https://www.irena.org/publications/2015/Oct/Concentrated-Solar-Power

ENERGY TECHNOLOGY SYSTEMS ANALYSIS PROGRAMME

International Renewable Energy Agency

Concentrating Solar Power

Technology Brief

IEA-ETSAP and IRENA© Technology Brief E10 – January 2013

www.etsap.org – www.irena.org

This brief is available for download from the following IEA-ETSAP and IRENA sites
iea-etsap.org/web/Supply.asp
www.irena.org/Publications

About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organization dedicated to renewable energy. In accordance with its Statute, IRENA's objective is to "promote the widespread and increased adoption, and the sustainable use of all forms of renewable energy". This concerns all forms of energy produced from renewable sources in a sustainable manner and includes bioenergy, geothermal energy, hydropower, ocean, solar and wind energy.

As of December 2012, the membership of IRENA comprises some 160 States and the European Union (EU), out of which 104 States and the EU have ratified the Statute.

About IEA-ETSAP

The Energy Technology Systems Analysis Programme (ETSAP) is an Implementing Agreement of the International Energy Agency (IEA), first established in 1976. It functions as a consortium of member country teams and invited teams that actively cooperate to establish, maintain, and expand a consistent multi-country energy/economy/environment/engineering (4E) analytical capability.

Its backbone consists of individual national teams in nearly 70 countries, and a common, comparable and combinable methodology, mainly based on the MARKAL / TIMES family of models, permitting the compilation of long term energy scenarios and in-depth national, multi-country, and global energy and environmental analyses.

ETSAP promotes and supports the application of technical economic tools at the global, regional, national and local levels. It aims at preparing sustainable strategies for economic development, energy security, climate change mitigation and environment.

ETSAP holds open workshops twice a year, to discuss methodologies, disseminate results, and provide opportunities for new users to get acquainted with advanced energy-technologies, systems and modeling developments.

FSC www.fsc.org MIX Paper from responsible sources FSC® C021260

Print CO2 compensated Id-No. 1225221 www.bvdm-online.de

Grüner Strom Label e.V.

Insights for Policy Makers

Concentrating Solar Power (CSP) plants use mirrors to concentrate sunlight onto a receiver, which collects and transfers the solar energy to a heat transfer fluid that can be used to supply heat for end-use applications or to generate electricity through conventional steam turbines. Large CSP plants can be equipped with a heat storage system to allow for heat supply or electricity generation at night or when the sky is cloudy. There are four CSP plant variants, namely: ***Parabolic Trough***, ***Fresnel Reflector***, ***Solar Tower*** and ***Solar Dish,*** which differ depending on the design, configuration of mirrors and receivers, heat transfer fluid used and whether or not heat storage is involved. The first three types are used mostly for power plants in centralised electricity generation, with the parabolic trough system being the most commercially mature technology. Solar dishes are more suitable for distributed generation.

CSP plants require high direct solar irradiance to work and are therefore a very interesting option for installation in the Sun Belt region (between 40 degrees north and south of the equator). This region includes the Middle East, North Africa, South Africa, India, the Southwest of the United States, Mexico, Peru, Chile, Western China, Australia, southern Europe and Turkey. The technical potential of CSP-based electricity generation in most of these regions is typically many times higher than their electricity demand, resulting in opportunities for electricity export through high-voltage lines.

However, the deployment of CSP is still at an early stage with approximately 2 GW of installed capacity worldwide up to 2012, although an additional 12 GW of capacity is planned for installation by 2015. Today's installed capacity of CSP is very small when compared with approximately 70 GW of solar photovoltaic (PV) plants already in operation globally, and the 30 GW of new PV installations completed in 2011. The total installation cost for CSP plants without storage is generally higher than for PV. However, it is expected that these costs will fall by around 15% by 2015 owing to technology learning, economies of scale, and improvements in manufacturing and performance, thus reducing the levelised costs of electricity from CSP plants to around USD 0.15-0.24/kWh. By 2020, expectations are that capital costs will decline even further by between 30% and 50%.

Like PV, an advantage of CSP plants is that their output, when no thermal storage is used, follows closely the electricity and heat demand profile during the day in Sun Belt regions. The significant advantage of CSP over PV is that it can integrate low-cost thermal energy storage to provide intermediate- and base-load electricity. This can increase significantly the capacity factor of CSP plants and the dispatchability of the generated electricity, thus improving grid integration and economic competitiveness of such power plants. However, there is a trade-off between the capacity of heat storage required and capital cost of the plant. Another advantage offered by CSP technology is the ease of integration into existing fossil fuel-based power plants that use conventional steam turbines to produce electricity, whereby the part of the steam produced by the combustion of fossil fuels is substituted by heat from the CSP plant. Similar to conventional power plants, most CSP installations need water to cool and condense the steam cycle. Since water is often scarce in the Sun Belt regions, CSP plants based on "dry cooling" are the preferred option with regards to efficient and sustainable use of water. However, such plants are typically about 10% more expensive than water-cooled ones.

Compared with PV, CSP is still a relatively capital-intensive technology with a small market. However, CSP plants could become economically competitive as a result of the significant potential for capital cost reductions. In addition to renewable heat and power generation concentrating solar plants have other economically viable and sustainable applications, such as co-generation for domestic and industrial heat use, water desalination and enhanced oil recovery in mature and heavy oil fields. CSP technology deployment also has the potential for substantial local value addition through localisation of production of components, services and operation and maintenance, thus creating local development and job opportunities.

Highlights

- **Process and Technology Status –** In Concentrating Solar Power (CSP) plants, mirrors concentrate sunlight and produce heat and steam to generate electricity via a conventional thermodynamic cycle. Unlike solar photo-voltaics (PV), CSP uses only the direct component (DNI) of sunlight and provides heat and power only in regions with high DNI (i.e. Sun Belt regions like North Africa, the Middle East, the southwestern United States and southern Europe). CSP plants can be equipped with a heat storage system to generate electricity even under cloudy skies or after sunset. Thermal storage can significantly increase the capacity factor and dispatchability of CSP compared with PV and wind power. It can also facilitate grid integration and competitiveness. In sunny, arid regions, CSP can also be used for water desalination. In past years, the installed CSP capacity has been growing rapidly in keeping with policies to reduce CO_2 emissions. In 2012, the global installed CSP capacity was about 2 GW (compared to 1.2 GW in 2010) with an additional 20 GW under construction or development. While CSP still needs policy incentives to achieve commercial competitiveness, in the years to come technology advances and deployment of larger plants (i.e. 100-250 MW) are expected to significantly reduce the cost, meaning that CSP electricity could be competing with coal- and gas-fired power before 2020. The CSP technology includes four variants, namely **Parabolic Trough** (PT), **Fresnel Reflector** (FR), **Solar Tower** (ST) and **Solar Dish** (SD). While PT and FR plants concentrate the sun's rays on a focal line and reach maximum operating temperatures between 300-550°C, ST and SD plants focus the sunlight on a single focal point and can reach higher temperatures. PT is currently the most mature and dominant CSP technology. In PT plants, synthetic oil, steam or molten salt are used to transfer the solar heat to a steam generator, and molten salt is used for thermal storage. Among other CSP variants, ST is presently under commercial demonstration, while FR and SD are less mature.

