75.6
Multi-fuel CCGT CCS	6.65	6.29	0.057	0.53	84.68		91.4	91.5
Gas CHP	11.39	12.62	0.087	0.21	61.80		73.3	74.6
Biomass (CFBC)	6.87	30.77	≈0	-	90.15		97.0	120.9
Biomass (CFBC) CCS	-15.95	13.23	≈0	-	116.16		100.2	129.4
Wind	≈0	≈0	≈0	-	79.25 (excl. storage)	198.30 (incl. storage)	79.3	198.3

Source: Direct costs based on CE, 2007; other cost calculations based on CE, 2007 (nuclear), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

1 Introduction

1.1 Introduction and goal of this study

In comparisons of the production costs of different types of power plant underlying investment decisions on new generating capacity, it is often only the direct costs associated with power production that are taken into account. In general, this leads to the assumption that electricity from coal-fired plants, say, is relatively cheap. However, in order to make a fair and complete comparison between different forms of power generation it is not only the direct production costs that should be taken into account, but also the costs associated with, among things, climate change, air pollution and potential accidents at the power plant itself, as well as environmental and other impacts occurring during excavation (mining) and transportation of fuels[15]. On top of these come other costs and benefits that need to be taken into due account, among them the costs and benefits of a more flexible and diversified energy supply, a requirement for integrating growing wind energy capacity and creating an energy supply that is less dependent on a single fuel source like oil.

Because these costs (and benefits) are not always (fully) internalised in electricity prices, we refer to them as *external costs.* Ignoring these external costs and benefits leads to over- or underestimation of the (relative) costs of different types of generating capacity. At the moment, for example, only a fraction of the costs associated with CO_2 emissions is passed on to electricity producers. This is achieved via the EU's Emissions Trading Scheme (EU ETS), which by putting a price on CO_2 emissions will lead to cost shifts. The CO_2 trading price is still low, however, owing to 'carbon leakage' as a result of CDM measures[16] and (obligatory) targets for renewable energy[17]. In addition, CO_2 is not the only driver of environmental impacts that needs to be taken into consideration. There are a string of other relevant emissions, too, and on top of these environmental impacts come yet other external costs and benefits that need to be factored in to arrive at a fair estimate of the total production costs of the various generating options.

This report provides insight into the external costs and benefits of different forms of electrical power generation, from the mining phase via transport through to electricity production, in order to compare generating options based on their total production costs, not merely their direct production costs.

---

15 More generally; the environmental costs due to emissions, costs related to health effects as a result of radioactivity, mining accidents or accidents at the power plant itself, social disadvantageous conditions in countries where fuels are sourced, etcetera.

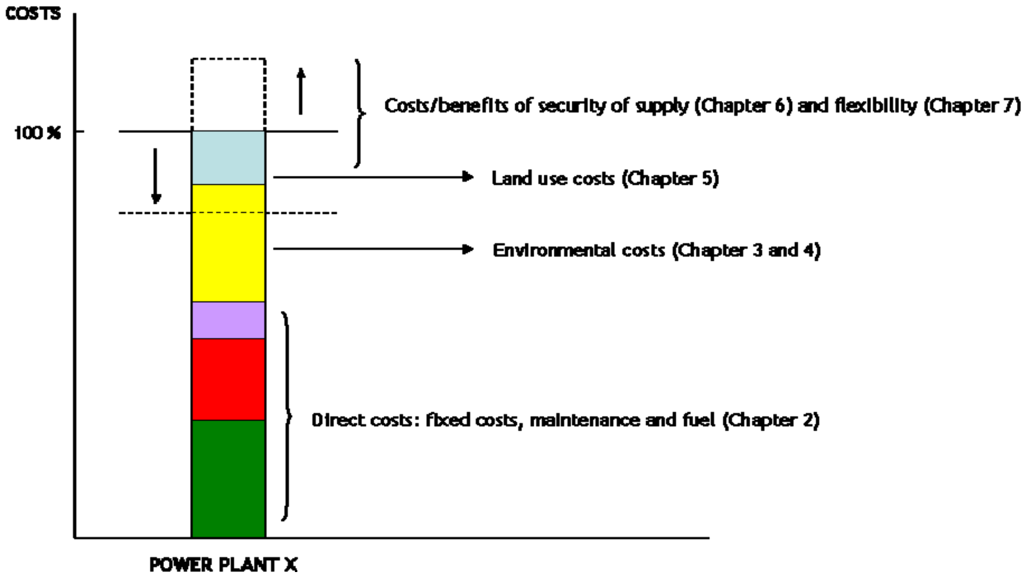
16 The Clean Development Mechanism, under which parties can meet CO_2 reduction targets by buying CO_2 reduction credits from projects in developing countries. As some of these reductions (an estimated 60%) would probably have taken place anyway, they cannot be regarded as additional.

17 If investment costs in renewables exceed the cost of alternative, fossil-fueled, production capacity, companies are compensated via subsidy schemes.

1.2 External costs (and benefits) and study scope

The aim of the study is to arrive at a comparison of the total direct and indirect production costs in Euro per MWh of different types of power plants. Direct production costs consist of fixed costs, related to depreciation of investments and operating costs (e.g. maintenance) and flexible costs (e.g. fuel costs). Besides these direct production costs, the external costs of the various generating options are relevant for making a complete and fair comparison. Figure 14 provides a schematic breakdown of the different kinds of external costs and benefits we shall be examining in successive chapters of this report.

Figure 14 Graphic presentation of types of external costs



In chapter 2 of this study we first consider the direct production costs (in Euro per MWh) of different types of power plant and the underlying assumptions introduced to enable comparison of these costs. This will provide insight into the competitiveness of the various generating options in terms of direct production costs only.

In chapter 3 the external costs (of health, economic and climate effects) associated with emissions of CO_2, CH_4, N_2O, SO_2, NO_x, PM_{10} (and $PM_{2.5}$) and radioactivity are calculated with the aid of so-called *shadow pricing*. Since we shall be assuming several different fuel origin scenarios, this will be done for various countries. In this context the following assumptions were made:
- Coal is mined in and transported from either South Africa or Australia.
- The natural gas burned in gas-fired power plants is from the Netherlands, Norway or Russia, or is in the form of LNG from Algeria.
- For calculating emissions, it has been assumed that all power is generated in new (modern) plant in the Netherlands[18].

[18] With respect to investment decisions, it is assumed that the (direct and indirect) production costs of the latest production technologies are assessed. If one wishes to use the analysis of external costs in a cost-benefit analysis to decide whether it is preferable to close down (depreciate) old power plant early, then the emissions of the entire existing production park should be taken into account in making such an assessment.

The analysis of chapter 3 will provide insight into the damage costs associated with each pollutant, expressed in Euro per tonne emission. The environmental costs associated with NMVOC, CO, NH_3, PAH, heavy metals and emissions to water have not been taken into account. NH_3 and NMVOC are beyond the scope of the present study and their impact appears to be limited[19]. The damage resulting from CO emissions is minimal compared with that due to NO_x, SO_2 and PM emissions, while the impacts of the other pollutant emissions to water are very hard to quantify, as there is widespread debate about the appropriate values to use.

Since different types of power plant emit differing amounts and species of pollutants, in chapter 4 the calculated damage costs in Euro per tonne emission are combined with data on the pollutants emitted by each type of power plant for a fixed annual output of 6,000 GWh. In doing so, different fuel origin scenarios have been adopted for the precombustion phase (fuel mining and transportation). These calculations also include the costs of unforeseen accidents along the entire fuel chain (precombustion and combustion phase) for each power plant type. The sum total of these external costs will be expressed in € per MWh output, to enable comparison with the direct production costs already discussed in chapter 2.

The environmental costs associated with damages to ecosystems and biodiversity as a result of land use for extraction of biomass for power generation are analysed in chapter 5. Inclusion of these costs provides an even completer and more realistic picture of the total costs to be attributed to the various forms of power generation, enabling a fair and comprehensive comparison of production costs.

Chapter 6 is concerned with the costs and/or benefits of security of supply issues. It is hereby assumed that diversifying the power plant fuel mix could lead to benefits (but perhaps also costs) related to the fact that the energy supply will become less dependent on one, or just a few, energy sources.

Chapter 7 considers the costs and/or benefits of a more flexible energy supply. When it comes to costs, a growing share of renewables (e.g. wind energy) is expected to create a need for increased flexible back-up capacity (in the form of gas-fired plant, for example). The associated costs can be estimated in two ways:

- Under the assumption that growth in renewable capacity will lead to a decrease in the operating times of conventional power plant and thus to an increase in the fixed costs per MWh output from this plant.
- By estimating the expected costs of the storage facilities required to provide the flexibility for matching differences between supply and demand at any given moment in time.

Finally, chapter 8 provides a summarising and concluding overview of the total production costs of the various different power plants compared in this study and the way in which direct and indirect (external) production costs influence the relative competitiveness of different forms of electrical power generation.

---

[19] The contribution of NMVOC from a coal-fired power plant to smog formation is somewhat less than 10% of that of NO_x (Ecoinvent: http://www.pre.nl/ecoinvent/default.htm). The contribution of NH_3 to acidification is about 10% of the impact of SO_2. Since the impact of both NO_x and SO_2 are small, the impact of NMVOC and NH_3 are estimated to be even smaller.

2 Direct production costs

2.1 Introduction

In this chapter we provide insight into the direct production costs of different types of power plant, expressed in Euro per MWh, and discuss the underlying assumptions employed. In this context, direct production costs are taken to refer to:
- The fixed costs associated with (depreciation of) investments and fixed maintenance costs.
- The variable costs of maintenance and fuel.

For the fixed costs and maintenance costs of the various power plants studied we have based ourselves on the (updated) data from the report *Nieuwe Elektriciteitscentrale in Nederland* (CE, 2007)[20]. Assumptions on fuel prices (gas 7 €/GJ, coal 2.5 €/GJ and biomass 6.5 €/GJ) are based on estimates by CE Delft[21].

For each power plant we assume a nominal capacity of 1,000 MW and 6,000 full-load operating hours a year, equivalent to an electrical output of 6,000 GWh a year (source: StatLine).

The following types of power plants will be compared:
- A regular coal-fired power plant, with/without CCS and with coal sourced in South Africa or Australia. The option of co-firing biomass (50%) is also analysed, with the biomass assumed to come from Canada or Brazil.
- A third-generation nuclear power plant.
- A combined-cycle gas turbine plant (CCGT), with/without CCS and with gas sourced from the Netherlands, Norway or Russia or as LNG from Algeria.
- A multi-fuel CCGT, with/without CCS and with coal sourced in Australia or South Africa.
- A decentralised CHP with gas sourced in the Netherlands, Norway or Russia or as LNG from Algeria.
- A 100% biomass-fired power plant (CFBC), with/without CCS and with biomass from Canada or Brazil.
- A wind farm, both offshore and onshore.

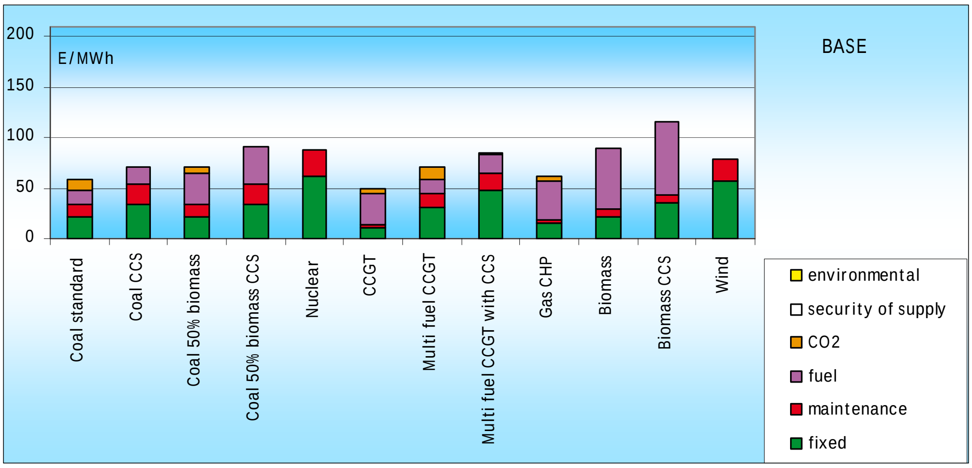
For further information on the characteristics of the different plants the reader is referred to annex B.

Figure 15 shows how operating costs differ across the various power plants if only direct production costs are taken into account. It is hereby assumed that currently the current CO_2 trading price of around 15 € per tonne is already factored in.

[20] Underlying sources: ECN, 2008; KEMA, 2007; KIVI, 2008 and Foster, 2008/2007.

[21] Due to lack of (up to date) data, fuel costs related to nuclear energy are not taken into account.

Figure 15 Comparison of direct production of different power plants (in € per MWh), incorporating a CO_2 price of 15 € per tonne



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE, 2007.

3 Environmental damage costs

3.1 Introduction

In chapter 2 we examined the relative competitiveness of different power plants if only the direct production costs are taken into account. We now complement this analysis by also considering the indirect production costs associated with the environmental damages accompanying power generation. In order to compare the external environmental costs of different power plants we need to:

1. Estimate the costs associated with a unit emission of each pollutant (in Euro per tonne of emission).
2. Assess how many units of each pollutant can be attributed to different power plants with the same output (6,000 GWh per year).
3. Multiply the costs per unit of each pollutant involved by the amount of emissions attributable to the different types of plant and express these in Euro per MWh.

In this chapter the external environmental costs of the various pollutants will be discussed (see (1) above). The other two stages will be addressed in chapter 4. In order to quantify the impacts of environmental damages due to the various pollutants, so-called *shadow prices* have been derived, which will be used to estimate the external costs in Euro per tonne of emission. In this chapter we review the assumptions made and the shadow prices used for each of the pollutants studied. First, though, we provide a brief introduction on the characteristics of the pollutants and the environmental impacts with which we are concerned.

3.1.2 Climate-changing emissions (CO_2, CH_4, N_2O)

In this study the following climate-changing emissions, also known as greenhouse gases (GHGs), have been analysed: CO_2 (carbon dioxide), CH_4 (methane), N_2O (nitrous oxide). These gases all contribute to global warming. Assessing the overall impact of GHGs is difficult because these gases have a long lifespan and consequently an impact lasting several hundred years. For the purpose of this report a lifespan of one hundred years has been assumed and, as discussed earlier, shadow prices are based both on avoidance costs (until 2020) and damage costs (2020–2050) because of uncertainties regarding the future damage costs of GHGs, especially CO_2. More detailed background information on this issue is provided in annex A.3.

3.1.3 Air-polluting emissions (SO_2, NO_x, PM_{10} and $PM_{2,5}$)

The following air-polluting emissions have been analysed in this study: SO_2 (sulphur dioxide), NO_x (nitrogen oxides), PM_{10} and $PM_{2.5}$ (particulate matter). These pollutants do not all have the same kind of impact; they may be acidifying (SO_2), eutrophying (NO_x) or induce respiratory problems (PM_{10} and $PM_{2.5}$). For these emissions the impact location is important, because weather conditions influence the effects and therefore the damage caused. Population density is another important factor. The scale and magnitude of damages are influenced by the degree of exposure of people (health damage) and crops (economic damage) to the various air-polluting emissions. In both respects (weather conditions and exposure) the height at which emissions take place is also important.

3.1.4 Radioactivity

In the nuclear chain, radioactive emissions are the most important determinant of external costs. Damage cost estimates are very sensitive to assumptions regarding the time horizon of the impacts assessed. In this study a standard time horizon of 100,000 years has been assumed (CE, 2007). The long-term impacts of possible leakages from nuclear waste storage facilities have not been taken into account, however, because it is not possible to make a reasonable assessment of these costs. This does not mean that they are not important or significant, though.

3.2 Shadow pricing in general

In this report the external costs of different emissions and pollutants are calculated using so-called *shadow prices*. In principle, a shadow price is a measure of the change in welfare due to an extra unit of a given good or service. In conventional markets with perfect competition, this measure can be expressed simply as the market price of the good or service concerned. As a market for environmental quality is lacking, however, to be able to account for welfare changes resulting from changes in environmental quality, shadow prices need to be developed as a measure of the monetary value to be assigned to a given environmental effect.

There are two main approaches to calculating shadow prices: the damage cost approach and the avoidance cost (or abatement cost) approach (CE, 2010). They differ as follows. In the damage cost approach, the overall impacts of emissions are calculated by taking into account all the various forms of damage to health, nature, crops and so on. These damages are quantified in one of two ways: using one of several formal valuation methods (in particular, stated preferences techniques based on questionnaires, and revealed preferences techniques based on observation of the real market) or, alternatively, the estimated direct costs (of hospital admittance, for example). The goal is to obtain a realistic estimate of the associated damages. In the avoidance cost approach, shadow prices are set with reference to the emission reduction target in force for the pollutant concerned and, more specifically, the costs associated with meeting those targets. This is thus an estimate of what society is willing to pay to mitigate one tonne of the emission(s) involved.

In this report we have generally adopted the damage cost approach, since we simply wish to know what damages can be attributed to changes in emissions of each of the specific pollutants[22]. Our aim here is to be able to assess the damage costs per MWh of generated electricity for each type of power plant. In addition, shadow prices based on damage costs are generally higher, so the risk of underestimating environmental damages is limited. An exception to this are the cost estimates we have adopted for global warming due to GHG emissions. The reason for this is that for GHGs in the short term (until 2020) shadow prices based on damage costs are lower than those based on avoidance costs and there are major uncertainties regarding long-term environmental impacts. For the period up to 2020, therefore, GHG-related costs have been based on avoidance costs and beyond that year on damage costs. To express future costs in today’s terms a discount rate has been employed. Further details on the methodology of the analysis are provided in annex A.

