Abstract—In this work, we demonstrate that partial shading of one solar cell in a state-of-the-art monocrystalline photovoltaic module with three bypass diodes results in hot cells with critical peak temperatures of 164°C. We examine two solar modules in the IEC 61215-2 MQT 09 hot-spot endurance test, one with 367.3 Wp featuring 72 full-cells and the other with 388.6 Wp featuring 144 half-cells. For the solar module with 72 solar cells, we measure a maximum temperature of 164°C, which results in a degradation of the encapsulation material and increases the risk of solar module failure. The high temperature results from the hot cell effect due to the power dissipation in the reverse-biased solar cell caused by partial shading. Our experiments show that the half-cell solar module is advantageous in terms of solar cell shading compared to the full-cell solar module. Although the half-cell solar module has a higher power output than the full-cell solar module, we measure a cooler peak temperature of 150°C. However, under certain shading conditions, the half-cell solar module can exhibit similar temperatures as the full-cell solar module. Based on our experimental results, we develop an electrical and a thermal model to predict the temperature of novel high-power solar modules with solar cells from larger silicon wafer formats in case of partial cell shading. Our predictions consider the trends of further increasing solar cell and module efficiencies, larger silicon wafer formats, and larger solar modules. We simulate a maximum peak temperature of 176°C at the solar module’s surface, which significantly increases the risk of solar module failure. Our results show that new high-power solar modules employing solar cells that are made from larger silicon wafer formats need a new protection against overheating. Three bypass diodes per solar module are no longer sufficient.

Index Terms—Breakdown characteristics, hot cells, solar module reliability.

I. INTRODUCTION

CURRENT mismatch due to cell cracks or partial shading of solar panels may result in reverse biasing of solar cells within a photovoltaic (PV) module. Instead of generating, the reverse-biased solar cells dissipate power and generate heat, which can irreversibly damage the solar cell and module [1]–[4]. In the past, this was especially a problem for multicrystalline silicon (mc-Si) solar cells due to their local junction breakdown [5], [6]. The local junction breakdown results in a localized heat generation, which is also known as hot-spot effect [7]. Hence, many studies have investigated this effect for mc-Si solar cells and developed electrical and thermal models to simulate the effect of partial shading of PV panels with mc-Si solar cells [8]–[13].

However, today more than 60% of the solar cells employ monocrystalline silicon (c-Si) solar cells, which are expected to increase in market share [14]. In contrast to multicrystalline solar cells, monocrystalline solar cells have a higher breakdown voltage and a homogeneous blocking characteristic. Kim and Krein showed that reverse biasing monocrystalline solar cells results in an evenly distributed heat generation in the solar cell resulting in temperatures well below 100°C [15]. These c-Si solar cells are therefore less prone to hot-spot failure. Thus, it is essential to distinguish between mc-Si solar cells with local junction breakdown and localized heat generation, resulting in high local temperatures (hot-spots) and c-Si solar cells with a homogeneously distributed heat generation. Additionally, today solar cells are pretested by many PV module manufacturers during the manufacturing process and solar cells with local defects vulnerable to hot-spots are rejected [16]–[18]. Furthermore, solar modules have to pass the hot-spot endurance test according to the IEC 61215-2:2019 MQT 09 standard for the certification [19].

In general, state-of-the-art solar modules employ three Schottky bypass diodes as a protection against overheating. The diodes limit the reverse voltage of a partially shaded or cracked solar cell in the PV module and, thus, mitigate the risk of overheating [20]. There also exist advanced mitigation techniques based on integrated circuits [21]–[23], multiple bypass diodes per substring [24], [25], and module level power electronics [26]. However, 95% of the commercially available c-Si solar modules employ three bypass diodes [14]. The application of three bypass diodes requires no complex wiring or additional components, such as multiple diodes or transistors, making this a low cost and reliable configuration. Thus, this configuration is predicted to be the mainstream for the next ten years [14]. It is therefore the industrially established overheating mitigation technique for state-of-the-art solar modules and has caused few problems in the past for PV modules with homogeneously blocking c-Si solar cells.

