no. 006602

EUSUSTEL

European Sustainable Electricity;
Comprehensive Analysis of Future European Demand and Generation of European Electricity and its Security of Supply

Priority SSP-3
Policy Support and Anticipating Scientific and Technological Needs
Specific Support Action

D5.1
Report on total social cost of electricity generation

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RE	Restricted to a group specified by the consortium (including the Commission Services)	
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EUSUSTEL

European Sustainable Electricity

Contract no.: 006602

Most Optimal Solution for Electricity Provision

Final Report for WP 5-1

Determination of total social cost
of electricity generation

HUT/KULeuven/CIEMAT/USTUTT

1 Average Lifetime Levelized Generation Costs (ALLGC)

The levelized cost calculations incorporate all the expenses associated with a project over the entire lifetime. Not only the investments but also the interest charges on borrowed funds needed to finance the construction and desired rate of return on investment are considered, and all running costs. The levelized cost calculation presents the expenses and revenues as a real annuity where the payments are assumed to be for the same Euro amount in every year of the plant's lifetime. The levelized costs enable to make a more objective economical comparison between different energy options /International Energy Outlook, 2006/.

The private cost of generating electricity may include in addition to the average lifetime levelized generation cost (ALLGC) also other cost items that may vary from region to region, from time to time. Such cost items may be for example environmental taxes on fuels, carbon emission charges, system integration costs, etc. For the sake of clarity and comparability, only the levelized costs (ALLGC) are reported here although WP5 also produced some indicative numbers on the private costs as well.

The levelized cost of produced energy c_{ene} is determined by the fixed and variable costs of the energy generation technology in question. In a simple generalized form it can be presented in the following way:

$$c_{ene} = d \cdot \frac{c_{inv}}{E} + c_{fuel} + c_{oem} \tag{1}$$

where

c_{fuel}	fuel cost
c_{inv}	investment cost
c_{oem}	operation and maintenance cost
E	net yearly electricity production
d	discount factor (d)

The discount factor d is defined by the effective interest rate (r) and the life-time of the investment (t_{life}):

$$d = \frac{1-(1+r)^{-t_{life}}}{r} \tag{2}$$

In the EUSUSTEL calculations to be shown, the input data used originates from the WP3. For the interest rate two values were used: 5% and 10%. The levelized costs were calculated for 2005, 2010, 2020, and 2030. Prices for near shore and long distance conditions were considered. It should also be pointed out that the assumptions made on investments and fuel costs impose a natural uncertainty in the analysis to be followed, in particular the 2020-2030 values include already a clear uncertainty. The basic calculations were made by the Stuttgart University.

Table 1 shows a summary of the levelized cost of main electric generation technologies with a 5% discount rate and Table 2 for 10%, respectively.

Table 1: Levelized cost of different electricity generation technologies, r=5% and near shore conditions

i=5%	2005	2010	2020	2030
Coal-fired PCC	26-31	25-30	22-29	21-30
Coal IGCC	-	29-35	28-33	27-33
Natural gas (CCGT)	56-59	52-58	53-55	53-55
Nuclear	24-27	24-27	24-27	24-27
CHP (NG)	40-54	38-55	39-54	37-56
Biomass	47	47	45	42
Small hydro	33-1267	33-1267	33-1267	33-1267
PV	250-303	106-222	57-106	33-51
Wind	35-73	29-41	20-45	20-45
Fuel cells (NG)	140-595	-	-	-

Table 2: Levelized cost of different electricity generation technologies, r=10% and near shore conditions

i=10%	2005	2010	2020	2030
Coal-fired PCC	37-39	36-37	29-38	28-39
Coal IGCC	-	39-47	37-45	36-44
Natural gas (CCGT)	59-62	58-61	58-60	57-60
Nuclear	35-41	35-42	35-42	35-42
CHP (NG)	57-63	56-59	42-59	41-60
Biomass	58	57	53	49
Small hydro	40-1282	40-1282	40-1282	40-1282

PV	409-495	153-364	84-180	50-89
Wind	48-104	39-83	28-67	28-67
Fuel cells (NG)	163-768	-	-	-

The cost of electricity is given as an interval because of the span in input values and operational conditions; for example the lower values for wind correspond to onshore and higher to offshore conditions, respectively. A more detailed description of the cost calculation and input values is illustrated in Annex 1 for one case (r=10%, t=2005-2030)

A few interesting observations can be made from Tables 1 and 2:

- coal-fired and nuclear condensing power have close to same generation costs and rank best in the comparison
- new technologies show an impressive progress in cost reduction over time; cost of on-shore wind fully competes with traditional baseload power plants from 2020 onwards and may even provide the cheapest electricity of all generation technologies
- the choice of the interest rate influences as expected the electricity cost of investment heavy electricity generation technologies, but does not essentially change the mutual ranking
- the cost reductions for mature technologies such as natural gas, nuclear and coal-fired power generation turn out to be quite small up to 2030
- the largest cost reductions are expected with photovoltaics, or a factor of 5-6 from today up to 2030; but this requires a true market breakthrough of PV in large scale.

Finally, the above cost estimates from the EUSUSTEL analysis were compared to recent other studies reported, namely with IEA's World Energy Outlook 2006 and the US International Energy Outlook 2006 (U.S. DOE/ Energy Information Admininstration: International Energy Outlook 2006, Washington D.C., 2006). The exact economic parameters used in these studies were not known in full detail. Also, the numbers given are more applicable globally than on a regional basis (e.g. European).

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In the recent World Energy Outlook 2006 issued by the International Energy Agency, the electricity generating costs for baseload technologies ranges from slightly under 40$/MWh to close to 80 $/MWh. The CCGT is expected to be between 50 and 70 $/MWh while the coal-fired plants 40-60 $/MWh in the OECD markets. Whereas coal may loose its competitiveness in the European market due to the Emission Trading Systems (ETS), the coal-fired generation is and will remain competitive elsewhere including the USA. Nuclear comes to 47-57 $/MWh (capital cost 2000-2500$/kW) and wind 50-77$/MWh (900-1100 $/kW for onshore wind).

The US International Energy Outlook 2006 data is shown in Table 3 indicating quite small differences in the costs between the four different technologies considered. The levelized generation cost comes around 55 $/MWh.

Table 3: US DOE cost estimates for different electricity generation technologies.

Levelized Cost Comparison for New Generating Capacity in the United States
(2004 Dollars per Megawatthour)

Cost Element	Technology			
	Coal	Natural Gas	Wind	Nuclear
Capital . . .	30.4	11.4	40.7	42.7
O&M.	4.7	1.4	8.3	7.8
Fuel	14.5	36.9	0.0	6.6
Total[a] . . .	53.1	52.5	55.8	59.3

[a]Includes transmission hookup costs.
O&M = operations and maintenance.
Source: Energy Information Administration, *Annual Energy Outlook 2006*, DOE/EIA-0383(2006) (Washington DC, February 2006).

We have compared the costs from the three sources in Table 4 (1€=1.3$).

Table 4: Comparison of the levelized cost of electricity generation in three studies. (€/MWh)

Energy technology	EUSUSTEL (5%)	EUSUSTEL (10%)	IEA/WEO 2006	US DOE/IEO 2006
coal fired	26-31	37-39	31-46	41
natural gas	56-59	59-62	39-54	40
nuclear	24-27	35-41	36-43	46
wind	35-73	48-104	39-59	43

The most striking difference is in the cost of natural gas electricity (CCGT) which is clearly higher in EUSUSTEL than in the two other studies. Nuclear power comes also much cheaper in EUSUSTEL as well as the coal-fired power. The range of wind power cost is much broader in EUSUSTEL though the lowest cost estimates appear slightly lower in EUSUSTEL than in the other sources.

Table 5: Levelized electricity generation costs 2005 with 10% interest rate

2005								
Overall discount rate	0.1							
Price assumptions		2005	2010	2015	2020	2025	2030	
Lignite	[EUR/GJ]	0.97	0.98	0.98	0.98	0.98	0.98	
Natural gas	[EUR/GJ]	4.98	5.19	4.90	4.82	5.49	5.51	
Coal	[EUR/GJ]	1.96	1.86	1.97	2.07	2.14	2.19	
Nuclear	[EUR/GJ]	0.80	0.80	0.80	0.80	0.80	0.80	
CO_2	[EUR/t]	10.00	10.00	10.00	10.00	10.00	10.00	
	Energy carrier	technology of electricity generation	max. net el. power (busbar)	el. efficiency at el. peak load	spec. Investment costs (overnight capital costs)	total specific investment costs	capacity factor (electricity)	ALLGC
			[MW]	[%]	[€/kW$_{el}$]	[Eur/kW$_{el}$]	[-]	[Eur/MWh$_{el}$]
Condensing	Lignite	PCC	965	44.50	1300	1641.14	0.85	36.88
	Coal	PCC	400	48.00	1136	1365.19	0.85	39.13
	Natural gas	CCGT (min)	400	60.00	515	594.83	0.90	59.08
	Natural gas	CCGT (max)	500	55.00	580	669.90	0.90	62.27
	Nuclear Repository	EPR (min)	900	36.00	1300	1676.33	0.90	35.14
	Nuclear Repository	EPR (max)	1450	34.00	1600	2063.18	0.90	40.52
CHP	Natural gas	CHP_CCGT_BT	200	45.50	535	617.93	0.85	57.30
	Natural gas	CHP_CCGT	470	56	490	565.95	0.85	42.72
	Natural gas	IC_Engine	11	40.00	636	699.60	0.85	63.53
	Natural gas	IC_Engine_Industrial	0.527	40.00	1483	1631.30	0.85	94.75
	Coal	CHP_BT	400	48.50	1131	1359.18	0.85	38.89
	Natural gas	PAFC (min)	0.05	37.00	4500	4950.00	0.96	163.87
	Natural gas	PAFC (max)	0.05	37.00	4500	4950.00	0.96	163.87
	Natural gas	MCFC (min)	0.3	55.00	2800	3080.00	0.85	226.21
	Natural gas	MCFC (max)	0.3	50.00	5000	5500.00	0.85	305.32
	Natural gas	SOFC (min)	0.3	55.00	15000	16500.00	0.85	469.63
	Natural gas	SOFC (max)	0.3	28.00	30000	33000.00	0.85	768.43
RES (Non-Fluct.)	Biomass	IG_Biomass	133	37.20	1747	1921.70	0.95	57.50
RES (Fluct.)	Hydro	Hydro small (min)	10	90.00	900	990.00	0.80	39.45
	Hydro	Hydro small (max)	10	90.00	1400.00	1540.00	0.57	1281.54
	Hydro	Hydro large (min)	10	90.00	1400.00	2201.41	0.91	287.85
	Hydro	Hydro large (max)	800	90.00	1900.00	2987.63	0.80	553.00
	Solar	PV Average large (min)	0.0001	14.00	4500.00	4630.53	0.15	409.24
	Solar	PV Average large (max)	0.0005	10.00	4500.00	4630.53	0.15	409.24
	Solar	PV Average small (min)	0.00005	14.00	5500.00	5659.53	0.15	495.44
	Solar	PV Average small (max)	0.0001	10.00	5500.00	5659.53	0.15	495.44
	Wind	Wind Onshore (min)	0.75		800.00	839.05	0.29	48.42
	Wind	Wind Onshore (max)	2		900.00	943.93	0.23	64.44
	Wind	Wind Offshore (min)	2		1550.00	1705.00	0.50	55.72
	Wind	Wind Offshore (max)	2		1750.00	1925.00	0.29	104.01
	Geo	Conventional (min)	3		640.00	769.12	0.45	*
	Geo	Conventional (max)	120		2400.00	2884.20	0.90	*
	Geo	Binary cycle (min)	1		800.00	961.40	0.45	*
	Geo	Binary cycle (max)	3		2000.00	2403.50	0.90	*

Table 6: Levelized electricity generation costs 2010 with 10% interest rate

2010								
Overall discount rate	0.1							
Price assumptions		2005	2010	2015	2020	2025	2030	
Lignite	[EUR/GJ]	0.97	0.98	0.98	0.98	0.98	0.98	
Natural gas	[EUR/GJ]	4.98	5.19	4.90	4.82	5.49	5.51	
Coal	[EUR/GJ]	1.96	1.86	1.97	2.07	2.14	2.19	
Nuclear	[EUR/GJ]	0.80	0.80	0.80	0.80	0.80	0.80	
CO_2	[EUR/t]	10.00	10.00	10.00	10.00	10.00	10.00	
	Energy carrier	technology of electricity generation	max. net el. power (busbar)	el. efficiency at el. peak load	spec. Investment costs (overnight capital costs)	total specific investment costs	capacity factor (electricity)	**ALLGC**
			[MW]	[%]	[€/kW$_{el}$]	[Eur/kW$_{el}$]	[-]	[Eur/MWh$_{el}$]
Condensing	**Lignite**	**PCC**	1050	45.00	1300	1641.14	0.85	36.14
	Lignite	**IGCC**	450	49.00	1200	1514.90	0.85	38.47
	Lignite	**IGCC_CCS**	425	43.00	1500	1893.62	0.85	46.93
	Coal	**PCC (min)**	400	52.50	1100	1321.93	0.85	37.51
	Coal	**PCC (max)**	1000	52.50	1100	1321.93	0.85	37.51
	Natural gas	**CCGT (min)**	400	61.00	464	535.92	0.90	57.89
	Natural gas	**CCGT (max)**	500	56.00	522	602.91	0.90	60.96
	Natural gas	**CCGT_CCS**	450	54.00	925	1068.38	0.85	58.04
	Nuclear Repository	**EPR (min)**	1450	37.00	1300	1676.33	0.90	34.92
	Nuclear Repository	**EPR (max)**	1450	36.00	1700	2192.13	0.90	41.69
CHP	**Natural gas**	**CHP_CCGT_BT**	200	47.10	535	617.93	0.85	56.16
	Natural gas	**CHP_CCGT**	470	58.00	490	565.95	0.91	41.25
	Natural gas	**IC_Engine**	11	45.00	636	699.60	0.85	58.71
	Natural gas	**IC_Engine_Industrial**	0.527	45.00	1483	1631.30	0.85	89.97
	Coal	**CHP_BT**	400	52.50	1223	1469.74	0.91	38.24
RES (Non-Fluct.)	**Biomass**	**IG_Biomass**	133	40.00	1500	1650.00	0.85	56.51
RES (Fluct.)	**Hydro**	**Hydro small (min)**	10	90.00	900	990.00	0.80	39.45
	Hydro	**Hydro small (max)**	10	90.00	1400.00	1540.00	0.57	1281.54
	Hydro	**Hydro large (min)**	10	90.00	1400.00	2201.41	0.91	287.85
	Hydro	**Hydro large (max)**	800	90.00	1900.00	2987.63	0.80	553.00
	Solar	**PV Average large (min)**	0.0001	15.00	4000.00	4116.02	0.15	363.77
	Solar	**PV Average large (max)**	0.0005	10.00	4000.00	4116.02	0.15	363.77
	Solar	**PV Average small (min)**	0.00005	15.00	4500.00	4630.53	0.50	153.11
	Solar	**PV Average small (max)**	0.0001	10.00	4500.00	4630.53	0.50	153.11
	Wind	**Wind Onshore (min)**	1.5		630.00	660.75	0.29	39.04
	Wind	**Wind Onshore (max)**	3		800.00	839.05	0.23	57.28
	Wind	**Wind Offshore (min)**	5		1100.00	1210.00	0.50	40.45
	Wind	**Wind Offshore (max)**	10		1400.00	1540.00	0.29	83.20
	Geo	**Conventional (min)**	3		640.00	769.12	0.45	*
	Geo	**Conventional (max)**	120		2400.00	2884.20	0.90	*
	Geo	**Binary cycle (min)**	1		800.00	961.40	0.45	*
	Geo	**Binary cycle (max)**	3		2000.00	2403.50	0.90	*

Table 7: Levelized electricity generation costs 2020 with 10% interest rate

2020								
Overall discount rate	0.1							
Price assumptions		2005	2010	2015	2020	2025	2030	
Lignite	[EUR/GJ]	0.97	0.98	0.98	0.98	0.98	0.98	
Natural gas	[EUR/GJ]	4.98	5.19	4.90	4.82	5.49	5.51	
Coal	[EUR/GJ]	1.96	1.86	1.97	2.07	2.14	2.19	
Nuclear	[EUR/GJ]	0.80	0.80	0.80	0.80	0.80	0.80	
CO_2	[EUR/t]	10.00	10.00	10.00	10.00	10.00	10.00	
	Energy carrier	technology of electricity generation	max. net el. power (busbar)	el. efficiency at el. peak load	spec. Investment costs (overnight capital costs)	total specific investment costs	capacity factor (electricity)	ALLGC
			[MW]	[%]	[€/kW$_{el}$]	[Eur/kW$_{el}$]	[-]	[Eur/MWh$_{el}$]
Condensing	Lignite	PCC	1050	45.00	900	1136.17	0.85	29.11
	Lignite	IGCC	450	49.00	1100	1388.66	0.85	36.71
	Lignite	IGCC_CCS	425	43.00	1370	1729.51	0.85	44.64
	Coal	PCC (min)	400	55.00	1200	1442.10	0.85	38.38
	Coal	PCC (max)	1000	55.00	1200	1442.10	0.85	38.38
	Natural gas	CCGT (min)	400	63.00	417	481.64	0.90	57.49
	Natural gas	CCGT (max)	500	58.00	470	542.85	0.90	60.35
	Natural gas	CCGT_CCS	450	54.00	925	1068.38	0.85	59.47
	Nuclear Repository	EPR (min)	1450	37.00	1300	1676.33	0.90	34.92
	Nuclear Repository	EPR (max)	1450	36.00	1700	2192.13	0.90	41.69
CHP	Natural gas	CHP_CCGT_BT	200	47.90	535	617.93	0.85	57.12
	Natural gas	CHP_CCGT	470	59.00	490	565.95	0.91	42.02
	Natural gas	IC_Engine	11	47.00	636	699.60	0.85	58.68
	Natural gas	IC_Engine_Industrial	0.527	45.00	1483	1631.30	0.85	91.87
	Coal	CHP_BT	400	55.00	1223	1469.74	0.91	38.49
RES (Non-Fluct.)	Biomass	IG_Biomass	133	50.00	1250	1375.00	0.85	52.59
RES (Fluct.)	Hydro	Hydro small (min)	10	90.00	900	990.00	0.80	39.45
	Hydro	Hydro small (max)	10	90.00	1400.00	1540.00	0.57	1281.54
	Hydro	Hydro large (min)	10	90.00	1400.00	2201.41	0.91	287.85
	Hydro	Hydro large (max)	800	90.00	1900.00	2987.63	0.80	553.00
	Solar	PV Average large (min)	0.0001	25.00	2000.00	2058.01	0.15	179.67
	Solar	PV Average large (max)	0.0005	15.00	2000.00	2058.01	0.15	179.67
	Solar	PV Average small (min)	0.00005	25.00	2500.00	2572.51	0.50	84.24
	Solar	PV Average small (max)	0.0001	15.00	2500.00	2572.51	0.50	84.24
	Wind	Wind Onshore (min)	3		500.00	524.40	0.29	31.64
	Wind	Wind Onshore (max)	5		600.00	629.29	0.23	43.96
	Wind	Wind Offshore (min)	10		800.00	880.00	0.50	28.13
	Wind	Wind Offshore (max)	20		1200.00	1320.00	0.29	67.24
	Geo	Conventional (min)	3		640.00	769.12	0.45	*
	Geo	Conventional (max)	120		2400.00	2884.20	0.90	*
	Geo	Binary cycle (min)	1		800.00	961.40	0.45	*
	Geo	Binary cycle (max)	3		2000.00	2403.50	0.90	*

Table 8: Levelized electricity generation costs 2030 with 10% interest rate

2030								
Overall discount rate	0.1							
Price assumptions		2005	2010	2015	2020	2025	2030	
Lignite	[EUR/GJ]	0.97	0.98	0.98	0.98	0.98	0.98	
Natural gas	[EUR/GJ]	4.98	5.19	4.90	4.82	5.49	5.51	
Coal	[EUR/GJ]	1.96	1.86	1.97	2.07	2.14	2.19	
Nuclear	[EUR/GJ]	0.80	0.80	0.80	0.80	0.80	0.80	
CO_2	[EUR/t]	10.00	10.00	10.00	10.00	10.00	10.00	
	Energy carrier	technology of electricity generation	max. net el. power (busbar)	el. efficiency at el. peak load	spec. Investment costs (overnight capital costs)	total specific investment costs	capacity factor (electricity)	**ALLGC**
			[MW]	[%]	[€/kW$_{el}$]	[Eur/kW$_{el}$]	[-]	[Eur/MWh$_{el}$]
Condensing	**Lignite**	**PCC**	1050	50.00	900	1136.17	0.85	28.32
	Lignite	**IGCC**	450	52.00	1100	1388.66	0.85	36.30
	Lignite	**IGCC_CCS**	425	46.00	1370	1729.51	0.85	44.11
	Coal	**PCC (min)**	400	55.00	1200	1442.10	0.85	38.68
	Coal	**PCC (max)**	1000	55.00	1200	1442.10	0.85	38.68
	Natural gas	**CCGT (min)**	400	65.00	375	433.13	0.90	56.94
	Natural gas	**CCGT (max)**	500	60.00	423	488.57	0.90	59.61
	Natural gas	**CCGT_CCS**	450	56.00	925	1068.38	0.85	59.36
	Nuclear Repository	**EPR (min)**	1450	37.00	1300	1676.33	0.90	34.92
	Nuclear Repository	**EPR (max)**	1450	36.00	1700	2192.13	0.90	41.69
CHP	**Natural gas**	**CHP_CCGT_BT**	200	52.00	535	617.93	0.85	55.22
	Natural gas	**CHP_CCGT**	470	64.00	490	565.95	0.91	40.50
	Natural gas	**IC_Engine**	11	47.00	636	699.60	0.85	60.12
	Natural gas	**IC_Engine_Industrial**	0.527	47.00	1483	1631.30	0.85	91.60
	Coal	**CHP_BT**	400	55.00	1223	1469.74	0.91	38.79
RES (Non-Fluct.)	**Biomass**	**IG_Biomass**	133	55.00	1000	1100.00	0.85	48.67
RES (Fluct.)	**Hydro**	**Hydro small (min)**	10	90.00	900	990.00	0.80	39.45
	Hydro	**Hydro small (max)**	10	90.00	1400.00	1540.00	0.57	1281.54
	Hydro	**Hydro large (min)**	10	90.00	1400.00	2201.41	0.91	287.85
	Hydro	**Hydro large (max)**	800	90.00	1900.00	2987.63	0.80	553.00
	Solar	**PV Average large (min)**	0.0001	25.00	1000.00	1029.01	0.15	89.42
	Solar	**PV Average large (max)**	0.0005	15.00	1000.00	1029.01	0.15	89.42
	Solar	**PV Average small (min)**	0.00005	25.00	1500.00	1543.51	0.50	50.36
	Solar	**PV Average small (max)**	0.0001	15.00	1500.00	1543.51	0.50	50.36
	Wind	**Wind Onshore (min)**	5		500.00	524.40	0.29	31.64
	Wind	**Wind Onshore (max)**	5		600.00	629.29	0.23	43.96
	Wind	**Wind Offshore (min)**	20		800.00	880.00	0.50	28.13
	Wind	**Wind Offshore (max)**	20		1200.00	1320.00	0.29	67.24
	Geo	**Conventional (min)**	3		640	769.12	0.45	*
	Geo	**Conventional (max)**	120		2400.00	2884.20	0.90	*
	Geo	**Binary cycle (min)**	1		800.00	961.40	0.45	*
	Geo	**Binary cycle (max)**	3		2000.00	2403.50	0.90	*

2 Determination of shadow costs

2.1 Intermittency, wind power and backup costs

Intermittency is a phenomenon related to the use of some renewable energy sources, i.e. these sources for which output is driven by environmental conditions mainly outside the control of the generators or the system operators. Examples are wind power, photovoltaic cells (PV) and combined heat and power (CHP). The inflexibility, variability, and relative unpredictability of intermittent energy sources are the most obvious barriers to an easy integration and widespread application of wind power. Apart from that, the technology is also relatively new. Information about wind power is not based on the same amount of experience as for conventional technologies. [18]

This report discusses the impact of intermittent generation on system operation and reliability and the extent of any new costs due to this generation (relative to costs and impacts imposed on the system by other generating options). [14] In particular, the report discusses the difficulties related to wind power integration.

Wind power is probably the most studied intermittent energy source and it will be the focus of the remainder of this report. In particular, the full cost related to the integration of wind in an electricity-generation system is examined. Other renewable energy sources are faced with similar problems and costs but we decided to focus on wind because wind is most likely to be the first renewable source to enter the market with a significant share. Obviously, the issues raised in this report also apply to other intermittent sources.

Shadow costs for intermittent sources such as wind power appear where constraints arising due to that wind power exist. The costs occurring due to wind power that cannot be accounted for directly in the costs such as the investment or operations and maintenance costs; are referred to as “backup costs”. The backup cost of wind has its origin in the uncertainty regarding wind as an energy source and the measures that have to be taken to cope with it. Risk of failures of the system might increase with the introduction of wind power without the inclusion of additional measures. Reliability issues, both on the adequacy and the security level arise. A certain risk premium attributed to wind power can become necessary. Utilities attempt to uphold a minimum level of reliability while at the same time minimizing system costs. The generation schedule is most likely to be adjusted with the introduction of wind power as to allow for an efficient and cost-effective operation of the system.

The electricity generation system is ideally built so as to minimize the total cost of operating the entire system. Currently, most systems are for the main part composed of conventional power plants. The introduction of wind power in a system may severely change the needs for efficient operation of the electricity generation system. The whole concept may have to be rethought, thereby inducing extra costs for adaptation of the system and new operating methods.

The feasibility of wind energy development depends on the ability to produce energy at very low operating costs. [16] With wind becoming an important alternative for generation of electricity, it is essential to accurately model the effects of wind power on the total electricity-generation system, especially regarding the underlying economics.

After this introduction with a brief overview of the terminology used for “costs”, specific aspects of wind will be discussed; more specifically, factors that characterize wind and its variability.

In a subsequent part, covered by chapter 5, the operation of electricity-generation systems is explained. This operation is very context-specific and is found to have an important impact on the integration and operation of wind power.

Next, the integration of wind power in the electricity-generation system is discussed in chapters 6 to 11. In this part, first a general overview of the different backup issues is presented. Then each of these three issues is elaborated in separate chapters. After a brief chapter on the grid effect of intermittent sources, an overview is given on the costs related to backup of intermittent sources and wind power in more general.

The last part, *Questions and Answers* focuses on some general misconceptions surrounding the issue of integrating wind power.

2.2 Some cost concepts and their relation

This chapter discusses cost concepts that are relevant for the discussion on the backup costs of wind. Clearly, in one way or another, the backup costs should be linked to the costs made by the generation firms and the system operator in their production processes. Economic theory distinguishes several types of costs within a firm and a good understanding of each of these cost concepts is necessary because some of them are often misinterpreted. Therefore, the next paragraphs survey and discuss the most important of these cost concepts. [4][7]

First, different cost concepts are explained. Then, the time horizons that can be considered for costs are explained. Next, the difference between costs and prices is elaborated. Finally, the backup cost of wind power is discussed.

2.2.1 What is a cost?

A cost is not a fix concept. Costs will usually be minimized to the best extent and are likely to change over time. Moreover, there are various types of costs that have to be seen in their specific context. It has to become clear that “costs” encompass a very broad scale of meanings and it is important to always understand what type of cost is being considered, especially when looking at complicated issues such as the backup for intermittent sources.

First, a distinction will be made between economic and accounting costs. Secondly, variable, fixed and total costs concepts will be explained. Thirdly, marginal costs are being defined. Next, external costs are looked at, after which the average cost concepts are described. The relationship between average costs and marginal costs is explained in section 2.1.6. Finally, sunk costs are compared to fixed costs.

Economic costs versus accounting costs

What is of relevance for our discussion are *economic* costs and not *accounting* costs. The latter refer to the actual expenses plus the depreciation charges of capital equipment. The former refer to costs of utilizing economic resources in production, including opportunity costs. Clearly, if accounts of firms are the only source of data, economic costs may require the use of these accounting data.

