



PV vs. Solar Thermal

Distributed solar modules are gaining ground on concentrated solar thermal plants

By Jonathan Lesser and Nicolas Puga

Reprinted from the July, 2008, issue of *Public Utilities Fortnightly*, © 2008 Public Utilities Reports, Inc. www.fortnightly.com.
[Editor's note: The solar power marketplace has undergone a radical shift in 2008, with improvements in "thin film" technology making photovoltaic (PV) solar power more cost-competitive with concentrating solar power (CSP). This fact, combined with other environmental and technical factors, has large implications for how we go forward to meet California's aggressive Renewables Portfolio Standard. Yet, as a recent New York Times article showed, even renewable energy advocates have been slow to appreciate these developments. We reprint this article from *Public Utilities Fortnightly* to shed light on this rapidly changing situation, and we encourage policy-makers, both in government and in NGOs, to pay it heed as they consider particular renewable energy proposals.]

Like an ever-receding mirage, solar power has for decades been viewed as the future of electric generation. It always seemed to offer virtually unlimited potential, yet always was just out of reach. Now, it is closer than ever. With soaring prices for fossil fuel and intensifying concerns about climate change, many state legislatures have adopted increasingly ambitious mandates for developing renewable resources through instruments such as renewable portfolio standards, feed-in tariffs, so-called green tags and net-metering standards. These mandates, along with dollops of federal and state subsidies, are now turning the solar mirage into a reality.

As the industry approaches the new solar oasis, companies and regulators will take a closer look at the differences in prices to be paid for different solar technologies, and will compare them to other options—most notably windpower.

While all of the solar technologies promise abundant and competitively priced electricity, for the long-term future the most economically viable options might not be the ones utilities have embraced in the past. Namely, photovoltaic technologies (PV) are appearing more attractive than concentrated solar thermal plants.

Wind Settles Down

The primary beneficiaries of government support for renewable energy projects have been windpower developers. Wind resources currently account for the majority of new renewable resources. Thousands of megawatts of capacity dot the landscape, especially across the sparsely populated expanses of the West and Midwest. Wind manufacturers have made great strides in exploiting scale economies. The generating capacity of individual turbines has increased many times over (with generating capacities today of over 1.5 MW) and so has the scale of individual wind farms. These typically contain dozens or even hundreds of turbines.

For a while, it seemed as if windpower would yield electricity at prices able to compete favorably even with the most efficient natural gas-fired facilities. But all has not gone smoothly with windpower, which has, to some extent, become a victim of its own success. Growth in manufacturing capacity for wind turbines has not kept pace with demand—to some degree stymied by the on-again, off-again status of federal tax credits for wind development. This has resulted in increased prices for turbines and multi-year queues.

Moreover, the full cost of providing needed transmission infrastructure for these wind developments hasn't always been accounted for in valuing the net benefit of wind-generation additions. The best sites for wind developments tend to be far from existing transmission infrastructure. Some states have responded to the lack of transmission infrastructure by forming government organizations to identify the necessary infrastructure and the mechanisms to encourage and subsidize its development.

Another concern is the inherent variability of windpower. Integrating wind generation with the high-voltage transmission grid caused only minor concern when there wasn't much of it, but now, with thousands of generators installed, transmission planners and operators face the challenge of how to integrate rapidly expanding windpower resources into the grid without jeopardizing transmission security and reliability.¹

The transmission system operators of California and Texas, two of the states with the largest windpower potential, have carried out studies on the cost of the infrastructure and ancillary services necessary to integrate wind with their generation resource portfolios. The studies have shown that, while feasible, the integration of large amounts of wind (perhaps as much as one-third of total installed capacity), especially where concentrated in a specific geographic area,

comes at a cost—and that cost must be added to the direct cost of wind generation and interconnection.^{2,3}

Solar on the Rise

As windpower continues growing toward its full potential, and transmission planners and regulators address integration issues, policymakers increasingly are focusing on solar power. In the United States, the power industry has focused on solar thermal technology because it was perceived as more economically competitive than solar PV technologies. Parabolic-trough collector fields with oil-based heat transfer fluids have been successfully used to drive steam-turbine generating plants since the 1980s. The collector technology painstakingly has been improved and O&M costs dramatically reduced over 20-plus years of operational experience, and the lion's share of proposed solar electric generation in the United States is based on this technology.

