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Solar Risk Assessment: 2020

Quantitative Insights from the Industry Experts

Introduction

"In God we trust, all others must bring data." - American Statistician W. Edwards Deming

Rarely does a single investment yield both significant social and financial benefit. In this way, solar is unique: this rapidly growing asset class offers the promise of substantial returns on investment in both.

While the financial community is—rightfully—focused on newly emergent risks of this asset class, such as managing the merchant tail and basis risk, it's important that the financial community remains vigilant on the question of solar production risk.

Over the past few years, it's become in vogue for financial investors and pundits alike to publicly dismiss the possibility of a solar power plant underperforming, with remarks like, "The sun will always shine," and "Panels always work because they have no moving parts." Success breeds complacency, and complacency breeds failure.

We are among the industry's leading experts on the measurement and management of solar production risk, cumulatively representing hundreds of years of experience in our respective fields. Each of us are risk specialists with in-depth data on a specific element of solar production risk.

Rather than publishing "yet another" opinion, we are committed to letting the data speak for itself. Designed intentionally for a non-technical financial community, this report will be refreshed every year to provide investors with the latest insights on the evolution of solar generation risk.

Fundamentally, it is our hope that this report will serve as a guide for investors who recognize the importance of allowing data-based insights to inform the deployment of capital.

We look forward to the shared work of advancing our solar industry.

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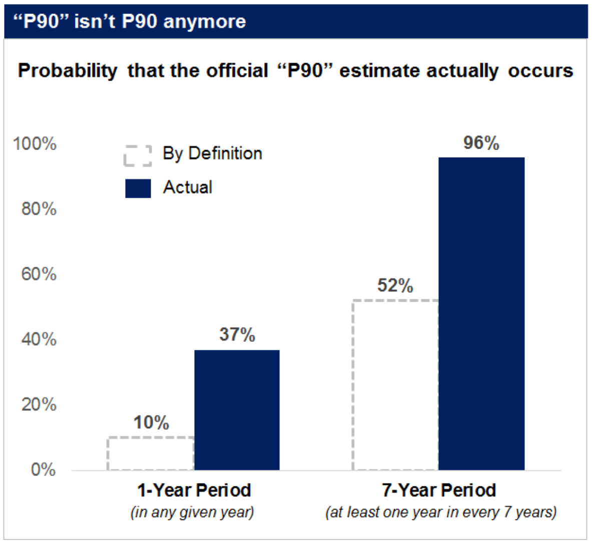
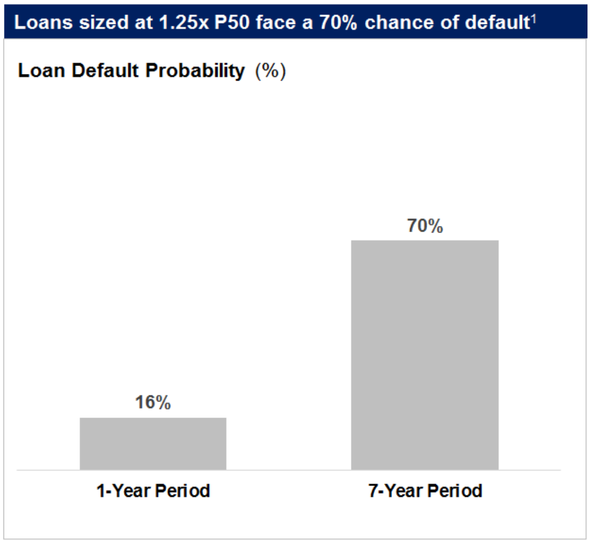
"P90" production actually occurs more than 1-in-3 years (instead of 1-in-10), jeopardizing equity returns

KWH ANALYTICS

Executive Summary: Unreliable energy estimates have resulted in systemic underproduction, now observed industry-wide. Equity investors' returns are most exposed to this risk, given their position in the capital structure and higher operating leverage from lower PPA rates.

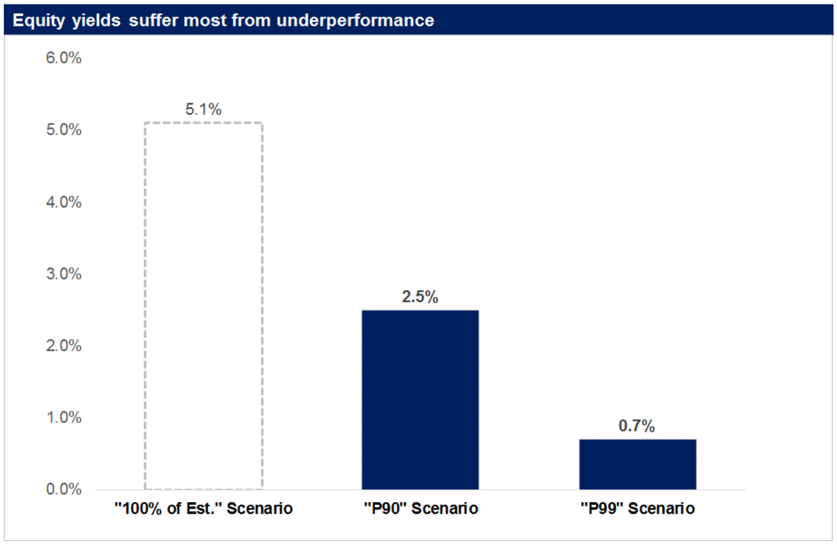
Portfolio Underperformance: Refreshed analysis from kWh Analytics' database of operating solar projects (covering 20% of the US operating fleet) reveals that "P90" production events are actually occuring >3x more frequently than the P90 definition implies. "P90" downside events occur so often that they have nearly become P50s.





Furthermore, extreme downside ("P99") scenarios are occurring 1-in-6 years (a significant increase from 1-in-20 observed last year, and far from the 1-in-100 per definition). Solar assets are underperforming far more frequently than official energy estimates would suggest, validating an industry-wide bias towards aggressive predictions.

Impact on Equity Cash Yields: Given its position in the capital structure, equity capital suffers disproportionately when solar assets underperform. When a typical solar project[1] performs at the official "P90", equity cash yield drops by 50%:



[1] 100 MW, $35/MWh PPA, ~$17/kW-year total OpEx, TE preferred cash distribution.

Commercial-scale solar: Optimistic irradiance assumptions contributing to 5% underperformance

DNV GL

In 2019, DNV GL presented results from an energy validation study of operational utility-scale solar projects. One key finding of that study was that utility-scale solar projects, on average, were underperforming expectations by 3% on a weather-adjusted basis.

In 2020, DNV GL has expanded the study to commercial-scale solar projects, typically ranging from 50 kW to 5 MW. Compared to utility-scale projects, the commercial-scale projects appear to underperform their financial model expectations by an even greater margin. DNV GL's analysis has identified several sources for this underperformance, which include optimistic irradiance assumptions, higher-than-expected equipment downtime, and higher-than-expected shading losses. This summary focuses on analysis of the impact that optimistic irradiance assumptions can have when reconciling actual versus expected project performance.

