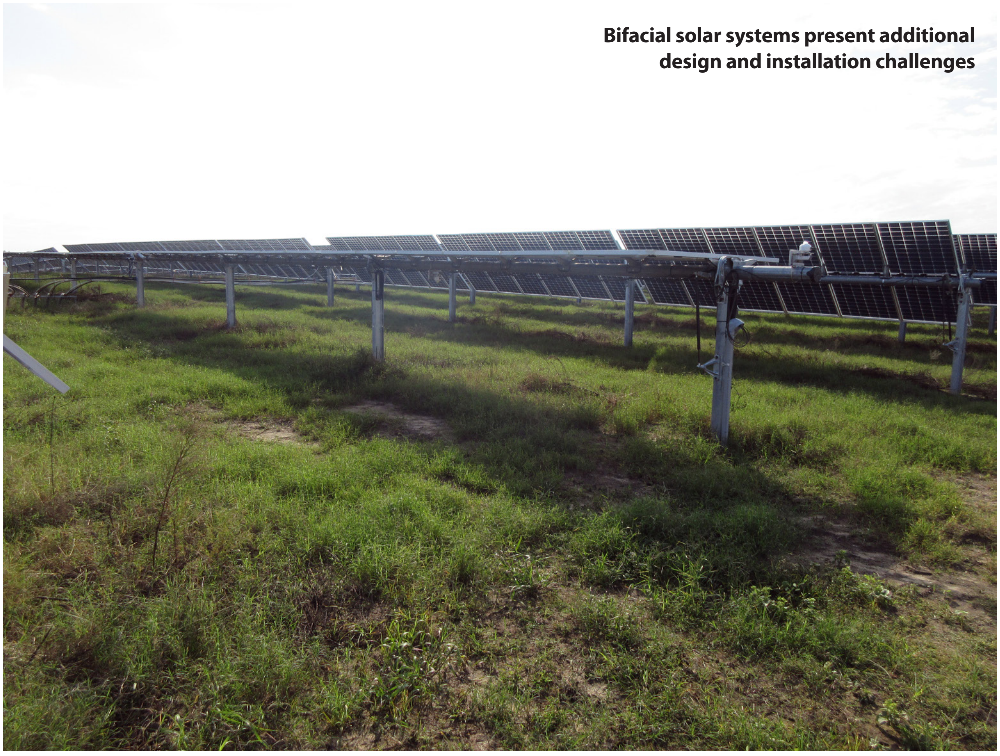
Getting the most from bifacial

System engineering | As the deployment of bifacial solar projects worldwide accelerates, so too is the industry's understanding of how to design and build systems that play to the technology's main strengths. Drawing on recent experiences in the field, Beth Copanas and James Willett from RES outline some of the technical lessons learned on realising bifacial's full potential



Bifacial solar systems present additional design and installation challenges

Credit: RES

With global installed capacity increasing from 97MW in 2016 to an expected 5,420MW by the end of 2019, the promise of bifacial photovoltaic (PV) solar has begun to materialise [1]. As a leading independent renewable energy company, RES has seen a marked increase in owner/developer procurement of bifacial solar modules over the past two years. RES currently has over 550MW_{DC} of bifacial capacity in the design/engineering phase and recently completed construction of a larger than 200MW utility-scale bifacial project. Currently, this is one of the largest utility-scale bifacial projects in the USA. Standard industry practices for utility-scale PV design, construction and testing can be impacted by the integration of bifacial technology. This article addresses some of the valuable design and construction lessons learned RES has garnered thus far.

Design and construction overview

Lessons learned on bifacial utility scale projects RES has designed or constructed thus far and that are addressed in this article include:

- DC collection system design;
- DC collection system construction;
- Commissioning and testing considerations;
- Meteorological station equipment and locations.

