ANNEX III

Recent Renewable Energy Cost and Performance Parameters

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This annex should be cited as:

Bruckner, T., H. Chum, A. Jäger-Waldau, Å. Killingtveit, L. Gutiérrez-Negrín, J. Nyboer, W. Musial, A. Verbruggen, R. Wiser, 2011: Annex III: Cost Table. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation [O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Annex III Recent Renewable Energy Cost and Performance Parameters

Annex III is intended to become a 'living document', which will be updated in the light of new information in order to serve as an input to the IPCC Fifth Assessment Report (AR5). Scientists that are interested in supporting this process are invited to contact the IPCC WG III Technical Support Unit (TSU) (using srren_cost@ipcc-wg3.de) in order to get further information concerning the submission process.[1] Comments and new data input will be considered for inclusion in Volume 3 of the IPCC AR5 according to the procedures of the IPCC review system.

This Annex contains recent cost and performance parameter information for currently commercially available renewable power generation technologies (Table A.III.1), heating technologies (Table A.III.2) and biofuel production processes (Table A.III.3). It summarizes information that determines the levelized cost of energy or energy carriers supplied by the respective technologies.

The input ranges are based on assessments of various studies by authors of the respective technology chapters (Chapters 2 through 7). If not stated otherwise, the data ranges provided here are worldwide aggregates. Data are generally for 2008, but can be as recent as 2009. They represent roughly the mid-80% of values found in the literature, hence, excluding outliers. The availability and quality of different sources of data varies significantly across individual technologies for a variety of reasons.[2] Some expert judgment is therefore required to determine data ranges that are representative of particular classes of technologies and specific periods of time and valid globally.

The references to specific information are quoted in the footnotes. If the full dataset is based on one particular reference, it is included in the reference column of the green part of the table. Further information on the data reported in the table is provided in the footnotes and in Chapters 2 through 7 (see in particular Sections 2.7, 3.8, 4.7, 5.8, 6.7 and 7.8).

1 No individual responses can be guaranteed, but all emails as well as relevant material attached to those emails will be archived and made available in appropriate form to the authors involved in the AR5 process.

2 No standardized uncertainty language has been used in this report. Nonetheless, the authors of this Annex have carefully assessed available data and highlighted data limitations and uncertainties in the footnotes. A fair impression of the breadth of the reference base can be deduced from the list of references in this Annex.

The levelized cost of electricity (LCOE), heat (LCOH) and transport fuels (LCOF)[3] are calculated based on the data compiled here and the methodology described in Annex II, using three different real discount rates (3, 7 and 10%). They represent the full range of possible levelized cost values resulting from the lower and upper bounds of input data in this table. More precisely, the lower bound of the levelized cost ranges is based on the low ends of the ranges of investment, operation and maintenance (O&M) and (if applicable) feedstock cost and the high ends of the ranges of capacity factors and lifetimes as well as (if applicable) the high ends of the ranges of conversion efficiencies and by-product revenue stated in this table. The higher bound of the levelized cost ranges is accordingly based on the high end of the ranges of investment, O&M and (if applicable) feedstock costs and the low end of the ranges of capacity factors and lifetimes as well as (if applicable) the low ends of the ranges of conversion efficiencies and by-product revenue.[4]

These levelized cost figures (violet parts of the tables) are discussed in Sections 1.3.2 and 10.5.1 of the main report. Most technology chapters (Chapters 2 through 7) provide more detail on the sensitivity of the levelized costs to particular input parameters beyond discount rates (see in particular Sections 2.7, 3.8, 4.7, 5.8, 6.7 and 7.8). These sensitivity analyses provide additional insights into the relative weight of the large number of parameters that determine the levelized costs under more specific conditions.

In addition to the technology-specific sensitivity analysis in the respective chapters (Chapters 2 through 7) and the discussions in Sections 1.3.2 and 10.5.1, Figures A.III.2 through A.III.4 (a, b) show the sensitivity of the levelized cost in a complementary way using so-called tornado graphs (Figures A.III.2 through A.III.4 a) as well as their 'negatives' (Figures A.III.2 through A.III.4 b).

Figures A.III.1a and A.III.1b show schematic versions of the tornado graphs and their 'negatives', respectively, explaining how to read them correctly.

3 The levelized cost represents the cost of an energy generating system over its lifetime. It is calculated as the per unit price at which energy must be generated from a specific source over its lifetime to break even. The levelized costs usually include all private costs that accrue upstream in the value chain, but they do not include the downstream cost of delivery to the final customer, the cost of integration, or external environmental or other costs. Subsidies for RE generation and tax credits are not included. However, indirect taxes and subsidies on inputs or commodities affecting the prices of inputs and, hence, private cost, cannot be fully excluded.

4 This approach assumes that input parameters to the LCOE/LCOH/LCOF calculation are independent from each other. This is a simplifying assumption that implies that the lower ranges of LCOE/LCOH/LCOF (as a combination of best-case input values) may in some cases be lower than is most often the case, while the upper range of LCOE/LCOH/LCOFs (as a combination of worst-case input values) may in some cases be higher than what is generally considered economically attractive from a private investors' perspective. The extent to which this approach introduces a structural bias in the LCOE/LCOH/LCOF ranges, however, is reduced by taking a rather conservative approach to the range of input values (partly involving expert judgement), that is, by restricting input values roughly to the medium 80% range where possible.

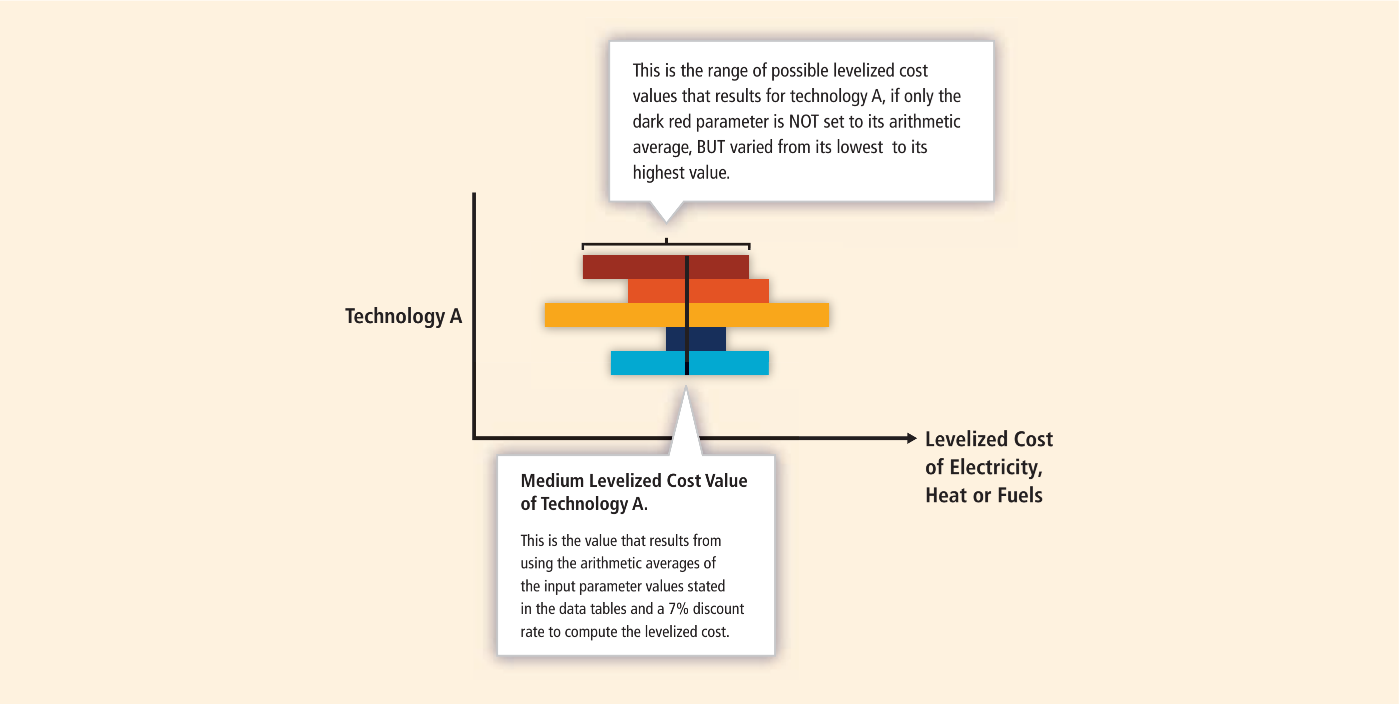

Figure A.III.1a | Tornado graph. Starting from the medium levelized cost value at a 7% interest rate, a broader range of levelized cost values becomes possible if individual parameters are varied over the full of range of values that these parameters may take on under different conditions. If the LCOE/LCOH/LCOF of a technology is very sensitive to variation of a particular parameter, then the corresponding bar will be broad. This means that a variation of that particular parameter may lead to LCOE/LCOH/LCOF values that can deviate strongly from the medium LCOE/LCOH/LCOF value. If the LCOE/LCOH/LCOF of a technology is robust for variations of the respective parameter, the bars will be narrow and only slight deviations from the medium LCOE/LCOH/LCOF value may result from variation of that parameter. Note, however, that no or narrow bars may also be the result of no or limited variation of the input parameters.