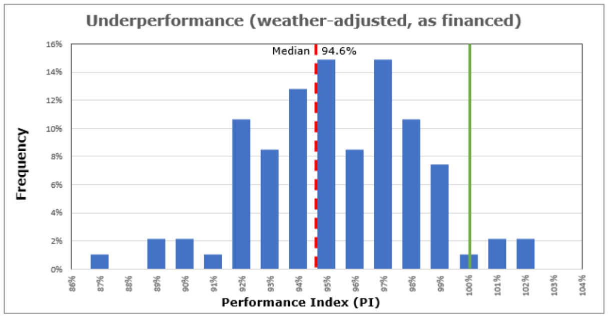
DNV GL's results demonstrate that, despite adjusting for the actual weather and availability during the operation of the plants, the assumed irradiance in the financial model (Assumed P50 Irradiance) was often higher than the long-term average irradiance at the site (Long-Term Average Irradiance). Optimistic irradiance assumptions (referred to as "irradiance shopping" when purposeful) can set unrealistic performance and revenue expectations for solar PV projects. Consider an example where the expected revenue is based on an assumed irradiance of 1800 kWh/m^2/year, but the actual long-term average is 1750 kWh/m^2/year. In this example, the financial model is assuming irradiance that is 3% higher than the long-term historical average. Over the life of the project, it is expected that the project will underperform the financial model by approximately 3%, even after weather-correction.

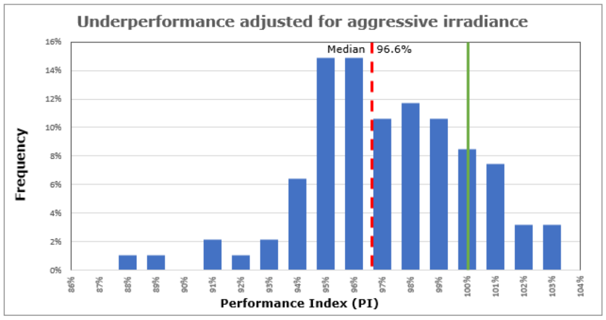
In this analysis, DNV GL evaluated whether the financial model irradiance basis (Assumed P50 Irradiance) skewed toward higher or lower estimates of irradiance for the location. To many, it may be a surprise that there are multiple sources of irradiance data, and that they can vary by up to 10% annually for the *same location* (and even higher on a monthly basis). Faced with choosing a single irradiance dataset for your project financial model, how do you choose between many different estimates of irradiance, each with different uncertainties? The highest value? The average value? The dataset with the lowest uncertainty? Do you blend them together? (Hint: Definitely exclude the first and last options in that list.)

As shown in Figure 1, one key result of this analysis is that financial model irradiance assumptions tend to overestimate long-term average irradiance by 2.0%, with the middle quartiles of projects overestimating irradiance by 1.2% to 5.2%. As such, these projects are likely to underperform revenue expectations over their operational life. This result does not necessarily suggest that this skew is a result of intentional irradiance shopping, as unintentional bias can also occur when relying on a single source of irradiance data or when a portfolio is weighted towards a particular region.

To mitigate the risk of optimistic irradiance assumptions, DNV GL recommends accessing irradiance data from multiple sources and screening them for seasonal consistency, uncertainty and data integrity to avoid outliers. Services exist to facilitate irradiance comparison to reduce the risk of choosing datasets that may result in long-term financial underperformance.

Figure 1: Impact of optimistic irradiance assumptions
Optimistic assumptions have been identified as one cause of revenue underperformance in commercial-scale projects.
[a] project performance relative to financial model expectations (5.4% shortfall), [b] project performance if adjusted to account for optimistic irradiance assumptions (3.4% shortfall).
[Performance Index (PI) = actual production / expected production. A PI less than 100% indicates underperformance.]





Sub-hour solar resource variability impacts actual energy production by approximately 1-4%

NEXTERA ANALYTICS

Accurate pre-construction estimation of solar energy production is critically important for the economic sustainability of new solar generation projects. Despite this importance, much of the solar industry continues to model generation using traditional methods, assumptions, and industry-standard software that does not always reflect real-world performance. One such outdated method is the modeling of solar energy production at an hourly temporal resolution despite the known highly-variable solar resource at the intra-hour time scale due to intermittent cloud cover.

As solar site overbuilds with respect to inverter capacity (e.g., DC:AC ratios greater than 1.0) become more common, accurately capturing intermittent cloud cover at minute-level temporal resolution is extremely important due to the fact that the presence of the AC energy cap can yield a bias in long-term energy production estimates (see Figure 1). Contrary to minute-resolution data, hourly irradiance averages fail to discern that any DC generation exceeding the maximum AC limit will be lost during partly cloudy hours. This can lead to a material overestimation bias in hourly solar energy models, which is particularly prominent for sites with higher DC:AC ratios and frequent, intermittent cloud cover. Nevertheless, industry-standard energy modeling software is not capable of running higher temporal resolution solar resource data.

NextEra Analytics conducted a study to quantify how intra-hour resource fluctuations vary with geography and meteorological conditions using 65 pre-construction solar meteorological stations with data sampling down to 1-minute resolution. That data was assimilated into the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) both at minute- and hourly-averaged resolutions. Results showed that hourly-resolution energy predictions were biased high compared to minute-resolution runs on the order of approximately 1-4%. In addition to location, site configuration (e.g., DC:AC ratio, AC size) also significantly influenced the hourly bias. These trends were also corroborated against minute-level operational data from several geographically-diverse sites which also showed similar biases (see Table 1).

Given the high economic sensitivity of 1-4% energy, it is important that model bias due to the hourly-averaging of solar resource data be accounted for either through direct modeling in a system such as SAM or through post-processing correction. In addition, all solar energy modeling systems should adopt intra-hour modeling capability and/or parameterization features as soon as possible.