DC collection system design

PV array output current is directly proportional to the amount of irradiance incident on the PV arrays. The instantaneous current value can be impacted by albedo, reflections, cloud edge effect, and site elevation. Bifacial module cells are exposed on both sides and cell exposure to rear-side irradiance should result in increased PV output current as compared with monofacial modules. Therefore, design of the PV DC collection system must consider total incident irradiance when sizing the DC current carrying conductors and fuses. The US National Fire Protection Association (NFPA) National Electric Code (NEC) is the industry standard for sizing DC conductors and fuses. DC conductors and fuses for projects are sized by determining the maximum current of the PV Source Circuits using NEC 2017 Article 690.8(A) [2].

According to Article 690.8(A), the following equation is used to determine the worst case continuous current that a DC cable may carry under load.

$$Imax = Isc * IF$$

Where:

Imax: Maximum PV Source Circuit Current

Isc : Short Circuit Current per module or per string of modules in series. The Isc value is taken from the module manufacturer datasheet at Standard Test Conditions (STC).

IF (Irradiance Factor): To account for increased current due to increased incident irradiance, the default irradiance factor is 1.25, which assumes 25% more irradiance than at (STC) where incident irradiance is assumed to be 1,000W/m2. Therefore, if the module Isc at STC is 10 Amps an Irradiance Factor of 1.25 assumes incident irradiance of 1,250W/m^2 and an Isc increase of 25% to 12.5Amps. Even monofacial systems must consider an irradiance factor for situations where the modules experience greater than 1,000W/m^2.

The default assumption per Article 690.8(A)(1)(1) is an Irradiance Factor of 1.25 or 1,250 W/m^2. However, 690.8(A)(1)(2) allows a licensed electrical engineer to use an industry-approved method for deriving an Irradiance Factor that is different than the default value per NEC 690.8(A)(1). The NEC references the SANDIA 2004-3535 Photovoltaic Array Performance Model and the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) simulation programme as an industry-approved method for calculating the "highest three-hour current average resulting from the simulated local irradiance on the PV Array accounting for the elevation and orientation. The current value used by this method shall not be less than 70 percent of the value calculated using 690.8(A)(1)(1)". In RES' experience, a method acceptable to owners and independent engineers (IEs) is to model 20 or more years of solar resource data using SAM to determine the highest three-hour average irradiance factor over the 20 years.

Example calculations for a utility-scale bifacial project using 690.8(A)(1)(2) are outlined below. For bifacial systems, the highest three-hour average circuit current must account for the additional current a bifacial module will see due to the rear-side irradiance contribution. Using SAM and historical data, the electrical engineer of record (EOR) can determine the Irradiance Factor. While the SAM POA output values include a rear-side irradiance contribution, in RES' experience some EORs choose to add another factor of safety by using the module manufacturer published Isc datasheet values multiplied by an additional bifacial gain factor (BGF). RES has seen this BGF value vary from 10-15% across projects. Therefore, in this example the maximum photovoltaic source circuit current per 690.A(A)(1)(2) is calculated as follows:

Imax = Isc * BGF * IF

Where:
Imax = 13.225
Isc = 10
BGF = Assumed Bifacial Gain Factor, 1.15
IF = 1.15

When using the method outlined in NEC 690.8(A)(1)(2), a project can end up with a total safety factor greater than the 1.25 value as dictated by 690.8 (A)(1)(1).

To size the DC overcurrent protection devices, NEC 690.9(B) requires "not less than 125% percent of the PV maximum output current calculated in 690.8(A)" [2].

Ioc = Imax* 1.25

Where:
Ioc = Current value for Overcurrent Protection Rating as required by 690.9(B)
Imax = Max current calculated according to 690.8(A)
1.25 = NEC required safety factor per 690.9(B) that states an Overcurrent protection device can only be run at 80% of its continuous rating.

Using this example, the *Ioc* as calculated per 690.8(A)(1)(2) and 690.9(B) ended up at 16.53 Amps per module or per module string. The BGF value selected for projects can have material and installation cost implications for the DC wiring system. Due to the limitation imposed by the current industry 32A in-line fuse rating, the BGF factor assumption can result in the purchase and installation of up to two times the number of wire harnesses as compared with an equivalent monofacial project.

