

Renewable Power Generation Costs in 2012: An Overview



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About IRENA

The International Renewable Energy Agency (IRENA) promotes the accelerated adoption and sustainable use of all forms of renewable energy. IRENA's founding members were inspired by the opportunities offered by renewable energy to enable sustainable development while addressing issues of energy access, security and volatility. Established in 2009, the intergovernmental organisation provides a global networking hub, advisory resource and unified voice for renewable energy. www.irena.org

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Foreword

As the world embarks on the transition to a truly sustainable energy future, the world's renewable resources and technologies increasingly offer the promise of cleaner, healthier and economically and technically feasible power solutions and sustainable energy access for all. With over 100 gigawatts of renewable power generation capacity added in 2011 alone, renewables have gone mainstream and are being supported by a “virtuous circle” of increasing deployment, fast learning rates and significant, often rapid, declines in costs.

Given the central role that transparent and up-to-date cost and performance data for renewable power technologies play in the setting of policy support measures and investor decisions for renewables, the lack of this data in the public domain represents a significant barrier to the accelerated deployment of renewables.

This report provides the most current, comprehensive analysis of the costs and performance of renewable power generation technologies available today. The results are largely based on new, original analysis of around 8 000 medium- to large-scale commissioned or proposed renewable power generation projects from a range of data sources. The analysis provides simple, clear metrics based on the latest reliable information, thereby helping to inform the current debate on renewable power generation and to assist governments and private sector investors in their decision-making.

The report highlights that renewables are increasingly becoming the most competitive option for new grid supply and swift grid extension. Where electricity systems are dominated by oil-fired plant, cheaper—sometimes *significantly* cheaper—renewable generation choices are available. For off-grid power supply, renewables are already the default economic solution.

IRENA will extend its costing analysis in 2013 to include transport and stationary applications. It will also launch the *IRENA Renewable Costing Alliance* to raise awareness of the importance of cost data. The alliance will bring together government agencies, financial institutions, equipment manufacturers, project developers, utilities and research institutions to provide data and feedback in support of IRENA's cost analyses of renewable energy technologies.

By reducing the uncertainty that currently surrounds renewable energy costs and performance, IRENA's cost analysis is aimed at assisting governments and regulators in their efforts to adopt more ambitious policies to promote renewables in an evolving investment environment. I hope that this report makes a valuable contribution in support of the global transition to a sustainable energy future.

Adnan Z. Amin

Director-General, IRENA

Contents

EXECUTIVE SUMMARY	4
LIST OF TABLES	10
LIST OF FIGURES	10
1. INTRODUCTION	12
1.1 Rationale for IRENA's cost analysis	12
2. RENEWABLE POWER GENERATION COSTS: AN OVERVIEW	14
2.1 Renewable power generation costs by technology	14
2.2 Renewable power generation costs by region	21
2.3 The declining costs of renewables: Implications	24
3. GLOBAL RENEWABLE POWER MARKET TRENDS	25
3.1 Total installed renewable power generation capacity at the end of 2011	25
3.2 Annual new renewable capacity additions	26
4. WIND POWER	28
4.1 Wind power capital costs	28
4.1.1 Wind turbine costs	31
4.1.2 Total installed costs onshore	32
4.1.3 Total installed costs offshore	34
4.2 Capacity factors for wind power	35
4.3 Operations and maintenance costs	36
4.4 The levelised cost of wind electricity	37
5. HYDROPOWER	39
5.1 Hydropower capital costs	39
5.1.1 Hydropower electro-mechanical costs	41
5.1.2 Total installed costs	42
5.2 Capacity factors for hydropower	44
5.3 Operations and maintenance costs	44
5.4 The levelised cost of hydro electricity	45

6. SOLAR PHOTOVOLTAICS	49
6.1 Solar PV capital costs	49
6.1.1 Solar PV module prices	49
6.1.2 Balance of system costs	51
6.1.3 Total installed costs	54
6.2 Capacity factors for solar PV	56
6.3 The levelised cost of solar PV	57
7. CONCENTRATING SOLAR POWER	58
7.1 CSP capital costs	59
7.2 Operations and maintenance costs for CSP plants	61
7.3 Capacity factors for CSP	62
7.4 The levelised cost of CSP	63
8. BIOMASS FOR POWER GENERATION	66
8.1 Biomass feedstocks	66
8.2 Biomass-fired power generation capital costs by technology	68
8.3 Biomass-fired power generation operations and maintenance costs	70
8.4 Biomass-fired power generation capacity factors and efficiency	70
8.5 The levelised cost of electricity from biomass-fired power generation	71
9. GEOTHERMAL POWER GENERATION	73
9.1 Geothermal power generation installed costs	73
9.2 The LCOE of geothermal power generation	76
10. COST REDUCTIONS TO 2020	77
ANNEX ONE: METHODOLOGY	80
A1.1 Different measures of cost	80
A1.2 Levelised cost of electricity generation	82
REFERENCES	83
ACRONYMS	87

EXECUTIVE SUMMARY

Renewables account for almost half of new electricity capacity installed and costs are continuing to fall.

Renewable power generation technologies now account for around half of all new power generation capacity additions worldwide. IRENA's analysis of around 8 000 projects and range of literature sources shows that the rapid deployment of renewables, working in combination with the high learning rates¹ for some technologies, has produced a virtuous circle that is leading to significant cost declines and is helping fuel a renewable revolution.

In 2011 additions included 41 GW of new wind power capacity, 30 GW of solar photovoltaic (PV), 25 GW of hydropower, 6 GW of biomass, 0.5 GW of concentrated solar power (CSP) and 0.1 GW of geothermal power.

The levelised cost of electricity (LCOE)² is declining for wind, solar PV, CSP and some biomass technologies, while hydropower and geothermal electricity produced at good sites are still the cheapest way to generate electricity.

Renewable technologies are now the most economic solution for new capacity in an increasing number of countries and regions. Where oil-fired generation is the predominant power generation source (e.g. on islands, off-grid and in some countries) a lower-cost renewable solution almost always exists today. Renewables are also increasingly the most economic solution for new grid-connected capacity where good resources are available. As the cost of renewable power drops, the scope of economically viable applications will increase even further.

Crystalline silicon (c-Si) PV module prices are a good example. Average prices for Chinese modules have fallen by more than 65% over the last two years to below

¹ The learning rate is the percentage reduction in costs for a technology that occurs with every doubling of cumulative installed capacity.

² The LCOE of a given technology is the ratio of lifetime costs to lifetime electricity generation, both of which are discounted back to a common year using a discount rate that reflects the average cost of capital. In this report all LCOE results are calculated using a fixed assumption of a 10% cost of capital to facilitate comparison unless an alternative is explicitly mentioned.

USD 0.75/watt (W) in September 2012. The increasing size of global renewable markets and the diversity of suppliers has produced more competitive markets for renewable technologies.

For those regions with significant remaining small hydropower³ potential, the weighted average LCOE for new small hydropower projects is between USD 0.032 and USD 0.07/kWh depending on the region, while for large hydropower the weighted average for a region is between USD 0.03 and USD 0.06/kWh (Figure ES.1) assuming a 10% cost of capital. For biomass, the weighted average LCOE for non-OECD regions varies between USD 0.05 and USD 0.06/kWh. For geothermal, the weighted average LCOE by region is between USD 0.05 and USD 0.09/kWh, while for onshore wind the range is between USD 0.08 and USD 0.12/kWh. CSP and utility-scale solar PV are more expensive, with the weighted average LCOE for utility-scale solar PV varying between USD 0.15 and USD 0.31/kWh. The weighted average LCOE for CSP for a region varies between USD 0.22 and USD 0.25/kWh.

The importance of the level of existing good quality resources that are available or remain to be exploited is also highlighted in Figure ES.1. Europe has higher LCOEs for hydropower and biomass-fired electricity because, in the former case, most of the economic potential has already been exploited, while in the latter case feedstock costs are typically high. Similarly, with the exception of Italy and Iceland, the geothermal resources in Europe are generally poor in quality and require expensive investment to exploit.

It is important to note that distributed renewable technologies, such as rooftop solar PV and small wind, can't be directly compared to large utility-scale solutions where transmission and distribution costs of USD 0.05 to USD 0.15/kWh must be added to the total costs.

³ Small hydropower is defined in this report as projects with installed capacity of up to 20 MW.

The rapid growth in the deployment of solar and wind is driving a convergence in electricity generation costs for renewable power generation technologies at low levels.

It is not possible to identify a clear cost hierarchy for renewable technologies, as each technology has its own supply curve that can vary significantly by country, or even region within a country, depending on the resource availability and the local cost structure. However, an important observation is that there is a general hierarchy for renewable power generation in terms of costs and the scale of available resources. When excellent local resources are available, mature technologies, such as biomass, geothermal and hydropower, can all produce electricity at very competitive costs, although in limited quantities. Onshore wind is typically the next most economic, followed by solar PV and CSP, but the resource availability of these technologies globally is many times that of the mature technologies. In the past, renewable technologies with the largest resource potential therefore also had high costs.

The much larger wind and solar resources and their cost reduction potentials have helped spur support for wind and solar technologies in order to provide

a larger share of power generation from renewables. As a result, as the deployment of wind and solar has increased, we are seeing a reduction in the costs of wind and solar technologies and a convergence in the LCOE of renewable technologies at low levels. How far this convergence will go remains to be seen, but it will continue in the short- to medium-term given the current manufacturing overcapacity for wind and solar PV.

The costs of renewables are very site specific, and resources are distributed unevenly across regions, countries and within a country. There is therefore no single “true” LCOE value for each renewable power generation technology. It is thus vital to collect national data to analyse renewable power generation costs and potentials.

This analysis is further complicated by the impact of variable renewables, which need to be analysed with a system-based approach. However, although a change in thinking is required in network operation, electricity storage or increased system flexibility with incremental system costs will typically only be needed when variable renewables reach 20-50% of total system capacity. Systems integration costs will vary widely and can be significantly reduced through proper system design.

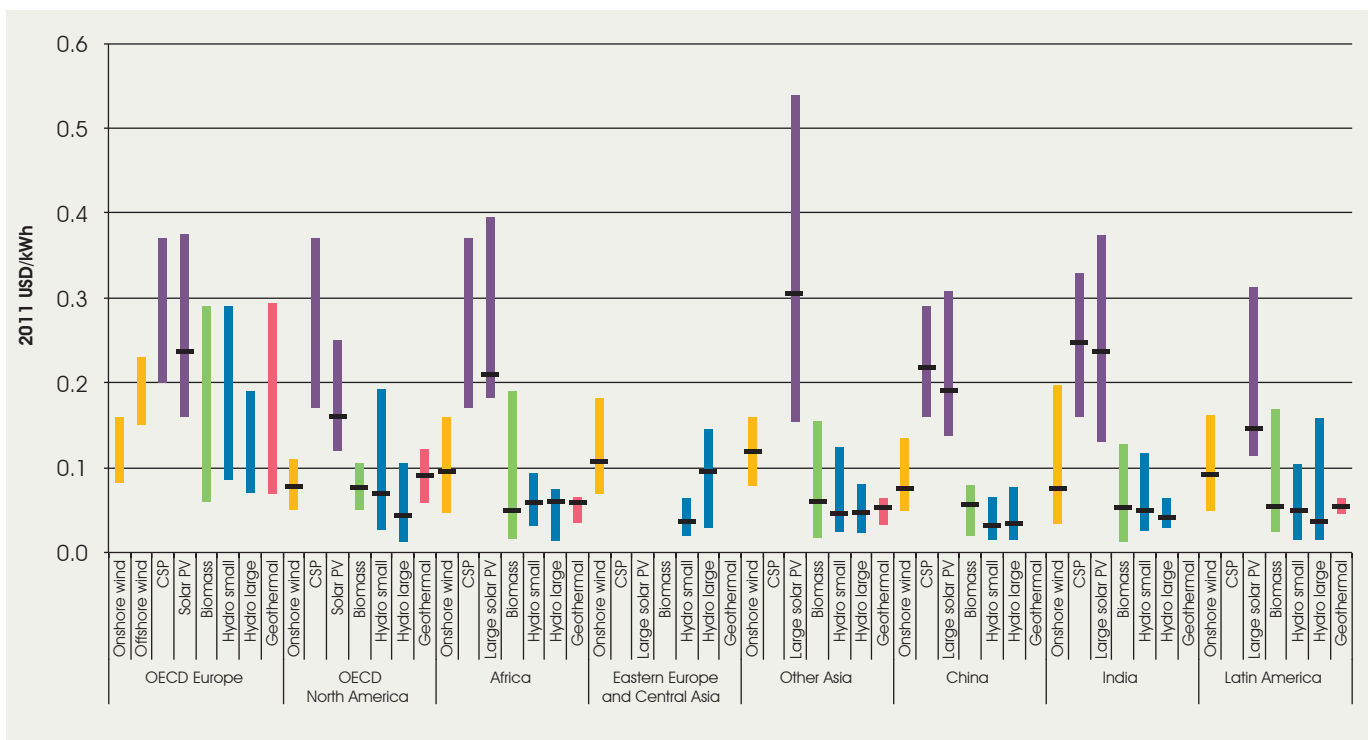


FIGURE ES.1: TYPICAL LCOE RANGES AND WEIGHTED AVERAGES FOR RENEWABLE POWER GENERATION TECHNOLOGIES BY REGION, 2012

Note: The bars represent the typical LCOE range and the black horizontal bars the weighted average LCOE if enough individual project data are available. Figures assume a 10% cost of capital and biomass costs of between USD 1.3 and USD 2.5/GJ in non-OECD countries and between USD 1.3 and USD 9/GJ in OECD countries.

As equipment costs decline, the share of balance of project costs and operations and maintenance costs in the LCOE will increase unless increased efforts are made to accelerate their decline as well.

Seven major components largely determine the LCOE for renewable power generation technologies – resource quality, equipment cost and performance (including capacity factor), the balance of project⁴ costs, fuel (if any), operations and maintenance costs (and reliability), economic life of the project and the cost of capital. As equipment costs drop, the importance of the balance of project, or balance of system (BoS), and operations and maintenance (O&M) costs, and the cost of capital increases. For instance, BoS costs in the United States have not declined as fast as in more competitive markets, meaning that the average installed price for residential PV systems were more than twice as expensive as in Germany in the second quarter of 2012. In contrast, O&M costs for wind in most major European markets are typically twice as high as in the United States. These issues merit much more analysis and policy attention than they receive today in order to prevent a slowing in the rate of reduction in the LCOE of renewables.

This is particularly true for smaller systems. For residential PV systems, BoS costs (including installation) can account for 60% to 80% of the total project cost. Non-equipment costs are also higher in developing countries where transmission lines and roads must be built as part of the project. The share of the BoS or balance of project costs and the importance of O&M costs, indicate the order of magnitude of the opportunities for local content and value added, that may help meet local social and economic development goals.

For renewables, access to affordable financing and capital is often not the norm globally, yet it is critical to the ability to develop a renewable project and the LCOE generated. In new markets for renewables, special attention needs to be paid to ensure the regulatory and investment framework is favourable and that projects can access funds in the initial growth phase of the market. Once banks and other local financing sources have experience with new technologies in their markets,

⁴ Sometimes referred to as “balance of system costs” for when small-scale applications of technologies like solar PV and wind are being discussed.

financing should, but may not necessarily always, then be easier to access on favourable terms.

Further equipment cost reductions can be expected to 2020, which will lower the weighted average LCOE of renewables. The rate of decline to 2020 for solar PV is likely to be slower than in recent years, but wind and CSP may see an acceleration.

The technologies with the largest remaining cost reduction potential are CSP, solar PV and wind. Hydropower, geothermal and most biomass combustion technologies are mature and their cost reduction potentials are not large (Figure ES.2).

The range for LCOE of solar PV systems will decline more slowly in absolute terms than in the past, given that module prices have fallen so far. However markets which have higher than average cost structures for BoS today could see dramatic cost reductions in installed prices by 2020, lowering the weighted average costs significantly. Solar tower CSP plants costs could come down significantly by 2020 if deployment accelerates, given the potential of the technology and the current very low level of deployment. Wind turbine prices are falling after a period of high prices and increasing LCOEs, despite turbine improvements that increased capacity factors. If the wind turbine market follows a similar dynamic to the solar PV market, where overcapacity has led to large price reductions, some degree of convergence with Chinese and Indian turbine prices might occur. This would see LCOE cost reductions accelerating compared to in 2011 and 2012.

Although this is the likely outcome, risks remain to the outlook for the competitiveness of renewables that are beyond the scope of their control, such as commodity price increases (e.g. cement and steel) or falls in the price of fossil fuels.

In 2020 the LCOE ranges for the other technologies are not likely to be significantly lower than at present. Also, since today's best practice projects in China and India in particular are unlikely to be beaten, the main shift for wind and biomass will be in a convergence of equipment costs towards Chinese and Indian levels as their suppliers start to compete more actively internationally and improve the quality of their overall offer (e.g. warranties, O&M contracts and reliability guarantees). The cost range therefore masks the projected decline in the weighted average costs that are likely to occur in OECD countries till 2020.

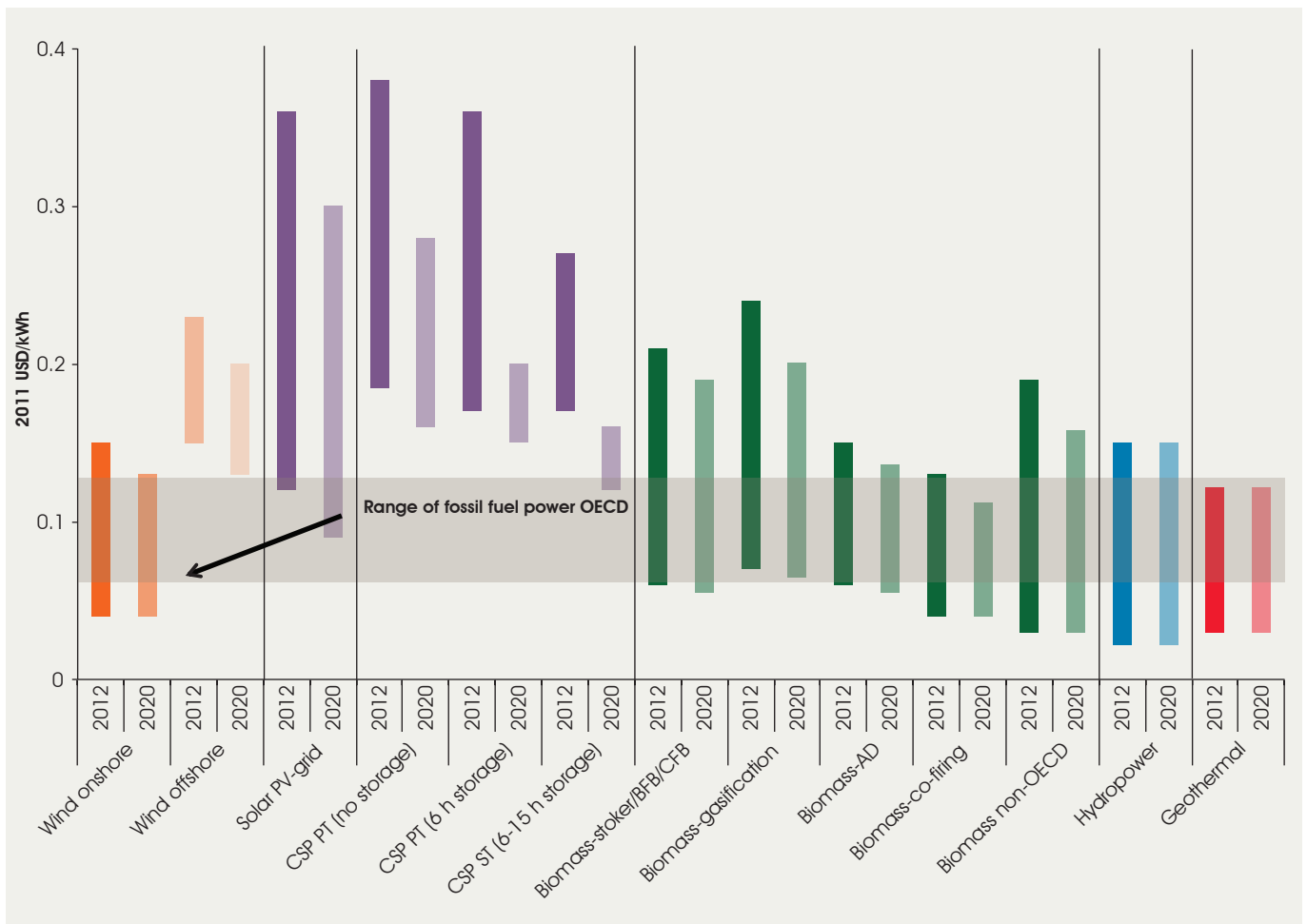


FIGURE ES.2: TYPICAL LCOE COST RANGES FOR RENEWABLE POWER GENERATION TECHNOLOGIES, 2012 AND 2020

Note: PT = parabolic trough, ST = solar tower, BFB/CFB = bubbling fluidised bed/circulating fluidised bed, AD = anaerobic digestion.

There are significant differences in installed capital costs between technologies and regions. This highlights the need to collect comprehensive real world project data in order to properly evaluate the costs and potential of renewables.

With the exception of hydro upgrades and biomass co-firing, where the existing investment in dams or coal-fired power plants respectively have already been made, the lowest capital costs for renewable technologies are for wind and biomass in non-OECD countries (Figure ES.3). What is notable about this picture, compared to the analysis of two years ago, is that today the costs of utility-scale solar PV rival those of wind in some regions and have not yet finished their downward trajectory.

The installed cost range for wind in the major markets⁵ is relatively narrow compared to those for other renewable technologies. This reflects not only the large share of wind turbine costs in the total, but also the more homogenous nature of wind farm developments.

For solar PV the installed cost range is very wide. For instance the total installed costs for residential PV systems in the second quarter of 2012 in Germany were as low as USD 1 600/kW for the cheapest systems (with an average of USD 2 200/kW), but rise to USD 8 000/kW for the most expensive systems in the United States (with an average of USD 5 500/kW). Some of this difference can be attributed to structural factors, the competitiveness of the local market, or the impact of policy support, but many factors remain unexplained.

⁵ If smaller markets were included, this range would widen to a maximum of around USD 3 000/kW due to the less mature market infrastructure for wind, as well as higher infrastructure and commodity costs in many developing countries.

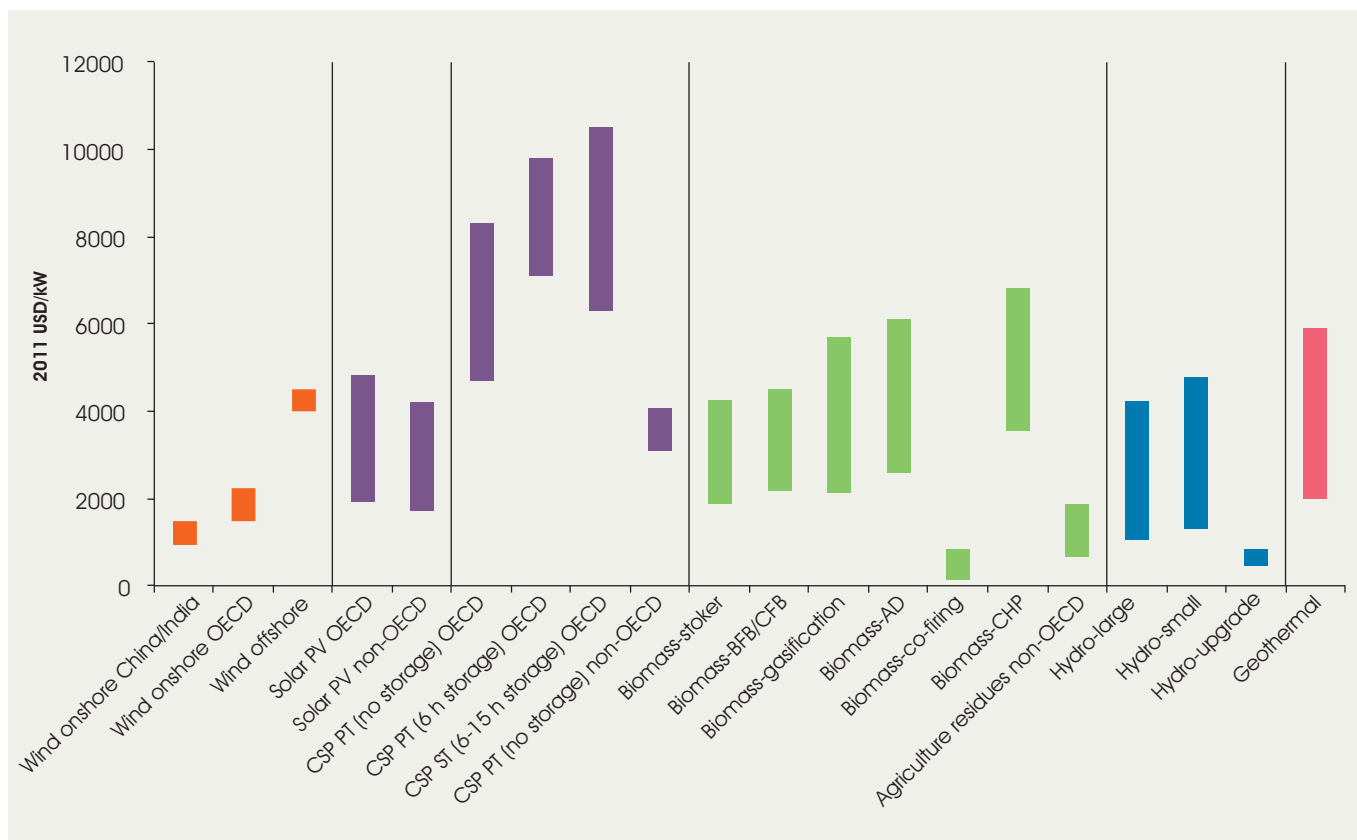


FIGURE ES.3: TYPICAL CAPITAL COST RANGES FOR RENEWABLE POWER GENERATION TECHNOLOGIES, 2012

Note: PT = parabolic trough, ST = solar tower, BFB/CFB = bubbling fluidised bed/circulating fluidised bed, AD = anaerobic digestion.

Typical capacity factors⁶ vary by technology and region. For instance, capacity factors for wind in Latin America range from 22% to 52%, with similar wide variations in North America. The importance of obtaining real project data to analyse the LCOE range for a given technology in a region cannot therefore be underestimated, since assumptions made on typical values can lead to misleading conclusions.

The rapid cost reductions in some renewable power generation technologies means that up-to-date data are required to evaluate support policies for renewables, while a dynamic analysis of the costs of renewables is needed to decide on the level of support.

Comparable, verified data on the costs and performance of renewable energy technologies are often not in the public domain, but need to be made available. It is clear that there is insufficient publicly available data to allow policy makers to make robust decisions about the role

of renewable power generation. IRENA's cost analysis programme and this report are designed to help reduce this barrier to the accelerated deployment of renewables. Although the IRENA Renewable Cost Database contains close to 8 000 projects, this is a small proportion of the total number of projects installed or in development. Much more work therefore needs to be done to collect real project data in order to analyse emerging trends and the challenges facing renewables.

The rapid growth in installed capacity of renewable energy technologies and the associated cost reductions mean that even data one or two years old can significantly overestimate the cost of electricity from renewable energy technologies. In the case of solar PV, even data six months old can significantly overstate costs. In addition, there is also a significant amount of perceived knowledge about the cost and performance of renewable power generation that is not accurate or is even misleading. Conventions on how to calculate costs can influence the outcome significantly and it is imperative that these are well-documented.

⁶ The ratio of the number of hours an electricity plant generates to the total number of hours in a year.

An integrated power generation approach that considers all renewable energy technologies is required, as renewables will need to increasingly work more closely together to unlock synergies and ensure there is sufficient flexibility in the electricity system to achieve least-cost integration of high levels of variable renewables. The lock-in of infrastructure that comes with current investment in long-lived renewable and conventional energy assets means that sooner, rather than later, policy makers will need to move away from technology-specific support packages, to ones designed to minimise overall electricity system costs with higher levels of variable renewables, given that this is the trend in new capacity additions.

LIST OF TABLES

Table 2.1: Number of projects for non-OECD regions in the IRENA Renewable Cost Database by technology	16
Table 2.2: Energy project risk factors	20
Table 4.1: Breakdown of the capital costs of the 39.9 MW Amayo wind farm	29
Table 4.2: Comparison of capital cost breakdown for typical onshore and offshore wind power systems in developed countries	30
Table 4.3: Typical total installed costs for wind farms by country	32
Table 4.4: Operations and maintenance costs for onshore wind projects by country	37
Table 7.1: Capital costs and key characteristics of parabolic trough and solar tower plant	59
Table 8.1: Biomass feedstock costs in the United States	67
Table 8.2: Biomass feedstock characteristics and costs in Brazil and India	67
Table 8.3: Fixed and variable operations and maintenance costs for biomass power	70

LIST OF FIGURES

Figure ES.1: Typical LCOE ranges and weighted averages for renewable power generation technologies by region, 2012	5
Figure ES.2: Typical LCOE cost ranges for renewable power generation technologies, 2012 and 2020	7
Figure ES.3: Typical capital cost ranges for renewable power generation technologies, 2012	8
Figure 2.1: Typical LCOE ranges and weighted averages by region for renewable power generation technologies, 2012	15
Figure 2.2: Typical capital cost ranges for renewable power generation technologies, 2012	18
Figure 2.3: Typical LCOE ranges and weighted averages for renewable power generation technologies by region, 2012	21
Figure 2.4: Levelised cost of electricity from renewable power generation technologies for Pacific islands	23
Figure 3.1: Installed renewable power generation capacity by type, end-2011	25
Figure 3.2: Global annual new installed capacity of solar PV and wind, 2000-2011	27
Figure 4.1: Typical onshore wind farm installed cost breakdown	29
Figure 4.2: Wind turbine prices in the United States and China compared to the BNEF wind turbine price index, 1997-2012	31
Figure 4.3: Total installed costs and weighted averages of commissioned and proposed large wind farms in non-OECD countries and regions (>5MW), 2009-2012	33
Figure 4.4: Total installed costs of commissioned and proposed small wind farms in India (<5MW)	34
Figure 4.5: Estimated total installed costs for offshore wind farms	34
Figure 4.6: Average cumulative capacity factor by year in the United States	35
Figure 4.7: Capacity factors and weighted averages for commissioned and proposed large wind farms (>5 MW) in non-OECD regions	36
Figure 4.8: The LCOE and weighted averages of commissioned and proposed large wind farms (>5 MW) in non-OECD regions	38
Figure 5.1: Cost breakdown of an indicative 500 MW greenfield hydropower project in the United States	40
Figure 5.2: Capital cost breakdown of small-scale hydro projects in Africa	41
Figure 5.3: Electro-mechanical equipment costs for hydropower as a function of capacity (log-scale)	42
Figure 5.4: Total installed cost ranges and capacity weighted averages for commissioned or proposed small and large hydropower projects by country/region	43
Figure 5.5: Capacity factor ranges and weighted averages for commissioned or proposed small and large hydropower projects by country/region	44

Figure 5.6: Operations and maintenance costs for small hydropower projects in developing countries	45
Figure 5.7: Levelised cost of electricity of unexploited hydropower resources in the United States	46
Figure 5.8: Levelised cost of electricity ranges and weighted averages of small and large hydropower projects by region	47
Figure 5.9: Levelised cost of electricity of small hydropower projects in developing countries	48
Figure 6.1: Average monthly solar PV module prices by technology in Europe, 2009 to 2012	50
Figure 6.2: Solar PV module cost learning curve for crystalline silicon and thin-film	51
Figure 6.3: Utility-scale solar PV balance of system costs	52
Figure 6.4: Residential solar PV system BoS costs in Germany and the United States, 2001 to 2011	53
Figure 6.5: Residential solar PV module and BoS costs in Germany and the United States, 2011	53
Figure 6.6: Solar PV system price trends by sector and country, 2006 to 2012	54
Figure 6.7: Solar PV installed costs by project and weighted averages in non-OECD regions for utility-scale projects, 2010 to 2012	55
Figure 6.8: Solar PV system capacity factors by location and tracking system in the United States	56
Figure 6.9: The LCOE and weighted averages of commissioned and proposed large-scale solar PV systems in non-OECD countries/regions, 2010 to 2012	57
Figure 7.1: Total installed costs for recently commissioned or proposed parabolic trough and linear Fresnel plants, 2010 to 2012	60
Figure 7.2: Total installed cost breakdown for 100 MW parabolic trough and solar tower CSP plant in South Africa	60
Figure 7.3: Operations and maintenance costs for parabolic trough and solar tower CSP plants	61
Figure 7.4: Full load hours for CSP as a function of direct normal irradiation and the solar multiple	62
Figure 7.5: Annual capacity factor for a 100 MW parabolic trough plant as a function of solar field size and size of thermal energy storage	63
Figure 7.6: The levelised cost of electricity of CSP plants as a function of direct normal irradiance	63
Figure 7.7: The levelised cost of electricity of CSP plants as a function of the solar multiple and hours of thermal energy storage	64
Figure 7.8: The levelised cost of electricity of CSP plants in 2011/2012	65
Figure 8.1: Total installed capital costs of biomass-fired electricity generation technologies in OECD countries	68
Figure 8.2: Total installed costs of stoker boiler-based electricity generation systems in non-OECD countries	69
Figure 8.3: Total installed cost breakdown of biomass-based electricity generation systems in non-OECD countries	69
Figure 8.4: Project capacity factors and weighted averages of biomass-fired electricity generation systems in non-OECD countries	71
Figure 8.5: Levelised electricity cost ranges and weighted averages of biomass-fired electricity generation by technology and country/region	72
Figure 8.6: Share of fuel costs in the levelised cost of electricity of bioenergy power generation for high and low feedstock prices in the OECD	72
Figure 9.1: Total installed costs for geothermal power stations, 1997 to 2009	74
Figure 9.2: Installed capital costs for geothermal power projects in Chile, Indonesia, Kenya, Mexico and the Philippines	75
Figure 9.3: Power plant only costs for geothermal projects by reservoir temperature	75
Figure 9.4: The levelised cost of electricity of geothermal power projects in Chile, Indonesia, Kenya, Mexico and the Philippines	76
Figure 10.1: Levelised cost ranges for renewable power generation technologies, 2012 and 2020	79
Figure A1.1: Renewable power generation cost indicators and boundaries	81

1. INTRODUCTION

Renewable energy technologies can help countries meet their policy goals for secure, reliable and affordable energy, electricity access for all, reduced price volatility and the promotion of social and economic development. This paper summarises the results of five papers on the cost and performance of renewable power generation technologies (biomass for power generation, concentrating solar power, hydropower, solar photovoltaics and wind) produced by IRENA in 2012 and adds new data to the analysis.⁷ The goal of this paper is to assist government decision-making and ensure that governments and other decision makers have access to up-to-date and reliable information on the costs and performance of renewable energy technologies.

In the past, deployment of renewables was hampered by a number of barriers, including their high up-front costs. Today's renewable power generation technologies are increasingly cost-competitive and are now the most economic option for off-grid electrification in most areas and, in locations with good resources, they are the best option for centralised grid supply and extension.

Renewable power generation technologies now account for around half of all new power generation capacity additions worldwide. In 2011 additions included 41 GW of new wind power capacity, 30 GW of solar photovoltaic (PV), 25 GW of hydropower, 6 GW of biomass, 0.5 GW of concentrated solar power (CSP) and 0.1 GW of geothermal power.⁸

The rapid deployment of these renewable technologies has a significant impact on costs, because of the high learning rates for renewables, particularly for wind and solar. For instance, for every doubling of the installed capacity of solar PV, module costs will decrease by as much as 22%.⁹ As a consequence crystalline silicon (c-Si) PV module prices have fallen by more than 65% over the last two years and since September 2012 Chinese c-Si

module prices have averaged around USD 0.75/watt (W). The increasing size of global renewable markets and the diversity of suppliers has produced more competitive markets for renewable technologies.

The following sections of this paper outline the principle findings of the five costing papers on solar PV, CSP, wind power, hydropower and biomass that IRENA released in 2012 and highlight their key insights for policy-makers.¹⁰

It is important to note that cost can be measured in a number of different ways and each way of accounting for the cost of power generation brings its own insights. The analysis summarised in this paper represents a static analysis of costs. The optimal role of each renewable technology in a country's energy mix requires a dynamic modelling of electricity system costs to take into account the many complexities of operating an electricity grid.¹¹

This paper compares the cost and performance of renewable energies, and the data across technologies, countries and regions. It also compares the results for the levelised cost of electricity (LCOE) from renewables, given a number of key assumptions. This up-to-date analysis of the costs of generating electricity from renewable power generation technologies will allow a transparent comparison of renewables with other generating technologies.¹²

1.1 RATIONALE FOR IRENA'S COST ANALYSIS

The real costs of a project are one of the foundations that an investment decision stands on and are critical to understanding the competitiveness of renewable energy. Without access to reliable information on the relative costs and benefits of renewable energy technologies it is difficult, if not impossible, for governments to arrive at an accurate assessment of which renewable energy

⁷ Hereafter referred to as "IRENA's power generation cost reports".

⁸ IRENA costing papers (www.irena.org/publications) and REN21's "Renewables 2012 Global Status Report".

⁹ For more information on learning rates for solar PV, see the IRENA costing report.

¹⁰ See www.irena.org/publications to download these free reports.

¹¹ This type of analysis is part of IRENA's work on scenarios and strategies. See www.irena.org for more details.

¹² IRENA, through its other work programmes, is also looking at the costs and benefits, as well as the macroeconomic impacts, of renewable power generation technologies. See www.irena.org for further details.

technologies are the most appropriate for their particular circumstances. IRENA's cost analysis programme is a response to a call from Member Countries for better and more objective cost data. Providing this information, with an accompanying analysis, will help governments, policy-makers, investors and utilities make informed decisions about the role renewables can play in their energy sector. This work fills a significant gap in information availability because there has been a lack of accurate, comparable, reliable and up-to-date data on the costs and performance of renewable energy technologies.

The rapid growth in installed capacity of renewable energy technologies and the associated cost reductions mean that data from even one or two years ago can significantly overestimate the cost of electricity from renewable energy technologies. In the case of solar PV, even data six months old can significantly overstate costs. There is therefore a significant amount of perceived knowledge about the cost and performance of renewable power generation that is not accurate and

can even be misleading. At the same time, a lack of transparency in the methodology and assumptions used by many to make cost calculations can lead to confusion about the comparability of data. It is imperative that these methodologies and assumptions are clearly documented.

The absence of accurate and reliable data on the cost and performance of renewable power generation technologies is therefore a significant barrier to the uptake of these technologies.

IRENA plans to collect renewable energy project cost data for power generation, stationary applications and transport over the coming years and use this data in publications and toolkits designed to assist countries with their renewable energy policy development and planning. The analysis will include projections of future cost reductions and performance improvements so governments can incorporate likely future developments into their policy decisions. This work is ongoing and further efforts are required to overcome significant challenges in data collection, verification and analysis.

2. RENEWABLE POWER GENERATION COSTS: AN OVERVIEW

A renewable revolution is underway. The rapid deployment of renewable power generation technologies and the corresponding rapid decline in costs are sustaining a virtuous circle. The levelised cost of electricity (LCOE) is declining for wind, solar PV, CSP and some biomass technologies, while hydropower and geothermal produced at good sites is still often the cheapest way to generate electricity.

These technologies, excluding hydropower, typically have significant or even very high learning rates.¹³ Solar PV modules, for instance, have learning rates of between 18% and 22%. The rapid deployment of renewables, working in combination with the high learning rates for some technologies, has produced a virtuous circle that leads to significant cost declines and is helping fuel the renewable revolution.

Renewables are therefore becoming increasingly competitive. As an example, c-Si PV module prices have fallen by over 65% over the last two years and Chinese c-Si PV modules in September 2012 were selling for just USD 0.75/watt. This is driving reductions in installed costs for residential PV systems, with installed costs in Germany for sub <100 kW rooftop systems falling by 65% between 2006 and 2012 to USD 2.2/W, making solar PV competitive with current residential electricity tariffs.

It is important to note that the analysis presented here excludes the impact of government incentives or subsidies, system balancing costs associated with variable renewables and any system-wide cost-savings from the merit order effect¹⁴. Furthermore, the analysis does not take into account any CO₂ pricing, nor the benefits of renewables in reducing other externalities (e.g. reduced local air pollution or contamination of the natural environment). Similarly, the benefits of renewables being insulated from volatile fossil fuel prices have not been quantified. These issues are important and if these were quantified would improve the economics of renewables for power generation. These issues are covered by other programmes of work at IRENA.

2.1 RENEWABLE POWER GENERATION COSTS BY TECHNOLOGY

Figure 2.1 shows the cost-effectiveness of today's renewable technologies. However, the cost ranges are wide and very site-specific. As a result, there is no single "best" renewable power generation technology. It is also important to note that distributed renewable technologies, such as rooftop solar PV and small wind, can provide new capacity without the need for additional transmission and distribution investment and therefore can not be directly compared with large utility-scale renewable solutions where transmission and distribution costs of USD 0.05 to USD 0.15/kWh would need to be added.

¹³ Learning rate refers to the fixed percentage reduction in equipment or installed costs for each doubling of cumulative installed capacity.

¹⁴ See EWEA, *Wind Energy and Electricity Prices*, April 2010 for a discussion.