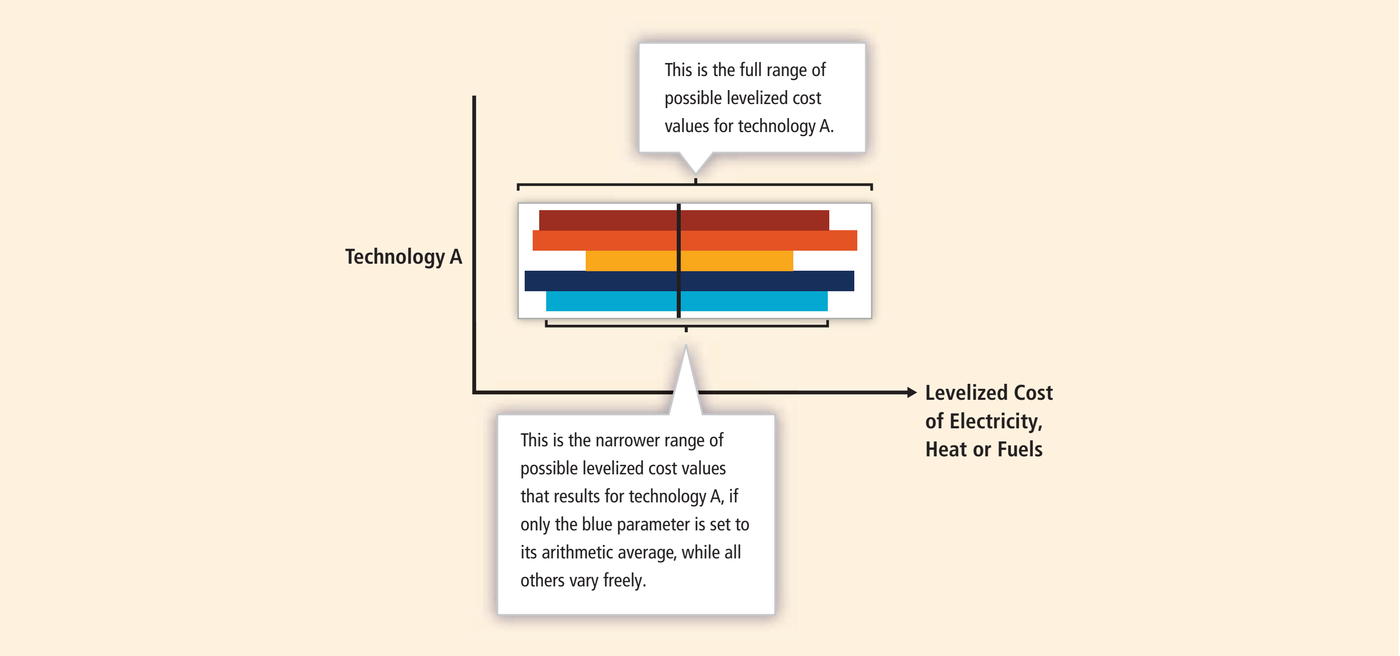

Figure A.III.1b | 'Negative' of tornado graph. Starting from the low and high bounds of the full range of levelized cost values at a 3% and 10% interest rate, respectively, a narrower range of levelized cost values remains possible if individual parameters are fixed at their respective medium values. If the LCOE/LCOH/LCOF of a technology is very sensitive to variations of a particular parameter, then the corresponding bar that remains will be narrowed to a large degree. Such parameters are of particular importance in determining the LCOE/LCOH/LCOF under more specific conditions. If the LCOE/LCOH/LCOF of a technology is robust for variations of the respective parameter, the remaining range will remain close to the full range of possible LCOE/LCOH/LCOF values. Such parameters are of less importance in determining the LCOE/LCOH/LCOF more precisely. Note, however, that no or small deviations from the full range may also be the result of no or limited variation of the input parameters.

Table A.III.1 | Cost-performance parameters for RE power generation technologies.[i]

		Input data									Output data		
Resource	Technology	Typical size of the device (MW)[ii]	Investment cost (USD/kW)	O&M cost, fixed annual (USD/kW) and/or (non-feed) variable (US¢/kWh)	By-product revenue (US¢/kWh)[iii]	Feedstock cost (USD/$GJ_{feed, HHV}$[iv])	Feedstock conversion $efficiency_{el}$ (%)	Capacity factor (%)	Economic design lifetime (years)	References	LCOE[v] (US¢/kWh)		
											Discount rate		
											3%	7%	10%
Bioenergy	Dedicated Biopower CFB[vi]	25–100	2,700–4,100[vii]	87 USD/kW and 0.40 US¢/kWh	N/A[viii]	1.25–5.0[ix]	28	70–80	20	McGowin (2008)	6.1–13	6.9–15	7.9–16
	Dedicated Biopower Stoker[x]	See above	2,600–4,000[vii]	84 USD/kW and 0.34 US¢/kWh	N/A[viii]	See above	27	See above	See above		5.6–13	6.7–15	7.7–16
	Dedicated Biopower (Stoker CHP[xi])	See above	2,800–4,200[vii]	86 USD/kW and 0.35 US¢/kWh	1.0[xii]	See above	24	See above	See above		5.1–13	6.3–15	7.3–17
	Co-firing: Co-feed	20–100	430–500[xiii]	12 USD/kW and 0.18 US¢/kWh	N/A[viii]	See above	36	See above	See above	McGowin (2008)	2.0–5.9	2.2–6.2	2.3–6.4
	Co-firing: Separate Feed	See above	760–900[xiii]	18 USD/kW	N/A[viii]	See above	36	See above	See above	Bain (2011)	2.3–6.3	2.6–6.7	2.9–7.1
	CHP (ORC[xiv])	0.65–1.6	6,500–9,800	59–80 USD/kW and 4.3–5.1 US¢/kWh	7.7[xv, xvi]	See above	14	55–68	See above	Obernberger et al. (2008)	8.6–26	12–32	15–37
	CHP (Steam Turbine)	2.5–10	4,100–6,200[xvii]	54 USD/kW and 3.5 US¢/kWh	5.4[xv, xviii]	See above	18	See above	See above		6.2–18	8.3–22	10–26
	CHP (Gasification ICE)[xix]	2.2–13	1,800–2,100	65–71 USD/kW and 1.1-1.9 US¢/kWh	1.0–4.5[xv, xx]	See above	28–30	See above	See above		2.1–11	3.0–13	3.8–14
Direct Solar Energy	PV (Residential Rooftop)	0.004–0.01	3,700–6,800[xxi]	19–110 USD/kW[xxii]	N/A[viii]	N/A[viii]	N/A[viii]	12–20[xxiii]	20–30	see Section 3.8 and footnotes	12–53	18–71	23–86
	PV (Commercial Rooftop)	0.02–0.5	3,500–6,600[xxi]	18–100 USD/kW[xxii]	N/A[viii]	N/A[viii]	N/A[viii]	See above	See above		11–52	17–69	22–83
	PV (Utility Scale, Fixed Tilt)	0.5–100[xxiv]	2,700–5,200[xxi]	14–69 USD/kW[xxii]	N/A[viii]	N/A[viii]	N/A[viii]	15–21[xxiii]	See above		8.4–33	13–43	16–52
	PV (Utility Scale, One-Axis)	0.5–100[xxiv]	3,100–6,200[xxi]	16–75 USD/kW[xxii]	N/A[viii]	N/A[viii]	N/A[viii]	15–27[xxiii]	See above		7.4–39	11–52	15–62
	CSP	50–250[xxv]	6,000–7,300[xxvi]	60–82 USD/kW[xxvii]	N/A[viii]	N/A[viii]	N/A[viii]	35–42[xxviii]	See above		11–19	16–25	20–31
Geothermal Energy	Geothermal Energy (Condensing-Flash Plants)	10–100	1,800–3,600[xxix]	150–190 USD/kW[xxx]	N/A[viii]	N/A[viii]	N/A[viii]	60–90[xxxi]	25–30[xxxii]	see Section 4.7 and footnotes	3.1–8.4	3.8–11	4.5–13
	Geothermal Energy (Binary-Cycle Plants)	2–20	2,100–5,200[xxix]	See above	N/A[viii]	N/A[viii]	N/A[viii]	See above	See above		3.3–11	4.1–14	4.9–17
Hydropower	All	<0.1 – >20,000[xxxiii]	1,000–3,000[xxxiv]	25–75 USD/kW[xxxv]	N/A[viii]	N/A[viii]	N/A[viii]	30–60[xxxvi]	40–80[xxxvii]	see Chapter 5 and footnotes	1.1–7.8	1.8–11	2.4–15
Ocean Energy	Tidal Range[xxxviii]	<1 – >250[xxxix]	4,500–5,000[xxxviii]	100 USD/kW[xxxviii]	N/A[viii]	N/A[viii]	N/A[viii]	22.5–28.5[xl]	40[xli, xxxviii]	see Section 6.7 and footnotes	12–16	18–24	23–32

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		Input data									Output data		
Resource	Technology	Typical size of the device (MW)[ii]	Investment cost (USD/kW)	O&M cost, fixed annual (USD/kW) and/or (non-feed) variable (US¢/kWh)	By-product revenue (US¢/kWh)[iii]	Feedstock cost (USD/$GJ_{feed, HHV}$[iv])	Feedstock conversion $efficiency_{el}$ (%)	Capacity factor (%)	Economic design lifetime (years)	References	LCOE[v] (US¢/kWh) Discount rate		
											3%	7%	10%
Wind Energy	Wind Energy (Onshore,Large Turbines)	5–300[xlii]	1,200–2,100[xliii]	1.2–2.3 US¢/kWh	N/A[viii]	N/A[viii]	N/A[viii]	20–40[xliv]	20[xlv]	see Chapter 7	3.5–10	4.4–14	5.2–17
	Wind Energy (Off-Shore, Large Turbines)	20–120[xlii]	3,200–5,000[xlvi]	2.0–4.0 US¢/kWh	N/A[viii]	N/A[viii]	N/A[viii]	35–45[xlii]	See above		7.5–15	9.7–19	12–23

General remarks/notes:

i All data are rounded to 2 significant digits. Most technology chapters (Chapters 2 through 7) provide additional and/or more detailed cost and performance information in the respective chapters' sections on cost trends. Direct comparison between levelized cost estimates taken directly from the literature should take the underlying assumptions into due consideration.

ii Device sizes are intended to be representative of current/recent sizes. If future sizes are expected to differ from these values, this is included in the footnotes to the relevant technologies.

iii For combined heat and power (CHP) plants, heat production is considered as a by-product in the calculation of the levelized cost of electricity providing full capital cost information as a stand-alone plant.

iv HHV: Higher heating value. LHV: Lower heating value.

v LCOE: Levelized cost of electricity. The levelized cost usually includes all private costs that accrue upstream in the value chain of electricity production, but they do not include the cost of transmission and distribution to the final customer. Output subsidies for RE generation and tax credits are not included. However, indirect taxes and subsidies on inputs or commodities affecting the prices of inputs and, hence, private cost, cannot be fully excluded. Depending on the context of discussion, LCOE may also stand for levelized cost of energy.