- **Performance and Costs –** Commercial PT plants in operation have capacities between 14-80 MWe. They reach a maximum operating temperature of 390°C, which is limited by a thermal degradation of the synthetic oil used as the heat transfer fluid. The efficiency (i.e. the ratio of electricity generated to the solar energy input) is about 14-16% and the capacity factor is on the order of 25-30%, depending on the location. Some PT and ST plants have molten salt thermal storage systems with storage capacities of 6-15 hours, which increase the plant capacity factors to over 40% and 70%, respectively. Two plants (i.e. a 5-MW PT plant in Italy and a 20-MW ST plant in Spain) are currently testing the use of high-temperature (550°C) molten salt for heat transfer and storage purposes. This option is expected to significantly improve the CSP performance and storage capacity. The available operational experience suggests that PT plants have a lifetime of more than 30 years. In the ST plants, steam (direct steam generation) and compressed gasses can also be used as alternative heat transfer fluids, and significant potential exists to improve performance (i.e. temperature and efficiency). The cost of CSP plants is still high in comparison with conventional power plants and other renewable technologies. The International Energy Agency (IEA) estimates a current investment cost for CSP plants between USD 4,200-8,500 per kW, depending on local conditions, DNI, the presence of thermal storage and – last but not least – the maturity level of the project (i.e. pilot, demonstration or commercial). Recent (2012) estimates by the International Renewable Energy Agency (IRENA) suggest upfront investment costs of between USD 5,500-8,000 per kW for PT plants with no storage and costs between USD 7,500-8,500 per kW for PT plants with six hours of storage. ST plants are usually designed with high storage capacity. Estimates range from USD 6,300-7,700/kW for 6-9 hours of storage to USD 9,000-10,500/kW for 12-15 hours of storage. The current levelised cost of electricity (LCOE) for PT plants ranges from USD 200/MWh (i.e. typically, plants with six hours of storage and high DNI) to USD 330/MWh (i.e. with no storage and low DNI). ST plants range from USD 170-240/MWh (i.e. with 12-15 hours of storage) to USD 220-280/MWh (with 6-7 hours of storage). Typically, investment and financing costs account for about 84% of the LCOE, the rest being operation and maintenance costs. Investment costs and LCOE are expected to decline by 10-20% by 2015 and by 30-50% by 2020 due to technology learning and economies of scale following the increasing deployment of CSP power. The benefits of carbon-free energy should also improve CSP's competitiveness.

- **Potential and Barriers –** CSP offers considerable potential in terms of energy production. In principle, assuming a land use of two ha/MWe, the North African potential could meet several times the combined electricity demands of Europe, the Middle East and North Africa. Assuming significant capital cost reduction and the contribution of energy storage, the IEA suggests in its roadmap that CSP could become economically competitive for intermediate and peak loads within the current decade. The global installed capacity could reach 150 GW by 2020, with an average capacity factor of 32%. Between 2020 and 2030, CSP could become economically competitive with conventional base-load power due to reduced CSP costs and the increasing prices of fossil fuels and CO_2. The global installed capacity could reach about 350 GW by 2030 (i.e. 3.8% of the global electricity demand, with an average capacity factor of 39%). The United States, North Africa and the Middle East would be major producers of CSP electricity while Europe would be the largest importer. At present, many countries around the world (e.g. Algeria, Australia, China, Egypt, India, Italy, Morocco, South Africa, Spain, United Arab Emirates, and the United States) have policies in place to support CSP deployment.

Process and Technology Status

Concentrating Solar Power (CSP) plants use mirrors to concentrate the sun's rays and produce heat for electricity generation via a conventional thermodynamic cycle. Unlike solar photovoltaics (PV), CSP uses only the direct component of sunlight (DNI)[1] and can provide carbon-free heat and power only in regions with high DNI (i.e. Sun Belt regions). These include the Middle East and North Africa (MENA), South Africa, the southwestern United States, Mexico, Chile, Peru, Australia, India, Western China, southern Europe and Turkey.

CSP plants can be equipped with a heat storage system to generate electricity even with cloudy skies or after sunset. For example, during sunny hours, solar heat can be stored in a high thermal-capacity fluid, and released upon demand (e.g. at night) to produce electricity. Thermal storage can significantly improve the capacity factor and *dispatchability*[2] of CSP plants, as well as their grid integration and economic competitiveness. To provide the required heat storage capacity, the *solar field* (i.e. mirrors and heat collectors) of the CSP plant must be oversized[3] with respect to the nominal electric capacity (MW) of the plant. There is a trade-off between the incremental cost associated with thermal storage and increased electricity production. Significant research efforts focus on thermal storage for CSP plants.

1 Sunlight consists of direct and indirect (diffused) components. The direct component (i.e. DNI or Direct Normal Irradiance) represents up to 90% of the total sunlight during sunny days but is negligible on cloudy days. Direct sunlight can be concentrated using mirrors or other optical devices (e.g. lenses). CSP plants can provide cost-effective energy in regions with DNIs>2000 kWh/m^2-yr, typically arid and semi-arid regions at latitudes between 15° and 40° North or South of the Equator. Note that equatorial regions are usually too cloudy. High DNIs can also be available at high altitudes where scattering is low. In the best regions (DNIs>2800 kWh/m^2-yr), the CSP generation potential is 100-130 GWhe/km^2-yr. This is roughly the same electricity generated annually by a 20 MW coal-fired power plant with a 75% capacity factor.

2 The *capacity factor* is the number of hours per year that the plant can produce electricity while *dispatchability* is the ability of the plant to provide electricity on the operator's demand.

3 The *solar multiple* is the ratio of the actual size of the solar field to the solar field size needed to feed the turbine at nominal design capacity with maximum solar irradiance (about 1 kW/m^2). To cope with thermal losses, plants with no storage have a solar multiple between 1.1-1.5 (up to 2.0 for LFR) while plants with thermal storage may have solar multiples of 3-5.

Figure 1 – CSP Parabolic Trough Solar Collectors

While CSP plants produce primarily electricity, they also produce high-temperature heat that can be used for industrial processes, space heating (and cooling), as well as heat-based water desalination processes. Desalination is particularly important in the sunny (and often arid) regions where CSP plants are often installed.

The first commercial CSP plants with no thermal storage (i.e. SEGS project, 354 MW) were built in California between 1984-1991, in the context of tax incentives for renewable energy. After a period of stagnation due to the low price of fossil fuels, the interest in CSP resumed in the 2000s, mainly in the United States and Spain, as a consequence of energy policies and incentives to mitigate CO_2 emissions and diversify the energy supply. While Spain and the United States are leading countries in CSP installations, CSP plants are in operation, under construction or planned in many Sun Belt countries. In 2012 the global installed CSP capacity amounted to about two GW with an additional 15-20 GW under construction or planned, mostly in the United States and Spain.

The available operational experience suggests that a CSP plant can be built in 1-3 years (depending on its size) and may operate for more than 30 years. Five to six months of full-power operation are needed to pay back the energy used for the construction (ESTELA & Greenpeace, 2009).

Based on a land use of two hectares per MWe, the CSP energy potential in Sun Belt regions is highly significant. Estimates suggest that the CSP potential in the southwestern United States could largely meet all of North America's electricity demand while the Northern African potential could meet the combined demand of Europe and the MENA Region several times over (IEA, 2010a). As electricity can be transported over long distances (i.e. over 1,000 km) using high-voltage direct-current (HVDC) lines[4], production of CSP electricity in Sun Belt regions (e.g. North Africa) and transmission to high-demand regions (e.g. Europe) is an option under consideration (e.g. Mediterranean Solar Plan, Desertec Initiative).