Figure 1: Schematic of minute resolution versus hourly averaged irradiance & power data

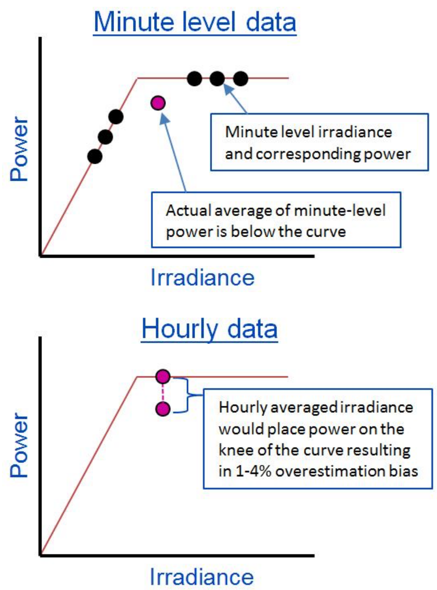


Table 1: Energy estimation bias due to hourly averaging

Site ID	U.S. Region	Hourly vs Minute Level Resolution Energy Bias
PV Farm A	Southeast	2.0%
PV Farm B	Southeast	4.1%
PV Farm C	Southeast	2.0%
PV Farm D	Midwest	1.5%
PV Farm E	South Central	1.6%
PV Farm F	South Central	2.0%
PV Farm G	South Central	2.5%
PV Farm H	Southwest	0.8%
PV Farm I	Southwest	1.3%

U.S. regional irradiance down 5 to 7% from average: Why real-time data is so important to understanding project value

CLEAN POWER RESEARCH

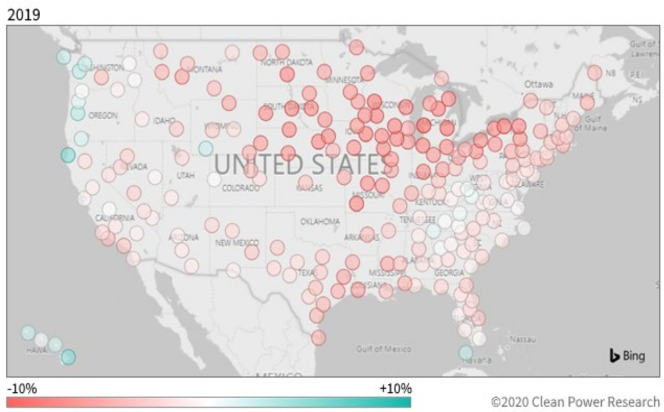
Accurate forecasts of solar photovoltaic (PV) output can make the difference between millions in losses or profitable net cash flow on a project. While forecasts are created with long-term solar resource, asset managers need real-time irradiance data to benchmark actual plant output. This need was elevated in 2018 and 2019, as many regions in North America experienced especially low solar resource, leading to lower project revenue.

Using real-time data, project investors and asset managers can understand how project value may be impacted due to revenue shortfalls. This is because multiple causes (i.e. low irradiance, hardware failure, soiling, modeling errors) can lead to underperformance and each cause has a different impact on value. To effectively understand updated project value, asset managers need to consider real-time solar irradiance in reference to: (1) long-term averages, (2) long-term accuracy and (3) spatial consistency.

Consideration #1: Use real-time irradiance data normalized to long-term average

While real-time data is important, it needs to be referenced to long-term averages to understand impacts on project value. This is important because project long-term cashflows are based on an average annual energy pro forma. So, while measuring total $ or MWhs can be useful for understanding annual output, impact to updated project value needs a reference to annual average expected energy. In 2018, for instance, certain U.S. project locations would have seen a deviation by as much as 5 to 7% below average. That shortfall in irradiance was again experienced in 2019, with regional impacts below.

Figure 1: Deviation of insolation (GHI) for 2019 from long-term averages (1998-2018) for 221 locations across the U.S.



Consideration #2: Real-time data is valuable when long-term accuracy is well documented

Real-time data adds value when referenced against well-vetted, long-term averages. Satellite models, which are the trusted source of long-term data, need validation over a long period because of how satellite hardware changes over time. Asset managers should rely on real-time data that is based on models backed by a long-term accuracy comparison, as this is not the case for all sources.

Consideration #3: Real-time data needs to be spatially consistent when used on more than one project

Unless you are evaluating a single project, using spatially consistent irradiance data is necessary to compare operating plant performance over multiple project locations. Using second-class ground-based sensors at different sites risks sensor error that confounds site comparison and thus lead to false conclusions about portfolio performance. Therefore, spatial consistency between irradiance data sources is needed.

O&M costs continue to fall, but what's been given up?

WOOD MACKENZIE POWER & RENEWABLES

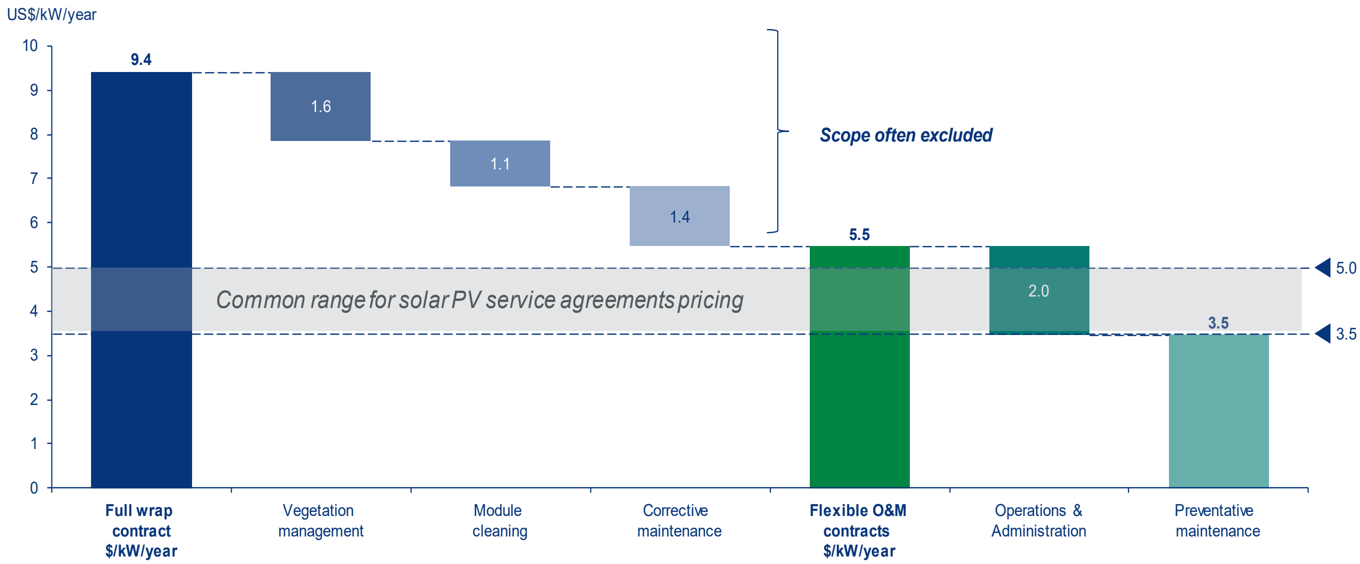
Solar power purchase agreement (PPA) pricing across the globe has been dropping dramatically over the last few years. Expiring incentives and the introduction of auction schemes exerts downward pricing pressure through the entire value chain, including the O&M segment.

As solar PV O&M prices continue to shrink around the globe, so does the scope of service agreements.

Looking solely at lower $/kW/year figures leads to an erroneous perception of "cheaper" service agreements. In reality, most of the current O&M contracts signed on the lower end of the cost range (3-5 US$/kW/year), miss vital aspects of operating and maintaining a solar power plant properly.