Bioenergy:

vi A circulating fluid bed (CFB) is a turbulent (high gas flow) fluid bed where solid particles are captured and returned to the bed. A fluid bed itself is a collection of small solid particles suspended and kept in motion by an upward flow of fluid, typically a gas.

vii The reference data are for a 50 MW plant. Investment costs for larger and smaller plants have been rescaled according to the power law: Specific investment $cost_{size\ 2}$ = Investment $cost_{size\ 1}$ x $(Size\ 2/Size\ 1)^{n-1}$, where the scaling factor n = 0.7. Capital cost estimates include facilities for fuel handling and preparation, boiler and air quality control, steam turbine and auxiliaries, balance of plant, general facilities and engineering fee, project and process contingency, allowance for funds used during construction, owner costs, and taxes and fees.

viii The abbreviation 'N/A' means here 'not applicable'.

ix Feedstock is wood with HHV = 20.0 GJ/t, LHV = 18.6 GJ/t.

x A mechanical stoker is a machine or device that feeds fuel to a boiler.

xi CHP: Combined heat and power.

xii The calculation of the by-product revenue for the large-scale CHP plant assumes: heat output used for industrial applications is 5.38 GJ of heat per MWh electricity; steam is valued at USD_{2005} 4.85/GJ (75% of US pulp and paper purchased steam price) (EIA, 2009, Table 7.2); and 75% of heat output is sold.

xiii The reference data are for a 50 MW plant. Investment costs for larger and smaller plants have been rescaled according to the power law: Specific investment $cost_{size\ 2}$ = Investment $cost_{size\ 1}$ x $(Size\ 2/Size\ 1)^{n-1}$, where the scaling factor n = 0.9 (Peters et al., 2003). The cofiring investment costs estimates were developed for retrofits of existing coal-fired power plants in the USA and include facilities for fuel handling and preparation, additional expenditures for boiler modifications, balance of plant, general facilities and engineering, project and process contingency, allowance for funds used during construction, owner costs, and taxes and fees. Cofiring cost estimate protocols in the USA do not include prorated boiler costs.

xiv ORC: Organic Rankine Cycle.

xv For the calculation of the by-product revenue for small-scale CHP plants, hot water is valued at USD_{2005} 12.51/GJ (average of Rauch (2010) and Skjoldborg (2010)), 33% of gross value is taken into account, because the operator can only recover a portion of the value and because use of hot water is seasonal.

xvi Heat output used for hot water is 18.51 GJ of heat per MWh electricity.

xvii The reference data are for a 5 MW CHP plant. Investment costs for larger and smaller plants have been rescaled according to the power law: Specific investment $cost_{size\ 2}$ = Investment $cost_{size\ 1}$ x $(Size\ 2/Size\ 1)^{n-1}$, where the scaling factor n =0.7 (Peters et al., 2003).

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xviii Heat output used for hot water is 12.95 GJ of heat per MWh electricity.

xix ICE: Internal combustion engine.

xx Heat output used for hot water is in the range of 2.373 to 10.86 GJ/MWh.

Direct solar energy – photovoltaic (PV) systems:

xxi In 2009, wholesale factory PV module prices decreased by more than 50%. As a result, the market prices for installed PV systems in Germany, the most competitive market, decreased by over 30% in 2009 compared to about 10% in 2008 (see Section 3.8.3). 2009 market price data from Germany is used as the lower bound for investment costs of residential rooftop systems (Bundesverband Solarwirtschaft e.V., 2010) and for utility-scale fixed tilt systems (Bloomberg, 2010). Based on US market data for 2008 and 2009, larger, commercial rooftop systems are assumed to have a 5% lower investment cost than the smaller, residential rooftop systems (NREL, 2011b; see also section 3.8.3). Tracking systems are assumed to have a 15-20% higher investment cost than the one-axis, non-tracking systems considered here (NREL, 2011a; see also Section 3.8.3). Capacity-weighted averages of investment costs in the USA in 2009 (NREL, 2011b) are used as upper bound to capture the investment cost ranges typical of roughly 80% of global installations in 2009 (see Section 3.4.1 and Section 3.8.3).

xxii O&M costs of PV systems are low and are given in a range between 0.5 and 1.5% annually of the initial investment costs (Breyer et al., 2009; IEA, 2010c).

xxiii The main parameter that influences the capacity factor of a PV system is the actual annual solar irradiation in kWh/m²/yr at a given location and the type of system. Capacity factors of some recently installed systems are provided in Sharma (2011).

xxiv The upper limit of utility-scale PV systems represents current status. Much larger systems (up to 1 GW) are in the proposal and development phase and might be realized within the next decade.

Direct solar energy – concentrating solar power (CSP):

xxv Project sizes of CSP plants can minimally match the size of a single power generating system (e.g., a 25 kW dish/engine system). However, the range provided is typical for projects being built or proposed today. 'Power Parks' consisting of multiple CSP plants in a single location are also being proposed at sizes of up to or exceeding 1 GW (4 x 250 MW).

xxvi Cost ranges are for parabolic trough plants with six hours of thermal energy storage in 2009. Investment cost includes direct plus indirect costs where indirect costs include engineering, procurement and construction mark-up, owner costs, land, and taxes. Investment costs are lower for plants without storage and higher for plants with larger storage capacity. The IEA (2010a) estimates investment costs as low as USD_{2005} 3,800/kW for plants without storage and as high as USD_{2005} 7,600/kW for plants with large storage (assumed currency base year: 2009). Capacity factors vary as well, if thermal storage is installed (see note xxviii).

xxvii The IEA (2010a) states O&M costs relative to energy output as US¢ 1.2 to 2.7/kWh (assumed currency base year: 2009). Depending on actual energy output this may result in lower or higher annual O&M cost compared to the range stated here.

xxviii Capacity factor for a parabolic trough plant with six hours of thermal energy storage for solar resource classes typical of the southwest USA. Depending on the size of the thermal storage capacity, capacity factors as well as investment costs vary substantially. Apart from the Solar Electric Generating Station plants in California, new CSP plants only became operational from 2007 onwards, thus few actual performance data are available and most of the literature just gives estimated or predicted capacity factors. Sharma (2011) reports multi-year (1998-2002) average capacity factors of 12.4 to 27.7% for plants without thermal storage, but with natural gas backup. The IEA (2010a) states that plants in Spain with 15 hours of storage may produce up to 6,600 hours per year. This is equivalent to a 75% capacity factor, if production occurs at full capacity during the 6,600 hours. Larger storage also increases investment costs (see note xxvi).

Geothermal energy:

xxix Investment cost includes: exploration and resource confirmation; drilling of production and injection wells; surface facilities and infrastructure; and the power plant. For expansion projects (i.e., new plants in the same geothermal field) investment costs can be 10 to 15% lower (see Section 4.7.1). Investment cost ranges are based on Bromley et al. (2010) (see also Figure 4.7).

xxx O&M costs are based on Hance (2005). In New Zealand, O&M costs range from US¢ 1 to 1.4/kWh for 20 to 50 MW_e plant capacity (Barnett and Quinlivan, 2009), which are equivalent to USD 83 to 117/kW/yr, i.e. considerably lower than those given by Hance (2005). For further information see Section 4.7.2.

xxxi The current (data for 2008-2009) worldwide capacity factor (CF) for condensing (flash) and binary-cycle plants in operation is 74.5%. Excluding some outliers, the lower and upper bounds can be estimated as 60 and 90%. Typical CFs for new geothermal power plants are over 90% (Hance, 2005; DiPippo, 2008; Bertani, 2010). The worldwide average CF for 2020 is projected to be 80%, and could be 85% in 2030 and as high as 90% in 2050 (see Sections 4.7.3 and 4.7.5).

xxxii 25 to 30 years is the common lifetime of geothermal power plants worldwide. This payback period allows for refurbishment or replacement of the aging surface plant at the end of its lifetime, but is not equivalent to the economic resource lifetime of the geothermal reservoir, which is typically much longer (e.g., Larderello, Wairakei, The Geysers: Section 4.7.3). In some reservoirs, however, the possibility of resource degradation over time is one of several factors that affect the economics of continuing plant operation.

Hydropower:

xxxiii The mid-80% of project sizes is not well documented for hydropower. The range stated here is indicative of the full range of project sizes. Hydropower projects are always site-specific as they are designed to use the flow and head at each site. Therefore, projects can be very small, down to a few kW in a small stream, and up to several thousand MW, for example 18,000 MW for the Three Gorges project in China (which will be 22,400 MW when completed) (see Section 5.1.2). 90% of the installed hydropower capacity and 94% of hydropower energy production today is in hydropower plants >10 MW in size (IJHD, 2010).

xxxiv The investment cost for hydropower projects can be as low as USD 400 to 500/kW but most realistic projects today lie in the range of USD 1,000 to 3,000/kW (Section 5.8.1).

xxxv O&M costs are usually given as a percentage of investment cost for hydropower projects. Typical values range from 1 to 4%, while the table relies on an average value of 2.5% applied to the range of investment costs. This will usually be sufficient to cover refurbishment of mechanical and electrical equipment like turbine overhaul, generator rewinding and reinvestments in communication and control systems (Section 5.8.1).