The CSP industry has been growing rapidly over the past years. In general these types of power plants are not yet economically competitive. CSP is still considerably more expensive than conventional coal and gas-based power and needs policy for market formation. In comparison with other renewable power sources (e.g. PV and wind power), the competitiveness of CSP plants should be assessed taking into account the significant potential for cost reduction and the role of the integrated thermal energy storage.

CSP Technologies and Performance

The CSP technology includes four variants; namely, **Parabolic Trough** (PT), **Fresnel Reflector** (FR), **Solar Tower** (ST) and **Solar Dish** (SD). In PT and FR plants, mirrors concentrate the sun's rays on a focal line, with concentration factors on the order of 60-80 and maximum achievable temperatures of about 550°C. In ST and SD plants, mirrors concentrate the sunlight on a single focal point with higher concentration factors (600-1,000) and operating temperatures (800-1000°C).

- **Parabolic Trough (PT) –** PT is the most mature CSP technology, accounting for more than 90% of the currently installed CSP capacity. As illustrated in Figure 2, it is based on parabolic mirrors that concentrate the sun's rays on heat receivers (i.e. steel tubes) placed on the focal line. Receivers have a special coating to maximise energy absorption and minimise infrared re-irradiation and work in an evacuated glass envelope to avoid convection heat losses.

The solar heat is removed by a heat transfer fluid (e.g. synthetic oil, molten salt) flowing in the receiver tube and transferred to a steam generator to produce the super-heated steam that runs the turbine. Mirrors and receivers (i.e. the solar col-

4 HVDC electricity loss is about 3% per 1,000 km, plus 0.6% for each direct current to alternate current conversion station.

lectors) track the sun's path along a single axis (usually East to West). An array of mirrors can be up to 100 metres long with a curved aperture of 5-6 metres.

Most PT plants currently in operation have capacities between 14-80 MWe, efficiencies of around 14-16% (i.e. the ratio of solar irradiance power to net electric output) and maximum operating temperatures of 390°C, which is limited by the degradation of synthetic oil used for heat transfer. The use of molten salt at 550°C for either heat transfer or storage purposes is under demonstration. High-temperature molten salt may increase both plant efficiency (e.g. 15%-17%) and thermal storage capacity.

In addition to the SEGS project (i.e. nine units with a total capacity of 354 MW in operation since the 1980s--, major and more recent PT projects in operation include two 70-MW units in the United States (i.e. Nevada Solar One and MNGSEC-Florida), about thirty 50-MW units in Spain and smaller units in a number of other countries[5]. The three 50-MW Andasol units by ACS/Cobra Group and Marquesado Solar SL and the two 50-MW (Valle I and II) plants by Torresol Energy in Spain are particularly interesting, as they use synthetic oil as the heat transfer fluid and molten salt as the thermal storage fluid. They have a thermal storage capacity of around 7.5 hours[6], which can raise the capacity factor up to 40%. In Italy, a 5-MW demonstration plant (ENEL, ENEA) with eight hours of thermal storage started operation in June 2010 to test the use of molten salt as either heat transfer or storage fluid, which can significantly improve the storage performance and the capacity factor (by up to 50%) because the higher operation temperature and thermal capacity of molten salt enable more storage capacity with reduced storage volume and costs[7]. Large PT plants under construction include the Mojave project (a 250 MW plant in California due to start operation in 2013), the 280 MW Solana project in Arizona due in 2013, the Shams 1 100MW project in the United Arab Emirates due in 2012/2013), the Godawari project (India, 50 MW, 2013) and a further fifteen 50-MW plants in Spain.

- **Fresnel Reflectors (FR) –** FR plants (Figure 2) are similar to PT plants but use a series of ground-based, flat or slightly curved mirrors placed at differ-

5 (www.nrel.gov/csp/solarpaces/project_detail.cfm)

6 Ensured by tanks of molten salt of around 29,000 tonnes each

7 The use of molten salt for either storage or heat transfer reduces storage volume by up to 60%, costs by 30% and complexity compared to PT plants using synthetic oil for heat transfer and molten salt for heat storage. However, molten salt also involves some drawbacks as it solidifies below 230ºC, and a heating system is needed during start-up and off-normal operation.

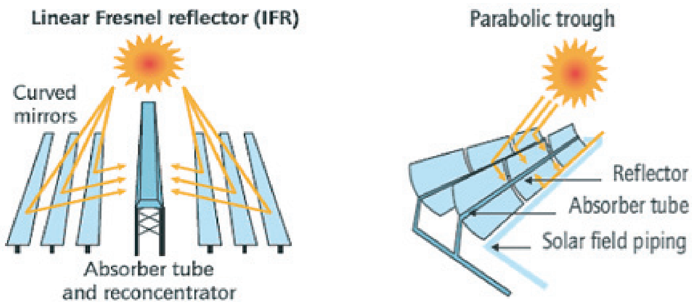

Figure 2 – Parabolic Trough and Fresnel Reflector

ent angles to concentrate the sunlight onto a fixed receiver located several meters above the mirror field. Each line of mirrors is equipped with a single-axis tracking system to concentrate the sunlight onto the fixed receiver. The receiver consists of a long, selectively-coated tube where flowing water is converted into saturated steam (DSG or Direct Steam Generation). Since the focal line in the FR plant can be distorted by astigmatism, a secondary mirror is placed above the receiver to refocus the sun's rays. As an alternative, multi-tube receivers can be used to capture sunlight with no secondary mirror. The main advantages of FR compared to PT systems are the lower cost of ground-based mirrors and solar collectors (including structural supports and assembly).

While the optical efficiency of the FR system is lower than that of the PT systems (i.e. higher optical losses), the relative simplicity of the plant translates into lower manufacturing and installation costs compared to PT plants. However, it is not clear whether FR electricity is cheaper than that from PT plants. In addition, as FR systems use direct steam generation, thermal energy storage is likely to be more challenging and expensive.

FR is the most recent CSP technology with only a few plants in operation (e.g. 1.4 MW in Spain, 5 MW in Australia and a new 30-MW power plant, the Puerto Errado 2, in Spain, which started operation in September 2012). Further FR plants are currently under construction (e.g. Kogan Creek, Australia 44 MW, 2013) or consideration.

- **Solar Towers (ST) –** In the ST plants (Figure 3), a large number of computer-assisted mirrors (heliostats) track the sun individually over two axes and concentrate the solar irradiation onto a single receiver mounted on top of a central tower where the solar heat drives a thermodynamic cycle and generates electricity. In principle, ST plants can achieve higher temperatures than PT and FR systems because they have higher concentration factors. The ST plants can use water-steam (DSG), synthetic oil or molten salt as the primary heat transfer fluid. The use of high-temperature gas is also being considered. Direct steam generation (DSG)[8] in the receiver eliminates the need for a heat exchanger between the primary heat transfer fluid (e.g. molten salt) and the steam cycle, but makes thermal storage more difficult. Depending on the primary heat transfer fluid and the receiver design, maximum operating temperatures may range from 250-300°C (using water-steam) to 390°C (using synthetic oil) and up to 565°C (using molten salt). Temperatures above 800°C can be obtained using gases. The temperature level of the primary heat transfer fluid determines the operating conditions (i.e. subcritical, supercritical or ultra-supercritical) of the steam cycle in the conventional part of the power plant.