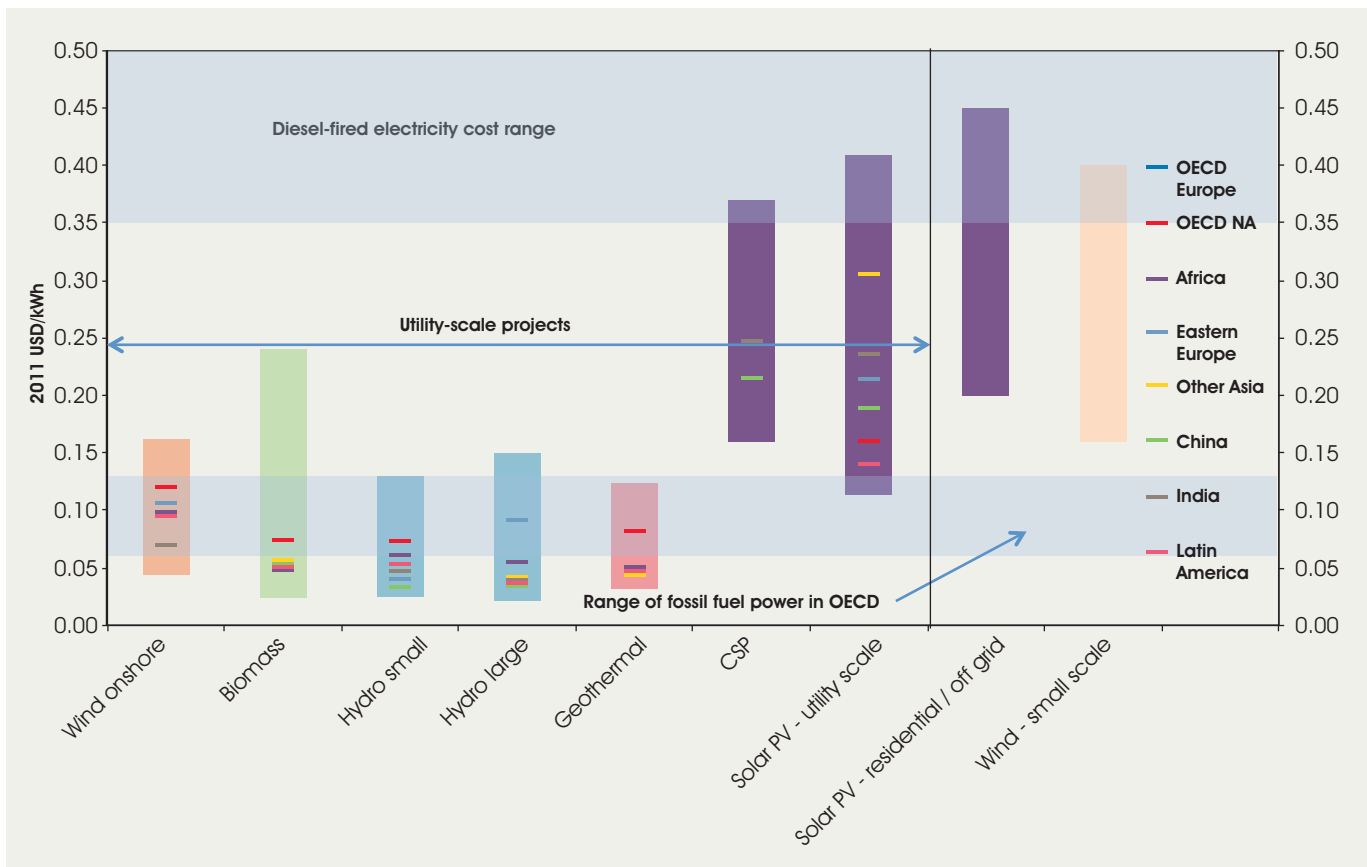


FIGURE 2.1: TYPICAL LCOE RANGES AND WEIGHTED AVERAGES BY REGION FOR RENEWABLE POWER GENERATION TECHNOLOGIES, 2012

Note: All LCOE data assume a 10% cost of capital. The large coloured bars represent the typical LCOE range by technology and the coloured horizontal lines the weighted average LCOE by country/region if enough individual project data are available.

SOURCE: IRENA RENEWABLE COST DATABASE.

What is clear however, is that with current prices for fossil fuels and conventional technologies, renewable technologies are now the most economic solution for off-grid electrification and for centralised grid supply in locations with good resources. Renewable energy technologies can therefore help countries to meet their policy goals for secure, reliable and affordable energy, expand electricity access, promote development, improve energy security, promote economic development, reduce greenhouse gas emissions and reduce energy price volatility.

On an economic basis renewables are now the default option for off-grid electrification and virtually all electricity systems based predominantly on oil-fired generation will see system generation costs fall by integrating renewables. Solar PV, biomass and wind are highly modular solutions to the challenge of extending electricity access to remote locations, and so help meet economic and social development goals. Renewable technologies

can be significantly cheaper than diesel-fired generation, particularly in remote areas with poor, or even non-existent, infrastructure where transport costs can increase the cost of diesel by 10% to 100%.

Different renewable power generation technologies can be combined in mini-grids to electrify isolated villages and extend existing grid networks. The complementary nature of different renewable options, sometimes deployed in combination with small hydro with small reservoirs for storage or other electricity storage options, can help reduce the overall variability of supply to low levels and provide low-cost, local electrification solutions that bring economic benefits at a lower cost than diesel-fired generation. However, a major challenge to the economics of these electrification projects is the high cost of capital, which can be two to three times higher in developing countries than in developed ones.

The typical LCOE of new onshore wind farms in 2011 was between USD 0.06 to USD 0.14/kWh, assuming

a cost of capital of 10%.¹⁵ However, at the best sites in North America projects can deliver electricity for as little as USD 0.04 to USD 0.05/kWh, making them competitive with, or cheaper than, gas-fired generation – even in this so-called “golden age of gas”. The LCOE of wind, for the same resource quality, is likely to fall in the near future, since after increasing for a number of years due to commodity price increases and demand outstripping supply, wind turbine prices have recently started to fall again – a trend that is likely to continue as low-cost

15 All LCOE calculations in this report assume a 10% cost of capital to allow for direct comparisons of the LCOE, unless explicitly mentioned that another value has been used.

manufacturers from emerging economies increasingly enter the global market.

Solar PV costs are declining rapidly due to high learning rates for PV modules and the very rapid deployment currently being experienced. If these trends continue, grid parity with residential electricity tariffs will soon be the norm, rather than the exception, around the world. The weighted average LCOE of grid-connected solar PV varies from as little as USD 0.15/kWh to a high of around USD 0.31/kWh. Cost reductions will continue as PV module costs decline. However, in many markets, even larger cost reductions could be possible if installed costs were to decline to the levels seen in the most competitive markets, such as Germany.

Box 2.1

THE IRENA RENEWABLE COST DATABASE

The IRENA Renewable Cost Database is an ongoing effort to collect cost and performance data of real world renewable projects. IRENA has initially collected data for the power generation sector, but this will be expanded to cover transport and stationary applications.

Data are collected from a variety of sources such as business journals, industry associations, consultancies, governments, auctions and tenders. IRENA is also engaging with banks and other financial institutions with a view to include data from the projects they fund. IRENA will officially launch the IRENA Renewable Costing Alliance in 2013. This alliance will bring together governments, financial institutions, utilities, project developers, companies, industry associations and research institutions sharing the same goals as IRENA in order to increase the availability of up-to-date and accurate real world project costs and thus facilitate more efficient renewable policy development.

The database contains fields for data on:

- Project name, location, region/sub-region/country.
- Project type and sub-type (i.e. hydro/run-of-river).
- Total capital costs and their breakdown.
- Capacity factors.
- Efficiency and fuel costs (where applicable).
- Operations and maintenance costs (labour, utilities, insurance, leases, etc.).
- Economic life of the project.
- Debt/equity ratio and the cost of finance from these two sources.
- Qualitative assessment of the quality of the data source.

As an example of the database’s content, Table 2.1 highlights the number of projects in the database for non-OECD regions by technology type for some of the technologies analysed in this paper.

TABLE 2.1: NUMBER OF PROJECTS FOR NON-OECD REGIONS IN THE IRENA RENEWABLE COST DATABASE BY TECHNOLOGY

	Africa	Middle East	Europe & Central Asia	Other Asia	China	India	Latin America
Small Hydro	24	1	5	151	668	125	97
Large Hydro	8	0	6	91	528	53	83
Small Wind	1	0	2	4	0	190	6
Large Wind	30	2	37	30	1372	416	177
Solar: utility-scale	14	6	0	35	92	24	5
Geothermal	4	0	0	12	0	0	2

The database currently contains data for around 8 000 projects from a variety of sources, although many of these are project proposals.¹ Every project incorporated in the database has basic data on the project location, type, capital costs and capacity factors, although only a smaller sub-set of the database contains more comprehensive data on the breakdown of capital costs, more complete performance data, operations and maintenance costs and financing details. IRENA is working to complete this picture, by extracting data for a single project from multiple sources for important projects.

Every effort has been made to ensure that the data are directly comparable and have the same system boundaries. Where this is not the case, the data have been corrected to a common basis using the best available data.

1 This excludes data on over 100 000 operating solar PV projects in the United States, predominantly in California, that IRENA also has access to. IRENA is also working on analysis that will reconcile the actual, ex-post costs of projects with their original project proposals (typically provided to access finance) in order to identify trends and draw out lessons for policy makers and project developers.

It is important to note that although the goal is to collect data on *costs*, strictly speaking the data available are actually *prices*. The difference between costs and prices is determined by the amount above, or below, the normal profit that would be seen in a competitive market.²

The rapid growth of renewables from a small base means that the market for renewable power generation technologies, like many other markets, is rarely well balanced. As a result, prices can rise significantly above costs in the short term if supply is not expanding as fast as demand. Conversely, in times of excess supply, losses can occur and prices may fall below the full amortised production costs to the cash cost of manufacture. While this makes analysing the cost of renewable power generation technologies challenging, it also means that the analysis has significant value. Identifying whether current equipment costs are above or below their long-term trend, and when supply and demand balances may change, can be critical to project development costs, commitment and financing decisions.

2 A normal level of profit occurs when the selling price of electricity yields a return over the life of the project equal to the cost of capital of the project. Prices above this yield "super normal" profits and prices below this lower than normal profits and potentially even losses.

The two main CSP systems are parabolic trough and solar towers. The majority of commercial experience has so far been with parabolic trough systems, which have LCOEs of between USD 0.20 to USD 0.36/kWh. The LCOEs of solar towers are similar, although a little lower, at between USD 0.17 to USD 0.29/kWh for solar towers. However, the LCOE of CSP in areas with excellent solar resources could be even lower and may be in the range of USD 0.14 to USD 0.18/kWh. Looking to the future, solar towers appear to have a greater potential for cost reductions, with higher operating temperatures also helping to improve efficiency and allow lower costs for thermal energy storage. These factors will help drive the LCOE lower and make solar towers very attractive solutions for providing flexible electricity generation and helping facilitate the penetration of wind and solar PV.

Biomass-generated electricity can be very competitive where low-cost feedstocks are available onsite at industrial, forestry or agricultural processing plants.

In such cases projects can produce electricity for as little as USD 0.06/kWh in the OECD, and as low as USD 0.02/kWh in developing countries. The typical LCOE range for biomass-fired power generation projects is between USD 0.06/kWh and USD 0.15/kWh, but where expensive feedstocks, such as woodchips or pellets, are required in gasifiers where technology experience is lower, the LCOE would be higher.

Geothermal electricity generation is a mature, baseload generation technology that can provide very competitive electricity where high-quality resources are well defined. The LCOE of conventional geothermal varies from USD 0.09 to USD 0.14/kWh for typical projects, assuming a 10% cost of capital. However, the LCOE can be as low as USD 0.05/kWh at the most competitive projects – such as those which utilise excellent well-documented or adjacent resources, or are adding capacity to an existing geothermal project – as past experience can reduce development risks and some existing infrastructure may already be in place.

Typical ranges for total installed costs by technology are presented in Figure 2.2. The total installed costs of onshore wind projects in the major OECD markets in 2011 were between USD 1 750 and USD 2 200/kW, but some projects in the United States were as low as USD 1 500/kW (Wiser and Bollinger, 2012). Costs in 2012 are trending lower, with average costs in the United States in the first half of 2012 around USD 1 750/kW. The total installed capital costs are lower

in China and India, mainly due to lower wind turbine prices (USD 630/kW for Chinese turbines in 2012), and range between USD 925 and USD 1 470/kW. Offshore wind farms are significantly more capital-intensive, with average costs of between USD 4 000 and USD 4 500/kW due to the higher costs of installation offshore, grid connection from onshore to the wind farm, and higher costs for equipment designed to cope with harsh marine environments.

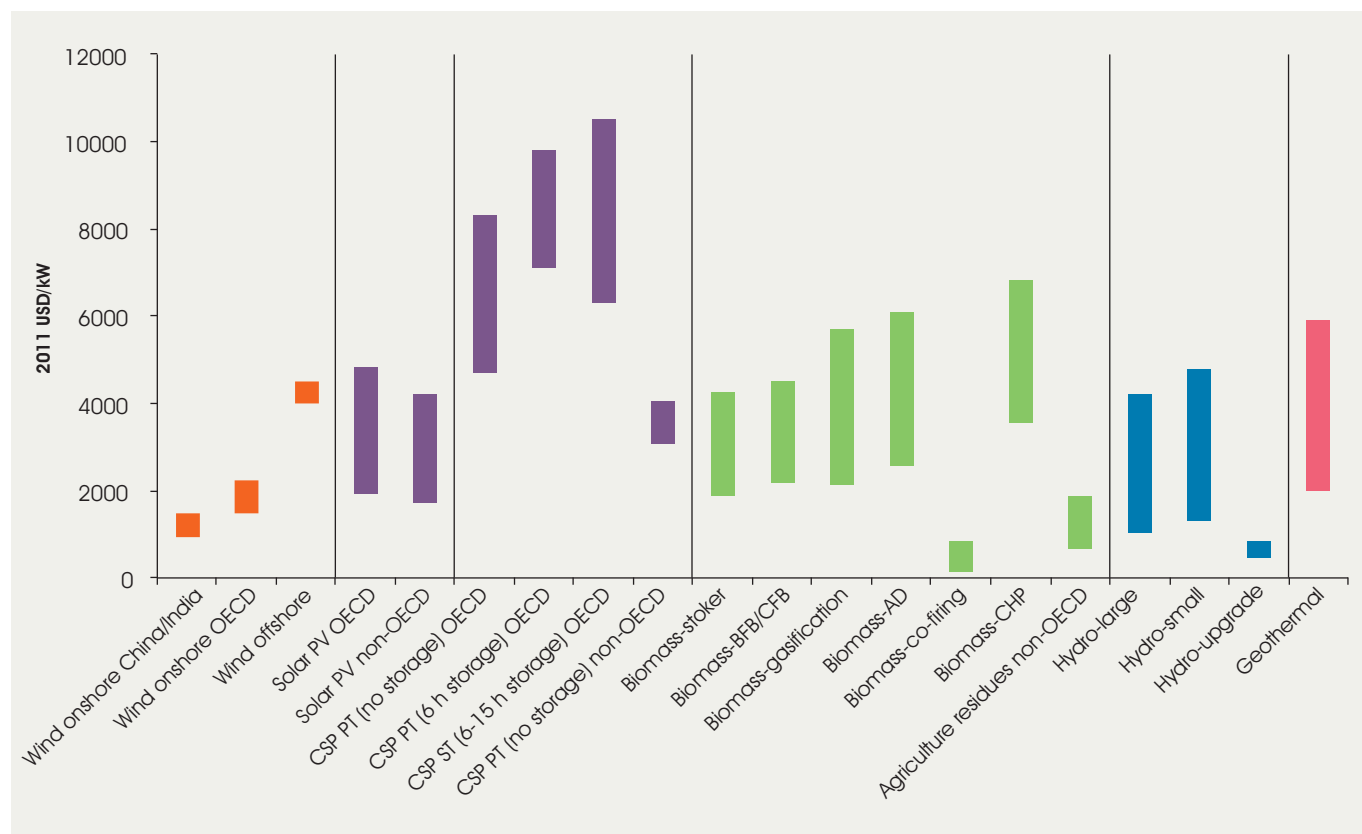


FIGURE 2.2: TYPICAL CAPITAL COST RANGES FOR RENEWABLE POWER GENERATION TECHNOLOGIES, 2012

SOURCE: IRENA RENEWABLE COST DATABASE.

The total installed cost of PV systems varies widely by sub-sector (i.e. residential rooftop, commercial rooftop, ground-mounted utility-scale), country, and even regions or states within a country. These variations reflect the maturity of domestic markets, local labour and manufacturing costs, incentive levels and structures, and a range of other factors. Total installed costs have been falling rapidly in the most competitive markets, driven by falling module prices and competitive pressures to reduce BoS costs.

Ground-mounted utility-scale systems in India, Germany and China were estimated to have the lowest average

total installed costs of USD 1 720/kW, USD 2 008/kW and USD 2 160/kW respectively (Photon Consulting, 2012) in 2012. At an average of around USD 2 200/kW for c-Si systems, Germany has the lowest PV system costs in the small-scale residential market (BSW, 2012). In comparison, the estimated average installed cost in 2012 for residential systems in China, California and Italy were USD 3 100/kW, USD 3 300/kW and 3 400/kW respectively (Photon Consulting, 2012). Average capacity factors for solar PV are typically between 0.13 and 0.25, but the recent cost reductions mean that solar PV grid-parity with residential and commercial tariffs is increasingly the norm.

CSP plants are just beginning to be deployed at scale. Parabolic trough plants without thermal energy storage have capital costs as low as USD 4 600/kW in OECD countries and may be as low as USD 3 500/kW for projects in developing countries. However, these plants have low capacity factors of between 0.2 and 0.3. Adding six hours of thermal energy storage increases capital costs to between USD 7 100 to USD 9 800/kW, but allows capacity factors to be doubled. Solar tower plants can cost between USD 6 300 and USD 10 500/kW when energy storage is between 6 and 15 hours. These plants can achieve capacity factors of 0.40 to as high as 0.80.

Globally, the least-cost generating opportunities for biomass are in developing countries, where large quantities of agricultural and forestry residues remain unexploited. These low-cost feedstocks, when combined with simple combustion technologies that can cost between USD 660 and USD 1 860/kW,¹⁶ can provide very competitive electricity for own-use and/or grid supply. In OECD countries, capital costs tend to be higher. The total installed costs of stoker boilers are between USD 1 880 and USD 4 260/kW, while those of circulating fluidised-bed boilers are between USD 2 170 and USD 4 500/kW. Anaerobic digester power systems have capital costs between USD 2 570 and USD 6 100/kW. Gasification technologies, including

16 Many of these technologies often don't meet stringent emissions regulations for local pollutants, which may limit opportunities for their use in the future.

fixed-bed and fluidised-bed solutions, had total installed capital costs of between USD 2 140 and USD 5 700/kW. Co-firing biomass at low-levels in existing thermal plants typically requires additional investments of USD 400 to USD 600/kW. The cost of installing combined heat and power (CHP) plants is significantly higher than for the electricity-only configuration.

Average investment costs for large hydropower plants with storage typically range from as low as USD 1 050/kW to as high as USD 4 215/kW. The upper end of this range represents projects that are difficult, far from existing infrastructure and/or include multi-use dams. The range of installed costs for small hydropower projects is wider and can be between USD 1 300 and USD 5 000/kW, although in developing countries costs can be as low as USD 500 to USD 600/kW at excellent sites. Adding additional capacity at existing hydropower schemes, or at existing dams that do not yet have a hydropower plant, is generally significantly cheaper than new greenfield plants, and can cost as little as USD 500/kW.

The cost of developing geothermal electricity projects has risen with other engineering costs, particularly due to increased costs of procuring drilling rigs. Average costs for condensing flash power plants are estimated to be around USD 2 000 to USD 4 000/kW, and for binary cycle plants are in the range USD 2 400 to USD 5 900/kW (Bromley *et al.*, 2010). However, where adjacent resources or untapped potential in an already operating field are being developed, costs can be lower.

Box 2.2

THE IMPORTANCE OF THE COST OF CAPITAL

The analysis in this report assumes an average cost of capital for a project of 10%. However, the cost of debt and the required return on equity, as well as the ratio of debt-to-equity varies between individual project and country. This can have a significant impact on the average cost of capital and the LCOE of renewable power projects.

The key factor that determines the cost of capital is risk. A project with greater risk (e.g. of non-payment of electricity sales, currency risk, inflation risk, etc.) will require a higher rate of return.

Capital can come in the form of equity and loans, while the project may be structured in a variety of ways. Equity is more expensive than secured loans because it carries more risk in the eventuality the project underperforms or goes bankrupt.

Governments and private sector companies can develop projects. Governments can generally borrow at a lower rate because the risk is generally, but not always, considered to be lower. However projects developed by governments tend to be more expensive

than commercial projects, which can negate the benefit of lower capital costs. An additional complication is that small projects from private investors or communities may have trouble finding finance and if they do, generally pay higher fees than large established companies.

Countries with lower perceived political and country risk, a proven track record and respected institutions benefit from more generous terms and are more likely to be able to attract private investors and arrange commercial loans. Efforts to minimise the sources of risk (Table 2.2), wherever possible, will help to reduce the cost of capital and improve the project economics.

TABLE 2.2: ENERGY PROJECT RISK FACTORS

Phase	Risks
Pre-construction	
	Technology risk
	Project design
	Debt and equity financing
Construction	
	Construction delays
	Cost overruns
	Environmental mitigation plans
	Social mitigation plans
Operation	
	Operation and maintenance costs
	Output quality/volume
	Resource fluctuations
	Electricity sales payments (PPA contracts, etc.)
Country risk	
	Currency devaluation
	Currency convertibility/transfer
	Political force majeure
	Environmental force majeure
	Regulatory risk

SOURCE: BASED ON WORLD BANK, 2007.

The financial structure of renewable generation projects and the cost of capital varies widely by technology, country, project developer and region. As an example, in the United States between the fourth quarter of 2009 and the fourth quarter of 2010 the quarterly average required return on equity for wind projects ranged from a low of 8% to a high of 14.5%. While over the same period, the quarterly average cost of debt for wind projects ranged from a low of 4.9% to a high of 11%. Making the simple assumption that the debt-to-equity ratio is between 50% and 80% and that debt maturity matches project length results in project discount rates of between 5.5% and 12.6%. This has a dramatic impact on the LCOE of wind projects, as the LCOE of wind with a capital cost of 12.6% will be 45% higher than one with a cost of 5.5% assuming a 35% capacity factor and USD 0.01/kWh for O&M.

The situation is very different in developing countries. It is often difficult for project developers to mobilise the funds necessary to bring a project to fruition. Multi-lateral and bi-lateral lending is often critical to unlocking commercial funding and terms that are not so onerous that they undermine the project economics. For instance, a reasonable weighted average cost of capital for African projects is 15-20%, except where strong guarantees are in place. This is significantly higher than the average cost of capital for renewable energy projects in OECD countries which typically are between 6% and 12%.

Public sector involvement (Government, multi-lateral or bi-lateral lenders) and guarantees can help to reduce risks that the developer has little control or no control over and encourage the private sector to invest based on the project's technical and economic merits. As a result, interest in public-private partnerships (PPPs) has been growing, with efforts to develop appropriate public policies and regulatory frameworks that will leverage multi-lateral and bi-lateral lending to increase private sector investments in renewables and climate finance in general.¹ As commercial lenders gain experience in funding renewable energy projects in robust regulatory and economic frameworks, then access to finance and the terms offered should improve.

¹ For a more detailed discussion of the challenges and opportunities of financing renewable projects in the context of "climate finance" see Limaye and Zhu, 2012.

2.2 RENEWABLE POWER GENERATION COSTS BY REGION

Figure 2.3 compares the weighted average LCOE and range of renewable power generation technologies by country/region. It is clear that there are significant differences in the cost ranges for different technologies in different regions. This is driven by the very site-specific nature of renewable resources and project costs. A regional and country-level analysis of costs is therefore critical to understanding costs and their implications for policy makers.

There is a general hierarchy of costs,¹⁷ with established renewable technologies such as hydropower, biomass and geothermal, all being able to provide electricity at low costs at the best sites. The large-scale deployment of wind since 2000 has seen its costs come down into a range that is very competitive with fossil fuels at the best sites in many regions. Solar PV is more expensive, but costs have been falling rapidly in the last two years

as over-capacity in module manufacturing has led to cutthroat competition and driven prices down below the learning curve, at least temporarily.

China has some of the most competitive renewable costs in the world. Large- and small-scale hydropower projects are the most competitive, followed by biomass, wind power, and solar PV. However, with China's abundant coal reserves and very low installed costs for fossil fuel-fired plant, the renewable energy industry still needs support to compete with incumbent technologies. Small- and large-scale hydro in China have a weighted average LCOE of USD 0.03 and USD 0.035/kWh respectively, while the range for biomass is between USD 0.05 and USD 0.06/kWh. Wind is also very competitive by global standards, with weighted average costs of around USD 0.075/kWh. Solar PV, with weighted average costs of around USD 0.19/kWh, is also quite competitive by global standards, and recent projects have been at the lower end of the range in Figure 2.3.

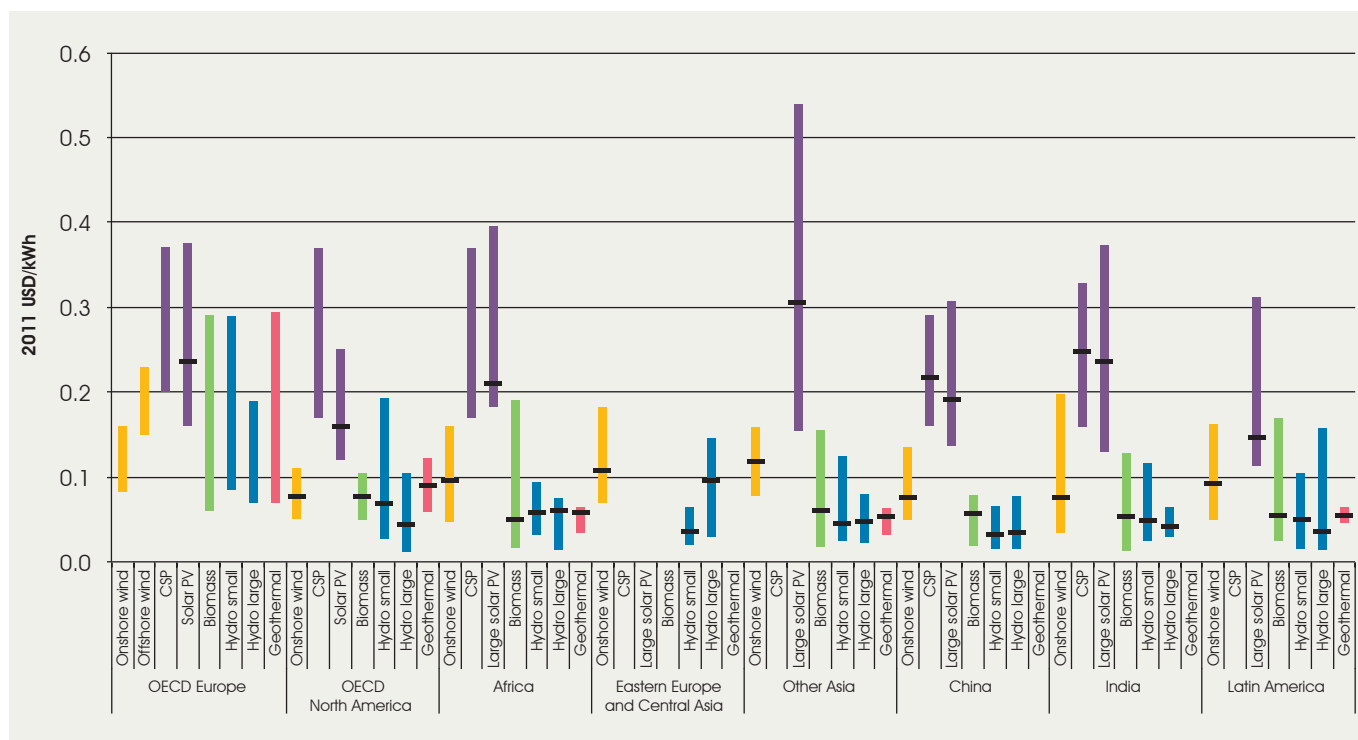


FIGURE 2.3: TYPICAL LCOE RANGES AND WEIGHTED AVERAGES FOR RENEWABLE POWER GENERATION TECHNOLOGIES BY REGION, 2012

Note: Figures assume a 10% cost of capital and biomass costs of between USD 1.3 and USD 2.5/GJ in non-OECD countries and between USD 1.3 and USD 9/GJ in OECD countries. In this chart and in all charts with individual project data, the horizontal black bars are the capacity weighted average value. Where no weighted average is shown this is because there are insufficient individual project data, usually due to only "indicative" costs being available by country.

SOURCE: IRENA RENEWABLE COST DATABASE; NREL, 2012A; AND SEIA/GTM, 2012.

¹⁷ However, given the very site-specific nature of renewables and the wide range of resource endowment by country, there is no one "true" LCOE figure that would imply a fixed hierarchy of costs.

In India, weighted average hydropower costs are between USD 0.04 and USD 0.05/kWh for small- and large-scale projects. Large-scale wind projects have average costs of around USD 0.075/kWh, while small-scale (<5 MW) projects have average costs of USD 0.083/kWh. Biomass-fired power generation costs averaged between USD 0.045 and USD 0.06/kWh assuming feedstock costs of between USD 1.3 and USD 2.5/GJ. The average LCOE of utility-scale solar PV was around USD 0.26/kWh, due to higher capital costs for the projects identified. The most recent projects for 2012 have much more competitive installed costs and appear to be closer to the Chinese average costs, with the best projects likely to have average costs of just USD 1.7/W.

In the rest of Asia the weighted average costs for biomass, solar PV and wind are all higher than in India and China. The Philippines and Indonesia both make extensive use of their excellent geothermal resources and the estimated LCOE for their geothermal power projects is around USD 0.05/kWh, assuming these projects can meet their projected high capacity factors of 80% to 90% over their entire project life. The average cost of hydropower projects in other Asian countries are very similar to those in China and India, and the region as a whole seems to share a similar cost structure.

The abundant bioenergy and hydropower resources in Latin America allow very competitive electricity generation from these two sources. The installed costs for wind are higher than in China and India, but good wind resources in many locations means the weighted average LCOE is around USD 0.09/kWh, with the best projects producing electricity for just USD 0.05/kWh. Although only a small sample of large-scale solar PV projects have sufficient data to be analysed, excellent solar resources in Peru and Chile, coupled with competitive costs for large-scale projects and the very high capacity factors achievable (27% or more), mean that some projects in these countries are as competitive as anywhere in the world.

The available data for renewable projects in Africa is thinner than for some other regions, but the costs follow a similar pattern to Latin America, with the exception that the LCOE of large hydro tends to be higher than for small hydro. Insufficient data is available to provide a definitive explanation of this finding, but poorer infrastructure, high grid connection/reinforcement costs for remote projects and multi-purpose dams probably all contribute. Collecting more data for Africa to verify if this data is accurate and the reasons for this is a priority.

Box 2.3

THE COST OF RENEWABLE POWER GENERATION ON ISLANDS

The increasing competitiveness of renewables is a welcome development for island states, particularly the least developed ones, as their reliance on diesel-fired generation is not only expensive (due to high oil prices and the generally low average efficiency of generation), but also threaten the islands' energy and economic security.

However, the barriers faced by islands to the deployment of renewable technologies are often more challenging than in other locations. With some exceptions, islands typically represent small, dispersed markets that cannot benefit from economies of scale and highly competitive supplier markets. Islands also have higher transport costs (sometimes much higher in the case of outer islands) and higher margins for the costs of procuring the balance of system components, the need to move qualified personnel between islands means installation costs will also be higher. Transaction costs and project

development costs will also be higher due to small-scale island markets and their geographically dispersed nature.

All these factors contribute to higher installed costs for renewable projects on islands than on the mainland. Despite these barriers renewables are becoming an increasingly competitive option for islands to meet the demand for electricity demand growth, reduce diesel costs and replace diesel generators at the end of their economic life.

As can be seen in Figure 2.4, renewable power generation options represent a competitive solution for meeting demand growth, particularly for remote off-grid electrification and for outer islands, where diesel costs are high and logistical problems (e.g. infrequent shipping schedules, inadequate port facilities, long lead times for parts, etc.) make renewables particularly

attractive and economic. Variable renewables can be integrated into these systems to a level of around half of total generation, while still achieving cost reductions due to the high costs of diesel-fired generation.¹ The data for off-grid solar PV systems is predominantly based on aid projects and the potential for cost

reductions from large-scale deployment, for instance by pooling projects across countries, is significant and could reduce the LCOE of off-grid solar systems with battery storage to USD 0.50 and USD 0.85/kWh.

To achieve their potential, however, renewable projects in the islands will need to overcome the difficulty in accessing capital that many projects face, particularly smaller-scale ones. As a result, many projects are funded through development banks and soft loans. In some cases this restricts competition in the procurement process, and it is often not clear to what extent the reported costs of many of these projects reflect commercial realities.

1 Not all island systems will be able to easily achieve this and additional investment in grid management and means to increase the flexibility of the existing diesel generators may be required. Higher levels of penetration than 50% will typically require investment in more expensive flexibility options such as “smart grids”, electricity storage and perhaps newer more flexible diesel generators.

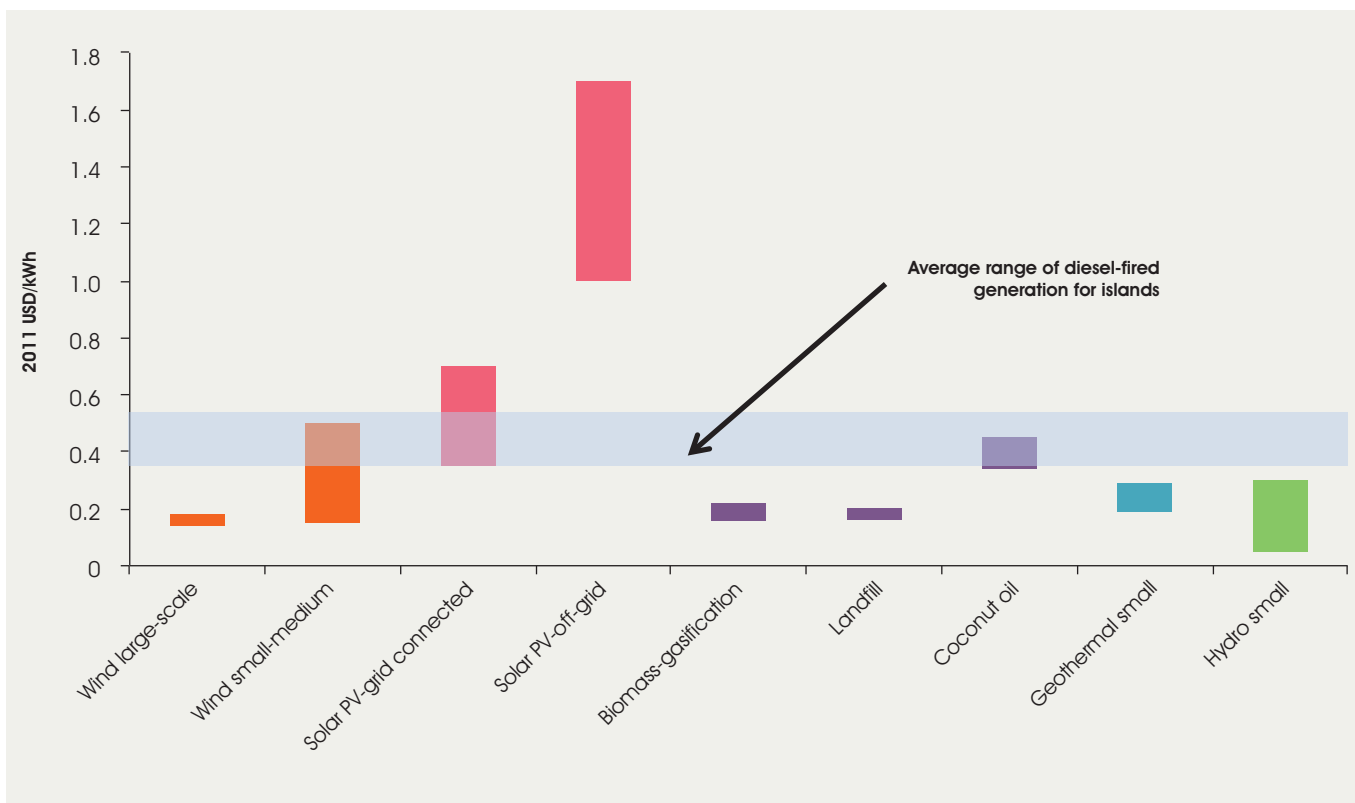


FIGURE 2.4: LEVELISED COST OF ELECTRICITY FROM RENEWABLE POWER GENERATION TECHNOLOGIES FOR PACIFIC ISLANDS

Note: Diesel generation costs can be as high as USD 2/kWh in remote, small-scale applications.

SOURCES: BASED ON DATA FROM KLIMBIE, 2012; SYNGELLAKIS, K., 2011; ZIEROTH, G.H., 2010; CASTLE ROCK CONSULTING, 2012; AND IRENA ANALYSIS.

2.3 THE DECLINING COSTS OF RENEWABLES: IMPLICATIONS

A general hierarchy exists for renewable power generation in terms of costs, but also in terms of available resources. Depending on local resources, biomass, geothermal and hydropower can all produce electricity at very competitive costs. Onshore wind is typically the next most expensive, while solar PV and CSP are more costly. However, this cost order typically follows an inverse relationship to resource availability. The availability of low-cost resources for hydropower, geothermal and biomass are all constrained to a greater or lesser extent, while long lead times for the first two mean that capacity additions cannot be ramped up or down rapidly. These factors, and the much larger wind and solar resources, have in part helped spur support for solar and PV to provide a larger share of power generation from renewables. As a result, as the deployment of wind and solar increases, we are seeing a convergence in the LCOEs for all renewable technologies.

Some regions have limited unexploited hydropower capacity and lead times are long for these projects, limiting the increase in the rate of growth in installed capacity from what was seen in 2011 that can be achieved. The overall contribution to electricity generation will remain significant and hydropower projects with storage reservoirs will be increasingly important to the least-cost integration of high levels of variable renewables. Similarly, the most competitive biomass power generation options rely on agricultural or forestry residues, where the value of the core product (food, feedstocks, or forestry products) means low-cost feedstocks for combustion are commonly produced or collected at a central location, minimising costs but also availability. Dedicated energy crops are significantly more expensive and care must be taken to ensure they are sustainably produced. Good geothermal resources are similarly not widely available and are confined to specific geographic areas.¹⁸

Conversely, wind and solar resources are much larger and are distributed, albeit unevenly, around the world. This, together with targeted policy support, has seen the level of wind and solar PV capacity grow much more rapidly than hydropower, biomass and geothermal. Since most of this recently added new renewable capacity has been variable in nature it has required an adjustment in how network operators manage electricity systems. However, the relatively modest levels of wind and solar penetration to date in most markets mean that their variable nature itself has not typically increased system operation costs.

With the increasing competitiveness and higher penetration of renewables, new challenges are emerging for policy-makers, as decisions taken today will shape the electricity system for decades into the future. The lock-in of infrastructure that comes with current investment in long-lived renewable and conventional energy assets means that sooner, rather than later, policy makers will need to move away from technology-specific support packages, to ones designed to minimise overall electricity system costs with higher levels of variable renewables, given that this is the trend in new capacity additions.

Renewable energy technologies need to work more closely together to unlock synergies and ensure there is sufficient flexibility in the system to integrate high levels of variable renewables at least cost. Since a static analysis of costs may lead to spurious conclusions about the best, and most appropriate, mix of renewable technologies, a dynamic system analysis will increasingly be required to identify the combination of renewable technologies and supporting infrastructure that will yield the lowest system costs over time. This analysis will be essential in order to inform the policy development that will incentivise the least-cost solution from a systems perspective.

18 The exception is enhanced geothermal projects where wells are drilled to significant depths before water is injected into the hot subsurface rock strata. However, this technology has not yet been deployed extensively commercially and costs are unclear.

3. GLOBAL RENEWABLE POWER MARKET TRENDS

3.1 TOTAL INSTALLED RENEWABLE POWER GENERATION CAPACITY AT THE END OF 2011

At the end of 2011, renewable power generation capacity had risen to around 1 360 GW. Although hydropower still dominates this total, the rapid growth in wind and solar PV means that its share is slowly declining. However, the rate of decline in hydro's share of renewable power generation, rather than capacity, is slower, as the capacity factors of wind and solar PV are generally lower than hydro.

Hydropower produces around 16-17% of the world's electricity and around 80% of the world's renewable

electricity, depending on the annual hydrological inflows, from around 970 GW of capacity (Figure 3.1) (REN21, 2012). This excludes pumped storage hydropower capacity, which has been estimated to be between 120 GW and 150 GW (IHA, 2011) with a central estimate of 136 GW.

Currently, more than 25 countries depend on hydropower for 90% or more of their electricity supply (99.3% in Norway), of which 12 countries have 100% hydro-based systems. Hydro produces the bulk of electricity in 65 countries and plays some role in more than 150 countries. Brazil, Canada, China and the United States have the largest hydropower generation capacity (IPCC, 2011; REN21, 2011; and IHA, 2011).