The typical scope included on current O&M contracts covers very few basic maintenance activities, mainly part of preventative maintenance and general operations. These events, although extremely important, don't reflect all the costs an asset owner is typically exposed to.

Figure 1: Solar PV O&M pricing breakdown



Source: Wood Mackenzie
Note: Average pricing for global utility-scale projects

With full-wrap contracts being avoided, vegetation management, corrective maintenance work and module washing are often excluded from the scope, despite being critical to keep solar power plants performing as expected. While these activities are very dependent on plant location and project-specific characteristics, it can roughly represent 40-45% of the project's total O&M costs.

These O&M events will eventually need to be carried out and, when contracted separately, can come at a higher price than if it had been bundled into a broader contract. Furthermore, one-off services won't be linked to any performance guarantee, increasing risks for asset owners. These guarantees on performance, availability, and/or response time benefit owners by limiting potential lost revenue. In the long run, asset owners are likely to incur more costs in with an a-la-carte service structure than if opting for an all-in service contract.

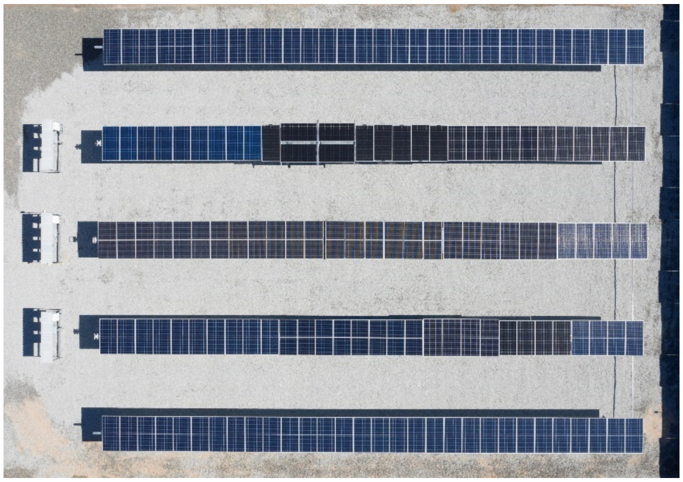
Owners and operators are therefore taking on riskier contracts blind-guided by a misleading traditional $/kW/year metric. With unplanned correctives frequently handled on an ad-hoc basis – an approach that is perceived as "money-saver" at first – typically results in higher total operating costs during the project's life span.

Utility-scale bifacial gains likely 5%-10%

CFV LABS

Bifacial modules are a definite improvement in PV module technology. But how large of an energy production improvement are they likely to be for a utility scale PV project? The exact answer depends on many factors, but test data from the CFV Labs bifacial test yard shows that answer is likely to be 5%-10% for large-scale deployments in high solar resource locations.

The picture on the left shows a drone camera shot of the CFV Labs bifacial test site in Albuquerque, NM. The site was built out with Array Technologies, Inc. single-axis trackers and custom CFV Labs instrumentation. The chart on the right shows the daily bifacial gain (incremental performance of bifacial modules over monofacial) from two different module technologies over several weeks in the test yard:



CFV Labs Bifacial Test Yard

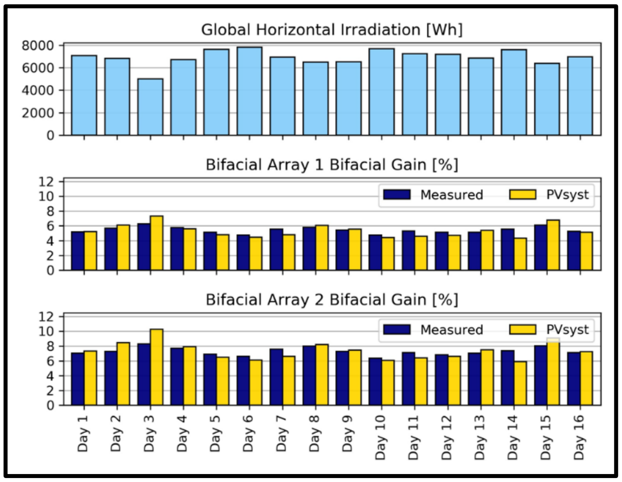


Chart courtesy of Array Technologies, Inc.

Takeaways from CFV Labs bifacial testing over the past year:

- Simulation models now have a high correlation with real-world bifacial performance. The performance chart above shows good correspondence with the PVsyst model purpose-built for the test yard. Average DC-side bifacial gains for the two arrays were around 5%-7% for this test period in our high solar resource Albuquerque, NM location. Note: this data does not include AC inverter clipping effects.
- Realistic test sites with long tracker rows show lower bifacial gains than previously reported data from smaller test sites. It is important to examine published bifacial data carefully to make sure the condition is was produced under is relevant to your application.
- Albedo is a first-order linear driver of bifacial gains. The data above was taken with an albedo of .30, which may be higher than some traditional utility-scale sites with sand, grass or soil groundcovers. Sites that experience long periods of snow cover will considerably outperform warmer climate sites during the winter season, as snow albedos can be .60 or higher.
- Bifacial gains are higher when there is a large percentage of diffuse radiation. You can see this by comparing days 3 and 6 in the chart above. However, overall irradiance and total energy production are generally lower on these days. Non-traditional low solar resource sites may exhibit higher bifacial gains but lower overall energy production than traditional high solar resource sites.
- Module technology matters. The ‘bifaciality’, or ratio of backside efficiency compared to frontside, varies widely across module technologies, from .65-.90. In the chart above, the performance difference between Array 1 and Array 2 was largely due to different module bifacialities. As always, it is important to have modules lab-tested to verify real-world versus data sheet performance.

Fix it on day 1, or pay in year 2: Diode and string anomalies are 60% more frequent after the first year of operation

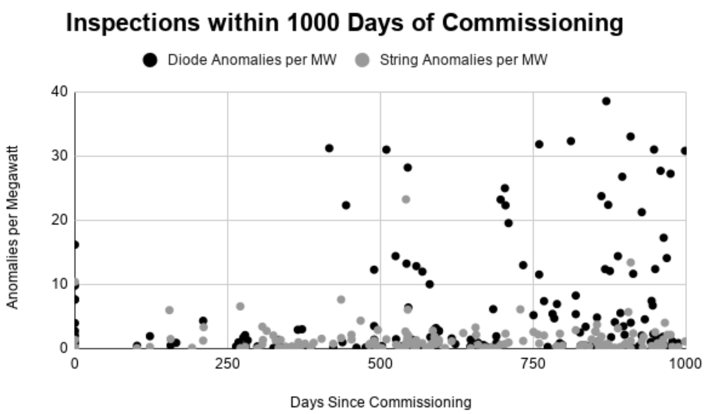
RAPTOR MAPS

Executive Summary: A transfer of risk occurs to the asset owner when a PV system is commissioned. Raptor Maps plotted a dataset of 347 aerial PV inspections, ranging from commissioning through 1000 days after Commercial Operation Date (COD). 96% of the modules were Bloomberg Tier 1. The data suggests a high level of anomalies detected at commissioning, followed by a lull in the year 1 of operation, followed by a large and sustained increase beginning in year 2.