ST plants can be equipped with thermal storage systems whose operating temperatures also depend on the primary heat transfer fluid. Today's best performance is obtained using molten salt at 565°C for either heat transfer or storage purposes. This enables efficient and cheap heat storage and the use of efficient supercritical steam cycles.

High-temperature ST plants offer potential advantages over other CSP technologies in terms of efficiency, heat storage, performance, capacity factors and costs. In the long run, they could provide the cheapest CSP electricity, but more commercial experience is needed to confirm these expectations[9].

Current installed capacity includes the PS10 and PS20 demonstration projects (i.e. Spain) with capacities of 11 MW and 20 MW, respectively. Both plants are equipped with a 30-60 minute steam-based thermal storage to ensure power production despite varying solar radiation[10]. The PS10 consists of 624 heliostats over 75,000 m^2. Its receiver converts 92% of solar energy into saturated steam at 250°C and generates 24.3 GWh a year (i.e. 25% capacity factor), with 17% efficiency. In Spain, a 19-MW molten salt-based ST plant (i.e. Gemasolar)

8 DSG also requires continuous management of heliostats to deal with sunlight variations.

9 For example, a high level of accuracy in heliostats control is needed with varying solar irradiance, and operation under windy conditions may cause problems.

10 The storage capacity is significantly limited by the use of steam and the cost of pressure vessels.

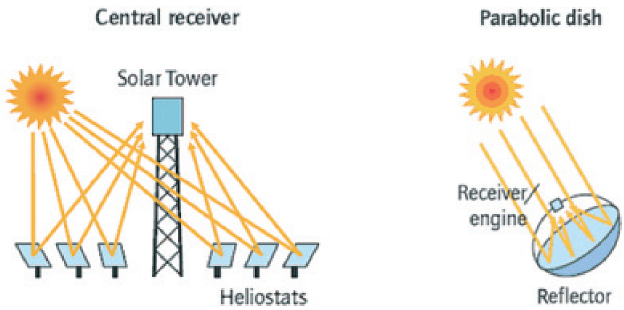

Figure 3 – Solar Tower and Solar Dish Concepts

with a 15-hour molten salt storage system started operation in the second half of 2011. It is expected to run for almost 6,500 operation hours per year, reaching a 74% capacity actor and producing fully dispatchable electricity.

Larger ST plants are under construction (e.g. the 370-MW Ivanpah project in California with water-steam at 565°C and 29% efficiency and the 50-MW Supcon project in China) or under development (e.g. eight units with a total capacity of 1.5 GW in the southwestern United States). Large plants have expansive solar fields with a high number of heliostats and a greater distance between them and the central receiver. This results in more optical losses, atmospheric absorption and angular deviation due to mirror and sun-tracking imperfections.

- **Solar Dishes (SD) –** The SD system (Figure 3) consists of a parabolic dish-shaped concentrator (like a satellite dish) that reflects sunlight into a receiver placed at the focal point of the dish. The receiver may be a Stirling engine (i.e. kinematic and free-piston variants) or a micro-turbine. SD systems require two-axis sun tracking systems and offer very high concentration factors and operating temperatures. However, they have yet to be deployed on any significant commercial scale. Research currently focuses on combined Stirling engines and generators to produce electricity.

The main advantages of SD systems include high efficiency (i.e. up to 30%) and modularity (i.e. 5-50 kW), which is suitable for distributed generation. Unlike other CSP options, SD systems do not need cooling systems for the exhaust heat. This makes SDs suitable for use in water-constrained regions, though at relatively high electricity generation costs compared to other CSP options. The SD technology is still under demonstration and investment costs are still high. Several SD prototypes have successfully operated over the last ten years with capacities ranging from 10-100 kW (e.g. Big Dish, Australian National University). The Big Dish technology uses an ammonia-based thermo- chemical storage system. Thermal storage systems for SD are still under development. Multi-megawatt SD projects (i.e. up to 100 MW) have been proposed and are under consideration in Australia and the United States.

At present, more than 90% of the installed CSP capacity consists of PT plants; ST plants total about 70 MW and FR plants about 40 MW. A comparison of CSP technology performance is shown in Table 1.

- **CSP Water Requirements –** CSP plants using steam cycles (i.e. PT, FR and ST) require cooling (i.e. 2-3 m^3 of water per MWh) to condense exhaust steam from the turbines; the lower the efficiency, the higher the cooling needs. As water resources are often scarce in Sun Belt regions, wet or dry cooling towers are often needed for CSP installations. In general, dry (air) cooling towers are more expensive and less efficient than wet towers. They reduce the electricity production by around 7% and increase the capital cost by 10%, but need just 10% water compared to wet towers.

- **CSP for Water Desalination –** CSP plants are designed for electricity generation, but they also produce high-temperature heat that can be used for industrial heating, water desalination, production of synthetic fuels (e.g syngas), enhanced oil recovery and refineries. The joint production of electricity, heat and desalinated water is of particular interest in arid regions where CSP can provide electricity for reverse-osmosis water desalination or heat for thermal distillation. Estimates (e.g. IEA-ETSAP &IRENA Technology Brief I12) show that, in MENA countries, CSP-based desalination could be competitive at USD 0.5/m^3.

- **Hybrid CSP Plants –** CSP plants can be integrated in coal- or gas-fired power plants to produce fully dispatchable electricity. In this case, the solar field provides steam to the thermodynamic cycle of the conventional power plant. Projects based on this concept are in operation in Algeria, Australia, Egypt, Italy and the United States.

- **Enhanced Oil Recovery (EOR) –** CSP plants can also be used to produce steam to inject into mature and heavy oil fields for thermal enhanced oil recovery. GlassPoint is building the first of such an application in the Middle East - a 5 MW_{th} CSP unit in Oman for EOR.

Current Costs and Cost Projections

Because the global installed capacity is limited and the technology is still under deployment, the cost of CSP plants and CSP electricity varies significantly depending on local labour and land cost, the size of the plant, the thermal storage system (if any), and – last but not least – the level of maturity (i.e. demo, pilot, commercial) of the project.

The cost of CSP electricity includes investment costs, operation and maintenance costs (O&M) and financing costs, the latter often being included in the investment costs. The investment and financing costs account for more than 80% of the electricity cost, the rest being fixed and variable O&M costs. The available cost information refers mainly to the dominant PT technology, while much less information

Table 1 – Performance of CSP Technologies (AT Kearney, 2010; IEA, 2010a; IRENA, 2012)

	PT	PT	PT	ST	ST	ST	FR	SD
Storage	no	yes	yes	no/ yes	no/ yes	yes	no	no
Status	comm	comm	demo	demo	comm	demo	demo	demo
Capac., MW	15-80	50-280	5	10-20	50-370	20	5-30	0.025
HT fluid	oil	oil	salt	steam	steam	salt	sat.st	na
HTF temp, C	390	390	550	250	565	565	250	750
Stor. Fluid	no	salt	salt	steam	na	salt	no	no
Storage, h	0	7	6-8	0.5-1	na	15	0	0
Stor. temp, C	na	380	550	250	na	550	na	na
Effic., %	14	14	14/16	14	16	15/19	11/13	25/30
Cap.factor,%	25-28	29-43	29-43	25-28	25-28	55-70	22-24	25-28
Optical eff.	H	H	H	M	M	H	L	VH
Concentrat.	70-80	70-80	70-80	1000	1000	1000	60-70	>1300
Land, ha/MW	2	2	2	2	2	2	2	na
Cycle	sh st	sh st	sh st	sat st	sh st	sh st	sat st	na
Cycle temp.,C	380	380	540	250	540	540	250	na
Grid	on	on	on	on	on	on	on	on/off

sat .st=saturated steam; sh.st=superheated steam;
L=low; M=middle; H=high; VH = very high

is available for other CSP options. CSP plants with thermal storage are usually more expensive because of the larger solar field and the storage system, but they allow higher capacity factors and/or the possibility to generate electricity at peak demand times when electricity prices are higher.