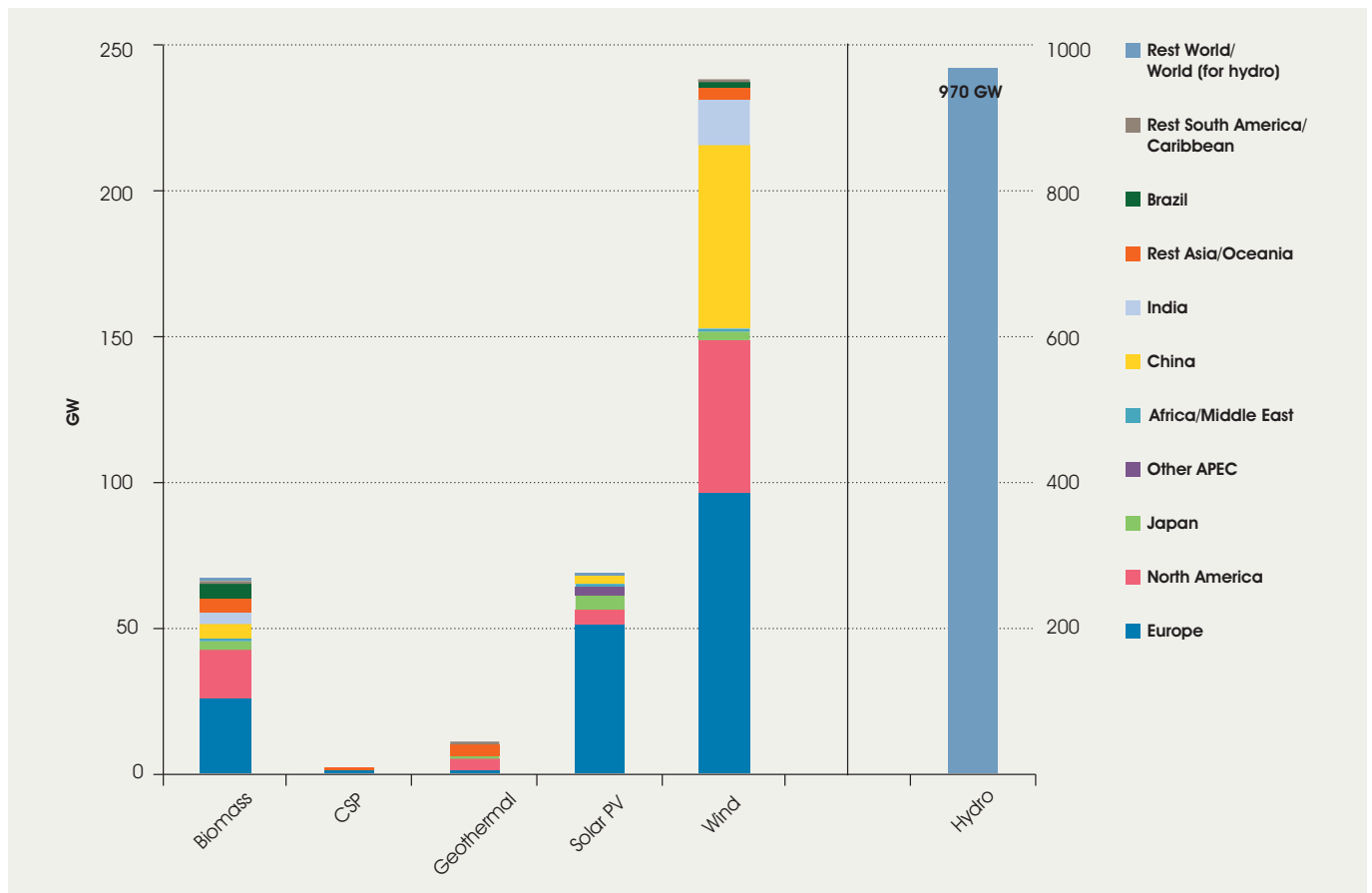


FIGURE 3.1: INSTALLED RENEWABLE POWER GENERATION CAPACITY BY TYPE, END-2011

SOURCE: EPIA, 2012; GWEC, 2012; IHA, 2012; IGA, 2012, PLATTS, 2011; AND REN21, 2012.

The total installed capacity of wind at the end of 2011 had grown to around 240 GW, making it the second largest contributor to renewable generation capacity after hydropower. Solar PV capacity had grown to around 70 GW at the end of 2011 and in 2012 has already surpassed biomass capacity, although not generation. Biomass-fired electricity generation capacity is estimated to be around 72 GW, but achieves much higher capacity factors than solar PV.

Europe and North America combined account for at least half of the total installed capacity except in the case of hydropower. Europe and North America dominate solar capacity worldwide, with 94% of global installed CSP capacity (virtually all of this CSP capacity is in Spain and the United States) and 81% of solar PV capacity in these two regions. Europe accounts for around three-quarters of total global installed solar PV capacity, with 52 GW in total. Japan and North America had around 5 GW of installed capacity at the end of 2011, while China had around 3 GW of installed solar PV capacity.

Europe accounted for around 41% of the total installed capacity of wind worldwide at the end of 2011 (GWEC, 2012), China for 26% and North America for 22%. China's wind market continues to account for around half of new installed capacity globally and its share of cumulative installed capacity will continue to increase. Of the non-hydro renewable electricity generation sources, geothermal is the most global, with 42% of capacity installed outside the OECD, predominantly in Indonesia (1.2 GW), Latin America (0.5 GW) and the Philippines (1.9 GW) (IGA, 2012). Although Europe and North America dominate the total installed biomass capacity for electricity generation, biomass distribution around the world is much more even, with significant capacity in Brazil, China, India, Japan and the rest of Asia (REN21, 2012 and PLATTS, 2011).

3.2 ANNUAL NEW RENEWABLE CAPACITY ADDITIONS

Although hydropower is the largest renewable electricity generation source, it is growing slower than other renewable technologies. In 2011, hydropower capacity increased by around 25 GW (REN21, 2012). This represents a percentage increase of around 3%. Long lead times and the fact that many of the best hydropower resources in OECD countries have already been exploited explain this slow growth. Geothermal is also a relatively mature technology, although its maturity depends on whether or not a country has a significant history of geothermal development and use. Only 136 MW of geothermal capacity was added in 2011, but 0.8 GW of new capacity was in an advanced stage of development at the end of 2011 in the United States and perhaps another 0.2 GW elsewhere (REN21, 2012).

Solar technologies are achieving the highest percentage rates of growth. In 2011, solar PV grew faster than any renewable energy technology, with 29.7 GW of new capacity installed in 2011, a 70% increase over 2010. This remarkable growth has capped an impressive 11 years, with the global installed capacity of PV having multiplied by a factor of 38 in the eleven years since 2000, when capacity was just 1.8 GW, to 70 GW at the end of 2011. This represents a growth rate of around 40% per year (Figure 3.2) (EPIA, 2012).

With virtually unlimited resources, the main constraints on the growth of solar technologies are the economic outlook and policy support measures. Annual capacity additions of 30 GW are still well below manufacturers' capabilities, as global PV module manufacturing capacity is estimated to have been around 60 GW/year in 2011 (a doubling of the 2010 capacity) and 70 GW/year in 2012 (GTM, 2012). Most of this expansion took place in mainland China and Taiwan. Given this overcapacity in PV module manufacturing capacity, some plants are being retired, but larger, newer plants in China are still coming online, so there is unlikely to be any reduction in overall capacity before 2014.

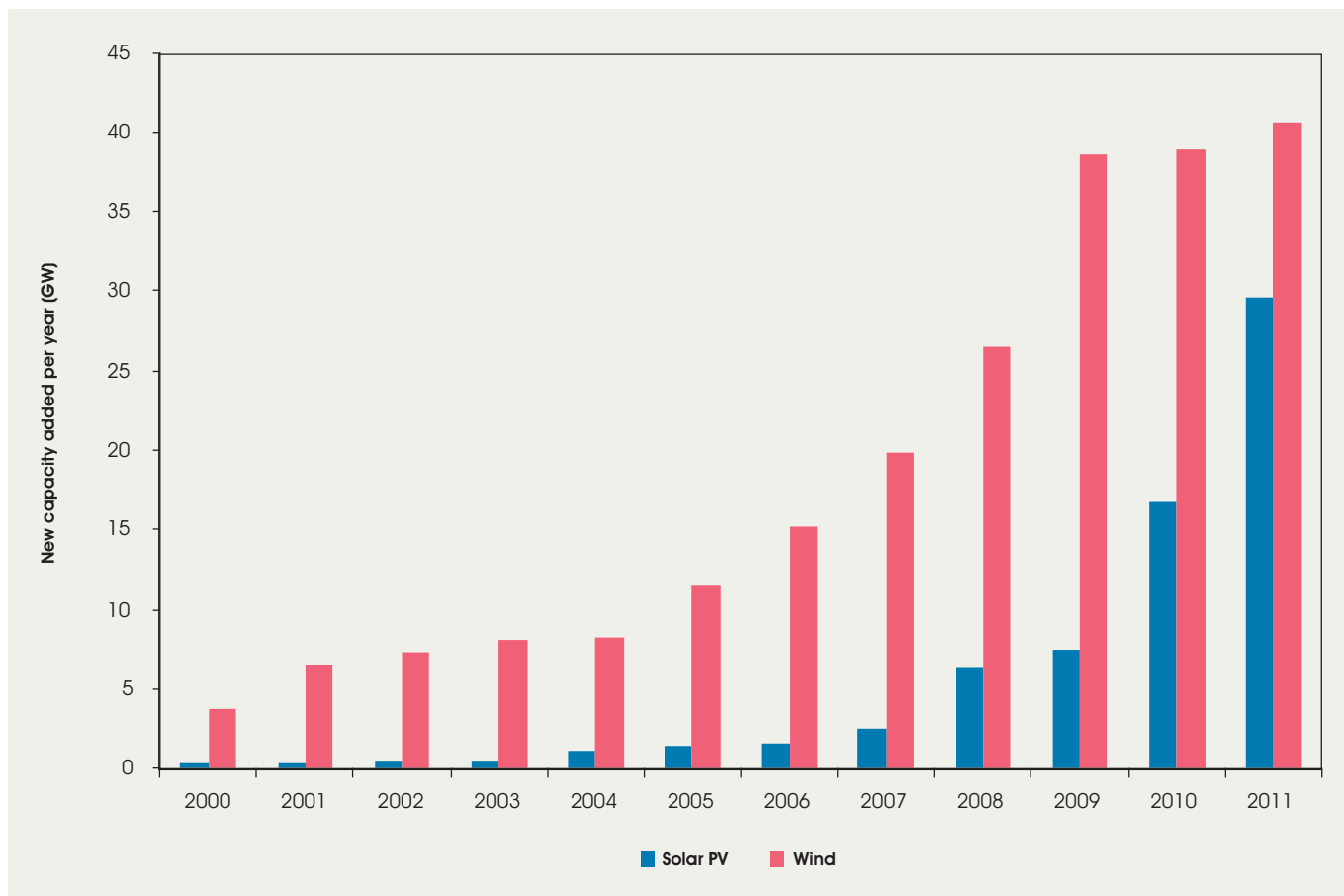


FIGURE 3.2: GLOBAL ANNUAL NEW INSTALLED CAPACITY OF SOLAR PV AND WIND, 2000-2011

SOURCE: EPIA, 2011; EPIA, 2012; AND GWEC, 2012.

The global wind power market was essentially flat in 2009 and 2010 as high wind turbine prices and economic uncertainty slowed growth, but in 2011 40.6 GW of new capacity was added, up from 38.8 in 2010 (Figure 3.3). This represents an investment of USD 68 billion in new capacity in 2011 (GWEC, 2012). Onshore wind still dominates new capacity additions and accounted for around 98% of all new capacity in 2011. However, the offshore wind market is growing rapidly, with around 0.9 GW added in 2011 (GWEC, 2012). The total global installed capacity of offshore wind reached 4.1 GW at the end of 2011.

China accounted for 43% of global wind power installations in 2011, installing 17.6 GW. In 2011, the European market added around 10 GW of new capacity, while in the United States new capacity additions rebounded from their lower levels in 2010 to add 8.1 GW in 2011. New markets are

emerging and, although starting from a low base, are seeing rapid increases in annual installed capacity. For instance, annual new capacity additions in Latin America and the Caribbean were 120% higher in 2011 than in 2010.

CSP is growing from a small installed base, but new capacity of 460 MW was installed in 2011, increasing cumulative installed capacity by 34%. Total installed capacity at the end of 2011 reached 1 760 MW and by October 2012 was around 2 400 MW. Most of this is concentrated in Spain and the United States, but an increasing number of countries are investing in CSP, including the United Arab Emirates, China, India, Italy, Algeria, Morocco and Australia.

The capacity of biomass-fired power generation is estimated to have reached around 72 GW at the end of 2011, with around 5.9 GW added in 2011.

4. WIND POWER

Wind power technologies come in a variety of sizes and styles although they can generally be categorised by whether they are horizontal axis or vertical axis wind turbines, and whether they are located onshore or offshore. Power generation of wind turbines is determined by the capacity of the turbine (in kW or MW), the wind speed, the height of the turbine and the diameter of its rotors.

The principal determinants of the LCOE of wind power systems include capital costs, operation and maintenance costs, and the expected annual energy production. Assessing the cost of a wind power system requires careful evaluation of all of these components over the life of the project. The following sections look at the latest trends in these components.

The key findings from the analysis for wind include:

- Total installed costs are declining again after having increased between 2004 and 2008/2009.
- Wind turbine costs, driven by a global overcapacity at wind turbine manufacturers, are declining and have fallen by around a quarter from their 2009 peak in the United States. There remain large discrepancies between Chinese turbine prices (USD 630/kW) and those found in the United States in 2012 (USD 900 to USD 1 270/kW), which suggest further price reductions are likely.
- With wind turbine prices in decline and capacity factors improving, the LCOE of wind is again declining after a period of increases, with this being reflected in power purchase agreements signed in 2012 in the United States.

4.1 WIND POWER CAPITAL COSTS

The installed cost of a wind power project is dominated by the upfront capital cost for the wind turbines (including towers and installation) which can account for as much as 84% of the total installed cost. The capital costs of a wind power project can be broken down into the following major categories:

- The turbine cost: Including rotor, blades, nacelle, tower and transformer;
- Civil works: Including construction costs for site preparation and the foundations for the towers;
- Grid connection costs: This can include transformers and sub-stations, as well as the connection to the local distribution or transmission network;
- Planning and project costs: These can represent a significant proportion of total costs; and
- Other capital costs: These can include the construction of roads, buildings, control systems, etc.

Figure 4.1 presents the breakdown in total costs for a typical onshore wind farm. These values can vary depending on the country, the project, and the wind turbines used, which by themselves can account for between 64% and 84% of total installed costs. Similarly grid connection costs can vary between 9% and 14%, construction and civil works from 4% to 16%, while other capital costs typically range between 4% and 10%.

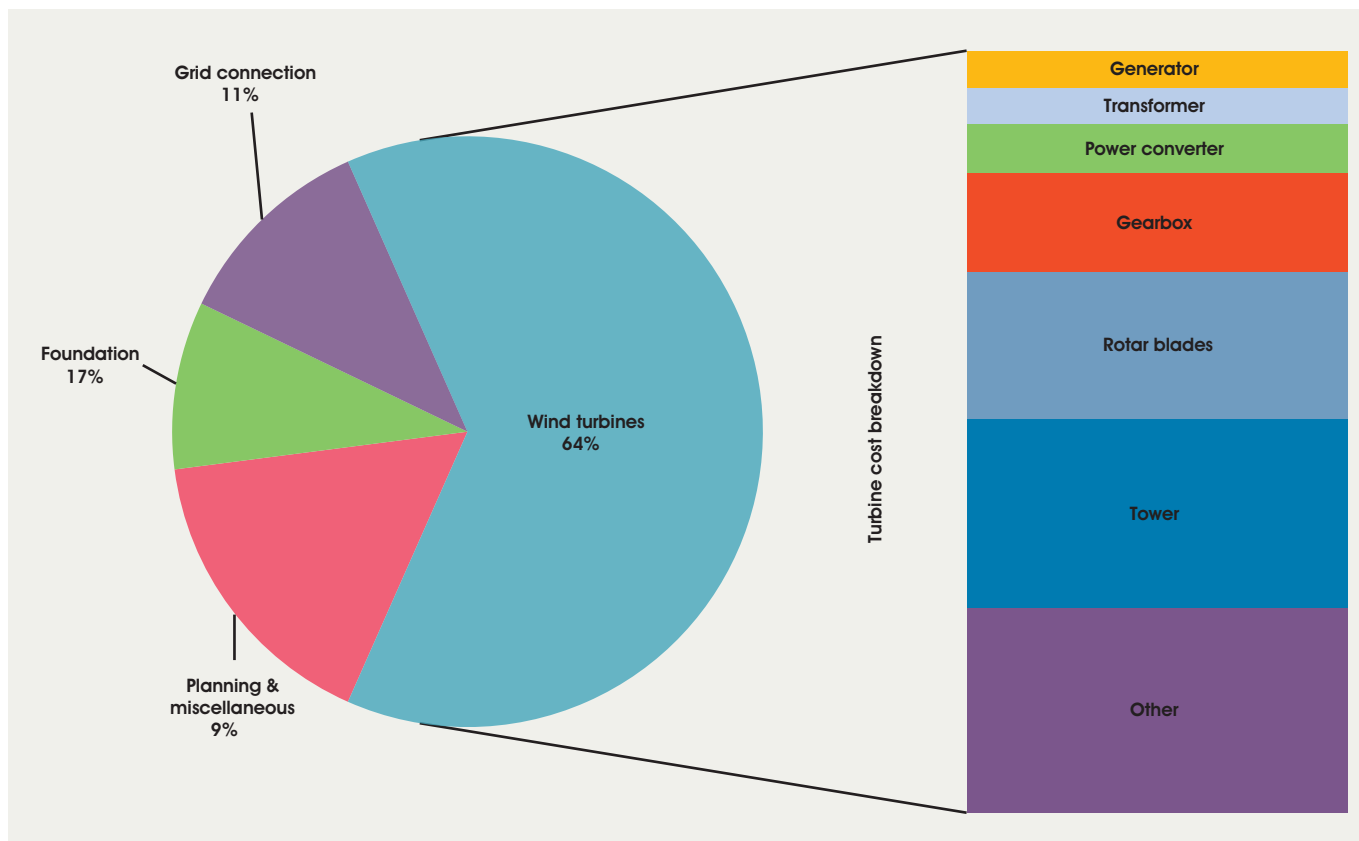


FIGURE 4.1: TYPICAL ONSHORE WIND FARM INSTALLED COST BREAKDOWN

SOURCE: BLANCO, 2009.

Table 4.1 presents a detailed capital cost breakdown for the 39.9 MW Amayo wind farm in Nicaragua. The wind turbine accounts for 69% of total installed costs, civil

works and grid connection for 15%, planning and other project development costs for 9%, while financial costs amounted to 1.4% of the total.

TABLE 4.1: BREAKDOWN OF THE CAPITAL COSTS OF THE 39.9 MW AMAYO WIND FARM

		USD million	Share
Civil works and grid connection	Civil works	7.03	7.8%
	Electrical installations low and medium voltage	1.09	1.2%
	Electrical substation (20/138 kV)	2.37	2.6%
	Overhead electrical line (20 km, 138 kV)	2.66	3.0%
	Project, engineering and management	0.59	0.7%
	<i>Total</i>	<i>13.73</i>	<i>15.3%</i>
Wind turbines and installation	Wind turbines (nacelle and rotor)	40.31	44.9%
	Tower, external switch gear and transformer	10.89	12.1%
	Supervisory control and data acquisition system	1.97	2.2%
	Installation	1.25	1.4%
	Transportation	2.64	2.9%
	Project and site management	0.28	0.3%
	Training	0.05	0.1%
	5-year warranty, maintenance and service	2.31	2.6%
	Commercial terms (costs of bonds and insurance)	0.56	0.6%
	Cranes	1.75	2.0%

		USD million	Share
	<i>Total</i>	62.00	69.1%
	Contingency	4.50	5.0%
TOTAL EPC		80.23	89.5%
Planning & other	Development costs & fees	2.00	2.2%
	Final development and feasibility studies	0.25	0.3%
	Licence for generation	0.05	0.1%
	EPC costs	0.10	0.1%
	Financial closing costs	0.15	0.2%
	Legal	0.25	0.3%
	Land agreement fee	0.43	0.5%
	Other costs	0.20	0.2%
	Construction management	0.51	0.6%
	Rights of way	0.25	0.3%
	Owners' insurance	0.57	0.6%
	Cash balance & collateral	1.00	1.1%
	Debt service reserve	2.40	2.7%
	<i>Total</i>	8.16	9.1%
Financing costs	Lender upfront fees	1.25	1.4%
	Letter of credit	0.05	0.1%
	<i>Total financing costs</i>	1.30	1.4%
TOTAL COST		89.69	100.0%

SOURCE: UNFCCC CDM DATABASE.

Offshore wind farms have significantly higher grid connection, construction costs and other project costs than onshore wind farms. These account for a higher

share of total installed costs than in onshore wind farms, lowering the share of wind turbines to between 30% and 50% for typical projects (Table 4.2).

TABLE 4.2: COMPARISON OF CAPITAL COST BREAKDOWN FOR TYPICAL ONSHORE AND OFFSHORE WIND POWER SYSTEMS IN DEVELOPED COUNTRIES

	Onshore	Offshore
Wind turbine cost share (%) ¹	64-84	30-50
Grid connection cost share (%) ²	9-14	15-30
Construction cost share (%) ³	4-10	15-25
Other capital cost share (%) ⁴	4-10	8-30

¹ Wind turbine costs include the turbine production, transportation and installation of the turbine.

² Grid connection costs include cabling, substations and buildings.

³ The construction costs include building roads and other related infrastructure required for installation of wind turbines.

⁴ Other capital costs here include development and engineering costs, licensing procedures, consultancy and permits, SCADA (Supervisory, Control and Data Acquisition) and monitoring systems.

SOURCE: BLANCO, 2009; EWEA, 2009; DOUGLAS WESTWOOD, 2010; AND MAKE CONSULTING, 2011.

4.1.1 WIND TURBINE COSTS

The wind turbine is the largest single cost component of the total installed cost of a wind farm. Between 2000 and 2002 turbine prices for onshore wind farms averaged USD 700/kW, but this had risen to USD 1 500/kW in the United States and USD 1 800/kW in Europe in 2009. This increase was due to rising costs for materials (e.g. steel and cement) and civil engineering, high profit margins for wind turbine manufacturers, and larger turbines that cost more (notably for towers and foundations) but achieve higher capacity factors.

Since the peak prices of around USD 1 800/kW in Europe and USD 1 500/kW in the United States (Wiser and Bollinger, 2012) for contracts with a 2008/2009 delivery, wind turbine prices have started to fall. Preliminary data for 2012 projects suggest quotes between USD 900 and USD 1 270/kW in the United States, which would represent a decline of around a quarter, compared to peak prices. This is in line with the BNEF Wind Turbine Price Index (WTPI), which indicates average turbine prices outside Asia of around USD 1 200/kW for 2012 (BNEF, 2012) (Figure 4.2).



FIGURE 4.2: WIND TURBINE PRICES IN THE UNITED STATES AND CHINA COMPARED TO THE BNEF WIND TURBINE PRICE INDEX, 1997-2012

Note: BNEF WTPI is the half-year average for non-Asian markets, while the United States data is for the specific month of a particular project, and the Chinese data are annual averages.

SOURCE: IEA WIND, 2007, 2008, 2009, 2010, 2011A, AND 2012; WISER AND BOLLINGER, 2012; AND BNEF, 2012.

These cost reductions are occurring at the same time as the yield of a given turbine is being improved by increased average hub heights and rotor diameters. In addition, a more buyer-friendly market has meant that better terms and conditions are being offered by manufacturers, including longer initial O&M contracts, improved warranty terms, better performance

guarantees and shorter lead times for delivery (Wiser and Bollinger, 2012).

The increased competition in the wind turbine market is partly due to the rise of Chinese and other emerging market manufacturers. Chinese manufacturers have increased capacity significantly above domestic

demand, resulting in domestic turbine prices averaging USD 658/kW in 2010 and falling to between USD 580 and USD 610/kW in 2011 (CWEA, 2012), before rebounding slightly to an average of USD 630/kW in 2012. Chinese manufacturers are therefore very competitive potential suppliers in the international market, although not all Chinese manufacturers' products are necessarily suited to international markets. If the wind market were to emulate a similar dynamic to past events in the PV market, where Chinese overcapacity led to cut-throat competition with significant cost and price declines, there could be further significant decreases in wind turbine prices as wind turbine costs converge globally.

4.1.2 TOTAL INSTALLED COSTS ONSHORE

The cost reductions in wind turbine prices are taking some time to flow into installed project costs. Initial data for 2012 from the United States suggest that total installed costs in 2012 have fallen from an average of around USD 2 100/kW in 2011 to USD 1 750/kW in the first half of 2012 (for 2.6 GW of projects), with the most competitive projects still around USD 1 500/kW (Wiser and Bollinger, 2012).

Average installed costs in 2011 in China were among the lowest in the world (Table 4.3), as overcapacity in manufacturing, a large domestic market, low commodity (steel and cement) costs and an ever-increasingly competitive development industry drives down costs.

TABLE 4.3: TYPICAL TOTAL INSTALLED COSTS FOR WIND FARMS BY COUNTRY

	Year for costs	New capacity 2011 (GW)	Cost range (USD/kW)
China	2011	17.60	1 114 – 1 273
Australia	2011	0.23	1 600 – 3 300
Austria	2011	0.07	2 368
Brazil	2011	0.58	1 650 – 2 850
Denmark	2010	0.18	1 600 – 1 700
Europe (weighted average)	2010	10.28	~1 600
Ireland	2011	0.24	2 000 to 2 600
Italy	2011	0.95	1 941 – 2 588
Japan	2011	0.17	3 900
Mexico	2011	0.05	2 000
Norway	2011	0.08	1 900 – 2 000
Portugal*	2011	0.38	1 810
Spain	2009	1.05	2 000
United States	2011	6.81	2 100

SOURCE: GWEC, 2012; IEA WIND, 2011A; IEA WIND, 2011B; AND EWEA, 2011.

Note: * excludes grid connection and land costs.

There are considerable economies of scale in wind power developments, shown by the fact that projects under 5 MW have significantly higher total installed costs than larger projects (Wiser and Bollinger, 2012). However, there do not appear to be the same economies of scale when shifting from the 5 MW to 20 MW range to higher capacities. Between 2009 and 2011, projects in the United States in the 0-5 MW scale had total installed costs of around USD 2 500/kW, while those in the 5-20 MW scale were around USD 2 300/kW. The average installed costs for projects 20 MW and above averaged around USD 2 100 to USD 2 200/kW (Wiser and Bollinger, 2012).

The total installed costs of projects in non-OECD countries show a significant spread, as can be seen in Figure 4.3. China and India have low-cost local manufacturing bases and have developed local wind industries of some scale. Their costs are therefore significantly lower than in other non-OECD regions. Other non-OECD countries and regions do not have such extensive local manufacturing and project development industries which, combined with higher costs for project development, overseas engineers and staff, transport, basic materials (e.g. cement, steel, etc.), cranes, grid connection and other costs mean that installed costs are typically higher, with average costs

in the range of USD 2 000 to USD 2 300/kW depending on the region. However, these are not dissimilar to OECD values. It is important to note that the non-OECD regions with higher costs than China and India offset this to some extent by having higher capacity factors (see Section 4.2).

The range of installed costs in non-OECD countries highlights the possibilities for the competitive deployment of wind outside of the OECD, China and India. Growing regional hubs for markets in wind will help to alleviate some of the cost pressures, although installed costs are unlikely to ever be as competitive as in China and India with their large domestic markets.

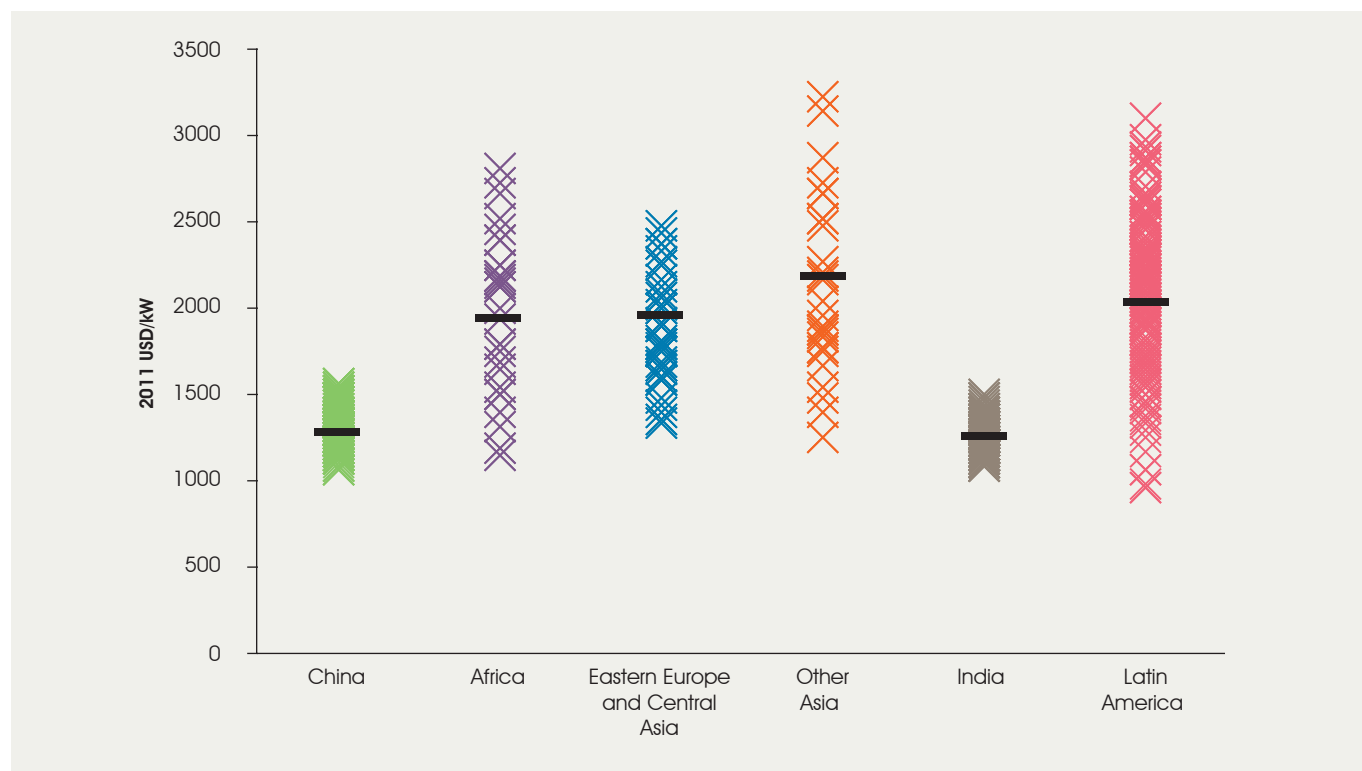


FIGURE 4.3: TOTAL INSTALLED COSTS AND WEIGHTED AVERAGES OF COMMISSIONED AND PROPOSED LARGE WIND FARMS IN NON-OECD COUNTRIES AND REGIONS (>5MW), 2009-2012

SOURCE: IRENA RENEWABLE COST DATABASE.

India has deployed large numbers of small wind farms of up to 5 MW. Figure 4.4 presents data for proposed and already commissioned small wind farms in India. The average cost of these projects is very similar to the

overall average cost for the country's large wind farms, although the range is narrower than for >5 MW scale wind farms. The most notable difference is that there are fewer wind farms with very low installed costs.

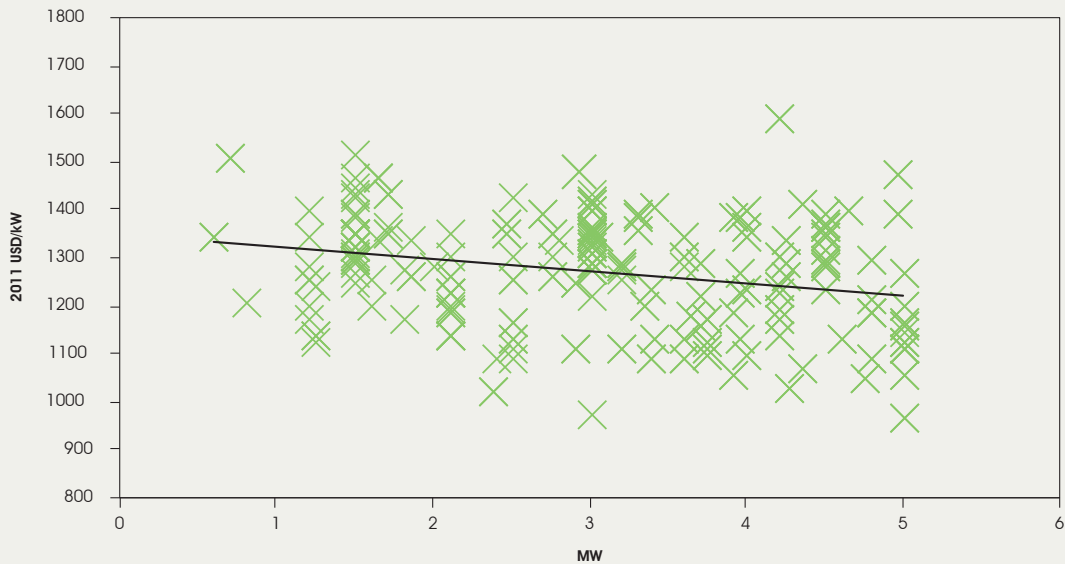


FIGURE 4.4: TOTAL INSTALLED COSTS OF COMMISSIONED AND PROPOSED SMALL WIND FARMS IN INDIA (<5MW)

SOURCE: IRENA RENEWABLE COST DATABASE.

Small wind turbines for rural electrification carry significantly higher costs, with installed costs of USD 10 000/kW for a 1 kW turbine, USD 5 000/kW for a 5 kW turbine and USD 2 500/kW for a 250 kW machine being representative for Africa (Klimbie, 2012).

4.1.3 TOTAL INSTALLED COSTS OFFSHORE

The installed costs of offshore wind power are typically twice that of onshore wind energy projects, but can be even higher (Figure 4.5). The higher cost is due

to increased investments in laying cables offshore, constructing expensive foundations at sea, transporting materials and turbines to the wind farm, and installing foundations, equipment and the turbines themselves. The turbines themselves, although based on onshore designs, are also somewhat more expensive. They need to be designed with additional protection against corrosion and the harsh marine environment to help reduce maintenance costs, which are also higher offshore (Douglas Westwood, 2010).

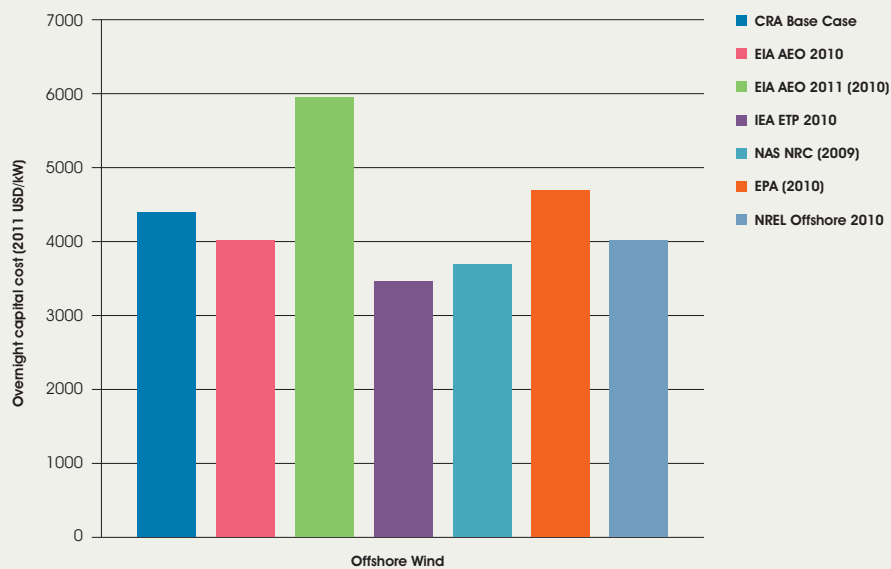


FIGURE 4.5: ESTIMATED TOTAL INSTALLED COSTS FOR OFFSHORE WIND FARMS

SOURCE: DOUGLAS WESTWOOD, 2010.

The largest cost component for offshore wind farms is still the wind turbine, but it accounts for less than half (44%) of the total capital costs (Douglas Westwood, 2010). Based on price assessment of wind turbines of the major manufacturers, and other research into the component costs, it was estimated that the average price of an offshore wind turbine was around USD 1 970/kW (Douglas Westwood, 2010). The foundations, electrical infrastructure, installation and project planning all account 16%, 17%, 13% and 10% of the total costs, respectively. According to the estimates of Douglas Westwood, the current capital cost of the offshore wind power system for typical shallow water and semi-near shore conditions in the UK is USD 4 471/kW which is around 2.5 times higher than onshore. It should be noted that offshore wind farm costs increased in the decade to 2012 as experience with the complexities of offshore wind farms grew.

4.2 CAPACITY FACTORS FOR WIND POWER

As wind speed increases, the amount of available energy increases, following a cubic function. A doubling of wind speed increases the power output of a wind turbine by a factor of eight (EWEA, 2009). There are therefore considerable economic incentives to the siting of wind farms in areas with high average wind speeds.

In addition, wind generally blows more consistently at higher speeds at greater heights. For instance, a fivefold

increase in the height of a wind turbine above the prevailing terrain can result in twice as much wind power. Increased height also allows larger rotor blade diameters, which is important because the maximum energy than can be harnessed by a wind turbine is roughly proportional to the swept area of the rotor. By doubling the rotor diameter, the swept area, and therefore the power output is increased by a factor of four.

Higher hub heights and larger swept areas have therefore played a role in increasing the average capacity factors of wind farms, as larger turbines will achieve higher capacity factors at the same site. For instance, the standard wind turbine technology from 2002/2003 at a wind site with a 6 metres/second wind speed would have yielded a capacity factor of around 0.22, while today's standard technology would yield a capacity factor of 0.29 and today's technologies specifically designed for low-wind speed regimes could boost that to as high as 0.37 (Wiser and Bollinger, 2012).

The net impact of these trends can be difficult to differentiate, but Figure 4.6 highlights the rise in average capacity factors that has occurred in the United States. In the United States, the capacity-weighted average capacity factors for projects rose until 2008 (for projects installed in 2007) to around 35%, dipped in 2009 and 2010 at around 31% to 32%, before increasing again in 2011 to around 33% (Wiser and Bollinger, 2012).

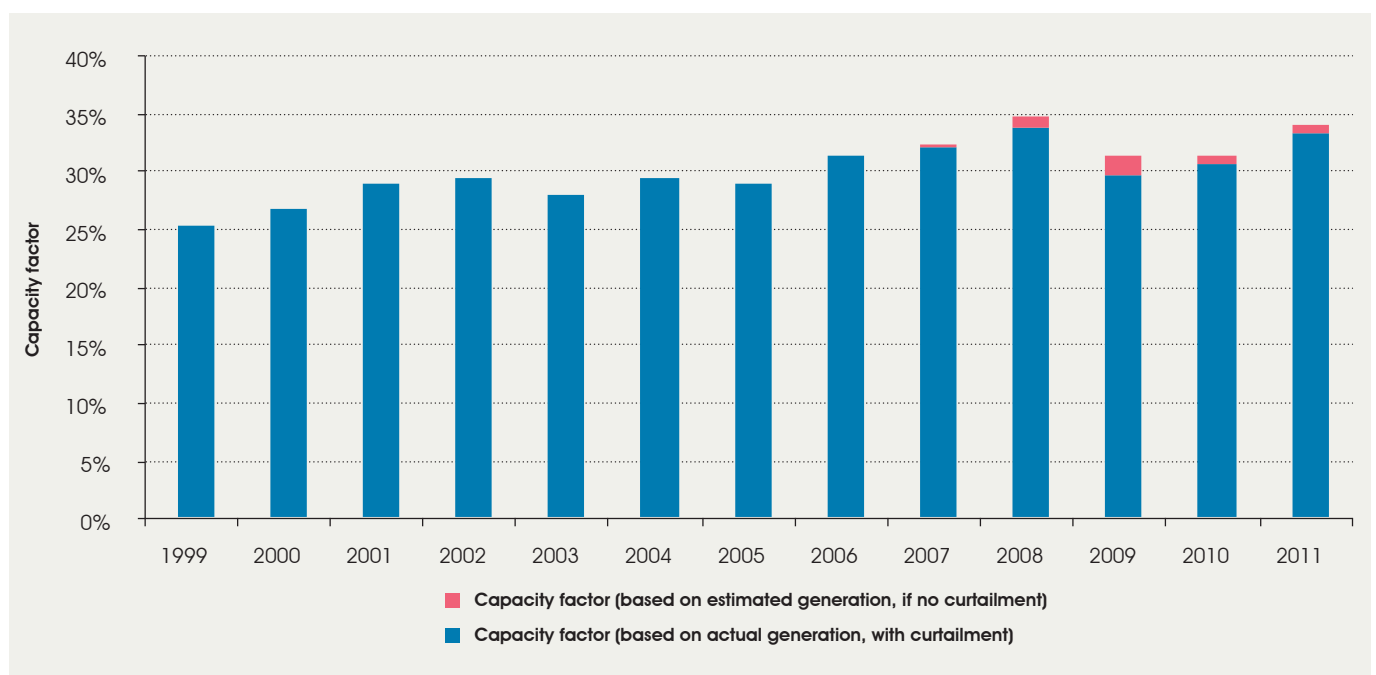


FIGURE 4.6: AVERAGE CUMULATIVE CAPACITY FACTOR BY YEAR IN THE UNITED STATES

SOURCE: WISER AND BOLLINGER, 2012.

Figure 4.7 presents the ranges for wind farm capacity factors for current and to-be-commissioned projects by region where data are available. Weighted average capacity factors varied by region between around 25% for China and 42% for Latin America. By comparison, new projects in the United States in 2011 had average capacity factors of 33%, with the

range between 18% and 53% (Wiser and Bollinger, 2012). The capacity factor ranges for Africa and Latin America are similar to those in the United States. China's capacity factors are similar to the European pattern, although curtailments due to grid constraints in China means the average capacity factor for dispatched generation is closer to 20%.