Advances in recent years have improved the solar cell and module efficiency with passivated emitter and rear cells (PERC) becoming the new standard in terms of mass production and resulting in high-efficiency PV modules with module powers exceeding 350 Wp [14], [27]. Some tier 1 solar module manufacturers even announced modules with 500 Wp and more for 2020 [28], which will also increase the dissipated power...
of reverse-biased solar cells. Kim and Krein showed that in case of 24 c-Si solar cells per string connected to a bypass diode, a significant amount of power is dissipated in a partially shaded solar cell, which may damage the PV module components. Nevertheless, the study showed no experimental results with solar modules exceeding critical temperatures or thermal modeling. Qian et al. compared half- and full-cell solar modules in theoretical and experimental studies [29], [30]. They also showed that half-cell solar modules are beneficial in the event of partial shading, since they exhibit lower temperatures during hot-spot experiments. The authors also reported on a phenomenon that during the experiment, solar cells in the nonshaded string became hot due to reverse biasing, though their work omits worst-case experiments and they examine only a single string with 16 full-cells and 32 half-cells, which is less than for state-of-the-art PV modules with 20, 24, or more full solar cells per bypass diode.

The most critical developments that further exacerbate the hot-spot issues are as follows.

1) Continuously improving solar cell and module efficiencies [14], [31].
2) Larger silicon wafer formats that are pushing into the market since they potentially reduce production costs [14], [27], [32]. This also increases the area and the current of the solar cells, which in turn increases the dissipated power at reverse bias.
3) The trend toward bifacial PV modules, which also increases the solar cell current and results in various inhomogeneous illumination cases for solar modules [33].
4) The increasing number of solar cells per module, which consequently increases the number of solar cells per bypass diode.

In this work, we investigate two state-of-the-art full-sized PV modules and show that already today, the three bypass diodes interconnection in half-cell solar modules can result in local module peak temperatures above 150°C. We investigate the reverse bias characteristics of state-of-the-art PERC solar cells that show a homogeneous blocking characteristic and result in a uniform heating of the cell. Therefore, we avoid the terminology of hot-spots and denote these solar cells as hot cells in the following. Based on our solar cell and module measurements, we develop an electrical and a thermal model to predict the solar cell and module temperatures of novel high-power PV modules with three bypass diodes and solar cells from larger silicon wafers. We further employ the electrical model to elucidate the effect of reverse biasing of only marginally shaded solar cells in half-cell solar modules.

II. EXPERIMENTAL METHODOLOGY

A. Measuring the Cell Parameters for the Electrical model

We measure the illuminated, dark, and $I_{SC} - V_{OC}$ current-voltage ($I(V)$) characteristics of 100 bifacial industrial c-Si PERC solar cells employing a LOANA measurement system [34]. Each PERC solar cell has an area of $(156.75 \times 156.75) \text{ mm}^2$ and features five busbars at the front and rear side. We model the $I(V)$ data with the double-diode model using the SCAN software [35]. Furthermore, we measure the reverse $I(V)$ characteristics of six PERC solar cells with a Neonsee solar cell analysis system [36]. This allows for $I(V)$ measurements down to $-40 \text{V}$. In this work, we limit the reverse current to $-5 \text{A}$ for all our reverse $I(V)$ measurements. The temperature-controlled brass chuck for the rear contact maintains $25^\circ \text{C}$ during the measurement and also allows measurements at elevated temperatures. We measure the reverse $I(V)$ characteristics of one solar cell for a varying temperature $T$ of $(25,35,\ldots,75)^{\circ} \text{C}$ to determine the temperature coefficient for the breakdown voltage.

B. Tested Solar Modules

We examine two solar modules with PERC solar cells that are similar to the cells in Section II-A. Each PERC solar cell features five cell interconnection ribbons on the front and rear side for the series interconnection of the cells. The cell-to-cell and the string-to-string spacing in each PV module is 3 mm.

Figure 1(a) shows a sketch of PV module M72 featuring 72 full PERCs with $(158.75 \times 158.75) \text{ mm}^2$. The solar module consists of six strings, each string containing 12 solar cells in series connection. The three red colored diodes at the top of the solar module indicate the three bypass diodes, each in a split-junction box on the module’s rear side. On the front and rear side, the PV module employs a 3-mm-thick glass. The red labels in Fig. 1(a) indicate the solar cells we test in the IEC 61215-2 MQTT 09 test. For all measurements, we attach a black foil to the rear side to avoid measurement artifacts due to the bifacial properties of the module.

Figure 1(b) shows a sketch of PV module M144 featuring 144 half PERCs with $(158.75 \times 79.38) \text{ mm}^2$. The solar cells
are equal to the cells in module M72 but cut into half-cells to reduce the module’s series resistance losses [37]. The red labels in Fig. 1(b) indicate the solar cells we test in the IEC 61215-2 MQT 09 test and the white labels denote the cell numbering. The PV module consists of two submodules in parallel connection, with the top submodule M144-T holding all solar cells from 1 through 72 and bottom submodule M144-B holding all solar cells from 73 through 144. The red-colored diodes in the center indicate the split junction boxes with the bypass diodes. Each bypass diode is connected antiparallel to a double string of submodule M144-T and M144-B. In contrast to M72, this solar module features a 3-mm-thick front glass and a white-colored polymer backsheet.