---

22 Further guidance on when the respective approaches should be used is provided in Annex A.

By using shadow prices, both average and marginal costs can be estimated. In the case of damage costs, marginal costs represent the costs associated with one tonne of additional emissions. Marginal costs are not constant and often depend on the emissions already in place. In this report we provide only central, average, estimates of damage and avoidance costs, though, because detailed information on marginal values is unavailable. The uncertainty surrounding these figures is very high: for the classical pollutants, for example, the confidence interval can be calculated as lying between 1/3 of and 3 times the central value (Spadaro and Rabl, 1999). In this study we have adopted the values per tonne of emissions cited in the Handbook of Shadow Prices (CE, 2010). These values can be viewed as averages and apply to any change in emissions.

The methodology employed here to derive shadow prices draws extensively on the results of the NEEDS[23] project, the final stage of the ExternE series of projects financed by the European Commission (the project was concluded in 2008). Since 1991, ExternE has engaged a network of over 50 research teams from more than 20 countries to estimate the external costs of energy production. Despite difficulties and uncertainties, ExternE has become a widely recognised source of both methods and results when it comes to estimating the external costs of pollution[24].

A related EU-funded research project, likewise concluded in 2008, was CASES (Costs Assessment for Sustainable Energy Systems)[25]. The main goal of CASES was to compile coherent and detailed estimates of both the external and private costs of energy production for the EU and certain non-EU countries under different energy scenarios through to 2030. The Excel tool with external costs per tonne of emission of the specific pollutants that was used in the aforementioned Handbook (CE, 2010) was developed for both the NEEDS and the CASES project. In that report these costs, which were originally reported in prices of 2000, have been converted to 2008 prices using the HICP (Harmonised Index of Consumer Prices for the Euro zone), and we will simply reiterate these figures. The methodology used to derive the various damage costs is described in annex A of the present report.

3.2.1 Shadow prices for the combustion stage

Different shadow prices have been used for the precombustion and combustion stage of emissions attributable to power generation, since several different fuel origin scenarios are examined. In this section, shadow prices for the combustion stage are analysed under the assumption that electricity generation is taking place in the Netherlands. Table 7 provides a summary of the cost values adopted per tonne of the various pollutant for the Netherlands. The values for classical pollutants are differentiated according to emission height ('high emission release height' is above 100 metres and these values should be used for power plant *combustion* in Table 7; 'low emission release height' is below 100 metres, so that e.g. *transport* emissions fall into this category, see Table 8; 'unknown height' provides an average figure). The values include the results of modelling impacts within Europe as well as the results of Northern-Hemispheric Modelling, i.e. valuation of impacts of the emissions released in Europe on areas situated outside Europe.

---

23 New Energy Externalities Developments for Sustainability.

24 For more information see http://www.externe.info.

25 For more information see http://www.feem-project.net/cases/.

For certain pollutants like PM_{10}, additional impacts associated with non-European receptors are very minor: less than 1% of the total value. For the calculations in the present report the high values were used, under the assumption that combustion-related emissions are released relatively high, via power plant stacks.

Table 7 **Total impact of the specific pollutants, in € per tonne of emission, discounted to the year of emission 2008; values for emissions from the Netherlands**

Pollutant	External cost 2008 at high emission release height
NO_x	8,647
PM_{10}	1,961
$PM_{2.5}$	29,925
SO_2	12,428
CO_2	25
CH_4	630
N_2O	7,450

Source: Calculations by CE Delft; based on CASES, 2008 and Goedkoop et al., 2009.

In Table 7 a shadow price of 25 € per tonne CO_2 has been used to express future damages related to CO_2 emissions in today's prices. This value is based on the avoidance cost approach, according to the recommendations of CE (2010). As the future damage costs of CO_2 are expected to increase in real terms, however, in this report we have carried out a sensitivity analysis using not only the central value of 25 € per tonne CO_2 but also values of 55 € per tonne (estimated value in 2030) and 85 € per tonne (estimated value in 2050).

3.2.2 Shadow prices for the precombustion stage

For the precombustion stage several different scenarios were considered, depending on where the power plant fuel is sourced. This will influence the shadow prices used for analysis. Table 8 provides an overview of the shadow prices used in the precombustion phase in the different fuel-origin scenarios, excluding gas from the Netherlands (since in that case the values of Table 7 apply). For the calculations the 'low emission release height' values were used, under the assumption that the emissions associated with the precombustion stage (transport and mining) generally occur at low heights (< 100 m). Since part of this transport will be across the ocean or Siberia, for example, in reality these values may sometimes be lower, but this approach guarantees that these external costs have not been underestimated. The values for precombustion for non-European countries have been roughly estimated using the ratio of GDP at PPP per capita between the country of origin of the fuel source and the EU. The reason for this adjustment is that the bulk of the value of damage costs can be attributed to human health effects, and among these effects increased mortality is the most significant endpoint. This endpoint was evaluated in the NEEDS project using the concept of the Value of Life Year Lost (VOLY), using a stated preferences survey. The estimate of VOLY is highly dependent on personal income, for which and GDP at PPP per capita can be used as a proxy. In addition, for human health damages, an adjustment for population density has been made using factors obtained by running a regression of estimates for different countries from the NEEDS project against population density. Although other factors like background concentration, meteorological conditions, etc. also play a role here, in this simple approach they are assumed not to have any significant influence on the estimates. In addition, because precombustion emissions contribute little to the total value of damages, we do not consider a very detailed adjustment necessary to maintain reliability.

For GHGs, the same values have been used for all countries (i.e. the same values as those presented in Table 7), reflecting the notion that the impact of these emissions does not depend on emission location and that the European policy targets could ideally refer to the entire globe. Such an approach may lead to a certain overestimation of these values (as damage values for countries like Brazil and Algeria can be expected to be lower than those for Europe), but as mentioned earlier, because of the major uncertainties involved and the rising value of damages due to GHGs, we prefer to present an overestimate rather than an underestimate. Table 8 below reports the adjusted values of damages for low emissions for all countries considered in this report.

Table 8 Total impact of the specific pollutants, in € per tonne of emission, discounted to the year of emission 2008; values for emissions dependent on fuel origin

Pollutant	External cost 2008 at low height of release						
	Algeria	Australia	Brazil	Canada	Norway	Russia	South-Afrika
NO_x	2,821	7,695	3,122	10,026	3,773	2,692	3,421
PM_{10}	247	950	346	975	352	2,263	403
$PM_{2.5}$	1,652	16,885	2,237	6,298	7,997	32,196	2,615
SO_2	2,589	7,273	3,114	10,035	4,128	5,584	3,357
CO_2	25	25	25	25	25	25	25
CH_4	630	630	630	630	630	630	630
N_2O	7,450	7,450	7,450	7,450	7,450	7,450	7,450

Source: Based on CASES, 2008. For Norway and Russia the values have been taken directly from the spreadsheet tool developed in the NEEDS and CASES projects (CASES, 2008).

In this chapter we have defined the shadow prices used in this study for quantifying the external costs attributed to one tonne of each of the pollutants considered. As can be seen from the table above, the monetary value assigned to CO_2 seems relatively low compared to the other values[26]. However, in order to draw conclusions on the environmental impacts of electricity generated in different types of power plant we have to know how many tonnes of each pollutant a power plant emits. If this amount is far larger for CO_2 than for other pollutants, for example, then the overall impact of CO_2 may be substantial.

26 As indicated earlier, the value of 25 € per tonne CO_2 will be subjected to some sensitivity analysis using higher values, since the (future) impact of CO_2 emissions is very uncertain and we do not wish to underestimate these costs.

4 Environmental costs associated with different power plants

4.1 Introduction

In chapter 3 the various shadow prices for valuing environmental costs per tonne of pollutant were determined. The next step is to assess how many tonnes of the various emissions are to be associated with a given amount of electricity production in different types of power plant. By combining these emissions data with the shadow prices per unit emission, the external costs for the various power plants can be estimated in € per MWh.

Another relevant factor in this respect, completing the picture, are the external costs (in Euro per MWh) of accidents attributable to different types of power plant and their respective fuel chains. To quantify these, shadow prices are again used (see section 4.2).

For every power plant type and fuel origin scenario, the external costs of CO_2, CH_4, N_2O, SO_2, NO_x, PM_{10} and $PM_{2.5}$ have been determined. Radioactive releases have also been taken into account where relevant (nuclear), as well as accidents, the cost estimates for which are discussed in the next section.

4.2 Shadow prices of accidents

In this section the external costs of accidents in the respective fuel life cycles are calculated. First, risk-neutral external costs due to accidents resulting in direct mortality are given. Since individuals as well as companies exhibit risk aversion, we have then tried to calculate these external costs taking risk aversion into account. A nuclear disaster leads not only to direct deaths, but also to long-term casualties. The external costs of these long-term damages have been estimated in the third subsection. Finally, we discuss the external costs of accidents for other energy sources (biomass, wind).

Risk-neutral external costs

Energy-related accidents are tracked in databases, which permit calculation of the probabilities of accidents of a certain magnitude (in terms of number of deaths and injuries). These probabilities are important for estimating the associated risk. The ‘risk-neutral’ approach to measuring the impact of accidents per MWh (per year) is given by:

$$risk = probability \times magnitude$$

In ExternE (2005) a monetary value is assigned to accidents using the so-called Value of statistical life (VSL). As some of the costs of accidents are internalised by way of insurance premiums and higher wages, the external costs of accidents are in fact lower than this value. A distinction has been made between work-related accidents (where the victims are employees) and non-work-related accidents. The assumption is that 80% of the costs of work-related accidents are internalised in OECD countries and 50% in non-OECD

countries. For non-work-related accidents, 50% of the damage costs are internalised in OECD countries, and 20% in non-OECD countries.
The risk-neutral external costs of accidents (direct deaths) for different energy sources are reported in Table 9.

Table 9 **Risk-neutral external costs of accidents (in € per MWh), direct deaths, 2008 prices**

	OECD countries	Non-OECD countries	China
Coal	0.0057	0.053	0.10
Gas	0.0044	0.010	-
Nuclear	0.000033	0.000033	-

Source: Hirschberg et al., 2004.

Risk aversion

It is debatable whether a risk-neutral valuation of accidents can justifiably be used, since insurance companies as well as individuals exhibit risk aversion. Risk aversion is the phenomenon of individuals (or companies) not attaching the same value to risks with the same expected value. If individuals or insurance companies are risk-averse, this means the external costs of the existence of risks are higher than the expected value. In other words: the external costs of an accident with large damages but a small probability are higher than those of an accident with small damages and a large probability, even though these accidents have the same expected value.

Unfortunately, the extent of risk aversion of individuals as well as other economic players is unknown, so we have had to estimate risk aversion based on our best knowledge[27]; see Table 10.

Table 10 **Aversion factors (assumed) for different energy sources and regions**

	OECD countries	Non-OECD countries	China
Coal	10	10	10
Gas	20	20	-
Nuclear	708	708	-

Source: Calculations by CE Delft; based on Jonkman et al., 2003.

The risk aversion factor is highest for nuclear power, since in this case there is a very small chance of an accident with a very large impact. The risk-neutral external costs of accidents (direct deaths) for nuclear power (see Table 9) are based on data from the Chernobyl disaster. We have assumed that the probability of another 'Chernobyl' is around 2 : 1,000,000, with a corresponding risk aversion factor of 708[28].

The external costs of accidents (direct deaths, with risk aversion) are given in Table 11.

[27] The risk aversion factors are based on the risk aversion measure discussed in Jonkman *et al*. (2003), which amounts to: *expected value* + *[A*standard deviation*] with A=1.

[28] See also: '*Nieuwe Elektriciteitscentrale in Nederland*', CE (2007), p. 48.

Table 11 **External costs with risk aversion for accidents (in € per MWh), direct deaths, 2008 prices**

	OECD countries	Non-OECD countries	China
Coal	0.057	0.53	1.0
Gas	0.087	0.21	-
Nuclear	0.034	0.034	-

Source: Hirschberg et al., 2004.

Long-term damages

A nuclear accident will result not only in direct deaths, but also in casualties in the medium to long term. The nuclear accident at Chernobyl has shown that there are types of cancer that will only start to increase several years after the accident. Recent estimates of the number of deaths resulting from the Chernobyl disaster range from 4,000 up to around 100,000.

For Belarus and Ukraine, it has been estimated that the damages occurring in the first 30 years after the Chernobyl disaster will amount to US$ 436 billion. We have assumed that these long-term damages are not internalised by way of insurances. Divided over all the nuclear energy produced worldwide over the last 30 years, the long-term damage costs, with no risk aversion, equal 0.033 €/MWh[29]. This is the risk-neutral way of measuring damages. To take risk aversion into account, this estimate has to be multiplied by a factor 708 (see Table 10). This means that for nuclear power the long-term external cost of accidents is 23 €/MWh.

Other energy sources

Until now our calculation of the external costs of accidents has focused on certain energy sources (coal, gas, nuclear). In this subsection we consider the other energy sources: biomass and wind.

Biomass

It has been assumed that in the case of biomass there are no significant uninsured accidents in the life cycle[30].

Wind

Volume 6 of ExternE (1995) contains an estimate of the damages due to accidents in the life cycle of wind turbines, with a focus on health impacts in turbine manufacturing, construction, operation and maintenance activities. It was concluded that these damages are very insubstantial: less than 1% of the price of electricity. Furthermore, these damages are likely to be internalised to a large extent, which means that the external costs of wind fuel cycle accidents may be even smaller. We therefore conclude that the external costs of accidents in the wind fuel cycle are negligible.

Conclusions

The total external costs due to accidents in the life cycle of the different energy sources are reported in Table 12.

---

[29] Using a discount rate of 3% and assuming damages evenly distributed over the entire period.

[30] For Brazil this is perhaps debatable, but even then the number of victims related to uninsured accidents is not assumed to reach the extent related to the other chains studied (coal, gas, nuclear).

Table 12 **Total external costs with risk aversion for accidents (in € per MWh), 2008 prices**

	OECD countries	Non-OECD countries
Coal	0.057	0.53
Gas	0.087	0.21
Nuclear	23	23
Biomass	≈0	-
Wind	≈0	-

Source: Hirschberg et al., 2004 and calculations by CE Delft; based on Jonkman et al., 2003.

4.3 External costs of emissions and accidents per plant type

Based on an electrical output of 6,000 GWh per year in the various power plants, Table 13 shows that the amount of CO_2 emissions in tonnes per year is the most substantial (positively as well as negatively). This holds for every power plant type, except for wind energy. This table reports the aggregate emissions occurring in the precombustion and combustion phases.

Table 13 **Total emissions (precombustion and combustion) per power plant type assuming 6,000 GWh/yr output (tonne per year)**

	CO_2	CH_4	N_2O	SO_2	NO_x	PM_{10}
Coal	4,404,528	5,358	0	441	1,095	56
Coal CCS	605,977	6,457	0	131	1,042	46
Coal/50% biomass	2,248,662	2,772	10	626	1,614	531
Coal 50% biomass CCS	-2,136,887	3,341	12	493	1,668	627
Nuclear	Very low					
CCGT	2,136,410	224	0	53	1,528	7
CCGT CCS	291,990	249	0	59	1,705	7
Multi-fuel CCGT	250,222	5,724	0	121	1,415	41
Multi-fuel CCGT CCS	657,770	6,996	0	141	1,730	39
Gas CHP	2,173,890	228	0	54	1,555	7
Biomass (CFBC)	11,038	208	22	906	2,387	1,126
Biomass (CFBC) CCS	-5,529,950	254	27	969	2,601	1,368
Wind	0	0	0	0	0	0

Source: Calculations by CE Delft; based on an update of CE (2007).

By combining the amount of emissions per pollutant with the shadow prices derived earlier in this report, the following external costs per MWh can be calculated for the various power plant types (Table 14).