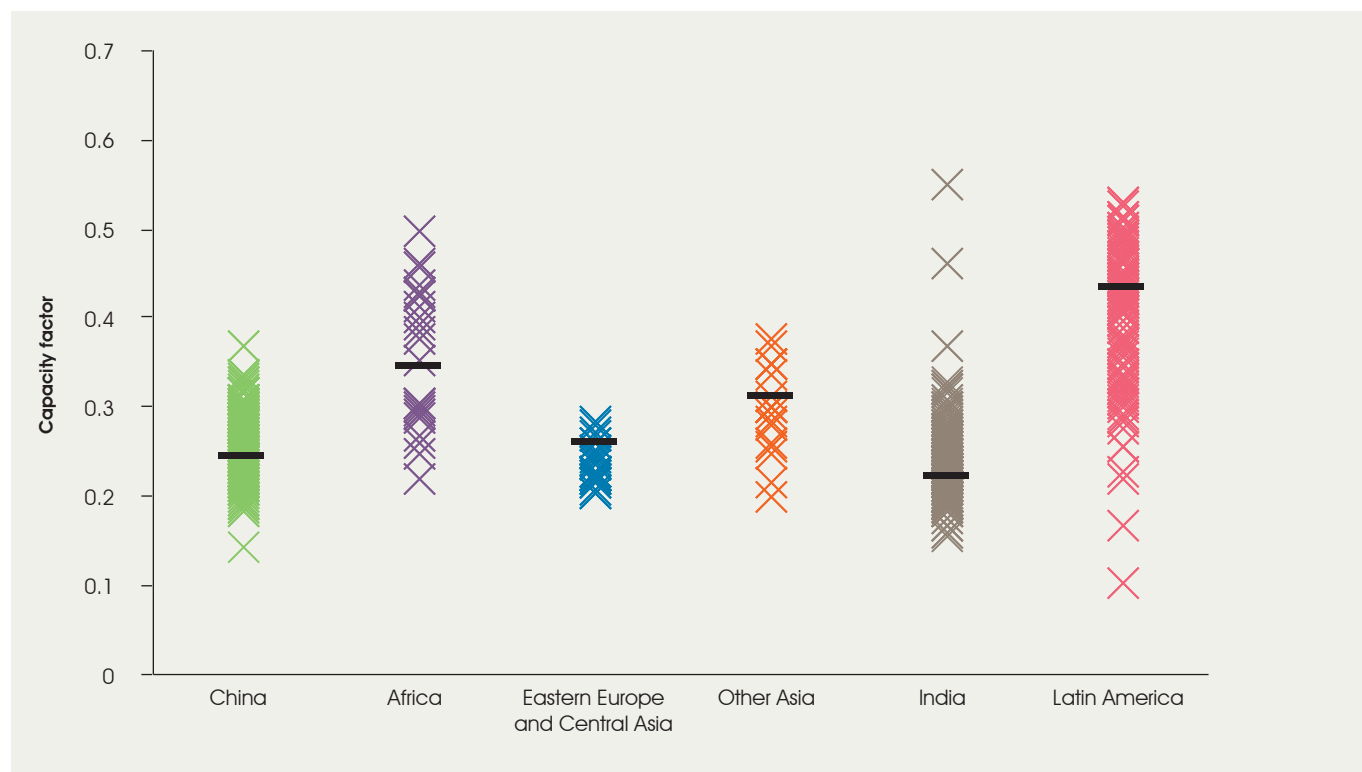


FIGURE 4.7: CAPACITY FACTORS AND WEIGHTED AVERAGES FOR COMMISSIONED AND PROPOSED LARGE WIND FARMS (>5 MW) IN NON-OECD REGIONS

SOURCE: IRENA RENEWABLE COST DATABASE.

4.3 OPERATIONS AND MAINTENANCE COSTS

The fixed and variable operations and maintenance (O&M) costs are a significant part of the overall LCOE of wind power. O&M costs typically account for 20% to 25% of the total LCOE of current wind power systems (EWEA, 2009).

Data for actual O&M costs from commissioned projects are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes that have occurred in wind turbine technology over the last two decades. However, it is clear that annual average O&M costs of wind power systems have declined substantially since 1980. In the United States, data for completed projects suggest that total

O&M costs (fixed and variable) have declined from around USD 0.03/kWh for 24 projects that were completed in the 1980s, to USD 0.02/kWh for 27 projects installed in the 1990s, and to USD 0.01/kWh for the 65 projects installed in the 2000s (Wiser and Bollinger, 2012).

Unfortunately, not all sources separate out fixed and variable O&M costs, and it is not uncommon for O&M costs to be quoted as a total of USD/kW/year. O&M costs appear to be the lowest in the United States at around USD 0.01/kWh, perhaps due to the scale of the market and the country's long experience with wind power. European countries tend to have higher cost structures for O&M for onshore wind projects (Table 4.4) where an average value of between USD 0.02 and USD 0.03/kWh is the norm.

TABLE 4.4: OPERATIONS AND MAINTENANCE COSTS FOR ONSHORE WIND PROJECTS BY COUNTRY

	Variable (2011 USD/kWh)	Fixed (2011 USD/kW)
Austria	0.038	
Denmark	0.0144 - 0.018	
Finland		35 - 38
Germany		64
Italy		47
Japan		71
The Netherlands	0.013 – 0.017	35
Norway	0.020 – 0.037	
Spain	0.027	
Sweden	0.010 – 0.033	
Switzerland	0.043	
United States	0.010	

SOURCE: IEA WIND, 2011B.

O&M costs for offshore wind farms are significantly higher than for onshore wind farms due to the higher costs involved in accessing and conducting maintenance on the wind turbines, cabling and towers. Maintenance costs are also higher as a result of the harsh marine environment and the higher expected failure rate for some components. Overall, O&M costs are expected to be in the range of USD 0.027 to USD 0.054/kWh (ECN, 2011).

Given that offshore wind farms are at the beginning of their deployment phase, O&M costs remain highly project-specific and it will take time for learning to reduce costs and for a clear trend to emerge. However, it is clear that reducing O&M costs for offshore wind farms remains a key challenge and one that will help improve the economics of offshore wind.

4.4 THE LEVELISED COST OF WIND ELECTRICITY

The levelised costs of electricity for wind power systems are set by total capital costs, wind resource quality, technical characteristics of the wind turbines, operations and maintenance costs and the discount rate.

Based on the data and analysis presented earlier, wind turbine costs in 2011 ranged from around USD 600/kW in China up to around USD 1 350/kW in developed countries. Wind turbine prices in 2012 are likely to be lower than their 2011 values and be in the range USD 900 to USD 1 300/kW in developed countries.

Total installed costs are starting to come down in line with reductions in wind turbine costs, with initial data for the United States suggesting that total installed costs have come down from around USD 2 100/kW in 2011 to around USD 1 750/kW for the projects with data for 2012. Similar cost reductions are likely to be seen in other OECD markets.

Operations and maintenance costs vary from a best practice case of around USD 0.01/kWh in the United States to a more typical USD 0.025/kWh in Europe.

Figure 4.8 presents the LCOE of wind power by region and country outside of the OECD assuming a 10% cost of capital. As can be seen, average costs are in the range of USD 0.08 to USD 0.12/kWh. China and India have the lowest estimated costs of electricity from wind, but the LCOE of wind is also competitive in Latin America and Africa, where good resources are available.

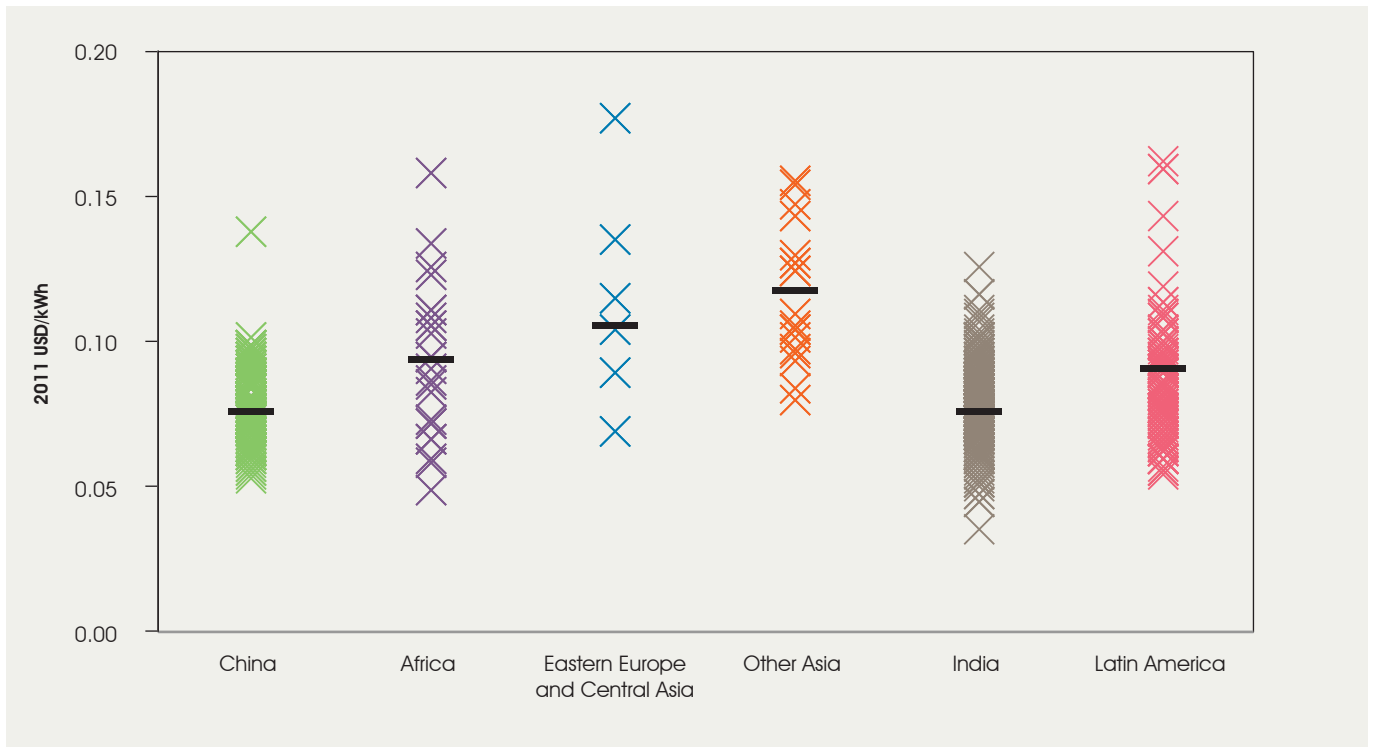


FIGURE 4.8: THE LCOE AND WEIGHTED AVERAGES OF COMMISSIONED AND PROPOSED LARGE WIND FARMS (>5 MW) IN NON-OECD REGIONS

SOURCE: IRENA COST DATABASE.

The LCOE of offshore wind, assuming a 45% capacity factor and USD 0.035/kWh O&M cost, is between USD 0.15 and USD 0.17/kWh. This range drops to USD 0.14 to USD 0.15/kWh when the capacity factor is

50%. The high O&M costs of offshore wind farms add significantly to the LCOE of offshore wind farms and cost reductions in this area will be critical to improving their long-term economics.

5. HYDROPOWER

Hydropower, excluding pumped storage, with a global installed capacity of around 970 GW at the end of 2011, is currently the largest renewable power generation source. At good sites it provides the cheapest electricity of any generation technology. Hydropower is a mature technology and the LCOEs of currently installed projects and those coming on stream are generally low. Hydropower is unique among other renewable power generation technologies in that it also provides other services, such as water storage, irrigation opportunities and flood control. However, ensuring that new hydropower projects respect the three pillars of sustainability will be critical to reducing project lead times and accelerating deployment.¹⁹

When hydropower schemes have storage that is manageable, in a reservoir behind the dam, hydropower can contribute to the stability of the electrical system by providing flexibility and grid services. It can help with grid stability, as spinning turbines can be ramped up more rapidly than any other generation source. Pumped storage hydropower is specifically designed to provide these services, as well as to provide an arbitrage between periods of low and high electricity prices. However, the LCOE analysis does not include an estimate of the value of these services, as they are very system-specific.

With large reservoirs, hydropower can also store energy over weeks, months, seasons or even years. Hydropower can therefore provide the full range of ancillary services required to allow a high penetration of variable renewable energy sources, such as wind and solar. The importance of hydropower is therefore likely to grow over time and, although it has long lead times, growth in hydropower capacity projects that respect the three pillars of sustainability will be very important in helping facilitate the high penetration of renewables where remaining resources are yet to be developed.

¹⁹ The three pillars or aspects of sustainability are economic, environmental and social.

Key findings from the analysis for hydropower include:

- Hydropower produces some of the lowest-cost electricity of any generation technology. The LCOE of large-scale hydro projects at excellent sites can be as low as USD 0.02/kWh, while average costs are around USD 0.05/kWh.
- Small hydropower can be a very attractive electrification option and can provide low-cost electricity to remote communities or for the grid.
- Hydropower is a mature technology, with limited cost reduction potentials in most settings. However, significant low-cost potential remains to be exploited in many countries.

5.1 HYDROPOWER CAPITAL COSTS

Hydropower is a renewable energy source based on the natural water cycle. Hydropower is the most mature, reliable and cost-effective renewable power generation technology available. Hydropower schemes often have significant flexibility in their design and can be designed to meet base-load demands with relatively high capacity factors, or have higher installed capacities and a lower capacity factor, but meet a much larger share of peak electricity demand.

One key advantage of hydropower is its unrivalled “load following” capability (i.e. it can meet load fluctuations minute-by-minute). As a result of this flexibility, hydropower is an ideal complement to variable renewables as, when the sun shines or the wind blows, reservoir levels can be allowed to increase, thus creating a reserve for times when there is less wind or sunshine. Similarly, hydro can meet the demands that arise when large ramping up or down of supply is needed due to increases or decreases in solar or wind generation.

Hydropower is the only large-scale and cost-efficient electricity storage technology available today. It is also a relatively efficient energy storage option. Despite promising developments in other energy storage

technologies, hydropower is still the only technology offering economically viable large-scale storage.

Hydropower plants can be constructed in a variety of sizes and with different characteristics. In addition to the importance of the head (height of the water drop to the turbine) and flow rate, hydropower schemes can be put into the following categories:

- Run-of-river hydropower projects have no, or very little, storage capacity behind their dams and generation is dependent on the timing and size of river flows.
- Reservoir (storage) hydropower schemes have the ability to store water behind the dam in order to de-couple generation from hydro inflows. Reservoir capacities can be small or very large, depending on the characteristics of the site and the economics of dam construction.
- Pumped storage hydropower schemes use off-peak electricity to pump water from one reservoir to a higher reservoir, so that the pumped storage water can be used for generation at peak times and provide grid stability and flexibility services.

Hydropower is a capital-intensive technology with long lead times for development and construction due to the significant feasibility, planning, design and civil

engineering works required. There are two major cost components for hydropower projects:

- The civil works for the hydropower plant construction, including any infrastructure development required to access the site and the project development costs.
- The costs related to electro-mechanical equipment.

Project development costs include planning and feasibility assessments, environmental impact analysis, licensing, fish and wildlife/biodiversity mitigation measures, development of recreational amenities, historical and archaeological mitigation, and water quality monitoring and mitigation.

The cost breakdown of an indicative 500 MW new greenfield hydropower project in the United States is presented in Figure 5.1. The civil works associated with the dam/reservoir account for just over one-quarter of the total costs, while penstocks, tailraces and tunnelling add another 14%. The powerhouse, shafts and electro-mechanical equipment together account for 30% of the total costs. The long lead times for these types of hydropower projects (7-9 years) mean that owner costs (including the project development costs) can be a significant portion of the overall costs due to the need for working capital and interest during construction.

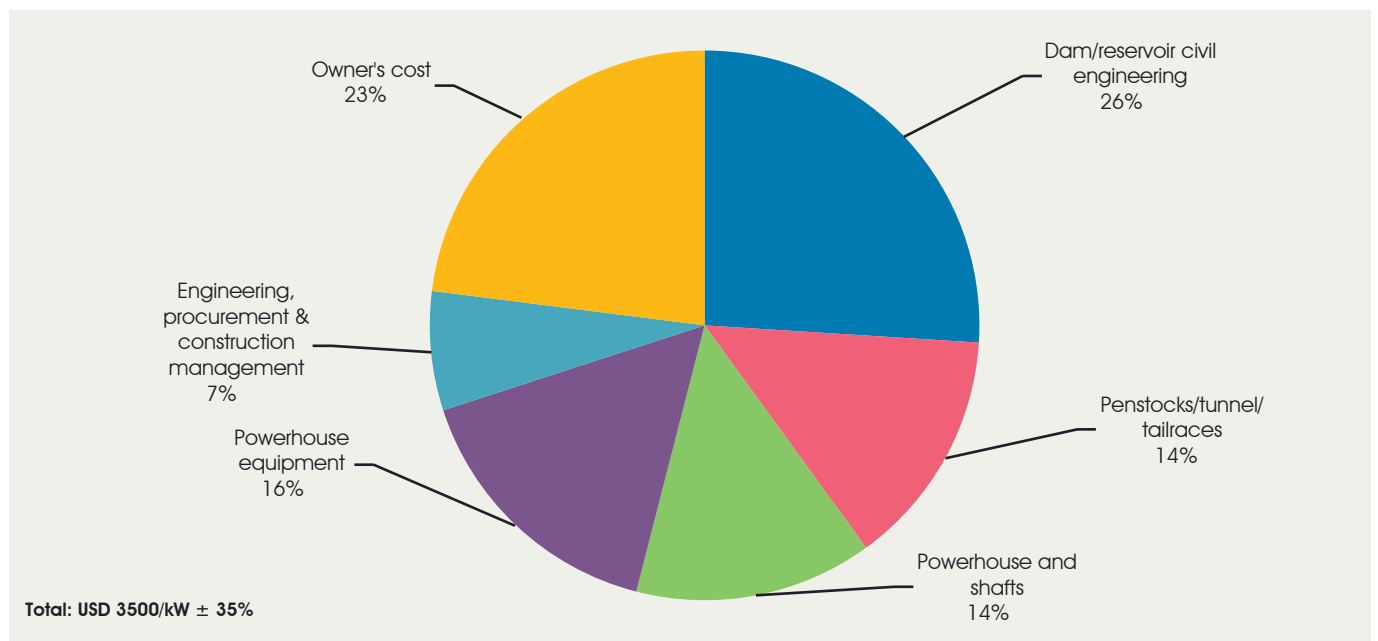


FIGURE 5.1: COST BREAKDOWN OF AN INDICATIVE 500 MW GREENFIELD HYDROPOWER PROJECT IN THE UNITED STATES

SOURCE: BLACK AND VEATCH, 2012.

The largest share of installed costs for large hydropower plant is typically for civil construction works (such as the dam, tunnels, canal and construction of powerhouse, etc.). Electrical and mechanical equipment usually contributes

less to the total cost. However, for hydropower projects where the installed capacity is less than 5 MW, the costs of electro-mechanical equipment may dominate total costs due to the high specific costs of small-scale equipment.

Box 5.1

CAPITAL COST BREAKDOWN FOR SMALL HYDROPOWER PROJECTS

The cost breakdown for small hydro projects in developing countries reflects the diversity of hydropower projects and their site-specific constraints and opportunities (Figure 5.2). Electro-mechanical equipment costs tend to

be higher than for large-scale projects, contributing from 18% to as much as 50% of total costs. Infrastructure costs can dominate total costs for projects in remote or difficult to access locations.

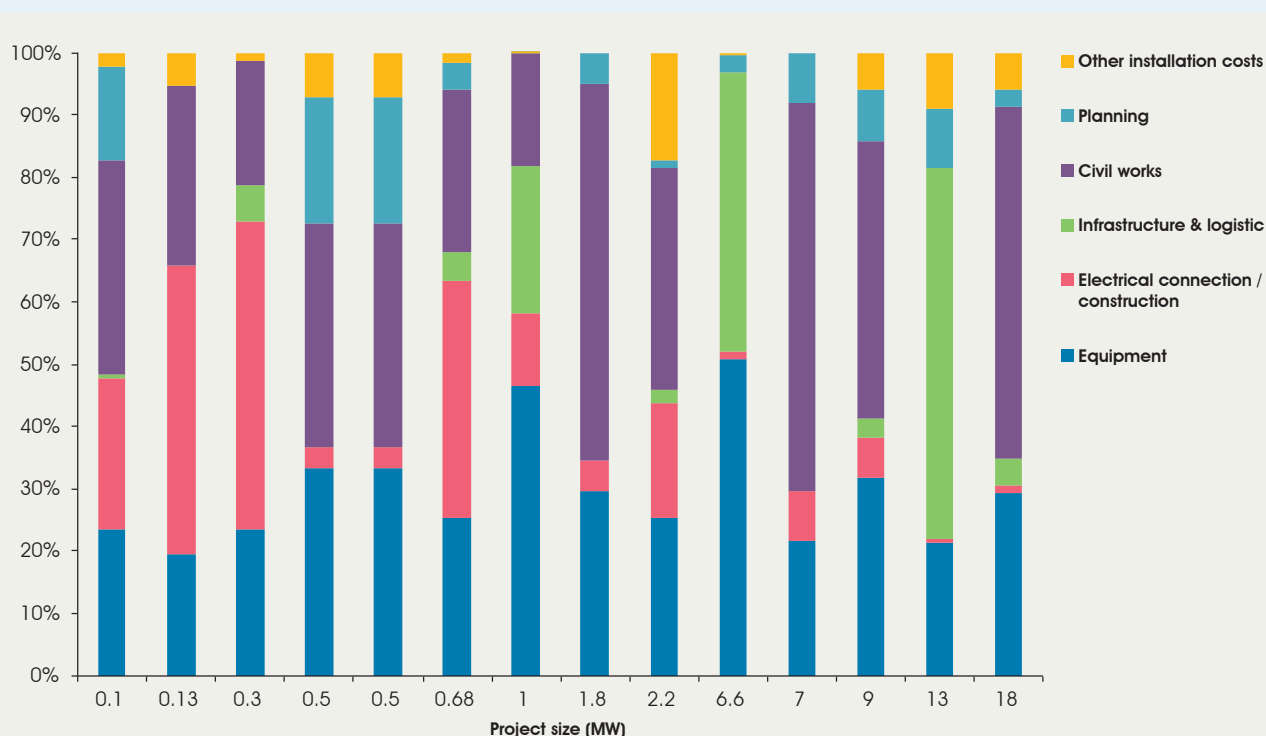


FIGURE 5.2: CAPITAL COST BREAKDOWN OF SMALL-SCALE HYDRO PROJECTS IN AFRICA

SOURCE: IRENA/GIZ, 2012.

5.1.1 HYDROPOWER ELECTRO-MECHANICAL COSTS

The electro-mechanical equipment used in hydropower plants is a mature technology. The cost is strongly correlated with the capacity of the hydropower plant and

there are important economies of scale (Figure 5.3). The proposed capacity of a hydropower plant can be achieved by using a combination of a few large turbines or many small turbines and generating units.

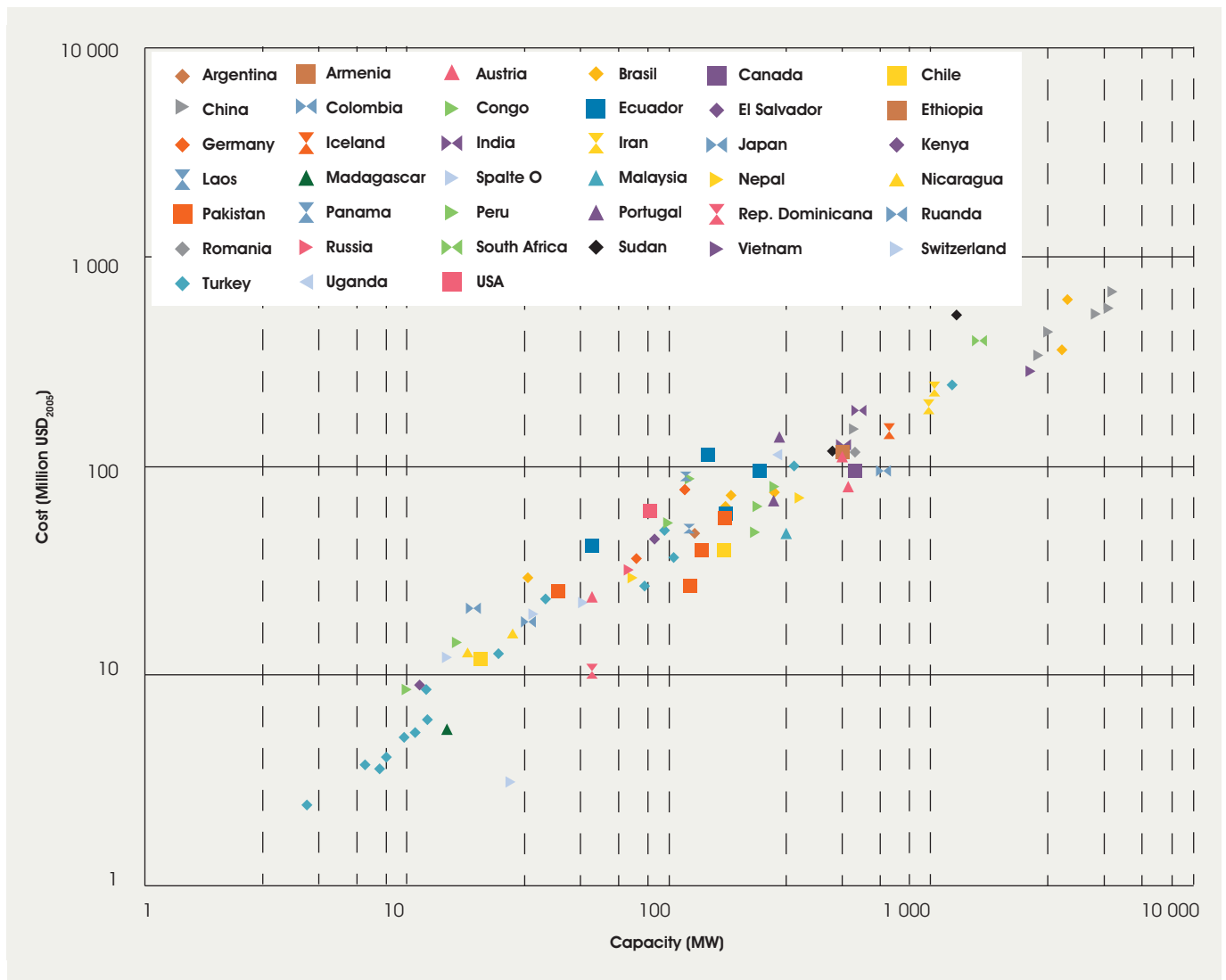


FIGURE 5.3: ELECTRO-MECHANICAL EQUIPMENT COSTS FOR HYDROPOWER AS A FUNCTION OF CAPACITY (LOG-SCALE)

SOURCE: ALVARADO-ANCIETA, 2009.

5.1.2 TOTAL INSTALLED COSTS

The capital costs of large hydropower projects are dominated by the civil works, the costs of which are influenced by numerous factors pertaining to the site, the scale of development and the technological solution that is most economic. Hydropower is a highly site-specific technology where each project is tailor-made for a particular location within a given river basin to meet specific needs for energy and water management.

Around three-quarters of the total investment costs of hydropower projects are driven by site-specific elements that impact on the civil engineering design and costs. Proper site selection and hydro scheme design are therefore key challenges, and detailed work at the design stage can avoid expensive mistakes (Ecofys, et al., 2011).

The total installed costs for large-scale hydropower projects typically range from a low of USD 1 000/kW to around USD 3 500/kW (Figure 5.4). However, it is not unusual to find projects with costs outside this range. For instance, installing hydropower capacity at an existing dam that was built for other purposes (flood control, water provision, etc.) may have costs as low as USD 500/kW. On the other hand, projects at remote sites, without adequate local infrastructure and located far from existing transmission networks, can cost significantly more than USD 3 500/kW due to higher logistical and grid connection costs.

Total installed costs are lowest in China, India and Latin America but are higher in Africa and Europe and Central Asia. This reflects the fact that in Europe and Central Asia most of the low-cost hydropower potential has already

been exploited. In Africa, the higher costs are partly due to the fact many projects are in remote areas with poor infrastructure and have higher transport and logistical, as well as grid connection costs.²⁰

An important conclusion from this analysis is that although the installed cost range for hydropower is wide, weighted average installed costs are typically low in regions with significant remaining potential and can provide electricity

at very competitive prices. This is despite the fact that the costs for the other services they provide, such as potable water, flood control, irrigation and navigation are included in the hydropower project costs and are typically not remunerated. In addition, plants with higher installed costs are often associated with higher capacity factors, reducing their LCOE, and are providing other services such as irrigation. This is also without taking into account that the additional value of grid services provided by hydropower in terms of short-term flexibility and long-term energy storage, which may have significant value over and above a simple LCOE analysis.

²⁰ These conclusions are tentative at best given the imbalance in total project numbers between regions.

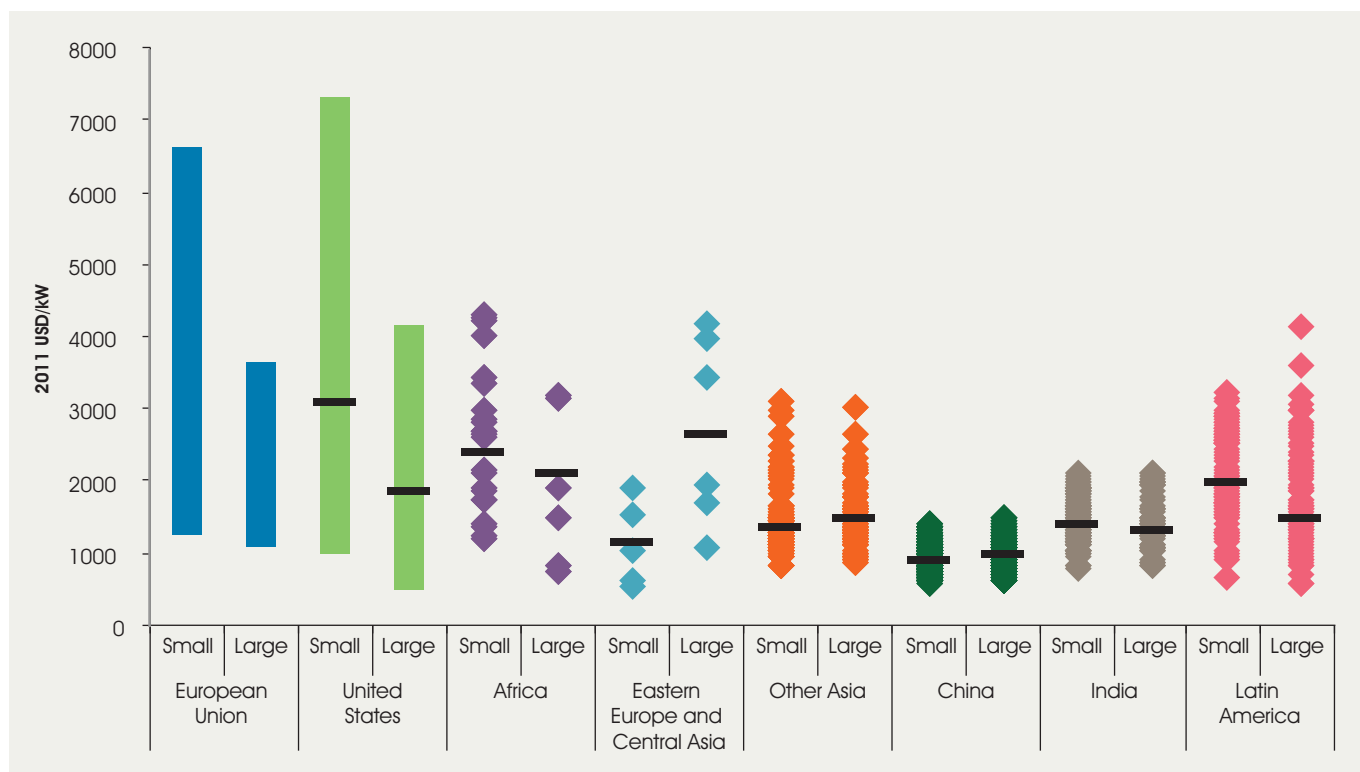


FIGURE 5.4: TOTAL INSTALLED COST RANGES AND CAPACITY WEIGHTED AVERAGES FOR COMMISSIONED OR PROPOSED SMALL AND LARGE HYDROPOWER PROJECTS BY COUNTRY/REGION

SOURCE: IRENA RENEWABLE COST DATABASE.

The cost ranges for small hydro are typically wider than for large hydro, although this is not always the case where significant unexploited hydropower potential remains. Weighted average installed costs for commissioned or proposed small hydro are very similar to those for large-scale hydropower projects in

Africa, China, India and other Asian countries. In Europe and Central Asia, weighted average installed costs are actually lower than for large-scale hydro, but this is not statistically significant. In Latin America, the range is similar to that for large hydro, but the weighted average capital costs are higher.

5.2 CAPACITY FACTORS FOR HYDROPOWER

Weighted average capacity factors are around 50% for small and large hydropower projects, with most projects in the range of 30% to 80% (Figure 5.5). Given the design flexibility for hydropower, depending on inflows and site characteristics, this wide range is to be expected

and uniquely to hydropower, low capacity factors are often a design choice to meet peak demands, not a handicap to project economics. In Latin America, where there are significant excellent, but as yet unexploited, hydropower resources, average capacity factors for new small and large hydropower projects are 68% and 60% respectively.

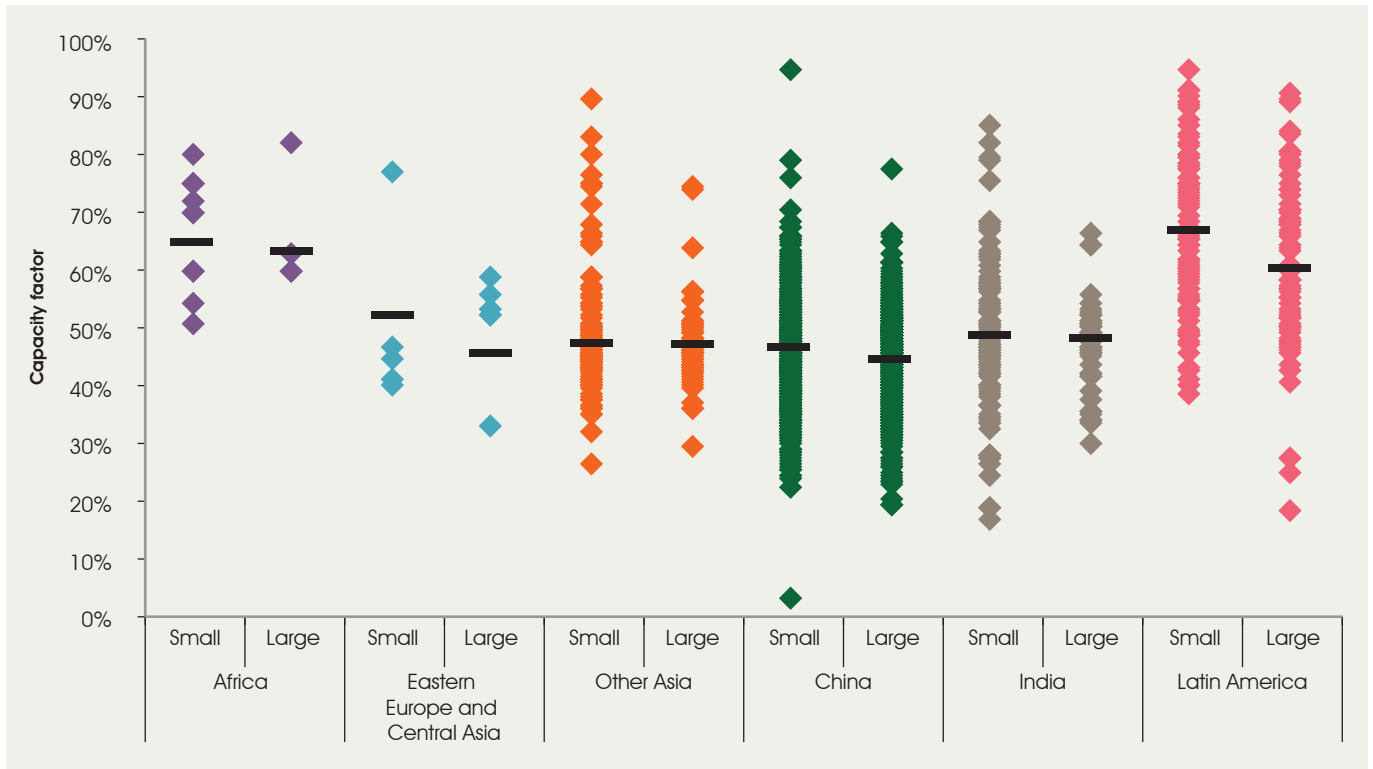


FIGURE 5.5: CAPACITY FACTOR RANGES AND WEIGHTED AVERAGES FOR COMMISSIONED OR PROPOSED SMALL AND LARGE HYDROPOWER PROJECTS BY COUNTRY/REGION

SOURCE: IRENA RENEWABLE COST DATABASE.

5.3 OPERATIONS AND MAINTENANCE COSTS

Once commissioned, hydropower plants usually require little maintenance, and operation costs will be low. When a series of plants are installed along a river, centralised control can reduce O&M costs to very low levels.

Annual O&M costs are often quoted as a percentage of the investment cost per kW per year. Typical values range from 1% to 4%. The IEA assumes 2.2% for large hydropower and 2.2% to 3% for smaller projects, with a global average of around 2.5% (IEA, 2010). Other studies (EREC/Greenpeace, 2010) indicate that fixed O&M costs represent 4% of the total capital cost. This figure may be appropriate for small-scale hydropower, but large hydropower plants will have significantly lower values. An average value for O&M costs of 2% to 2.5% is considered

the norm for large-scale projects (IPCC, 2011). This will usually include the refurbishment of mechanical and electrical equipment such as turbine overhaul, generator rewinding and reinvestments in communication and control systems.

These values are consistent with data collected by IRENA and GIZ for small hydropower projects in developing countries (Figure 5.6).²¹ Average O&M costs for mini- and pico-hydro projects can be significantly above the average, given the economies of scale for O&M costs presented by large hydropower projects.

²¹ The high values in the 13 to 18 MW range size in terms of percentage of installed capital costs per year for O&M costs appear to be partly explained by the remote location of these projects.

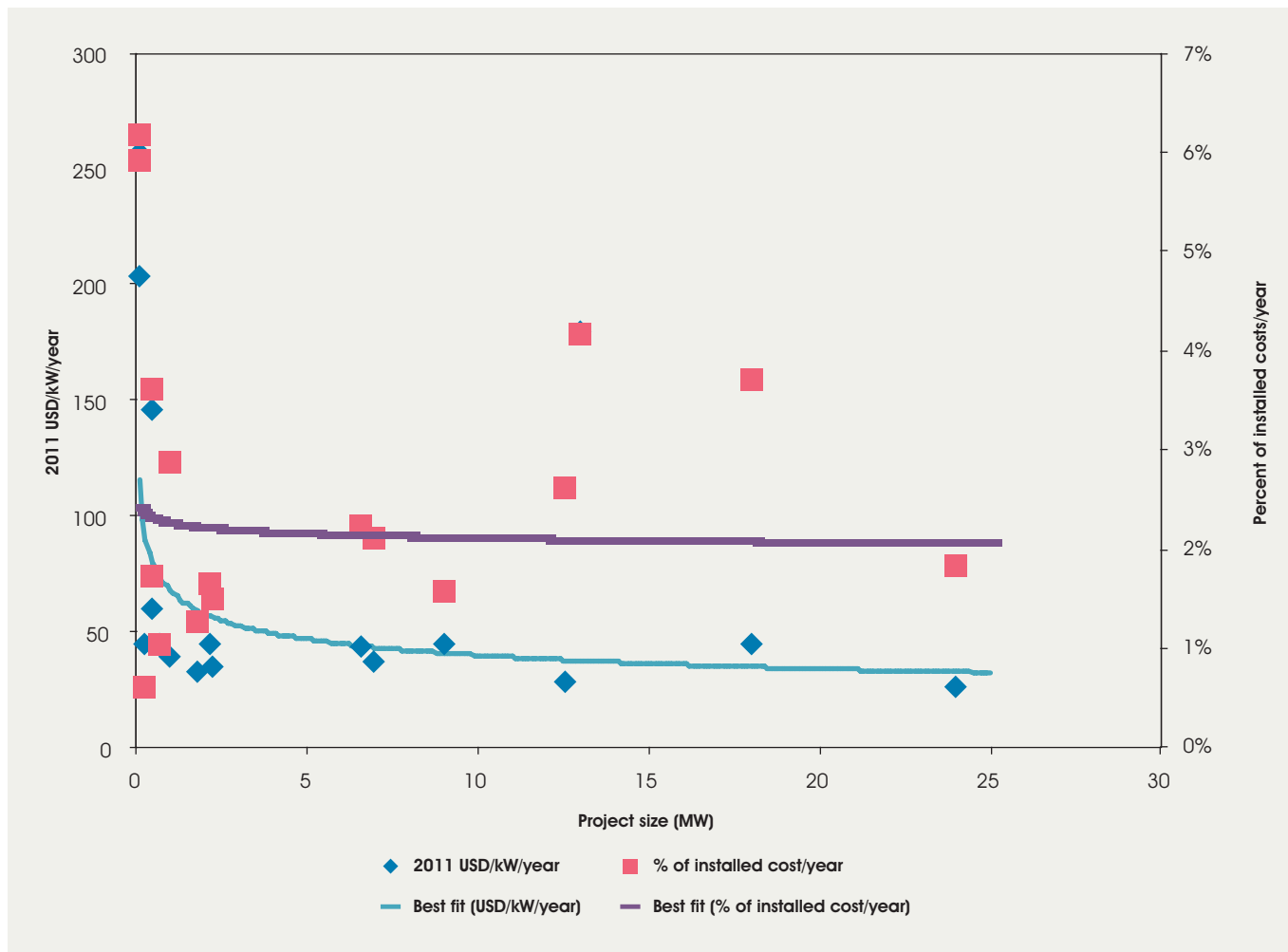


FIGURE 5.6: OPERATIONS AND MAINTENANCE COSTS FOR SMALL HYDROPOWER PROJECTS IN DEVELOPING COUNTRIES

SOURCE: IRENA/GIZ, 2012.