C. Solar Module Characterization

We measure the illuminated \( I(V) \) characteristics of the solar modules with a HALM flasher system under standard testing conditions. Additionally, we also measure the \( I(V) \) characteristics for an irradiance of 800 Wm\(^{-2}\) and 600 Wm\(^{-2}\) to determine the modules’ series resistance [38]. Subsequently, we determine four solar cells of M72 in accordance to the IEC 61215-2:2019 MQT 09 test [19]. The IEC 61215-2:2019 MQT 09 test, also known as hot-spot endurance, evaluates the durability of PV modules when individual solar cells are partially shaded.

Within the flasher system, we fully shade each solar cell of module M72 with an opaque cover (cardboard) and measure the module’s \( I(V) \) characteristics to determine the solar cells for the IEC 61215-2 MQT 09 test [19]. Cells 1, 49, and 72 are the solar cells with the lowest shunt resistance and cell 17 the cell with the highest shunt resistance. Subsequently, we determine the worst-case shading scenario for these cells in accordance with IEC 61215-2 MQT 09.1 f)-3) [19].

For PV module M144, we only consider solar cell 1 of submodule M144-T and solar cell 73 of submodule M144-B. Both solar cells are adjacent to the same bypass diode, as illustrated in Fig. 1(b). We determine the worst-case shading scenario, similar to the solar cells in M72.

After the IEC 61215-2 MQT 09 test in the steady-state sun, we remeasure the \( I(V) \) characteristics of the PV modules. Furthermore, we measure the ultraviolet (UV) fluorescence of the module using our fluorescence inspection system [39].

D. IEC 61215-2 MQT 09 Testing

Figure 2 shows a picture of solar module M72 in our steady-state sun simulator for the IEC 61215-2 MQT 09 test [19]. The halogen reflector lamps of the sun simulator illuminate the examined PV modules with an average irradiance intensity of 925 Wm\(^{-2}\). The illumination homogeneity is 3.5% measured with a UniformSun module [40]. The solar panel is mounted horizontally to the ground. A transparent temperature-controlled plate between the module and the light source creates an artificial cool sky with a temperature of 23°C. During the test, we measure the average PV module temperature at the positions of the unshaded solar cells with four thermocouples on the rear side of the module. An air conditioning unit maintains an ambient temperature of 22°C. The rear side of the PV module is cooled with an airflow to maintain a module temperature of (50 ± 10)°C. We measure an average wind speed of (0.24 ± 0.14) ms\(^{-1}\) at the rear side with a hot-wire anemometer. In addition, we monitor the irradiance in the PV module plane with two thermopile pyranometers during the test.

Before shading the individual solar cells, we measure the short-circuit current of the module in the steady-state sun simulator employing a current clamp. We shade each solar cell in module M72 with the worst-case shading fractions, as determined according to the IEC standard [19]. During the test, we measure the temperature with a Fluke Ti32 infrared camera [41]. For module M144, we start with shading only cell 1 of submodule M144-T and subsequently additionally shade cell 1 and cell 73 of submodule M144-B simultaneously.

III. MODELING METHODOLOGY

A. Electrical Modeling

We model the forward \( I(V) \) characteristics of the solar cells and modules with the double-diode model in SPICE network simulations. For the reverse \( I(V) \), we use the model of Ruiz and Garcia [42] and Alonso-Garcia and Ruiz [43]

\[
I = \frac{I_{SC} - G_{sh}V - eV^2}{1 - \exp\left(\frac{B_e V}{\sqrt{V_T(\Phi_T - V) / (\Phi_T - V)}}\right)}
\]

Here, \( G_{sh} \) is the shunt conductance, \( e \) is a parabolic term for the reverse \( I(V) \) characteristics, \( B_e \) is a quasi-constant parameter, \( \Phi_T \) is the built-in junction potential, and \( V_B \) is the breakdown voltage. In this work, we consider a constant \( \Phi_T \) of 0.850 V and that \( I_{SC} \) is 0 since we measure the reverse \( I(V) \) characteristics in the dark. We assume ideality factors of 1 and 2 for the first and second diode, respectively. For the bypass diodes, we consider a saturation current of 1 nA and an ideality factor of 1.