Table 14 Total external costs per plant type (in € per MWh)

Power plant	Pollutant								
	CO_2	CH_4	N_2O	SO_2	NO_x	PM_{10}	Radio-activity	Acci-dents	**Total**
Coal	18.35	0.56	0	0.82	1.55	0.44	-	0.057	**21.78**
Coal CCS	2.53	0.67	0	0.16	1.47	0.50	-	0.057	**5.39**
Coal/50 % biomass	9.37	0.29	0.01	1.11	2.45	0.68	-	0.057	**13.92**
Coal 50% biomass CCS	-8.90	0.35	0.01	0.79	2.55	0.81	-	0.057	**-4.33**
Nuclear				0.1			0.02-8.3	23	**23.1-31.4**
CCGT	8.90	0.02	0	0.08	2.15	0.1	-	0.087	**11.34**
CCGT CCS	1.22	0.03	0	0.09	2.4	0.05	-	0.087	**3.88**
Multi-fuel CCGT	1.04	0.60	0	0.15	2.02	0.46	-	0.087	**4.33**
Multi fuel CCGT CCS	2.75	0.73	0	0.17	2.46	0.54	-	0.057	**6.71**
Gas CHP	9.06	0.02	0	0.09	2.18	0.04	-	0.087	**11.48**
Biomass (CFBC)	0.42	0.02	0.03	1.56	3.76	1.08	-	0	**6.87**
Biomass (CFBC) CCS	-23/04	0.03	0.03	1.62	4.13	1.28	-	0	**-15.95**
Wind	0	0	0	0	0	0	0	0	**0**

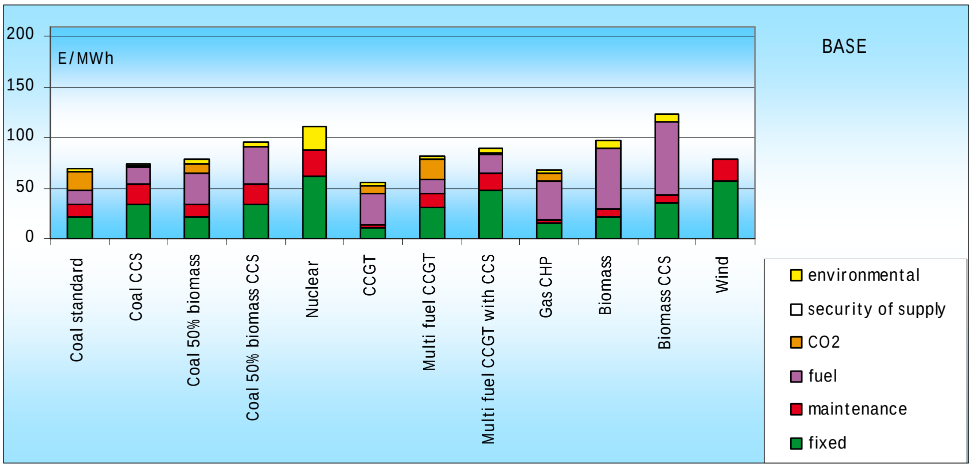
Source: Calculations by CE Delft, based on CE, 2007 and the NEEDS and CASES projects (CASES, 2008).

4.4 Comparing total production costs, including environmental costs and accidents

In this section we report the results of comparing the direct and indirect (external) production costs of different power plant types in Euro per MWh, as derived so far. In chapter 2 we reviewed the various operating costs when only direct production costs are taken into account (see Figure 2). When environmental costs, including accidents and radioactivity, are also factored in, the picture changes. Below, three different figures are presented, one assuming a CO_2 shadow price of 25 € per tonne, one with a shadow price of 55 € per tonne (2030) and one with a shadow price of 85 € per tonne (2050)[31]. As can be seen, power plants now considered relatively ‘cheap’ become more expensive when environmental damages and accidents down the fuel life cycle are factored into the equation.

[31] NB: the values of external costs (shadow prices) have been calculated for 2008. When estimates are being made for CO_2 emissions in other years (2030 and 2050) it would be reasonable to recalculate the external costs of other emissions, too. This has not been done here, though, since the figures are intended mainly to show what a rise in CO_2 price might mean for differences in total production costs.

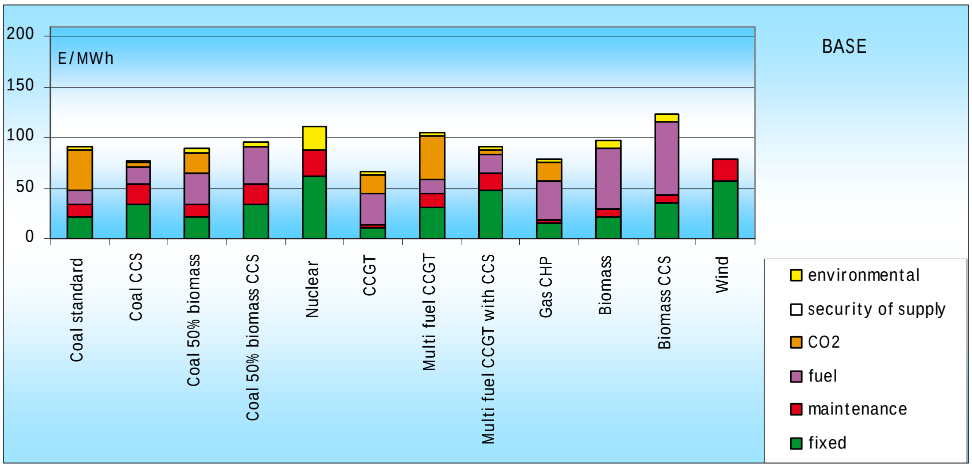
Figure 16 **Comparison of production costs of different power plants (in € per MWh), including environmental costs and accidents and assuming a CO_2 price of 25 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

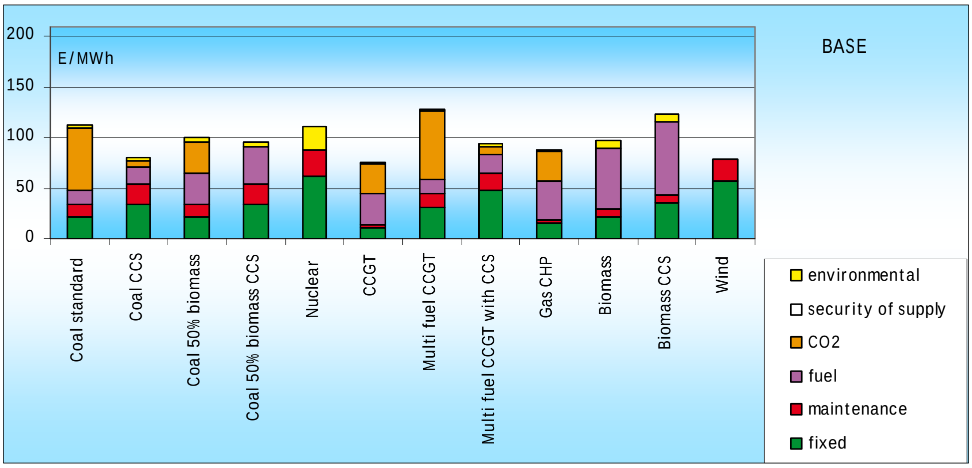
Figure 17 **Comparison of production costs of different power plants (in € per MWh), including environmental costs and accidents and assuming a CO_2 price of 55 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

Figure 18 **Comparison of production costs of different power plants (in € per MWh), including environmental costs and accidents and assuming a CO_2 price of 85 € per tonne**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al. (2003), NEEDS and CASES (CASES, 2008).

As can be seen from these three figures, CO_2 emissions clearly have the greatest impact on the comparison of external environmental costs (in the case of coal-fired power plants without CCS, for example, 70 to 85% of the total external environmental costs studied).

In the next chapter we extend the analysis of external costs further by quantifying the external costs associated with land use.

5 Land use

5.1 Introduction

In this section we consider the issue of valuing the external costs associated with land use for biomass production. For other types of power generation, the costs of land use are assumed to be internalised, for example in land prices, and are therefore not external. For wind energy, in particular, the external costs of land use are hard to quantify or are estimated to be limited. Impacts from visual intrusion are difficult to value, while impacts from noise are quite low. Also, both types of impact can be minimised through planning and consultation. When quantified, impacts on birds and animals prove negligible[32].

With regard to biomass production, the main impact of land use is damage to ecosystems due to the effects of land occupation and conversion. The biodiversity impacts associated with land conversion are generally substantial. Unfortunately, there is as yet no consensus on how these can best be calculated. This section will therefore explore the effects of occupation of a given area of land for a certain time.

Not all types of land occupation have the same effect on biodiversity. We therefore distinguish different types of land use. When a certain area is occupied we assume it causes damage to the ecosystem, because it cannot return to the reference state. If the number of species in the occupied area is lower than the number of species in the reference situation, we consider occupation to result in damage.

For valuing ecosystems we have adopted the NEEDS approach, which is based on work by Köllner (2001). This approach compares the species abundance of a specific type of land use (S_i) to that of a reference type of land use (S_{ref}). Species abundance is measured as the number of vascular plant species per square metre. The reference land use is a composite of various land uses that would occur in Europe without any human intervention (woodland).

The NEEDS approach uses the inverse of the relative species abundance, termed the Potentially Disappeared Fraction (PDF):

$$PDF_i = 1 - \frac{S_i}{S_{ref}} \qquad (1)$$

For valuing land use, we used the approach developed by Kuik *et al*. (2008) in the CASES project. In this project, PDF was defined in terms of Ecosystem Damage Potential (EDP). On the basis of 24 studies on valuation of ecosystems, the average value per EDP per hectare per year was calculated as equal to € 4,706 (2004 prices). This is the average global value (mainly for Europe and North America) and will therefore not reflect very specific local conditions. However, the value can serve as a first approximation.

---

32 http://www.externe.info/externpr.pdf.

In the ReCiPe project (Goedkoop *et al*., 2009) the average PDF values for different land use types have been estimated based on data from the United Kingdom and Switzerland. In ReCiPE, two effects are considered:

1. The regional effect. The regional damage is the marginal species loss in the surrounding area, attributable to occupation reducing the size of the surrounding area and thus the number of species found there.
2. The local effect. The local damage is the marginal species loss in the occupied area itself.

The potentially disappeared fractions (PDF) associated with both these effects are summed. For certain land use types, the total PDF value may therefore be greater than 1. See Table 15[33].

Table 15 Average PDF values for 18 land use types

Land use type	PDF (per m^2 per year)
Monoculture Crops/Weeds	1.39
Intensive Crops/Weeds	1.33
Extensive Crops/Weeds	1.29
Monoculture Fertile Grassland	1.13
Intensive Fertile Grassland	0.92
Extensive Fertile Grassland	0.69
Monoculture Infertile Grassland	0.85
Extensive Infertile Grassland	0.44
Monoculture Tall Grassland/Herb	1.36
Intensive Tall Grassland/Herb	1.05
Extensive Tall Grassland/Herb	0.75
Monoculture Broadleaf, mixed forest and woodland	0.63
Extensive Broadleaf, mixed and yew LOW woodland	0
Broad-leafed plantation	0.81
Coniferous plantations	0.91
Mixed plantations	1.10
Continuous urban	1.4
Vineyards	0.86

Source: Goedkoop et al., 2009.

Multiplying the PDF values from Table 15 by the monetary value of € 0.47 per PDF per m^2 per year (derived from the CASES project), yields the monetary values reported in Table 16.

33 The PDF values in Table 15 are derived for European circumstances (Goedkoop et al., 2009). We have assumed they can be applied to Canadian forestry, although further analysis is necessary to assess whether this is indeed reasonable.

Table 16 **Values of external costs for occupation of a certain area of land for different land use types (2004 prices)**

Land use type	External costs (€ per m^2 per year)
Monoculture Crops/Weeds	€ 0.65
Intensive Crops/Weeds	€ 0.63
Extensive Crops/Weeds	€ 0.61
Monoculture Fertile Grassland	€ 0.53
Intensive Fertile Grassland	€ 0.43
Extensive Fertile Grassland	€ 0.32
Monoculture Infertile Grassland	€ 0.40
Extensive Infertile Grassland	€ 0.21
Monoculture Tall Grassland/Herb	€ 0.64
Intensive Tall Grassland/Herb	€ 0.49
Extensive Tall Grassland/Herb	€ 0.35
Monoculture Broadleaf, mixed forest and woodland	€ 0.30
Extensive Broadleaf, mixed and yew LOW woodland	-
Broad-leafed plantation	€ 0.38
Coniferous plantations	€ 0.43
Mixed plantations	€ 0.52
Continuous urban	€ 0.66
Vineyards	€ 0.40

Source: Own calculations based on Goedkoop et al., 2009 and Kuik et al., 2008.

External costs of Canadian biomass

The assumption is that land conversion due to demand for (Canadian) biomass is negligible. We have therefore calculated only the external costs attributable to loss of biodiversity associated with land occupation.

The biomass from Canada is assumed to be in the form of pellet boards made from sawdust deriving from coniferous plantations. Sawdust is a sawmill by-product.

One hectare of forest comprises approximately 45 tonnes (dry matter, d.m.) of trees (Bradley, 2006). When the trees are harvested, around 40% of this wood remains in the forest as harvesting waste (Smeets, 2008). The other 60% (28 tonnes) is transported to the sawmill as roundwood. For 1 tonne of planks, approximately 1.5 tonnes of roundwood is required (Smeets, 2008). This means **19 tonnes of planks** can be produced from this one hectare of forest. Around 10% of the roundwood consists of bark and cannot be used for pellet production. The one hectare of forest therefore produces 6.6 tonnes (d.m.) of sawdust, available for pellet production. For pellet production around 20% of the sawdust is needed for drying the wood. This means **5.3 tonnes of pellets** can be produced from one hectare of forest.

One hectare of Canadian forests thus yields approximately 19 tonnes of planks and 5.3 tonnes of pellets. To attribute this total land use to planks and pellets, the ‘economic allocation method’ is used. Mill-gate prices for pellets are reported to be approximately $ 100 per tonne (CE, 2007). Combining the export volume and export value[34] of planks (sawnwood NC) from Canada to the Netherlands gives a price of $ 1,940 per tonne (FAO stat, 2007).

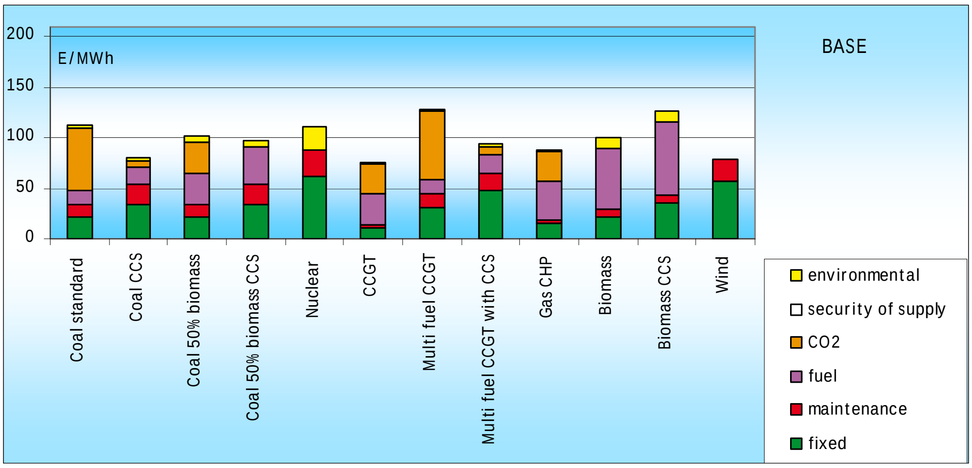
34 Ideally it would be better to use mill-gate values for both pellets and planks, in order to avoid transportation being incorporated in the value used. However, CE Delft has no information on the mill-gate value of planks.

This means that 1% of the total land use should be attributed to pellets and the remaining 99% to planks (5.3*100/(19*1,940)+(5.3*100) = 1%). In other words, 100 m^2 of land is necessary to 'produce' 5.3 tonnes of pellets.

Using a net heating value of 18.5 GJ per tonne of dry matter and an electricity production efficiency of 46%, land use for pellets totals 8 m^2 per MWhe. Table 16 shows that the external cost of land occupation amounts to 0.43 € per m^2 per year (land use type: coniferous plantations).

The external costs of land use associated with biomass from Canada are therefore **3.43 € per MWh**. If this is added to the external production costs of a coal-fired power plant running on 50% biomass and to the production costs of a 100% biomass-fuelled plant, this yields the picture shown in Figure 19.

Figure 19 Comparison of production costs of different power plants (in € per MWh), including environmental costs, accidents and land use costs (biomass) and assuming a CO_2 price of 85 € per tonne



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft based on (an update of) CE (2007), Hirschberg et al. (2004), Jonkman et al . (2003), NEEDS and CASES (CASES, 2008), Goedkoop et al. (2009) and Kuik et al. (2008).

6 Security of supply

6.1 Introduction

This section is based on the CASES report on national and EU-level estimates of energy supply externalities (CASES, 2007). In this document, energy security is defined as follows: “a state in which consumers and their governments believe, and have reason to believe, that there are adequate reserves and production and supply distribution facilities available to meet their requirements in the foreseeable future, from sources at home and abroad, at costs which do not put them at a competitive disadvantage or otherwise threaten their well-being. Insecurity arises as a result of physical failure of supplies or as a result of sudden and major price changes” (CASES, 2007, based on Belgrave, 1987). The impacts associated with energy security have two components: energy price fluctuations and Value of Lost Load (supply interruptions). These are described in the next two sections.

6.2 Energy price fluctuations

The external costs associated with energy price fluctuations can provide an indication of the value society attaches to having a more diverse fuel mix and being less reliant on a single fuel source (generally oil). Macroeconomic costs of energy insecurity are examples of pecuniary externalities where the actions of one economic agent affect another agent via changes in prices. The CASES report (2007) focuses on energy security with respect to oil, gas and coal as it relates to electricity supply, with the focus on the EU region. Most literature refers to the prices of oil. If we follow mainstream economic modelling of energy prices and their macroeconomic linkages, there is a clear line of causation from oil price increase to macroeconomic impact:

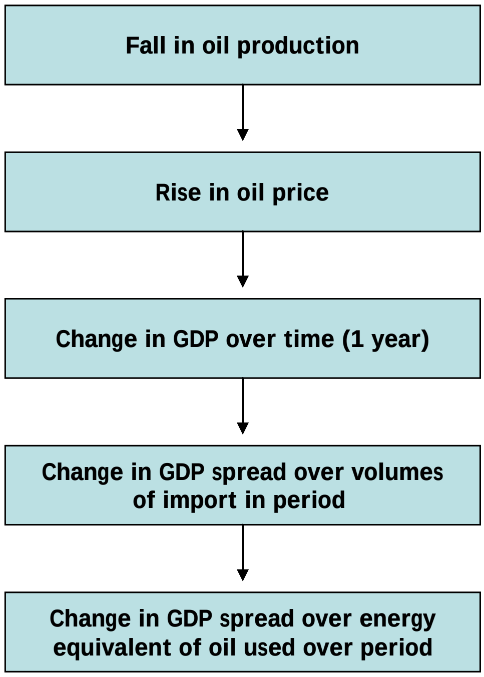
- Payments for oil imports result in a worsening trade balance for the importing country.
- The consequent current account and balance of payment deficits, and associated depreciation of the exchange rate, result in other, more costly imports from outside the EU.
- Higher import costs – for oil and other commodities – may lead to higher price levels and inflation; higher unemployment may result from the transfer of resources needed to pay for the oil imports; lower GDP may result.