By contrast, policymakers in Europe made a significant commitment to solar power years ago, including PV. That commitment is especially apparent in Germany, where 20-year contracts and supportive feed-in tariff rates have signaled a long-term commitment to PV manufacturers, project developers, and the entire PV-plant supply chain. This has led to hundreds of megawatts of installed PV, and also allowed some PV manufacturers to improve their manufacturing processes and reap economies of scale by producing modules at declining prices. This in turn has produced a new model of grid-connected utility-scale solar PV—distributed central solar (DCS).

Additionally, DCS has benefited from the increasing efficiencies achieved by thin-film PV manufacturers, as well as realized economies of scale never achieved before. For example, thin-film PV technologies based on cadmium-telluride (Cd-Te) have become much less costly than their better-known, silicon-based brethren. Although Cd-Te cells have lower conversion efficiencies than silicon-based cells, their costs are much lower. Some manufacturers of this PV technology already have committed to sales contracts with levelized costs around 12 cents/kWh over a 20-year term in the desert Southwest.⁴

As a result of these innovations, solar power appears to be becoming a viable, large-scale source of renewable generation, after so many years of being considered the technology of the future. A recent article in *Scientific American* presented a vision of the solar future in which thousands of megawatts of concentrated solar power (CSP) and PV would meet almost 70 percent of the United States' electric needs by 2050.⁵

Just as with windpower, however, a number of economic questions must be addressed, because solar technologies present challenges and risks that must be factored into the vision in order to be truly attainable.

Solar Thermal Chills Out

Solar thermal technology has dominated the market for utility-scale solar power for decades. Although it still faces technical and economic challenges, interest in this technology

remains strong as the industry searches for climate friendly energy sources.

In February 2008, Arizona Public Service (APS) announced plans to build a 280-MW parabolic-trough solar-thermal generating facility near Gila Bend, Ariz., with a levelized cost of 14.4 cents per kilowatt hour over the plant's estimated 30-year lifetime. APS also plans to issue a second joint solicitation, with other Arizona utilities, to build another 250-MW plant using the same technology. These announcements coincided with the release of several studies of the generation potential for CSP across the southwest United States.⁶

The Gila Bend plant will be built by the Spanish firm Abengoa, and it will draw on that firm's experience with similar technology in Spain. Tracking, concentrating, parabolic-trough collectors will heat synthetic oil, and a two-tank molten salt-storage system will store the heat and allow the plant to generate electricity at near capacity during the long APS summer peak-demand period. The plant will generate electricity using a medium pressure steam turbine with wet cooling towers. The project's collector-field technology results from more than 20 years of European and U.S. experiences, most notably the Luz International Solar Electric Generating System (SEGS) projects built in the Mojave desert in California beginning in 1984. The same cannot be said for the molten salt-storage technology, which never before has been built or operated on this scale. (Smaller similar systems have been tested in the United States and are under construction by Abengoa in Spain.) Given the lack of commercial operating experience, the Electric Power Research Institute (EPRI) declined to include such storage in a recent study of the potential for parabolic-trough electric plants in the southwest United States.⁷

Irrespective of molten salt-storage technology, CSP development faces some more mundane challenges. CSP plants are basically steam turbines that rely on the sun, rather than fossil or nuclear fuel, to make steam. Like most steam-turbine plants, economies of scale dictate that a parabolic-trough CSP plant must be sized in the 100-MW to 300-MW capacity range. The size of the collector field for such a plant, particularly one designed to provide hours of storage, is enormous.

For example, the Gila Bend plant will require a contiguous 1,900-acre site to build its collector field. (For comparison, a 21-MW thin-film PV plant to be built near Blythe, CA, would require less than 150 contiguous acres.) The size of Gila Bend's collector field will, in turn, require a detailed environmental impact review, perhaps spanning several jurisdictional boundaries.