- **Investment Costs –** The current investment costs for PT plants with no thermal storage and capacity factor of 20-25% are estimated to range from USD 4,600-7,100/kW (Hinkley, 2011; Turchi, 2010a). These costs can be compared with the investment costs for the SEGS project in operation since 1984, which have been estimated at USD 3,000-4,000/kW (Cohen, 1999). The investment cost for PT plants with 4-6.5 hours thermal storage (with a capacity factor above 40%) ranges from USD 7,300/kW to over USD 9,000/kW (Hinkley, 2011; Turchi, 2010a; Turchi, 2010b; Fichtner 2010). The International Renewable Energy Agency (IRENA, 2012) estimates that the cost of PT plants with no storage commissioned or under construction in 2010-2011 is between USD 5,500-8,000/kW, while PT plants with thermal storage range between USD 7,500-8,500/kW. The International Energy Agency (IEA, 2010a) estimates the current investment cost for large PT plants at between USD 4,200-8,400/kW, depending on the plant's size and thermal storage capacity.

  Available data on ST plants are limited; ST projects are usually designed with higher thermal storage capacities as they tend to have higher operating temperatures and hence are more efficient and have lower unit storage costs. ST projects with 6-9 hours storage and capacity factors between 41-54% cost between USD 6,300-7,700/kW. Plants with 12-15 hours of storage and 68-79% capacity factors are estimated to cost USD 9,000-10,500/kW (Hinkley, 2011; Turchi, 2010a; Turchi, 2010b; Fichtner, 2010; IRENA, 2012).

  The investment cost of FR and SD systems is not presented in this discussion due to the very early stages of development and deployment of these technologies. However, FR systems are expected to be less expensive than PT plants, thus compensating for their lower performance.

  The CSP investment cost is significantly higher if compared with conventional power technologies. However, assuming an average 10% technology learning rate and a cumulative capacity doubling seven times over the current decade, the IEA estimates that the typical CSP investment cost could fall by 40-50% by 2020. The Global CSP Outlook (i.e. ESTELA-Greenpeace, 2009) also envisages steadily declining investment costs from today's level to USD 3,250-3,650/kW by 2030, depending on CSP's penetration of the energy market. The present estimates are mostly based on international costs and prices.

Manufacturing of CSP components in developing and emerging countries could lead to significant cost reductions.

- **Breakdown of Investment Costs –** The breakdown of the investment costs depends on several factors, including the specific CSP technology under consideration and the presence of thermal storage. The cost breakdown (Fichtner, 2010) for two comparable 100 MW PT and ST plants with similar total investment costs and thermal storage capacities (i.e. 13.5 and 15 hours, respectively) shows that the solar field is the most important cost element (i.e. approximately one-third of the total cost) in both plants. In the ST plant, the second cost element is the central receiver (1/6th of the total cost, followed by thermal storage and power block. In the PT plant, receivers are part of the solar field. Therefore, the second cost elements are the storage system and the power block (1/6 of total cost each). While the share of the thermal storage system depends to a certain extent on the storage capacity, in general it tends to be lower in ST plants due to their higher operating temperatures and the substantial impact that the central receiver has on the total cost.

  A detailed breakdown of CSP capital costs is provided by Ernst & Young and Fraunhofer (2011) for a 50 MW PT plant similar to the Andasol plant in Spain, with a storage capacity of 7.5 hours and an estimated cost of USD 364 million (i.e. USD 7280/kW). The most important cost element (i.e. 38.5 %) is the solar field (510,000 m^2), which includes the support structure (10.7%), receivers (7.1%), mirrors (6.4%), heat transfer system (5.4 %) and fluid (2.1%). The thermal storage system accounts for 10.5% of the total cost and is dominated by the cost of salt (5%) and storage tanks (2%). Power block, balance of plant and grid connections account for about 14%. Other costs include labor (i.e. around 500 persons) for plant construction (17%), EPC and financing costs (19.5%).

  Other cost analyses of CSP plants (Fichtner, 2010; Turchi, 2010a and 2010b; Hinkley, 2011) confirm that in PT plants the solar field is the largest cost component (i.e. 35-49% of the total cost); thermal storage ranges from 9% for a 4.5 hours to 20% for 13.5 hours, and the molten salt accounts for 8-11%. Dry cooling towers can add up to 10% to the investment cost.

- **Technology Advances and Cost Reductions –** In many countries, research and industry are committed to improve CSP performance and reduce its costs. Important drivers for cost reduction include:

- Technology advances of components and systems;
- Advanced thermal storage;

- Increased plant size and economies of scale; and
- Industrial learning in component production.

Technical advances, such as high-reflectivity mirrors[11] with reduced maintenance needs,[12] apply to all CSP technologies while others focus on specific CSP variants. A detailed analysis of potential technical advances and associated cost reductions for each CSP technology has been carried out by AT-Kearney and ESTELA (AT-Kearney, 2010). The main outcomes are summarised in Table 2.

Advanced thermal storage systems include:

- Lithium-based molten salts with high operation temperatures and lower freezing points;
- Concrete or refractory materials at 400–500ºC with modular storage capacity and low cost (USD 40/kWh);
- Phase-change systems based on Na- or K-nitrates to be used in combination with DSG; and
- Cheaper storage tanks (e.g. single thermocline tanks), with reduced (30%) volume and cost in comparison with the current two-tank systems[13].

An increased **plant size** reduces the costs associated with conventional components and systems, such as power block and balance of plant rather than the cost of the solar field, which depends primarily on industrial learning and large-scale production of components. The specific cost (USD/kW) of a PT plant with a 7.5 hour storage can be reduced by about 12% if the plant size is increased from 50 MW to 100 MW and by 20% if it is increased up to 200 MW (Kistner, 2009).

The **learning rate** for CSP systems and components is highly uncertain given the early stage of deployment of CSP technology. Estimates of 8-10% based on other technologies (IEA 2010b; Trieb, 2009) are considered conservatively realistic.

- **Operation and Maintenance Costs –** The O&M costs of CSP plants are low compared to those of fossil fuel-fired power plants. A typical 50 MW PT plant requires about 30-40 employees for operation, maintenance and solar field

11 The reflectivity of thin mirrors increases by 1% per mm of thickness reduction; low-iron concentration in mirror material reduces diffusion.

12 Special coatings can reduce cleaning and washing needs by 50%; robotics can reduce cleaning costs.

13 If compared with other electricity storage technologies (e.g. pumped hydro and batteries), the energy storage systems of CSP plants offer the lowest energy losses.