First, we model the \( I(V) \) characteristics of the PERC solar cell measurements to extract average cell parameters for the solar module simulations. Subsequently, we use these parameters to model the measured \( I(V) \) characteristics of the unshaded solar module M72 considering equal parameters for all 72 solar
B. Thermal Modeling of the Solar Modules in the IEC 61215-2 MQT 09 Test

We perform three-dimensional finite element modeling (FEM) employing COMSOL Multiphysics to simulate the solar module temperature in the IEC 61215-2 MQT 09 cell shading test [44]. Our model considers a PV module with $3 \times 3$ solar cells. Figure 3 shows a cross-sectional sketch of the thermal model. The solar cells are embedded between two layers of ethylene vinyl acetate (EVA) with a front-side glass and a rear-side backsheet. The rear-side backsheet is either a glass for module M72 or a polymer backsheet for module M144. In the simulation, we also account for the solar cell interconnection with five cell interconnection ribbons. The copper ribbons have a width of 1 mm and a thickness of 200 $\mu$m. Furthermore, we consider the aluminum (Al) frame with a width of 1 cm. Table I lists the individual material parameters we take from Vogt [45] and thicknesses of each component.

The arrows in Fig. 3 indicate the heat flux we consider in our thermal model. We consider all solar cells as a heat source such that the simulated module temperature corresponds to the average PV module temperature as measured in the IEC 61215-2 MQT 09 test. For the shaded solar cell in the middle, we consider an additional heat source with a power dissipation according to our electrical model. In the thermal model, we simulate steady-state conditions, i.e., the heat generation of a solar cell is in thermal equilibrium with the external environment due to conduction, convection, and radiation [46]. For further details of the thermal model, we refer to the Appendix.

IV. EXPERIMENTS RESULTS AND DISCUSSION

A. Reverse $I(V)$ Characteristics of State-of-the-Art PERC

Figure 4 shows the reverse $I(V)$ characteristics of six PERC cells. All solar cells show a homogeneous blocking characteristic with a breakdown voltage below $-20$ V. Table II summarizes the average parameters we extract from modeling our solar cell measurements with the double-diode model and the breakdown model. These average parameters are required as initial parameters for the modeling of the solar modules.

We measure a linear temperature dependence of the breakdown voltage for all currents below $-0.3$ A of

$$V_B(T) = \beta T - 25.8 \text{V}$$  (2)
where $T$ is the solar cell temperature in degree Celsius and $\beta$ is the temperature coefficient, which is $-0.02 \, \degree \text{C}^{-1}$ for our measurements. The negative $\beta$ of $-0.02 \, \degree \text{C}^{-1}$ indicates that the breakdown characteristic is a typical avalanche breakdown due to high local electric fields. In contrast, a positive temperature coefficient would imply a local junction breakdown via energy states in the band gap due to defects, which typically occurs at low reverse bias [47]. From the cell measurements, we deduce that all PERC cells of the modules M72 and M144 have similar reverse bias characteristic with a high breakdown voltage and a homogeneously blocking p-n junction. Thus, we conclude that the cells heat up homogeneously in the IEC 61215-2 MQT 09 test and that the heat generation is evenly distributed over the cell area. We therefore refer to the IEC 61215-2 MQT 09 test as a cell shading test, since we do not observe any hot-spots for the tested solar cells.

### B. Results of the Solar Module Characterization and the IEC 61215-2 MQT 09 Cell Shading Test

Table III lists the modules’ power output at the maximum power point (MPP) $P_{MPP}$, short-circuit current $I_{SC}$, open-circuit voltage $V_{OC}$ as well as the current $I_{MPP}$ and voltage $V_{MPP}$ at MPP, and the modules’ series resistance $R_S$. Table IV lists the shading fraction for each solar cell we apply in the IEC 61215-2 MQT 09 cell shading test. Furthermore, the table shows the peak temperature $T_{PM}$ we measure during the IEC 61215-2 MQT 09 test with an infrared camera. For the temperature evaluation, we use a surface emissivity $\varepsilon_s$ for the glass of 0.9 [48]. The uncertainty of the camera is $\pm 2 \, \degree \text{C}$ according to the manufacturer. The orientation of the camera differs for each solar cell from the normal of the module to avoid additional shading effects by the camera during the cell shading test. Therefore, we also consider the directional emissivity to estimate the uncertainty of the temperature measurements [49], [50]. We determine the view angle of the camera for each solar cell and consider the values of Pantinakis and Kortsalioudakis [49] as a worst-case estimation. Table IV lists the peak temperatures and their uncertainties for the shaded solar cells in the PV modules M72 and M144.

