NREL
NATIONAL RENEWABLE ENERGY LABORATORY

2017 NREL Photovoltaic Reliability Workshop

Technical Monitor: Sarah Kurtz

February 28 – March 2, 2017
Lakewood, Colorado

NREL/PR-5J00-68942

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

NREL's PHOTOVOLTAIC (PV) MODULE RELIABILITY WORKSHOP (PVMRW) brings together PV reliability experts to share information, leading to the improvement of PV module reliability. Such improvement reduces the cost of solar electricity and promotes investor confidence in the technology—both critical goals for moving PV technologies deeper into the electricity marketplace.

NREL's PVMRW is unique in its requirement that all participating organizations share at least one presentation (either oral or poster). This requirement greatly increases information sharing: If everyone shares a little information, everyone takes home a lot of information.

In 2017, the PVMRW was held in Lakewood, Colorado, February 28 – March 2. Workshop participants shared more than 100 presentations and posters, covering topics such as cracked cells, nameplate ratings, bankability, and power electronics.

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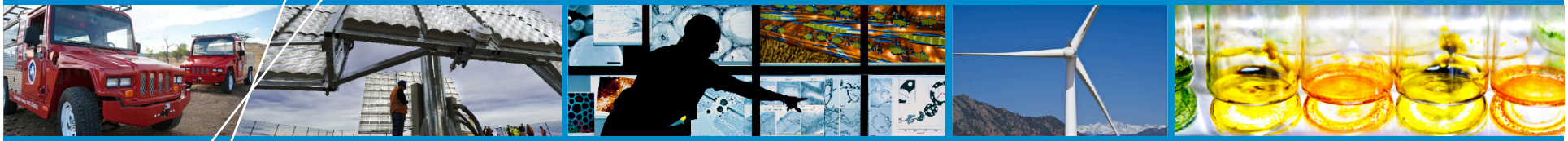
Changes in observed PV failure & degradation modes



PV Reliability Workshop

Lakewood, CO

Dirk Jordan, Tim Silverman, Sarah Kurtz, John Wohlgemuth, Kaitlyn VanSant

2/28/2017

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Outline

- Definitions: failure - degradation
- Failure rates
- Degradation modes
- Changes in the last 10 years
- “New” degradation modes

Why study literature?

Great overview of the aggregated knowledge of the PV community
but determination of trends from literature can be difficult:

1. Unknown quality of modules/systems/installation
2. Many factors may influence failure/degradation modes and often they are not clearly documented
3. Inconsistent use of reporting terminology
4. Misidentification
5. Synergy of degradation modes: often multiple modes can be seen in single module/system

Failure ↔ Degradation

Definition of failure: IEC 60050-191

"Failure is the termination of the ability of an item to perform a required function"

What does that mean for PV module?

Failure ↔ Degradation

Definition of failure: IEC 60050-191

"Failure is the termination of the ability of an item to perform a required function"

What does that mean for PV module?

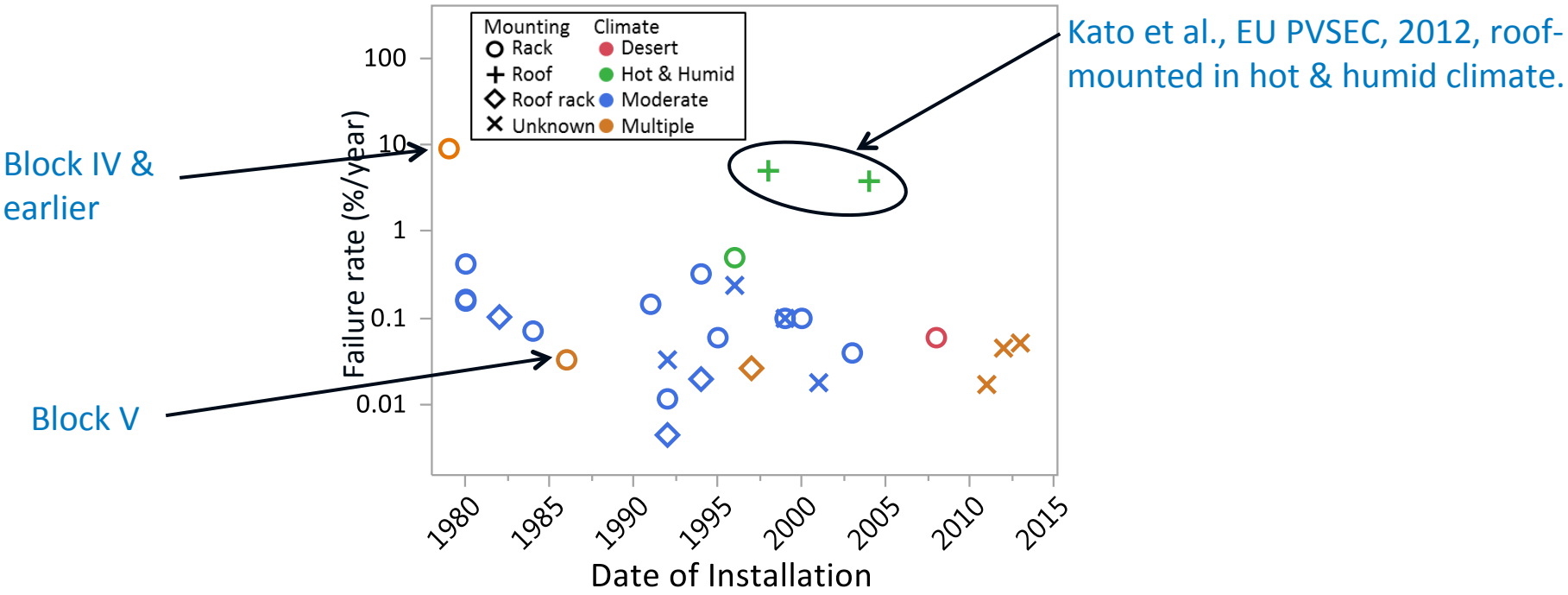
Several different definitions of PV "failures" have been used!!

1993: EPRI: power decline > 50% that cannot be repaired in field
2014: IEA: modules undergoing irreversible changes
Maybe: Modules that default on warranty, which warranty?

Failure rates need to take into account field exposure

Failure rates are typically not reported, failure ratios are reported.

Define failure as modules that required replacement.



Expected failure rate 5 out of 10,000 modules annually

Jordan et al., *Progress in PV*, 2017

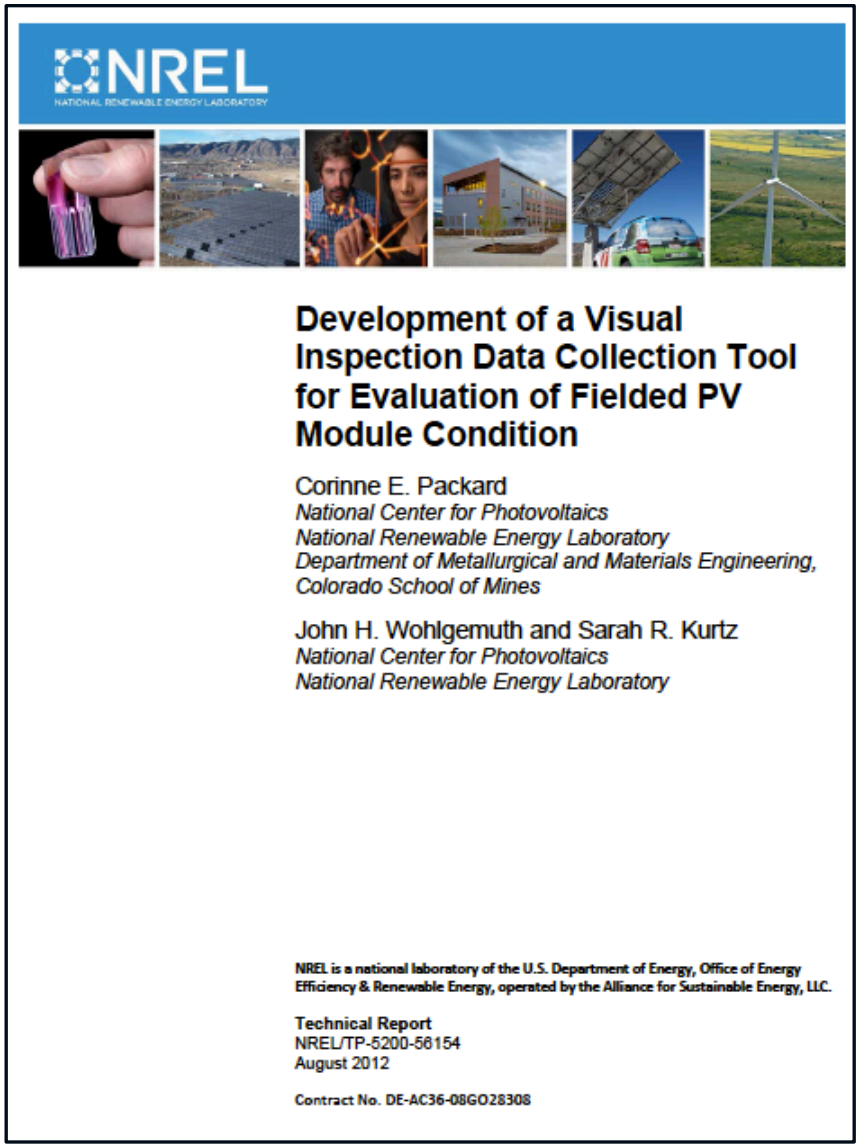
Visual Inspection Tool is not as widely used as we'd like

- Uses IEC/UL standard terminology
- Balance collection of sufficient detail for degradation mode evaluation against minimizing recording time per module
- Consists of 14 sections- based on module component
- Short & long version available

Example: front glass

Polverini et al. , Prog in PV, 2012.

Visual inspection could help discriminate between these cases



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Development of a Visual Inspection Data Collection Tool for Evaluation of Fielded PV Module Condition

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Technical Report
NREL/TP-5200-56154
August 2012

Contract No. DE-AC36-08GO28308

How can we be more quantitative?

Risk priority number (RPN) = No. reports*No. affected modules * Severity * ~~Detectability~~

Severity	Rating
Major impact on power & safety	10
Major impact on power	8
Significant impact on power	5
Slight deterioration of performance	3
No effect on performance	1

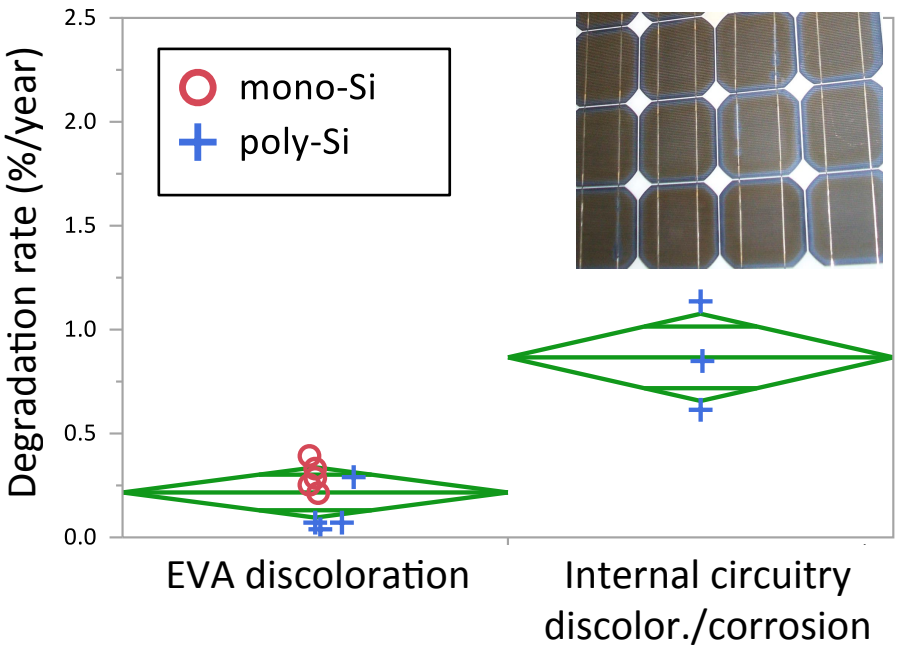
For better discrimination the scale is not continuous

Mode	Severity
Backsheet insulation compromise	10
Hot spots	10
Internal circuitry (IC) failure	8
PID	8
Major delamination	5
Internal circuitry (IC) discoloration	5
Fractured Cells	5
Diode/J-box problem	5
Glass breakage	5
Encapsulant discoloration	3
Frame deformation	3
Permanent soiling	2
Minor delamination	1
Backsheet other	1

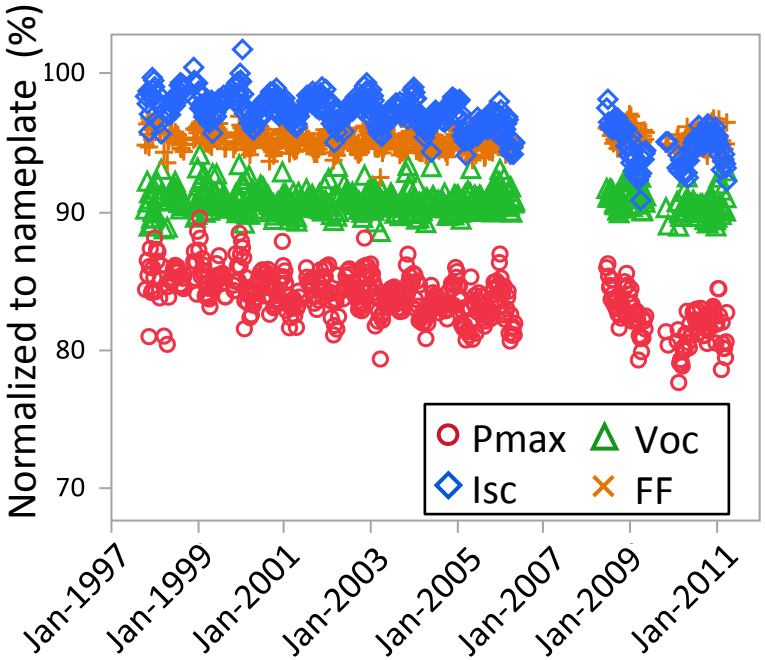
Synergy of degradation modes often make it difficult to determine the power impact of a specific degradation mode.

Kuitche et al., *JPV*, 2014

Encapsulation discoloration associated with small power loss



Jordan, et al., 35th PVSC, Honolulu, HI, USA, 2010.

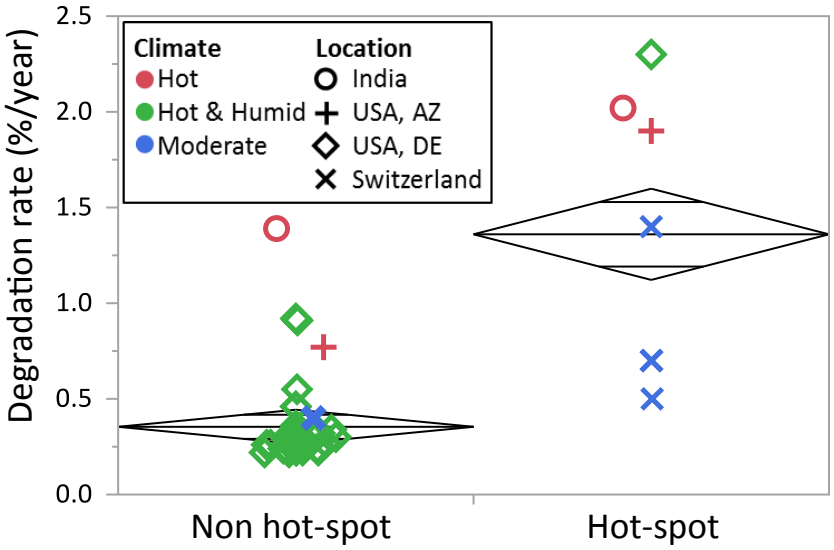


Encapsulant discoloration associated with lower power loss in direct comparison.

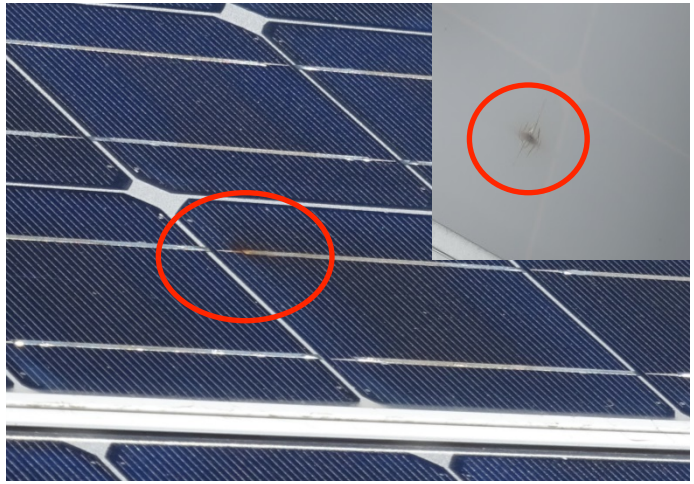
Encapsulant discoloration shows linear decline below 0.5 %/year, dominated by Isc losses.

Smith et al., *WREF* 2012

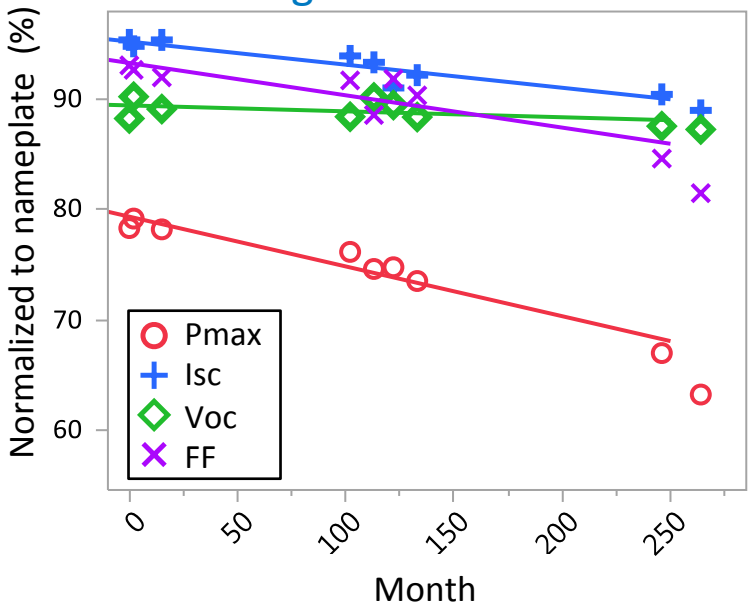
Hot-spots lead to larger power loss & pose safety issue



Internal circuitry (IC) failure due to solder bond



String IV measurements

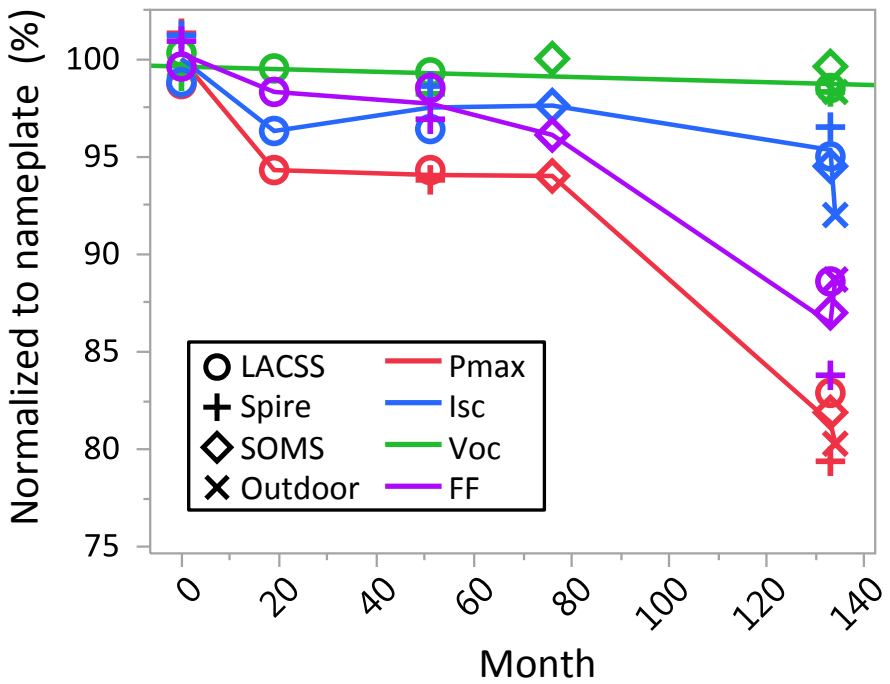


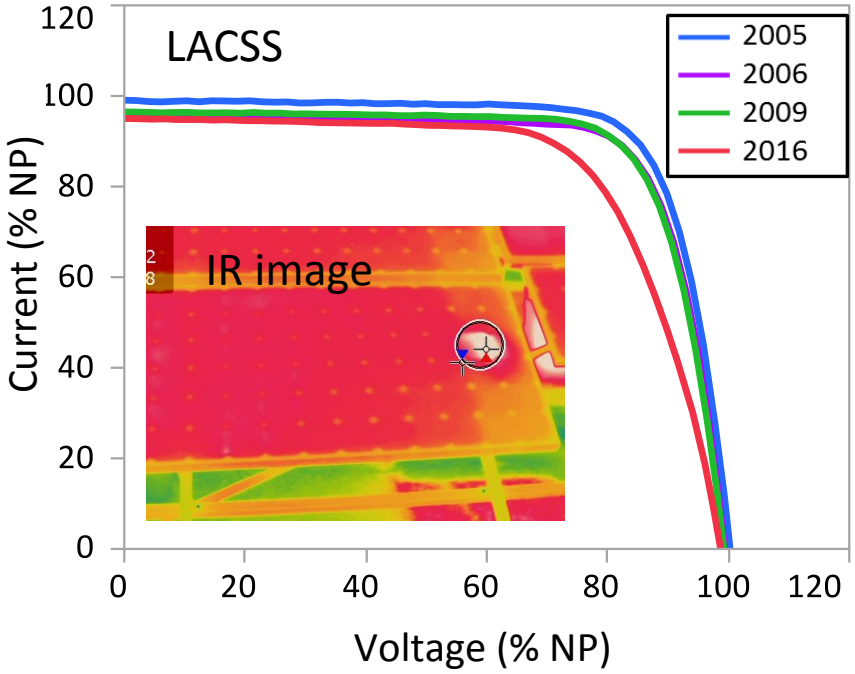
The first 20 years decline appears to be around 0.5 %/ year.

More rapid decline associated with FF loss.

Hot spot because of cracked cell causing non-linearity

I-V measurements





LACSS: large area solar simulator
Spire: indoor flash tester
SOMS: standard outdoor measurement system
Outdoor: Daystar field measurements

- Module was stable for several years
- Now we see more precipitous decline associated with FF losses, Rs increase

Jordan et al., *Progress in PV*, 2016

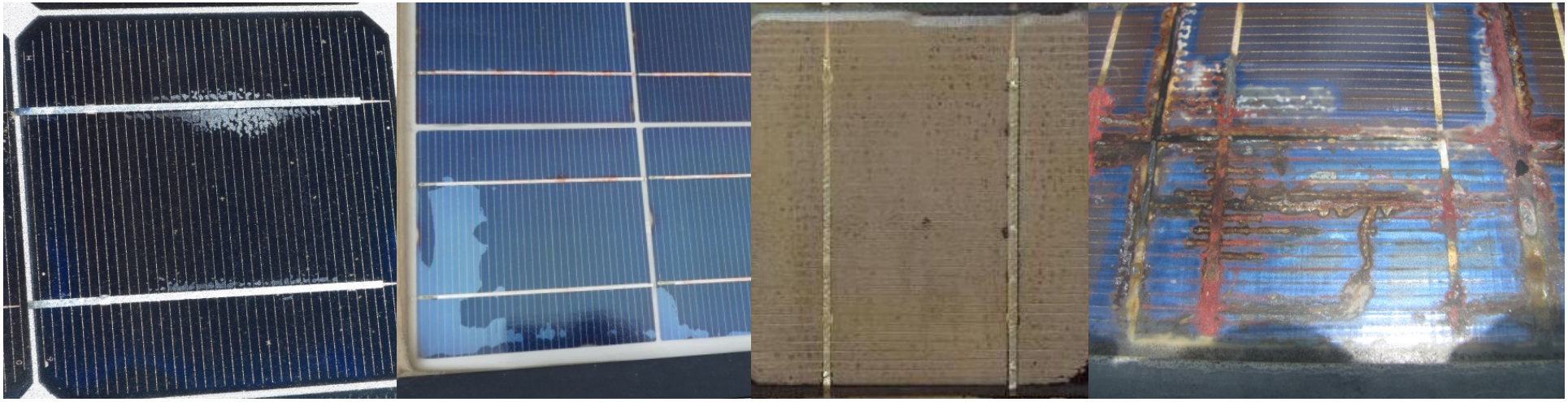
Delamination can have different impact

Initial stages

More advanced stages

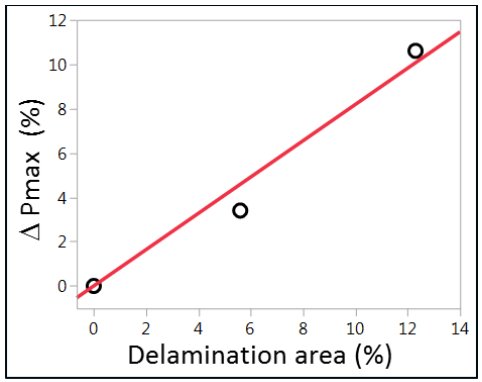
Encapsulant/Si

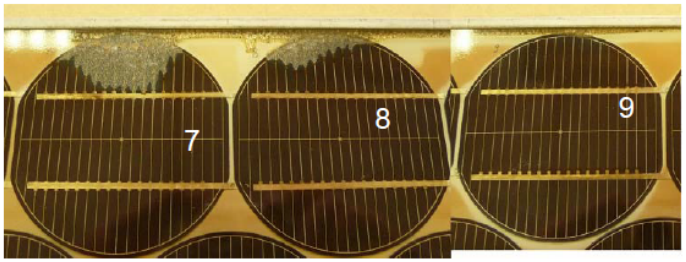
Glass/encapsulant



Skoczek et al., *Progress in PV*, 2009

Before moisture ingress & corrosion delamination appears to scale with affected area, dominated by Isc losses

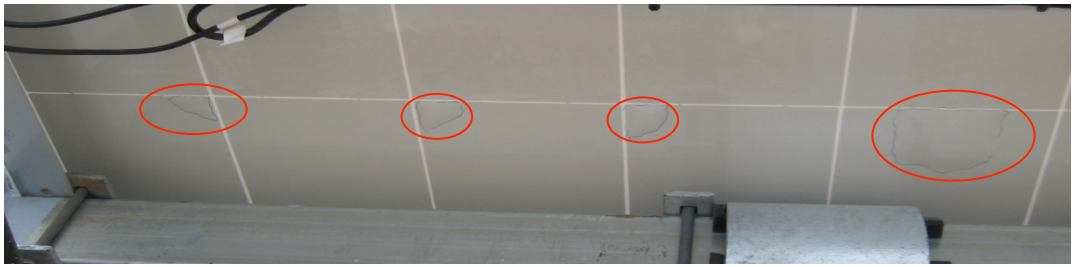




Friesen et al., PVMR, 2011

Backsheet issues can have different impact

Minor issues

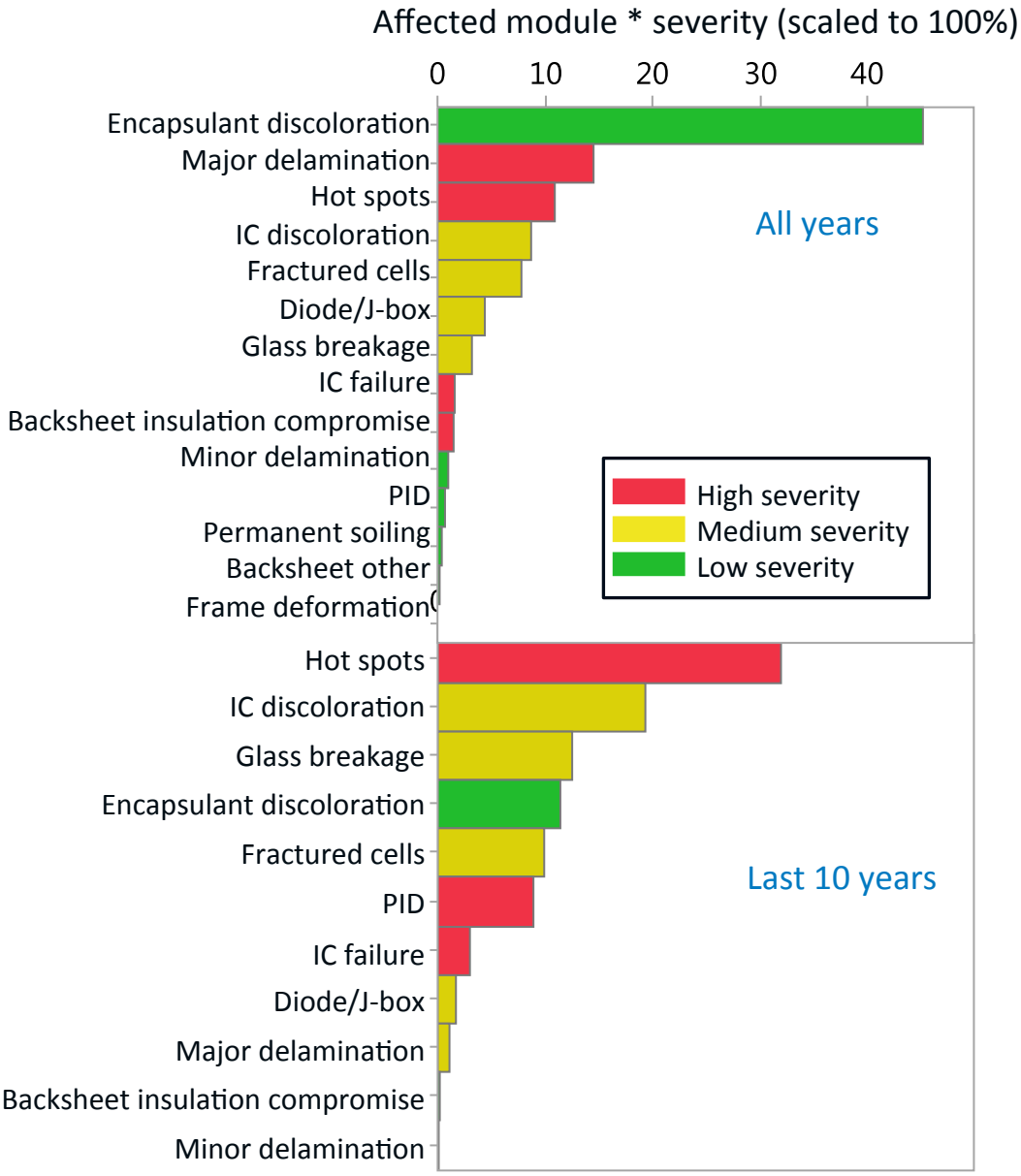


deGraaff et al. , PVMR, 2011

Major problem

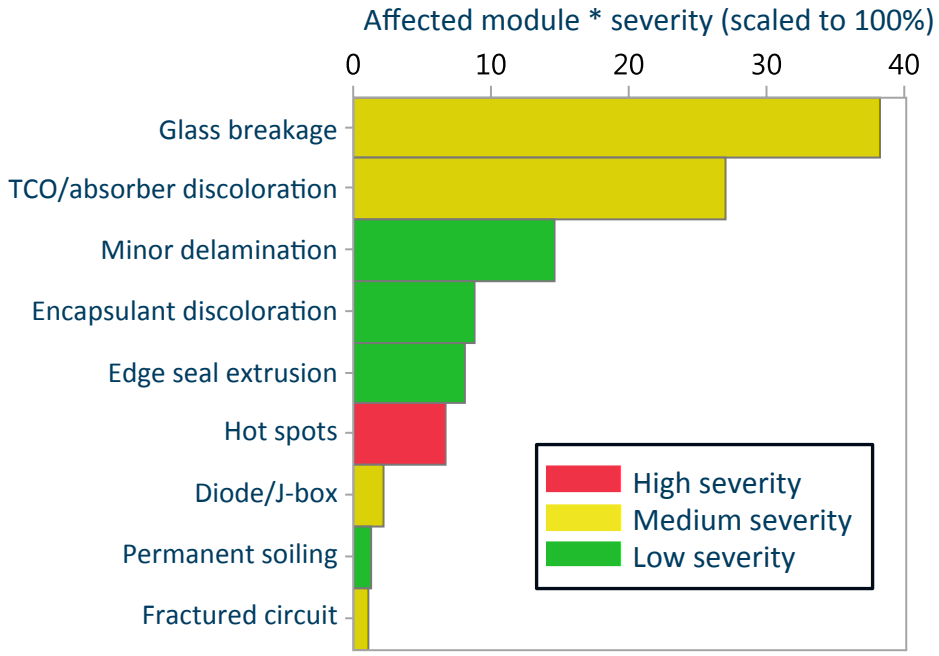
Mani et al. , PVSC, 2014

Hot-spots most common degradation mode in recent years



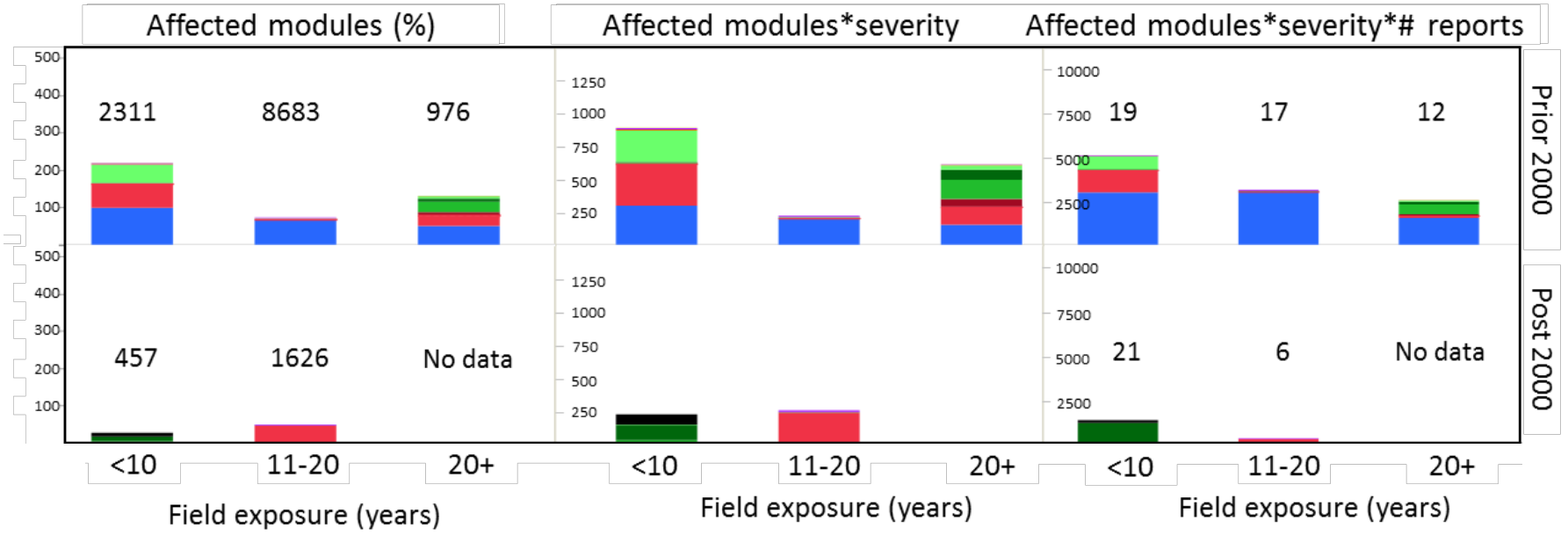
Thin-films: glass breakage most important

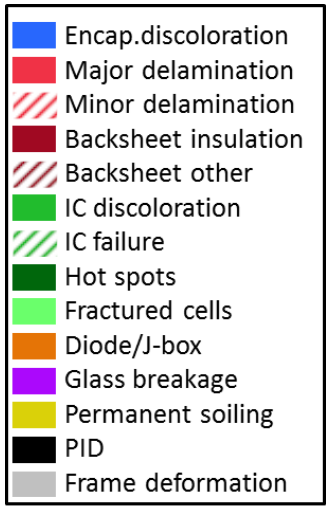
Don’t have a lot of data on thin-film degradation modes



Percent of affected modules has gone down in newer installations

Moderate Climate

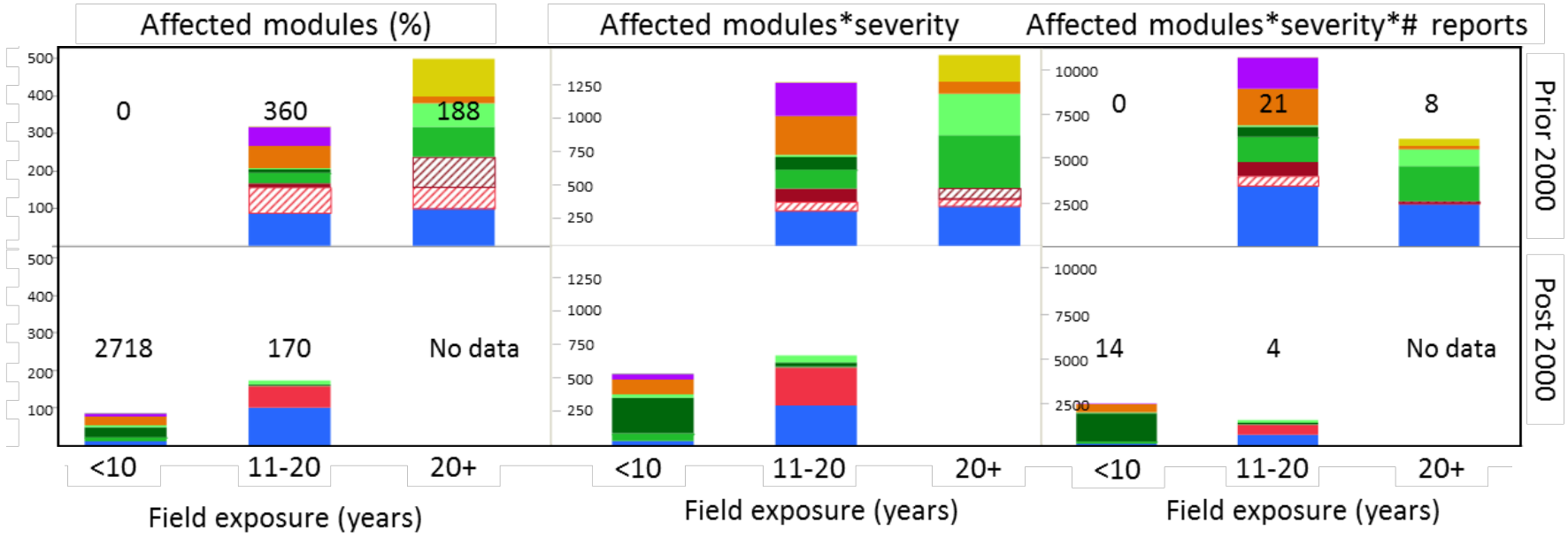


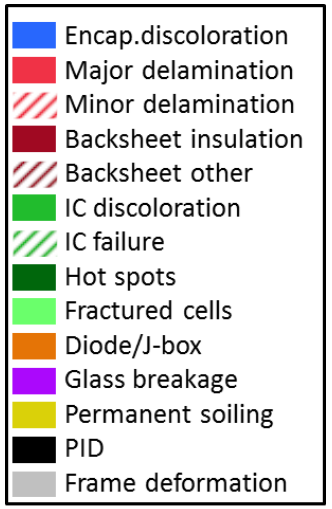


- Older installations, less than 10 field exposure dominated by pre-Block V modules
- Older installations: encapsulant discoloration dominant but absent in newer installations
- Percent of affected modules has gone down and changed.
- Hot spots & PID, and with more field exposure major delamination

Hot & humid see higher fraction of modules affected

Hot & humid climate

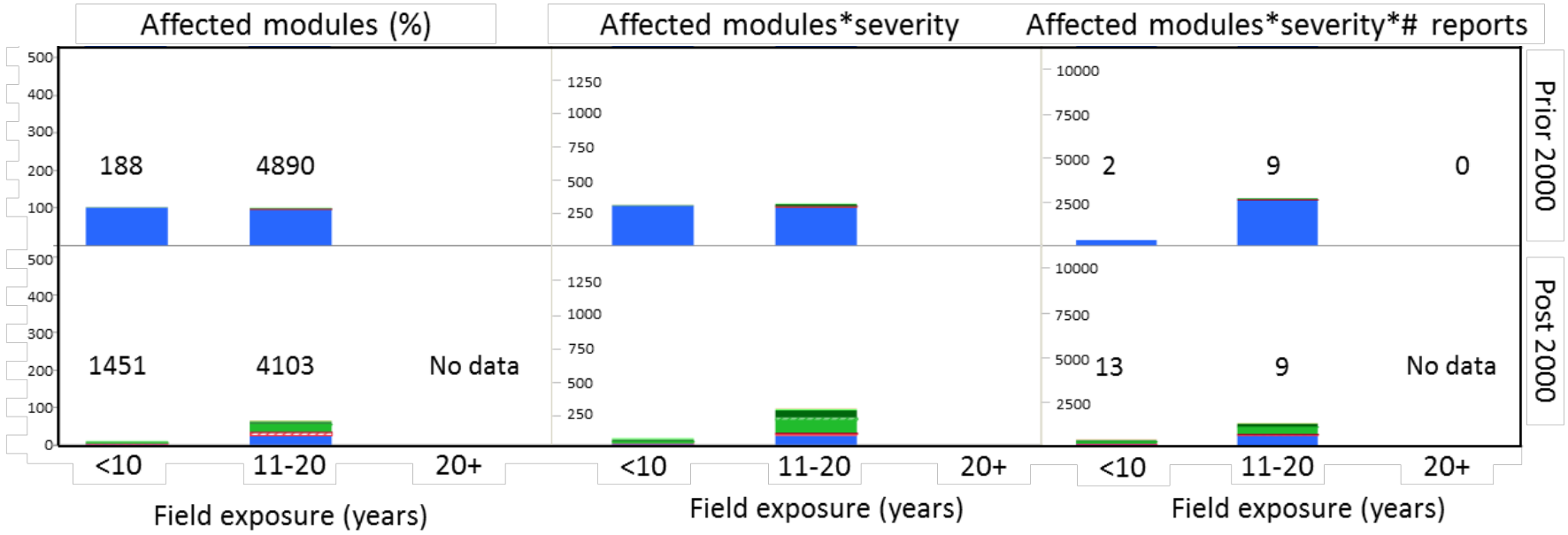


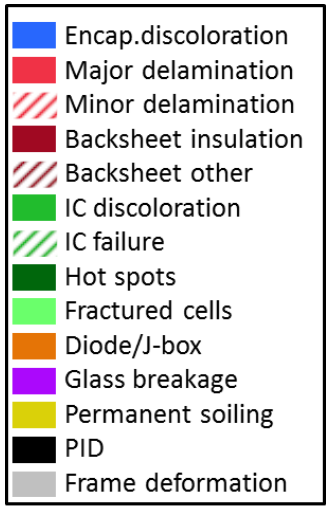


- Hot & humid climate more mix of degradation modes.
- Newer installations: hot spots, J-box issues
- For longer exposure major delamination appears
- Encapsulant discoloration still showing up in newer installations

Desert, new installations: hot spots & internal circuitry discoloration

Desert climate

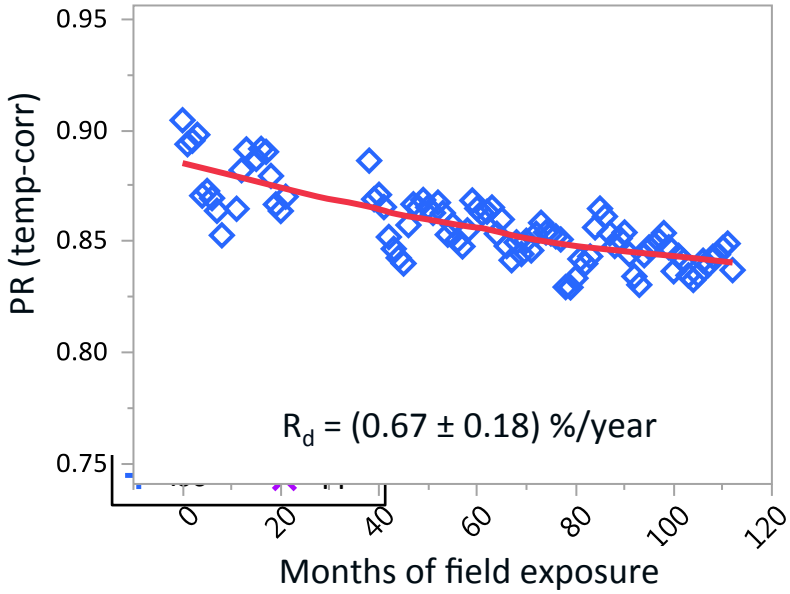


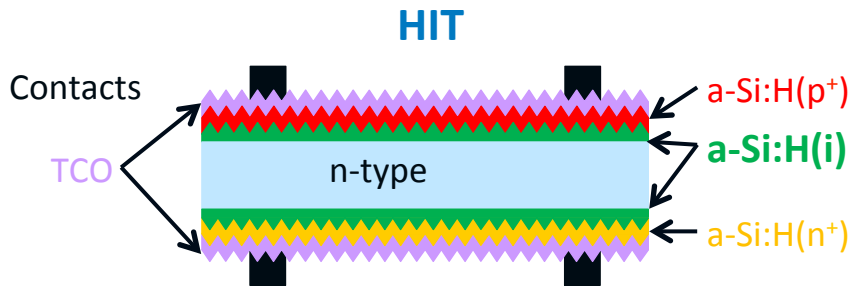


- Older installations: encapsulant discoloration
- Newer installations: hot spots & internal circuitry discoloration
- Encapsulant discoloration still showing up in newer installations

“New” Degradation Mode?

HIT (heterojunction with intrinsic thin layer)

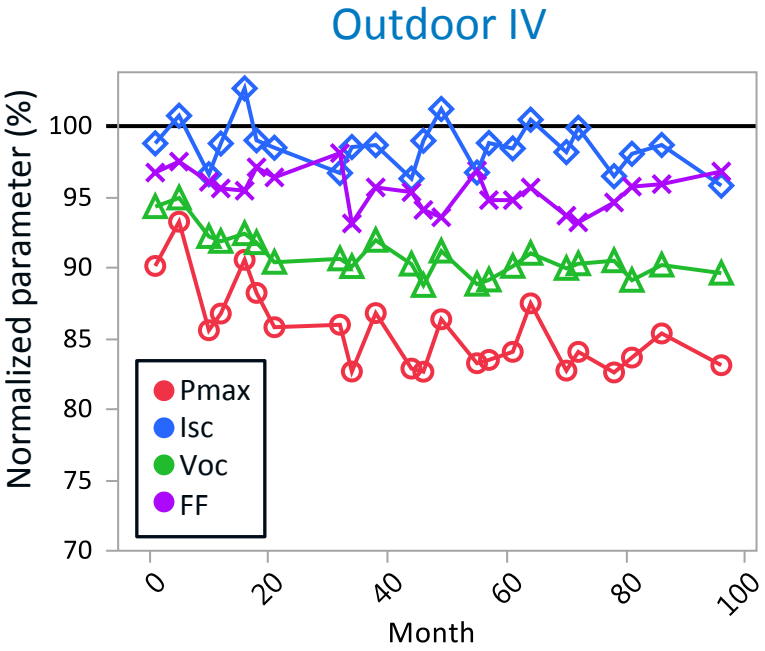


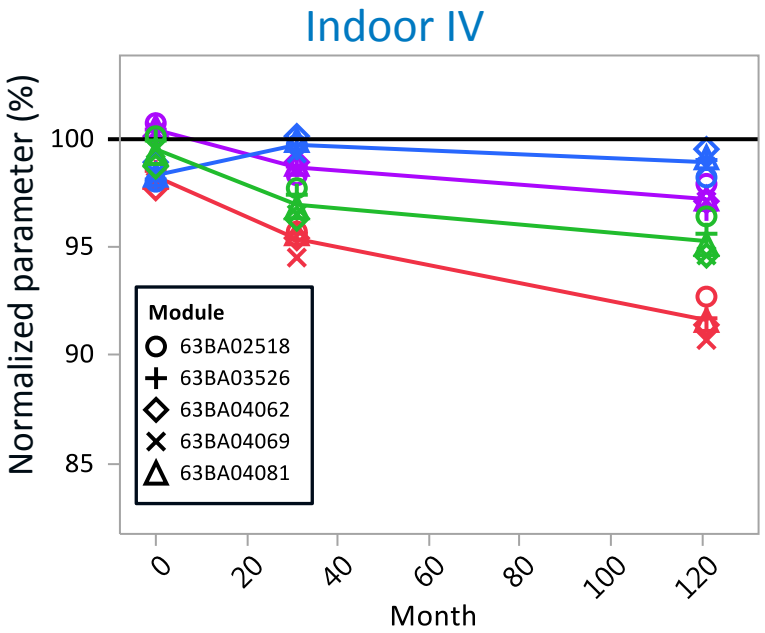


- System size: 1kW, 5 modules
- Installed Sep. 2007
- Kept control module indoors
- **Degradation is within warranty**

Jordan et al., *PVSC,* 2017

Nonlinear decline in *Voc*



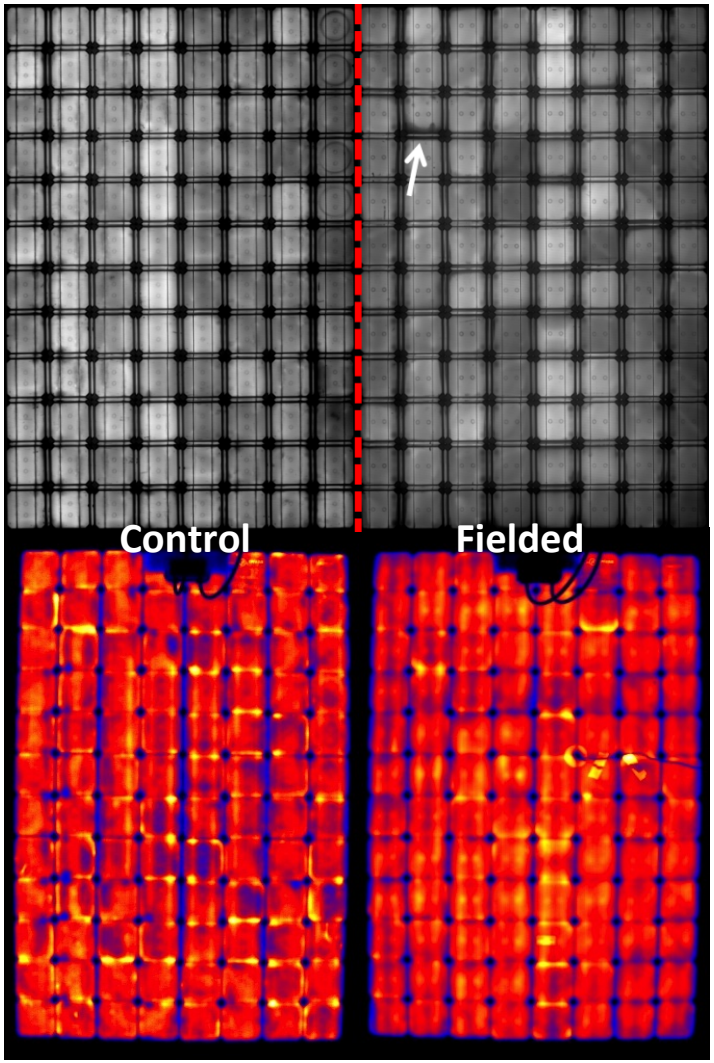


Temperature corrected to 45°C

Isc: within measurement uncertainty
FF: small decrease
Voc: most of the decline in first 2 years

Uniform across module, R_s increase

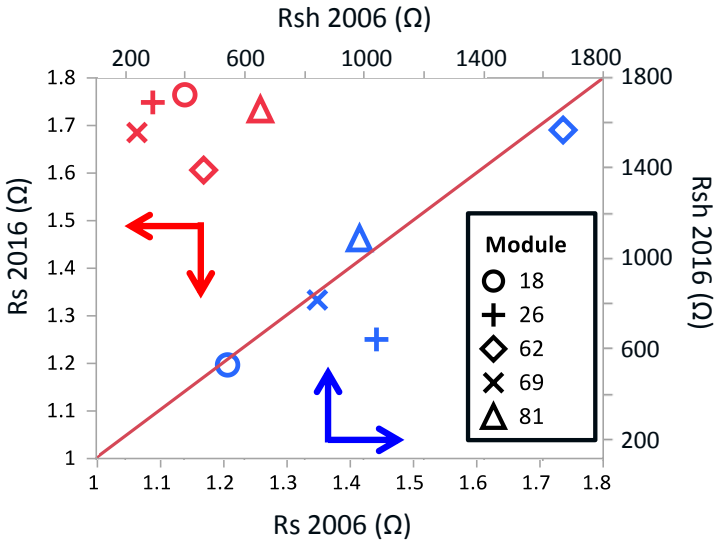
Electroluminescence



Dark Lock-in Thermography

Some cells show slight edge-shunting, but..
it is also present in the control module!

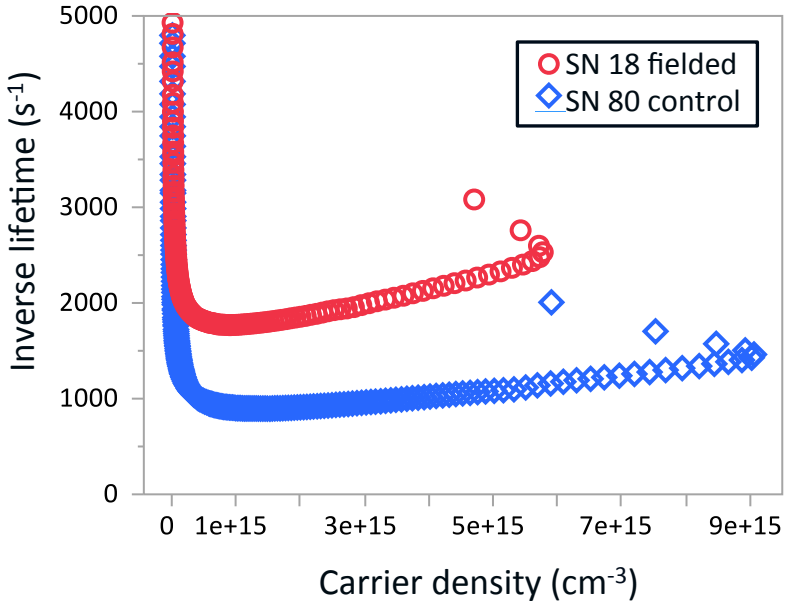
Dark IV taken in 2006 & 2016



Some series resistance increase
No shunt resistance decrease

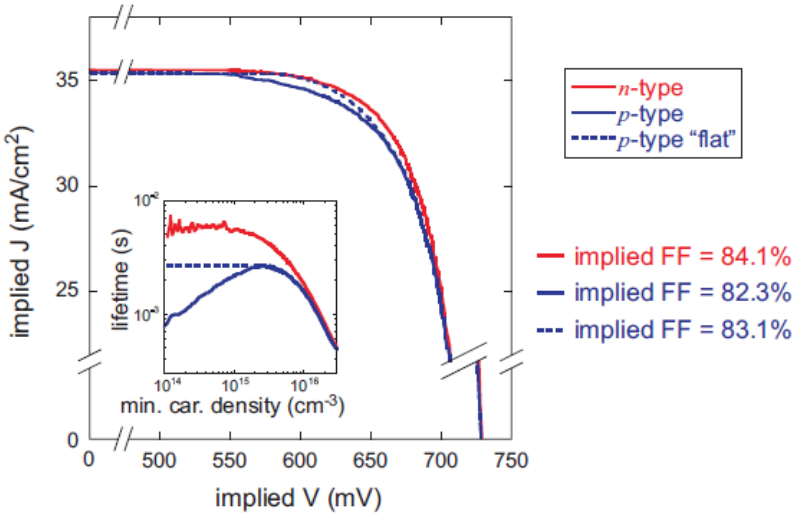
New cell designs may lead to new degradation modes

From Suns-Voc measurements



Sinton et al., EU PVSEC, 2000.

Same HIT structure on n- & p-type



Descoeudres, De Wolf et al., JPV, 2013.

p-type lower FF → lower quality passivation layer
Appears as a slightly "higher series resistance"
Passivation layer is degrading

Cell structure has changed with field exposure

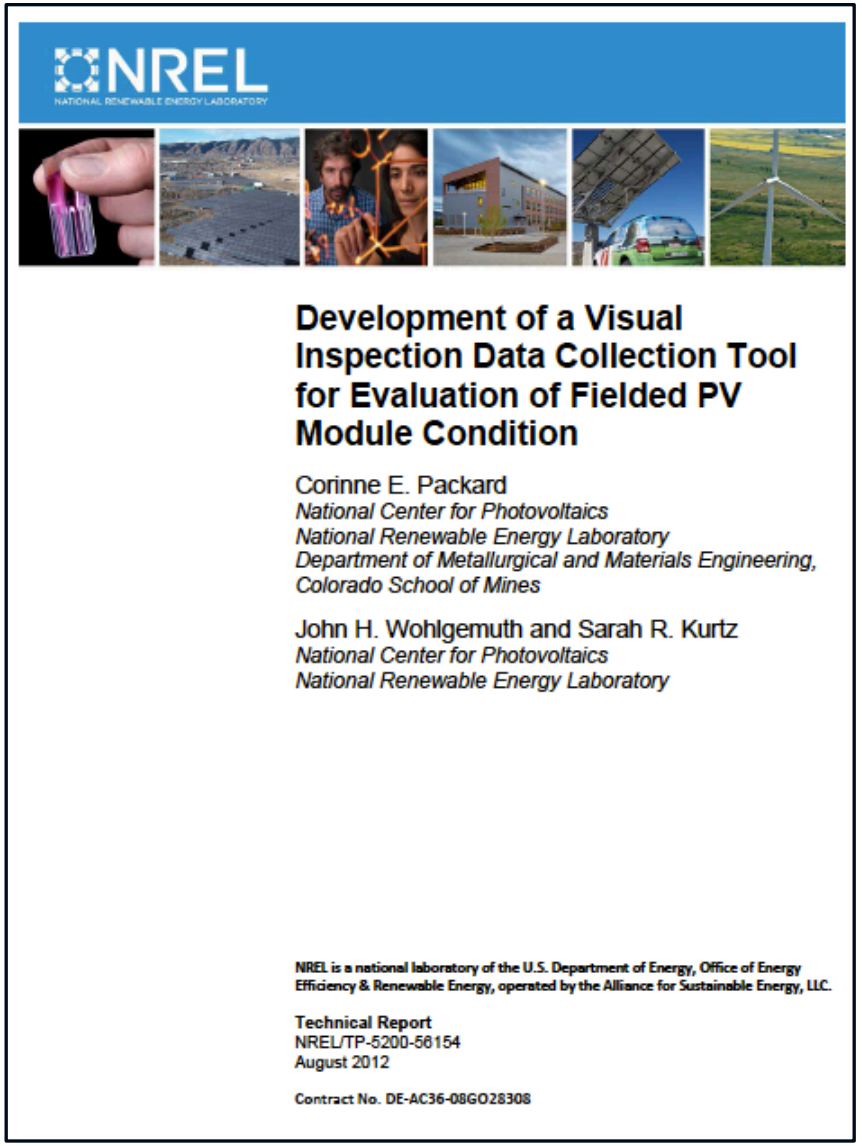
1. **Prices go down → new bill of materials leads to question on dependability**
2. **Efficiencies go up → new cell designs may lead to new degradation modes**

Summary

- Failure rates are not often reported but mostly relatively low ca. 5 out of 10,000 annually
- Fewer degradation modes in newer installations
- Most dominant degradation modes in the last 10 years is hot-spots
- “New” degradation modes can occur from new change of bill of materials & different cell designs

Please use Visual Inspection Tool

- Uses IEC/UL standard terminology
- Balance collection of sufficient detail for degradation mode evaluation against minimizing recording time per module
- Consists of 14 sections- based on module component
- Short & long version available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Development of a Visual Inspection Data Collection Tool for Evaluation of Fielded PV Module Condition

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NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-5200-56154
August 2012

Contract No. DE-AC36-08GO28308

Acknowledgments

Thank you for your attention

NREL reliability group
Steve Rummel
Steve Johnston
Ron Sinton
Cassidy Sainsbury
Harrison Wilterdink
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This work was supported by the U.S. Department of Energy under Contract No. DE-AC36-08-GO28308 with the National Renewable Energy Laboratory

ARIZONA STATE UNIVERSITY
PHOTOVOLTAIC RELIABILITY LABORATORY

Degradation of Solder Bonds in Field Aged PV modules: Correlation with Series Resistance Increase

Abhishiktha Tummala and Mani G. TamizhMani
Contact: manit@asu.edu

Funding Support

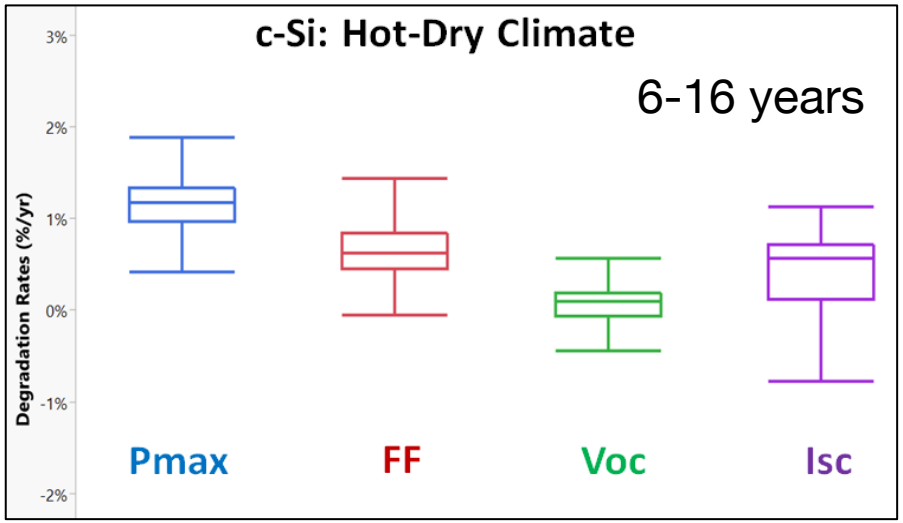
SERIIUS Solar Energy Research Institute for India and the United States

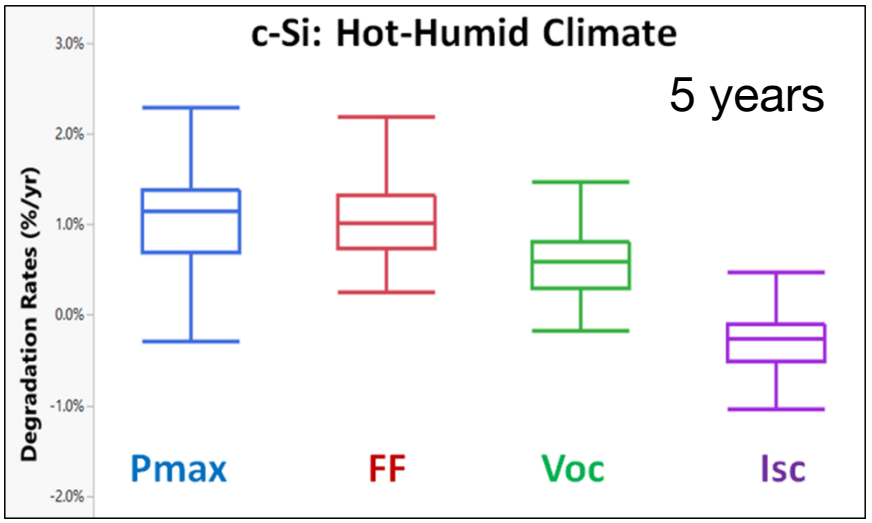
Lesson Learned: Isc and FF losses dominant

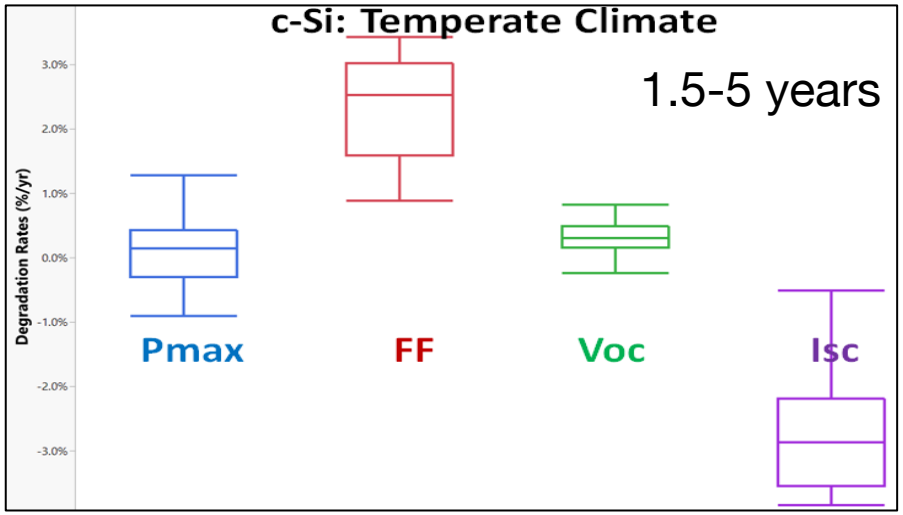
2014-2015 PV Plants Evaluated: 59,000 String and Individual Modules

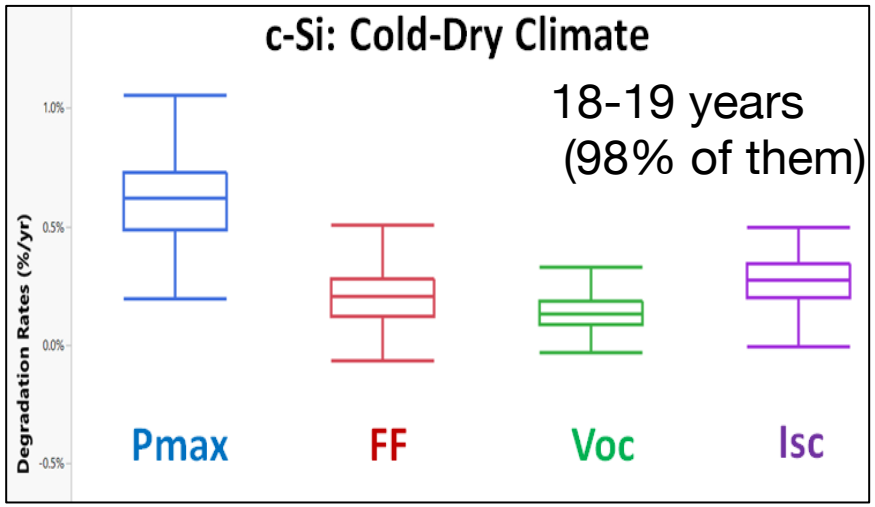
Site	Age (yrs)	Technology	No. of Modules Evaluated	Location	Climate Zone
AZ1	8	poly-Si	1,128	Arizona	Hot-Dry
AZ2	6	poly-Si	54	Arizona	Hot-Dry
AZ3	16	mono-Si	1,512	Arizona	Hot-Dry
AZ4	16	mono-Si	1,512	Arizona	Hot-Dry
AZ5	6	HIT	1,280	Arizona	Hot-Dry
AZ6	12	mono-Si	2,352	Arizona	Hot-Dry
AZ7	6	HIT	504	Arizona	Hot-Dry
AZ8	9	poly-Si	324	Arizona	Hot-Dry
CA1	5	poly-Si	23,500	California	Temperate
CO1	1.3	CdTe	132	Colorado	Temperate
CO2	3	mono-Si	24	Colorado	Temperate
CO3	2	HIT	40	Colorado	Temperate
CO4	1.5	HIT	35	Colorado	Temperate
CO5	3	CIS	64	Colorado	Temperate
CO6	3	CIGS	72	Colorado	Temperate
CO7	3	poly-Si	33	Colorado	Temperate
CO8	3	poly-Si	36	Colorado	Temperate
NY1	18	poly-Si	744	New York	Cold-Dry
NY2	19	poly-Si	360	New York	Cold-Dry
NY4	3	poly-Si	28	New York	Cold-Dry
TX1	5	CdTe	22,000	Texas	Hot-Humid
TX2	5	CdTe	1,035	Texas	Hot-Humid
TX3	5	CIGS	720	Texas	Hot-Humid
TX4	5	a-Si	672	Texas	Hot-Humid
TX5	5	poly-Si	340	Texas	Hot-Humid
TX6	5	poly-Si	340	Texas	Hot-Humid

Lesson Learned – Isc and FF loses dominant



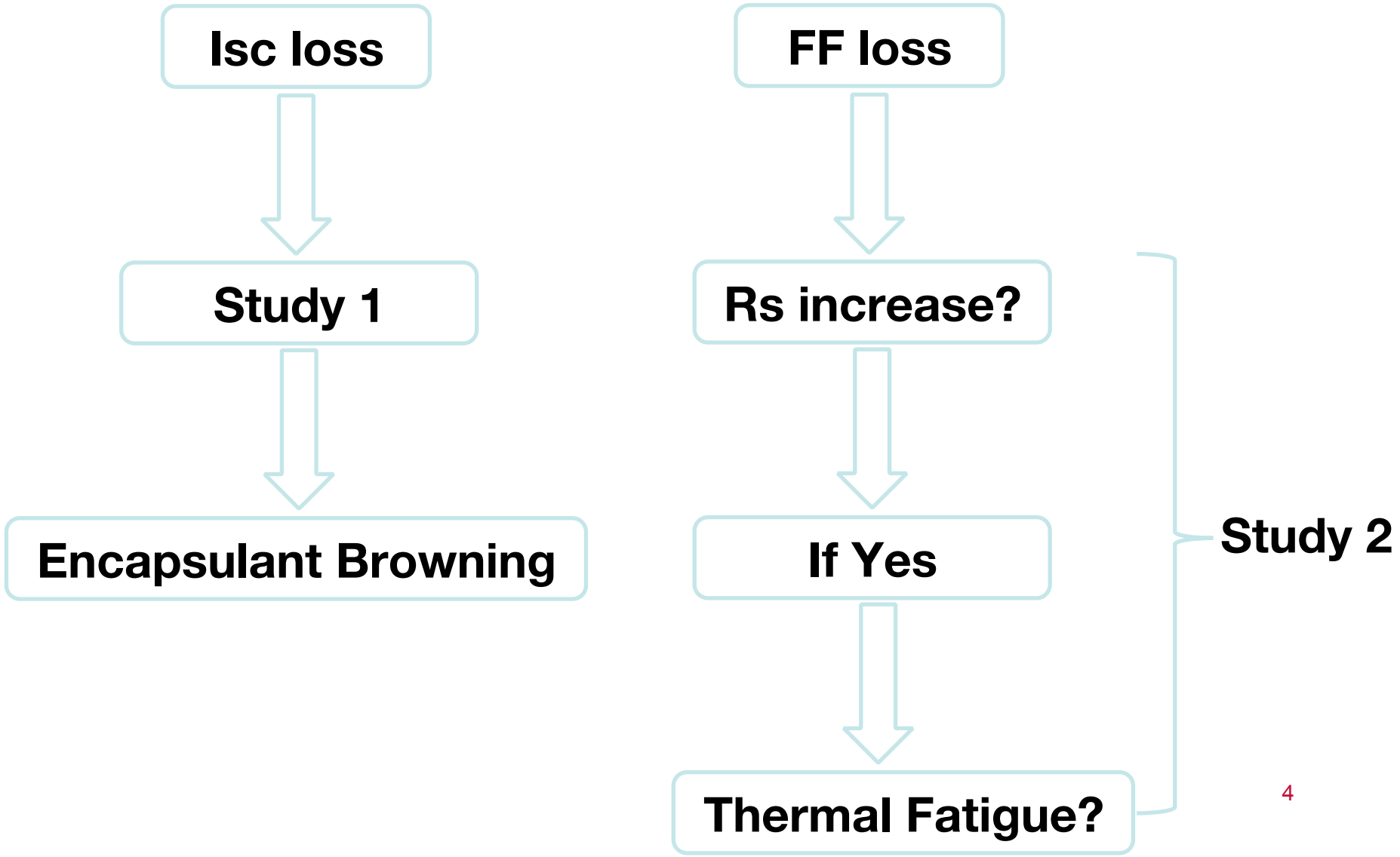






FF drop is due to series resistance, Rs, increase

Question


Isc loss
FF loss
Study 1
Rs increase?
Encapsulant Browning
If Yes
Study 2
Thermal Fatigue?

Presentation Outline

- Siemens M55 modules from three climates
- Light & Dark I-V: FF vs Rs correlation
- IR imaging: T vs. Rs correlation

  } Cut backskin

- Sample extraction:

  Chemical Methode vs. Mechanical method

  } Cell or cell strip extraction

- Peel strength: Peel strength vs. Rs correlation
- Four-point Rs: Exposed vs. Unexposed

  } Extracted cell

- Thermal modeling: Thermal fatigue vs. Rs

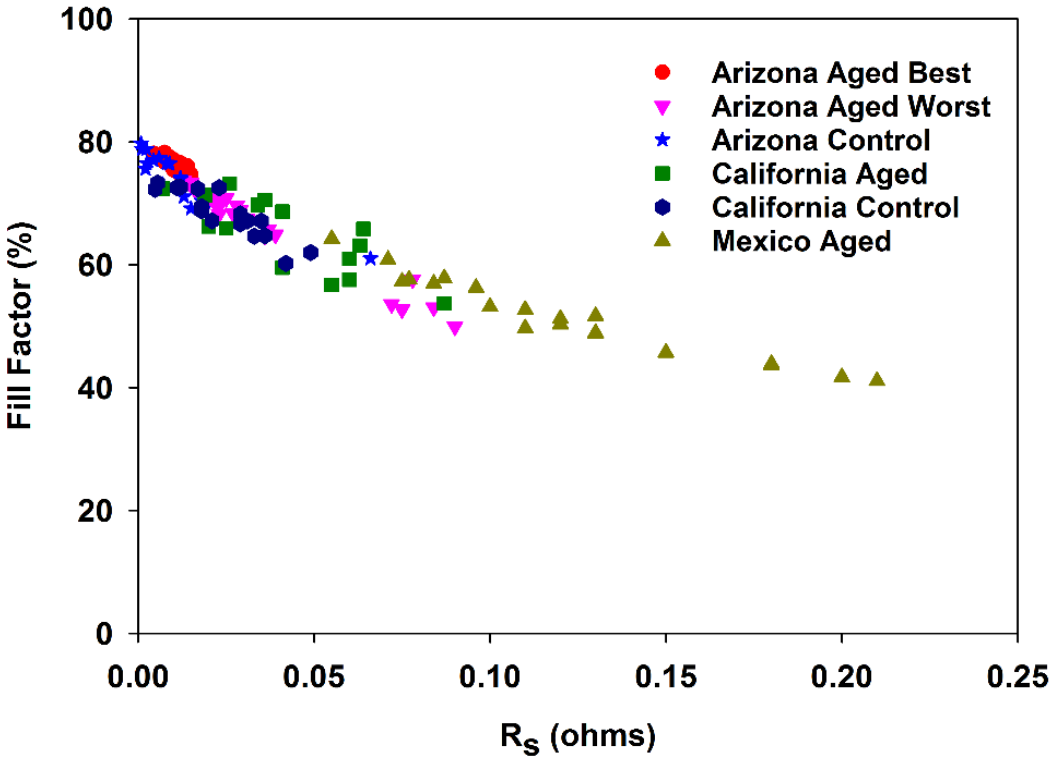
Source: https://www2.pvlighthouse.com.au/calculators/grid%20calculator/grid%20calculator.aspx

The following c-Si M55 Siemens modules were used in this study

- **Arizona (Location: Phoenix, Latitude - 33.44º)**
  - Climate - Hot and dry
  - Age - 18 years
  - No. of modules - 3 [514210, 464185, 19490 (control)]
- **California (Location: Sacramento, Latitude - 38.58º)**
  - Climate - Temperate
  - Age - 28 years
  - No. of modules - 2 (1 aged and 1 control)
- **Mexico (Location: Xoxocotla, Latitude - 18.64º)**
  - Climate - Warm and Humid
  - Age - 23 years
  - No. of Modules - 1

Dark I-V: FF vs. Rs correlation

Average cell level R_S vs FF for all modules



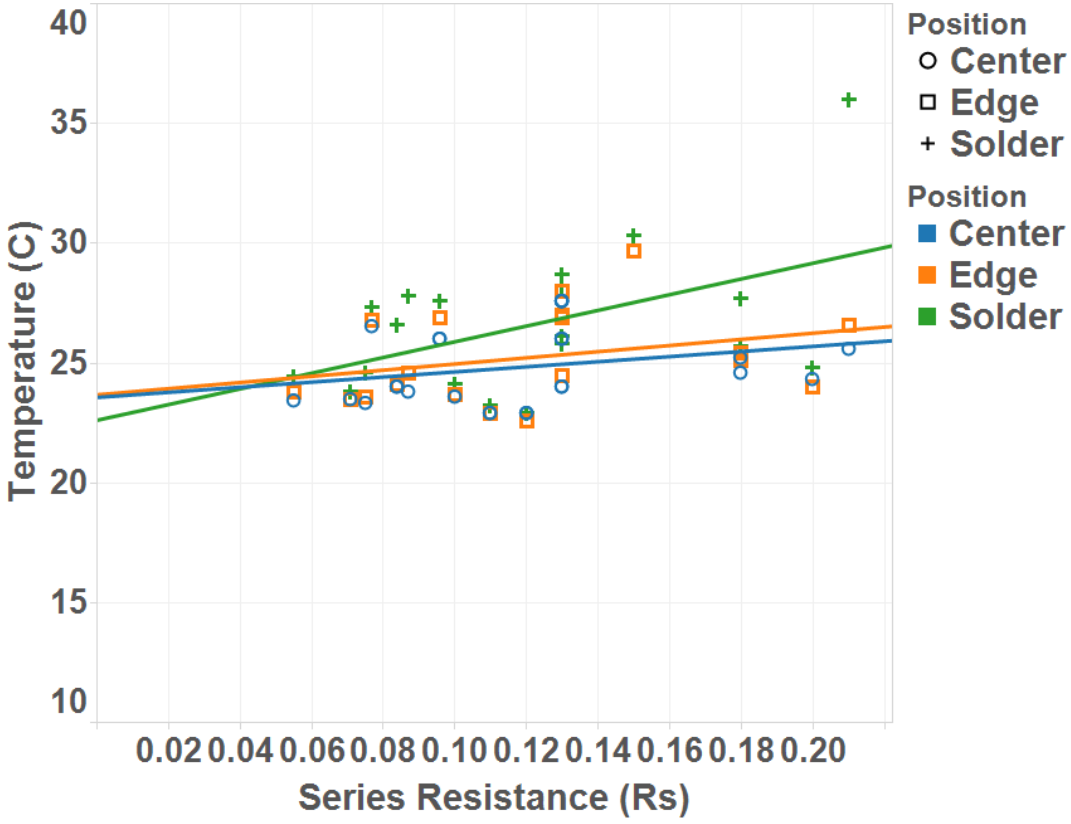
Age
Arizona Aged – 18 Years
Mexico Aged – 23 Years
California Aged – 28 Years
Arizona Control – unexposed
California Control – unexposed

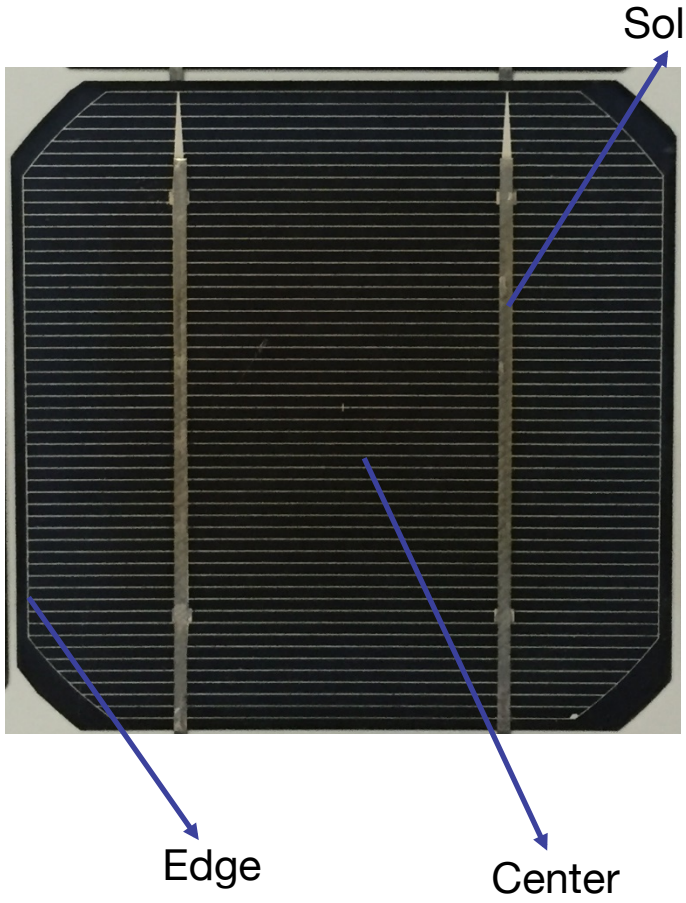
Climate
Arizona – Hot and Dry
California – Temperate
Mexico – Warm and Humid

No. of Cells
Arizona Aged Best - 31
Arizona Aged Worst - 31
Arizona Control - 17
California Aged - 15
California Control - 17
Mexico Aged - 21

IR Imaging: Temperature vs. Rs Correlation (Mexico cell)

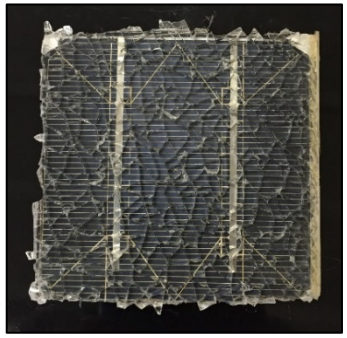
Cell level R_s vs Temperature for Mexico Module



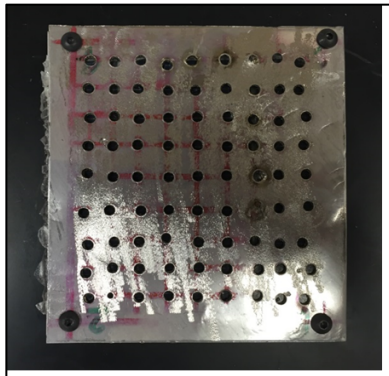


The temperature of the cell was measured by using IR imaging by passing dark I_{SC} current

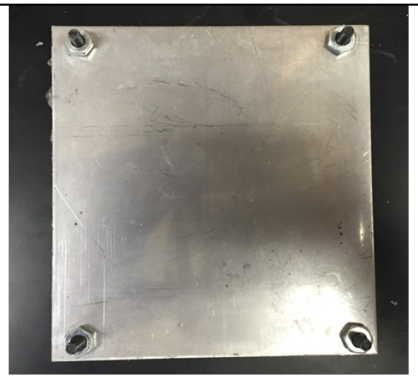
Cell extraction – Chemical method



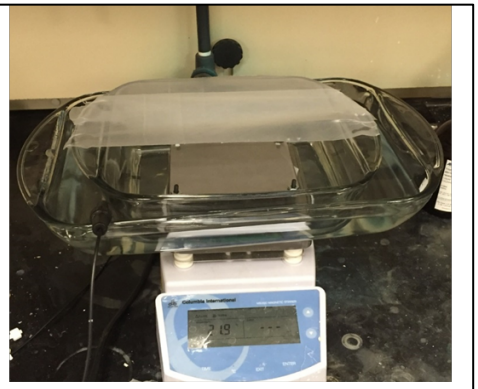
Sample before EVA dissolution



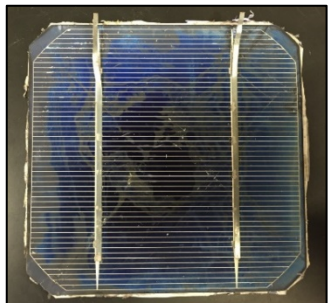
Fixture Top View



Fixture Bottom View



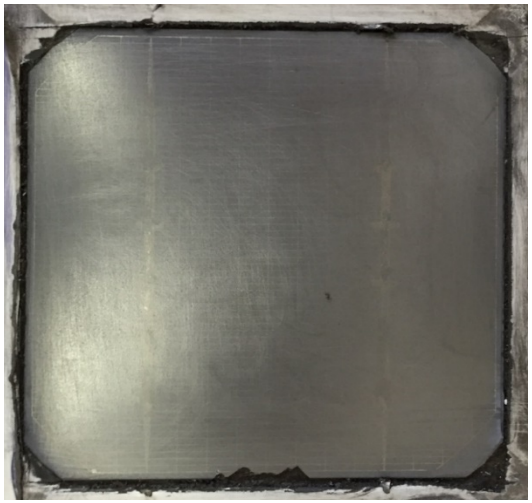
Fixture Immersed in TCE Bath



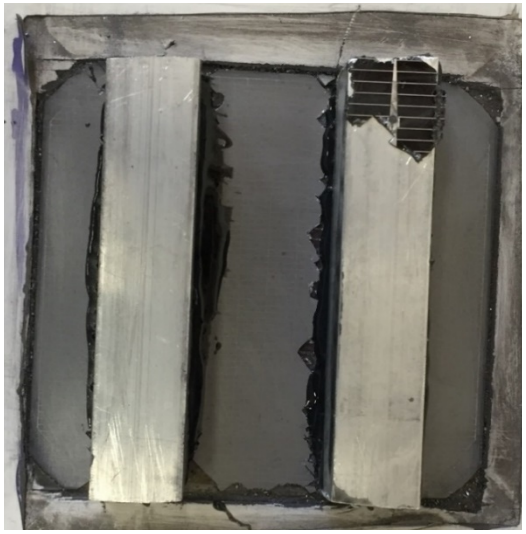
Sample after EVA dissolution

Cell strip extraction – Mechanical method

- The chemical method may or may not affect the solder bond properties of the PV cell
- In order to check the validity of the method, a mechanical method was also used*
- In this method, a strip of the cell is removed from the module without breaking the glass



Cell after smoothening and removal of backside metallization

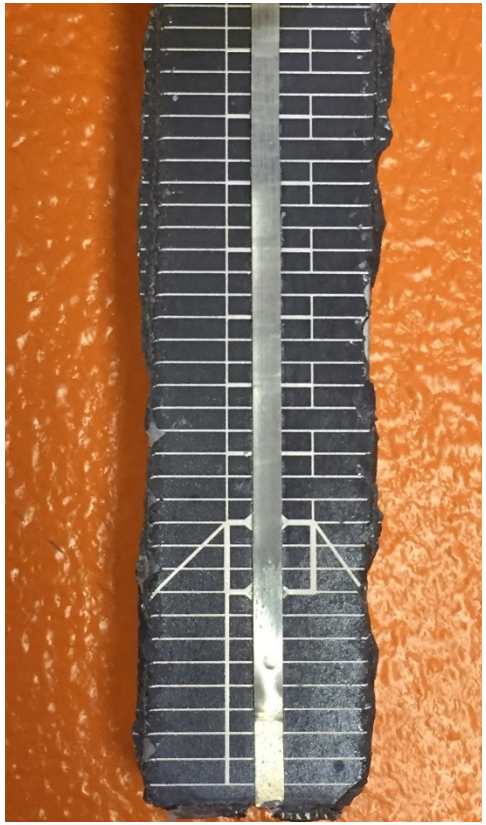


Metal tube attached to the cell (right tube reused)

*Personal communication: Dr. Nick Bosco, NREL

Cell strip extraction – Mechanical method

- This setup is left untouched for 8 hours to allow the epoxy glue to cure
- Heat is provided from the front side using heat gun to loosen the encapsulant
- Force is applied on the metal tube in opposite direction and the cell strip is extracted

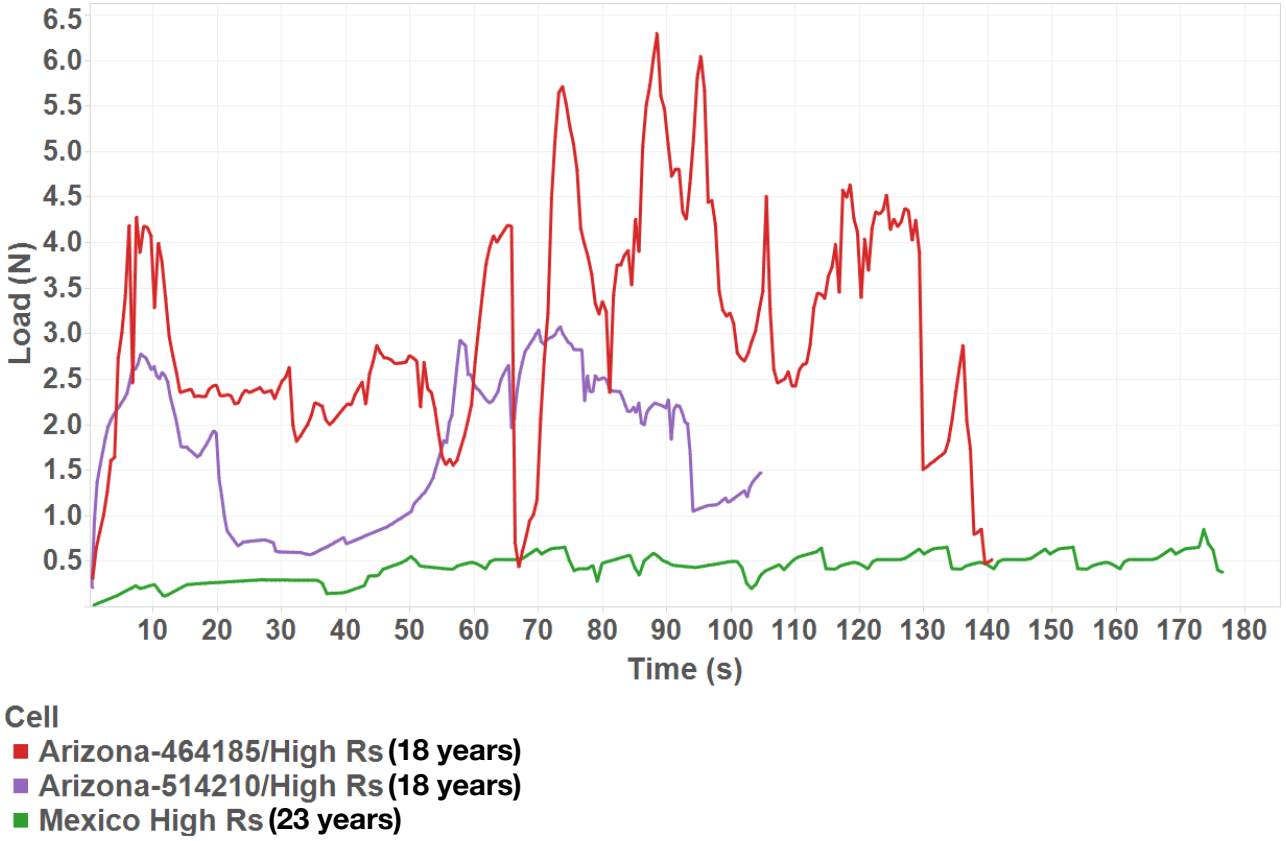


Extracted Strip

Comparison of sample extraction methods

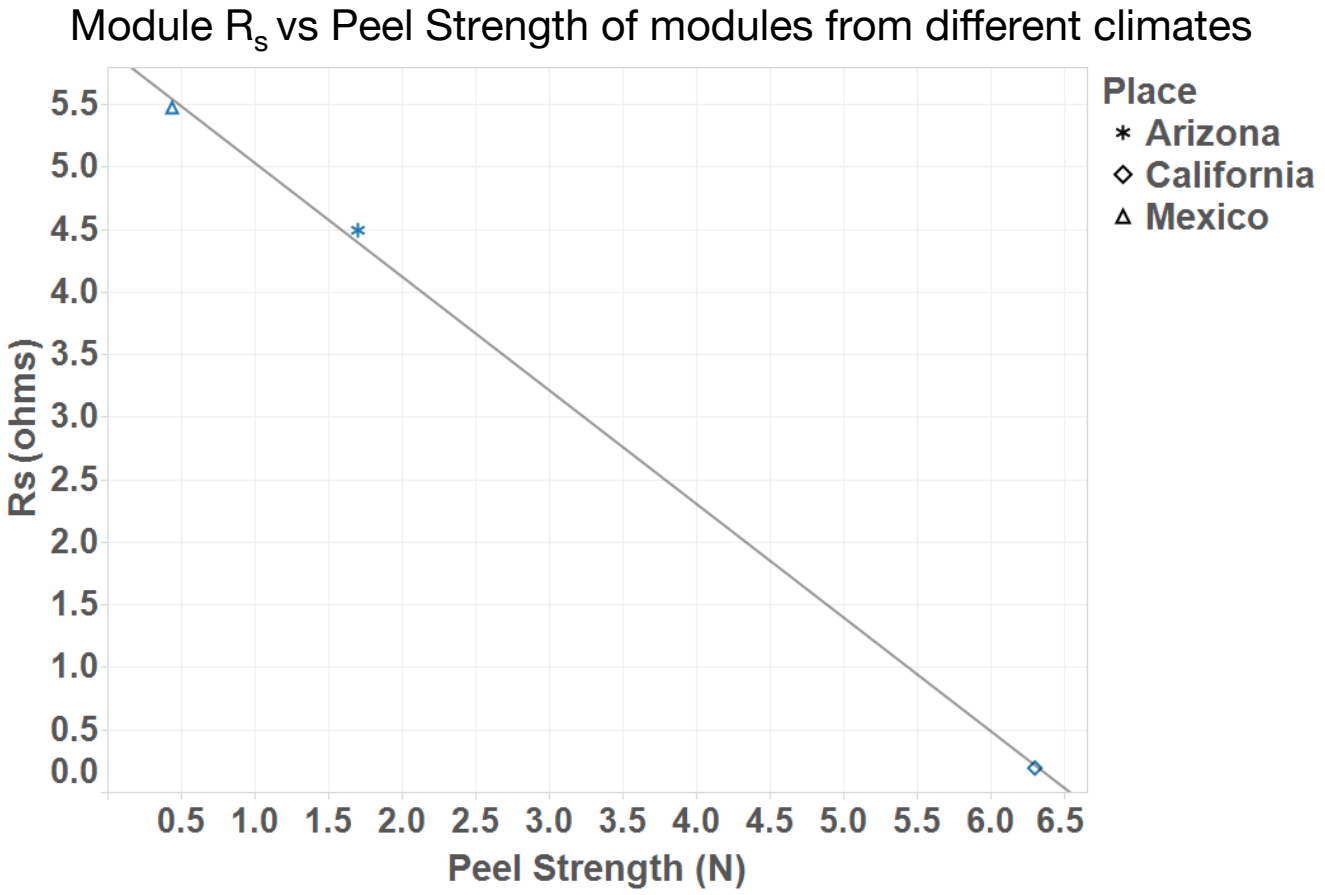
Factor (↓)	Chemical Method	Mechanical Method
Time	1-2 hours	8-10 hours
Sample Size	Size of a single cell	A strip of cell along solder
Hazardous	Very hazardous	Not hazardous
Cost (for 5 samples)	$60	$35

Peel strength vs. Rs Correlation



- A module with high series resistance observes a lower value of peel strength.
- Mexico modules has a lower peel strength when compared to Arizona modules.