In the economic literature ([56]), economic cost and opportunity cost are often used as synonyms. The concept of an opportunity cost refers to the idea that using a resource for one purpose, for example burning gas for electricity generation, implies that the resource cannot be used any more for other purposes, for example house heating. An opportunity is foregone and the value of this foregone opportunity is the cost of the chosen application. In short it means that a certain asset that is used by an actor could have been employed elsewhere as well and the opportunity cost expresses the most valuable forgone alternative.

For example, consider an electricity producer that owns a greenfield land which is used to build a wind park on it, with the aim of generating and selling electricity. The producer could also have used the land to build a coal power plant and the foregone profit from that investment is part of the opportunity cost. It should be included as part of the economic cost of the business of the electricity supplier.

Opportunity costs in many cases also refer to non-monetary costs. For example, the time invested by the owner of a Greenfield in getting all the necessary licences for building the wind park, could have been used could have been used for other purposes, such as thinking about new ways to improve the operation of his existing power plants. Accountants and economists alike work with the concept of cash flow, which comprises salaries, cost of payments to other actors and all other direct payments. These are real expenses with money that could also have been spent elsewhere.

Variable costs, Fixed costs and Total costs

A distinction has to be made between variable (VC) and fixed costs (FC). In order to produce, a firm needs inputs. For some of these inputs, the quantity used does not depend on the level of output and therefore they are called fixed inputs. For other types of input, the quantity that is used does vary with the level of output. These are the so-called variable inputs. The costs associated with this latter type of inputs are called *variable costs* ($VC(q)$).

Costs associated with the fixed inputs are either *fixed costs* or *sunk costs* (F)[1]. The sum of the variable costs and the fixed costs are the *total costs* ($TC(q)$):

$$TC(q) = VC(q) + F \tag{0.1}$$

A fixed cost has to be paid regardless of the presence or level of output. It can only be avoided by stepping out of the business. Examples are rent and insurance premiums. Examples of variable costs are materials.

[1] The difference between fixed costs and sunk costs will be clarified below.

Marginal costs

The marginal cost, sometimes also called incremental cost, is the increase in cost due to the production of one extra unit of output. It is the most important concept when it comes to deciding on the profit maximising level of output. The *marginal cost* $MC(q)$, which is the extra cost that the firm makes to produce an extra unit of output, is determined by the variable costs since the fixed cost does not change as the actor's level of output changes. Formally, the marginal cost of producing one additional unit of output given that q units have already been produced is

$$MC(q+1) = TC(q+1) - TC(q) \tag{0.2}$$

External costs

External costs occur when production or consumption decisions of one agent have a negative impact on the production or consumption opportunities of another agent. External costs are usually not easily expressed in monetary terms but rather in inconveniences to the society. Pollution is a typical example of an external cost. For example, damages due to emissions by thermal power plants are generally not an element of the production costs of the generator, except if the generator is required to pay for them via a tax or emission permits. Wind power can reduce emissions and therefore bring about a decline in total cost for society, when taking external costs into account as well.

Average cost concepts

The average cost (AC) is the previously mentioned total cost divided by output. The average total cost (ATC) can be split up into average fixed cost (AFC) and average variable cost (AVC).

The average cost ($AC(q)$) is defined as the total cost divided by the output. The average fixed cost ($AFC(q)$) equals fixed costs divided by output and average variable cost ($AVC(q)$) equals variable costs divided by output.

$$\begin{aligned} AFC(q) &= \frac{F}{q}, \\ AVC(q) &= \frac{VC(q)}{q}, \\ AC(q) &= \frac{TC(q)}{q} = \frac{VC(q)+F}{q} = AVC(q) + AFC(q). \end{aligned} \tag{0.3}$$

These average cost concepts are related in the sense that the average cost equals average fixed cost plus average variable cost.

Relation between the average cost and the marginal cost curves

There is a simple relationship between average costs and marginal costs. If, for a given level of output, the marginal cost is lower than the average cost, then the average cost is decreasing. If on the contrary, the marginal cost is above the average cost, then the average cost is increasing. And finally, if the marginal cost equals the average cost, then the average cost reaches its minimum.

The same relation exists between the average variable cost and the marginal cost. These relations are illustrated in Figure 1.

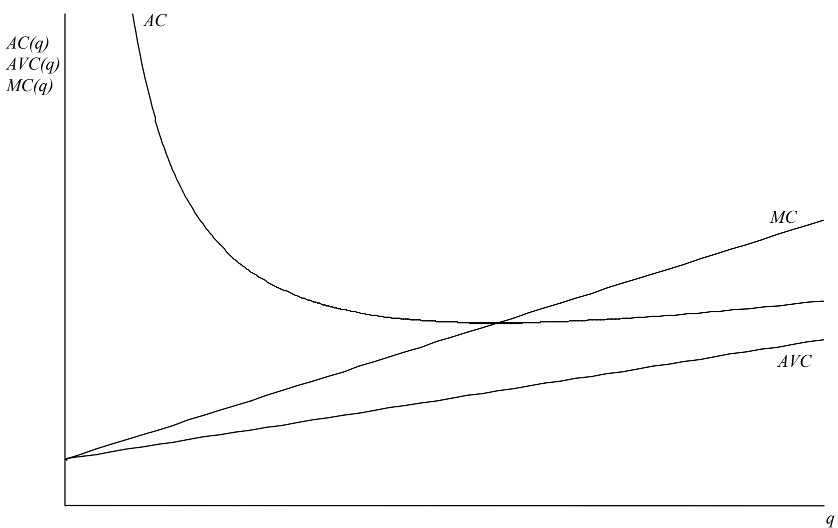

Figure 1: The relation between marginal and average costs

Fixed costs versus Sunk costs

It was mentioned before that the costs linked to the fixed inputs are either fixed or sunk. The distinction between *fixed costs* and *sunk costs* is more one of degree than one of nature. In a one-period textbook model (or a timeless world), a firm's fixed costs can be defined as the cost that the firm must incur in order to produce and that is independent of the number of units of output. [63] In other words, it defines a cost that is incurred regardless of the scale of production. In such a world, fixed costs are also sunk.

Clearly, a timeless world is an abstraction of reality and once time is introduced the concept of fixed costs should be more carefully defined. In that case fixed costs are defined as costs that are independent of the scale of production and that cannot be avoided for 'some period of time'. This 'period of time' is typically called the short run. Crucial is that some of these fixed costs can be recovered or recouped if the firm decides to go out of production after 'some period of time'[2]. In a sense, fixed costs are sunk only in the short run. Summarising, one could say that sunk costs are always fixed, but fixed costs are not always sunk.

For example, a firm might rent a building on a yearly basis to locate its production line. The rent is an annual cost that is independent of the amount of production and as such it is fixed. If the firm goes out of business, the firm stops renting the building. If the firm had bought the building, then the price paid to buy the building would have been considered a fixed cost as well. When the firm stops production, some of it can be recovered by selling the building. The same firm might also invest in a logo and in a marketing campaign to promote its product. If the firm quits business, then the expenditures on the logo or the marketing campaign cannot be recovered. These latter costs are sunk costs.

Where an opportunity cost is often hidden but nevertheless has to be taken into account for the decision-making process, the opposite is true for sunk costs. The sunk cost should not be taken into account when making economic decisions. Consider, for example the investment in special maintenance equipment for a wind turbine that cannot be put to another use or be sold. Once made, this expenditure has only one purpose and will entail no opportunity cost since there are no other opportunities for this equipment.

[2] The short run indicates the period of time in which it is impossible to increase the use of one of the inputs (usually capital) above the available capacity. The long run indicates the situation where it is possible to vary all levels of input.

2.2.2 What are the different horizons for costs?

Two important time horizons can be considered for the study of costs. First, there is the short run during which has to be decided how much to produce with the different available assets to get to the desired level of production. In the long run, an economic actor has the choice to foresee investments that will enlarge the extent of available options on the production side. The long run is more flexible than the short run. [56]

The short run

The short run is that period in which at least one input level, usually capital, cannot be changed. Variables Output can be chosen so as to optimise the total gains, but the firm is bound by the investments that have been done in the past. In the short term, no new investment can be considered.

In the short run, a typical course of marginal cost for the production of output, such as electricity, consists of two parts. First, there is a diminishing marginal cost until, at a certain turning point, the marginal costs will start to increase as output increases. In **Figure 2**, a typical course of the mentioned costs is presented.

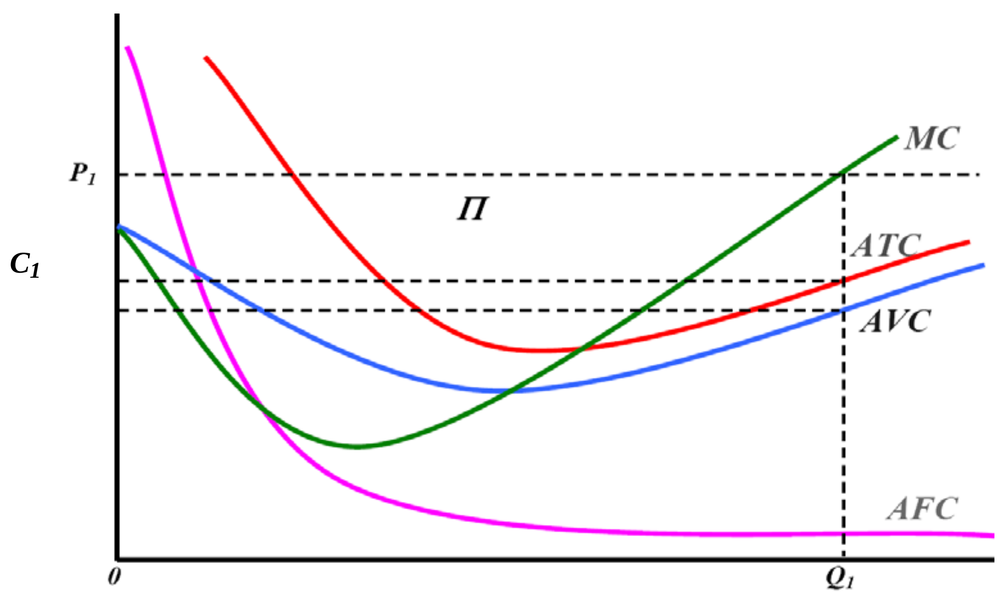

Figure 2: Short run cost curves [26]

The long run

In the long run all inputs are variable. Investments can be done and, therefore, the amount of capital used can vary. This additional flexibility, compared to the short run, allows a firm to produce at lower average cost than in the short run. Indeed, more flexibility allows for more optimal usage of input.

The long run cost curve is in fact made up of a combination of all the possible short run cost curves. It touches the short run average (SAC) curves at their extremities, as can be seen in Figure 3. The figure exhibits three possible investment levels with corresponding short run cost curves. These investment levels could represent three options for investing in a wind turbine park, which is a long run decision. The electricity producer will get the lowest possible average cost by opting for an output level Q_2. Once the corresponding investment level chosen, the producer will be able to adjust his options according to the curves SAC_2 and SMC_2 on the short run.

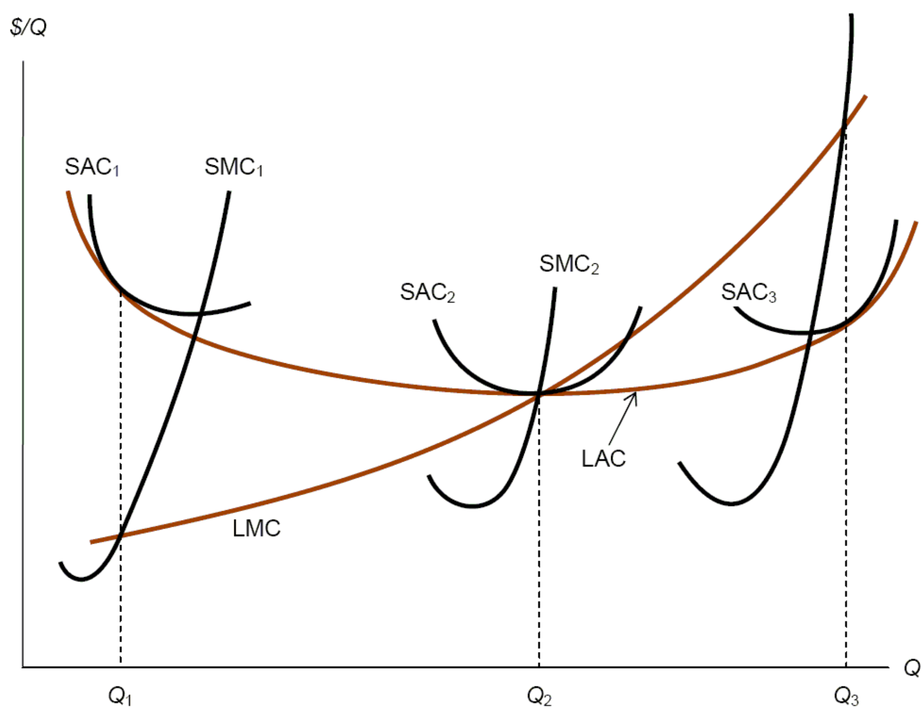

Figure 3: Typical course of long run cost curves for one actor. The Y-axis defines the cost per unit of output; the X-axis represents the amount of output [25]

2.2.3 Is there a difference between costs and prices?

There is often a misunderstanding in the use of the terms “cost” and “price”. Both relate to a different, albeit related, concept. Generally speaking, costs are defined by the expenses made for the production of a certain output. Prices come about after an interaction of supply and demand, depending on the considered market structure. Mostly in real life, prices and costs do not have the same value.

Market actors are driven by profit maximization. The difference between total revenue and total costs has to be a large as possible. This is true for individual actors as well as for an entire society. The price that originates from the market equilibrium is therefore based on the aggregated profit maximization.

As stated above, in real life, the price paid will mostly differ from the cost of the producer. Under perfect market conditions however, the price will be equal to the marginal cost of the producer under the considered amount of output. In **Figure 2**, this price is set to be P_1 and the corresponding output for this price is Q_1. With this amount Q_1, the cost per unit produced will be C_1. The maximized profit Π of the producer is given by the difference between total revenue ($P_1 * Q_1$) and total cost ($C_1 * Q_1$) and is represented by the surface between the price-line and average cost line. This is true for markets under perfect competition but also under other market forms will the output price usually differ from its cost.

Prices in a competitive market are determined by the equilibrium of aggregated demand and supply. All actors on this market are price-takers and cannot influence it on their own. The elasticity of demand and supply will determine the amount of price variation in the market.
For example, the electricity market is a typical example of a market with an inelastic demand. This means that the demand curve will be practically vertical and that the demand has to be met by (almost) all means. The price may go up or down but this will have practically no influence on demand. The reason for this is the importance electricity has in today's economy and the lack of substitutes for it. High electricity prices typically coincide with a low level of supply, whereas large amounts of supply will lower the equilibrium price. An extreme example of this phenomenon can be witnessed in Denmark where large amounts of wind power are installed. [39] At moments wind power functioning at full capacity in Denmark, the supply might become so high that the price for electricity on the Nordpool market will drop to zero. This is illustrated in **Figure 4**. The supply at these moments is in fact too high for the given demand.

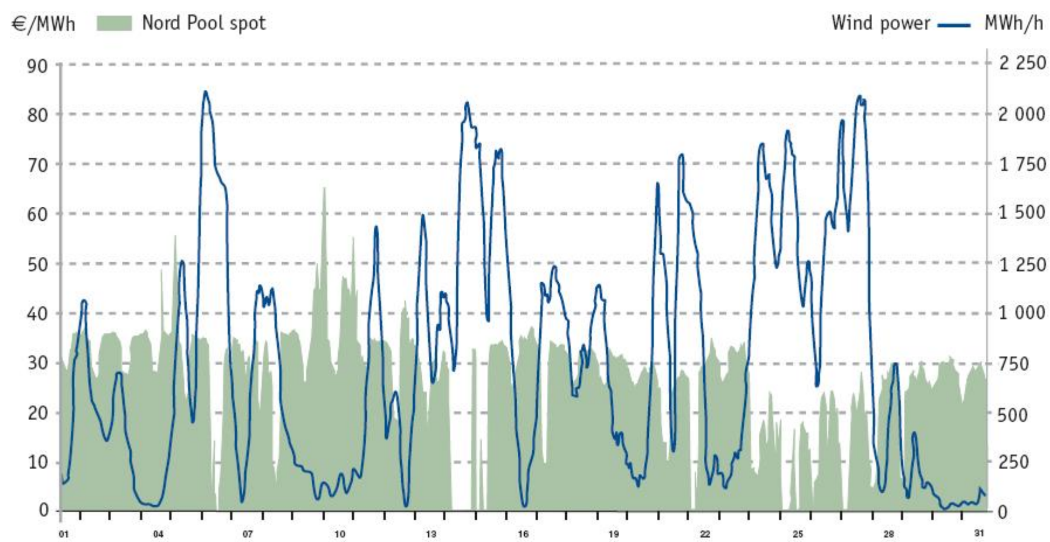

Figure 4: Evolution of wind power output in Denmark and electricity prices of the Nordpool market in December 2003 [39]

Sometimes, the price will be the only known or best estimate of the cost. Often, the price one actor has to pay, will be the cost another actor has to take into account. When an electricity supplier buys his electricity from a producer for example, the price he will have to pay will make up a part of his costs.

This report will focus on the costs of incorporating wind power in an electricity-generation system and this from the point of view of the society as a whole. The actor who will see to the cost in the end is of lesser importance for the analysis. It is important to give a clear view of the total actual impact of wind power and other intermittent energy sources on the system.

2.2.4 The backup cost and shadow cost

The backup cost is a specific type of cost. In short it defines all the costs that are added to the electricity-generation system due to the integration of, in this specific case, intermittent power sources. It does *not* include the costs that are related to the investment or operation of the wind turbines themselves. As in any incorporation of an element into a system, adjustments to this system have to be made. The magnitude of these adjustments depends on the type and volume of these elements and the composition of the system. There is reason to believe that the integration of wind power or any other intermittent energy source in the electricity-generation system will have an impact, certainly when considering the amounts mentioned by several investment plans of countries all over the world.

Shadow costs refer to costs that are not directly attributable to a certain measure but nevertheless arise indirectly due to that measure. A shadow cost is a concept linked to the operations research theory. It stands for the reduction in cost that can be achieved when a certain constraint on the system is relaxed. [62] The introduction of wind power causes several of these constraints to arise or to change. The costs are not directly linked to wind power, but since adjustments to the system are needed, wind power is responsible for them. The obligations on reserve requirements can illustrate this in broad lines. The reserve requirement can be presented by a constraint on the operation of the system. The stronger this constraint and the more reserves are needed, the more it will cost to the system. The introduction of wind power usually brings about even more requirements concerning reserve. Although the additionally incurred costs fall to the operation of the system in general, they can be attributed to wind power through the change in constraints on the system operation. Wind power can be asked to provide a risk premium for its inclusion in the system. Since “shadow cost” refers to the same concept as “backup cost”, be it in a more technical way, the term will not be used in the remainder of this report. Instead, the additional charges that are incurred due to wind power, will always be referred to as backup cost.

Just like any other type of cost, the backup cost of wind power can be seen on short and long term. The short term is taken to reflect the operational part of the backup cost, while the long term encompasses the capacity issues of backup. The operational backup cost can again be split up in two parts, namely the backup balancing cost and the backup unit commitment cost. These categories of backup and related costs will be explained in more detail in chapter 2.6.

2.3 Wind power Characteristics

Although some disagree on the exact definition of intermittency, which is further elaborated in what follows, in general wind power plants can be considered as examples of intermittent power generation. These power plants only generate electricity when the wind is blowing. Wind speed cannot be predicted with high accuracy on short term and even less on long term and, consequently, the operating costs of the energy system may increase when wind power is introduced. Most known examples to characterise this are the additional costs that occur to balance the extra imbalances created by wind power. These have to do with security of electricity-generation systems. Also longer-term investments to preserve system adequacy after the installation of large amounts of wind power, have to be seen in this context. New investments in conventional power may be needed to partially act ad capacity backup for wind power. How wind power affects costs of the energy system, will be explained more thoroughly in chapters 6 to 11.

In this chapter, the term “intermittency” is defined, after which the relation between wind speed and wind power is given. Wind power is characterised by three elements, namely limited control, relative unpredictability and temporal variations. [20] Getting a better insight into these elements, allows for a better understanding of the whole wind power integration issue. They are further discussed in this and the subsequent chapter.

2.3.1 Intermittency - Variability

In the context of electricity-generation systems, intermittency indicates the non-continuous output of power plants. Thus, the starting and stopping at irregular intervals is what defines an intermittent energy source. In theory, it also covers conventional thermal plants that, for some reason, become unavailable, but intermittency is an issue that is commonly linked to wind power and other, non-conventional variable power plants. [12]

Theoretically speaking, intermittency does not completely accurately define the behaviour of electricity sources such as wind turbines. The exact definition of intermittency refers to “*the coming at intervals; the operation by fits and starts*” of a certain appliance. The European Wind Energy Association ([12]), for example, states that wind power should not be denoted as an intermittent energy source. It all depends on how exactly the definition of intermittency is interpreted.

Both “variability” and “intermittency” are used to define the particular behaviour of renewable energy power plants. Renewable energy sources can, according to the UCTE ([65]), be classified as one of these categories: wind energy, photovoltaic or solar energy, geothermal energy and energy from biomass and waste[3]. Neither “variability” nor “intermittency” can entirely accurately distinguish conventional thermal plants from renewable plants since the former can also be intermittent, for example during faults.

Although not completely accurate according to the core definition of “intermittency”, in what follows the terminology “intermittency” will be used to describe the specific behaviour of many types of renewable electricity generation such as wind, solar and wave. It is meant to define the non-controllable variability of these energy sources that can never be completely accurately forecasted. While all plants are inherently intermittent, insofar they all suffer from occasional outages, intermittent renewable production capacity fluctuates much more

[3] Such as biogas, damp gas, municipal waste, industrial waste, wood and waste of wood.

explicitly. In most cases, the contribution of renewable energy sources to reliability is lower than for conventional thermal power plants. [14] This definition is consistent with the usage of the term in most of the literature on the topic ([14], [37], [18], [52], [39]). In this context, an intermittent electric generator should therefore more be interpreted as "*an electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements.*" [9]

The variability of wind is discussed in more detail in chapter 2.4.

2.3.2 From wind speed to wind power

Wind power is the result of the conversion of wind to power, achieved by means of wind turbines. Wind power capacity data and data on electricity produced by wind turbines exist for installed wind turbines. However, it is not possible to analyse wind power data from locations that do not have wind turbines installed. Often, wind power output data are not available for studies to be performed on. *Real wind power output data* can only be collected on already existing wind turbine sites. To perform analyses, not being constrained by the presence of wind turbines or to analyse potential impacts of wind power in some locations, before wind turbines are built, *meteorological wind speed data* offer a solution. These data can be transposed to reflect the electricity output of a wind turbine.

Wind speed characteristics

Wind speed data, as opposed to wind power output data, are widespread and are reported according to the same rules in most European countries. Their uniformity and the number of measuring stations make it a valuable tool for the study of the introduction of wind power into an electricity-generation system.

When no wind speed data are available, wind speed can also be studied according to statistical measures. The statistical probability density function of wind can be approximated by the Weibull function, which is written as ([69][32])

$$f(v) = \frac{b}{v_c} . \left(\frac{v}{v_c} \right)^{b-1} . \exp \left[- \left(\frac{v}{v_c} \right)^{b} \right] \quad (b > 1, v \geq 0, v_c > 0) \tag{0.4}$$

In this formula, v expresses the wind speed; v_c represents a scale parameter and b a form parameter. *F(v)dv* expresses the probability that the wind speed is situated between *v* and

$v+dv$. In most temperate environments, $b=2$, which represents the Rayleigh distribution, a special case of the Weibull distribution.

Conversion of wind speed data to wind power data

Wind speed data are more readily available than data on wind power output. The conversion of wind speed data can be performed according to clear calculations. Internet sites such as the one from the Danish Wind Industry Association ([36]) and Retscreen International ([32]) offer practical info and various tools for calculation of different parameters related to wind power. In what follows, a short explanation on the conversion of wind speed data to wind power data is given.

This expected power output of wind turbines depends on various parameters, namely the wind speed, the considered turbine type, the surface roughness and the hub height. There are numerous types of wind turbines, all with their own power curves that represent how a certain wind speed will be transformed into wind power. The surface roughness depends on the surroundings of the wind turbines. Flat landscape results in lower surface roughness whereas relief and urbanisation will entail a higher surface roughness. Finally, the wind speed is mostly measured at a different height than the height of the hub of a wind turbine. This hub height also determines the final output characteristics and will have to be extrapolated from the measurement data.

Based on standard measurements of wind speed, the wind power output can be calculated according to the following method. [45][69]

First the wind speed data are extrapolated to a higher point, typically from 10m to about 70-80m. Two methods can perform this operation, namely the empirical "power law" and the "logarithmic law". The parameters h_1 and h_1 represent the wind speed measurement height and the height to which it is extrapolated respectively, while v_1 and v_2 represent the corresponding wind speeds. The power law is expressed as follows:

$$v_2 = v_1 \left(\frac{h_2}{h_1} \right)^{\alpha} \qquad (0.5)$$

with α being 1/7 for smooth surfaces, α = 0.16 more inside the country and α = 0.3 and higher for city environments and surfaces with obstructions.

The logarithmic law is expressed as follows:

$$v_2 = v_1 \frac{\ln(h_2 / z_0)}{\ln(h_1 / z_0)} \tag{0.6}$$

with z_0 as surface roughness taking values between 0.0002m for water surfaces up to 0.4m for city environments and landscapes with obstructions.

Once the hub height extrapolated, the according wind power output can be determined using the power output characteristics of the considered wind turbine. As an example, the Vestas V80 wind turbine's power curve is given in **Figure 5**. The different curves in the Figure represent the power curves at different sound levels. The Vestas V80 is a common type of wind turbine with a cut-in speed of 4 m/s, which means that it will start producing electricity from that speed on. The maximum power is obtained with wind speeds of 15 m/s and higher. The cut-out speed, when the turbine has to be taken offline due to too strong wind speeds, is 25 m/s.

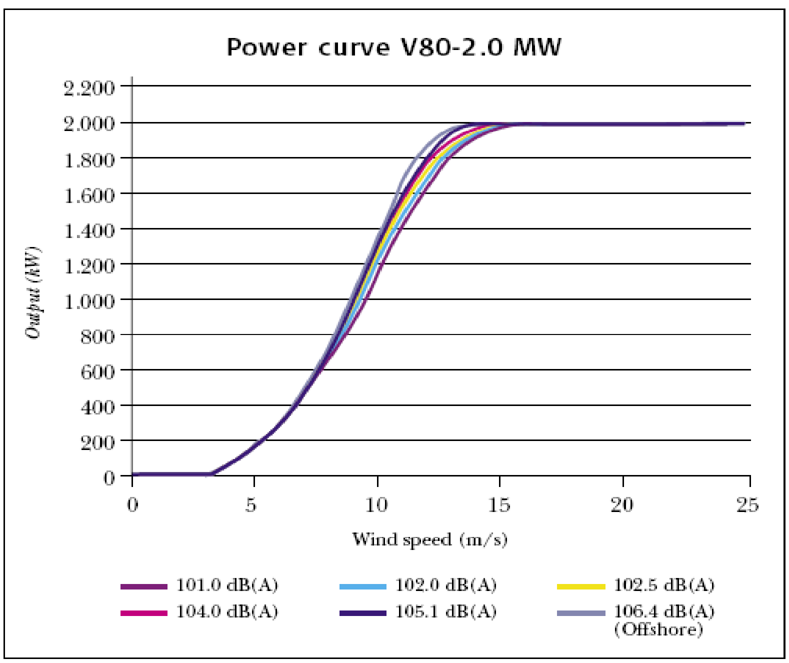

Figure 5: Power curve of Vestas V80, 2 MW wind turbine [34]

2.4 The variability of wind

Wind behaves according to certain patterns, influenced by various parameters such as climatologic conditions or location. The result is that wind has a very irregular course. As mentioned above, wind has an intermittent and variable behaviour. This has serious consequences for the use of wind as an energy source. Both wind as a natural phenomenon and wind power are examined in what follows. The variability of wind on different timescales is analysed first. Subsequently the geographic spread of wind will be looked at.