The O&M costs reported do not typically cover the replacement of major electro-mechanical equipment or refurbishment of penstocks, tailraces, etc.²² These replacements are infrequent and design lives of 30 years or more for electromechanical equipment, and 50 years or more for penstocks and tailraces are normal, meaning that the original investment has been completely amortised by the time these investments need to be made.

5.4 THE LEVELISED COST OF HYDRO ELECTRICITY

Hydropower is a proven, mature, predictable technology and can also be a very low-cost source of electricity. Although it requires relatively high initial investments

²² Penstocks are a tunnel or pipeline that conducts the water to the turbine, while the tail race is the tunnel or pipeline that evacuates the water after the turbine.

it has the longest lifetime of any generation plant (with parts replacement) and, in general, low O&M costs. Investment costs are highly dependent on location and site conditions. Although the installed costs of hydropower plants span a wide range, the average LCOE from hydropower is typically low and excellent hydropower sites offer the lowest cost electricity of any generating option.

Hydropower projects can be designed to perform very differently, which complicates a simple LCOE assessment of hydropower. Installed capacity can be low relative to inflows where storage is possible, in order to ensure the plant is nearly always generating and achieves high average capacity factors. Alternatively, a scheme could have relatively high installed electrical capacity that is not designed to run continuously and would have a relatively lower annual capacity factor, but would meet peak demands by providing large amounts of capacity at short notice, as well as providing a spinning reserve and/

or other ancillary grid services. The latter strategy would involve higher costs and lower capacity factors, but where system flexibility is required it is likely to be the cheapest and most effective solution.

Deciding which strategy to pursue for any given hydropower scheme design is highly dependent on the local market, structure of the power generation pool, grid capacity/constraints, the value of providing grid services, etc. More than perhaps in the case of any other renewable energy, the true economics of a given hydropower scheme will be driven by these factors, not just the amount of kWhs generated relative to the investment, as the value of peak generation and the provision of ancillary grid services can have a large impact on the economics of a hydropower project.²³

23 This is without taking into account the other services being provided by the dam (e.g. flood control) that are not typically remunerated, but are an integral part of the projects purpose.

Figure 5.7 presents the supply curve for the LCOE of 2 155 hydropower projects at undeveloped sites, existing dams without hydropower, and the expansion of existing hydropower schemes in the United States. It shows that many new hydropower projects are very competitive, despite nearly three-quarters of the existing potential having already been exploited. The LCOE of the evaluated projects ranged from a low of just USD 0.012/kWh for additional capacity at an existing hydropower project to a high of USD 0.19/kWh for a 1 MW small hydro project with a capacity factor of 30%. The weighted average cost of all the sites evaluated was USD 0.048/kWh. The LCOE of 80% of the projects was between USD 0.018 and USD 0.085/kWh and roughly half were below USD 0.05/kWh.

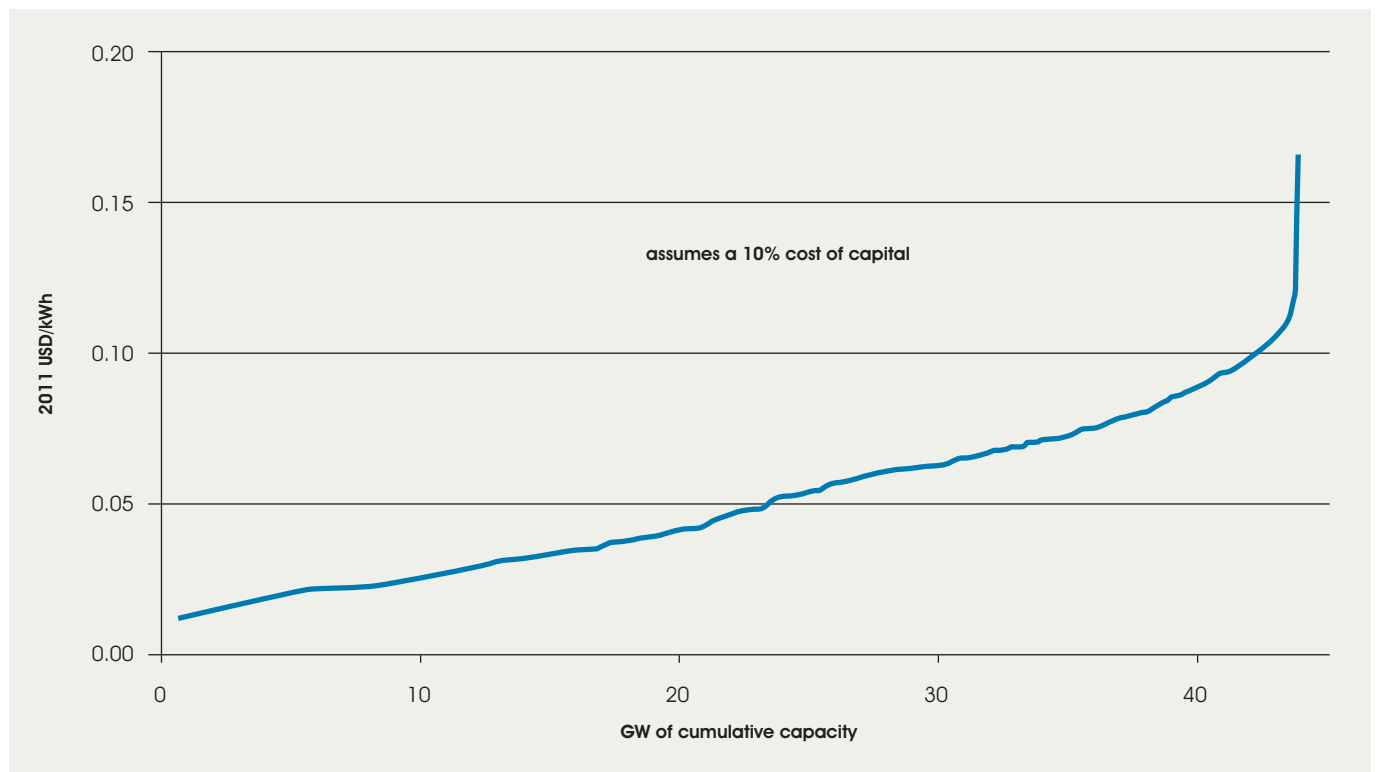


FIGURE 5.7: LEVELISED COST OF ELECTRICITY OF UNEXPLOITED HYDROPOWER RESOURCES IN THE UNITED STATES

SOURCE: HALL, ET AL. 2003 AND IRENA ANALYSIS.

A brief review of the LCOE range for hydropower in countries with the largest installed capacity is revealing. At the best sites, the LCOE of hydro is very competitive and

can provide the cheapest electricity available in the world today (Figure 5.8). Although the range of estimated costs is wide, much of the higher cost potential will never be built.

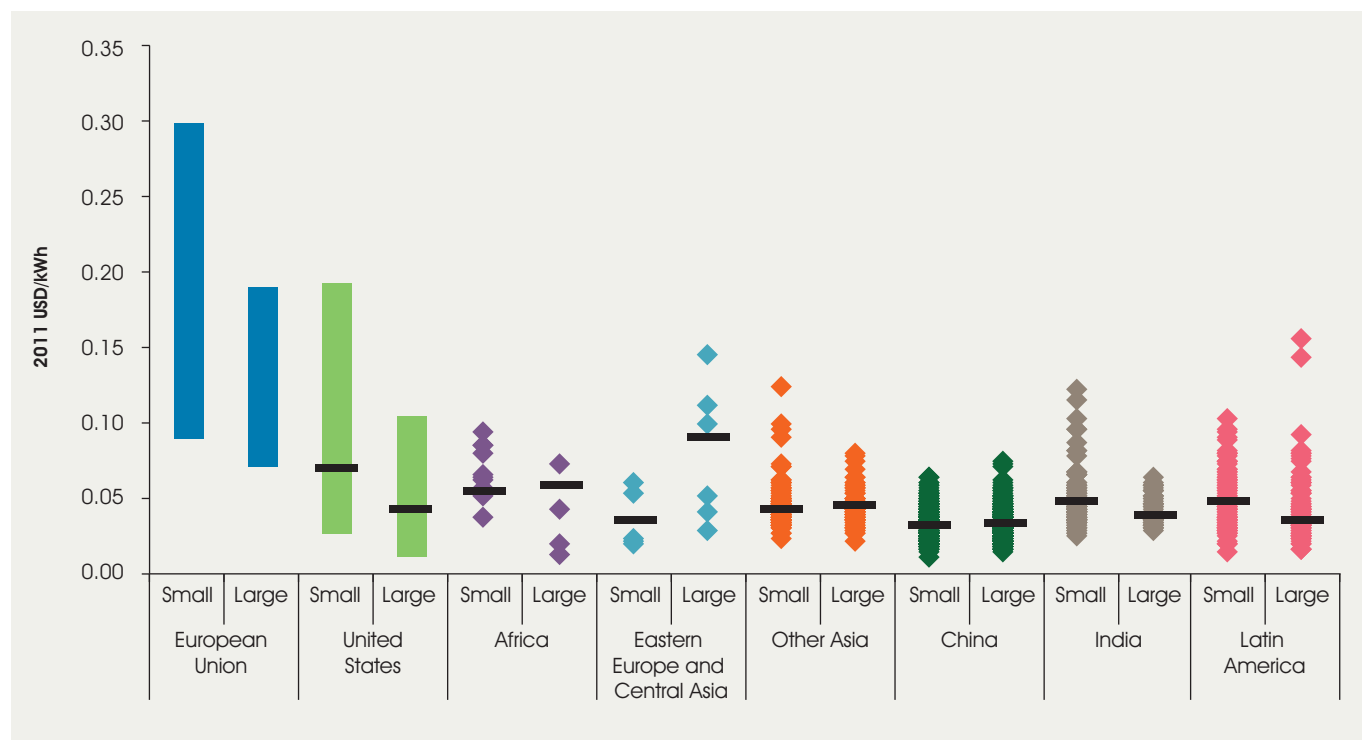


FIGURE 5.8: LEVELISED COST OF ELECTRICITY RANGES AND WEIGHTED AVERAGES OF SMALL AND LARGE HYDROPOWER PROJECTS BY REGION

SOURCE: IRENA RENEWABLE COST DATABASE.

Figure 5.8 emphasises that globally, where significant untapped resources remain, hydropower is still capable of providing the lowest-cost electricity of any generation type. Average costs for new capacity are low and typically range between USD 0.04 and USD 0.06/kWh depending on the region. Countries in the European Union are an exception, as most of the economic hydropower potential has already been exploited. New projects are few and far between and face long lead times.

Figure 5.9 presents the LCOE of small hydropower projects in developing countries, broken down by source and highlights just how competitive small hydropower can be for grid-supply, rural electrification and economic development. The share of O&M costs in the LCOE of the

hydropower projects examined ranges from 1% to 6%. The largest share of the LCOE is taken up by the costs for the electro-mechanical equipment and the civil works. The share of the electro-mechanical equipment in the total LCOE ranged from a low of 17% to a high of 50%, with typical values falling in the range 21% to 31%. The cost of civil works made the highest contribution to the total LCOE in nine of the projects examined and their share ranged from zero (for an existing dam project) to a high of 63%. In some remote projects, grid connection and electrical infrastructure dominated costs and were significant, without being dominant, in a number of other projects. Similarly, infrastructure and logistical costs can be a significant contributor to overall costs where site access is difficult and/or far from existing infrastructure.

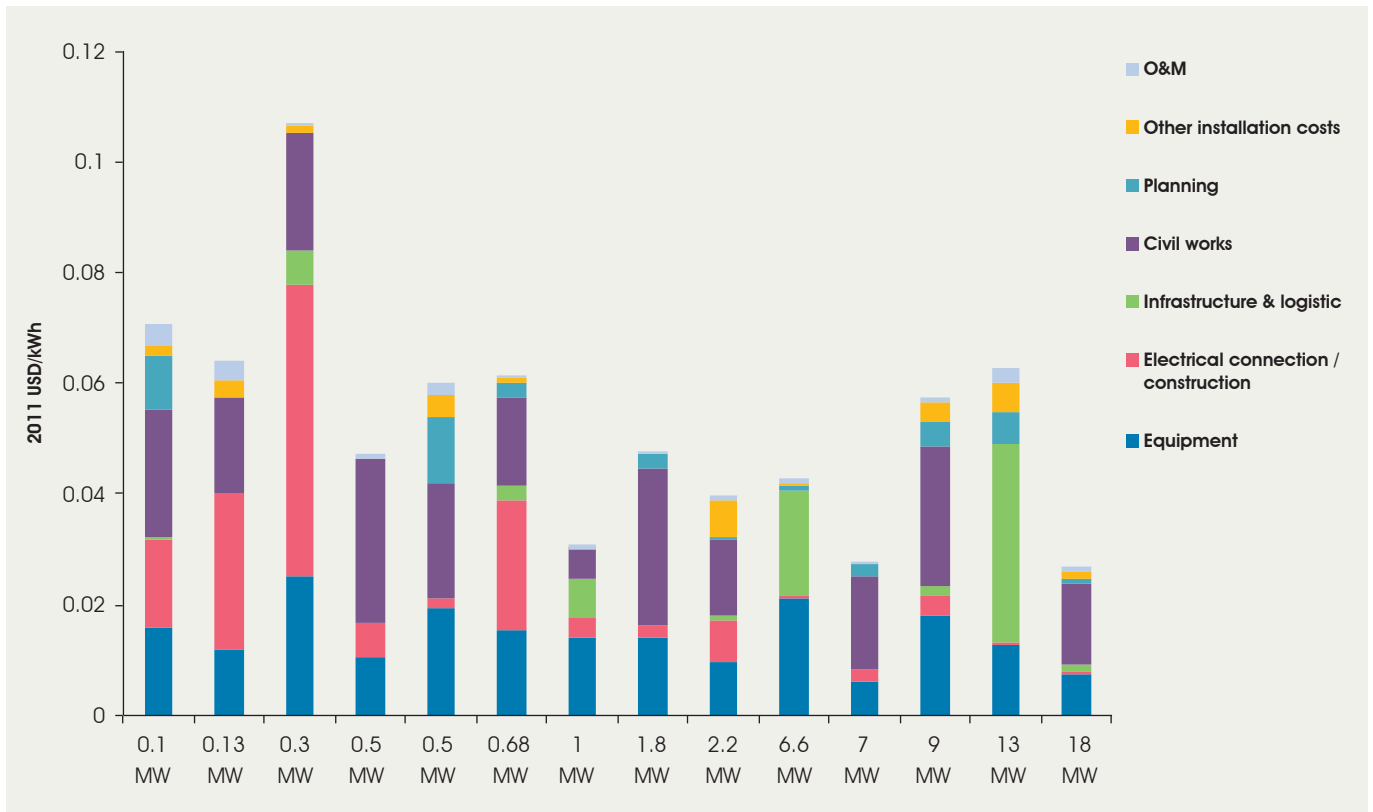


FIGURE 5.9: LEVELISED COST OF ELECTRICITY OF SMALL HYDROPOWER PROJECTS IN DEVELOPING COUNTRIES

SOURCE: IRENA RENEWABLE COST DATABASE.

6. SOLAR PHOTOVOLTAICS

Solar photovoltaics, also called solar cells or just PV, are electronic devices that convert sunlight directly into electricity. The modern form of the solar cell was invented in 1954 at Bell Telephone Laboratories. Today, PV is one of the fastest-growing renewable energy technologies and is expected to play a major role in the future global electricity generation mix.

Solar PV systems are one of the most “democratic” renewable technologies, in that their modular size means that they are within the reach of individuals, co-operatives and small-scale businesses that want their own generation facilities and so lock-in electricity prices.

A PV system consists of a number of PV cells grouped together to form a PV module, along with auxiliary components (i.e. balance of system or BoS), including the inverter, controls, etc. There are a wide range of PV cell technologies on the market today, using different types of materials, and an even larger number will be available in the future. PV cell technologies are usually classified into three generations, depending on the basic material used and their level of commercial maturity:

- First-generation PV systems (fully commercial) use the wafer-based crystalline silicon (c-Si) technology, either single crystalline (sc-Si) or multi-crystalline (mc-Si).
- Second-generation PV systems (early market deployment) are based on thin-film PV technologies and generally include three main families: 1) amorphous (a-Si) and micromorph silicon (a-Si/ μ c-Si); 2) Cadmium-Telluride (CdTe); and 3) Copper-Indium-Selenide (CIS) and Copper-Indium-Gallium-Diselenide (CIGS).
- Third-generation PV systems include technologies, such as concentrating PV (CPV) and organic PV cells, which are still under demonstration or have not yet been widely commercialised, as well as novel concepts under development.

This paper focuses on the costs of those first and second-generation technologies that are available commercially.

Solar PV systems operate in the presence of direct or diffuse solar irradiation. The higher the level of solar resource, all things being equal, the lower the system's LCOE will be. Siting solar PV systems in areas with high solar resources (usually expressed as annual mean figures in kWh/m²/year or as kWh/m²/day) will therefore minimise the cost of electricity.

6.1 SOLAR PV CAPITAL COSTS

PV is a mature, proven technology that has achieved grid parity in a number of markets. With continued cost reductions, grid parity will soon be the norm, rather than the exception.²⁴ PV is a renewable, secure energy source with very high plant reliability and is not exposed to any fuel price volatility. PV has made remarkable progress in reducing costs, as until recently grid parity still seemed very far away.

The capital cost of a PV system is composed of the PV module cost and the BoS cost. The cost of the PV module – the interconnected array of PV cells – is determined by raw material costs, notably silicon costs, cell processing/manufacturing and module assembly costs. The BoS cost includes items such as the cost of the structural system (e.g. structural installation, racks, site preparation and other attachments), the electrical system costs (e.g. the inverter, transformer, wiring and other electrical installation costs) and the cost of the battery or other storage system, if any, in the case of off-grid applications.

6.1.1 SOLAR PV MODULE PRICES

The cumulative installed capacity of solar PV grew by around 70% in 2011. Combined with the high learning rate for solar PV and overcapacity in the manufacturing base, this growth has resulted in significant price declines over recent years.

24 The term “grid parity” is often used loosely and inconsistently. In this paper, it is meant to represent the point where the LCOE of PV, without subsidies, is the same or lower than the residential electricity price, excluding taxes. Other definitions include a price equal to, or lower than, the price of peak, shoulder or base-load electricity generation. In some cases, it will include or exclude taxes and subsidies.

Accurate data on global average PV module prices are difficult to obtain and in reality there is a wide range of prices in the market, depending on the cost structure of the manufacturer, market features, market pressures and module efficiency. Figure 6.1 presents trends in PV module prices in Europe by technology and source.

Prices for PV modules have fallen by between 30% and 41% in the year to September 2012 and by between 51% and 64% for the two years to September 2012, depending on the technology and source for European buyers. Continued and significant overcapacity in the PV

module supply chain has led to cut-throat competition, with prices falling very close to “cash cost” levels as companies try to maintain cash flows. Crystalline silicon PV module prices from respected Chinese manufacturers had fallen to an average of just USD 0.75/W²⁵ between September and December 2012, with western manufacturers more expensive at around USD 1.1/W over this period.

²⁵ This is an average figure. The lowest cost transactions from cash-strapped manufacturers are reported to have been as low as USD 0.4/W for some volumes.

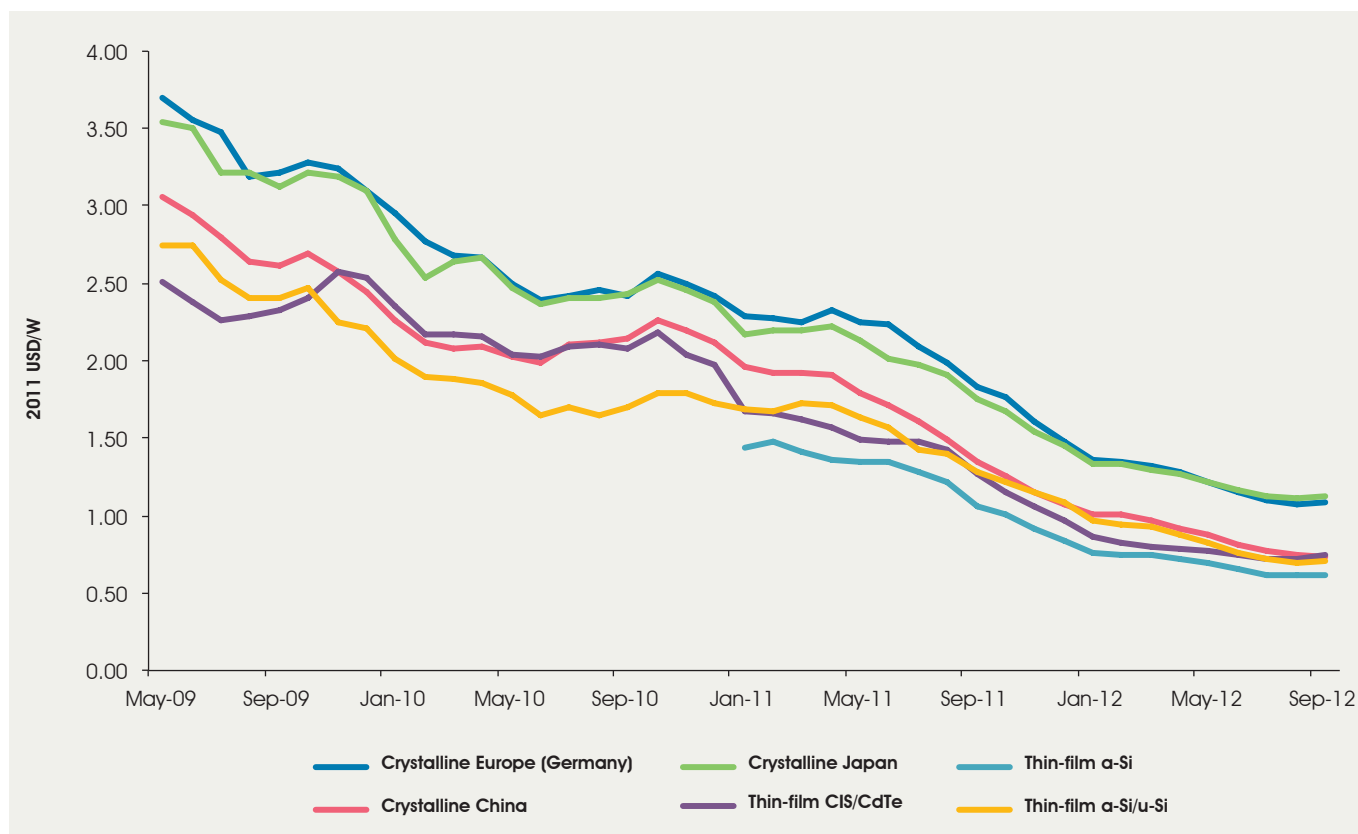


FIGURE 6.1: AVERAGE MONTHLY SOLAR PV MODULE PRICES BY TECHNOLOGY IN EUROPE, 2009 TO 2012

SOURCE: SOLOGICO, 2012.

The rate of decline in PV module prices is slowing, but continued overcapacity means that pressures on price will remain severe for the foreseeable future. PV module prices, after moving above the curve in 2006, have dropped significantly below the learning curve in 2012 (Figure 6.2). Even in normal times, projecting PV module cost reductions has been complicated by the high learning rate of 22%. With the PV market growing so rapidly compared to the installed base, projections of cost reductions can quickly become

out of date. This uncertainty is further accentuated by overcapacity in the global PV module manufacturing base. Although conventional wisdom would suggest a slowing down of PV module cost reductions, further significant falls cannot be ruled out in the short-term. However, given the current low level of prices, historical rates of cost reduction will yield much more modest cost reductions in absolute terms. The competitiveness of PV will therefore increasingly be determined by BoS costs.

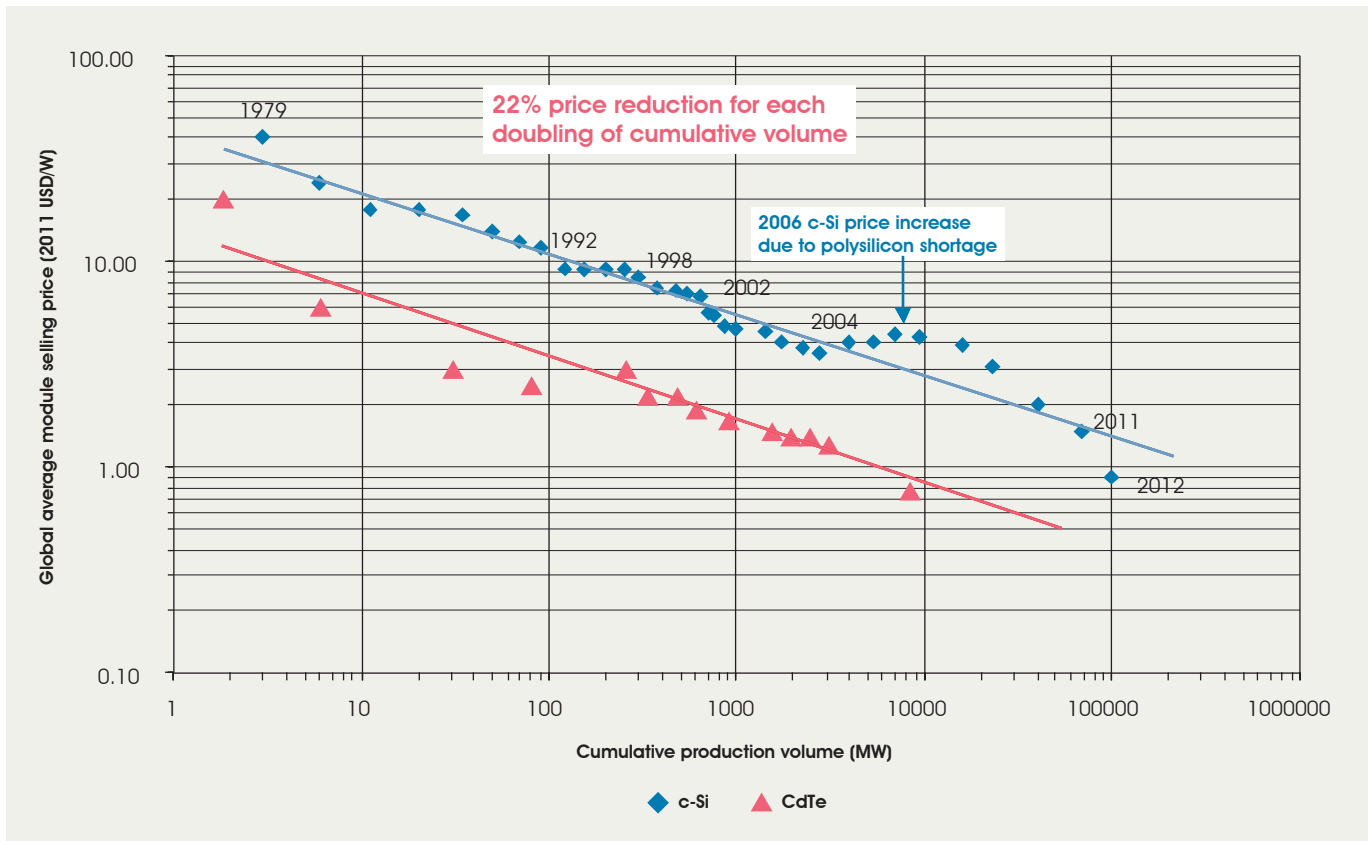


FIGURE 6.2: SOLAR PV MODULE COST LEARNING CURVE FOR CRYSTALLINE SILICON AND THIN-FILM

SOURCE: BASED ON DATA FROM EPIA AND PHOTOVOLTAIC TECHNOLOGY PLATFORM, 2011; LIEBREICH, 2011; SOLOGICO, 2012 AND IRENA ANALYSIS.

The rapid decline in c-Si PV module prices due to overcapacity has put severe pressure on the thin-film PV module market. Thin-film PV manufacturers are struggling to compete against Chinese c-Si modules that are not much more expensive than thin-film PV modules, and have a higher efficiency and hence require lower BOS costs per MW. Whether specific technological advantages such as better performance in low light conditions or hot climates are sufficient to regain a competitive edge remains to be seen.

6.1.2 BALANCE OF SYSTEM COSTS

The BoS costs and installation costs comprise the remaining capital costs for a PV system. BoS costs largely depend on the nature of the installation, with large-utility-scale projects typically being cheaper than large ground-mounted commercial or residential systems, which are in turn cheaper than small-scale rooftop residential systems. However, there are some exceptions, notably the addition of single or two-axis tracking systems on utility-scale projects to raise their capacity factor, and across different country

markets, where the most competitive residential markets can rival the costs of utility-scale projects in high-cost countries.

BoS and installation costs include:

- The inverter, which converts the direct current (DC) PV output into alternating current (AC);
- The components required for mounting and racking the PV system;
- The combiner box and miscellaneous electrical components;
- Site preparation and installation (i.e. roof preparation for residential systems, or site preparation for utility-scale plants), labour, costs for installation and grid connection;
- Battery storage for off-grid systems; and
- System design, management, installer overheads, permit fees, project development costs, customer acquisition costs, and any up-front financing costs.

The global weighted average estimated BoS cost and breakdown for 2012 is presented in Figure 6.3 along with the best practice total BoS cost. Installation, engineering, procurement and construction (EPC); and other development costs account for 31% of the global average BoS costs, as do “other soft costs”. The inverter accounts for 16% of the BoS, the racking and mounting infrastructure 15% and electrical and other hardware for the final 7%. What is interesting is that best practice BoS costs are just half of the global average, representing the wide range in both markets and applications.

Utility-scale systems typically have the lowest BoS costs, which can be anywhere from a low average of around USD 0.95/W for Chinese and Indian ground-mounted systems in 2012, to between USD 1.36 and USD 1.73/W for utility-scale ground-mounted systems in the United States. These variations reflect the maturity of markets and supply chains, but also the efficiency of support mechanisms since solar system pricing is often value-based to some extent and influenced by the support levels in place.

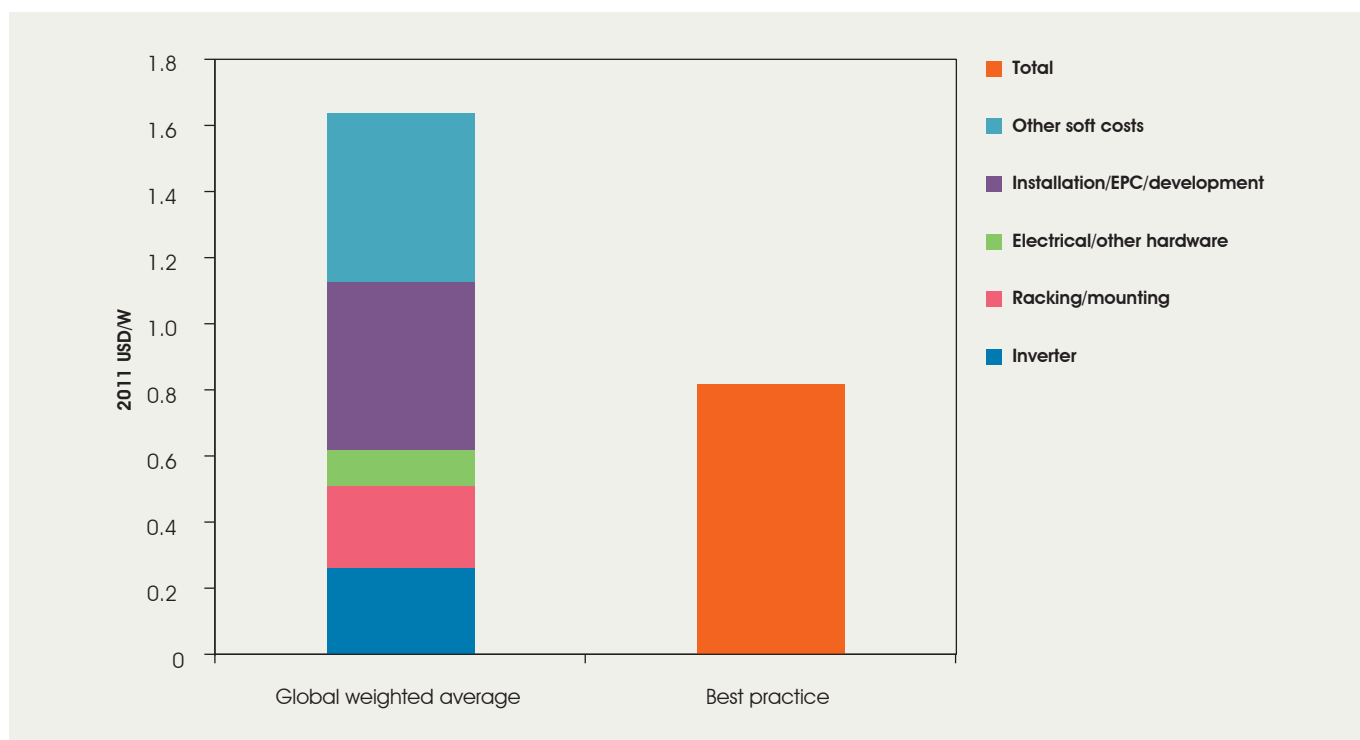


FIGURE 6.3: UTILITY-SCALE SOLAR PV BALANCE OF SYSTEM COSTS

SOURCE: PHOTON CONSULTING, 2012.

BoS costs for smaller-scale commercial and residential systems are typically higher than utility-scale systems due to the increased costs associated with small-scale projects and rooftop installations. However BoS costs can still be competitive, particularly for large commercial rooftop installations. For instance, the

2012 average BoS costs for large commercial rooftop systems in Italy and Germany were 30% and 12% respectively below the global average. BoS costs for residential systems in Germany in the first half of 2012 were in the range of USD 1 to USD 1.4/W (Sologico, 2012 and BSW, 2012).

Box 6.1:

WILL THE FUTURE OF PV INSTALLED COST REDUCTIONS BE DETERMINED BY BOS COSTS?

Balance of system costs in both Germany and the United States have come down with increased PV deployment. However, at 1 GW, BoS costs in the United States have strongly diverged from Germany (Figure 6.4). While BoS costs in Germany have followed a fairly consistent downward trend, they have remained at high levels in the United States. The result has been a dramatic difference in BoS

costs and hence in total installed costs in 2011. Further investigation is needed to identify why this is the case, but initial analysis suggests that it is partly structural, partly policy design but also due to reasons that are not well understood (such as labour hours for installation in the United States being three to ten times higher than in Germany for similar sized systems) (Seel, *et al.*, 2012).

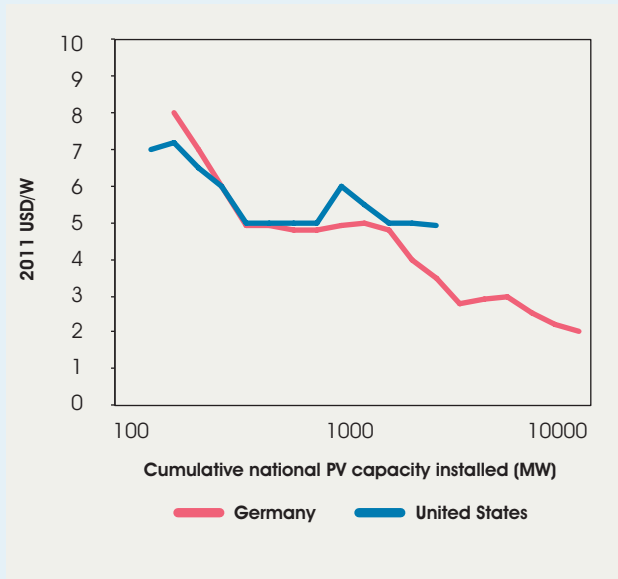


FIGURE 6.4: RESIDENTIAL SOLAR PV SYSTEM BOS COSTS IN GERMANY AND THE UNITED STATES, 2001 TO 2011

SOURCE: SEEL ET AL., 2012.

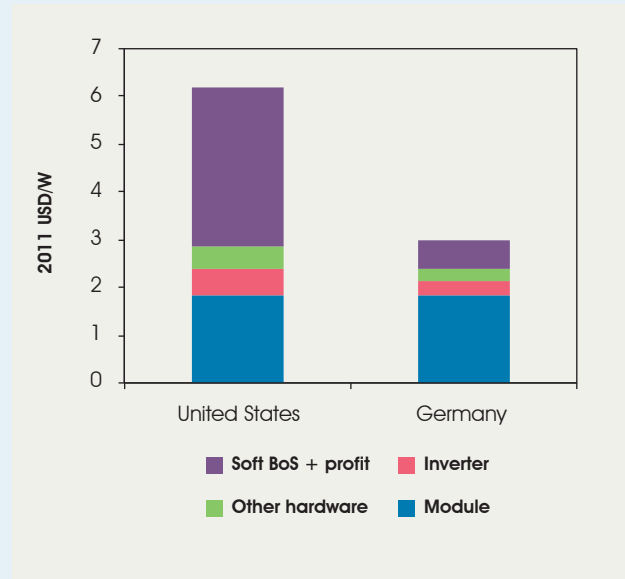


FIGURE 6.5: RESIDENTIAL SOLAR PV MODULE AND BOS COSTS IN GERMANY AND THE UNITED STATES, 2011

SOURCE: SEEL ET AL., 2012.

Figure 6.5 looks at a sample of residential systems in the United States (over 6 000 systems) and Germany (over 2 000 systems). For these projects, the total installed costs for the United States were more than twice as high as in Germany. The total soft costs in Germany were just 19% of those in the United States.

Analysis of these differences is just beginning, but further research is needed to examine the reasons for these differences since understanding them will be critical to identifying how to drive cost reductions in solar PV in markets that have, to date, experienced higher system costs than in more competitive markets.

6.1.3 TOTAL INSTALLED COSTS

The rapid decline in PV module prices and BoS costs in some countries has led to significant declines in the installed costs of PV systems. German residential systems have fallen from around USD 7/W (USD 7 000/kW) in the

second quarter of 2008 to just USD 2.2/W in the second quarter of 2012 (Figure 6.6). In contrast, average prices for residential systems in the United States, in the second quarter of 2012 had only fallen to USD 5.5/W, with a range of between USD 4 to USD 8/W.

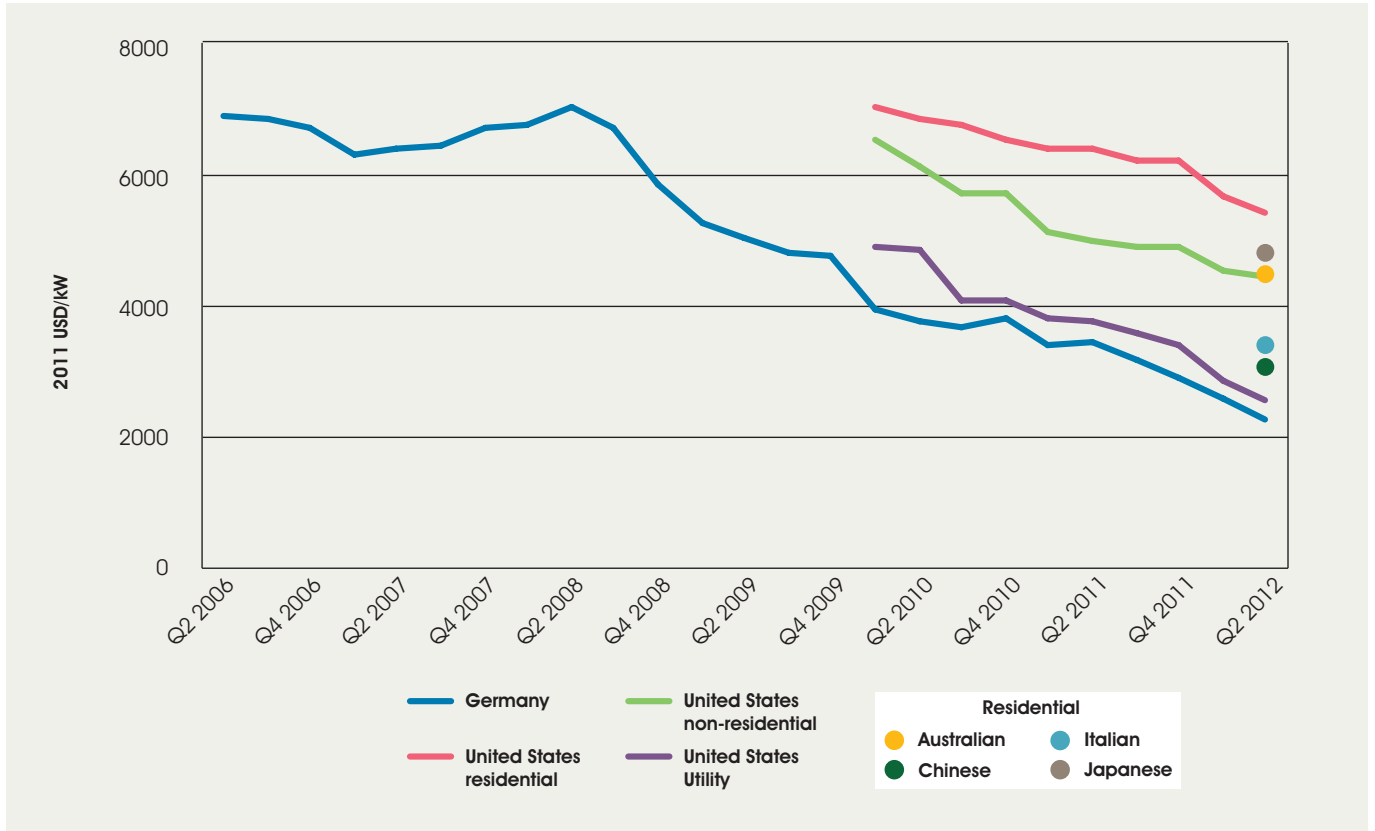


FIGURE 6.6: SOLAR PV SYSTEM PRICE TRENDS BY SECTOR AND COUNTRY, 2006 TO 2012

SOURCES: BSW, 2012; PHOTON CONSULTING, 2012; AND SEIA/GTM RESEARCH, 2012.