Peel strength vs. Rs Correlation

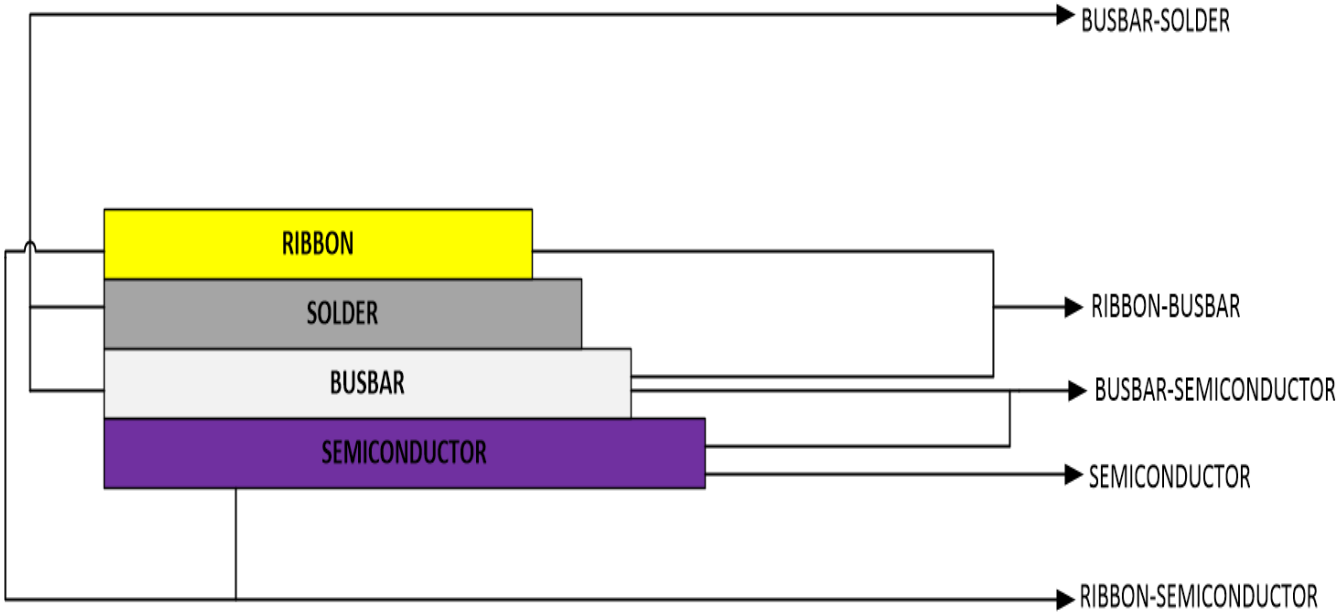


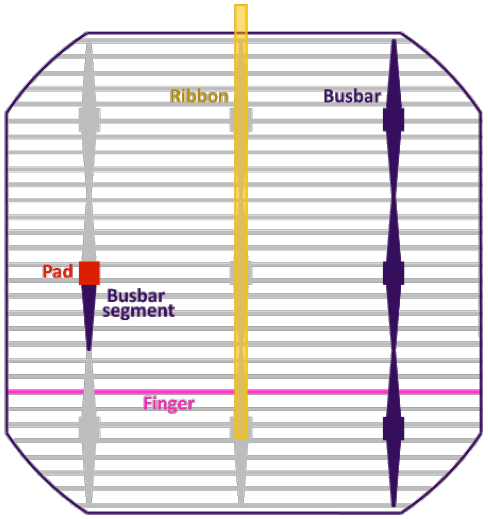
- Peel strength decreases with increase in series resistance

Four point probe resistance measurements

- Samples extracted from chemical and mechanical methods were used for the four point probe resistance measurements.
- Resistance of various combinations that contribute to series resistance were measured.
- The four point probe apparatus consists of **Signatone SP-4** machine which is connected to the **Keithley 2700** multimeter.

Four point probe resistance measurements

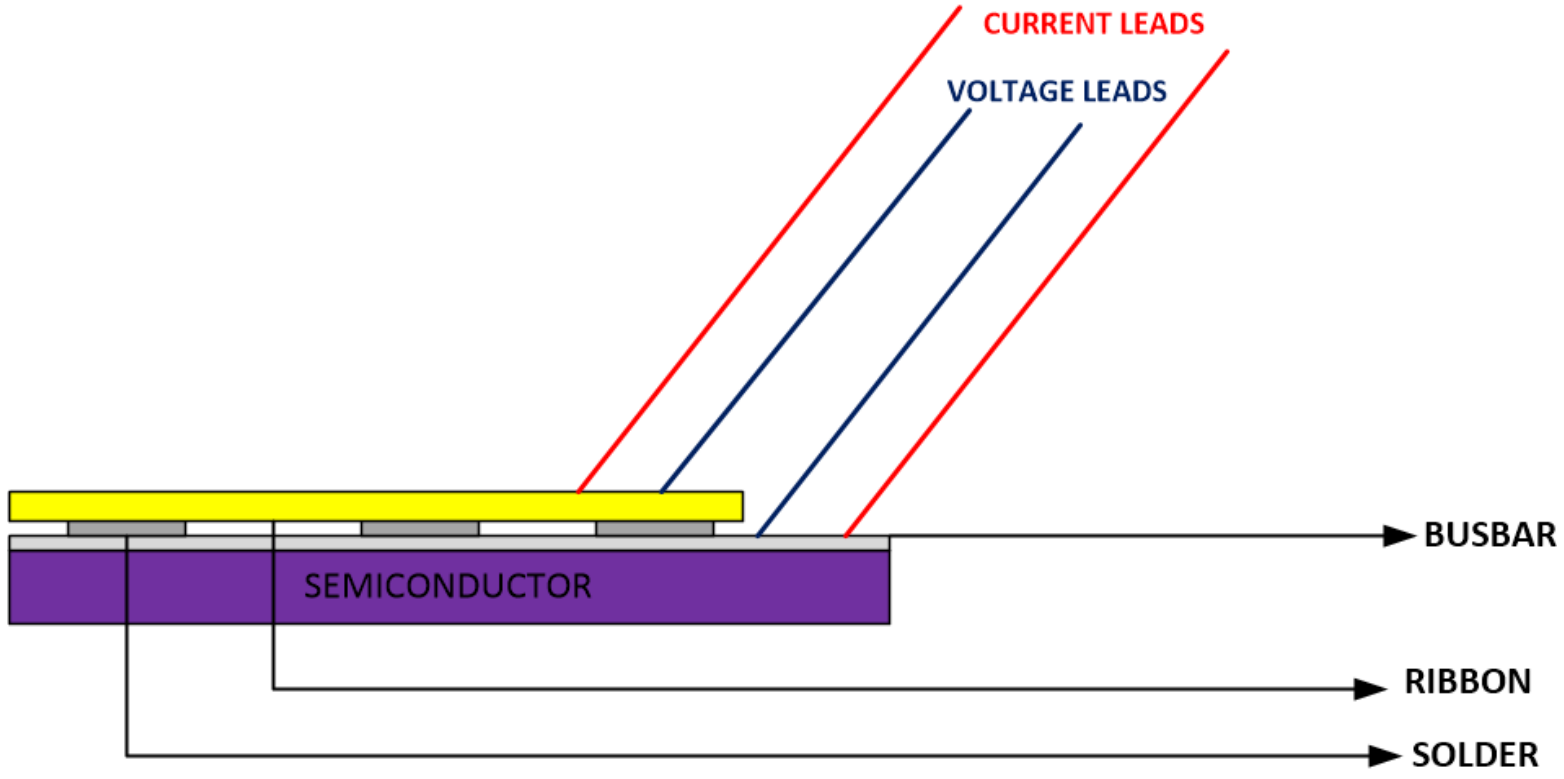




Combinations influencing series resistance increase

Source: https://www2.pvlighthouse.com.au/calculators/grid%20calculator/grid%20calculator.aspx

Four point probe resistance measurements



Four point probe position

Four point probe resistance measurements

Comparison of resistances of aged modules with control module

Combination	Control module (Ω)	Arizona modules (Ω)	% change	Mexico module (Ω)	% change
$R_{(Semiconductor)}$	4.6	8.73	89.78 (↑)	11.1	141.3(↑)
$R_{(Ribbon - Semiconductor)}$	6.045	6.88	13.81(↑)	9.77	61.62(↑)
$R_{(Busbar - Solder)}$	0.0045	0.011	144.44(↑)	0.0143	217.77(↑)
$R_{(Busbar - Semiconductor)}$	4.35	5.57	28.04(↑)	7.015	61.26(↑)
$R_{(Ribbon- Busbar)}$	0.0052	0.0176	238.4(↑)	0.0171	228.8(↑)
$R_{(Busbar - Fingers)}$	0.0212	0.0656	209.43(↑)	0.0235	10.84(↑)

- The major combinations that have a significant rise in series resistance are the ribbon-busbar and ribbon-solder combinations

Four point probe resistance measurements

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Climate specific thermal modeling

- Thermal fatigue in a module is mainly caused due to two important factors
- The first factor is the daily temperature change due to day and night temperatures which effects the solder bond gradually by expansion and contraction
- The second factor is due to cloud cycles which occur every day causing the sudden expansion and contraction

Climate specific thermal modeling

- In this study, the fatigue accumulated for 20 years (1991-2010) was calculated using the model developed by Dr. Nick Bosco of NREL
- Four different climates were used in this study
  - Arizona - Hot and dry
  - California - Temperate
  - Mexico - Warm and humid
  - Colorado - Temperate
- Weather data was used for the calculation of thermal fatigue and was obtained from TMY3 data

Climate specific thermal modeling for thermal fatigue

- The thermal fatigue accumulated is given by the formula

$$D = C.(\Delta T)^n .(r(T))^b .e^{Q/k_B} .T^{max}$$

where,

ΔT is the mean daily maximum cell temperature change

T_{max} is the mean daily maximum cell temperature

C is a scaling constant

Q and k_B are activation energy and Boltzmann's constant

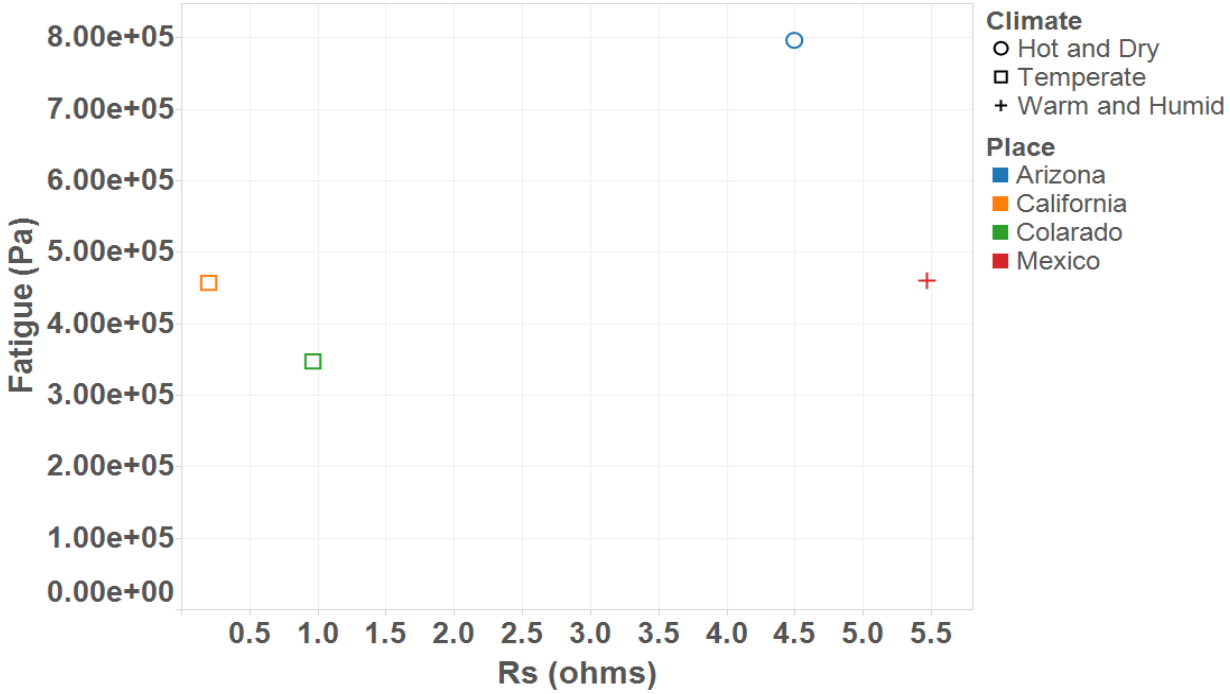
r(T) is the temperature reversal term

C= 405.6, T= 54.8°C, n= 1.9, b= 0.33, Q= 0.12 eV

Time Interval (min)	C	Reversal Temperature (°C)
1	239.9	56.4
5	249.9	56.9
30	344.1	55.8
60	**405.6**	**54.8**

Source: Nick Bosco, NREL

Module R_s vs Thermal Fatigue accumulated 20 years (1991-2010) of modules from different climates



- Higher thermal fatigue is expected to weaken the solder bonds resulting in higher Rs
- Mexico (warm and humid) has the highest series resistance but not the highest fatigue. This indicates that fatigue alone is not responsible for the Rs increase. Instead a combination of factors including thermal fatigue, IMC (intermetallic compound) formation and corrosion seem to be responsible for the Rs increase.

Conclusions

- Aged modules (18-28 years) from 3 climates investigated in this correlation study
- Dark IV - FF vs. Rs: A strong correlation exists
- IR imaging – T vs. Rs: Hotter along the ribbon-busbar
- Sample extraction – Chemical vs. Mechanical method: Nearly same (mechanical method is preferred as it is non-hazardous)
- Peel strength – Peel strength vs. Rs: A strong correlation exists
- Four-point Rs: Largest increase in Rs is attributed to the solder bonds
- Thermal fatigue: No direct correlation between thermal fatigue and series resistance could be established (Series resistance increase seems to be dictated by a combination of factors including IMC formation, thermal fatigue and/or corrosion, but not thermal fatigue alone)

NREL/SNL/BNL PV Module Reliability Workshop

Tuesday morning discussions:

Twist test: Eric Daniels presented evidence that inclusion of a twist test in IEC 61215 might help to identify modules that are susceptible to damage during installation and other handling. A twist test was used years ago but was discontinued in about 2002 because all modules passed it, but with larger modules, larger cells, thinner wafers, thinner glass and thinner frames (which have moved from 50 mm to 40 mm to 30 mm), many of today's modules would fail the test.

While multiple individuals voiced support for the addition of a twist test, there was also concern about requiring sturdier modules that would be more costly if the problem could be solved by careful handling of the modules.

Follow up on twist test discussion: We may need to define:

- How a test would be administered, (For example: How much twist for how long? Do we need to vibrate it while it's twisted? After the mechanical stress is applied, do we need additional thermal cycling stress? Would the pass-fail criteria be based on observed damage or on power reduction?)
- What level of twisting should we allow during installation? What are strategies for reducing the mechanical stress that is applied at different stages of handling? Would watching the installers educate us about how modules are handled?
- What does it mean to be installed flat? Is some flexing on the rack acceptable? What effect may trackers have by applying differing stress as the tracker moves?
- How might a test procedure be adjusted if a module manufacturer specifies a particular approach to handling modules during installation? Could a tool be developed that allows handling without twisting?
- How much power loss is occurring? If damage is observed in the field at the time of installation, can we estimate the associated power loss that will subsequently occur?
- Is it just the twisting? Sometimes modules are damaged during transportation while still in the crate. Would it help to train the installers about the difference of letting the backsheet bounce on their hard hat vs the glass side bounce on their hard hat when carrying modules over their head? What else?

Degradation rates: Customers care a lot about degradation rate; what do we know? Substantial effort is going into studying degradation rates. We can provide statistical data about what is seen in the field, but it is preferable to measure the degradation directly on the product of interest. For example, SunPower has developed a model and compared it to field data. These studies require substantial investment.

General advice: If a neighbor asks what to look for, what shall I say?

The panel responded with a range of answers including:

- Get a good inverter (inverters are reported to have higher failure rates than modules)
- Ask whether the installer walks on the modules (walking on modules or carrying them by balancing them on hard hats is likely to damage them)

- Look at the reliability data from the module manufacturer (for example, SunPower has developed a model predicting performance out to 40 years)
- But, the manufacturer data may be biased, so look at 3rd-party data on the modules.
- Ask if the installer is NABCEP certified (NABCEP provides continuing education for installers – usually at the residential or commercial level – on installation best practices and the latest technology developments)
- Ask if the installer has considered locally useful precautions such as guards to keep squirrels from building nests and/or designs that avoid leaves building up under modules. If the installer's response reflects revisions to system design based on local experience, this is a good sign.

Exceptional service in the national interest

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Thermal-mechanical-electrical model for PV module-level mechanical failure mechanisms

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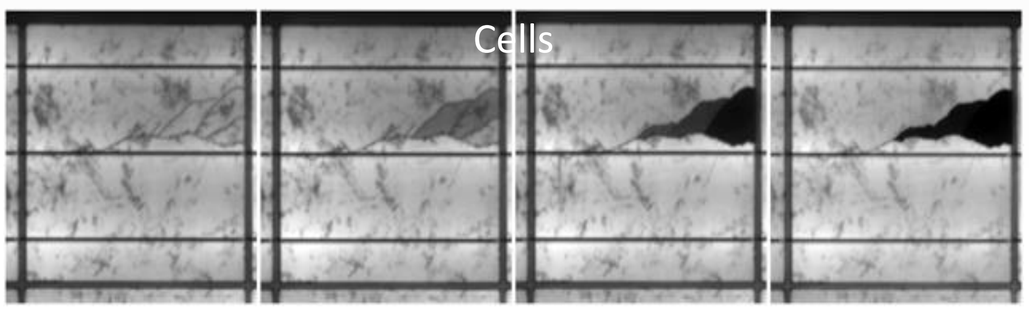
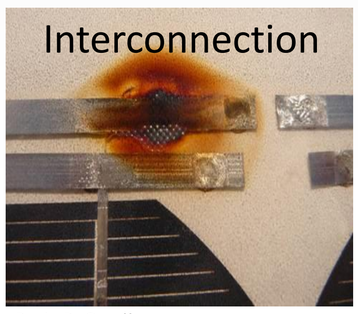
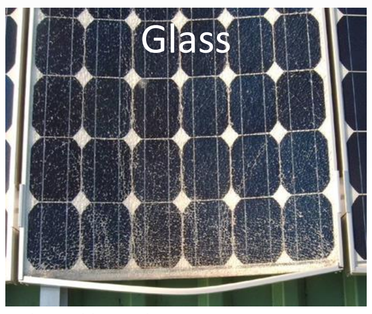
PV module mechanical failure modes



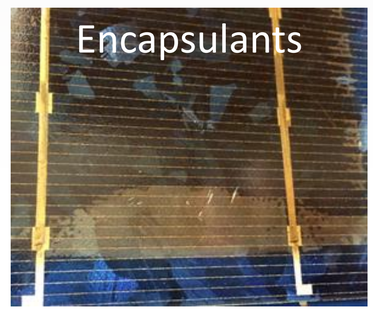
David DeGraaff



David DeGraaff



John Wohlgemuth



David DeGraaff

Capability proposal

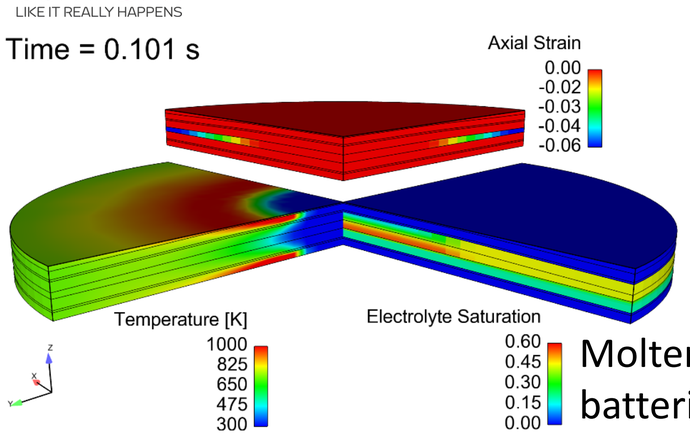
Thermomechanical stress induced in a PV module is a leading driving force of module failure. These failures include delamination, cell fracture, and solder bond fatigue, among others. Each of these failure modes depend on the specific deployment environment (temperature, humidity, etc) and electrical characteristics (e.g. temperature non-uniformity) of the module.

A predictive thermal-mechanical-electrical simulation capability is desired to quantify loads on PV module interfaces and materials as the result of the environment and stressors. The model will be three-dimensional in order to capture details of the module configuration. As a part of the Predictive Simulation Capability, this model framework should integrate predictive simulation with capabilities in materials discovery and module durability testing. Thermal loads (from environmental cycling or from electrically-generated temperature non-uniformities) will drive mechanical deformation, and the mechanical component of the model will predict generated stresses, interface and material failures. A major part of this effort will include the development of appropriate constitutive models for the complex thermo-visco-elastic/plastic behavior of many materials. Model validation is also critical, both at the materials and module scales.

This capability will be a computational code (model), documented workflow, and a community of practice for industry and academia to characterize environmental thermomechanical loads on PV modules. This model will enrich PV degradation databases to expose the origins and magnitudes of thermal and structural stressors on modules, materials, and materials interfaces.

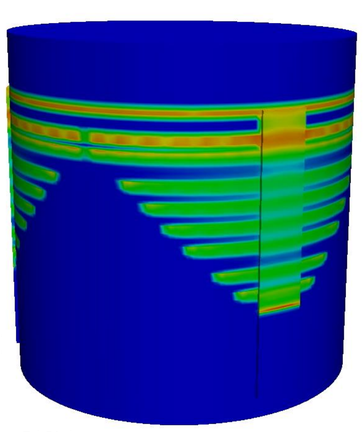
COMPSIM LIKE IT REALLY HAPPENS

3D thermal, mechanical, electrical finite element modeling

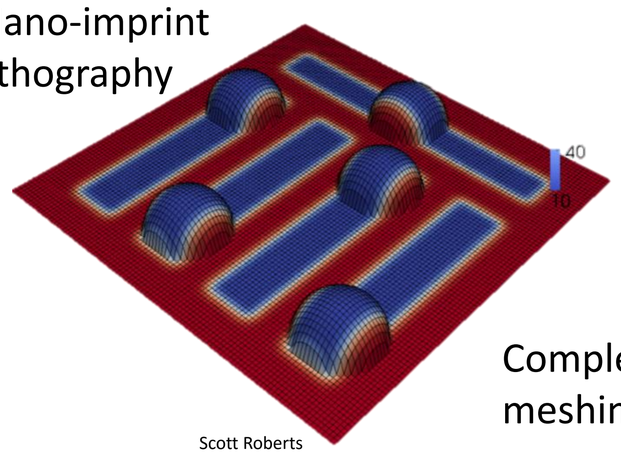


Scott Roberts

Molten salt batteries

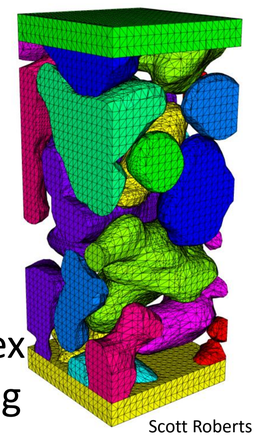

Ed Piekos

Nano-imprint lithography

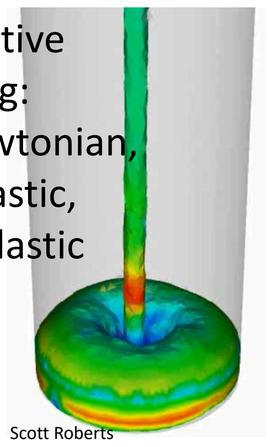


Scott Roberts

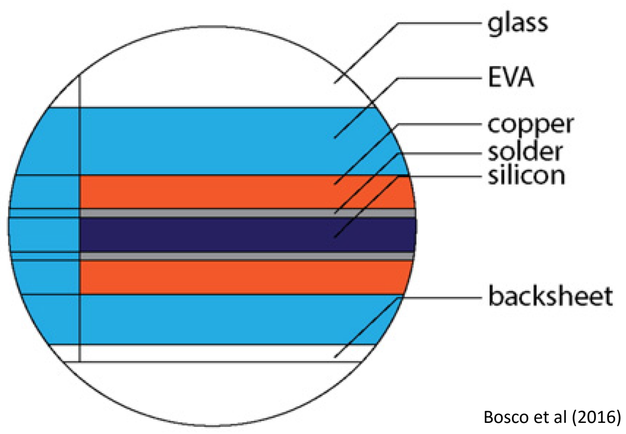
Complex meshing

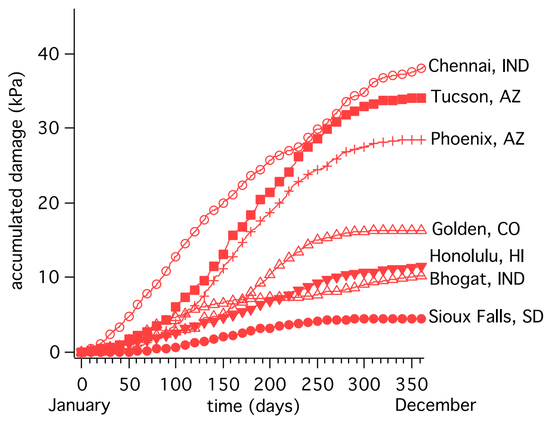

Scott Roberts

Constitutive modeling: non-Newtonian, visco-plastic, elasto-plastic


Scott Roberts

Previous 2D PV models





Bosco et al (2016)

Component-scale validation

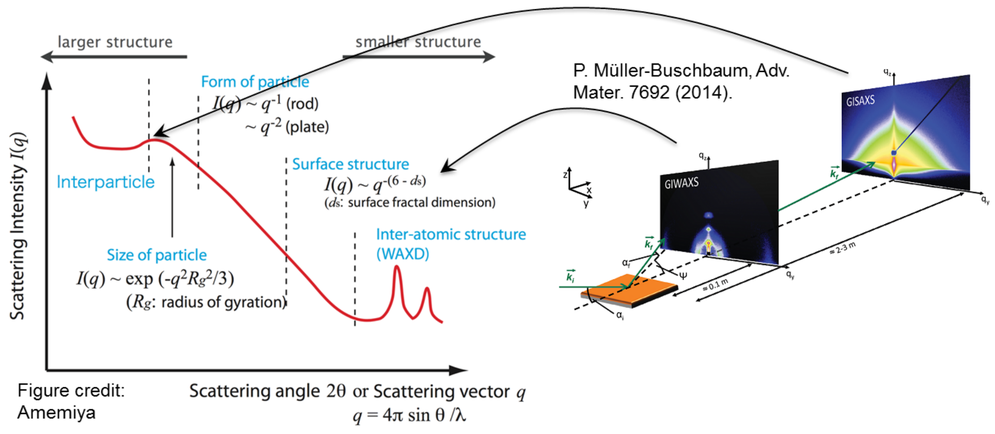


Figure credit: Amemiya

U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy
NNSA National Nuclear Security Administration

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NREL is a national laboratory of the U.S. Department of Energy Office of Energy Efficiency & Renewable Energy Operated by the Alliance for Sustainable Energy, LLC.
This material is based upon work supported by the U.S. Department of Energy, Office of Science, Office of Basic Energy Sciences, under Contract No. DE-AC02-76SF00515.

SAND2016-10041 D

DuraMat Field Deployment Capability

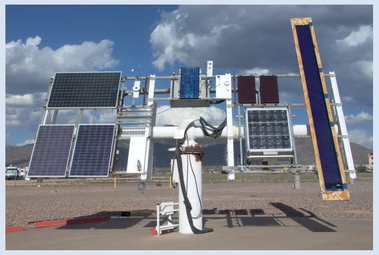
SAND2016-10543D

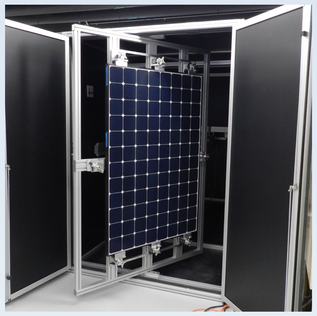
Bruce King
Sandia National Laboratories, Albuquerque, NM 87185
DuraMat Workshop
October 10-11, 2016

Abstract

Field deployment is a key aspect of confirming the durability of new module materials and module designs. Field deployment validates the results of *Accelerated Module Testing (Capability 4)* by confirming the field relevance of degradation mechanisms and acceleration factors. These considerations are particularly important in demonstrating the bankability of either newly developed or known materials that are being used in a new environment, such as those identified by *Predictive Simulation (Capability 2)* and *Materials Discovery (Capability 3)* and facilitate technology transfer, commercialization, and market success for the most promising materials.

Linking Outdoor Performance with Laboratory Diagnostics





Outdoor Capabilities

- Two fully programmable Two-Axis trackers
- Large, flexible mounting surfaces
- Single cell packages to full scale modules, complicated form factors
- Full electrical performance (IV curves, temperature coefficients, angle of incidence)

Indoor Module Lab

- Industry standard AAA 1-sun flash tester
- Custom Electroluminescence (EL) enclosure, mini-modules to full-size
- Temperature controlled light-soaking chamber, integrated IV sweep capability

Cell and Device Lab

- Reflectance and transmission measurements, Cary Spectrophotometer
- Solar cell spectral response/quantum efficiency measurements
- 2 1-sun cell testers

Project Synergies

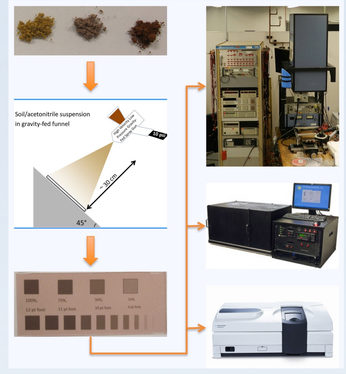
PV Lifetime

- Newly established project to assess the lifetime and durability of commercially available PV modules.
- Multi-year, multi-climate effort conducted at the RTC's
- Grid-tied PV systems that reflect U. S. commercial market share. Target 10kW minimum system size (30+ modules).
- 100% pre-deployment flash testing
- In-situ IV sweeps using novel hardware
- Data obtained from these systems will be used to construct degradation rate curves with greater fidelity than currently exists.

Soiling

- Performance loss stations in operation at most RTC sites
- Laboratory tools to study fundamental impacts to PV performances
  - Artificial soiling capability
  - Analytical methods to quantify loss, characterize interaction of incident light with surface soil

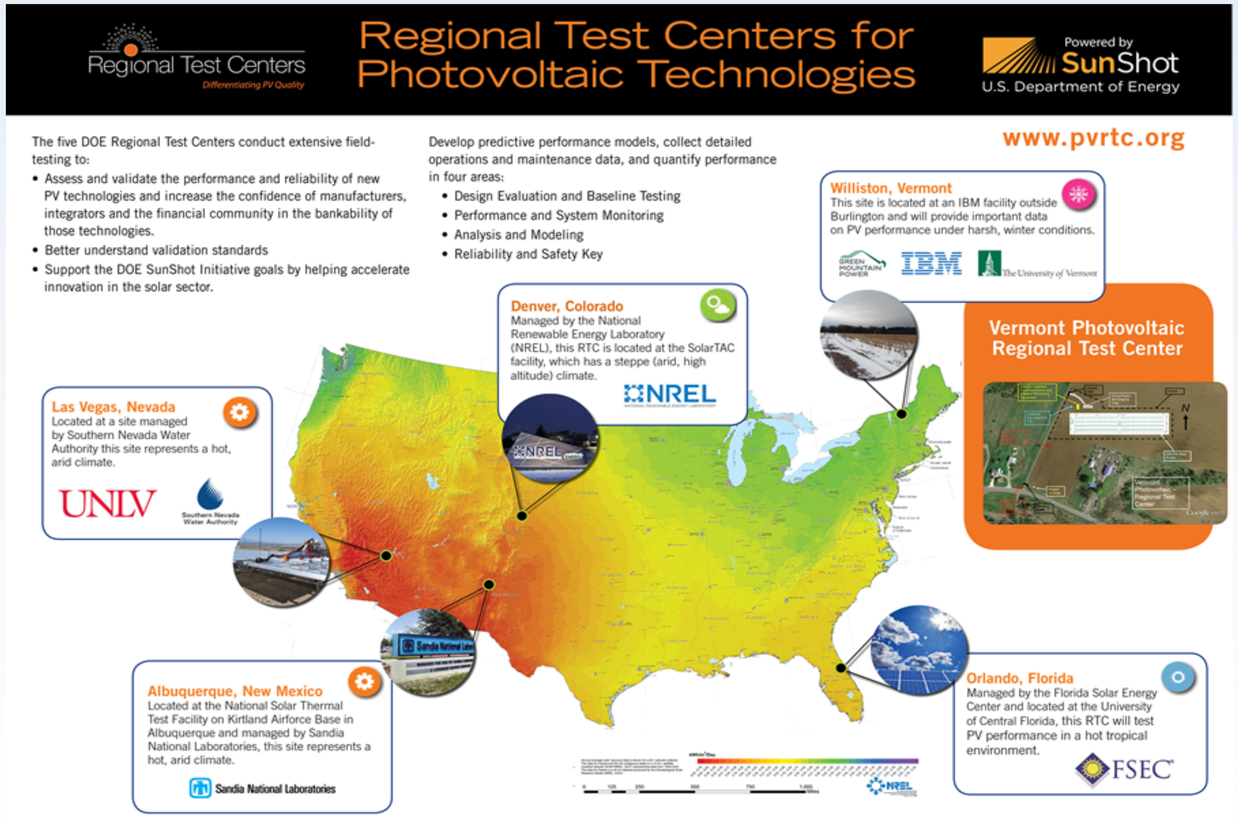
Predicts II?



Scalable Deployments from Components to Systems

- 1-month to multi-year installations
- Evaluate materials and component reliability and degradation rates
- Flexible, stand-alone platforms at any orientation
- Tracker-mounted for maximum sun exposure
- Can be set up to be completely autonomous
- Configured per experimental needs

- Minimum 1-year installations typical
- Evaluate system reliability and degradation rates
- Validate energy yield calculations
- DC Voltage and Current (string and combiner)
- Module Temperature
- Localized Irradiance Sensors



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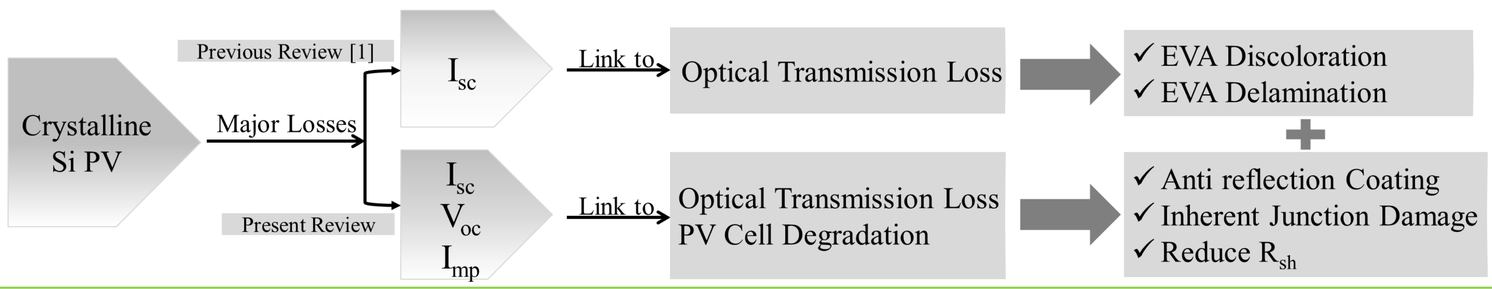
Causes of the Most Frequent Degradation Mode of Crystalline Silicon Photovoltaic Modules

Mohammad Aminul Islam[1], Yasuaki Ishikawa[1], Sadao Sakamoto[2], Hidenari Nakahama[3], and Atsushi Masuda[2]
[1] NAIST, [2] AIST, [3] Nisshinbo Mechatronics Inc., Japan

Introduction



- ✓ **No. of modules reviewed: 449**
- ✓ **Observation duration: 1990-2010**
- ✓ **Characteristics measured before and after installation**

Methods and Results

Four different published works has been reviewed in this study-

Case 1: 145 mono- & multi-Si PV modules at Hamamatsu, Japan for 1990-2000 [2].

Case 2: 42 mono-Si PV modules at Southern Spain for 1996-2008 [3].

Case 3: 70 multi-Si PV modules at Northern Italy for 1991-2010 [4, 5].

Case 4: 192 mono-Si PV modules at N. California, cool marine environment, for 1990-2001-2010 [6].

Case 1 Similar degradation in delaminated and non-delaminated modules

Table 1 Average power loss(%), coefficient of correlation between ΔP_{max}x ΔI_{sc} and ΔP_{max}x ΔV_{oc}, and visual observation (each group is for different manufacturer)

Group	Ave. ΔPmax/%	Corr. Coef., $\Delta P_{max}x\Delta I_{sc}$	Corr. Coef., $\Delta P_{max}x\Delta V_{oc}$	Delamination
B	6	0.52	0.6	O
C	6.4	0.13	0.34	x
H	6.5	**0.97**	**0.84**	x
M	5.9	**0.88**	**0.84**	O

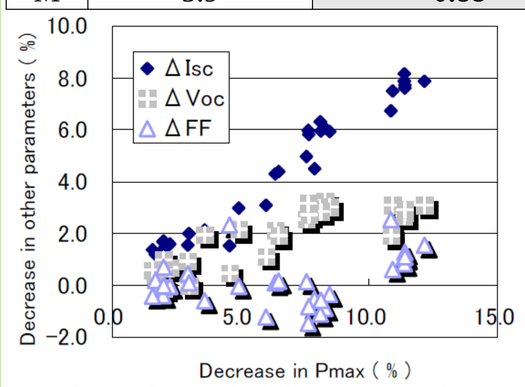


Fig. 1 Group H (29, non-delaminated) [2]

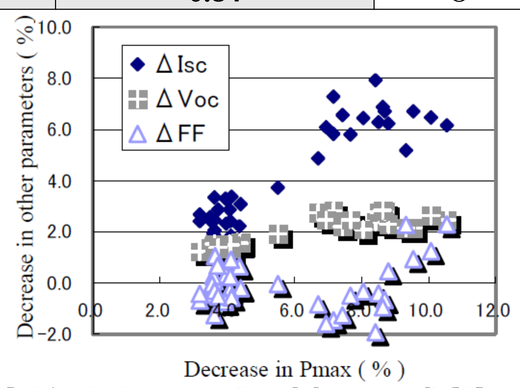


Fig. 2 Group M (39, delaminated) [2]

Delaminated and non-delaminated modules are showing similar losses indicating delamination is not the only cause of I_{sc} or P_{max} degradation.

Case 2 Correlation between the visual defects and electrical parameters

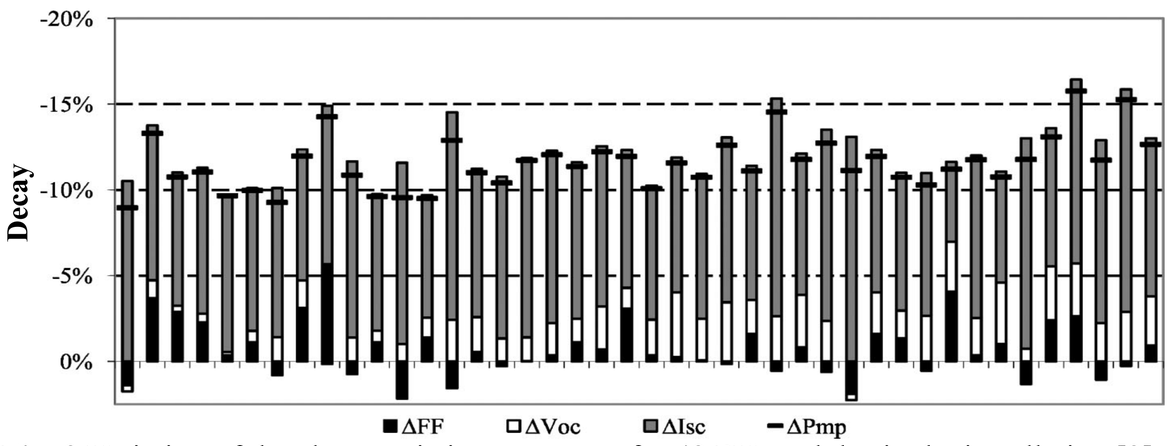


Fig. 3 Variation of the characteristic parameters for 42 PV modules in the installation [3]

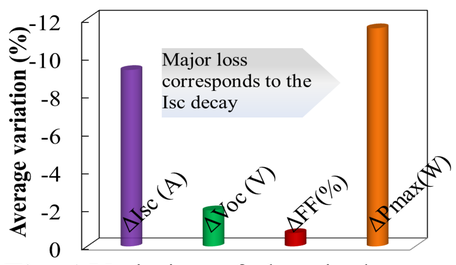


Fig. 4 Variation of electrical parameters after 12 years of installation

I_{sc}/P_{max} loss mechanisms is ascribed to the-
- ☐ Antireflective coating,
- ☐ Front delamination and
- ☐ Inherent junction degradation.

Case 3 20 years of field exposed (all discolored, slightly deteriorated)

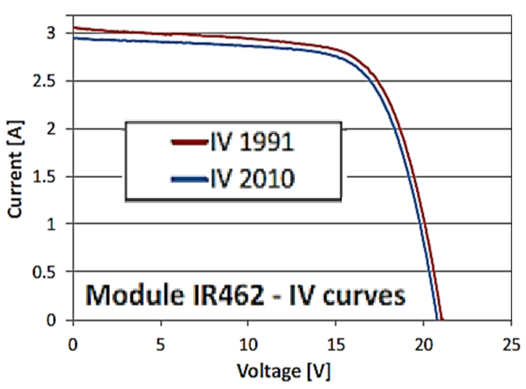


Fig. 5 I-V curve of a module at 1991 and 2010 [4]

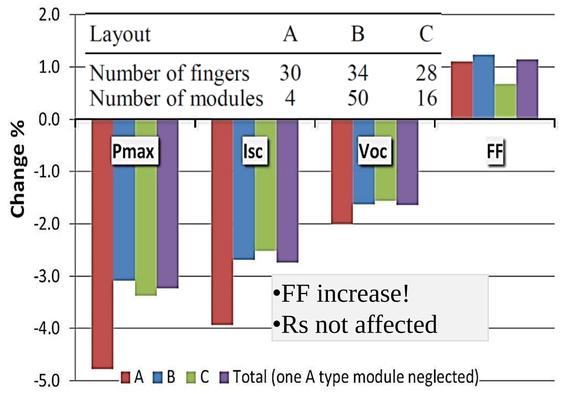


Fig. 6 Average change of I-V parameters [4]

Table 2 Average electrical parameters change from 1991to 2010

	I_{sc} [A]	V_{oc} [V]	FF [%]	P_{max} [W]
Absolute change	-0.079	**-0.51**	0.57	-1.82
Change [%]	-2.6	**-2.4**	0.8	-4.1

**Modules degraded by keeping the shape of the I-V curve, similar degradation was found recently in PID of n-type Si PV module [7].*

I_{sc}/P_{max} losses may dominated by the-
- ☐ Discoloration
- ☐ Diffusion length variation
- ☐ Crack
- ☐ Cell quality

Case 4 20 years of field exposed module (non-uniform degradation)

- ☐ First 11years -degradation rate: 0.4%/y, EVA yellowing observed
- ☐ Next 9 years -degradation rate: 1.37%/y, indication of additional deterioration mechanism

Table 3 Statistical comparison of module parameters (partially modified from [6])

Statistic	Year	P_{max} (W)	I_{sc} (A)	V_{oc} (V)	I_{mp} (A)	V_{mp} (V)	FF
%Change	1990 v. 2001	**-4.35%**	-4.37%	-0.29%	**-6.31%**	2.12%	0.8%
	2001 v. 2010	**-12.32%**	-6.04%	-0.66%	**-10.94%**	-1.46%	-6.4%
	1990 v. 2010	**-16.13%**	-10.15%	-0.95%	**-16.57%**	0.63%	-5.7%
% Change	1990 v. 2001	-0.395%	-0.398%	-0.027%	-0.574%	0.192%	0.07%
/Year	2001 v. 2010	-1.369%	-0.671%	-0.073%	-1.216%	-0.162%	-0.71%
	1990 v. 2010	-0.807%	-0.507%	-0.047%	-0.828%	0.031%	-0.28%

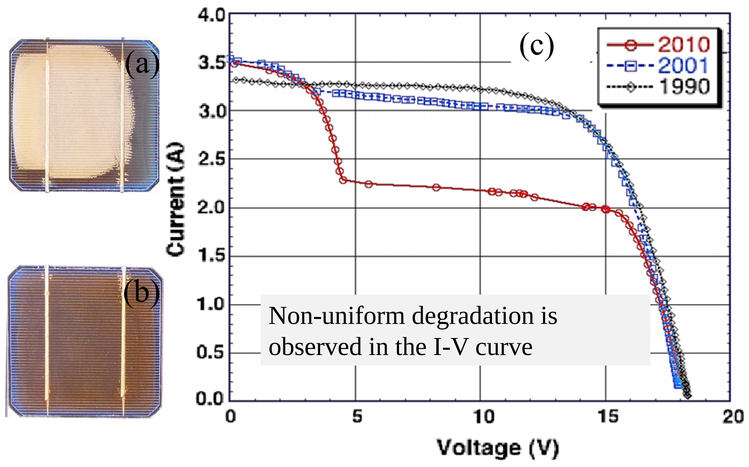


Fig. 7 (a) Delaminated cell, (b) discolored cell, and (c) comparison of IV curves for a module [6]

P_{max} decay corresponded closely to I_{mp} decay rather than I_{sc}

Estimated degradation-
- ☐ Reduce Rsh
- ☐ Delamination
- ☐ Discoloration

Conclusion

※ For crystalline Si PV module, P_{max} loss is dominated by the I_{sc} degradation mode in most cases, although it is not the only cause.

※ However, I_{sc}/P_{max} degradation could not be attributed to only visual changes (optical transmission loss), sometimes, lead to misunderstandings of the main deterioration mechanism.

※Also, delamination and discoloration could affect the cell I_{mp}.

※ It is estimated that several degradation mechanisms of PV cells could affect I_{sc} degradation mode.

※One of the leading cause is the inherent junction quality degradation which induces reduction of V_{oc} as well as I_{sc} of PV cells over time.

References

[1] D. C. Jordan *et al.,* Proc. of 27th EU-PVSEC (2012) 3118-3124.
[2] S. Sakamoto and T. Oshiro, Proc., of 20th EU-PVSEC (2005) 2155-2158.
[3] P. Sánchez-Friera *et al., Prog. Photovolt.: Res. Appl.* **19** (2011) 658-666.
[4] D. Polverini *et al., Prog. Photovolt.: Res. Appl.* **21** (2013) 1004-1015.
[5] A. Pozza and T. Sample, Proc. of 29th EU-PVSEC (2014) 2523-2529.
[6] C. E. Chamberlin *et al.,* Proc. of 37th IEEE PVSC (2011) 101-105.
[7] K. Hara *et al., Sol. Energy Mater. and Sol. Cells* **140** (2015) 361-365.

Role of Encapsulants on the Process Induced Residual Stress in the Crystalline Silicon Solar Cell Modules using 2D Finite Element Simulations

Sasi K. Tippabhotla [1*], W. J. R. Song [1], A. A. O. Tay [1], A.S. Budiman [1]

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SINGAPORE UNIVERSITY OF TECHNOLOGY AND DESIGN

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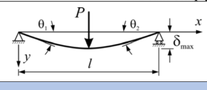
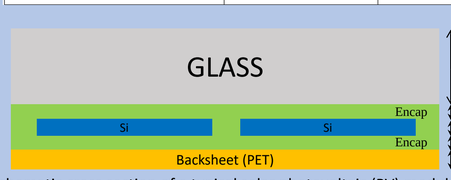
XPV Lab

NREL PVMRW 2017

Introduction

Silicon Stress (from the Theory of Elasticity)

BEAM TYPE	SLOPE AT ENDS	DEFLECTION AT ANY SECTION IN TERMS OF x	MAXIMUM AND CENTER DEFLECTION
6. Beam Simply Supported at Ends – Concentrated load P at the center			
	$\theta_1 = \theta_2 = \frac{Pl^2}{16EI}$	$y = \frac{Px}{12EI}\left(\frac{3l^2}{4} - x^2\right)$ for $0 < x < \frac{l}{2}$	$\delta_{max} = \frac{Pl^3}{48EI}$

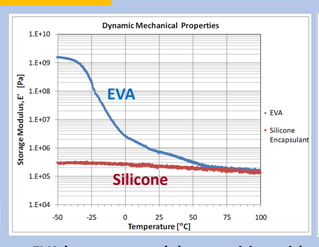


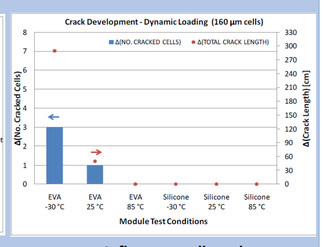
Schematic cross section of a typical solar photovoltaic (PV) module (with crystalline silicon cells showing thickness and elastic modulus of all the layers)

Glass is expected to influence the silicon cell stress but **Encapsulant !! really??**

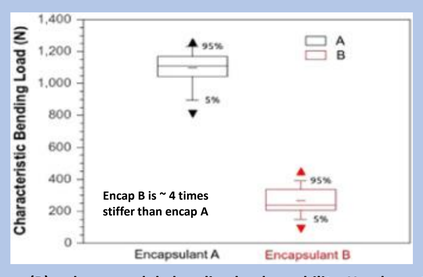
Motivation

- Recent Experimental research studies show strong encapsulant influence on cell fracture [1-2] and residual stress [2]
- Encapsulant, EVA has steep transition of modulus with temperature, hence affects cell residual stress during lamination
- Effect of encapsulant on PV module stress was not modeled systematically





EVA has steep modulus transition with temperature, Influences cell cracks, Mickiewicz et al. , 2011 [1]

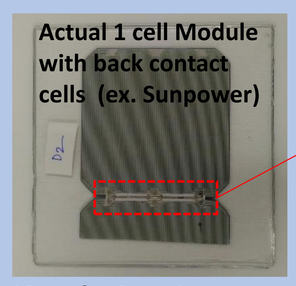


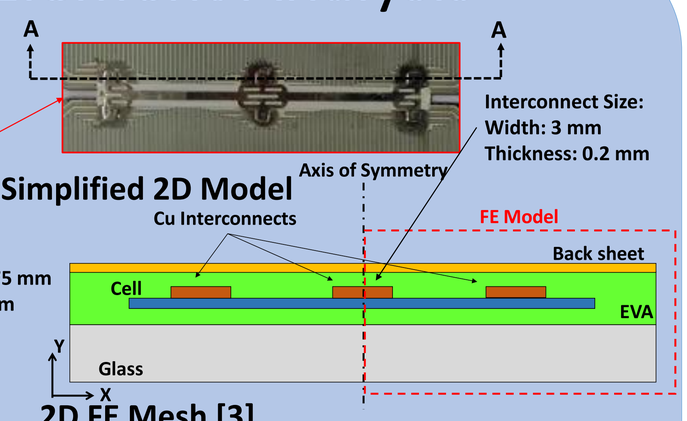
A stiffer encap (B) reduces module bending load capability, Handara et al. , 2017 [2]

Systematic modeling of encapsulant effect on cell residual stress is essential to optimize PV module strength and reliability

2D Finite Element Analysis

FE Model Details



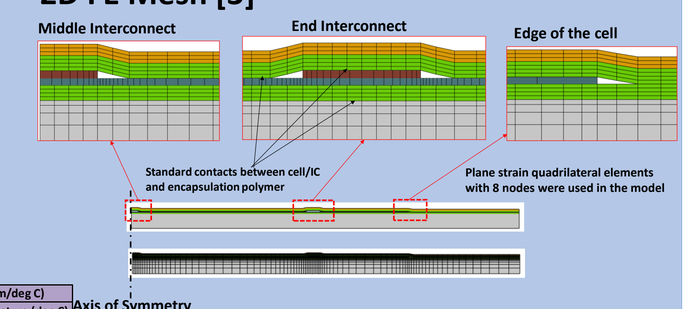


Model Size:
Module: 175x175 mm
Cell: 125x125 mm

Simulation Steps:

1. Soldering of cell & interconnect @ 210 ^{0}C, cooling to room temperature (RT)
2. Lamination:
   a. Preheating to 50 ^{0}C
   b. Vacuum pressure (0.1 Mpa) application
   c. Heating to lamination temperature, 150 ^{0}C
   d. Cooling to RT
3. Mechanical Loading (@RT): Load of 1kN applied as uniformly distributed load over module span

2D FE Mesh [3]



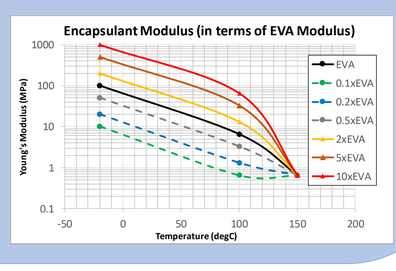
Material Properties [4-5]

Material	Young's Modulus, E (GPa)		Poisson's Ratio	CTE (mm/mm/deg C)	
	Value	Temperature (deg C)		Value	Temperature (deg C)
Silicon	130	---	0.28	1.72E-06	-53
				2.23E-06	-13
				2.61E-06	27
				2.92E-06	67
				3.34E-06	147
Copper (Interconnect)	91.5	-40	0.3	1.70E-05	---
	85.7	25			
	82	125			
	79.2	225			
Glass	73	---	0.235	8.00E-06	---
Encapsulant (EVA)	0.1	-20	0.4	2.70E-04	---
	0.0065	100			
	0.00065	150			
Backsheet	3.5	---	0.29	5.04E-05	---

Encapsulant Material Variation:

$E_{stiff / soft\ encap} = \text{Stiffness Multiplier} * E_{EVA}$ (-20 to 100 ^{0}C)

$CTE_{high / low\ encap} = \text{CTE Multiplier} * CTE_{EVA}$

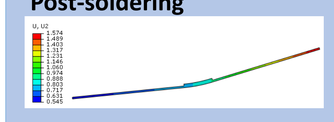


2D FE model can be used to evaluate the limits of encapsulation polymer on cell stress

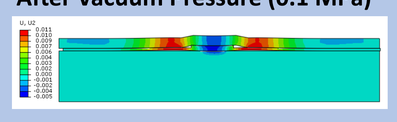
Results & Discussion

Cell deformation during module integration

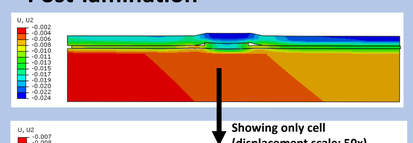
Post-soldering



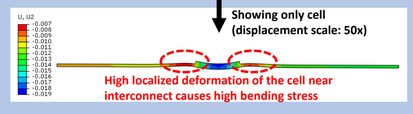
After Vacuum Pressure (0.1 MPa)



Post-lamination



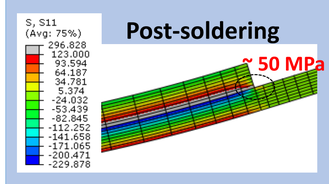
Showing only cell (displacement scale: 50x)



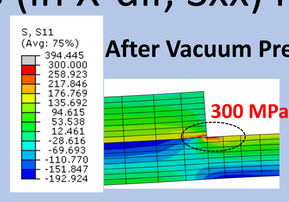
Vacuum pressure and thermal contraction are transferred to the cell through the encapsulant

Cell residual stress (in X-dir, Sxx) near the interconnect

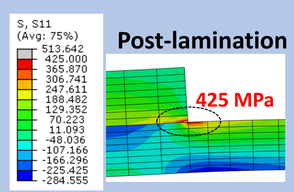
Post-soldering



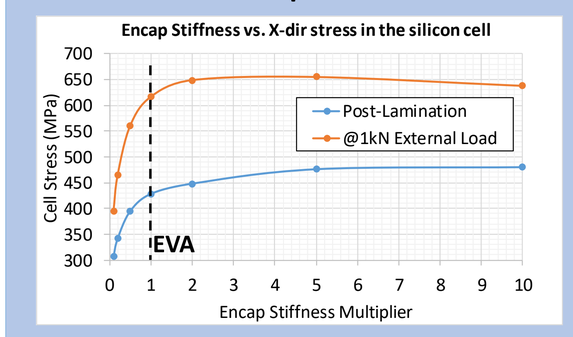
After Vacuum Pressure

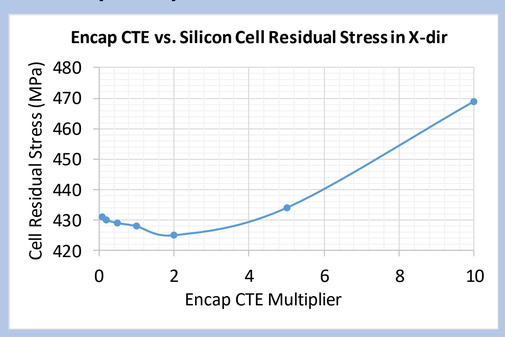


Post-lamination



Effect of encapsulant on cell stress (Sxx)



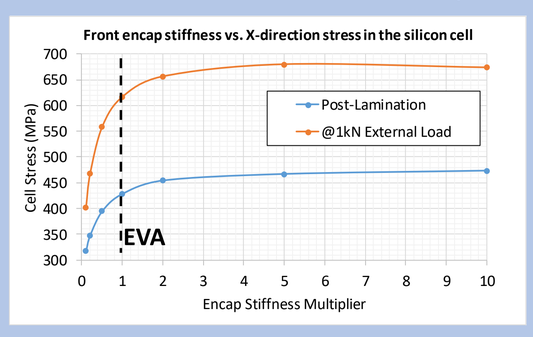


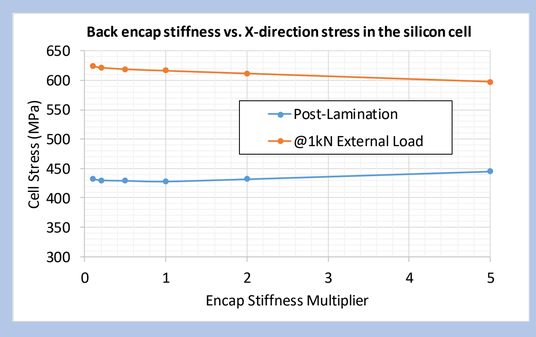
Encapsulant modulus significantly affect the cell stress, both residual and operational

Effect of the CTE of encapsulant on cell stress is insignificant

Results & Discussion cont..

Effect of front/back encapsulant modulus on cell stress (Sxx)





Front encapsulant modulus has dominating effect on the cell stress

Conclusions & Path Forward

Conclusions:

- Encapsulant (front) modulus effects the cell stress significantly
- Selecting dissimilar encapsulants with softer front encapsulant will lower the stress significantly
- This study can be used to guide low stress encapsulation materials

Ongoing Further Research:

- Dynamic mechanical analysis (DMA) of commercial encapsulants evaluate the actual modulus differences.
- Experimental evaluation of mini-modules with different encapsulation polymers to validate the FE simulations.

Acknowledgements

Singapore National Research Foundation *(Grant No. NRF2013EWT- EIRP002-017)*

Sunpower Corporation, CA, USA

REC Solar Pte. Ltd.

NATIONAL RESEARCH FOUNDATION
PRIME MINISTER'S OFFICE
SINGAPORE

SUNPOWER®

REC Solar

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2. V. A. Handara et al., Solar Energy Materials and Solar Cells, Volume 162, April 2017
3. ABAQUS 6.14, SIMULIA, Dassault Systems, 2015
4. Ulrich Eithner, PhD Thesis, Martin Luther University Halle-Wittenberg, 2011.
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RCPV Research Center for Photovoltaics

NMIJ

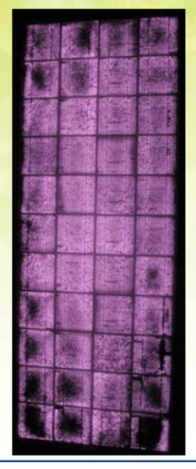
Cause of Current-Collection Failure Observed in *I*sc-Reduction Phase of PV Cells and Modules Exposed to Acetic Acid

°Tadanori Tanahashi, Norihiko Sakamoto, Hajime Shibata, and Atsushi Masuda
National Institute of Advanced Industrial Science and Technology (AIST), Japan

Introduction & Experimental Procedures

Motivation

How does *I*sc-reduction contribute to the power-loss, irrespective of irradiance-reduction by discoloration?



Our Experience

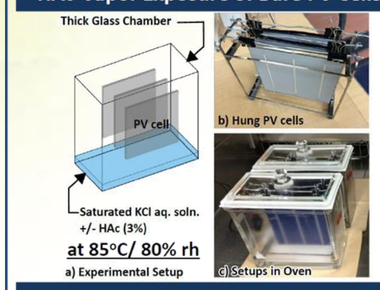
Mfg. in 1993
in field (Cfa): over 20 years

***P*max: -21.8%**
***I*sc: - 7.3%**
***V*oc: -1.5%**
FF: -14.4%
(vs. Name Plate)

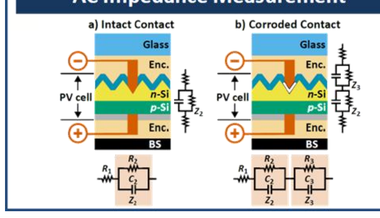
-No / Slight Discoloration
-ca. 1%/Year Degradation with Δ Isc & Δ FF

Experimental (HAc = Acetic Acid)

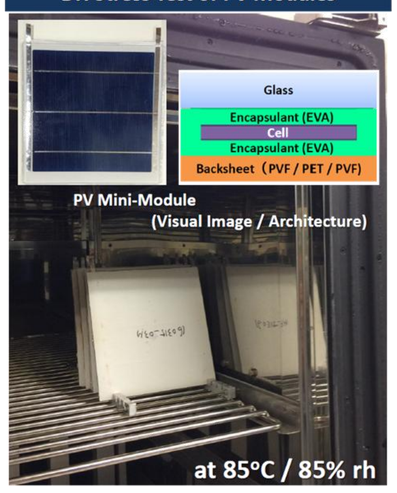
HAc-Vapor Exposure of Bare PV Cells



AC Impedance Measurement

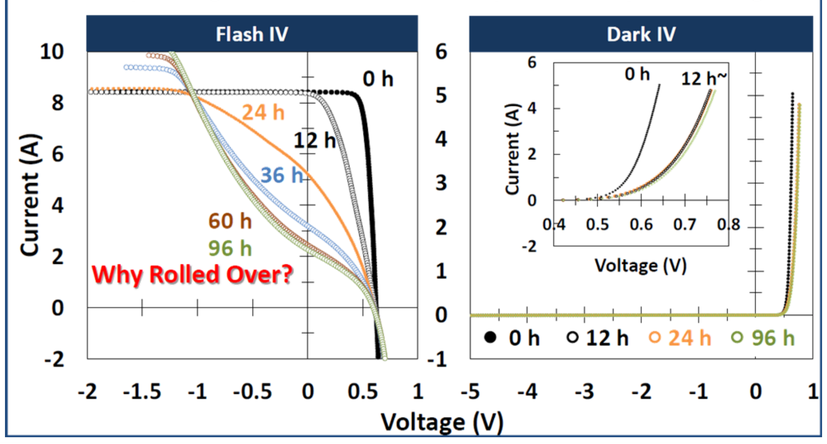


DH Stress Test of PV Modules



Background (HAc-Vapor Exposure of Bare PV Cell)

- *R*s rapidly increased during the early stage of HAc-vapor exposure.
- *Additional enhancement of Rs is not induced by further exposure.*
- Electric power generation is substantially reduced by decreasing *I*sc.



Summary

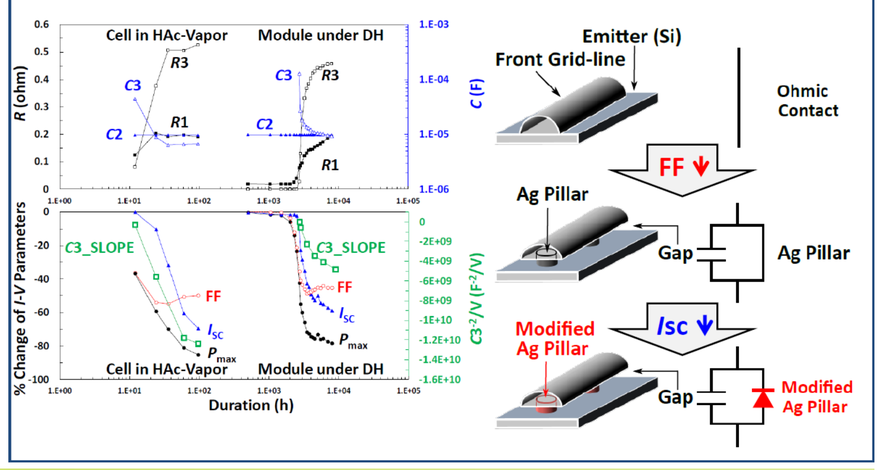
We have proposed the two-phase degradation mechanism involved in the corrosion process of PV cells / PV modules, which is comprised of power-losses induced by FF-reduction (Phase I) and by ***I*sc-reduction (Phase II)** [Tanahashi et al., *Proc. 43rd IEEE Photovoltaic Spec. Conf.*, 2016, pp. 1075–1079]. Although we have already known that the degradation in FF-reduction phase (Phase I) is due to the formation of gap underneath front electrodes, **the precise mechanism on degradation in *I*sc-reduction phase (Phase II) has not been understood**.

In this study, we analyzed the characteristics of AC impedance of PV cells and PV modules in Phase II, by DC bias-voltage dependency of them. And, it is suggested that **the power-loss in *I*sc-reduction phase (Phase II) is induced by denaturation or modification of direct contact (with shift from ohmic contact to rectifying contact) between silver (Ag) bulk and emitter of Si wafer**, from the following results;

- In both corrosion tests (acetic acid-vapor exposure of PV cells and damp-heat stress test of PV modules), DC bias-voltage dependency of *C*3 was drastically changed in the *I*sc-reduction phase (**Panels 4 & 8**), although the characteristics of *p*-*n* junction (*R*2 and *C*2) were stable even in this phase (**Panels 2 & 6**).
- In both test conditions, the evolutions of ***C*3_SLOPE** were correlated with those of *I*sc (**Right Panel** & **Panel 12**).
- By using the degraded PV cell with single-comb front grids, the origin of current-collection failure in the *I*sc-reduction phase was identified as in the front grids (**Panels 9 to 11**).

Conclusions

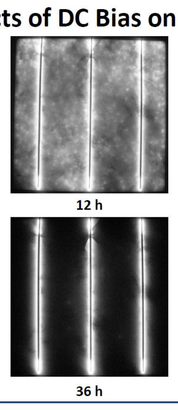
Correlation between Evolutions of *C*3_SLOPE and *I*sc (left panel), and Putative Degradation Mechanism (right panel).

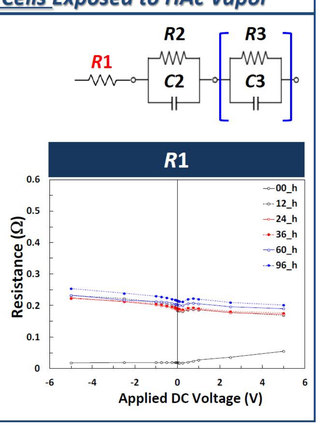


Results

Panel 1: in *Bare PV Cells Exposed to HAc Vapor*

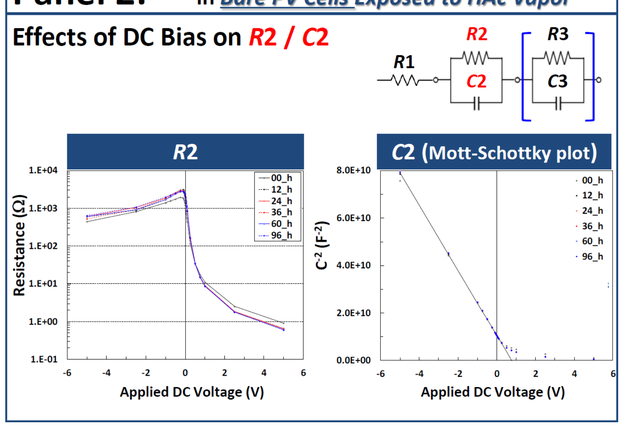
Effects of DC Bias on *R*1





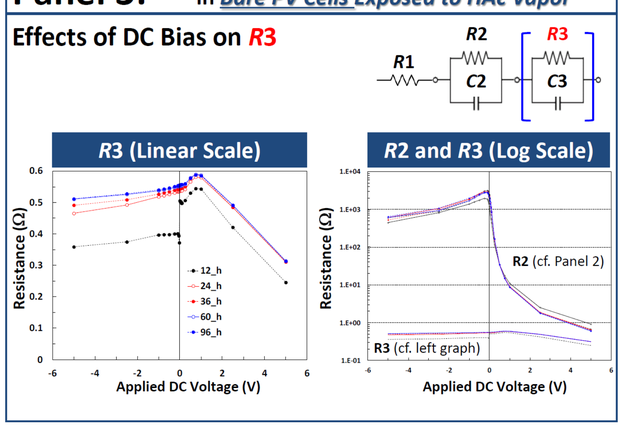
Panel 2: in *Bare PV Cells Exposed to HAc Vapor*

Effects of DC Bias on *R*2 / *C*2



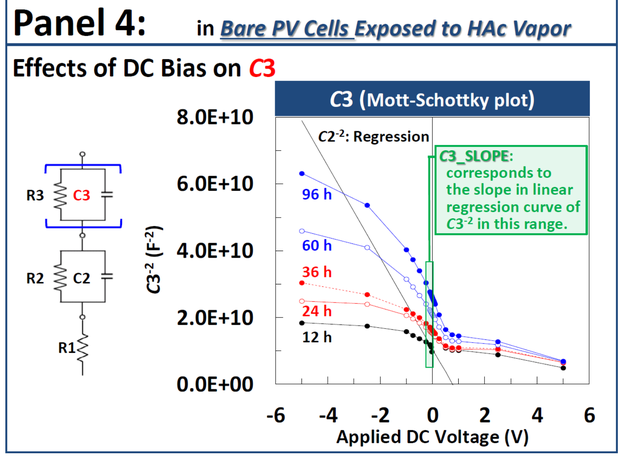
Panel 3: in *Bare PV Cells Exposed to HAc Vapor*

Effects of DC Bias on *R*3



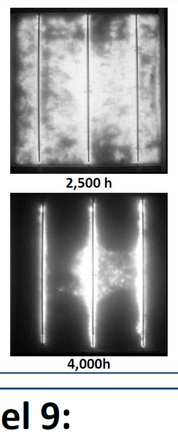
Panel 4: in *Bare PV Cells Exposed to HAc Vapor*

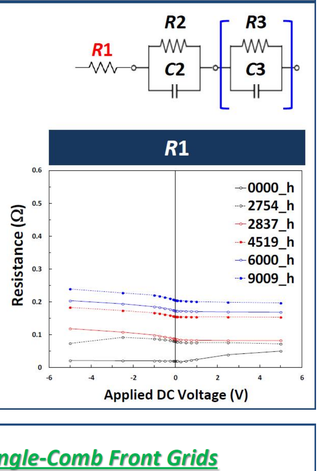
Effects of DC Bias on *C*3



Panel 5: in *PV Modules under DH Stress Test*

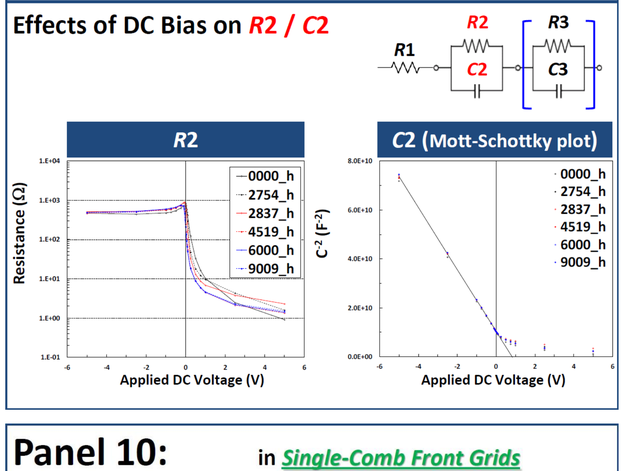
Effects of DC Bias on *R*1





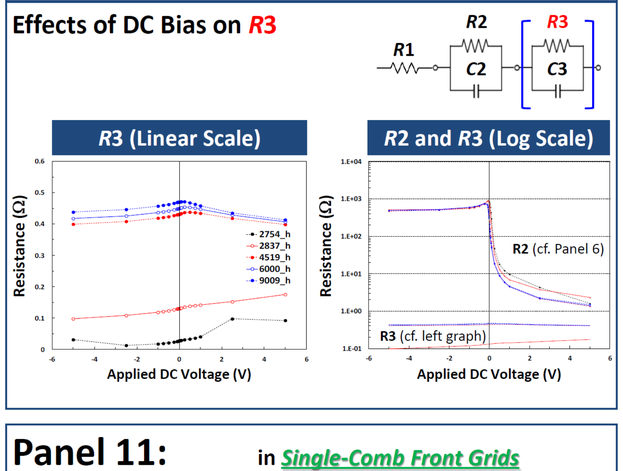
Panel 6: in *PV Modules under DH Stress Test*

Effects of DC Bias on *R*2 / *C*2



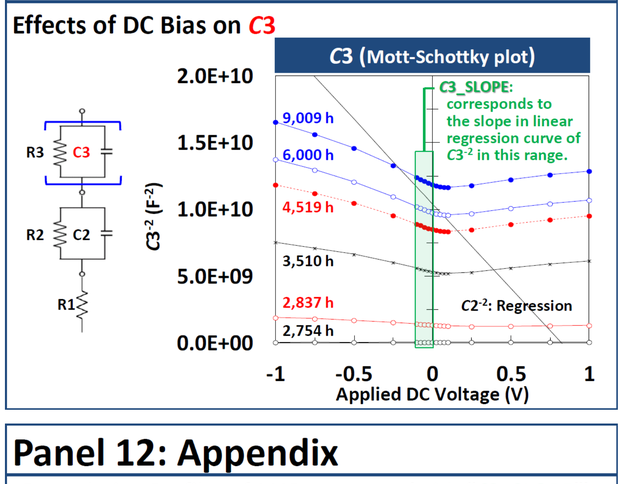
Panel 7: in *PV Modules under DH Stress Test*

Effects of DC Bias on *R*3



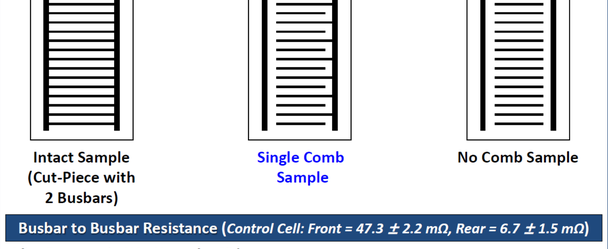
Panel 8: in *PV Modules under DH Stress Test*

Effects of DC Bias on *C*3



Panel 9: in *Single-Comb Front Grids*

Preparation of Single Comb in Front Grid-Lines



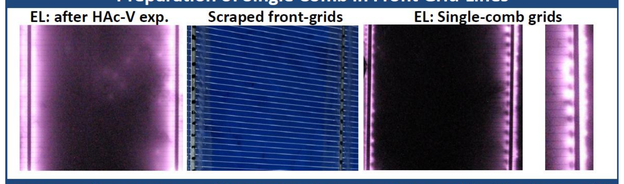
Busbar to Busbar Resistance (*Control Cell: Front = 47.3 ± 2.2 mΩ, Rear = 6.7 ± 1.5 mΩ*)

After Exposure to HAc-Vapor for 48 h

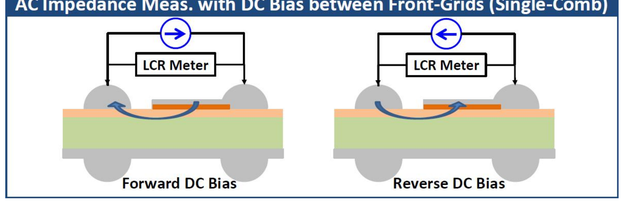
	Intact	*Single-Comb*	*No Comb*
Front = 48.7 ± 2.0 mΩ		6.86 ± 0.36 Ω	17.2 ± 1.1 Ω
Rear = 7.5 ± 2.0 mΩ		9.70 ± 2.40 mΩ	9.8 ± 2.2 mΩ

Panel 10: in *Single-Comb Front Grids*

Preparation of Single Comb in Front Grid-Lines

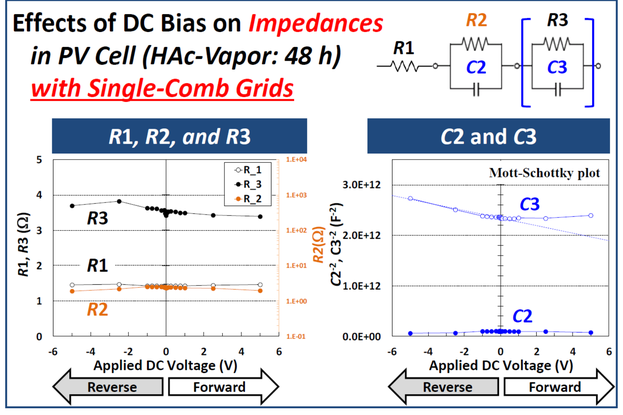


AC Impedance Meas. with DC Bias between Front-Grids (Single-Comb)



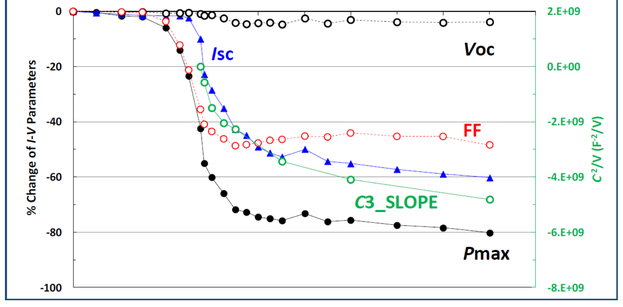
Panel 11: in *Single-Comb Front Grids*

Effects of DC Bias on *Impedances in PV Cell (HAc-Vapor: 48 h) with Single-Comb Grids*



Panel 12: Appendix

Degradation Profiles of *I*-*V* Parameters (with "*C*3_SLOPE") during DH Stress Test of PV module



This work was supported by New Energy and Industrial Technology Development Organization, Japan.
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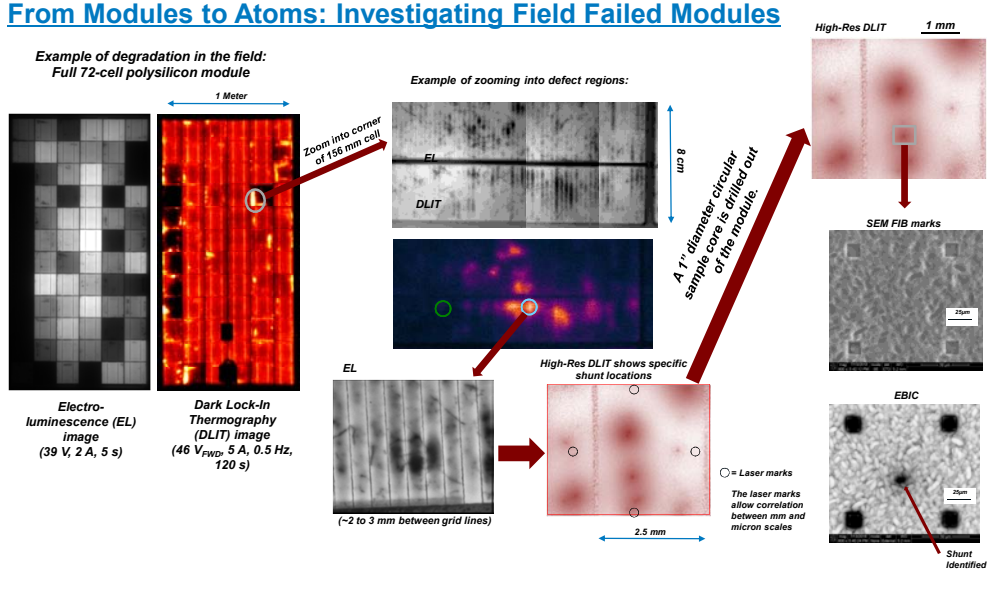
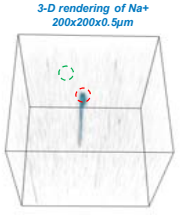
Investigating PID Shunting in Polycrystalline Silicon Modules via Multi-Scale, Multi-Technique Characterization

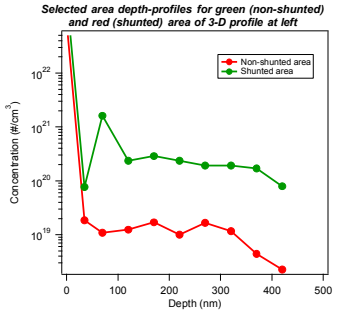
Steven P. Harvey, John Moseley, Adam Stokes, Andrew Norman, Brian Gorman, Peter Hacke, Steve Johnston, Mowafak Al-Jassim

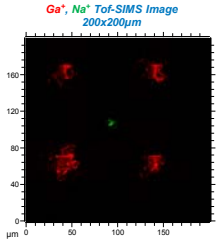
From Modules to Atoms: Investigating Field Failed Modules



- *Sodium at a concentration of ~1 atomic % decorating a structural defect is causing shunting in this region of the module.*
- *TEM analysis of similar shunted areas confirm presence of stacking faults.*







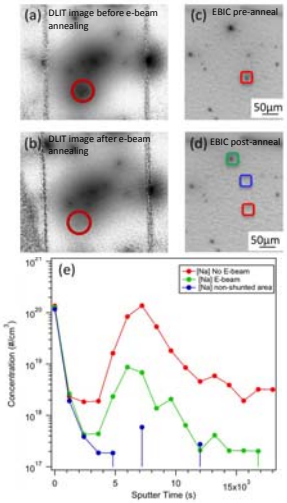
Recent Publications

1. Harvey, S.P., et al., Sodium Accumulation at Potential-Induced Degradation Shunted Areas in Polycrystalline Silicon Modules. **IEEE Journal of Photovoltaics**, 2016. 6(6): p. 1440-1445.