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xxxvi Capacity factors (CF) will be determined by hydrological conditions, installed capacity and plant design, and the way the plant is operated (i.e., the degree of plant output regulation). For power plant designs intended for maximum energy production (base-load) and with some regulation, CFs will often be from 30 to 60%. Figure 5.20 shows average CFs for different world regions. For peaking-type power plants the CF will be much lower, down to 20%, as these stations are designed with much higher capacity in order to meet peaking needs. CFs for run-of-river systems vary across a wide range (20 to 95%) depending on the geographical and climatological conditions, technology and operational characteristics (see Section 5.8.3).

xxxvii Hydropower plants in general have very long physical lifetimes. There are many examples of hydropower plants that have been in operation for more than 100 years, with regular upgrading of electrical and mechanical systems but no major upgrades of the most expensive civil structures (dams, tunnels, etc.). The IEA (2010d) reports that many plants built 50 to 100 years ago are still operating today. For large hydropower plants, the lifetime can, hence, safely be set to at least 40 years, and an 80-year lifetime is used as upper bound. For small-scale hydropower plants the typical lifetime can be set to 40 years, in some cases even less. The economic design lifetime may differ from actual physical plant lifetimes, and will depend strongly on how hydropower plants are owned and financed (see Section 5.8.1).

Ocean Energy:

xxxviii The data supplied for tidal range power plants are based on a very small number of installations (see subsequent footnotes). Therefore, all data should be considered with appropriate caution.

xxxix The only utility-scale tidal power station in the world is the 240 MW La Rance power station, which has been in successful operation since 1966. Other smaller projects have been commissioned since then in China, Canada and Russia with 3.9 MW, 20 MW and 0.4 MW, respectively. The 254 MW Sihwa barrage is expected to be commissioned in 2011 and will then become the largest tidal power station in the world. Numerous projects have been identified, some of them with very large capacities, including in the UK (Severn Estuary, 9.3 GW), India (1.8 GW), Korea (740 MW) and Russia (the White Sea and Sea of Okhotsk, 28 GW). None have been considered to be economic yet and many of them face environmental objections (Kerr, 2007). The projects at the Severn Estuary have been evaluated by the UK government and recently been deferred.

xl An earlier assessment suggests capacity factors in the range of 25 to 35% (Charlier, 2003).

xli Tidal barrages resemble hydropower plants, which in general have very long design lives. Many hydropower plants have been in operation for more than 100 years, with regular upgrading of electro-mechanical systems but no major upgrades of the most expensive civil structures (dams, tunnels etc). Tidal barrages are therefore assumed to have a similar economic design lifetime as large hydropower plants, which can safely be set to at least 40 years (see Chapter 5).

Wind energy:

xlii Typical size of the device is taken as the power plant (not turbine) size. For onshore wind energy, 5 to 300 MW plants were common from 2007 to 2009, though both smaller and larger plants are prevalent. For offshore wind energy, 20 to 120 MW plants were common from 2007 to 2009, though much larger plant sizes are expected in the future. As a modular technology, a wide range of plant sizes is common, driven by market and geographic conditions.

xliii The lowest cost onshore wind power plants have been installed in China, with higher costs experienced in the USA and Europe. The range reflects the majority of onshore wind power plants installed worldwide in 2009 (the most recent year for which solid data exist as of writing), but plants installed in China have average costs that can be even below this range (USD 1,000 to 1,350/kW is common in China). In most cases, the investment cost includes the cost of the turbines (turbines, transportation to site, and installation), grid connection (cables, sub-station, interconnection, but not more general transmission expansion costs), civil works (foundations, roads, buildings), and other costs (engineering, licensing, permitting, environmental assessments, and monitoring equipment).

xliv Capacity factors depend in part on the strength of the underlying wind resource, which varies by region and site, as well as by turbine design.

xlv Modern wind turbines that meet International Electrotechnical Commission standards are designed for a 20-year life, and turbine lifetimes may even exceed 20 years if O&M costs remain at an acceptable level. Wind power plants are typically financed over a 20-year time period.

xlvi For offshore wind power plants, the range in investment costs includes the majority of offshore wind power plants installed in the most recent years (through 2009) as well as those plants planned for completion in the early 2010s. Because costs have risen in recent years, using the cost of recent and planned projects reasonably reflects the 'current' cost of offshore wind power plants. In most cases, the investment cost includes the cost of the turbines (turbines, transportation to site, and installation), grid connection (cables, sub-station, interconnection, but not more general transmission expansion costs), civil works (foundations, roads, buildings), and other costs (engineering, licensing, permitting, environmental assessments, and monitoring equipment).

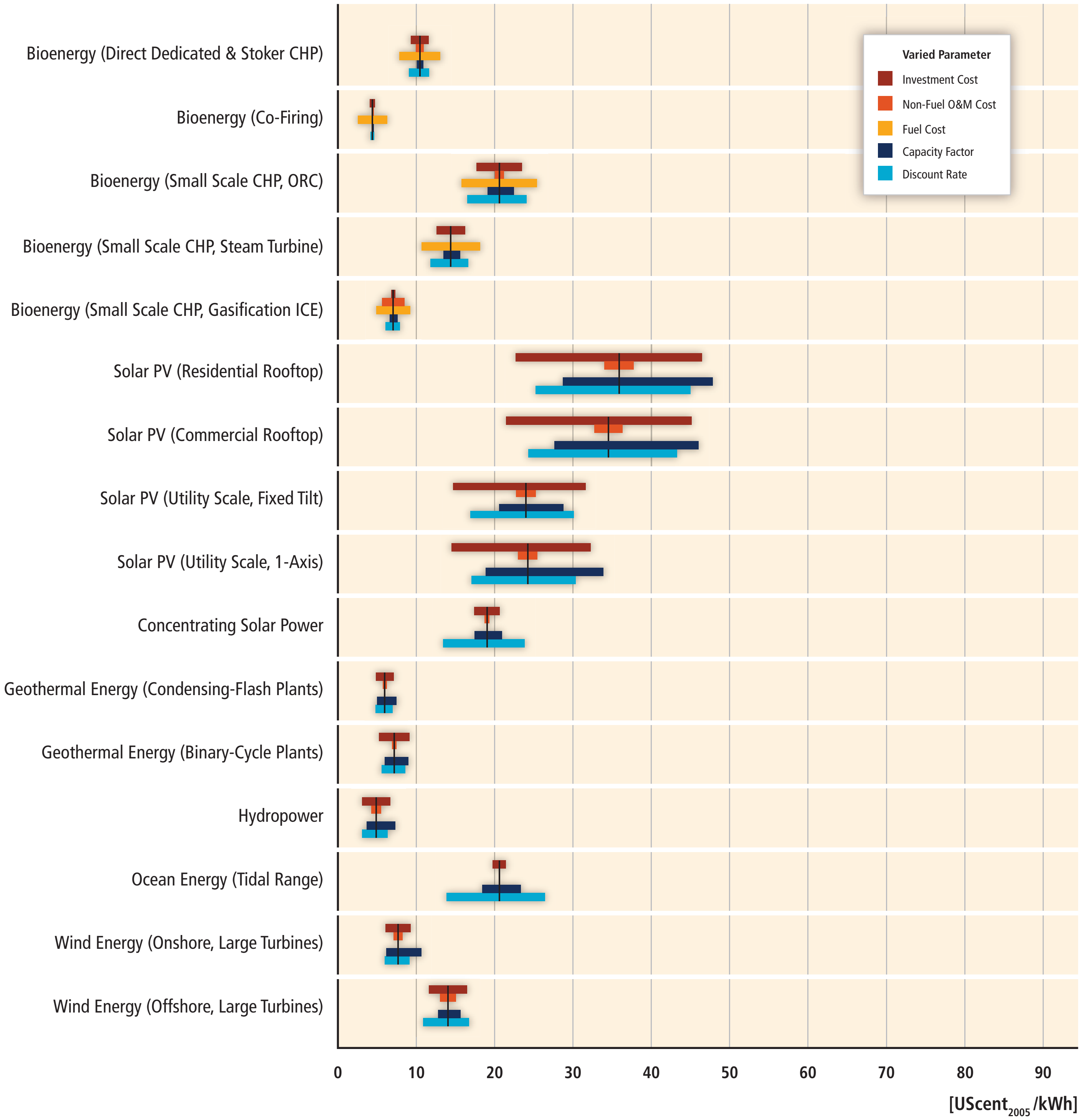

Figure A.III.2a | Tornado graph for renewable power technologies. For further explanation see Figure A.III.1a.