Figure 1. Wiring considerations for bifacial modules: to prevent shading of the rear-side of the module how the DC wire harnesses will travel down the racking structure without shading the rear side of the modules must be considered during the design and procurement stages of the project. Different modules paired with different racking structures require custom approaches

As Isc values on modules continue to increase with increased module efficiency, the assumptions around the bifacial gain factor are increasingly important. The DC collection system, including procurement and installation of the DC string wire harnesses and DC conductor homeruns (from field installed combiners to inverters), can comprise 7-8.5% of the total balance of system (BOS) cost stack – not including modules or project substation costs. A higher rated DC in-line fuse (~50A) coming to market could allow for more strings per wire harness. While this would have allowed the current design to use the industry standard method of two-string and one-string harnesses per three-string tracker row, the ability to put more strings in parallel per string, even with a higher fuse rating, will still depend on the EOR assumptions around the IF and the BGF.

If the bifacial current increase assumption is too aggressive owners run the risk of systems blowing fuses or compromising conductor insulation over the life of the project. However, conservative BGF and IF factors can add additional unnecessary capital costs to projects. Important consideration needs to be given to the seasonal and clear sky versus diffuse hourly rear-side irradiance gains when determining the total IF and therefore the assumed worst-case current value.

DC wire management

DC wire management is a critical aspect of the PV system installation that impacts project performance and the long-term reliability and health of the DC system. The size of these utility-scale PV projects means there are millions of feet of PV string wire to install. Per the NEC, system wiring must be installed such that exposed conductors are correctly rated for outdoor exposure, are protected by and secured to the racking structure, and maintain the correct bend radius to prevent conductor damage. For bifacial modules the typical method of securing DC string harness wiring to the backside

Figure 2. Installation crew familiarity with bifacial modules. To prevent shading of the rear side of the module ensure that crews are properly trained and understand that in addition to the usual wire management considerations the goal is to minimise rear-side shading

QTY per MET station	Measurement device	Instrument type	Typical ranges	Typical accuracy
1	Irradiance in the plane of array (E_{POA})	Pyranometer classified as secondary standard by ISO 0960:2018 and high quality by the World Meteorological Organization Guide 6th Edition	0-2,000 W/m2, 285 to 3,000nm	±2.0%
1	Irradiance in the plane of array (POA)-module rear side ($E_{\_Rear}$)	Pyranometer classified as secondary standard by ISO 0960:2018 and high quality by the World Meteorological Organization Guide 6th Edition	0-2,000 W/m2, 285 to 3,000nm	±2.0%
1	GHI irradiance	Pyranometer classified as secondary standard by ISO 0960:2018 and high quality by the World Meteorological Organization Guide 6th Edition	0-2,000 W/m2, 285 to 3,000nm	± 2.0%
1	Ambient air temp	Temperature probe	-40°C to +70°C	± 0.3°C @ 20°C
	Back of the module temperature sensor	Temperature probe	-40°C to +135°C	±(0.15°C + 0.002t)°C
1	Wind speed	Sonic wind sensor	0.1-60/ms-1	±3% (up to 40/ms-1)
1	Relative humidity	Humidity sensor	0-100%	±2%@20°C (10 to 90% RH)

Table 1. Example MET station equipment for a bifacial PV project

of the modules will contribute to shading of the modules and interfere with rear-side irradiance gain.

Before construction, the design and procurement phases must capture the conductor lengths required to prevent shading of the rear side of the modules. Figure 1 is an example of extra length required to keep the wire harnesses secure and maintain the correct bend radius without shading the module cells. Failure to evaluate wire management early in the project design phase may result in additional material and labour costs.

Additionally, as per Figure 2, installation crews largely familiar with monofacial systems need additional training to ensure that they are aware and working to minimise rear-side shading. Care must be taken to ensure crews' hours associated with array wiring is as efficient as monofacial module installations while still maintaining the required wire management practices.