2. Luo, W., et al., Potential-induced degradation in photovoltaic modules: a critical review. **Energy & Environmental Science**, 2017.

In-Situ PID recovery in an SEM

- *We have recently documented the recovery of individual PID shunts in an SEM via electron-beam induced annealing.*
- *TOF-SIMS shows at-least an order-of-magnitude decrease in sodium content in the recovered PID defects.*

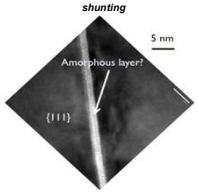


- TOF-SIMS selected-area depth profiles from areas shown in (d); red is the annealed shunt, green is a non-annealed shunt; a nonshunted region is shown in blue for comparison.
- An order-of-magnitude decrease in sodium content is noted due to the high-resolution EBIC scan of a single shunt.

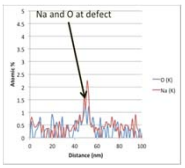
Is Sodium the Only Culprit in PID Degradation?

TEM & Atom-Probe Tomography show sodium & oxygen at PID shunts

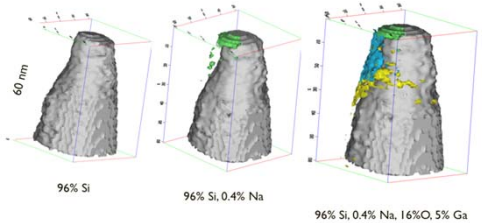
HRTEM image showing {111} defect associated with PID shunting



STEM EDS line profile shows segregation of small amounts (1-2 atomic %) of Na and O to the defect

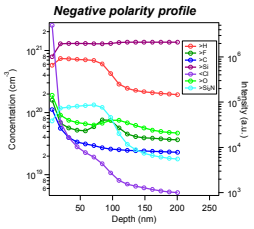


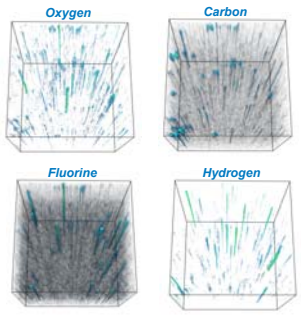
Atom Probe Tomography of PID shunt reveals Na (green), O (blue) present at the defect consistent with the STEM results



TOF-SIMS negative polarity measurement identifies additional species potentially related to PID shunting

Negative polarity profile





- *The species H, Cl, F, C, O, have a distribution similar to sodium in PID shunts.*
- *However they are not all localized at the same structural defects*

All images are 200x200x0.2µm

Future work in this area:

- *We will utilize the DLIT + EBIC + FIB marking techniques we have developed to investigate the affect of PID recovery on sodium distribution in individual shunts.*
- *Utilizing these same techniques, we will elucidate the potential role of oxygen, chlorine, fluorine, hydrogen, or carbon in PID shunting.*

This work was supported by the U.S. Department of Energy under Contract No. DE-AC36-08-GO28308 with the National Renewable Energy Laboratory.

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Contact: Steve.Harvey@nrel.gov

Effect of Light Irradiation on PID Testing of CIGS Photovoltaic Modules

Hiroshi Tomita[1], Darshan Schmitz[1], Shuuji Tokuda[1], Keiichiro Sakurai[2], Kinichi Ogawa[2] and Atsushi Masuda[2]

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February 28, 2017. NREL / SNL / BNL PV Reliability Workshops

Summary

Premise: **Indoor PID testing in dark conditions is not representative of field conditions since system bias is not typically generated without sunlight exposure.**

Goal: **To study effect of light irradiation during and after PID stress of CIGS modules.**

Findings: **1. Conducting PID stress in the dark causes temporary power loss. While partial recovery is observed after light soaking, power loss still remains.**
2. Applying light irradiation during PID stress further suppresses power loss.

Introduction

IEC standards for testing of potential-induced degradation (PID), one of the most severe forms of degradation for photovoltaic (PV) modules, are currently being developed by the PV community. PID testing is typically conducted under high voltage stress, high temperature, in a *dark* condition. In the field, however, PV systems experience high system bias and high module temperatures only when exposed to significant levels of sunlight. For example, in the case of CIGS modules manufactured by Solar Frontier (SF), module temperature does not rise above 50℃ when exposed to low levels of irradiation (< 200 W/m^2) as shown in Figure 1. Irradiation dependence of normalized open-circuit voltage (V_{oc}) of CIGS cell is also plotted in the same figure. V_{oc}, an element of system bias, declines with the decrease of irradiation.

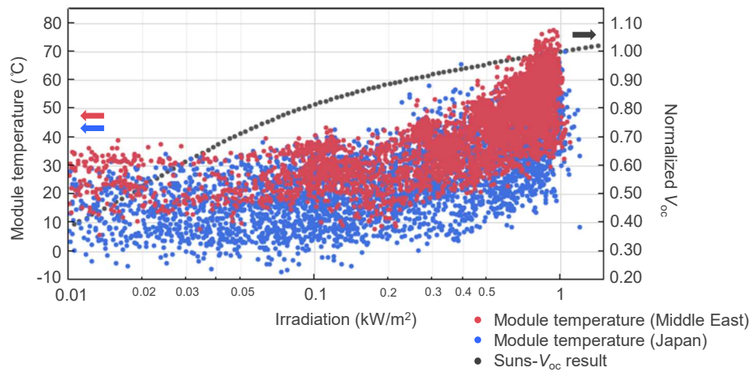

Figure 1: Irradiation dependence of CIGS module temperature (red and blue dots, left axis) and irradiation dependence of open-circuit voltage of CIGS cell fabricated by SF (gray dots, right axis). The former data are collected in the field (Middle East and Japan) and the latter data are from Suns-V_{oc} measurement. The latter values are normalized with V_{oc} at 1.0 kW/m^2.

The negative impact of a dark condition with high temperature is negligible in some PV reliability tests. However, last year we confirmed that damp heat (DH) testing in dark conditions causes degradation that is not observed in the field (test-specific degradation, or 'TSD'). Applying light irradiation or forward bias during the test prevented modules from exhibiting TSD [1, 2]. Based on the results of these DH tests, we assumed the same issue may also arise in PID testing.

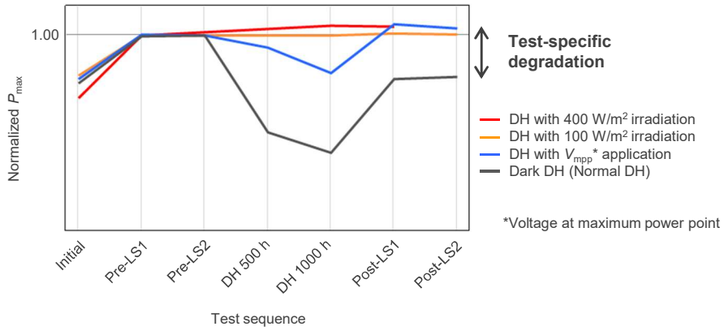

Figure 2: Results of DH testing for CIGS modules with varying test conditions. Commercial modules manufactured by SF were used. DH without light irradiation caused TSD. Application of light irradiation or forward bias during the DH test prevented TSD.

Motivation

In this study, we surveyed the effect of light irradiation on PID testing. To achieve this goal, we conducted two PID tests: one with a dark condition during stress and one with light irradiation during stress. We also evaluated the recovery of module performance with the addition of post conditioning (light soaking, LS) after the PID stress.

Experimental procedure

Test sequence

The test sequence in this study is indicated in Figure 3. After preconditioning (LS), 300 hours of DH stress was performed before the PID stress to simulate more severe field conditions. After the PID test, post-LS and I-V measurements were performed at every 10 kWh/m^2 to check for recovery.

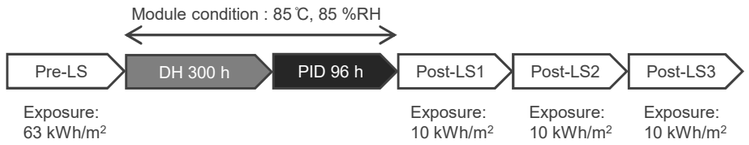

Figure 3: Sequence of DH and PID tests in this study.

Test conditions

The test conditions used in this study are shown in Table 1. Conditions for pre- and post-conditioning as well as the DH stress preceding PID are common for all tests. The final test noted in Table 1, PID with forward bias application, is now in progress and referred to in the discussion section. For all tests, commercial CIGS modules manufactured by SF were used.

Table 1: Conditions of PID test in this study.

Test type	Pre/post LS	DH stress	PID stress	Status
1. Dark PID	Metal-halide lamp 1000 W/m^2 P_{mpp}-state**	85℃, 85 %RH with V_{mpp}, 300 h	Dark, without V_{fwd}* (Normal PID test)	Complete
2. PID with light irradiation			Under 200 W/m^2, Resistor-loaded. See Figure 4(b).	Complete
3. PID with V_{fwd}* application			Dark, with V_{mpp}	In progress

*V_{fwd} : forward bias
** P_{mpp} : Power at maximum power point.
Module cables are connected to a resistor during LS to simulate P_{mpp}-state.

Setup for test type 2: PID testing with light irradiation

A test chamber containing white-LEDs was used for the PID test with light irradiation (see Figure 4(a)). Irradiance of 200 W/m^2 was used during the PID stress. Figure 4(b) indicates the setup for the test. Test module cables were connected to a resistor to keep forward bias generated by light. The module condition was maintained at 85℃ / 85 %RH during the test under 200 W/m^2.

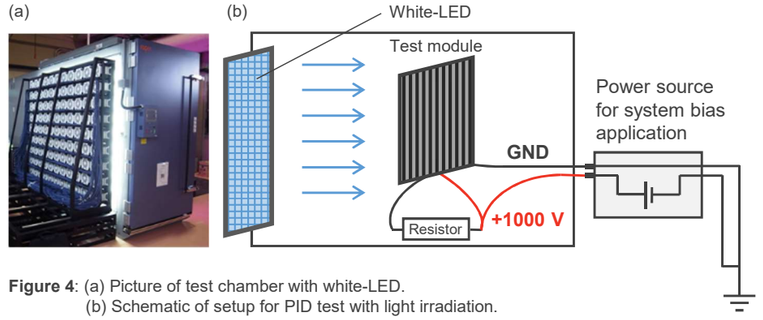

Figure 4: (a) Picture of test chamber with white-LED.
(b) Schematic of setup for PID test with light irradiation.

Results

Figure 5 shows the results of test type 1, DH + dark PID (gray line), and test type 2, DH + PID with light irradiation (red line). In the case of DH + dark PID, the modules exhibited temporary power loss immediately after the PID stress, but showed quick recovery with the following post conditioning. There was, however, still some power loss that remained even after post-LS3. In the case of DH + PID with light irradiation, the degree of power loss after the PID test was much smaller and the module showed complete recovery after post-LS1. These results suggest the existence of TSD during the PID stress conducted in the dark.

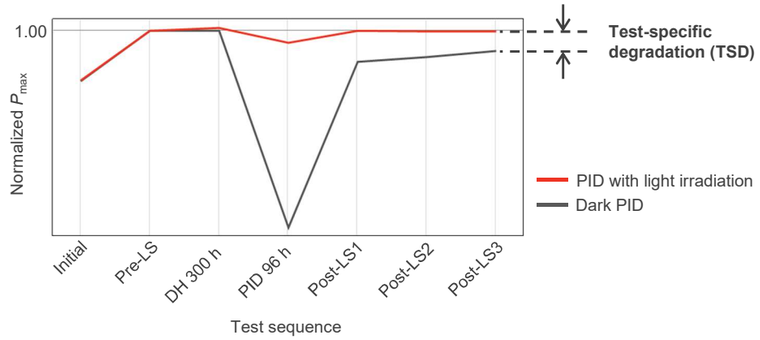

Figure 5: Comparison of test results between PID in the dark and PID with light irradiation. All P_{max} values on the left axis are normalized to 1.00 by the P_{max} value measured just after the pre-LS.

Discussion

As described in the previous section, this study revealed that power loss can be suppressed and recovered with the use of light irradiation in PID testing. A similar result has been reported with crystalline silicon modules, in which degradation was suppressed with the use of light irradiation during PID testing [3].

We are working to identify the suppression mechanism of light irradiation. In the case of DH testing, forward bias is the key factor in preventing modules from exhibiting TSD (see Figure 2). Therefore forward bias generated by light irradiation might also suppress power loss in PID testing. We are now planning two tests to check this assumption. The first is a PID test with forward bias applied under dark conditions and the second is a PID test with light irradiation while the modules are in short-circuit.

In the field, PID occurs only when the module is exposed to sunlight. Our results suggest that a test lacking light or bias voltage, might be too harsh, or might be invoking a different degradation that occurs only in test chambers. Therefore, PID test standards may need alternative options to bring the test conditions closer to field conditions, such as adding light irradiation or forward bias during the PID stress.

References

[1] H. Tomita et al., "Alternate DH Test Methods to Mitigate Test-Specific Degradation in CIGS Modules" NREL PV Module Reliability Workshop, Denver, 2016.
[2] K. Sakurai et al., "Bias and Irradiation Dependence of CIGS Module Reliability during Heat Tests" Proc. 32nd EU PVSEC, Munich, 2016, p.1690.
[3] S. Koch et al., "Work towards Simulation Model for the Potential Induced Degradation Effect on Crystalline Silicon Cells" Proc. 28th EU PVSEC, Paris, 2013, p.1665.

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Notice

Our follow-up will be reported at SPIE and EU PVSEC by Keiichiro Sakurai, AIST.

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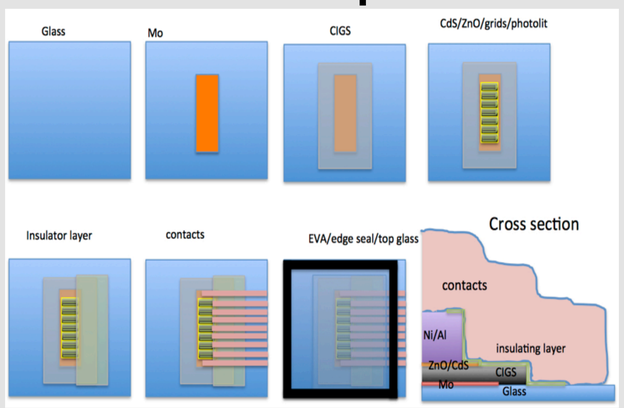
Accelerated PID Testing on Packaged CIGS Devices

Lorelle M. Mansfield, Peter Hacke, Miguel A. Contreras, and Ingrid L. Repins

Abstract

Potential-induced degradation (PID) has been identified in recent years as a source of degradation in some deployed modules. Thus, the community is working to develop accelerated tests and standards that can predict susceptibility to PID in various module designs. In this study, we have packaged small-area CIGS devices with the same type of constructions found in some thin-film modules. Leads to the devices are accessible through the package for more detailed electrical characterization than possible in a full-size module. We observe short-time-scale (<100 hours) PID and associated depletion width widening. Direction of Na movement for the damage is from the substrate (back glass) into the device.

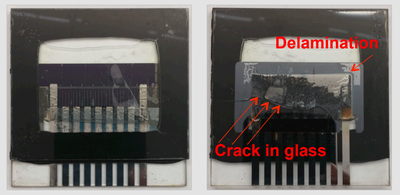
Test Coupons



(Top) Solar cell fabrication using patterned back contact and absorber layers. (Bottom) Coupon fabrication: electrical isolation between front and back contacts, deposition of external contact leads, encapsulation using EVA and PIB edge seal.

PIB Edge Seal Keeps Out Moisture

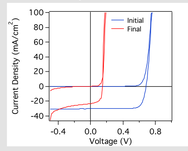
Example of moisture ingress after damp heat stress (85°C/85% RH) in sample with cracked glass:



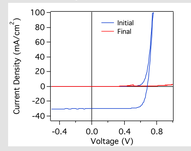
Front *Back*

Moisture causes degradation:

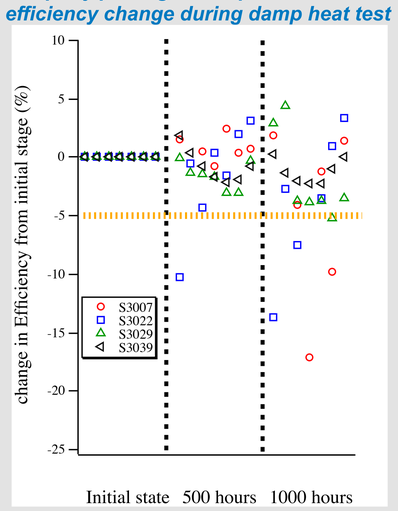
Device 3 Δη = 87%



Device 5 Δη = 100%



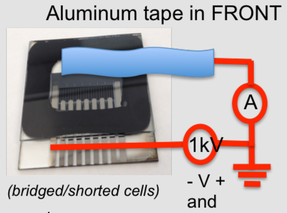
Properly packaged samples show <5% efficiency change during damp heat test



PID Stress

Four Configurations Are Possible

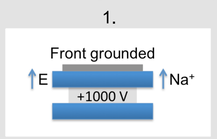
Aluminum tape in FRONT



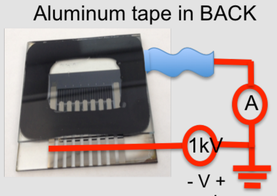
(bridged/shorted cells)

- V + and + V -

1.

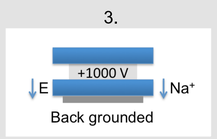


Aluminum tape in BACK

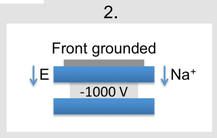


- V + and + V -

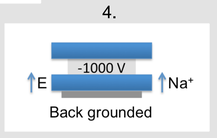
3.



2.

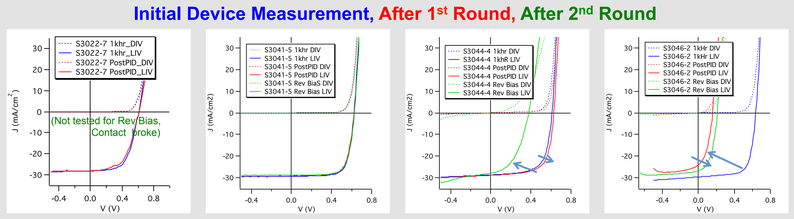


4.

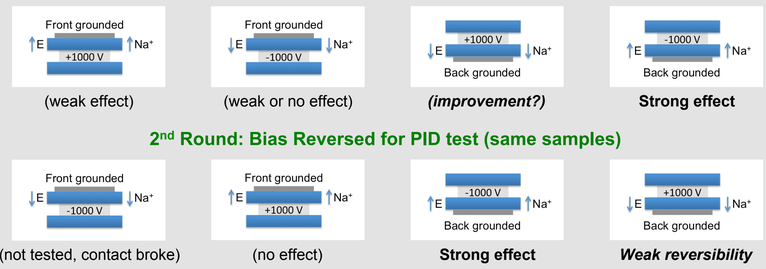


J-V Measurements

Initial Device Measurement, After 1st Round, After 2nd Round



1st round PID test ~ 100 hours

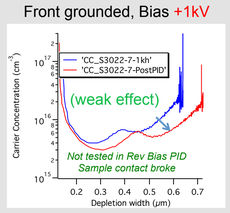


2nd Round: Bias Reversed for PID test (same samples)

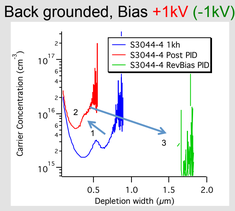
C-V Measurements

Initial Device Measurement, After 1st Round, After 2nd Round

Front grounded, Bias +1kV



Back grounded, Bias +1kV (-1kV)



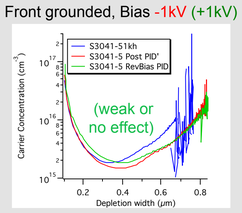
C-V data indicate changes to the p-n junction

Reduced carrier concentration leading to larger depletion width can be from

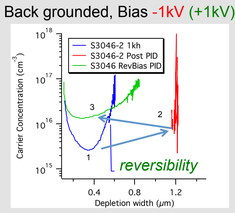
- Depletion of Na in the absorber
- Increased Na in CdS/ZnO
- Or both?

Damaging configuration: Na in glass moves toward the cells

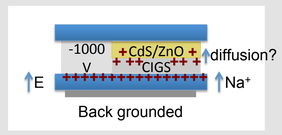
Front grounded, Bias -1kV (+1kV)



Back grounded, Bias -1kV (+1kV)



Weak reversibility as in [2].

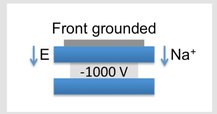


Na may diffuse from the CIGS to the CdS/ZnO
Fjallstrom et al. found Na in CdS by GDOES [3].

Comparisons

Yamaguchi et al. [4] did see PID in front-grounded configuration

- ***Concluded that Na was moving from the top glass to the ZnO***
- ***Similar test set-up to ours, with low humidity***
- ***Began to show cell degradation after 7 days (168 hours)***
- ***Our tests are less than 100 hours***
- ***If we extend the time, we might see the same damage***
- ***Showed recovery when bias was reversed***



Jansen et al. [5] developed a test for transparent conductive oxide (TCO) delamination

- ***Included bias, heat, AND humidity***
- ***Tested TCO on soda-lime glass and borosilicate (low Na) glass***
- ***Found that Na migrated to the TCO/glass interface and reacted with water vapor to cause delamination***
- ***Also showed recovery if bias was reversed before exposure to humidity***

Standards in Progress

Document Number	Stage in IEC Process	Cell Material	Proposed Test Duration (hours)	Proposed Test Temperature (C)	Proposed Test Voltage	Proposed Test RH (%)	Uses foil?
Proposed amendment to IEC 61215	NWIP submitted	Si	Option a: 96 Option b: 168	Option a: 85 Option b: 25	Maximum system voltage	Option a: 85 Option b: <60	Option a: No Option b: Yes
Planned 62804-1-1 (delamination test)	NWIP submitted	Si	250 hour PID test (after 1000 hour damp heat test)	85	Module rated system voltage in negative polarity	85	Yes
IEC 62804-2	CD submitted	Thin Film	Variable	85	Module rated system voltage and polarity	85	Foil frame if no mounting hardware is specified

Conclusions

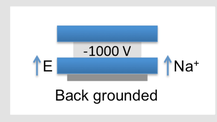
Fabricated test coupons and tested 4 PID configurations

No short-term damage found in front-grounded configurations

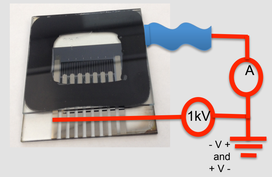
- ***Tests were not as long as Yamaguchi et al.***

Established damaging configuration

- ***back grounded***
- ***-1000 V applied to cells***
- ***Electric field from back glass to cells***



Aluminum tape in BACK



C-V shows the net effect is reduced carrier concentration and large depletion width

Hypothesize that Na moves into the CdS/ZnO

Further investigation planned with Na-free glass to help confirm the origin and destination of the mobile Na^+.

[1] M. A. Contreras, P. Hacke, and I. Repins, "Development of Cu(In, Ga)Se_2 test coupons for potential induced degradation studies," in 2016 IEEE 43rd PVSC, 2016, pp. 0857-0862.

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[3] V. Fjallstrom, P. M. P. Salome, A. Hultqvist, M. Edoff, T. Jarmar, B. G. Aitken, K. Zhang, K. Fuller, and C. K. Williams, "Potential-induced degradation of $CuIn_{1-x}Ga_xSe_2$ thin film solar cells," IEEE J. Photo., vol. 3, pp. 1090-1094, 2013.

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This work is supported by the U.S. Department of Energy under SuNLaMP agreement 30296.

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2017 Module Reliability Workshop
Lakewood, CO
2/28/2017

Presence of sulfur in screen printed front contact mc-Si cells results in Ag depletion in biased damp heat (85°C/85%RH +1kV)

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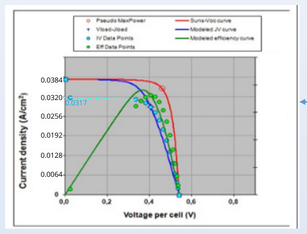
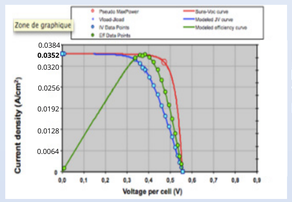
5858 Horton St, Emeryville, CA 94608 & 2 Place Jean Millier, Courbevoie, France

Abstract

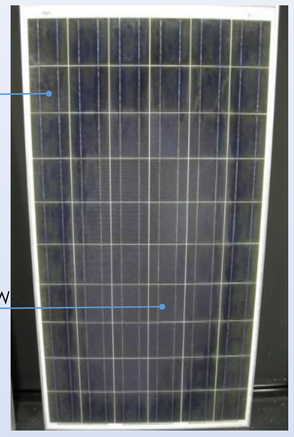
Sulfur compounds present in the screen printed silver conductors of a commercially purchased 2009 front contact mc-Si module resulted in loss of power in 85%RH/85°C biased DH at +1kV. EL images of the edge cells after 600 and 1000 hours showed loss of luminescence. Examination of the silver conducting grid structure of one of the edge cells exhibiting dark EL showed the thickness was half the thickness of the bright EL middle cell. The other half of the edge cell conductor was distributed through the EVA encapsulant and on the glass. The Ag that lifted off with the encapsulant had reacted and converted into $AgSO_4^-$. $AgSO_4^-$ and HSO_4^- are distinctive markers of the degraded metal found in the encapsulant. Sulfur containing compounds were not found in the encapsulant, but were present in the screen printed silver of both good and degraded cells as well as deep in the control (not-aged) sibling module, indicating sulfur was present prior to testing, most likely as an impurity or contaminant.



Pmax = 2.70W
Isc =7.35A
Voc = 0.539V
FF = 0.681



Pmax = 3.16W
Isc = 8.19A
Voc = 0.562V
FF = 0.687



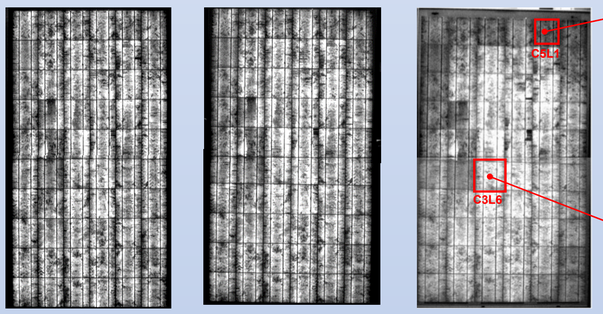
Edge cells discoloration.
Photo of module after 1000 hours.

Analytical Tests

Core cell samples from a front contact 2009 commercial module were examined after 85°C/85%RH Biased DH +1KV exposure.
Edge cells power were substantially lower than center cells

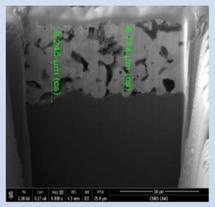
Analytical tests performed:
SEM Imaging
Focused Ion Beam (FIB) cross section
FTIR of the encapsulant
ToFSIMS of the encapsulant and front cell Ag grid conductors
Nano Auger of the control module cell FIB

85°C/85% RH, Biased DH, +1kV*



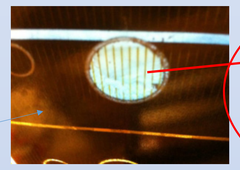
400 hours 600 hours 1000 hours

*cells at +1kV, anodized Al frame at 0V; EVA, glass and silicone RTV at intermediate voltages

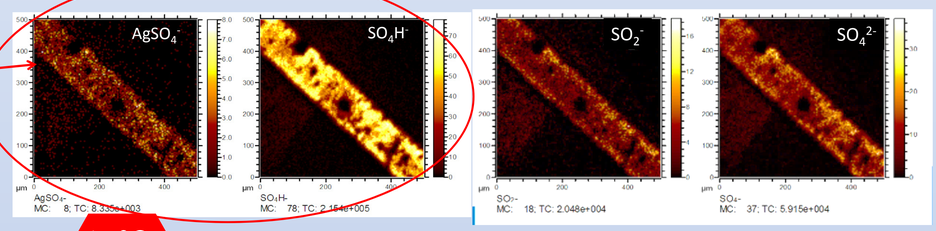


Missing metal?

No S- compounds found in the encapsulant



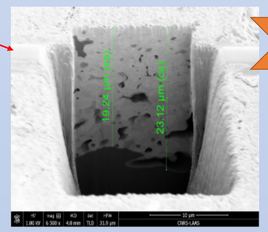
Edge cell (C5L1) encapsulant with degraded printed metal residue



$AgSO_4^-$ HSO_4^-

ToF SIMS of the corroded printed metal material that diffused through the encapsulant to the glass. $AgSO_4^-$ and HSO_4^- present only in the degraded cell

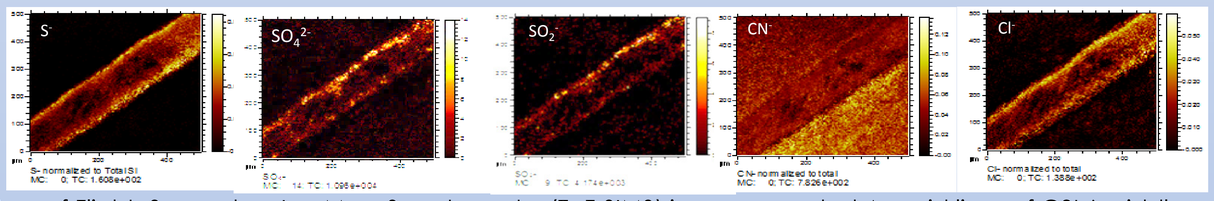
FIBs:
C5L1 edge cell Ag grid line thickness is 8.8 to 9.2 um
compared to C3L6 middle cell: 19.2 and 23.1 um



85C/85%RH +1kV

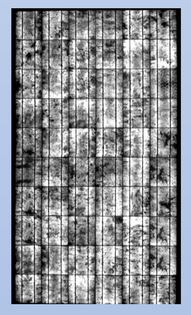
Ag+, S^-, SO_2^- SO_4^{2-} + H_2O

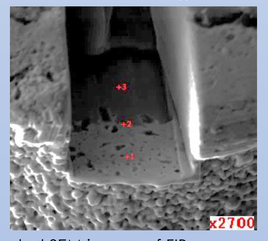
Ag+ HSO_4^-



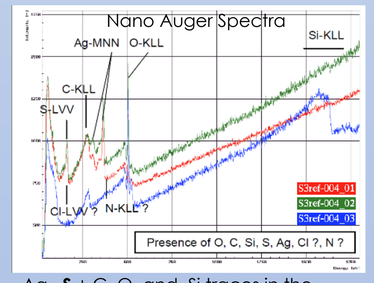
Time of Flight- Secondary Ion Mass Spectrometry (ToF-SIMS) in non-corroded Ag grid lines of C3L6 middle cell

Room Temperature Sibling Control Module





Angled SEM image of FIB cross-section of cell from RT control module. Sulfur found in positions 2 & 3, indicates sulfur is present deep in the conducting grid line, prior to testing.



Ag , **S** + C, O, and Si traces in the middle(+1) and bottom(+2) locations of the grid line found

	ToF SIMS				Auger
Key Results	**Edge Cell Corroded conductors**	**Edge Cell not corroded metal**	**Center Cell not corroded metal**	**Encapsulant**	**RT Control Module cell**
$AgSO_4^-$	YES	NO	NO	NO	
HSO_4^-	YES	NO	NO	NO	
S^- &/or S^- compounds	YES	YES	YES	NO	YES

Results

EL and electrical differences after 85°C/85%RH biased DH +1kV, between the edge and middle cells of this commercial solar module were evident. Fill Factor indicates equally poor series resistance for the edge and middle cells; however, cores examination show the edge cells have undergone irreversible degradation via depletion of Ag in the grid lines.

Cores of a low luminescence cell (edge cell C5L1) and a high luminescence middle of the module cell (C3L6) of the test module were examined. The encapsulant separated easily from the cell area for the edge cell and imprints of the grid lines were visible on the encapsulant and glass.

- FIB cross sections of the cell grid lines showed that the Ag grid line of the degraded cell was about half that of the middle, non-degraded cell.
- ToF SIMS examination of the edge cell degraded line imprints on the encapsulant found $AgSO_4^-$ and HSO_4^-. This is the only location where these compounds were found, indicating that the conduction degradation was due to the Ag metal conversion into $AgSO_4^-$.
- Several forms of S^- ionic species (S^-, SO_2^-, SO_4^{2-}) were found on the non-degraded Ag of the edge cell and the middle cell, but not $AgSO_4^-$ and HSO_4^-.
- No sulfur was found in the encapsulant.
- A subsequent core from a sibling room temperature module was examined. Using Nano Auger, sulfur was detected on FIB cross sections of the Ag grid line, at the middle and at the interface with the silicon, indicating presence of sulfur across the full thickness of the examined Ag gridline prior to testing.

Discussion

- The main purpose of this work was failure analysis.
- Sulfur is not a desirable material in silver printing pastes, so it is concluded that its presence is most likely due to impurity or contamination. This was a commercial module obtained in the open market, so we do not have access to data and do not know whether this module is typical and representative of other modules or whether this was an anomalous case.
- Potential contamination sources for this case could have been: (a) silver screening paste processing, (b) prolonged exposure of cells to high sulfur content air, and less likely, (c) cell processing; for current products (d) module components [1]
- The acceleration factors for this test is presently unknown. It is performed in varying durations (96, 400 & 600 hrs), RH(65%, 85%) and voltages (± 600V, ± 1000V) conditions as IEC testing[2] and in special more severe test protocols [3,4]
- it's possible that this case test conditions and/or durations were too severe and resulted in inducing an irreversible degradation mechanism that would not occur in real world conditions. Nevertheless, given that most modules connected to central inverters and half of modules connected to transformerless inverters are installed positive voltage with respect to ground, further investigation and alertness with respect to sulfur impurities allowed in silver pastes and un-encapsulated cell exposures to sources of sulfur would be good precautions.
- For all of the reasons mentioned, it is uncertain whether this is or not a problem of concern. Statistically significant sample sizes of modules & manufacturers and correlation between testing and field conditions and sulfur exposure levels and durations would be needed.

Conclusions

- Presence of sulfur caused depletion of the Ag conducting metal in the grid lines of the degraded edge cells of a front contact commercial module exposed to 85°C/85%RH biased DH, +1kV test
- The mechanism of Ag depletion on this module was due to chemical conversion of metallic Ag to $AgSO_4^-$ in the presence of sulfur, water and bias.

(1) Duerr, et.al, "Snail tracks: identification of critical environmental stresses, corrosion products and influences of module components", 2016 PVMRW
(2) IEC62804 and IEC 61215, PID 60°C, 85°C/85%RH ± 600V , 96 hours
(3) Fraunhofer PV Durability Initiative for Solar Modules, PV Tech, Part I, 2013; Part 2, 2014, PID: 85°C/65%RH, ± 1kV , 400 hours
(3) PV Evolution, Product Qualification Program: 85°C/85%RH, ± 1kV, 600 hours

Multiple Failure Modes on Fielded Glass/mc-Si/polymer Modules

Larry Pratt*, Cordula Schmid+, Cameron Stark+
*CFV Solar Test Laboratory, Inc., +Fraunhofer CSE

Introduction Snail trails, micro-cracks, and cracked backsheets have been reported on numerous occasstions[1,2,3], but cracks in the back sheet that follow the topology of the interconnect ribbons have not been found in the literature. A set of three mc-Si modules from one large manufacturer were fielded in Albuquerque, NM test yard in January 2013. Snail trails, micro-cracks, heavily cracked backsheets, and > 1% Pmp loss per year were observed on all three modules after four years, while none of the modules of similar vintage but different manufacturers showed the same failure modes.

This poster was submitted primarily to document the occurrence of an unusual pattern in backsheet cracking that matched the ribbon interconnect topology.

Procedures EL images and indoor IV measurements were made on each module before fielding in 2013. The modules were connected to micro-inverters and/or fixed loads and monitored over four years. IV measurements were made to quantify the module degradation.

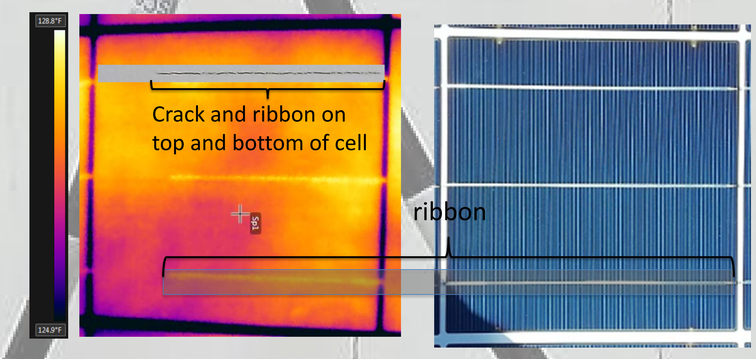
Observations

Snail Trails/Micro-Cracks

1. 'Snailtrails'– small, dark lines that have begun to crop up on modules starting around 2006[1].
2. Modules from several manufacturers in the U.S., Europe and Asia are affected.
3. Snail trails do not occur in modules stored indoors.
4. Snail trails appear to develop quicker in humid and hot climates and slower in dry and cold climates, (for the same module type).
5. Snail trails develop to a certain width; after that they stop growing or appear to grow very slowly.

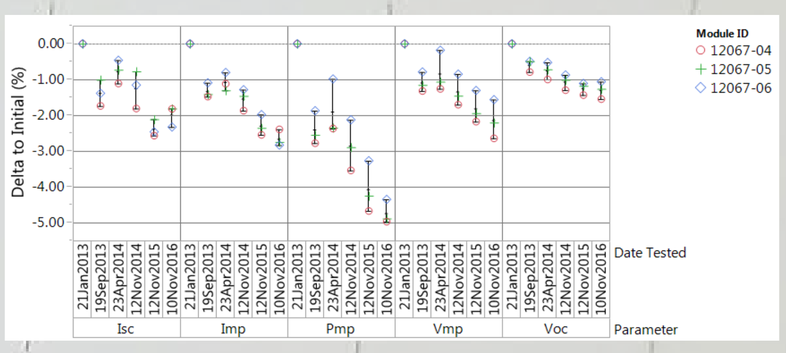
1. Snail trails are correlated with cracks in the cells.
2. Not every crack can be correlated with a snail trail.
3. The three modules have between 21 and 27 cracked cells each out of 60
4. A solar cell with micro-cracks, which separate a part of less than 8% of the cell area, results in no power loss in a PV module or a PV module array for all practical cases. In between approximately 12 and 50% of inactive area of a single cell in the PV module the power loss increases nearly linearly from zero to the power of one double string.[2]

Cracked Backsheet



1. Backsheet cracks have been well documented[3]
2. The cracks observed in these samples correspond to the ribbon interconnect, as shown in the figure above
3. The background image of this poster is an optical photo of the backsheet, with cracks lining up on the ribbon interconnect
4. IR image as seen from the backside shows slight interconnect ribbon heating, and confirms the cracks stop near the end of the backside interconnect ribbon
5. This pattern repeats itself over many cells in 2 of the 3 modules. Module -04 shows backsheet cracks on roughly 5 cells, while more than half the cells are affected on -05 and -06
6. The cracks start near the top of the cells and extends down to about 4-5 cm from the bottom of the cell, likely where ribbon ends on the underside of the cell
7. The backsheet cracking might be due to the combination of mechanical stress from the top and bottom interconnect ribbon and the electrical field stresses
8. These modules did pass Wet IR in 2016, despite the cracks in the outer layer

Electrical Degradation (Indoor HALM)



1. Three modules exhibiting snail trails, cell cracking and back sheet splitting were fielded at Fraunhofer CSE's Outdoor Test Facility in Albuquerque, NM for almost four years.
2. When degradation was discovered during periodic testing indoors on CFV Solar Test Laboratory's indoor HALM solar simulator, continuous outdoor performance measurements began and have been in place for over three years.
    1. Two modules are being measured via an electronic variable load-based IV curve tracer.
    2. One module is biasing a calibrated fixed load power resistor with period voltage measurements quantifying power generated.
    3. Module temperature and local irradiance are measured concurrently.
3. Roughly half of the overall Pmp degradation measured to date occurred during the initial eight months
4. 2.2%-2.5% Pmp degradation occurred in the subsequent 3 years, or roughly 0.8% per year, on average
5. The Pmp degradation exceeds the levels stated in the warranty
    1. < 95% of NP after only 3.8 years in the field
6. The Pmp degradation correlates to degradation in all the IV characteristics, with correlation coefficients ranging from 0.89 for Isc to 0.98 for Imp and Vmp

Summary

1. Three failure modes were observed in a set of three c-Si modules fielded for four years in Albuquerque, NM
    1. Snail trails
    2. Micro-cracks in roughly 1/3 of the cells in each module
    3. Back sheet cracks that line up with the ribbon interconnect (see background image)
2. Pmp degradation greater than warranty limits, although there is no proof that any of the failure modes observed caused the excessive power degradation

References

1 Ines Rutschmann, Unlocking the secret of snail trails, Photon International,01-2012
2 M. Köntges, I. Kunze, S. Kajari-Schröder, X. Breitenmoser, B. Bjørneklett, Sol. Energy Mater. Sol. Cells (2011), doi:10.1016/ j.solmat.2010.10.034
3. W. Gambogi et al, Sequential and Weathering Module Testing and Comparison to Fielded Modules, NREL PVMRW 2015

JOINTLY OWNED BY: CSA INTERNATIONAL Fraunhofer ISE Fraunhofer USA

PV Module Reliability Workshop, Lakewood Colorado, 28th Feb. 2017

Ultraviolet fluorescence method to detect cell cracks and safety issues of cell cracks

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[1]Institute for Solar Energy Research Hamelin (ISFH)
[2]TÜV Rheinland Energy

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Outline

- Introduction of UV fluorescence method
- Statistic on cell cracks and hot spots with UV fluorescence in the field
- Theory of safety issues of cell cracks
- Compare theory with IR imaging in the field
- Discuss new technologies and cell cracks

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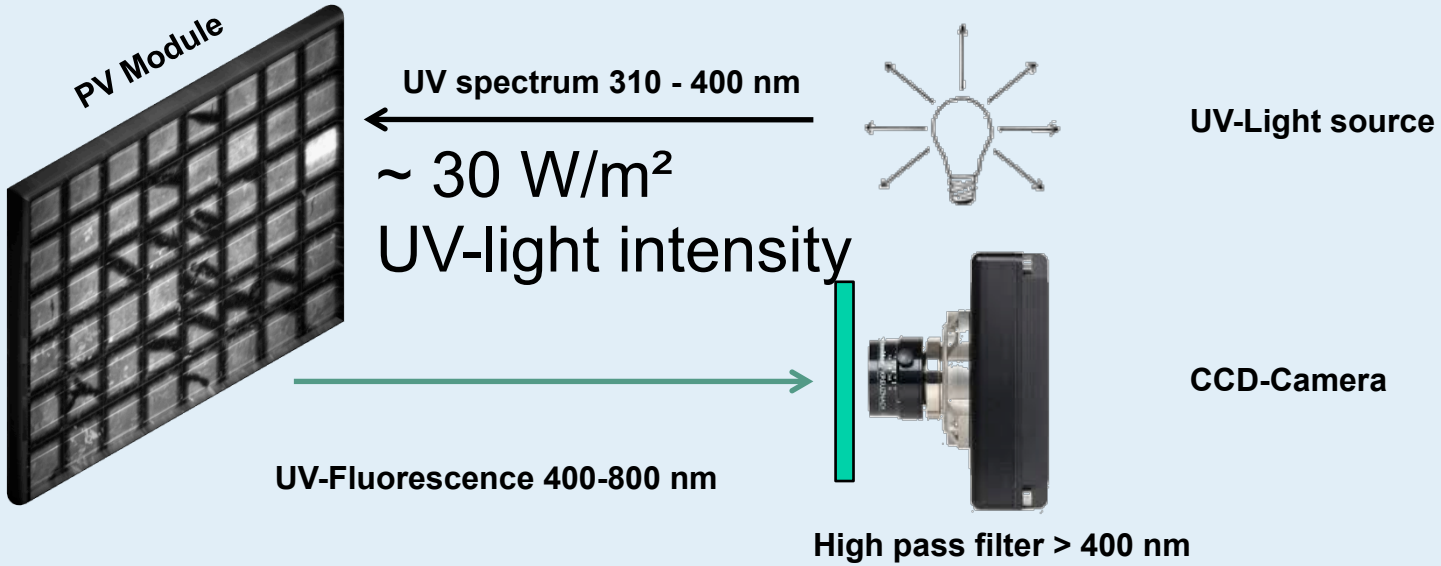
UV fluorescence (FL) detection



- No change of electric circuit of PV module
- Outdoor measurement possible with housing
- Fluorescent degradation products of EVA

Basic literature on the fluorescence effect:
F.J. Pern, *Sol. Energy Mater. Sol. Cells* **41/42**, 1996, 587-615
L. King, et al., *Prog. Photovolt.: Res. App.*, **8**: 241–256 (2000). doi: 10.1002
Detection of micro cracks with the fluorescence effect:
Schlothauer, et al. , *Photovolt. Int.* 10 (2010), pp. 149-154
M. Köntges, et al., *Proc. 27th EUPVSEC*, Frankfurt, Germany, 2012.

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Field measurement tool

- Transport in a car trunk possible
  - 0.5 h assembling
  - Adaptable to module size

- Easy to use for 1 or 2 persons
- 200 modules/h max. speed incl. placement, handling
- Measurement cond. up to 500 W/m²

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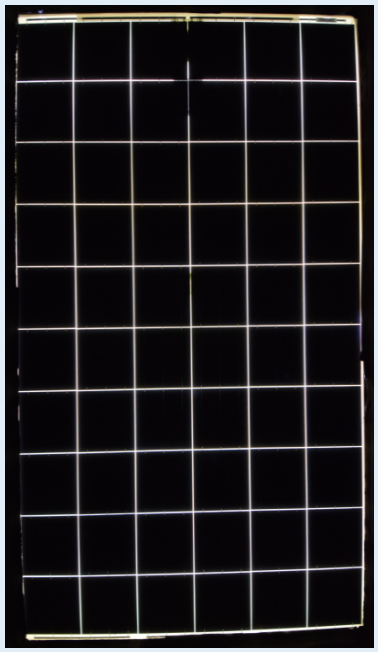
Basics of UV fluorescence

- Light and temperature produce degradation products in encapsulant [1]
- UV fluorescence make degradation products visible [1]
- Oxygen + light quenches UV fluorescence [2]
- Oxygen can diffuse through cell cracks and cell gaps in between cells and glass into encapsulant [2]
- Need ~ 300 kWh/m² global irradiation dose to see first pattern in UV fluorescence image

[1] Peike C., *et al*., Proc. IEEE PVSC Conference 2013, 1579-1584
[2] Schlothauer, et al. , *Photovolt. Int.* 10 (2010), pp. 149-154

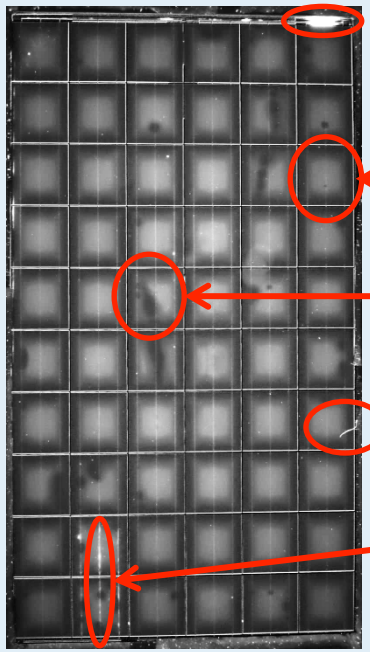
Field measurements

Module 3 years in the field



Dark field

Fluorescence image



Dark field substraction

- Dark field substraction increases noise, but
- reduces blooming between cells
- increases contrast remarkably

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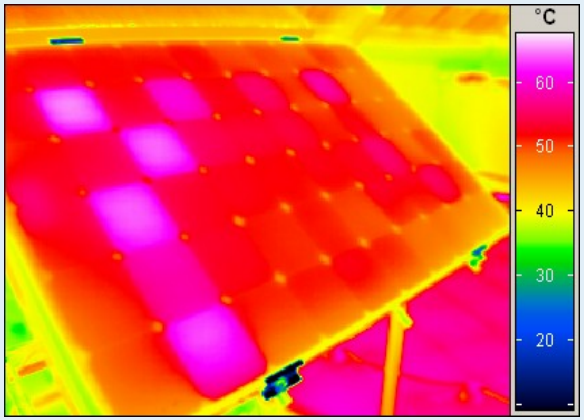
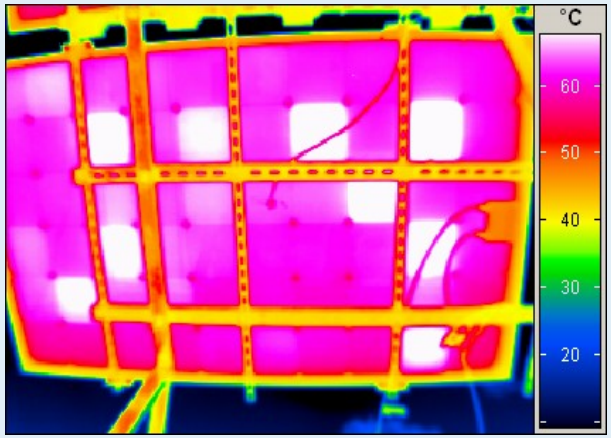
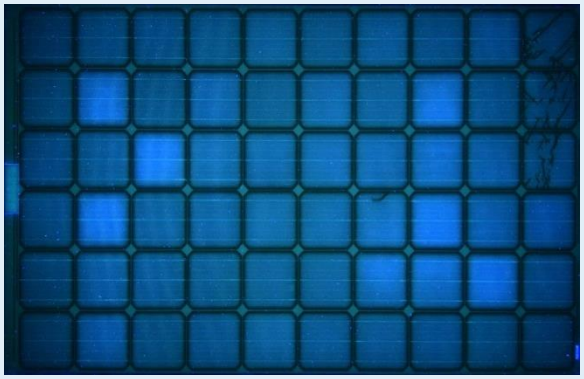
Correlation FL intensity / temperature

- Module @ Isc for 398 kWh/m² (77 days)
- IR-image taken @ ~ 780 W/m²
- UV-FL image taken @ 25°C







55.2	55	53	53.5	56.2	56.2	56	56.5	58.9	58.8
58.2	72.6	61.1	67.4	60	62.6	59.7	68.4	58.3	56.8
56.9	58.7	64.9	57.9	58.1	60	58.6	61.2	56.4	56.8
58.1	69.9	57.9	58.6	59.1	62.5	64	66.8	59.2	58.9
56.6	63.7	57.5	56.3	56.5	56	60.2	62.6	65.5	59.5
54.4	65.4	57.7	58.3	59	59.1	59	59.7	56.6	54.6

- UV fluorescence can identify ~ 10°C temperature difference @ 780 W/m²
- Enable to identify temperature history

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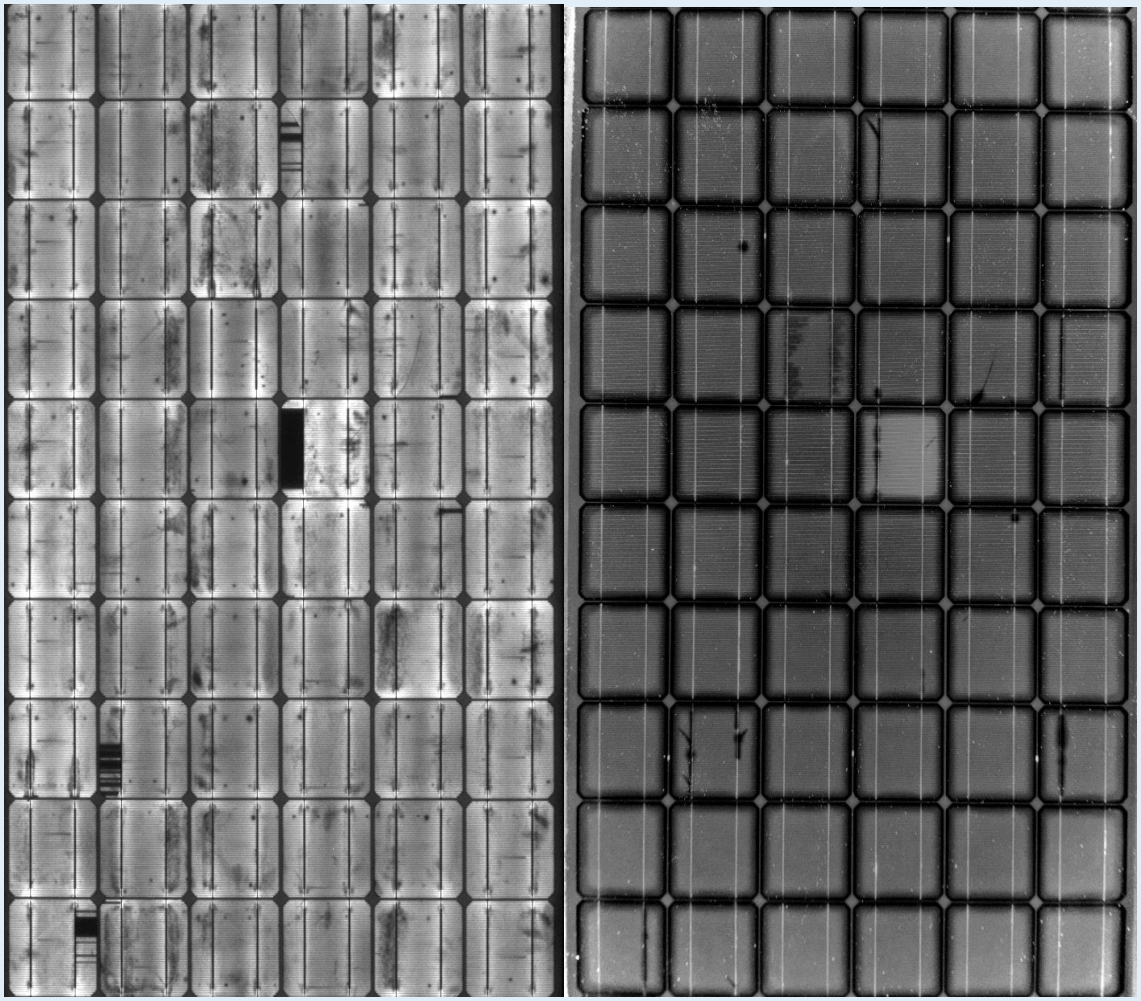
Hot cells with UV fluorescence



- Warm cells with cracks can be identified by UV Fluorescence
- Important cell cracks can be detected

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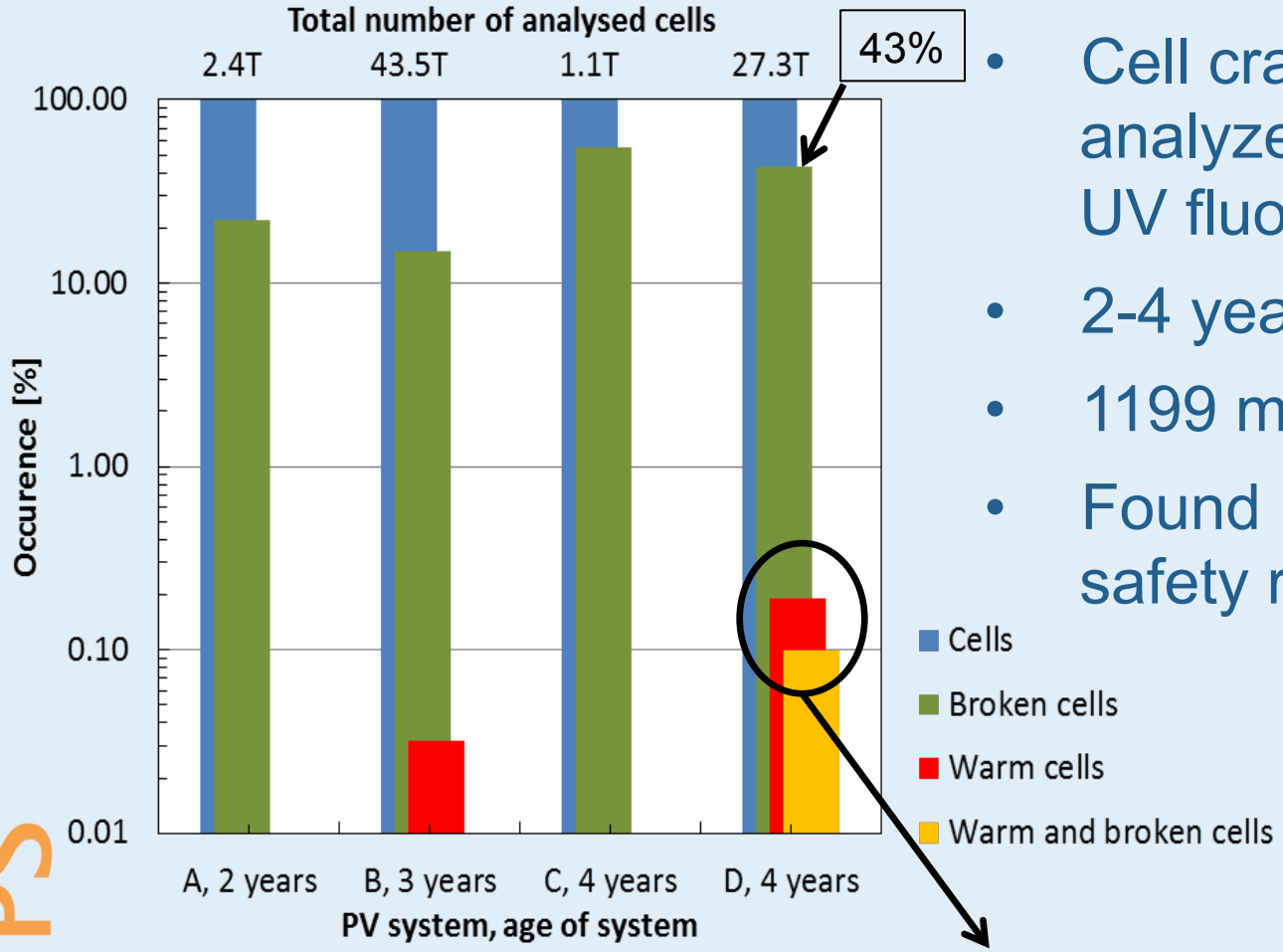
4 PV parks analyzed with UV FL



- Cell cracks and warm cells analyzed with UV fluorescence method
- 2-4 years old systems
- 1199 modules/71940 cells
- Found no indication for a safety risk of cracked cells

43% of all cell have a cell crack,
so 43% of all warm cells have a cell crack

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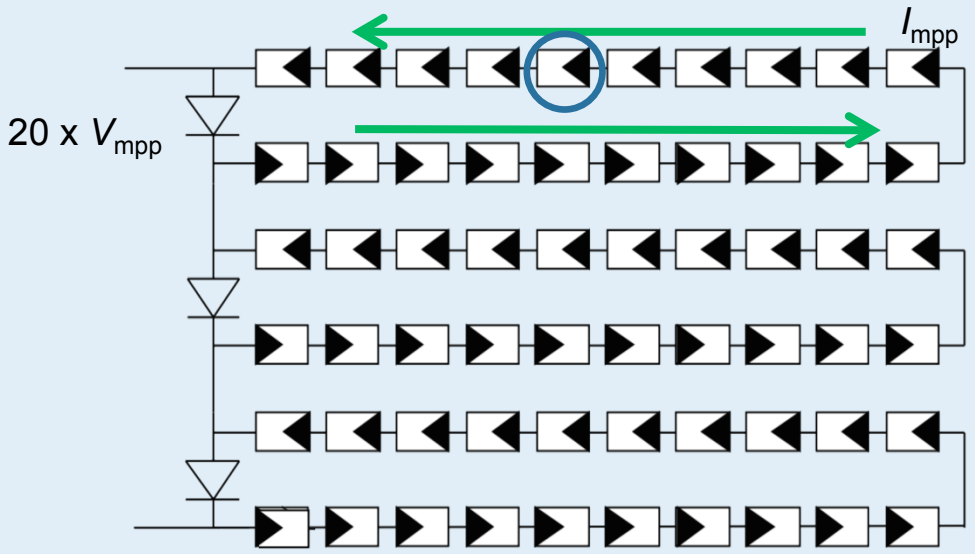
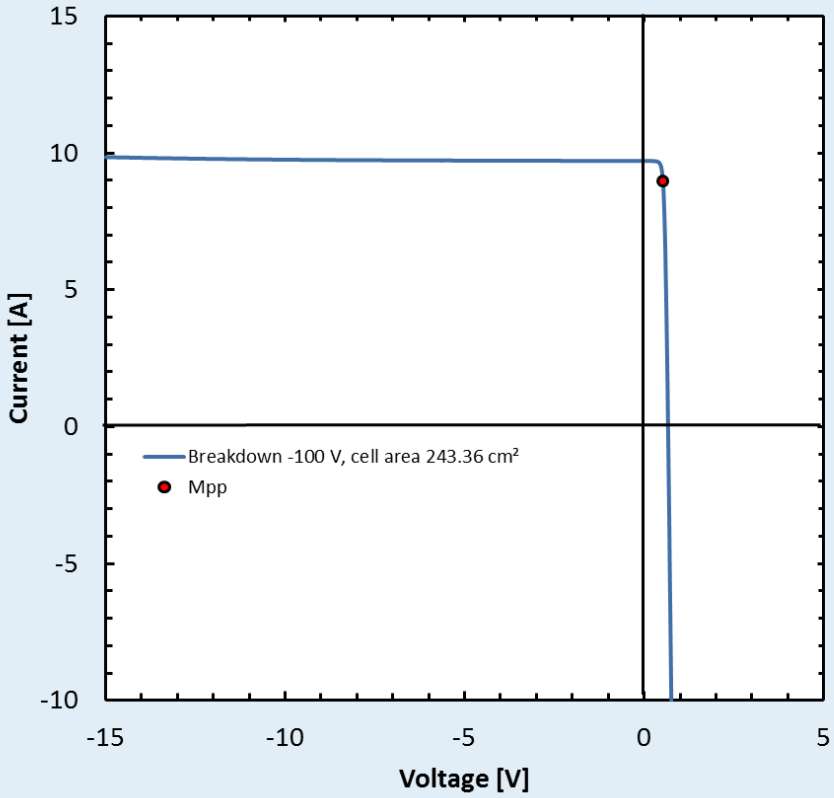
Safety risks due to cell cracks





- Calculation for 1000 W/m² @ 25ºC
  280 W PV module

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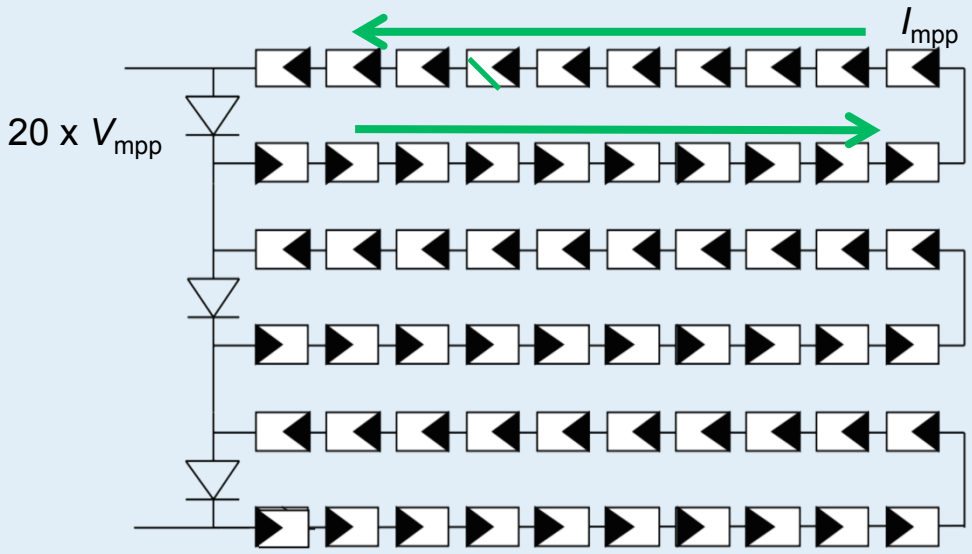
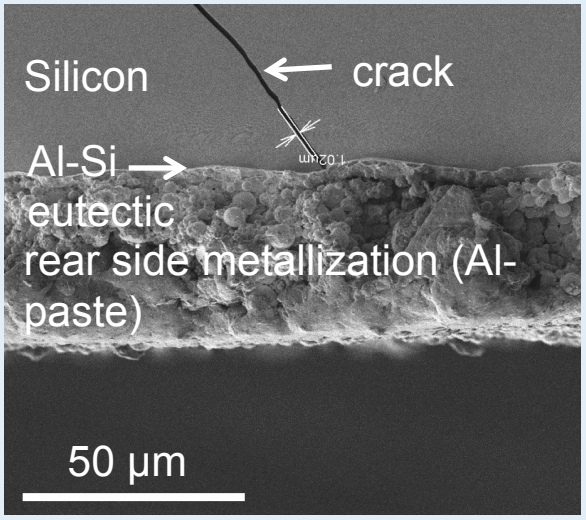
One cracked cell



Cause	Effect
Cell crack	Surf. recomb.



F. Haase et al., Energy Procedia, Volume 92, August 2016, p. 554

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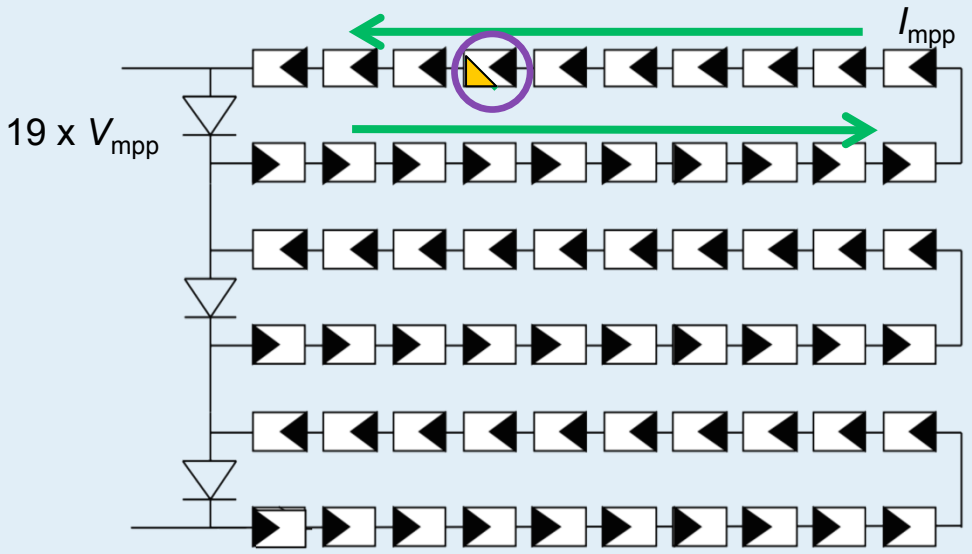
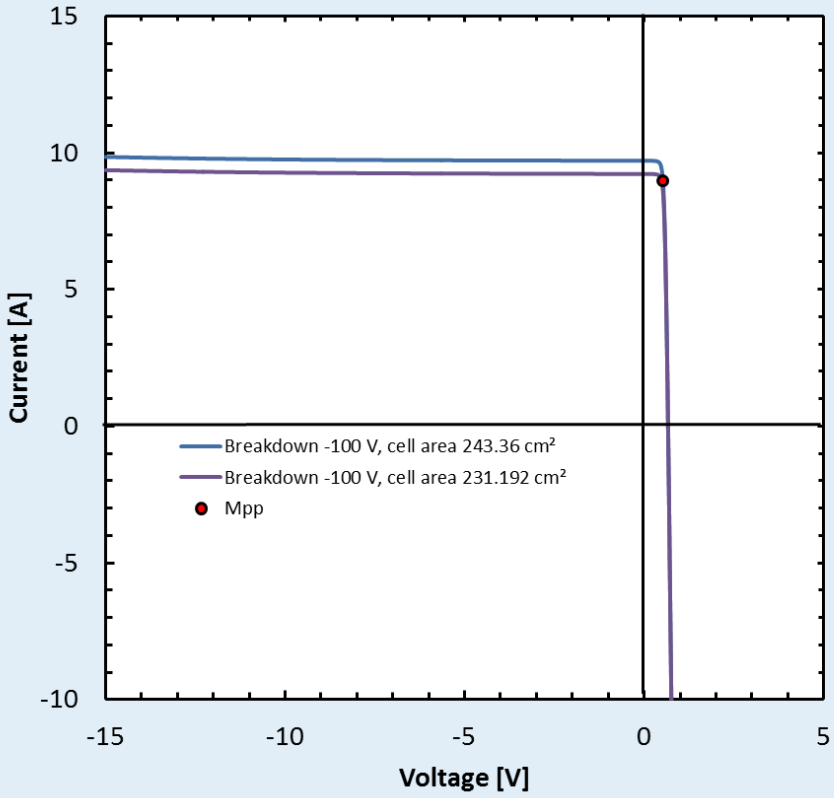
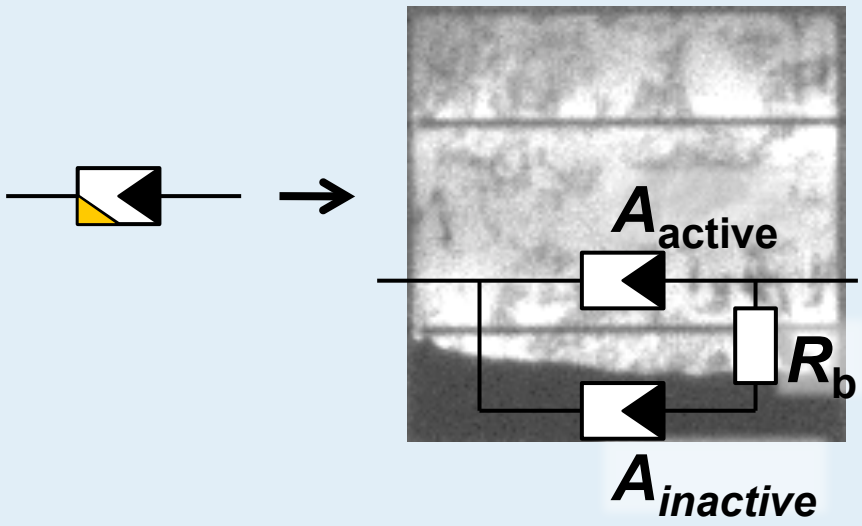
One small cell part isolated



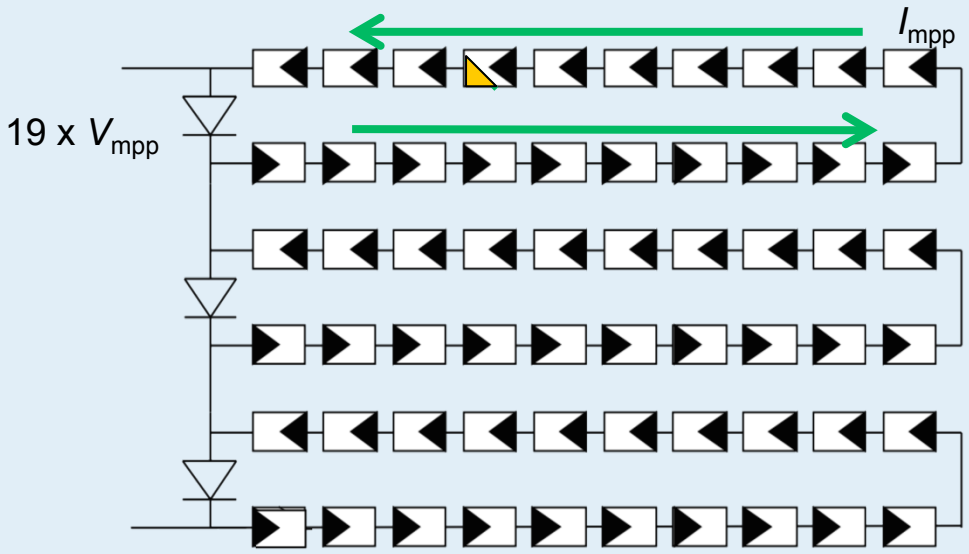




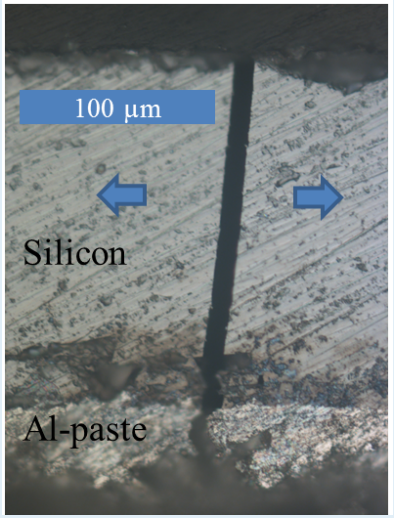
PVPS

ISFH

One small cell part isolated



Cause	Effect
Cell crack Part isolated	Surf. recomb.
$A_{inactive}/A_{total}$ < $(I_{sc}-I_{mpp})/I_{sc}$	Nearly no effect, P_{mpp} shifts a bit

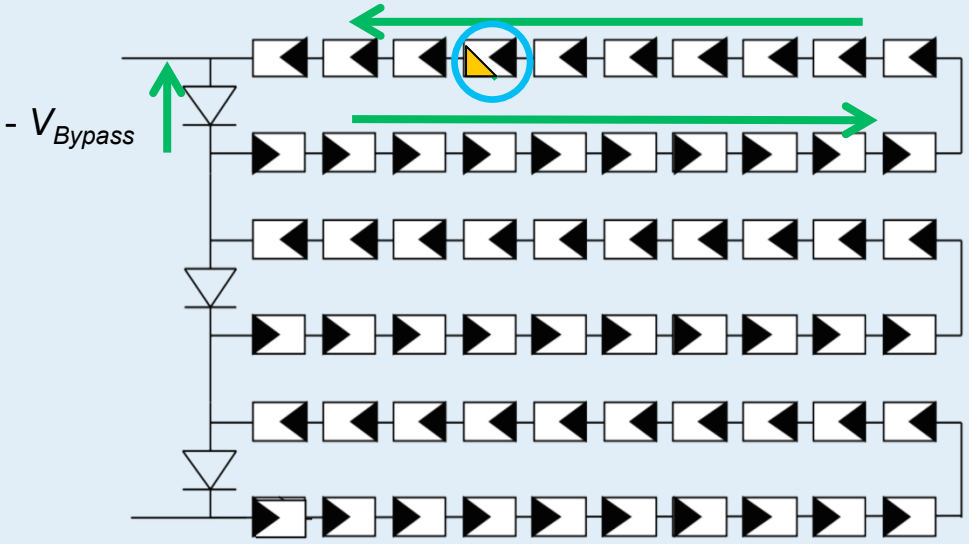


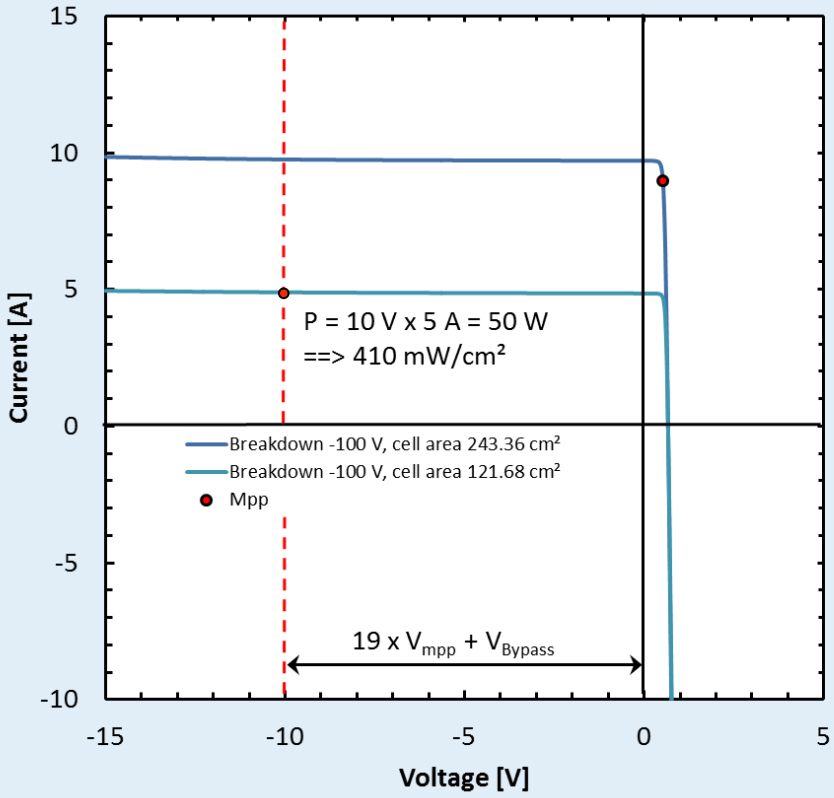
J. Käsewieter et al., Model of Cracked Solar Cell Metallization Leading to Permanent Module Power Loss, in IEEE J-PV **6** (1), pp. 28-33, (2016) doi: 10.1109/JPHOTOV.2015.2487829

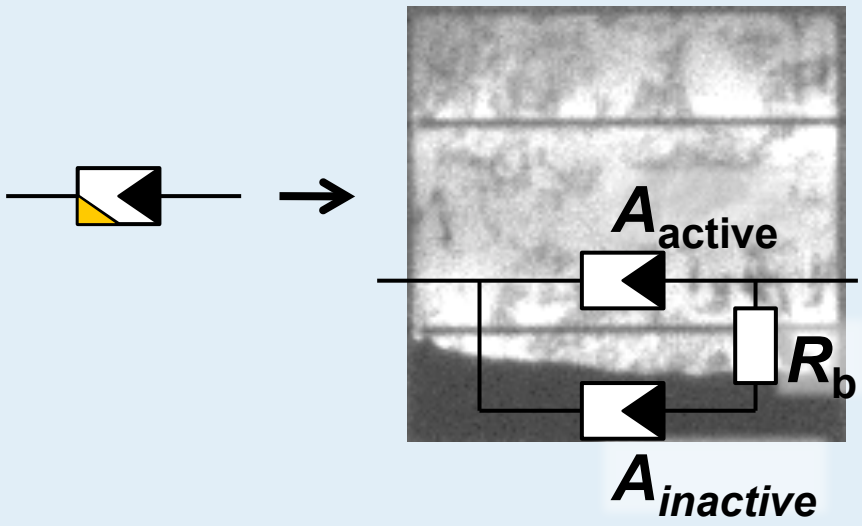
PVPS

ISFH

One large cell part isolated







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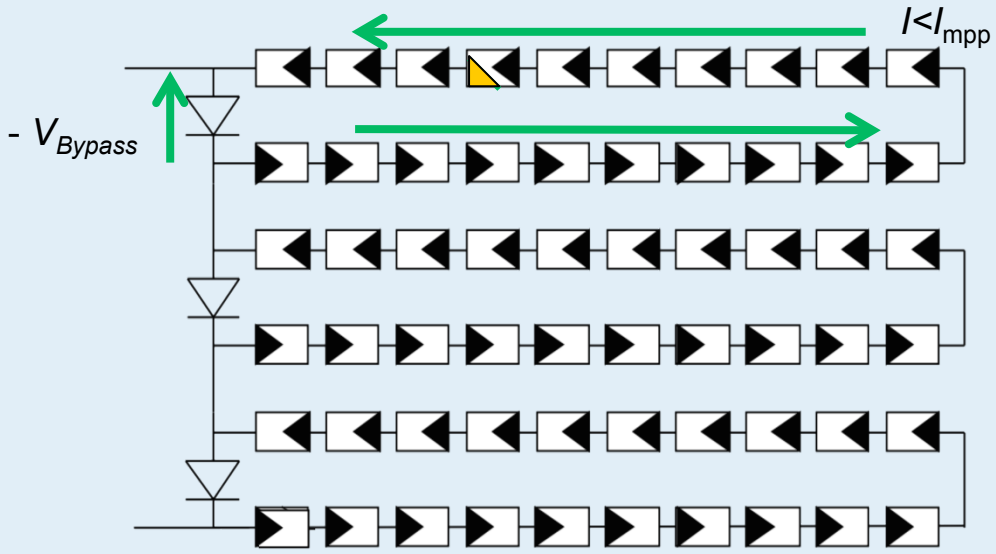
One large cell part isolated