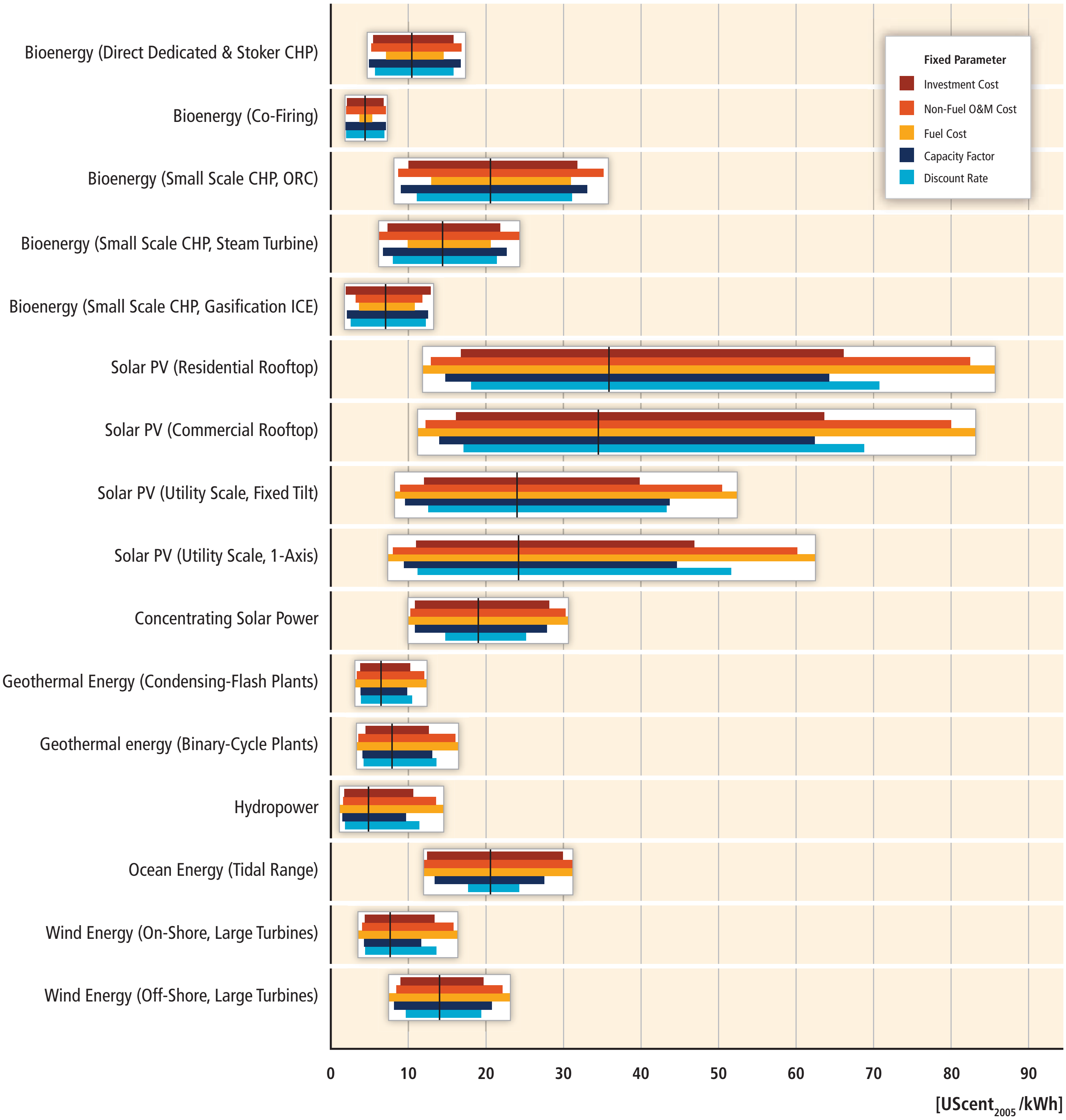

Figure A.III.2b | 'Negative' of tornado graph for renewable power technologies. For further explanation see Figure A.III.1b.

Note: The upper bounds of both geothermal energy technologies are calculated based on an assumed construction time of 4 years. In the simplified approach used for the sensitivity analysis shown here, this assumption was not taken into account, resulting in upper bounds that were below those based on the more accurate methodology. The ranges were rescaled, however, to yield the same results as the more accurate approach.

Table A.III.2 | Cost-performance parameters for RE heating technologies.[i]

Resource	Technology	Input data									Output data		
		Typical size of the device (MW_{th})	Investment cost (USD/kW_{th})	O&M cost, fixed annual (USD/kW) and/or variable (USD/GJ)	By-product revenue (USD/GJ_{feed})[ii]	Feedstock cost (USD/GJ_{feed})	(Feedstock) conversion efficiency (%)	Capacity factor (%)	Economic design lifetime (years)	References	LCOH[iii] (USD/GJ) Discount rate		
											3%	7%	10%
Bioenergy	Biomass (DPH[iv])	0.005–0.1[v]	310–1,200[vi]	13–43 USD/kW[vii]	N/A[viii]	10–20	86–95	13–29	10–20	IEA (2007b)	14–70	15–77	16–84
	Biomass (MSW[ix], CHP[x])	1–10[xi]	370–3,000[xii, xiii]	15–130 USD/kW[vii]	N/A[viii]	0–3	20–40[xiv]	80–91	10–20		1.4–34	1.8–38	2.1–41
	Biomass (Steam Turbine, CHP)[xv]	12–14	370–1,000[xii]	1.2–2.5 USD/kW[vii]	N/A[viii]	3.7–6.2	10–40	63–74	10–20		10–69	11–70	11–72
	Biomass (Anaerobic Digestion, CHP)	0.5–5[xi]	170–1,000[xii,xvi]	37–140 USD/kW[vii]	N/A[viii]	2.5–3.7[xvii]	20–30[xviii]	68–91	15–25		10–29	10–30	10–32
Solar Energy	Solar Thermal Heating (DHW[xix], China)	0.0017–0.01[xx]	120–540[xxi]	1.5–10 USD/kW[xxii]	N/A[viii]	N/A[viii]	20–80[xxiii]	4.1–13[xxiv]	10–15[xxv]	see Section 3.8.2 and footnotes	2.8–56	3.6–67	4.2–75
	Solar Thermal Heating (DHW, Thermo-siphon, Combi-systems)	0.0017–0.07[xx]	530–1,800	5.6–22 USD/kW[xxii]	N/A[viii]	N/A[viii]	20–80[xxiii]	4.1–13[xxiv]	15–25	IEA (2007b)	8.8–134	12–170	16–200
Geothermal Energy	Geothermal (Building Heating)	0.1–1	1,600–3,900[xxvi]	8.3–11 USD/GJ[xxvii]	N/A[viii]	N/A[viii]	N/A[viii]	25–30	20	see Section 4.7.6	20–50	24–65	28–77
	Geothermal (District Heating)	3.8–35	600–1,600[xxvi]	8.3–11 USD/GJ[xxvii]	N/A[viii]	N/A[viii]	N/A[viii]	25–30	25		12–24	14–31	15–38
	Geothermal (Greenhouses)	2–5.5	500–1,000[xxvi]	5.6–8.3 USD/GJ[xxvii]	N/A[viii]	N/A[viii]	N/A[viii]	50	20		7.7–13	8.6–14	9.3–16
	Geothermal (Aquaculture Ponds, Uncovered)	5–14	50–100[xxvi]	8.3–11 USD/GJ[xxvii]	N/A[viii]	N/A[viii]	N/A[viii]	60	20		8.5–11	8.6–12	8.6–12
	Geothermal Heat Pumps (GHP)	0.01–0.35	900–3,800[xxvi]	7.8–8.9 USD/GJ[xxvii]	N/A[viii]	N/A[viii]	N/A[viii]	25–30	20		14–42	17–56	19–68

General remarks/notes:

i All data are rounded to 2 significant digits. Most technology chapters (Chapters 2 through 4) provide additional and/or more detailed cost and performance information in the respective chapters' sections on cost trends. The assumptions underlying some of the production cost estimates quoted directly from the literature may, however, not be as transparent as the data sets in this Annex and should therefore be considered with caution.

ii CHP plants produce both, heat and electricity. Calculating the levelized cost of one product only, that is, either heat or electricity, can be done in different ways. One way is to assign a (discounted) market value to the 'by-product' and subtract this additional income from the remaining expenses. This has been done in the calculation of the LCOE of bioenergy CHP plants. The calculation of LCOH has been done in a different way according to the methodology used in IEA (2007) which served as main reference for the input data: Instead of considering electricity as a 'by-product' and subtracting its value from the remaining expenses for the supply of heat, the total expenses over the lifetime of the investment project were split according to the average heat/electricity output ratio and only the heat shares of investment and O&M costs were taken into account. For this reason no by-product revenue is stated in the heat table. Both methodologies come with different advantages/disadvantages.

iii LCOH: Levelized cost of heat supply. The levelized cost does not include the cost of transmission and distribution in the case of district heating systems. Output subsidies for RE generation and tax credits are also excluded. However, indirect taxes and subsidies on inputs or commodities affecting the prices of inputs and, hence, private cost, cannot be fully excluded.

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Bioenergy:

iv DPH: Domestic pellet heating.

v This range is typical of a low-energy single family dwelling (5 kW) or an apartment building (100 kW).

vi Investment costs of a biomass pellet heating system for the combustion plant only (including controls) range from USD_{2005} 100 to 640/kW. The higher range stated above includes civil works and fuel and heat storage (IEA, 2007).

vii Fixed annual O&M costs include costs of auxiliary energy. Auxiliary energy needs are 10 to 20 $kWh/kW_{th}/yr$. Electricity prices are assumed to be USD_{2005} 0.1 to 0.3/kWh. O&M costs for CHP options include heat share only.

viii The abbreviation 'N/A' means here 'not applicable'.

ix MSW: Municipal solid waste.

x CHP: Combined heat and power.

xi Typical size based on expert judgment and cost data from IEA (2007).

xii Investment costs for CHP options include heat share only. The electricity data in Table A.III.1 provides examples of total investment cost (see Section 2.4.4).

xiii Investment costs of MSW installations are mainly determined by the cost of flue gas cleaning, which can be allocated to waste treatment rather than to heat production (IEA, 2007).

xiv Heat-only MSW incinerators (as used in Denmark and Sweden) could have a thermal efficiency of 70 to 80%, but are not considered (IEA, 2007).

xv The ranges provided in this category are mainly based on two plants in Denmark and Austria and have been taken from IEA (2007).

xvi Investment costs for anaerobic digestion are based on literature values provided relative to electric capacity. For conversion to thermal capacity an electric efficiency of 37% and a thermal efficiency of 55% were used (IEA, 2007).

xvii For anaerobic digestion, fuel prices are based on a mix of green crop maize and manure feedstock. Other biogas feedstocks include source-separated wastes and landfill gas, but are not considered here (IEA, 2007).

xviii Conversion efficiencies include auxiliary heat input (8 to 20% for process heat) as well as use of any co-substrate that might increase process efficiency. For source-separated wastes, the efficiency would be lower (IEA, 2007).

Solar Energy:

xix DHW: Domestic hot water.

xx 1 m^2 of collector area is converted into 0.7 kW_{th} of installed capacity (see Section 3.4.1).

xxi 70% of the 13.5 million m^2 sales volume in 2004 was sold below Yuan 1,500/m^2 (USD_{2005} ~190/kW) (Zhang et al., 2010). The lower bound is based on data collected during standardized interviews in the Zhejiang Province, China, in 2008 (Han et al., 2010). The higher bound is based on Chang et al. (2011).

xxii Fixed annual operating cost is assumed to be 1 to 3% of investment cost (IEA, 2007) plus annual cost of auxiliary energy. Annual auxiliary energy needs are 2 to 10 kWh/m^2. Electricity prices are assumed to be USD_{2005} 0.1 to 0.3/kWh.

xxiii The conversion efficiency of a solar thermal system tends to be larger in regions with lower solar irradiance. This partly offsets the negative effect of lower solar irradiance on cost as energy yields per m^2 of collector area will be similar (Harvey, 2006, p. 461). Conversion efficiencies, which affect the resulting capacity factor, have not been used in LCOH calculations directly.

xxiv Capacity factors are based on an assumed annual energy yield of 250 to 800 kWh/m^2 (IEA, 2007).

xxv Expected design lifetimes for Chinese solar water heaters are in the range of 10 to 15 years (Han et al., 2010).