All examined solar cells heat up homogeneously and reach temperatures above 140 $\degree \text{C}$. Cell 1 in module M72 exhibits a peak temperature of 164 $\degree \text{C}$. Cells 49 and 72 are cooler than cells 1 and 17 in M72, which is due to the positioning of the cover. Cell 49 and 72 heat up homogeneously during the IEC 61215-2 MQT 09 test, and thus, we position the cover in the center of the cell. For solar cell 1 and 17, one cell side appears cooler with the cover positioned at the cell’s center. Therefore, we shift the cover to the cooler cell side according to IEC 61215 MQT 09 [19]. Note that the difference in temperature between each side is only approximately 5 $\degree \text{C}$ without showing local hot-spots.

For module M144, we position the cover at the cell edge, since in this case, we observe higher temperatures for the solar cells in M72. We measure a 10 $\degree \text{C}$ lower peak temperature for the half-cell solar module, when shading only cell 1. Shading solar cells 1 and 73 simultaneously in module M144, we measure a peak temperature of 159 ± 4 $\degree \text{C}$. In this case, both cells in the center of the PV module and the adjacent bypass diode (cf. Fig. 1) generate heat. Due to the localized heat sources, this results in a similar peak temperature as for the full-cell module M72.

Figure 5 shows the fluorescence image of solar module M72. Solar cells 1, 17, 49, and 72 appear brighter than the other cells of the module except in the areas where we apply the cover stripes to the cells during the IEC 61215-2 MQT 09 test. For solar cells 49 and 72, the cover is in the center and for solar cells 1 and 17, at the edge of the cell. Morlier et al. showed that heat induces the decomposition of the encapsulation polymer and the reaction products tend to fluoresce in the fluorescence image [39]. This fluorescence correlates with the yellowing of the encapsulation materials, which results in a reduction in PV module power. Furthermore, the degradation of the encapsulation material increases the risk of module failure [51].

All examined solar cells heat up homogeneously without showing local hot-spots. According to our reverse $I(V)$ measurements, the state-of-the-art PERC solar cells have an average breakdown voltage of $-26.3 \, \text{V}$ (cf. Table II and Fig. 4). In the tested modules, one bypass diode is in parallel to $N_c = 24$ solar cells. Even when considering the average $V_{OC}$ of the cells of 665.5 mV and a bypass diode with a forward voltage $V_{FP}$ of 0.6 V,
the maximum reverse bias \( V_{rev} \) of a shaded cell is about \(-16\) V. Hence, the cells operate far away from their breakdown voltage and effectively block the current of the other solar cells within the string (cf. Fig. 4). Nevertheless, the solar cells operate at negative voltage and, thus, dissipate power. Due to the homogeneously blocking solar cells, the heat generation is evenly distributed over the entire active cell area.

Therefore, we suggest the terminology of hot cells in case of multicrystalline PERC solar cells instead of hot-spots as it is typical for multicrystalline solar cells. Our results show that the risk of failure due to hot cells is larger for state-of-the-art PV modules with 72 full-cells than for modules with half-cells. Furthermore, we measure significantly higher temperatures than reported in the past for modules with less than 72 solar cells [30]. This is due to the increasing solar module efficiency, the higher current for each of the module’s solar cells and the larger number of cells per string in the module. In comparison to the full-cell module design, the half-cell module design shows 10°C lower peak temperatures when shading one solar cell. However, shading two neighboring half-cells from two parallel connected strings in a half-cell module results in similar module peak temperatures in terms of measurement uncertainty as shading one full-cell in a full-cell solar module.

Our measurements show that module M72 already operates at a critical temperature due to the hot cell effect with cell 1 reaching peak temperatures of 164°C. The fluorescence image reveals that even maintaining the test conditions for 1h already damages the PV module’s encapsulation polymer. Temperatures above 150°C may result in a yellowing and embrittlement of the encapsulation material [11], [52]. Accumulated over the lifetime of a PV module, this reduces the module’s power output and increases the risk of module failure. Temperatures of 170°C may lead to bubbles and deformation of the backsheet material or even to a detachment of the junction box [11]. Furthermore, the hot cell temperature should not raise above the solder temperature. The liquidus temperature of Sn63Pb37 solder is at 183°C and for lead-free solders around 220°C. Above this temperature, leaching of the silicon metal may occur [53], resulting in solder joint failures. Temperatures close to the solidus intermetallic phase can also weaken the solder joint [54]. Hot cells may also increase the risk of glass breakage due to temperature gradients in the glass of novel high-power solar modules.