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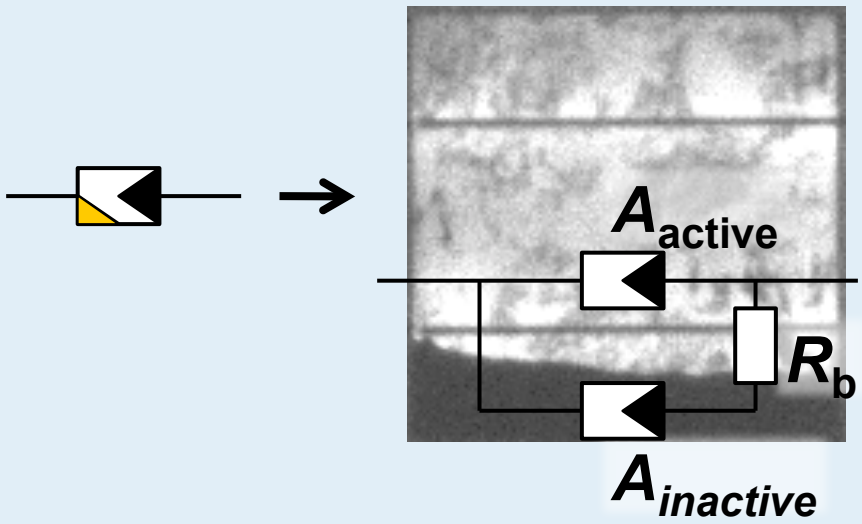
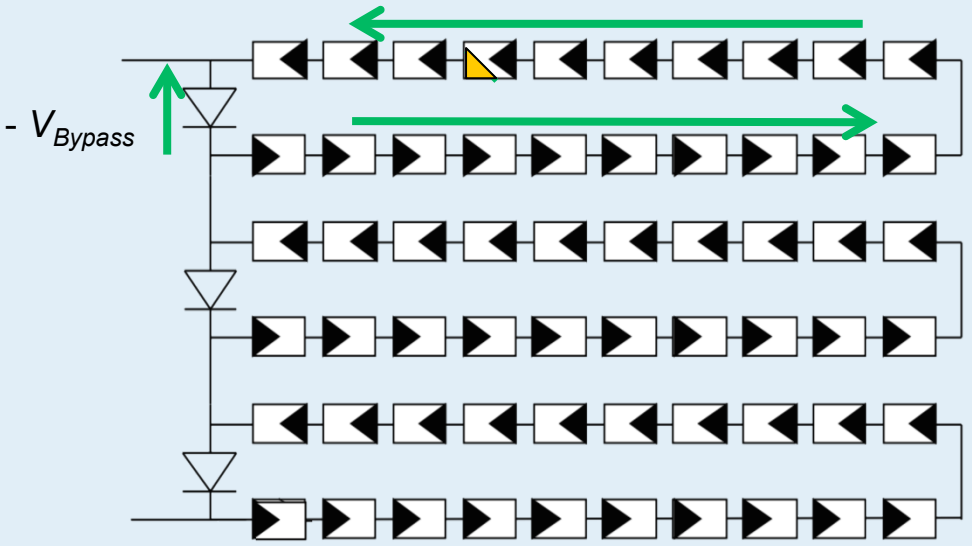
Cell crack Part isolated	Surf. recomb.
$A_{inactive}/A_{total}$< $(I_{sc}-I_{mpp})/I_{sc}$	Nearly no effect
$A_{inactive}/A_{total}$> $(I_{sc}-I_{mpp})/I_{sc}$	Power loss, cell heats up

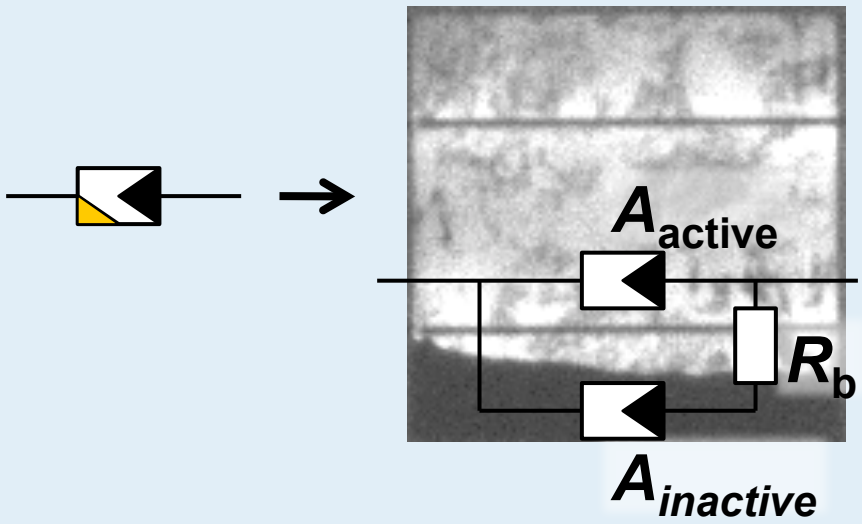


PVPS

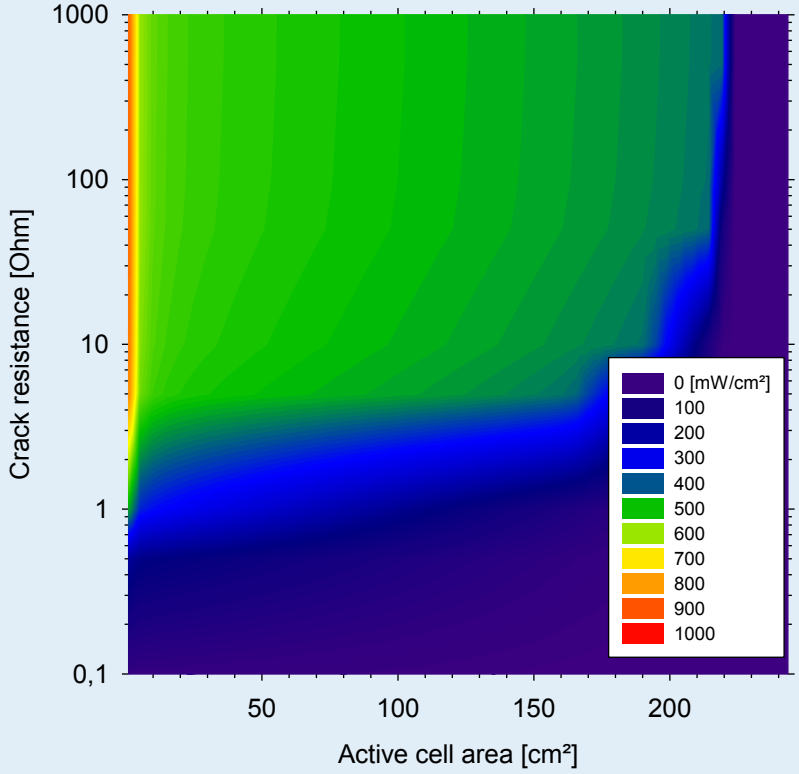
ISFH

Perfect blocking cell





Power loss density active cell area



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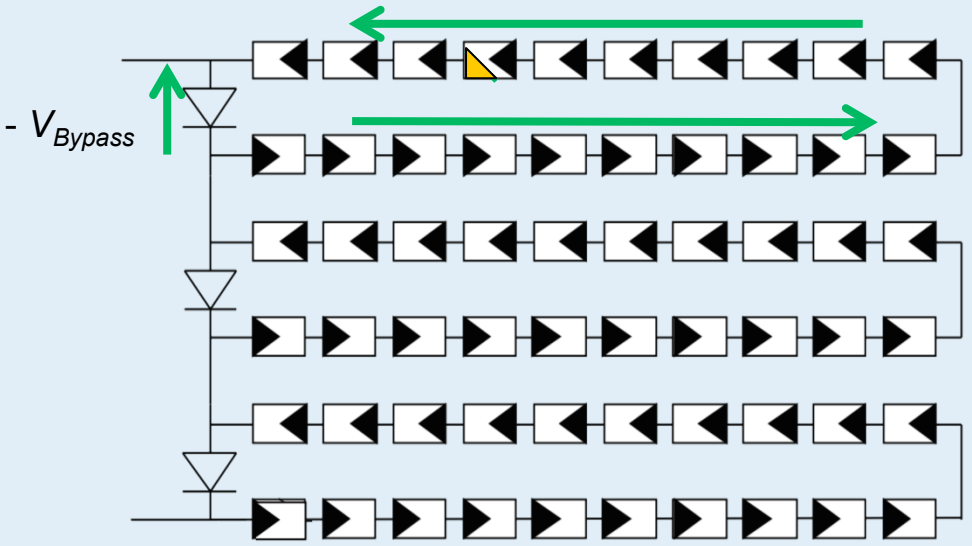

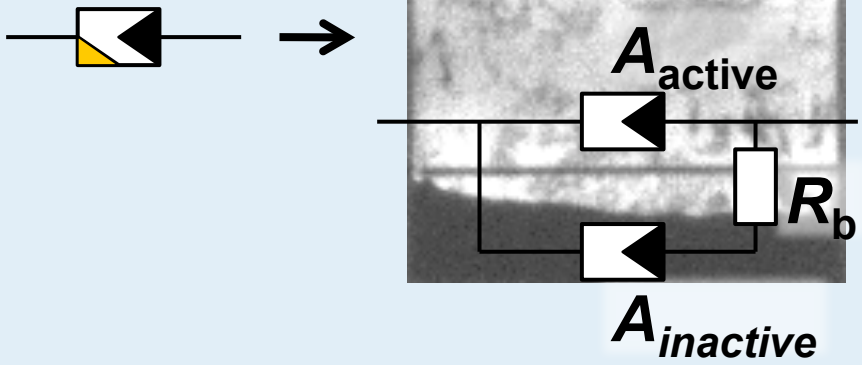

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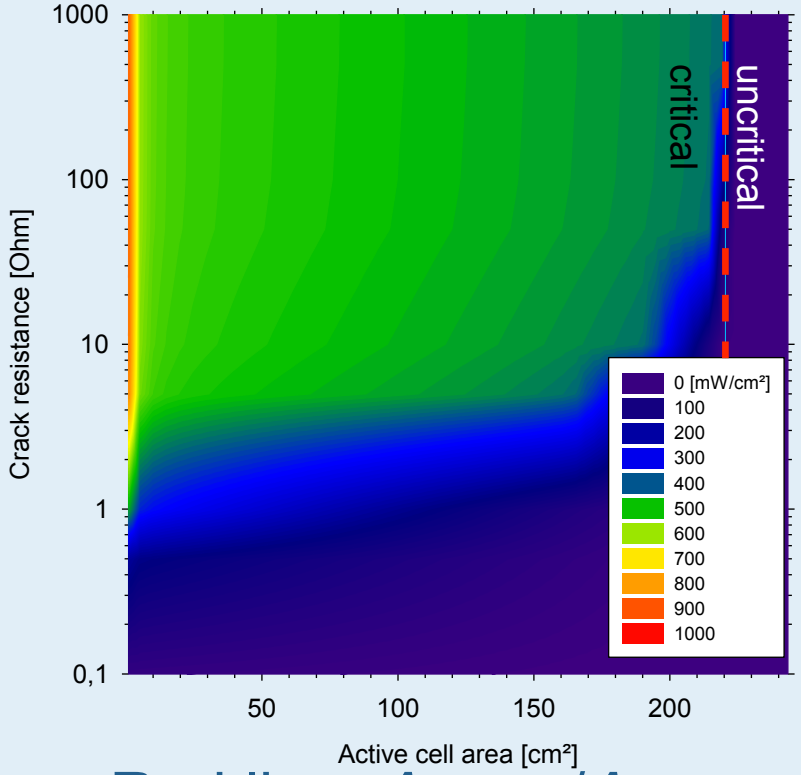
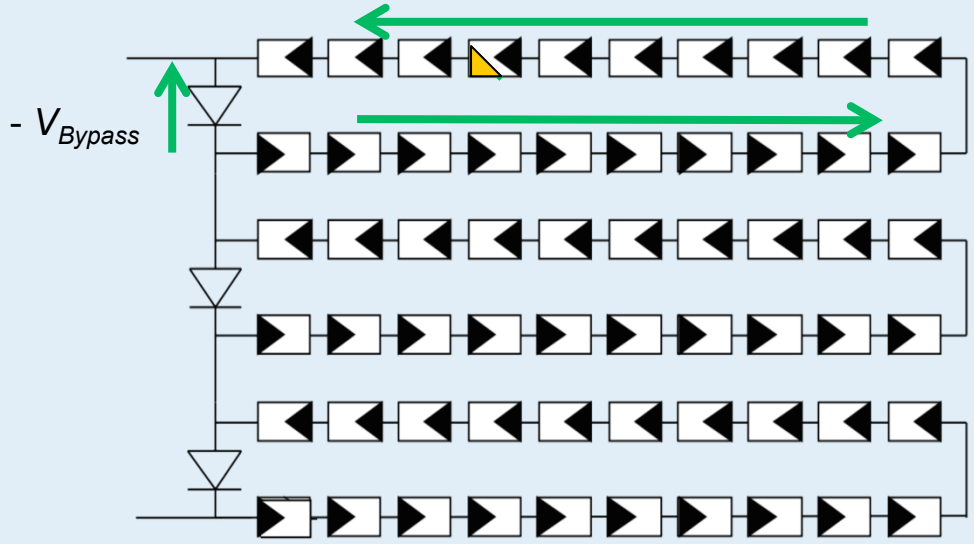


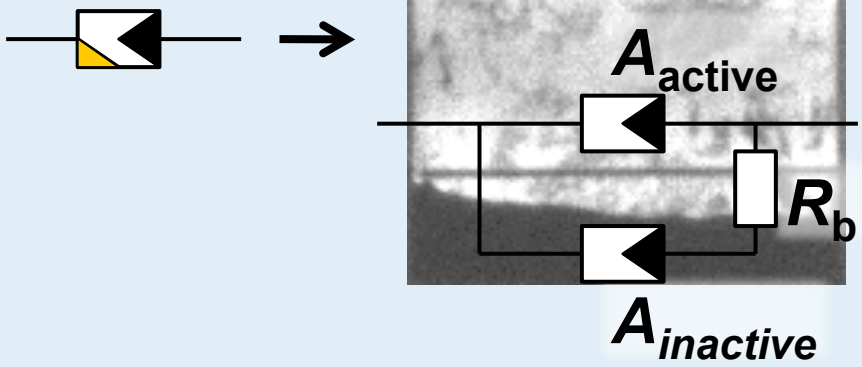
Red line: $A_{inactive}/A_{total} > (I_{sc}-I_{mpp})/I_{sc}$

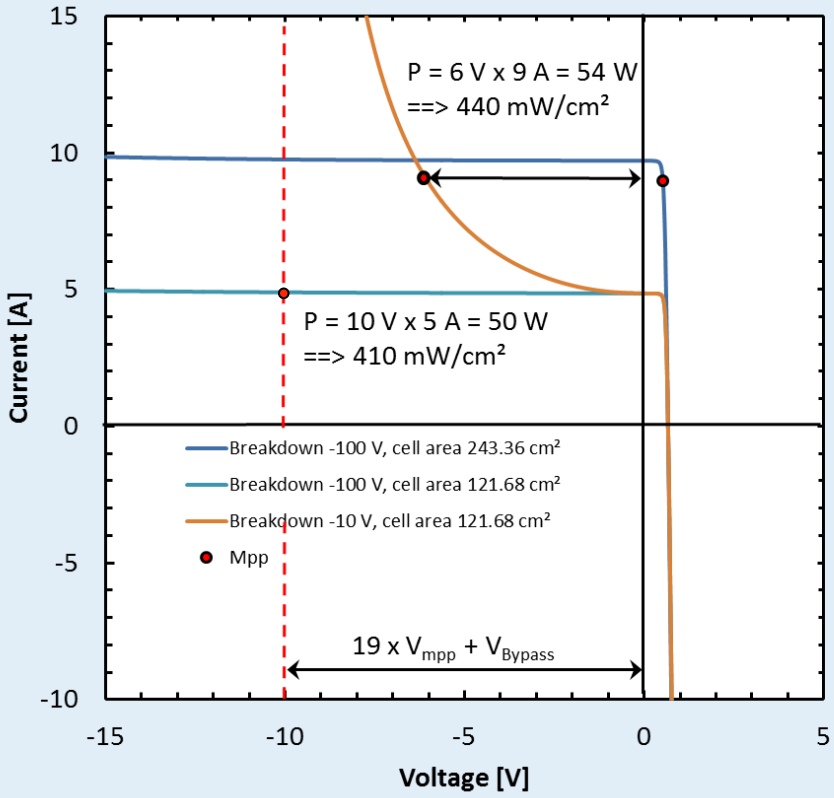
PVPS

ISFH

Cell break down V_b=-10 V







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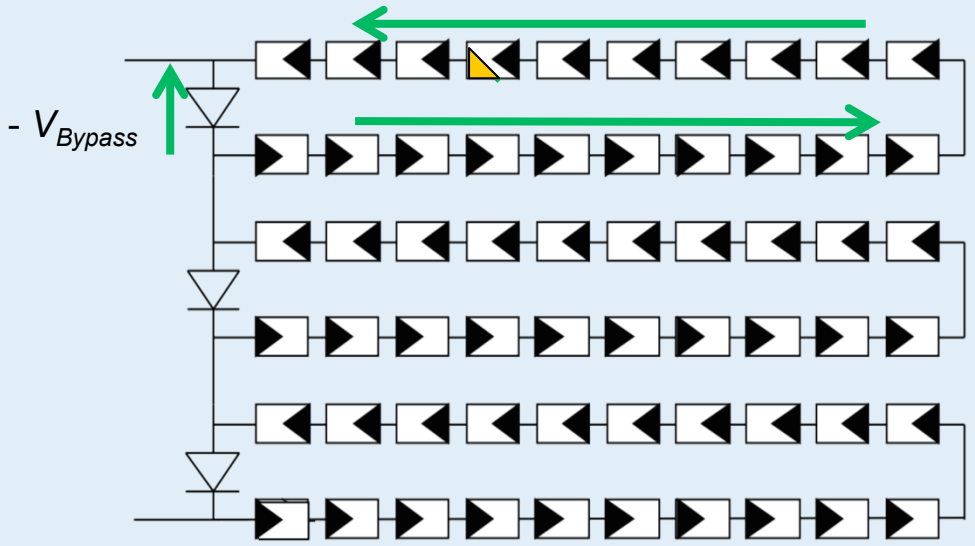

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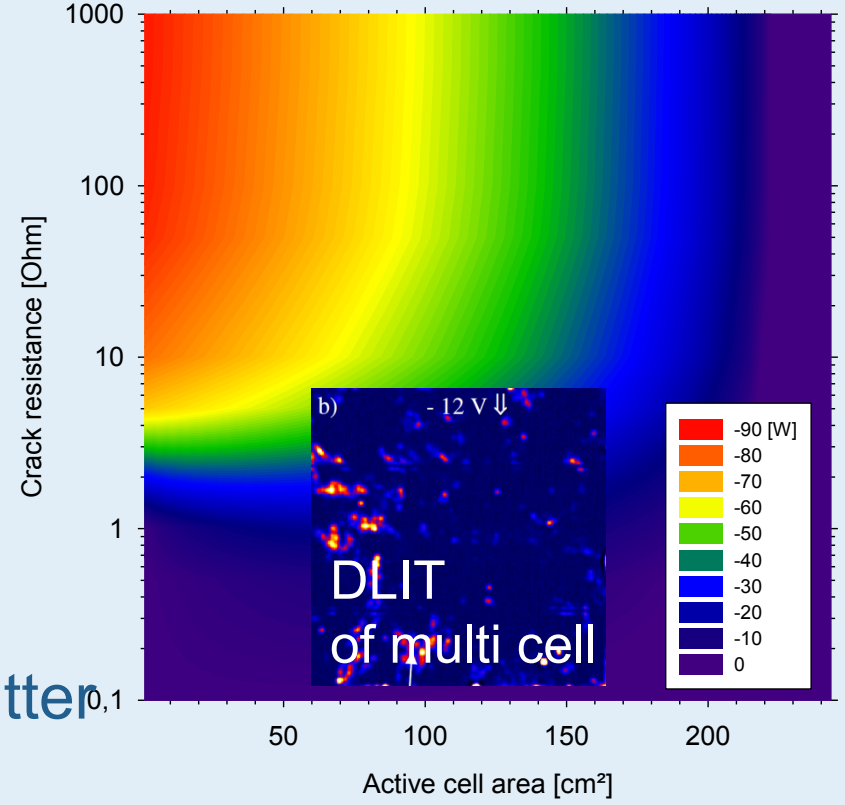


Local power ➔ high temp.

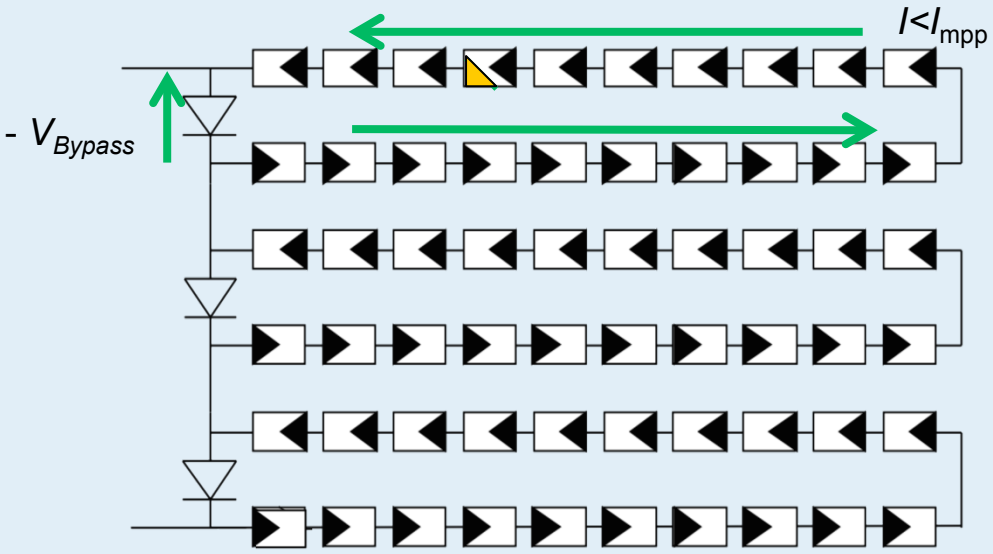
- Al particle compensate emitter
- Fe precipitation
- Etch pits at crystal defects

PVPS

[1] O. Breitenstein, et al., Journal of Applied Physics 109, 071101 (2011)

ISFH

One large cell part isolated



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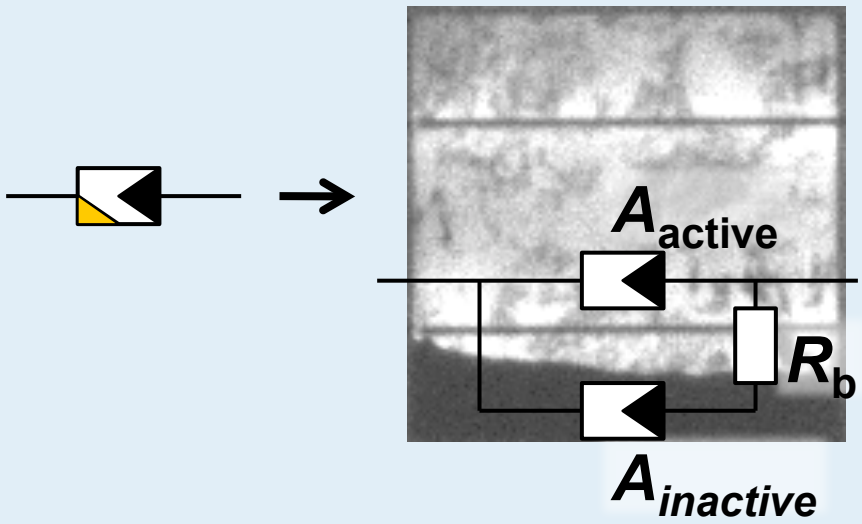

Modules that fail hot spot test have a cell crack safety risk

PVPS

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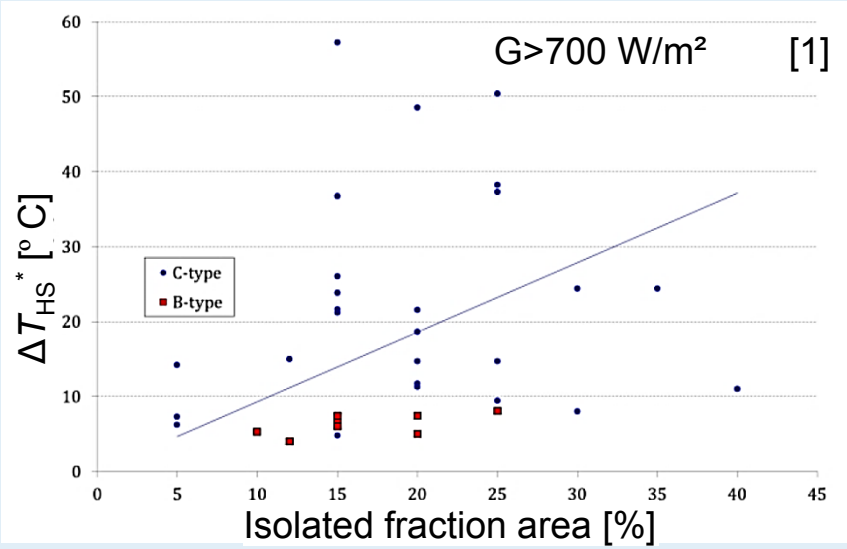
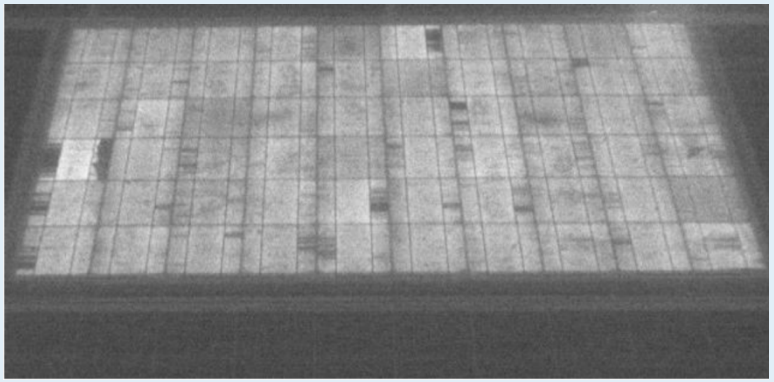
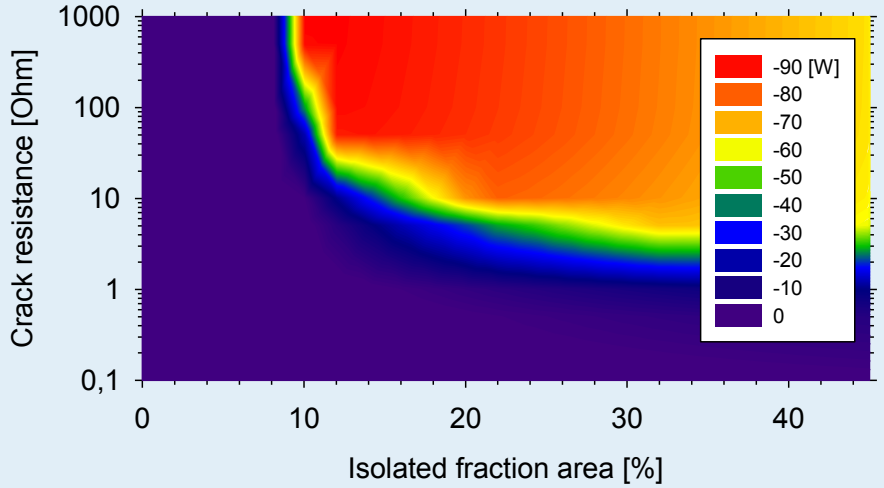
Hot cells due to cell cracks





- $\Delta T_{HS}^* = \Delta T_{HS} \bullet 1kW/m^2/G$
- Cell cracks cause hot spots
- Temperature increases as function of isolated fraction area follows shape of power dissipation in theory



[1] R. Moretón, et al. DEALING IN PRACTICE WITH HOT-SPOTS, 29th EUPVSEC (Amsterdam, Netherlands, 2014) p. 2722

PVPS

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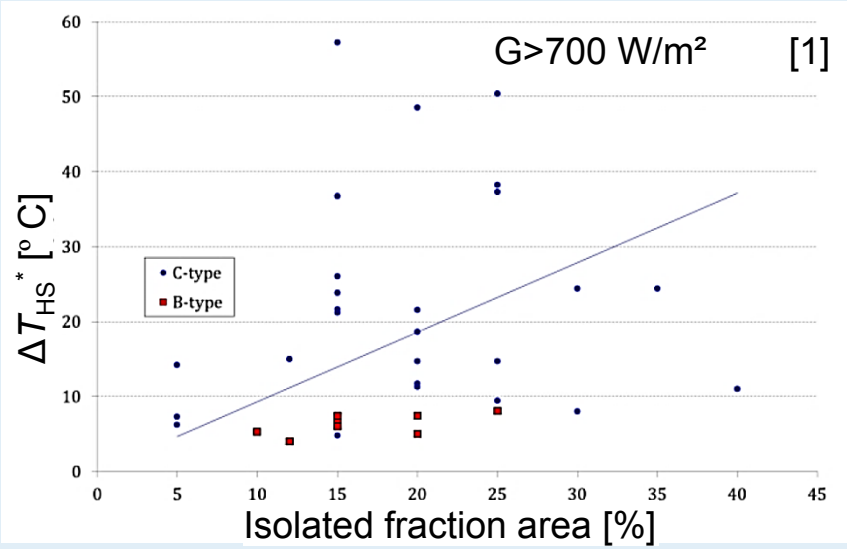

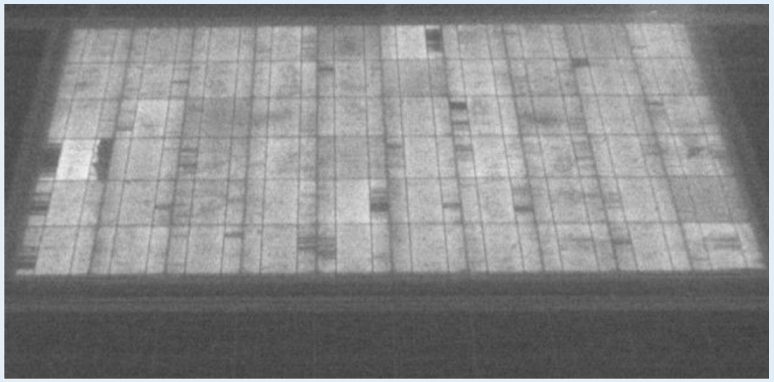

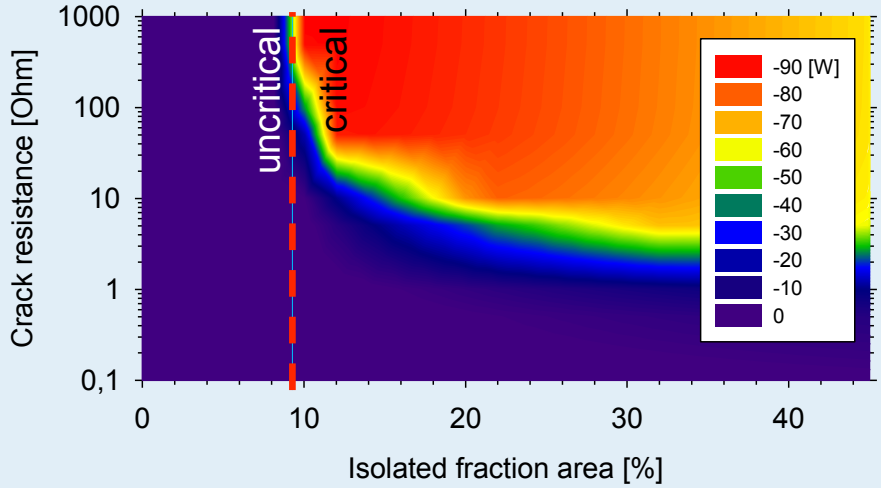

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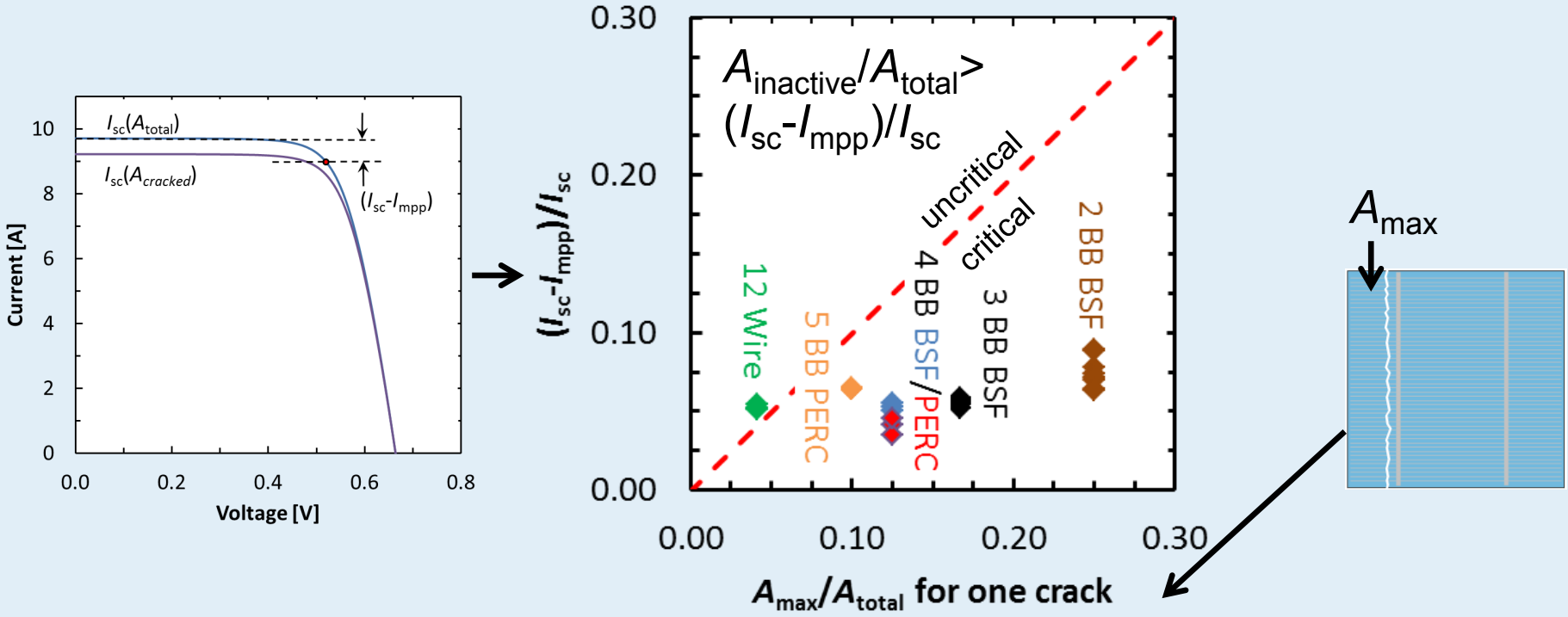
PVPS

Get new technologies less critical ?



- Technologies with more busbars get less critical because one crack detach less cell area
- Improving cell efficiency without more busbars get more critical because (I_{sc}-I_{mpp}) gets smaller

PVPS

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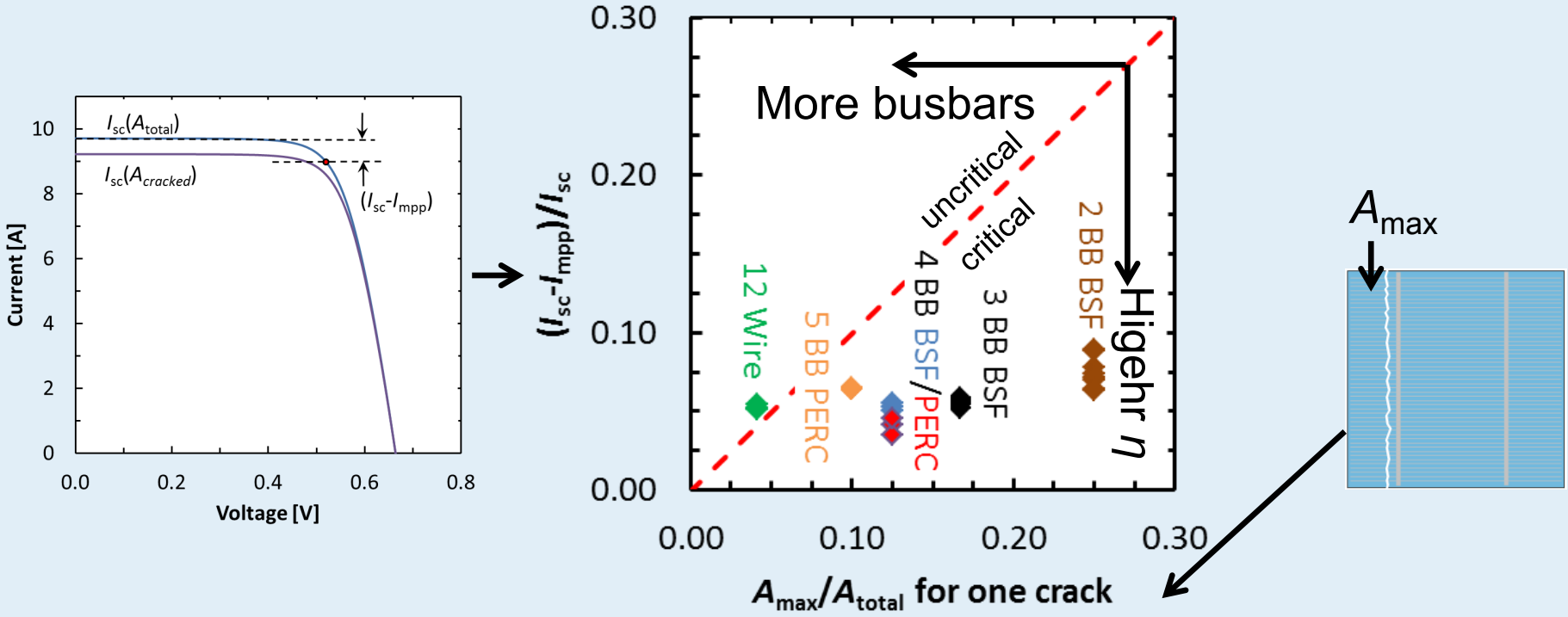
Get new technologies less critical ?



- Technologies with more busbars get less critical because one crack detach less cell area
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Conclusion

- UV fluorescence is able to detect cell cracks and warm/hot cells
- Module inspection max. speed 200 modules/h
- Cell cracks may generate safety risk if
  - Cell part gets isolated and
  - $A_{inactive}/A_{total} > (I_{sc}-I_{mpp})/I_{sc}$ and
  - Module fails hot spot test or bypass diode is in V_{oc} failure mode
- Most cell cracks do not generate isolated cell parts => safe
- It is not known why some modules get isolated cell parts
- Increasing number of BB will reduce safety risk

PVPS

Supported by:

Federal Ministry for Economic Affairs and Energy

on the basis of a decision by the German Bundestag

Thanks for financial support:

State of Lower Saxony and BMWi under contract no. 0325786C

ISFH

Field Observations of Cracked Solar Cells

2/28/2017

Jim Rand, jim.rand.solar@gmail.com

Mason Reed, masonjreed@gmail.com

Outline

1. Technical Work
    A. Transportation Damage Study – Incipient Cracks
    B. Impact of Intentional Rough Handling on Different Technologies
    C. Case Study – 6 year old Arrays
2. Summary of Quantified Conclusions
3. Summary of Opinions

Core Energy Works

Equipment

- Class AAA Berger Module Pulse Tester (for STC IV measurements)
- 2 Electroluminescence Imaging Stations
  One optimized for high volume work in the laboratory
  One optimized for EL images in the field
- Meggers for Leakage Current Test
- FLIR Infrared cameras for hot spot detection.
- Test Equipment Associated with may IEC/UL Certification Tests
- Full suite of warehouse management tools

Samples in This Study

- CEW has 1,000 Modules in inventory from 5 different Manufacturers
- The 3 Summaries of “Technical Work” are each by a Different Manufacturer

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Transportation Damage

An on ramp for U.S. 64 in Edgecombe County was shut down after a shipping container full of solar panels fell off a truck.

"Gentle" Accident

- Similar Module In All Cases
  - Conventional 72 Cell Module
  - 3 Busbar, Multicrystalline Si
- 1154 Modules Tested from 2 Accidents
- Accident #1 - Gentle

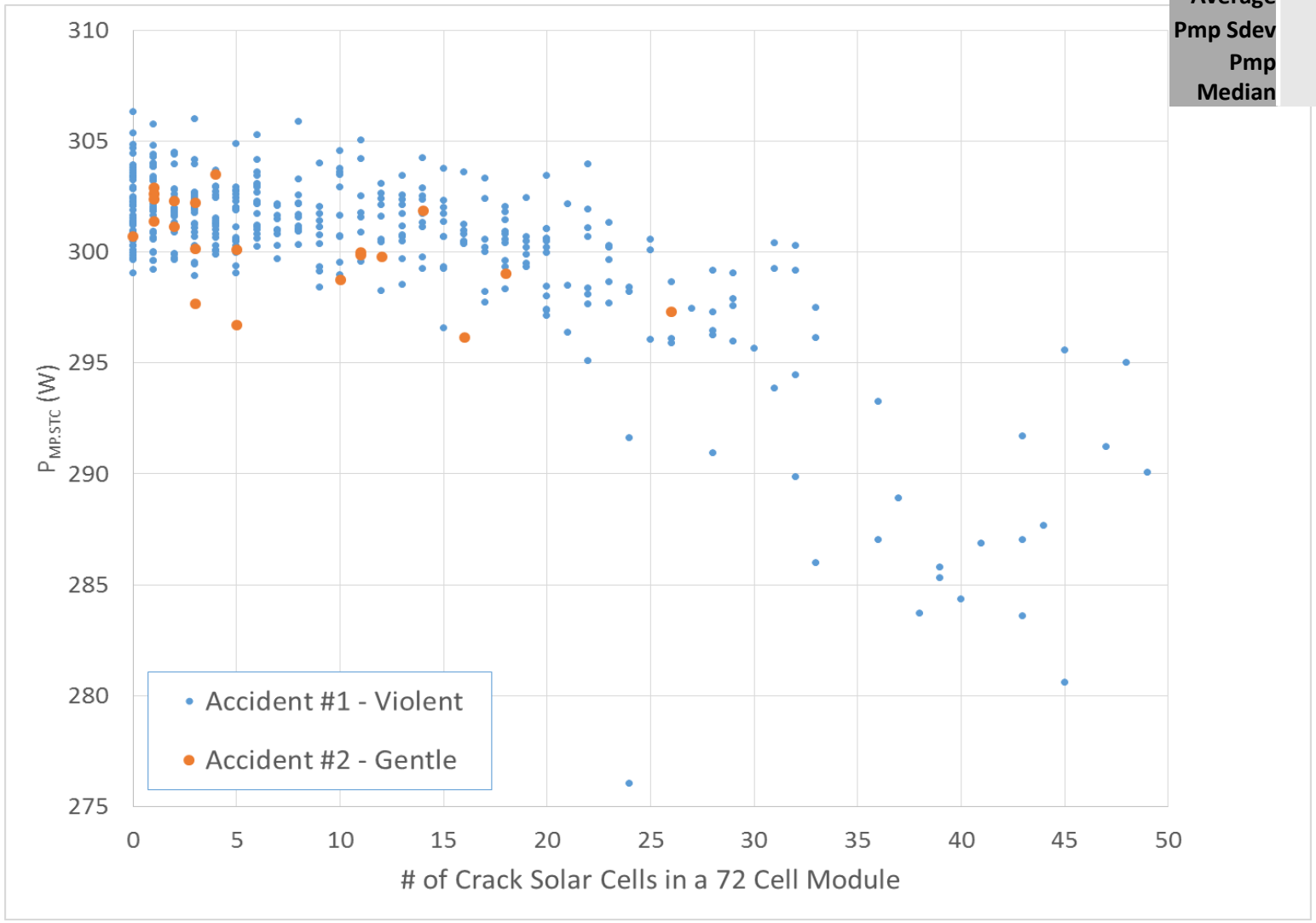
  Tipped over Container
- Accident #2 - Violent

  ? - Much more violent
- Results:

  65% had at least one cracked solar

Incipient Cracks – Impact to Power

	Full Dist	None Cracked	1-5 Cracked	6-10 Cracked	
Module Count	393	46	131	60	
Pmp Average	299.9	302.1	301.9	301.7	Watts
Pmp Sdev	11.5	1.7	1.4	1.5	Watts
Pmp Median	301.2	302.1	302.0	301.6	Watts



Up to 10 Incipient Cracks (10/72)
No Impact to Power

Caveats: For this technology
For these accidents

Cracking by Position
Gentle Accident

11 pallets, 275 Modules Total, 113 bad, remainder good.

Non-uniform, Coarsely Similar to Expected Strain

Suggests all were dropped the same way.

Heavy point Impact on some Edge Cells

	A	B	C	D	E	F
1		1.8%	2.7%	1.8%	1.8%	
2	5.3%	9.7%	3.5%	4.4%	4.4%	1.8%
3	7.1%	11.5%	9.7%	8.0%	3.5%	1.8%
4	4.4%	9.7%	5.3%	5.3%	5.3%	1.8%
5	7.1%	10.6%	4.4%	7.1%	5.3%	1.8%
6	12.4%	11.5%	4.4%	8.8%	7.1%	4.4%
7	10.6%	15.9%	7.1%	8.0%	5.3%	2.7%
8	10.6%	15.9%	13.3%	8.8%	10.6%	1.8%
9	11.5%	9.7%	8.8%	5.3%	10.6%	2.7%
10	13.3%	9.7%	8.0%	4.4%	3.5%	3.5%
11	7.1%	2.7%	1.8%	1.8%	3.5%	2.7%
12		2.7%	0.9%	0.9%	1.8%	

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Impact of Intentional Rough Handling on Different Technologies

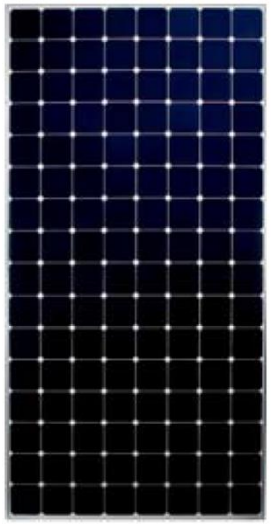
Goal: Compare different module technologies to there tolerance to rough handling

Repeatable
Quick
Cheap

Plan:

1. “Damage” Modules
2. Predict Long term Field Degradation

Phase I Utilized 3 Different Module Technologies

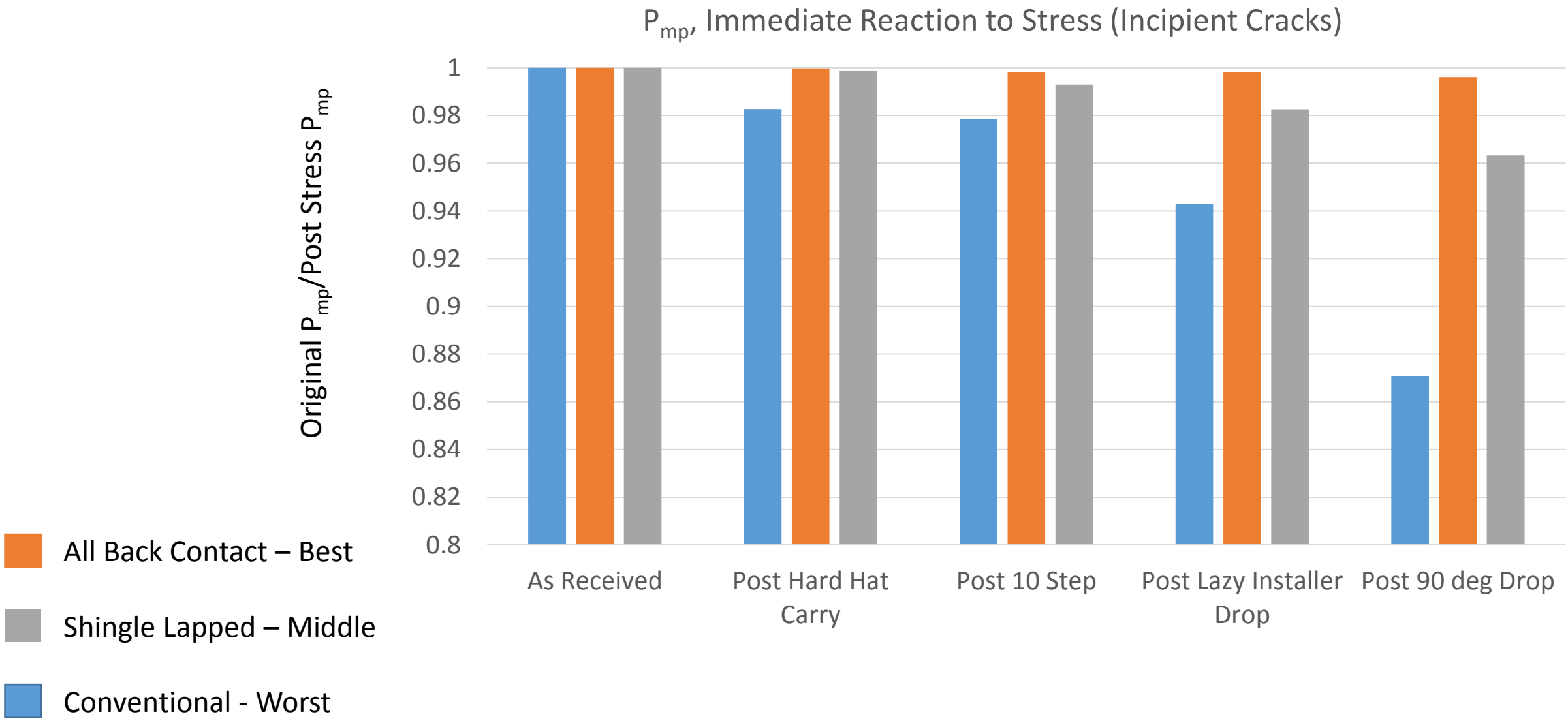


Single Crystal
Copper Metalization
All Back Contact

Multicrystalline
Shingle Lapped Small Cells
High Level of Parallel Devices

Multicrystalline
Conventional Metal
Conventional Device Design

3. *Damage and Test Modules*



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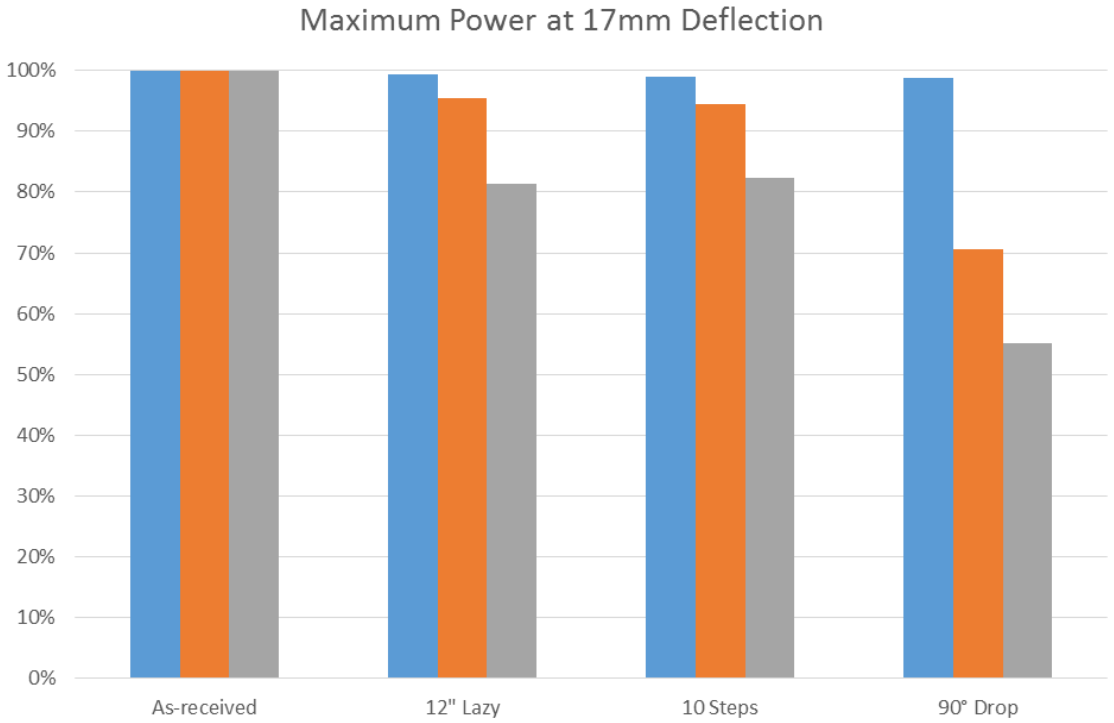
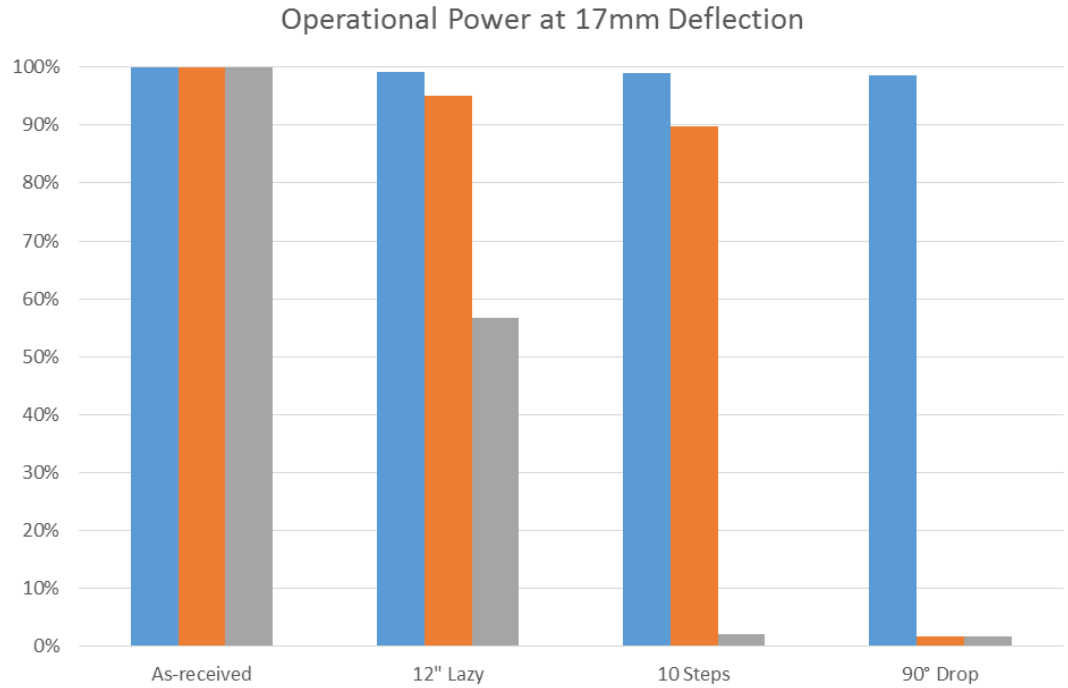




All Back Contact – Best

Shingle Lapped – Middle

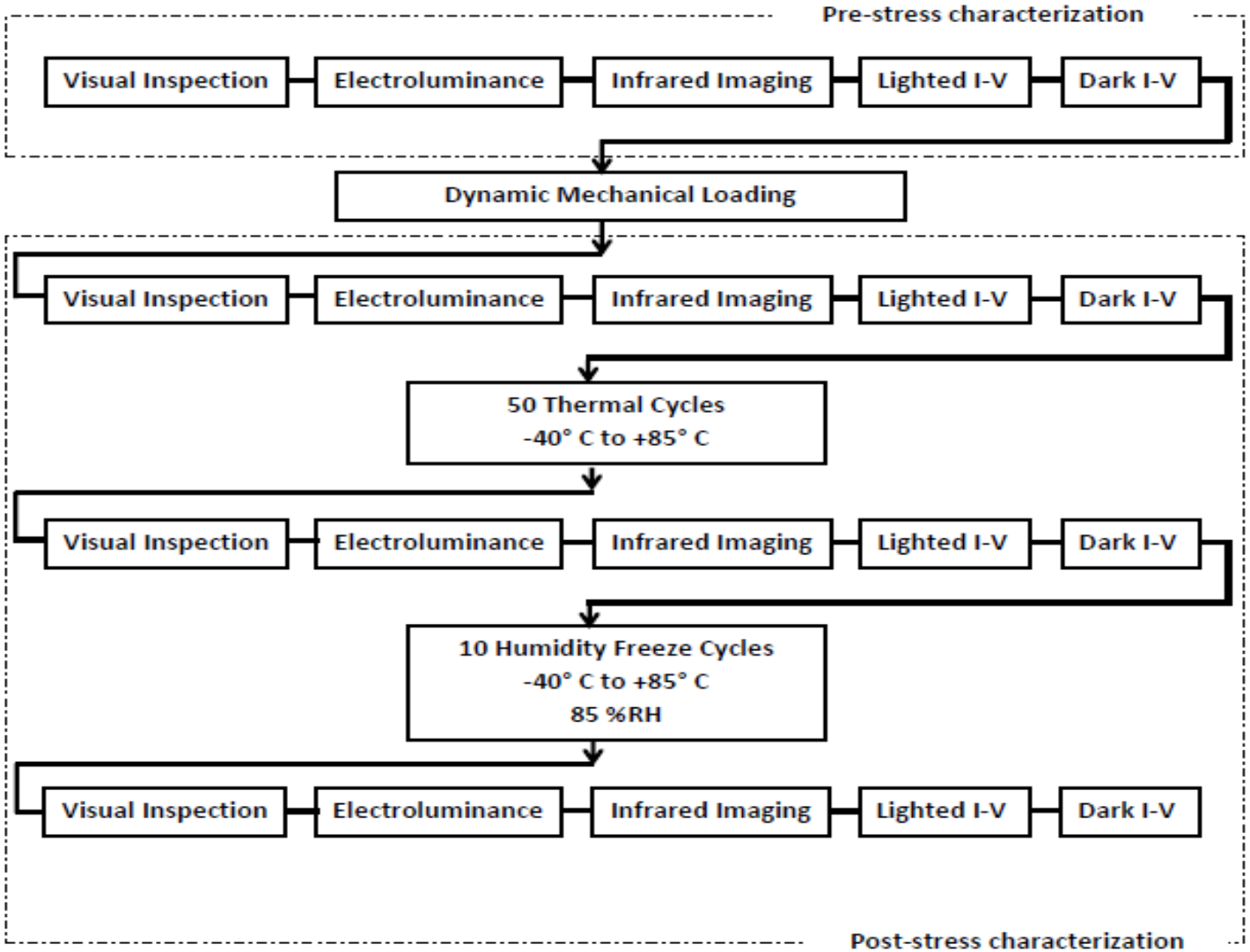
Conventional - Worst

A Phase II Effort is Underway Now

More Technologies Being Sampled

Data in 2 Months

Generate “Damaged” Sample Set for Conventional Aging at NREL



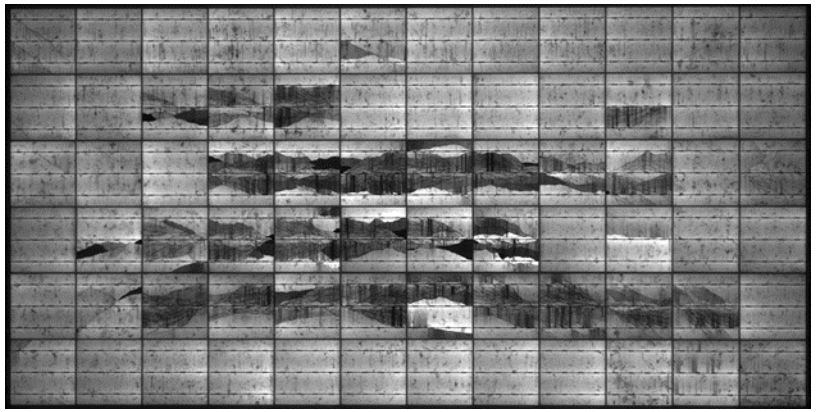
Work done by Rajiv Dubey*, John Wohlgemuth, Sarah Kurtz, Ingrid and others at NREL.

The NREL part of this work was completed under Contract No. DE- AC36-99GO10337 with the U.S. Department of Energy

*This research is based upon work supported by the Solar Energy Research Institute for India and the U.S. (SERIIUS) funded jointly by the U.S. Department of Energy subcontract DE AC36-08G028308 (Office of Science, Office of Basic Energy Sciences, and Energy Efficiency and Renewable Energy, Solar Energy Technology Program, with support from the Office of International Affairs) and the Government of India subcontract IUSSTF/JCERDC-SERIIUS/2012 dated 22nd Nov. 2012.

Relative Power Loss Due to Conventional Aging

		Post DML	Post 50 TC	Post 10 HF		Final
ABC	As Received					
	Post 12" Drop	0.05%	-0.23%	-0.12%		-0.30%
	Post 24" Drop	0.03%	-0.05%	-0.21%		-0.23%
	Post Heavy Steps	-0.16%	-0.14%	-0.19%		-0.49%
Shingled	As Received	-0.33%	-0.14%	-0.59%		-1.06%
	Post 12" Drop	-0.23%	-1.06%	-0.91%		-2.20%
	Post 24" Drop	-1.11%	-0.95%	-2.02%		-4.08%
	Post Heavy Steps	-0.09%	-0.86%	-1.91%		-2.86%
Conv	As Received	-0.20%	-0.90%	-0.23%		-1.33%
	Post 12" Drop	-0.37%	-1.30%	-0.10%		-1.77%
	Post 24" Drop	-0.24%	-1.50%	-0.43%		-2.17%
	Post Heavy Steps	-0.16%	-0.60%	-0.54%		-1.30%



Observations:

Surprising Low levels of power loss based on the high level of Damage.

ABC performed the best

More Analysis to come, including a detailed comparison with the PUMT results

Outline

1. Technical Work
    A. Transportation Damage Study – Incipient Cracks
    B. Impact of Intentional Rough Handling on Different Technologies
    C. Case Study – 6 year old Arrays
2. Summary of Quantified Conclusions
3. Summary of Opinions

A. *Case Study on 6 Year Old Array*

Commercial Array
- Total 584kW

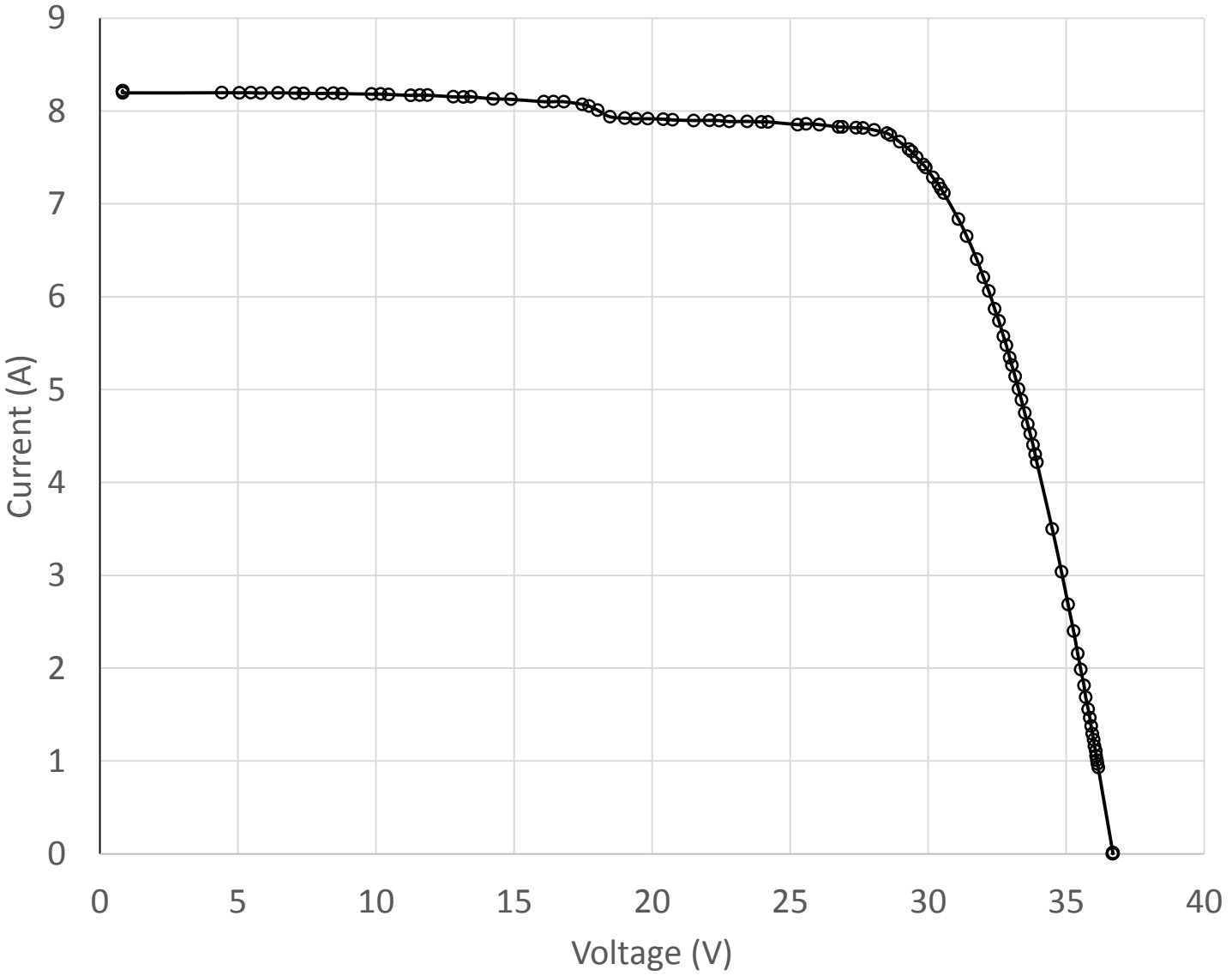
60 Cell Multicrystalline Silicon Modules
- 235W Label
- 2 Busbar
- “Conventional” Construction
- 2480 Modules Total

Ballasted Rack System on a Flat Roof

Core Energy Works was Called out for Hot Spot Inspection

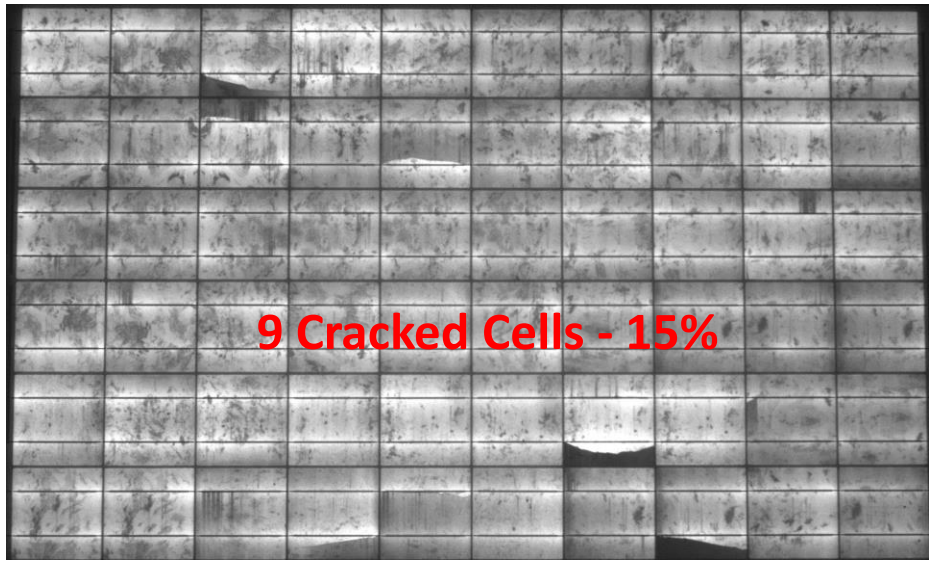
Originally found by annual OM inspection

47 Modules were Replaced Due to High T_{Delta}
(1.9% of the array)

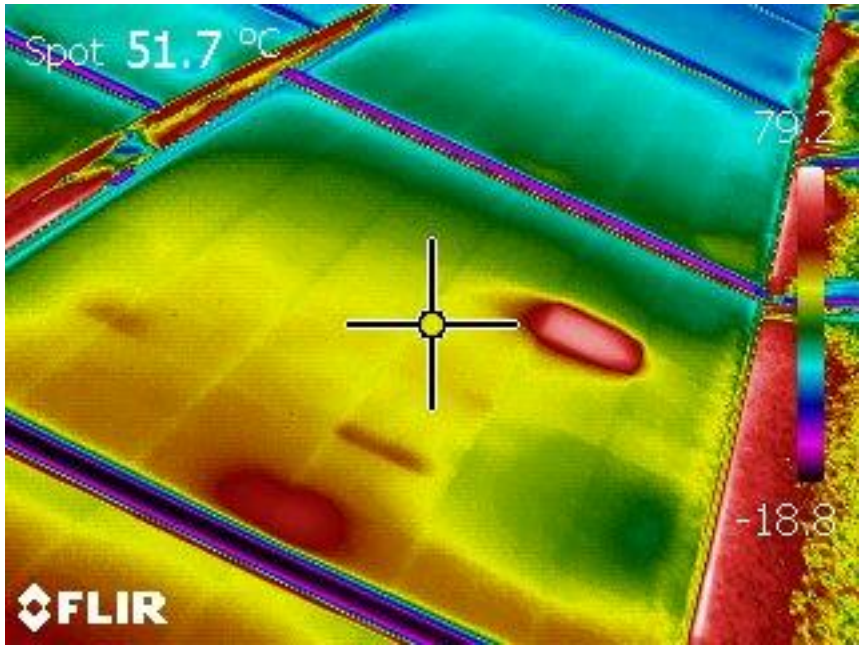


SerialNumber	Uoc (V)	Isc (A)	Pmpp (W)	Umpp (V)	Impp (A)	FF (%)	ΔT (°C)
0177	36.69	8.21	222.3	29.29	7.59	73.8	27

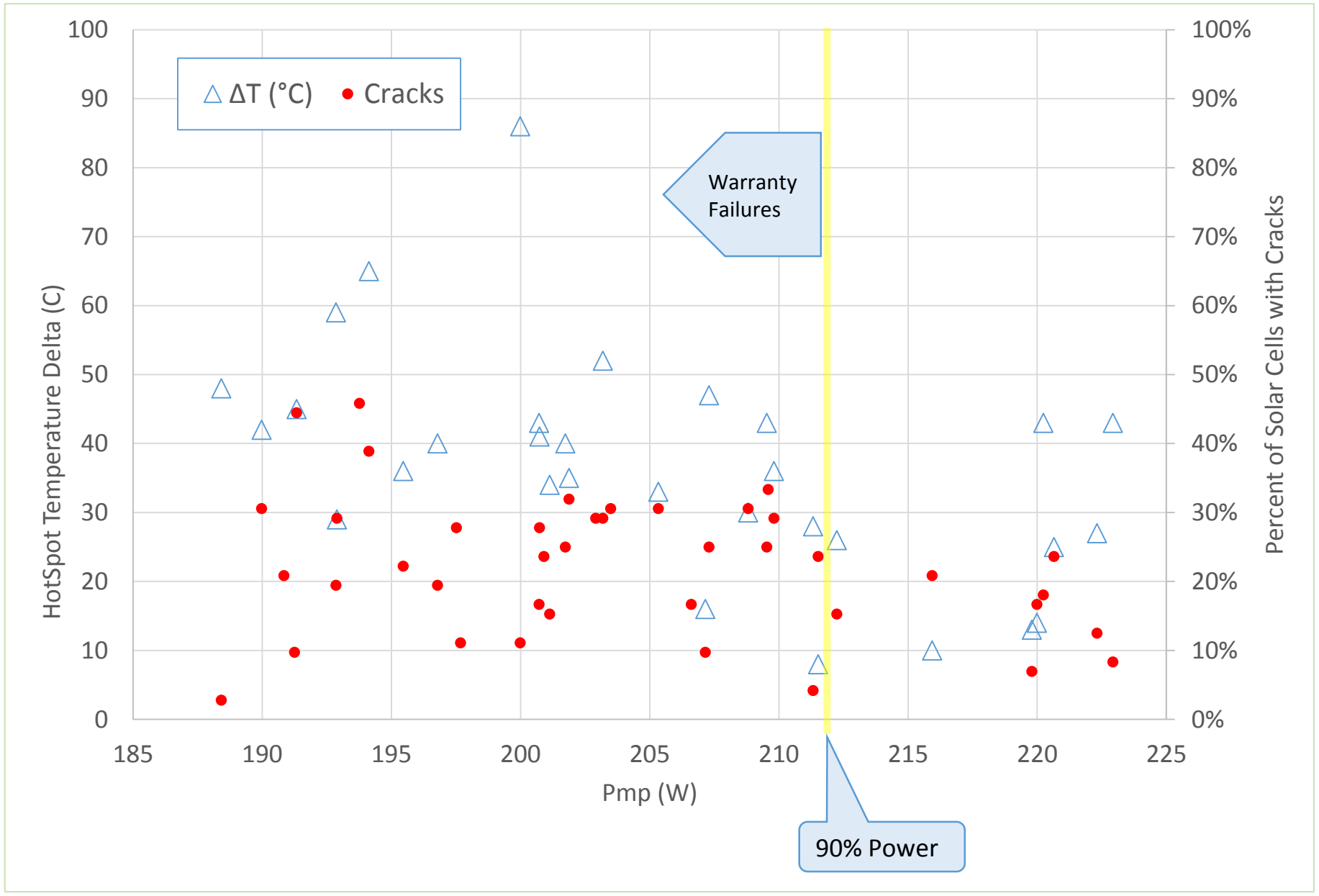
Electroluminescence



Infrared



Correlating STC IV Testing to IR and Cracks



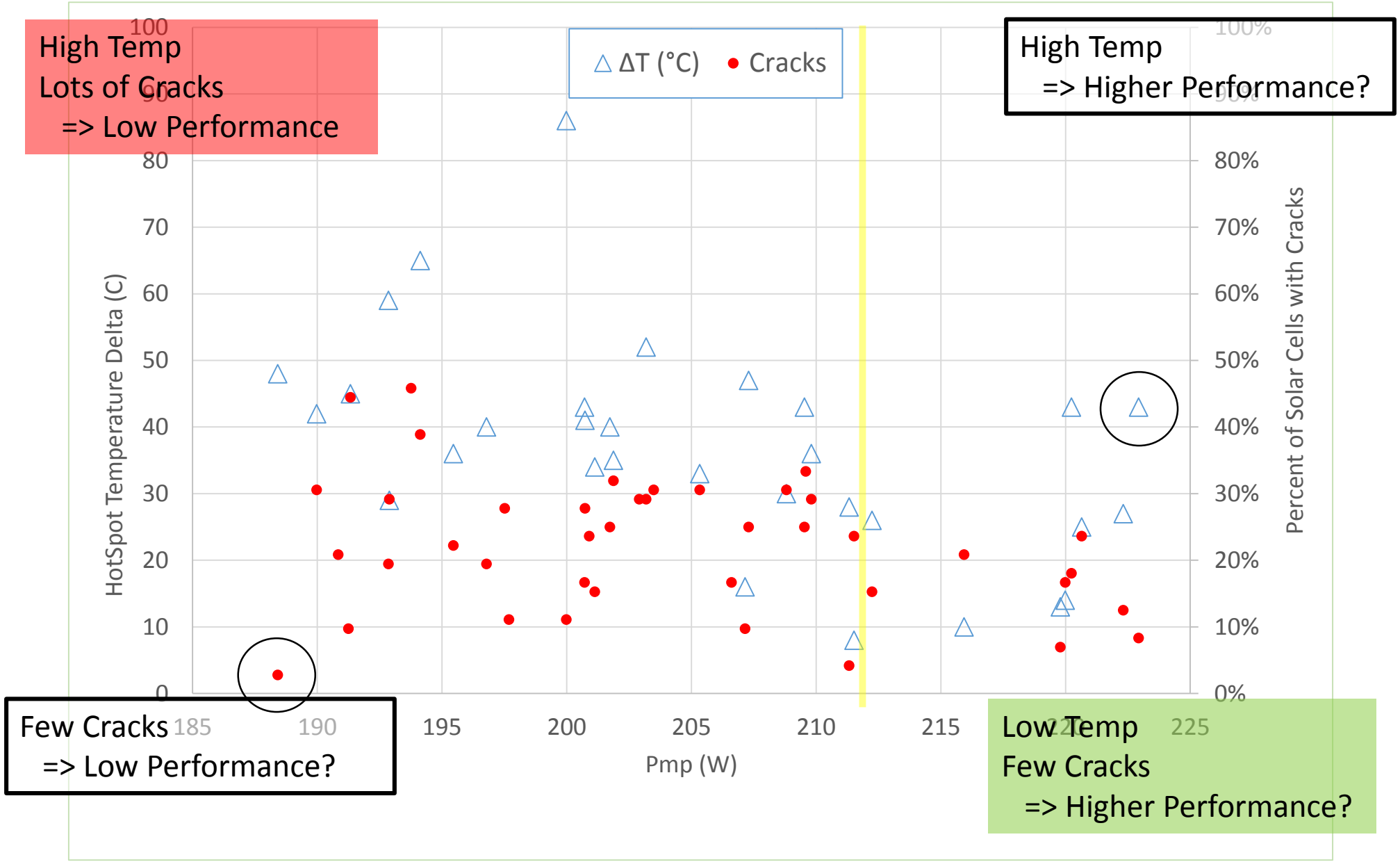
1. Weak Association at best between peak hot spot temp and Pmp.

2. Weak Association at best between # Cracked Solar Cells and Pmp.

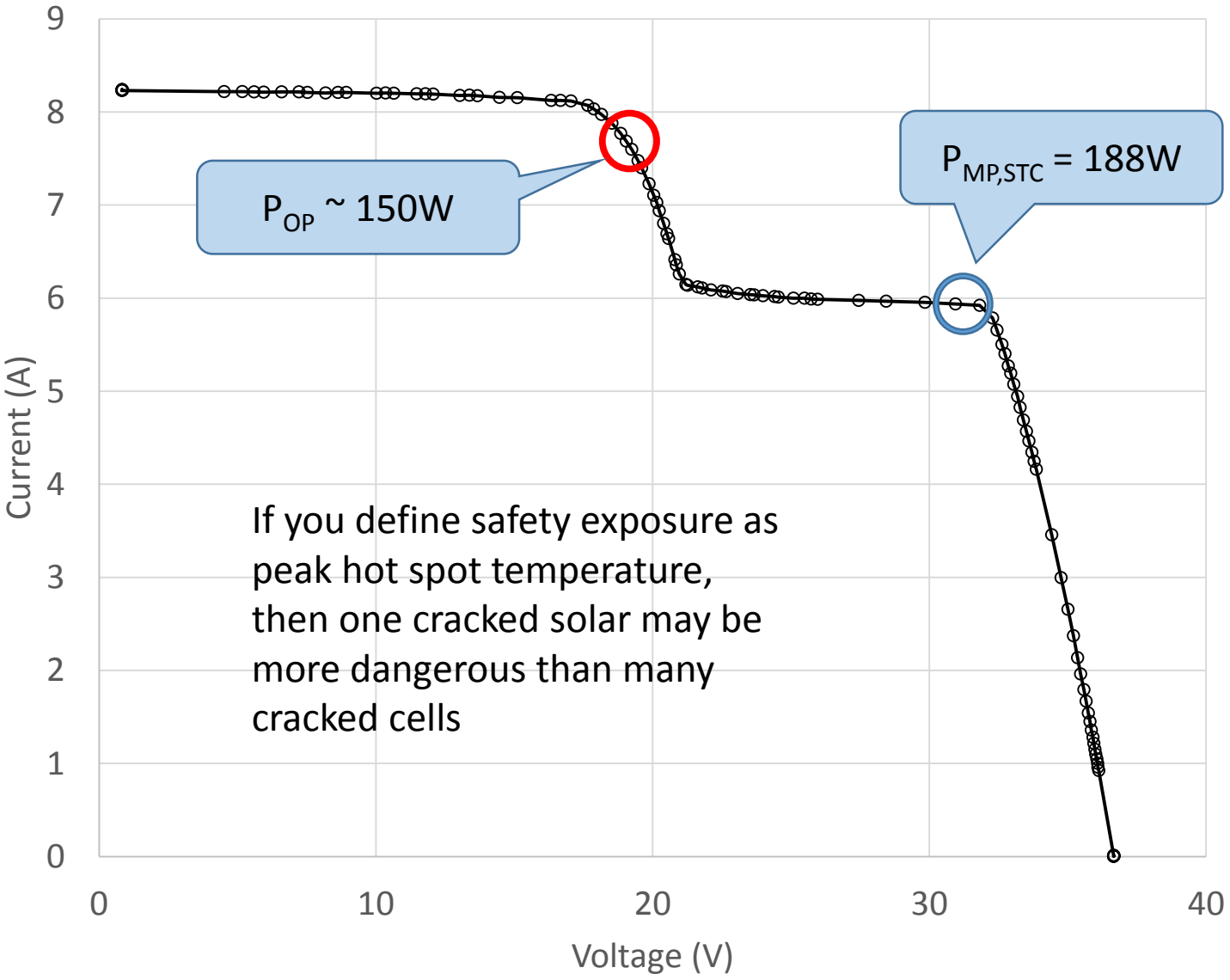
3. 75% of the Modules found in the IR Testing in the Field were warranty failures.

The question begged is “what does the non-hot spot distribution look like”.