Geothermal energy:

xxvi For geothermal heat pumps (GHP) the bounds of investment costs include residential and commercial or institutional installations. For commercial and institutional installations, costs are assumed to include drilling costs, but for residential installations drilling costs are not included.

xxvii Average O&M costs expressed in USD_{2005}/kWh_{th} are: 0.03 to 0.04 for building and district heating and for aquaculture uncovered ponds, 0.02 to 0.03 for greenhouses, and 0.028 to 0.032 for GHP.

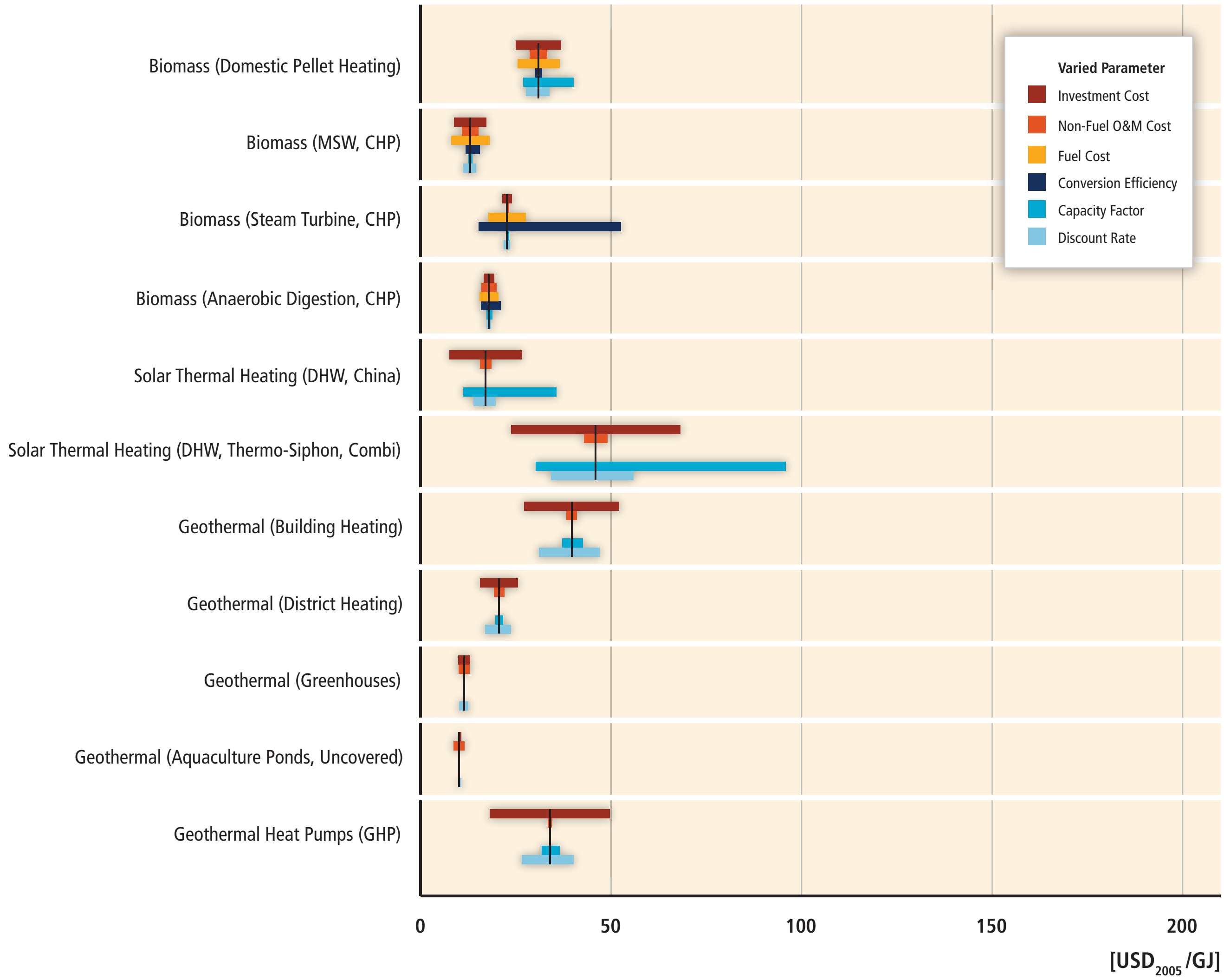

Figure A.III.3a | Tornado graph for renewable heat technologies. For further explanation see Figure A.III.1a.

Note: It may be somewhat misleading that solar thermal and geothermal heat applications do not show any sensitivity to variations in conversion efficiencies. This is due to the fact that the energy input for solar and geothermal has zero cost and that the effect of higher conversion efficiencies of the energy input on LCOH works solely via an increase in annual output. Variations in annual output, in turn, are fully captured by varying the capacity factor.

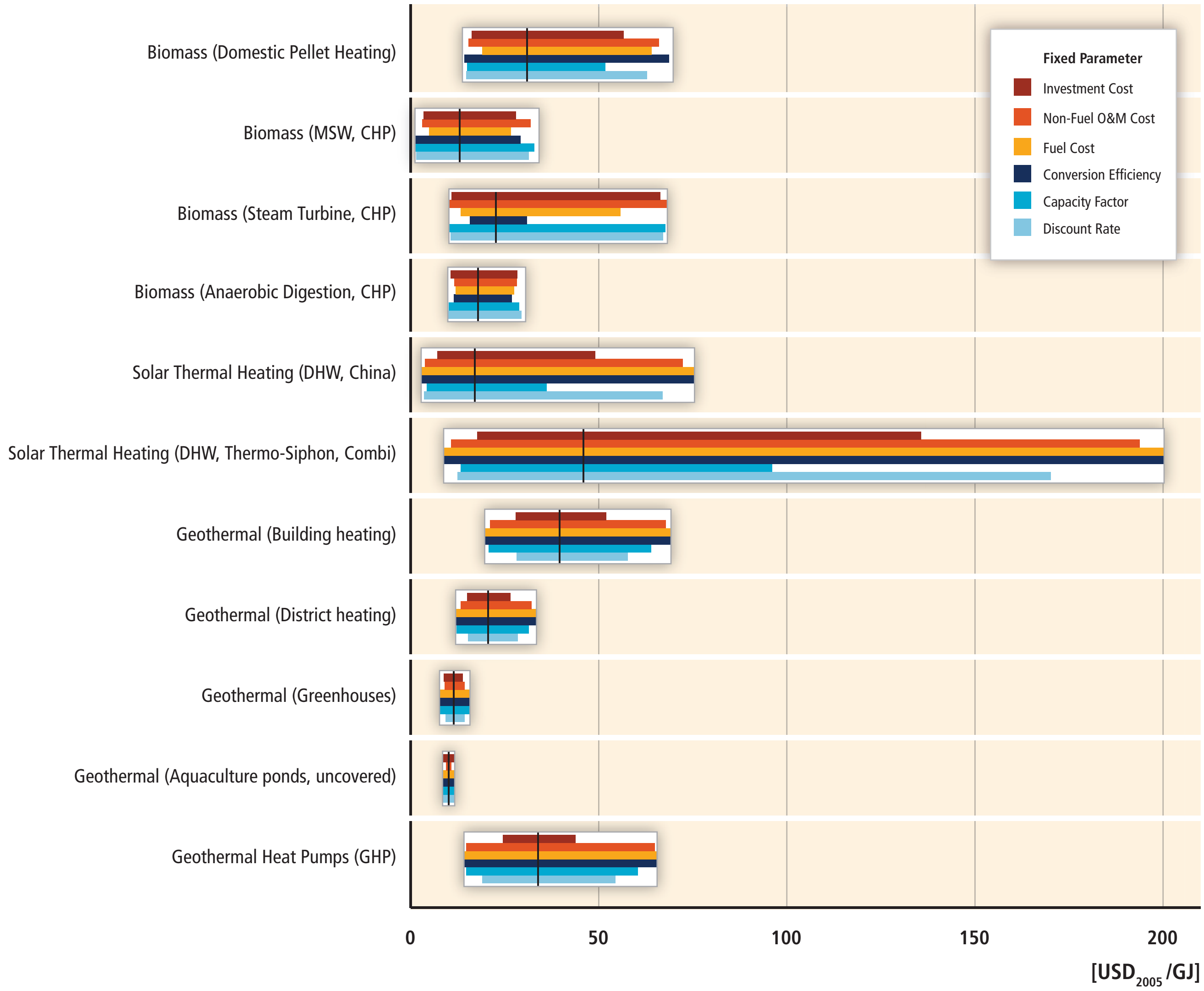

Figure A.III.3b | 'Negative' of tornado graph for renewable heat technologies. For further explanation see Figure A.III.1b.