The sheer amount of real estate required increases the likelihood of concerns about negative impacts on plant and animal species. Moreover, plants this size likely will require dedicated high-voltage transmission lines that will need to be permitted. These permitting requirements will increase the regulatory risk of the project and potentially lead to construction delays and higher costs.

Another critical issue is water, or rather a lack of water. The steam turbines used at CSP plants require water for

cooling; using wet cooling towers, the proposed APS/Abengoa 280-MW CSP generating facility can be expected to consume between 600 million and 700 million gallons of water, roughly 1,900 acre-feet, per year. But in the desert Southwest, available water resources are becoming more scarce, as populations continue to grow. There are virtually no additional surface water supplies available and groundwater recharge rates are so slow as to make groundwater supplies effectively fixed.⁸

While several conventional thermal generating facilities use treated wastewater from nearby urban areas, it is doubtful that this approach could be adopted for all of the proposed CSP generating plants in the desert Southwest. Moreover, treating and piping wastewater to far-flung CSP plants in the desert will add significant costs. As a result, CSP plants likely will require dry-condenser cooling—which minimizes water use, but does so at a significant cost, in the order of \$200/kW by some estimates.⁹ Furthermore, dry-cooling reduces both net generation and thermal efficiency, especially on the hottest days of the year, when summer-peaking utilities most need power. The loss of efficiency in a steam plant with a state-of-the-art dry-cooled condenser can be as high as 25 percent on very hot Southwest summer days. This reality will affect the economics of CSP plants as Black & Veatch recognized in a report prepared for the Renewable Energy Transmission Initiative (RETI) in California.¹⁰

Black & Veatch estimates that if the Gila Bend plant were dry-cooled, it could cost between \$50 million and \$60 million more to build, and would produce less electricity at a higher cost than currently expected. And a recent EPRI feasibility study for central-station solar power estimates power from a utility-owned 125-MW dry-cooled solar-trough plant (located in New Mexico and without molten salt storage) will cost between 24 and 26 cents/kWh, including the 30-percent federal investment tax credit.¹¹

CSP technologies (including central solar receiver, linear Fresnel concentrator, and parabolic dish Stirling cycle) pose a number of other technical and financial risks. For example, parabolic dish Stirling engine technology lacks manufacturing capacity or commercial operation experience, although a leading manufacturer has signed between 800 MW and 1,750 MW in long-term power purchase agreements for commercial development. This suggests that building these plants will require the manufacturer to abbreviate the technology development stage and move straight into manufacturing and commercial operation, skipping manufacturing optimization or operational pilot-plant stages. How such a strategy will work in practice remains uncertain, but the effort likely will show the strengths and weaknesses of the latest CSP technologies.

PV Catches Up

PV technology also is advancing as a result of significant utility commitments. Although announced with much less fanfare, Southern California Edison plans to install 250 MW of commercial rooftop PV at an estimated cost of \$3,500/kilowatt

(2008 dollars). This figure reflects an accelerating price differentiation between PV technologies.

Some types of thin-film technology rapidly have gained ground in both efficiency and price relative to traditional silicon PV, where costs per watt actually have increased slightly since 2004. As a result, thin-film PV has become competitive with utility-scale solar-thermal generation, and also can provide additional benefits in the form of modular development, lower transmission-system interconnection costs, fewer technical uncertainties, and no need for copious quantities of cooling water.

For example, First Solar, the largest manufacturer of thin film Cd-Te technology, reports that process improvements and growing manufacturing capacity has allowed it to increase the efficiency of its panels to 10.5 percent, while reducing module production costs from \$2,940/kW in 2004 to \$1,120/kW for the fourth quarter of 2007.¹²

First Solar is supplying PV panels for a 40-MW solar PV facility in Brandis, near Leipzig, Germany. When completed, the Brandis facility, which currently has 12.5 MW commissioned and 20 MW installed, will be the largest PV generating facility in the world. The project development arm of the same manufacturer also recently signed a contract with SCE to develop a 7.5-MW to 21-MW facility, at a price lower than the 20-year, 2007 California Market Price Referent.¹³ The facility is expected to be interconnected to an existing 34.5 kV line near Blythe, Calif., and thus won't require any transmission-system upgrades.