Correlating STC IV Testing to IR and Cracks

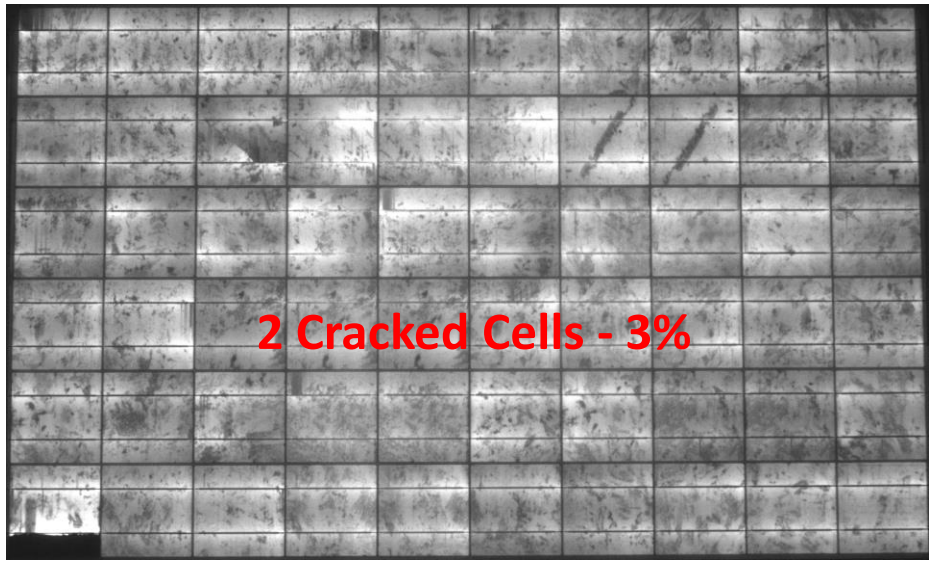


Few Cracks yet Low Performance

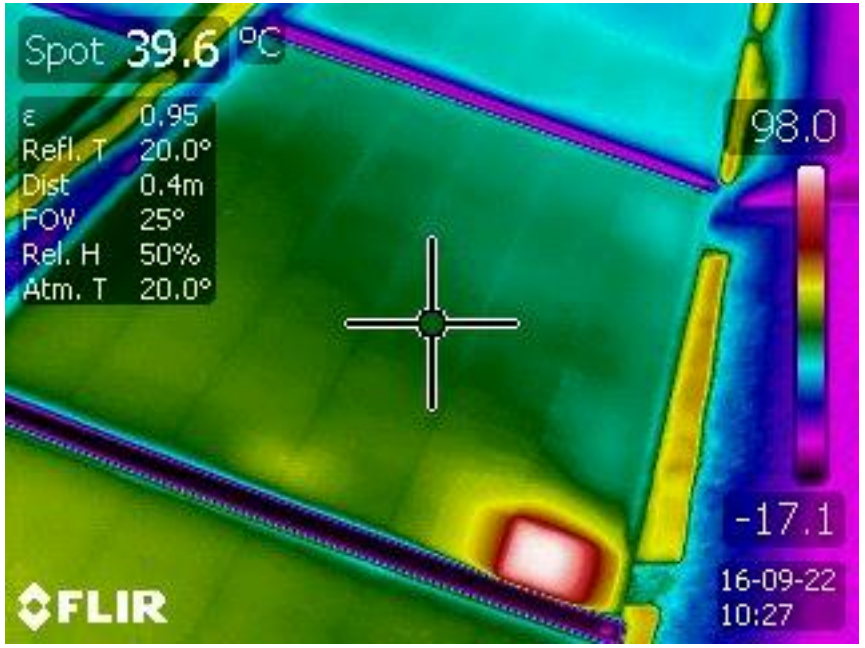


SerialNumber	Uoc (V)	Isc (A)	Pmpp (W)	Umpp (V)	Impp (A)	FF (%)	ΔT (°C)
00232	36.66	8.24	188.41	31.81	5.92	62.40	48

Electroluminescence

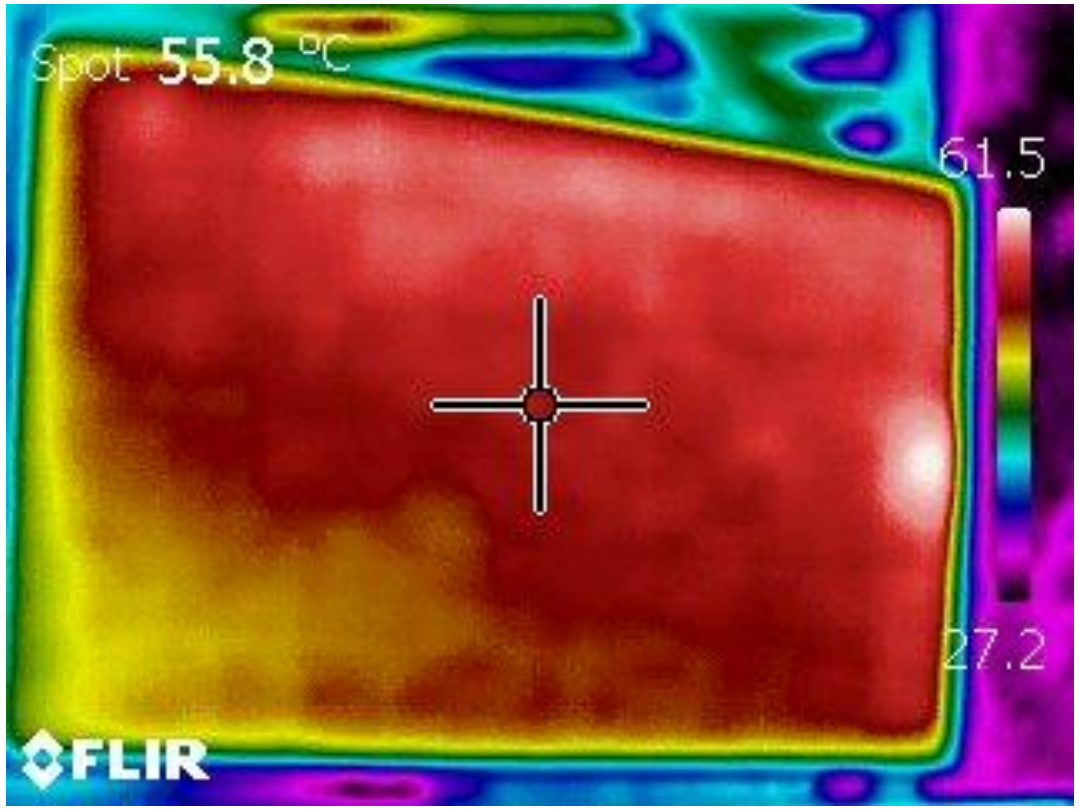


Infrared

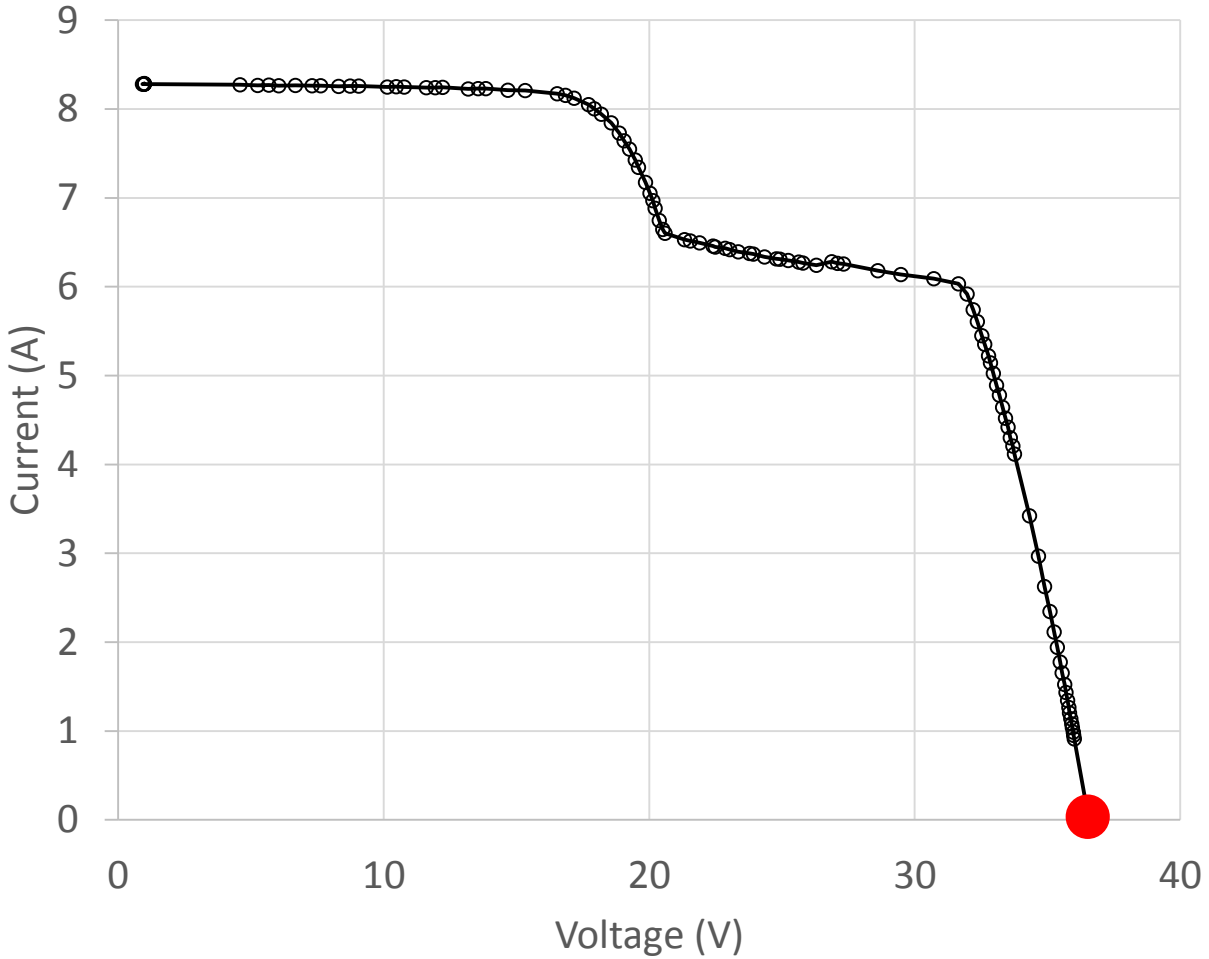


Case One:
One Current Limiting Cell with high Shunt Resistance

SN: C201012230710, 60 cell, 2 busbar, multicrystalline silicon , 235 W nameplate



ΔT ≈ 0°C



Module History:

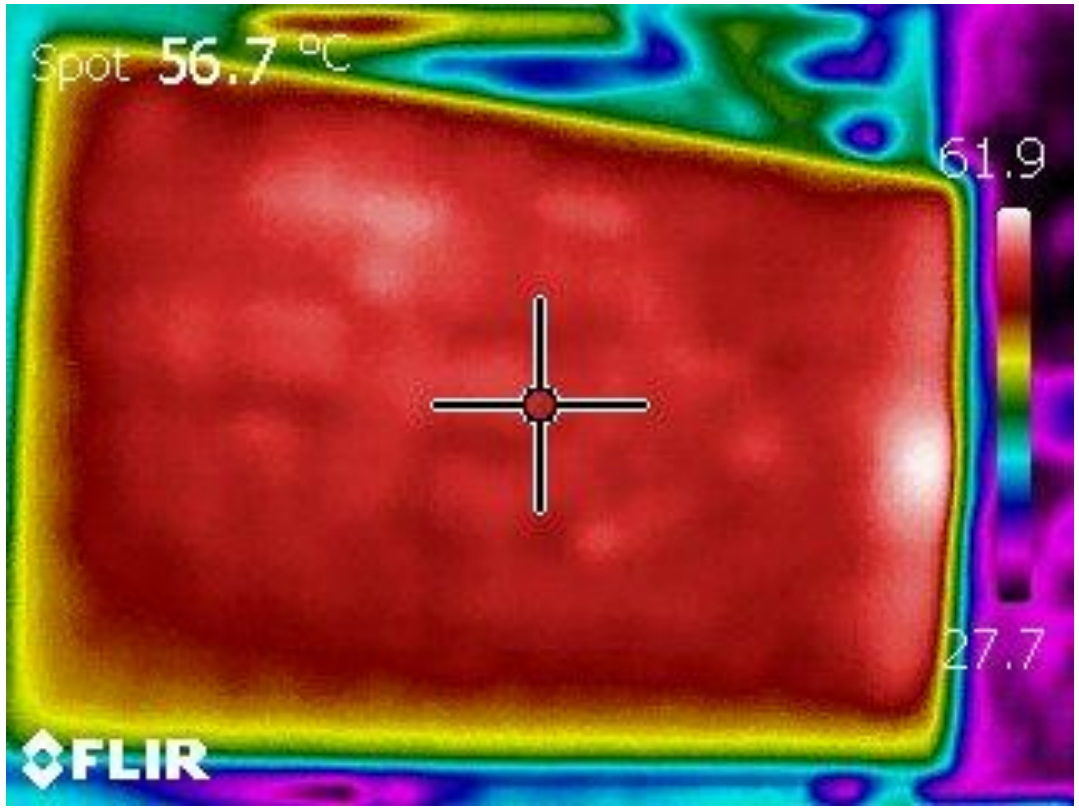
Warranty return from a commercial rooftop.

6 years in operation.

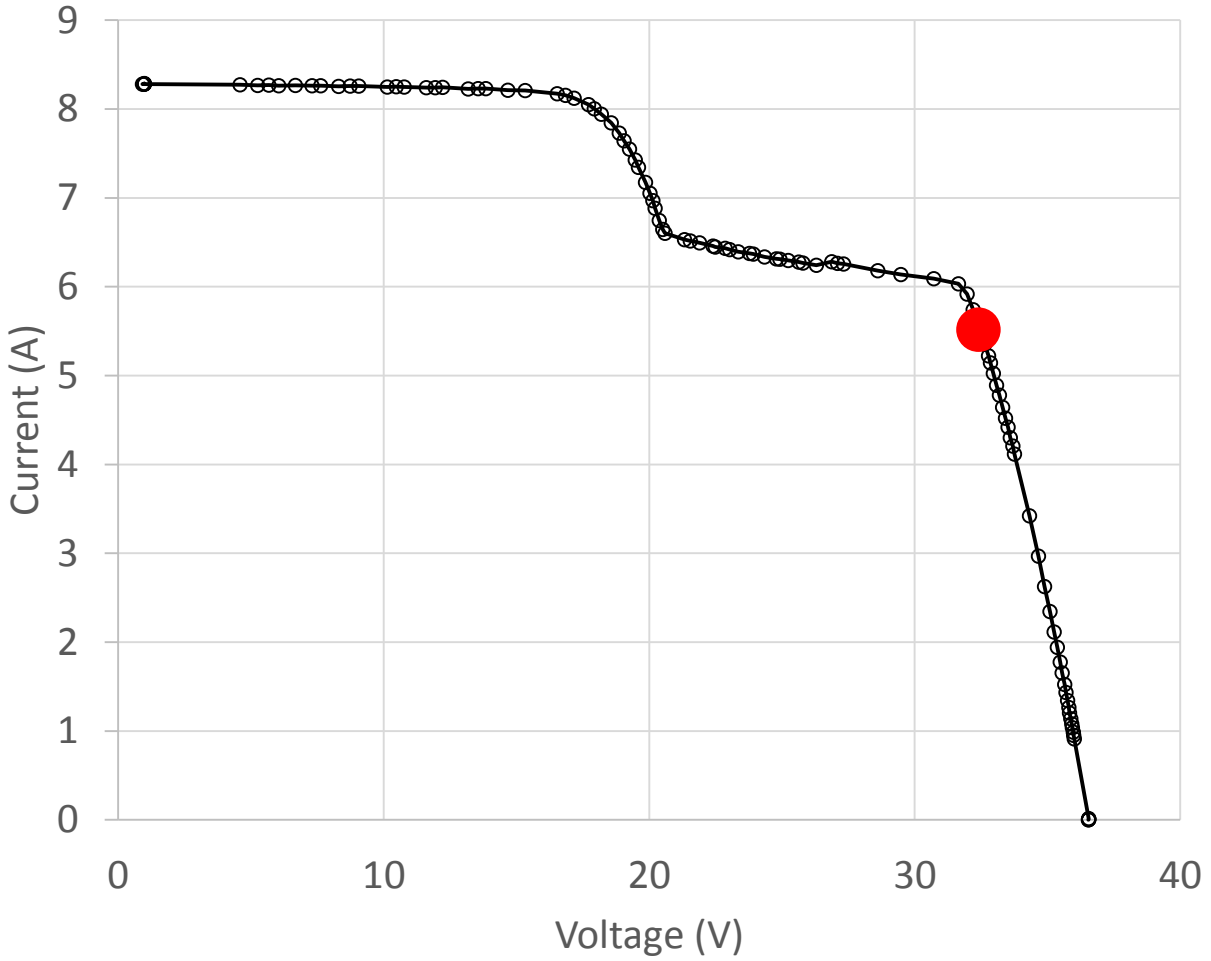
~20% Power loss at STC

Case One: One Current Limiting Cell with high Shunt Resistance

SN: C201012230710, 60 cell, 2 busbar, multicrystalline silicon , 235 W nameplate



ΔT ≈ 0°C



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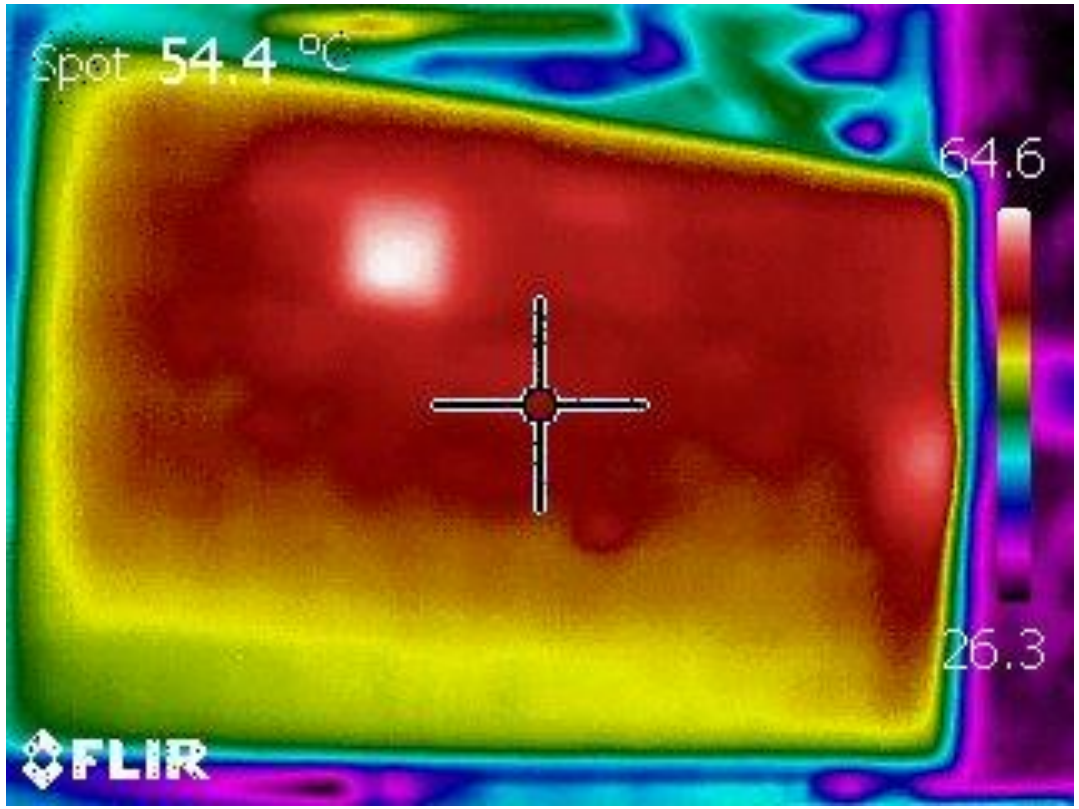
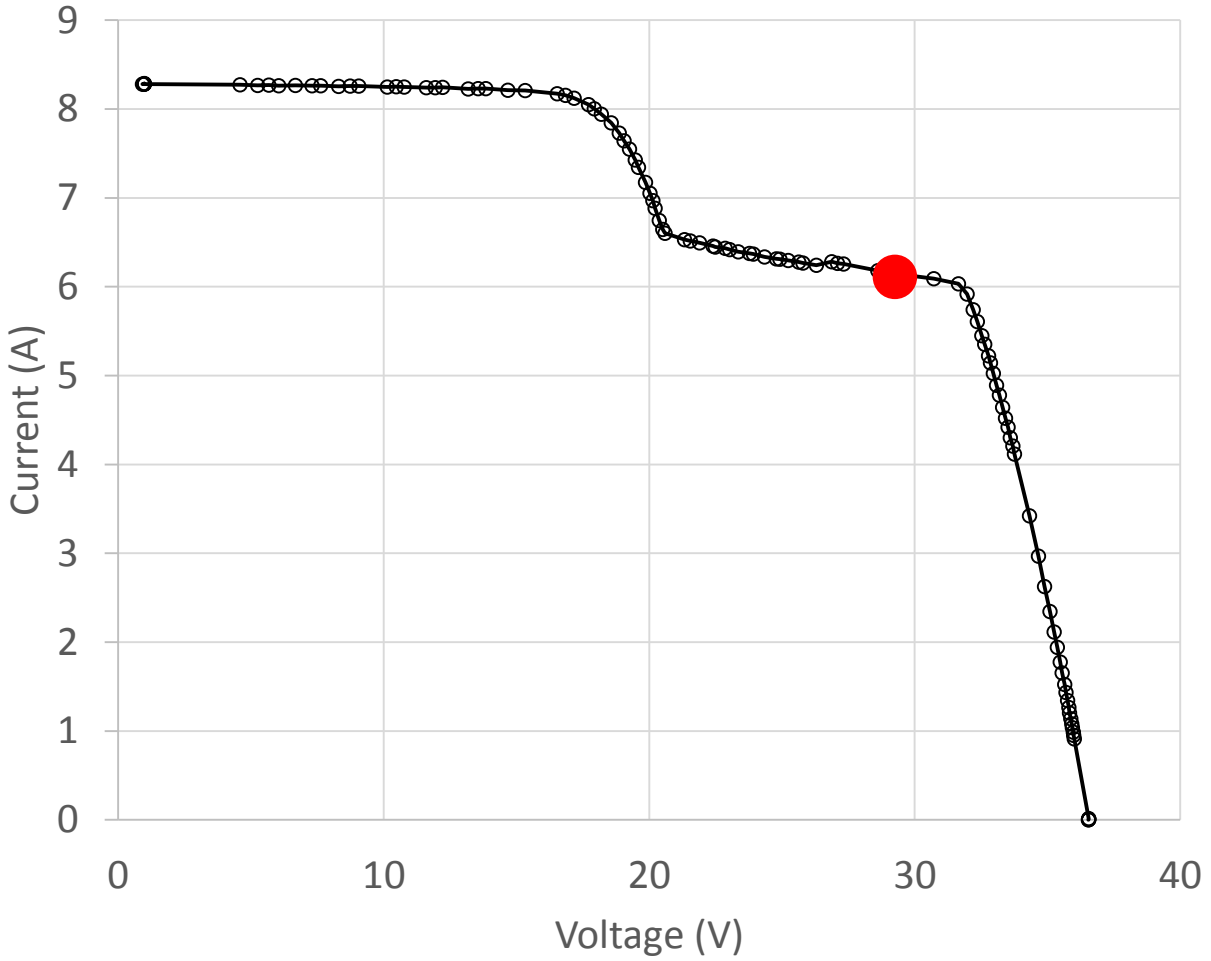
SN: C201012230710, 60 cell, 2 busbar, multicrystalline silicon , 235 W nameplate



ΔT ≈ 6°C



Module History:

Warranty return from a commercial rooftop.

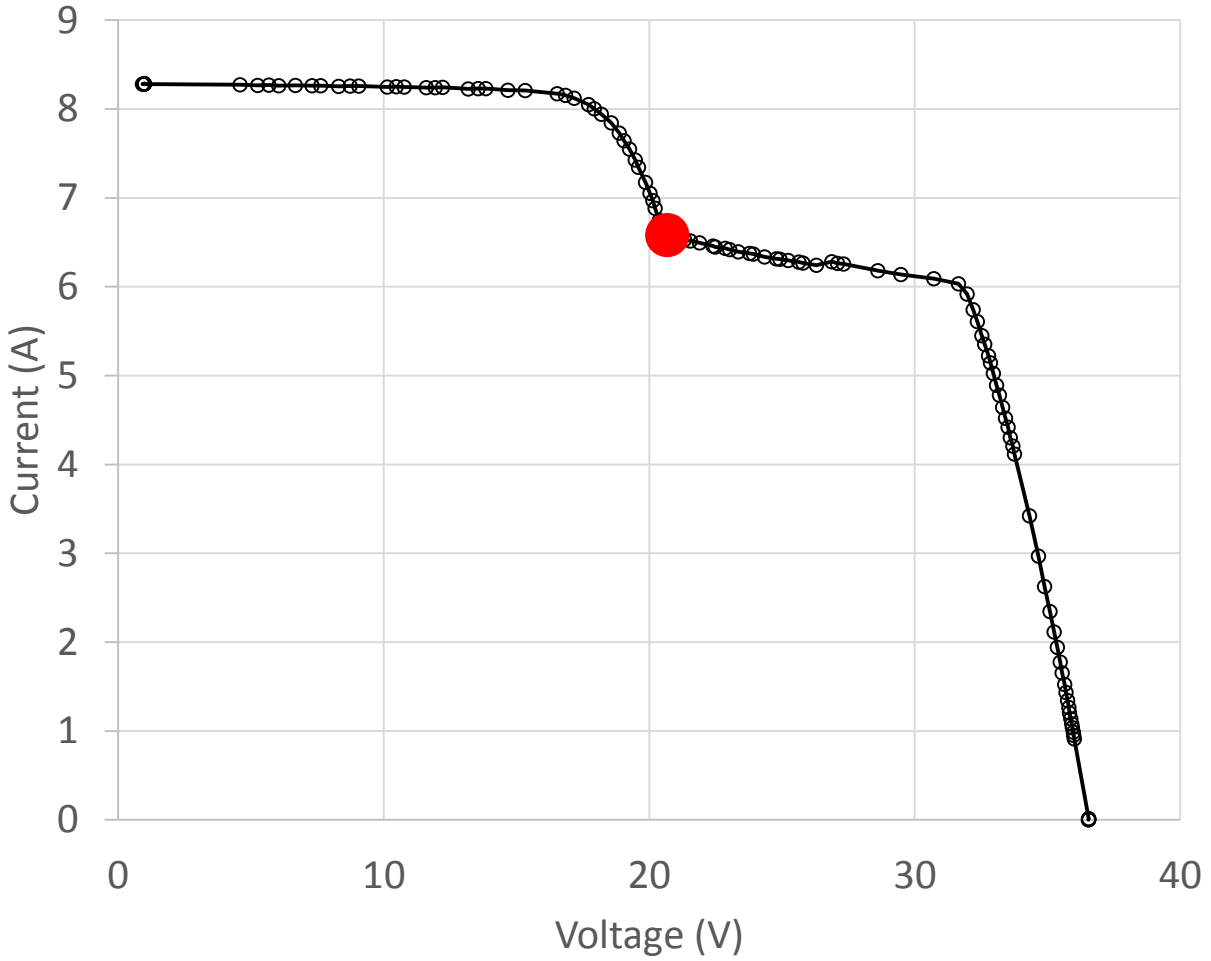
6 years in operation.

~20% Power loss at STC

Case One: One Current Limiting Cell with high Shunt Resistance

SN: C201012230710, 60 cell, 2 busbar, multicrystalline silicon , 235 W nameplate

ΔT ≈ 60°C



Module History:

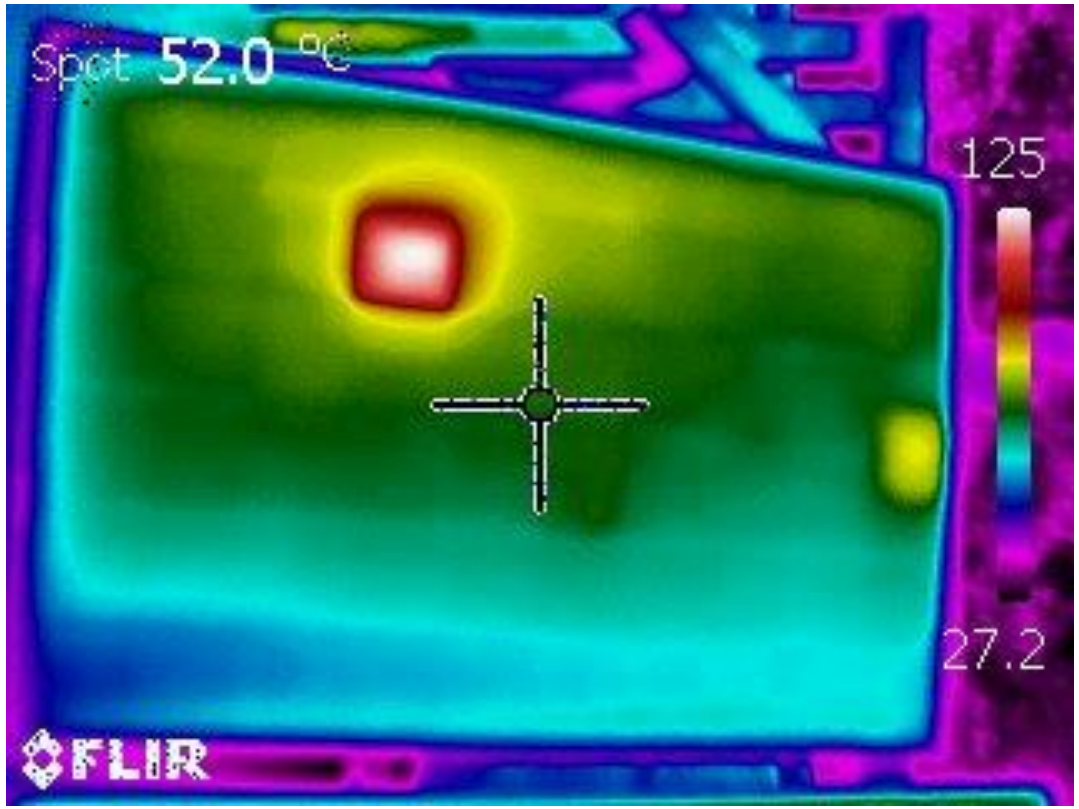
Warranty return from a commercial rooftop.

6 years in operation.

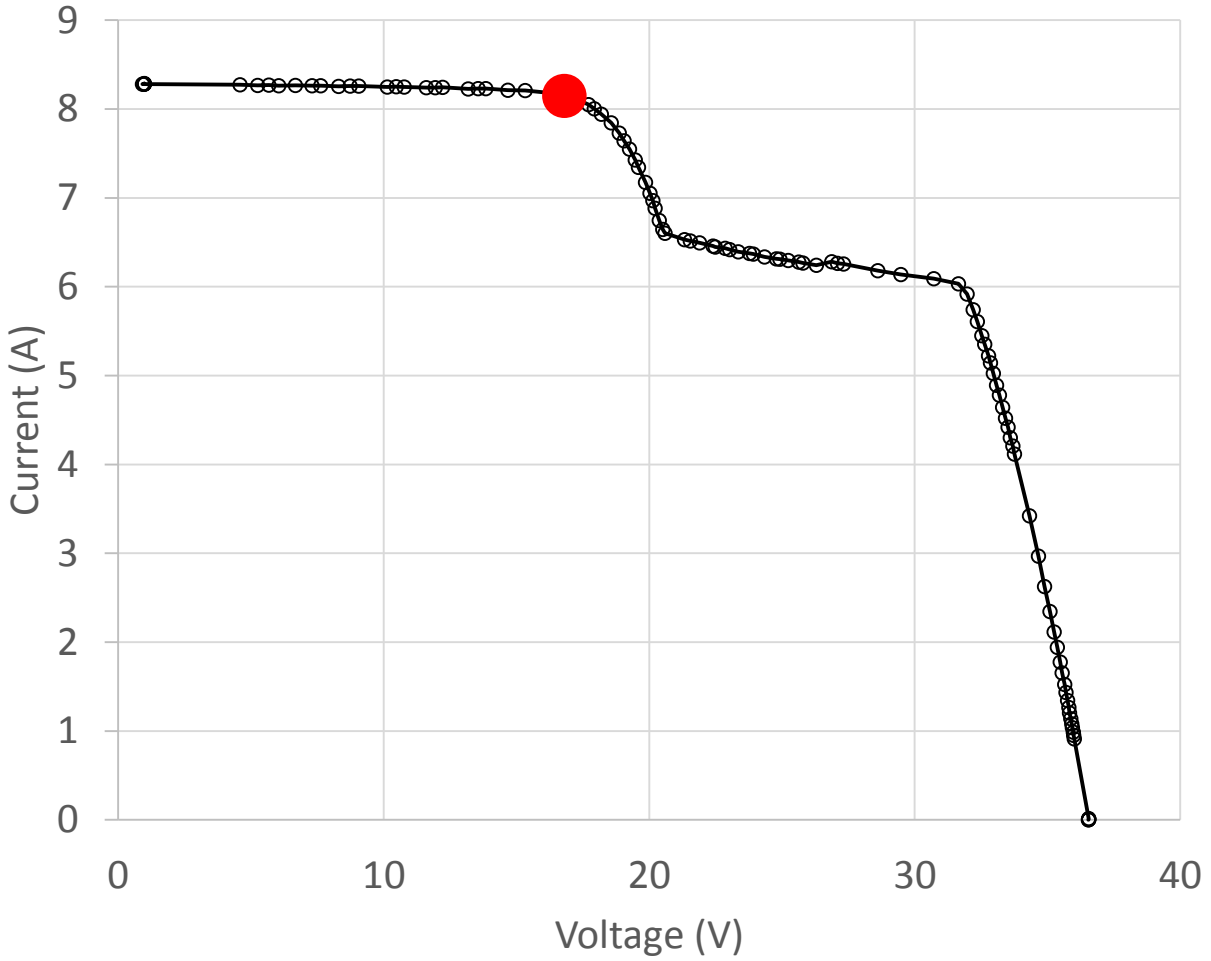
~20% Power loss at STC

Case One: One Current Limiting Cell with high Shunt Resistance

SN: C201012230710, 60 cell, 2 busbar, multicrystalline silicon , 235 W nameplate



ΔT ≈ 66°C



Module History:

Warranty return from a commercial rooftop.

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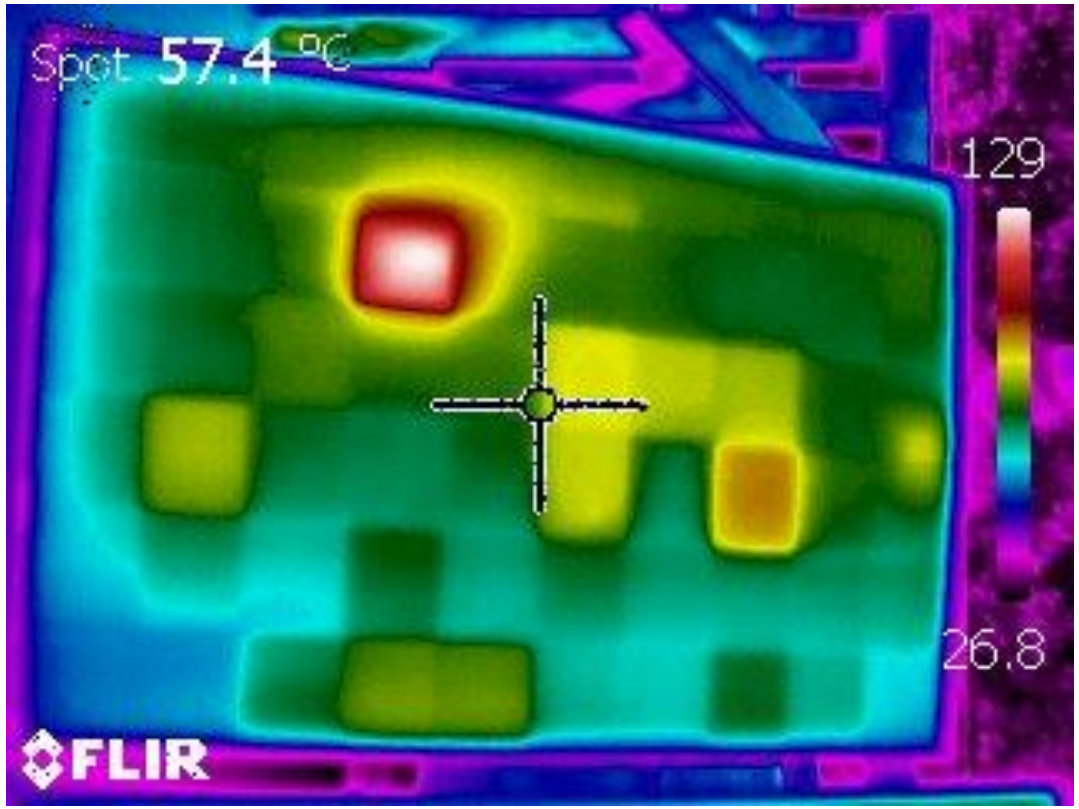
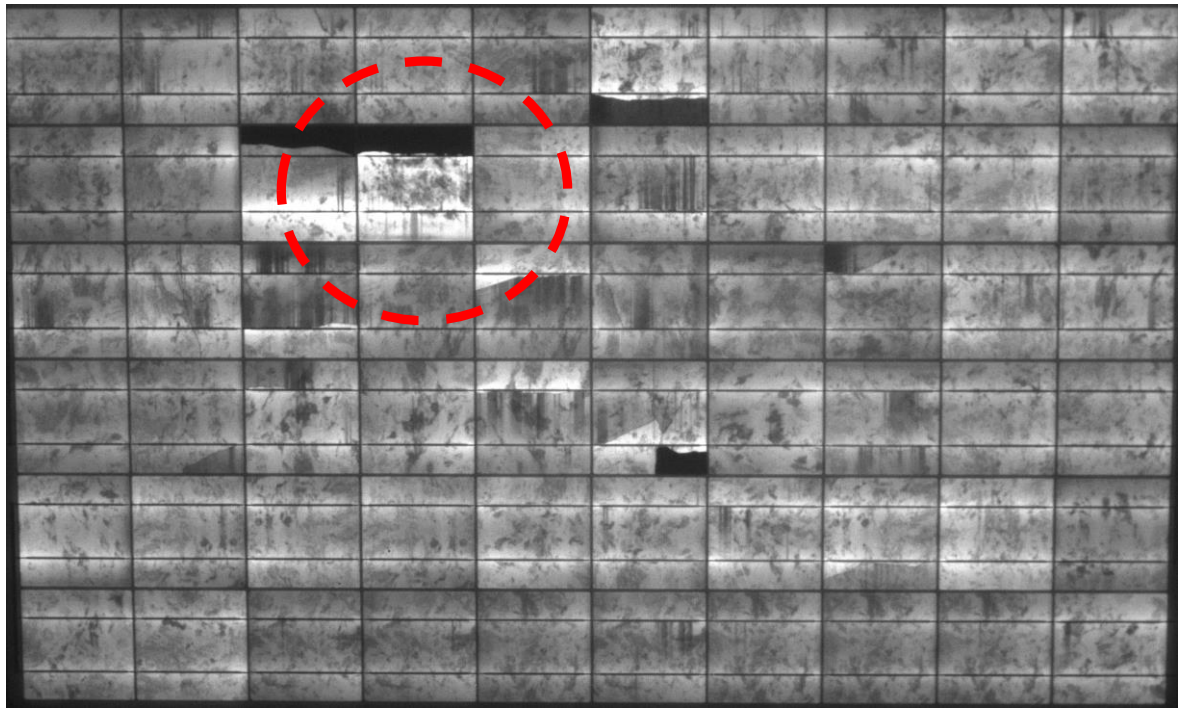
Case One: One Current Limiting Cell with high Shunt Resistance

SN: C201012230710, 60 cell, 2 busbar, multicrystalline silicon , 235 W nameplate





ΔT ≈ 70°C @ short-circuit

Module History:

Warranty return from a commercial rooftop.

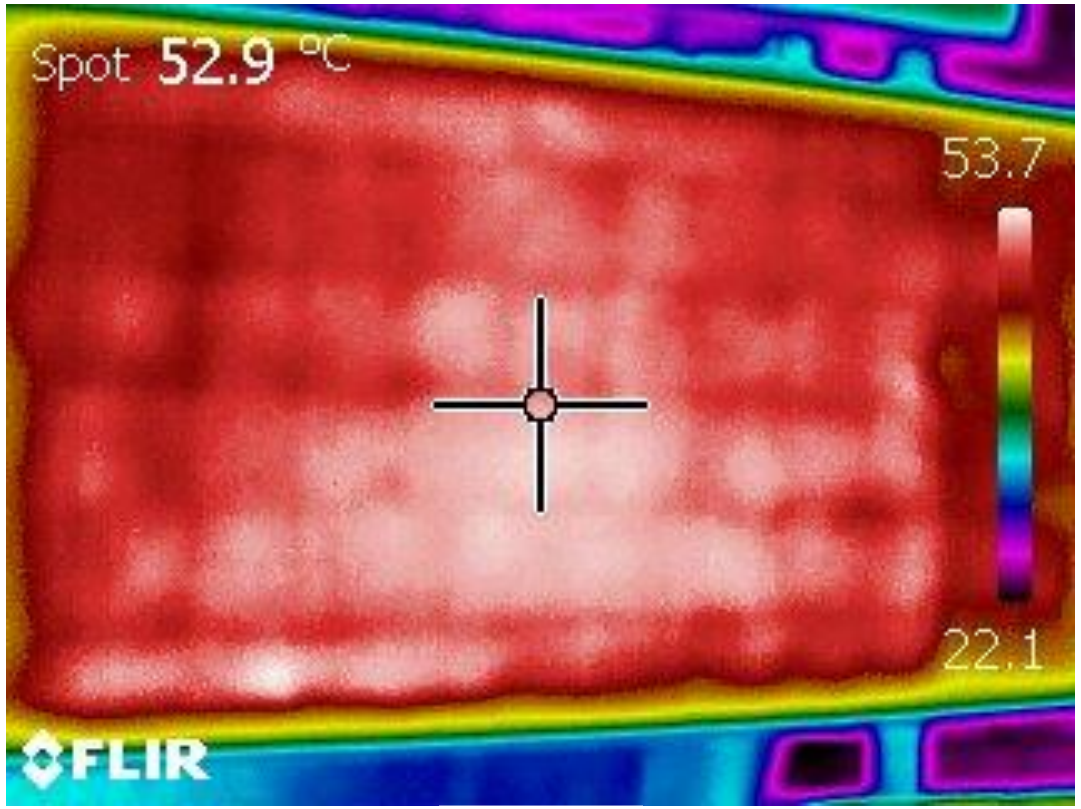
6 years in operation.

~20% Power loss at STC

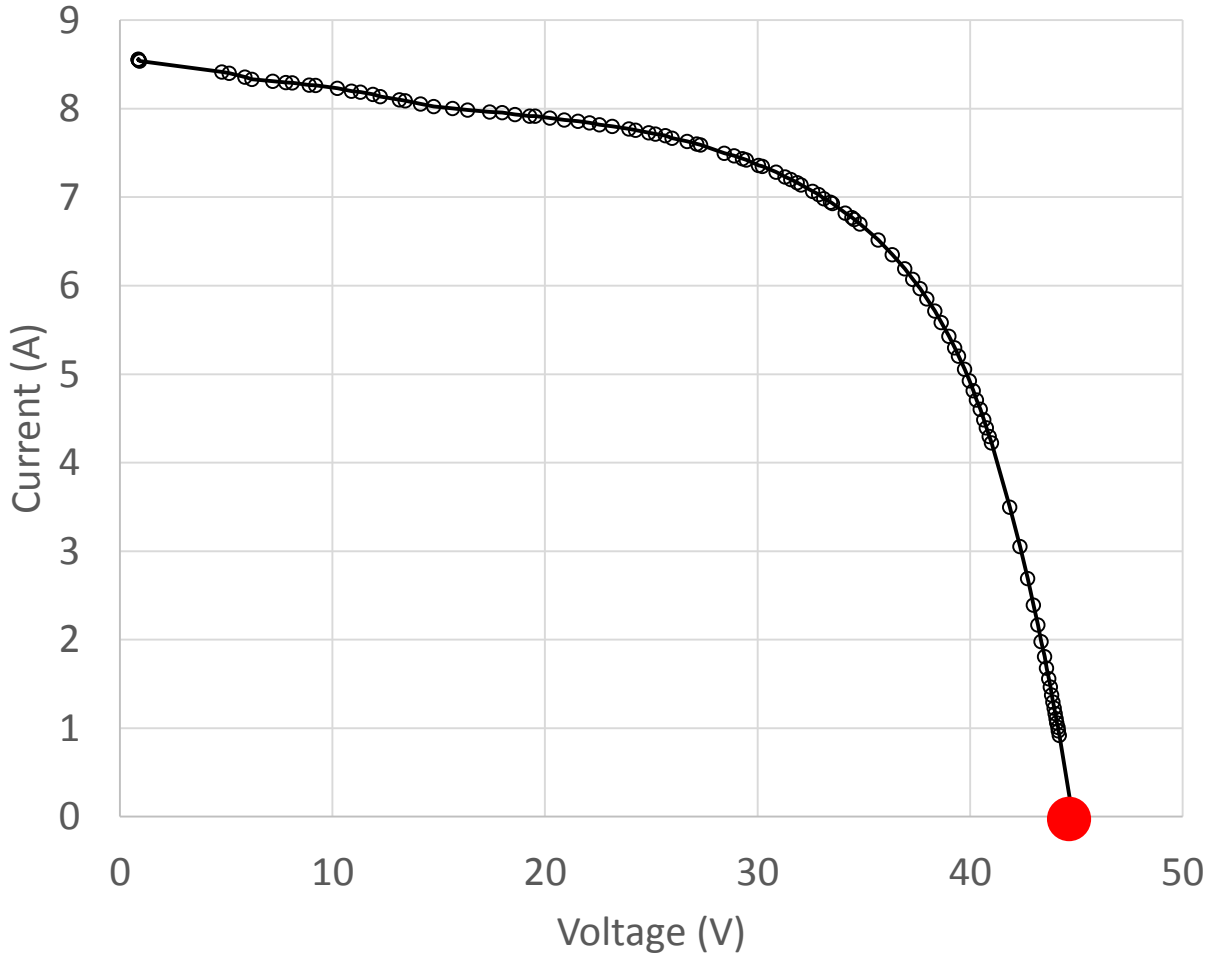
Case One: One Current Limiting Cell with high Shunt Resistance

Case Two:
Widespread Cell Damage

SN:W5174514121603140, 72 cell, 3 busbar, multicrystalline silicon , 300 W nameplate



ΔT ≈ 0°C



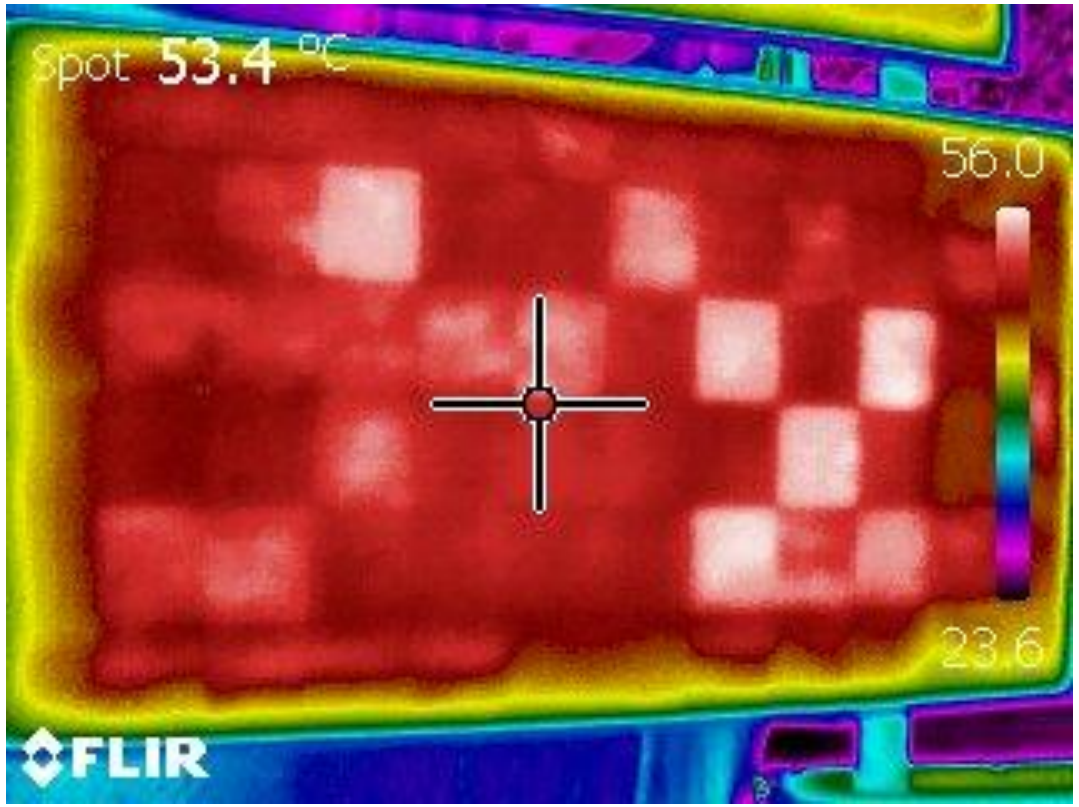
Module History:

Initially damaged due to transportation incident

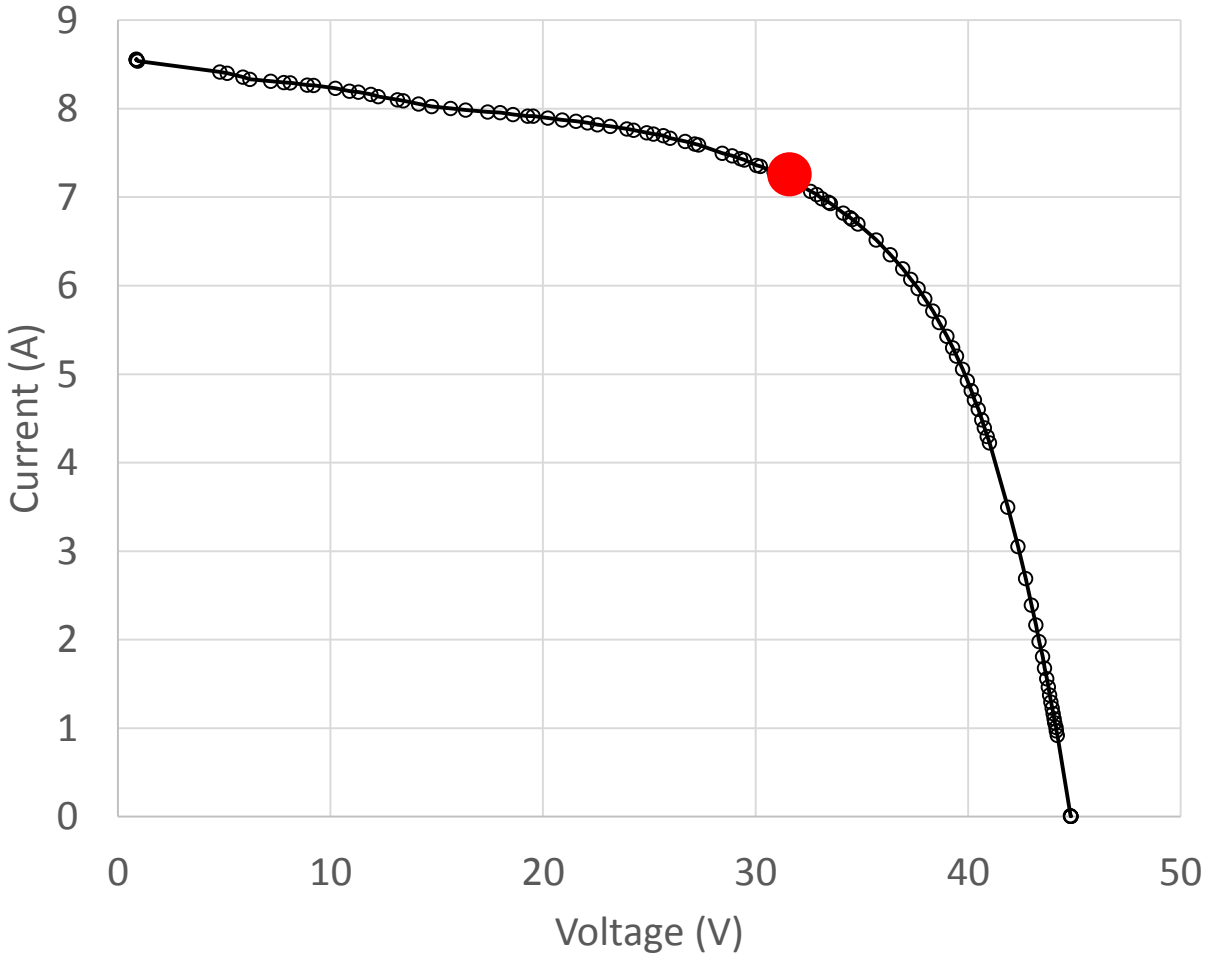
Vibration aged in the lab and sun-soaked 1 month while at short-circuit.

~20% Power loss at STC

SN:W5174514121603140, 72 cell, 3 busbar, multicrystalline silicon , 300 W nameplate



ΔT ≈ 2°C



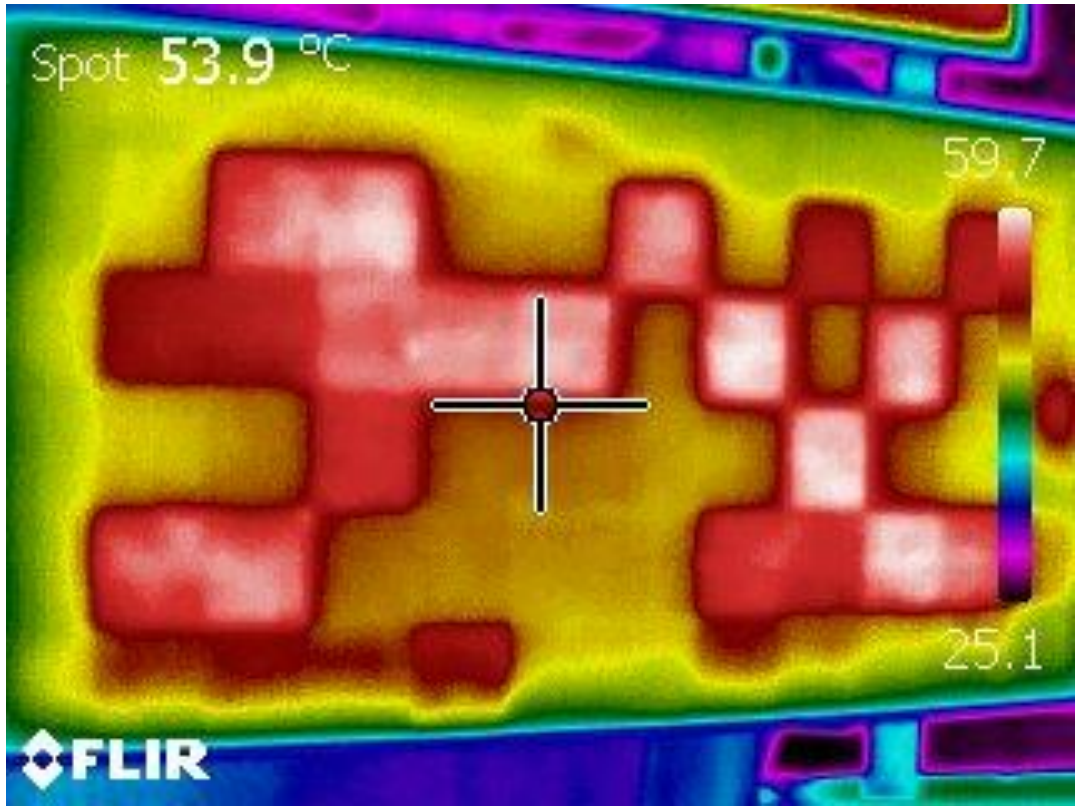
Module History:

Initially damaged due to transportation incident

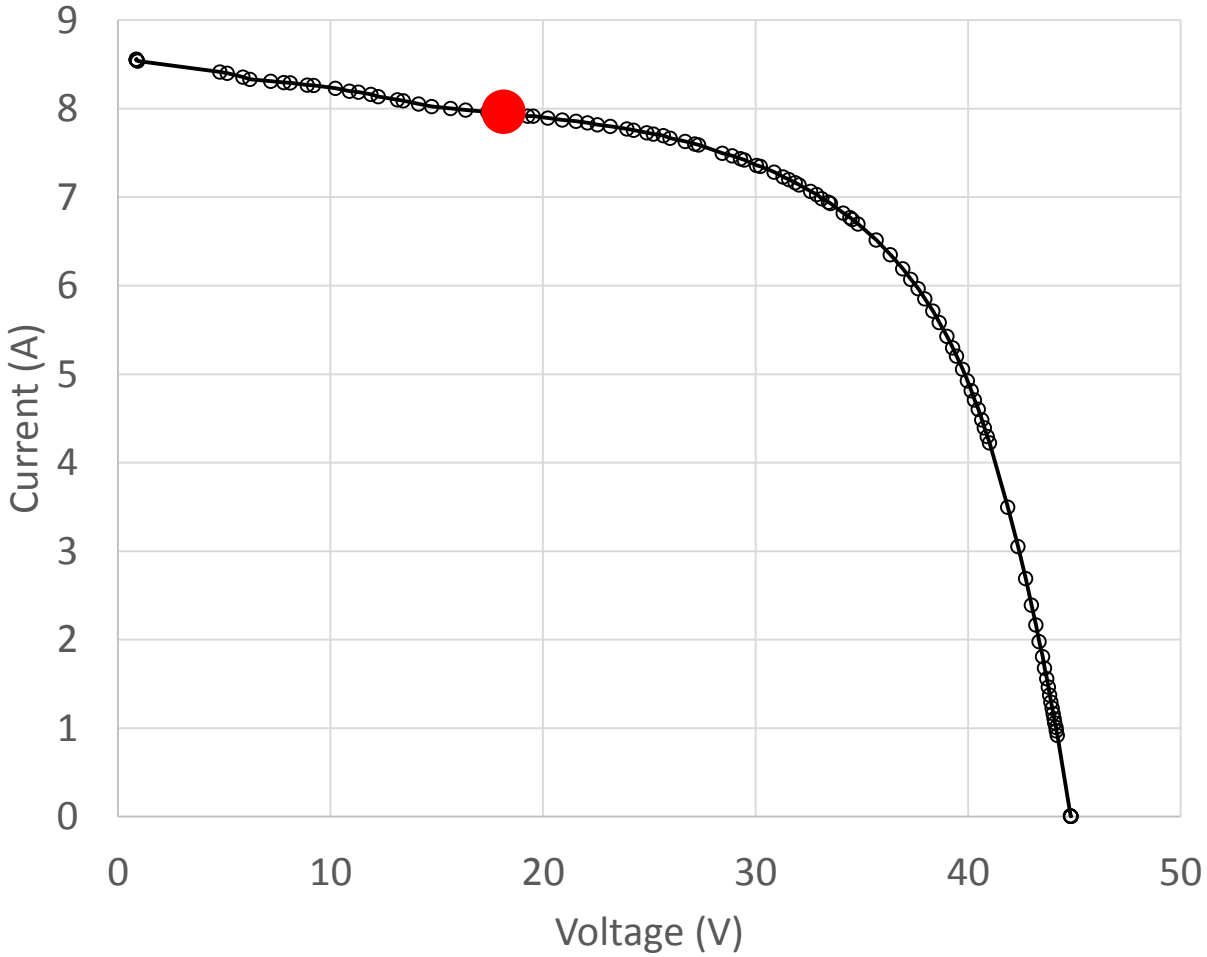
Vibration aged in the lab and sun-soaked 1 month while at short-circuit.

~20% Power loss at STC

SN:W5174514121603140, 72 cell, 3 busbar, multicrystalline silicon , 300 W nameplate



ΔT ≈ 5°C



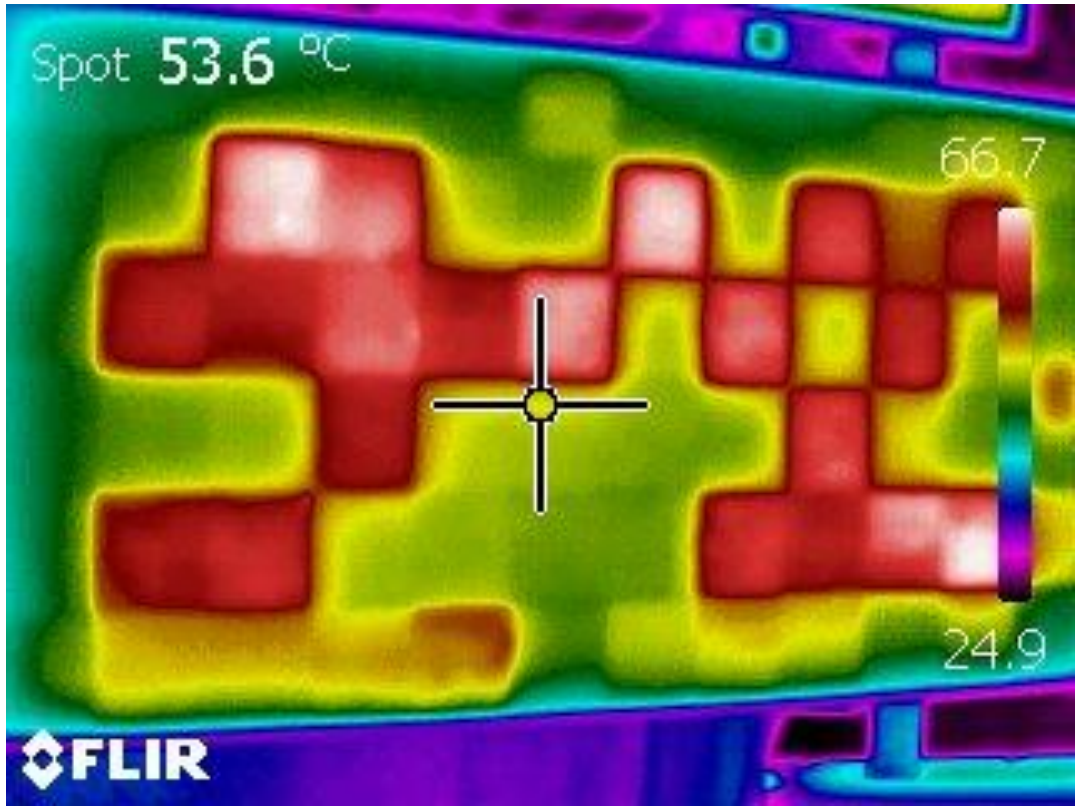
Module History:

Initially damaged due to transportation incident

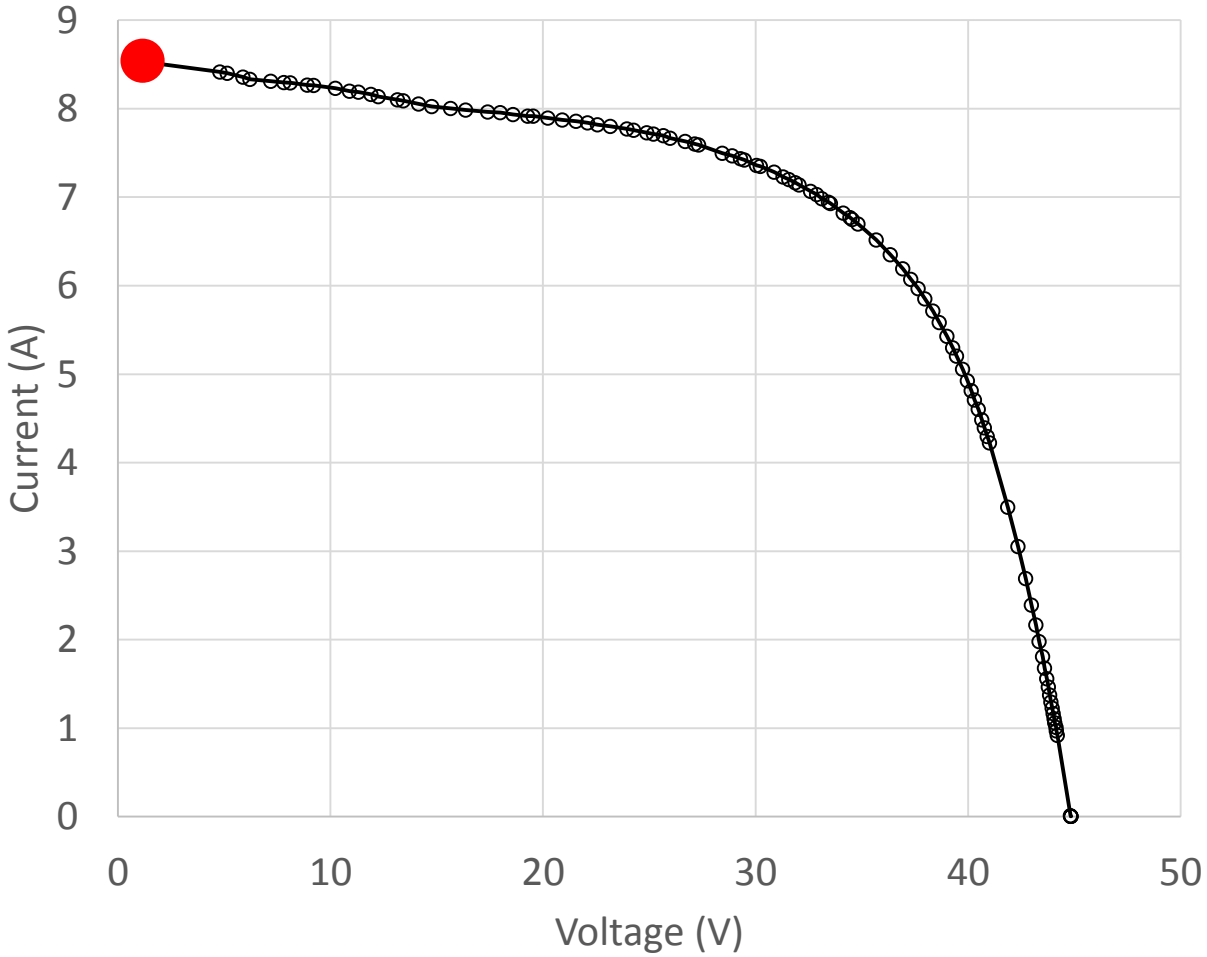
Vibration aged in the lab and sun-soaked 1 month while at short-circuit.

~20% Power loss at STC

SN:W5174514121603140, 72 cell, 3 busbar, multicrystalline silicon , 300 W nameplate



ΔT ≈ 13°C



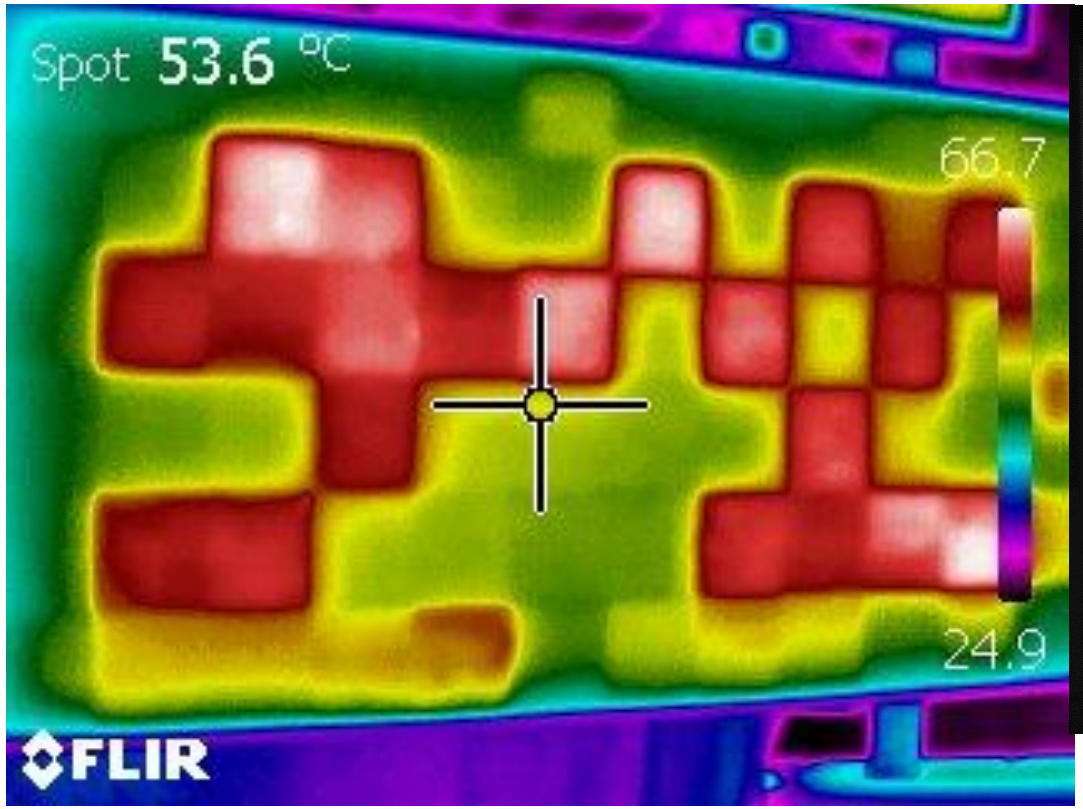
Module History:

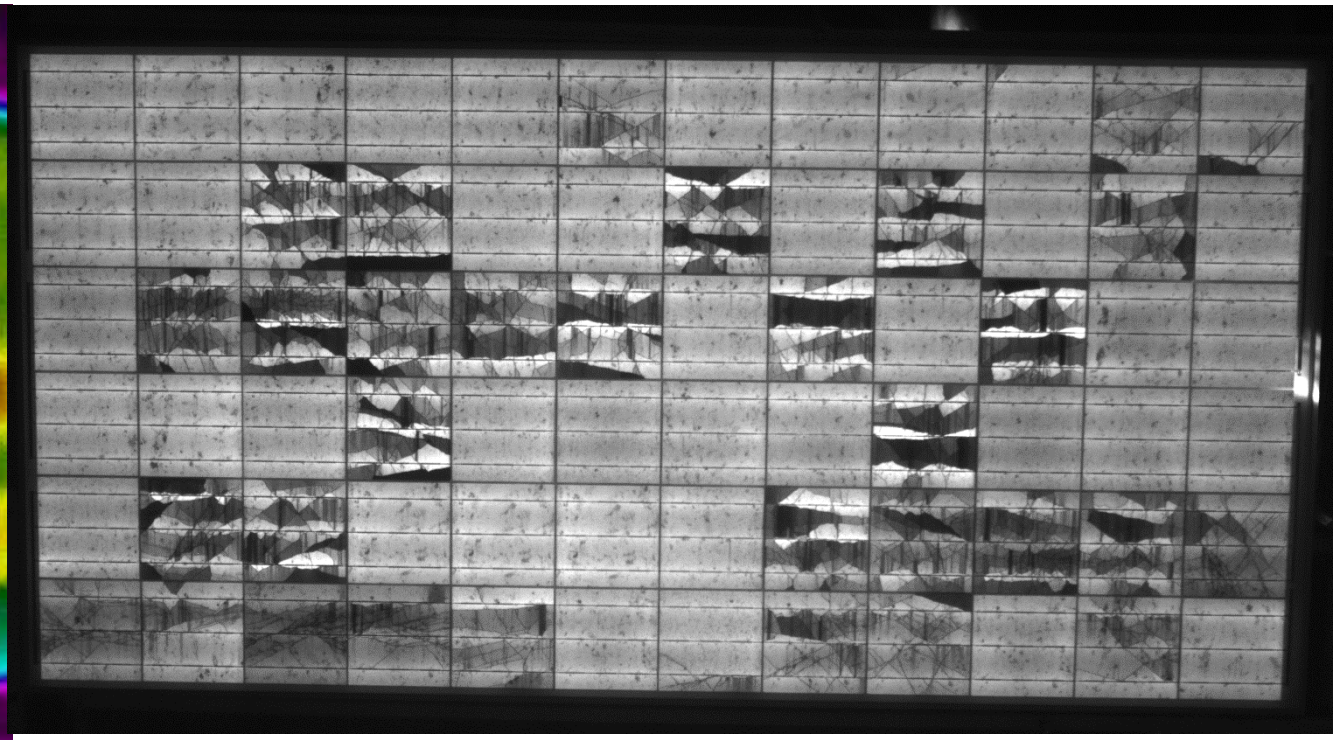
Initially damaged due to transportation incident

Vibration aged in the lab and sun-soaked 1 month while at short-circuit.

~20% Power loss at STC

SN:W5174514121603140, 72 cell, 3 busbar, multicrystalline silicon , 300 W nameplate





ΔT ≈ 13°C @ short-circuit

IR may not catch widespread cell cracking, even if the STC power is impacted.

Module History:

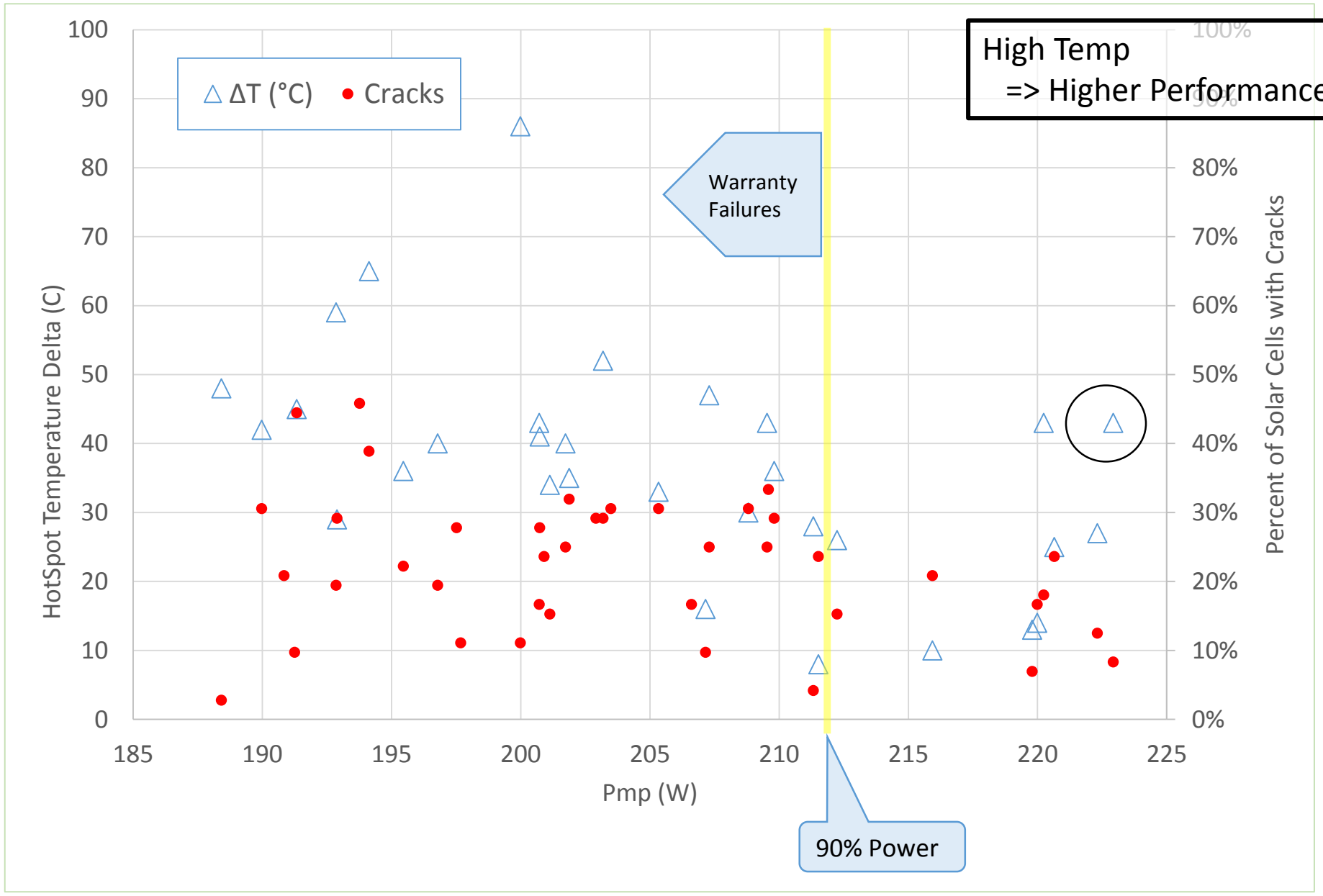
Initially damaged due to transportation incident

Vibration aged in the lab and sun-soaked 1 month while at short-circuit.

~20% Power loss at STC

W5174514121603140

Correlating STC IV Testing to IR and Cracks



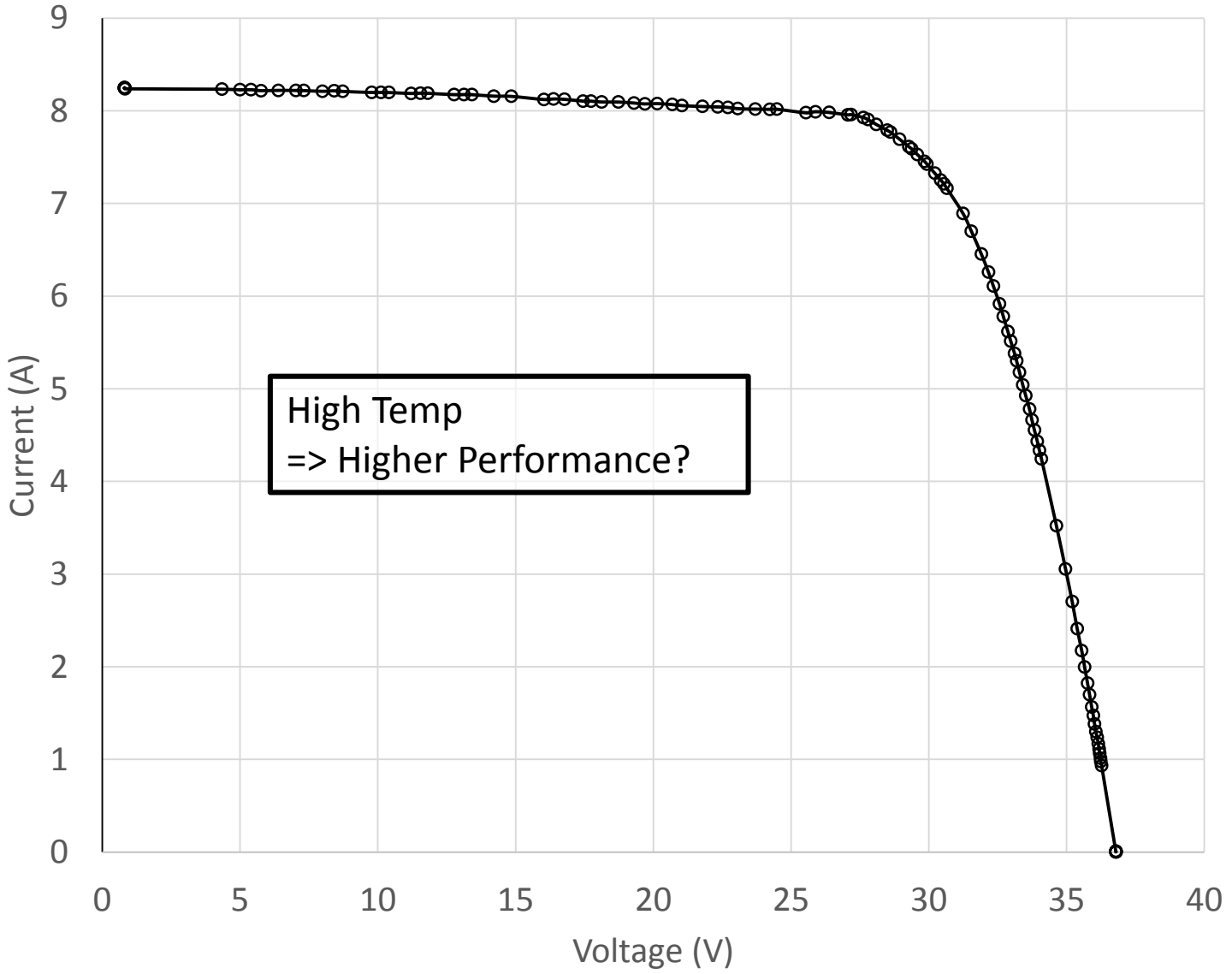
1. Weak Association at best between peak hot spot temp and Pmp.

2. Weak Association at best between peak hot spot temp and Pmp.

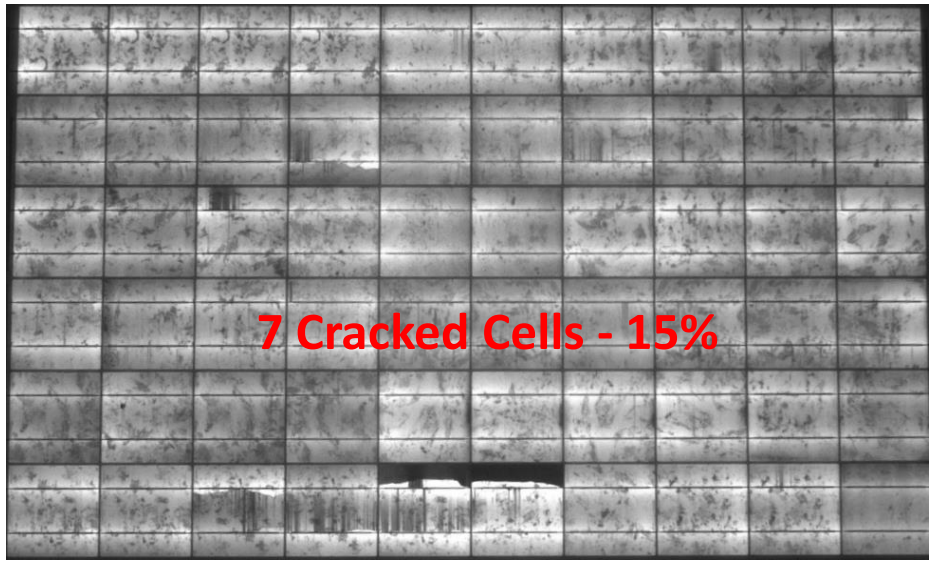
3. The sample identified using IR based testing (for peak hot spot) included 75% with powers that had degraded 10% from nameplate.

The question begged is “what does the non-hot spot distribution look like”.

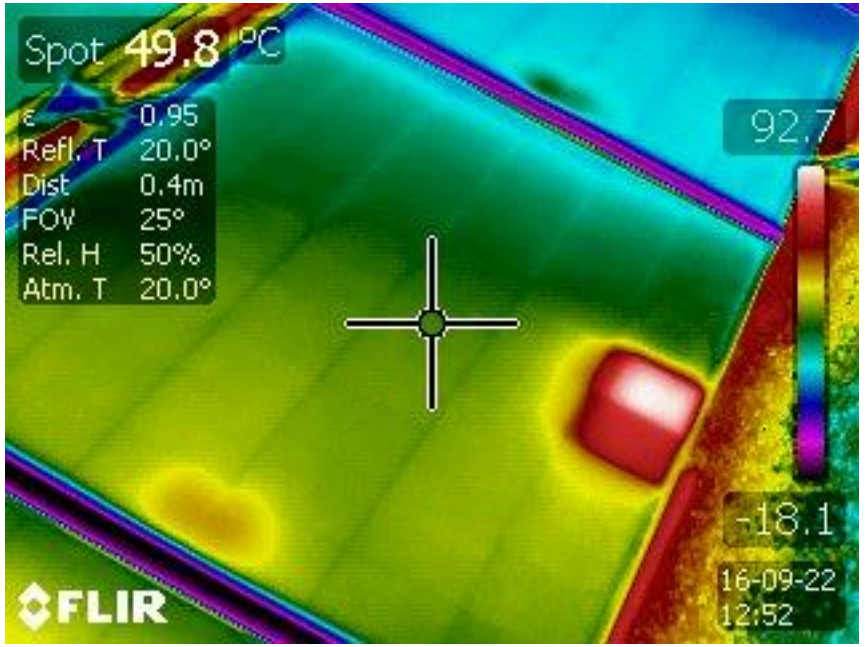
0056



Electroluminescence



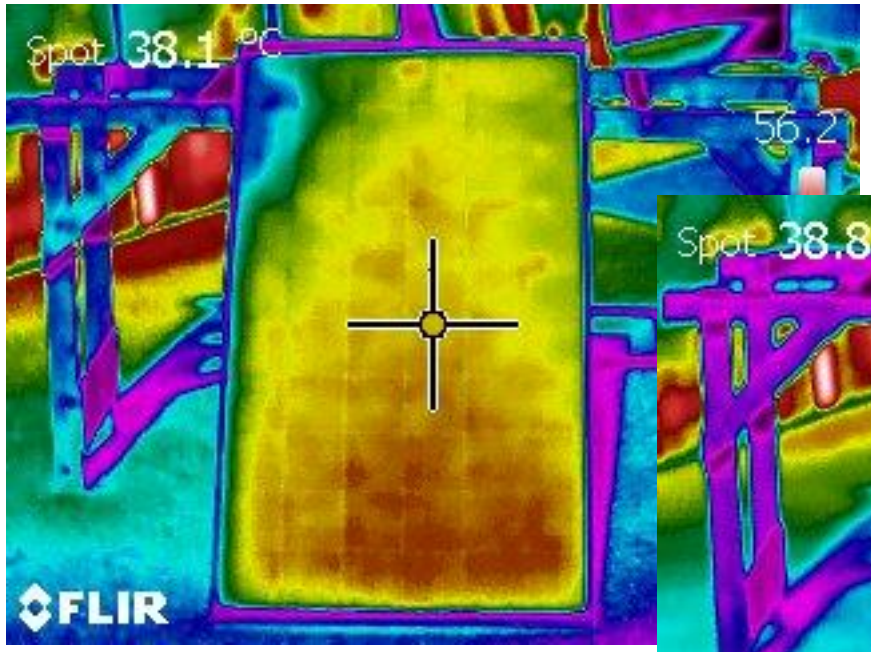
Infrared



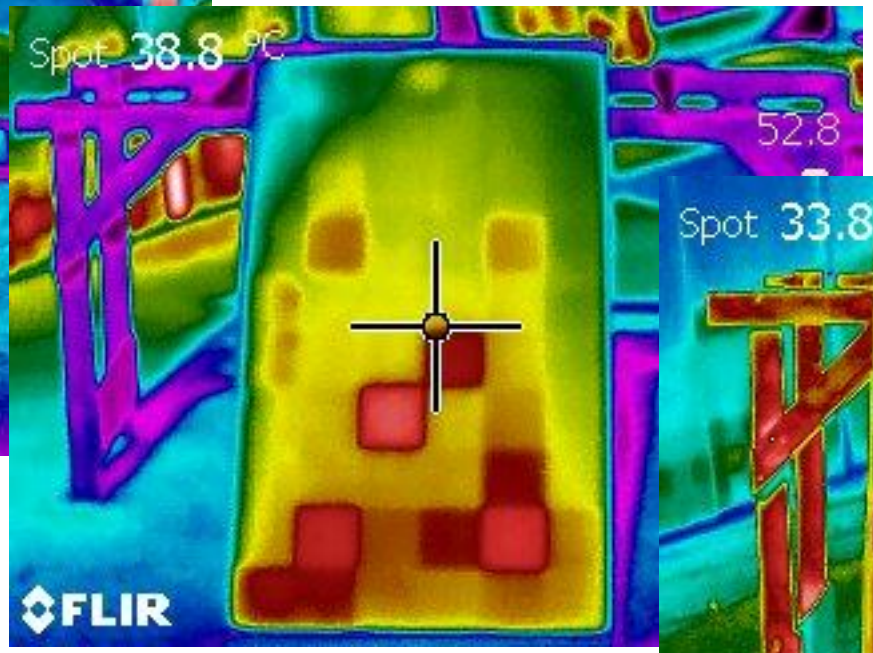
SerialNumber	Uoc (V)	Isc (A)	Pmpp (W)	Umpp (V)	Impp (A)	FF (%)	ΔT (°C)
C201012220056	36.79	8.25	222.9	29.38	7.59	73.5	43

0056

High Temp
=> Higher Performance?

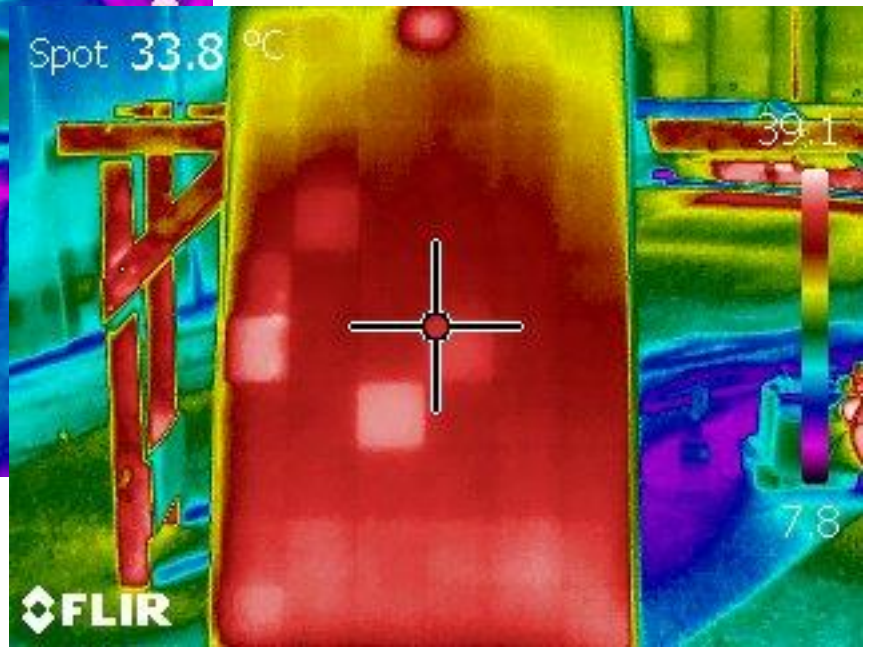


@Voc



@Isc

The Hot Spot Was Not Repeatable!