2.4.1 Time scales in variability

Wind has natural cycles in many different time scales, ranging from minutes to years. [40] These timescales will be discussed in what follows.

Short-term variability

On the short term, wind can already become relatively variable, especially when considering only one location and therefore one measurement, without looking at the interaction with an aggregated region. The short-term wind variations are mainly due to fluctuating weather patterns and the geographical spread of the considered measurements. [12] The short-term variability of wind influences the balancing of wind power, when wind turbines are integrated into an electricity-generation system and will then interact with the generation mix, the long-distance transmission capacity and the load. This is discussed in more detail in chapter 2.7.

On the short term, a distinction can be made between variability within the minute or within the hour.

Within the minute

The fast variations of wind, from seconds to a minute, occur in this timescale. The variation of wind speed on the seconds scale will be reduced to a very small value once it is transformed into electricity by means of a wind turbine. The wind turbine itself compensates part of the fluctuations on the very short time scale. [68] For a larger group of measuring points for wind speed, the fluctuations within the minute become even smaller. [40] Aggregated wind speed fluctuations as a consequence of turbulence or transient events are quite small as a result of this aggregation and are hardly felt when incorporated into an electricity-generation system after the transformation of wind speed to wind power took place.

Within the hour

The variations within an hour, that is to say, from 10 to 30 minutes are considerably more significant. These variations are smoothened to a great extent through geographic dispersion of considered wind speed measurements. Again, when considering the aggregated sum of wind farms spread over a large area, the variations usually remain inside ±5% of installed wind power. [12] The largest variations have to do with passing storm fronts. Wind speeds can go up very fast and installed wind turbines have to be shut down once their cut-out speed is reached.

Hourly variations

The hourly variation of wind speed or the variations on a time scale of a couple of hours is the one usually faced by wind turbine operators. This is the time scale in which predictions have to be made to plan the provision of electricity produced by wind turbines. Forecast errors can occur. Again, these variations have to be seen in the context where the wind is being used in. The longer the considered timescale, the more variation will occur. **Figure 6** provides a good illustration of this fact. The 4-hour variation is much more spread out than the hourly variation and will tend to vary more on average. [52] Holttinen finds that within one hour, the step changes stay inside ± 20% of installed capacity for Sweden, Norway and Finland and a little more for Denmark. [22] The maximum 4-hour variations for each Nordic country are situated around ± 50% and for the entire Nordic area as a whole it is found to be ± 35%. Similar conclusions can be found in analyses performed by Van Wijck ([67]) or Johansson ([42]).

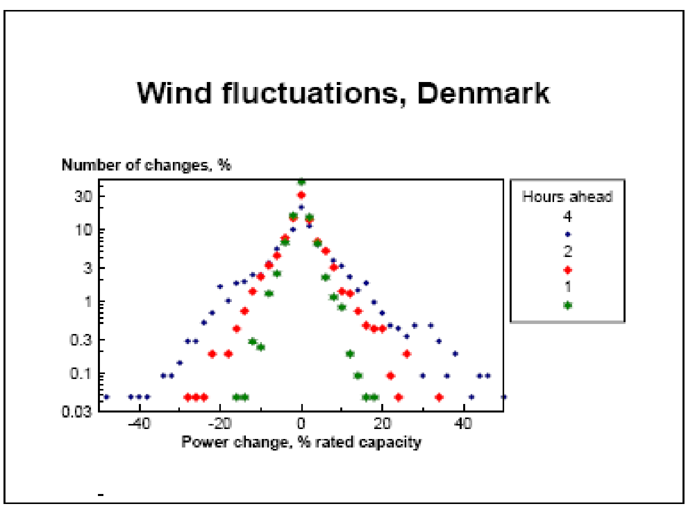

Figure 6: Hourly, 2-hour and 4-hour variation in wind power output with the corresponding frequency distribution [52]

Wind as a natural phenomenon, is suitable for statistical analysis and physical forecasting. Multiple prediction tools, based on statistical properties and historical data, exist. Predictions are made based upon the physical description of wind fields or according to statistical methods. [12] Some of the major short-term wind power forecasting models available on the market are enumerated by Giebel et al. [13] A set of criteria was developed for comparison of the performance of short-term forecast models. [48] The Anemos project compared 11 models for six wind farms in four European countries. [43] The results show that the difference between the models was site dependent and that not one single model dominated the others in all sites. Moreover, the mean error of all models was found to be related to the complexity of the terrain. Two aspects, related to hourly variations, namely the forecast error and the gate-closure time deserve some more attention.

The forecast error

Two standards are commonly used to represent the forecast error, namely the Root Mean Square Error (RMSE) and the Mean absolute Error or Mean Absolute percentage error (MAPE). [12] For the TSO, the forecast errors need to be as low as possible, up to around 12 hours ahead. The formula for the MAPE is given by:

$$MAPE = \frac{\sum_h |e_h - c_h|}{\sum_h c_h}.100 \qquad (0.7)$$

e_h: Casandra energy production forecast for hour h

c_h: Real measured energy production in hour h

With current tools, the forecast error, represented by the RMSE, for a single wind farm is between 10% and 20% of the installed wind power capacity for a forecast horizon of 36 hours. Thanks to the smoothing effects, scaling up to aggregated wind power of a whole area results in a drop of the error below 10%. Therefore, the larger the area, the better the overall prediction. Holttinen calculated that the MAPE of wind power prediction is of 8-9% of installed capacity for the Nordpool electricity market. [22]

When seen in combination with the errors in load forecast and in the forecast of the output of other thermal plants, the resulting forecast error is lower than the sum of the individual errors, because load and wind forecasts are not correlated. [50] It has to be stressed however that wind speed forecasts remain less accurate than load forecasts since the latter have more predictable diurnal and seasonal patterns. [22] The longer ahead the prediction horizon is situated, the higher the forecast error will be.

In the future, forecasts are expected to become more accurate, which will lead to positive effects in the wind power usage. Prediction models are constantly ameliorating. [24]

The gate-closure time

The forecast accuracy is reduced for longer prediction periods. Thus, reducing the time needed between scheduling supply to the market and actual delivery, called gate-closure time, would significantly reduce unpredicted variability and, thereby, lead to more efficient system operation without compromising system security. The gate-closure time is defined as the moment on which the power plant operators have to provide their planned output for the considered period. For this they have to rely on the wind speed provisions at hand. The closer this gate-closure time is to the moment of operation, the better will the forecast be. This gate closure-time is usually situated between one hour ahead and 24-36 hours ahead.

In most countries system operators set gate-closure times arbitrarily, without any technical justification and at the expense of the electricity consumer. The prediction accuracy is improved by a factor two when moving from a gate-closure time of 36 hours ahead to 3 hours ahead. [12]

Gate-closure time will be discussed in more detail in 0.

2.4.2 Long-term variability

Variability of wind also exists on the longer term and will be driven by seasonal climatologic parameters and inter-annual variations of wind. These are not necessarily important for the daily operation and management of the grid, but do play a role in strategic system planning. Again a distinction can be made between monthly or seasonal variations and annual variability. [12]

Monthly – Seasonal variations

Seasons play an important role for intermittent sources that are dependent of climatic circumstances. This is certainly true for wind energy. Parameters such as the wind direction and the strength of wind are season-dependent. The peaks in average available capacity of wind farms is typically situated around the winter season.[67]

Annual variation

The annual variability of long-term mean wind speeds at sites across Europe tends to be similar and can be represented by a normal distribution with a standard deviation of 6%. The inter-annual variability of wind is relatively low. Moreover, on this term, the evolution in wind power integration into the world is changing.

2.4.3 Geographical dispersion and amount of installed wind turbines

Apart from variability over time, wind also shows particular behaviour according to geographical location and spread. The variability of wind is very site dependent and when considering a large region, the aggregation of wind turbines reduces the extent of short-term fluctuations. [40] This area has to be large enough to create a significant effect. For individual turbines, only the variations on the seconds level are relatively small. For a wind farm, the small variation also occurs on somewhat longer timescales. For a number of wind farms spread over a large area, the variability of wind can strongly be reduced. Values of variation from hour to hour and from 4 to 12 hours in between, are presented in **Table** and **Table** respectively [12].

Area Size (km*km)	Largest variation (%)	Example
100 * 100 km	50	UK
200 * 200 km	30	Denmark
400 * 400 km	20	Germany, Denmark, Finland
Group of countries	10	

Table 1: Largest hourly variation of wind power with respect to the size of the area. Taken from [12]

Area Size (km*km)	Largest variation (%)	Example
One country	40-60 80	Denmark Germany
Larger area	35	Nordic Area
400 * 400 km	4h: 80% 6h: 80%	UK

	12h: 90%	

Table 2: Largest 4-12 hour variation of wind power with respect to the size of the area. Taken from [12]

In Germany the ISET has performed analyses on wind data and found that, whereas a single wind farm can exhibit hourly power swings of up to 60% of capacity, the maximum hourly variation of 350 MW of aggregated wind farms in Germany does not exceed 20%. [41] This can be seen in the next figures that depict the frequency of variations from hour-to-hour and within 4 hours respectively. (**Figure 7**,**Figure 8**).

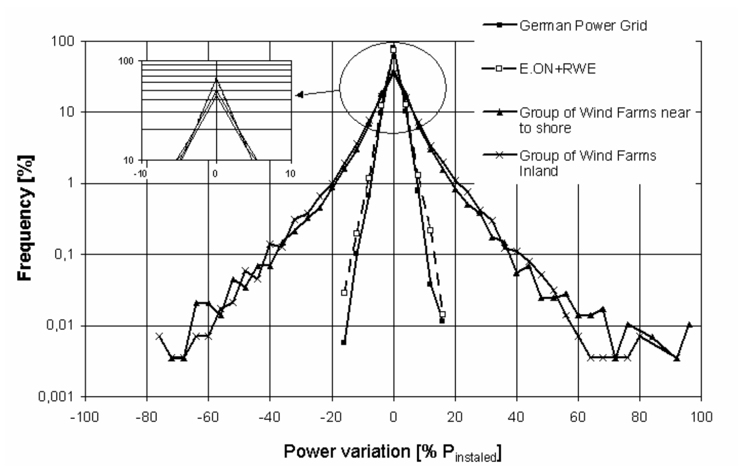

Figure 7: Hourly wind power variation and frequency of occurrence [41]

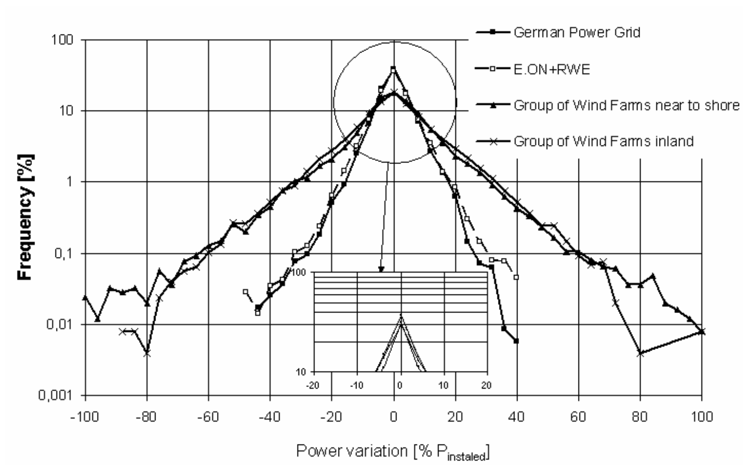

Figure 8: 4-hour wind power variation and frequency of occurrence [41]

Similar results are obtained for Denmark [47]. The difference in frequency of large variations occurring is drastically reduced when considering the entire Western Denmark area instead of a single wind farm of 5 MW. The results can be seen in **Figure 9**.

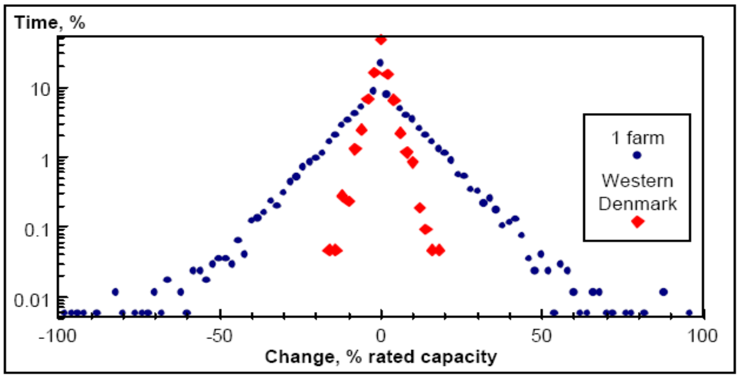

Figure 9: The frequency of hourly wind power variations aggregated for Western Denmark, compared to a single wind farm of 5 MW [47]

Milborrow also found comparable results and focused on the maximum variations in wind power on the hourly and 4-hour scale. [52] The larger the considered geographical area, the smaller the fluctuations of hourly variations become. For small areas such as Denmark, the maximum hourly fluctuation amounts to about 30%; [52] for an area the size of Germany, 20% will be the most extreme variation; [14] Holttinen found a 10% variation for the aggregated total over the Nordic states. [23]

Milborrow analyses the difference in penalty, for discrepancy between actual and predicted wind power production, to be paid for a single wind farm and a countrywide consolidation. [50][52] He clearly states that a geographical spread within the UK, results in reduced penalties related to wind power production. The penalties that are due in reality however, are not based on this principle of aggregation. Each electricity producer is responsible for his own balance. The benefit, both on the costs and the emissions side, which can be achieved from countrywide aggregation of electricity production from different sources with country-wide load is not applied in the UK.

Holttinen comes to the same conclusion regarding geographical smoothing when analysing the data of the Nordic countries. [22] The duration curve of wind power production is flattened when considering the whole Nordic area instead of just one turbine or one country. This can be seen in **Figure 10**. Moreover, the standard deviation of the hourly variations in wind power production is shown to decrease with increasing geographical area. However, even for large geographical spread will the range of wind power production still be large compared to classical forms of electricity generation.

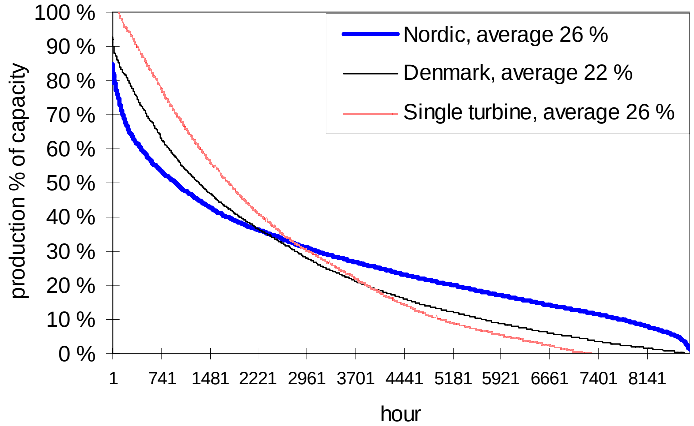

Figure 10: The duration curves of wind power production for three different geographical spreads.

2.5 Backup provision by TSOs and electricity suppliers

The operation of an electricity-generation system is complicated. In the light of backup costs for intermittent sources, it is important to understand the basic rules regarding backup provision in the system. Within a given system, load should at all times be covered by electricity production. In order to maintain this balance, the system has to have reserve generating capacity at its disposal to deal with power plant outages or any disturbance affecting generation, demand or transmission.[64] The power balance between the expected and the actual situation can differ for various reasons. Unforeseen changes may occur both on the demand and on the supply side. Meteorological conditions, for example, can influence both demand and supply. Colder and windier weather than forecasted, can increase the demand for electricity (due to more heating demand and persons staying inside their homes) while at the same time making wind turbines operate at a higher than expected regime.

This chapter will focus on the reserve requirements of both the transmission system operators (TSO's) and the electricity producers. The fulfilment of having adequate reserve available to act as backup, is something to be seen on the short term. TSOs and electricity providers have to ensure a reliable operation of the system at all times with the means at their disposal. Careful planning is essential.

In chapters 2.7 and 0, more attention will be paid to the particular role of backup services when wind is integrated in the system. In this chapter, the general functioning of reserve provision for backup is analysed. First, an overview of the different components in power balance is given. Then, the different timescales of reserve provision are described.

2.5.1 Power Balance components

It is useful to have a clear understanding of the different components that make up the power balance. A short overview of these components is given here, for more detailed explanation of the used definitions, the "Union for the Co-ordination of Transmission of Electricity" (UCTE) website is referred to. [33]

A first element in the power balance of an electricity-generation system is its **generating capacity**, which defines the maximum electrical net active power that a system can produce continuously during a long period of operation under normal conditions. The **unavailable capacity** is made up of all the elements that reduce capacity, such as maintenance and overhauls, outages, system-services reserve and non-usable capacity. The **reliably available capacity** designates the difference between the generating capacity and the unavailable capacity. Next, the **load** is the power that is absorbed by all installations, connected to the system. This includes network losses and international agreements but excludes the pumping in pumping-storage units and export. The **remaining capacity** defines the difference between the reliably available capacity and the load. This represents the reserves available for power plant operators and will serve to balance unforeseen conditions and can compensate for the forecast error. The different time scales that exist for this remaining capacity are discussed in the next part.

2.5.2 Timescales in reserve provision

The so-called system-services reserves are intended to set off power imbalances. They can be split up in three categories, namely seconds reserve, minutes reserve and hours reserve. [33][65][71] The terminology used is general and defined by the UCTE. For more detailed information on different European operational reserve methods, [11] is referred to.

The seconds reserve operates, as can be deducted from its name, on the very short seconds scale. It offers power-frequency control through the control bandwidth of power stations operating under primary control. The frequency should remain at all times around 50 Hz with an allowed margin of 50 mHz. The seconds reserve falls completely under the responsibility of the TSO. The TSO contracts sufficient reserve power with producers that operate plants with automatic speed control. The UCTE recommends a seconds-reserve margin of about 2.5% of the total installed capacity in an electricity-generation system. [71]

Seconds reserve can be split up in primary and secondary control reserve. Secondary control reserve is used to allow primary reserve to operate at normal level again and operates in the time-frame of seconds to typically 15 minutes. [65]

The minutes reserve, also called tertiary control reserve, is started to free the seconds reserve. It also falls under the responsibility of the TSO. It is used to restore the secondary control range after an incident. Sufficient control reserve must be permanently at hands to cover the loss of a generating unit. This restoration may take up to 15 minutes, whereas the tertiary control for the optimisation of the network and electricity-generation system will not necessarily be complete after these 15 minutes. The minutes reserve can also be described by warm reserve or spinning reserve. The units providing these reserve services are storage stations, pumped-storage stations, gas turbines or thermal power stations operating at partial load. [65]

The range of primary, secondary and tertiary control reserves is depicted in **Figure 11**. The primary and secondary control reserve fall under the seconds reserve, while the tertiary control reserve is a synonym for minutes reserve. All these operational reserves are contracted by and therefore well known to the TSO.

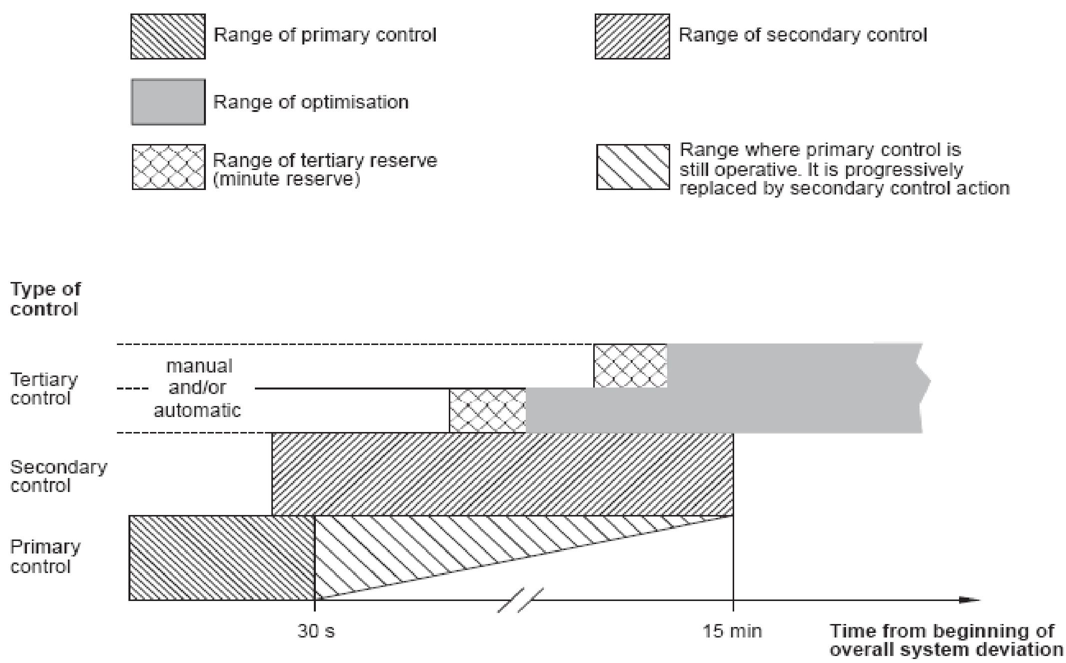

Figure 11: The range of primary control, secondary control and tertiary control in an electricity-generation system [65]

The third category is the hours reserve, also called cold reserve or stand-by reserve. It denotes the availability of thermal units that have to be started for this purpose. Hours reserve is used to restore normal operation of the system, allowing seconds reserve and minutes reserve requirements to be met. The hours reserve, however, is the responsibility of the power-plant operators. Reserves are activated according to contractual arrangements between customers and power-plant operators, to a large extent independently of the TSO. These reserves can, in some countries, be traded in a central Pool.

2.6 Backup of Intermittent Sources

In this chapter, a view will be shed on the concepts surrounding the backup of intermittent sources. As often in this kind of subjects, confusion arises on what terminology to use when defining elements to study. In what follows, an overview will be given of the various elements that make up the backup of intermittent sources. This view is, in broad terms, consistent with other literature such as [14], [37], [40], [58] and [66].

First of all, it is important to consider two different time horizons when discussing the backup of a power plant, or more specifically, intermittent generation sources, namely the long and the short-term horizons. [56] On the short term, all relevant decisions have to be made taking into account the configuration of the electricity-generation system as it is. Speaking in economic terms, the short term is too short to change the system fundamentally. In other words, the entire system can be operated in any feasible manner but no new capacity can be added to it. This addition of new capacity is an element that does come into play when operating on the long term. In the long term, investment in new capacity becomes a possibility. This allows market players to choose from a larger radius of options to achieve the most cost-efficient delivery of electricity and its related services, under the considered boundaries. More information on time horizons can be found in [14].

These two different horizons allow for a clear distinction between operational and capacity issues. Assuming that investment decisions only arise when considering capacity-related problems, it is possible to assign all operational actions to the short term and the capacity-related matters to the long term.

Looking more into detail to the operational component of backup for intermittent electricity sources, a more detailed distinction can be made between the balancing issues and non-balancing issues. Expressed in time horizon terms, balancing is what happens after gate closure, mostly by the TSO. The non-balancing part of operation backup belongs to the time span before gate closure time. During this operational backup time span, the day-ahead unit commitment takes place. As defined by [49], wholesale trade stops at gate closure, when Access Responsible Parties (ARP's) have to submit their unit commitment program to the TSO.

One of the most important factors when considering operational backup, is the forecasting of the various elements that define the balance in electricity demand and supply. On the one hand, there is the provision of electricity by multiple sources of power plants, amongst which intermittent generation. On the other hand stands the electricity load. All elements of supply and demand are subjected to variations. For each component in the balancing of demand and supply, forecasts are made at different moments in time. The accuracy of these forecast highly depends on the type of element being considered. The overall forecast error determines to a large extent what the balancing requirements and costs for the system will be. In this context, the provision of electricity by intermittent sources plays an important role. The forecasts of intermittent sources should not be seen separately from the system. However, they do exert an important influence on the overall forecast and associated forecast error.

When considering the capacity component of the backup for intermittent sources, two related important elements come into play. On the one hand there is the investment option, on the other hand the capacity credit of intermittent sources. The focus on the amount and type of capacity on the electricity-generation system is to be seen in the context of adequacy of the system. An electricity-generation system has to be able to provide a very reliable electricity output at all times. This requirement is a logical consequence of the economy being highly dependent of electricity provision. Careful planning on the long term is therefore an essential part of the electricity provision.

Investment planning in an electricity-generation system is not an easy task and becomes even more complicated when intermittent generation sources are added to the system. Electricity-generation systems have operated for a very long time without intermittent generation (according to the definition stated above) and they have been designed to become more reliable and practical over the years. In the last few decades, intermittent sources have been added to these systems and this has had and will have serious impacts on the preservation of the adequacy of the system. It is generally assumed that intermittent sources tend to lower the reliability when they are preferred above more conventional power and when no additional measures are taken. In the future, significant amounts of wind power and other intermittent sources are foreseen to be added to the electricity-generation systems all over the world. The adequacy level however, has to remain constant and to achieve this, other capacity is needed to provide backup on intermittent generation sources when needed.

There are several measures to assess the adequacy of an electricity-generation system. The most known are the Loss-of-load probability (LOLP), Loss-of-load expectation (LOLE) and the Loss-of-energy expectation (LOEE). LOLP expresses the likelihood of load being shed during a certain time period due to insufficient supply. LOLE identifies how much time would be spent without load being served in due amounts. LOEE detects which volume of load, in terms of its power, is not served and over what time period by measuring how much energy is not supplied.[4] [6][14][53][71]

[4] Energy is related to power since it is the product of power and time.

2.6.1 The integration of intermittent sources in an electricity-generation system

At all moments, an instantaneous balance between aggregate demand for electricity and total electricity generation is necessary. Transmission system operators (TSO) perform this task based on known operating characteristics of the electricity generation system and years of accumulated experience. An electricity-generation system can have difficulties managing large amounts of wind power. Indeed, many excess-energy and reserve-shortcoming situations occur when significant amounts of wind power are produced.

Factors influencing the integration of wind power

A multitude of factors influence the integration of wind power into an electricity-generation system. Some of these are related to the installation of wind power, such as the share of wind power in the system and the absolute amount, the location in the grid and the geographical spread. Other factors relate to the operation of wind power. These factors include the intermittency of wind and its low emission rate. Finally, many factors of influence can be found in the country-specific context. The load curve will vary from country to country and is important in the sense that it also shows a variable behaviour. The planning cycle of the electricity-generation system, and with it the gate-closure time have an impact on the operation of wind power. The method of acquiring backup for wind on the different considered levels directly impacts the cost of this backup. Opportunities for international trade can offer better conditions for the operation and backup provision of wind energy. Next, the composition of the traditional generating capacity and the amount of flexibility in this system affects the integration of wind power into that system. Finally, the market type determines the way in which the operation and backup provision of wind will take place and who is responsible for it.

Wind power introduction and GHG emissions

Wind power will usually lower GHG emissions. Since a wind turbine in itself is an emission-free power plant, the investment in wind power can substantially reduce overall emissions due to reduced investment in thermal power plants.

However, wind power introduction is no synonym for GHG reductions. Although wind turbines are considered being zero-emission power plants, the total impact on the environment when looking at the electricity-generation system as a whole, is more complex.

One example is that large investments in wind might postpone expansion of the system with, for example a gas-fired combined cycle power plant. In a system with relatively low gas prices, this might, in turn, lead to a use of coal power plants that could otherwise have been outperformed by the CC power plant.