Table 2 – Technical Advances and Cost Reductions for CSP Technologies (based on AT-Kearney, 2010)

PT Plants
• Thin, low-cost mirrors with high (95%) reflectivity and low focal deviation to increase efficiency by up to 3%; large-size mirrors and receivers to reduce components and costs by 30%; • High-absorptance coating to increase efficiency by up to 4%; • Alternative heat transfer fluids (e.g. molten salts, steam[1], organic fluids, nano-tech fluids) to replace costly synthetic oil; • New mirror supports (stamped steel, aluminium, composites) and foundations to reduce costs.[2]
ST Plants
• Larger heliostats (up to 150m^2) to reduce components and costs by up to 7%, but even smaller heliostats (1 to 7 m^2), with cheaper foundation and tracking systems[3]; • Improved central receivers with high-temperature heat transfer fluids (e.g. molten salt) to raise efficiency up to 28% while ultra-supercritical Rankine steam cycles or pressurized air and gases can reach potential efficiencies above 45%[4]; • Multi-tower solar fields can reduce costs and increase efficiency due to improved optical efficiency (although with increased plant complexity).
FR Plants
• Structural and reflector materials to reduce costs by 20%; • Use of superheated steam instead of current saturated steam to improve the efficiency by up to 18%; • Storage systems based on phase-change materials to be associated to DSG.
SD Systems
• New designs, materials and engines (e.g. multi-cylinder free piston engines) can significantly reduce costs .

1 DSG in high-pressure receiver tubes enables higher operating temperatures and plant efficiency, as well as design simplification (e.g. no steam generator) and cost savings compared with synthetic oil. However, it does not facilitate thermal storage.

2 Support structures and foundations cost about twice as much as mirrors.

3 Small heliostats could also be equipped with common-row tracking systems and micro-robotic individual drives, which may result in a 40% cost reduction for the tracking system. Further cost optimisation of the solar field (10%) and improved efficiency (3%) could be achieved using different heliostat designs, depending on the specific location in the solar field.

4 High temperatures involve the use of more expensive materials, which would drive up cost

Table 3 – Current and Future LCOE for CSP (IRENA, 2012)

Source PT	2011 Low	 High	2020 Low	 High	Notes
IEA 2010a	200	295	100	140	10% dr[1]
Fichtner 2010	220	240			S. Africa, 8% dr
India	330	360			wet/dry cooling
Morocco	220	230			wet/dry cooling
Kutscher 2010	220		100	110	United States
Hinkley 2011	210		130		Australia, 7% dr
AT Kearney 2010	230	320	130	160	
Fichtner 2010	185	202			S. Africa, 8% dr
India	270	280			wet/dry cooling
Morocco	220	220			wet/dry cooling
Kolb 2010	160	170	80	90	United States
Hinkley 2011	210		160		Australia, 7% dr
AT Kearney 2010	230	320	130	160	

1 dr: discount rate

cleaning[14]. In the California SEGS plants, the O&M costs are estimated at USD 0.04/kWh (Cohen, 1999), the most significant components being the substitution of broken receivers and mirrors, and mirror washing. In modern CSP plants, automation can reduce the O&M costs, including fixed and variable costs, and insurance by more than 30% (Turchi, 2010b, Fichtner, 2010). Further significant reductions are expected in the coming years (Turchi, 2010a).

- **Levelised Cost of Electricity (LCOE) –** Key elements for the levelised cost of electricity (LCOE) of CSP plants are investment and financing costs, capacity factors, lifetimes, local DNIs, discount rates and O&M costs. Caution is advised in drawing general conclusions from the available information as very often data from most recent projects are not in the public domain or are based on different assumptions.

14 Estimates carried out in Germany, Spain and the US show that some 8-10 jobs are created for each megawatt of installed CSP capacity, including manufacturing, installation, operation and maintenance.

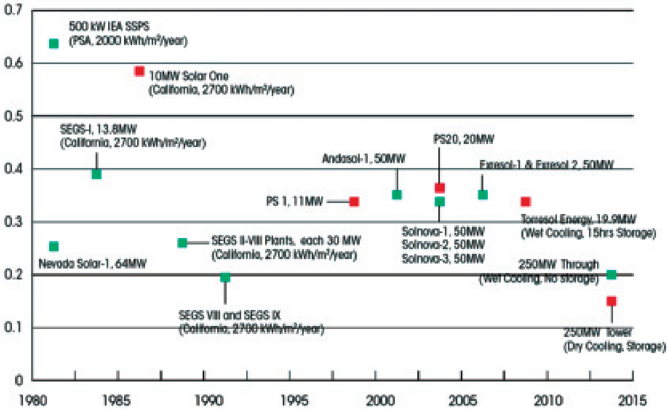

Figure 4 – Estimated LCOE for Existing and Proposed PT and ST CSP Plants

Available studies and sources (e.g. IEA, 2010a; Fichtner, 2010; Kutscher 2010, Kolb 2010, Hinkley, 2011, A.T. Kearney 2010) suggest that (Table 3) the current LCOE for PT plants ranges from USD 200-330/MWh while ST plants are estimated to range between USD 160-270/MWh, depending on location (DNI), energy storage, interest rate and other assumptions.

Based on IEA assumptions of a 30-year lifetime and a 10% interest rate, they estimates that today's levelised cost of electricity for large PT plants ranges between USD 200-295[15]/MWh (IEA, 2010a). Industrial estimates (i.e. ESTELA-Greenpeace, 2009) suggest current (levelised) costs of electricity between USD 190-290/MWh (with high and low DNIs, respectively). These ranges broadly agree with the limited data available from existing or commissioned CSP projects (Figure 4). In Spain, new 50-MW PT units are planned based on an estimated LCOE between USD 300-350 per MWh, while the LCOE for ST plants tends to be relatively more expensive as the technology is less mature and the size of plants is smaller (10-20 MW).

In comparison, estimates based on SEGS plants in operation since the 1984 show that the largest 80-MW power plants would produce electricity at about USD 180/MWh.

15 Investment and cost figures are expressed in 2010 USD or converted from EUR into USD using an exchange rate of 1EUR=1.3USD.

For both PT and ST plants, the LCOE is dominated (84%) by the investment cost, including financing, while fixed O&M costs account for 10-11%, and personnel and consumables account for 4-6% (Fichtner, 2010).

Based on available sources, an interest rate of 10% and other assumptions listed in Table 4, the IRENA analysis (IRENA, 2012) estimates the LCOE for PT and ST plants with and without storage, in 2011 and 2015. The LCOE for PT plants with no storage ranged from USD 300-370 per MWh in 2011 and could decline to USD 260-340 per MWh by 2015, depending on the capital costs and capacity factors. Assuming a six hour storage, the LCOE of PT plants ranged between USD 210-370 per MWh in 2011 and could decline to USD 180-310 per MWh by 2015.

The LCOE for ST plants with 6-7.5 hours storage, estimated at USD 220-280/MWh in 2011, could decline to USD 170-240/MWh by 2015. Assuming 12 to 15 hours storage, the LCOE declined to USD 170-240/MWh in 2011 and may decline further to USD 150-205/MWh by 2015.

- **LCOE Sensitivity to Plant Size and Economy of Scale –** Given the CSP capacity under construction or announced, substantial LCOE reductions (i.e. between 30-50%) are expected for both PT and ST plants, due to increased size (100-200 MW), economies of scale, industrial learning and improved performance. Industry's projections to 2025 (A.T. Kearney and ESTELA 2010) envisage cost reductions between 40-55% and attribute 18-22% of them to reduced investment costs, 21-33% to economies of scale and 10-15% to improved efficiency.