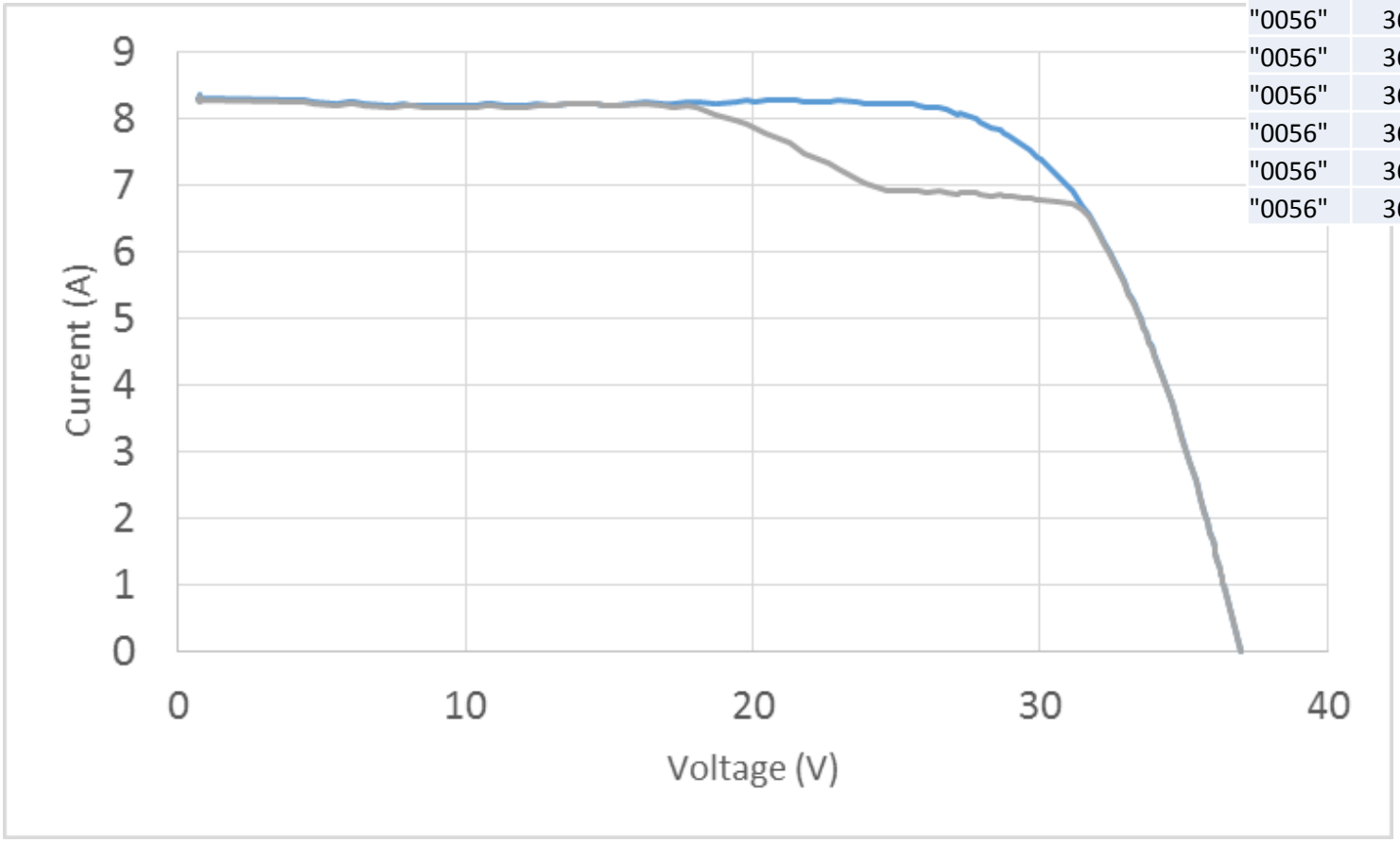


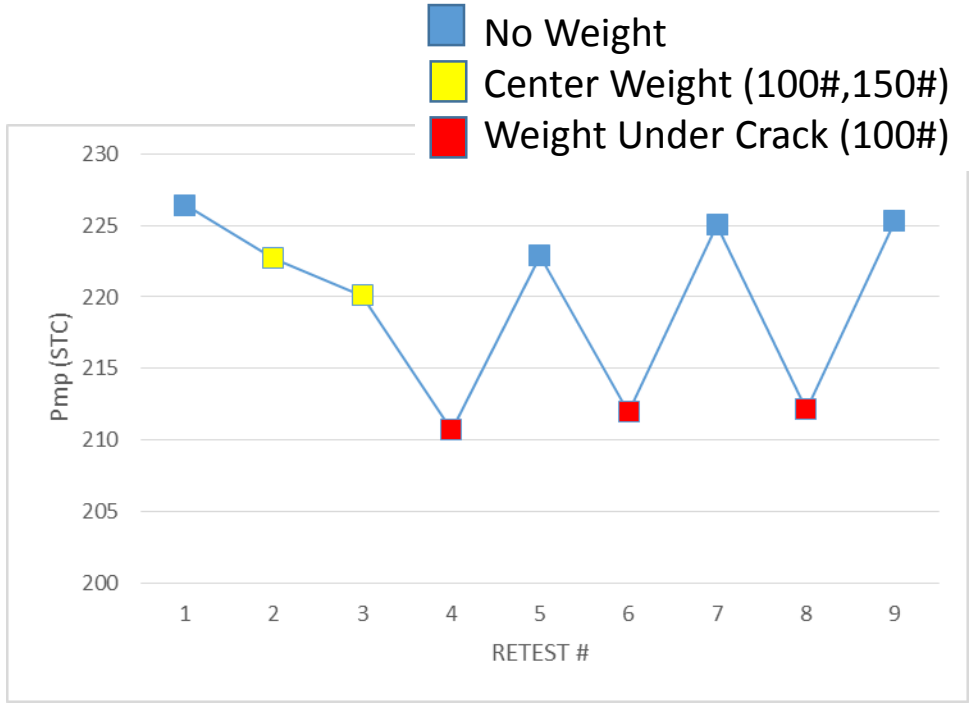
@≈Pmp

0056

Crack Connectivity Can Be Intermittent Even After 6 Years

SN	Uoc	Isc	Pmpp	Umpp	Impp	FF	Note
"0056"	36.68	8.35	226.43	29.38	7.71	73.91	
"0056"	36.80	8.38	222.70	28.95	7.69	72.21	100 lbs center
"0056"	36.84	8.34	220.09	29.51	7.46	71.63	150 lbs center
"0056"	36.77	8.36	210.70	31.20	6.75	68.54	100 lbs behind cell
"0056"	36.81	8.36	222.90	28.89	7.71	72.44	no weight
"0056"	36.86	8.35	211.97	31.20	6.79	68.88	100 lbs behind cell
"0056"	36.85	8.35	225.02	29.01	7.76	73.18	no weight
"0056"	36.83	8.35	212.11	31.21	6.80	69.00	100 lbs behind cell
"0056"	36.84	8.36	225.29	29.36	7.67	73.16	no weight



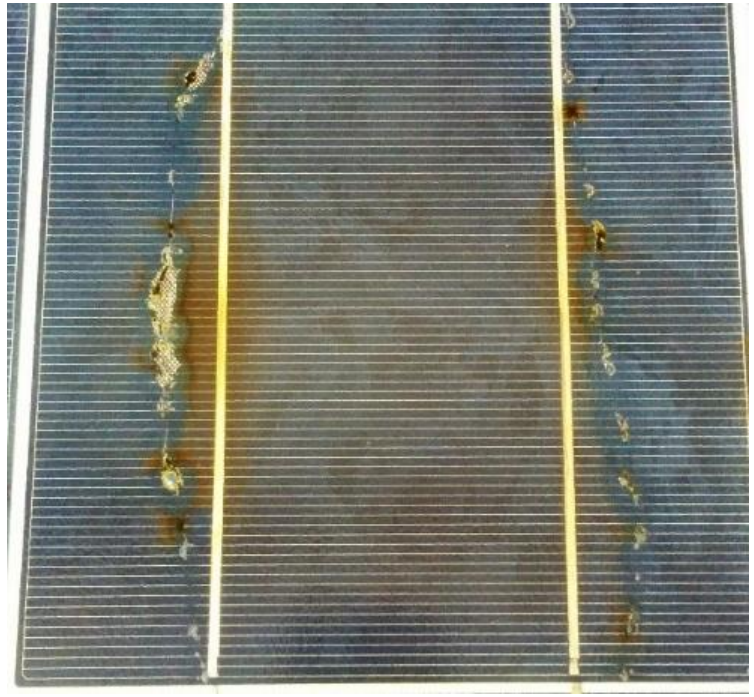


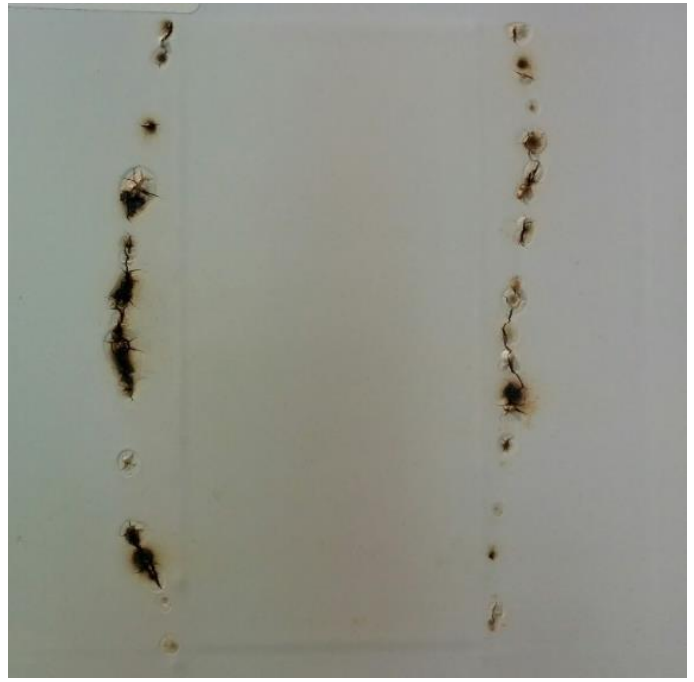
PUMT Test got the Crack to Reveal

Safety Concerns

Primary Concerns
1. High Peak Temperatures
2. Arcing – Fires
3. Shock Hazard

Secondary Concerns
1. Accelerated Aging of EVA/Backsheet
2. Continuous Operation of the ByPass Diode



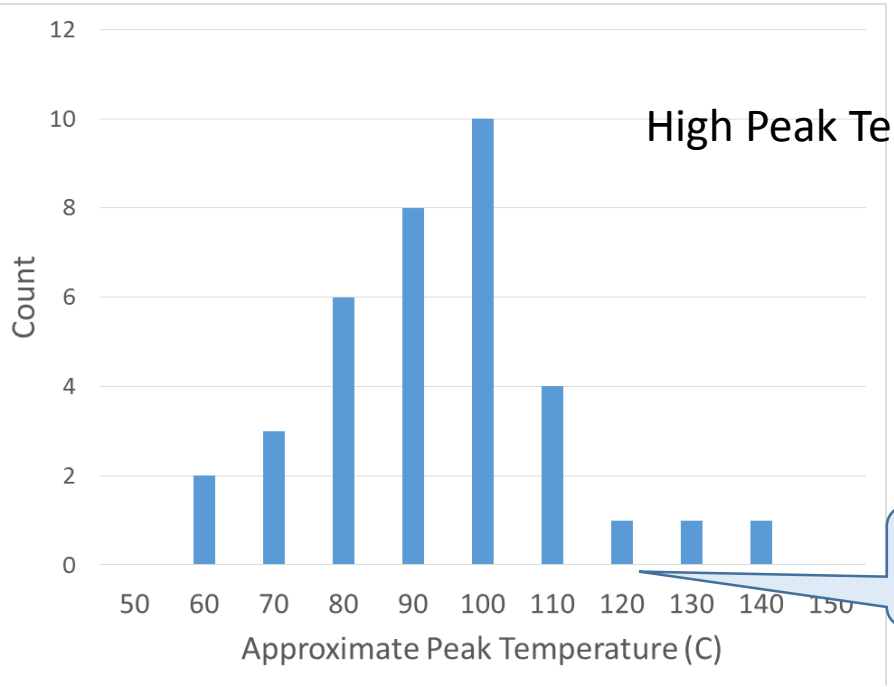


Safety Concerns

Primary

1. High Peak Temperatures
2. Arcing – Fires
3. Shock Hazard

High Peak Temperatures



How High T_{peak} is a Safety Issue?

Note on T_{peak} – Not Worst Case, Based on Module Operating Temp of 50C

	Module Count	% of Sample	% of Array
Total Replaced	46		
Visually Good	23	50%	0.9%
Compromised Back Sheet	19	41%	0.8%
Failed Dry Leakage*	0	0%	0.0%
Failed Wet Leakage*	10	22%	0.4%

Shock Hazard

*Carried out UL1703/IEC 61215 “Wet Insulation-Resistance Test” first dry, then wetted in the area of the compromised back sheet.. Test Voltage was 600Vdc

Financial Analysis of the Case Study

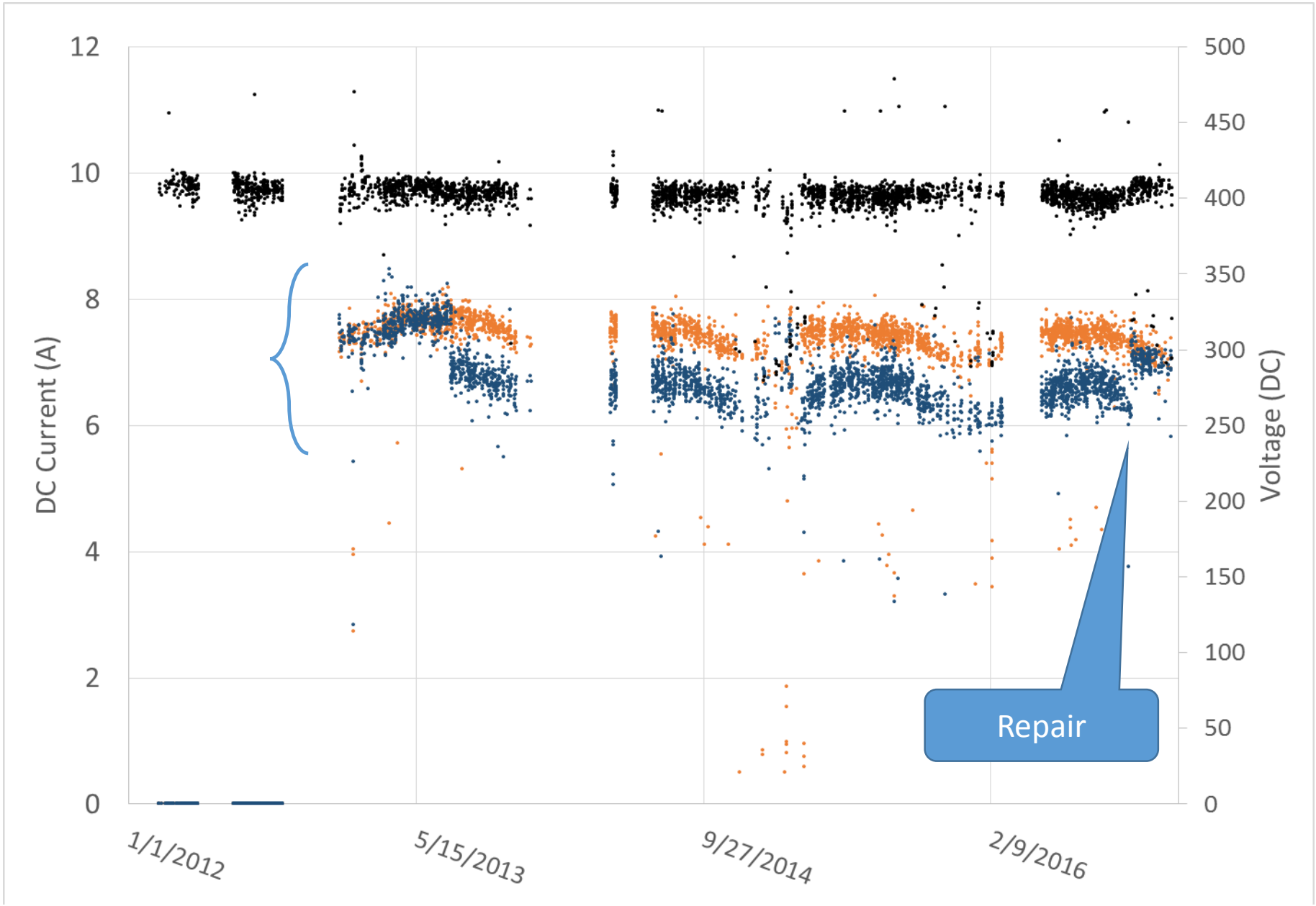
Costs

Detailed IR Inspection of 2500 Modules
Replaced 47 modules (11405 W)
Worked like a Dog – 5-7 man days
Lots of Nice Tools Available
40 Man Hours to Mine the System Data

Benefit

Safer System (How Much Safer?)
Performance Gain

Financial Analysis of the Case Study



Sub-Array Voltage* (DC)

Control String Current

Damaged String Current

10V Drop over 5 year
2.1V/Year
0.53% degradation in Vdc
6.4V increase after fix

One String increased 9% in Current

* Temp Corrected

Measured Impacts From This Case Study

Hot Spot Temperatures Approaching Lamination Temperatures were Measured with cracked solar cells as the cause.

Cracked Solar Cells led to High Temperatures, Arcing, Compromised Back Sheets.

47 Modules were found and replaced by a detailed Hot Spot Inspection of the array. 10 of the 47 Failed the Wet Insulation Resistance Test.

System Performance Increased. Best Case is that new modules contribute power as if defective modules were Contributing No Power. This is a Fundamentally Shift in the Cost/Benefit Analysis

Caveats: Single Snap Shot of a technology, transportation, and handling, and manufacturing practices. No other array may act like this one.

General Observations that Need Substantiation Through Statistically Significant Sampling

IR may not catch widespread cell cracking, even when the STC power is impacted.

If you define safety exposure as peak hot spot temperature, then one cracked solar may be more dangerous than many cracked cells

Not all defects in the field duplicate in the Lab, cracks are intermittent.

The Cell/Module technology plays a big role in the tolerance of the module to cracks, and to long term performance impact.

More work is needed in accelerated aging of cracked solar cells.

Look While You Load: Electroluminescence and IV Testing of Solar Panels Under Mechanical Load

Andrew M. Gabor[1], Rob Janoch[1], Andrew Anselmo[1], Eric Schneller, Jason L. Lincoln[2], Hubert Seigneur[2]

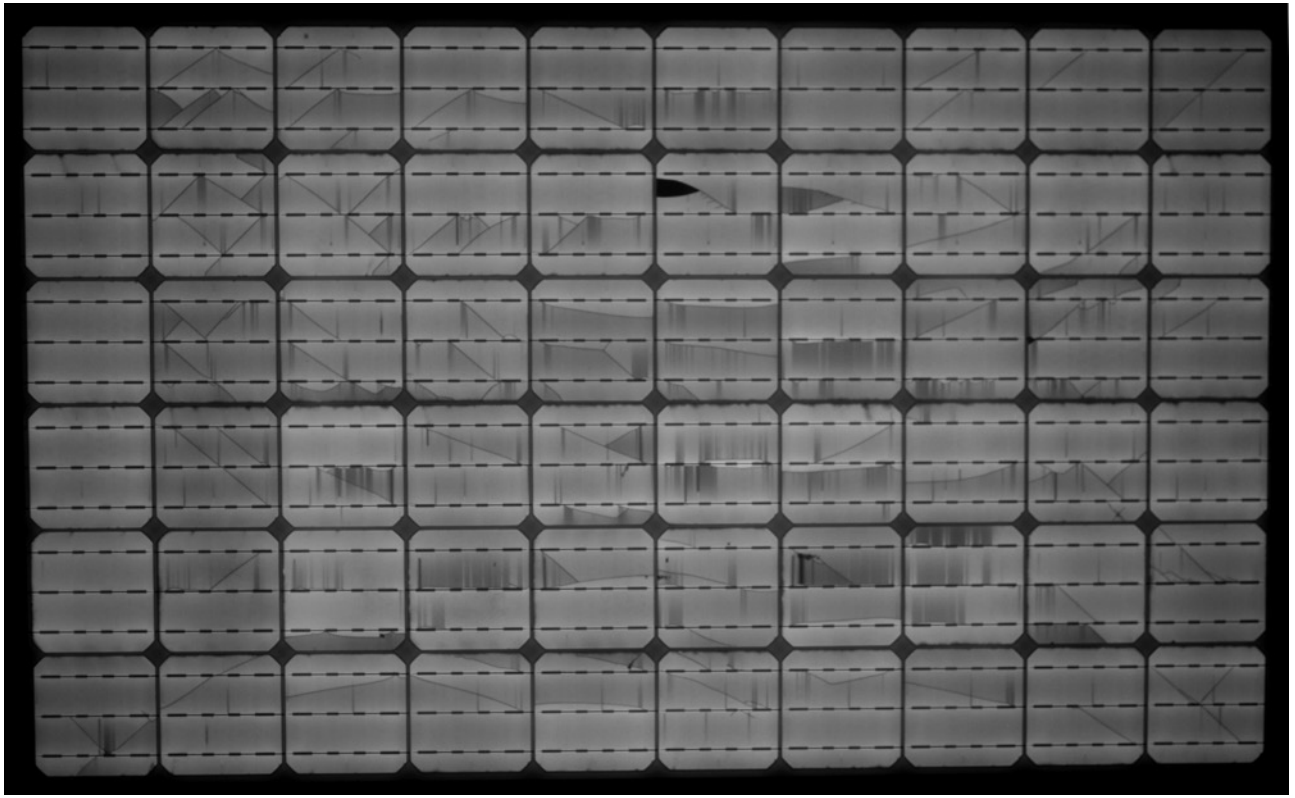
[1] BrightSpot Automation LLC, Westford, MA, USA

[2] Florida Solar Energy Center at the University of Central Florida, Orlando, FL, USA

This material is based upon work supported in part by the U. S Department of Energy's Office of Energy Efficiency and Renewable Energy, in the Solar Energy Technologies Program, under Award Number DE-EE0004947.

Problem

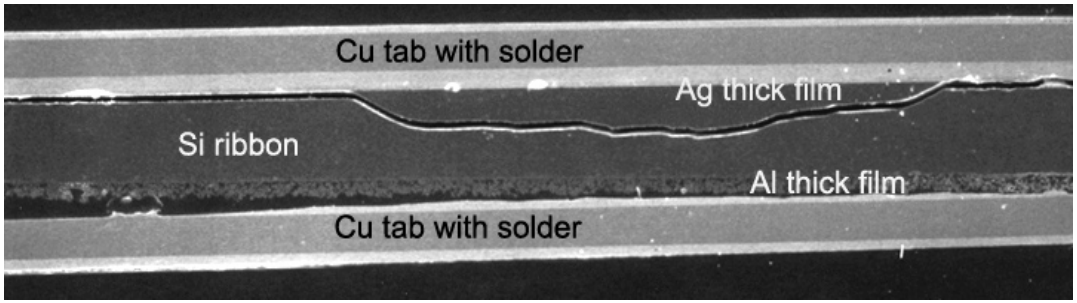
- Most panels (glass frontsheet, polymer backsheet) will develop cracks with front side loading



[BrightSpot EL Camera image]

Step 1

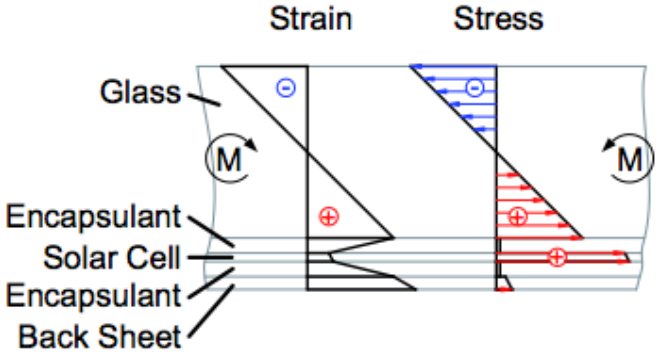
- Microcracks in Si under busbars from soldering
  - Differential contraction: Cu vs Si
- Other sources of damage



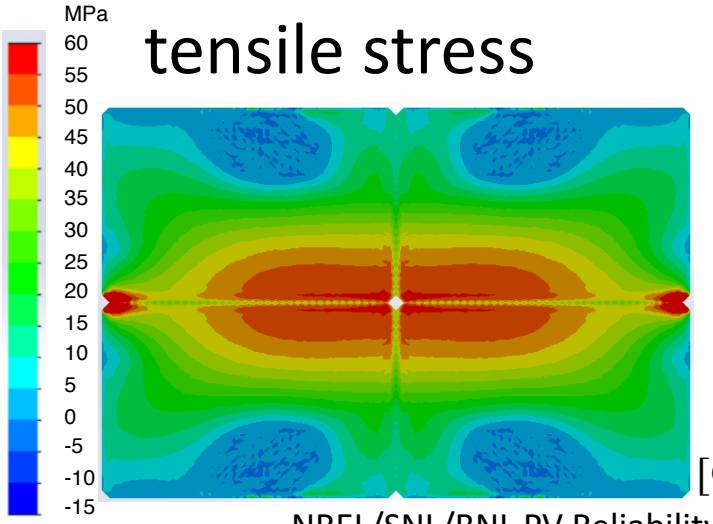
[Gabor, Evergreen Solar, PVSEC 2006]

Step 2

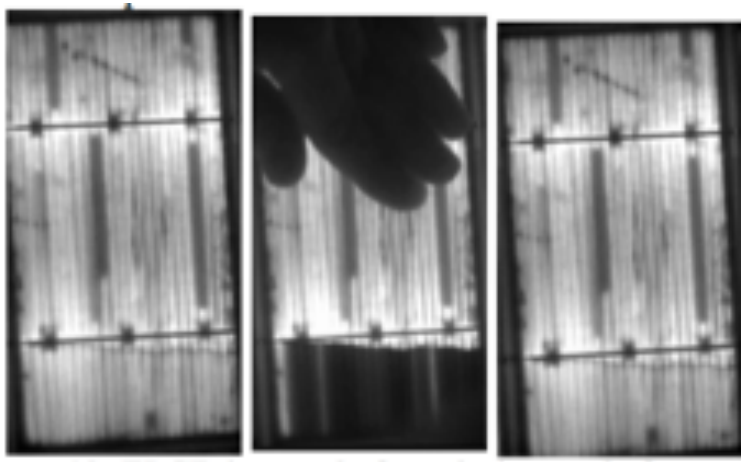
- Pressing on front side cause microcracks to propagate into full cracks (usually closed)
  - Asymmetric construction - cells not in neutral axis
  - Frontside loads puts cells into tensile stress



[Sander, Fraunhofer CSP, Solar Energy Materials & Solar Cells 2013]



[Gabor, BrightSpot, PVSC 2016]



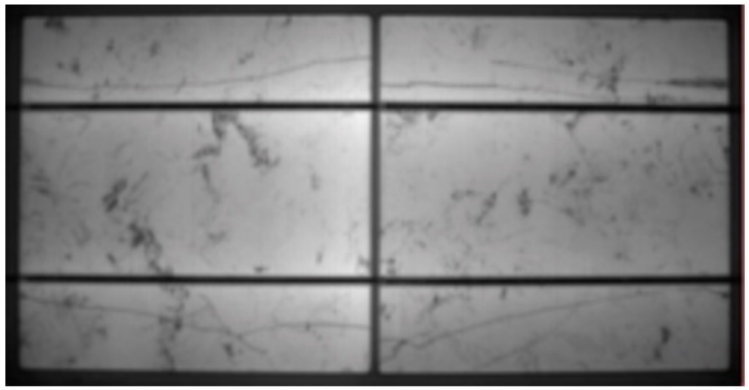
[Gabor, Evergreen Solar, PVSEC 2006]

Step 3

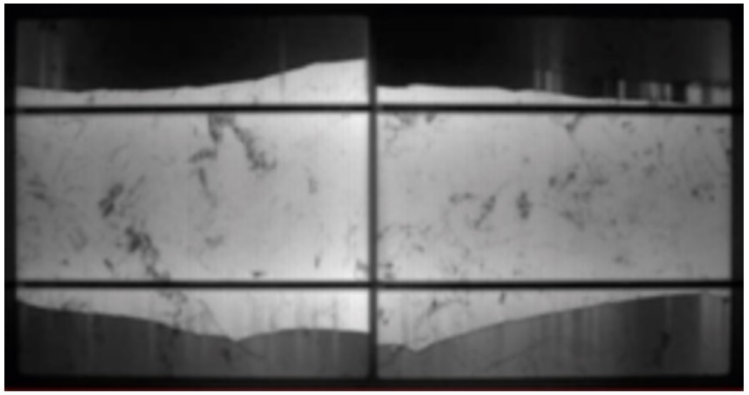
- Subsequent loading/vibration and climate exposure can cause some closed cracks to “open up”
  - Power loss in module
  - Mismatch loss in system
  - Higher temp operation → further degradation
  - Higher sensitivity to shading

Source: MBJ-solutions.com

Solar cells before thermal cycling:
PMP [Wp] = 7.9



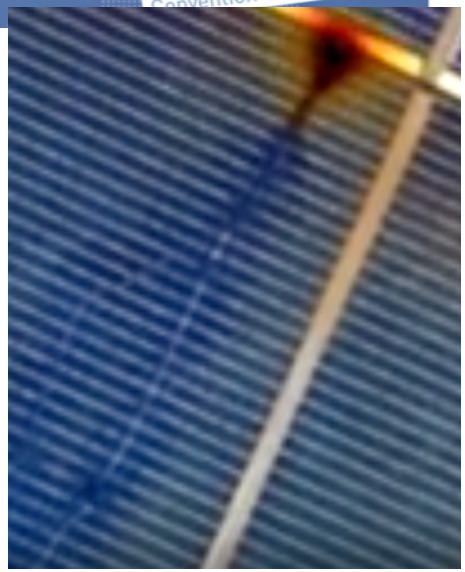
Solar cells after thermal cycling:
PMP [Wp] = 6.3



Scary anecdotes

BrightSpot Automation

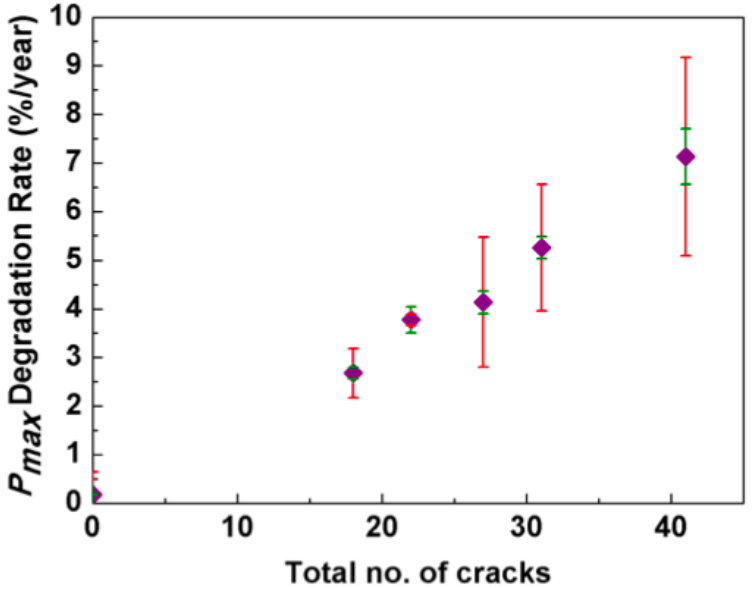
pv magazine group



Snail Trails: c-Si

Climatic Zone	Age Groups				Total
	0-5 Years	5-10 Years	10-20 Years	20-30 Years	
Hot & Dry	35% (74)	NA	0% (29)	0% (39)	18% (142)
Warm & Humid	17% (93)	0% (58)	0% (119)	0% (2)	6% (272)
Composite	0% (125)	0% (7)	6% (124)	NA	3% (256)
Moderate	56% (123)	NA	8% (12)	NA	52% (135)
Cold & Sunny	50% (34)	NA	0% (22)	NA	30% (56)
Cold & Cloudy	44% (112)	NA	NA	NA	44% (112)

[Kottantharayil, IIT, *Lessons Learned from the All India Survey of Photovoltaic Modules*, NREL PVMRW 2016]



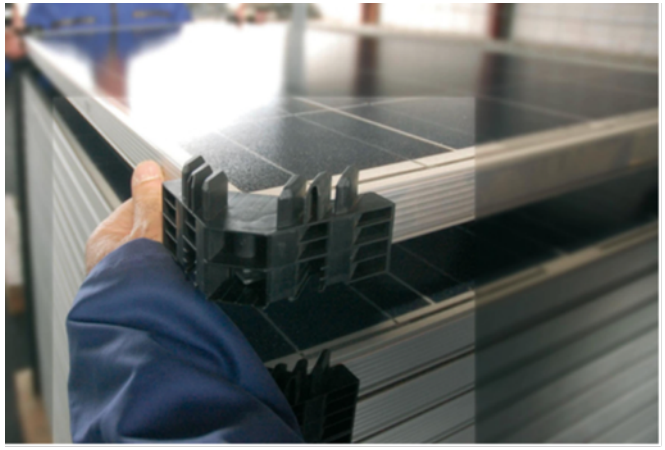
Substandard module processing

- Soldering
- Wire
- Handling

[Tier1 manufacturer, ~2012]

Substandard shipping and handling

- Pack on edge vs
- Sunnyside up vs
- Sunnyside down



[Enlog]

Substandard installation

- Rough handling
  - Hard to control
- Bad mounting

Loads in the field

- Wind
- Snow
- Snow + wind
- Improper O&M

Very hard to control

3 Options

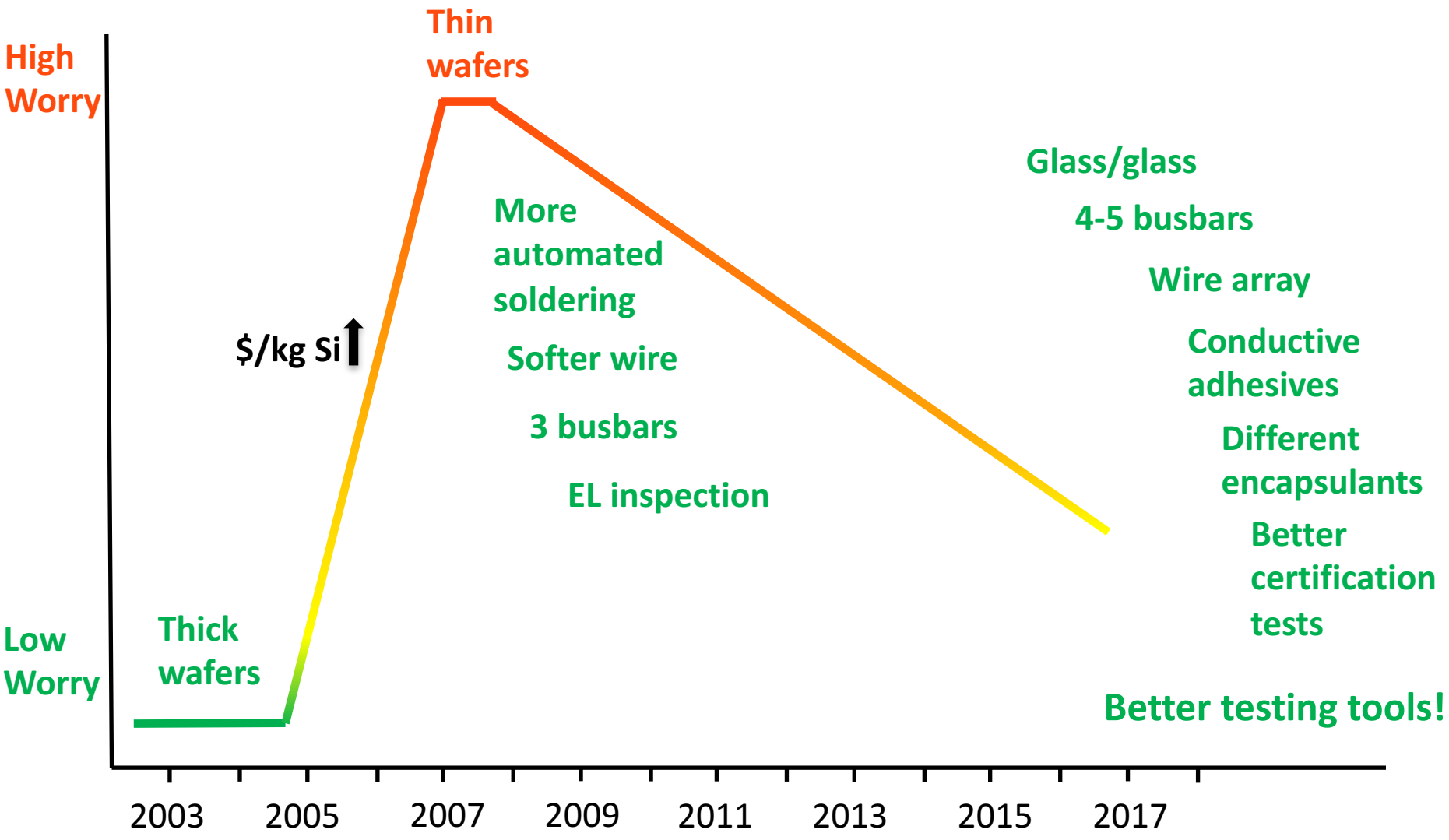
- Control everything so modules don't see crack producing conditions
- **Make modules that are less prone to cracking**
- **Make modules that are less prone to degradation from cracks if they do occur**

Cell Cracking Solutions

Method	Cure/ Bandaid	Desirability
Optimize soldering and QC	Cure	High
Improved metallization	Cure	High
Racking to reduce bending	Cure	High
Glass/glass construction	Cure	High
Stiffer modules	Cure	High
Compressive stress from backsheets	Cure	High
Conductive adhesives	Cure	High
More wires	Bandaid	High
Wires closer to edges	Bandaid	High
Low reverse breakdown	Bandaid	High
Strings wired in parallel	Bandaid	Med
Cells wired in parallel	Bandaid	Med
Rectangular cells + thin wires	Cure	Med
Module level electronics	Bandaid	Med
Increased bypass diodes	Bandaid	Med
Thicker wafers	Cure	Low

[Gabor, BrightSpot Automation, NREL PVMRW, 2015]

Crack Worry Trendline



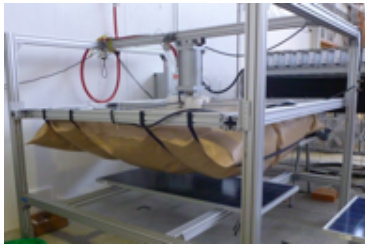
What tools would help?

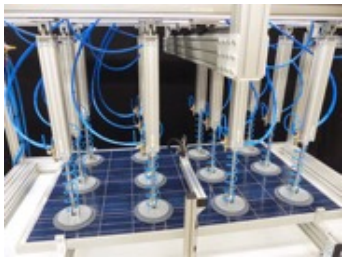
BrightSpot Automation

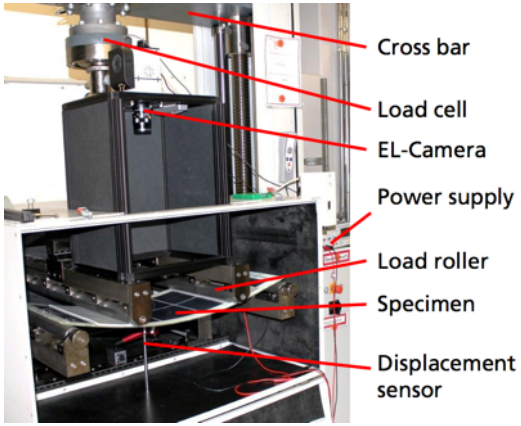
- BrightSpot's conclusion
  - See when cracks form as load levels are increased
  - Higher resolution EL to better see tightly closed cracks (24 Megapixels vs <1.5 Megapixels)
    - Low-cost so everyone can afford

Existing Load Methods

- Most block front side
  - Prevent EL imaging
  - Uniformity?
- 4 bar bending of laminates
  - Allows EL!
  - But forces are different than in the field



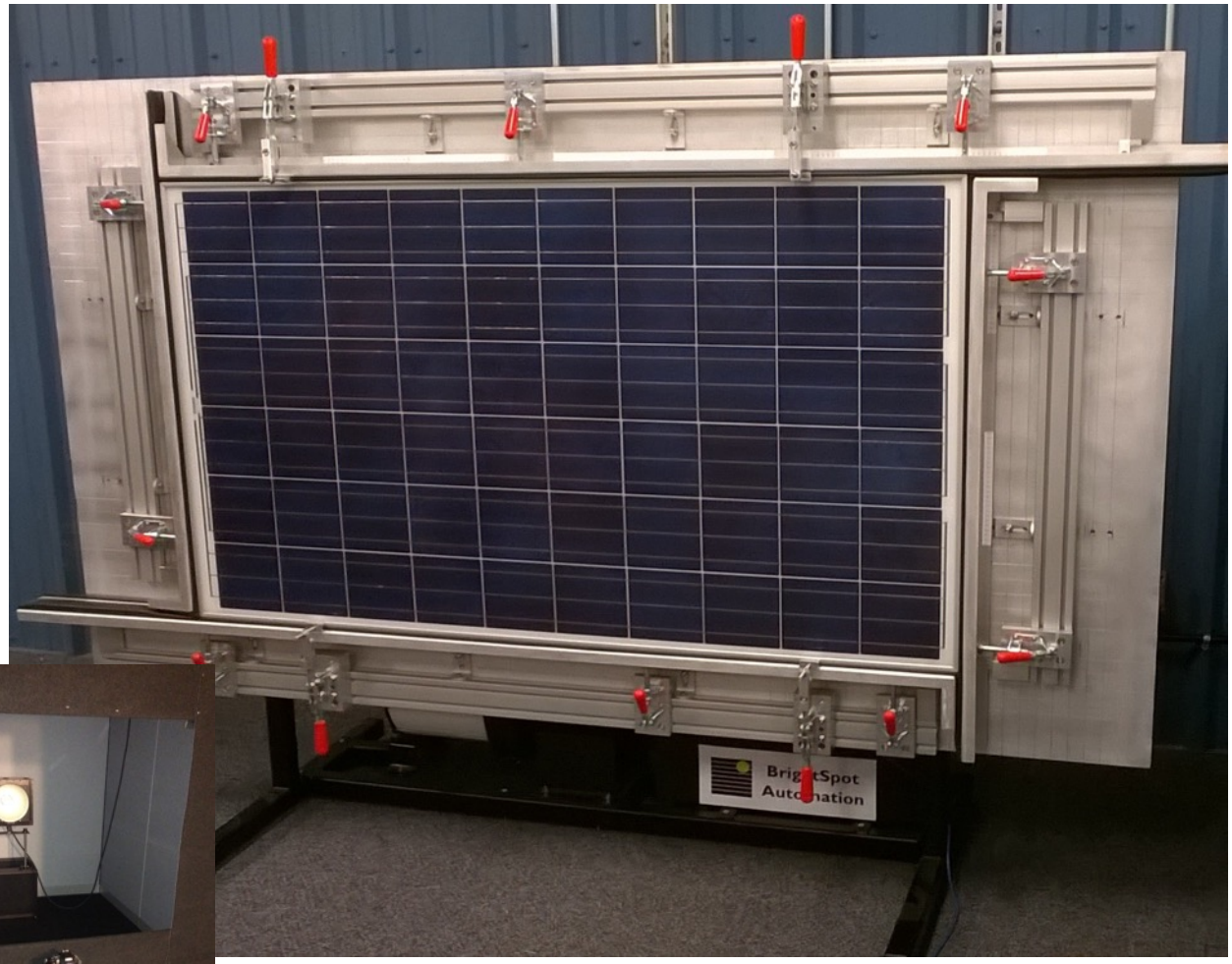


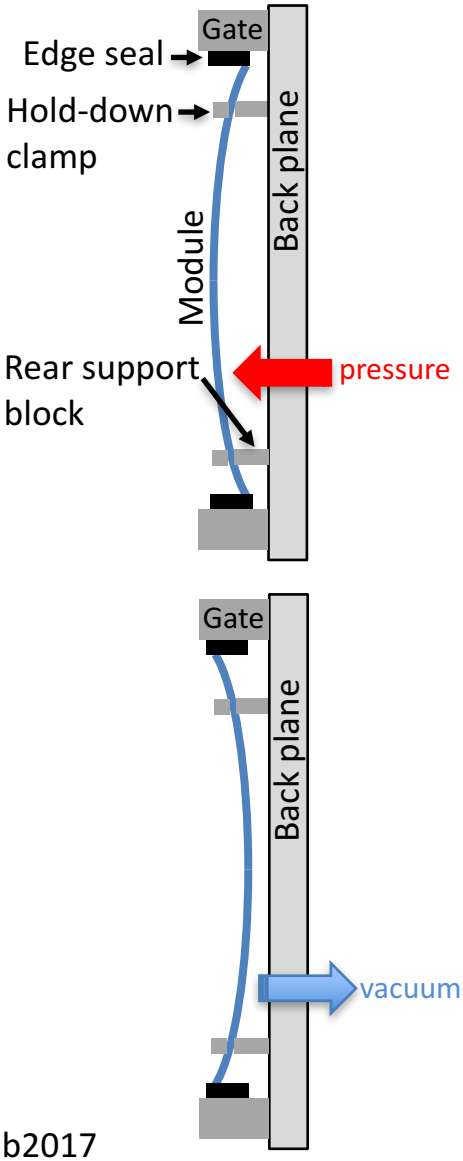


[Dietrich, Fraunhofer CSP 2015]

[Gade, Jabil, NREL PVMRW, 2015]

The *LoadSpot* solution

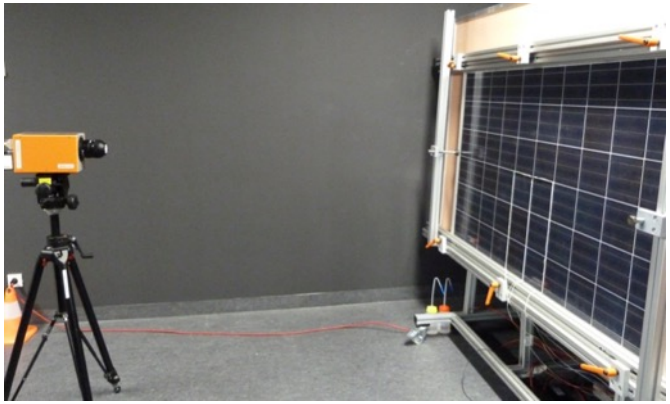




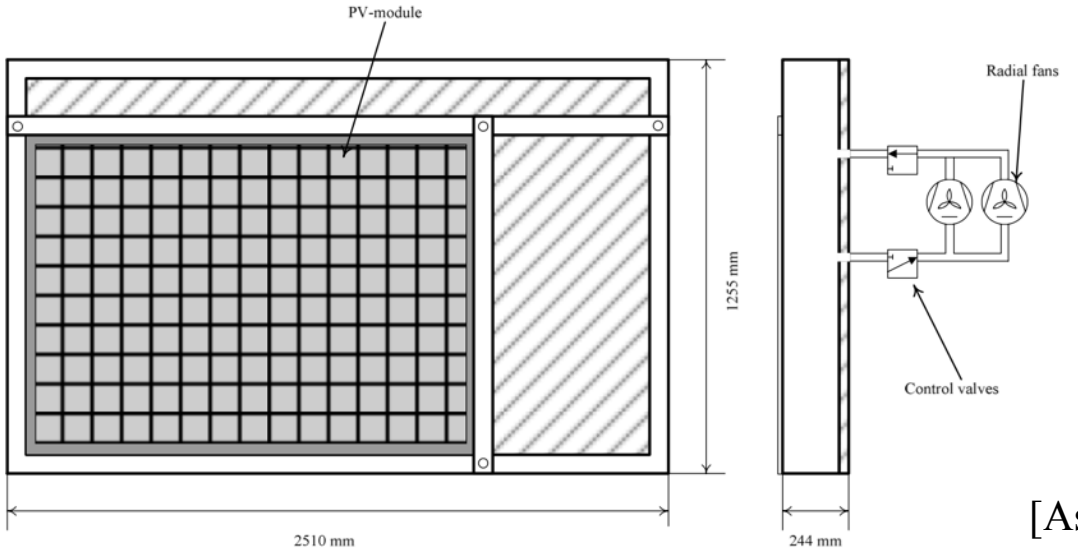
- Support at 4 mounting points
- Uniform loading

Other backside vacuum solutions

- Full perimeter support

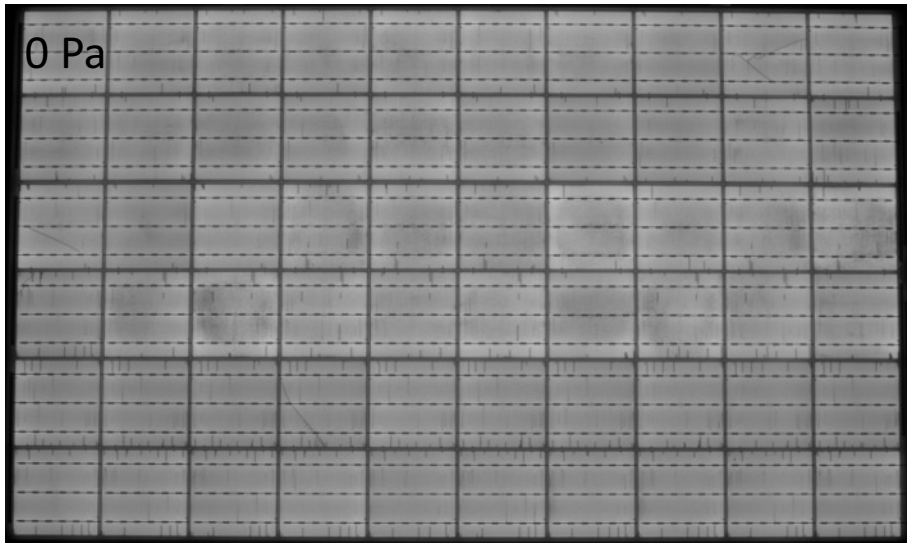


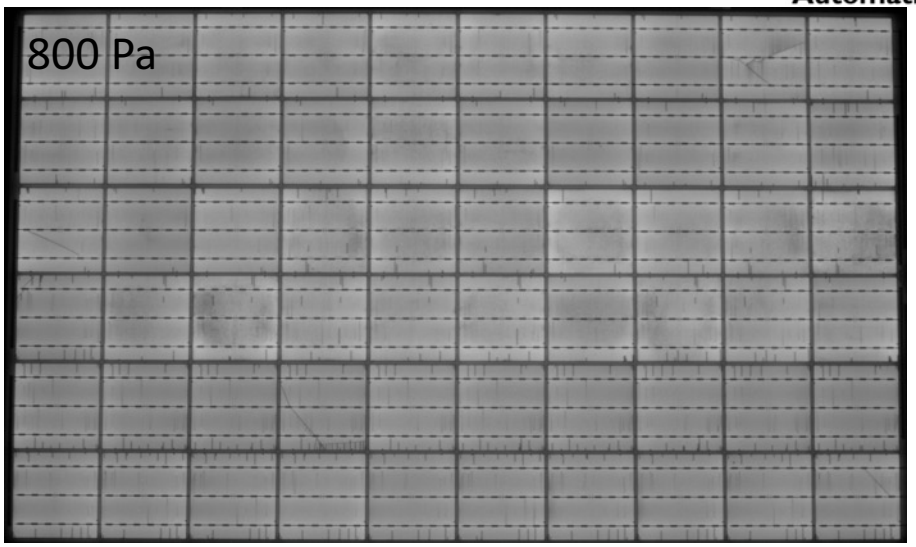
[ZAE Bayern, 2017]

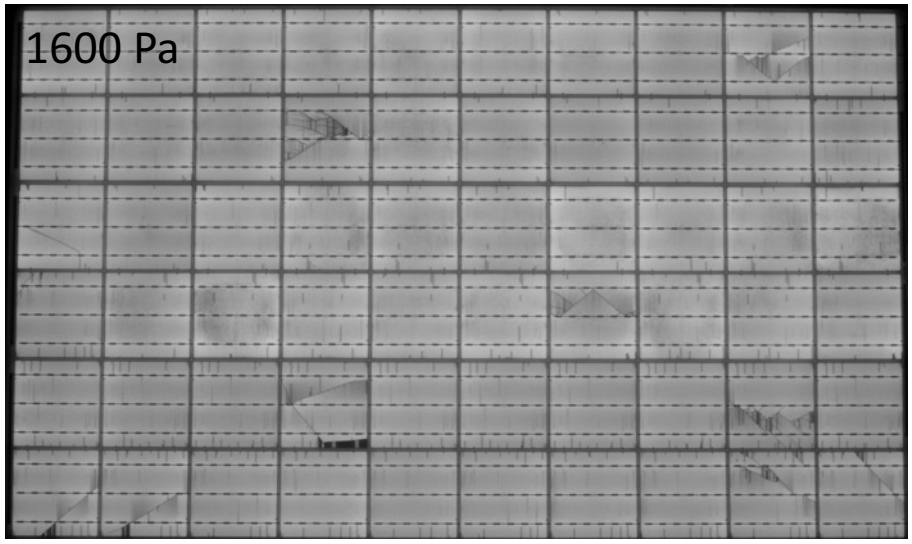


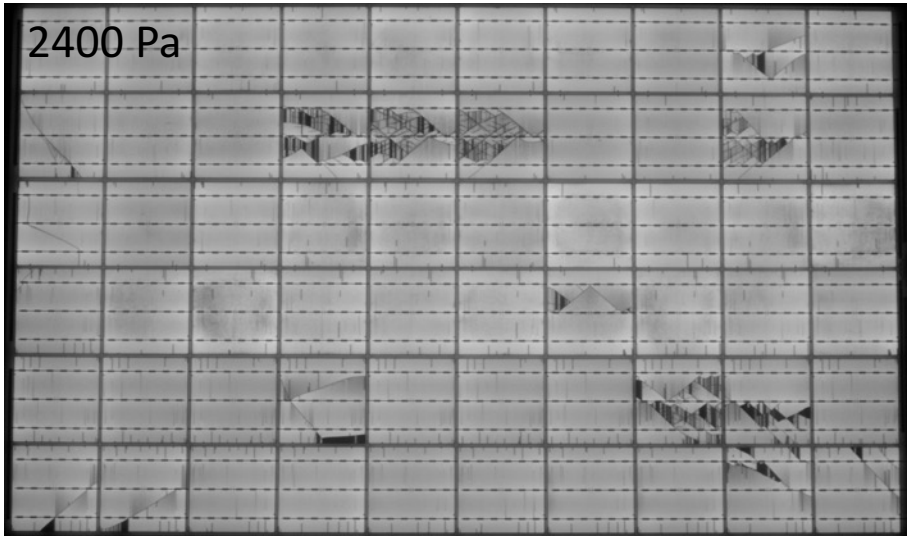
[Assmus, ISE, 2009]

Crack evolution vs load – Panel1

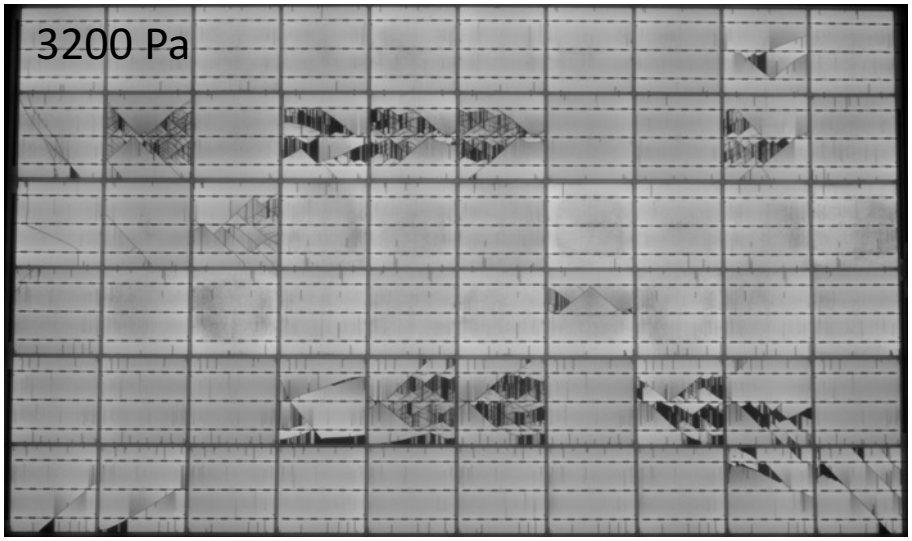


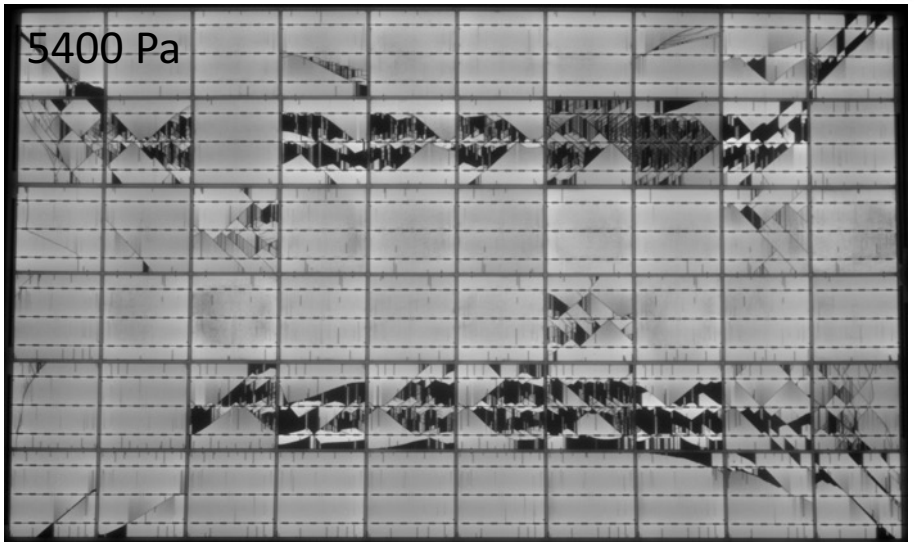


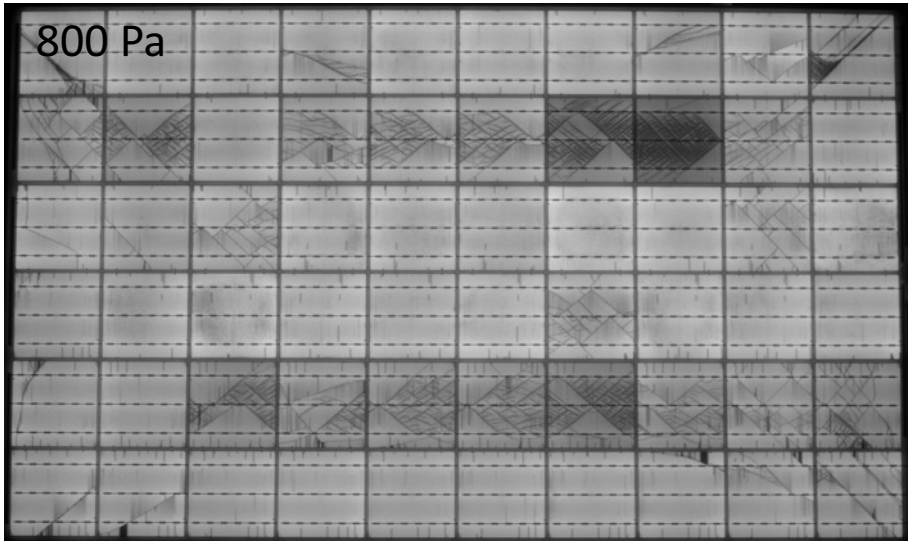


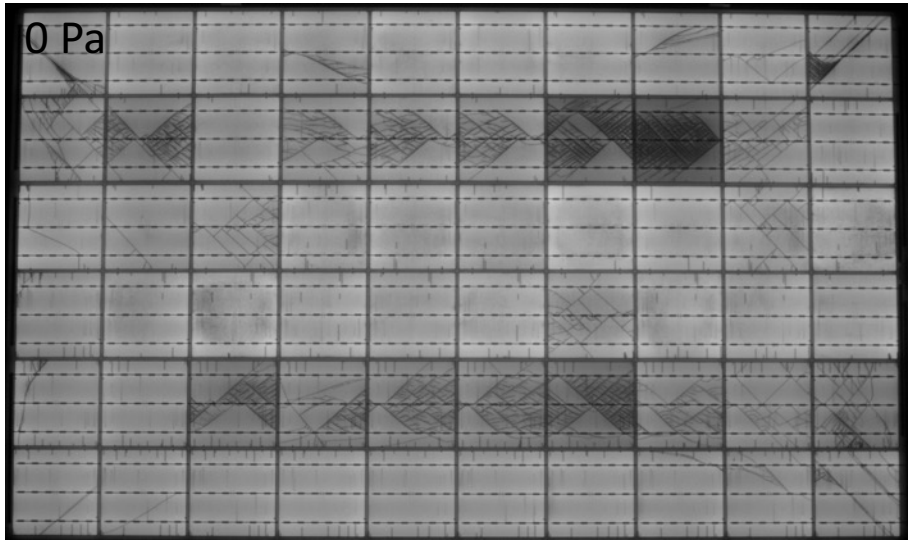


Crack evolution vs load – Panel1

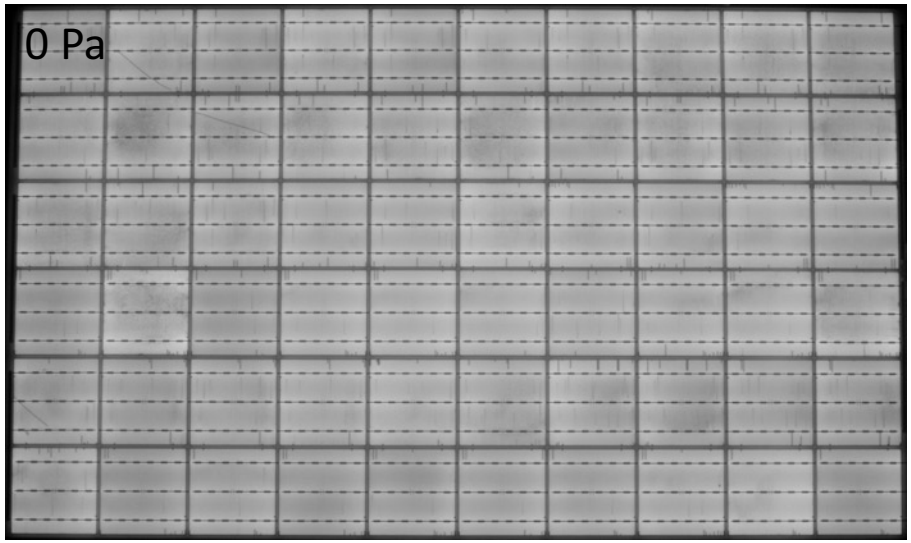


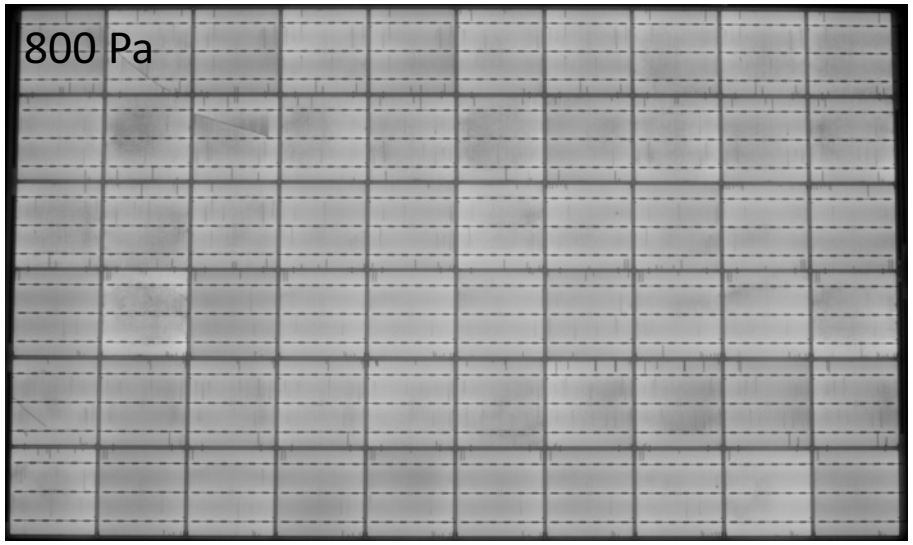


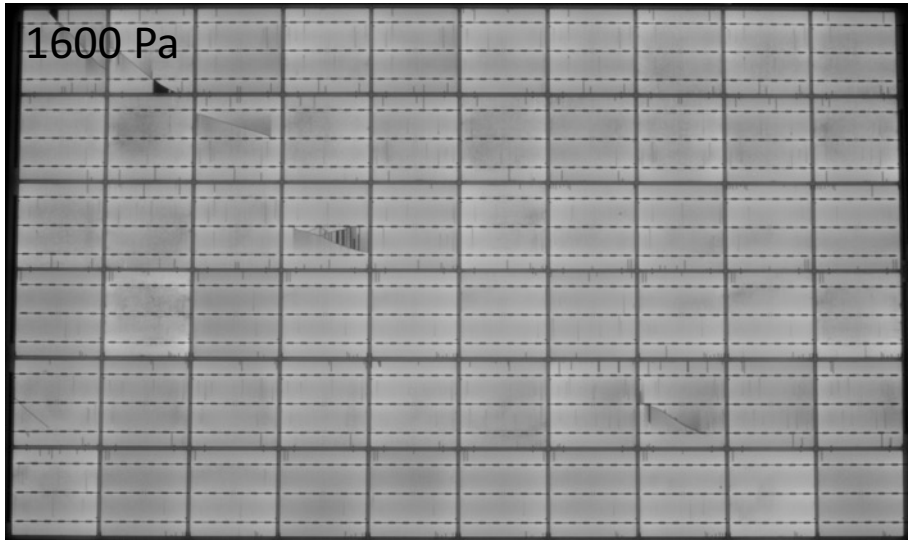


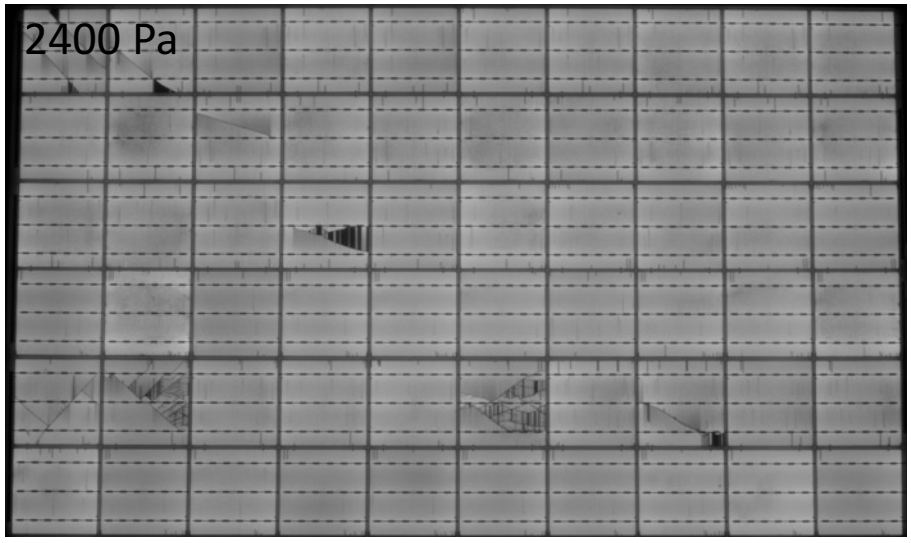


Crack evolution vs load – Panel2

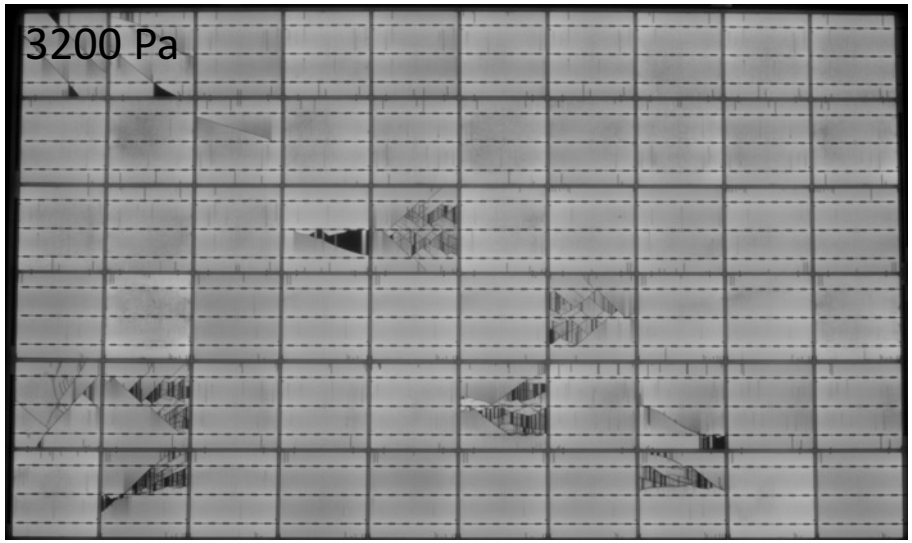


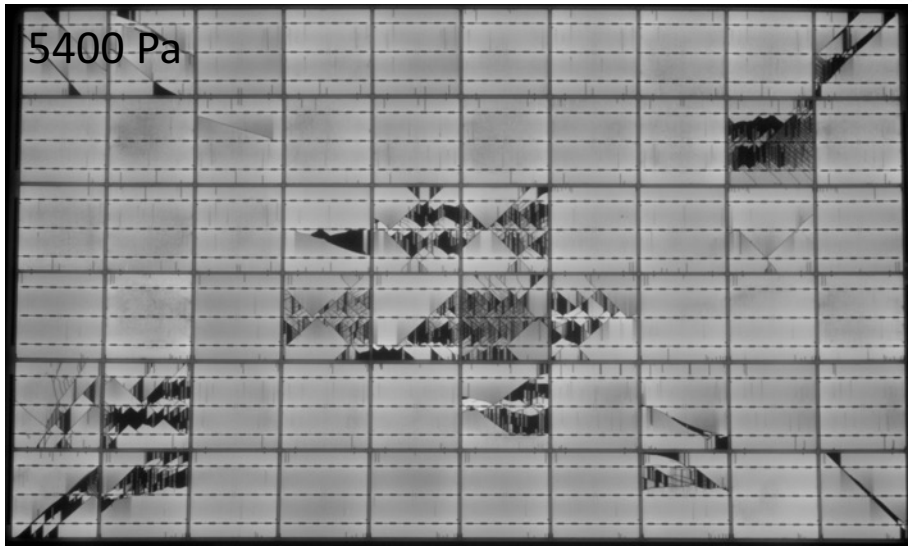


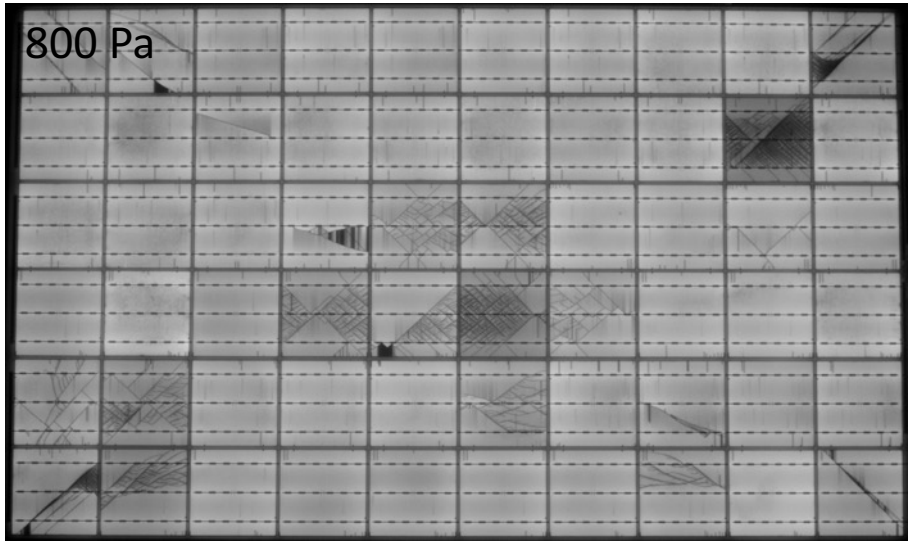


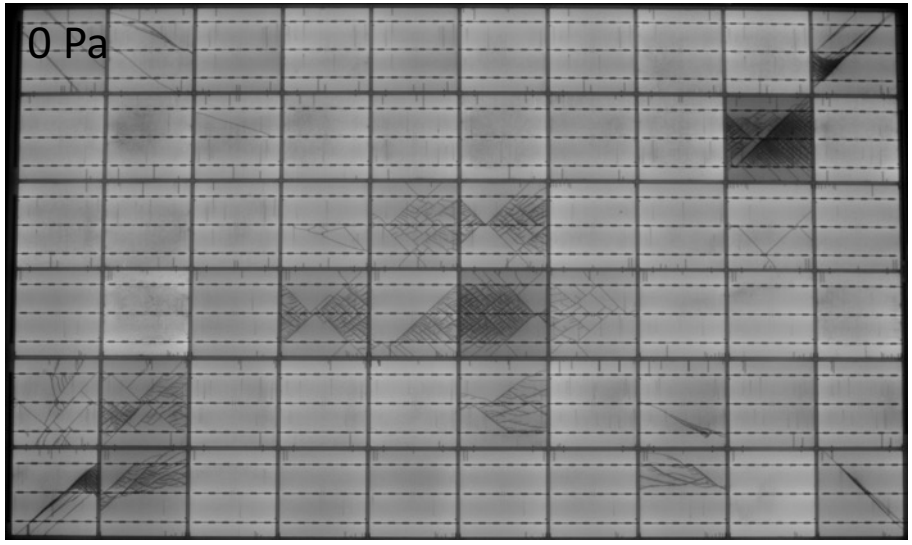


Crack evolution vs load – Panel2

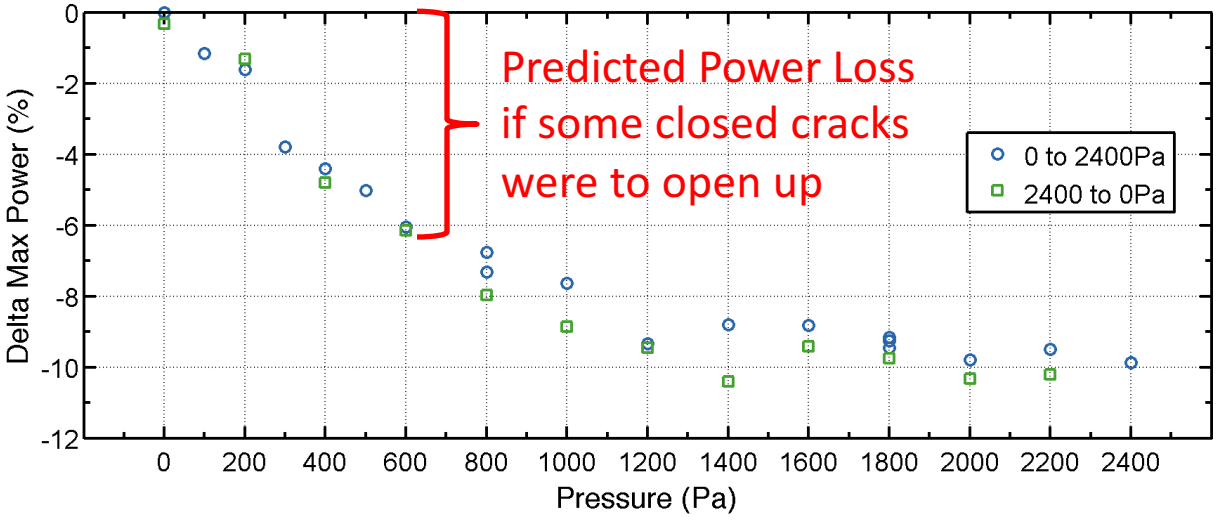


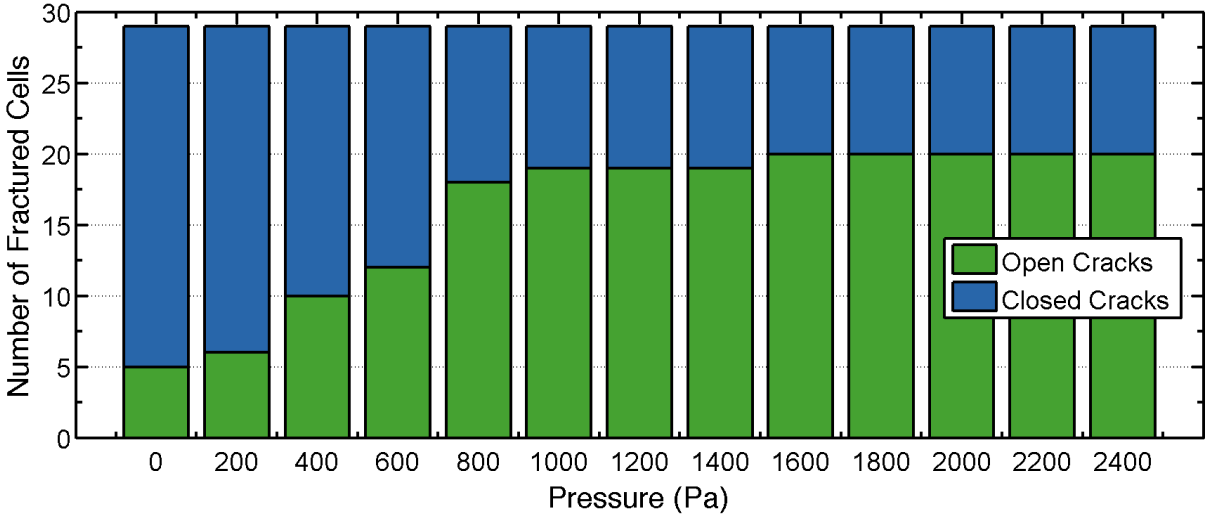




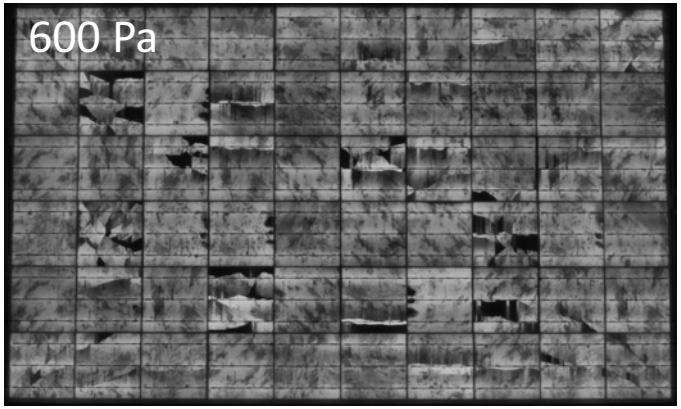


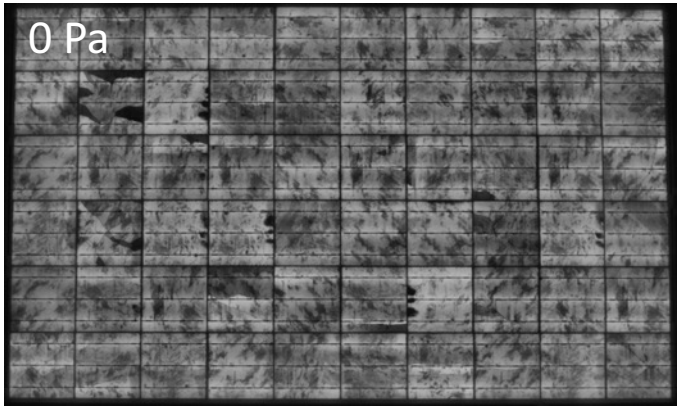
Predictive Crack Opening - PCO Test





Full perimeter frame support
- More uniform stress
- Easier to implement





Do module buyers care?

BrightSpot Automation

- What if you knew that modules from Vendor-A had fewer cracks at a given load than Vendor-B?
  - For similar price
    - For slightly higher price?
  - For similar weight
  - For similar warranty
  - For similar backsheet

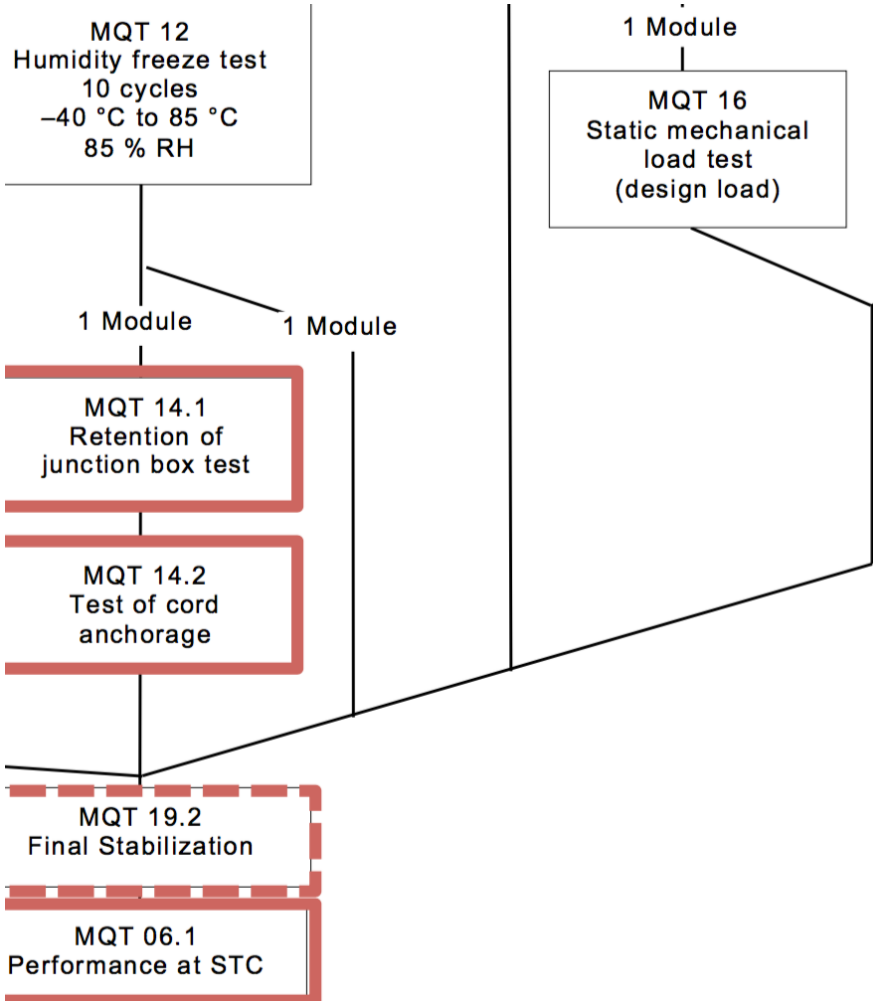
What are the right tests?

BrightSpot Automation

- How best assess module durability regarding cracked cells?

Static load portion of IEC61215?

- 2400 Pa is higher than most installations will see from snow and wind
- Does backside load do anything?
- Is one hour any better than 1 second?
- Is 3 times front then back better than 1 time?
- Is it worthwhile doing this test if don't follow with "crack opening" sequence?
  - Too severe?
  - Are we afraid to do this?
- Is this test more about other failure modes?



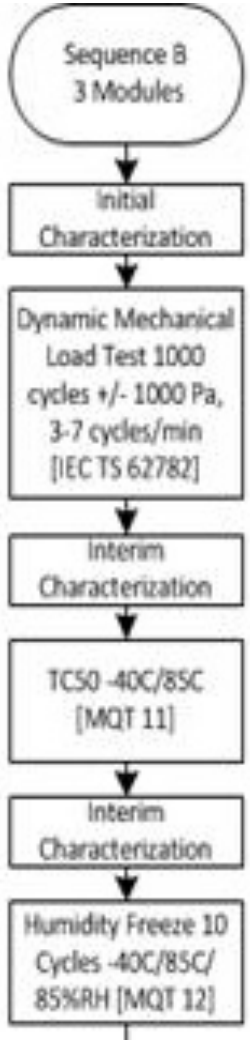
[Beck, Siva, NREL PVMRW 2016]

Cyclic Load Test IEC-TS-62782?

- Is +1000 Pa the right level for crack formation?
  - Initially mostly “closed” cracks
- Are +/-1000 Pa the right levels for crack opening?
  - Every cycle is a chance to allow the crack to become propped open (ISFH – Koentges)

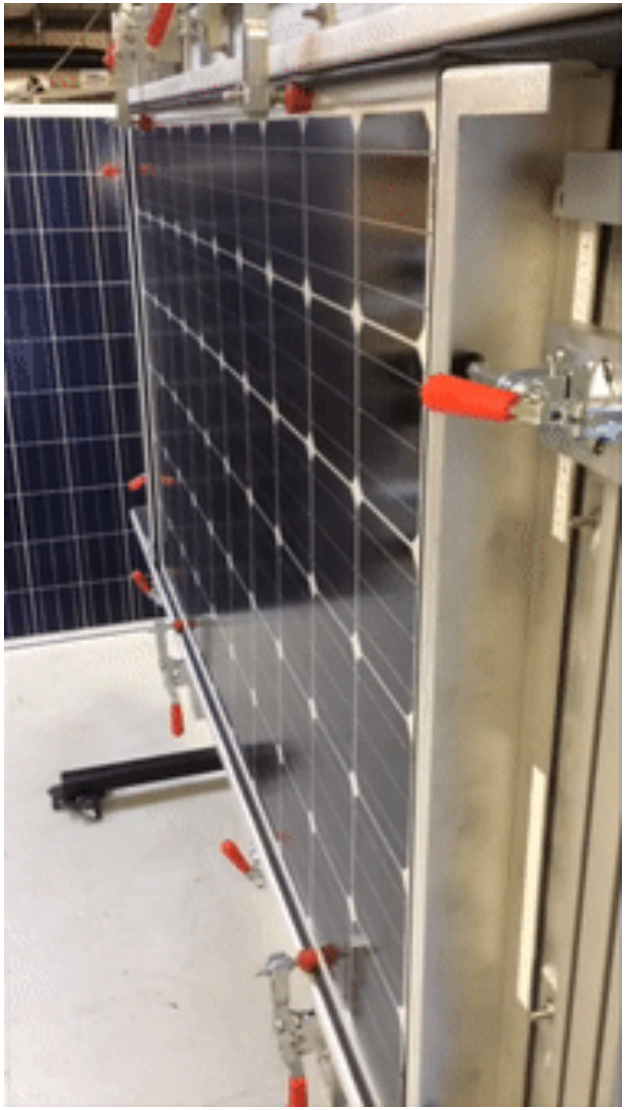
CSA Group: Exp450 Sequence B?

- Sequence (based on PVQAT)
  - 1000 cycles at +/-1000 Pa
  - 50 Thermal cycles
  - 10 Humidity-Freeze cycles
- Data?
- Mechanisms?
- > 20 days!



How use the *LoadSpot*?

- Crack formation vs load as a function of:
  - Module vendor
  - Mounting hardware
  - Mounting locations
  - Prior module history
- Predictive Crack Opening test
  - Correlate to environmental chamber degradation
- Fast cyclic loading
  - EL/IV progression



Other *LoadSpot* test ideas

BrightSpot Automation

- Loading at high and low temperature
- Interactions between shading and loading
- Different mounting hardware
- Different clamp positions
- Cyclic/static combinations
- Your ideas!

Who should use the *LoadSpot*?