To illustrate this point, some simulations are performed in PROMIX[5] on a balanced electricity-generation system such as the Belgian system in 2005, as can be seen in **Table** . Promix calculates the cost-optimal usage of the available power plants to cover the varying electricity demand. This is achieved by establishing a merit order for all available plants, based on minimal marginal fuel costs. The tool takes into account the composition of the electricity-generation system, the fuel costs and other country-specific parameters so as to offer a realistic simulation of the considered systems. The Promix output consists of the hourly electric power generated by each separate power plant, as well as the corresponding energy use, costs and emissions. Further information on Promix can be found in papers written by Voorspools and D'haeseleer ([72], [73]) and Luickx et al ([46]).

Nuclear	5700
Coal	3000
Natural gas	1400
Natural gas CC	3200
Renewables	100
CHP	1600

Table 3: Belgian electricity-generation system in 2005

Two separate scenarios are run for 2005. Both have the same input, except for some incremental capacity that, in scenario 1 is covered by additional gas-fired CC power plants, and in scenario 2 by wind turbines with a capacity factor of almost 25%. Both scenarios represent the trade-off between investment in wind power and combined cycle power plants. The additional amount of CC capacity is 800 MW. The installed wind power has a capacity of 800 MW and follows the profile of an existing wind park in Belgium. The PROMIX simulations show that in this particular case, the GHG emissions will indeed increase with the introduction of wind, compared to the introduction of CC power plants. Where, the overall GHG emissions amount to 26110 kton for scenario 1, they total 26804 kton in scenario 2.

[5] A unit commitment model operating under cost minimization, used to investigate the effect of various policies on the operation of a specific electricity-generation system.

This can be explained by the decrease in the use of coal-fired power plants when additional gas-fired capacity is invested in. The gain in GHG emissions saving cannot be compensated by the installed capacity of wind power in scenario 2.

This example evidently considers specific situations. Most of the time, investments in wind power will lead to a reduction in GHG emissions. However, it cannot automatically be assumed that this will be the case for every considered investment in wind power. That is why it is so important to always consider wind power as part of an electricity-generation system with its own characteristics and needs.

This is only one facet of the many issues surrounding the integration of intermittent energy sources in an electricity-generation system.

2.6.2 The variability of wind power, conventional generation and load in the electricity-generation system

The variability of wind power has to be seen in the context of the integration in an operational electricity-generation system. Both the load of the system and the conventional power plants has its own variability that will interact with the variability of the wind power. Basic statistics ([4]), represented in formula (0.8), show that the variability, measured by the standard deviation, will decrease when considering wind power, conventional power and load together as one, compared to taking the sum of each of the separate components into account.

Therefore, not the total standard deviation of wind power has to be taken into account, but only the additional effect it brings about in the system. This additional effect is dependent on the correlation of wind power variability with the variability of load and the other electricity-generation plants. When this correlation is lower than 1, the standard deviation of the entire system as a whole will always be lower than the sum of the standard deviations of its components.

$$\sigma_{load-wind} = \sqrt{\sigma_{load}^2 + \sigma_{wind}^2 - 2\rho_{load,wind}\sigma_{load}\sigma_{wind}} \tag{0.8}$$

With $\sigma_{load-wind}$ = the combined standard deviation of the load and wind power

σ_{load} = the standard deviation of the load

σ_{wind} = the standard deviation of the wind power output

σ_{load}^2 = the variance deviation of the load

σ^2_{wind} = the variance of the wind power output

$\rho_{load,wind}$ = the correlation between the load and the wind power output

The wind power has to be subtracted from the load since wind power represents electricity output and load demand. When considering both load and wind power, it becomes interesting when they are positively correlated. In that case, whenever the load is higher than the average load, there is a high probability that wind power output will increase as well, and so somewhat compensate for this deviation. Wind will rip the benefits out of this. With negative correlation, increasing load, which is increasing demand and subsequently increasing price for electricity, on moments of decreasing wind power, will lead to wind farms being charged with that higher price to cover the imbalance themselves.

Holttinen [22] states that the Nordic area shows slight positive correlation between wind power production and load. During the winter months, this correlation approaches the value of zero. These low correlations will lead to low overall variations when taking both wind power production and load into account.

Vogstad [70] determined a possible increased value for wind power when being incorporated in hydropower scheduling. The relations between wind power and other sources of electricity will always affect the total impact that the wind power output will have on the system.

2.7 Balancing Backup

As already defined in chapter 2.6, the operational side of backup for intermittent sources can be split into two categories, namely the balancing and the unit commitment-related backup. This chapter will focus on the former category, while the latter will be analysed in the next chapter.

Basically, the balancing of an electricity-generation system is the operational activity that takes place after gate closure. It falls to the responsibility of the TSO that has to foresee sufficient backup capacity to operate this balancing. This can be achieved by contracts that the TSO makes with power plant operators. In other literature, this balancing reserve is sometimes referred to as “response requirements” ([14], [1], [37]).

Because of the balancing taking place on the short term, it has to be seen in the timeframe of the seconds and minutes reserve[6]. Planned or forced outages from intermittent sources, as well as from the conventional power sources are to be covered by this reserve. According to the EWEA ([12]), the power-balancing requirements due to wind power mainly address reserve power in secondary/tertiary control time scales. This reserve power is in general offered on the balancing market.

In broad terms, intermittent energy sources will have a combination of the following impacts on the electricity-generation system and will bring about extra charges to the system. [14] First, more frequent use of flexible plants with corresponding loss in efficiency will burn more fuel than without the introduction of intermittent energy sources. Moreover, keeping these plants at the disposal of reserve provision services entails an opportunity cost. Furthermore, too much intermittent sources can in some situations difficultly be absorbed by the system, which leads to energy being spilt. The quantification of these additional costs due to the incorporation of intermittent sources in a system, is dealt with in chapter 2.10.

In the first section, the different timescales that can be considered on the balancing side are defined. Next, the balancing of intermittent sources is discussed. Subsequently, different balancing solutions are offered. Finally, the concept of gate-closure time is elaborated.

2.7.1 Balancing reserves timescales

As explained in chapter 2.5, balancing of the electricity-generation system can be seen on different timescales. The primary and secondary control reserve, which together define the seconds reserve, as well as the tertiary control or minutes reserve have to be balanced by the TSO.

Wind power development has little to no influence on the amount of seconds reserves needed, as concluded by several studies. [22][54] The amount of seconds reserve allocated in the power systems is dominated by outages of large thermal generation plants, thus more than large enough to cope with these very fast variations.

On the scale of minutes reserve, more reserve capacity has to be kept. This is achieved by a combination of contracts with power plant operators that keep some capacity on part-load and industrial customers that allow load shedding when certain events occur. The technical cost

[6] Cfr. Section 2.5.2

of operating for example fossil fuelled power plants in part load operation is 5–10 €/MWh and for hydro power it is less. [12] The minutes reserve encompasses the time scale where relevant changes in large-scale wind power occur. The forecasting method and gate-closure time are of utmost importance to quantify the required increase in minutes reserves. Not only should the reserve allocation and utilization be optimised, but also the minimisation of forecast errors should be looked at.

Hirst and Hild ([21], [18]) distinguish between two different timescales in the balancing of electricity-generation systems, namely the intra-hour balancing or load following and regulation. Both entail charges for wind since wind power will usually need more of these services than it can provide. In fact, wind power will rarely be used for providing reserve services. It is mostly not technically possible and moreover not optimal not to use the full potential of wind power. The intrahour balancing is defined by time steps of 5 minutes. For each one of these time intervals, the difference between the hourly wind power average and the 5-minute wind power average in of the interval defines the balancing requirements. It is different to regulation in the sense that load-following patterns are highly correlated to each other and that the changes in load-following patterns are predictable to a high extent, which yields more stable diurnal load evolutions.

Regulation is defined as the standard deviation of the 60 1-minute values of the variations around the 5-minutes imbalance values. Regulation is a synonym for the provision of ancillary services to the system. The regulation requirement of wind power is seen within the context of the total regulation of the electricity-generation system. Wind does not have to regulate each kWh of one-minute imbalance by one kWh. Only the total imbalance needs justification and wind is allocated a fair share of this regulation.

2.7.2 Balancing intermittent sources

The balancing of intermittent sources should preferably not be seen on its own. Since intermittent energy sources such as wind power, are part of an electricity-generation system, just like any conventional power plant, the balancing conditions have to be seen in the context of the entire system. Because of load and the different power sources not being correlated, there will be a significant reduction in balancing needs for the totality of a system when compared to the sum of its elements.

The EWEA reports estimates of extra balancing reserve requirements due to wind power around 2-8% of installed wind power capacity. This is valid for a penetration rate of 10% of gross consumption provided by wind power. [12] When using good forecasts, these reserve requirements are situated between 2 and 4% of installed wind power capacity. These requirements obviously lead to additional costs, which will be analysed in more detail in chapter 2.10.

The integration of wind power does not only bring about additional charges to the system. Wind power integration also provides benefits on the balancing side. [12] First of all, wind power can improve the quality of the distribution grid. Weak grids may be supported by wind power, and the users on the line may get better service, as wind power adds to the grid voltage. Power electronics of wind farms can improve power quality characteristics in the grid. Moreover, wind power may reduce the network losses. When consumed within the distribution network, the electricity gets directly to the user and transmission costs can be avoided. Finally, wind power can also help avoiding black-outs. It may keep parts of the system running in the event of transmission failures that would otherwise cause black-outs.

2.7.3 Balancing solutions

An interesting line of thought that can be followed when considering the balancing of intermittent sources, is all possible actions that could reduce the balancing needs or deal with them effectively. Wind power and other new technologies raise the need for more appropriate approaches to system balancing. Different possible options are briefly discussed in this section.

Demand-side management

Demand side management can offer several ways for balancing by giving impulses for changes on the demand side of the electricity. First, this demand can be shifted in time. The load can be increased on moments with considerable wind power, for example through utilisation of heat pumps with a storage possibility of the heat. Next price signals could be used to stimulate higher electricity usage with low electricity prices when more capacity is available and increased electricity prices at moments with relatively low reliably available capacity. Finally, flexible load contracts can be used by temporarily stopping the provision of electricity to certain customers at critical moments. This last method is already well-used in the current electricity-generation systems.

Flexible generation units

Flexible generation units such as hydro-power can easily be adapted to the combination of varying load and supply. New thermal units with advantageous start-up and shutdown characteristics are a logical way of balancing intermittent generation. These thermal units are mainly gas-fired.

Storage

Storage options are designed to better match supply with demand. Pumped-hydro power is the most common and best-known technology. These can shift load in time by stocking energy at moments of relatively low demand while giving it free when load is high. Other technologies include compressed air, flywheels, batteries (lead acid, advanced), fuel cells (including regenerative fuel cells, ‘redox systems’), electrolysis (e.g. hydrogen for powering engine-generators or fuel cells) and ‘super-capacitors’. [12]

Wind power cluster management

When needed, a wind farm can be operated as a regular power plant that can provide ancillary services. The wind parks become Virtual Power Plants (VPP). [12] One has to bear in mind that every non-usage of cheap wind power however, leads to an opportunity cost.

Interconnection with other grids

By optimal usage of interconnection with other grids, a larger area can be considered as “aggregated system”. For wind power, this interconnection means a more significant geographical dispersion effect. For the balancing services, this means more opportunities and options to deliver the required reserve services. The extension and operation of the interconnections between control areas will play an important role in the future operation of electricity-generation systems, particularly when large amounts of installed wind power is considered.

Distributed generation

Another option could be the provision of reserve to the grid on a regional level as an alternative to large-scale power plants. These reserves could be provided by distributed generation power plants such as CHP plants

Curtailment of wind power

A last option that deals with an excess of wind energy is the simple curtailment of wind power at moments the electricity produced by wind cannot be absorbed by the system.

Gate-closure time

The gate closure time is an important parameter in the study of backup of wind power. It defines the moment on which the unit commitment of the energy sources stops and the power plant operators have to provide their planned output for the considered period. It defines the boundary between balancing backup and unit commitment backup[7].

Careful determination of this gate-closure time is necessary. A good balance has to be found between the advantages of a gate-closure time long before the actual provision of electricity and a gate-closure time just before the electricity delivery. A longer gate-closure time forces the power plant operators to foresee more reserve since more uncertainty exists on the actual final load and electricity production. These reserves can be contracted for in advance, usually at lower rates than on very short term. When the gate-closure time falls just before the considered actual delivery moment, better predictions of, mainly, wind power and load will be available, reducing the costs associated to the forecast error. However, close to the actual moment of delivery, the acquisition of additional reserves will be more costly. On the short term fewer options exist to make up for forecast errors. With the introduction of large amounts of wind power, it might well be that the gate-closure times in many countries is not optimally chosen.

With the increased use of communication technology as a result of evolving market structures, the information flow is improving in many markets and might facilitate the reduction of gate closure times further. Yet, even with reduced gate-closure times, liquidity in most electricity markets is highest in the day-ahead trades, while activity in short-term energy trades on the spot market for one- or two hour-ahead contracts is typically low. Thus, some of the benefits from reduced gate-closure times might be mitigated by reduced trading opportunities in the short-term markets in many IEA member countries.

While the UK has a 'gate-closure time' of currently one hour (between final declaration of capacity and actual use of it), many IEA countries have gate-closure times between 12 and 36

[7] Unit Commitment backup is the subject of the next chapter.

hours in advance. These times have often developed out of historic structures and in many cases have no technological and economic background in the current system. [40]

Unit Commitment Backup

The unit commitment backup is also part of the operational side of the backup provision. Whereas the balancing backup encompasses the time span after gate closure, unit commitment backup focuses on what happens before gate closure. Generation units have to be appointed to cover the expected load for a given period. Since this commitment is based upon forecasts, a certain amount of reserves has to be foreseen as well.

Unit commitment still falls under the short term according to the economic interpretation of short and long term since no new investments are considered[8]. It falls to the responsibility of the power-plant operators, who have to meet their contracts with their customers. In terms of timescale of reserves, the unit commitment reserve largely coincides with the hours reserve. In other literature, this reserve might be referred to as "reserve requirements" ([1], [14], [37]).

In the following, the determination of unit commitment reserve is discussed first. Afterwards, the unit commitment reserves are seen in the light of intermittent sources.

2.7.4 Determination of unit commitment reserve

The process of unit commitment is complicated due to the many operational constraints of generators regarding start-up and shutdown. The electricity demand is instantaneous but the decision of committing units in due time takes place well in advance. A certain security margin, consisting of units providing reserve capacity, is therefore required. Unpredicted variations in output have to be met by these reserves. The more unpredictable a system becomes, the higher this margin should be. [1] The reserves in this context refer to additional resources that can adjust their output relatively fast to absorb unexpected changes in loads and production.

The determination of the unit commitment reserves is based on years of experience rather than calculations. Minimum reserve requirements have been established to meet operational

[8] Cfr Chapter 2.2.2

malfunctionings such as sudden power plant outages[9] or failure of important transmission capacity.

It is obvious that both unit commitment reserve and balancing reserve are related to one another. The amount of margin foreseen in the unit commitment will determine the options available for balancing after gate closure. The more reserve margin is appointed, the lower the costs for balancing will be. On the other hand, more reserve margin will bring about higher costs for the unit commitment.

2.7.5 Unit commitment reserves with intermittent sources

The factors that influence the additional unit commitment requirements when wind is invested in are largely related to the factors influencing the balancing backup. The operational backup in general is driven by a wide set of factors[10]. Investment- and country-specific issues as well as the particular operating characteristics of the considered investments in wind power, will influence the unit commitment backup, just as they have an effect on the balancing backup.

According to Dragoon and Milligan ([4]), the increase in reserve is assumed to be proportional to the proportional increase in the standard deviation of hourly loads during a year, considered with and without wind power generation. The reserve requirements follow the same trend as other studies, increasing more than proportionally with the amount of installed wind power capacity. The results of their analysis for their case study of Pacificorp are shown in **Figure 12**. Hirst and Hild ([21]) confirm this conclusion. When no additional measures are taken to cover increasing amounts of wind power, more excess-energy and reserve-shortfall violations occur. Hirst and Hild also observe that, due to more generation resources being available for backup, the number of violations is lower in the unit commitment than in the balancing period.

[9] This is referred to as the Forced Outage Rate (FOR)

[10] Cfr Section 2.6.1

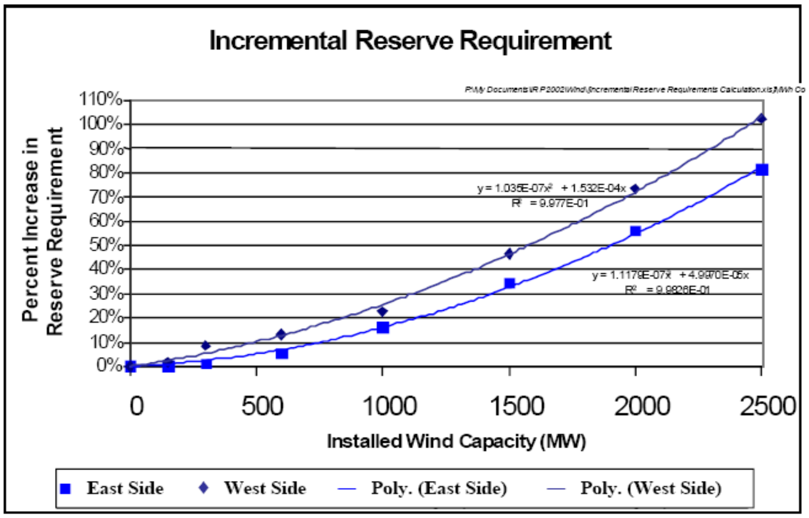

Figure 12: The incremental reserve requirements as a function the total capacity of installed wind power [4]

Several other factors influence the amount of additional reserves needed. [14] First of all, it is related to how fast intermittent sources fluctuate and what the extent of the aggregated impact on the total system will be. In addition, the accuracy of the forecasts has a very important influence on the amount of reserves required. A forecast that is 100% reliable should in fact not need any backup. However, there will always be some sort of unpredictability, which makes no system or unit in the system completely reliable. Next, the correlation between existing variations in demand or load and the intermittent sources will define the extent of additional reserves needed. Finally, the composition of the existing reserve-delivering capacity on the system will have an impact on the reserve requirements.

Reserves are often chosen to amount three times the standard deviations of the potential uncertain fluctuations[11]. This corresponds to 99% of fluctuations being covered by reserves. Foreseeing a margin of four standard deviations will statistically result in 99.9% of the fluctuations being covered by sufficient backup capacity. [14]

An important factor is that, in systems where both unpredicted fluctuations and largest units failure are foreseen with reserve, the size of this largest unit might almost cover all other reserve requirements. Even the largest wind farms are much smaller than the largest single generating unit and therefore an introduction of wind power might not change anything on the amount of necessary reserve. With modest amount of intermittent energy sources such as

[11] Originating from uncertainties from load, conventional power plants and intermittent sources.

wind power being introduced to the system, the requirements for additional reserve will be almost negligible. Wind power fluctuations can be handled by the backup already at hand. In the event with very large amounts of wind power installed, a shortcoming in the number or availability of reserve-providing plants may occur.

According to most studies on the matter (such as [14],[18],[21],[37],[52], and [58]), from a certain point on, additional reserve is required in the system operation to absorb the wind energy. This reserve margin has to be foreseen in the unit commitment period. Milborrow refers to several studies where this point is being calculated. [52] Values range between 5 and 15% but with most numbers situated around 10% wind penetration. In most cases, this reserve margin can be provided by existing power plants. As soon as this does not suffice anymore, new peaking plants have to be installed. As a last resort, according to Milborrow, an expensive Regenesys plant can be built, which will drive the price even higher. The last two options however, are already situated in the domain of capacity backup extension and are treated in the next chapter.

2.8 Capacity Backup

This chapter on backup balancing is to be situated in the long run. As can be remembered from chapter 2.2.2, in the long run, all inputs are variable, implying that new investments can take place. It is important to understand that, apart from the operational issues concerning the introduction of intermittent power sources in an electricity-generation system, also capacity issues arise. Together with the investment decision of wind power introduction, other investment in backup capacity might be necessary. All this has to be seen in the context of the expected development of the electricity-generation system.

The introduction of large amounts of wind power, will often lead to additional system capacity adaptations. For example, when wind turbines are installed to cover (part of) a rise in demand, this will often require additional generation capacity investments to produce electricity at moments of low wind power production[12]. Wind turbines might also be seen as a replacement for older conventional power plants, but it should become clear that wind power cannot replace conventional thermal power plants on a MW to MW basis.

This chapter deals with issues of (long run) system adequacy and reliability issues. The electricity-generation system has to be designed so that peak demand does not exceed

[12] This occurs with too low and too high wind speeds.

production capability. The chapter successively investigates the system adequacy, different existing reliability indices, the role of intermittent sources in the contribution to system reliability, the capacity credit of power plants and ways for providing backup capacity.

2.8.1 System adequacy

System adequacy has different components. On the one hand it is essential that generation units in the electricity-generation system are able to match the load. On the other hand the transmission system has to be able to carry the power flows between generators and users.

When electricity production is inadequate, the load will not be met and a loss-of-load event will occur. These loss-of-load events have to be avoided. The security of supply ranges between 99% (only on 1 occasion out of 100 years the peak load cannot be covered) and 91% for various countries. The UCTE reviews the system adequacy in their 10-year forecasts. [33]

In the estimation of the adequacy, each power plant is assigned a typical capacity value. This takes into account scheduled and unscheduled outages. No plant has a capacity value of 100%, because there is always the probability that it will not be available when required. Forced outage rates, maintenance and other unavailability of power plants cause every power plant to become unavailable some moment during the year. Every power plant type has its own factors influencing this unavailability. Intermittent sources tend to have a significantly lower capacity value than conventional thermal power plant. It is however wrong to assume that intermittent sources have to be compared with power plants that have a capacity value of 100%. The adequacy for wind power will be expressed by the “capacity credit” and is elaborated in detail in section 2.8.3.

In the UK the standard reliability level for the electricity-generation system is taken to be one day in ten years of outage caused by insufficient generation. [8]

2.8.2 LOLP, LOLE and LOEE

The reliability of the electricity-generation system is an important issue. Therefore, the long-term planning of system capacity extension and replacement of older power plants has to be performed with the greatest attention. Several indices can be used to quantify the reliability of an electricity-generation system. The most commonly used are the Loss-of-load probability (LOLP), the Loss-of-load expectancy (LOLE) and the Loss-of-energy expectancy (LOEE).

LOLP defines the probability that load exceeds the available generating capacity in a given time span. [71]

The LOLE expresses the expected number of hours within a certain period in which the system load is expected to exceed the available electricity-generation capacity. [67] Capacity outages of a system have a discrete probability distribution function, which can be approximated by a continuous function when the system is taken large enough. This distribution approaches the normal distribution. The calculation of LOLE can be expressed as follows: Typical values of LOLE are situated between 2 and 25 hours per year for the entire system, where failure will occur when no additional action is taken. [61][71] The LOLE is calculated as follows:

$$LOLE = \sum_{i=1}^{n} P_i\left(C_i < L_i\right) \qquad (0.9)$$

With n = number of units (e.g. hours) in the considered period

C_i = available capacity in period i

L_i = maximum load in period i

$P_i\left(C_i < L_i\right)$ = LOLP in period i

LOEE, also called Expected Unserved Energy (EUE) or EENS (Expected Energy Not Supplied), gives the expected amount of energy not supplied by the electricity-generation system. The Energy Index of Unreliability (EIU) expresses the ratio between LOEE and the total energy demand. [71]

2.8.3 System reliability contribution of intermittent sources

Intermittent sources such as wind power will usually bring about a negative impact on the overall reliability of the electricity-generation system. However, this will not always be the case. The extent to which intermittent sources contribute to system reliability, in positive or negative sense, has a lot to do with their capacity credit, which will be discussed in the next section.

Intermittent generators can make a contribution to system reliability. Since their output may be independent of fluctuations in the load, they can provide electricity when conventional power plants experience forced outages. If wind power is often available on occasions conventional capacity is unavailable, they can constitute a significant advantage to the system and its reliability. Wind power is one way of diversifying energy sources.

In general however, intermittent energy sources will negatively impact overall system reliability because of their unpredictable and variable nature. It is, for example, almost impossible to make accurate predictions on wind power output on the long run. Therefore this uncertainty has to be taken into account when developing the electricity-generation system. Intermittent generation changes the character of the possible unreliability issues and this has to be compensated by the system.

2.8.4 Capacity credit

Capacity credit is defined by the amount of conventional capacity that can be saved by wind power. The capacity credit of wind power should not be confused with its capacity factor. The capacity factor only reflects the percentage of its rated capacity a wind turbine (or group of wind turbines) produces during a year, as expressed by the amount of full-load hours equivalents[13]. The capacity credit is related to this capacity factor but will give a better idea on the effectivity of the considered wind power introduction when seen in the entire electricity-generation system.

Definition of capacity credit

An electricity-generation system has a certain level of reliability, expressed by one of the measures discussed in 2.8.2. After the introduction of wind power, this reliability should remain at the same level. Only introducing wind power as an additional measure to what was planned, will tend to increase this reliability. Mostly however, the investment in wind power will outplace other investments. The measure to which this can occur without loss of reliability is designated by the capacity credit.

Capacity Credit is defined by how much installed wind capacity statistically contributes to the guaranteed capacity at peak load. Due to the variability of wind, its capacity credit is lower than other technologies. [12] The capacity credit expresses the contribution of variable-output wind power to system security. It should be quantified by determining the capacity of

[13] To obtain the full-load hours equivalent of a wind turbine, the total energy output over a year is divided by 8760 (the number of hours per year). This represents the amount of hours the wind turbine would have been operational if all that energy had been provided when the wind turbine was working at full load.

conventional plants displaced by wind power, whilst maintaining the same degree of system security, with unchanged probability of loss of load in peak periods.

The capacity credit is related to the indices quantifying the system reliability such as LOLP, LOLE or LOEE. Indeed, the capacity credit is determined by looking at options with and without additional wind power, while maintaining the same level of reliability. This level is expressed by one of the reliability indices.

A smaller capacity credit brings the need for a larger system margin as to maintain reliability.

Calculation methods

There are basically two different ways to calculate the capacity credit of wind power, namely through simulations and through probabilistic analyses.

In simulation methods, the secure operation of the system is analysed by means of time-series data using simulation models. The most significant events are special combinations of load and wind speed, especially at moments of high load. Often a sensitivity analysis is performed with the time-series data, shifting the time series of wind power against the load data in steps of hours or days.

The probabilistic method is the preferred method for system planning purposes. It assesses the availability of each power plant in the electricity-generation system. For instance, it is commonly assumed that a coal power plant has an operational probability of about 96% and the probability of a non-operational condition of 4%. Wind power output is taken into account by introducing both its capacities and probability of generation into the model. The probability of generation of individual wind turbines is established by the wind regime. The smoothing effects of considering multiple wind turbines that are geographically dispersed also have to be taken into account. Based on the probabilities of individual power plants, wind turbines or wind farms, the probabilities of the whole electricity-generation system to cover diverse load levels can be determined. [12]

A first way of calculating capacity credit is by first determining the LOLE, or any other reliability measure, of the base scenario of an electricity-generation system before wind power introduction. Then the hourly wind power production, based on historic time series, is subtracted from the load. The LOLE is then recalculated. Next conventional capacity is removed from the system by iteration until the original reliability level is reached again. This conventional capacity that is being removed in comparison to the base scenario, is called the capacity credit. It is mostly expressed as the ratio of removed conventional capacity to the installed wind power capacity. [67]

It has to be kept in mind, however that other methods, using different indices than LOLP, LOLE or LOEE might also apply to the calculation of capacity credit. There is no absolute standard on this matter. Other tools might even show themselves more appropriate for the determination of the capacity credit for wind power.

Factors influencing Capacity Credit

Several factors influence the capacity credit value. These are often the same factors that already influence the operational backup of intermittent sources. Now however, they operate on a different timescale.