In countries reliant on and inflexible with regard to their use of oil, there will be a greater decline in home output relative to other countries.

A number of general equilibrium models have been developed to simulate the impact of energy price increases and/or supply disruptions on the economy and these have largely focused on the impact of oil supply shocks that last for a year or more. The outputs of such models are helpful in isolating these impacts from other economic trends. Despite differences in the models, there is some consistency in the pattern and extent of GDP changes attributable to increased oil prices. Thus, for the industrialised countries a 10 $ price increase per barrel gives rise on average to a 0.5% loss of GDP (EC, 2002), or a linearly proportionate scaling of this figure (IMF, 2000). In the Euro zone it appears that GDP is more sensitive to oil price increases than for the industrialised countries as a whole. In this zone a 50% increase in oil prices results in a decline of approximately 0.4% in annual GDP in the first year (this is simply the arithmetic mean of the results from different studies).

In order to estimate the external effects of energy insecurity in terms of cost per MWh, the CASES report follows the methodology of Hunt and Markandya (2004). The model used for calculations is a simplified model of the economy which estimates the external pecuniary effect of a decline in the supply of oil. Figure 20 shows the successive steps of this methodology.

Figure 20 Methodology for estimating macroeconomic variables of a decline in oil supply



Source: CASES, 2007.

Using this methodology and GDP data for the EU-27 in 2005, a fall in GDP due to the assumed 50% increase of oil price has been calculated as being equal to 0.4%, or approximately € 43.8 billion annually. Because the proportion of oil used in the EU for power generation was found to be 5%, with 4% of generation taking place in oil-fired power plants, the fraction of oil price variation to be apportioned to electricity generation has been calculated as 4% * 5% = 0.002%. To obtain an annual equivalent (expected value), this figure has been multiplied by the probability of the event occurring in any given year. Based on historical data, 20% probability has been assumed. The change in GDP has been converted to a change per barrel of oil consumed and, consequently, using a figure of 40% for thermal efficiency, to a value per MWh. The resulting expected value for the EU-27 – assuming a 0.4% annual loss in GDP – has been calculated as equal to **€ 0.004 per MWh**, within a range of 0.001–0.008 for a 0.1% and 0.8% annual loss of GDP. The calculation steps are reproduced in Table 17.

Table 17 **Summary of cost estimation for oil security externality**

	EU-27
GDP loss over 1 year (€)	43,798,143,600
GDP loss over 4 years (€)	175,192,574,400
Original oil consumption (mb/day)	82.5
Fall in oil consumption (mb/day)	3
New oil consumption (mb/day)	79.5
Change in GDP per barrel consumed (1 year loss) (€)	1.5
Change in GDP per barrel consumed (4 years loss) (€)	6.0
Each barrel is equal to 1,649 MWh	
Thermal efficiency	40%
Likelihood of shock	0.2
Cost estimate per MWh – 1 year loss (€)	2.29
Cost estimate per MWh – 4 year loss (€)	9.15
Cost (€/MWh) 1 year loss	0.46
Cost (€/MWh) 4 year loss	1.83
Cost proportional to electricity generation (€/MWh)	0.004

Source: CASES, 2007.

Although these calculations are for the EU as a whole, it is to be expected that under the assumptions adopted in the model, the impact for the Netherlands would be very similar because the main factors influencing the final results in the Netherlands are not that different from the EU-related factors[35].

Given all the assumptions made to arrive at the reported figures, these should be regarded as merely indicative. It should be noted that gas, coal and nuclear power account for much larger shares of electricity generation both in the EU as a whole (20-30%, compared with 4-5% for oil) and in the Netherlands (24.1% for coal and 60.4% for gas, compared with 2.1% for oil), which means any price volatility of these may have significant effects.

The costs of security of supply of oil have also been calculated in other studies, using different approaches from that applied in the CASES study. These studies also factor in costs for measures taken to increase security of supply. On the other hand, there are costs associated with a *lack* of security of supply.

Costs relating to increasing security of supply are:
– Strategic Oil reserves (e.g. US: 700 million barrels with a maintenance cost of $ 21 million a year (W1) and IEA: 4.1 billion barrels, of which 1.4 billion are government-controlled (W2); of these, The Netherlands had a stock of 37.1 million barrels in 2003, at a cost of $ 90 million a year (storage and interest (Joode, 2005)).
– US (but also EU) presence in the Middle East (Leiby, 2007), although it is debatable to what extent the military presence here can be attributed to oil security (Toman, 2002).

Costs due to lack of security of supply are:
– Costs of disruptions, which are analysed below (‘Value of Lost Load’).
– Costs of dependence on suppliers (cartel-forming).

35 In fact, the share of oil-fired power plants in the Netherlands is even smaller than for the EU as a whole: about 2.1%.

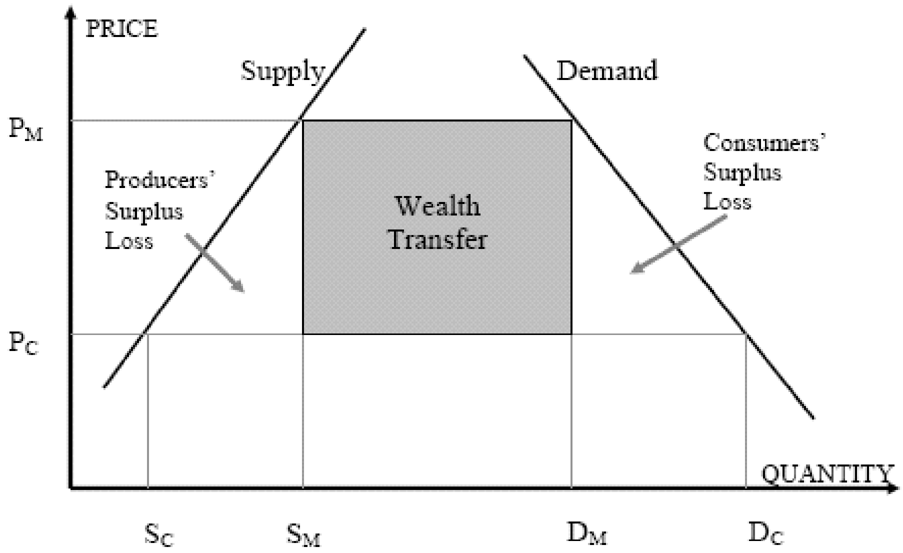
Leiby and Greene (Leiby, 2007; Greene and Leiby 1993) have identified three ways to determine the security costs of oil imports, based on three different reference points:

1. Hypothetical perfectly competitive market conditions.
2. Optimal levels of imports, given market imperfections (such as cartel-forming among suppliers).
3. A marginal (small incremental) change in imports from the current level.

Ad 1. Proceeding from the first reference situation, the security costs are taken as the difference of the costs of current oil imports relative to the competitive ideal (e.g. Greene and Leiby, 1993; Greene and Tishchishyna, 2000; Greene and Ahmad, 2005). The reference situation presumes competitive supply and demand, no unanticipated price shocks, and no unpriced environmental damages or other social costs. In other words, actual per-barrel costs of oil are compared with the costs that would exist in the absence of any market failures.

The study by Greene and Ahmad takes into account the following costs: (1) transfer of wealth, (2) reduction of the maximum output the economy is capable of producing due to the increased economic scarcity of oil (loss of potential GDP, as discussed earlier), and (3) costs of adjusting to sudden, large price changes (macroeconomic adjustment costs). In the absence of sudden price changes, the first and second types of costs still apply as long as monopoly power is used to hold prices above competitive market levels. These two costs can be illustrated as shown in Figure 21, where S_c and D_c are the domestic supply and demand under competitive conditions at price P_c, and S_m and D_m are supply and demand under the imperfect (monopoly) conditions at price P_m. The difference between domestic demand and supply (D-S) is imported.
Wealth transfer is loss of income for the oil-importing economy, which is gained by the exporting economy without the importing economy incurring extra benefits for it. The producers' and consumers' surplus losses constitute the reduction of the maximum output of the economy due to oil scarcity. The triangular area under the demand curve labelled 'Consumers' Surplus Loss' is a deadweight economic loss, a potential benefit to consumers that now no one receives. The triangular area under the supply curve labelled 'Producers' Surplus Loss' represents real economic resources spent by domestic oil suppliers to increase production that would not have been spent in the competitive market. To calculate these economic losses the hypothetical competitive market price of oil has to be estimated.

Figure 21 Illustration of economic losses at non-competitive (m) market prices



Source: Greene and Ahmad, 2005.

The third type of cost, the macroeconomic adjustment costs, arises when a sudden price shock throws the economy out of equilibrium, wages and prices are not able to adjust rapidly enough, and underemployment of labour and capital results. Over the past decade there have been important contributions to understanding the specific mechanisms by which price shocks affect the economy. Analysis of detailed sectoral job creation and destruction (Davis and Haltiwanger, 2001) has shown that oil price shocks result in more destruction than creation and have about twice the impact of monetary shocks. Furthermore, the increase in unemployment due to an oil price increase is about ten times larger than the decrease in response to a drop in price.

The total cost of oil dependence in the period 1973-2000 was calculated to be around $ 3.6 trillion (undiscounted dollars) which adjusted to present values exceeds $ 8 trillion, with roughly equal shares of the three aforementioned cost types (US oil consumption in this period was around 170 billion barrels, bringing the dependence costs down to 47 $/barrel in present values).

Ad 2. Taking the second reference point, the potential costs of oil can be defined in terms of the difference between the optimal (efficient) level and the current level of costs, recognising that certain government programmes are already in place to respond to potential market failures. One way to approach this is to evaluate government policies using cost-benefit analysis. Such a study has been conducted by Joode et al. for Dutch energy prices. They performed a cost-benefit analysis of different technologies that improve energy security (oil, gas and electricity) and calculated the 'break-even' frequency of disruptions, where the costs of the technology equal the costs of disruption. Among the investigated measures were expansion of emergency oil stocks and subsidising biofuels and biofeedstocks. For all the cases investigated, it was concluded that supply policy is hardly ever beneficial to welfare. The break-even frequency of disruptions is at a higher level than can be expected to occur in reality. However, the analysis is based on the oil prices of 2005. For biofuels to break even with conventional petroleum-derived diesel and gasoline, for example, would require an oil price of around 70 € per barrel. Current oil prices might put this policy option in a different perspective.

Ad 3. Taking the third reference point, the costs are determined that would be caused (or saved) by a marginal (small incremental) change in oil imports from the current level. The reference point can be regarded as the costs at a marginally lower import level. The marginal costs per barrel can be seen as the total costs of oil import at the current level minus the total costs of oil import at the current level minus one barrel; it is the derivative of the total costs.

This method has been applied by many authors for the US situation (Leiby *et al.*, 1997; NRC, 2002; Parry, 2004; Leiby, 2007). The most recent example of such an analysis is a study by Leiby (2007), who calculated the US costs of oil insecurity in terms of a so-called import premium; the marginal benefit to the US of decreasing oil imports. According to Leiby, this premium can be considered as import costs on top of the purchase price and includes (1) higher costs for oil imports resulting from the effect of US import demand on the world oil price and OPEC market power ('Monopsony component'), (2) the costs of reductions in US economic output during disruptions in the supply of imported oil, and (3) the costs of existing policies designed to improve oil security (e.g. maintaining the strategic oil reserve and a military presence in the Middle East). The latter costs are not included in Leiby's calculations, because they are not likely to change as a function of oil import. The results are reported in Table 18 below and compared with the results of a 1997 study. It should be noted that these costs also apply to domestically produced oil, while the oil market is an globally integrated market.

Table 18 Costs related to oil insecurity (in 2004 $ per barrel)

Effect/study	ORNL 1997 Report (2004 $/BBL)	ORNL 2006 Updated (2004 $/BBL)
Monopsony component	$ 2.57 ($ 1.54-$ 3.59)	$ 8.90 ($ 2.91-$ 18.40)
Macroeconomic disruption/Adjustment costs	$ 1.03 ($ 1.03-$ 2.05)	$ 4.68 ($ 2.18-$ 7.81)
Aggregate midpoint	$ 3.59 ($ 2.57-$ 5.64)	$ 13.58 ($ 6.71-$ 23.25)
Results in 2004 $. Columns report mean estimates and ranges that include 90% of results.		

Source: Leiby, 2007.

After recalculating the midpoint estimates from both studies indicated in the Table 18, we obtain a range of approximately € 2-6 per MWh[36], which is a far higher estimate than that reported in the aforementioned CASES study.

Conclusions

Analysis of different scenarios of oil supply and demand makes clear that security of energy supply will be a major concern for the future. Policies which reduce dependence on energy sources like oil and gas, increase investments in infrastructure and enhance political stability in the world are necessary to keep the costs of energy supply under control. For shaping these various policies it is important to gain more insight into the costs involved in security of supply and the potential benefits of reduced energy dependence. Three different methods for determining the costs of security of supply have been reviewed, using three different reference points, viz.: (1) hypothetical perfectly competitive market conditions; (2) optimal levels of imports given

36 The estimates are based on the following assumptions: 1 barrel of oil is equivalent to 1,649 MWh (as in the CASES study), exchange rate USD/Euro: 1.3 in 2006 and 1.1 in 1997; in this rough estimate. prices have not been adjusted for inflation.

market imperfections; (3) a marginal change in imports from the current level. Most existing studies on the costs of security of supply are US studies on the costs of US oil imports. The two major costs cited are economic losses due to oil prices exceeding competitive market levels (market power of oil suppliers) and the costs of oil-supply disruptions. For Europe the only known study is that by Joode et al. (2005), which provides insight into the costs and benefits of particular policies to enhance security of supply.

6.3 Value of Lost Load

The term 'security of electricity supply' refers mainly to aspects of operational reliability, taken to encompass both the production and distribution network. Quantifying security of supply is difficult, because no market for the quality of the energy supply exists, or, conversely, a market for interruptions of supply. One way of dealing with quantification of energy security is to estimate the costs of the impact of power supply interruptions on consumers.

The cost or value of interruptions in the supply of electricity is defined as the Value of Lost Load (VOLL). The aggregate value of (in)security of supply can be expressed by multiplying the probabilities of the intensity, frequency and duration of supply disruptions.

Background

The value of security of supply is strongly influenced by the cause of interruptions, since production failures usually have deeper consequences than network failures. A production failure may result in a real shortage of power, which strongly increases the price of electricity, given that demand is unlikely to be significantly affected (electricity consumption is characterised by a low price elasticity). With network failures, both suppliers and users of electricity are affected at the same moment and in the same way, implying that prices typically change only modestly. Also, a break-down of parts of the network often does not imply a total interruption, because networks are built with redundancy so that the intermittency problems can be mitigated. The consequences of network failures are therefore usually smaller than those of production failures.

As the failures from the perspective of production and networks are often presented separately, this will also be reflected in the present report.

In the *production market*, market failure can occur for three main reasons:

- Lack of transparency. As a result of insufficient market transparency, power supply and demand may not be in balance. Availability of production capacity is usually based on the prevailing peak demand, which can never be predicted beforehand with complete certainty. Predicting the demand for electricity in the long term is also very difficult. Market players are decentralised and are imperfectly informed, aggravating the problem.
- Knock-on effects of supply interruptions. A shortage in certain production capacity may lead to an interruption of other production capacity. If demand exceeds the available supply, the network frequency drops. If the network frequency deviates from the frequency of the electricity delivered to the network, it will be automatically cut off from the network. This process can continue in a cascade of production capacity being cut off from the network as soon as their supply frequencies fall outside the acceptable network bandwidth. In 2003 this kind of knock-on effect

resulted in power supply interruptions lasting several days in the US and in Italy, for example.

- Free-riding of reserve capacity. Liberalisation of the electricity production market has resulted in declining reserve capacity, as producers seek to keep their capacity as limited as possible in order to boost their profits. From a social point of view, however, it may be optimal to have more reserve capacity, to reduce the likelihood of supply interruptions. Reserve capacity has the characteristics of a public good, because for technical and economic reasons it is not easy to prevent consumers from consuming electricity. Thus, in some cases there may be free-riding of electricity consumers on the reserve capacity.