V. Modeling Results and Discussion

A. Modeling the \( I(V) \) Measurements of the PV Module With Varying Cell Shading

Figure 6 shows the measured and the modeled \( I(V) \) characteristics for solar cell 1 in M72 for a varying shading fraction \( S \). The symbols indicate the measurement and the solid lines indicate the modeling data. For a better illustration, Fig. 6 only shows every fifth measurement value. The red dashed line ( \( S = 0 \% \)) indicates \( I_{MPP} \) of the unshaded PV module. The shading fraction \( S \) corresponds to the geometrical size of the opaque covers we apply to the cell in the flasher measurements. The worst-case condition is encountered when the current of the shaded solar cell is equal to \( I_{MPP} \) of the PV module before the bypass diode starts conducting. In Fig. 6, this is the case for a shading fraction \( S \) of 25%.

For the modeling, we use the values in Table II as initial parameters. The parameters in Table II are the average fit parameters for the double-diode model for the individual PERC cell measurements. Table V lists our parameters to model solar cell 1 in module M72.

- Our electrical model allows to determine the dissipated power in a partially shaded solar cell. For cell 1 in module M72, we simulate a dissipated power of 95W. When shading more than one solar cell, the cells share the dissipated power, which results in lower temperatures during the IEC 61215-2 MQT 09 cell shading test.

Table IV shows that this is not the case when shading two adjacent solar cells, each from another submodule in M144. In this case, both cells are reverse-biased and generate heat. If the solar module operates at \( I_{SC} \) as is required for the IEC 61215-2 MQT 09 test, the worst-case shading scenario is similar for both cells.

B. Modeling a Half-Cell Module in a PV System

This worst-case shading scenario changes when considering a realistic scenario with an inverter holding the shaded solar module at the MPP of the unshaded solar modules in a PV system. Figure 7 shows the modeling results for three shading scenarios for module M144. The symbols indicate the operating point of each solar cell, which corresponds to the MPP of the PV system.
In Fig. 7(a), we simulate the unshaded module, in Fig. 7(b), we shade solar cell 1 in submodule M144-T by 23%, and in Fig. 7(c), we simultaneously shade solar cell 1 in submodule M144-T by 23% and solar cell 73 shaded by 5%. Each graph in Fig. 7 shows the $I(V)$ characteristics of the following.

1) Cell 1, representing a shaded solar cell in submodule M144-T with 23% shading in Fig. 7(b) and (c).
2) Cell 12, an unshaded solar cell in the same string as cell 1 in submodule M144-T.
3) Cell 73, a shaded solar cell in submodule M144-B with 5% shading in Fig. 7(c).
4) Cell 84, an unshaded solar cell in the same string as solar cell 73 in submodule M144-B.
5) Cell 144 in submodule M144-B, a solar cell in an adjacent string without shaded solar cells. The $I(V)$ characteristic of this solar cell is equal to solar cell 74 of submodule M144-T.

6) The $I(V)$ characteristic of the bypass diode that is parallel to the string with solar cell 1 and solar cell 73.

In Fig. 7(a), the PV module is unshaded and all solar cells are at the same operating point. The shading of solar cell 1 by 23% reduces the current of this cell in Fig. 7(b). The inverter of the PV system holds all solar modules at the operating point, which is similar to the MPP of an unshaded module in case of a large system with 20 modules. Due to the reduced current, the operating point of solar cell 1 shifts in the negative voltage range and the cell dissipates 57 W. This solar cell also limits the current of all other solar cells in the string and thus, the operating point of solar cell 12 shifts to a higher voltage to generate the same current as solar cell 1. Cell 144 is still at the same operating point as in the unshaded PV module in Fig. 7(a) and generating the same current. According to Kirchhoff’s law, the sum of the currents of the parallel strings holding cell 1 and cell 73 has to be identical to the sum of the parallel unshaded strings with cell 144 and 74. Hence, the operating point of solar cell 73 in submodule M144-B shifts to a lower voltage and the cell generates a higher current. This also applies to all solar cells in this string represented by solar cell 84 in Fig. 7(b). Due to the shift to a lower voltage, cell 73 operates close to the short-circuit operating point. Thus, only a small shading fraction of 5% is necessary to force cell 73 into reverse bias in Fig. 7(c). Both solar cells dissipate power in Fig. 7(c) with cell 1 dissipating 57 W and cell 73 dissipating 49 W.

In Fig. 7(a), we simulate the unshaded module, in Fig. 7(b), we shade solar cell 1 in submodule M144-T by 23%, and in Fig. 7(c), we simultaneously shade solar cell 1 in submodule M144-T by 23% and solar cell 73 shaded by 5%. The symbols indicate the operating points.