First the correlation between intermittent energy sources and peak load, determines to a great extent what the capacity credit of that intermittent source will be. Negative correlation between intermittent energy sources and (peak) load cause the intermittent sources to offer no contribution to peak demands. Photovoltaic cells in cold western countries, for example, cannot provide energy at peak moments, that is in winter evenings, when it is dark. They will therefore have a very low capacity credit. A different story exists in warm countries where peak load is dependent on large air conditioning demands, which often coincides with significant production from photovoltaic cells. Load and wind output are considered to be uncorrelated on a day to day basis. [14]

Apart from correlation of intermittent sources output and load, the correlation between several intermittent sources is of importance. For instance, wind speeds at different wind farm sites might be uncorrelated. This will lead to a better aggregate wind energy provision since the smoothing of wind power across different geographical sites makes it less variable and therefore more reliable. Less backup capacity is needed to cover extreme variations in wind power. [67]

Another factor has to be found in the range of output and total variability of the intermittent energy sources. [14] When wind power, for example, fluctuates only between two extreme output levels, namely 100% and 0% of its capacity, normally more backup capacity will be needed. At moments of 0% output, wind power does not contribute at all to the system. When wind power always produces 30% of its capacity, all year round, it can practically be considered as a very reliable conventional power plant and will hardly need any backup.

Related to this last factor, the average level of output of the intermittent source, its capacity factor, will strongly determine the level of the capacity credit. [14] The more energy is delivered on average during a year, the more it will consequently contribute to the system. For wind power, this average output value is related to the average wind speed.

A fifth influence has to do with the penetration level of wind power. [12] The more wind power is introduced in an electricity-generation system, the lower the overall capacity credit will become. This effect is dealt with in more detail in section 0.

An obvious element in the determination of the capacity credit is the desired degree of system reliability. Higher required system reliability levels coincide with lower values for LOLP, LOLE and LOEE. To get these higher security levels, more investment in backup is needed and the resulting capacity credit will be lower.

A last factor is the possibility of exchange of energy from intermittent sources through interconnections between different control areas. [12] More exchange possibilities offer more options to manage wind power. Necessary capacity can be found abroad, sometimes at better conditions than what could be done within the same control area. Also, the geographical dispersion effect becomes more interesting when looking at wind power with interconnections.

Evolution of Capacity Credit

Capacity credit of wind power has been found to behave according to a typical path in relation to the amount of intermittent sources that is integrated into the system. The capacity credit, relative to the amount of wind power capacity shows a decreasing pattern, as shown in **Figure 13**, representing the results for Germany. [12] The reason has to be found in the fact that a system can easily cope with a small amount of variation coming from wind power, without the need for new investments. When the volumes of wind power become larger however, the system will need relatively more capacity to cope with the particular behaviour of wind power. Really large amounts of wind power will have a capacity credit close to zero. It has to be remembered, however, that even with the improbable event of capacity credit being zero, wind power still has its use since it will still save up thermal energy and emissions.

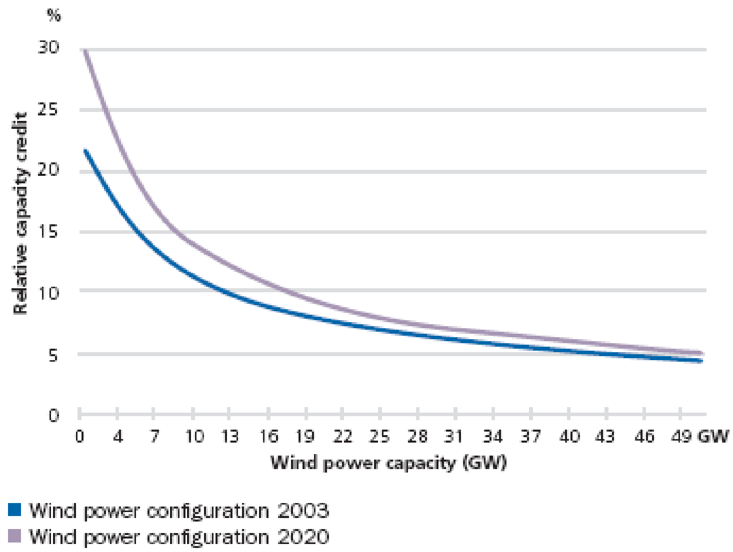

Figure 13: Decreasing trend in relative capacity credit with increasing amount of wind power capacity [12]

Other studies confirm the fact that capacity credit declines as the share of electricity provided by intermittent sources increases. ([10],[14],[45]). In absolute terms, the capacity credit is still increasing; additional wind still can replace a certain amount of conventional capacity. However, this replacement value becomes smaller with every MW of additional wind power installed. **Figure 14** and **Figure 15** illustrate this.

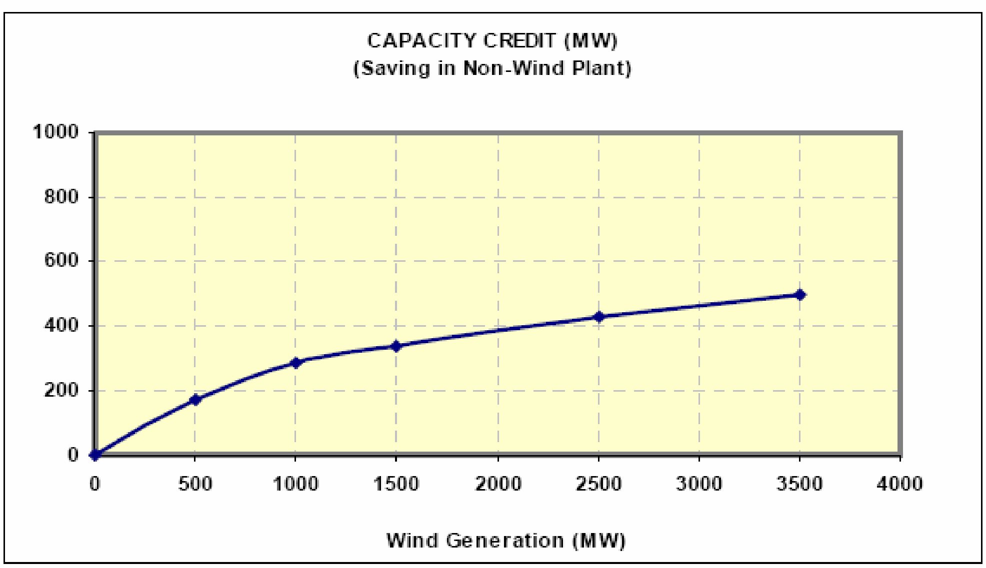

Figure 14: Increase in absolute capacity credit becoming smaller with increasing amounts of wind power capacity on the electricity-generation system [10]

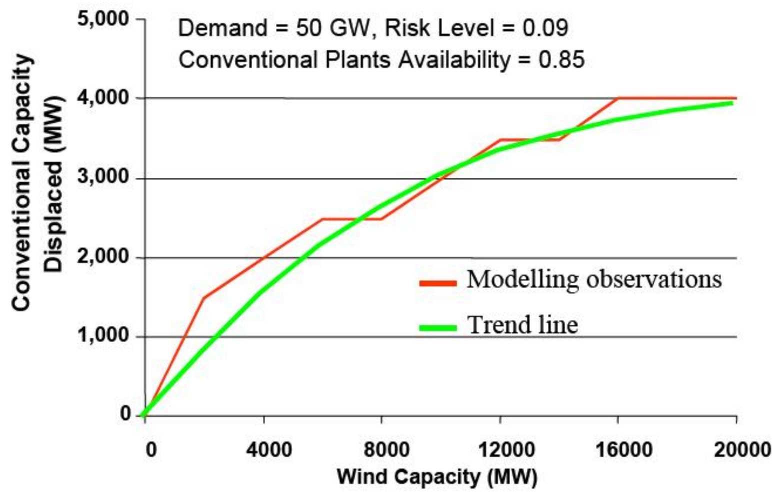

Figure 15: The results of the ILEX report showing the declining increase in capacity credit as wind capacity is added to the system [37]

The UKERC study ([14]) compared a multitude of other reports on capacity credit. Nearly all considered reports and articles show the same trend for the capacity credit of wind power. Capacity credit expressed as a percentage of intermittent capacity declines with increasing intermittent generation in a system. Only the values of the different studies differ, although most values lie in the same area. The results are presented in **Figure 16**.

Most studies find a capacity credit of about 20% for intermittent generation when 10% of the electricity is provided by the intermittent sources. The range of capacity credit varies between 10% and 35% for 10% of energy foreseen by intermittent sources. All results also show capacity credits greater than zero, which proves that wind power indeed does have a capacity credit.

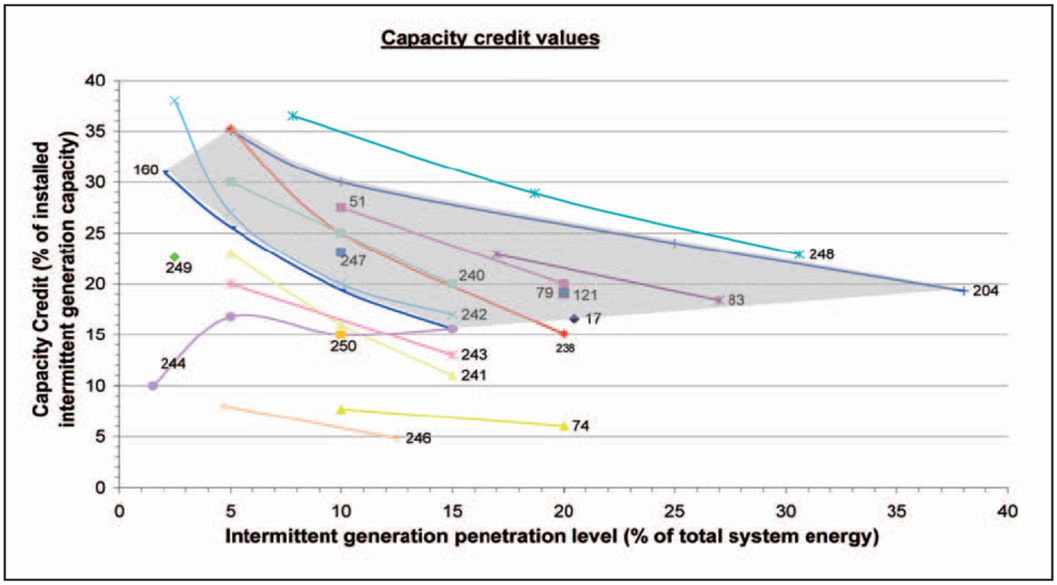

Figure 16: The relative capacity credit relative to the penetration level of intermittent energy sources, calculated by various studies, as reported by the UKERC [14]

2.8.5 Providing backup capacity

When intermittent generators have to be backed up by other capacity, many possibilities exist. The capacity backup of these intermittent energy sources can originate from several sources. On the one hand, this capacity can be provided by other power plants, on the other hand, alternatives exist for capacity backup.

Backup capacity-providing power plants

The provision of backup capacity can in broad terms be divided up in two options, namely the construction of one or more new power plants, or the retention of older power plants that would otherwise have been decommissioned.

First, there is the choice of building a new plant to provide the necessary backup. It can be chosen and dimensioned so as to provide optimal backup capacity services. This option will be more interesting when the system has to be expanded and the additional intermittent energy sources are foreseen to cover an increase in annual load. The existing capacity has to be retained and the intermittent generator, together with its backup, will be added to the system. Of course, the new backup plant can provide more services than only capacity backup. If run optimally, it will probably be used to provide backup for the system as a whole and perhaps also offer ancillary services. An efficient CC gas turbine, storage plant or other type of plant can be built, to provide this backup capacity for intermittent sources.

The second option, is to utilize existing power plants as backup capacity. This situation will mostly occur when intermittent sources are added to the system with no actual need for more provision of electricity. The positive about using existing power plants, is that no new investments are needed. However, there is still a cost to keep the plants operational. There are also some disadvantages of using existing power plants. First, if these plants were truly economical, they would operate for more than just reserve, unless the reserve pricing is very high. Secondly old plants are often less reliable just because they are old. Furthermore, older existing power plants are more polluting, thereby counter-working one of the main purposes of installing extra wind energy. Finally, older power plants are not always started up fast, which might make them inappropriate as backup capacity.

Alternatives for back-up

Alternatives to backup capacity also exist. There are ways to reduce the need for actual power plants delivering backup capacity. However, these alternatives are best seen as variants on the backup capacity needs.

First of all, interconnectors with other control areas might be an option. Effectively enlarging the control area, improves the efficiency backup provision. More players usually mean more efficient pricing. Instead of looking for backup capacity in its own control area, it might be more interesting to look for it abroad. A requirement for this however is to increase the interconnection capacity between control areas. The cost for this has to be weighted off against the cost of providing backup capacity within the own control area. Increasing interconnection also has other benefits than for just capacity backup purposes.

Storage might also be considered an option. With a 100% storage of wind power, for example with hydro pumping units, intermittent sources such as wind power become more controllable and reliable, therefore diminishing the need for additional capacity. The intermittent energy source, combined with storage, can provide a constant output or, even better, focus its output on moments of high load. This way, the power provided by intermittent sources becomes of greater value. More power can be provided at crucial moments, at peak load, thereby increasing the capacity credit of the intermittent source.

2.9 Grid infrastructure

Related to the problem of backup capacity, rises the issue of grid infrastructure development. When additional wind power or any other volume of intermittent energy source is introduced in an electricity-generation system or when additional conventional power plants for backup capacity are invested in, these have to be put on the grid as well. The difficulty is to determine how much of the necessary investment can be related to the introduction of this new capacity of intermittent energy sources. The investments in grid infrastructure do not only serve the intermittent sources and with increasing annual loads, the grid has to be upgraded together with new capacity anyway.

In this chapter, a brief overview of the different horizons for grid infrastructure-related matters is give. Subsequently, a short setting of the gird upgrades problem is discussed.

2.9.1 Different Horizons

The grid infrastructure issue when considering the introduction of intermittent sources, taking wind power as an example can be seen on three different timescales, namely the short term, the mid- to long term and the long term. [12]

Short term

In the short term, and with relatively low levels of wind power penetration, transmission network upgrades facilitate wind power integration and coincide to a large extent with methods for congestion management and optimisation in the transmission system. Network congestion can usually not be allocated to a particular technology.

Wind energy will not automatically add to existing transmission bottlenecks, although it can occur in reality. In general, network congestion measures can be classified into three categories. The soft measures include the improvement and harmonisation of operational methods or standards regarding the definition of technical limits or the way in which different sources of operational uncertainty are taken into account. It also includes the setting of tolerances related to short-term overloading of network elements. The second category encompasses investments that are not construction of new lines. These include the implementation of power flow controlling devices and the reinforcement of weak points on existing interconnections. The third type of measures covers the construction of new lines and substations.

Mid- to long term: on a European level

On the mid- to long term the transmission and interconnection on a European level has to be determined. In Europe, the TEN-E guidelines have been established. These clearly acknowledge the integration of wind power in the European electricity-generation system. Smoothing effects from geographical dispersion have to be used to their fullest extent. Both high voltage lines and offshore transmission links have to be invested in on a European level. Cross-border coordination between Member States is advisable so as to achieve optimal interconnection and transmission.

Long term

In the long run, a European offshore wind power super grid can be envisaged. Wind power would then be transmitted through Europe, ripping the highest benefits of its geographical dispersion and good wind locations.

2.9.2 Grid upgrades

The necessary upgrades of the grid can take place at two levels. First, regular conventional power plants and intermittent sources can be put on the transmission grid. This centralises the electricity provision. Electricity can then be dispatched to where necessary. Secondly, power plants and intermittent generators such as wind turbines or photovoltaic cells, can be put on the distribution grid and be operated decentrally[14]. Transmission losses are thereby avoided.

The additional measures that have to be taken for the incorporation of intermittent sources on the system have to be compared to grid upgrades for all other technologies. There are however remarkably few studies reflecting upon the upgrade of conventional power.

2.10 Costs

After having discussed all the elements related to the backup of wind power and other intermittent energy sources, this chapter provides an overview of different costs related to the integration of intermittent sources on the electricity-generation system. These costs are first split up in their different categories. The focus will be on the costs related to the backup of intermittent sources and more specifically wind power. However, other costs (and benefits) will also be discussed.

[14] For a more elaborated insight on decentral electricity generation, [55] is referred to.

After a description of the different costs, the chapter ends with an survey of cost figures based on research done on this subject.

2.10.1 Generation costs

The most straightforward component of the costs of a wind turbine or a wind park is the generation cost. This is made up of both investment and operation costs. Generation costs for wind power are very technology-specific. Onshore and offshore wind power are both based on distinct requirements. Moreover, the location and the number of wind turbines invested in, will determine the costs to a great extent as well. The location of wind turbines defines the average wind speed the turbine will operate with. [12] The dependence of wind power generation costs on wind speed is represented in **Figure 17**.

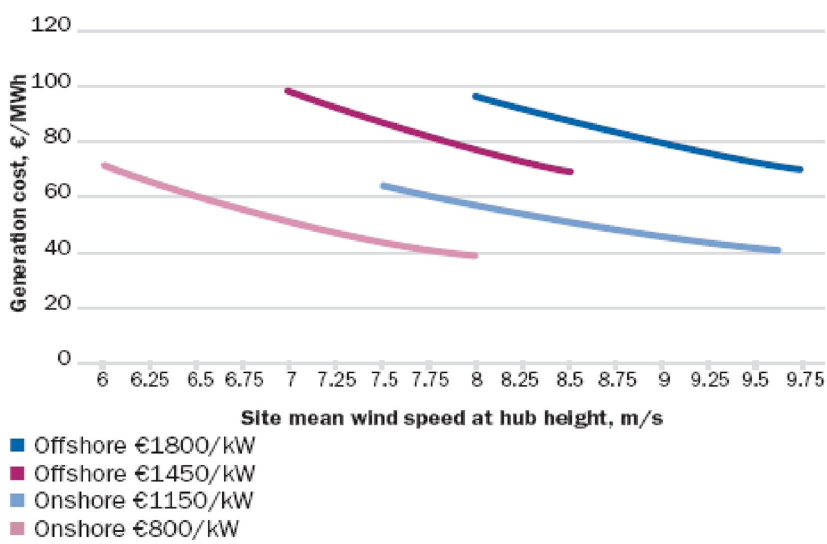

Figure 17: The dependence of wind power generation cost on average wind speed [12]

Milborrow [51] found onshore wind to cost between 40 and 64 €/MWh, where the lower value is given for higher average wind speeds of around 9.5 m/s. The investment is annualised over the considered lifespan of the wind turbine. For offshore wind power the costs vary between 68 and 98 €/MWh. These are high numbers, but experts agree that wind energy generation costs will decrease considerably in the next decades. On the other hand, the generation costs of conventional power plants are situated around 45-55€/MWh for combine-cycle gas power plants, 35-45€/MWh for new coal power plants and 35-58€/MWh for nuclear power plants. These costs are much lower, but wind power offers other benefits as well. These will be discussed in further sections of this chapter.

The investment cost of wind power takes up the largest share in generation cost. This encompasses wind turbine building with connections to the grid. Everything from the planning to the execution is taken into account to calculate these costs.

The other element in the generation cost is represented by the operation cost of wind power. Since wind is a free resource, no fuel costs arise from the production of wind energy. The operations and maintenance costs such as personnel and check-ups fall under this category.

2.10.2 Complete System Integration costs

Generally speaking, large, less reliable and unpredictable power plants are likely to increase system costs, whereas smaller, flexible and predictable generators tend to reduce these costs. Intermittent energy sources belong to the first category. Inflexible and lesser reliable plants demand more services from the rest of the system they are integrated into. When installing flexible power plants into an electricity-generation system, more services will be offered to the system, allowing for more regulating and operational options. This expansion of options usually brings about a decrease in costs since they are synonym for a decrease in constraints in the operation of the system. [14]

Backup costs are the additional costs wind power integration leads to, apart from its generation costs. The costs related to integration in the electricity-generation system have to be seen in this context.

System Operation costs

As discussed in chapters 2.6, 2.7 and 0, the operational backup can be split up in balancing backup and unit commitment backup. The costs are split up in two related categories as well, namely balancing costs and unit commitment costs.

Balancing Costs

The balancing costs encompass all the costs related to the balancing of the electricity-generation system. The actions that take place after gate-closure time all have their costs, which are taken into account in this category.

Hirst and Hild ([21]) state that, even for considerable amounts of wind power capacity, the imbalance charges, which have to be seen on a minutes scale, due to volatility in wind power output are still remarkably low, with values around 0.01$/MWh. The reason for this is twofold. First, the fact that both load and wind are uncorrelated will equally offset or worsen the variations in the electricity-generation system. The combined imbalance of both is smaller than the sum of the separate imbalances. Secondly, the price changes originating from the TSO to maintain the reliability in the system are very small. The imbalance charges rise with increasing wind power penetration.

According to Hirst and Hild ([21]), the real balancing cost arises because of regulation requirements, which according to their definition of regulation would in broad terms coincide with the seconds reserve. The charges to wind for the regulation service is also relatively low, around 1$/MWh, albeit substantially higher than the intrahour balancing cost. These costs will decrease with more wind power being integrated into the system. Other studies ([18],[19]) show considerably lower regulation cost figures which might point to a dependence of the regulation charges to the overall electricity-generation system's size. Larger systems are presumed to provide cheaper alternatives for regulation services.

Dragoon and Milligan ([4]), found a linear relationship between imbalance costs and installed wind power capacity for their study of PacifiCorp. They stress the importance of hydropower as a balancing opportunity. However, using hydropower as a balancing mechanism will also have a negative impact on the total generation price since hydropower will be less available for advantageous peak shaving.

The theoretical emissions savings resulting from the introduction of intermittent sources is reduced because of the decrease in efficiency of conventional plants. [14] Since emissions are considered to generate an external cost, this efficiency loss will increase overall costs related to wind power introduction, by reducing part of its benefit. The conventional power plants have to adjust their output more frequently to cope with changes in provision. Moreover, their overall load factor will be lower as to provide more reserve. Apart from that, the problem of energy spilling might also occur. The extent, to which forecasts can predict the output of intermittent sources, will influence the amount of emissions savings. Better predictions allow for less conventional power being part-loaded to provide backup. Less part-load will in turn lead to higher overall efficiency of the electricity-generation system.

Apart from conventional power plants that have to offer flexible solutions to the variability of intermittent sources, another (opportunity) cost may arise when the system cannot absorb all output of intermittent sources and energy has to be discarded. The frequency of energy being spilled depends on the capacity of inflexible plants (such as nuclear power plants or combined heat and power) in a system. It also depends on the correlation between load and availability of the intermittent sources.

Unit Commitment Costs

The unit commitment cost is the cost associated to providing adequate capacity ahead of gate closure, so as to avoid failures. A certain system margin has to be taken to provide sufficient reserve capacity during the operation of the system. According to the UKERC ([14]), additional reserves are necessary for the incorporation of intermittent generation. Two approaches to estimate the costs can be used. On the one hand, the least cost option to provide these reserves can be calculated through optimisation of the system. This can be achieved through specialised optimisation software packages such as GAMS ([30]) or Lingo ([31]). On the other hand, the market price of reserve services can be used to estimate the costs of additional unit commitment due to the integration of wind power. These can clearly only be used when markets for these services are available. The UKERC ([14]) have given an overview of the additional reserves requirements according to intermittent power penetration level. This is depicted in **Figure 18**. Most of the studies present additional reserve requirements below 10% of intermittent generation capacity, for penetration levels up to 20% of energy provision covered by intermittent sources.

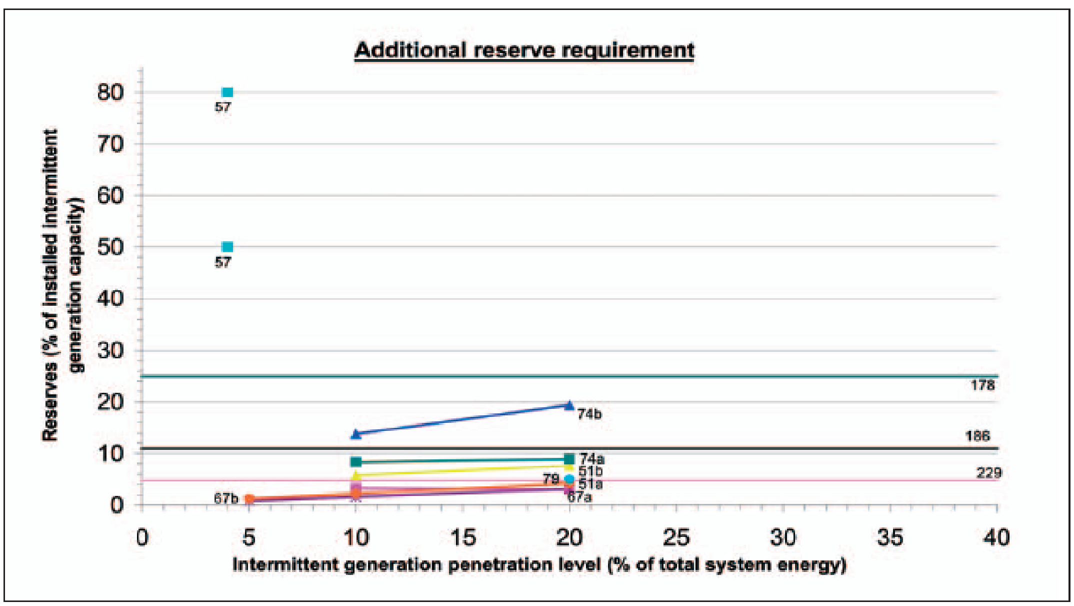

Figure 18: The additional reserve requirements expressed in relation to the penetration level of intermittent generation sources [14]

The costs related to unit commitment arise from prediction errors. Different costs estimates are usually explained by different gate-closure times or different prediction methods. These costs are therefore to a large extent system-dependent. Studies form different countries will normally show different results.

According to Knight ([44]), increasing balancing market liquidity, will help reducing the costs related to reserve requirement. Better and cheaper reserve options become available in more liquid markets.

Capacity Cost

The capacity cost comprises the costs related to the necessary backup capacity when intermittent sources are incorporated into an electricity-generation system. The costs are therefore strongly related to the capacity credit of the considered intermittent generator. The investment in additional capacity that has to cover the rise in backup needs, will make up the capacity cost.

Since in current liberalised markets, no single body is responsible to purchase system margin, estimating reliability costs is more ambiguous than balancing-related costs. The expansion of the system and the system adequacy do not fall to the responsibility of a centralised body. The foresight of investments that will create revenue for the investors is what drives the expansion of the park. Investors will invest in backup capacity when they expect they will gain from it in the long run. The price incentives have to be so that an appropriate technology mix will follow. Sometimes extra regulation by the government might become necessary.

The costs of maintaining reliability are found to increase with rising shares of intermittent generation sources. [14] There are two distinct elements that have an impact on capacity costs. On the one hand, the cost savings from displaced conventional power plants will decrease the capacity costs. On the other hand, the additional costs due to the need for conventional plants maintaining reliability will increase the total capacity cost.

To quantify these costs, the real costs have to be used since in most systems (such as the UK), no explicit payment for adequacy service exists. Therefore no price can be determined. Two possibilities arise. A first option consists in using the change in costs for the total system and attributing it to the intermittent sources. No direct capacity reserves are attributed to the intermittent power sources. A second possibility is that the costs are derived from the generation costs of the back up plants that are used to provide the needed reliability. Known or assumed power plants are used for this. For example, a gas-fired combined-cycle power plant can be assumed to provide the backup and the costs can be derived from this type of power plants. In [1], a method that combines both approaches is developed. According to calculations performed with this method, it can be concluded that it is the size of the capacity credit relative to the capacity factor that determines the costs of maintaining reliability.

In general, relative few studies attempt to define the costs related to the relatively low capacity credit of intermittent energy sources. Most studies focus on the balancing aspects or merely define the capacity credit without attributing a specific cost to it.

Grid cost

A third factor in the total integration costs for intermittent energy sources, is to be found in the grid upgrades. New capacity will always need to be connected to the grid. This will sometimes raise the need for additional investment in grid capacity.

According to the IEA and the NEA ([39]), the grid upgrade costs make up about 28% of the total integration costs with 20% of energy covered by wind power, rising to 35% of costs with 30% of wind power penetration. The absolute values are around 4€/MWh and 5.5€/MWh respectively.