Two particular characteristics of the electricity sector worsen these three forms of market failure. On the supply side, the fact that electricity is essentially not storable implies that production must be flexible and rapidly adjustable. Thus, reserve capacity is needed for peak demand. On the demand side, there is a lack of information on real-time metering and billing (a large proportion of consumers pay a price averaged over a certain period, rather than differentiated by time and location). Households are not usually faced with high prices when these are experienced by other sectors, and their electricity demand does not respond immediately to price changes. Large firms, on the other hand, are usually subjected to real-time metering and so their marginal costs increase substantially when electricity prices suddenly rise as a result of a supply interruption, say. The marginal costs of electricity may exceed the marginal willingness-to-pay (WTP) of these firms. In such cases some firms may decide to halt their production processes to limit the losses incurred. Many large firms, however, often do not halt their activities under such circumstances, because curtailment costs may be high, leading to an increase in the added value of their products or services. Overall, i.e. for all consumers combined, electricity demand usually responds only moderately to interruptions in supply; when demand approaches maximum supply capacity, then, power prices are likely to rise sharply.

Because of these market failures, the objectives of producers may deviate from the objectives of society as a whole. If the social costs of these failures are high, there is good reason for government intervention in the electricity production market and stimulation of at least partial internalisation of VOLL-related externalities.

The situation regarding security of supply in *transmission and distribution networks* is slightly different. Investment decisions on these networks, with an obvious influence on energy security, are made by their respective operators, the transmission system operator (TSO) and the distribution system operator (DSO). In most countries these networks are still highly regulated, because they are natural monopolies; consequently, special power network regulation is often introduced. While this regulation is likely to bring the prices of electricity down, it may also put pressure on the quality of supply. Such regulation therefore usually also has components relating to the quality of electricity supply. Without quality regulation, network operators may be focused too much on network costs only, instead of on overall social costs (which include interruption costs for customers). Knowledge on the value of security of supply, or VOLL in particular, constitutes important information that is essential for determining the optimal level of network investments from a social welfare point of view.

Estimating VOLL

Calculating VOLL constitutes one of the most important approaches towards evaluating security of electricity supply. VOLL can be expressed in terms of the estimated total damage caused by undelivered electricity divided by the amount of electricity not delivered in MWh. The higher the product of VOLL and the probability of supply disturbances, the more valuable are investments in electricity generation and/or network capacity extension or improvement.

To determine the costs of interruptions in power supply, the factors causing these interruptions must be identified. Interruption costs are highly variable, owing to many factors, including differences between distinct types of customers (some sectors may suffer more from interruptions), differences in perceived reliability level (in some countries one interruption per week may be perceived as normal), differences in time of occurrence (e.g. night-time interruptions are usually perceived as less severe), differences in duration (in principle longer duration implies higher total costs, but marginal costs may be decreasing), differences in notification (advance notice tends to reduce the consequences).

Because of the impact of these factors, VOLL does not take a single value but rather a large range of values depending on the relative importance of these factors. As VOLL cannot be calculated directly, simply because no market exists in which supply interruptions are traded, it has to be estimated indirectly. In the literature on the subject several approaches can be distinguished, including:
- Revealed preferences (observations of market behaviour).
- Stated preferences (surveys to reveal WTP to avoid interruptions).
- Proxy methods (including the production function approach).
- Case studies (e.g. analyses of black-outs).

It is to be noted that estimates of VOLL vary widely across different studies. First, the values differ from country to country, depending on the amount to which a countries economy depends on a sufficient security of supply level. Second, VOLL calculated for different sectors may be very different. Third, one blackout may be very different from another, even when considering a single country or sector. Differences in the years of reference and currencies used across different studies constitute an additional difficulty in finding a reliable central estimate of VOLL, as it is sometimes challenging to choose the right inflation and conversion rates, especially when the investigated countries are characterised by large differences in living standards and purchasing power.

CASES (2007) summarises the results of several studies on the value of VOLL. This review has revealed that the values reported depend significantly on the sector under consideration. The commercial sector seems to be highly sensitive to power outages, with VOLL reaching levels up to around 70,000 $/MWh in countries like the US. Values for the residential and industrial sectors are lower on average, reaching levels of up to 25,000 $/MWh. Economy-wide values are significantly lower than those for each of the reported economic sectors; for the Netherlands the economy-averaged value oscillates around **10,000 $/MWh**, which would be equivalent to about 7,000 € per MWh.

VOLL is typically higher for countries with a relatively high GDP per capita than for those with a low per-capita GDP. The main reason is that developed countries usually have a higher share of electricity in total energy consumption and are therefore more dependent on power supply than developing countries.

Table 19 summarises the central estimates based on the literature review. The estimates are presented in two forms: as a maximum range and as an approximate 90% confidence level. The depicted ranges are an expert estimate based on the literature review and refer to the levels of VOLL in the year 2030 (so current levels would be expected to be slightly lower). With 90% confidence interval, the data range is narrowed down to 5,000-25,000 $/MWh for the developed countries and to 2,000-5,000 $/MWh for developing countries. The data suggests that the distribution is left-skewed, that is, that lower values prevail in each range and that the median value would therefore be closer to the lower bound than to the upper bound.

Table 19 Levels of VOLL in 2030: maximum range and 90% CL range (authors' estimates based on literature review)

	VOLL, entire economy in US(2007) $/MWh	
	Maximum range	**90% CL range**
Developed countries	4,000-40,000	5,000-25,000
Developing countries	1,000-10,000	2,000-5,000

Source: CASES, 2007.

Another way to try and estimate the benefits of a more secure energy supply might be to make the assumption that the costs associated with renewable energy policy can, to an extent, be regarded as a measure of the value attributed by society to a more diversified fuel mix. The extent to which this is the case is difficult to quantify, however, since one could also argue that these costs overlap with analysis on price volatility and/or are made also for other purposes and a more diverse fuel mix is just a side-effect.

6.4 Conclusions

Based on the above sections, we can conclude that with respect to energy security, the Value of Lost Load is the most important component of costs. For the Netherlands, VOLL has been estimated to be up to 7,000 € per MWh. The costs of price fluctuations have been found to be fairly negligible. The various values are reported in Table 20.

Table 20 Value (benefits) of security of supply (in € per MWh)

	Estimated value in €/MWh
Source: CASES, 2007	
Energy price fluctuations	**0.004**
Value of Lost Load (VOLL)	**7,000**
Source: other	
Energy price fluctuations and VOLL (total)	**2-6**

Source: CASES, 2007, a.o.

It seems reasonable to assume, however, that VOLL benefits are not (entirely) external, since one might anticipate these being internalised to some extent in transportation charges from network operators and financial power interruption compensation schemes. Also, one might in general argue that it is somewhat counterintuitive to regard the costs of power interruptions (VOLL) as an estimate of the benefits accruing from a more diverse energy supply.

This is because a *technical* interruption due to grid problems in itself is unrelated to the source of the electricity being transported[37].

In summary: the external costs of price fluctuations are negligible. On the information available, moreover, it does not seem reasonable to attribute an uncertain fraction of the external costs associated with VOLL as benefits of a more diverse energy supply. CE Delft is of the opinion that it is not to be expected that the benefits relating to security of supply issues influence the costs associated with (different types of) electricity production to any substantial extent.

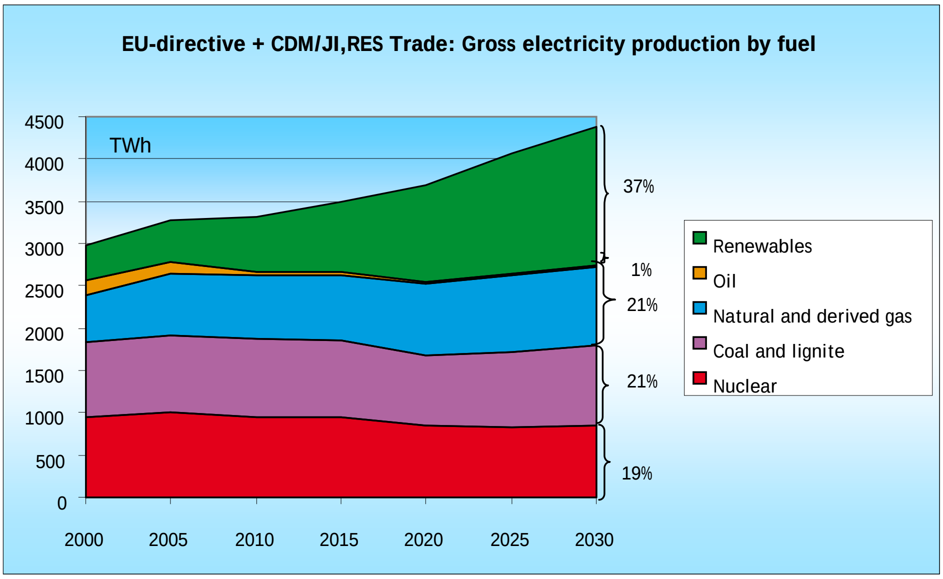
[37] Although the extent to which electricity comes from distributed generation (e.g. wind turbines, CHP) might, in theory, influence the frequency of power interruptions. This might perhaps offset the benefits associated with a more diversified fuel mix. CE Delft did not look into this issue in detail, though.

7 Flexibility of electricity supply

7.1 Introduction

The growing share of renewable energy will alter the future mix of the European electricity supply, as illustrated in Figure 22.

Figure 22 Prognoses of future EU-27 electricity production (in TWh per year)



+ RES, +CDM/JI: EC Proposal with CDM and with RES trading: scenario which takes into account RES-trading and the possibility to take emission credits from CDM, lowering the carbon price to a uniform level of 30 €/tonne CO_2.
Source: Capros et al., 2008.

This growing share of renewably-sourced power will give rise to (external) costs related to the need for a more flexible power supply to satisfactorily incorporate these intermittent energy sources, including wind. In the Netherlands it is expected that in 2020 there will be 6,000 MW of offshore and 6,000 MW of onshore wind capacity, i.e. 12,000 MW in total[38].

Many forms of renewable power generation, such as wind, wave and solar, provide intermittent output that varies with environmental conditions like wind strength, over which the operator has no control. Assimilating these fluctuations has the potential to affect the operation and economics of transmission networks, markets and output from other forms of generating capacity. It can affect the reliability of power supplies and the actions needed to ensure demand meets supply every instant. The extent to which this occurs and (therefore) the flexibility costs involved depend on several factors:
- The rise in installed wind capacity relative to total electrical output.
- The extent to which wind energy is geographically concentrated or dispersed, which influences (full-load) operating times at different locations.

[38] See, for example: *De Groei van Windenergie op Land* (EZ, VROM *et al.*, 2009).

– Different prices for flexible back-up and storage capacity during the day, for example (and therefore flexibility costs associated with and caused by wind energy).

It is sometimes said that wind energy, for example, does not reduce carbon dioxide emissions because the intermittent nature of its output means it needs to be backed up by fossil fuel plant. While wind turbines do not displace fossil generating capacity on a one-for-one basis, though, it is undeniably the case that they do displace such capacity in absolute terms, reducing both fuel use and CO_2 emissions.

The introduction of significant amounts of intermittent generating capacity will affect the way the electricity system operates. There are two main categories of impact and associated cost. The first has to do with the fact that available wind energy (as well as solar energy and, to an extent, combined-cycle gas-fired power plants) is considered 'must-run' capacity[39]. Due to renewable sources being given priority access to the grid, whenever renewable electricity is fed in, other power plants will have to ramp down, causing their average annual (base-load) operating time to decline. As a result, their (fixed) costs per MWh output will rise.

The second category of impacts, here termed 'reliability impacts', relates to the extent to which we can be confident that sufficient generating capacity will be available to meet peak demands. No electricity system can be 100% reliable, since there will always be a small chance of major failures in power stations or transmission lines when demands are high. Intermittent generation introduces additional uncertainties, and the effect of these can be quantified (UKERC, 2006). In the present study, however, it has been assumed that wind energy will not be regarded as providing base load for which sufficient back-up capacity is needed at all times to ensure that base-load demand can be met. Instead, electricity from wind farms is seen as must-run capacity which, when the wind blows, leads to a lower net demand for alternative capacity. Therefore, no additional back-up costs have been assumed (other than those relating to security of supply; see previous chapter) and this second category of impacts has therefore here been ignored.

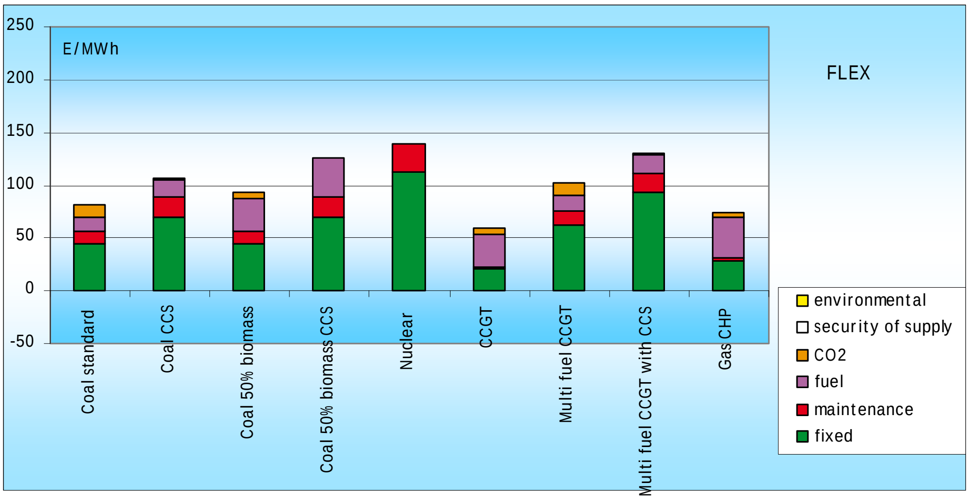
In the following sections, the impact of incorporating intermittent capacity in the energy system is assessed. As indicated above, market circumstances are complex and will change over time as the share of renewable sourced electricity increases. This makes it impossible to come up with a single quantitative figure providing a reasonable overall indication of the costs associated with flexibility demands on the energy system due to (a rising share of) wind energy. To get some feel for the upper bound of a bandwidth of these costs, though, i.e. a maximum figure, we consider two rather extreme ways to estimate the flexibility costs associated with wind power:
1. Assuming lower operating times of conventional power plants.
2. Assuming that wind energy should be able to meet base-load electricity demand, so that storage capacity is needed.

[39] Electricity cannot be stored to any substantial extent, at least not in the Netherlands itself, where there is hardly any pumped hydro storage capacity available. This option could be made available via interconnection, though.

7.2 Lower operating times of alternative production capacity

Because of the rising share of intermittent, must-run renewable capacity (mainly wind), the average annual operating times of alternative plant (e.g. coal-fired) will decline. The impact of a decline in production from 6,000 to 3,500 GWh (source: StatLine) and increased operating hours of intermittent sources on the direct fixed production costs of different conventional power plants can be seen by comparing Figure 23 below with Figure 2 earlier in the report.

Figure 23 Comparison of production costs of different conventional power plants (in € per MWh), assuming a CO_2 price of 15 € per tonne and 3,500 operating hours per year



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas sources: Netherlands and Norway (50-50%), biomass source: Canada (100%).

Source: Calculations by CE Delft, based on (an update of) CE, 2007.

Owing to lower operating times, for conventional coal-fired or nuclear power plants these fixed costs increase by up to about **50 € per MWh**, which can serve as an indication of the costs of flexibility associated with facilitating use of more intermittent energy sources in the total electricity supply.

7.3 (Additional) storage facilities

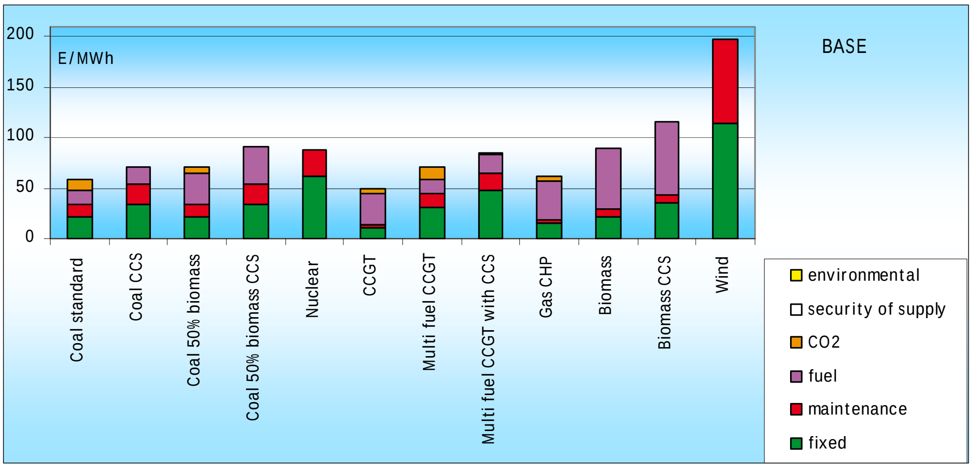
Another way to approximate the costs associated with flexibility is to assume that an intermittent source like wind energy should be able to provide base-load electricity[40]. For this to be feasible requires storage facilities[41] to level out fluctuations in wind energy supply relative to demand. Adding the estimated costs associated with these storage facilities to the production costs of wind energy leads to the picture depicted in Figure 24.

---

40 In other words: wind energy becomes demand-driven production capacity rather than supply-driven (must-run) production capacity.

41 Pumped hydro storage in Norway (via interconnection), for example, or in the future perhaps the batteries of electric vehicles.

Figure 24 **Comparison of production costs of different power plants (in € per MWh), assuming a CO_2 price of 15 € per tonne and attributing all energy storage costs to wind energy**



Assumptions: Fuel prices: gas 7 €/GJ, coal 2.5 €/GJ, biomass 6.5 €/GJ; coal source: Australia (100%), gas source: Netherlands and Norway (50–50%), biomass source: Canada (100%).