These costs compare to Chinese rooftop systems with costs of around USD 3.1/W, Italian rooftop systems at around USD 3.4/W, Australian systems at around USD 4.5/W and

Japanese systems at around USD 4.8/W. The downward trend in installed costs for large-scale projects in non-OECD regions is also highlighted in Figure 6.7.

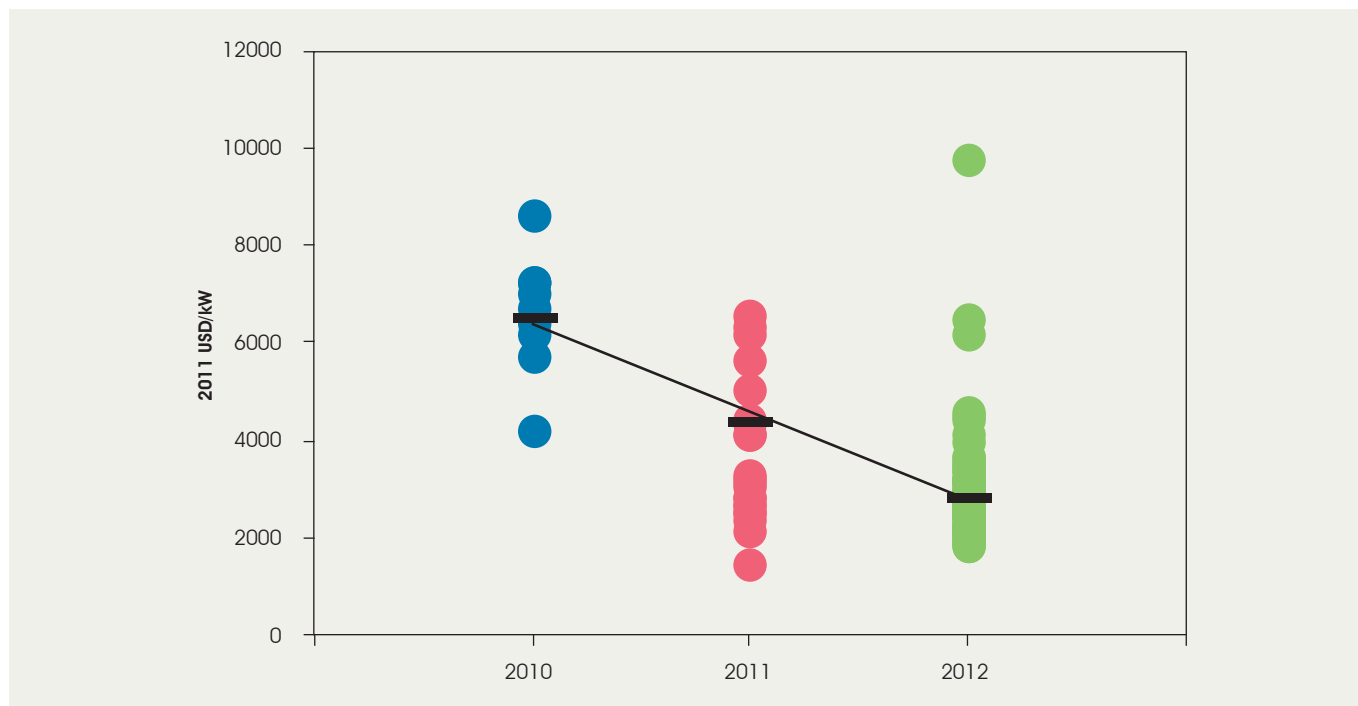


FIGURE 6.7: SOLAR PV INSTALLED COSTS BY PROJECT AND WEIGHTED AVERAGES IN NON-OECD REGIONS FOR UTILITY-SCALE PROJECTS, 2010 TO 2012

SOURCE: IRENA RENEWABLE COST DATABASE.

Utility-scale projects in the United States are much more competitive than residential systems but, with a range of installed costs between USD 2 and USD 3.6/W and a capacity weighted average of USD 2.9/W in the second quarter of 2012, are sometimes more expensive than residential systems in Germany (BSW, 2012 and SEIA/GTM Research, 2012). However, utility-scale projects in the development stage in the second half of 2012 in the United States are targeting costs similar to German values.

Chinese and Indian ground-mounted systems are achieving low installed costs of around USD 2.2/W and USD 1.7/W respectively on average for 2012. The Chinese figure is similar to that found in Germany, where ground-mounted systems are expected to have an average cost of USD 2.1/W over 2012. The higher BoS costs for residential systems in the United States means that the ratio of costs for residential to utility-scale systems is much higher, at around 2, than for Germany, where for 2012 it may eventually average only 1.2 to 1.3.

6.2 CAPACITY FACTORS FOR SOLAR PV

Capacity factors vary with the solar resource available and whether or not the systems have tracking systems (single or two-axis). Capacity factors for PV are typically in the range of 10% to 25% for fixed tilt systems, but values outside of this range are possible for exceptional sites or where siting is not optimal (e.g. tilt-angle, shading, etc.). The weighted average capacity factor for utility-scale projects in Asia outside China and India is around 17%, while in China and Africa it is around 18%, and in India 19% (IRENA

Renewable Cost Database). Adding tracking systems can significantly raise these capacity factors, but the additional expense is rarely justified on economic grounds.

However, average values can be very misleading for a country or a region, as solar resources are very site-specific (Figure 6.8) and “micro-climates” can mean that even sites geographically very close together can show a wide discrepancy in capacity factors. Accurate solar resource mapping is therefore essential to the identification of the least-cost sites for solar.

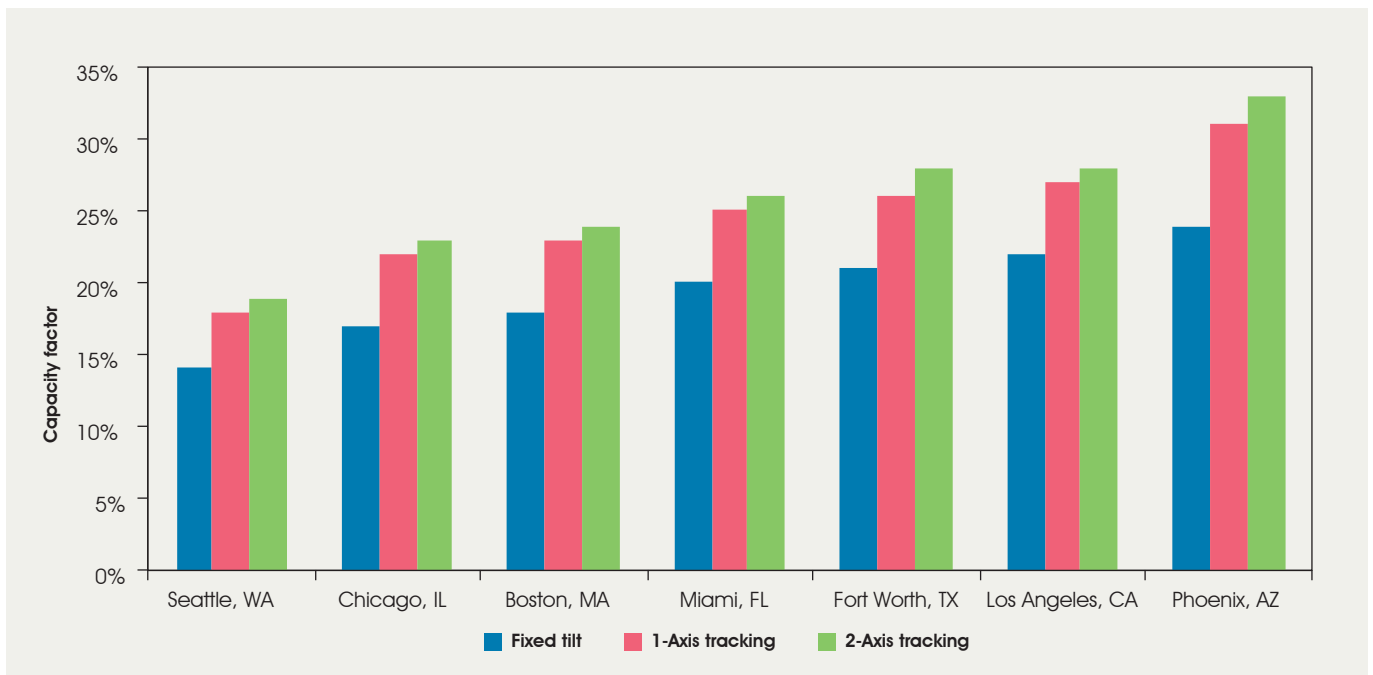


FIGURE 6.8: SOLAR PV SYSTEM CAPACITY FACTORS BY LOCATION AND TRACKING SYSTEMS IN THE UNITED STATES

SOURCE: NREL, 2011.

6.3 THE LEVELISED COST OF SOLAR PV

The LCOE of c-Si residential PV systems without battery storage was estimated to be between USD 0.28 and USD 0.70/kWh in 2010. This is estimated to have declined to between USD 0.25 and USD 0.65/kWh in 2011 with the reduction in c-Si module prices in 2011.

However, by the second quarter of 2012 continued reductions in PV module prices and total installed costs meant that these values had already been eclipsed by even lower costs of electricity. The LCOE of typical small-scale systems in Germany, for instance, had fallen to between USD 0.19/kWh to USD 0.27/kWh by the second quarter of 2012, which is lower than most residential tariffs. In the United States, where installed costs are higher, the LCOE of residential systems for the

second quarter of 2012 was estimated to vary between USD 0.23 and USD 0.50/kWh.

Cost reductions mean that the LCOE of the latest utility-scale projects in 2012 are increasingly competitive. Figure 6.9 presents the LCOE ranges and capacity weighted averages for PV projects in non-OECD regions between 2010 and 2012. The range of the LCOE varies from a low of between USD 0.11 to USD 0.31/kWh for a small number of projects in Latin America to between USD 0.15 to USD 0.35/kWh in China for typical projects. The widest range occurs in Other Asia, however, the most expensive projects in this region are in South Korea and have high capital costs and relatively low capacity factors. Excluding these South Korean projects reduces the range for Other Asia to between USD 0.15 to USD 0.56/kWh. These values compare to LCOEs for utility-scale projects in Germany that have fallen to between USD 0.16 and USD 0.23/kWh.

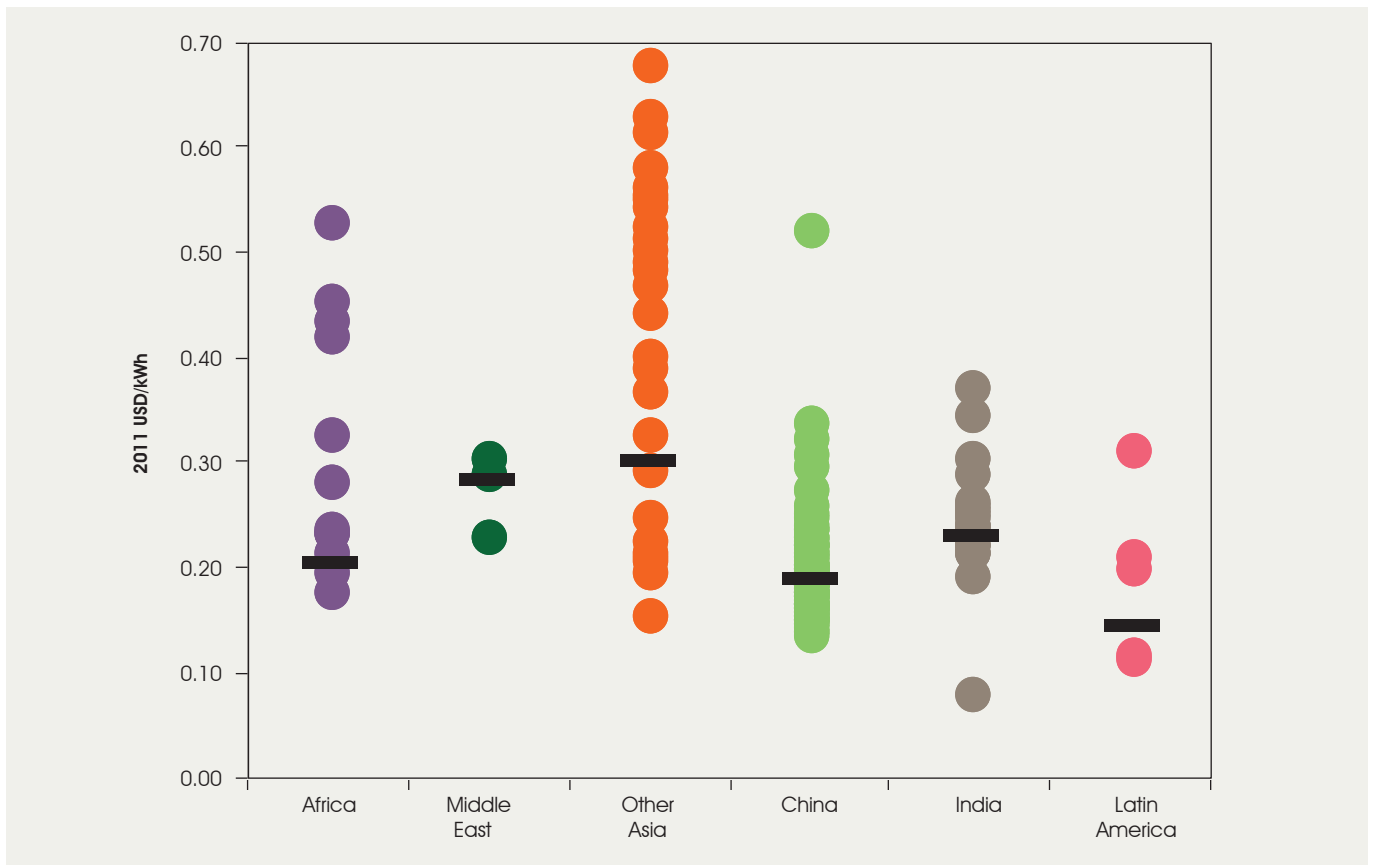


FIGURE 6.9: THE LCOE AND WEIGHTED AVERAGES OF COMMISSIONED AND PROPOSED LARGE-SCALE SOLAR PV SYSTEMS IN NON-OECD COUNTRIES/REGIONS, 2010 TO 2012

SOURCE: IRENA RENEWABLE COST DATABASE.

7. CONCENTRATING SOLAR POWER

Concentrating solar power (CSP) is a power generation technology that uses mirrors or lenses to concentrate the sun's rays and, in most of today's CSP systems, to heat a fluid and produce steam. The steam drives a turbine and generates power in the same way as conventional power plants. However, other concepts are being explored and not all future CSP plants will necessarily use a steam cycle.

CSP plants can be divided into two groups, based on whether the solar collectors concentrate the sun rays along a focal line or on a single focal point (with much higher concentration factors). Line-focusing systems include parabolic trough and linear Fresnel plants and have single-axis tracking systems. Point-focusing systems include solar dish systems and solar tower plants and include two-axis tracking systems to concentrate the power of the sun.

Parabolic trough collectors (PTC) consist of solar collectors (mirrors), heat receivers and support structures. A single-axis tracking mechanism is used to orient both solar collectors and heat receivers toward the sun (A.T. Kearney and ESTELA, 2010). Most existing parabolic troughs use synthetic oils, which are stable up to around 360 to 400°C, as the heat transfer fluid. Some new plants use molten salt at 540°C either for heat transfer and/or as a thermal storage medium. High temperature molten salt may considerably improve the system's thermal storage performance.

Linear Fresnel collectors (LFCs) are similar to parabolic trough collectors, but use a series of long, flat, or slightly curved mirrors placed at different angles to concentrate sunlight on either side of a fixed receiver (located several metres above the primary mirror field). Unlike parabolic trough collectors, the focal line of Fresnel collectors is somewhat distorted and requires a mirror to be installed above the tube (a secondary reflector) to refocus any rays missing the tube, or several parallel tubes forming a multi-tube receiver that is wide enough to capture most of the focussed sunlight without a secondary reflector. LFCs can use cheaper mirrors, lighter and cheaper support structures, and have lower capital costs than PTC systems, but have lower solar efficiency.

Solar tower technologies use a ground-based field of mirrors (heliostats) that track the sun individually in two axes to focus direct solar irradiation onto a receiver mounted high on a central tower where the light is captured and converted into heat. The heat then drives a thermo-dynamic cycle, in most cases a water-steam cycle, to generate electric power. Solar towers can achieve higher temperatures than parabolic trough and linear Fresnel systems, because more sunlight can be concentrated on a single receiver and the heat losses at that point can be minimised. By using molten salt as the heat transfer fluid the potential operating temperature can rise to between 550 and 650°C, sufficient to allow higher efficiency supercritical steam cycles and lowering the cost of thermal energy storage. However, this advantage needs to be balanced by the higher investment costs for super-critical steam turbines. An alternative is direct steam generation (DSG), which eliminates the need and cost of heat transfer fluids, but this technology is at an early stage of development and storage concepts for use with DSG still need to be demonstrated and perfected.

The key advantage of solar towers is their higher operating temperatures which allow low-cost thermal energy storage to raise capacity factors and to achieve higher efficiency levels. This also allows a more flexible generation strategy to be pursued to maximise the value of the electricity generated. Given this, and other advantages, if costs can be reduced and operating experience gained, solar towers could potentially achieve significant market share in the future, despite PTC systems having dominated the market to date.

Solar dish systems consists of a parabolic dish-shaped concentrator (like a satellite dish) that reflects direct solar irradiation onto a receiver at the focal point of the dish. The receiver may be a Stirling engine (dish/engine systems) or a micro-turbine. Stirling dish systems require the sun to be tracked in two axes, but the high energy concentration onto a single point can yield very high temperatures. Stirling dish systems are just beginning to be deployed at scale, with a 1 MW system at the Maricopa plant in Arizona, while a 1.5 MW system is under construction in Utah, also in the United States.

7.1 CSP CAPITAL COSTS

The current CSP market is dominated by PTC technologies which are used in more than 80% of CSP power plants in operation or under construction. As a consequence, most of the available cost information refers to parabolic trough systems. The cost data for parabolic trough systems are also the most reliable, although uncertainties still remain, because it is the most mature CSP technology.

Current investment costs for PTC plants without storage in the OECD are between USD 4 700 and USD 7 300/kW (Hinkley, 2011; Turchi, 2010a and IRENA analysis), although plants in non-OECD countries have capital costs as low as USD 3 100/kW. CSP plants with thermal energy storage tend to have higher investment costs, but allow higher capacity factors and potentially lower LCOEs (particularly for molten salt solar towers), while also having the ability to shift generation to when the sun does not shine and/or the ability to maximise generation at peak demand times.

The cost of PTC and solar tower plants with thermal energy storage is generally between USD 6 400 and USD 10 700/kW (Table 7.1). These cost ranges, obtained from the available literature, are not inconsistent with estimates of recent plant commissioned in 2010 and 2011,

or that are under construction. Figure 7.1 presents the estimated total installed capital costs of these recent projects, drawing on data in the media and various industry sources. The costs for parabolic trough systems without storage are at the higher end of the range identified in the literature, while those for plants with storage quite closely match the cost data found in the literature.

Although CSP plants with thermal energy storage have higher specific investment costs (USD/kW) due to the storage system and the larger solar field, their greater capacity for electricity generation will generally result in a lower electricity generation cost. Energy storage should therefore be looked at carefully, as it can reduce the cost of electricity generated by CSP plants and increase electricity production (capacity factors).

The breakdown of the capital costs of two proposed CSP plants in South Africa (one a parabolic trough and the other a solar tower) is presented in Figure 7.2. These plants have very similar total capital investments of USD 914 million for the parabolic trough system and USD 978 million for the solar tower system. The capital costs for the solar field and receiver system are a larger percentage of the total costs in solar tower systems than in PTC systems, while the thermal energy storage and power block costs are a smaller percentage.

TABLE 7.1: CAPITAL COSTS AND KEY CHARACTERISTICS OF PARABOLIC TROUGH AND SOLAR TOWER PLANT²⁶

	Source	Heat transfer fluid	Solar multiple	Storage (hours)	Capacity factor (%)	Cost (2011 USD/kW)
Parabolic trough	Turchi, 2010a	Synthetic oil	1.3	0	26	4 700
	Hinkley, 2011	Synthetic oil	1.3	0	23	7 300
	Turchi, 2010a	Synthetic oil	2	6	41	8 170
	Turchi, 2010b	Synthetic oil	2	6.3	47-48	9 140 – 10 020
	Hinkley, 2011	Synthetic oil	2	6	43	7 900
	Fichtner, 2010	Molten salt	2.8	4.5	50	7 535
				2.5	9	56
Solar tower			3	13.4	67	9 330
	Ernst and Young/Fraunhofer, 2011	Molten salt		7.5		7 430
	Turchi, 2010a	Molten salt	1.8	6	43	6 430
	Kolb, 2011	Molten salt	2.1	9	48	7 580
	Hinkley, 2010	Molten salt	1.8	6	41	7 620
	Fichtner, 2010	Molten salt	2	9	54	7 880
				3	12	68
			3	15	79	10 740

²⁶ The solar multiple is the ratio of the thermal energy provided by the solar field, relative to what the power block requires for 100% operation when the sun is shining. The solar multiple is typically always slightly larger than one to ensure the power block is always fully utilised. Solar multiples significantly higher than one are associated with systems with thermal storage to allow the excess solar energy to be stored for use when the sun is not shining.

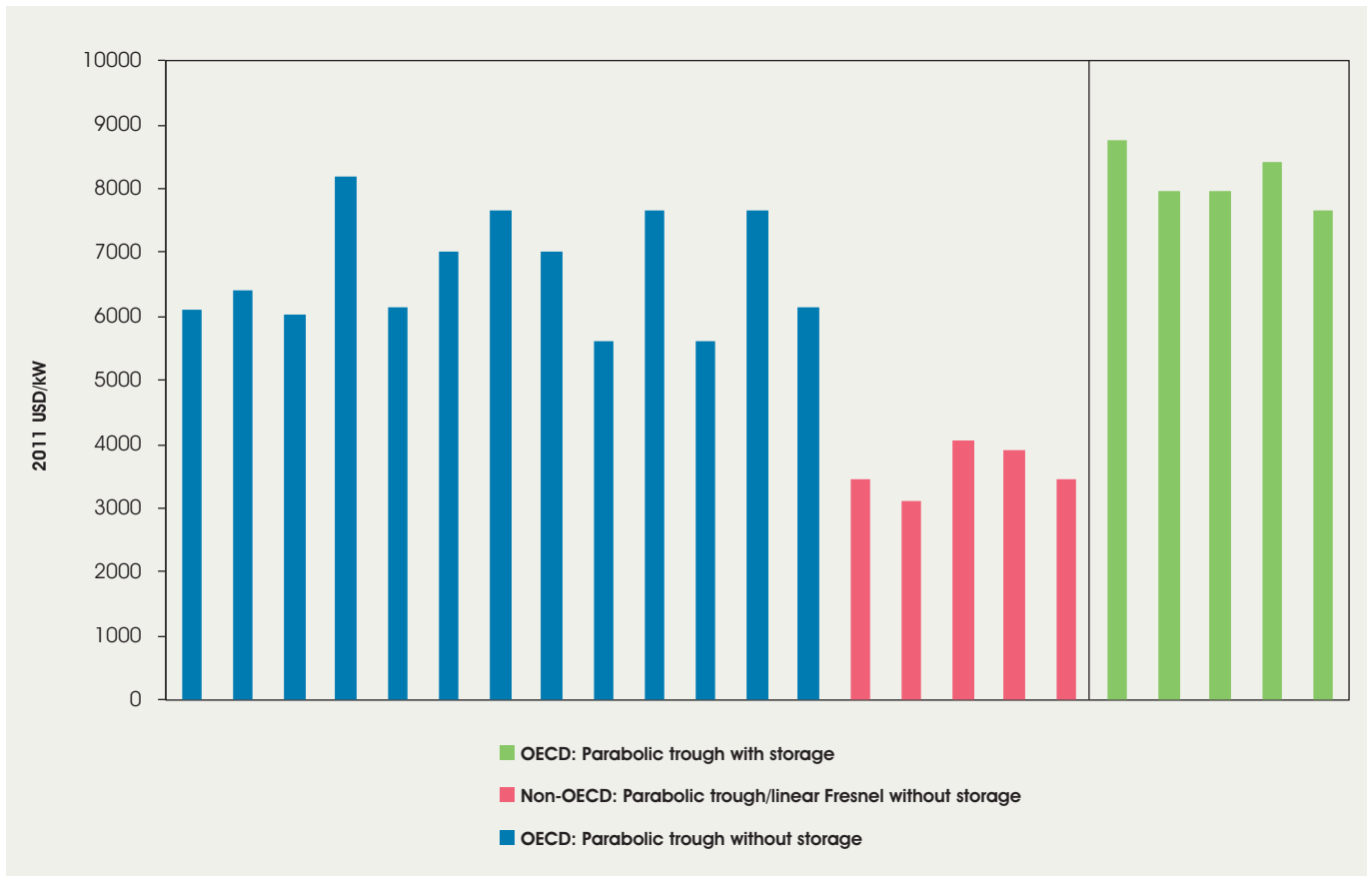


FIGURE 7.1: TOTAL INSTALLED COSTS FOR RECENTLY COMMISSIONED OR PROPOSED PARABOLIC TROUGH AND LINEAR FRESNEL PLANTS, 2010 TO 2012
 SOURCE: IRENA ANALYSIS

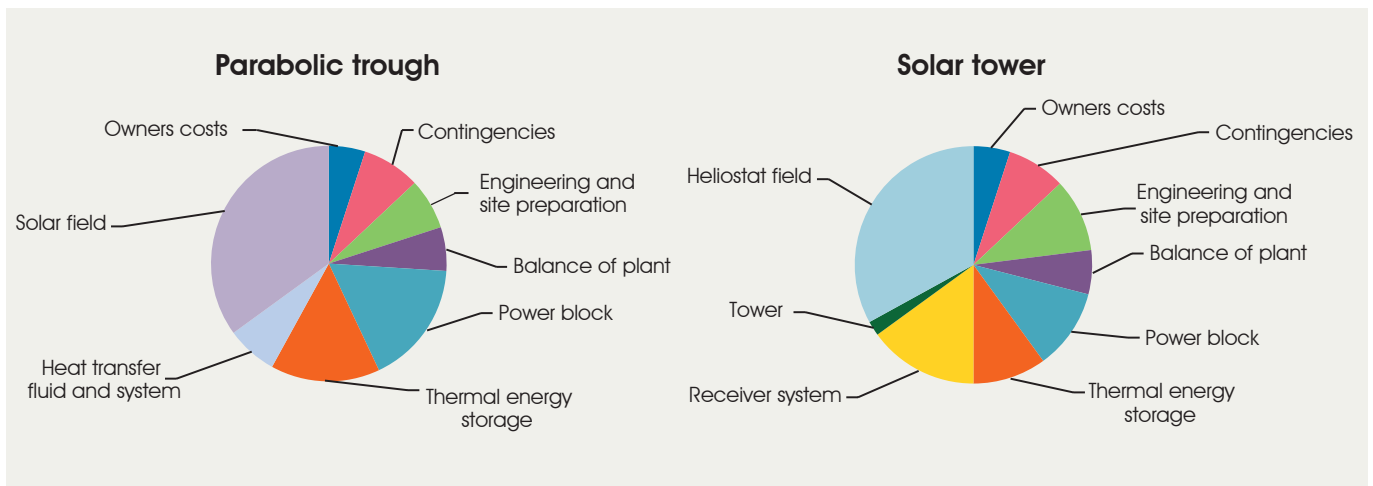


FIGURE 7.2: TOTAL INSTALLED COST BREAKDOWN FOR 100 MW PARABOLIC TROUGH AND SOLAR TOWER CSP PLANT IN SOUTH AFRICA
 Note: The parabolic trough system has 13.4 hours of thermal energy storage and the solar tower system 15 hours.
 SOURCE: FICHTNER, 2012.

The capital costs of simple parabolic trough or linear Fresnel systems without energy storage in non-OECD countries can be lower than the ranges quoted for those in OECD countries in Table 7.1. Costs for five projects

in non-OECD countries ranged between USD 3 100 and USD 4 050/kW, sometimes due to the lower cost of local content and the nature of the support mechanism used to promote CSP.

7.2 OPERATIONS AND MAINTENANCE COSTS FOR CSP PLANTS

The O&M costs of recent CSP plants are not publically available. However, a very detailed assessment of the O&M costs of the Californian SEGS plants estimated their O&M costs to be USD 0.04/kWh. The replacement of receivers and mirrors, due to glass breakage, are an important component of the O&M costs. The cost of mirror washing, including water costs, is also significant. Plant insurance can also be a large expense and its

annual cost can be between 0.5% to 1% of the initial capital cost.

The O&M maintenance costs of modern CSP plants are lower than those for the Californian SEGS plants, as technology improvements have reduced the requirement to replace mirrors and receivers. Automation has reduced the cost of other O&M procedures by as much as 30%. As a result of improved O&M procedures (both cost and plant performance), total O&M costs of CSP plants in the long run are likely to be below USD 0.025/kWh.

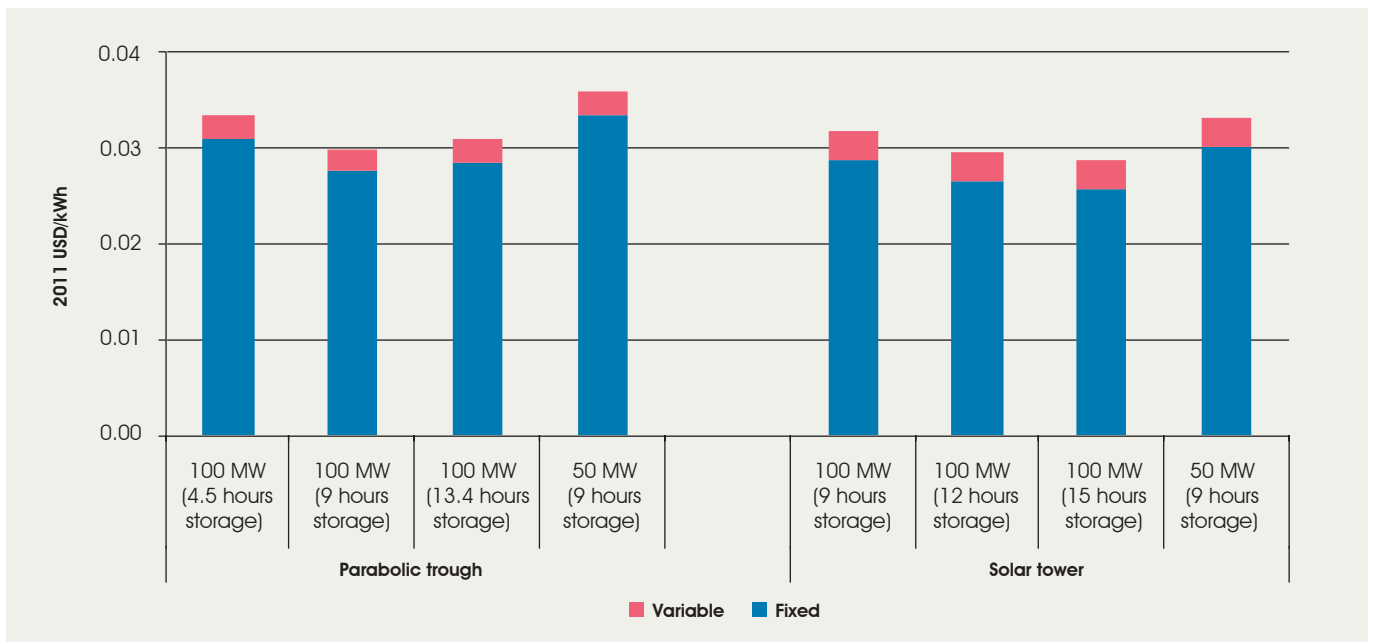


FIGURE 7.3: OPERATIONS AND MAINTENANCE COSTS FOR PARABOLIC TROUGH AND SOLAR TOWER CSP PLANTS

SOURCE: FICHTNER, 2010.

It is currently estimated that a parabolic trough system in the United States would have O&M costs of around USD 0.015/kWh, comprised of fixed costs of USD 70/kW/year and around USD 0.003/kWh in variable costs (Turchi, 2010b). However, this excludes insurance and other potential costs also reported in some O&M cost estimates, so care should be taken in interpreting this value. Given that insurance alone typically adds 0.5% to 1% to O&M costs, a figure of USD 0.02 to USD 0.03/kWh seems a robust estimate of the total costs, including all other miscellaneous costs. For

solar towers, the fixed O&M costs are estimated to be USD 65/kW/year (Turchi, 2010a)

The O&M costs of two proposed parabolic trough and solar tower projects in South Africa have estimated O&M costs (including insurance) of between USD 0.029 and USD 0.036/kWh. Parabolic troughs and solar tower plants benefit from important economies of scale in O&M costs relative to the level of thermal energy storage when moving from 4.5 hours to 9 hours of storage, although adding more storage does not yield any further significant reductions.

7.3 CAPACITY FACTORS FOR CSP

CSP technologies require large quantities (>5 kWh/m²/day) of direct normal irradiance (DNI) in order to function and be economic. Unlike photovoltaic technologies they cannot operate on diffuse or scattered irradiance as well. The generation potential of a solar CSP plant is therefore largely determined by the prevailing DNI, which obviously depends on average meteorological conditions over a year. However, the direct solar irradiance on any particular day will be determined by meteorological factors (e.g. cloud cover, humidity) and local environmental factors (e.g. local air pollution, dust). Tracking the sun provides a significantly greater energy yield for a given DNI than using a fixed surface, which is why tracking is so important to CSP plants.

The relationship between DNI, energy output and LCOE values is strong. Sites with higher DNI will yield more energy, allow greater electricity generation and have a correspondingly lower LCOE. High DNI sites yield more electricity for a given solar multiple (the size of the collector field relative to what is required to drive the power block), but also make higher solar multiples to feed thermal energy stores more attractive.

The relationship between DNI and the capacity factor (full load hours) is stronger at higher solar multiples (Figure 7.4). The practical impact of higher DNI on the LCOE of CSP plants with identical design and capital costs is significant. For instance, the LCOE of identical CSP plants will be around one-quarter lower in good sites in the United States, Algeria or South Africa where the DNI is around 2 700 kWh/m²/year, than for a site in Spain with a DNI of 2 100 kWh/m²/year (A.T. Kearney and ESTELA, 2010).

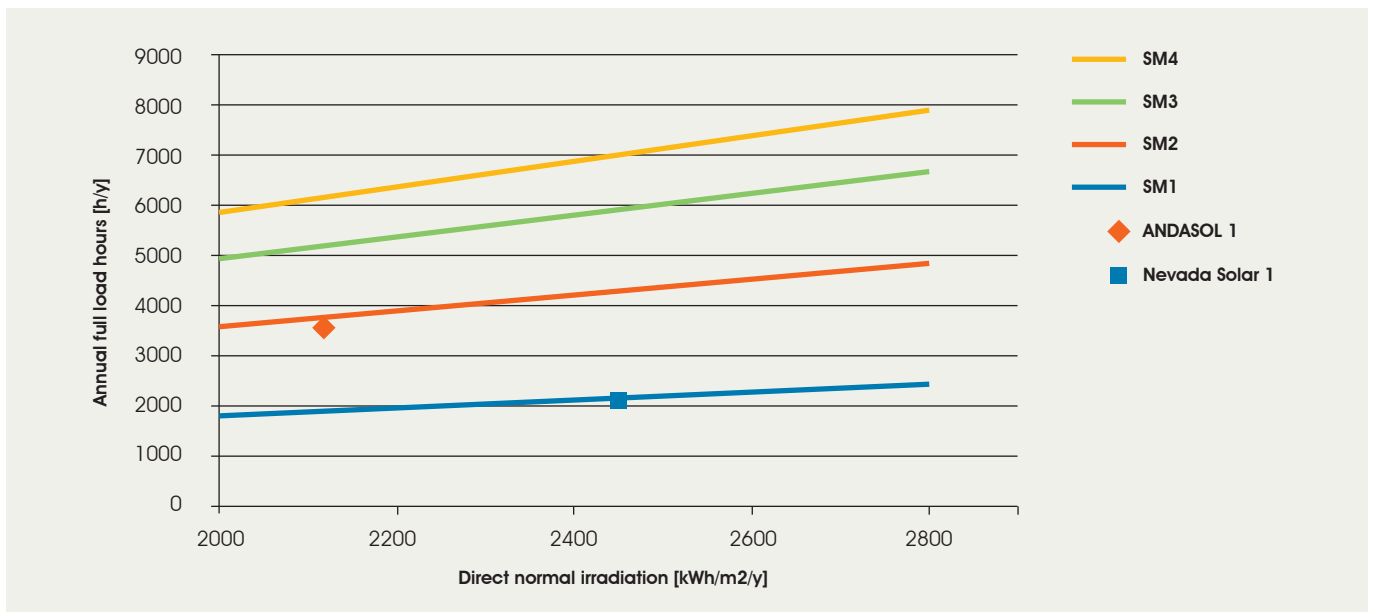


FIGURE 7.4: FULL LOAD HOURS FOR CSP AS A FUNCTION OF DIRECT NORMAL IRRADIATION AND THE SOLAR MULTIPLE

Note: SM1 = solar multiple of one, SM2 = solar multiple of two, etc.

SOURCE: TRIEB, ET AL., 2009.

The importance of the solar multiple is highlighted in Figure 7.4. To guarantee that the power block is effectively used during the year, the solar multiple

is usually larger than unity and is typically between 1.3 and 1.4 for plants without thermal energy storage.

Figure 7.5 shows the relationship between capacity factor and thermal energy storage in hours (h) for different solar multiples in regions with a good solar resource. The trade-off between the incremental costs of the increased

solar field and the storage system must be balanced against the anticipated increase in revenue that will accrue from higher production and the ability to dispatch power generation at times when the sun is not shining.

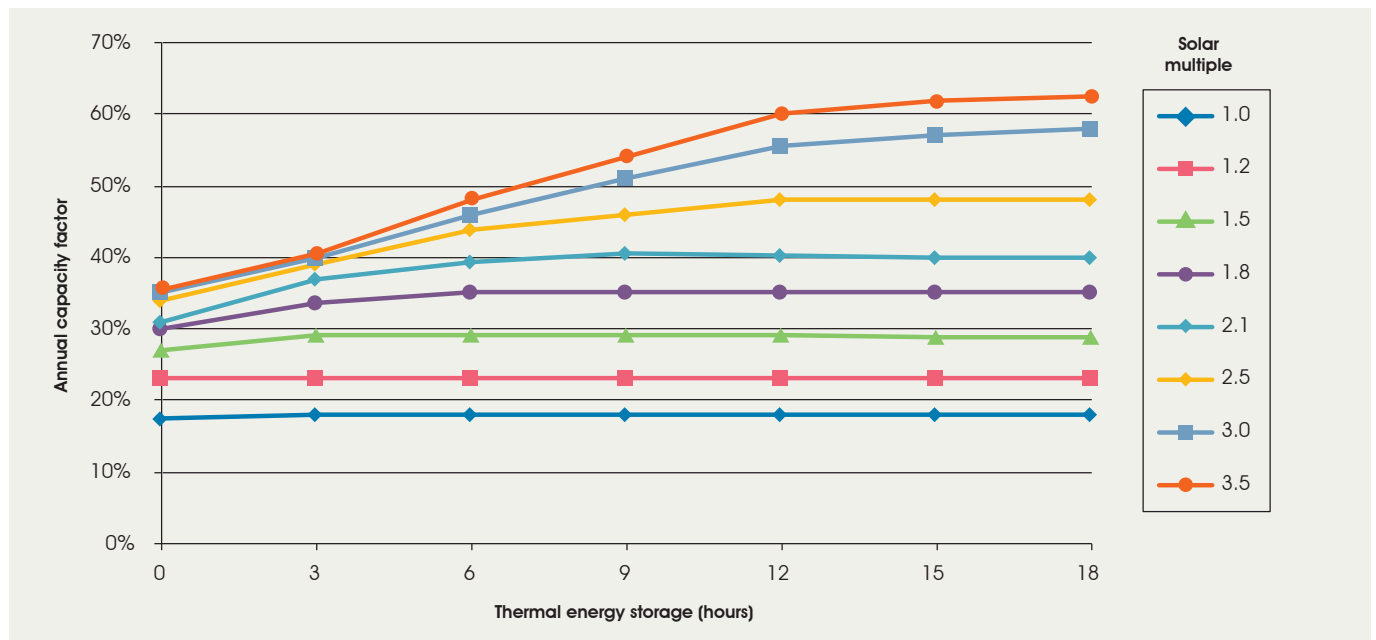


FIGURE 7.5: ANNUAL CAPACITY FACTOR FOR A 100 MW PARABOLIC TROUGH PLANT AS A FUNCTION OF SOLAR FIELD SIZE AND SIZE OF THERMAL ENERGY STORAGE
SOURCE: TURCHI, 2010A.