2.10.3 Social benefits – revenues of wind

Wind power, or any other intermittent energy source, should not only been seen as bringing costs to the system. The benefits for wind power are also considerable. A benefit can be seen as a negative cost. First of all there is the above-mentioned benefit of having no fuel costs. Once built, a wind turbine will generate electricity at a very low cost. It will almost always outperform other, conventional power plants, on the moments wind energy is being produced.

Secondly, wind power will result in GHG reductions in most cases[15]. The (external) costs from emissions will be spared when wind energy is being produced. With increasing importance for environmental aspects of our society and with more stringent emissions reduction targets, these external costs may become increasingly important in the near future. The more value attributed to emissions savings, the higher the savings in external costs from emission-free power plants will be.

[15] Cfr. Section 0

Furthermore, wind power offers a way to diversify resources. Diversification usually brings the advantage of overall risk reduction. This risk can be seen on different levels. The diversification of primary energy resources makes an economy less dependent on the price of one resource. The risk of variability is reduced through the low correlation between different energy sources as well. The theory of diversification has to be found in the financial literature, where it is applied on portfolio analysis. Awerbuch ([2], [3]) has performed studies on the application of this portfolio analysis for intermittent energy sources and electricity generation.

Finally, intermittent energy sources might also contribute to the security of supply. For wind power, countries and regions are not dependent on other countries. The commodity being wind, everyone has free access to it. There is a substantially lower political risk associated to wind power and other renewable energy sources.

Estimates of studies on costs for integration of wind power

Numerous studies, reports and articles have analysed the costs associated to the backup of wind power or other intermittent sources. In what follows, an overview is given of the most relevant results of these studies. It has to be kept in mind however, that the results are always very much country-, context- and method-dependent and have to be seen rather as sets of estimates amongst many others. All reported costs refer to additional backup costs due to the integration of intermittent energy sources.

Smith, DeMeo and Milligan ([60]) provide a summary of various case studies concerning backup costs for wind power. The UWIG/Xcel Energy case study reported a total operational backup cost of about $1.85/MWh for a 280 MW wind park being integrated into a 7200 MW system. The forecast error is taken to be 50%. The Pacificorp study reported unit commitment costs of $2.50/MWh and balancing costs of $3.00/MWh. The penetration level is of 2000MW wind power in a 10000MW system. The Bonneville Power Administration operates a large hydropower and transmission system with a peak load of 14000 MW. The unit commitment costs is calculated to be $1.00-1.80/MWh. The load following costs and regulation costs, that together make up the balancing cost are taken to be $0.28/MWh and $0.19/MWh respectively, which brings the overall operational cost to $1.47-2.27/MWh. Next, Hirst made a study on the Lake Benton II project, where a 103 MW wind power farm is integrated in a 52000 MW summer peak load system. The balancing costs are calculated and split between load-following costs and regulation costs. For January, the former are found to be

$0.70/MWh; in August they are $2.80/MWh. The latter are relatively low with values of $0.05/MWh for January and $0.30/MWh for August. WE Energies calculate the operational backup costs for a 7000MW system in 2012, consisting of coal and nuclear power plants. Wind penetration levels vary from 250MW to 2000MW. The costs are found to be in the range of $2/MWh-$3/MWh. Great River Energy has an electricity-generation system of 2300MW. The operational costs for 4.3% and 16.6% wind power penetration levels are found to be $3.19/MWh and $4.53/MWh respectively. Finally, the California study comes up with a regulation cost of $0.17/MWh. [59] All mentioned results are also shown in **Table** .

		$/MWh			
Study	Relative Wind Penetration (%)	Regulation	Load Following	Unit Commitment	Total
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	0	2.50	3.00	5.50
BPA	7	0.19	0.28	1.00 - 1.80	1.47 - 2.27
Hirst	0.06 - 0.12	0.05 - 0.30	0.70 - 2.80	na	na
We Energies I	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92
Great River I	4.3				3.19
Great River II	16.6				4.53
CA RPS Phase I	4	0.17	na	na	na

Table 4: Results of the values for operational backup costs of wind power integration by Smith, DeMeo and Milligan [60]

The UKERC made a report on the costs and impacts of intermittency. [14] It gives a clear overview of the backup costs related to the integration of intermittent energy sources. Results are given for operational as well as for capacity backup costs.

Concerning the balancing costs, no explicit cost figures are provided. However, two distinct sources of costs are analysed. On the one hand, the reduction in fuel and emissions savings due to operational aspects of the integration of the intermittent sources is analysed. With penetration rates varying from 5.4% to 60% of installed *capacity* being covered by intermittent sources and between 2.5% and 48.3% of total *energy*[16] being provided by intermittent energy sources, the total fuel savings range from 3.5% to 34% for the penetration level expressed in capacity terms and from 0% to 48% for the penetration level expressed in energy terms. On the other hand, energy is found to be spilled due to the balancing measures. The results for the amount of energy spilt vary strongly with the type of considered research. Values range between 0 and 56% of spilling of energy.

[16] Remark the different ways in presenting the penetration levels. Capacity is expressed in the amount of MW of intermittent sources, whereas energy designates the amount of MWh produced by intermittent sources.

The unit commitment costs in the UKERC report are strongly related to the unit commitment reserve requirements. Most of the results are situated between 1£/MWh and 3£/MWh of intermittent energy produced. The results are depicted in **Figure 19**. It is obvious that, as reserve requirements rise with increasing wind power penetration levels, the costs will rise accordingly.

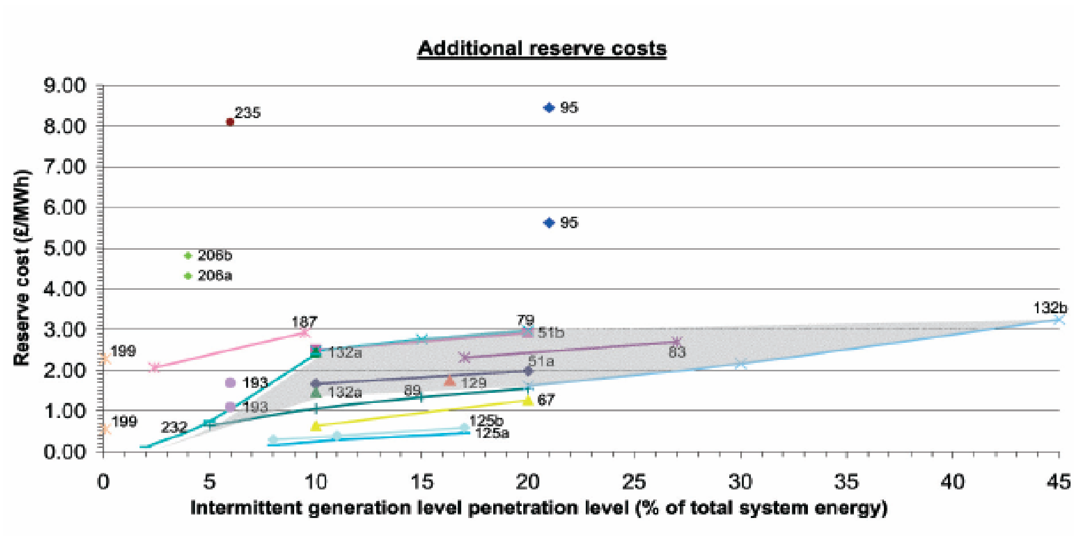

Figure 19: The results for the unit commitment backup costs of different studies, as reported in [14]

The costs related to the backup capacity of wind power are also defined by the UKERC report and explained in more detail by Anderson ([1]). The capacity costs are to a great extent determined by the capacity credit of the wind power. The wind power penetration level in itself does not explain the capacity cost; it does however affect the capacity credit. The capacity cost results are represented in **Table** for a penetration level of 10% and 20% of energy being provided by intermittent generators.

Wind Energy penetration level	Capacity Credit	Capacity cost (£/MWh of wind)
10%	19.4%	£4.76
	30%	£2.44
20%	19.1%	£4.82
	26%	£3.32

Table 5: Capacity costs of wind power for different wind power penetration levels, with varying capacity credit [14]

The Ilex Energy Consulting report ([37]) also gives a clear overview of the costs related to the backup of renewables. Different scenarios, of which only the ones with wind power are considered in what follows, are developed for that purpose. The operational cost for a penetration level of 20% of the energy in 2020 being covered by wind power is calculated by the report. The cost is situated around £2.2/MWh. About half of that value can be attributed to balancing purposes, while half of it has to do with unit commitment backup costs. The capacity cost is calculated to be significantly higher, namely £4.5/MWh. It takes up the largest share in the backup cost of wind power, about twice as high as the operational costs. With a penetration level of 30% these costs increase to £2.5/MWh and £4.8/MWh respectively.

The GreenNet study within the 5th framework programme of the European Commission conducted a set of analyses on different European countries. [17] The range of values for a 20% energy provision penetration level of wind power is taken out of the study. The operational costs, both balancing and unit commitment costs, range from 1.5€/MWh to 2€/MWh. The backup capacity costs are situated between 3€/MWh and 4€/MWh.

The IEA report on “Variability of Wind Power and other Renewables” ([40]) offers some cost figures as well. Regarding an overview of the total costs related to the backup of wind power, the same data are used as in the Ilex Report ([37]) and the GreenNet Study ([17]). For the balancing costs however, the report offers a range of values related to the wind power penetration level, expressed as the ratio of wind power capacity to the total installed capacity of the system. The report based itself on a study performed by MacDonald ([47]). The range of these estimates is represented in **Table** . Again it is clear that the additional relative balancing cost rise with increasing wind power penetration.

	Wind power penetration proportional to total system capacity			
	5.3%	**7.6%**	**10%**	**14.2%**
Lower estimate	1.3	1.6	1.8	2.1
Median estimate	1.4	2.0	2.3	2.4
Upper estimate	2.1	2.9	3.4	3.7

Table 6: The costs of balancing wind in the UK; expressed in €/MWh of wind energy. Taken from [40]

2.11 Questions and Answers

Criticism on wind power is expressed by, for example, Country Guardian ([28]), the Industrial Wind Energy Opposition with Rosenbloom as main contributor ([38],[57]) Windaction ([35]) and White ([74]). Each of these organizations and authors, reflect on one or several aspects regarding wind power. Where heavy advocates of wind power (such as the European Wind Energy Association [12], [29] and American Wind Energy Association [27]) focus on all the benefits of wind power, the former will enumerate all the problems faced with wind power integration, going from environmental to economic concerns. It is important to keep in mind that wind power is a technology that has both strong advantages and disadvantages. It is equally important to shed a clear view on the factors influencing either positive or negative effects without talking only in very broad general terms. Therefore, it is essential to briefly discuss some misconceptions that are easily made when talking about wind power.

"400 MW of wind power can replace a 400 MW conventional power plant"

Of course, this is not true. For a 400 MW wind park to replace the same capacity of conventional power, it should have the same flexibility and operating characteristics as that conventional power. Wind power operates is an intermittent energy source however and will not offer the same amount of reliability. The amount of conventional power actually replaced by wind power is expressed by the capacity credit of wind power.

"Wind turbines only operate 30% of the time, therefore we must provide 70% backup"

A 30% capacity factor does not coincide with wind farms being operational 30% of the time. In reality they will generate electricity about 80% of the time ([14]), be it at levels below their rated capacity.

Moreover, the capacity factor of renewable energy does not provide any information on the backup requirements. Managing intermittency is a statistical matter.

"Wind turbines need back up so they do not save any CO_2"

CO_2 emissions reductions are not a function of how many times "backup power plants" have to provide electricity, not even of the total **capacity** of available backup. The moment on which a "back up plant" has to cover a loss in wind power provision is not really an issue. Only the total amount of **energy** provided by renewable energy sources directly relates to

CO_2 emissions reduction. Therefore, even the slightest amount of energy produced by wind energy, can already contribute to conventional fuel saving and CO_2 emissions reduction, when compare to a situation where this energy was provided by a CO_2-emitting power plant.

"Capacity credit of wind power is zero since extremely low wind speed sometimes coincides with high load."

This argument states that wind power would only contribute to the capacity of the system, when it can guarantee some output at times of high demand. Following this reasoning would be equal of demanding a conventional plant of being 100% guaranteed available on these moments of high demand. However, conventional power plants as well, may undergo unplanned outages, just like wind might disappear all of a sudden for some time. Following this argument would signify that any plant has a capacity credit of zero and needs 100% backup capacity.

However, even with a capacity credit of zero, intermittent power plants can still contribute to fossil fuel saving, diversification of sources and security of supply. [14]

"When wind is considered as an investment that can save up gas by providing electricity instead of a STAG power plant whenever possible, this wind power does not have a backup cost."

This statement is also wrong. It has to do with opportunity costs. The STAG power plant would only be used when wind power is not available. However, even when wind power is operational, it might be optimal to produce electricity with the STAG as well. All depends on the production costs and electricity prices. Moreover, the STAG will run less hours during a year than it would have without the wind power. Therefore, the investment cost is spread over a shorter time span of operation and it will be amortized slower.

2.12 Conclusion

The introduction of wind power or any other intermittent energy source on a large scale, affects the electricity-generation system. The inflexibility, variability, and relative unpredictability of intermittent energy sources are the most obvious barriers to an easy integration and widespread application of wind power. In addition, since the technology is relatively new, still many unanswered questions remain concerning wind power. The knowledge on the use and operation of wind power in a multitude of electricity-generation systems is not based on the same amount of experience as for conventional technologies.

Although wind power is probably the most studied intermittent energy source, many issues still require more investigation. The effects of several parameters, such as the gate closure time, the geographical spread, the composition of the electricity-generation system, the extent of the wind power introduction and the backup provision rules, on the short and long term, remain ambiguous to a certain extent. Moreover, it is important to bear in mind that, currently, most systems are modelled for the operation of conventional power plants. The introduction of wind power may severely change the needs for efficient operation of the electricity-generation system. The entire concept may have to be rethought, so as to most optimally combine and use each of the available energy sources.

This report discusses the impact of intermittent generation, and more specifically wind power, on system operation and reliability. Mainly due to the specific uncertainty and variability of wind power as an energy source, it affects both security and adequacy of an electricity-generation system. Utilities attempt to uphold a minimum level of reliability while at the same time minimizing system costs. The generation schedule is most likely to be adjusted with the introduction of wind power as to allow for an efficient and cost-effective operation of the system. Therefore, the balancing, unit commitment and backup generation capacity of the system undergo changes due to wind power. These changes can bring about additional costs or benefits for the society. The backup cost of wind power is the term used to refer to this type of cost.

The additional costs and benefits that wind power brings about are strongly related to these parameters. Several studies have been using country data to provide estimates of these costs. These have to be seen in light with the desired benefits of wind power, such as emissions reduction and security of supply. Weighing off the total costs and benefits is the only way to make a sound analysis of wind power as an alternative for electricity provision.

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3 Differences in generation related CO_2 emissions in the EU-25

3.1 Introduction

In work package 3.4.2, we have studied in detail the consequences of the large scale introduction of CHP. As a conclusion, the necessity for the use of a detailed simulation model to bring into account the dynamic effects of the park, came forward. As most "normal" simulation codes make only a static analysis or a much simplified dynamic one, investment consequences, effects on GHG's… are not taken into account and it is difficult to estimate the effect of simultaneous supply and demand actions. The properties of the *average* system are not relevant because incremental changes in demand only affect the activation of this limited number of plants, characterised by their own emissions, efficiency and fuel costs.

Here, in this sub work package, we lift the analysis of WP3.4.2 to a higher level and do not only look at the influence of the large scale introduction of cogeneration, but also at other technologies like wind, solar and biomass. In another section, we look at the different methods to implement the intermittent character of generation sources (focus on wind). In a last section, we compare the impact of the same measure in different member states. That section will deal with the introduction of heat pumps in Belgium, France, Germany and The Netherlands.

As for WP3.4.2, all results are based on the simulation code PROMIX. As discussed before, although this model has been developed for the Belgian generation park, the results can easily be interpreted into a larger context. From a modelling point of view, the Belgian power system is very interesting, due to its variety in power plants: nuclear base-load units, coal- and gas-fired mid-load units, gas- and oil-fired peak units and hydro pumped-storage units. The results of the last section of this chapter are based on an enlarged version of PROMIX, in which the generation park of France, Germany and The Netherlands is included.

3.2 Environmental impact of decentralised generation

It is important to make correct judgements on the global performance of the concept of embedded generation. To bring into account the hourly generation profiles, a *capacity credit* is introduced. The capacity credit expresses the amount of installed conventional power that can be avoided or replaced by intermittent sources (i.e. the fraction of the installed decentralised power for which no “double investment” is needed). In section 3.3, different methods to implement the intermittent character of generation sources will be discussed more in detail.

As for the introduction of CHP-units in WP3.4.2, the starting point is a reference scenario, without the implementation of extra distributed units. The other scenarios will analyse the environmental impact of 3 different distributed technologies (with a unit capacity smaller than 2 MW); i.e. biomass, wind and solar power. The results are largely based on [1].

3.2.1 Biomass

The biomass installations which are considered in this analysis have a power output of 1 to 2 MW. In contrast with the large scale biomass units, which can act as pure electricity generation plants as well, the smaller units are considered to operate as cogeneration facilities. 65% of those units work under continuous operation (7/7 – except for the summer; i.e. the larger units). 25% work in a continuous operation (5/7 – except for summer and weekends, i.e. the small units) and 10% operates in cyclic behaviour (i.e. full power during the day, standstill during the nights, the weekends and the summer period). A capacity credit of 100% is assigned to those cogeneration facilities, as they operate at full load when the overall electricity demand is the highest (i.e. during the winter daytime in NW European coutnries). So, the CHP-units avoid the installation of conventional units.

As the biomass units are only operated in CHP-mode, both emission-free heat and electricity are produced. This results in a huge environmental benefit. If (in Belgium) 2000 MW of biomass CHP is installed, the CO_2-equivalent emissions can be reduced with approximately 6.5%, compared to the reference scenario without extra installed biomass units.

As a last remark in the paragraph on biomass units, it needs to be said that the assessment of biomass cogeneration units is quite difficult, as there is an interaction with the heating appliances in other sectors. This fact stresses even more the necessity of a detailed simulation model which can handle detailed demand and supply profiles.

3.2.2 Wind power

This paragraph will analyse the theoretical installation of 2000 MW of on-shore wind turbines in Belgium (without questioning whether or not this is practically feasible). As offshore plants are seen as one large centralised – albeit still indispatchable – production unit, only on-shore turbines are studied here. The simulations are based on accurate wind speed measurements and an on-shore capacity credit of 25% is assumed.

The simulations show that wind power is an interesting technology to reduce the overall CO_2-equivalent emissions. Compared to the reference scenario, the emissions sublinearly decrease with approximately 1%. Due to the low capacity credit of 25%, it is partly required to keep investing in highly efficient CCGT units, which leads to a higher overall efficiency of the central power system compared to the CHP-biomass scenario. The positive energetic and emission results need unfortunately to be balanced by the double investments in generation capacity, which results in unfavourable economics.

3.2.3 Solar power

For the simulations with distributed solar power, an hourly electric-energy output profile, based on measurements for several years (on a five minute basis), has been used. Since PV-units do no produce electric energy in the winter, approximately from 4 pm, they cannot avoid the expansion of the central power system. This is expressed with the use of a capacity credit of 0%.

As for the analyses for the other decentralised generation options, an installation limit of 2000 MW is assumed (even if not practically feasible). The emission reduction will linearly increase with the installed capacity, up to 0.55%. Due to the capacity credit of 0%, the overall efficiency of the centralised system will be very high. As for the installation of wind power, the favourable energetic and emission results will be countered by a high economic tag.

3.3 Wind power: how to simulate intermittent character

This section, which is largely based on [2], focuses on the implementation in simulation models of the intermittent character of generation methods. Here the analysis is done for wind power, but the analysis can easily be interpreted for other non-dispatchable production methods.

There are two possible strategies to deal with the fluctuating power output of wind. The first option is to base the simulation on actual measurements or on simulated plausible profiles. In this case, the produced wind power is seen as a negative load profile (i.e. generated by wind, so not longer to be generated by conventional power supply). In practice, this is implemented by subtracting the produced wind power from the demand. By this, the fluctuating character is fully taken into account. This option is possible with PROMIX.

The second option is for the case in which the model cannot cope with a detailed output profile. Here a strongly simplified profile, often simulated as a constant reduced power output, is used. E.g. a 1000 MW wind farm with a capacity factor[17] of 30% is simulated as a constant power output of 300 MW. So the hourly profile is averaged over the entire year.

This section analyses the different simulations options with PROMIX, because this model can handle both the detailed and the averaged option. Again, as mentioned in the previous section, only the Belgian situation has been looked at, but the results are valid for the European context as well. In the reference scenario, no additional wind power (i.e. WECS, Wind Energy Conversion Systems) has been installed.

In the first simulations, no capacity credit is assigned and the actual WECS' output profiles – based on measurements - are being used. The produced wind power is considered as a negative load. The simulations show that the emission reductions increase (slightly sublinear) with the WECS's installed capacity. Besides that, the reductions increase with the capacity factor. It is seen that not only the capacity factor, but also the variability of the profile determines the possible GHG emission reductions. This can be explained as a smoother

[17] Capacity factor: expresses the equivalent amount of full-load hours per year. E.g. 1000 MW of installed wind power, with a capacity factor of 30% (or with 2630 equivalent full-load hours per year) is seen as a generation unit with a constant output of 300 MW

Capacity credit: expresses the amount of installed conventional power that can be avoided or replaced by wind power. This CC is the fraction of the installed wind power for which no "double investment" is needed. E.g. 1000 MW of installed wind power, with a capacity credit of 30% can avoid 300 MW investments in conventional dispatchable power.

WECS power output profile allows a more efficient use of the base-load units. The potential emission reductions are about 350 to 400 kg CO_2 per MWh of WECS. This figure suggests that the WECS replace CCGT power.

In the second set of simulations, the WECS are simulated with the constant reduced output option and without the use of a capacity credit. So the first set of simulations, as described above, are repeated, but under a constant reduced wind power output. In order to respect the capacity factor, the wind turbines are expected to be constantly available at reduced power of rated power. The reductions equal the capacity factor. The simulations show that the approach of the constant reduced power output slightly overestimates the potential GHG emission reduction by approximately 10 to 15%. This can be explained by the fact that because of the use of a constant reduced power output, the WECS can be used more efficiently, as the system does not have to cope with the fluctuations of the WECS variable power output.

A last set of simulations combines the WECS actual output profile with the use of a capacity credit. By the use of the capacity credit, the WECS replace other “conventional” generation capacity units. For different location of wind farms, a different capacity credit is used. The use of a capacity credit reduces the GHG emission reduction potential by using WECS in a power system. This unfavourable effect is caused by the avoided investment in CCGT’s. If those units would have been built, they would have replaced less efficient conventional plants. So, the capacity credit partly inhibits the renewing evolution, which leads to a lower reduction potential. The resulting emission reduction potential from the simulations is expected to be 350 kg per MWh power generated by WECS.

3.4 Influence on the GHG emissions of the massive introduction of heat pumps in 4 different European Countries

The two sections above focussed on the consequences and the differences of the introduction of a decentralised production method in an existing power system. The discussion was limited to one specific country, i.e. Belgium, but due to the composition of the Belgian power system, the results can easily be interpreted in a broader European context. This section will examine more in detail the consequences of the different composition of the electricity generation system in 4 countries. More especially will be examined how the generation systems of France, Belgium, Germany and The Netherlands will react if a similar change in demand occurs. The analysis is largely based on [3]. The similar action that will be simulated in all countries is the massive implementation of heat pumps. The amount is chosen so, as to generate a significant impact on the electricity production. As a result, there will be a shift from conventional (i.e. fossil) heating to electric heating, and so, the emissions from the fossil-fuel heating systems will be shifted to emissions from electric power plants. Rising GHG emissions due to higher electricity demand for electric heating will have to be compared with avoided emissions from conventional heating. The focus of the analysis is on the operation characteristics of the system and on the interaction between the electricity demand and the electricity generation system. No emphasis is put on the costs of the installation of the heating system.

For this analysis, the simulation model PROMIX, which was originally developed only for the Belgian power system, was extended with the details on the power systems of the 3 other countries mentioned above. The four different generation system that were implemented (anno 2000), can be described roughly as follows:

- Belgium: combination of nuclear power plants, CCGT's, classic thermal power plants (mainly coal-based)
- France: importance of nuclear, some thermal power plans on coal and little over 10% of the produced electricity is produced by hydro. There is an absence of large sources of gas-driven power plants.
- Germany: important role (approximately half of the electricity generation) for lignite and hard coal plants. About 30% of the electricity generation by nuclear and the remaining share is done by CHP and RES-plants.
- The Netherlands: approximately 60% of the generated electricity is gas dependent. Both single gas turbine and CCGT plants and gas-based cogeneration units are used. 30% is produced by coal-fired plants, and the residual share is provided by nuclear and RES. There is a high share of decentralised power generation in The Netherlands.

As in the sections above, a reference scenario was used in which only conventional fossil-fired heating was made use of. In the other scenarios, direct electric heating and heat pumps (with a COP[18] of 2.5 and with a COP of 5, in combination with accumulation heating[19]) were introduced.

In Belgium, more electric heating leads to a decrease in the overall GHG emissions. This is largely triggered by the high COP of the heat pumps. The best options are the installation of the direct heat pumps in combination with the commissioning of new CCGT's and the accumulation heat pumps. The higher GHG emissions due to the rise in electricity production are compensated by the lower GHG emissions due to the avoided conventional heating.

[18] COP: Coefficient of Performance

[19] Accumulation heating: i.e. electricity production during off-peaks.

For France, it seems from each scenario that it is interesting to switch to electric heating. This is mainly due to the fact that an increased electricity demand of such a proportion triggers the increased use of dispatchable nuclear power stations. And if the usage rate of a nuclear power plant is high enough, it outperforms the thermal plants, both on GHG emissions and on costs. If the electricity park is further expanded with CCGT's, there is also a shift from lower efficient coal plants to high efficient CCGT's, which would result in additional GHG reductions.

In Germany, it is less interesting to replace the conventional heating by electric heating. In most scenarios, this shift leads to higher overall emissions. Only the scenario with heat pumps with a COP of 5 (in combination with accumulation heating) leads to a GHG reduction. This overall negative shift to electric heating is mainly due to the important role of coal-based power plants in the electricity generation.

In The Netherlands, the addition of heat pumps will result in lower GHG emissions; however, this to a less important extent than the commissioning of new CCGT's. The combination of new CCGT's and accumulation heat pumps gives the most positive results.

The scenarios show differences between the different countries. However, the combination of the introduction of accumulation heat pumps – with a high COP – with new CCGT units – which are relatively clean, results in a GHG reduction for all countries. The high COP reduces the amount of required kW_{elec} for every kW_{th}, and the new CCGT's will be in operation throughout the year, ousting more polluting power plants (not only for providing electricity for heat pumps).

3.5 Conclusion

This brief chapter on the differences in the CO_2 emissions due to the electricity generation, leads to several conclusions, which are based on simulations with the code PROMIX. Although this code was originally developed for the Belgian production system, the results from this chapter can easily be interpreted in a wider European context. Even more, for the simulations of the last section, the model has been extended to other European countries.

Overall emissions can be significantly reduced whenever biomass units are installed and whenever this amount is increased. However, one may not forget that sufficient qualitative resources are needed to supply those units. Massive introduction of other decentralised sources (e.g. solar and wind) result in emission reductions as well, but to a much lesser extent. For WECS, the emission reduction potential increases with the amount of installed units, but only sublinearly. If the output profile could be smoothened, the reduction potential would become larger because of the more efficient use of the base load plants. The introduction of capacity credits reduces the emission reduction potential, compared to the situation without bringing into account capacity credits. This is related to the inhibiting of the renewing evolution of the power system, which would naturally lead to reduced emissions.

The analysis above has shown that the consequences of changing the electricity demand (e.g. by the massive introduction of electric heating and heat pumps) will influence the GHG emissions in a different way. This will depend on the composition of the country's electricity generation park.

As a general conclusion, it can be said that every change in an electricity generation park (on centralised or decentralised level), or every measure which influences the electricity demand or supply, has an impact on the overall system. This has to be examined in a dynamical way!