- **LCOE Sensitivity to DNI –** CSP requires high direct normal irradiance (DNI) and sun tracking to work economically. The DNI has a strong impact on electricity generation and cost. According to A.T. Kearney and ESTELA (2010), the LCOE is expected to decline by about 4.5% for each incremental 100 kWh/m^2/

Table 4 – Assumptions for LCOE Analysis (IRENA, 2012)

	Cap. factor (%)	2011 Inv. cost (USD/kW)	2015 Inv. cost (USD/kW)
PT			
No storage	20-25	4600	3900-4100
6h storage	40-53	7100-9800	6300-8300
ST			
6-7.5h storage	40-53	6300-7500	5700-6400
12-15h stor.ge	65-80	9000-10500	8100-9000

Table 5 – LCOE (USD/MWh) for PT as a Function of the Interest Rate and the Capacity Factor (IRENA, 2012)

Capacity factor	40%	53%
5.5% interest rate	220	160
10% interest rate	310	230
12.8% interest rate	370	280

year between 2,000-2,100 kWh/m^2-yr (Spain) and 2,700-2,800 kWh/m^2-yr (i.e. California, Algeria, South Africa). This means that a plant installed in the southwestern United States produces 25% cheaper electricity than the same plant installed in Spain.

- **LCOE Sensitivity to Interest Rate and Capacity Factors –** The financing cost and the capacity factor have a significant impact on the LCOE. Table 6 provides the LCOE for a PT plant with six hours thermal storage for different capacity factors and interest rates and assuming that the debt lasts for the plant's 25-year economic lifetime. Similar scaling applies to ST plants.

- **LCOE Sensitivity to Thermal Storage –** Thermal storage allows CSP to achieve higher capacity factors and dispatch electricity when the sun is not shining. This can make CSP a competitor of conventional power plants. Several analyses focus on the impact of thermal storage on the electricity generation cost. It is clear that there is a trade-off between the incremental investment cost for thermal storage and the reduction of the electricity cost due to the improved capacity factor. Available analyses agree that for a given plant, the minimum LCOE is achieved with a solar multiple of three and twelve hours of energy storage. However, this assumes that electricity always has the same economic value while in most actual markets the electricity prices vary over by day and season and are higher during peak demand periods. Therefore, the economic optimisation of CSP services and thermal storage depends heavily on local conditions. If the production of the CSP plant coincides with peak demand and price periods, little or no storage may be more convenient, while if peak demand occurs in the early evening, thermal storage allows electricity to be dispatched when the electricity price is higher. If this is the case, the CSP plant with thermal storage not only offers a higher capacity factor but is also more flexible to capture market opportunities. The economic value of the ability to dispatch CSP electricity during peak-demand periods depends on the specific country and project. The value of this service is estimated to be in the range of USD 15-65 per MWh (Richter, 2011).

Potential and Barriers

According to Emerging Energy Research (2010), the total installed CSP capacity in Europe could grow to 30 GW by 2020 and to 60 GW by 2030. This would then represent 2.4% and 4.3% of EU-27 power capacity in 2020 and 2030, respectively. The IEA's CSP technology roadmap estimates that, under favorable conditions, the global CSP capacity could grow to 147 GW in 2020, with 50 GW in North America and 23 GW each in Africa and the Middle East. By 2030, the global CSP capacity could rise to 337 GW.

The Global CSP Outlook (i.e. ESTELA-Greenpeace, 2009) explores three scenarios (*business-as-usual, moderate* and *advanced)* accounting for increasingly favorable policies and trends for CSP deployment and a rapid growth of HVDC transmission lines. The three scenarios also include two options for future electricity demand with a 28% and 94% increase by 2030, thus accounting for two different rates of energy efficiency implementation measures. Other key assumptions include CSP annual capacity growth, increasing plant size and capacity factors and declining capital costs. In the ***moderate*** scenario the cumulative installed CSP capacity is about 68 GW by 2020 and 231 GW by 2030, with CSP electricity meeting one percent of global demand in 2020 and up to 12% by 2050.

The IEA CSP Technology Roadmap (i.e. IEA 2010a) suggests that CSP could represent up to 11 % of the global electricity production by 2050. **From 2010 to 2020** CSP deployment is expected to be sustained by policy incentives and emissions trading. The global CSP capacity would reach 148 GW by 2020, producing 1.3% of the global electricity with an average capacity factor of 32%. **From 2020 to 2030,** CSP could become competitive with conventional base-load power due to cost reductions and the increasing prices of CO_2 and fossil fuels. Incentives to CSP will gradually disappear, and HVDC lines will reach a global extension of some 3,000 km. The global installed capacity would reach 337 GW, producing 3.8% of the 2030 electricity demand, with an average capacity factor of 39%. **Beyond 2030,** CSP cumulative capacity could reach the level of about 1,090 GW by 2050, providing about 9.5% the global electricity with an average capacity factor of 50%. The United States, North Africa, India and the Middle East would be the largest producers and exporters, while Europe would be the largest importer from the MENA Region via HVDC transmission lines. In the long term, low-cost CSP electricity would compensate for the additional costs of electricity transmission (i.e. USD 21-63 per MWh).

References and Further Information

AT Kearney and ESTELA, 2010, Solar Thermal Electricity 2025 – A.T. Kearney, www.atkearney.com.

Cohen, G.E. (1999), Final Report on the Operation and Maintenance Improvement Program for Concentrating Solar Power Plants, SAND99-1290, Sandia National Laboratories, USA.

Emerging Energy Research (2010), Global Concentrated Solar Power Markets and Strategies: 2010-2025, IHS, Cambridge, MA.

Ernst & Young and Fraunhofer Institute (2011), MENA Assessment of the Local Manufacturing Potential for Concentrated Solar Power (CSP) Projects, The World Bank, Final Report, Washington, DC.

ESTELA- Greenpeace, 2009, Concentrating Solar Power Global Outlook 2009, www.estelasolar.eu; www.greenpeace.org.

Fichtner (2010), Technology Assessment of CSP Technologies for a Site-Specific Project in South Africa, World Bank & ESMAP.

Hinkley, J. et al. (2011), Concentrating Solar Power-Drivers and Opportunities for Cost-competitive Electricity, CSIRO, Victoria, March 2011, http://www.garnautreview.org.au/update-2011/commissioned-work/concentrating-solar-power-drivers-opportunities-cost-competitive-electricity.pdf

IEA, 2010a, Concentrating Solar Power Technology Roadmap – International Energy Agency, Paris 2010, www.iea.org.

IEA, 2010b, Energy Technology Perspectives 2010, International Energy Agency, Paris 2010, www.iea.org.

IEA-ETSAP & IRENA, 2012, Water Desalination using Renewable Energy, Technology Brief I12, March 2012.

IRENA (2012), Concentrating Solar Power – Renewable Energy Technologies, Cost Analysis Series, IRENA Working Paper, June 2012, www.irena.org.

Kistner, R. et al. (2009), Analysis of potential cost decrease and competitiveness of parabolic trough plants, SolarPACES 2009.

Kolb, G.J.(2011), Power Tower Technology Roadmap and Cost Reduction Plan, Sandia National Laboratories, Alburquerque, NM.

Kutscher, et al. (2010), Line-Focus Solar Power Plant Cost Reduction Plan, NREL, Boulder, CO.

Richter, C. (2011), Personal Communication with Dr. Christoph Richter, Institut für Solarforschung, Deutsches Zentrum für Luft- und Raumfahrt (DLR).

Trieb, F., (2009), Global Potential of Concentrating Solar Power, DLR, Stuttgart.