7.4 THE LEVELISED COST OF CSP

The LCOE of CSP plants is strongly correlated with the DNI. Assuming a base of 2 100 kWh/m²/year

(a typical value for Spain), the estimated LCOE of a CSP plant is expected to decline by 4.5% for every 100 kWh/m²/year that the DNI exceeds 2 100 (Figure 7.6).

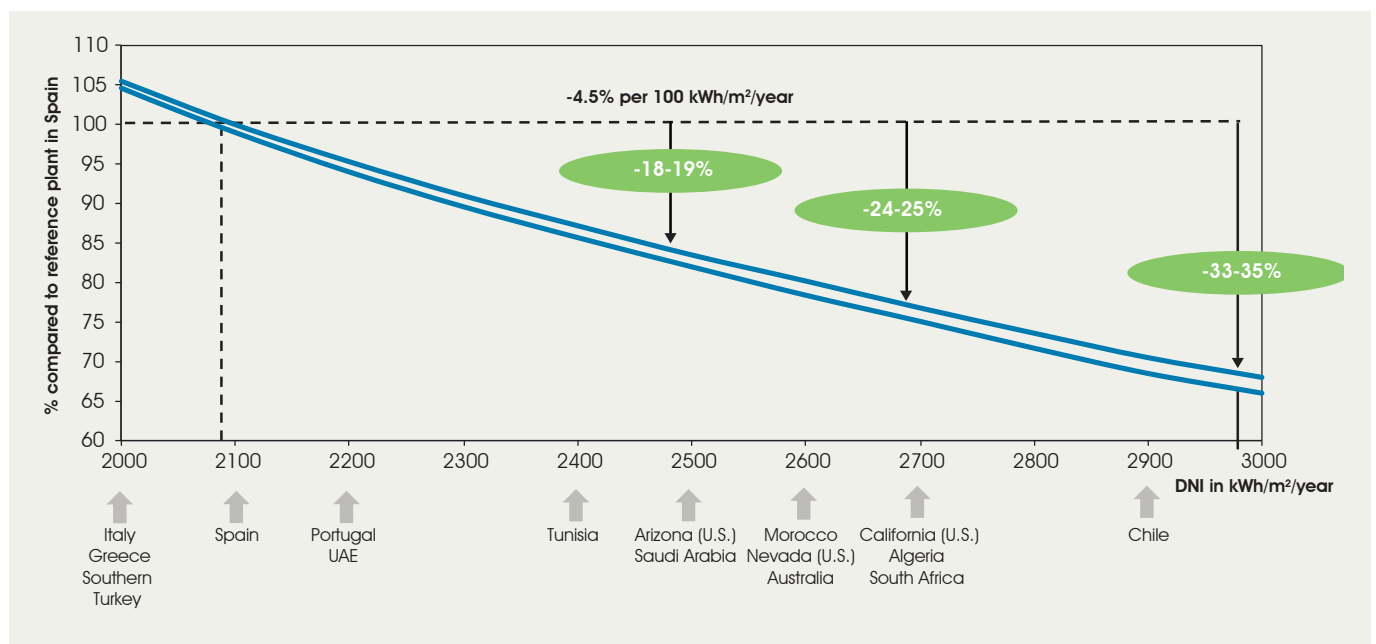


FIGURE 7.6: THE LEVELISED COST OF ELECTRICITY OF CSP PLANTS AS A FUNCTION OF DIRECT NORMAL IRRADIANCE
SOURCE: A.T. KEARNEY AND ESTELA, 2010.

An important consideration in the design of CSP plant is the amount of thermal energy storage and the size of the solar multiple. Various combinations of these two parameters yield different LCOE results (Figure 7.7). Thermal storage allows CSP to achieve higher capacity

factors and dispatch generation when the sun is not shining. This can make CSP a competitor for conventional base- or intermediate-load power plants. A large-scale example of this technology is the 280 MW Solana 1 power plant in Arizona.

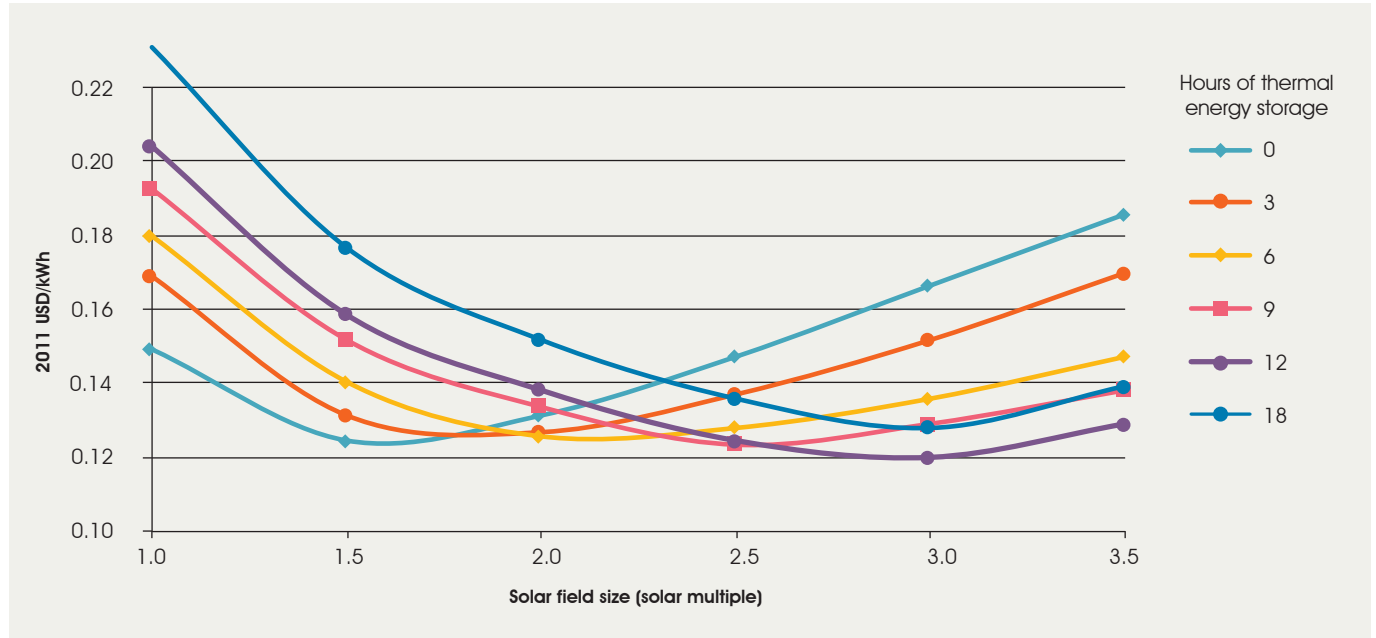


FIGURE 7.7: THE LEVELISED COST OF ELECTRICITY OF CSP PLANTS AS A FUNCTION OF THE SOLAR MULTIPLE AND HOURS OF THERMAL ENERGY STORAGE

SOURCE: ANDERS, 2005.

However, for a given PTC plant, the minimum range of LCOE can be achieved by varying the thermal energy storage and solar multiple values (Figure 7.7). This analysis suggests that the minimum LCOE is achieved with a solar multiple of 3 combined with 12 hours energy storage. However, there is relatively little difference between a plant with a solar multiple of 1.5 and no thermal energy storage, a solar

multiple of 2 with 6 hours energy storage, and a plant with a solar multiple of 3 with 12 hours energy storage. Choosing the optimal plant design will therefore depend on the project's specifics and the local power market. The integration of thermal energy storage in solar towers is cheaper than for PTC plant and increasing the level of storage will therefore usually yield lower LCOEs.

It is important to remember that these calculations assume that all electricity generated has the same value. Given this is typically not the case, then plants with higher storage levels are likely to provide more flexibility to capture the increased value of peak prices. This situation will evolve over time as thermal energy storage costs decline. Lower storage costs, particularly for solar tower projects, will result in a lower LCOE for plants with higher storage.

The estimated LCOE of parabolic trough and linear Fresnel CSP systems without storage ranges from around USD 0.19 to USD 0.38/kWh, assuming capital costs of between USD 3 400 and USD 4 600/kW and capacity

factors of between 20% and 27% (Figure 7.8). The lower end of this range represents very competitive projects in non-OECD countries with high capacity factors. Adding six hours storage reduces the LCOE of the parabolic trough and linear Fresnel CSP systems to a range of between USD 0.17 to USD 0.37/kWh.

Solar towers are a significantly less mature technology than parabolic trough systems, although they already have similar costs with an LCOE range of between USD 0.20 to USD 0.29/kWh when associated with six and a half hours of storage. Increasing storage to between 12 and 15 hours of operation lowers the LCOE range to between USD 0.17 and USD 0.24/kWh.

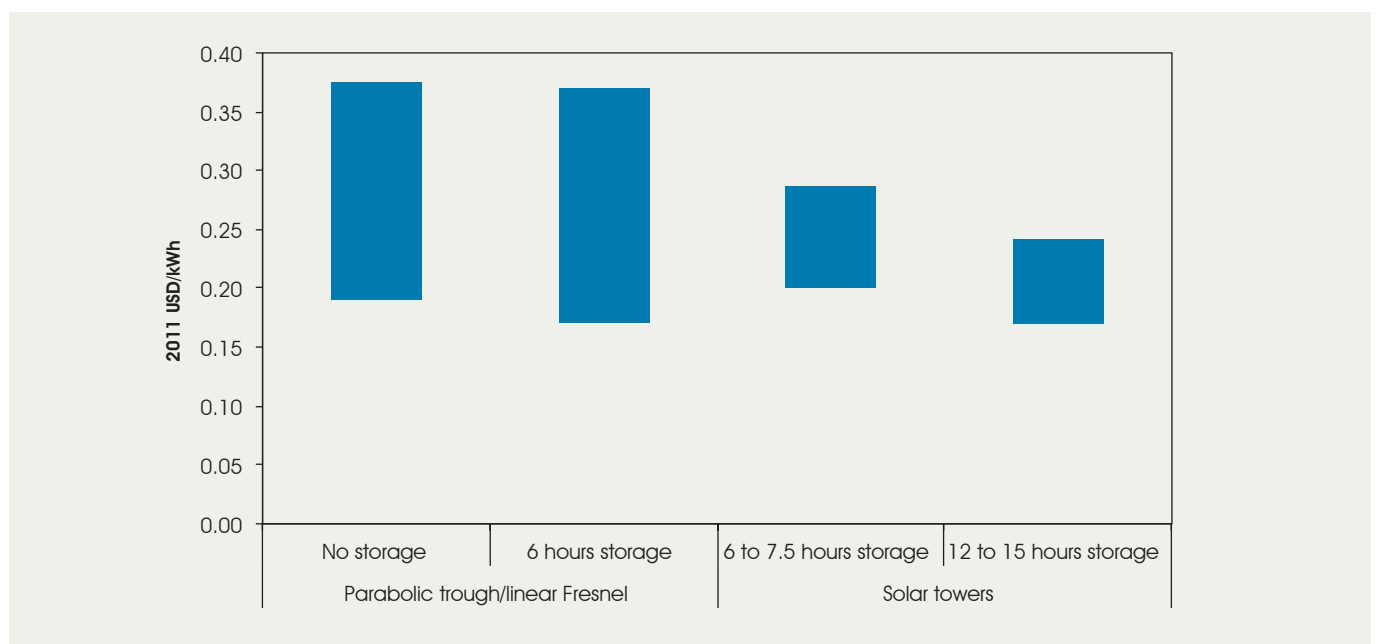


FIGURE 7.8: THE LEVELISED COST OF ELECTRICITY OF CSP PLANTS IN 2011/2012

SOURCE: IRENA RENEWABLE COST DATABASE; FICHTNER, 2010; TURCHI, 2010A AND 2010B; AND HINKLEY, 2011.

8. BIOMASS FOR POWER GENERATION

Many biomass power generation options are mature, commercially proven technologies with long track records. They include direct combustion in stoker boilers, low-percentage co-firing, anaerobic digestion, municipal solid waste incineration, landfill gas and combined heat and power. Other less mature technologies, such as atmospheric biomass gasification and pyrolysis are only at the beginning of their deployment, while others, such as integrated gasification combined cycle, bio-refineries and bio-hydrogen, are only in the demonstration or R&D phases. The potential for biomass cost reductions is therefore very heterogeneous. While only marginal cost reductions can be anticipated in the short term, the long-term potential for cost reductions from those technologies that are not yet widely deployed is good.

In order to analyse the use of biomass for power generation, it is important to consider three critical components of the process:

- Biomass feedstocks: These come in a variety of forms and have different properties that impact their use for power generation.
- Biomass conversion: This is the process by which biomass feedstocks are transformed into the energy form that will be used to generate heat and/or electricity.
- Power generation technologies: A wide range of commercially proven power generation technologies that can use biomass as a fuel input are available.

The following analysis focuses on the costs of the last two components and briefly discusses feedstock costs. The source and sustainability of the biomass feedstock is a very important determinant of a biomass power generation project's economics and success.

8.1 BIOMASS FEEDSTOCKS

Biomass is the organic material of recently living plants such as trees, grasses and agricultural crops. Biomass feedstocks are very heterogeneous and their chemical composition is highly dependent on the plant species. This can be a problem since, although some combustion technologies can accept a wide range of biomass feedstocks, others require much more homogeneous feedstocks.

Secure, long-term supplies of low-cost, sustainably sourced feedstocks are critical to the economics of biomass power plants. Feedstock costs can be zero for wastes that are produced onsite at an industrial installation or less than zero for those which would otherwise incur disposal costs (e.g. black liquor at pulp and paper mills or bagasse at sugar mills). Feedstock costs can be modest where agricultural residues can be collected and transported over short distances, although the low energy density of biomass (such as wood chips and pellets) can greatly increase costs where significant transport distances are involved.

Feedstock costs can represent 40% to 50% of the total cost of electricity produced by biomass technologies. The lowest cost feedstock is typically agricultural residues such as straw and bagasse from sugar cane, as these can be collected at harvest. For forest residues, the cost is dominated by collection and transportation costs. The density of the forestry residues has a direct impact on the radius of transport required to deliver a given total energy requirement to a plant. The low energy density of biomass feedstocks tends to limit the transport distance from a biomass power plant that it is economical to transport the feedstock. This can place a limit on the scale of the biomass power plant, meaning that biomass power plants struggle to take advantage of economies of scale in its generating plant because large quantities of low-cost feedstock are not always available.

Prices for biomass sourced and consumed locally are generally difficult to obtain and no data are available to make comparisons over time. Prices paid will depend on the energy content of the fuel, its moisture content and

other properties that will impact on the costs of handling or processing at the power plant and on the efficiency of generation. The range of costs can be quite wide and are very site-specific (Table 8.1).

TABLE 8.1: BIOMASS FEEDSTOCK COSTS IN THE UNITED STATES

	Typical moisture content	Heat value kJ/kg (LHV)	Price (USD/GJ)	Price (USD/tonne)	Cost structure
Forest residues	30% - 40%	11.5	1.30 - 2.61	15 - 30	Collecting, harvesting, chipping, loading, transportation and unloading, stumpage fee and return for profit and risk.
Wood waste ^a	5% - 15%	19.9	0.50 - 2.51	10 - 50	Cost can vary from zero, where there would otherwise be disposal costs, to quite high where there is an established market for their use in the region.
Agricultural residues ^b	20% - 35%	11.35 - 11.55	1.73 - 4.33	20 - 50	Collecting, premium paid to farmers, transportation.
Energy crops ^c	10% - 30%	14.25 - 18.25	4.51 - 6.94	39 - 60	Not disclosed.
Landfill gas		18.6 - 29.8 ^d	0.94 - 2.84	0.017 - 0.051 ^d	Gas collection and flare.

Notes:

- a) Sawmills, pulp and paper companies (bark, chip, sander dust, sawdust). Moisture content is often low because they have already been through a manufacturing process. In cases where disposal is required, prices can be zero as the avoided costs of disposal can make it worthwhile to find a productive use for the feedstock.
- b) Corn stover and straw.
- c) Poplar, willow and switchgrass.
- d) For landfill gas the heat value and price is in MJ/m³ and USD/m³ respectively.

SOURCE: BASED ON EPA, 2007

Some prices for feedstocks in developing countries are available but information is relatively limited. In the case of Brazil, the price of bagasse varies significantly, depending on the harvest period. It can range from zero to USD 27/tonne with the average price being around USD 11/tonne, where a market exists (Table 8.2). These low bagasse prices make

the economics of bioenergy power plants using other feedstocks extremely challenging, except in situations where a captive feedstock exists (i.e. in the pulp and paper industry). As a result, most of the other bioenergy power generation projects in Brazil rely on black liquor or woodwaste for cogeneration in industry with the surplus electricity sold to the market.

TABLE 8.2: BIOMASS FEEDSTOCK CHARACTERISTICS AND COSTS IN BRAZIL AND INDIA

	Typical moisture content	Heat value MJ/kg	USD/GJ	USD/tonne
Bagasse	40% - 55%	5.6 - 8.9	1.3 - 2.3 1.4 - 2.5	11 - 13 (Brazil) 12 - 14 (India)
Woodchip		7.75	9.30	71 (Brazil)
Charcoal mill		18.84	5.31	95 (Brazil)
Rice husk	11%	12.96	...	22 - 30 (India)

SOURCE: RODRIGUES, 2009; AND IRENA RENEWABLE COST DATABASE.

The analysis in this report for OECD countries examines feedstock costs of between USD 10/tonne for low-cost residues to USD 160/tonne for internationally traded

pellets (Tables 8.1 and 8.2). This compares to forward spot pellet prices at Rotterdam that ranged between USD 165 and USD 177/tonne during 2012.

8.2 BIOMASS-FIRED POWER GENERATION CAPITAL COSTS BY TECHNOLOGY

The cost and efficiency of biomass power generation equipment varies significantly by technology. Equipment costs for an individual technology type can also vary, depending on the region, but also on the nature of the feedstock and how much feedstock preparation and handling is done onsite.

The total investment cost – capital expenditure (CAPEX) – consists of the equipment (prime mover and fuel conversion system), fuel handling and preparation machinery, engineering and construction costs, and planning. The costs can also include grid connection, roads and any kind of new infrastructure or improvements to existing infrastructure required for the project. Figure 8.1 presents the range of capital costs for different technologies in OECD countries.

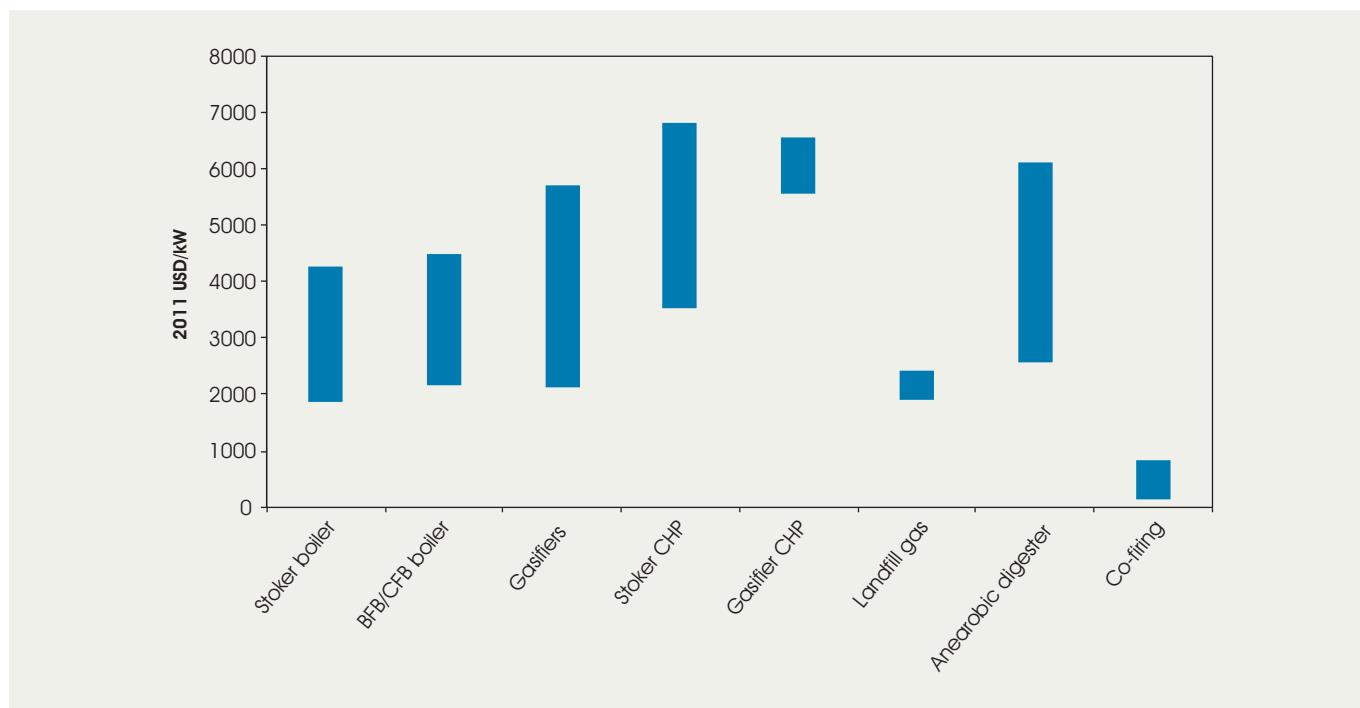


FIGURE 8.1: TOTAL INSTALLED CAPITAL COSTS OF BIOMASS-FIRED ELECTRICITY GENERATION TECHNOLOGIES IN OECD COUNTRIES

Note: Co-firing is for the additional cost only. It excludes the cost of the coal-fired power plant itself. BFB = bubbling fluidised bed, CFB = circulating fluidised bed and CHP = combined heat and power.

SOURCE: IRENA, 2012.

The costs of simple, mature technologies for biomass combustion in developing countries can be significantly lower than these ranges, as local content and the use of equipment that may not meet very stringent emissions regulations can reduce costs. For instance, manure and wastewater systems associated with electricity generation – 42 manure and 82 wastewater projects – have been installed in developing countries under the Clean Development Mechanism with capacities between

1 MW and 3 MW, with some incurring total capital costs as low as USD 500/kW, while others have cost as high as USD 5 000/kW.

Figure 8.2 highlights the relatively low cost of biomass combustion technologies for projects in non-OECD countries. Although small-scale projects can have higher capital costs, the majority of larger projects have installed capital costs in the range of USD 600 to USD 1 400/kW.

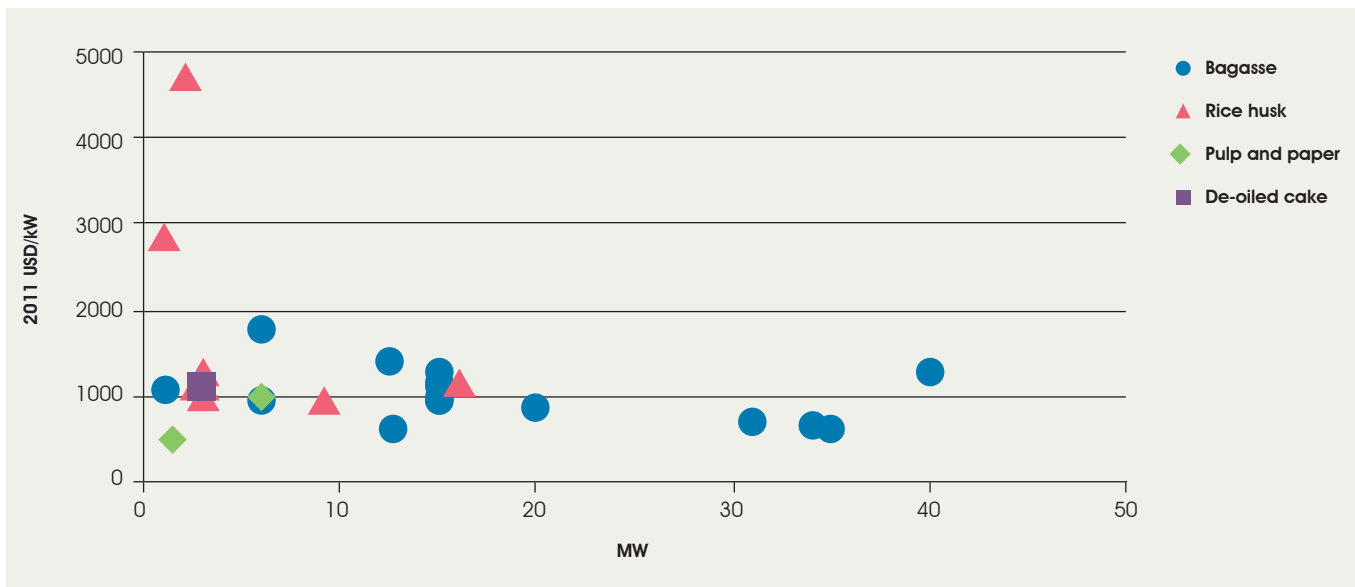


FIGURE 8.2: TOTAL INSTALLED COSTS OF STOKER BOILER-BASED ELECTRICITY GENERATION SYSTEMS IN NON-OECD COUNTRIES

SOURCE: IRENA RENEWABLE COST DATABASE.

Different projects will have different requirements for each cost component, with infrastructure requirements/ improvements being particularly project-sensitive. Figure 8.3 presents the capital cost breakdown for a range

of biomass-fired electricity generation projects in Africa and India. Equipment costs tend to dominate, but specific projects can have high costs for infrastructure and logistics, or for grid connection when located in remote areas.

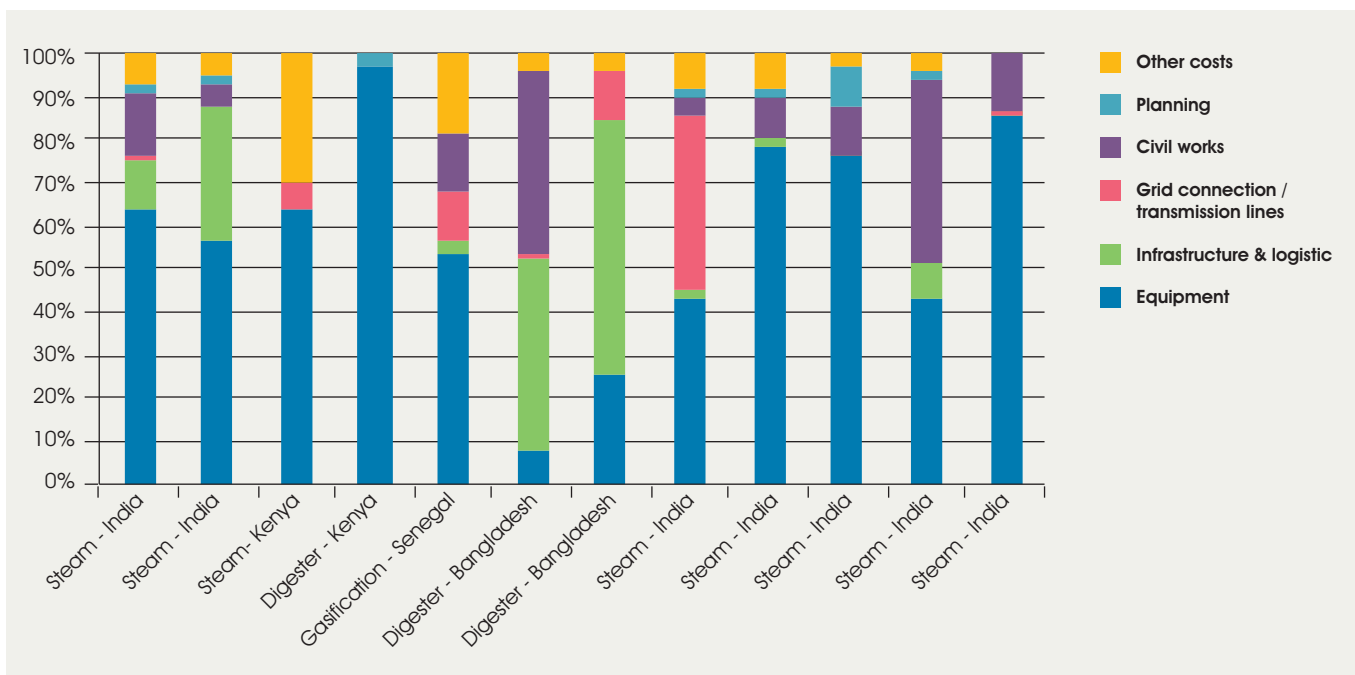


FIGURE 8.3: TOTAL INSTALLED COST BREAKDOWN OF BIOMASS-BASED ELECTRICITY GENERATION SYSTEMS IN NON-OECD COUNTRIES

SOURCE: IRENA RENEWABLE COST DATABASE.

8.3 BIOMASS-FIRED POWER GENERATION OPERATIONS AND MAINTENANCE COSTS

Fixed O&M costs for biomass power plants typically range from 1% to 6% of the initial CAPEX per year (Table 8.3). Fixed O&M costs consist of labour, scheduled maintenance, routine component/equipment replacement (for boilers, gasifiers, feedstock handling equipment, etc.), insurance, etc. The larger the plant, the lower the specific (per kW) fixed O&M costs, due

to the impact of economies of scale, particularly for the labour required. Variable O&M costs depend on the output of the system and are usually expressed as a value per unit of output (USD/kWh). They include non-biomass fuel costs, ash disposal, unplanned maintenance, equipment replacement and incremental servicing costs. Available data often combines fixed and variable O&M costs into one number, so a breakdown between fixed and variable O&M costs is often not possible.

TABLE 8.3: FIXED AND VARIABLE OPERATIONS AND MAINTENANCE COSTS FOR BIOMASS POWER

	Fixed O&M (% of CAPEX/year)	Variable O&M (USD/MWh)
Stoker/BFB/CFB boilers	3.2 - 4.2	3.8 - 4.7
Gasifier	3 - 6	3.7
Anaerobic digester	2.1 - 3.2 2.3 - 7	4.2
Landfill gas	11 - 20	n.a.

SOURCES: US DOA, 2007; US EPA, 2009; AND MOTT MACDONALD, 2011.

Note: BFB = bubbling fluidised bed and CFB = circulating fluidised bed.

8.4 BIOMASS-FIRED POWER GENERATION CAPACITY FACTORS AND EFFICIENCY

Although biomass-fired electricity plants can achieve availabilities in the range 85% to 90%, they will not always operate at these levels. Systems relying on agricultural residues in particular, may not have access to year-round supplies of low-cost feedstock and may find it uneconomic to purchase alternative supplies to achieve a high overall capacity factor for the entire year. This is illustrated in Figure 8.4, where the lower capacity factors for projects in Latin America represent the impact

of a large number of bagasse-fired projects that will only operate around the harvesting period until they exhaust the available feedstock supply.

The assumed net electrical efficiency (after accounting for feedstock handling) of the prime mover (generator) is assumed to average 35% and varies between 31% for wood gasifiers to a high of 36% for stoker/CFB/BFB and anaerobic digestion systems (Mott MacDonald, 2011). Biomass integrated gasification combined cycle (BIGCC) systems should achieve higher efficiencies but would require higher capital costs.

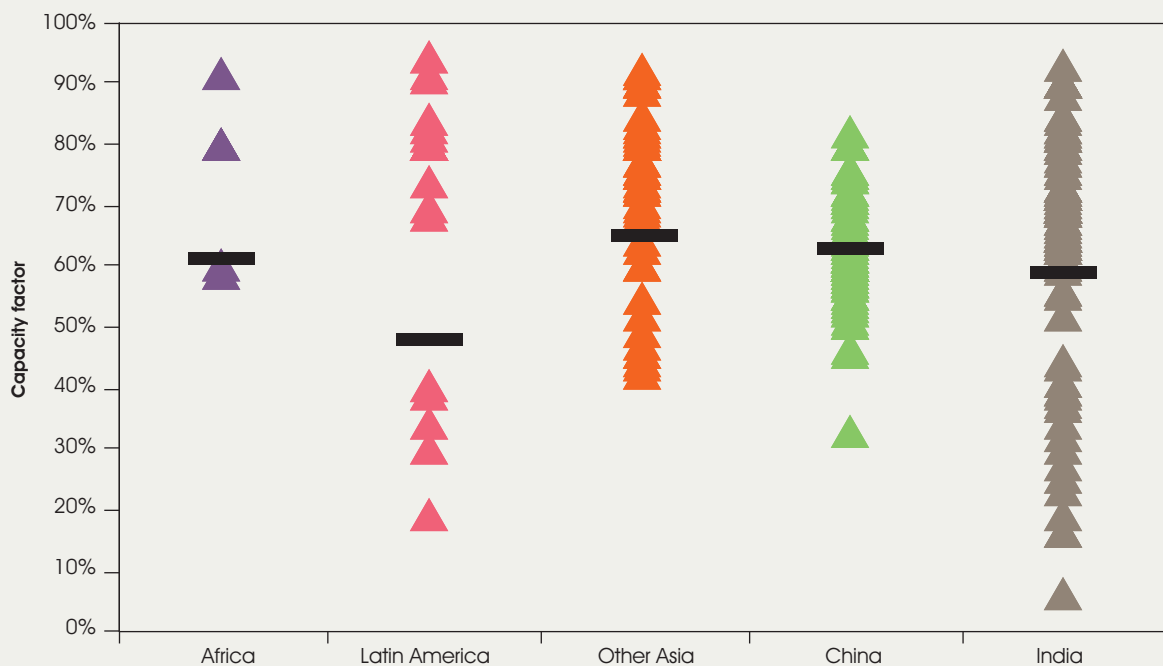


FIGURE 8.4: PROJECT CAPACITY FACTORS AND WEIGHTED AVERAGES OF BIOMASS-FIRED ELECTRICITY GENERATION SYSTEMS IN NON-OECD COUNTRIES

SOURCE: IRENA RENEWABLE COST DATABASE.

8.5 THE LEVELISED COST OF ELECTRICITY FROM BIOMASS-FIRED POWER GENERATION

The range of biomass-fired power generation technologies and feedstock costs result in a large range for the LCOE of biomass-fired power generation. The range can be wide, even within individual technologies, as different configurations, feedstocks, fuel handling and, in the case of gasification, gas clean-up requirements can lead to very different installed costs and efficiencies for a “single” technology.

Figure 8.5 summarises the range of costs that are possible for the core biomass power generation technologies in OECD countries when the low and high estimates of investment costs and feedstock costs are examined. Assuming a cost of capital of 10% and feedstock costs between USD 1 and USD 9/GJ, the LCOE of biomass-fired electricity generation ranges from a low of USD 0.06/kWh to a high of USD 0.29/kWh in the OECD. Where capital costs are low and low-cost feedstocks are available, bioenergy can provide competitively priced, dispatchable electricity generation with an LCOE as low as around USD 0.06/kWh.

Many of the low-cost opportunities to develop bioenergy-fired power plants will therefore be in taking advantage of existing forestry or agricultural residues and wastes (e.g. from the pulp and paper, forestry, food and agricultural industries) where low-cost feedstocks

and sometimes handling facilities are available to keep feedstock and capital costs low. The development of competitive supply chains for feedstocks is therefore very important in making bioenergy-fired power generation competitive.

This is the pattern seen in non-OECD countries where biomass costs for most projects are typically in the range of USD 1.3 and USD 2.5/GJ from agricultural residues (e.g. bagasse, rice husks, etc.) or forestry or wood processing residues. These projects, using simple and cheap combustion technologies²⁷ can have very competitive LCOEs (Figure 8.5). Low LCOEs are generally required to make the projects financially viable, as no or very low subsidies are usually available. However, even higher-cost projects in certain non-OECD countries will be attractive because they provide security of supply where brown-outs and black-outs can be particularly problematic for the efficiency of industrial processes. However, the results in Figure 8.5 for non-OECD countries need to be treated with caution, because many of the projects are not greenfield and take advantage of existing feedstock storage and handling facilities, and may also take steam from existing boilers.

²⁷ An important caveat is that these will often not meet stringent air quality standards.

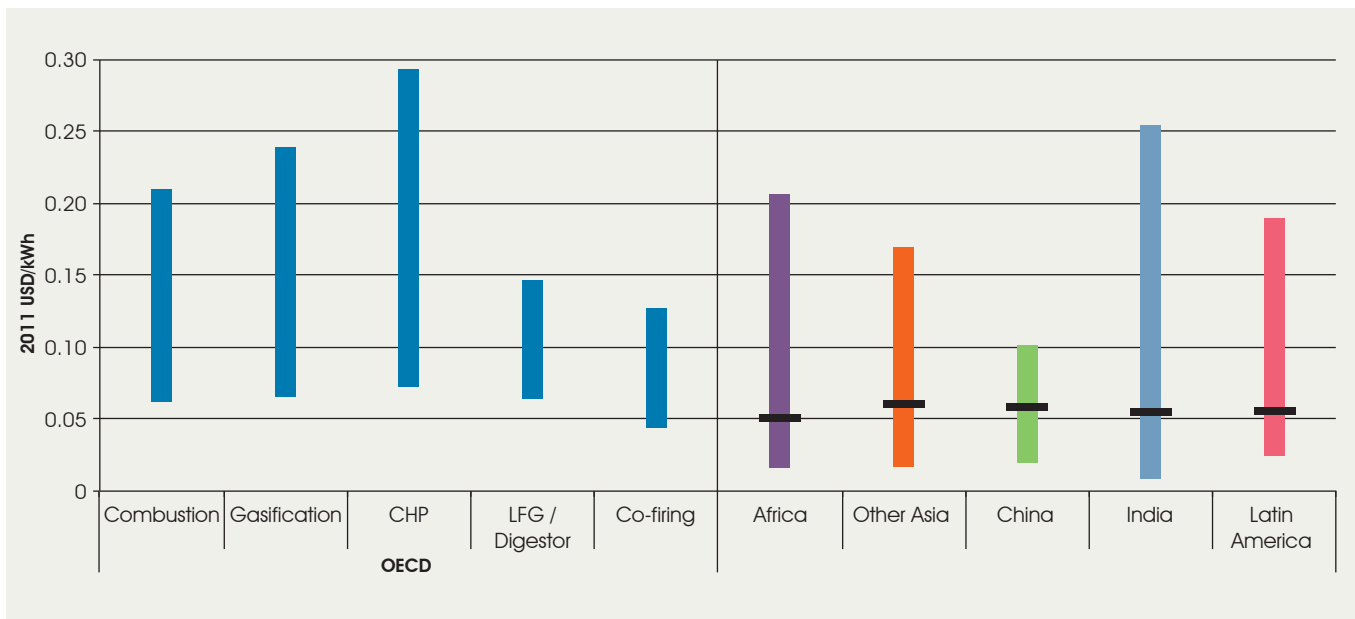


FIGURE 8.5: LEVELISED ELECTRICITY COST RANGES AND WEIGHTED AVERAGES OF BIOMASS-FIRED ELECTRICITY GENERATION BY TECHNOLOGY AND COUNTRY/REGION

SOURCE: IRENA RENEWABLE COST DATABASE.

The importance of feedstock costs in OECD countries, where costs can range from as little as USD 1/GJ for residues up to USD 9/GJ or more for imported pellets is highlighted in Figure 8.6. Excluding co-firing, which is a special case, feedstock costs typically account

for between 20% and 50% of the LCOE of power generation-only options. The range is significantly wider for gasifier-based CHP projects, where feedstock costs can account for as little as 14% of the LCOE but up to 85% in the case of using imported wood chips.

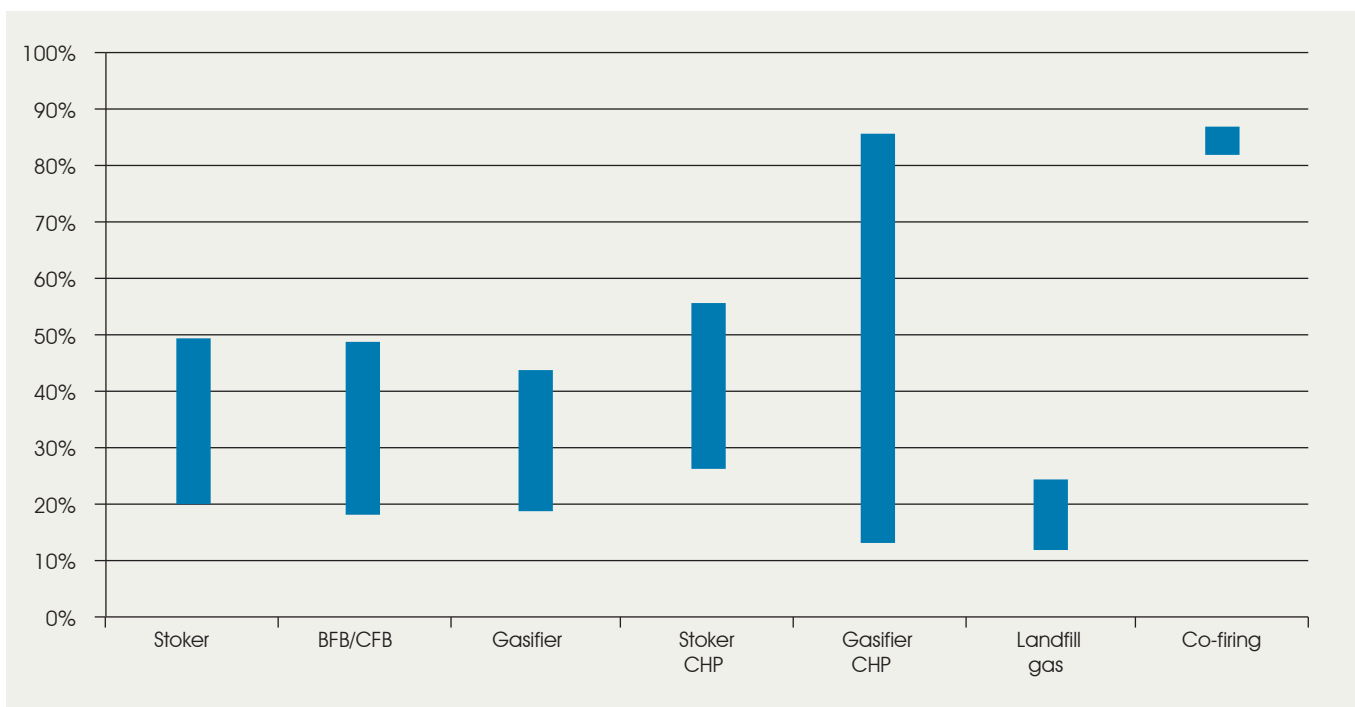


FIGURE 8.6: SHARE OF FUEL COSTS IN THE LEVELISED COST OF ELECTRICITY OF BIOENERGY POWER GENERATION FOR HIGH AND LOW FEEDSTOCK PRICES IN THE OECD

SOURCE: IRENA RENEWABLE COST DATABASE.