Table A.III.3 | Cost-performance parameters for biofuels.[i]

Feedstock	Fuel, Region	Input data									Output data		
		Typical size of the device (MW_{th})	Investment cost (USD/kW_{th})[ii]	O&M cost, fixed annual (USD/kW_{th}) and non-feed variable (USD/GJ_{feed})	By-product Revenue (USD/GJ_{feed})	Feedstock cost (USD/GJ_{feed})	Feedstock conversion efficiency[iii] (%) Product only (product + by-product)	Capacity factor (%)	Economic design lifetime (years)	References	LCOF[iv] USD/GJ_{HHV}[v] Discount rate		
											3%	7%	10%
Sugarcane	Ethanol				Co-product: sugar[vi]								
	Overall	*170–1,000*	*83–360*	*16–35 USD/kW_{th} and 0.87 USD/GJ_{feed}*	*4.3*	*2.1–7.1*	*17 (39)*	*50%*	*20*	*Alfstad (2008), Bain (2007), Kline et al. (2007)*	*2.4–39*	*3.5–42*	*4.5–46*
	Brazil, Case A[vii]	See above	100–330	20–32 USD/kW_{th} and 0.87 USD/GJ_{feed}	See above	2.1–6.5[viii]	See above	See above	See above	Bohlmann and Cesar (2006), Oliverio (2006), van den Wall Bake et al. (2009)	2.4–38	3.5–41	4.5–44
	Argentina	See above	110–340	21–34 USD/kW_{th} and 0.87 USD/GJ_{feed}	See above	6.5[ix]	See above	See above	See above	Oliverio and Riberio (2006), see also row 'Overall' above	28–39	30–42	31–46
	Caribbean Basin[x, xi]	See above	110–360	22–35 USD/kW_{th} and 0.87 USD/GJ_{feed}	See above	2.6–6.2	See above	See above	See above	Rosillo-Calle et al. (2000) see also row 'Overall' above	6.4–38	7.7–42	8.8–46
	Colombia	See above	100–320	20–31 USD/kW_{th} and 0.87 USD/GJ_{feed}	See above	5.6	See above	See above	See above	McDonald and Schrattenholzer (2001), Goldemberg (1996), see also row 'Overall' above	23–32	24–36	25–39
	India	See above	110–340	21–33 USD/kW_{th} and 0.87 USD/GJ_{feed}	See above	2.6–6.2	See above	See above	See above	see row 'Overall' above	5.9–37	7.1–41	8.2–44
	Mexico	See above	83–260	16–25 USD/kW_{th} and 0.87 USD/GJ_{feed}	See above	5.2–7.1	See above	See above	See above	see row 'Overall' above	19–37	19–40	20–42
	USA	See above	100–320	20–31 USD/kW_{th} and 0.87 USD/GJ_{feed}	See above	6.2	See above	See above	See above	see row 'Overall' above	27–36	28–40	29–43

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Feedstock	Fuel, Region	Input data: Typical size of the device (MW_{th})	Investment cost (USD/kW_{th})[ii]	O&M cost, fixed annual (USD/kW_{th}) and non-feed variable (USD/GJ_{feed})	By-product Revenue (USD/GJ_{feed})	Feedstock cost (USD/GJ_{feed})	Feedstock conversion efficiency[iii] (%) Product only (product + by-product)	Capacity factor (%)	Economic design lifetime (years)	References	Output data: LCOF[iv] USD/GJ_{HHV}[v], Discount rate 3%	7%	10%
Corn	Ethanol				By-product: DDGS[xii]								
	Overall	***N/A***	***160–310***	***9–27 USD/kW_{th} and 1.98 USD/GJ_{feed}***	***1.56***	***4.2–10***[xiii]	***54 (91)***	***95%***	***20***	***Alfstad (2008), Bain (2007), Kline et al. (2007)***	***9.3–22***	***9.5–22***	***10–23***
	USA	140–550[xiv]	160–240	9–18 USD/kW_{th} and 1.98 USD/GJ_{feed}	See above	4.2–10[xv]	See above	See above	See above	Delta-T Corporation (1997), Ibsen et al. (2005), Jechura (2005), see also row 'Overall' above	9.3–22	9.5–22	10–23
	Argentina	See above	170–260	9–17 USD/kW_{th} and 1.98 USD/GJ_{feed}	See above	7.5	See above	See above	See above	McAloon et al. (2000). RFA (2011), University of Illinois (2011), see also row 'Overall' above	16–17	16–17	17–18
	Canada	See above	200–310	13–27 USD/kW_{th} and 1.98 USD/GJ_{feed}	See above	4.8–5.7	See above	See above	See above	see row 'Overall' above	11–15	12–15	12–16
Wheat	Ethanol				By-product: DDGS[xii]								
	Overall	***150–610***	***140–280***[xvi]	***8–25 USD/kW_{th} and 1.41 USD/GJ_{feed}***	***1.74***	***5.1–13***	***49 (91)***	***95%***	***20***	***Alfstad (2008), Bain (2007), Kline et al. (2007)***	***12–28***	***12–28***	***12-28***
	USA	See above	140–220	8–17 USD/kW_{th} and 1.41 USD/GJ_{feed}	See above	6.3–13	See above	See above	See above	OECD (2002), Shapouri and Salassi (2006), USDA (2007), see also 'Overall'	13–28	14–28	14–28
	Argentina	See above	150–230	8–16 USD/kW_{th} and 1.41 USD/GJ_{feed}	See above	6.5–7	See above	See above	See above	see row 'Overall' above	14–16	14–16	14–17
	Canada	See above	190–280	12–25 USD/kW_{th} and 1.41 USD/GJ_{feed}	See above	5.1–6.9	See above	See above	See above	see row 'Overall' above	12–16	12–17	12–17

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		Input data									Output data		
Feedstock	Fuel, Region	Typical size of the device (MW_{th})	Investment cost (USD/kW_{th})[ii]	O&M cost, fixed annual (USD/kW_{th}) and non-feed variable (USD/GJ_{feed})	By-product Revenue (USD/GJ_{feed})	Feedstock cost (USD/GJ_{feed})	Feedstock conversion efficiency[iii] (%) Product only (product + by-product)	Capacity factor (%)	Economic design lifetime (years)	References	LCOF [iv] USD/GJ_{HHV} [v] Discount rate 3%	7%	10%
Soy Oil	Biodiesel[xvii]				By-product: Glycerin[xviii]								
	Overall	*44–440*	*160–320*	*9–46 USD/kW_{th} and 2.58 USD/GJ_{feed}*	*0.58*	*7.0–24*	*103 (107)19*	*95%*	*20*	*Alfstad (2008), Bain (2007), Kline et al. (2007), Haas et al. (2006), Sheehan et al. (2006)*	*9.4–28*	*10–28*	*10–28*
	Argentina	See above	170–320	12–42 USD/kW_{th} and 2.58 USD/GJ_{feed}	See above	14–16[xx]	See above	See above	See above	Chicago Board of Trade (2006), see also row 'Overall' above	16–19	16–19	17–20
	Brazil	See above	160–310	9–27 USD/kW_{th} and 2.58 USD/GJ_{feed}	See above	7.0–18[xx]	See above	See above	See above	Chicago Board of Trade (2006), see also row 'Overall' above	9.4–21	10–21	10–21
	USA	See above	160–300	12–46 USD/kW_{th} and 2.58 USD/GJ_{feed}	See above	9.7–24	See above	See above	See above	USDA (2006), see also row 'Overall' above	12–28	12–28	12–28
Palm Oil	Biodiesel				By-product: Glycerin[xviii]								
	Overall	*44–440*	*160–340*	*10–46 USD/kWth and 2.58 USD/GJfeed*	*0.58*	*6.1–45*	*103 (107)*	*95%*	*20*	*Alfstad (2008), Bain (2007), Kline et al. (2007), Haas et al. (2006), Sheehan et al. (1998)*	*8.7–48*	*8.9–48*	*9.0–49*
	Colombia	See above	160–300	10–34 USD/kW_{th} and 2.58 USD/GJ_{feed}	See above	6.1–45	See above	See above	See above	see row 'Overall' above	8.7–48	8.8–48	9.0–49
	Caribbean Basin[x]	See above	180- 340	13–46 USD/kW_{th} and 2.58 USD/GJ_{feed}	See above	11–45	See above	See above	See above	see row 'Overall' above	14–48	14–48	14–48
Wood, Bagasse, other	Pyrolytic Fuel Oil				By-product: Electricity[xxi]								
	Overall	*110–440*	*160–240*	*12–44 USD/kWth and 0.42 USD/GJfeed*	*0.07*	*0.44–5.5*[xxii]	*67 (69)*	*95%*	*20*	*Ringer et al. (2006)*	*2.3–12*	*2.6–12*	*2.8–12*
	USA	See above	160–230	19–44 USD/kW_{th} and 0.42 USD/GJ_{feed}	See above	1.4–5.5	See above	See above	See above	see row 'Overall' above	4.0–12	4.3–12	4.5–12
	Brazil	See above	160–240	12–24 USD/kW_{th} and 0.42 USD/GJ_{feed}	See above	0.44–5.5	See above	See above	See above	see row 'Overall' above	2.3–11	2.5–11	2.8–11

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General remarks/notes:

i All data are rounded to two significant digits. Chapter 2 provides additional cost and performance information in the section on cost trends. The assumptions underlying some of the production cost estimates quoted directly from the literature may, however, not be as transparent as the data sets in this Annex and should therefore be considered with caution.

ii Investment cost is based on plant capacity factor and not at 100% stream factor, which is the normal convention.

iii The feedstock conversion efficiency measured in energy units of input relative to energy units of output is stated for biomass only. Conversion factors for a mixture of biomass and fossil inputs are generally lower.

iv LCOF: Levelized Cost of Transport Fuels. The levelized costs of transport fuels include all private costs that accrue upstream in the bioenergy system, but do not include the cost of transportation and distribution to the final customers. Output subsidies for RE generation and tax credits are also excluded. However, indirect taxes and subsidies on inputs or commodities affecting the prices of inputs and, hence, private cost, cannot be fully excluded.

v HHV: Higher heating value. LHV: Lower heating value.

vi Price of / revenue from sugar assumed to be USD_{2005} 22/GJ_{sugar} based on average 2005 to 2008 world refined sugar price.

vii A cane sucrose content of 14% is used in the calculations of case A with the additional assumption that 50% of the total sucrose is used for sugar production (97% extraction efficiency) and the other 50% of the total sucrose is used for ethanol production (90% conversion efficiency). The bagasse content of cane used is 16%. The HHVs used are bagasse: 18.6 GJ/t; sucrose: 17.0 GJ/t; and as received cane: 5.3 GJ/t.

viii Brazilian feedstock costs have declined by 60% in the time period of 1975 to 2005 (Hettinga et al, 2009). For a more detailed discussion of historical and future cost trends see also Sections 2.7.2, 2.7.3 and 2.7.4.

ix 55.2% of feed used is bagasse. More detailed information on feedstock characteristics can, for instance, be found in Section 2.3.1.