Turchi, C., M. (2010a), Current and future costs for Parabolic trough and power tower systems in the US market, NREL 2010.

Turchi, C. (2010b), Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model, NREL, BoulderIEA, 2008, Energy Technology Perspectives 2008, International Energy Agency, Paris 2010, www.iea.org.

Other useful bibliography:

Asociación Española de la Industria Solar Termoeléctrica (AEIST) (2012), Mapa de la Industria Solar Termoélectrica en España, Protermosolar, www.Protermosolar.com.

Childs, Staley B., J. Goodward, C. Rigdon and A. McBride (2009), Juice from Concentrate: Reducing Emissions with Concentrating Solar Thermal Power, World Resources Institute, Washington, DC.

IEA SolarPACES, Annual Reports 2009, www.solarpaces.org.

Muller-Steinhagen, H. (2011), Solar Thermal Power Plants-On the way to commercial market, German Aerospace Centre (DLR).

Nieto, J.M. (2009), Levelised Cost of Thermosolar Energy: Short and Medium-term Reduction Opportunities, Solar Power Generation Summit Barcelona. February 23-24.

NREL (2012), Concentrating Solar Power Projects Database, US DoE, http://www.nrel.gov/csp/solarpaces/by_country.cfm.

Sargent & Lundy Consulting LLC., (2003), Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts, NREL and US DOE, Washington, DC. http://www.nrel.gov/csp/pdfs/34440.pdf.

Viebahn, et al. (2010), Final report on technical data, costs and life cycle inventories of solar thermal power plants, DLR and CIEMAT, Stuttgart and Madrid.

Table 3 – Summary Table – Key Data and Figures for CSP Technologies

Technical Performance Energy input/output	Typical current international values and ranges Sunlight/Electricity, High Temperature Heat								
	In operation						Under construction/planned		
CSP Technology	PT	PT stor	PT stor	ST stor	ST stor	FR	PT	ST	SD
Status	comm.	comm.	demo	demo	demo	demo	comm.	comm.	demo
Typical capacity size, MW	14-80 (50)	50	5	10-20	20	5-30	50-250	50-370	10/25 kW
Efficiency, %	13-15	13-15	14-16	15-17	15-17 (19)	8-13	13-15	17-20 (28)	>30
Efficiency potential	low	low	medium	medium	high	low	low	high	v.high
Heat transfer fluid	oil	oil	m. salt	steam	m. salt	steam	oil	sh. steam	H_2, He
Max fluid temperature °C	390	390	550	250	565	270	390	up to 565	>800
High temperature potential	low	low	medium	high	high	low	low	high	v.high
Thermal storage	no	yes	yes	yes	yes	no/yes	no/yes	no/yes	no
Storage fluid		m. salt	m. salt	steam	m. salt	steam	m. salt	m. salt	na
Storage capacity, h	0	6	8	1	15	0.5	0-7	na	na
Storage potential	no	medium	high	low	v. high	low	medium	high	na
Land use, ha/MW	2	2	2	2-2.5	2-2.5	2.5	2	2-2.5	1-1.5
Lifetime, yr	>30	30	na	30	na	na	>30	30	>15
Construction time, yr	1-3	1-3	1	1-2	1-2	1-2	1-3	1-3	1
Energy payback time, yr	~ 0.5	~ 0.5	~ 0.5	~ 0.5	~ 0.5	~ 0.5	~ 0.5	~ 0.5	na

Capacity factor, %	25-28	~ 40	45-50	25-28	>70	25-28	25-40	na	28-30a
Optical concentration factor	70-80	70-80	70-80	>600	> 600	60-70	70-80	> 600	600-1000
Total installed capacity, MW	> 1500	~ 200	5	< 50	20	<50	~20,000	~1500	na
Water cooling need, m^3/MWh	~ 0.3-3	~ 0.3-3	~ 0.3-3	~ 0.3-3	~ 0.3-3	~ 0.3-3	~ 0.3-3	~ 0.3-3	0
Market share, %	> 90	<10	na	na	Na	na	na	na	na
Typical generation potential	100-130 GWhe/km^2-yr in the best regions with DNI > 2800KWh/m^2-yr								

Costs[1] (*)	Typical current international values and ranges (USD 2010)			
	PT no stor	PT 6-8h stor	ST 6-9h stor	ST 12-15h stor
Invest. Cost, USD/kWe	4500-8000	7300-9000	6300-7700	9000-10,500
	depends plant size, storage capacity, project maturity (demo, commercial) and local cost of labour			
Investment cost breakdown				
Solar field, %	~ 38% (support structure 11%, receivers 7%, mirrors 6.5%, HT system 5.5% and HT fluid 2%)		~ 33% (support structure and mirrors)	
Central receiver, %	na		~ 17%	
Thermal storage, %	~11%, if any (salt 5%, tanks 2%)		~ 9%	
Power block, BoP, Grid %	~ 14%		~ 11%	
Labour	~ 17%		~ 14%	
EPC, financing, %	~ 20%		~ 16%	
O&M cost, USD(2010)/MWh	~ 25-35			
LCOE 2011, USD/MWh	300-350	210-350	220-280	170-240
	depends on investment cost, DNI, capacity factor, lifetime (30 yr), interest rate (10%). About 4.5% per each additional 100kWh/m^{2}yr of DNI from the basic level of 2000-2100 kWh/m2-y (Spain)			
LCOE breakdown, %	Investment and financing cost ~ 84%; Operation and Maintenance ~ 16%			

Data Projections CSP Technology	Typical current international values and ranges			
	PT	ST	FR	SD
Efficiency (%) 2020-30	16-18 (m. salt HTF)	20 (m.salt HTF) 28 (sh steam HTF) 35-40 (gas HTF+GTCC)	15 (sh steam HTF)	>30 (40)
Capacity factor, %, 2020-30(2050)	32-39 (>50)		na	na
Lifetime (yr)	30-40			20-30
Costs	PT no storage	PT 6-8h storage	ST 6-9h storage	ST 12-15h storage
Investment cost (USD/ kW) 2015	3900-4100	6300-8300	5700-6400	8100-9000
Investment cost 2020-2030	30%-50% reduction due to larger plant size, economy of scale, technology learning. About 12% if the plant size increases from 50 MW to 100 MW, and by 20% from 50 to 200 MW.			
LCOE (USD/MWh) 2015	260-330	180-310	175-240	150-205
LCOE (USD/MWh) 2020-2030	40% to 55% reduction due to reduced investment cost (18-22%), economy of scale (21-33%) and improved efficiency and capacity factor) (10-15%) - A.T. Kearney and ESTELA 2010			
Market 2010-2020	CSP still sustained by incentives. Global capacity up to 150 GW by 2020 (1.3% electricity share)			
Market 2020-2030	CSP economically competitive. Incentives disappear, capacity up to 337 GW (3.8% electricity)			
Market beyond 2030	Global capacity could grow up to 1100 GW by 2050, providing about 9.5% the global electricity Largest producers: US, North Africa, India and Middle East; largest importer Europe			

1 Cost information refers mostly to PT plants, the most mature CSP technology

Disclaimer

The preparation of the paper was led by
Giorgio Simbolotti (ENEA).

Comments are welcome and should be addressed to
Michael Taylor (MTaylor@irena.org),
Giorgio Simbolotti (giorgio.simbolotti@enea.it)
and Giancarlo Tosato (gct@etsap.org)