Source: Calculations by CE Delft, based on (an update of) CE, 2007.

This method of estimating the additional costs related to flexibility leads to a figure of approximately **120 € per MWh**, which in the above figure is attributed to wind energy as an intermittent power source. These costs can be seen as an estimate of the upper bound of the flexibility costs associated with enabling the energy system to 'absorb' increasing levels of electricity generated by wind turbines.

7.4 Conclusions

For the energy system to incorporate a growing share of intermittent energy sources (mainly wind) a more flexible energy system is required and/or use of energy storage. If the associated costs are attributed solely to wind energy, the total production costs of this source of power increase by **120 € per MWh**.

References

Belgrave et al., 1987
R. Belgrave, C.K. Ebinger and H. Okino
Energy Security to 2000
Aldershot (UK) : Westview Press, 1987

Blogger News Network, 2007
Our strategic oil reserve won't help America at the pump
http://www.bloggernews.net/17028

CASES, 2008/2007
M. Blesl, S. Wissel and O. Mayer-Spohn
'Private costs of electricity and heat generation',
Cost Assessment of Sustainable Energy Systems (CASES)
- Deliverable D.4.1 : Institut für Energiewirtschaft und Rationelle Energieanwendung, (IER), Universität Stuttgart, 2008
- Deliverable D.5.1 : Report on National and EU level estimates of energy supply externalities, 2007

CE, 2007
M. Sevenster, H. Croezen, M. Blom and F. Rooijers
Nieuwe elektriciteitscentrale in Nederland : de 'vergeten' kosten in beeld
Delft : CE Delft, 2007

CE, 2010
S.M. de Bruyn, M.H. Korteland, A.Z. Markowska, M.D. Davidson, F.L. de Jong, M. Bles and M. Sevenster
Shadow prices handbook : Valuation and weighting of emissions and environmental impacts
Delft : CE Delft, 2010

Costantini et al., 2007
Valeria Costantini, Francesco Graccevaa, Anil Markandyaa and Giorgio Vicinia
Security of energy supply: Comparing scenarios from a European perspective
In : Energy Policy, Volume 35, Issue 1 (2007); p. 210-226

CPB, 2005
Jeroen de Joode, Douwe Kingma, Mark Lijesen, Machiel Mulder and Victoria Shestalova
Energy Policies and Risks on Energy Markets : A cost-benefit analysis,
The Hague : Netherlands Bureau for Economic Policy Analysis (CPB), 2005

Damen and Faay, 2004
K. Damen and A. Faaij
A Life Cycle Inventory of existing international biomass import chains for 'green' electricity production
In : Mitigation and Adaptation Strategies for Global Change, May 2004

Davis and Haltiwanger, 2001
S.J. Davis and J. Haltiwanger
Sectoral Job Creation and Destruction Response to Oil Price Changes
In : Journal of Monetary Economics, Volume 48 (2001); p. 465-512

EWEA, 2004
B. Parsons, M. Milligan, B. Zavaldi, D. Brooks, B. Kirby, K. Dragoon and J. Caldwell
Grid impacts of wind power: a summary of recent studies in United States
European Wind Energy Conference, Madrid
In : Wind Energy, Volume 7, No. 2 (2004); p. 87-108

ExternE, 1995
Externalities of Energy, Vol. 6: Wind and Hydro
Luxembourg : Office for Official Publications of the European Communities, 2005

ExternE, 2005
P. Bickel and R. Friedrich
Externalities of Energy Methodology, 2005 update
Luxembourg : Office for Official Publications of the European Communities, 2005

Ford and Milborrow, 2005
Richard Ford and David Milborrow
'Integrating renewables'
S.l. : British Wind Energy Association, 2005

Goedkoop et al., 2008
M.J. Goedkoop, R. Heijungs, M. Huijbregts, A. De Schryver, J. Struijs and R. Van Zelm
A life cycle impact assessment method which comprises harmonised category indicators at the midpoint and the endpoint level; ReCiPe
First edition Report I : Characterisation, 2009
http://www.lcia-ReCiPe.net

Greene and Ahmad, 2005
L. David and Sanjana Ahmad
Costs of U.S. Oil Dependence: 2005 Update
Oak Ridge : Oak Ridge National Laboratory, 2005

Greene and Leiby, 1993
David L. Greene and Paul N. Leiby
The Social Costs to the U.S. of Monopolization of the World Oil Market, 1972-1991
Oak Ridge : Oak Ridge National Laboratory, 1993

Greene and Tishchishyna, 2000
David L. Greene and Nataliya I. Tishchishyna
Cost of Oil Dependence: A 2000 Update
Oak Ridge : Oak Ridge National Laboratory, 2001

Hirschberg et al., 2004
S. Hirschberg, P. Burgherr and A. Hunt
Accident risks in the energy sector: comparison of damage indicators and external costs
Berlin : PSAM7 Conference, June 14-18, 2004

IEA, 2004
Fact Sheet on IEA Oil Stocks and Emergency Response Potential
http://www.iea.org/Textbase/Papers/2004/factsheetcover.pdf

Jonkman et al., 2003
S.N. Jonkman, P.H.A.J.M. van Gelder and J. K. Vrijling
An overview of quantitative risk measures for loss of life and economic damage
In : Journal of Hazardous Materials A99 (2003); p. 1-30

Leiby et al., 1997
Paul N. Leiby, Donald W. Jones, T. Randall Curlee and Russell Lee
Oil Imports : An Assessment of Benefits and Costs
Oak Ridge : Oak Ridge National Laboratory, 1997

Leiby, 2007
Paul N. Leiby
Estimating the Energy Security Benefits of Reduced U.S. Oil Imports
Oak Ridge : Oak Ridge National Laboratory, 2007

MNP, 2006
M.M. Berk, J.C. Bollen, H.C. Eerens, A.J.G. Manders and D.P. van Vuuren
Sustainable energy : trade-offs and synergies between energy security, competitiveness, and environment
Bilthoven : Milieu en Natuurplanbureau, 2006

NRC, 2002
National Research Council (NRC)
Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards
Washington, DC : National Academy Press, 2002

Ogden et al., 2004
Joan M. Ogden, Robert H. Williams and Eric D. Larson
Societal lifecycle costs of cars with alternative fuels/engines
In : Energy Policy, Volume 32, Issue 1 (2004); p. 7-27

RFF, 2003
Ian W.H. Parry and Joel Darmstadter
The Costs of US Oil Dependency : Report prepared for National Commission on Energy Policy
Washington DC : Resources for the Future (RFF), 20043

Roth and Ambs, 2004
Ian F. Roth and Lawrence L. Ambs
Incorporating externalities into a full cost approach to electric power generation life-cycle costing
In : Energy, Volume 29, Issues 12-15, p. 2125–2144

Toman, 2002
Michael A. Toman
International Oil Security: Problems and Policies
In : The Brookings Review, Volume 20, No. 2 (2002), p. 20-23

UKERC, 2006
R. Gross, P. Heptonstall, D. Anderson, T. Green, M. Leach and J. Skea
The Costs and Impacts of Intermittency
London : UK Energy Research Centre (UKERC), 2006

Annex A Shadow prices: backround and methodology

A.1 Damage costs versus avoidance costs

Shadow prices can be based either on damage costs or avoidance (or abatement) costs. The general rule for using one or the other approach is: if a project results in changes in environmental quality, these should be valued according to the shadow prices based on damage costs. However, if a project results in changes in environmental policy-induced reduction efforts, these should be valued according to the shadow prices based on avoidance costs. As an example of the second approach we can imagine that in a situation where there are specific goals for CO_2, as in the Netherlands (*Programma Schoon en Zuinig*, with a target of 30% reduction of energy consumption in 2020 relative to 1990), there is a need to assess the costs and benefits of a programme to introduce energy-saving light bulbs which will reduce the abatement efforts envisaged for industry. The benefits accruing from a drop in CO_2 emissions due to such a programme should be assessed using the marginal costs of CO_2 abatement in the Netherlands.

External versus damage costs

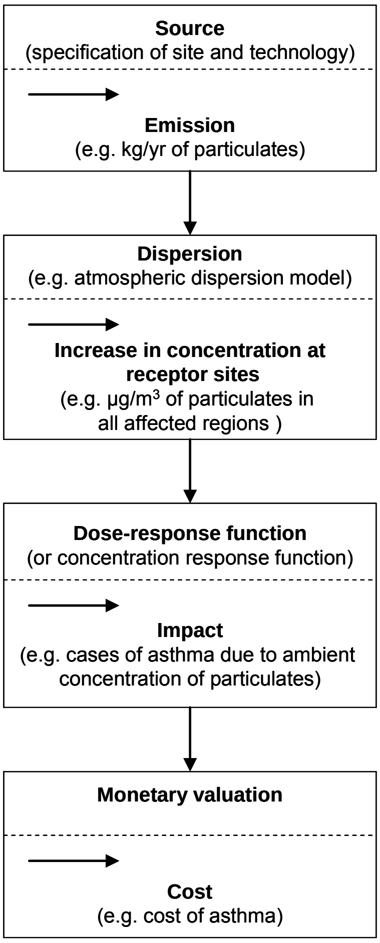
In the absence of environmental policy goals and instruments, the external costs of pollution are equal to the damage costs and can be measured using shadow prices (damage cost approach). If policy goals are established, the shadow prices for a specific project can be expressed using the avoidance cost approach. If environmental policy instruments are in force to mitigate pollution-related damages, a certain proportion of external costs is internalised, so that external costs are no longer equal to damage costs.

It may be noted that in a hypothetical ideal situation in which policy goals reflect a 'socially optimal' level of pollution, both methods of shadow price estimation (based on damage costs and avoidance costs) would give the same outcome.

A.2 Methodology for estimating damage costs

For assessing damage costs per unit of specific pollutants in monetary terms for so-called **classical pollutants** (in our study: SO_2, NO_x and PM_{10}) the Impact-Pathway Approach (IPA) can be used (see Figure 25). This approach has been used in a variety of studies, including the NEEDS (the final stage of the ExternE series) and CASES projects.

Figure 25 Impact Pathway Approach



Source: Based on EC, 2003.

The various steps are described below.

Step 1: Source-Emissions

This step identifies, on a geographical scale, the sources of emissions. In the Ecosense model used in the final stages of the ExternE project, the emissions are taken from the EMEP (European Monitoring and Evaluation Programme) database with a spatial resolution of approximately 50 x 50 km^2.

Step 2: Dispersion-Receptor sites

This step translates the emissions into concentrations at specific geographically diversified receptor points. For classical air pollutants, dispersion and chemical transformation in Europe has been modelled using the EMEP/MSC-West Eulerian model, which also incorporates meteorological data. Source-receptor matrices have been derived which allow a concentration or deposition change to be attributed to each unit of emission for each of the EMEP grid cells across Europe. Model runs have been performed for 15% reduction of each airborne pollutant. Within the model, meteorological conditions are averaged across four representative meteorological years. For emissions in the years 2000-2014, dispersion results reflect the estimated background emissions in 2010. For other future years, the estimated background emissions modelled for 2020 are used. It should be noted that the chemical reactions and interactions are quite complex. For example, a reduction of NO_x emissions leaves more background NH_3 for reaction with background SO_2 than without reduction of NO_x. The reaction of additional free

NH_3 and SO_2 increases the concentration of sulphates at certain locations (NEEDS, 2008).

Step 3: Dose-response functions and impacts
This step establishes the relationship between the concentration of pollutants and the physical impacts at the endpoint level. With the aid of a so-called concentration-response function and the size of the exposed population, physical impacts have been calculated for each grid cell. Population density data have been taken from SEDAC (2006).

The following types of physical impact are taken into account:
– Mortality: the chance of premature death due to reception of the pollutant, with a distinction between acute mortality (immediate death) and chronic mortality (occurring after a certain period of exposure to a given pollutant). Acute mortality may be the result of photo-oxidant formation (smog), while chronic mortality is typically associated with particulate emissions (primary and secondary). For classical air pollutants, the reduced life time expectancy (YOLL, years of life lost) was found to be the most important endpoint. YOLL has been evaluated using the Value of Life Year (VOLY), which was estimated in a CVM[42] survey carried out within the NEEDS project.
– Morbidity: the chance of developing a disease due to reception of the pollutant. The following effects have been evaluated and taken into account in final calculations: restricted activity days, work loss days, hospital admissions, medication use.
– Impact on ecosystems and availability of biodiversity: potentially disappearing species (PDF indicator) is used as a measure of how pollutants impact on ecosystems. PDF has been evaluated based on the meta-analysis of various valuation studies on biodiversity using stated preference methods (thus resulting in an average Willingness to Pay for a unit change in biodiversity measured with PDF).
– Impacts on crops: changes in soil fertility due to the impact of various pollutants. These effects have been evaluated using the market prices of specific crops.
– Impact on materials and buildings: increased rate of degradation and failure. These impacts have been estimated in monetary terms using costs of replacement and repair based on scientific literature.

For discounting the future impacts of emissions, within the NEEDS project the following discount rates have been used: 3% for the period 2000-2030, 2% for the period 2031-2075 and 1% for the period 2076-2300. Ideally, the discount rates used for calculating private and external costs should be the same. However, it is impossible to change these assumptions for calculating external costs, as this would require running the Ecosense model with new assumptions, which would go beyond the scope and budget of the present project. This said, though, we believe the impact of this discrepancy between discount rates would not have any significant impact on the final outcomes, as the impacts of most pollutants analysed in this report do not endure for a particularly long period of time. The only exception are GHGs[43]; for these, however, we

[42] Contingent Valuation Method, one of the methods in the 'stated preferences' category, in which respondents are asked to state directly how much they would be willing to pay for a given change (e.g. in environmental quality), described in the survey scenario. In this particular case, the scenario described a programme of improving air quality in Europe which would result in increasing life expectancy by three months (and in a second scenario by six months).

[43] As well as radioactivity (CE, 2007).

propose using an avoidance cost approach whereby costs relate to a given target and are not dependent on a discount rate, as discussed in the following section.

A.3 Global warming

Global warming impacts are due mainly to emissions of the so-called greenhouse gases carbon dioxide, (CO_2), nitrous oxide (N_2O) and methane (CH_4). Other pollutants contributing to global warming include refrigerants (hydrofluorocarbons), and high-altitude aircraft emissions of water vapour, sulphate, soot aerosols and nitrous oxides. In this report we focus only on CO_2 and CH_4, these being the most relevant emissions for power generation.

There are three main problems relating to damage estimates for climate change: (a) the problem is global in nature; (b) the atmospheric lifetime of CO_2 is rather uncertain; (c) the damaging effects of global warming are not distributed evenly across the globe. In other words, an additional emission of CO_2 results in impacts that occur far away, both in time and space.

Our estimates of the costs associated with global warming are based on the results of Integrated Assessment Models (IAMs) in which forecasts of economic growth are interlinked with the predicted impacts of climate change. The models typically include assessment of the costs of direct impacts, while excluding certain indirect effects (such as the incidence of wars due to climatic stress, termed 'socially contingent effects' by Watkiss (2005)).

Global warming damages include a broad range of effects related to temperature rise, such as changes in global precipitation, rising sea levels, increased risk of extreme events like drought and severe storms, and in the longer term possible alteration of ocean currents. These effects may lead to various impacts associated with social costs and can be summarised as follows (based on Watkiss, 2005):

- Sea level rise may lead to loss of dry land and wetlands. These impacts may be measured in terms of costs of protection, which are relatively easy to assess. Another category of costs related to this type of impact is the cost associated with migration, which depends on various social and political factors (and is thus such a 'socially contingent effect') and is not captured by most valuation models.
- Energy use impacts will depend on the range and scale of changes in temperature and is a combination of increase and decrease of demand for heating. Declining demand for heating in winter may be offset by increased demand for air conditioning in summer.
- Agricultural impacts relate to changes in cultivated area, type of crops and yields as a result of changes in temperature and precipitation. In addition to these direct changes, there may be effects related to adaptive abilities, as well changes in demand and trading patterns that depend on socio-economic factors.
- Water supply impacts, e.g. in some areas water shortages will be exacerbated due to climate change. Thus there is a potential for increased water scarcity. The costs of these shortages may be very high and highly socially contingent.

- Health effects include decreased cold stress in winter and increased heat stress in summer. To an extent at least, these direct effects will partly cancel out. Additional effects include increased incidence of certain parasitic diseases like malaria. Indirect effects on human health include impacts relating to changes in food production (especially decreased production in tropical/subtropical countries).
- Ecosystem and biodiversity impacts are the most complex and difficult to evaluate. Possible impacts include an increased risk of extinction of certain vulnerable species. Certain isolated systems, such as coral reefs, are particularly at risk.
- Extreme events such as heat waves, drought, storms and cyclones may not be linearly dependent on temperature change and the impact of these events is also very difficult to assess. Damages will depend on the location and timing of the hazard and adaptive responses and are thus also partly socially contingent.
- Major events, including potentially catastrophic effects such as loss of the West Antarctic ice sheet, loss of the Greenland ice sheet, methane outbursts, instability or collapse of the Amazon Forest, changes in ocean currents, Indian monsoon transformation and others are extremely hard to assess.

These impacts, in turn, influence the endpoints human health, ecosystems and capital goods. However, they may also result in other social costs, such as migration, which are included in most of the IAM (e.g. in the FUND model).