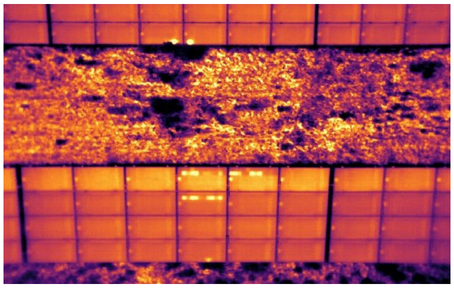
A transfer of risk occurs to the asset owner when a PV system is commissioned, which is a necessary precondition to reach the Commercial Operation Date (COD). In order to minimize performance risk and reduce the time and expense of claiming liquidated damages (LDs), detailed commissioning inspections are required by asset owners. This is also beneficial to the EPCs, which can address issues prior to demobilization, as well as asset managers and operations and maintenance (O&M), which can establish a performance baseline.

The analysis draws on a dataset of 347 aerial PV inspections across 4,723 MW of PV systems. 96% of modules inspected are Bloomberg Tier 1, representing 12 manufacturers. Inspection times ranged from commissioning through 1,000 days past the Commercial Operation Date (COD).

Higher-resolution color and long-wave infrared (thermal) imagery was collected via unmanned aerial system (UAS). Radiometric infrared data was captured at either 5.5 cm/px (typical for US preventative maintenance inspections) or 3.0 cm/px (IEC TS 62446-3:2017 compliant, typical for commissioning and warranty claims) with detector sensitivity of less than 50 mK. Flights were conducted according to a pre-programmed standard operating procedure (SOP).



Example Thermal Image of Energized System



The scatter plot illustrates two anomaly types. The “Diode” classification refers to activated bypass diodes or multiple degraded cells corresponding to a single bypass diode. The “String” classification refers to an entire string of series-connected PV modules that are offline. The x axis is days after COD, and the y axis is anomalies normalized by MW for the inspection.

Conclusion: The data show that a high number of anomalies are detected at commissioning. We observe a lull in the first year after COD in which the frequency of anomalies is lower, followed by a large and sustained increase beginning in the second year of operation. This suggests that asset owners should opt for rigorous, high-detail commissioning inspections, as unresolved issues will manifest and cause operational challenges later on.

Weaknesses in cell soldering represents nearly 25% of all quality-related defects in PV module manufacturing

PI BERLIN

PI Berlin assessed the results of quality assurance conducted on PV modules used in over 3 GW of projects between 2017 and 2020. The results were based on independent supervision of manufacturing processes conducted in-factory by PI Berlin quality engineers. Over 69 individual projects are represented with modules made by 54 different factories.

The results show that the process of connecting solar cells within a module, usually done by automated soldering equipment, has consistently been the top-quality concern (Figure 1), corresponding to 23.7% of all observed defects in 2019.

The quality of connections between solar cells is vital to the long-term energy production of a PV module. Poor soldering quality, often evidenced by poor temperature or process control, is difficult to identify in the finished module and often doesn't cause power loss until after several years in the field.

The process of assembling the various materials that make up a PV module along with the processes to reworking defective modules in the factory are the next most significant source of quality concerns being 15.1 and 12.2%, respectively. Together these top-three defects make up over 50% of all quality related observations.

In terms of trends, the largest increase in defects observed since 2017 has been in two of the three top defects (Figure 2) with cell soldering remaining the number one defect in terms of occurrence frequency. Another observed concern has been the increasing frequency of non-compliance to industry standard module certifications. The instances of materials being used that do not comply with IEC or UL certification have increased in recent years to more than 10% of all defects observed.

Production line supervision allows these types of defects to be identified earlier and then corrected 'at manufacturing source', thus preventing these defects from potentially impacting systems in the field.

Figure 1: A pareto of PV module manufacturing defects identified by production supervision for 2019 (by total number of defects identified).

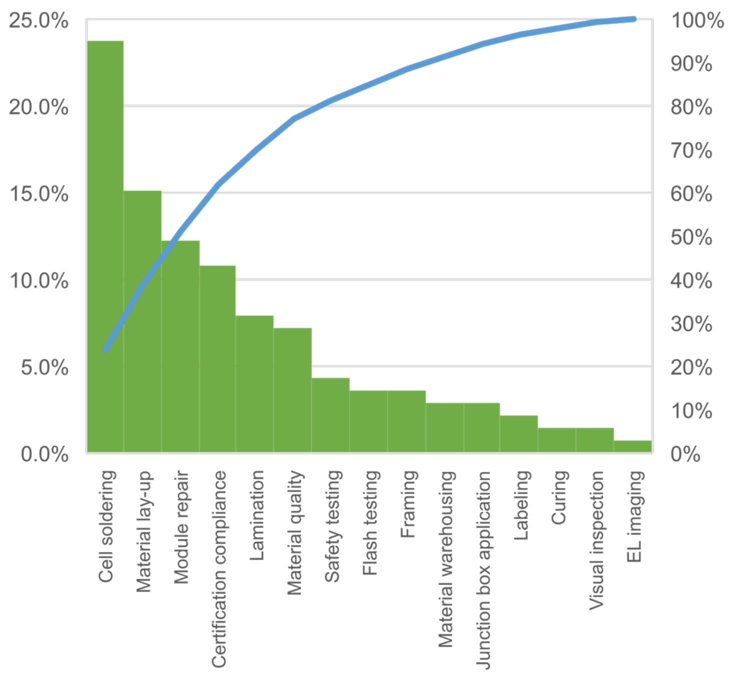
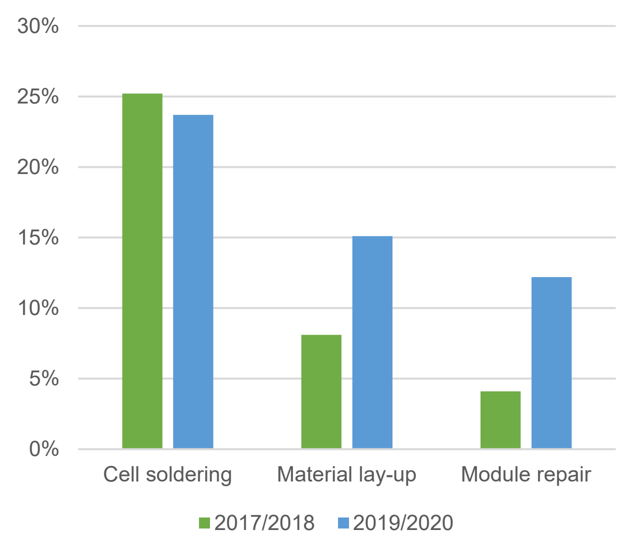


Figure 2: Occurrence trends over time for the current top three PV module manufacturing-related defects.