Figure 1(a) shows that cell 1 and cell 73 are neighboring cells. If both solar cells are shaded, e.g., by a leaf or bird droppings, both cells dissipate a power of 106 W, which results in similar heat generation as in a full-cell module according to our measurements results in Table IV. Furthermore, only a mismatch of 5% is necessary for reverse biasing the second solar cell. Thus, production-related current mismatch of the individual solar cells and inhomogeneous front- and rear-side illuminations [55] can trigger this event. Nevertheless, the parallel connection of two submodules in the half-cell module design reduces the risk of overheating, since only the solar cells in the center of the PV module create such a local heat generation. In contrast, in a full-cell module, each cell may dissipate this power.

C. Thermal Modeling of a Solar Module in the IEC 61215-2 MQT 09 Cell Shading Test

Figure 8(a) shows a blended image of the thermal and the visual images of cell 1 measured during the IEC 61215-2 MQT 09 cell shading test. The peak temperature at the module surface is 164 °C. Figure 8(b) shows the modeling of the same hot cell with a peak temperature of 166 °C. For the heat source of the unshaded solar cells, we assume a power of 18 W, which results in a temperature of 55 °C at the module surface. This agrees with the measured average PV module temperature in the IEC 61215-2 MQT 09 test. For the unshaded parts of the partially shaded solar cell, we use an additional heat source employing the dissipated power from our electrical model. Our thermal model allows a qualitative remodeling of the experimental results within the
D. Temperature Prediction for New High-Power Solar Modules

We employ our electrical and thermal model to simulate the module peak temperature in seven scenarios for novel high-power solar module developments. As initial input parameters, we employ the $I(V)$ characteristics of module M144. All area-dependent parameters scale with the cell and module size. For the electrical model, we consider a constant shading fraction and a module temperature of $55\,^\circ\text{C}$ in each scenario. All scenarios consider a shading ratio $S$ of 25%. In this study, we consider the following scenarios summarizing our simulation results for the scenarios.

i) Verification of the experimental results with the half-cell module M144.

Table VI summarizes our simulation results for the scenarios.

We start in scenario i) with remodeling the experimental results of the IEC 61215-2 MQT 09 test for module M144. The simulated solar module has an output power $P_{\text{MPP}}$ of 388.6 W under STC and the cell efficiency inside the module $\eta_{\text{cell}}$ is 21.6%. The power dissipation of the shaded solar cell is 52 W. In this case, our FEM simulation results in a module peak temperature $T_{\text{P,M}}$ of 152 $^\circ\text{C}$, which is within the measurement uncertainty of our experiment (cf. Table IV). The FEM simulation also allows to determine the peak temperature at the solar cell’s surface $T_{\text{P,C}}$, which is 159 $^\circ\text{C}$ in scenario i).

Increasing the irradiance from 925 W/m$^2$ to 1000 W/m$^2$ increases $T_{\text{P,M}}$ to 160 $^\circ\text{C}$. In scenario iii), we assume that current and voltage contribute equally to improving the efficiency by 0.5%, which increases the module’s peak temperature at the surface to 163 $^\circ\text{C}$. Increasing the silicon wafer format to
M6 in scenario v) results in $T_{PM}$ of 165°C in the IEC 61215-2 MQT 09 test. This temperature is similar to the temperature in the IEC 61215-2 MQT 09 test for the full-cell module M72. Thus, employing the M6 wafer format for half-cells in a solar module with 144 cells and three bypass diodes can result in critical temperatures for the encapsulation material by partial shading of one cell in a substring.

For further increasing silicon wafer sizes, we consider fewer solar cells per string in scenario vi) or reducing the cell area by one-third in scenario vii). Both scenarios result in a similar PV module power of 487 Wp. However, using 15 solar cells per string increases the reverse biasing of the shaded solar cell and results in a power dissipation of 86 W. This results in the highest module peak temperature of 176°C in our simulations. According to our simulation, the module with M12 half-cells in scenario vi) exhibits a lower module peak temperature due to hot cells. However, the PV module’s $I_{SC}$ of 17.8 A is challenging for the bypass diodes. In the case of a fully shaded cell, the bypass diode has to conduct the current of the unshaded solar cells, which significantly increases the power dissipation in the bypass diode for the rear side of the module, as determined in our experiments.

One solution to address the hot cell issue is to employ fewer solar cells per bypass diode as in scenario vii). Figure 9 shows a sketch of a half-cell module with 144 PERC from M6 silicon wafers featuring six bypass diodes. A similar concept was already proposed by Qian et al. [56]. In contrast to their approach, we suggest an interconnection where the cell interconnection ribbons are aligned parallel to the short solar cell edge, since this reduces series resistance losses [37]. Considering the PV module layout in Fig. 9 with the same parameters as in scenario v) with M6 wafer format and using six bypass diodes reduces the power dissipation in the shaded solar cell to 29 W. This results in the solar module peak temperature of 110°C in scenario vii), which prevents an overheating of the module due to hot cells.