The central estimate of CO_2 damage costs is derived based on various studies using IAMs, mainly NEEDS and the studies summarised in the IMPACT handbook (Infras *et al*., 2008). The estimate of CH_4 is derived on the basis of characterisation factors relating the impact of different GHGs to the impact of CO_2 (characterisation factor at the midpoint level based on the ReCiPe study, Goedkoop *et al*., 2009). Among the controversial aspects of these models that underlie the differences among the various studies are the following:
- The time horizon adopted (to what horizon are effects taken into account?).
- Treatment of risk and uncertainty.
- Underlying emission and economic growth scenarios.
- The discount rate used to account for damages occurring in the (distant) future.
- Valuation of damages as a function of income (so that similar damages incurred by a rich person are assigned a higher monetary value than in the case of a poorer person). In other words: the question of whether or not equity weighting is used (see Box).

Equity weighting

In most Integrated Assessment Models (IAM) it is assumed that value to be assigned to damages is dependent on income level, so that VSL, for example, is set proportional to GDP. Equity weighting, in contrast, attaches *more* weight to damages occurring in low-income regions than to damages in high-income regions. This corresponds with the theory of declining marginal utility of consumption: the higher the income level of an agent, the less welfare loss she or he incurs from the same absolute loss of income, i.e. the same absolute loss of income causes a greater welfare loss to a poor person than to a rich person (based on Anthoff (2007)).

As the IAM models do not normally differentiate the damages across the various endpoints defined in this study, we can only give estimates of the total damages. We focus solely on the damages due to CO_2, moreover, expressing these in GHG emissions by using equivalence factors at the endpoint level.

Total damage costs of CO_2

Over the past several years the term 'Social Cost of Carbon' (SCC) has been gaining in currency and an growing number of studies are being devoted to monetary assessment thereof. The SCC can in fact be interpreted as the total discounted value of future costs and benefits related to emission of one additional unit of CO_2. Tol (2008) provides a meta-analysis of 211 studies on SCC, with the mean being found equal to 23 $ per tonne of carbon, at a 3% discount rate. This figure is equivalent to approximately 6.3 $ per tonne of CO_2 (or about 5 € per tonne of CO_2). The range of estimates reported in the cited paper is very high, however, with the lowest estimates below zero and the highest in excess of 2,000 $ per tonne of carbon[44].

The damage cost approach shows that external costs of GHG emissions rise over time, as the negative effects of global warming become more severe as global temperatures rise. Hence, the literature on the damage cost approach normally gives a range of values that can be used in tools like SCBA if a project results in CO_2 emissions for a longer period of time.

Within the NEEDS and CASES projects[45] the damage costs have been based on the results of the FUND model (for a model description, see Box 2). Table 21 shows the results.

Table 21 Recommended values of damage costs for CO_2 (€ 2008[46] per tonne CO_2, discounted to the year of emission, without equity weighting)

Emissions in decade	2000-09	2010-19	2020-29	2030-39	2040-49	2050-59	2060-69	2070-79	2080-89	2090-99
Damage costs	8	13	16	18	21	33	30	38	48	54

Source: CASES, 2008.

44 In the literature, the (damage or abatement) costs associated with carbon dioxide emissions are typically expressed in dollars or Euro per tonne of carbon dioxide (CO_2) or per tonne of carbon (C). Costs per tonne of C translate into costs per tonne of CO_2 by dividing by a factor 44/12 = 3,667.

45 NEEDS: New Energy Externalities Developments for Sustainability, European Commission research project implemented in the period 2004-2008, part of the ExternE series; CASES: Cost Assessment for Sustainable Energy Systems, European Commission research project implemented in the period 2006-2008.

46 The original values reported in 2,000 € per tonne have been recalculated using HICP indicator (Harmonized Indicator of Consumer Prices).

FUND model

FUND is an Integrated Assessment Model (IAM), a computer model of economic growth with a controllable externality of greenhouse warming effects developed by Professor Richard Tol (IVM VU Amsterdam and Economic and Social Research Institute, Dublin). The model distinguishes 16 major regions of the world and runs from 1950 to 2300 in time steps of one year. The period 1950-1990 is used for calibration of the model. The period 1990-2000 is based on observations. The climate scenarios for the period 2010-2100 are based on the EMF14 Standardized Scenario, which lies somewhere between the IS92a and IS92f scenarios of IPCC. The model estimates marginal damages from one extra tonne emission of carbon dioxide (and other greenhouse gas). The climate impact module includes the following categories: agriculture, forestry, sea level rise, cardiovascular and respiratory disorders related to cold and heat stress, malaria, dengue fever, schistosomiasis, diarrhoea, energy consumption, water resources, and unmanaged ecosystems. The impacts of climate change are monetised. If people die prematurely due to temperature stress or have to migrate because of sea level rise, these effects are evaluated using approximate valuation factors from literature. For example, the Value of a Statistical Life (VOSL) is set at 200 times annual per capita income. The value of emigration is set at three times per capita income, while the value of immigration is 40 percent of the per capita income in the host region. The monetary value of a loss of one square kilometre of dryland was adopted at the level of 4 million USD in OECD countries in 1990, and was assumed to be proportional to GDP per km^2. FUND uses Ramsey-style discounting, which is a combination of the consumption growth rate, risk aversion and the pure rate of time preference (PRTP). with PRTP assumed at three different levels: 0, 1 and 3%. The effective discount rate used even for a specific PRTP varies over time and region, since per capita consumption growth rates vary over time and by region (based on Anthoff, 2007).

In the IMPACT handbook (INFRAS *et al*., 2008) a number of other studies on CO_2 damage costs of has been summarised; see Table 22 and Figure 26 below.

Table 22 Overview of the damage costs of climate change (in € per tonne CO_2) as estimated by various studies

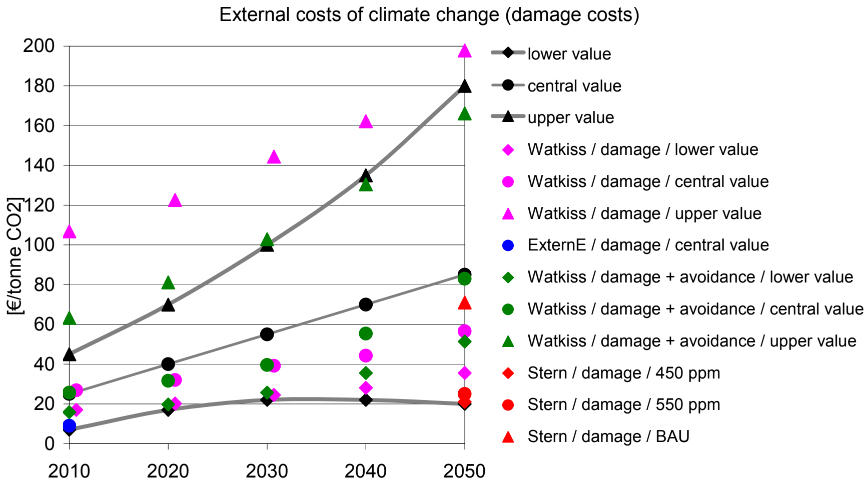
		Damage costs (€/tonne CO_2)			
Source	Year of application	Min	Central	Max	Comments
ExternE, 2005	2010		9		
Watkiss, 2005b	2000	14	22	87	Results based on damage costs only
	2010	17	27	107	
	2020	20	32	138	
	2030	25	39	144	
	2040	28	44	162	
	2050	36	57	198	
Watkiss, 2005b	2000	14	22	51	Results based on comparison of damage and avoidance costs
	2010	16	26	63	
	2020	20	32	81	
	2030	26	40	103	
	2040	36	55	131	
	2050	51	83	166	
Tol, 2005		-4	11	53	Based on studies with PRTP = 1%
Stern, 2006*	2050		71		Business-as-usual scenario
	2050		25		Stabilisation at 550 ppm
	2050		21		Stabilisation at 450 ppm
DLR, 2006		15	70	280	Based on Downing, 2005

Source: INFRAS et al., 2008.

* See Box 4.

It may be noted that the values recommended within the NEEDS project converge with the lower bound of the values proposed in Watkiss (2005).

Figure 26 Overview of the damage costs of climate change (in € per tonne CO_2) as estimated by various studies



Source: INFRAS et al., 2008.

Box 4. The Stern Review

The Stern Review deserves special attention not because of its scientific merits but because of its significant political impact. The report, which discusses the effects of climate change and global warming on the world economy, was released on October 30st, 2006 by the economist Lord Nicolas Stern of Brentford for the British government. Its main conclusion is that the benefits of strong, early action on climate change considerably outweigh the costs. Stern proposes that one percent of global gross domestic product (GDP) *per annum* should be invested in order to avoid the worst effects of climate change, and that failure to do so could risk global GDP being up to twenty percent lower than it otherwise might be. To model damages the Stern Review uses the PAGE model (one of the Integrated Assessment Models).

The Stern Review has been criticised by many economists. Most critiques relate to the modelling details and assumptions, especially the assumed rate of discounting, which is very low compared with most other studies (Stern adopted a pure rate of time preference PRTP of 0.1%, while within the NEEDS project, for example, a PRTP of 1% was assumed). The estimated damages associated with GHG emissions are therefore much higher than the figures reported in most other studies. Tol (2008), for instance, considers the Stern Review an outlier and that its impact estimates are pessimistic even when compared to grey literature and other estimates using low discount rates. Despite this criticism, the Stern Review remains the most influential, widely known and discussed report on the economics of climate change to date. Even some of Stern's adversaries admit that the Stern review is 'right for wrong reasons' (e.g. Arrow, 2007; Weitzman, 2007).

(Based on Tol (2008) and Wikipedia).

Comparison with avoidance costs

The following conclusions can be drawn regarding comparison of the estimates of CO_2 external costs based on the damage and avoidance cost approach (based on INFRAS *et al*., 2008):

- Damage costs estimates tend to be *lower* than estimates based on avoidance costs, certainly in the short run.
- The spread in estimates for short-term external costs across different studies is smaller for avoidance costs than for damage costs.

- The central values for long-term (i.e. 2050) damage and avoidance costs calculated in recent studies tend to be in the same range: 50–100 € per tonne CO_2.
- Both damage costs and avoidance costs are expected to increase over time.

Conclusion and recommended values

We here take the approach recommended in CE (CE, 2010) and the IMPACT study (INFRAS *et al.*, 2008) based on a literature review of the various estimates for CO_2. In this approach, avoidance costs are used for the time frame up to 2020, and damage costs thereafter. The reason for using avoidance costs in the short run at least derives from the notion that current environmental policies obviously impose stricter targets than one would expect based on damage costs. The average avoidance cost of 25 € per tonne CO_2 for 20% reduction for the year 2010 is much higher than the median damage costs based on Tol (2008), which equal approximately 5 € per tonne CO_2, and also higher than the estimates presented in the NEEDS project (about 13 € per tonne CO_2). The reason is that politicians obviously place a higher value on preserving the climate than economists would advocate. This may be for various reasons, such as omissions in the damage estimates (excluding indirect effects), a lower rate of time preference by politicians than estimated by economists, and moral imperatives such as 'global stewardship'. As yet, however, policies have only been formulated until the year 2020. For emissions occurring after then, IMPACT refers to damage costs to estimate the longer-term impacts.

The recommended values for CO_2 shadow prices based on CE (2010) are presented in Table 23. Recommended values are specified for different years of application.

Table 23 Recommended values for the external costs of climate change (in € per tonne CO_2), expressed as single values for a central estimate and lower and upper values

	Central values (€/tonne CO_2)		
Year of application	Lower value	Central value	Upper value
2010	7	25	45
2020	17	40	70
2030	22	55	100
2040	22	70	135
2050	20	85	180

Source: Infras et al., 2008.

Based on this recommendation, throughout our study we have used the central value of 25 € per tonne CO_2.

Annex B Detailed tables of emissions and power plant characteristics

In this annex the environmental effects of the different plant types are discussed in detail. Further information is also provided on the assumptions made concerning power plant efficiency, fuel characteristics and so on. For all types of power plant the latest available technology has been assumed. With regard to Carbon Capture and Storage, the assumption was made that future CCS capacity expansion will be feasible (CE, 2007). Environmental impacts associated with plant decommissioning have not been taken into account: because of recycling, etcetera, these are probably very limited, although an exception to this rule has been made for materials from nuclear reactors.

B.1 Fuels

Before going into the details of the various power plants studied, we first provide details on the sourcing and typology of the fuels (coal, gas, biomass) used for power generation in the Netherlands.

B.1.1 Coal

Several Dutch power plants burn a mixture of coal from a number of countries. During the 1990s coal was imported mainly from Australia and the United States. More recently South Africa has become a preferred supplier. In this study we analyse the effects of coal imported from either Australia or South Africa. To provide insight into the various effects of the origin of the coal (bandwidth of external costs), it was first assumed that 100% of the coal comes from Australia. By means of sensitivity analysis, a second fuel origin scenario was then studied in which all the coal derives from South Africa instead.

B.1.2 Gas

At the moment the gas market for large consumers is still a market in which Dutch gas is dominant (CE, 2007). In order to study possible future developments and their effect on external costs in the precombustion phase of electricity generation in gas-fired power plants, however, two (alternative) fuel scenarios were examined. In the first scenario 50% of the gas is sourced in the Netherlands and 50% in Norway. In the second scenario 30% of the gas is from the Netherlands, 60% from Russia[47] and 10% from Algeria as LNG (all gas-fired power plant except decentralised CHP). For decentralised CHP in the second scenario 30% of the gas is from the Netherlands, with 70% from Russia.

47 This rather high percentage was adopted in order to study the effects of the Netherlands possibly becoming more dependent on Russian gas as a result of depletion of the Dutch (Groningen) gas stocks (sensitivity analysis).

B.1.3 Biomass

In this study the biomass used in power stations is assumed to be in the form of pellet boards made from sawdust[48] deriving from coniferous plantations in Canada. The assumption regarding this biomass is that the pellets would have normally been dumped as a waste product if not utilised for power generation (Damen, 2004). In a sensitivity analysis, the effects of alternative sourcing from Brazil were also examined. In that case deforestation may be an issue and this has consequently been taken into due account when analysing the environmental external costs down the fuel chain.

B.2 Power plants

B.2.1 Costs

Table 24 provides an overview of the costs that form the basis for comparing the total production costs of the various different 1,000 MW power plants. It is thereby assumed that all the plants have an average annual output of 6,000 GWh (6,000 full-load operating hours).

Table 24 Background data for the costs of different power plants (in € per MWh)

	Environmental costs, incl. radioactivity		Accidents		Direct production costs		Total (€/MWh)	
Scenario	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Coal	21.72	22.52	0.057	0.53	58.66		80.4	81.7
Coal CCS	5.33	5.02	0.057	0.53	71.62		77.0	77.2
Coal 50 % biomass	13.91	24.98	0.057	0.53	70.45		84.4	96.0
Coal 50% biomass CCS	-4.39	8.32	0.057	0.53	85.57		81.2	94.4
Nuclear	0.12	8.4		23	88.25		111.4	119.7
CCGT	11.25	12.71	0.087	0.21	61.73		73.1	74.7
Multi-fuel CCGT	4.27	3.98	0.057	0.53	71.13		75.5	75.6
Multi-fuel CCGT CCS	6.65	6.29	0.057	0.53	84.68		91.4	91.5
Gas CHP	11.39	12.62	0.087	0.21	61.80		73.3	74.6
Biomass (CFBC)	6.87	30.77	≈0	-	90.15		97.0	120.9
Biomass (CFBC) CCS	-15.95	13.23	≈0	-	116.16		100.2	129.4
Wind	≈0	≈0	≈0	-	79.25 (excl. storage)	198.30 (incl. storage)	79.3	198.3

Source: Direct costs based on CE, 2007; other cost calculations based on CE, 2007 (nuclear), Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

48 Sawdust is a sawmill by-product.

B.2.2 Coal-fired power plant with/without CCS

The coal is first crushed and then ground in pulverizers to yield very small fragments (< 0.1 mm) that are blown into the furnace. Handling of the coal will cause emissions of fine particles (PM < 2.5 and PM 2.5 – 10), which are included in the analysis. The efficiency of a coal-fired power plant burning 100% coal is about 47%. With CO_2 capture and storage (CCS), plant efficiency is estimated to be about 39%.

Coal-fired power plant without CCS

Table 25 External costs in € per MWh of emissions/accidents for coal-fired plant without CCS, assuming 100% coal from Australia

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.27	18.08	18.35
CH_4	0.50	0.06	0.56
N_2O		0	0
SO_2	0.13	0.69	0.82
NO_x	0.22	1.33	1.55
PM < 2.5	0.33	0.06	0.39
PM 2.5 - 10	0.03	0.02	0.05
Total emissions	*1.48*	*20.24*	*21.72*
Accidents	*0.057*	-	*0.057*
Total	**1.54**	**20.24**	**21.78**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 26 External costs in € per MWh of emissions/accidents for coal-fired plant without CCS, assuming 100% coal from South Africa

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.28	18.75	19.03
CH_4	0.68	0.07	0.75
N_2O	-	0	0
SO_2	0.07	1.13	1.2
NO_x	0.08	1.33	1.41
PM < 2.5	0.03	0.07	0.1
PM 2.5 - 10	0.01	0.02	0.03
Total emissions	*1.15*	*21.37*	*22.52*
Accidents	*0.53*	-	*0.53*
Total	**1.68**	**21.37**	**23.05**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

The above tables indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 1.27 €/MWh.