While not as impressive in sheer scale as 200-plus MW solar thermal plants, modular DCS PV facilities with 20 MW to 50 MW of installed capacity can be placed closer to load centers and can interconnect to existing 69-kV or 115-kV transmission lines. This avoids the need for large-scale transmission investment (and the all-too-common permitting delays) and increases both the potential cost advantage and the likelihood of completing a DCS PV facility, compared to its much larger solar thermal brethren.

Solar Life Cycle

As with all generating resources, renewable or not, a number of tradeoffs must be evaluated in order to identify the most suitable generating resources with the lowest life-cycle costs. Today, CSP technologies are perceived as having lower life-cycle costs than PV, and policymakers in the Southwest are incorporating greater quantities of CSP into their RPS portfolios. However, CSP technologies also pose a number of risks that affect life-cycle costs in ways that haven't always been fully accounted.

These risks include:

- Potentially significant cost increases due to protracted and risky site-specific development cycles. This can affect regulatory approval if proposed facilities are to be rate-based.
- Reliance on technologies that are not commercially proven.
- Reliance on technologies in limited production that may not

be sufficiently available when demand suddenly increases, as has happened with wind resources. This might drive prices higher and cause schedule delays. As a related matter, maintenance costs might be higher than projected, as is typical of commercially immature technologies and one-off designs.

- Environmental risks, especially reliance on scarce—and currently underpriced—water supplies.
- O&M complexities, with each facility requiring miles of pipe and thousands of joints and seals to circulate heated fluid. In the early years of operation of the parabolic-trough CSP plants in the U.S., built between 1985 and 1991, the loss of heat transfer oil through leaks was a significant problem.¹⁴ Although much has been learned through the operation and maintenance of existing parabolic-trough plants, it is unlikely that technological improvements will eliminate the risks of leaks or the associated impact on performance and cost.

By comparison, the technological and operating risks of utility-scale PV are small compared to those of CSP plants. PV facilities face far fewer challenges for siting and permitting—largely because they are modular and don't need to be installed in several hundred megawatt increments to achieve economies of scale. Moreover, that modularity allows DCS to be installed in dispersed locations, and this can improve availability by reducing the impact of site-specific weather patterns. Additionally, DCS has little or no need for water, no air- or water-borne pollutant emissions, and uses no environmentally hazardous working fluids such as oil and molten salt.

O&M costs likewise are much smaller for state-of-the-art PV arrays than they are for parabolic trough fields. Nontracking, ground-mounted PV arrays have no moving parts, and today's thin-film Cd-Te modules exhibit both low failure and low performance degradation rates.¹⁵

Finally, the manufacturing supply chain for thin-film Cd-Te equipment is well established and is growing quickly. First Solar, which today has a manufacturing capacity of 300 MW a year, plans to more than triple its capacity by the end of 2009. Other thin-film manufacturers also are increasing their production capacity, and this is resulting in significant reductions in equipment prices.

A recent presentation by Lazard projects a levelized cost of energy of \$90/MWh for First Solar thin-film technology, based on total project capital costs of \$2,750/kW and fixed O&M costs of \$25.00/kW-yr.¹⁶ If those cost estimates hold true, or are even close, then Cd-Te DCS represents a significant advance over the projected costs of CSP and of competing PV technologies. And, given the modular nature of DCS installations, those installations can more closely track load growth and can even be developed in conjunction with planned residential, commercial, and industrial growth centers.

Given today's relatively limited PV manufacturing capacity and the momentum of CSP development, the industry likely will continue to invest in parabolic trough CSP plants. However, thin-film PV technology already is knocking at the generation developer's door. In the long run, DCS plants likely

will gain a strong foothold in the market as economic forces drive the industry toward the most efficient, cost-effective, and environmentally benign solar electric technologies.

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