9. GEOTHERMAL POWER GENERATION

Geothermal resources are the thermal energy available from the Earth's interior, which is stored as heat in rocks or as steam or hot water in the surface's crust, or in active geothermal areas, on the Earth's surface. High-temperature water or steam-based resources ($>180^{\circ}\text{C}$) are the best for electricity generation, as the liquid can be used directly by dropping the pressure to create steam, (the so-called "flashing" process), that can drive a turbine. Where only medium temperature resources are available, more expensive "binary" plants are required. These use a heat exchanger to create steam from a liquid with a low boiling point for subsequent use in a steam turbine.

Initial exploration (e.g. surface seismic) will be conducted to identify promising geothermal reservoirs suitable for electricity production. This will then be followed by exploratory drilling to confirm or refute the estimations of the exploration process, and to define the extent of the reservoir and its characteristics. This is a time-consuming and expensive process, and a barrier to the uptake of geothermal power generation.

A field development programme can then be developed that takes into account production and reinjection wells, reservoir management, infrastructure and power plant design. However, the field management programme will evolve over time as a better understanding emerges of the reservoir and its flows and characteristics.

Geothermal power generation is a mature, commercially available solution to provide low-cost baseload capacity in areas with excellent high-temperature resources close to the surface.

9.1 GEOTHERMAL POWER GENERATION INSTALLED COSTS

Geothermal power plants are capital-intensive, but have very low and predictable running costs. Development costs have increased over time as EPC and commodity prices have risen, but also due to drilling costs rising in line with trends in the oil and gas sectors. The total installed costs of a geothermal power plant are composed of the following:

- Exploration and resource assessment costs;
- The drilling of production and re-injection wells. This will require a contingency plan, as a success rate of 60% to 90% is the norm for production (Hance, 2005; GTP, 2008).
- Field infrastructure and other surface installations;
- The power plant and its associated costs; and
- Project development and grid connection costs.

Today's total installed costs for geothermal power plant are around 60% to 70% higher than in 2000 (IPCCC, 2011). The costs of conventional condensing "flash" geothermal power generation projects have installed costs of between USD 1 900 and USD 3 800/kW for typical projects (Figure 9.1). The more expensive binary power plant have installed costs for typical projects of between USD 2 250 and USD 5 500/kW (IPCCC, 2011).

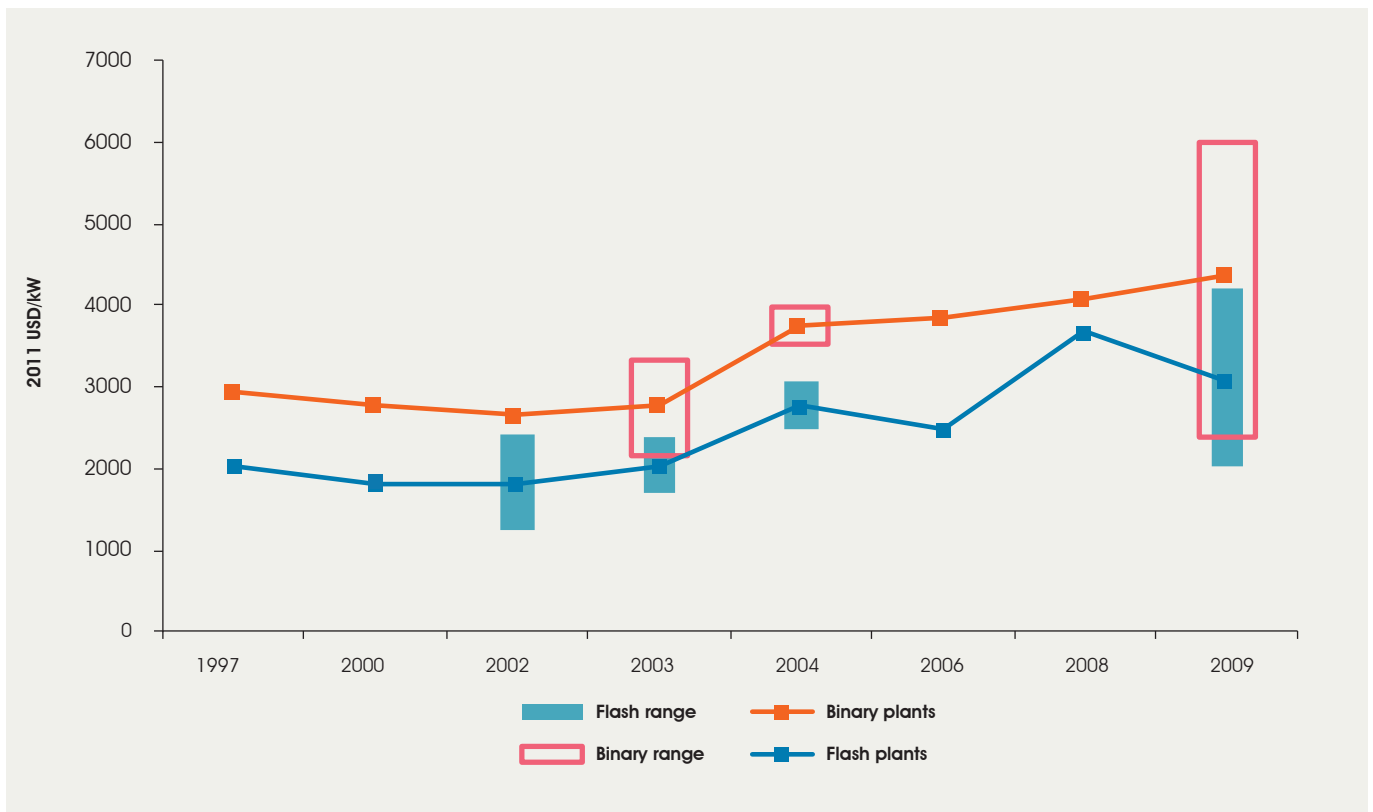


FIGURE 9.1: TOTAL INSTALLED COSTS FOR GEOTHERMAL POWER STATIONS, 1997 TO 2009

SOURCE: IPCC, 2011.

Project costs can be lower than this, and can be as little as USD 1 500/kW where capacity is being added at an existing geothermal reservoir which is already well characterised and existing infrastructure can be utilised, but such cases are exceptional. Data for recent projects (Figure 9.2) fit within the general range band in Figure 9.1.

However, these cost ranges are narrow compared to some of the analysis in the literature and may represent the lower end of the cost range when exploiting the best geothermal resources. Analysis for the United States (Figure 9.3) suggests a wider range for binary plant exploiting low temperature resources, based on the power plant costs alone (i.e. excluding production and injection wells) (NREL, 2012b).

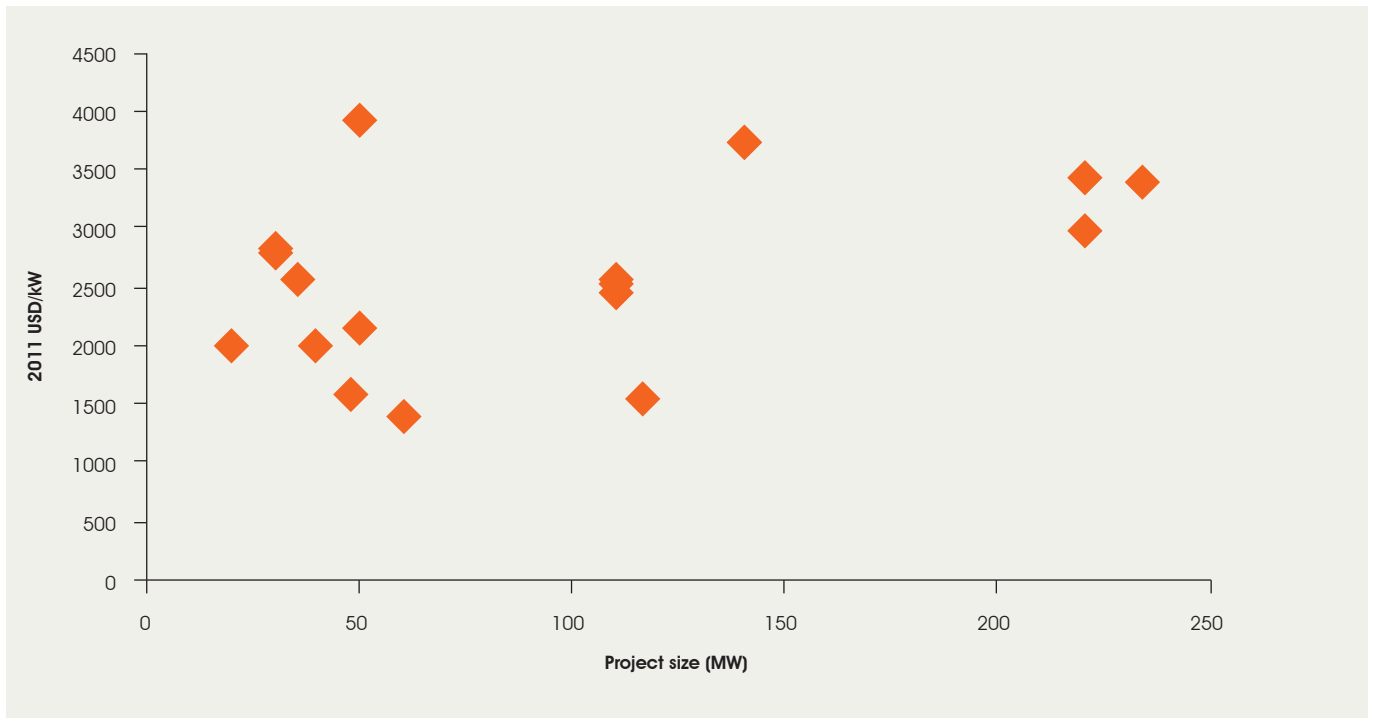


FIGURE 9.2: INSTALLED CAPITAL COSTS FOR GEOTHERMAL POWER PROJECTS IN CHILE, INDONESIA, KENYA, MEXICO AND THE PHILIPPINES

SOURCE: IRENA RENEWABLE COST DATABASE.

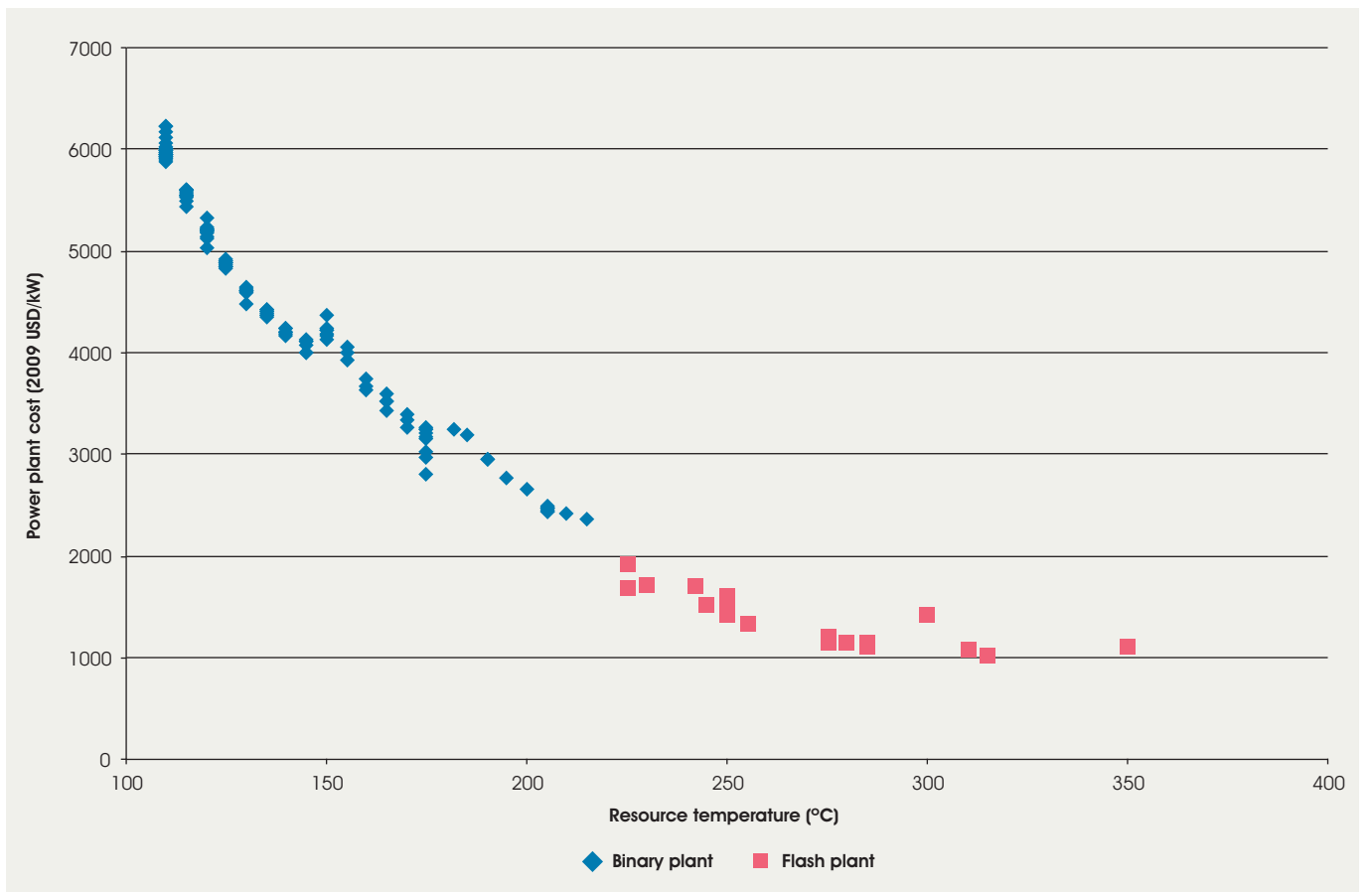


FIGURE 9.3: POWER PLANT ONLY COSTS FOR GEOTHERMAL PROJECTS BY RESERVOIR TEMPERATURE

SOURCE: NREL, 2012B.

The estimates of total installed costs for the remaining geothermal resources in the United States, show a very large range from around USD 1 500/kW to figures beyond USD 10 000/kW (Augustine, 2011). Much of this supply curve for the United States is not economic and does not represent typical geothermal project costs, but it does show the importance of identifying the best geothermal reservoirs and geothermal resources for project development. Cost ranges for small-scale low-temperature resource binary plants are therefore likely to have a wider range than those typical for excellent geothermal reservoirs and resources, and might have typical costs in the range USD 5 000 to USD 10 000/kW.

9.2 THE LCOE OF GEOTHERMAL POWER GENERATION

The LCOE of a geothermal plant is determined by the usual factors, such as installed costs, O&M costs, economic lifetime and the weighted average cost of capital. However, the analysis for geothermal is a more dynamic question than for some other renewables. One complication is a larger uncertainty in project

development, due to the risk of poorly performing production wells. Similarly, over the life of a project, reservoir degradation can play an important role in costs (since additional production wells will be required) and in performance (lower output while remedial measures are taken). These factors tend to introduce greater uncertainty into the development of geothermal projects and may increase financing costs, compared to technologies such as wind. However, this uncertainty factor is typically manageable in mature geothermal markets where financing institutions have previous experience with the industry.

Assuming a 10% cost of capital, a 25-year economic life, O&M costs of USD 100/kW/year, a capacity factor of 90% and the capital costs outlined in section 9.1, the LCOE of geothermal plant can vary between as little as USD 0.03/kWh (Figure 9.4) for second-stage development of a field, to as much as USD 0.10/kWh for greenfield developments. However, taking into account poorer than expected field performance can mean that costs can rise to as much as USD 0.14/kWh if investment costs are at the high end of the range and average capacity factors are 20% lower than assumed.

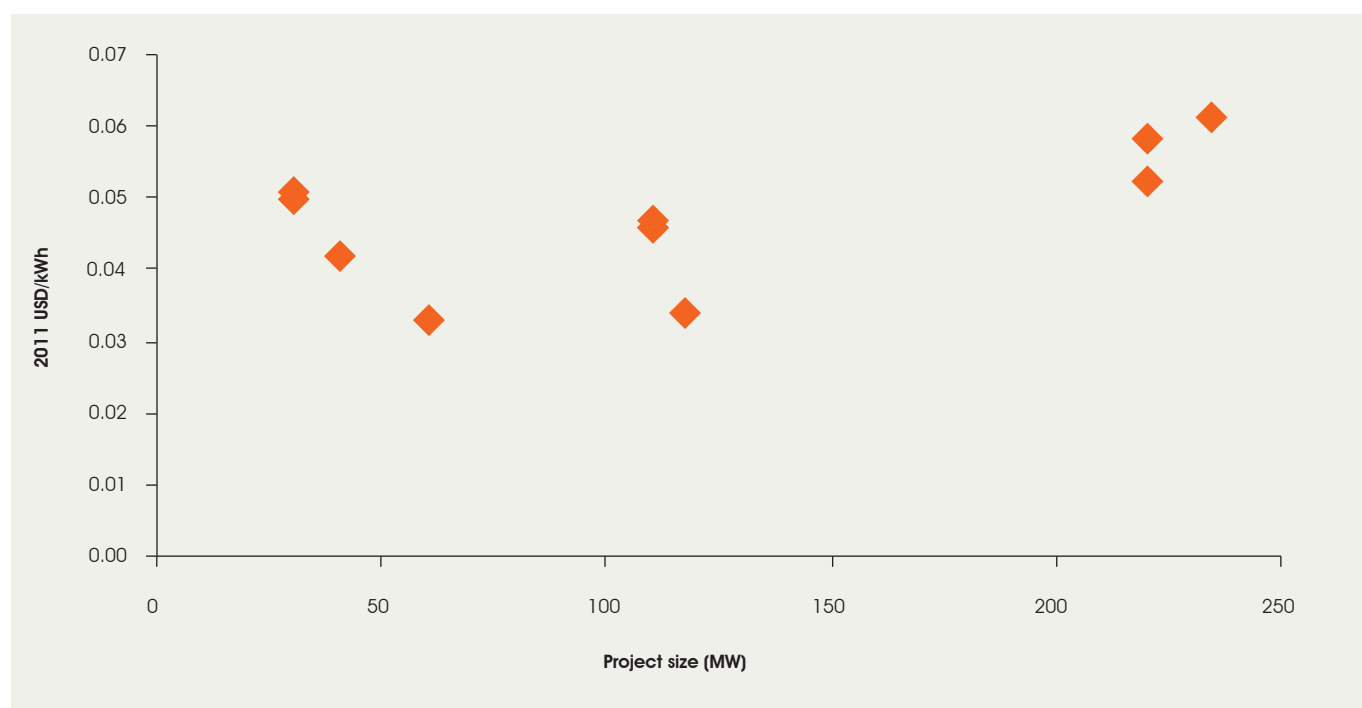


FIGURE 9.4: THE LEVELISED COST OF ELECTRICITY OF GEOTHERMAL POWER PROJECTS IN CHILE, INDONESIA, KENYA, MEXICO AND THE PHILIPPINES

SOURCE: IRENA RENEWABLE COST DATABASE.

10. COST REDUCTIONS TO 2020

The recent declines, and in the case of solar PV, dramatic declines in the LCOE of renewables reflects the increasing maturity of non-hydro technologies. The striking improvement in the competitiveness of renewables is changing the power generation landscape to one where renewables are fast becoming the economic choice not only for off-grid and mini-grids, but also are increasingly competitive in supplying electricity to the grid. However, for a transition to a truly sustainable energy sector to be achieved, this improvement needs to be expanded from a situation where the best renewable resources and most competitive projects are cheaper than incumbent technologies, to one where it is the norm for renewables to be the least-cost solution for almost all new electricity generation capacity required worldwide to meet either demand growth or plant retirements.

To reach this point, where renewables become the default economic option for new capacity, renewable power generation costs will have to continue to decline and performance improve.²⁸ However, even as this occurs, further policy measures will be required to overcome those market barriers, unrelated to price, which hinder the accelerated deployment of renewable power generation technologies.

It is assumed that there will be no decline in hydropower costs by 2020, and that any changes in costs are due to underlying commodity price variations and general civil engineering costs. Most biomass combustion technologies are mature, although the projected growth in the market will allow modest capital cost reductions of between 10% and 15% to be possible by 2020 for the higher-cost markets for stoker, bubbling fluidised bed, and circulating fluidised boiler technologies. The cost reduction potential for gasification technologies, excluding anaerobic digestion, is higher and, if deployment accelerates, capital cost reductions of 10% to 20% might be possible by 2020.

28 A future with more rapid price increases for fossil fuels than is anticipated today would also help accelerate the competitiveness of renewable power generation.

The technologies with the largest cost reduction potential are CSP, solar PV and wind. Hydropower and most biomass combustion technologies are mature and their cost reduction potentials are not as large.

Solar PV module prices have declined so rapidly in recent years that prices are now significantly below the learning curve. Price reductions have therefore, to some extent, been brought forward and we are likely to see slower price reductions in the period to 2020 than in the past five years. By 2020, Chinese c-Si modules could be retailing for between USD 0.4 and USD 0.5/W with full recovery of capital costs. However, given the overcapacity in production, projections of future prices are extremely uncertain due to the impact of competitive pressures.

What is clear is that now that PV module prices have fallen so much that there is likely to be a slowing in their price reduction, BoS costs are becoming the crucial determinant of the LCOE of solar PV. This can easily be seen by comparing one of the most competitive markets, Germany, with the United States. The gulf in the difference in BoS costs has had a huge impact on the LCOE of solar PV. Further analysis to better understand the reasons behind these differences and how to eliminate them will largely determine the rate of cost reductions in many markets. Convergence, or not, of BoS costs to the most competitive levels will therefore determine as much as 80% of the cost reduction potential for solar PV, outside of the most competitive markets, to 2020. This will be a structural shift in the PV market and one that will require significant investment in data collection and analysis in order to identify policy measures to accelerate convergence in BoS costs.

For CSP plants, the overall capital cost reductions for parabolic trough plants by 2020 are estimated to be between 17% and 40% (Hinkley, 2011; and Kutscher, 2010). For solar towers the cost reduction potential could be as high as 28% on a like-for-like plant basis (Hinkley, 2011). Alternative analysis suggests that the evolution of costs and performance is a little more complex, with the

possibility that capital costs might decline by between 10% and 20% by 2017, depending on the components, although from an LCOE perspective, a better solution would be to have overall installed costs that are around the same as today, and instead use the cost reductions to increase the thermal energy storage and solar field size to increase the capacity factor from 48% to 65% (Kolb, 2011). Looking slightly further ahead to 2020 and assuming higher cost reductions (from one-fifth to one-third, depending on the components) and the switch to super-critical steam cycles, capital costs could be reduced by 24% and the capacity factor raised to 72% (Kolb, 2011).

By 2020, it is assumed that the capital cost range for a parabolic trough plant with six hours energy storage could drop by around 20% to between USD 4 200 and USD 5 500/kW, with capacity factors of around 40% to 45%. Solar tower plants with 6 to 7.5 hours of storage could see their capital costs fall to between USD 4 700 and USD 6 000/kW for capacity factors of 45% to 50%. Solar tower plants with 12 to 15 hours of storage could see their capital costs fall to between USD 6 000 and USD 7 000/kW for capacity factors of 65% to 80%. O&M costs are assumed to fall to USD 0.02/kWh by 2020.

The decline in wind turbine prices from their peak in 2008/2009 has been around a quarter, with preliminary data for 2012 projects in the United States suggesting quotes between USD 900 and USD 1 270/kW. However, these are still some 50% to 100% higher than average wind turbine prices in China. Given continued overcapacity at wind turbine manufacturers, prices are likely to continue to fall. The critical issue is to what extent wind turbine prices in high-cost markets might converge with Chinese and Indian wind turbine prices. Wind turbines are not necessarily interchangeable commodities, unlike solar PV modules²⁹, given their design characteristics, quality and their manufacturer's warranty terms and reliability guarantees vary. The extent to which wind turbine prices can converge may be limited by these factors and the high local content component of wind turbines (e.g. cement, steel, labour, etc.).

By 2020 installed costs for wind farms in the United States could fall to between USD 1 350 and USD 1 450/kW from their current levels of around USD 1 750/kW in 2012,

29 Despite the convergence of manufacturing quality among most leading manufacturers it still remains to be seen if solar PV modules are truly interchangeable commodities globally.

assuming wind turbine prices stabilise at around USD 800/kW. Capital costs in Europe are likely to follow similar trends, with values for 2020 of between USD 1 400 and USD 1 600/kW for the major markets.

Average capacity factors for new wind farms will continue to rise, as the average size and hub-height of turbines grows. However, this effect is likely to slow. A major question, similar to the emergence of the importance of BoS costs for PV, is how will O&M costs respond to lower installed costs and higher capacity factors. O&M costs in the United States are around USD 0.01/kWh, but can be two to three times higher in other markets. If these costs cannot be brought down, they will account for an increasing share of the LCOE of wind and act as a break on cost reduction. Further analysis and data are needed to try to identify policy recommendations to drive down O&M costs to best practice levels.

Figure 10.1 presents the cost ranges for wind, solar PV, CSP and biomass today as well as projections for 2020 based on the assumptions already presented. For wind, the LCOE range does not shift significantly, but this masks the significant cost reductions that are occurring in OECD countries and will continue until 2020. Depending on where new installed capacity is built, this will significantly lower the weighted average LCOE.

The typical LCOE range for solar PV will decline from between USD 0.12 and USD 0.36/kWh in 2012 to between USD 0.09 and USD 0.30/kWh in 2020. Grid parity for residential applications will increasingly be the norm in competitive PV markets and the best utility-scale projects will be approaching or have surpassed wholesale grid-parity in some regions where fossil-fired electricity generation is expensive.

The reduction in LCOE for CSP will depend to a large extent on improvements in the current investment climate and longer-term commitments to policy support measures that can underpin deployment and learning. If deployment can be accelerated, costs will come down, with solar towers showing the greatest potential for LCOE reduction. By 2020 solar towers could be producing electricity for between USD 0.12 and USD 0.16/kWh on average.

Biomass technologies will not see the lower range for their LCOE shift significantly by 2020, given that today's cheapest options rely on very cheap or even free feedstocks. However, for less mature technologies such as gasification, capital cost reductions will drive down the upper end of the range.

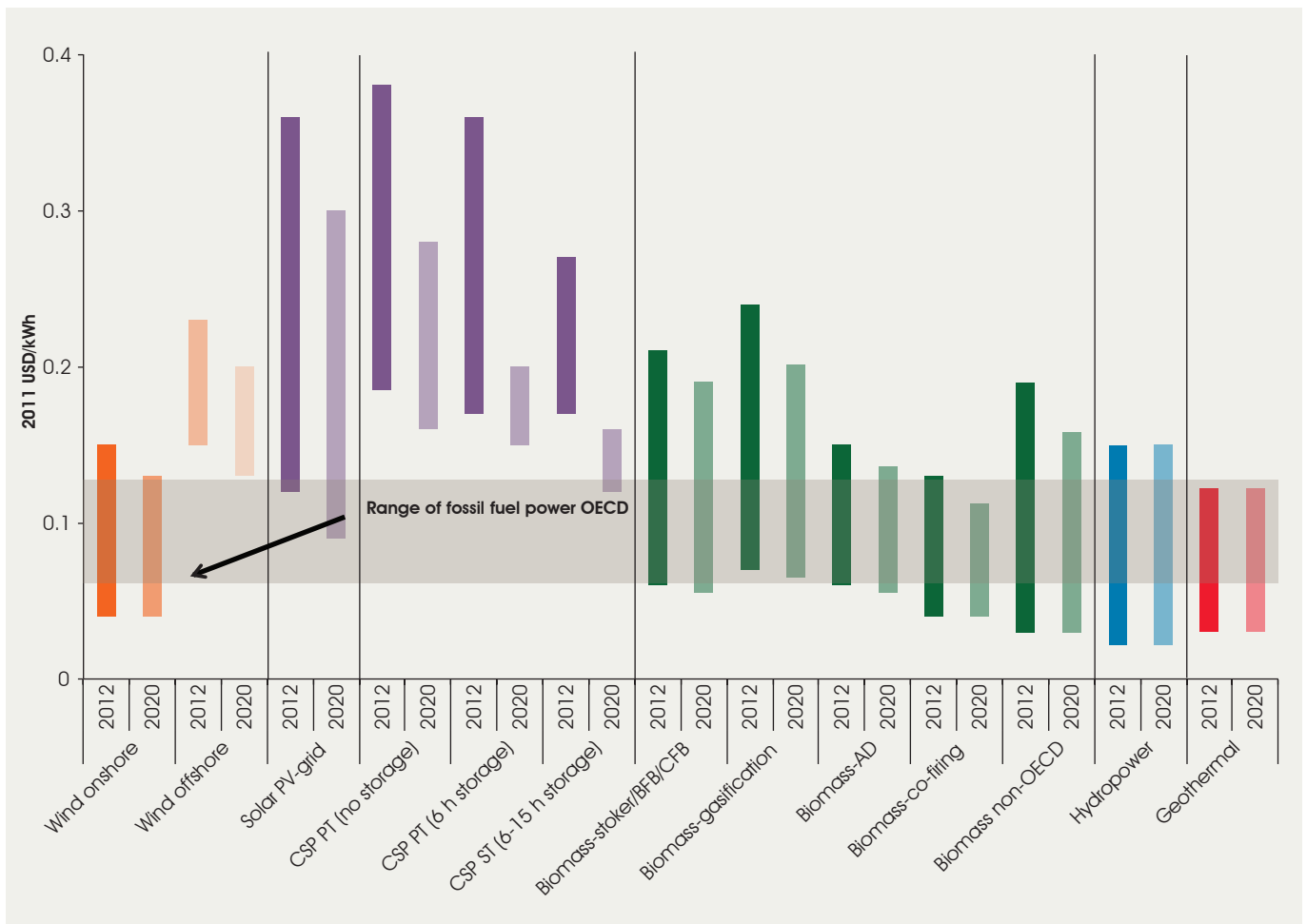


FIGURE 10.1: LEVELISED COST RANGES FOR RENEWABLE POWER GENERATION TECHNOLOGIES, 2012 AND 2020

Note: This is based on an assumed cost of capital of 10%. The bands reflect ranges of typical investment costs (excluding transmission and distribution), fuel costs and capacity factors. PT = parabolic trough, ST = solar tower, BFB/CFB = bubbling fluidised bed/circulating fluidised bed, AD = anaerobic digester.

Annex One: Methodology

A1.1 DIFFERENT MEASURES OF COST

Cost can be measured in a number of different ways, and each way of accounting for the cost of power generation brings its own insights. The costs that can be examined include equipment costs (e.g. PV modules), financing costs, total installed cost, fixed and variable operating and maintenance costs (O&M), fuel costs and the levelised cost of energy (LCOE), if any.

The analysis of costs can be very detailed, but for comparison purposes and transparency, the approach used here is a simplified one. This allows greater scrutiny of the underlying data and assumptions, improves transparency and confidence in the analysis, and also facilitates the comparison of costs by country or region for the same technologies in order to identify the key drivers in any differences.

The three indicators that have been selected are:

- Equipment cost (factory gate FOB and delivered at site CIF);
- Total installed project cost, including fixed financing costs³⁰; and
- The levelised cost of electricity, LCOE.

The analysis in this paper focuses on estimating the costs of renewables from the perspective of private investors, whether they are a state-owned electricity generation utility, an independent power producer or an individual or community looking to invest in small-scale renewables. The analysis excludes the impact of government incentives or subsidies, system balancing costs associated with variable renewables and any system-wide cost-savings from the merit order effect³¹. Furthermore, the analysis does not take into account any CO₂ pricing, nor the benefits of renewables in reducing other externalities (e.g. reduced local air pollution or contamination of the natural environment). Similarly, the benefits of renewables being insulated from volatile fossil fuel prices have not been quantified. These issues are important, but are covered by other programmes of work at IRENA.

30 Banks or other financial institutions will often charge a fee, such as a percentage of the total funds sought, to arrange the debt financing of a project. These costs are often reported separately under project development costs.

31 See EWEA, Wind Energy and Electricity Prices, April 2010 for a discussion.

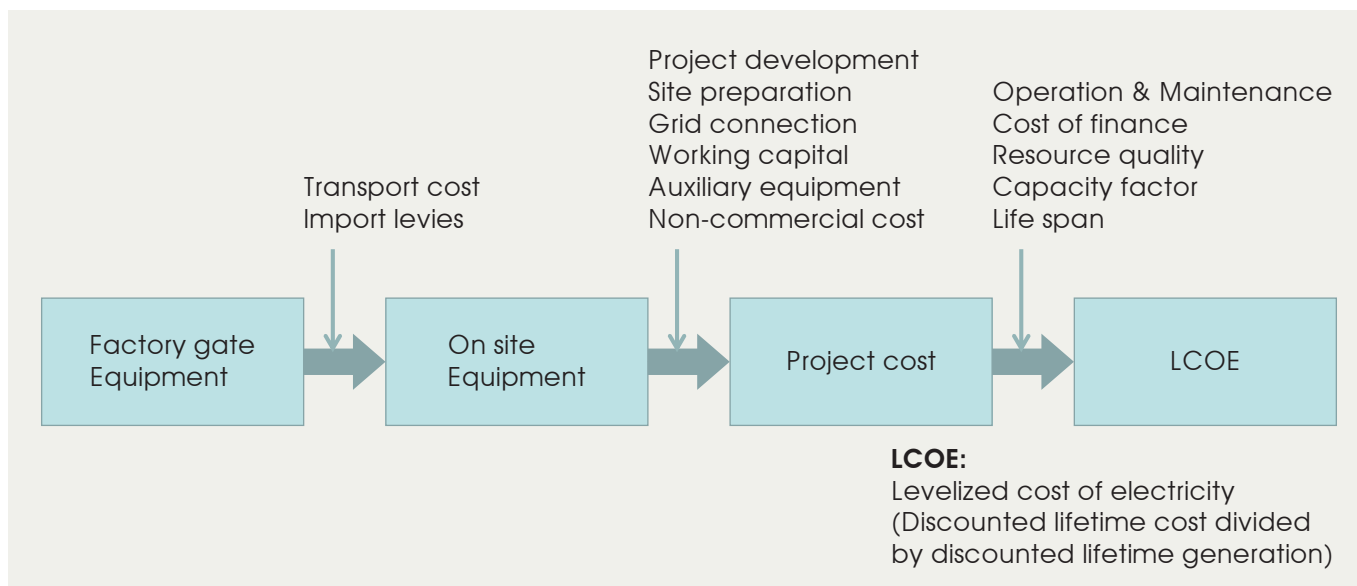


FIGURE A1.1: RENEWABLE POWER GENERATION COST INDICATORS AND BOUNDARIES

It is important to include clear definitions of the technology categories, where this is relevant, to ensure that cost comparisons are robust and provide useful insights (e.g. off-grid PV vs. utility-scale PV). Similarly, it is important to differentiate between the functionality and/or qualities of the renewable power generation technologies being investigated (e.g. concentrating solar power with and without thermal energy storage). It is important to ensure that system boundaries for costs are clearly set and that the available data are directly comparable. Other issues can also be important, such as cost allocation rules for combined heat and power plants, and grid connection costs.

The data used for the comparisons in this paper come from a variety of sources, such as business journals, industry associations, consultancies, governments, auctions and tenders. Every effort has been made to ensure that these data are directly comparable and are for the same system boundaries. Where this is not the case, the data have been corrected to a common basis using the best available data or assumptions. It is planned that this data will be complemented by detailed surveys of real world project data in forthcoming work by IRENA.

An important point is that, although this paper tries to examine costs, strictly speaking, the data available are actually prices, and not even true market average prices,

but price indicators. The difference between costs and prices is determined by the amount above, or below, the normal profit that would be seen in a competitive market. The rapid growth of renewables markets from a small base means that the market for renewable power generation technologies is rarely well-balanced. As a result, prices can rise significantly above costs in the short term if supply is not expanding as fast as demand, while in times of excess supply, losses can occur and prices may be below production costs. This makes analysing the cost of renewable power generation technologies challenging and every effort has been made to indicate whether current equipment costs are above or below their long-term trend.

The cost of equipment at the factory gate is often available from market surveys or from other sources. A key difficulty is often reconciling different data sources to identify why data for the same period differ. For example, the balance of capital costs in total project costs tends to vary even more widely than power generation equipment costs, as it is often based on significant local content, which depends on the cost structure of where the project is being developed. Total installed costs can therefore vary significantly by project, country and region depending on a wide range of factors.

A1.2 LEVELISED COST OF ELECTRICITY GENERATION

The LCOE of renewable energy technologies varies by technology, country and project, based on the renewable energy resource, capital and operating costs, and the efficiency/performance of the technology. The approach used in the analysis presented here is based on a discounted cash flow (DCF) analysis. This method of calculating the cost of renewable energy technologies is based on discounting financial flows (annual, quarterly or monthly) to a common basis, taking into consideration the time value of money. Given the capital-intensive nature of most renewable power generation technologies and the fact that fuel costs are low, or often zero, the weighted average cost of capital (WACC), often also referred to as the discount rate, used to evaluate the project has a critical impact on the LCOE.

There are many potential trade-offs to be considered when developing an LCOE modelling approach. The approach taken here is relatively simplistic, given the fact that the model needs to be applied to a wide range of technologies in different countries and regions. However, this has the additional advantage that the analysis is transparent and easy to understand. In addition, more detailed LCOE analyses result in a significantly higher overhead in terms of the granularity of assumptions required. This often gives the impression of greater accuracy, but when it is not possible to robustly populate the model with assumptions, or to differentiate assumptions based on real world data, then the “accuracy” of the approach can be misleading.

The formula used for calculating the LCOE of renewable energy technologies is:

$$\text{LCOE} = \frac{\sum_{t=1}^n \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^n \frac{E_t}{(1+r)^t}}$$

Where:

- LCOE = the average lifetime levelised cost of electricity generation;
- I_t = investment expenditures in the year t ;
- M_t = operations and maintenance expenditures in the year t ;
- F_t = fuel expenditures in the year t ;
- E_t = electricity generation in the year t ;
- r = discount rate; and
- n = life of the system.

All costs presented in this paper are real 2011 USD; that is to say, after inflation has been taken into account unless otherwise stated.³² The LCOE is the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. An electricity price above this would yield a greater return on capital, while a price below it would yield a lower return on capital, or even a loss.

As already mentioned, although different cost measures are useful in different situations, the LCOE of renewable energy technologies is a widely used measure by which renewable energy technologies can be evaluated for modelling or policy development. Similarly, more detailed DCF approaches taking into account taxation, subsidies and other incentives are used by renewable energy project developers to assess the profitability of real world projects.

32 An analysis based on nominal values with specific inflation assumptions for each of the cost components is beyond the scope of this analysis. Project developers will develop their own specific cash-flow models to identify the profitability of a project from their perspective.

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Acronyms

AC	Alternating current
AD	Anaerobic digester
a-Si	Amorphous crystalline
a-Si/uc-Si	Micromorph crystalline
BFB	Bubbling fluidised bed
BIGCC	Biomass integrated gasification combined cycle
BoS	Balance of system
°C	Degree Celsius
CAPEX	Capital expenditure
CDM	Clean Development Mechanism
CdTe	Cadmium-Telluride
CFB	Circulating fluidised bed
CHP	Combined heat and power
CIGS	Copper-Indium-Gallium-Diselenide
CIF	Cost, insurance and freight
CIS	Copper-Indium-Selenide
CO₂	Carbon dioxide
c-Si	Crystalline silicon
CSP	Concentrated solar power
DC	Direct current
DCF	Discounted cash flow
DNI	Direct normal irradiance
DSG	Direct steam generation
EPC	Engineering, procurement and construction
EUR	Euro
FOB	Free-on-board

GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH
GJ	Gigajoule
GW	Gigawatt
IRENA	International Renewable Energy Agency
kJ	Kilojoule
kW	Kilowatt
kWh	Kilowatt hour
LFC	Linear Fresnel collectors
LFG	Landfill gas
LCOE	Levelised cost of electricity
m²	Square metres
mc-Si	Multi-crystalline
MW	Megawatts
MWh	Megawatt hour
OECD	Organisation for Economic Co-operation and Development
O&M	Operating and maintenance
PT	Parabolic trough
PTC	Parabolic trough collectors
PV	Photovoltaic
R&D	Research and development
Sc-Si	Single crystalline
SEGS	Solar energy generating system
ST	Solar trough
USD	United States dollar
W	Watts
WACC	Weighted average cost of capital



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