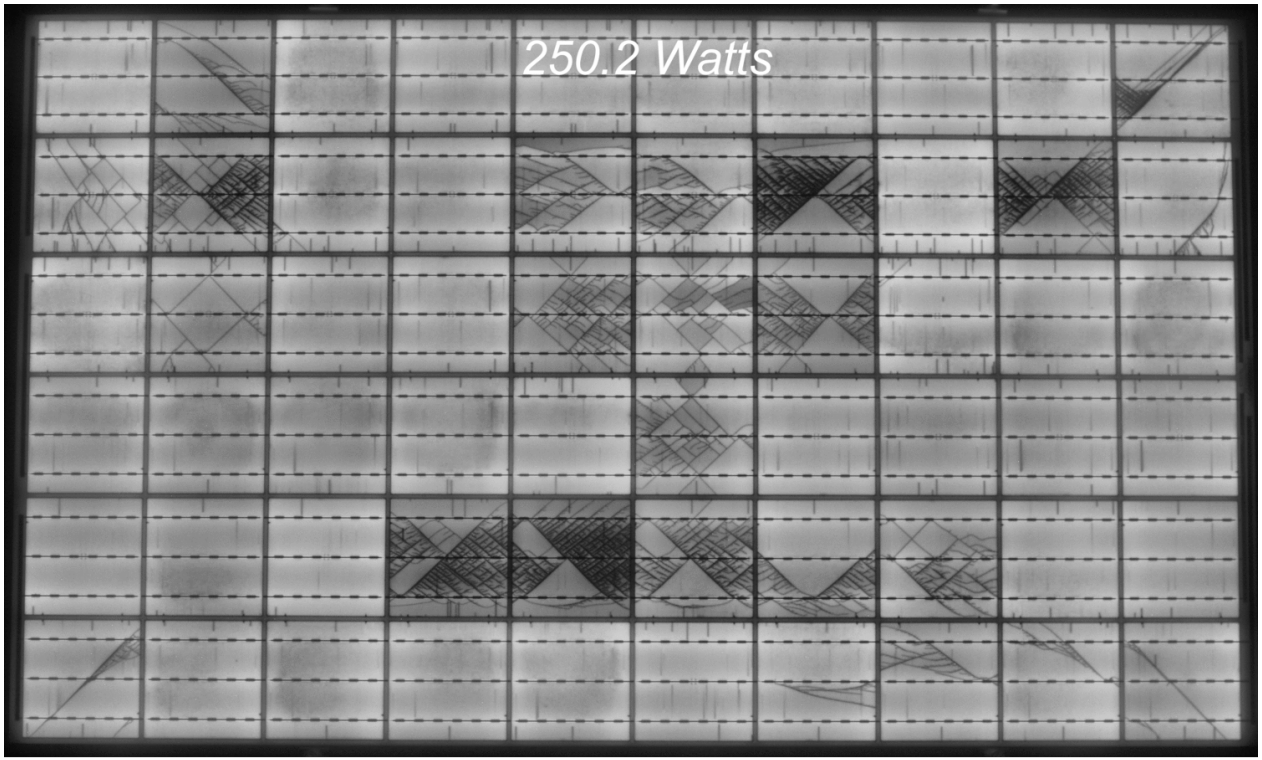
BrightSpot Automation

- Product development and R&D groups
  - Modules
    - Efficiency/cost gains
  - Mounting hardware
- Quality control groups
- Testing and certification labs
  - Does the standard IEC static and cyclic tests
- Module buyers/investers

Test your modules at FSEC!

BrightSpot Automation

- Eric Schneller eschneller@fsec.ucf.edu See poster #86
- Joe Walters jwalters@fsec.ucf.edu
- Me gabor@brightspotautomation.com



Metrology for Cracks in Modules

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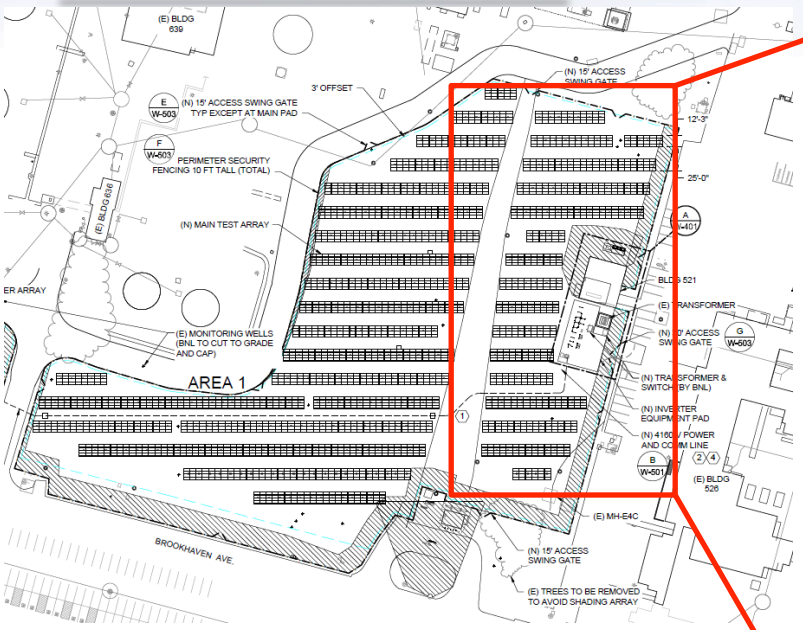
U.S. DEPARTMENT OF ENERGY | Office of Science

BROOKHAVEN NATIONAL LABORATORY | National Synchrotron Light Source II

Outline

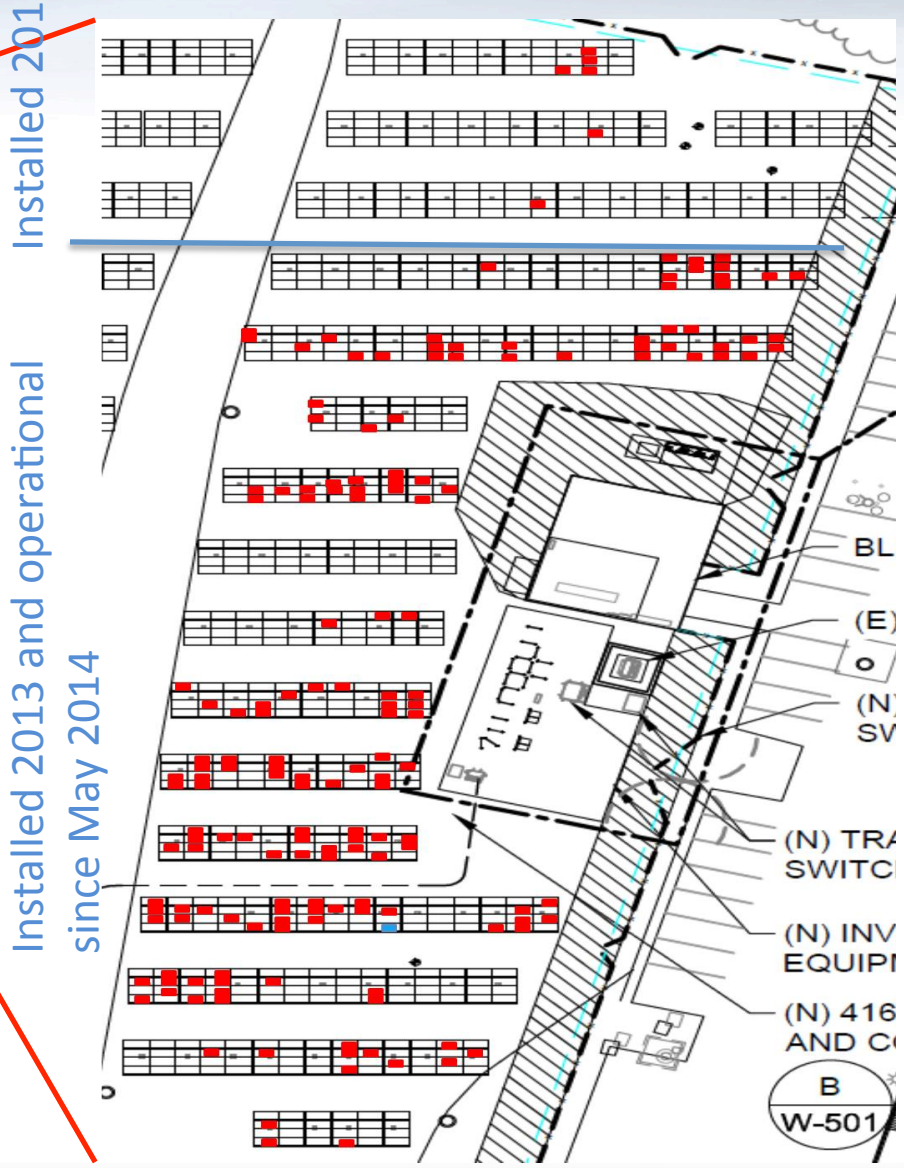
- Motivation: Can Finite Element Analysis (FEA) explain snail trail observations in the field?
- X-ray Diffraction Imaging: A metrology appropriate to test and tune FEA
  - The method
  - Data and results from a mini module
  - White light imaging: a fast and easy to use tool (capability for field setups)
  - next steps
- Conclusion

Location of Modules Showing Snail Trails and Visual Defects

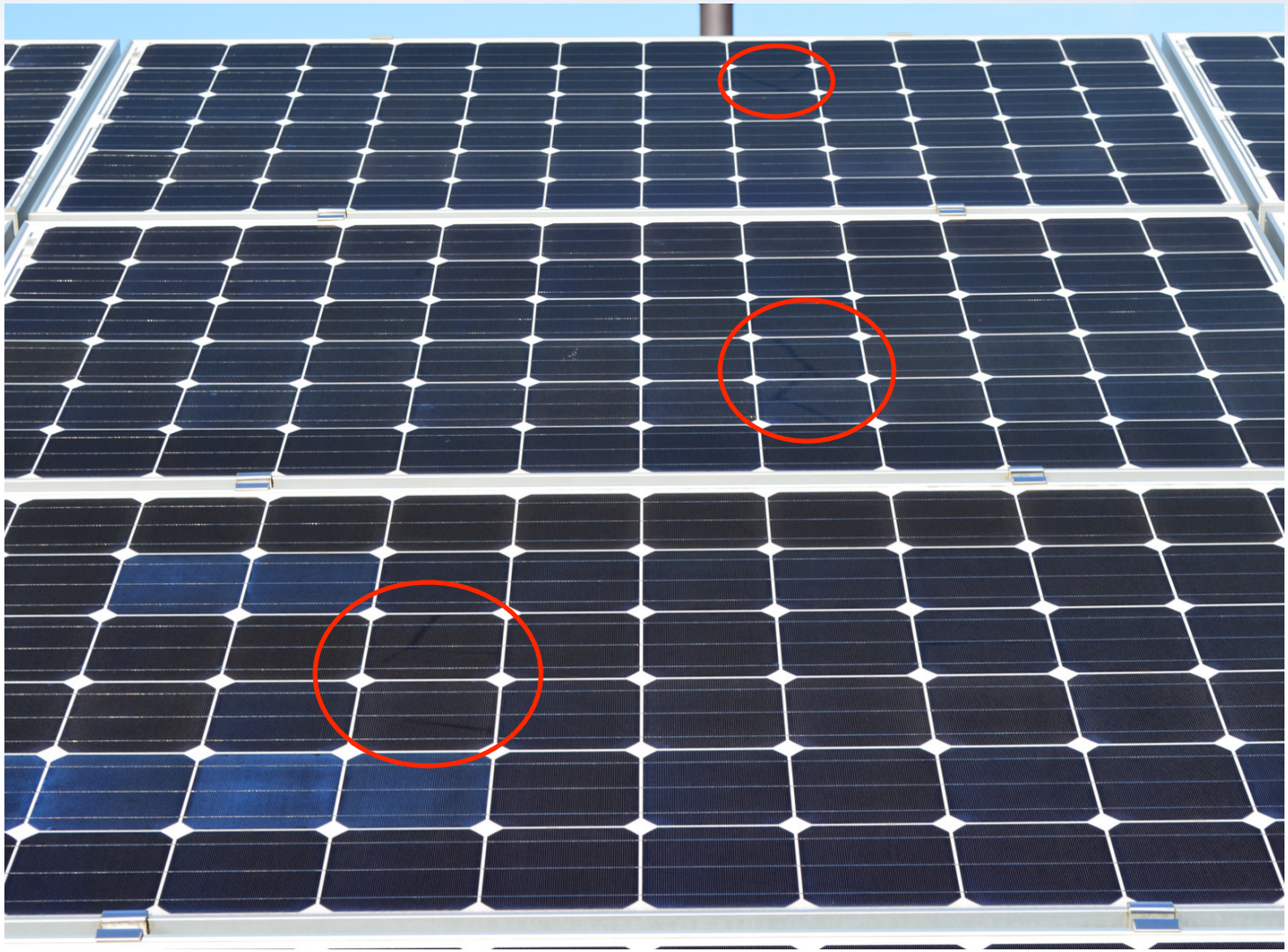


Above the full area 1 of the NSERC array. Only the right portion has been visually inspected in the first exit. The full Area 1 is a 1 MW, 1000 V system.

On the right, the location of the modules presenting snail trails (red) and the broken module (blue) is shown.



Snail Trails and Discolorations

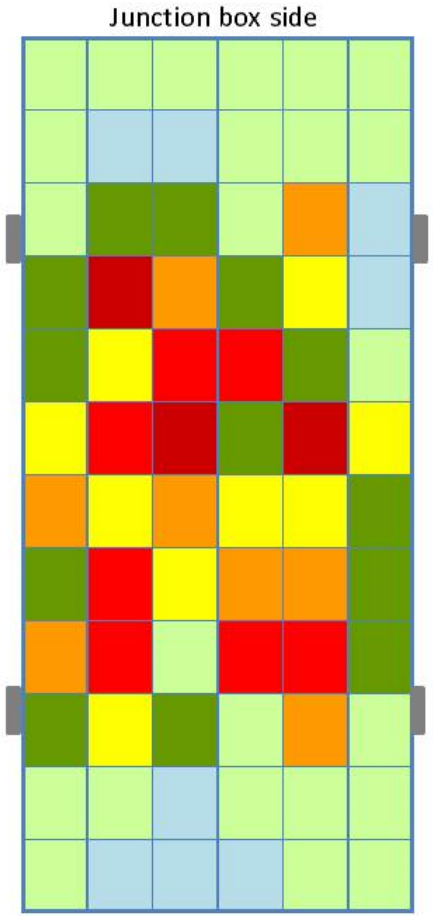


Snail trails on multiple adjacent modules.

Various cases of adjacent modules showing snail trails have been found.

Prevalent Location of Snail Trails on the Module

Statistical analysis of BNL filed data:



FEM-analysis of **thermal cycling effects**:

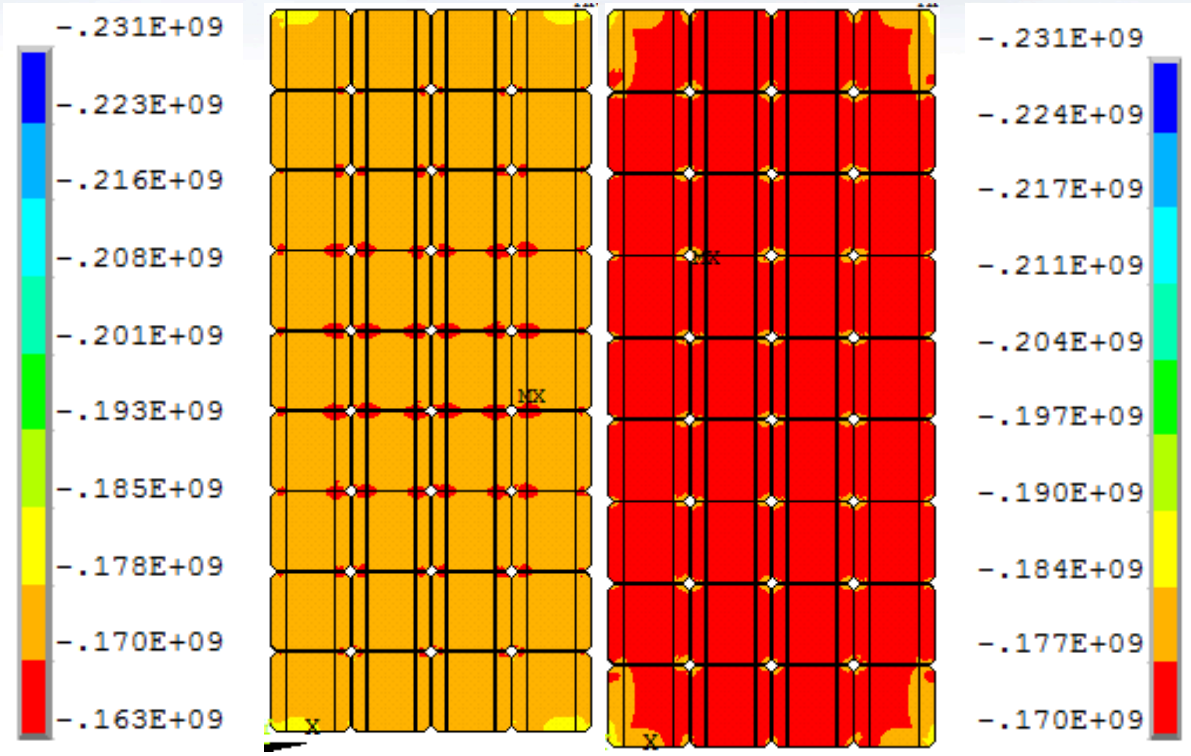
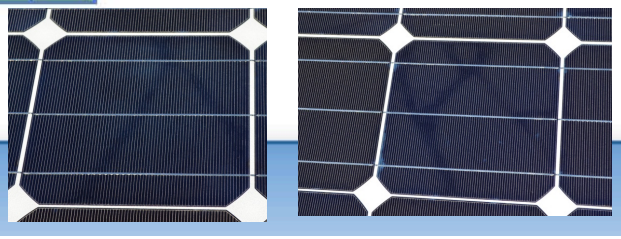


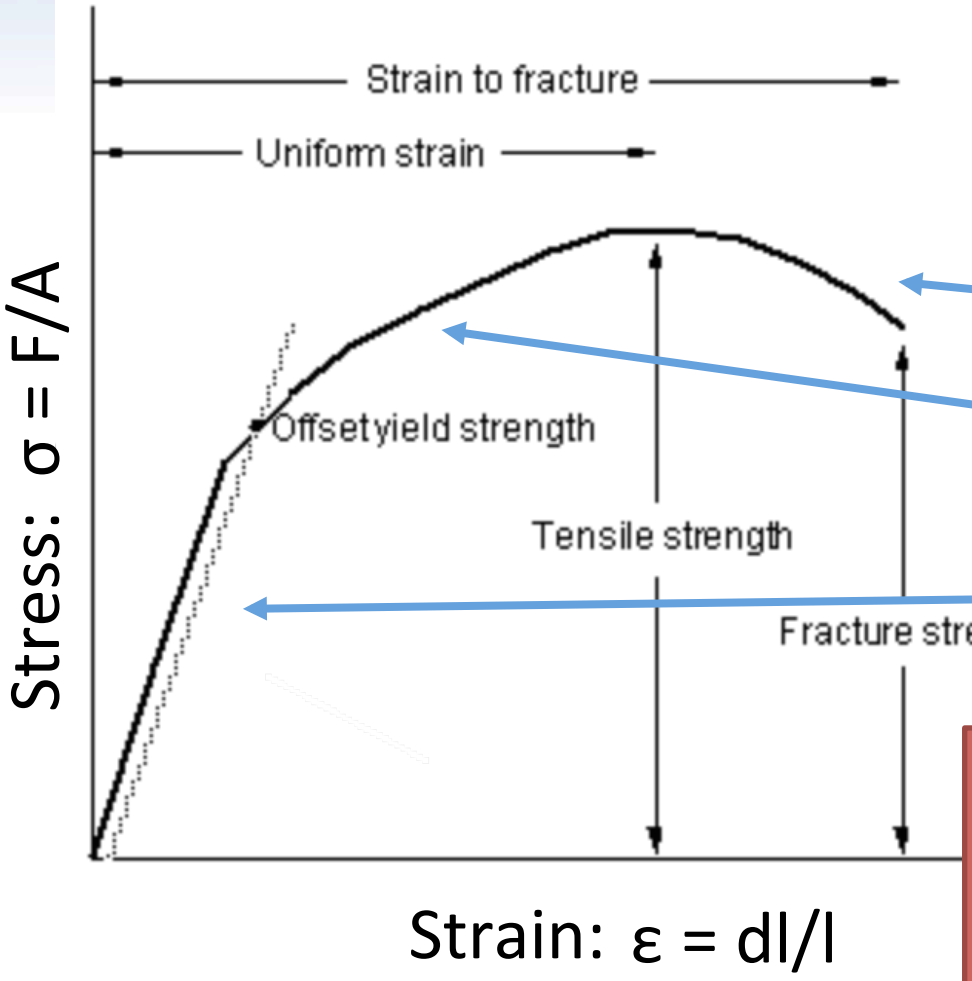
Fig. 13: x-direction stress in cells (left) and third principle stress in cells (right) at -40°C

Hasan, Arif, Siddiqui, IMECE2012-89429, 2012



What metrology can quantitatively verify the FEA results?

Material's Response to Applied Forces



Stress: Force per area (pressure)

Strain: Deformation due to stress

Plastic regime: Not applicable to brittle materials

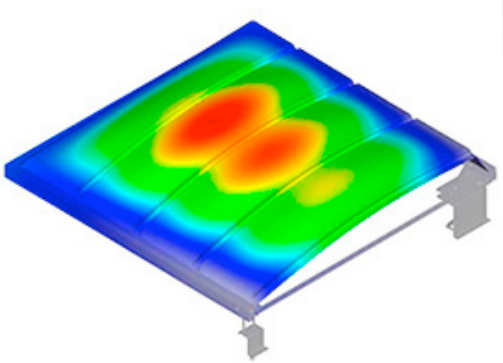
Strain hardening regime

Elastic regime: Following Hooks law

- Measuring the deformation of the material due to a given stress (fatigue testing) allows to determine the functional behavior for a material
- Measuring the deformation of the material and knowing the functional behavior allows to determine local forces

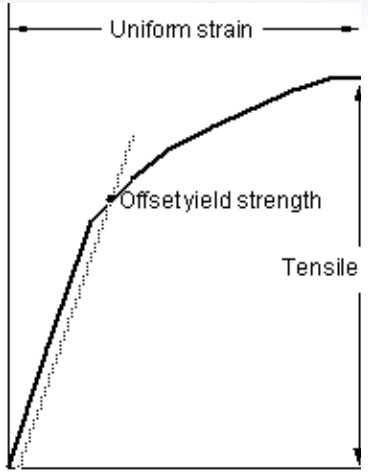
http://www.mscsoftware.com/training_videos/patran/Reverb_help/index.html#page/Fatigue%2520Users%2520Guide/fat_theory.15.4.html

Fracture: What to Measure



http://www.predictiveengineering.com/consulting/fea

$\sigma = F/A$



Fracture

$\varepsilon = dl/l$

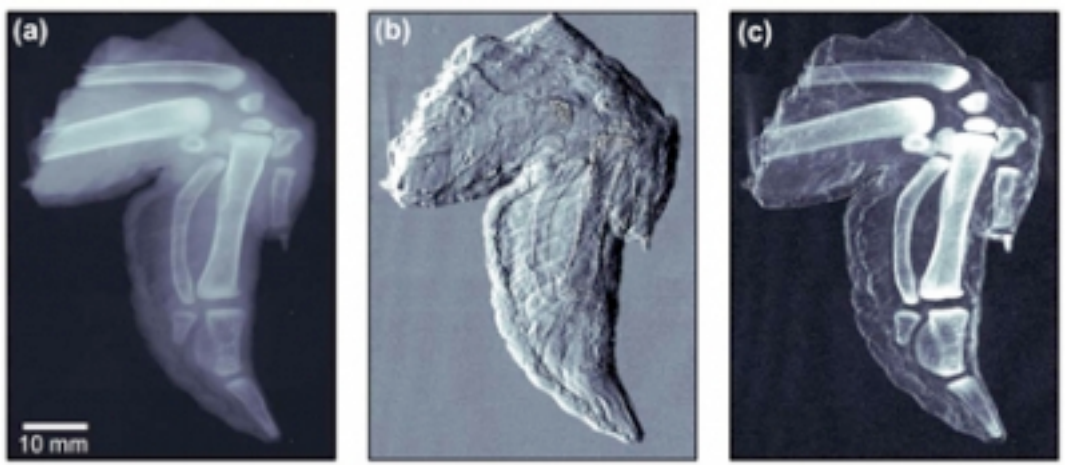
Mechanical properties

External force to bend

FEA + Curvature of wafer = $\sigma = F/A$

l_x + l of Reference/Standard = dl/l → Crack Development

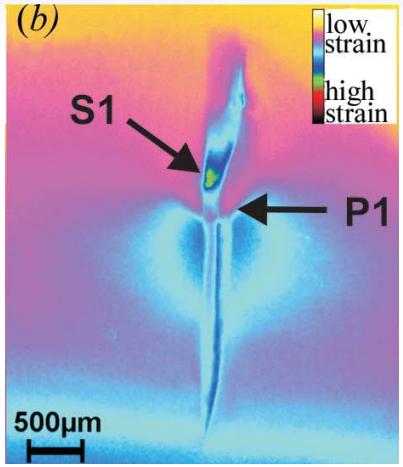
X-ray Diffraction Imaging: Using Bragg Diffraction as a Contrast Mechanism



Absorption contrast | Phase contrast | Dark field image

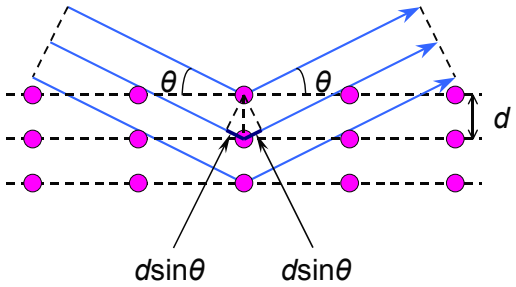
https://www.dectris.com/pci_application.html

Diffraction image

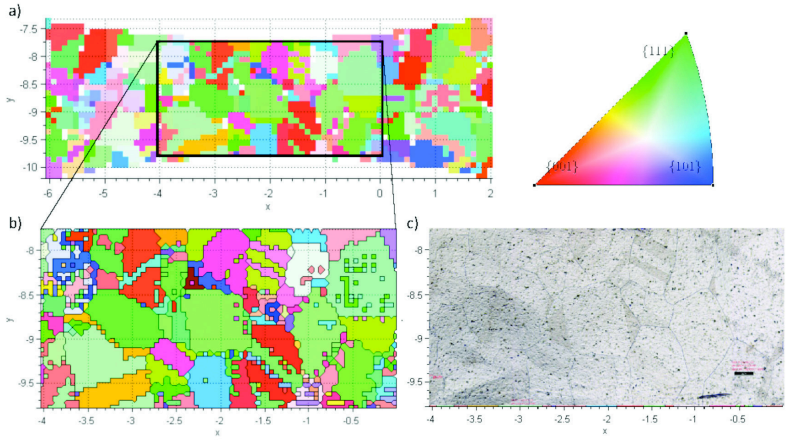


J. Appl. Cryst. (2013). 46, 849–855

Diffraction contrast mechanism:



Wave-front is preserved if crystal is perfect (acts like a mirror)



Angular and Spatial Resolution

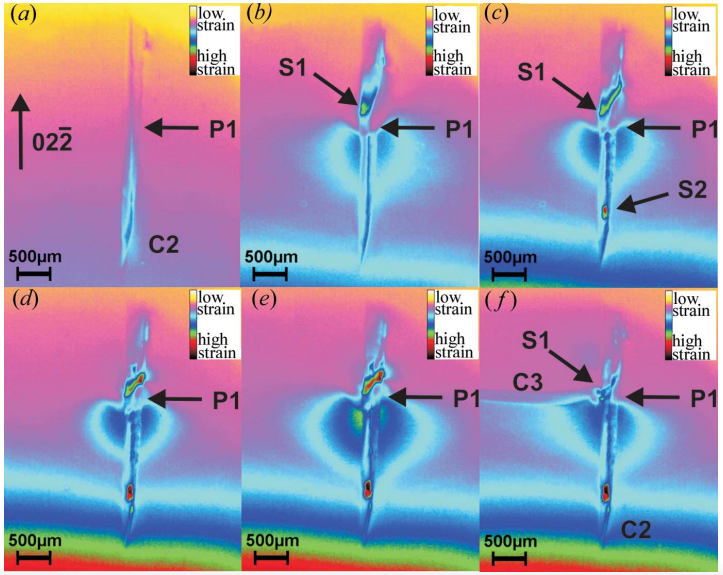
Angular Resolution:

- Fundamental limit is given by the width of the bragg reflection
- At 30keV the width of a Si bragg reflection is in the order of 1-3μrad (~0.05-0.1mdeg)
- State of the art full field and pencil beam setups can easily achieve fundamental limit.

Spatial Resolution:

- Fundamental limit is given by diffraction limit
- At 30keV the diffraction limit is beyond 1A

- Easily achieved resolution with commonly used equipment is 1-10μm. World record is currently 7nm.



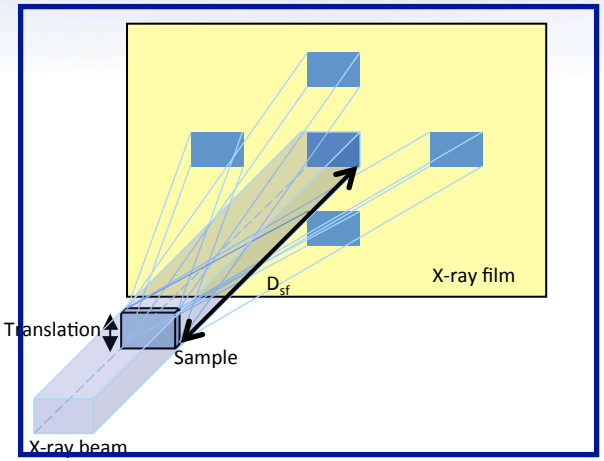
Example of crack formation and relaxation of strain during tempering of a processed Si wafer measured with a pencil beam; by determining the local lattice constant the strain map can be produced.
Spatial resolution: sub-micrometer

J. Appl. Cryst. (2013). 46, 849–855

White Beam X-ray Diffraction Imaging

Principle:

- Every allowed reflection can be observed in one "shot"; this results in redundancy and increased statistics.
- Background/signal ratio is large (figures showing low background cannot be detected)
- Efficient way of X-ray diffraction imaging if monochromatic sources are not available

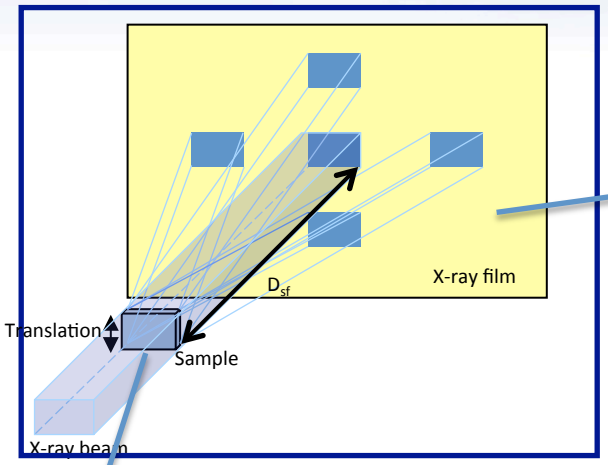


Experimental Requirements:

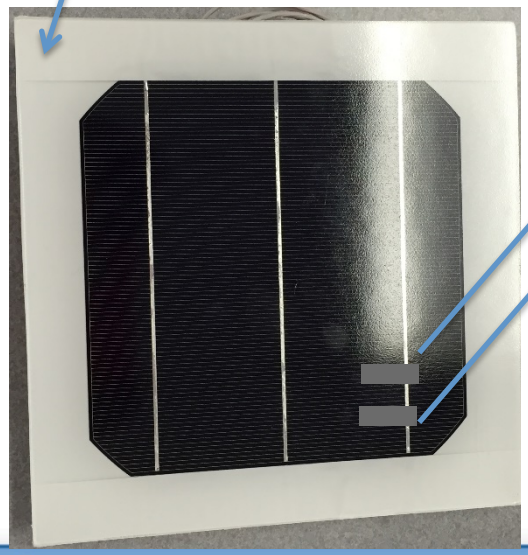
- Source: collimated high energetic polychromatic X-ray source (bemsstrahlung spectrum); energies above 30keV are preferred for typical packaging.
- Spatially resolving detectors (typically 1-5μm resolution):
  - Films: cheap but requires large manpower to make many exposures
  - Scintillator screens in combination with optical microscope (detection efficiencies of roughly 10^{-3}-10^{-4}, frame rates of 100Hz are realistic)
  - Scintillators with directly coupled single photon detectors (detection efficiency close to 1, frame rates in the 100-1000Hz, but expensive (emerging technology)
- Module manipulation: needs only translated to scan beam over full module

First White Beam Diffraction Imaging Data (Full Field)

Digitized and background removed data from film

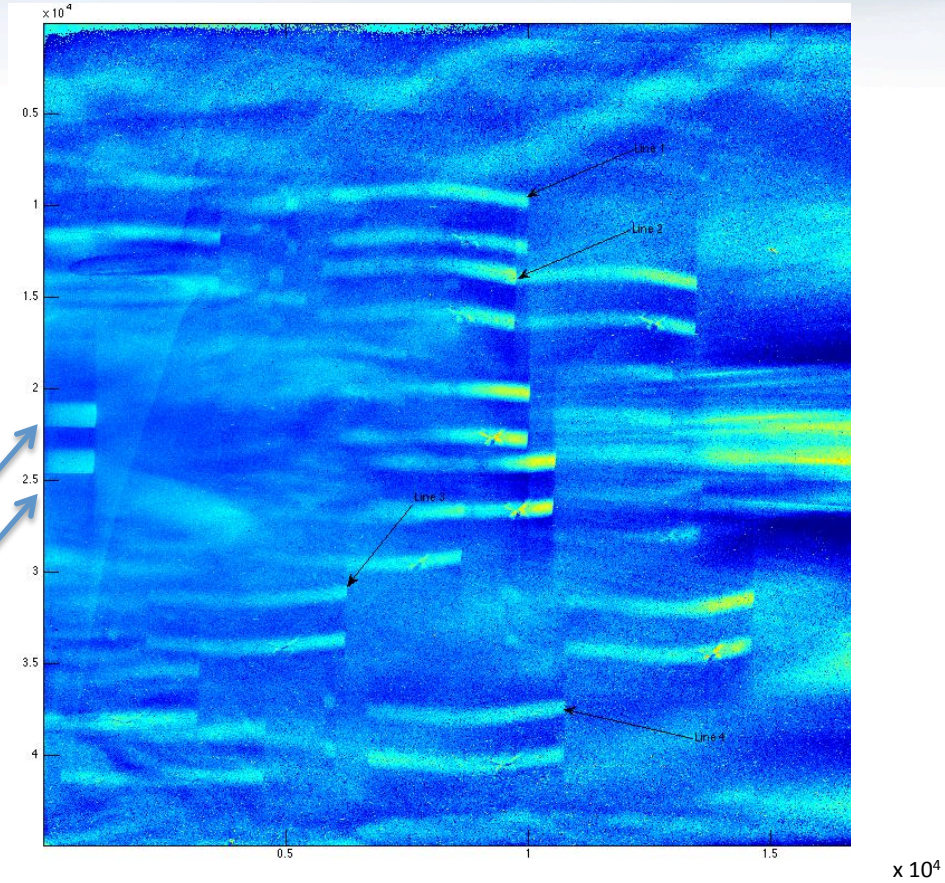


Calibration Mini Module as test sample



Exposure 2

Exposure 1

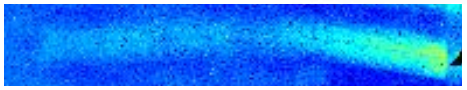


x 10^4

- Film was used for two exposures (film was vertically moved by 10mm)
- Beam size: 3x16mm^2
- Two sets of diffraction images are visible

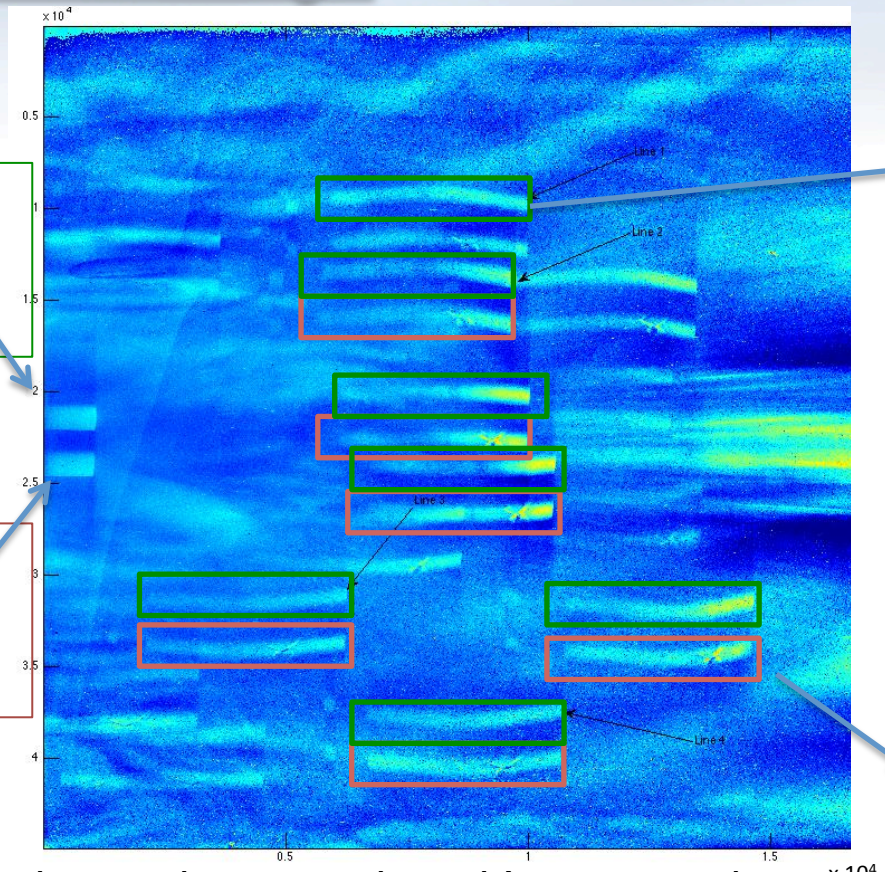
The Diffraction Image

Exposure 2 shows non-cracked wafer with Ag metallization lines

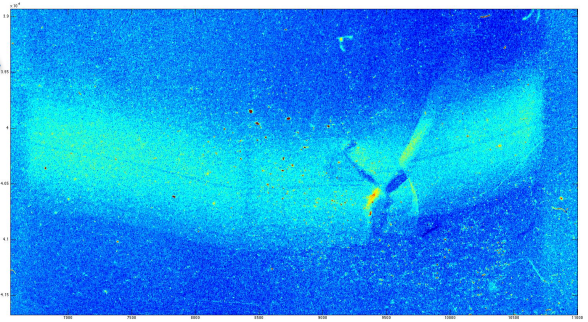


Direct beam (partial image): Exposure 2

Direct beam (partial image): Exposure 1

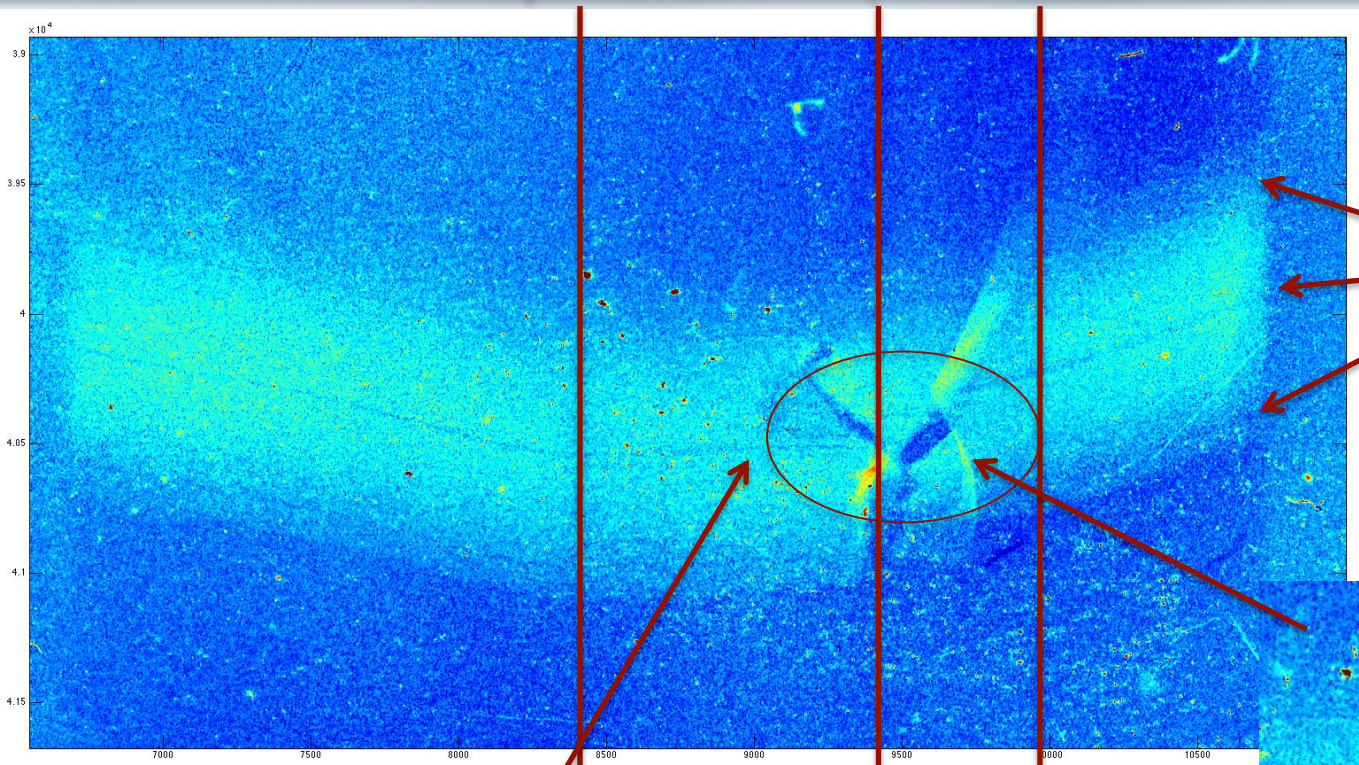


Exposure 1 shows clearly micro crack with bus-bar and 3 Ag metallization lines



- One exposure produces a large number of images, each correlated to a different diffraction plane (like mirrors)
- Information content:
  - Intensity variations due to Ag absorption contrast or
  - due to scattering contrast (crack with low angle grain boundaries)
  - Wavy line shape reflects bend of wafer

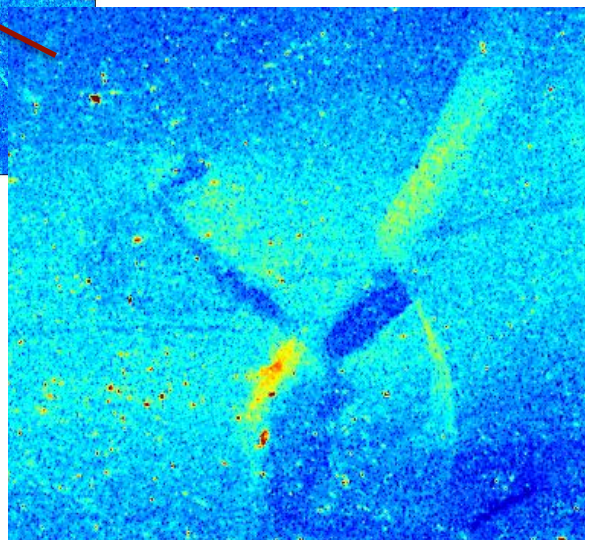
The Crack in Exposure 1 (Close to Solder Point)



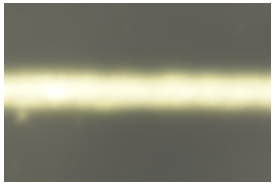
Three metallization lines: curvature reflects (measures) deformation of wafer

High Compression Area on the Back Sheet

Bus bar contact



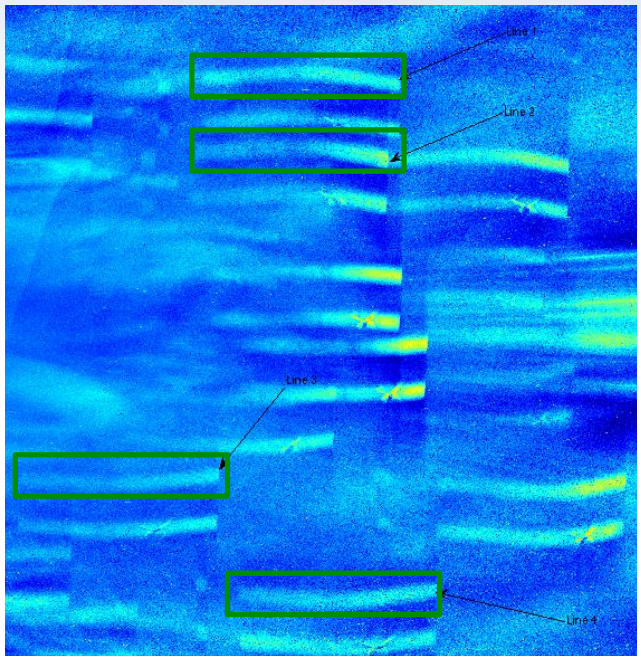
Optical microscope



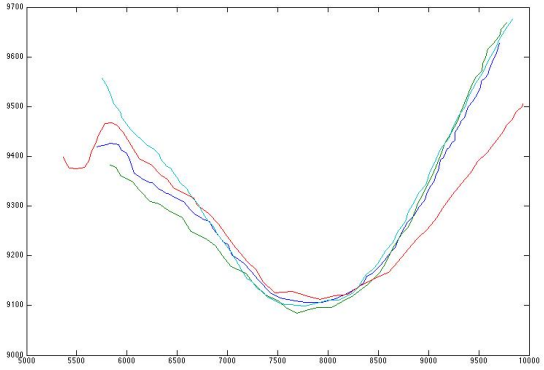
Multiple light scattering makes imaging of Si impossible

- Metallization line shows two discontinuities reflecting three independent parts of the wafer
- Crack is not visible in microscope
- Crack dimensions is in mm-range

Wafer deformation: Quantitative Analysis

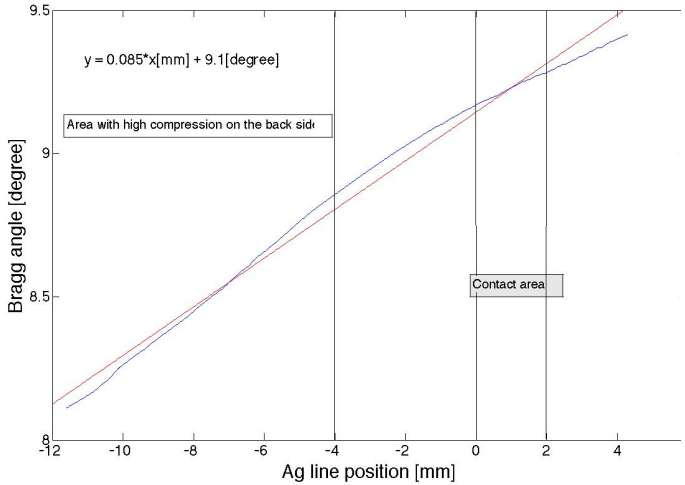


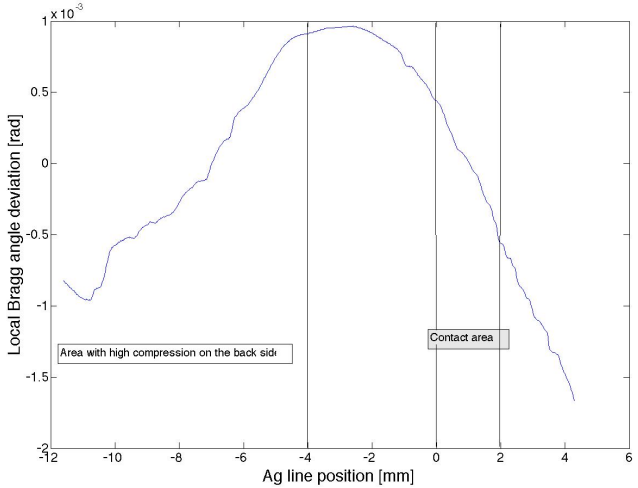
- Reflections of Exposure 2 were selected to avoid effects due to the crack
- Four reflections selected which represents positive and negative reflection indices (utilizing symmetry to minimize systematic errors)



Digitized shape of metallization line using symmetry inversion

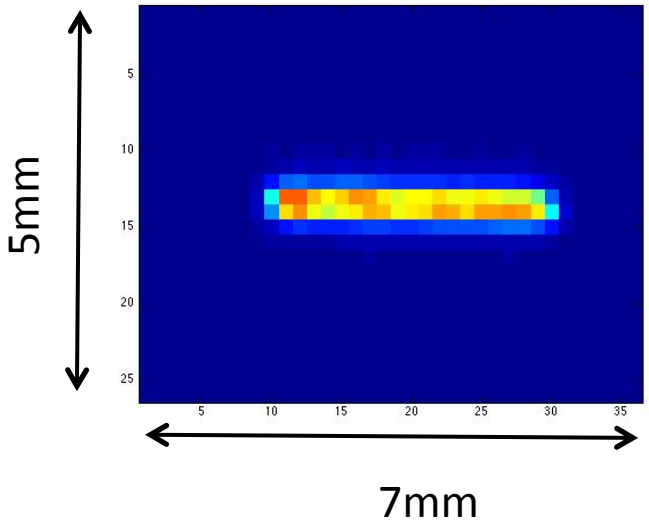
- Strong deformation about 1.4 degrees (bending of wafer correlated with structure)
- "local" deformation in the order 3mrad (~0.18 degrees)

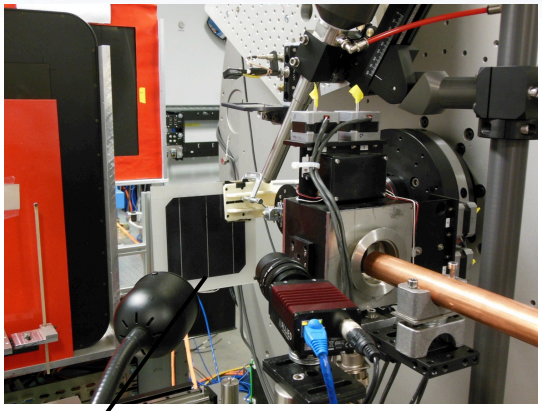




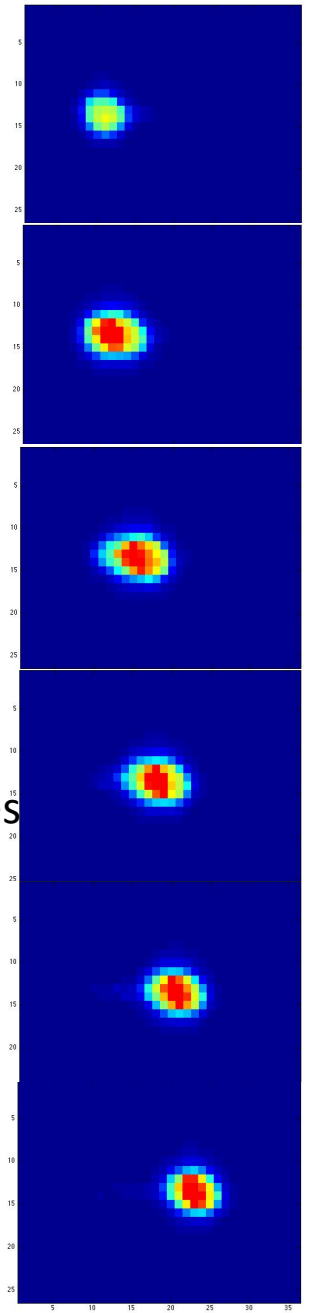
First Experiments with monochromatic beam at XPD/NSLS-II

Reflected beam in Laue geometry @ 34.5keV



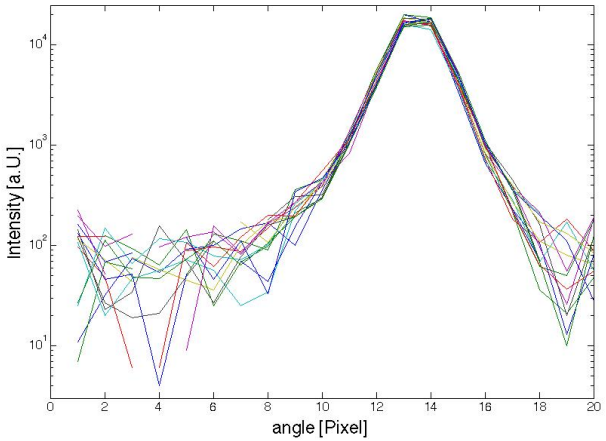


Mini-Module



0.02 degrees rotation between frames

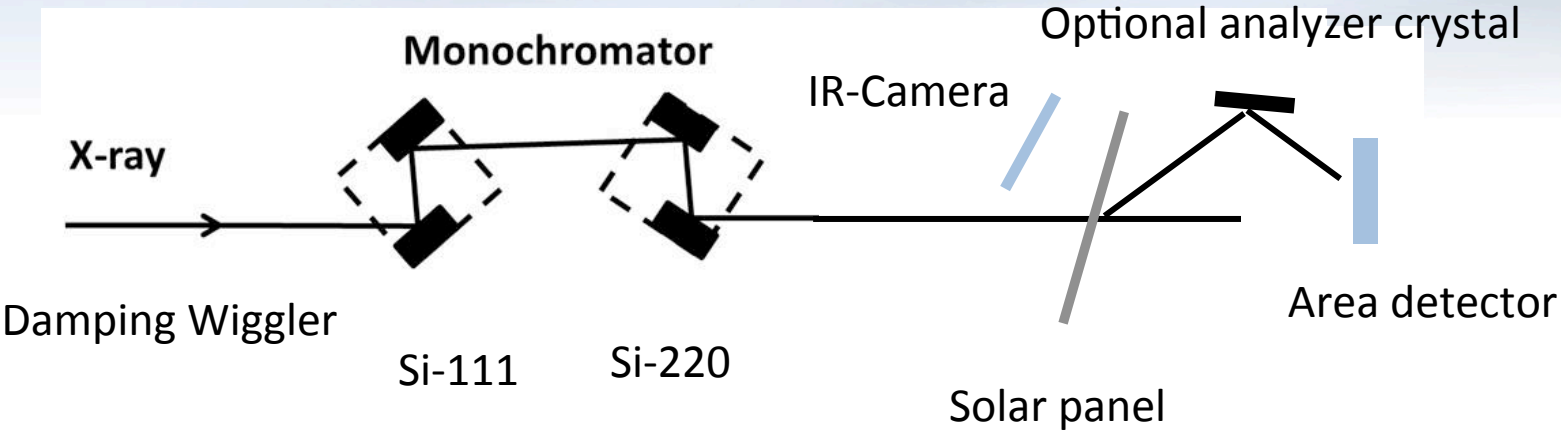
Signal to Background: 26000/100

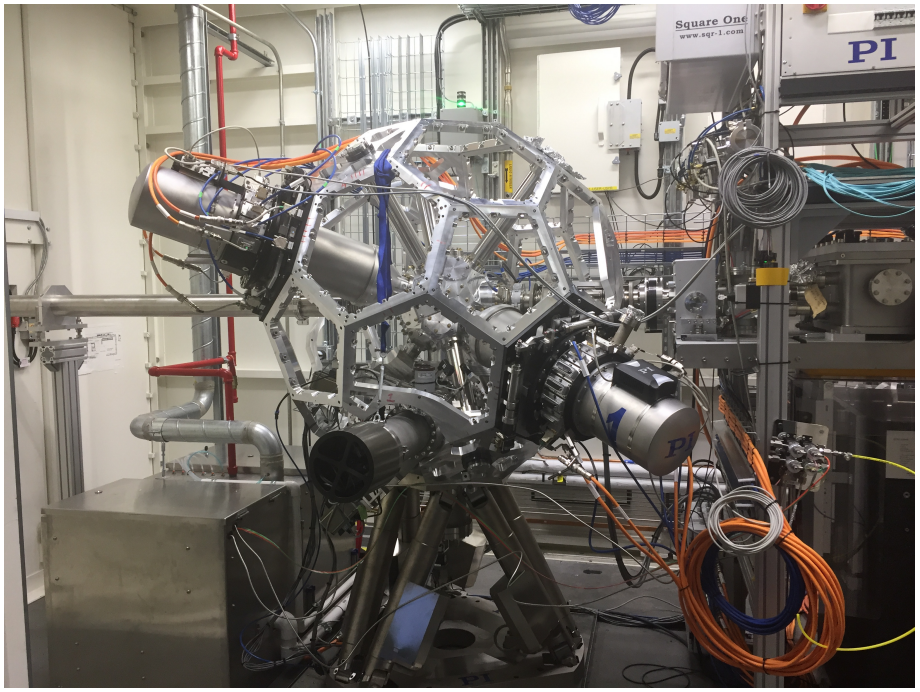


Results:

- Signal/Background ~300
- Bend of cell in wafer is 0.18 degrees
- Setup needs to be improved to provide strain analysis (easy task)

Proposed Setup at NSLS-II: 8-ID





- Required time:
  - ~20min-25min per cell with 5-10μm resolution
  - Detector readout determines time
- Available beam time: 3x7days per quarter year
- Number of cells per quarter year: ~2000

About: 3TB/hour!

Summary

- X-ray diffraction imaging provides:
  - Strain measurements with spatial resolution in the micrometer and nanometer regime and high sensitivity
  - It is relative fast and can be easily applied if analysis software is provided
  - Can be applied in monochromatic synchrotron experiments (high resolution) or in white light field experiments for manufacturing or field inspection.
- X-ray diffraction imaging is a perfect metrology tool to test and improve (refining models and parameters) and verify FEA.

NREL/SNL/BNL PV Module Reliability Workshop

Tuesday afternoon first discussion:

Cracked cells: Presentations described how cells may crack, how cracks can be detected with different levels of resolution, and that power loss may result – sometimes immediately and sometimes after subsequent thermal cycling or other stress in the field. The ensuing discussion explored many aspects of the problem. The discussion is summarized here according to three themes:

1. **Characterization of cracks and their effects:**

• The characterization of the cracks is complicated by the observation that the electrical connection between the cell pieces changes when mechanical, electrical, and environmental stresses are applied to the module (e.g. by the LoadSpot). The electrical connection can also change with time both by self mending and/or further opening of cracks after thermal cycling and other stresses.
• The power loss at system level may be much greater and more relevant than the power loss from each individual module, since the maximum power point current for each module may vary, causing the current flowing in the string to deviate from the optimal value for each module.
• Many of the studies use electroluminescence imaging performed indoors, but it would be useful to collect images of modules throughout entire fields (real-world operation), including investigating the effects of tracker movement, inverter clipping, etc. Cases have been discussed of cracked modules showing hot spots while in the field, but not when moved to the laboratory; they had to be put under tension to show the crack problem again. This aspect highlights the importance and the effects of the real-world working conditions for the modules.
• Conversely, some disconnected cell pieces may not be noticed during field (infrared) imaging if the system causes the module to be in forward bias rather than to be biased at a point that places the cracked cell in reverse bias. This situation may occur when multiple strings are connected in parallel or when the inverter limits the output of the system by forcing all strings into forward bias relative to the maximum power point.
• Application of cyclic mechanical load followed by thermal cycling and humidity-freeze cycling is presently our most accepted method of aging cracks, but it is unclear if it is optimal at predicting end of life impact to performance and safety.
• UV fluorescence (based on the fluorescence of degradation products in the lamination material) may provide a high throughput method for detecting cracks and heat-generating isolated cells parts in the field.
• X-ray diffraction imaging can be applied in laboratory environment for high-resolution micro-cracks (micron size) and cracks visualization in correlation with material defects, interactions with other materials, and stress/strain on the silicon cell in the encapsulated environment. The technique could be implemented for industrial applications.

2. **Understanding of causes and impacts of cracked cells:**

• In commercialized modules the tendency is that micro-cracks can be correlated to manufacturing, while major cracks can happen during shipping, handling, operation and maintenance of modules.
• Testing to date has shown that the majority of cracks are benign, showing no safety concerns as well as no major degradation in the module performance. However isolated solar cell areas resulting from cracks can strongly degrade power and pose a safety issue in the worst cases. The connection between cracked solar cells at beginning of life and isolated solar cell areas later in life is still unclear.
• Correlations between cracks, hot spots and loss of performance are still unclear. Some cracked modules have low performance, and some hot modules have very good performance.
• Despite hot spots happening rarely, they are a source of safety concerns. They can also unleash a series of other degradation modes within the module. More study is needed to understand when cracks are a cause vs. an effect of hotspots and what percentage of hotspots are crack related.
• More study is also needed to understand whether wind-related opening and closing of cracks is a significant factor in bypass diode failure due to the potential for rapid/frequent switching of the diodes.
• Should we look to develop modules that crack less or that degrade less in time once a crack is present? It is practically impossible to avoid cracks, thus we need to act on the environment surrounding the cracks by focusing on module packaging materials and contact improvement.
• We still need to understand the encapsulant's mechanical properties (both temperature and time dependence) in more detail and how these interact with soldering and other stresses within the module to affect the formation and propagation of microcracks.

3. **Strategies for reducing the effects of cracks:**

• More busbars or replacing the few flat interconnect wires with an array of round interconnect wires. It has been shown that more busbars make the system less sensitive to cracked cells, while higher efficiency makes the system more sensitive.
• Glass-glass construction instead of glass-backsheet construction places the cells at the neutral axis. However, glass-glass modules may present other issues.
• Half-size cells that allow the use of less tall interconnect wires that place less stress on the cells during soldering.
• Some cell designs like Sunpower's are less susceptible to problems correlated with cracks (would bifacial and HIT cells behave in a similar way?).
• Controlling the soldering process to avoid stress at the point of connection. Soldering can be an initiator for cracks.
• Developing a stiffer module frame.
• Improving the function and the lifetime of the encapsulant material.

• Tests may be developed, such as a twist test to simulate bad handling during module installation. However, the industry may not be supportive of additional test requirements.

Determination of mechanical stress in encapsulated solar cells by combination of finite element analysis and strain gage measurements

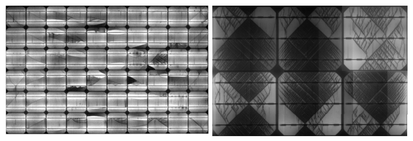
Martin SANDER, George MSEIS, Ludovic HUDANSKI, TOTAL GAS, RENEWABLES & POWER, 2 place Jean Millier, 92400 COURBEVOIE, France

Abstract

Encapsulated solar cells in PV modules are prone to cracking when applying certain mechanical loads. This represents a particular risk for module performance and reliability. The use of thin silicon solar cells increases this risk further and therefore concepts for reliability and robustness have to be developed. For such a reliability assessment the failure criteria (cell strength) and the local stress have to be known.
Measurements of mechanical strength of bare and encapsulated cells have been presented by different authors in the past, but determination of mechanical stress in PV modules under realistic boundary conditions still needs improvement and verification.
In this contribution we present results of finite element analysis of full size PV modules under different boundary conditions and load cases. To verify the simulated stress values, mechanical tests have been conducted on full size PV laminates (unframed and framed) with applied strain gages that directly measure mechanical strain at the wafer or cell surface. Knowing Young's modulus of silicon one can directly calculate mechanical stress.
We observed significant differences for different load cases (point vs. area load), significant impact of the module frame and we were able to verify the accuracy of the finite element model that we are using for our reliability assessments. The obtained learning is currently used to improve PV modules and systems for improved durability especially for harsh environments.

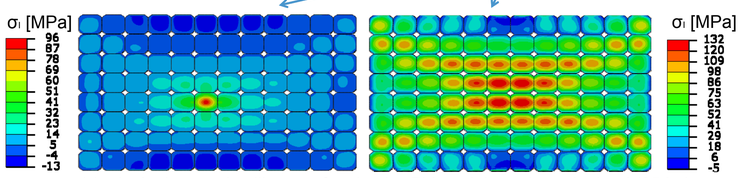
Motivation / Background

- Cracks in c-Si solar cells can lead to power loss and should be avoided.



Electroluminescence of solar cells after mechanical loading: Left: PV module after area load, *Potthoff et al, Workshop PV-Modultechnik (2009);* Right: PV laminate after uniaxial bending, *Sander et al, Proceedings EU-PVSEC (2013)*

- Silicon solar cells break if: the local stress exceeds **(Failure criteria)** the fracture strength



1st principal stress in silicon wafers in a) a PV module under point load (85 kg), b) a PV module under area load (5400 Pa)

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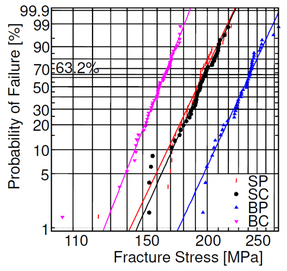


Weibull diagramm of solar cells in 4 point bending in different orientation *Kaule et al, SolMat 120, (2014)*

- Numerical simulation is very useful to simulate mechanical stress, but requires experimental verification
- Direct measurements of mechanical stress: RAMAN spectroscopy, x-ray micro-diffraction, photoelasticity → difficult to perform on full size PV modules
- Indirect measurements: cell cracking + statistical evaluation → requires a lot of effort, costly
- Use of **strain gages** as a novel method to directly measure mechanical strain

Methods

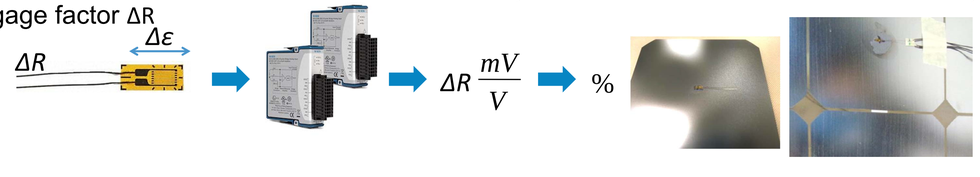
Finite Element Analysis

- Muli-layered FEA model is developed in Abaqus to explicitly model the laminate stack

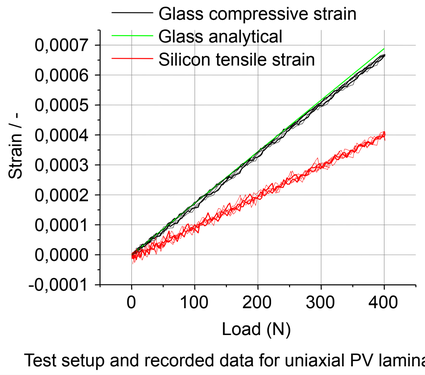
Material	Element type	Constitutive response
Glass	Continuum Shell	Elastic
Encapsulant	Solid (C3D8R)	Visco-Elastic
Silicon	Continuum Shell	Elastic, Cubic symmetry
Back sheet	Solid (C3D8R)	Elastic
Aluminum	Solid (C3D8R)	Elastic-Plastic
RTV	Cohesive Elements	Continuum, Elastic response

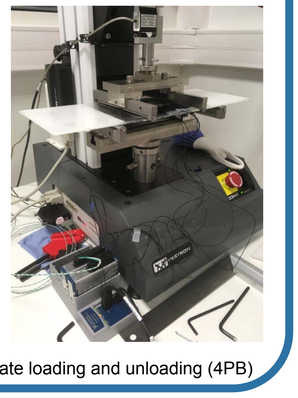
Strain gages

- Electrical strain gages consist of an insulating flexible support structure with an attached thin metallic pattern. They are attached to the test specimen by means of a suitable adhesive.
- A deformation of the surface of the test specimen causes deformation of the strain gage leading to a change in its electrical resistance that can be directly transferred into mechanical strain by knowing the gage factor ΔR



- Verification:
  - To verify strain gage accuracy uniaxial bending tests have been performed on PV laminates
  - Strain gage signal has been found to be very reproducible
  - Uncertainty of ~1E-5 = 0.7 MPa (glass), = 1.3 MPa (silicon)



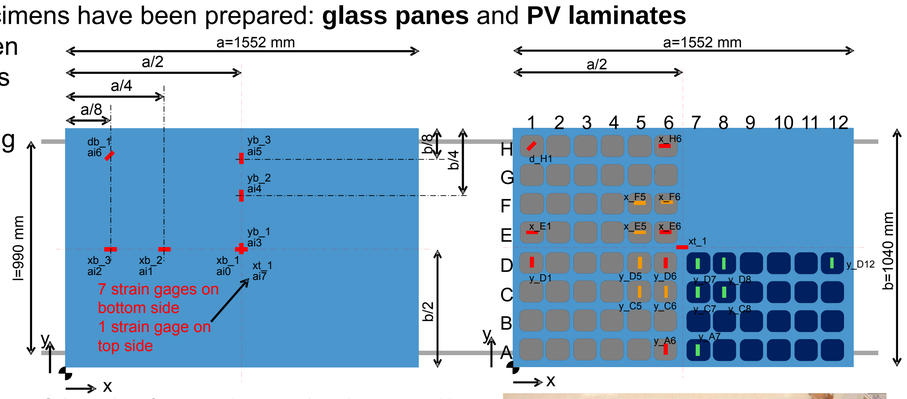


Test setup and recorded data for uniaxial PV laminate loading and unloading (4PB)

Tests

Test specimens and setup

- Two types of test specimens have been prepared: **glass panes** and **PV laminates**
- Strain gages have been applied at the positions shown on the scheme
- Mechanical load testing was done with a line support along the long edges
- A standard Al frame has been attached to the test specimens
- Mechanical load testing has been repeated for frame flat on ground and for quarter point mounting

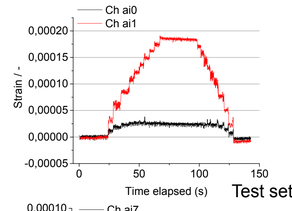


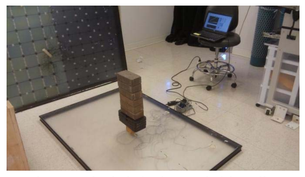
Schematics of test specimens and strain gage positions; left: bare glass pane; right: PV laminate

Unframed PV laminate with applied strain gages

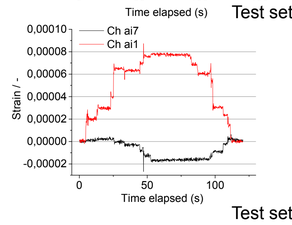
Test procedure

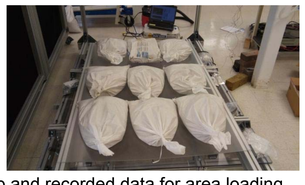
- Test specimens have been used several times to be sure about their properties → load range was set to a low value to stay in the linear regime and to not cause plastic deformation
- Strain gage signal was recorded constantly so that load steps can be identified
- 8 channels were recorded in parallel
- Area loading has to be improved (just one load step was possible using sand bags and uniformity was not perfect)





Test setup and recorded data for point loading





Test setup and recorded data for area loading

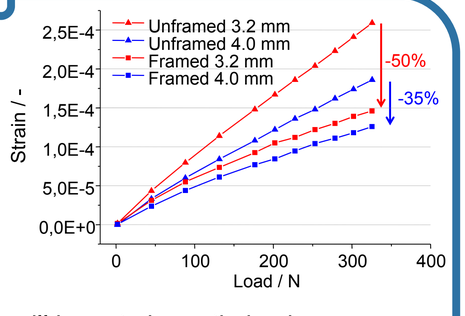
Results

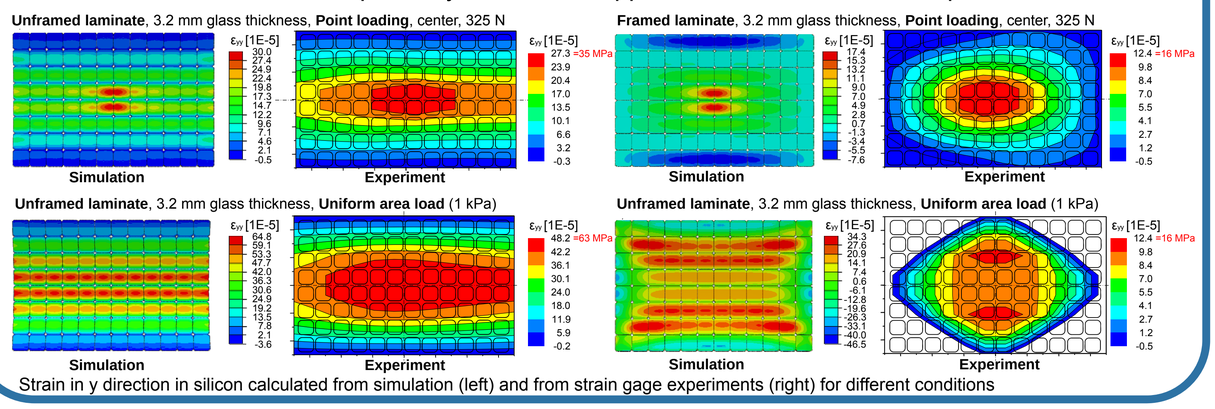
Unframed laminates

- Almost linear dependency between strain and load
- Strain in y direction is dominating, strain in x direction almost 0

Framed laminates

- Significant reduction of mechanical strain by adding frame
- Nonlinear behavior for framed panels
- Reduced influence of glass thickness for framed PV laminates and point load
- Good correlation between experiment and simulation for point load. Deviation for area load probably due to load application → will have to be optimized





Strain in y direction in silicon calculated from simulation (left) and from strain gage experiments (right) for different conditions

Potential-induced Degradation of n-type Bifacial Modules

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Solar Energy Research Institute of Singapore

Introduction

- In Singapore, the temperature of silicon PV modules can easily go up to 60°C, with the highest recorded value of 79°C. The average relative humidity is 81%. Therefore, potential-induced degradation is a major reliability concern for PV modules deployed in the tropical climate.
- N-type crystalline silicon PV technologies have gained momentum recently. In particular, n-type bifacial modules can achieve a 10% to 30% power gain in fields than conventional monofacial modules.
- The majority of the PID-related researches have been focused on p-type silicon PV technologies. However, the understanding of PID effects in n-type silicon PV technologies is still limited.
- In this study, we conducted experiments to investigate PID in n-type bifacial modules.

Experimental setup

- One-cell n-type module is fabricated. PID test is performed by applying -1000V to the module at 50℃ and 30% R.H.

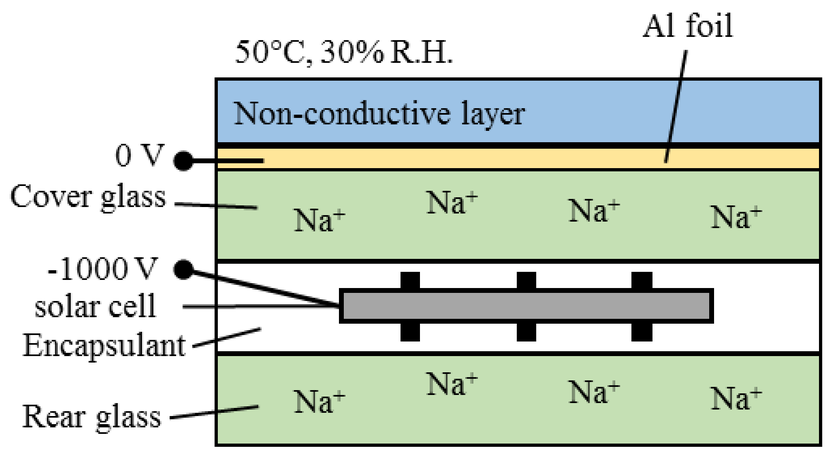

Figure 1: Experimental setup to accelerate PID

Results

- **I-V measurements at Standard testing conditions (STC).** We measured the I-V characteristics of the sample from both the front and back side. As shown in Figure 2, the front side suffered more power loss than the back side. We also observed significant loss in open-circuit voltage and short-circuit current. However, the fill factor is almost unaffected by PID.

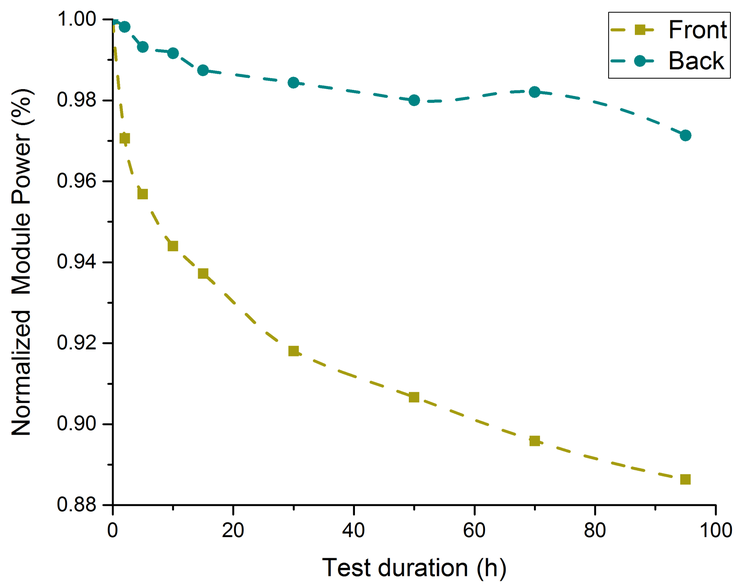

Figure 2: Normalized module power versus the test duration

- **External quantum efficiency measurements**. By comparing the external quantum efficiency of a PID-affected sample (front side, see Figure 3), it is shown that there is a huge drop for wavelength ranging from 300nm to 800nm. To rule out the possibility that this observation is due to a drop in optical performance, the reflectance of the sample was measured; there is no change in reflectance before and after PID.

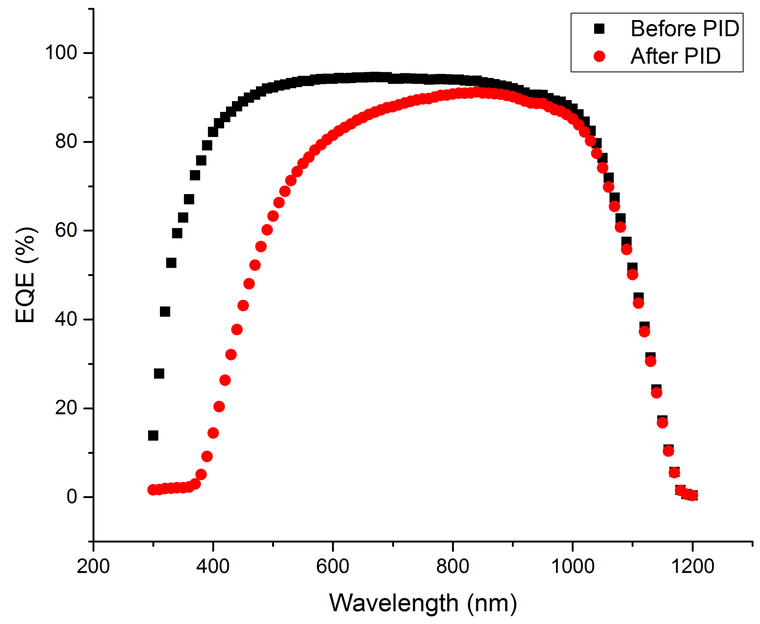

Figure 3: EQE measurement of a sample before and after PID tests (measured from the front side).

- **Photoluminescence Imaging.** PL imaging were also captured for a PID-affected sample. The PL responses from the emitter and base region are separated (see Figure 4). It can be seen that the emitter is affected by PID, while the bulk and rear region remains unaffected.

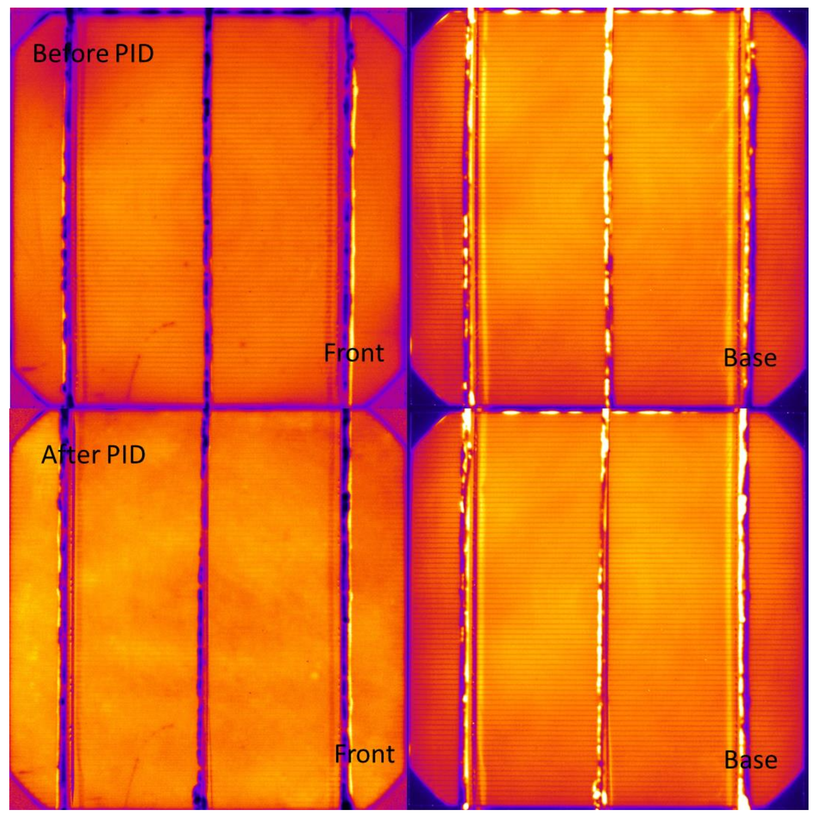

Figure 4: PL imaging of a sample before and after PID tests.

- **Surface passivation degradation.** The results from I-V, EQE and PL measurements indicate that the cause of the degradation could be due to an increase in surface recombination. When the cell is negatively biased, positive charges (such as Na^+ from the sola-lime glass) migrate into the AR coating layer and accumulate there. These positive charges attract the negatively-charged light-generated electrons in the emitter to the front surface of the cell, thereby increasing the surface recombination.

Conclusions

- Both the front and rear side of the n-type bifacial modules are affected by PID, whereas the front side is more sensitive to the PID.
- N-type bifacial modules suffers significant loss in open-circuit voltage and short-circuit current due to PID, while the fill factor is almost unaffected.
- Further investigations using EQE measurement and PL imaging strongly show that the cause of degradation is likely to be due to an increased front surface recombination.

National Research Foundation Prime Minister's Office Singapore
EDB singapore
SERIS is a research institute at the National University of Singapore (NUS). SERIS is sponsored by the National University of Singapore (NUS) and Singapore's National Research Foundation (NRF) through the Singapore Economic Development Board (EDB).
NUS National University of Singapore

Probe indentation method for fast and non-destructive determination of the cross-linking degree of EVA encapsulants

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LAYTEC Knowledge is key

Introduction

EVA cross-linking governs module quality

- Level of cross-linking of ethylene vinyl acetate (EVA) encapsulant is decisive for long-term stability and performance of a solar module.
- Cross-linking is achieved by thermally curing EVA during lamination process. To date, process control and quality assurance rely on lab-based tests for monitoring lamination quality.
- Most common conventional test is gel-content analysis, which is slow (~24h), destructive, manual, inaccurate, with small sampling fraction (~1:1000).
- This poster shows a novel method of testing the level of EVA cross-linking, suitable for in-line application.

Key features of indentation method

- Non-destructive
- Test duration < 1m
- Precision: 3%
- All types of EVA / back-sheet laminates
- Mechanical aproach
- Repeatable results
- No consumables
- Based on patent licensed from Fraunhofer USA [1]

Comparison with conventional test methods

Quantity of interest	Metrology method	Tested EVA property
Degree of EVA cross-linking	Presented method	Mechanical resistance
	Gel content test	Solubility
	DSC	Residual peroxide

Most relevant property for long-term stability of solar modules: Mechanical resistance.

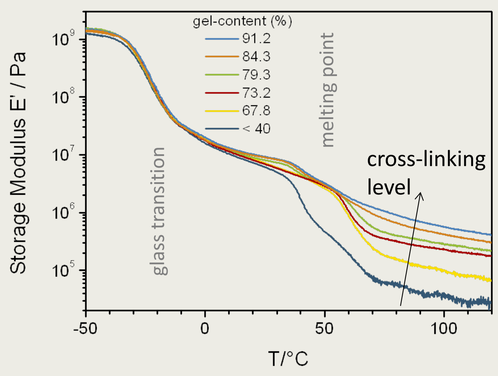
Technical approach of indentation method

Mechanical properties of cured EVA

Dynamic mechanical analysis (DMA) of EVA samples with varying levels of cross-linking reveals:

- Mechanical properties of EVA depend on temperature.
- Above 80 °C all phase transitions are completed.

Direct correlation between EVA cross-linking and mechanical properties above 80 °C.



Quantities recorded within 10 seconds:

Mechanical properties | Temperature | Dynamics

Data processing

System output:

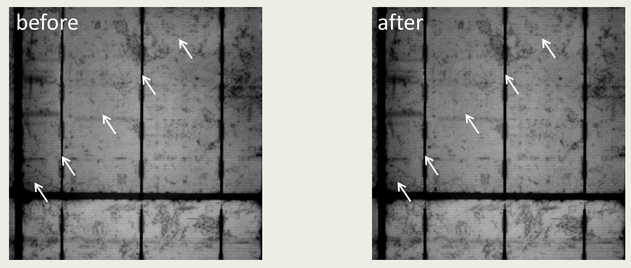
Figure of marit (LXM) characterizing the degree of cross-linking

The indentation method is 100% non-destructive!

EL- and flasher-tests were performed before and after the indentation measurement. The tests were repeated after 2,000 h damp heat test. Additionally, wet leakage tests were performed. All tests prove that the module properties remain unchanged.

- For low cross-linked and high cross-linked modules
- Flasher tests
- Electroluminescence analysis before and after the measurement. The locations of measurements are indicated.

No harm for module quality or performance detected.

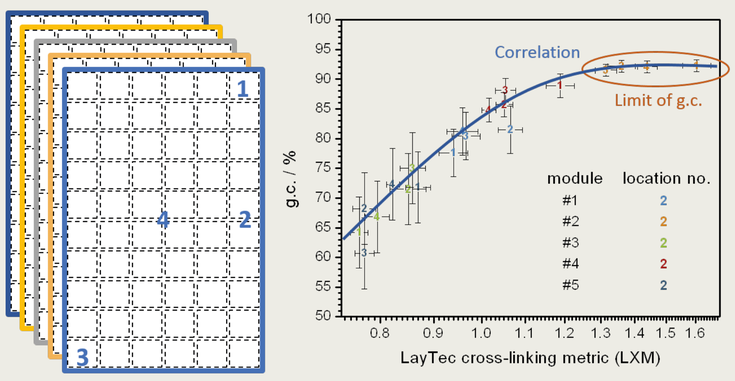


Experimental correlation

LXM vs. gel-content (g.c.)

Experiment

Series of five modules laminated under various lamination times: Four locations were tested on each module.
First, non-destructive new method (10 times/location); Second, gel-content test



Results

- Clear correlation between the two methods (LXM and g.c.)
- Indentation method gives high resolution of cross-linking degree and is sensitive even for high cross-linking degree while g.c. test is limited to values of cross-linking < 92%
- Spatial inhomogeneity on individual modules is clearly resolved
- Projection of error bars onto fit reveals superior accuracy as compared to gel-content test

Conclusion

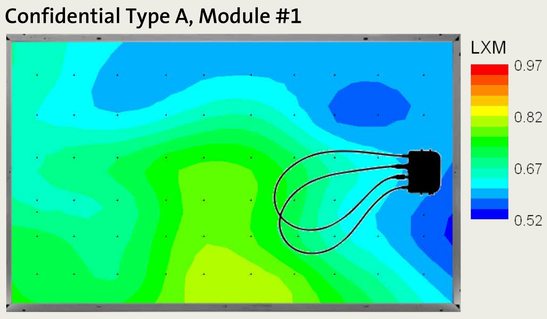
Precise information far beyond gel-content test.