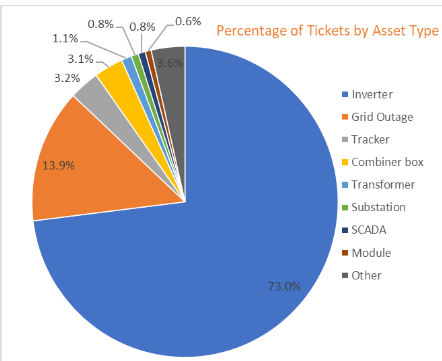


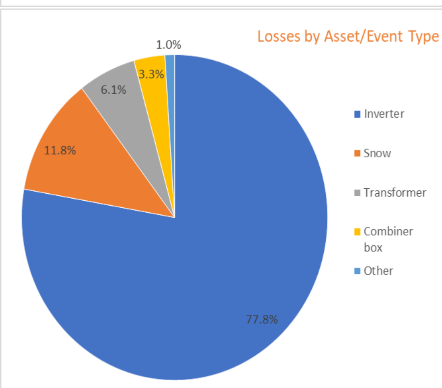
Inverters account for nearly 80% of production losses. Are they meeting your pro-forma expectation?

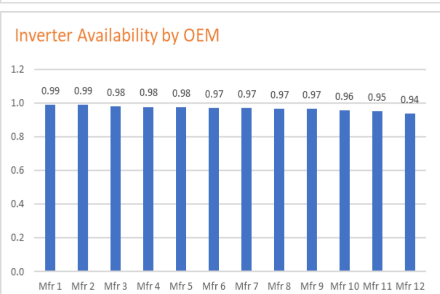
RADIAN GENERATION

Inverter failures are the single largest source of production losses on solar projects. The analysis below looks at a dataset of nearly 6,000 inverters operating at utility and commercial solar power plants across North America over the past year. This data shows 73% of performance-related plant tickets are due to inverter outages. Further analysis within the dataset reveals inverter outages accounted for almost 78% of energy production losses excluding grid-induced outages.

Inverter availability is a common metric related to performance and is the measure of an inverters' ability to generate power when the solar resource is within operating limits. While a common assumption for inverter availability is 99% in pro-forma models, actual experience can be significantly lower. The inverter availability a site experiences is based on several factors including:







String or Central Inverter Type: Failed string inverters can be wholly swapped out by the O&M provider without having to wait for a visit from the OEM technician. However, a cost-benefit analysis may reveal a single string inverter outage does not warrant an immediate truck roll and a replacement could be put off until multiple outages exist or a preventative maintenance visit is planned. Also, string inverters create a larger data networking challenge than central inverters and often experience more frequent communication outages which creates challenges discerning between data and production outages.

Staffed or Unstaffed Site: A staffed site is much more likely to achieve 99-100% availability since investigation and troubleshooting is typically included in the O&M scope and many of the outages can be resolved immediately. However, staffed facilities are more likely to have central inverters where many subcomponent failures require a visit from the OEM technician to maintain the warranty. Furthermore, the size threshold for projects able to support full-time staffing has increased dramatically as PPA prices have fallen.

OEM Response Time and Training: There is a wide variety of response times to failures from inverter manufacturers. Some manufacturers have robust remote technical support teams and qualified technicians across the country. Others can be difficult to schedule, slow to respond and, if the inverters are several years old, may have extremely long lead times on parts.

Actual Measured Availability: The chart on the left shows how actual availability differed across twelve manufacturers. Here we see the median inverter availability was 97%. Mitigation of inverter underperformance can be achieved through various means and one size will not fit all.

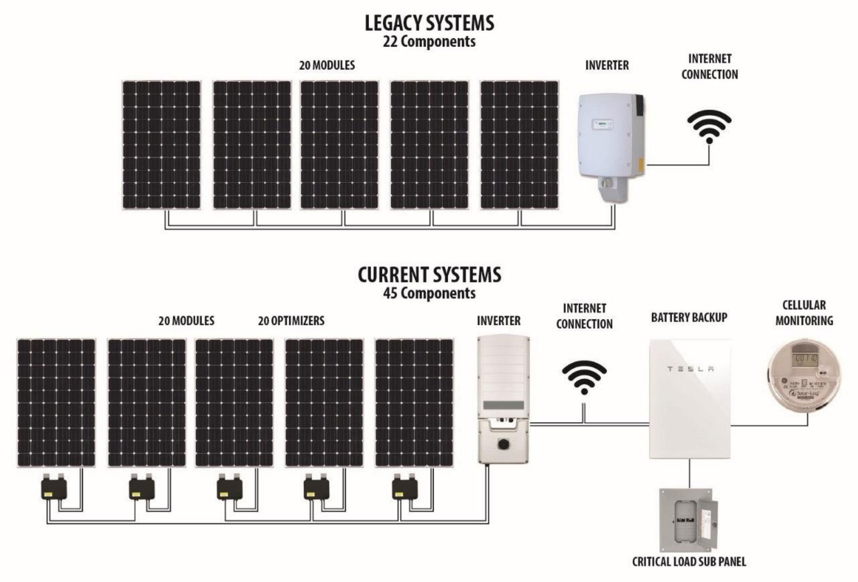
Top 5 Inverter Production Outage Mitigation Strategies:

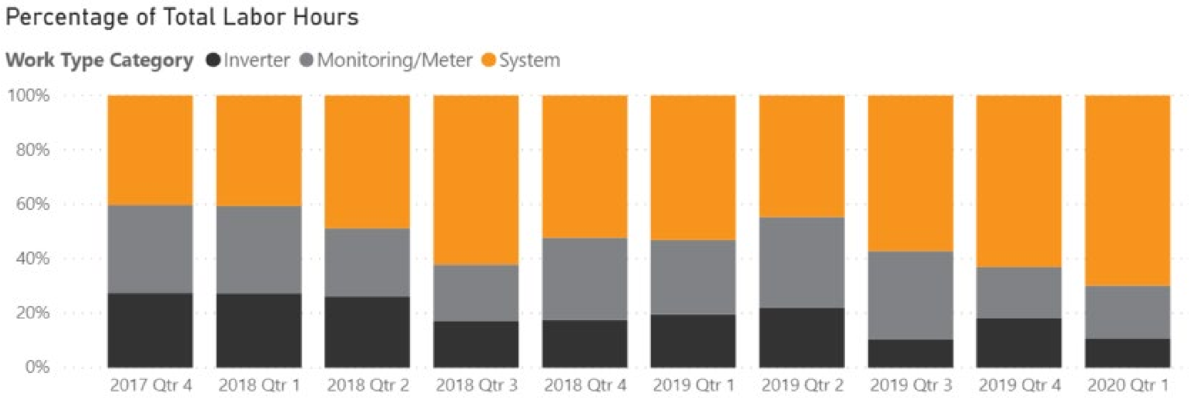
1. Choose the right OEM (equipment quality and technician response dependent).
2. Use best practices in design and installation (consider system size and type when choosing between string and central inverters, invest in robust communication and metering)
3. Ensure SLAs are in the O&M and inverter OEM agreements.
4. Choose an OEM providing training and warranty authorization for O&M teams. (Or plan on lobbying for this service.)
5. Develop and employ smart spare parts strategies that leverages operational history and plan for inverter model/manufacturer obsolescence.