3.6 References

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4 Calculation of global external costs

4.1 Introduction

An externality is commonly defined as a cost that arises when the social or economic activities of one group of persons have an impact on another group and that impact is not fully accounted for by the first group.

During the operation of a power station, there are some emissions which cause damages to human health, crops and materials among others, generating an externality because the resulting impacts are not taken into account by the generator.

Externalities also arise in other stages of the fuel cycle, up and downstream, such as the mining and processing of the fuels, the construction of the plant, the waste treatment and the final decommissioning. Thus, to fully calculate the external costs all the main impacts from all the stages have to be considered.

In this work, some estimation on externalities for different power generation technologies has been carried out. Methodology and data used for this calculation are described in the next section.

4.2 Determination of external costs

The methodology followed to calculate the external costs of the different technologies analysed in the EUSUSTEL project consisted of the following steps:

- Gathering of environmental data for all the technologies
- Extrapolation/calculation of missing emission data
- Determination of direct, indirect and total external costs

4.2.1 Data gathering

Work package 3, *Electricity generation technologies and system integration,* in the EUSUSTEL project consisted of a description of basic characteristics, peculiarities, and environmental and technical aspects for each present and future electricity generation technology shown in table 1. The present position and future development of the technology in the market has also been analysed.

Table 1: Electricity generation technologies

Fossil-based technologies: – Coal fired – Oil and gas fired – Combined heat and power – CO_2 capture and storage
Nuclear: – Fission – Fusion
Renewable flows and alternative technologies and carriers: – Wind power – Photo-voltaic conversion – Biomass applications – Hydro power – Geothermal conversion – Fuel cells – Hydrogen economy – Electricity storage – Other

From all the information gathered in the EUSUSTEL WP3 reports, technical, economic and environmental data have been collected in several tables for each period under study. Atmospheric emission data for all the stages of the technology cycle are needed to evaluate the external costs. When those data were not available, some calculations had to be done in order to fulfil the data tables.

4.2.2 Missing data calculation

To calculate external costs, atmospheric emissions have to be multiplied by a factor which relates the amount of pollutant emitted with an economic value of the resulting impact. When emission data for future technologies were not available, they were estimated using other technical or economic parameters. Here, direct and indirect emissions were calculated as follows:

For future direct emissions, which are those from the power generation stage, electrical efficiency evolutions of the plant have been used, when available, to extrapolate present data to future. In this way, the improvement on efficiency is supposed to lead to an emission reduction. Emission data reduction rates have been calculated from the electrical efficiency improvement growths.

For indirect emissions, which are those from the other stages different from power generation, specific investment cost evolutions have been used, when available, to extrapolate present data to future. An increment in the specific investment costs is related to a bigger amount of materials and may lead to an emission increase. Future emission data rates have been calculated from specific investment costs increases.

Results are shown in Annex I: tables IV, V, VI and VII.

4.2.3 Determination of total external costs

Once the atmospheric emissions for present and future periods were calculated, external costs were estimated by multiplying those emissions by a damage factor shown in table 2:

Table 2: Damage factors

CO_2	10 Euro/ton
SO_2	3300 Euro/ton
NOx	3300 Euro/ton
N_2O*	748.3 Euro/ton
CH_4*	44.9 Euro/ton
Particles	10100 Euro/ton
NMVOC	870 Euro/ton
C_{14}	0.014125044 Euro/kBq

* Data from ExternE Transport (Friedrich R. and Bickel P., 2001)

4.3 Results

For present and future years, the highest external costs correspond to coal technologies followed by fuel cells and coal technologies with CO_2 capture and sequestration.

Then follow biomass gasification and natural gas technologies. In the first periods, biomass gasification shows higher values than gas technologies. From 2020 on, gas combined cycle external costs exceed those for biomass gasification except for the gas technologies with CO_2 capture and sequestration.

Regarding the renewable technologies, photovoltaic technologies external costs drop through time mainly due to increments in efficiency. Wave and tidal have the highest costs for the renewable technologies, while geothermal and hydrothermal have the lowest. Wind energy presents intermediate values.

Finally, nuclear fission technologies have similar costs to those from renewable technologies. Table 3 and figure I show the external costs for all the technologies and periods in cEuro/kWh.

Table 3: External costs in cEuro/kWh

Technology	2005	2010	2020	2030
Lignite, IGCC	1.3861	1.3179	1.2455	1.2349
Lignite, ST	1.4488	1.4260	1.2970	1.2970
Coal condensing	1.0628	1.0628	1.0628	1.0628
CCGT	0.4383	0.4313	0.4179	0.4043
Natural gas CS		0.2928	0.2849	0.2820
Lignite CS		0.7336	0.6935	0.6758
Nuclear fission	0.0293	0.0278	0.0278	0.0278
Wind onshore	0.0156	0.0127	0.0127	0.0127
Wind offshore	0.0156	0.0106	0.0106	0.0106
PV	0.0744	0.0753	0.0533	0.0369
Biomass gasification	0.5247	0.4684	0.3747	0.3187
Hydro Large scale	0.0054	0.0054	0.0054	0.0054
Geo Conventional	0.0054	0.0054	0.0054	0.0054
PEMFC	0.7431	0.7431	0.7431	0.7431
PAFC	0.7766	0.7766	0.7766	0.7766
MCFC	0.6969	0.6969	0.6969	0.6969
SOFC	0.6172	0.6172	0.6172	0.6172
Wave	0.0939	0.0939	0.0939	0.0939
Tidal	0.0483	0.0483	0.0483	0.0483

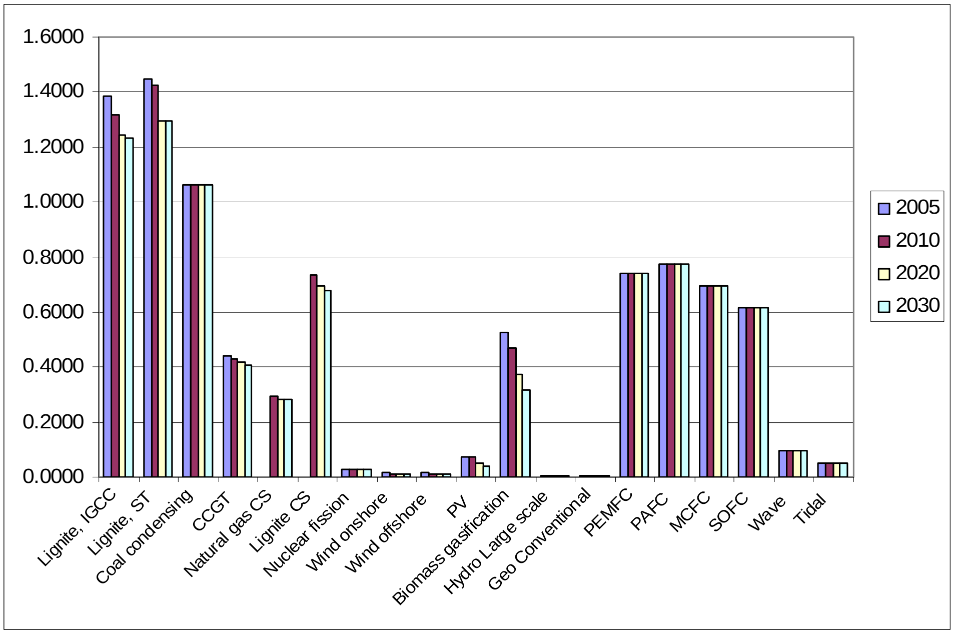

Figure 1: External costs for all the technologies and periods in cEuro/kWh. 10 €/t CO_2

Following the last ExternE series project, NewExt (Friedrich R. et al., 2004), a factor of 19€/t CO_2 has been applied in the calculations. Results are shown in figure II.

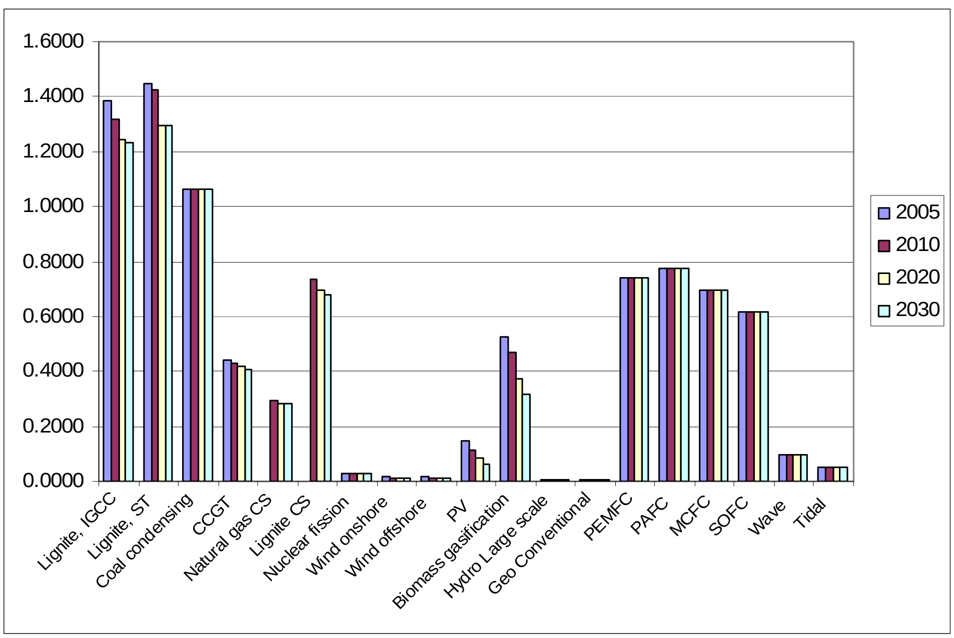

Figure 2: External costs for all the technologies and periods in cEuro/kWh. 19 €/t CO_2

These last results have been compared with those from some ExternE projects:

For the coal technologies, ExternE National Implementation (EC, 1999b) gives a range of 4.2 to 12.3 cEuro/kWh, while NewExt (Friedrich R. et al., 2004) gives a range of 2.53 to 6.33 cEuro/kWh. Our results are closed to the low margin of NewExt results.

For the gas technologies, ExternE National Implementation gives a range of 1.1 to 1.9 cEuro/kWh, while NewExt gives a range of 0.80 to 1.55 cEuro/kWh. Our results are also closed to the low margin of NewExt results.

Results for nuclear are much lower than those from Externe National Implementation. This could be due to the fact that in our case, only C-14 related externalities have been considered, and probably some other cycle stages have been omitted. Comparing the C-14 emission data gathered in WP3 with those corresponding to the whole cycle given in ExternE studies, a considerable difference can be observed. For instance, emission data from the reprocessing stage reported in ExternE resulted much higher than total emission data used from WP3.

For hydro and wind technologies, results are lower than those from ExternE. Regarding wind technologies, data from WP3 only included CO_2 emissions and, according to ExternE data, also other pollutant emissions such as SO_2, NOx and particles during the turbine manufacture can cause health impacts. ExternE also included occupational health impacts which are not included in our study. For hydro technologies, the main impacts in ExternE are due to amenity losses and ecological effects which have not been considered in our analysis.

PV results, when using the 19€/tCO_2 damage factor, are similar than those from Externe when the CO_2 damage factor of 18 €/tCO_2 (low illustrative restrictive range) is taken.

Biomass gasification results however are slightly higher than the average costs of this technology in ExternE.

4.4 References

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4.5 Annex I. Data on atmospheric emissions from WP3

Table IV. Current technologies

Current	Direct emissions (g/kWh)								Indirect emissions (g/kWh)							
	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*
3.1.1 COAL																
Lignite, IGCC	886.2	0.779	0.483	0.044	0.013	0.154	0.027	5E-05	3.076	0.005	0.009	0.027	0.001	0.003	0	6E-06
Lignite, ST	901.5	0.651	0.674	0.097	0.018	0.016	0.028	1E-05	1.135	0.004	0.005	0.004	0.001	0.004	0	1E-05
Coal condensing	854.9 (1)	0.270 (1)	0.360 (1)	n.d.	n.d.	n.d.	n.d.	n.d.	(1)	(1)	(1)	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.2 OIL & GAS																
CCGT	348.8	0	0.176	8E-04	0	0	0	0	26.25	0	0.013	6E-05	0	0	0	0
3.1.3 CHP																
Small-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Large-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.4 CO_2 CS																
Natural gas																
Lignite																
3.2.1 FISSION																
Nuclear fission				2E-05 (1)	3E-04 (1)	6E-04 (1)	9E-06 (1)	0.02 (1)	0.3	0.001	0.001	(1)	(1)	(1)	(1)	(1)
3.2.2 FUSION																
Nuclear fusion																

3.3.1 WIND																
Wind turbine									15.61	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.2 PV																
Crystalline									48.3	0.01	0.095	0.006	0.016	0.114	4E-04	4E-04
Thin-film amorphous									41.9	0.009	0.091	0.002	0.011	0.077	4E-04	2E-04
Thin-film CIGS									42.5	0.006	0.005	0.004	0.011	0.083	2E-04	0.003
3.3.3 BIOMASS																
Biomass gasification	11.5 (2)	0.265 (2)	0.494 (2)	0.01 (2)	0.522 (2)	0 (2)	0 (2)	n.d. (2)	34.4 (2)	0.302 (2)	0.192 (2)	0.003 (2)	0.073 (2)	0.005 (2)	0.010 (2)	n.d. (2)
3.3.4 HYDRO																
Large scale						0.006 (1)			2.778	0.001	0.007	n.d.	n.d.	(1)	n.d.	n.d.
Small scale									n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.5 GEO																
Conventional (3) H_2S	122	3.65 (3)	0		n.d.	n.d.			n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Binary cycle	0	0	0			n.d.			n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.6 FUEL CELLS																
PEMFC	601 (1)	0.3 (1)	0.088 (1)	0.011 (1)	2E-06 (1)	0.64 (1)	6E-04 (1)	n.d.	(1)	(1)	(1)	(1)	(1)	(1)	(1)	n.d.
AFC	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
PAFC	649 (1)	0.38 (1)	0.006 (1)	n.d.	0.002 (1)	0 (1)	n.d.	n.d.	(1)	(1)	(1)	n.d.	(1)	(1)	n.d.	n.d.
MCFC	481	0.32	0.319	0.005	n.d.	0.006	n.d.	n.d.	(1)	(1)	(1)	(1)	n.d.	(1)	n.d.	n.d.

	(1)	(1)	(1)	(1)		(1)										
SOFC	511 (1)	0.25 (1)	0.032	0	7E-05 (1)	0.238	n.d.	n.d.	(1)	(1)	0.012	0.008	(1)	0	n.d.	n.d.
3.3.7 HYDROGEN																
Hydrogen economy																
3.3.8 STORAGE																
Electricity storage	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.9 MARINE																
Wave									18	0.16	0.07	n.d.	n.d.	n.d.	n.d.	n.d.
Tidal									12	0.08	0.03	n.d.	n.d.	n.d.	n.d.	n.d.

* kBq/kWh

Shadow cells mean 'not applicable'

n.d.: no data

(1) direct and indirect emissions

(2) data on materials for construction available

Table V. Advanced technologies- 2010

Advanced- 2010	Direct emissions (g/kWh)								Indirect emissions (g/kWh)							
	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*
3.1.1 COAL FIRED																
Lignite, IGCC	841.3	0.74	0.461	0.041	0.013	0.147	0.026	5E-05	3.076	0.005	0.009	0.027	0.001	0.003	0	6E-06
Lignite, ST	883.5	0.644	0.667	0.097	0.018	0.016	0.028	1E-05	1.081	0.004	0.005	0.004	0.001	0.003	0	1E-05
Pulverised Coal	854.9 (1)	0.270 (1)	0.360 (1)	n.d.	n.d.	n.d.	n.d.	n.d.	(1)	(1)	(1)	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.2 OIL & GAS																
CCGT	343.2	0	0.173	8E-04	0	0	0	0	25.83	0	0.013	6E-05	0	0	0	0
3.1.3 CHP																
Small-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Large-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.4 CO_2 CS																
Natural gas	44.90	0.208	0.454	0.008	0.150	1.010	0.011	3E-05	0.215	0.001	0.001	0.002	0	0	0	1E-06
Lignite	139.7	0.823	0.520	0.109	0.016	0.046	0.031	5E-05	3.252	0.005	0.010	0.028	0.001	0.004	0	6E-06
3.2.1 FISSION																
Nuclear fission				2E-05 (1)	3E-04 (1)	6E-04 (1)	9E-06 (1)	0.02 (1)	0.3	0.001	0.001	n.d.	n.d.	n.d.	n.d.	n.d.
3.2.2 FUSION																
Nuclear fusion																
3.3.1 WIND																

Wind turbine									12.66	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.2 PV																
Generic									41.21	0.008	0.075	0.005	0.013	0.095	3E-04	3E-04
Crystalline									25.42	0.005	0.05	0.003	0.008	0.06	2E-04	2E-04
Thin-film amorphous									44.11	0.009	0.096	0.002	0.012	0.081	4E-04	2E-04
Thin-film CIGS									42.5	0.006	0.005	0.004	0.011	0.083	2E-04	0.003
3.3.3 BIOMASS																
Biomass gasification	10.7	0.246	0.459	0.01	0.485	0	0	n.d.	28.74	0.252	0.16	0.003	0.061	0.004	0.008	n.d.
3.3.4 HYDRO																
Large scale						0.006 (1)			2.778	0.001	0.007	n.d.	n.d.	(1)	n.d.	n.d.
Small scale									n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.5 GEO																
Conventional	122	3.65	0		n.d.	n.d.		n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Binary cycle	0	0	0			n.d.		n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.6 FUEL CELLS(4)																
PEMFC	601 (1)	0.3 (1)	0.088 (1)	0.011 (1)	2E-06 (1)	0.64 (1)	6E-04 (1)	n.d.	(1)	(1)	(1)	(1)	(1)	(1)	(1)	n.d.
AFC	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
PAFC	649 (1)	0.38 (1)	0.006 (1)	n.d.	0.002 (1)	0 (1)	n.d.	n.d.	(1)	(1)	(1)	n.d.	(1)	(1)	n.d.	n.d.
MCFC	481 (1)	0.32 (1)	0.319 (1)	0.005 (1)	n.d.	0.006 (1)	n.d.	n.d.	(1)	(1)	(1)	(1)	n.d.	(1)	n.d.	n.d.
SOFC	511	0.25	0.032	0	7E-05	0.238	n.d.	n.d.	(1)	(1)	0.012	0.008	(1)	0	n.d.	n.d.

	(1)	(1)			(1)											
3.3.7 HYDROGEN																
Hydrogen economy	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.8 STORAGE																
Electricity storage	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.9 MARINE																
Marine									18	0.16	0.07	n.d.	n.d.	n.d.	n.d.	n.d.
Tidal									12	0.08	0.03	n.d.	n.d.	n.d.	n.d.	n.d.

* kBq/kWh

Shadow cells mean 'not applicable'

n.d.: no data

(1) direct and indirect emissions

(4) Data for current and advanced FC are the same

Table VI. Advanced technologies- 2020

Advanced- 2020	Direct emissions (g/kWh)								Indirect emissions (g/kWh)							
	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*
3.1.1 COAL FIRED																
Lignite, IGCC	793.1	0.699	0.436	0.039	0.013	0.140	0.025	5E-05	3.076	0.005	0.009	0.027	0.001	0.003	0	6E-06
Lignite, ST	802.5	0.579	0.603	0.093	0.017	0.015	0.025	1E-05	0.974	0.004	0.005	0.003	0.001	0.003	0	1E-05
Pulverised Coal	854.9 (1)	0.270 (1)	0.360 (1)	n.d.	n.d.	n.d.	n.d.	n.d.	(1)	(1)	(1)	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.2 OIL & GAS																
CCGT	332.3	0	0.168	8E-04	0	0	0	0	25.01	0	0.013	6E-05	0	0	0	0
3.1.3 CHP																
Small-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Large-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.4 CO_2 CS																
Natural gas	44.18	0.202	0.44	0.008	0.146	0.982	0.011	3E-05	0.215	0.001	0.001	0.002	0	0	0	1E-06
Lignite	130.9	0.771	0.488	0.106	0.016	0.043	0.028	5E-05	3.252	0.005	0.01	0.028	0.001	0.004	0	6E-06
3.2.1 FISSION																
Nuclear fission				2E-05 (1)	3E-04 (1)	6E-04 (1)	9E-06 (1)	0.02 (1)	0.3	0.001	0.001	n.d.	n.d.	n.d.	n.d.	n.d.
3.2.2 FUSION																
Nuclear fusion																
3.3.1 WIND																

Wind turbine									12.66	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.2 PV																
Generic									31.88	0.006	0.044	0.003	0.010	0.070	2E-04	3E-06
Crystalline									6.93	0.001	0.014	9E-04	0.002	0.016	6E-05	6E-05
Thin-film amorphous									12.03	0.003	0.026	6E-04	0.002	0.022	1E-04	6E-05
Thin-film CIGS									11.59	0.002	0.001	0.001	0.003	0.023	5E-05	8E-04
3.3.3 BIOMASS																
Biomass gasification	8.56	0.197	0.368	0.008	0.388	0	0	n.d.	22.99	0.202	0.128	0.002	0.049	0.003	0.007	n.d.
3.3.4 HYDRO																
Large scale						0.006 (1)			2.778	0.001	0.007	n.d.	n.d.	(1)	n.d.	n.d.
Small scale									n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.5 GEO																
Conventional	122	3.65	0		n.d.	n.d.		n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Binary cycle	0	0	0			n.d.		n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.6 FUEL CELLS(4)																
PEMFC	601 (1)	0.3 (1)	0.088 (1)	0.011 (1)	2E-06 (1)	0.64 (1)	6E-04 (1)	n.d.	(1)	(1)	(1)	(1)	(1)	(1)	(1)	n.d.
AFC	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
PAFC	649 (1)	0.38 (1)	0.006 (1)	n.d.	0.002 (1)	0 (1)	n.d.	n.d.	(1)	(1)	(1)	n.d.	(1)	(1)	n.d.	n.d.
MCFC	481 (1)	0.32 (1)	0.319 (1)	0.005 (1)	n.d.	0.006 (1)	n.d.	n.d.	(1)	(1)	(1)	(1)	n.d.	(1)	n.d.	n.d.
SOFC	511	0.25	0.032	0	7E-05	0.238	n.d.	n.d.	(1)	(1)	0.012	0.008	(1)	0	n.d.	n.d.

	(1)	(1)			(1)											
3.3.7 HYDROGEN																
Hydrogen economy	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.8 STORAGE																
Electricity storage	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.9 MARINE																
Marine									18	0.16	0.07	n.d.	n.d.	n.d.	n.d.	n.d.
Tidal									12	0.08	0.03	n.d.	n.d.	n.d.	n.d.	n.d.

* kBq/kWh

Shadow cells mean ‘not applicable’

n.d.: no data

(1) direct and indirect emissions

(4) Data for current and advanced FC are the same

Table VII. Advanced technologies- 2030

Advanced- 2030	Direct emissions (g/kWh)								Indirect emissions (g/kWh)							
	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*	CO_2	SO_2	NOx	PM_{10}	NMVOC	CH_4	N_2O	C_{14}*
3.1.1 COAL FIRED																
Lignite, IGCC	785.6	0.693	0.432	0.039	0.013	0.138	0.025	5E-05	3.076	0.005	0.009	0.027	0.001	0.003	0	6E-06
Lignite, ST	802.5	0.579	0.603	0.093	0.017	0.015	0.025	1E-05	0.974	0.004	0.005	0.003	0.001	0.003	0	1E-05
Pulverised Coal	854.9 (1)	0.270 (1)	0.360 (1)	n.d.	n.d.	n.d.	n.d.	n.d.	(1)	(1)	(1)	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.2 OIL & GAS																
CCGT	321.8	0	0.162	8E-04	0	0	0	0	24.22	0	0.012	6E-05	0	0	0	0
3.1.3 CHP																
Small-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Large-scale	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.1.4 CO_2 CS																
Natural gas	43.24	0.2	0.437	0.008	0.144	0.970	0.011	3E-05	0.215	0.001	0.001	0.002	0	0	0	1E-06
Lignite	127.3	0.749	0.477	0.103	0.016	0.042	0.027	5E-05	3.252	0.005	0.010	0.028	0.001	0.004	0	6E-06
3.2.1 FISSION																
Nuclear fission				2E-05 (1)	3E-04 (1)	6E-04 (1)	9E-06 (1)	0.02 (1)	0.3	0.001	0.001	n.d.	n.d.	n.d.	n.d.	n.d.
3.2.2 FUSION																
Nuclear fusion																
3.3.1 WIND																

Wind turbine									12.66	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.2 PV																
Generic									25.75	0.004	0.019	0.002	0.007	0.052	2E-04	2E-04
Crystalline									1.16	2E-04	0.002	1E-04	4E-04	0.003	1E-05	1E-05
Thin-film amorphous									2	4E-04	0.004	1E-04	5E-04	0.004	2E-05	9E-06
Thin-film CIGS									1.93	3E-04	2E-04	2E-04	5E-04	0.004	9E-06	1E-04
3.3.3 BIOMASS																
Biomass gasification	7.78	0.179	0.334	0.007	0.353	0	0	n.d.	17.24	0.151	0.096	0.002	0.037	0.003	0.005	n.d.
3.3.4 HYDRO																
Large scale						0.006 (1)			2.778	0.001	0.007	n.d.	n.d.	(1)	n.d.	n.d.
Small scale									n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.5 GEO																
Conventional	122	3.65	0		n.d.	n.d.		n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Binary cycle	0	0	0			n.d.		n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.6 FUEL CELLS(4)																
PEMFC	601 (1)	0.3 (1)	0.088 (1)	0.011 (1)	2E-06 (1)	0.64 (1)	6E-04 (1)	n.d.	(1)	(1)	(1)	(1)	(1)	(1)	(1)	n.d.
AFC	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
PAFC	649 (1)	0.38 (1)	0.006 (1)	n.d.	0.002 (1)	0 (1)	n.d.	n.d.	(1)	(1)	(1)	n.d.	(1)	(1)	n.d.	n.d.
MCFC	481 (1)	0.32 (1)	0.319 (1)	0.005 (1)	n.d.	0.006 (1)	n.d.	n.d.	(1)	(1)	(1)	(1)	n.d.	(1)	n.d.	n.d.
SOFC	511	0.25	0.032	0	7E-05	0.238	n.d.	n.d.	(1)	(1)	0.012	0.008	(1)	0	n.d.	n.d.

	(1)	(1)			(1)											
3.3.7 HYDROGEN																
Hydrogen economy	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.8 STORAGE																
Electricity storage	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
3.3.9 MARINE																
Marine									18	0.16	0.07	n.d.	n.d.	n.d.	n.d.	n.d.
Tidal									12	0.08	0.03	n.d.	n.d.	n.d.	n.d.	n.d.

* kBq/kWh

Shadow cells mean ‘not applicable’

n.d.: no data

(1) direct and indirect emissions

(4) Data for current and advanced FC are the same

5 Total social cost of electricity generation

5.1 Introduction

Given the variations in technical and economic parameters for the various generation technologies described within WP3 and based on the data comparison made by IER (cf. IER, 2006a), a synthesis of all available information allows to calculate the total social cost of electricity generation based on an illustrative data set. The total social costs of electricity generation summarize the private and external costs of a technology and therefore indicate its use of resources from an economic and environmental point of view. It can be regarded as a relative measure for sustainability.

Reviewing the differences in key parameters like overnight investment costs, electrical efficiencies and other variable generation costs for the technologies, it seems to be helpful to create an illustrative data set that takes the given cost ranges into account and describes a balanced parameter set.

5.2 Fuel prices

The fuel prices that have been assumed in the EUSUSTEL project for the cost calculations are presented in Table 1. Due to the long life time of the power plants, price assumptions have been made beyond the year 2030. As price developments are highly uncertain in the long run, fuel prices are assumed to be constant after 2030.