Coal-fired power plant with CCS

Table 27 **External costs in € per MWh of emissions/accidents for coal-fired plant with CCS, assuming 100% from Australia**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.33	2.20	2.53
CH_4	0.60	0.07	0.67
N_2O		0	0
SO_2	0.16	0	0.16
NO_x	0.27	1.20	1.47
PM < 2.5	0.40	0.05	0.45
PM 2.5 - 10	0.03	0.02	0.05
Total emissions	*1.79*	*3.54*	*5.33*
Accidents	*0.057*	-	*0.057*
Total	**1.85**	**3.54**	**5.39**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 28 **External costs in € per MWh of emissions/ accidents for coal-fired plant with CCS, assuming 100% coal from South Africa**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.33	2.28	2.61
CH_4	0.82	0.08	0.9
N_2O		0.00	0
SO_2	0.08	0.01	0.09
NO_x	0.10	1.20	1.3
PM < 2.5	0.04	0.05	0.09
PM 2.5 - 10	0.01	0.02	0.03
Total emissions	*1.38*	*3.64*	*5.02*
Accidents	*0.53*	-	*0.53*
Total	**1.91**	**3.64**	**5.55**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 27 and Table 28 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 0.16 €/MWh.

B.3 Coal-fired power plant burning 50% biomass

In coal-fired plants some of the coal can be replaced by biomass. In our analysis we assumed use of 50% biomass as a supplementary fuel. Again, the biomass was taken to be wooden pellets imported from Canada (cf. B.1.3). Like the coal, the pellets are pulverised before being sent to the furnaces. The efficiency of a coal-fired power plant burning 50% biomass is 44%. With CCS added on, this figure drops to 36%. Two fuel scenarios were analysed. In the first, all the coal is sourced in Australia and all the biomass in Canada. In the second, all the coal is from South Africa, with 80% of the biomass from Canada and 20% from Brazil.

Coal-fired power plant burning 50% biomass without CCS

Table 29 **External costs in € per MWh of emissions/accidents for coal-fired plant burning 50% biomass, without CCS, assuming 100% coal from Australia and 100% biomass from Canada**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.31	9.06	9.37
CH_4	0.26	0.03	0.29
N_2O	0.01	0	0.01
SO_2	0.66	0.45	1.11
NO_x	1.12	1.33	2.45
PM < 2.5	0.61	0.03	0.64
PM 2.5 - 10	0.03	0.01	0.04
Total emissions	*3*	*10.91*	*13.91*
Accidents	*0.057*	-	*0.057*
Total	**3.01**	**10.91**	**13.92**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 30 **External costs in € per MWh of emissions/accidents for coal-fired plant burning 50% biomass, without CCS, assuming 100% coal from South Africa, 80% biomass from Canada and 20% biomass from Brazil**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	11.53	9.39	20.92
CH_4	0.35	0.03	0.38
N_2O	0.01	0.00	0.01
SO_2	0.44	0.67	1.11
NO_x	0.85	1.33	2.18
PM < 2.5	0.33	0.03	0.36
PM 2.5 - 10	0.01	0.01	0.02
Total emissions	*13.52*	*11.47*	*24.98*
Accidents	*0.53*	-	*0.53*
Total	**14.05**	**11.47**	**25.51**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 29 and Table 30 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 11.59 €/MWh.

Coal-fired power plant burning 50% biomass with CCS

Table 31 **External costs in € per MWh of emissions/accidents for coal-fired plant burning 50% biomass, with CCS, assuming 100% coal from Australia and 100% biomass from Canada**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.38	-9.28	-8.9
CH_4	0.31	0.04	0.35
N_2O	0.01	0	0.01
SO_2	0.79	0	0.79
NO_x	1.35	1.20	2.55
PM < 2.5	0.74	0.03	0.77
PM 2.5 - 10	0.03	0.01	0.04
Total emissions	*3.61*	*-8*	*-4.39*
Accidents	*0.057*	-	*0.057*
Total	**3.67**	**-8**	**-4.33**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 32 **External costs in € per MWh of emissions/accidents for coal-fired plant burning 50% biomass, with CCS, assuming 100% coal from South Africa, 80% biomass from Canada and 20% biomass from Brazil**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	13.90	-9.24	4.66
CH_4	0.42	0.04	0.46
N_2O	0.01	0.00	0.01
SO_2	0.53	0.00	0.53
NO_x	1.02	1.20	2.22
PM < 2.5	0.39	0.03	0.42
PM 2.5 - 10	0.01	0.01	0.02
Total emissions	*16.29*	*-7.96*	*8.32*
Accidents	*0.53*	-	*0.53*
Total	**16.82**	**-7.96**	**8.85**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 31 and Table 32 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 13.18 €/MWh.

B.4 Third-generation nuclear power plant

The analysis of a nuclear power plant is based on a plant with EPR technology (European Pressurized Water Reactor). This technology is to be applied in the two new nuclear power plants in Finland (Olkiluoto) and France (Flamanville). Mined uranium is not directly suitable as a nuclear fuel, but must first be enriched using centrifuge technology. The ‘tails’ left over from this process are transported to Russia and have been assumed to be stored there. It is also assumed that the spent uranium rods from reactors are stored deep underground. Decommissioning of the power plant at the end of its technical life is also incorporated in the results. There are various potential sources of power plant uranium, including Canada and Kazakhstan, and no precise assumptions were made on this point (CE, 2007). The heat from the fission process is used to raise steam that drives a steam turbine. The efficiency of a third-generation nuclear power plant is about 36%.

The long-term impact of possible leakages from nuclear waste storage facilities has not been taken into account in our analysis, because it is not possible to make a reasonable assessment of these costs. This does not mean these costs are not important or significant, though.

Nuclear power plant

Table 33 External costs in € per MWh of emissions/accidents at a nuclear plant

Pollutant	'Precombustion'	'Combustion'	Total (€/MWh)
Total emissions	0.1		**0.1**
Radioactivity[49]	0.02 - 8.3	-	**0.02 - 8.3**
Accidents	23		**23**
Long term damages	Unknown (excluded)		**-**
Total	**23.1 - 31.4**		**23.1 - 31.4**

Source: Calculations by CE Delft, based on CE Delft (2007), Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

B.5 CCGT with/without CCS

A modern gas-fired power plant is a combination of a gas turbine and a steam turbine (combined-cycle gas turbine, CCGT). Natural gas is burnt in the gas turbine, with the heat of the flue gas being used to raise steam to drive the steam turbine. Modern CCGT plant has an efficiency of about 58%. With CO_2 capture the efficiency is estimated at 52%.

CCGT without CCS

Table 34 External costs in € per MWh of emissions/accidents for CCGT without CCS, assuming 50% gas from the Netherlands and 50% from Norway

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.22	8.68	8.9
CH_4	0.02	-	0.02
N_2O	0.00	-	0
SO_2	0.08	-	0.08
NO_x	0.27	1.88	2.15
PM < 2.5	0.10	-	0.1
PM 2.5 - 10	-	-	0
Total emissions	*0.69*	*10.56*	*11.25*
Accidents	*0.087*	-	*0.087*
Total	0.78	10.56	**11.34**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

49 In the figures throughout the report the lower bound of the bandwidth is used, thereby assuming 'best case' mining conditions. If 'worst case' mining conditions are more appropriate, given the origin of the uranium, the upper bound of the bandwidth is more representative (see for more information on assumptions: CE, 2007).

Table 35 **External costs in € per MWh of emissions/accidents for CCGT without CCS, assuming 30% gas from the Netherlands, 60% from Russia and 10% (LNG) from Algeria**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.87	8.58	9.45
CH_4	0.55	-	0.55
N_2O	0.00	-	0
SO_2	0.09	-	0.09
NO_x	0.69	1.88	2.57
PM < 2.5	0.05	-	0.05
PM 2.5 - 10	-	-	0
Total emissions	*2.25*	*10.46*	*12.71*
Accidents	*0.21*	-	*0.21*
Total	2.46	10.46	**12.92**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 36 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 1.58 €/MWh.

CCGT with CCS

Table 36 **External costs in € per MWh of emissions/accidents for CCGT with CCS, assuming 50% gas from the Netherlands and 50% from Norway**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.25	0.97	1.22
CH4	0.03	-	0.03
N_2O	0	-	0
SO_2	0.09	-	0.09
NO_x	0.30	2.10	2.4
PM < 2.5	0.05	-	0.05
PM 2.5 - 10	-	-	0
Total emissions	*0.72*	*3.07*	*3.79*
Accidents	*0.087*	-	*0.087*
Total	**0.81**	**3.07**	**3.88**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 37 **External costs in € per MWh of emissions/accidents for CCGT with CCS, assuming 30% gas from the Netherlands, 60% from Russia and 10% (LNG) from Algeria**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.97	0.96	1.93
CH_4	0.62	-	0.62
N_2O	0.00	-	0
SO_2	0.10	-	0.1
NOx	0.77	2.10	2.87
PM < 2.5	0.06	-	0.06
PM 2.5 - 10	-	-	0
Total emissions	*2.51*	*3.05*	*5.58*
Accidents	*0.21*	-	*0.21*
Total	**2.72**	**3.05**	**5.79**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 36 and Table 37 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 1.91 €/MWh.

B.6 Multi-fuel CCGT with/without CCS (coal gasification)

The gasification of coal is still in its infancy. Globally there are about 5 coal gasification plants in operation, one of them in Buggenum in the Netherlands. During gasification the coal is burned in two stages:
- Gasification with oxygen to yield synthetic gas (a mixture of CO, H_2, CO_2 and H_2O).
- Combustion of the synthetic gas in a CCGT power plant.

Between these steps the synthetic gas is purified and the heat used for steam generation. This steam, combined with that from the CCGT, is used for power generation. The efficiency of coal gasification plants is estimated at about 44%. With CO_2 capture the efficiency is reduced to about 36%.

Multi-fuel CCGT, without CCS

Table 38 External costs in € per MWh of emissions/accidents for multi-fuel CCGT without CCS, assuming 100% coal from Australia

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.29	0.75	1.04
CH_4	0.53	0.07	0.6
N_2O		0	0
SO_2	0.14	0.01	0.15
NO_x	0.24	1.78	2.02
PM < 2.5	0.36	0.05	0.41
PM 2.5 - 10	0.03	0.02	0.05
Total emissions	*1.59*	*2.68*	*4.27*
Accidents	*0.057*	*-*	*0.057*
Total	**1.65**	**2.68**	**4.33**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 39 External costs in € per MWh of emissions/ accidents for multi-fuel CCGT without CCS, assuming 100% coal from South Africa

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.29	0.82	1.11
CH_4	0.73	0.07	0.8
N_2O	-	0.00	0
SO_2	0.07	0.02	0.09
NO_x	0.09	1.78	1.87
PM < 2.5	0.03	0.05	0.08
PM 2.5 - 10	0.01	0.02	0.03
Total emissions	*1.22*	*2.76*	*3.98*
Accidents	*0.53*	*-*	*0.53*
Total	**1.75**	**2.76**	**4.51**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 38 and Table 39 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 0.18 €/MWh.

Multi-fuel CCGT with CCS

Table 40 External costs in € per MWh of emissions/accidents for multi-fuel CCGT with CCS, assuming 100% coal from Australia

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.36	2.39	2.75
CH_4	0.65	0.08	0.73
N_2O		0	0
SO_2	0.17	0	0.17
NO_x	0.29	2.17	2.46
PM < 2.5	0.44	0.04	0.48
PM 2.5 - 10	0.04	0.02	0.06
Total emissions	*1.95*	*4.7*	*6.65*
Accidents	*0.057*	*-*	*0.057*
Total	**2.01**	**4.7**	**6.71**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 41 External costs in € per MWh of emissions/accidents for multi-fuel CCGT with CCS, assuming 100% coal from South Africa

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.36	2.47	2.83
CH_4	0.89	0.09	0.98
N_2O	-	0.00	0
SO_2	0.09	0.00	0.09
NO_x	0.11	2.17	2.28
PM < 2.5	0.04	0.04	0.08
PM 2.5 - 10	0.01	0.02	0.03
Total emissions	*1.49*	*4.80*	*6.29*
Accidents	*0.53*	*-*	*0.53*
Total	**2.02**	**4.80**	**6.82**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 40 and Table 41 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 0.11 €/MWh.

B.7 Decentralised CHP

In a decentralised gas-fired combined heat and power (CHP) plant, heat and electricity are generated simultaneously. The electrical efficiency of decentralised CHP is estimated to be about 43%, the thermal efficiency around 35%. Two fuel scenarios were considered. In the first, 50% of the gas is from the Netherlands and 50% from Norway. In the second, 30% of the gas is from the Netherlands and 70% from Russia.

Table 42 **External costs in € per MWh of emissions/ accidents for decentralised CHP, assuming 50% gas from the Netherlands and 50% from Norway**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.23	8.83	9.06
CH_4	0.02	-	0.02
N_2O	0.00	-	0
SO_2	0.09	-	0.09
NO_x	0.27	1.91	2.18
PM < 2.5	0.04	-	0.04
PM 2.5 - 10	-	-	0
Total emissions	*0.65*	*10.74*	*11.39*
Accidents	*0.087*	-	*0.087*
Total	**0.74**	**10.74**	**11.48**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 43 **External costs in € per MWh of emissions/accidents for decentralised CHP, assuming 30% gas from the Netherlands and 70% from Russia**

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.80	8.71	9.51
CH_4	0.65	-	0.65
N_2O	0.00	-	0
SO_2	-	-	0
NO_x	0.55	1.91	2.46
PM < 2.5	0.00		0
PM 2.5 - 10	-	-	0
Total emissions	*2.01*	*10.62*	*12.62*
Accidents	*0.21*	-	*0.21*
Total	**2.22**	**10.62**	**12.83**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 42 and Table 43 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 1.35 €/MWh.

B.8 Biomass gasification (CFBC) with/without CCS

For analysis of a biomass power plant we took a circulating fluidised bed combustion (CFBC) plant, in which the biomass is burnt in a ‘bed’ of sand. The heat of combustion is used to raise steam to drive a steam turbine. Because of the high steam temperature, the efficiency is about 42%. With CO_2 capture the efficiency is estimated at 34%.

We consider two fuel scenarios. In the first, 100% of the biomass is sourced in Canada and consists of saw-dust and bark from sawmills. The biomass is compressed to pellets and shipped to the Netherlands. In the second scenario 80% of the biomass is from Canada, with 20% imported from Brazil. If the saw-dust and bark were not utilised, it would be dumped in the vicinity and decay. During this decay process methane would be emitted, but at the same time carbon would remain in the ground and as such be withdrawn from the global carbon cycle. Both aspects, with positive and negative greenhouse effect, have been incorporated in this study.

Biomass gasification without CCS

Table 44 External costs in € per MWh of emissions/accidents for (CFBC) biomass plant without CCS, assuming 100% biomass from Canada

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.40	0.02	0.42
CH_4	0.02	0	0.02
N_2O	0.03	0	0.03
SO_2	1.33	0.23	1.56
NO_x	2.27	1.49	3.76
PM < 2.5	1.00	0.05	1.05
PM 2.5 - 10	0.03	0	0.03
Total emissions	*5.08*	*1.79*	*6.87*
Accidents	*≈0*	-	***≈0***
Total	**5.08**	**1.79**	**6.87**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 45 External costs in € per MWh of emissions/accidents for (CFBC) biomass plant without CCS, assuming 80% biomass from Canada and 20% from Brazil

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	25.50	0.02	25.52
CH_4	0.02	0.00	0.02
N_2O	0.03	0.00	0.03
SO_2	0.91	0.23	1.14
NO_x	1.80	1.49	3.29
PM < 2.5	0.70	0.05	0.75
PM 2.5 - 10	0.02	0.00	0.02
Total emissions	*28.98*	*1.79*	*30.77*
Accidents	**-**	-	**-**
Total	**28.98**	**1.79**	**30.77**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 44 and Table 45 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 23.90 €/MWh.

Biomass gasification with CCS

Table 46 External costs in € per MWh of emissions/accidents for (CFBC) biomass plant with CCS, assuming 100% biomass from Canada

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	0.49	-23.53	-23.04
CH_4	0.03	0	0.03
N_2O	0.03	0	0.03
SO_2	1.62	0	1.62
NO_x	2.77	1.36	4.13
PM < 2.5	1.22	0.03	1.25
PM 2.5 - 10	0.03	0	0.03
Total emissions	*6.19*	*-22.14*	*-15.95*
Accidents	≈0	-	***≈0***
Total	**6.19**	**-22.14**	**-15.95**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 47 External costs in € per MWh of emissions/accidents for (CFBC) biomass plant with CCS, assuming 80% biomass from Canada and 20% from Brazil

Pollutant	Precombustion	Combustion	Total (€/MWh)
CO_2	31.13	-23.53	7.6
CH_4	0.03	0.00	0.03
N_2O	0.03	0.00	0.03
SO_2	1.12	0.00	1.12
NO_x	2.19	1.36	3.55
PM < 2.5	0.85	0.03	0.88
PM 2.5 - 10	0.02	0.00	0.02
Total emissions	*35.38*	*-22.13*	*13.23*
Accidents	**-**	-	**-**
Total	**35.38**	**-22.13**	**13.23**

Source: Calculations by CE Delft, based on Hirschberg et al. (2004), Jonkman et al.(2003), NEEDS and CASES (CASES, 2008).

Table 46 and Table 47 indicate that the difference in the external costs of emissions and accidents between the two fuel scenarios is 29.18 €/MWh.