Residential system complexity leads to increased service, with average component count more than doubling

SUNSYSTEM TECHNOLOGY

As technology has evolved and electrical codes have changed, the number of components in an average rooftop solar system has more than doubled, leading to increased system complexity and cost of maintenance. Where a typical residential system used to simply consist of panels and an inverter, newer systems can include panels, module level electronics, an inverter, battery storage, system controller, and a cellular-enabled meter. Many of these new devices are “smart” devices that need to be networked to each other and to the outside world. Each additional device increases the potential for failure and total cost to maintain.





In an analysis of over 110,000 work orders processed over the past 3 years, we found that the percentage of our techs’ time spent troubleshooting system components other than inverters and meters has increased by nearly 50%. At its most basic level, it is unsurprising that adding components and complexity to a system will lead to increased initial cost and maintenance expenses since every new device brings an increased risk of failure, and each “smart” device adds a microprocessor and communications equipment into the system architecture. This means that not only do you have more potential points of electrical failure, you also have a chance of processor failure or communications outage.

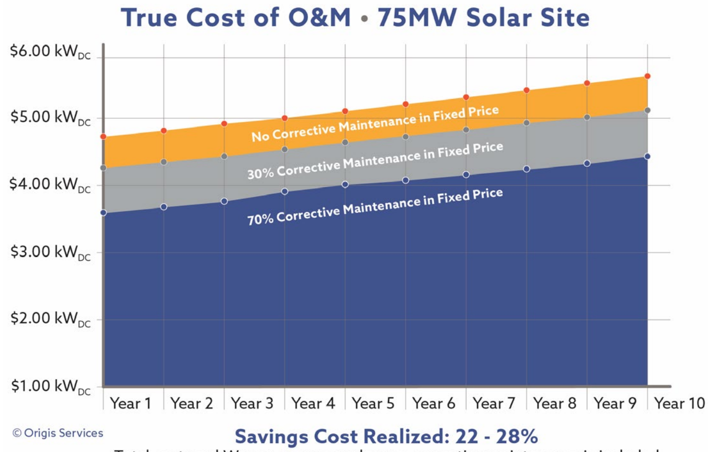
While some of these additional components have been forced on the industry by changes to the National Electrical Code as arc fault protection and rapid shutdown capabilities have been mandated to reduce risk to people and property, other components – such as battery storage – have been added to increase resiliency or provide additional revenue streams for the system owner. These are excellent reasons to add additional components, and the new equipment can provide other benefits, including reduced risk of catastrophic failure and increased monitoring granularity. However, when designing new systems, it is important to weigh the advantages of these new components against the tradeoff of not just additional upfront costs in equipment, installation, and commissioning, but also increased maintenance costs over the life of the system.

True cost of O&M can be 28% higher than planned/budgeted

ORIGIS SERVICES

Utility-scale solar Operations and Maintenance has seen a decrease in pricing over recent years. According to Wood Mackenzie Power and Renewables, "Pricing pressure continues as prices have dropped by approximately 58% in 2018 compared to just a few years ago." This decrease in O&M pricing however does not exactly translate to a lower overall cost for the asset owner.

In fact, reductions in scope of services such as included corrective maintenance services are proving to increase the overall cost for owners. To truly reduce overall O&M costs, should asset owners and service providers be advocating for additional scope of services? Data from Origis Services' operating assets suggests the true cost of O&M can be up to 28% higher than planned or budgeted if corrective maintenance is excluded from the annual scope.



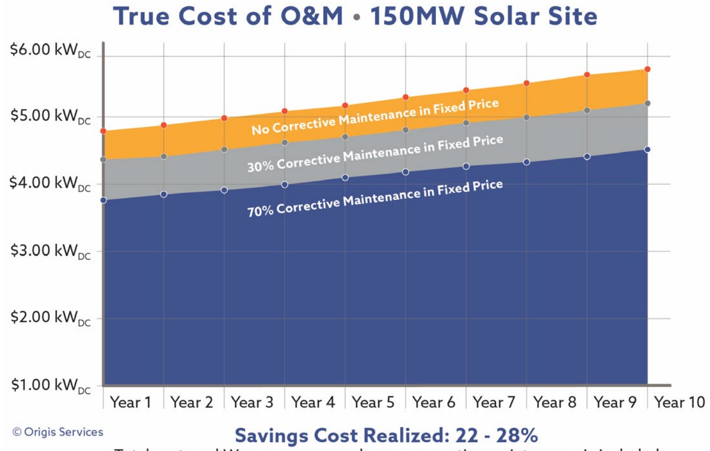
Savings Cost Realized: 22 - 28%
Total cost per kW year over year when no corrective maintenance is included in fixed rates compared to 30% or 70% of corrective maintenance included.

To meet market pricing pressures, one of the major scope items often removed or decreased in a service contract is the included corrective maintenance. Asset owners have accepted this reduction in scope, resulting in lower annual O&M fees. In aggregate, however, this reduction in scope increases the risk for the asset owner and, in fact, results in more costly corrective maintenance overall.

The result of removing corrective maintenance from the annual scope causes higher rates to the owner when corrective maintenance services are needed. Although this may seem like a profit-maker for the O&M provider, it produces a variable level of service hours needing to be dispatched to the site. This is a costly model for both the service provider and the asset owner, resulting in an inconsistent business model for the provider and a higher price for the owner.

By including a strategic level of corrective maintenance hours into the annual service fee, the O&M provider can more accurately predict staffing needs for the plant. Dedicated, on-site staff can then service most corrective maintenance tasks in tandem with the preventive maintenance scope and other needs of the site.

Data from the Origis Services portfolio, combined with industry standard time studies and pricing models, demonstrate including roughly 70% of corrective maintenance into the annual service fee is the most effective way to reduce overall O&M costs for the asset owner.



Savings Cost Realized: 22 - 28%
Total cost per kW year over year when no corrective maintenance is included in fixed rates compared to 30% or 70% of corrective maintenance included.

In summary, including corrective maintenance in the scope of service reduces the exposure to high-priced, dispatched services and provides additional benefits of dedicated plant personnel. This strategy decreases the overall cost of O&M for asset owners by up to 28% or more and enhances the service-model stability of O&M providers, thus reducing the overall cost of O&M.

“Weather Adjustment Bias” responsible for up to 8% bias in measured underperformance

KWH ANALYTICS

Executive Summary: The industry often incorrectly measures weather impact on a solar site by relying on two separate weather files when calculating actual versus expected insolation. Asset owners typically rely on on-site pyranometers for actual insolation, but they rely on Independent Engineer satellite TMY file for expected insolation. This approach causes “Weather Adjustment Bias” because pyranometer and satellite weather files each carry their own biases.