x Caribbean Basin Initiative Countries: Guatemala, Honduras, Nicaragua, Dominican Republic, Costa Rica, El Salvador, Guyana, and others.

xi Mixed ethanol/sugar mill: 50/50. More detailed information on sugar mills can be found in Section 2.3.4.

xii DDGS: Distillers dried grains plus solubles.

xiii For international feed range, supply curves from Kline et al. (2007) were used. For more information on feedstock supply curves and other economic considerations in biomass resource assessments see Chapter section 2.2.3.

xiv Plant size range (140-550 MW is the equivalent of 25-100 million gallons per year (mmgpy) of anhydrous ethanol) is representative of the US corn ethanol industry (RFA, 2011).

xv Corn prices in the USA have declined by 63% in the period from 1975 to 2005 (Hettinga et al., 2009). For a more detailed discussion of historical and future cost trends see also Sections 2.7.2, 2.7.3 and 2.7.4.

xvi Based on corn mill costs, corrected for HHV, and distillers dried grain (DDG) yields for wheat. More detailed information on milling can be found in Section 2.3.4.

xvii Installation basis is soy oil, not soybeans. Crush spread is used to convert from soybean prices to soy oil price. HHV soy oil = 39.6 GJ/t.

xviii Glycerine is also referred to as glycerol and is a simple polyol compound (1,2,3-propanetriol), and is central to all lipids known as triglycerides. Glycerine is a by-product of biodiesel production.

xix The yield is higher than 100% because methanol (or other alcohol) is incorporated into the product.

xx Soy oil prices are estimated from soybean prices (Kline et al., 2007) and crush spread (Chicago Board of Trade, 2006).

xxi Process-derived gas and residual solids (char) are used for process heat and power. Excess electricity is exported as a by-product.

xxii Feedstock cost range is based on bagasse residue and wood residue prices (Kline et al. 2007). High range is for wood-based pyrolysis, low range is typical of pyrolysis of bagasse. For more information on pyrolysis see Section 2.3.3.2. For a discussion of historical and future cost trends see also Sections 2.7.2, 2.7.3 and 2.7.4.

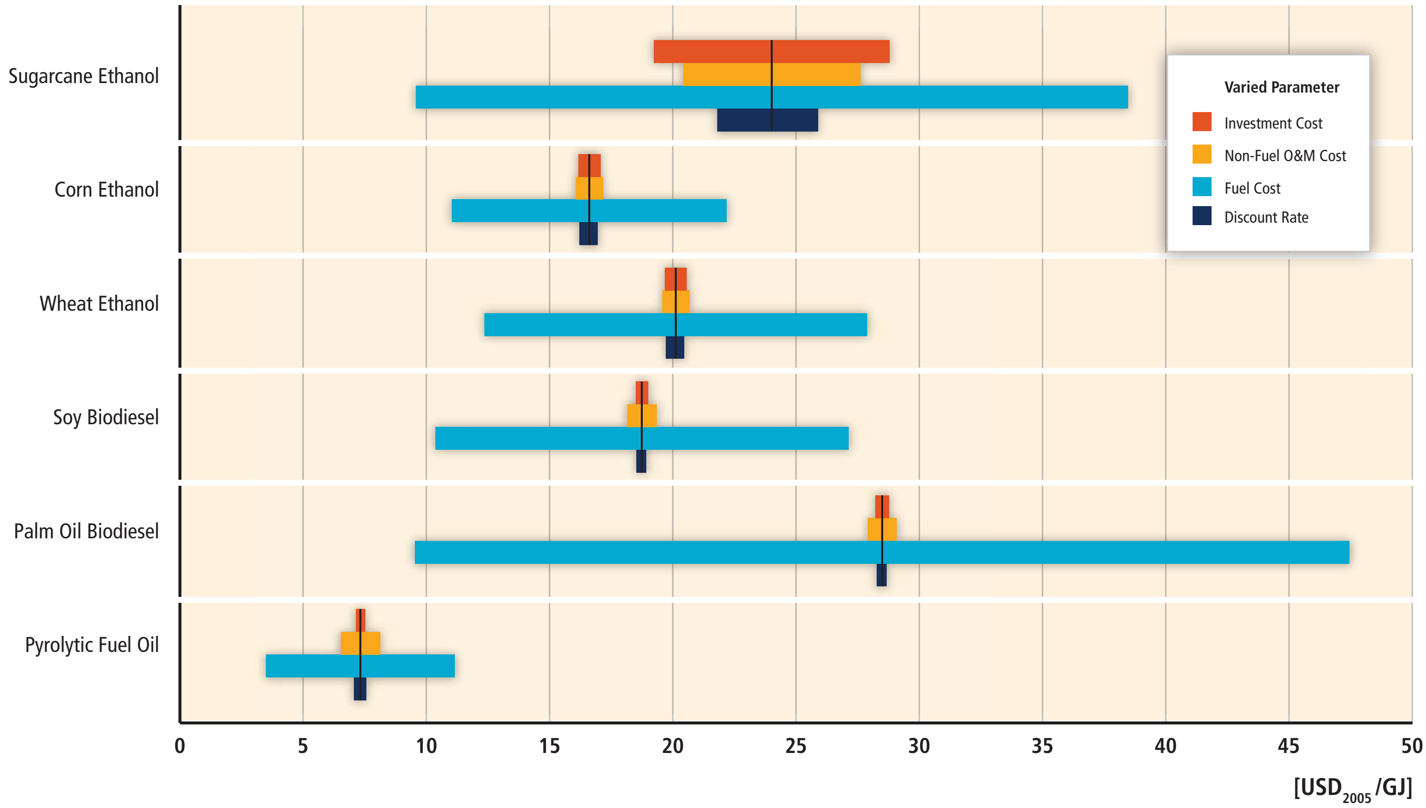

Figure A.III.4a | Tornado graph for biofuels. For further explanation see Figure A.III.1a.

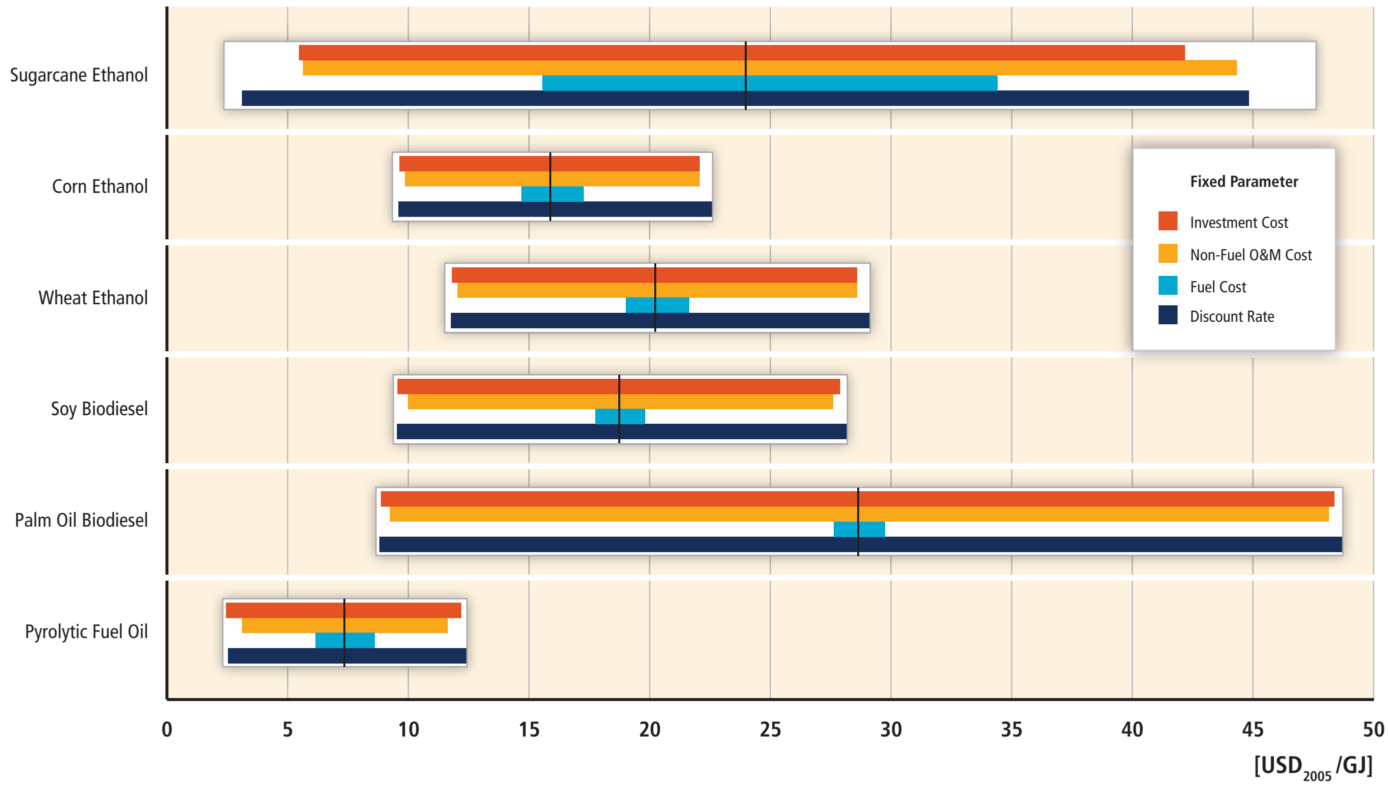

Figure A.III.4b | 'Negative' of tornado graph for biofuels. For further explanation see Figure A.III.1b.

Note: Aggregation of input data over various regions and subsequent LCOF calculations leads to slightly larger LCOF ranges than those obtained if region-specific LCOF values are calculated first and these regional LCOF values are subsequently aggregated. In order to allow for a broad sensitivity analysis the first approach was followed here. The broader ranges were, however, rescaled to yield the same results as the latter approach, which is more accurate and is used in the remainder of the report.

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The references in this list have been used in the assessment of the cost and performance data of the individual technologies summarized in the tables. Only some of them are quoted in the text of this Annex to support specific information included in the explanatory text. All references are sorted by energy type/carrier and by technology.

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