VI. CONCLUSION

We examine the reverse $I(V)$ characteristics of state-of-the-art monocrystalline c-Si PERC solar cells. All solar cells in this study are homogeneously blocking at reverse bias with high breakdown voltages below ~20 V. In the tested PV module with 24 solar cells per bypass diode, these homogeneously blocking cells result in an evenly distributed heat generation of the solar cells during the IEC 61215-2 MQT 09 cell shading test. Thus, we introduce the terminology of hot cells.

Our experimental results show that commercially available high-efficiency solar modules with 72 full-cells reach peak temperatures of 164°C due to the hot cells effect. This is a critical temperature since the lamination material and the backsheet are typically designed for maximum permanent temperatures of 150°C. The UV fluorescence images reveal that maintaining the test conditions for 1 h already damages the module’s encapsulation polymer. Our simulation scenarios show that new high-power PV modules with solar cells from larger silicon wafer formats reach peak temperatures of 176°C, which further increases the risk of module failures due to hot cells.

Our experimentally verified electrical and thermal model shows that half-cell modules are advantageous compared to full-cell modules in terms of partial cell shading. In our experiment, the half-cell module is cooler than the full-cell module, although it has a 21 W higher module power output. Half-cells are thus advantageous due to the larger perimeter to area aspect ratio. Similarly, the increasing silicon wafer format affects this aspect ratio, which results in higher PV module temperatures for modules employing solar cells with larger wafer formats.

In the past, three bypass diodes per module were sufficient for a solar module with low output power and featuring monocrystalline solar cells from M2 wafer formats. Our results show that highly efficient solar modules with 72 cells or more, which are larger than the M6 wafer format, require new techniques to mitigate hot cells. Neither a presorting of solar cells with low reverse breakdown voltage nor the application of DC-DC converters per module or replacing the conventional diodes with active bypass diodes will solve the hot cell problem for the next generation of high-efficiency PV modules. Considering that we test the solar modules only according to the IEC standard, particularly the higher current of bifacial PV modules will result in even higher module temperatures in the event of current mismatch compared to monofacial solar modules. Thus, also the IEC 61215-2 MQT 09 standard needs to be adjusted for bifacial high-efficiency modules with half-cells made from larger silicon wafers.

A solution to address the hot cell issue is to employ fewer cells per bypass diode, e.g., using six bypass diodes as in scenario vii). Employing module level power electronics to operate each substring at the individual MPP [26] or at open circuit in case of shading [57] offer alternative possibilities to mitigate hot cells.

APPENDIX

THERMAL MODEL

In the thermal model, we simulate steady-state conditions, i.e., the heat generation of a cell $q_{cell}$ is in thermal equilibrium with the external environment due to conduction, convection, and radiation [46]

$$q_{cell} = -k\nabla^2 T + q_{rad} + q_{con}$$  \hspace{1cm} (3)

where $k$ is the thermal conductivity, $T$ is the temperature, and $q_{rad}$ and $q_{con}$ are the heat flux by radiation and convection, respectively. The radiation heat flux $q_{rad}$ is given by

$$q_{rad} = \varepsilon_s \sigma (T^4 - T_s^4)$$  \hspace{1cm} (4)

where $T_s$ is the temperature of the surrounding surfaces, $\sigma$ is the Stefan Boltzman constant, and $\varepsilon_s$ is the surface emissivity of the glass and backsheet. For $T_s$, we consider the temperature of the artificial sky $T_{sky}$ for the front side and the ambient temperature $T_{amb}$ for the rear side of the module, as determined in our experiments.

For the convection term, we use

$$q_{con} = h (T - T_{amb})$$  \hspace{1cm} (5)
We consider natural convection at the front side with a heat transfer coefficient
\[ h_{\text{natural}} = \frac{k}{L} \frac{0.15 \text{Ra}^\frac{1}{3}} \] (6)
and a laminar forced convection flow on the rear side
\[ h_{\text{forced}} = \frac{2k}{L} \frac{0.337\text{Pr}^\frac{1}{3} \text{Re}^\frac{1}{3}} \] (7)
Here, \( L \) is the area over perimeter ratio of the module, \( k \) is the thermal conductivity, \( \text{Pr} \) is Prandtl’s number, \( \text{Re} \) is Reynold’s number, and \( \text{Ra} \) is Rayleigh’s number.

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