This bias occurs because both pyranometer and satellite report insolation (W/m^2) based on their respective calibration, which introduces significant sources of error:

- **Calibration Errors** - Pyranometers are unreliable, requiring regular and expensive recalibration.
- **Temperature and Snowfall Impacts** - Current methods often do not account for temperature or snowfall.
- **Non-weather, Operational Impacts** - Pyranometer readings misreport non-weather, operational impacts. For example, kWh Analytics has identified inaccurate weather-adjustment readings for sites during high wind events. In these instances, the plant operator stowed panels to reduce risk of damage, and the reduction in insolation due to non-optimal tilt is reported as a weather event instead of an operational intervention.
- **“Irradiance Shopping”** - As discussed by DNV in this report, weather satellite file selection can exacerbate this issue.

Consequently, the typical weather adjustment calculation that compares two different measurement tools (Pyranometers vs. TMY) introduces significant bias. Weather Adjustment Bias is a classic “apples-to-oranges” problem.

Figure 1 demonstrates the difference when comparing pyranometer to two satellite products in the market today. A comparison of the pyranometer readings to satellite product 1 indicates a weather factor adjustment of 11% on a plane of array, W/m^2 basis. The same pyranometer readings compared to satellite product 2 would indicate a weather factor adjustment of 1%. While picking an accurate weather file is important, comparing the pyranometer to the satellite TMY inherently results in an inaccurate assessment.

Figure 1: Annual Satellite POA

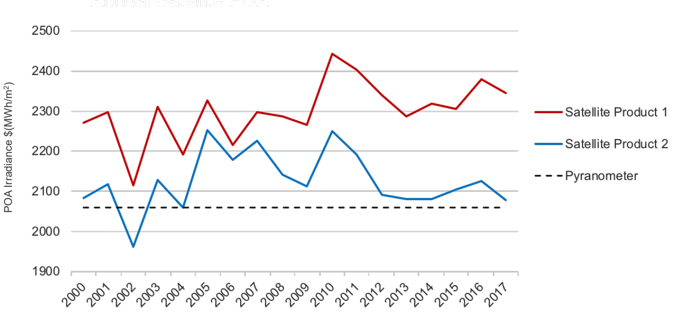
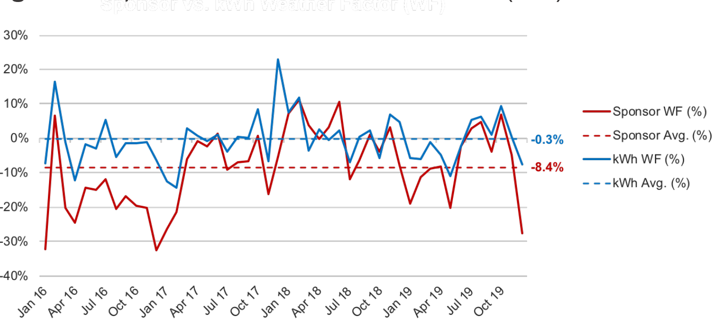


Figure 2: Sponsor vs. kWh Weather Factor (WF)



Weather Adjustment Bias is solved by referencing a single source of weather data. kWh Analytics uses this approach in its automated weather model, requiring basic system metadata (e.g. tilt and azimuth) and a single irradiance dataset to measure the insolation resource at the site against the long-term historic average. The result removes the bias through an “apples-to-apples” comparison. This approach sets a superior baseline for weather-adjusted performance which then guides both O&M and financial decisions.

While this calculation can be computationally intensive, the impact is significant. To quantify the difference between the two approaches, kWh Analytics compared the industry’s current “apples-to-oranges” methodology to an automated weather model. kWh Analytics found that Weather Adjustment Bias overstated weather-related energy losses by up to 8% for utility-scale sites. Figure 2 compares the two weather adjustment methodologies at the same site.

Contributors

kWh Analytics: kWh Analytics is the market leader in solar risk management. By leveraging the most comprehensive performance database of solar projects in the United States (20% of the U.S. market) and the strength of the global insurance markets, kWh Analytics' customers are able to minimize risk and increase equity returns of their projects or portfolios. Website

DNV GL: DNV GL is a global quality assurance and risk management company. Driven by our purpose of safeguarding life, property and the environment, we enable our customers to advance the safety and sustainability of their business. Website

NextEra Analytics: NextEra Analytics offers renewable energy consulting services using industry-leading scientific analysis for planning, siting, forecasting and optimizing renewable energy projects. Our customers include NextEra Energy businesses and North American renewable energy and electric utility industries. Website

Clean Power Research: Clean Power Research has delivered award-winning cloud software solutions to utilities and industry for more than 20 years. Our PowerClerk®, WattPlan® and SolarAnywhere® product families allow our customers to make sense of and thrive amid the energy transformation. Website

Wood Mackenzie Power & Renewables: Wood Mackenzie Power & Renewables delivers actionable insight into the state and the future of the global electricity sector, from wind and solar to power markets and grid edge technology. Wood Mackenzie research is backed by exclusive relationships with industry partners, proprietary models, and an ever-expanding executive network. Website

CFV Labs: CFV Labs is a leading solar laboratory located in Albuquerque, New Mexico. We offer market leading R&D, testing and analytical services to the PV community across the supply chain. We are dedicated to Powering Renewable Innovation by improving the performance, cost and reliability of PV technologies. Website

Raptor Maps: Raptor Maps is the leading provider of software and aerial inspection services across the solar lifecycle. Its products range from IEC-compliant inspections of operating systems to active construction monitoring. Raptor Maps has serviced 20 GW of solar PV in 34 countries across 1,900 utility-scale and C&I PV systems. Website

PI Berlin: PI Berlin provides expert technical diligence, procurement and quality assurance services for a wide range of solar integrators, developers, utilities, banks and investors worldwide. We enable our clients to manage risk associated with PV equipment by independently verifying quality, reliability and performance. Website

Radian Generation: Radian Generation provides technology enabled asset management solutions and advisory services to developers and owners of renewable energy power plants with a focus on risk management and optimal portfolio performance. Website

SunSystem Technology: SunSystem Technology (“SST”) is a diversified national solar services company, delivering unparalleled expertise to the nation's distributed generation infrastructure. We provide safe, professional, and reliable operations and maintenance services enabling the growth of C&I (Commercial and Industrial) and Residential renewable energy sectors. Website

Origis Services: Origis Services delivers the promise of clean energy with operations and maintenance (O&M) and asset management services for solar and energy storage across North America. A wholly owned subsidiary of Origis Energy, Origis Services manages a diverse utility scale and distributed generation project portfolio utilizing one of the industry’s largest Remote Operations Centers located at its headquarters in Austin, Texas. Website