Commissioning and testing considerations

The recent deployment of bifacial PV technologies that can convert rear-side irradiance into additional module power output has impacted the energy modelling and actual evaluation and measurement of utility-scale PV system performance. Testing and commissioning of large, utility-scale projects is a contractual obligation intended to demonstrate that a PV project is installed correctly and can achieve expected performance levels under actual environmental conditions.

As suggested by the PVSC 46 Manuscript, PVSC 46 2019-6-3, total Irradiance E_{Total} can be used to evaluate total incident irradiance on the modules for energy modelling and actual site performance evaluation purposes [3].

$$E_{\_Total} = E_{\_POA} + E_{\_Rear} * \varphi$$

Where:

$E_{\_POA}$ = frontside plane of array irradiance (POA)

$E_{\_Rear}$ = rear-side plane of array irradiance (POA)

φ = Bifaciality factor, ratio of rear-side to front-side efficiency determined by module manufacturer

Utilisation of this performance evaluation methodology requires modification of standard meteorological station equipment and placement as described below.

MET stations

While the increased equipment and installation cost for bifacial-compatible MET stations is not a significant adder to overall project costs, the design, location, and installation of the MET stations

Figure 3. Rear-side irradiance sensor location. Inverter cut-outs, roads, high traffic areas, and natural ground cover variations can result in rear-side POA measurements that are not representative of overall site albedo. Close-ups of the sensors can be found in Figure 4

Figure 4. Rear-side pyranometer mount. Options for rear-side pyranometer mounting systems are currently limited and non-standard. Most mounting systems will result in the pyranometer being some distance away from the back of the modules

can impact the system performance evaluation. In terms of equipment, the main addition to MET stations for bifacial projects is rear-side pyranometers or reference cells to measure rear-side irradiance for performance evaluations. Typically, utility-scale projects will consist of one or two front-side irradiance sensors and one rear-side sensor per 20-25MW_{AC}. To date, RES has used class A secondary standard rear-side pyranometers that match the model number and quantity of the front-side pyranometers. The remaining MET station measurement devices are the same as those used on standard utility-scale MET station configurations. A list of bifacial MET station equipment with ranges and accuracies is provided in Table 1.

In addition to selecting the appropriate types and quantities of rear-side irradiance sensors, the location and mounting of the sensors should be given due consideration. The placement of the rear-side irradiance sensors should be representative of the overall site albedo. This can be a challenge for 1,000 to 1,500-acre sites (400-600ha) where natural or unnatural variations in ground cover can make it difficult to get rear-side measurements that are characteristic of the overall site albedo. One difficulty is that due to power and communications requirements, MET stations are often located near inverter cut-outs and roads that see high traffic and construction activities. These areas will often have reduced ground cover that is not representative of the rest of the site. Natural variations in ground cover height/density can also cause rear-side irradiance measurements to not accurately reflect site albedo (Figure 3).

The rear-side sensor location and mounting method near the back of the bifacial modules should also be given consideration. Ideally, the rear-side mount should accurately reflect rear-side shading and irradiance uniformity, be as close as possible to the exposed cells, and be free from reflections and/or shading. Figure 4 depicts a rear-side pyranometer mount. Current mounting options for rear-side pyranometers are limited, non-standardised, and should be given forethought when designing MET stations for bifacial projects.

Although the equipment requirements and costs of bifacial MET stations are not substantially different from standard utility-scale MET stations, the design and siting of the stations and sensors can affect measurement accuracy. Proper consideration should be given to the MET station design to ensure successful performance testing.

Conclusions

As bifacial solar quickly moves to the mainstream, to fully realise the potential gains from bifacial projects, specific design and construction considerations should be incorporated into the project. Through RES' experience with recent projects, the most consequential considerations were related to DC collection system design (fuses and wire sizing), DC wire management, MET station design and location, and commissioning and testing procedures. ■

References

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[2] National Fire Protection Agency, National Electric Code, Quincy, Masschusetts, 2017.
[3] M. Waters, C. Deline and J. Kemnkitz, "Suggested Modifications for Bifacial Capacity Testing," in PVSC 46, Chicago, Illinois, 2019.

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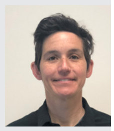

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