Table 1: Assumptions on fuel price development

Energy Carrier	Unit	2005	2010	2015	2020	2025	2030
Coal	[EUR/GJ]	1.96	1.86	1.97	2.07	2.14	2.19
Lignite	[EUR/GJ]	0.97	0.98	0.98	0.98	0.98	0.98
Natural gas	[EUR/GJ]	4.98	5.19	4.90	4.82	5.49	5.51
Oil	[EUR/GJ]	5.24	3.94	3.98	4.42	5.30	5.73
Nuclear	[EUR/GJ]	0.80	0.80	0.80	0.80	0.80	0.80
Biomass	[EUR/GJ]	3.70	3.70	3.70	3.70	3.70	3.70

5.3 Overnight investment costs

Given the variations in overnight investment costs that have been identified within WP3 and in the comparison report, the assumed overnight investment costs for calculating the total social cost of the illustrative electricity generation data set are presented in Table 2.

Table 2: Assumptions on overnight investment costs and electrical efficiencies

Technology	Parameter	Unit	2010	2030
Lignite (1050 MW)	Overnight investment cost	[€/kW]	1150	1150
	Efficiency	[%]	45	50
Coal (1020 MW)	Overnight investment cost	[€/kW]	1000	1050
	Efficiency	[%]	47	50
Natural Gas (CCGT)	Overnight investment cost	[€/kW]	440	400
	Efficiency	[%]	60	62
Nuclear (3rd Gen.)	Overnight investment cost	[€/kW]	1700	1500
	Efficiency	[%]	36	36
Biomass (IG, Wood)	Overnight investment cost	[€/kW]	2000	1900
	Efficiency	[%]	39	42
Wind (Onshore)	Overnight investment cost	[€/kW]	925 - 1000	750 - 900
Wind (Offshore)	Overnight investment cost	[€/kW]	1950	1750
PV (Open Space)	Overnight investment cost	[€/kW]	4040 - 4275	1650 - 2500
PV (Roof)	Overnight investment cost	[€/kW]	4933 - 5200	2000 - 3000

5.4 External Costs

For calculating the total social costs of electricity generation, the external costs have to be considered based on an analysis of direct and indirect emissions as well as the damage factors for the various pollutants.

In an LCA study the material use, energy consumption and emissions release throughout a product's life (i.e. cradle-to-grave) from raw material acquisition through production, use and disposal is investigated. Based on the identified input and output flows of material and energy the resulting environmental interventions like emissions in air, soil and water are analysed. This life cycle inventory data on emissions is required for the calculation of external costs.

The emissions of the various generation technologies within the illustrative data set are based on the values collected in WP3. Due to variations for some of the technologies compared to other LCA studies considering direct and indirect emissions (cf. comment on missing data in chapter 4), emission data have been used taken these variations into account (cf. Briem et al. 2002 and 2004, Marheineke et al. 2000). As has been used for the external cost calculations (cf. chapter 4), the average damage factors for SO_2, N_2O, PM_{10}, NMVOC, CH_4, and C_{14} are considered for the external cost of the various generation technologies within the illustrative data set.

5.5 Total social electricity generation cost

As one part of the total social cost of electricity generation the Average Lifetime Levelized Generation Costs (ALLGC) reflect the private costs based on the assumptions for fuel price development, overnight investment costs and efficiencies.

The ALLGC for selected generation technologies in the year 2010 are presented in Figures 1 and 2. Figure 1 shows the ALLGC for Lignite, Hard Coal, Natural Gas, Nuclear and Biomass power plants given an overall discount rate of 5 % and 10 % respectively. For the cost calculations a capacity factor of 85 % has been assumed.

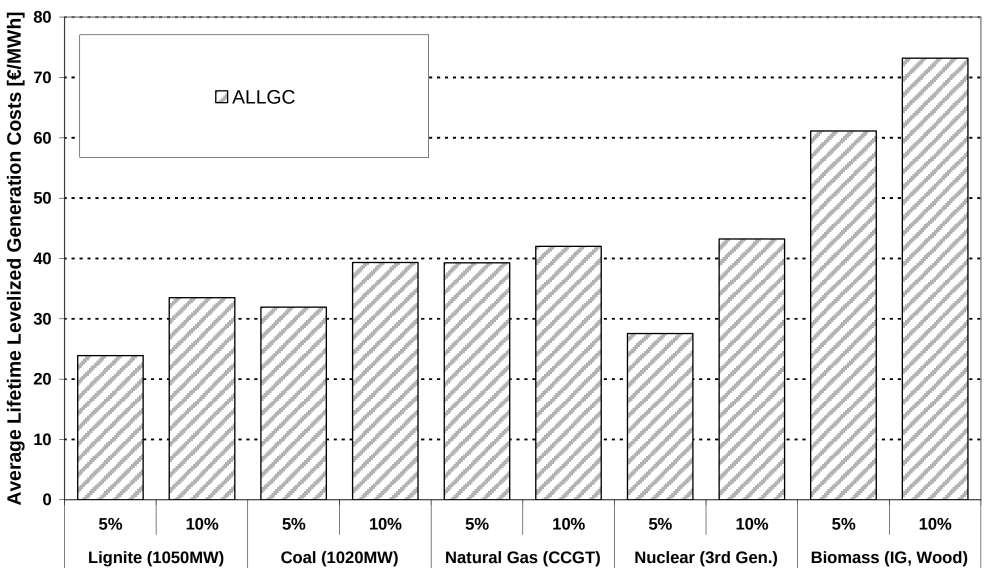

Figure 1: Average Lifetime Levelized Generation Costs for selected generation technologies, 2010

As can be seen for the year 2010, Lignite has the lowest ALLGC of 23.1 €/MWh given a discount rate of 5 %, followed by Nuclear (3^{rd} Gen.) with 27.6 €/MWh. Changing the discount rate from 5 % to 10 % has a major impact on ALLGC for those technologies facing high specific investment cost like Lignite and Nuclear (3^{rd} Gen.). The ALLGC increases for Lignite to 33.5 €/MWh and for Nuclear (3^{rd}. Gen.) to 43.2 €/MWh. Biomass (Integrated Gasification, Wood) shows ALLGC of approximately 60 €/MWh (5 %) and 73 €/MWh (10 %), respectively. For the cost calculations a constant price for biomass of 3.7 €/GJ has been assumed between 2010 and 2030. Regarding Natural gas technologies, cost calculations for a Combined Cycle Gas Turbine (CCGT) have been performed within the illustrative data set.

Due to technological development of the electricity generation technologies, changes in cost characteristics are projected. Moreover, assuming for technical progress regarding CO_2 emissions, power plants with Carbon Capture and Storage (CCS) which will be available after the year 2015 or 2020 have to be taken into account. Lignite without CCS is projected to stay the most competitive fossil fired technology regarding private generation costs for discount rates of 5 % and 10 %. Hard Coal follows with approximately 40 % (5 % discount rate) and 24 % (10 % discount rate) higher ALLGC. Natural Gas fired power plants face an economic disadvantage if fuel prices will increase as assumed (cf. Table 1), even when specific overnight investment costs are lower than for other conventional generation technologies (cf. Table 2).

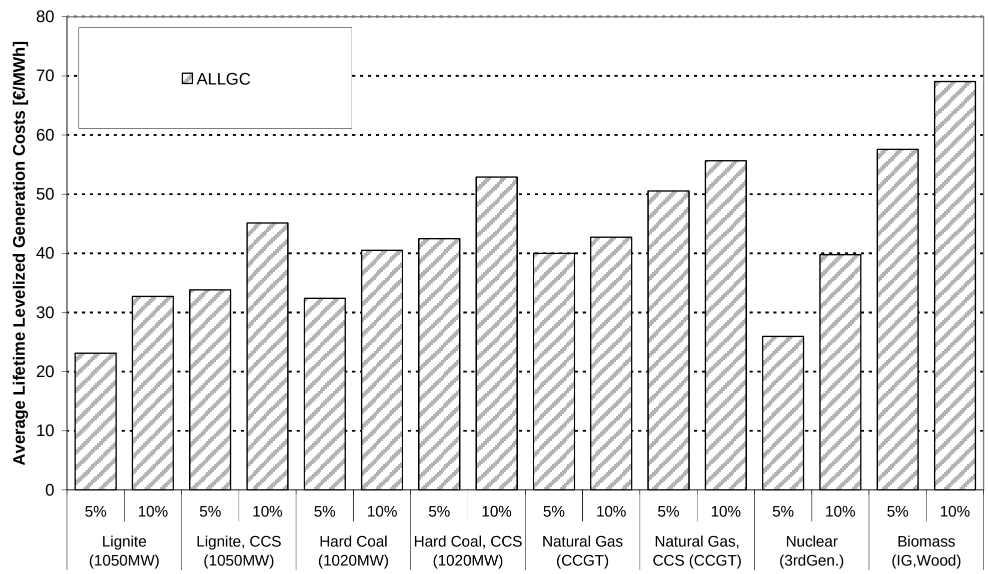

Figure 2: Average Lifetime Levelized Generation Costs for selected generation technologies, 2030

Considering CCS technologies, Lignite fired power plants are projected to have approximately 26 % lower private costs than Hard Coal and 49 % lower costs than Natural Gas CCS, assuming 5 % discount rate. These differences will become lower with higher discount rates. Biomass (Integrated Gasification, Wood) will face an increase in efficiency as well as a decrease in overnight investment costs until 2030 and therefore decreasing production costs of 58 €/MWh (5 % discount rate) and 70 €/MWh (10 % discount rate). As another CO_2 free generation technology, Nuclear (3^{rd} Gen.) is projected to stay the most competitive technology in 2030.

For calculating the total social cost of electricity generation, external costs due to direct and indirect emissions have to be considered. Therefore the external costs of electricity generation, due to emissions of CO_2 and other pollutants like SO_2, NO_x, NMVOC, CH_4, PM_{10}, N_2O and C_{14} have been taken into account.

The total social costs of the various electricity generation technologies for the year 2010 are given in Figure 3 for a 5 % and 10 % discount rate as well as 10 and 20 €/t CO_2. Due to the lower specific direct and indirect emissions of Natural Gas fired CCGT power plants, these technologies are projected to have a total social cost advantage compared to Hard Coal fired power plants given a discount rate of 5 % and even compared to Lignite power plants given a discount rate of 10 %. However, the comparatively low external costs of Nuclear electricity generation of 0.64 €/MWh assuming repository fuel cycle enables these generation technologies to be competitive even at a high discount rate of 10 %. A strong advantage regarding total social costs is due to the zero CO_2 emissions compared to fossil fuel fired technologies like Lignite and Hard Coal. Natural Gas CCGT is projected to receive a better market position due to the lower emissions of the different pollutants. Biomass is projected to be not fully competitive in the year 2010, due to the higher overnight investment costs.

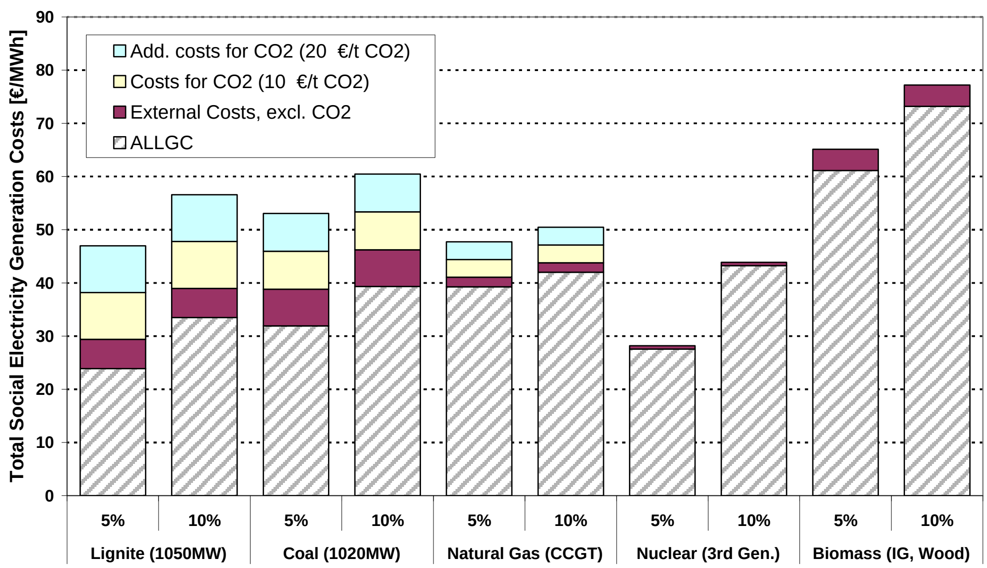

Figure 3: Total social costs for selected generation technologies, 2010

Taking into account changes in overnight investment costs and efficiency due to technological progress between 2010 and 2030, the total social costs in the year 2030 are presented in Figure 4. As can be seen, for clean coal and gas technologies with Carbon

Capture and Storage (CCS), e.g. Natural gas CCS technologies will have an advantage compared to Hard Coal CCS given a discount rate of 10 %, but are projected to be more expensive than Lignite CCS. However, Nuclear electricity generation is projected to stay the most competitive technology in the year 2030.

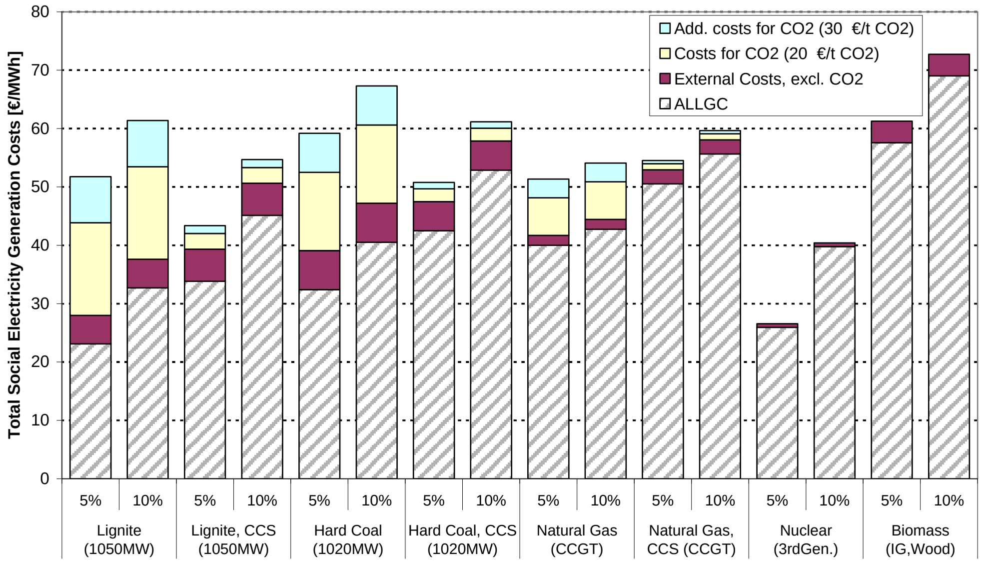

Figure 4: Total social costs for selected generation technologies, 2030

Table 3 summarizes the ALLGC and external costs for the selected technologies in the year 2010 and 2030.

Table 3: Summary of ALLGC and external costs for selected generation technologies, 2010 and 2030

		ALLGC		External Costs, excl. CO_2		Cost for CO_2	
						(20€/t CO_2)	(30€/t CO_2)
Technology	Discount rate	2010	2030	2010	2030	2010	2030
Lignite (1050MW)	5%	23.89	23.10	5.50	4.90	17.6	23.76
	10%	33.49	32.70	5.50	4.90	17.6	23.76
Lignite, CCS (1050MW)	5%	-	33.83	-	5.50	-	4.05
	10%	-	45.12	-	5.50	-	4.05
Coal (1020MW)	5%	31.93	32.39	6.90	6.70	14.24	20.09
	10%	39.33	40.51	6.90	6.70	14.24	20.09
Hard Coal, CCS (1020MW)	5%	-	42.48	-	5.00	-	3.28
	10%	-	52.87	-	5.00	-	3.28
Natural Gas (CCGT)	5%	39.27	39.99	1.80	1.70	6.66	9.67
	10%	42.00	42.72	1.80	1.70	6.66	9.67
Natural Gas, CCS (CCGT)	5%	-	50.52	-	2.40	-	1.61
	10%	-	55.64	-	2.40	-	1.61
Nuclear (3rd Gen.)	5%	27.55	25.93	0.64	0.30	0.00	0.00
	10%	43.24	39.76	0.64	0.30	0.00	0.00
Biomass (IG, Wood)	5%	61.13	57.56	4.00	3.70	0.00	0.00
	10%	73.21	69.03	4.00	3.70	0.00	0.00

For electricity generation technologies Wind Converters and Solar PV, total social costs for 2010 and 2030 have been calculated for low and high specific overnight investment costs (cf. Table 2) as well as for two different capacity factors and discount rates respectively. Due to the stochastic nature of Wind supply and Solar radiation, variations in utilisation with respect to different regions have to be taken into account. To assure security of electricity supply, backup capacities and therefore backup costs have to be considered for the renewable generation technologies. As induced back-up costs of fluctuating energy sources are highly related to the electricity generation system structure that is considered, the cost calculation is not obvious. Assuming the thermal equivalent, defined as the production costs of either a coal fired power plant or a natural gas fired CCGT, back-up costs for the Wind and Solar PV technologies are projected to be between 9 €/MWh and 17 €/MWh. These are included in the total social generation costs given in Figure 5.

Given the differences in specific investment costs and capacity factors, Wind converters face total social costs of approximately 72 €/MWh (Onshore, low inv. costs, 5 % discount rate, 25 % capacity factor) up to 170 €/MWh (Offshore, 10 % discount rate, 25 % capacity factor) in the year 2010. For Solar PV overall social costs are projected to range from approximately 213 €/MWh (Open Space, low. inv. costs 5 % discount rate, 20 % capacity factor) to 650 €/MWh (Roof, high inv. costs 10 % discount rate, 10 % capacity factor) (cf. Figure 5). Taking direct and indirect emissions into account, external costs of RES based generation only represent a very small part of the total social costs of electricity generation.

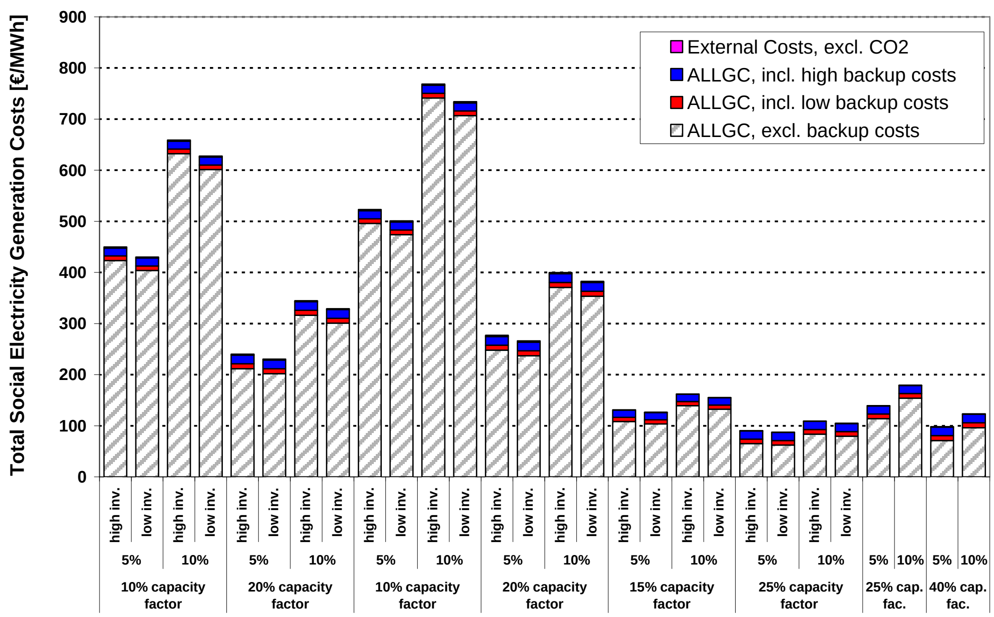

Figure 5: Total Social Electricity Generation Costs in the year 2010

Due to technological progress between 2010 and 2030, overnight investment costs will decrease for Wind as well as for PV, showing higher costs reduction for PV (cf. Table 2). Therefore total social costs are going to decrease as is presented in Figure 6. However, especially Solar PV is projected not to become competitive, showing production costs of 113 €/MWh to 474 €/MWh in the year 2030. For Wind converters, total social costs range from 65 €/MWh to 159 €/MWh, still being more expensive than conventional power plants. However, relative competitiveness of Wind converters is mainly subject to the assumed technological progress, i.e. investment cost reduction and the given discount rate.

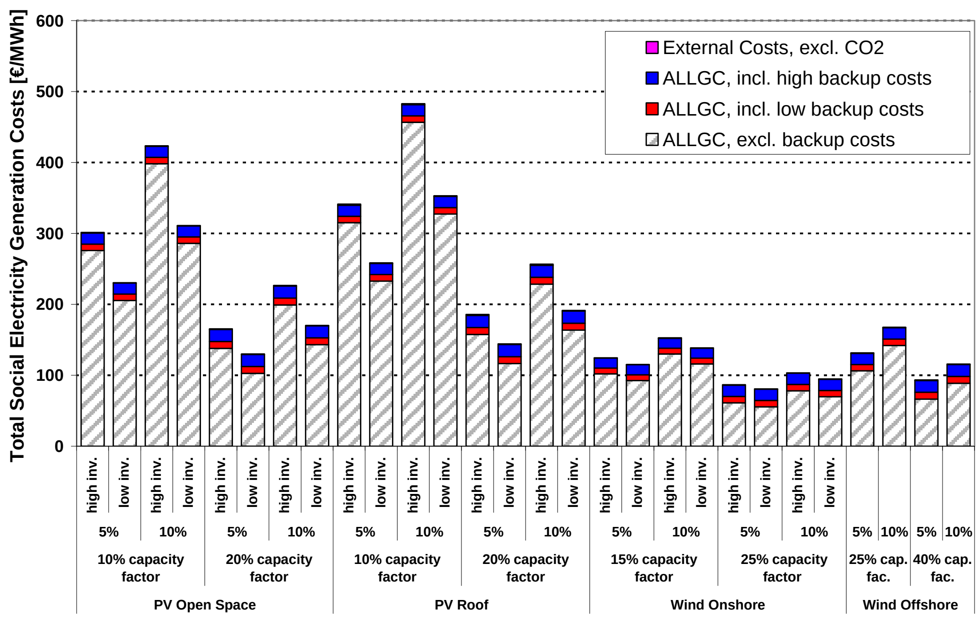

Figure 6: Total Social Electricity Generation Costs in the year 2030

Table 4 summarizes the private and external costs of electricity generation for Wind and Solar PV technologies for the years 2010 and 2030, taking into account variations in overnight investment costs, utilisations rate and overall discount rate.

Table 4: ALLGC incl. backup costs and external costs for Wind and Solar PV [€/MWh]

Technology	Discount rate	Invest. costs	ALLGC, incl. Backup Costs (BC) 2010 low BC	2010 high BC	2030 low BC	2030 high BC	External costs, excl. CO_2 2010	2030
PV (Open Space, 10%)	5%	high	432.22	438.88	284.90	291.56	1.90	0.80
		low	412.72	419.38	214.35	221.02	1.80	0.53
	10%	high	641.29	647.95	407.16	413.82	1.90	0.80
		low	610.29	616.95	295.05	301.71	1.80	0.53
PV (Open Space, 20%)	5%	high	221.35	228.59	147.69	154.93	1.90	0.80
		low	211.60	218.84	112.42	119.66	1.80	0.53
	10%	high	325.88	333.13	208.82	216.06	1.90	0.80
		low	310.38	317.63	152.76	160.01	1.80	0.53
PV (Roof, 10%)	5%	high	504.89	511.62	324.07	330.80	2.45	1.45
		low	482.94	489.67	241.88	248.61	2.32	0.97
	10%	high	750.44	757.16	465.73	472.46	2.45	1.45
		low	715.88	722.61	336.32	343.05	2.32	0.97
PV (Roof, 20%)	5%	high	257.68	264.96	167.28	174.55	2.45	1.45
		low	246.71	253.99	126.18	133.46	2.32	0.97
	10%	high	380.46	387.73	238.11	245.38	2.45	1.45
		low	363.18	370.46	173.40	180.68	2.32	0.97
Wind (Onshore, 15%)	5%	high	116.32	122.36	110.07	116.11	0.60	0.50
		low	111.63	117.67	100.68	106.72	0.56	0.42
	10%	high	147.50	153.54	138.13	144.17	0.60	0.50
		low	140.47	146.51	124.06	130.10	0.56	0.42
Wind (Onshore, 25%)	5%	high	73.99	80.74	70.23	76.99	0.60	0.50
		low	71.17	77.92	64.60	71.35	0.56	0.42
	10%	high	92.69	99.45	87.07	93.82	0.60	0.50
		low	88.47	95.23	78.63	85.38	0.56	0.42
Wind (Offshore, 25%)	5%		122.88	129.63	115.18	121.94	0.80	0.70
	10%		162.90	169.66	151.10	157.86	0.80	0.70
Wind (Offshore, 40%)	5%		80.73	87.88	75.92	83.08	0.80	0.70
	10%		105.74	112.90	98.37	105.53	0.80	0.70

Summarizing the calculation results for the various electricity generation technologies, regarding Average Lifetime Levelized Generation Costs and external costs for CO_2 and other emissions, it can be observed that the conventional power plants are projected to have economic advantages compared to technologies using renewable energy sources like Wind and Solar PV.

Given the comparatively high overnight investment costs for Wind and PV combined with the low utilization rates due to Wind supply and Solar radiation, renewable electricity is becoming more competitive in the year 2030 but faces still higher total social costs. Table 5 presents the total social costs of electricity generation for the selected conventional and renewable technologies for the years 2010 and 2030.

Table 5: Total social costs incl. backup costs of selected electricity generation technologies in the years 2010 and 2030 [€/MWh]

Technology	Capacity factor	Invest. Costs	2010				2030			
			5%		10%		5%		10%	
Thermal power plants										
Lignite (1050MW)	85%	-	46.99		56.59		51.76		61.36	
Lignite, CCS (1050MW)	85%	-	-		-		43.38		54.67	
Hard Coal (1020MW)	85%	-	53.07		60.47		59.18		67.29	
Hard Coal, CCS (1020MW)	85%	-	-		-		50.75		61.15	
Natural Gas (CCGT)	85%	-	47.73		50.46		51.35		54.09	
Natural Gas, CCS (CCGT)	85%	-	-		-		54.52		59.65	
Nuclear (3rdGen.)	85%	-	28.19		43.88		26.23		40.06	
Biomass (IG,Wood)	85%	-	65.13		77.21		61.26		72.73	
			Backup costs		**Backup costs**		**Backup costs**		**Backup costs**	
RES			**low**	**high**	**low**	**high**	**low**	**high**	**low**	**high**
PV Open Space	10%	high	434.12	440.78	643.19	649.85	285.70	292.36	407.96	414.62
		low	414.51	421.17	612.09	618.75	214.88	221.54	295.58	302.24
	20%	high	223.25	230.49	327.78	335.03	148.49	155.73	209.62	216.86
		low	213.39	220.64	312.18	319.42	112.94	120.19	153.29	160.53
PV Roof	10%	high	507.34	514.06	752.88	759.61	325.53	332.25	467.19	473.91
		low	485.26	491.99	718.20	724.93	242.85	249.58	337.29	344.02
	20%	high	260.13	267.41	382.90	390.18	168.73	176.01	239.56	246.84
		low	249.03	256.31	365.50	372.78	127.15	134.43	174.37	181.65
Wind Onshore	15%	high	116.92	122.96	148.10	154.14	110.57	116.61	138.63	144.67
		low	112.19	118.23	141.03	147.07	101.10	107.14	124.48	130.52
	25%	high	74.59	81.34	93.29	100.05	70.73	77.49	87.57	94.32
		low	71.73	78.48	89.03	95.78	65.02	71.77	79.05	85.80
Wind Offshore	25%		123.68	130.43	163.70	170.46	115.88	122.64	151.80	158.56
	40%		81.53	88.68	106.54	113.70	76.62	83.78	99.07	106.23

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