Automated mapping of full size modules

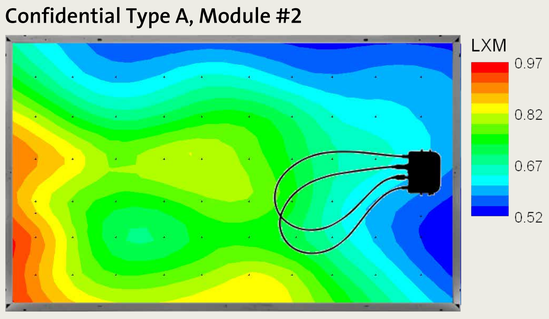
- Indentation method can be used in a fully automated mapping station (X Link® SAM)
- Lamination uniformity inspection across the entire module
- Designed for regular spot tests in production lines
- Fast feed-back and quality control in lamination process and goods receipt inspection

Lateral mapping of lamination quality

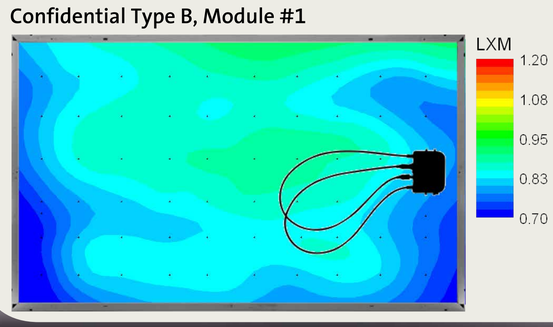
Confidential Type A, Module #1



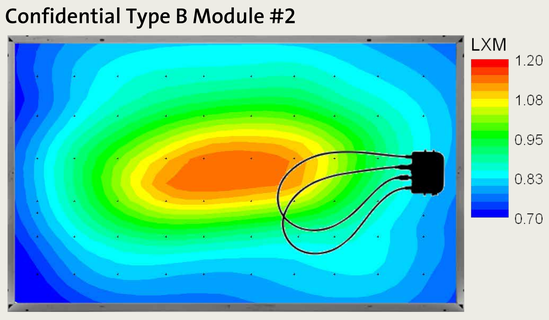
Confidential Type A, Module #2



Confidential Type B, Module #1



Confidential Type B Module #2



- Indentation method facilitates the non-destructive and fast technique of lateral high resolution mapping of solar modules
- Huge variation of cross-linking degree across each module due to inhomogeneity of foil quality or lamination conditions clearly visible
- Mappings reveal lamination characteristics
- Measurement facilitates troubleshooting

Summary

A novel method of testing EVA cross-linking was developed and turned into an industrial metrology tool. Advantages over conventional methods:

- Fast and non-destructive
- Automated
- Superior accuracy

In-line application for process control and quality assurance: 100% coverage of module production. Lateral maps of solar modules reveal huge variations of cross-linking level and facilitate troubleshooting.

Acknowledgement

Hanwha Q-Cells for preparation of test modules and providing gel-content data.
Fraunhofer USA for conducting dynamic mechanical analysis

Bibliography

[1] B. MacBride, Fraunhofer CSE, "LayTec and CSE Partner to Successfully Commercialize a New PV Metrology Method", www.cleantechnotes.org/2012/06/laytec-and-cse-partner-to-successfully-commercialize-a-new-pv-metrology-method, accessed February 2013
Proceedings paper EU PVSEC 213

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Thermal Cycling of Silicon PV Modules at High Ramp Rate and High Temp

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CFV Solar Test Laboratory, Inc., Albuquerque, NM

Introduction

Thermal cycling has proven to be a useful accelerated stress test for comparing module durability across manufacturers and BOM. Thermal cycling (TC) causes stress/failure of the solder bonds that result in a higher series resistance and reduced performance over time[1,2]. TC stresses the thermal mismatch of components, as well as the ability of the encapsulant to hold the laminate together under high temperatures. PV module failures related to thermal cycling can be accelerated with more cycles, faster ramp rates, or higher peak temperatures[3]. Higher peak temperatures during TC are allowed under the new IEC 62892-2 procedure for thermal cycling in order to shorten the number of cycles needed reach 500 equivalent cycles at 85 C [1] on solder bond fatigue[4]. PVQAT TG4 is also considering climate specific and mounting specific accelerated TC which include higher peak temperatures during TC.

CFV conducted a simple design of experiments to quantify the power degradation by varying peak dwell temperature (85 °C versus 100 °C) and ramp rate (100 °C/hour per IEC versus 200 °C/hour). We hope that these results will help to drive new standards that lead to shortened time periods for extended reliability testing by allowing faster ramp rates during thermal cycling. We also hope to provide useful module test results from a small sample of silicon modules subjected to 100 °C peak temperatures over 300 cycles to help validate the physical models under development.

Procedures

1. Solicit participation from module manufacturers
2. Identify 3 PV module BOMs for the DOE, 3 modules from each BOM per leg
3. Select modules to provide a sampling of commercially available PV modules with a variety of BOMs, particular as they relate to cell interconnect.
    A. 5 BB, PERC mono, ribbon interconnect, glass-EVA-cell-EVA-polymer, 1 m x 2m
    B. ALT interconnect, mc-Si, glass-Alt encapsulant-cell- Alt encapsulant -polymer, 1 m x 2m
    C. 3 BB, mc-Si, ribbon interconnect, glass-EVA-cell-EVA-polymer, 1 m x 2m
4. Design the 2 x 2 factor experiment, 3 modules per leg, with IV and EL at initial inspection and after each 100 cycles:
    - IEC85 8 cycles/day, 85 C peak temp. IEC 61215 Thermal Cycling
    - IEC100 8 cycles/day, 100 C peak temp
    - RTC85 12 cycles/day, 85 C peak temp
    - RTC100 12 cycles/day, 100 C peak temp
5. Analyze the resulting IV data to rank the importance of each factor on power degradation
6. Next steps: Solicit additional manufacturers to quantify the effects of power degradation on a large sample of BOMs

Results

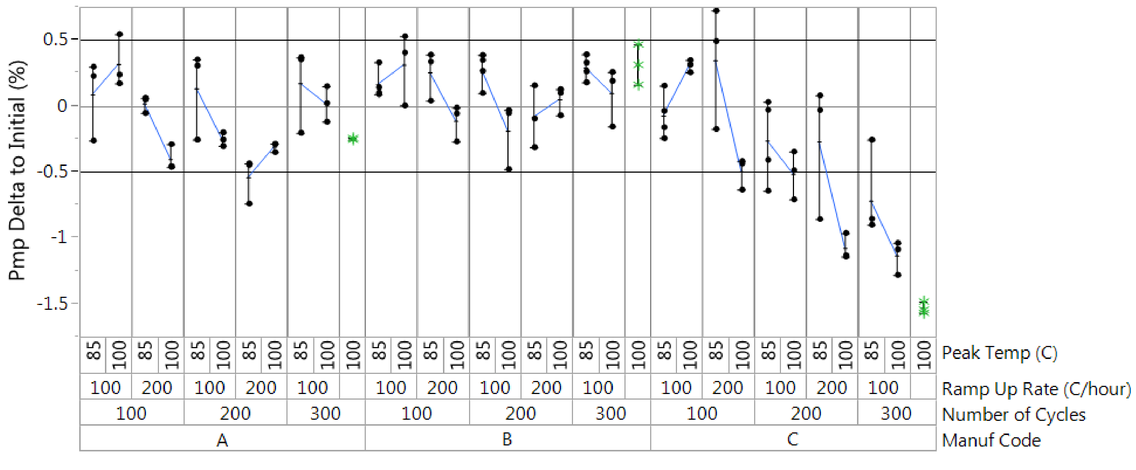

Figure 1. Variability plot of power degradation relative to initial power over the range of peak temp and ramp rates for three manufacturers and 300 thermal cycles

1. Roughly 43% of the variability in Pmp degradation is due to module-to-module variability and measurement reproducibility of the indoor flasher (+/- 0.5%)
2. Roughly 57% of the variability in Pmp degradation can be explained by the factors in the model. The majority of the Pmp degradation is correlated to Vmp degradation.
3. "Manuf Code" explains 32% of the variability in the measurements, driven by Manuf C
    a) Manuf C is not as durable as Manuf A and B
    b) These results confirm that that TC is effective at discriminating among module manufacturer in terms of durability
4. After 200 cycles, Manuf C RTC100 shows higher Pmp degradation compared to the IEC85 leg (-0.3% versuse -1.1%)
    a) Peak Temp and Ramp Rate provide some statistically significant acceleration, but the magnitude of the effect is relatively small compared to cycle count
    b) The combined stress of 100 °C/hr and peak temp at 100 °C did not result in a catastrophic failure of any BOMs after 300 cycles
5. Ramp rate can be increased to shorten time required for TC without a significant increase in Pmp degradation

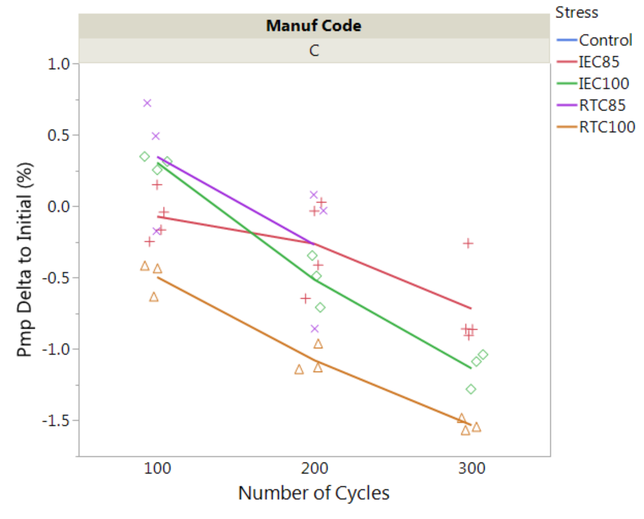

Figure 2. Manuf C Overlay plot of power degradation relative to initial power for each thermal cycling profile

IEC85		IEC100		RTC85		RTC100	
Cycles	Days	Cycles	Days	Cycles	Days	Cycles	Days
200	25	175	22	200	17	<100	< 9
300	38	225	28	?	?	135	11

Table 1. Manuf C power degradation equivalency in number of cycles and number of days

Factor	Effect Size	PValue
Number of Cycles	-1.0	0.000
Peak Temp (C)	-0.5	0.000
Peak Temp (C)*Ramp Up Rate (C/hour)	-0.7	0.001
Ramp Up Rate (C/hour)	-0.2	0.031

Table 2. Manuf C Pareto of effects and effect size in % change over the range tested

1. Manuf A and B showed little Pmp degradation out to 300 cycles
2. Manuf C power loss was roughly 1.5% after 300 cycles under the highest stress RTC100 profile compared with 0.7% for the IEC at 85 C profile
3. Table 1 provides an estimate of acceleration factors for each leg in terms of cycles and days for Manuf C.
    1. TC200 for certification could be done in 9 days instead of 25 days.
    2. TC for durability testing could be significantly accelerated from 38 days for TC300 down to 11 days under the RTC100 profile
4. Table 2 shows the relative importance of the factors and an estimate of the impact on additional power degradation over the range of each effect tested

Conclusions

1. Thermal cycling is effective at discriminating among BOMs in terms of power degradation
2. Number of Cycles was the most important acceleration factor considered in this DOE
3. Faster ramp rates had an added effect of 0.2% for Manuf C after 300 cycles.
4. Ramp rates up to 2x currently allowed in the EIC 61215 standard should be included in future standards for durability and certification
5. All BOMs under all TC conditions would have passed the IEC 61215 requirements under the qualification testing
6. The three BOMs under test would pass testing at higher temperature test conditions under future climate specific protocols with less than 5% power degradation

References

1. Climate Specific Thermal Cycling- Is It Required For Reliability Testing?, Nick Bosco, NREL PVMRW 2016
2. Highly Accelerated Thermal Cycling Test for Short Term Examination of Photovoltaic Module, M. Fujimori et al, Hitachi
3. Accelerated Lifetime Testing of Photovoltaic Modules, TamizhMani G. and Joseph Kuitche, Solar ABCs
4. IEC CD 62892-2 TESTING OF PV MODULES TO DIFFERENTIATE PERFORMANCE IN MULTIPLE CLIMATES AND APPLICATIONS – Part 2: Test Procedure for Thermal Cycling

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Microstructure Simulation of Polycrystalline Thin Films

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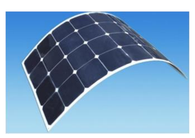
Introduction

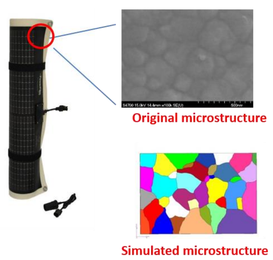
- Polycrystalline thin films for solar cell
  - An important material form for solar cells
  - Modeling and simulation are important parts of design
  - Temperature effect, mechanical effect, microstructural effect can be analyzed through Finite Element Method (FEM) simulations

Flexible solar cells



Rollable solar cells

Microstructure



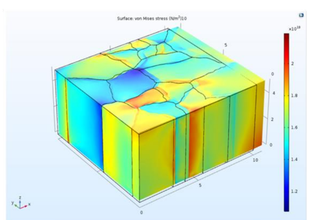
Original microstructure

Simulated microstructure

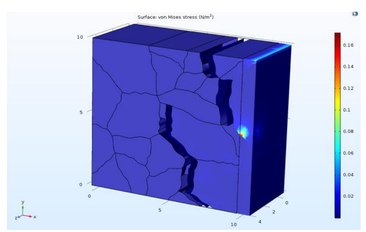
Microstructure Simulation of Thin Films

- Accurate microstructure simulation is important for FEM modeling of thin films
  - Mechanical properties: Young's modulus, Poisson's ratio, fracture strength
  - Thermal stress and mechanical stress distribution

Stress distribution of silicon thin films



Crack propagation of silicon thin films



Grain size distribution (Gamma)

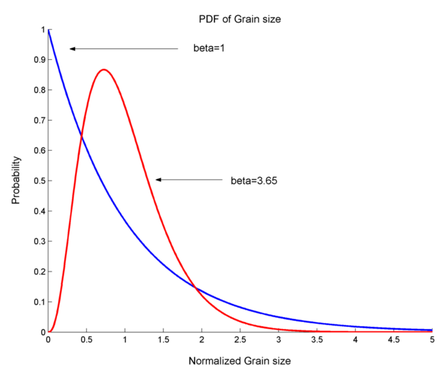
$$P(A') = \frac{\beta^{\beta}}{\Gamma(\beta)} A'^{\beta-1} e^{-\beta A'}$$

A': is the normalized grain size

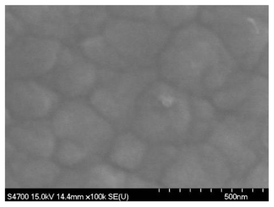
β (Beta): Shape parameter
1<= β <=3.65

β=1 represents continuous nucleation (i.e. 1 nuc/step)

β=3.65 represents site saturation (Voronoi)

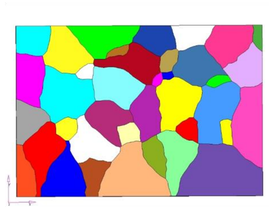


General Microstructure Simulation

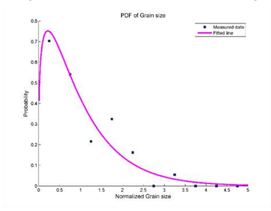


Input Micrograph
(37 grains, 12.7 X 8.83 μm)

For a given micrograph, simulation has the same number of grain



Simulated Microstructure (37 grain)

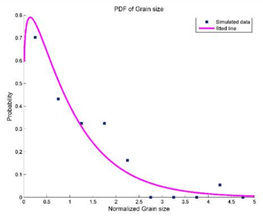


Beta=1.28

Grain Size Distribution

↓

Gamma Distribution



Beta= 1.20

Microstructure Simulation of Thin Films

- Nucleation rate (Ohring)

$$\dot{N} = n_s \left[e^{-\frac{\Delta G^*}{kT}} \right] 4\pi r^2 \frac{\alpha (P_v - P_s) N_A}{(2\pi MRT)^{1/2}}$$

ΔG^* : free energy barrier to nucleation process
ns : density of all possible nucleation sites
K = Boltsman constant
T: temperature
r : radius of critical nuclei
R : Gas constant
α: sticking coefficients
P_v : Pressure of the supersaturated vapor
P_s : Pressure above solid
M = Molecular weight
N_A = Avogadro number

- Growth rate (Ohring)

$$\dot{G} = \frac{k_s h_g C_g}{(k_s + h_g) N_0}$$

$$k_s \propto e^{-(E/RT)}$$

E : characteristic activation energy
Ks=rate constant for surface reaction
hg = gas phase mass transfer coefficient
Cg = Gas concentration
$N0$ = atomic density

M. Ohring, *Materials Science of Thin Films*, Second ed: Academic Press, 2002.

Microstructure Simulation of Thin Films

- Nucleation and growth rate are not easy to be calculated analytically
- Based on experimental findings and Ohring's equation, nucleation rate and growth rate is formulated
  (Nucleation density and grain radius as a function of time at 620, 660, and 750 ℃ at 20 mTorr, 1mTorr=0.1Pa)

$$\dot{N} = [-0.000744 * (T) + 5.058] * P \quad \textbf{(Nuclei/ μm²/sec)}$$

$$\dot{G} = 0.01922 * (T) - 11.57 \quad \textbf{(nm/sec)}$$

T **: Temperature (℃), 620 ℃ <= T <= 750 ℃**

C. Basa, M. Tinani, and E. A. Irene, "Atomic force microscopy and ellipsometry study of the nucleation and growth mechanism of polycrystalline silicon films on silicon dioxide," Journal of Vacuum Science & Technology A, vol. 16, pp. 2466-2479, 1998.

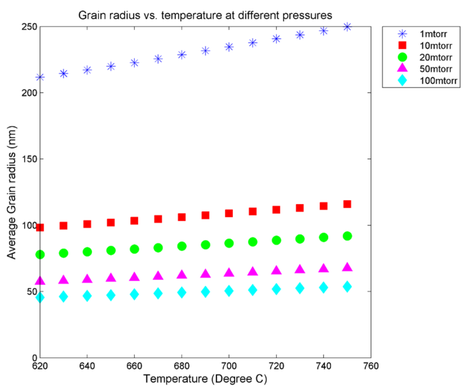
Microstructure Simulation

- Grain size (lg)

$$l_g = 0.9 \left(\frac{\dot{G}}{\dot{N}} \right)^{1/3}$$

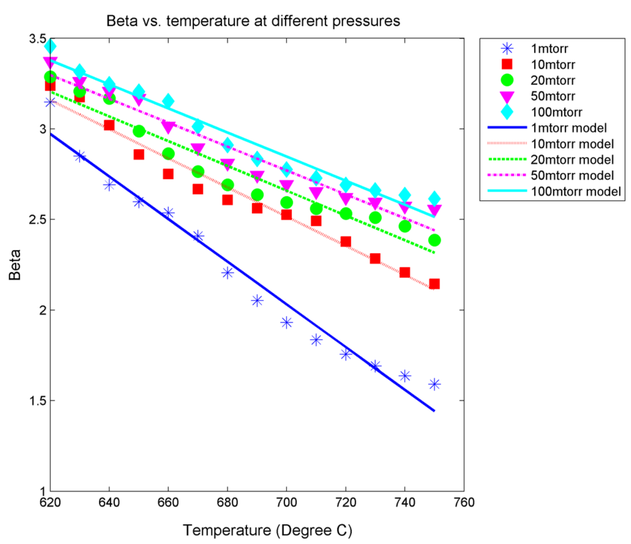
$$\frac{l_{g1}}{l_{g2}} = \left(\frac{P_2}{P_1} \right)^{1/3}$$

P: Pressure



M. Ohring, *Materials Science of Thin Films*, Second ed: Academic Press, 2002.

Simulation results (Grain size distribution)



Conclusion and Future Work

- Microstructures of polycrystalline thin films are simulated controlling nucleation rate and growth rate during deposition process
  - Grain size distribution can be controlled
- The influence of temperature and pressure on the grain size as well as the grain size distribution is analyzed

Probing residual stress evolution in crystalline silicon cells using synchrotron X-ray micro-diffraction

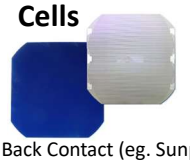
- Enabling thin silicon solar cell technologies for next-generation solar PV systems

A.S. Budiman [1*], **Sasi K. Tippabhotla [1]**, I. Radchenko [1], N. Tamura [2]

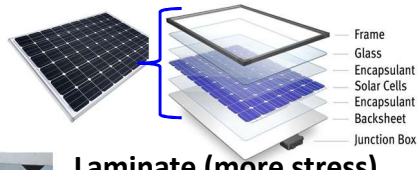
[1] Xtreme Photovoltaics (XPV) Laboratory, Singapore University of Technology and Design, Singapore
[2] Advanced Light Source, Lawrence Berkeley National Laboratory, Berkeley, USA
* suriadi@alumni.stanford.edu

Introduction : Stressful journey of cells to modules

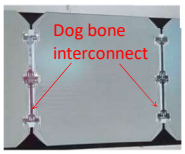
Cells



Back Contact (eg. Sunpower)



Soldering ~ 220^{0}C



Soldered cells (some stress)

Lamination ~ 150^{0}C, 0.1 MPa

Laminate (more stress)

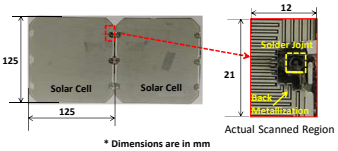
- Crystalline Si cells crack near interconnects in photovoltaic (PV) modules [1]
- Cracking is severe for thin c-Si solar PV [2]
- The origin of cracking is tensile residual stress in Si near interconnects [2]
- Residual stress in Si is developed during module fabrication due to mismatch of coefficients of thermal expansion (CTE) for different PV components:
  - Soldering: CTE mismatch between Si cell and soldered interconnects [3]
  - Lamination: CTE mismatch between Si cell, encapsulant and glass [4]

Effect of soldering induced bowing/warpage of the cell on cell residual stress during lamination was not studied

Mechanics of residual stress evaluation from soldering to lamination

Synchrotron X-ray Micro-diffraction (μSXRD) Experiment

Soldered cells (before lamination)

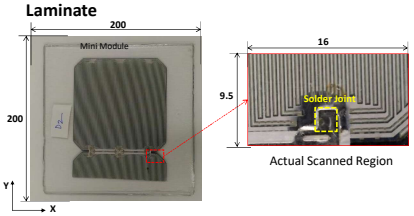


* Dimensions are in mm

Actual Scanned Region

Silicon cell thickness ~180 μm

Laminate



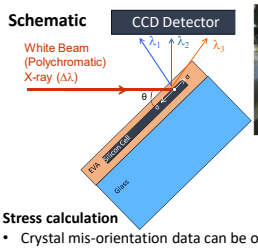
Actual Scanned Region

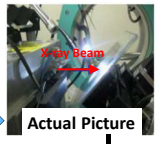
Lamination Process:

Polymer: EVA
Temperature: 150 ^{0}C
Vacuum Pressure: 0.1 Mpa
No back-sheet was used

μSXRD Experimental Setup

Schematic





Actual Picture

μSXRD Highlights:

- Experiments were conducted at Beamline 12.3.2 of ALS, LBNL Berkeley, CA., USA
- High energy (5-26 keV) beam of dia 0.8 μm can penetrate the encapsulated solar cell sample to get silicon Laue diffraction data, recorded by 2D CCD detector [7]
- Stress can be determined by analyzing diffraction peaks

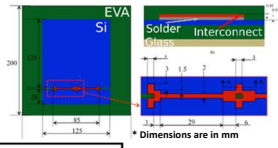
Stress calculation

- Crystal mis-orientation data can be obtained via μSXRD [5]
- The cell curvatures can be calculated from the crystal plane mis-orientations thus obtained.
- The theory of thin plates can be used to calculate the cell bending strains from respective curvatures, thus stress can be calculated.

Curvature, $\kappa = \frac{d\varphi}{dS}$ Where, φ is mis-orientation angle and S is special coordinate

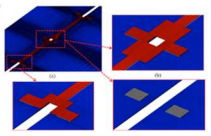
3D Finite Element Simulation of Module Integration

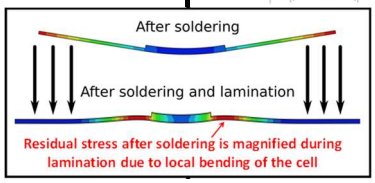
3D FE model details



* Dimensions are in mm

Mesh details around solder joint





Material Properties:

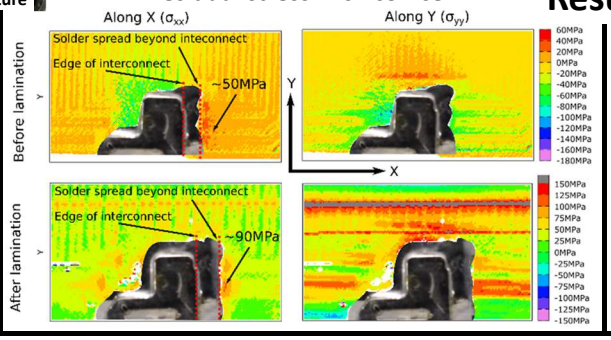
Silicon: Anisotropic elastic
EVA: Elastic, Temperature dependent
Glass: Isotropic Elastic
Cu Interconnect: Isotropic elastic-plastic
Solder (Sn-Ag): Isotropic elastic

Simulation Steps:

1. Soldering of cell & interconnect @ 210 ^{0}C
2. Lamination:
   a. Preheating to 50 ^{0}C
   b. Vacuum pressure (0.1 Mpa) application
   c. Heating to lamination temperature, 150 ^{0}C
   d. Cooling to room temperature

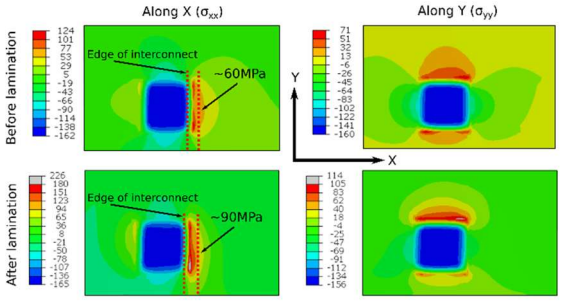
FE Solver: ABAQUS 6.14 [6]

Residual stress in silicon cell



Results

Residual stress in silicon cell



Conclusions

- μSXRD was used to find residual stress in soldered and laminated solar cells. It shows significant stress increase after lamination
- The fundamental physics of the residual stress evolution in the silicon solar cells was explained by FE analysis.
- The local cell curvature near the solder joint was found to be the actual reason for high residual stress after lamination
- FE simulations demonstrate a good agreement with results of μSXRD, except effects of metallization.

References

1. Sander et al., Proceedings of SPIE –The International Society for Optical Engineering, 2011.
2. Pingel et al., Proc. 24th European Photovoltaic Solar Energy Conf., Hamburg, Germany; 2009, pp. 3459-3463.
3. Chih-Hung Chen et al., "Residual Stress And Bow Analysis For Silicon Solar Cell Induced By Soldering", (http://140.116.36.16/paper/c38.pdf).
4. Guohui Sun et al., Advanced Materials Research Vols. 97-101 (2010) pp 2699-2702.
5. Tamura N., XMAS: A Versatile Tool for Analyzing Synchrotron Xray Microdiffraction Data,Chapter-4 of Strain and Dislocation Gradients from Diffraction, World Scientific, 2014.
6. ABAQUS 6.14, SIMULIA, Dassault Systems Simulia Corp., 2015.
7. A. S. Budiman et al., SOLMAT 2014

Acknowledgements

Singapore National Research Foundation *(Grant No. NRF2013EWT- EIRP002-017)*
Advanced Light Source, Lawrence Berkeley National Laboratory, Berkeley, CA.
Sunpower Corporation, CA, USA
Center for Solar Photovoltaics (CPV), Surya University, Indonesia

Phantom Inhomogeneities in CdTe PV Devices as Seen by Electroluminescence

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Introduction

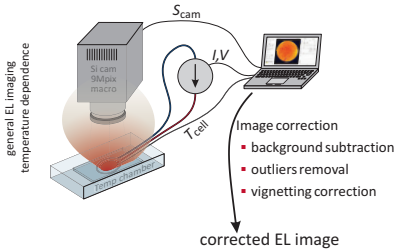
In research of CdTe PV devices with electroluminescence (EL) we observed different forms of extremely bright inhomogeneities. They appeared as bright rings around small circular laboratory cells and as bright lines in commercial PV modules.

Phantom inhomogeneities are temperature dependent and disappear above certrain temperautre threshold.

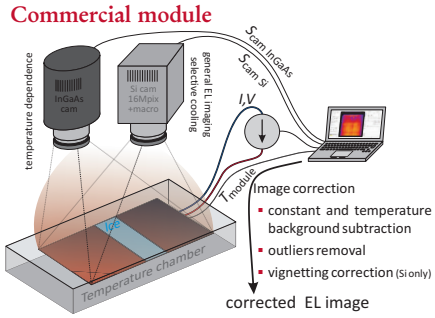
Experimental

Electroluminescence

Small circular laboratory cell

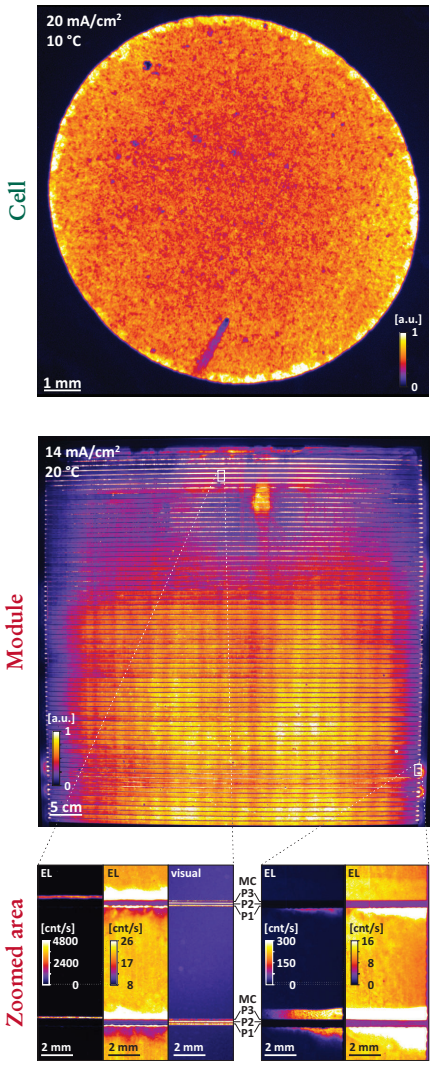


Commercial module

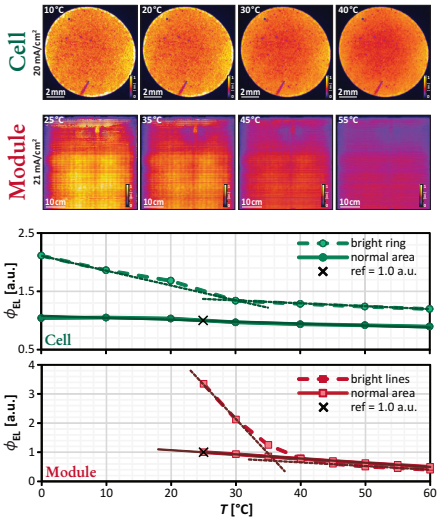


Results

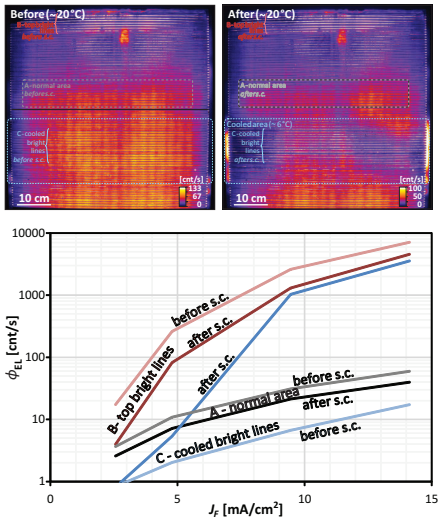
Extremely bright EL



Temperature dependence



Selective cooling (s.c.)



Conclusion

Phantom inhomogeneities appear in EL as:

- bright ring around the circular CdTe cells
- bright lines along- and dots at the end of the monolithic contacts in CdTe modules

The exact shape of the inhomogeneities may be defined by the grainy CdTe structure.

Bright lines appear on the cell's active area near the P3 cut where the local voltage is the highest.

The inhomogeneities are highly temperature and injection dependent. The threshold at 20 mA/cm² forward bias is 30 and 35 °C in the cell and in the module, respectively.

Normally unaffected areas exhibit these inhomogeneities when cooled.

Based on the results so far, we correlate the temperature-conditioned bright EL inhomogeneities with the break down of the back contact barrier which exists between the CdTe and the metal back contact.

Acknowledgments

- Slovenian Research Agency
  - Research Programme P2-0197, Project J2-7105
  - Bliateral Project Bi-US/15-16/008
- EU Social Fund and Slovenian Ministry of Education, Science and Sport
  - Post-doc funding for M. Bokalič (UL FE-664)
- Materials Engineering Laboratory, Colorado State University
  - Cell fabrication
- Forschungszentrum Jülich
  - Temperature dependent module measurements

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Fraunhofer USA

FRAUNHOFER CENTER FOR SUSTAINABLE ENERGY SYSTEMS - CSE

Glass-less, Frame-less, Lightweight c-Si Module Durability and Robustness Testing: A Survey

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MOTIVATION

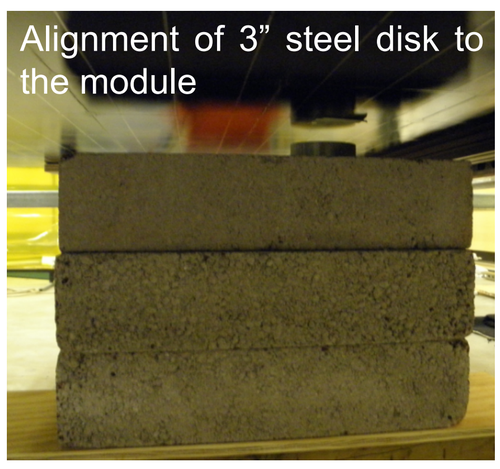
An increasing number of PV module start-up companies have developed glass-less silicon modules recently.
By replacing the glass front sheet with a thin transparent polymer sheet and using a rigid back panel instead of an aluminum frame, the module weight can be reduced by as much as 85 % compared to a conventional PV module.
While this approach has many advantages including the reduction of transportation costs and installation time as well as enabling new mounting approaches questions about the durability and robustness of these modules need to be addressed.

APPROACH

Custom-designed robustness and durability tests evaluated sensitivity to damage during the installation process and operation in the field.

Overview of tests

Durability Tests	DH1000
	TC500
	Hail +TC50
	Junction Box adhesion
Robustness Tests	Bending Test (Up/down; center/edge)
	Localized Pressure Test



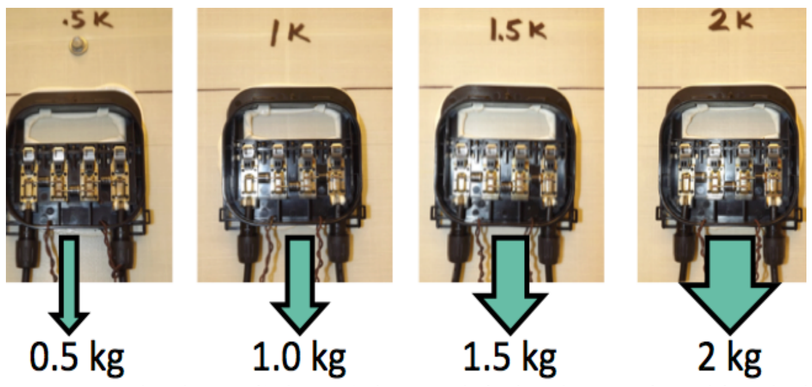
Test set-up of a localized pressure test: Load application with an instrumented pallet jack: load is applied from below by the pallet jack. A 3 inch disk is pressed against the module until the required pressure reading is reached on the screen. The localized pressure test simulates a 200 lb person standing on the module. The disk was located in the most sensitive location: at the center of the cell and at the edge of a shingle tab.

Test set-up of bending test

RESULTS

Summary of module durability test results

	Post-(Hail+TC50)	TC500	DH1000
Manufacturer a	Passed ΔP = 0	1 Failure (burnt diode) 2 passed with ΔP = +2.0%	Passed ΔP = -1.3%
Manufacturer b	Passed ΔP = -1%	Failed (ΔP = -90%) Cracking	Failed (-80%) Cracking
Manufacturer c	Passed ΔP = -0.5%	Passed ΔP = +0.7%	Passed ΔP = -2.1%



Junction boxes attached to a lightweight module back-panel and loaded with increasing weights. Samples from all three lightweight module manufacturers did not show any slippage after TC500 and DH1000.

No slippage of the j-boxes was observed after either TC500 or DH1000 exposure.

Summary of module robustness test results

	Bending: Face-Up	Bending: Face-Down	Localized pressure test
Manufacturer a	Passed ΔP <-0.5%	Passed ΔP < -1.2%	Passed ΔP < -1%
Manufacturer b	Passed ΔP < -4%	Passed ΔP < -1.6%	Passed ΔP < 2%
Manufacturer c	Passed ΔP = -0.5%	Passed ΔP <-0.5%	Passed ΔP <-0.5%

CONCLUSION

Durability and robustness testing on several lightweight (glass-less, frame-less) modules showed both the potential as well as some of the current technical challenges. One vendor’s modules suffered from a manufacturing defect. All modules exhibited cell cracking after hail testing. Despite these issues all modules exhibited <5% power loss after robustness testing and one manufacturer’s modules also showed <5% power loss after durability testing. Acceptable lightweight module lifetime will need to be demonstrated with extended indoor and outdoor testing.

This work was supported by the Department of Energy under Award Number DE-EE0006035 Plug and Play PV Systems for American Homes.

Simulation of Shading Induced Hotspots in PV Modules

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Abstract

- Partial shading causes heating of cells in PV modules.
- Heat is dissipated in the shaded cell under reverse bias.
- We present a method for solving cell temperature.
- Stage 1 predicts the uniform temperature by referencing NOCT.
- Stage 2 predicts the non-uniform temperature by thermal modeling with local heat determined using Electroluminescence (EL) images.

'Hotspot Effect'

Commercial PV modules with 60/72 series-connected cells and 3-string design can experience 'Hotspot Effect' due to cell current mismatch under partial shading or from cell damages.

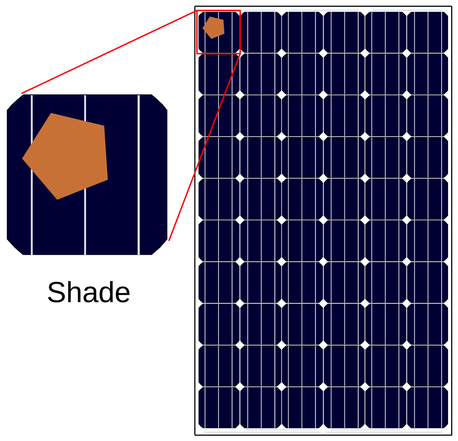

Figure 1. Typical partial shading condition potentially causing the 'Hotspot Effect'

Cell *IV* simulation

PV module mismatch simulation in MATLAB and Excel[1]

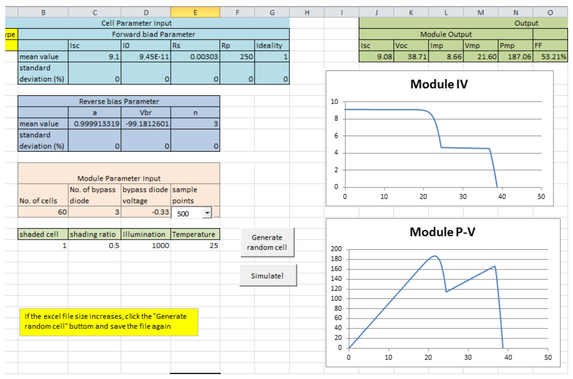

Figure 2. Screenshot of module mismatch simulation tool in Excel

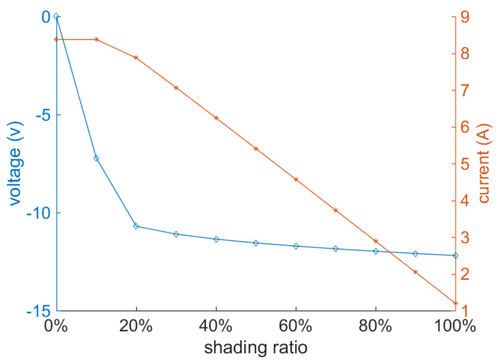

Figure 3. Simulated shaded cell operating *IV* with string MPP tracking

Three-path heat dissipation

- $\dot{Q}_{\mathrm{light}}$ is homogeneous across un-shaded area
- $\dot{Q}_{\mathrm{ph}}$ mapped using MPP EL image
- $\dot{Q}_{\mathrm{rev}}$ mapped using Reverse Bias EL image

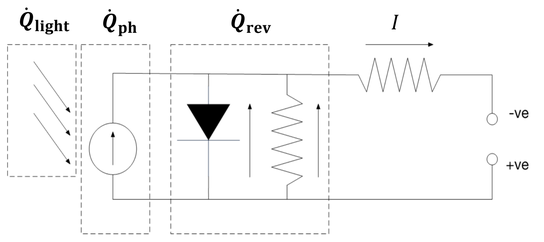

Figure 4. Three heat sources of cell under reverse bias

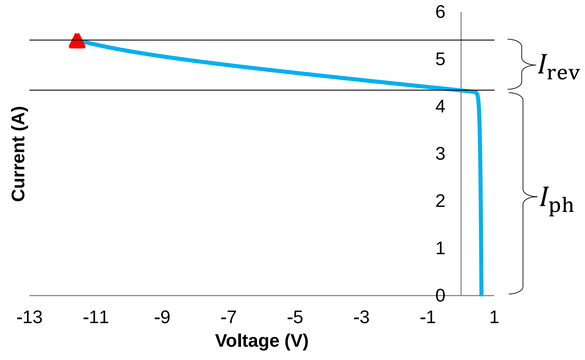

Figure 5. Two components of current through the 50% shaded cell in a module

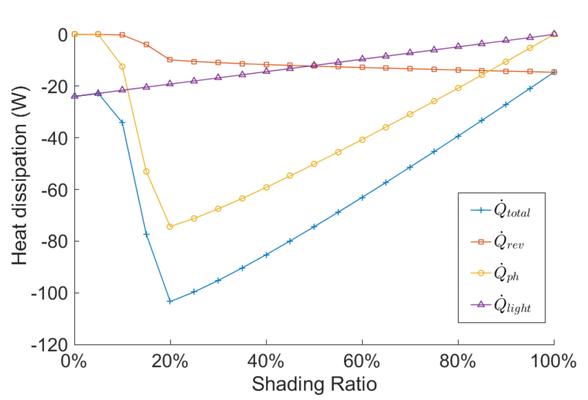

Figure 6. Simulated heat generation via three paths under different shading ratio

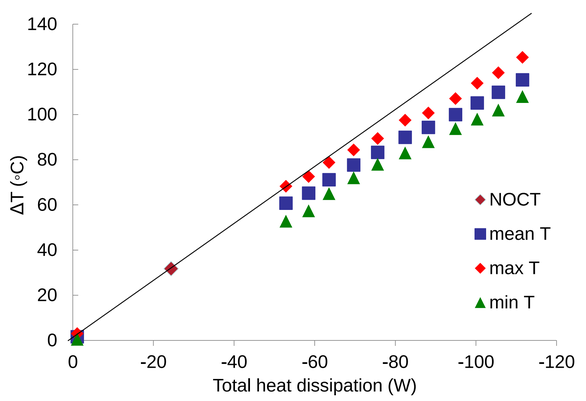

Figure 7. Measured temperature difference (with air) versus NOCT for reverse biased cell with uniformly heat distribution

- Uniform distributed heat source: cell temperature can be predicted with NOCT and heat simulation

Non-uniform heating

- Non-uniform distributed heat source with partial shading: use EL image to map local heat generation

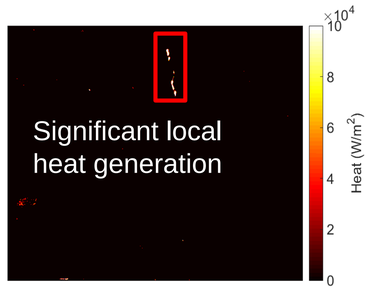

Figure 8. Local heat source by I_{rev} mapped using reverse bias EL image

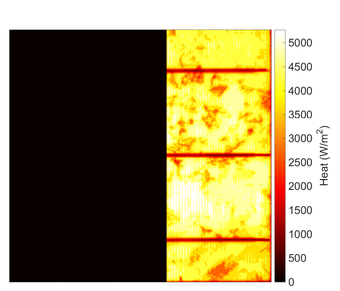

Figure 9. Heat source by I_{ph} mapped using forward EL image

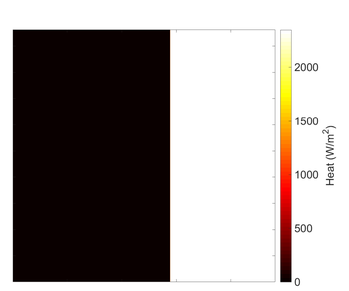

Figure 10. Uniform heat source from solar irradiance

- 2D thermal simulation with uniformly reduced irradiance and reverse voltage from *IV* simulation
- Temperature measurement captured using infrared camera

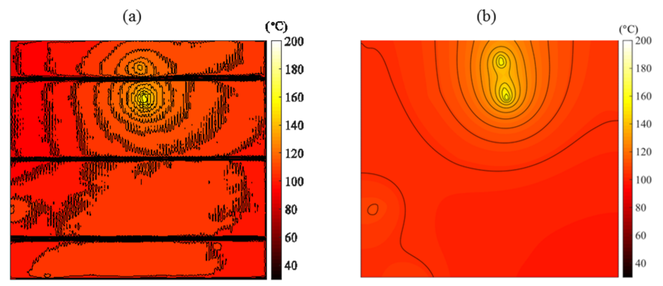

Figure 11. Measured temperature of a reverse biased cell (a) compared with the simulation results (b)

This Program has been supported by the Australian Government through the Australian Renewable Energy Agency (ARENA). Responsibility for the views, information or advice expressed herein is not accepted by the Australian Government.

[1]Jiadong (Harry) Qian, Andrew Thomson, Andrew Blakers, Elissa Tokusato, Marco Ernst, Ingrid Haedrich, *'A PV Module Current Mismatch Simulation Model and Application to Bifacial Modules'*, Proc. APSRC 2016

Correlating Infrared Thermography with Electrical Degradation of Modules inspected in All India Survey of Photovoltaic Module Reliability 2016

Sonali Bhaduri[1], Shashwata Chattopadhyay[1], Rajiv Dubey[2], Sachin Zachariah[2], Vivek Kuthanazhi[2], Chetan S. Solanki[1], Brij M. Arora[2], K. L. Narsimhan[2], Anil Kottantharayil[2], Juzer Vasi[2]

[1]Department of Energy Science & Engineering, Indian Institute of Technology Bombay, Mumbai, 400076, India

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Introduction

- In the All India Survey of Photovoltaic Module Degradation 2016 [1], 925 numbers of PV modules were inspected in 37 sites spread across 6 different climatic zones of India.
- Current-Voltage *(I-V)* characterization was done using Solmetric PVA-1000S *I-V* tracers, and important parameters like plane of array irradiance, module temperature, ambient temperature and humidity level was also recorded.
- Infrared (IR) thermography was performed (using FLIR E-60 camera) under both operating condition (MPPT) and short-circuit condition.

Methodology

Analysis of *I-V* data

- The analysis of the *I-V* data has been presented in details elsewhere by Dubey *et al.* [1], so an overview is being presented here.
- The *I-V* curves were translated to STC condition using a simplified version of **IEC 60891 translation procedure 1** (by assuming the series resistance and the curve correction factor as zero).
- The tolerance band in the nameplate power ratings have been considered in determining the nominal ratings [1], based on which the degradation rates have been calculated.

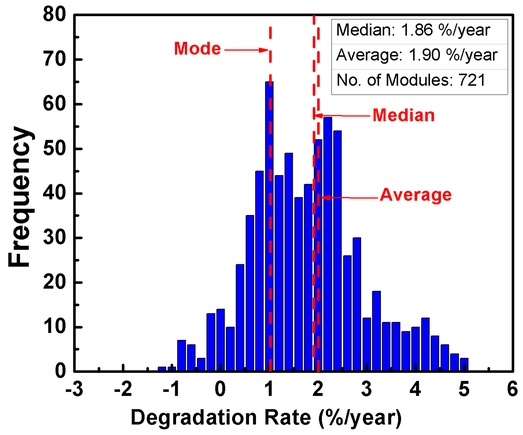

Fig. 1. Histogram of the Pmax degradation rates of crystalline silicon modules inspected in the survey

Analysis of IR data

- The IR thermographs usually contain not only the module of interest but many other surrounding objects. First the temperature matrix is extracted from the thermal image (using FLIR software). Then, separate software (developed in-house in Matlab) is used to select the region of interest from the IR temperature matrix (Fig. 3a), and it saves the histogram of the cropped region, as shown in Fig. 3b.

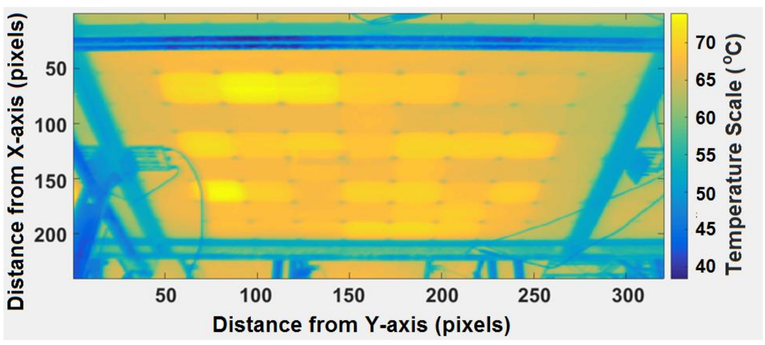

Fig. 2. IR image of PV modules in a power plant. The plane of array irradiance was 870 W/m^2 and the ambient temperature was 42.6 °C

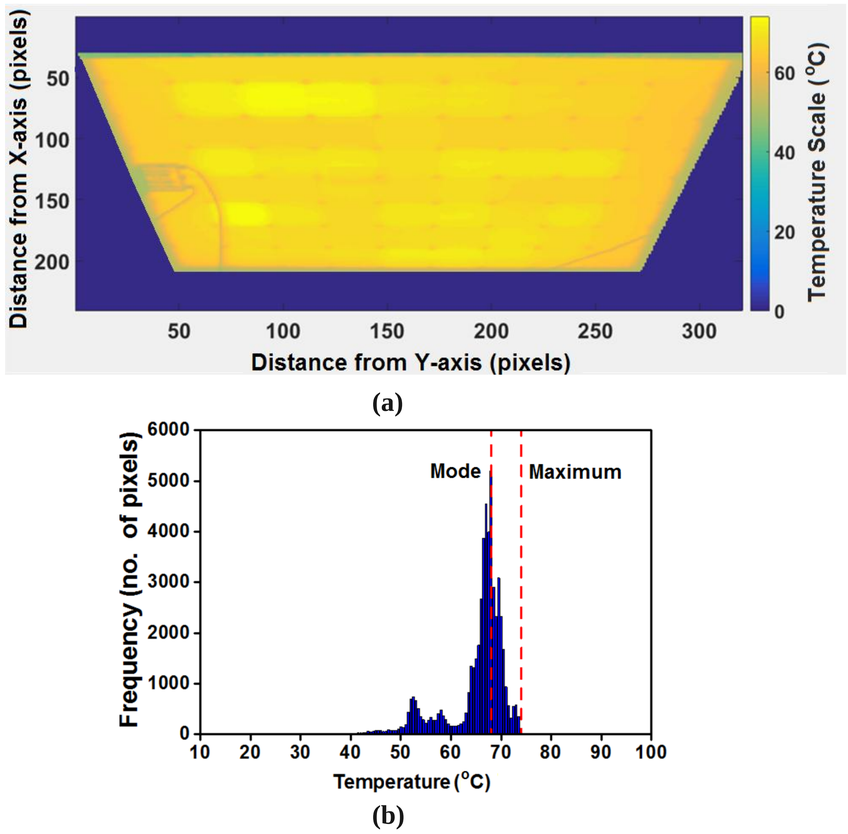

Fig. 3. (a) Region of interest cropped from the IR image shown in Fig. 2, and (b) Temperature histogram of the module, showing distinct sections of the module support and ambient (the low temperature humps), and the module backsheet (the high temperature hump).

- The extent of mismatch in the temperature of different parts of the module has been quantified using the following relation [2][3]:

$$Module\,\Delta T = T_{max} - T_{module}$$

where,

T_{max}= maximum cell temperature of the module

T_{module}= modal temperature of the module

- Based on the works of Moreton *et al.* [2] and Oh *et al.* [4], the *Module* ΔT is translated to 1000 W/m^2 irradiance using the following relation:

$$Module\,\Delta T^* = Module\,\Delta T \text{ x } 1000 / G$$

Where,

Module ΔT^* = translated *Module* ΔT

G = plane of array irradiance at the time of measurement

Results

Effect of *Module* ΔT^* on Degradation Rate

- The modules have been grouped into 3 categories based on the translated *Module* ΔT – (a) 0-5 °C (b) 5-10 °C (c) >10 °C
- Fig. 4 shows the variation of the P_{max} degradation rate with the translated *Module* ΔT, for both MPPT condition and short-circuit condition. The power degradation rate is higher for modules having higher degree of temperature mismatch (higher *Module* ΔT^*) .
- Fig. 5 shows the degradation rates of various electrical parameters for the different categories of temperature mismatch. The fill factor (*FF*) degradation is the largest contributing factor to P_{max} degradation in modules with higher temperature mismatch.

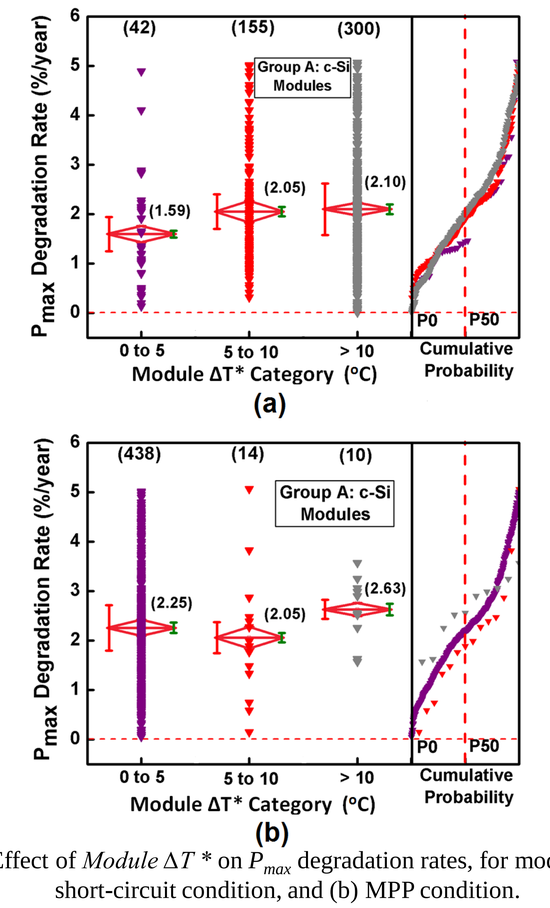

Fig. 4. Effect of *Module* ΔT * on P_{max} degradation rates, for modules at (a) short-circuit condition, and (b) MPP condition.

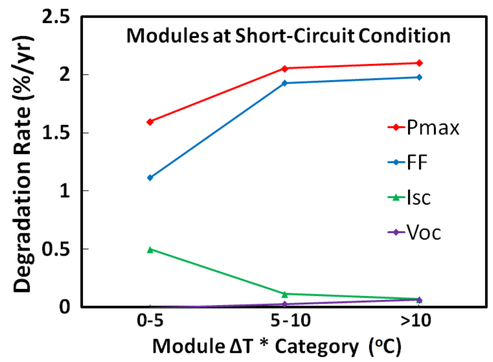

Fig. 5. Effect of *Module* ΔT * (under short-circuit condition) on electrical parameter degradation rates

Conclusions

- IR data analysis software developed in-house has enabled us to analyze the EL images of hundreds of modules within a short time.
- The power degradation rates are higher for modules with higher temperature mismatch between the cells.
- The major contributing factor to the higher power degradation is the fill factor (*FF*) degradation. This is likely to be due to high temperature differences leading to electrical mismatch between the cells which is showing up as *FF* degradation.

References

[1] R. Dubey *et al.*, "Performance of field-aged PV modules in India: Results from the 2016 All India Survey of Photovoltaic Module Reliability", submitted to *44th IEEE Photovoltaic Specialists Conference*, Washington DC, 2017

[2] R. Moreton *et al.*, "Dealing in Practice with Hot Spots," in *Proceedings of the 29th European Photovoltaic Specialists Conference*, Amsterdam, 2014.

[3] S. Chattopadhyay *et al.*, "Effect of Hot Cells on Electrical Degradation of PV Modules," presented at NREL PVMRW, Denver, 2016

[4] J. Oh and G. TamizhMani, "Temperature Testsing and Analysis of PV modules per ANSI/UL 1703 and IEC 61730 standards", in *Proceedings of the 35th IEEE Photovoltaic Specialists Conference*, Honolulu, 2010.

Acknowledgements

This paper is based upon work partly supported under National Centre for Photovoltaic Research and Education (NCPRE), through funding from MNRE, Govt. of India, and partly under the US-India Partnership to Advance Clean Energy-Research (PACE-R) for the Solar Energy Research Institute for India and the United States (SERIIUS), funded jointly by the U.S. Department of Energy (Office of Science, Office of Basic Energy Sciences, and Energy Efficiency and Renewable Energy, Solar Energy Technology Program, under Subcontract DE-AC36-08GO28308 to the National Renewable Energy Laboratory, Golden, Colorado) and the Government of India, through the Department of Science and Technology under sub-contract IUSSTF/JCERDC-SERIIUS/2012 dated 22nd Nov. 2012. The authors would also like to acknowledge the help and support of the All India PV Survey team members, including students and staff from the National Institute of Solar Energy (NISE) and the Indian Institute of Technology Bombay (IIT Bombay), India.

Evaluation of Cell Cracking Risks Beyond Certification in Crystalline and Thin-Film PV Modules

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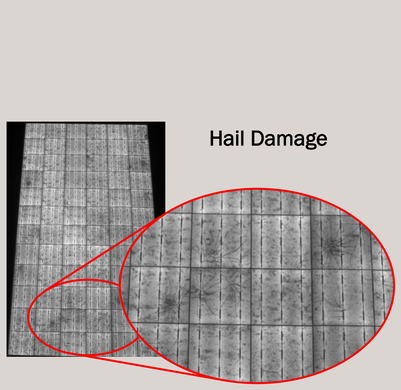
Typical module qualification and certification standards for terrestrial non-concentrating PV modules are not sufficient to protect module end-customers from power loss due to cracking of crystalline silicon cells.

Increased usage in applications where modules are installed on center-mount tracking structures can increase risk of dynamic loading exposure.

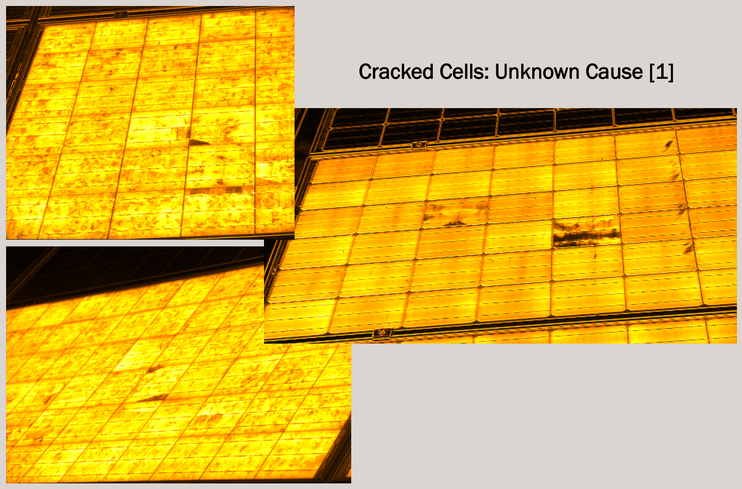
Monolithically integrated technologies (i.e. thin-film) are not susceptible to this type of failure mode.

Observed Field Issues

Hail Damage



Cracked Cells: Unknown Cause [1]



Dynamic Mechanical Loading:

Dynamic mechanical loading has recently been added as a technical specification in IEC 62782:2016.

HOWEVER:

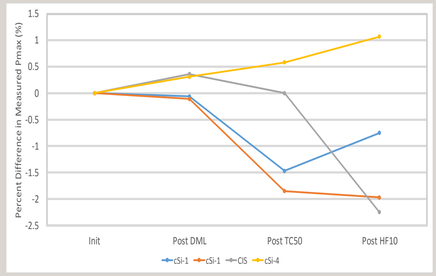
- Prior to the issuance of the TS 62782 standard many independent agencies used unique stress conditions, and have yet to consolidate on harmonized conditions.
- The critical steps of stressing the module after loading are only listed as an appendix, and not required.
- The critical portion of the various test methods is to follow the mechanical loading with temperature and/or humidity stressing. It has been shown [4] that power loss may not be evident with mechanical loading by itself, but when paired with environmental cycling, power loss is demonstrated.

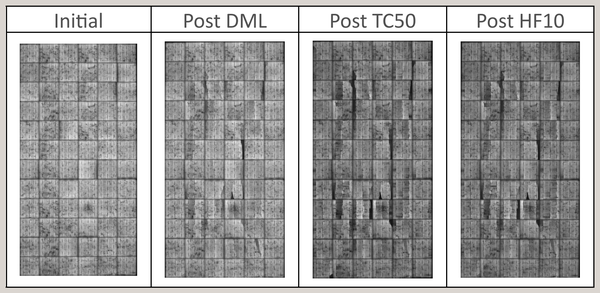
Inconsistency in Stress Levels:

- While dynamic mechanical loading was recognized very early in the development of commercial PV (as early as 1977 [3]), it has only recently been adopted as a standard test protocol.
- Several independent laboratories and institutes have included a dynamic loading cycle into their comparative programs. Notable among these are DNV GL PVEL's Product Qualification Program, and Fraunhofer-CSE's PV Durability Initiative. In addition, a stand-alone standard (IEC 62782) has been published specifying a method of dynamic loading.
- **Despite the new standard, specifications for dynamic mechanical loading varies, leading to confusion among end customers.**

A comparison of Specifications for Dynamic Mechanical Loading

Doc/Program	Pre-Sequence	Temp (°C)	Load (Pa)	Number Cycles	Cycle Rate (cycles/min)	Post-Sequence
JPL Block V / IEEE 1262	UV + TC50 + HF10	25	1440	10000	20	n/a
BP Solar		25	1000	1000	n/s	TC50 + HF10
DNV GL PVEL PQP		25	1440	1000	n/s	TC50 + HF30
Fraunhofer-CSE PVDI		-30	2400	500	60	TC50 + HF10
IEC TS 62782:2016		n/s	1000	1000	3 - 7	Suggests TC50 + HF10

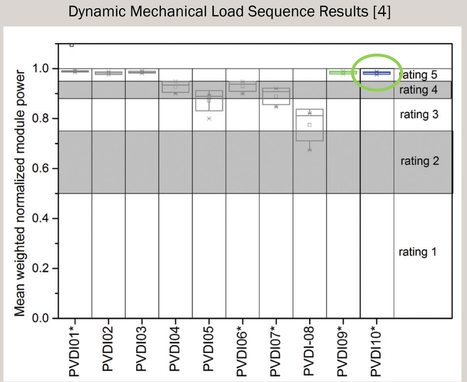




c-Si Module: Cell Cracks worsen with stress

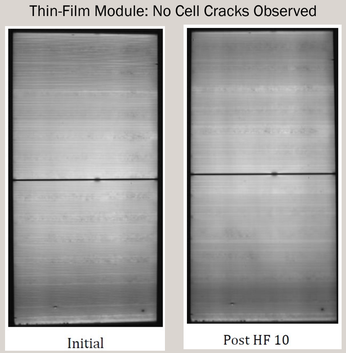
Fraunhofer PVDI

Dynamic Mechanical Load Sequence Results [4]



EL Image of Module from Fraunhofer PVDI sample 13062-07 (PVDI10)
Test sequence = DML + TC50 + HF10

Thin-Film Module: No Cell Cracks Observed

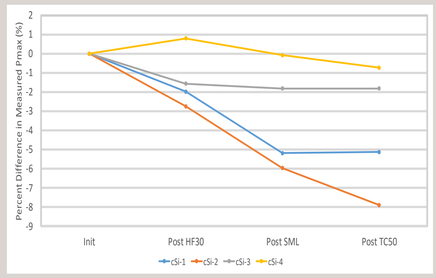


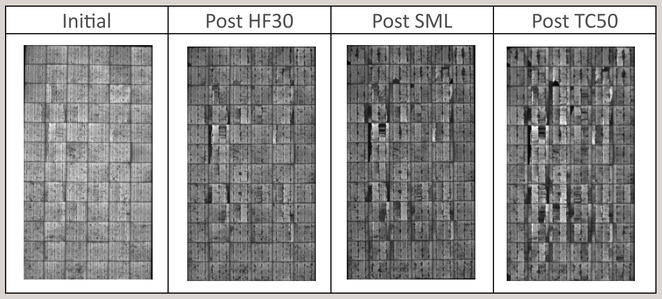
Static Mechanical Loading:

The requirement to conduct and assess performance to a static load test, has long been a certification requirement.

HOWEVER:

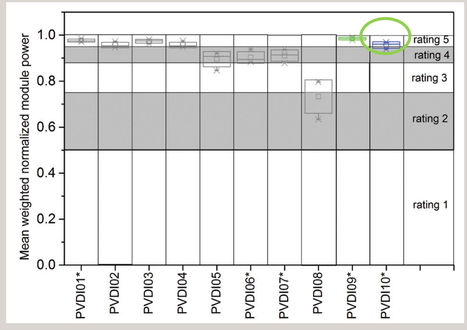
- Some manufacturers of c-Si modules show significant cell cracking and finger delamination after the basic test described in IEC 61215 10.16, Mechanical Load Test at 2400 Pa.
- The certification standard (IEC 61215) is only a pass/fail test, and does not inform buyers of how much power may be lost.





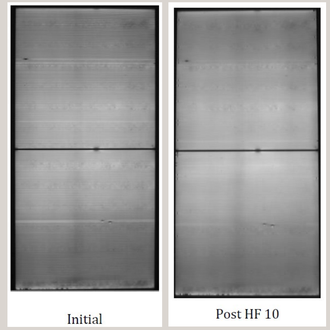
c-Si Module: Cell Cracks worsen with stress

Fraunhofer PVDI Static Mechanical Load Sequence Results [4]



EL Images of Module from Fraunhofer PVDI sample 13062-09 (PVDI10)
Test sequence = SML + TC50 + HF10

Thin-Film Module: No Cell Cracks Observed



Conclusions:

- In c-Si modules, cell cracking and its associated power loss is not comprehensively evaluated in typical industry standardized tests. Supplemental dynamic load testing and associated power loss evaluations should be employed.
- Cracked cells in c-Si modules cannot generally be seen with the eye, and require special detection methods (EL).
- Similar defects are seen in fielded modules, demonstrating the realistic nature of cell cracking induced in laboratory mechanical loading tests.
- Thin-film modules are not subject to cell cracking failure mechanisms and associated power loss.
- Non-standardized test conditions and test sequences causes confusion and uncertainty. This increases the burden for manufacturers and decreases certainty for stakeholders (customers, lenders, etc).

References

[1] Images taken by Solarzentrum Stuttgart GmbH

[2] J.H. Wohlgemuth "The effect of cell thickness on module reliability," Proc. 33rd IEEE Photovoltaic Specialist Conference, 2008.

[3] Moore, D.M., "Cyclic Pressure-Load Developmental Testing of Solar Panels", JPL Internal Document 5101-19, Jet Propulsion Laboratory, Pasadena, California, February 28, 1977.

[4] C. Schmid, R. Singh, C. Stark, and J. Ashmore. "Fraunhofer PV Durability Initiative for Solar Modules: Part 3." *PV Tech Power*. Solar Media Ltd., Sept. 2015. Web.

Modification of ZnO:Al Surfaces for Improved Lifetime Performance

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2. The National Renewable Energy Laboratory, Golden, CO, 80401

Case Western Reserve University EST. 1826 think beyond the possible

SDLE SOLAR DURABILITY AND LIFETIME EXTENSION CENTER

phys.cwru.edu/sites/morecenter Contact: ina.martin@case.edu

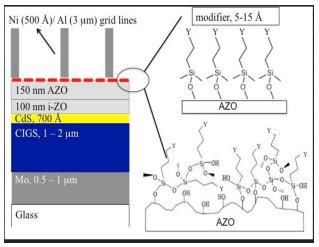
NREL NATIONAL RENEWABLE ENERGY LABORATORY

Motivation

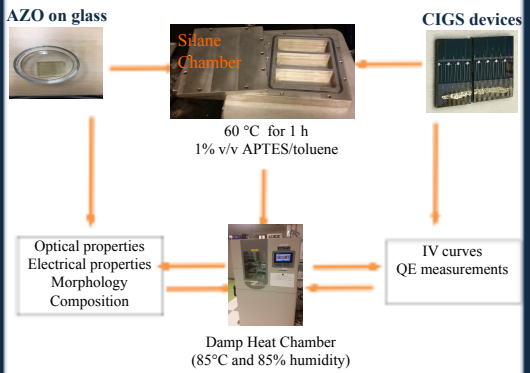
Aluminum-doped zinc oxide (AZO) degradation is a known failure mode in Cu(In,Ga)Se2 solar cells via water-induced degradation, which results in resistivity increase and delamination

Objectives

- Demonstrate modification of AZO front contacts of CIGS solar cells without significant reduction of initial performance
- Determine effect of interfacial modifiers (IFMs) on AZO film and CIGS device degradation in real world and accelerated aging conditions

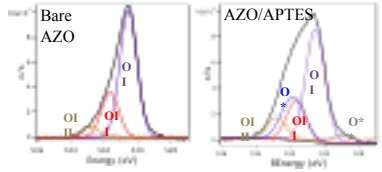


Approach



Films Results: Surface modification lessens surface and bulk AZO degradation

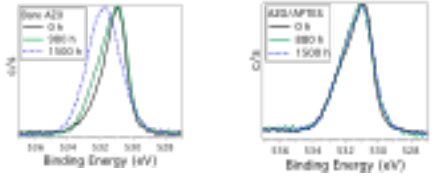
High resolution X-ray photoelectron spectroscopy (XPS) data



	Binding Energy (eV)	
	Bare	APTES
O_I	530.4 ± 0.1	530.6 ± 0.2
O_{II}	531.5 ± 0.2	531.1 ± 0.1
O_{III}	532.6 ± 0.3	532.9 ± 0.2
O*	-	531.9 ± 0.2
O**	-	529.0 ± 0.2

O 1s envelope of bare AZO and AZO/APTES, fit with component peaks

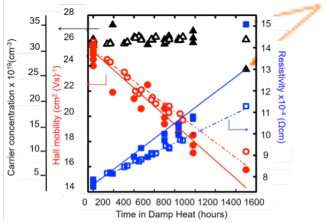
- OI: O2- in wurtzite structure
- OII: O2- in O2 deficient regions, correlated with carrier concentration
- OIII: adsorbed O-containing small molecules, correlated with degradation products and adsorbates linked to degradation
- O*: O from APTES (Si-O)

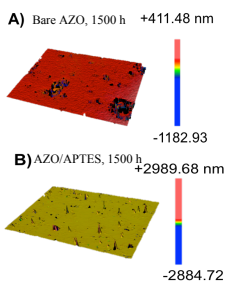


Bare AZO:

- O 1s envelope broadens and shifts to a higher binding energy w DH exposure
- @1500, cannot be fit with the method established for AZO
- Decrease in intensity at lower binding energy values is consistent with loss of OI and OII components significant degradation of the wurtzite structure

AZO/APTES: O 1s is stable up to 1500 h DH exposure





Resistivity of bare AZO, AZO/APTES increase with DH, effect mitigated by APTES

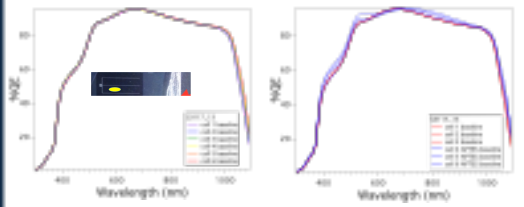
- Slope of the AZO/APTES 30% lower than bare AZO
- First 1000 h: mobility decreases and n constant for both bare and AZO/APTES

At 1500 h, bare AZO diverges from linear behavior of first 1000 h

- Mobility AND *n* decrease, ρ increases
- Optical profilometer images of bare AZO show pitting of the surface at 1500 h

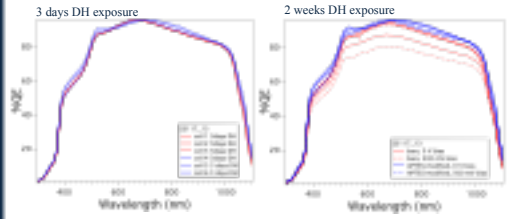
Devices : APTES lessens CIGS degradation

As-received CIGS devices — Bare and APTES-modified CIGS devices



- QE data show slightly different current based on sample position
- Adding APTES layer slight improvement in current
  35.2 mA/cm2 35.6 mA/cm2

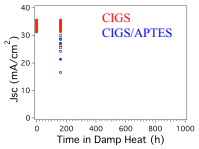
3 days DH exposure — 2 weeks DH exposure

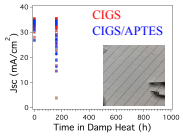


- Unmodified CIGS has 5% decrease in current after 2 weeks in DH
- APTES: 35.6 ± 0.3 mA/cm2 (at both 0 V and 500 mV bias)
- Bare: 33.5 ± 1.8 mA/cm2 at 0V bias, 32.3 ± 2.3 mA/cm2 at 500 mV bias

For unmodified CIGS, Jsc lower at 500 mV bias, increase in RS

Encapsulated CIGS Device Results





- Decrease after 1 w in DH
- Filled symbols: QE w/o bias
- Open symbols: QE @ 0.5 V

- Encapsulated samples with cracks experience more degradation

Acknowledgments

Funding:
DOE award DE-EE0007360
The CWRU College of Arts and Sciences; Undergraduate funding: SURES, Dominion, CWRU Alumni Association
This work made use of CWRU core facilities: The Materials for Opto/electronics Research and Education (MORE) Center; est. 2011 via the Ohio Third Frontier, TECH 09-021; The Solar Durability and Lifetime Extension (SDLE) Research Center, est. via the Ohio Third Frontier, Wright Project Program Award tech 12-004; The Swagelok Center for Surface Analysis of Materials (SCSAM).
Thank you to Stephen Glynn, Carolyn Beall, and Karen Bowers for device processing at NREL, and Elizabeth Hodges, Nolan Kovach and Jen Braid for device measurements at CWRU . Thank you to Jon Mackey at the Glenn Research Center at Lewis Field, NASA for use of the Hall measurement system.

Advanced Mechanical Stress Testing Using the *LoadSpot*

Eric J. Schneller[1], Andrew M. Gabor[2], Rob Janoch[2], Andrew Anselmo[2], Jason Lincoln[1], Joseph Walters[1], Hubert Seigneur[1], and Winston Schoenfeld[1]

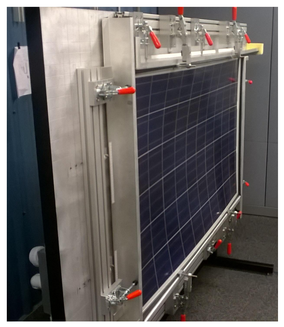
[1]*Florida Solar Energy Center, University of Central Florida, Cocoa, FL*

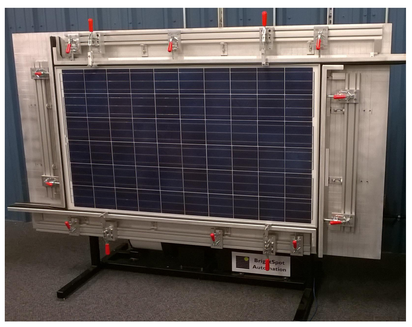
[2]*Brightspot Automation, Westford, MA*

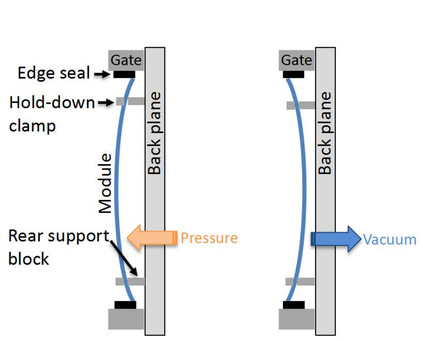
Abstract

Cell cracking presents a serious risk for the long term reliability of c-Si photovoltaic modules. Cracks may not initially result in performance loss, but over time performance may degrade as the module experiences stresses in the field such as temperature cycling and snow/wind loading. This performance loss is due to the formation of new cracks with front side loading, propagation of existing cracks, and the opening of existing cracks in which regions of the cell become more electrically isolated. This presentation will discuss the results from a new tool, the *LoadSpot*, that allows for I-V performance characterization and electroluminescence imaging of PV modules while under mechanical load. We explore how cell cracks form and open as a function of loading condition, and how these defects impact performance for several module technologies. We also present a discussion focused on how this test could be used for qualification testing and quality control in a manufacturing environment.

LoadSpot Operation







Images of the *LoadSpot* at the Florida Solar Energy Center that is coupled with a Sinton FMT-350 Module Flash Tester and a Brightspot Automation EL-Spot Electroluminescence Camera for *in-situ* characterization.

- **Applies load using either vacuum or air pressure from rear side**
- **Open front side allows for simultaneous characterization during mechanical loading**
- **Applies more uniform pressure than suction cups**
- **Capable of applying up to 5400 Pa front side load and 2400 Pa rear side load**
- **Greater than 20 cycles/min possible for Dynamic Load Testing**
- **2 Minute module change out / 30 minute new configuration changeover time**
- **All load tests in IEC 61215 and IEC DTS 62782 can be performed**

Load application method comparison

Factor	Sand Bags	Suction Cups	Air Bladder	Vacuum & Air Pressure
Static Test	Manual Flip	Auto	Manual Flip	Auto
Cyclic Test	No	Yes	One Side	Yes
Point Loading	No	Yes	No	No
Test With Racking	Top Static	Yes	Top Static	No
Parallel EL/IV	No	No	No	Yes

We can test your modules at FSEC!

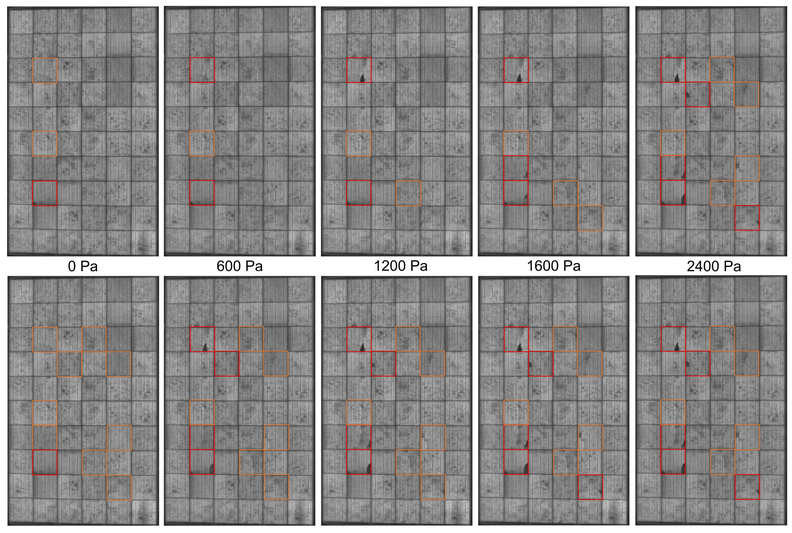
Contact Eric Schneller: eschneller@fsec.ucf.edu

or Joe Walters: jwalters@fsec.ucf.edu

Crack Generation and Crack Opening

Example 1: Multi-crystalline 60-cell Module

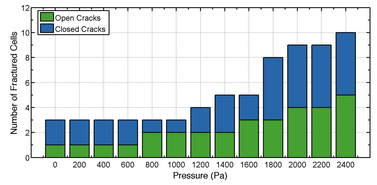
Increasing Pressure



Decreasing Pressure

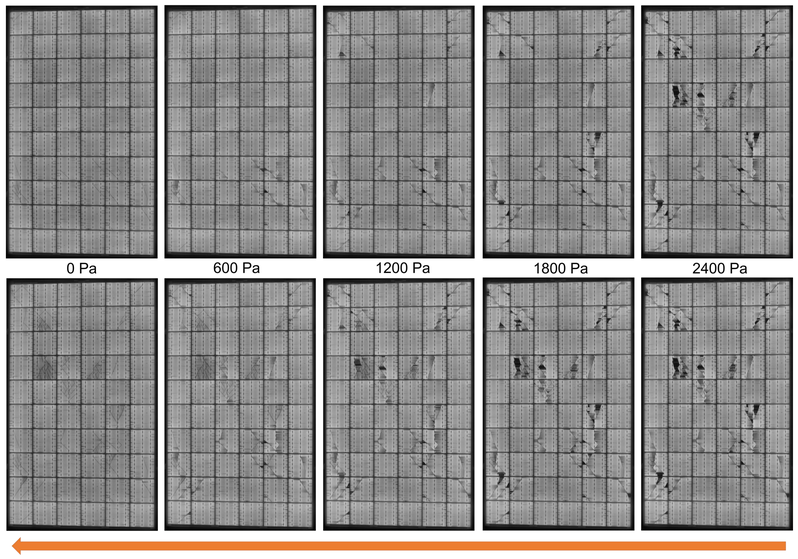
- **Diagram shows EL images with applied front side load with full perimeter support**
- **Started with 3 cracks(1 open / 2 closed)**
- **7 new cracks created up to 2400 Pa**
- **No measurable power loss between starting and final unstressed state**
- **Total test time less than 30 minutes**

Number of Cracks (Opened and Closed)



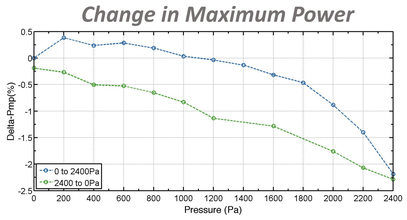
Example 2: Mono-crystalline 60-cell Module

Increasing Pressure

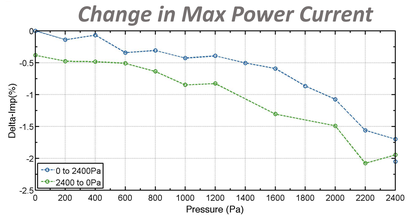


Decreasing Pressure

Change in Maximum Power

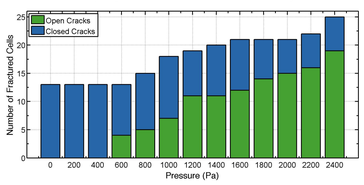


Change in Max Power Current



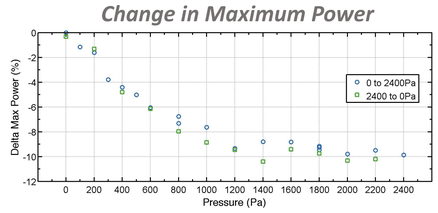
- **Module was supported at 4-points representing field mounting conditions**
- **Started with 13 cracks (all closed)**
- **17 new cracks created up to 2400 Pa**
- **Cracked generated above 2000 Pa are much more severe than cracks generated at lower pressures**
- **Less than 0.5% Power loss between starting and final unstressed state**
- **Over 2% loss between 2400 Pa and 0 Pa measurements**

Number of Cracks (Opened and Closed)

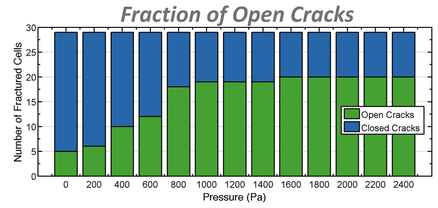


Impact of Crack Opening on Power

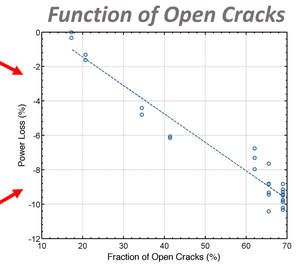
Change in Maximum Power



Fraction of Open Cracks



Power Loss as a Function of Open Cracks

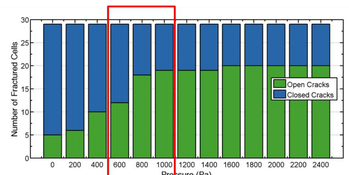


***Module Previously exposed to 5400 Pa*

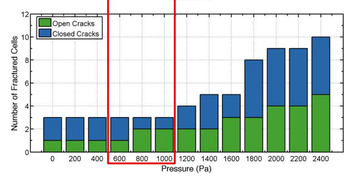
- **Strong correlation between opening of cracks and the magnitude of Power Loss**
- **Most crack are open with a front side applied pressure of 1200 Pa**
- **Power loss also stabilizes above 1200 Pa**
- **Future work will look at image analysis algorithms to quantify cracks (*e.g.* directions, distributions, impacts, etc.) and look to correlate these metrics to power loss**

Development of a Predictive Crack Opening Test

- **Cracks only have a significant impact on performance once they open up**
- **When a module is unloaded a large majority of cracks remain closed**
- **It is assumed that after several years in the field closed cracks will open up to varying degrees due to various environmental stressors**
- **A Predictive Crack Opening test (PCO Test) could be used to estimate future power loss if benign cracks were to open after exposure to environmental stress**

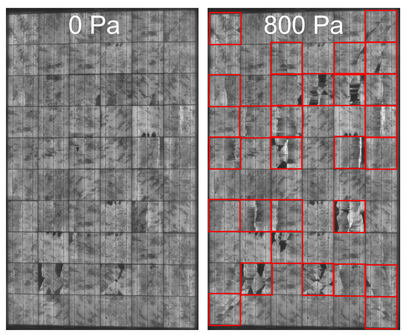


Module previously exposed to 5400Pa

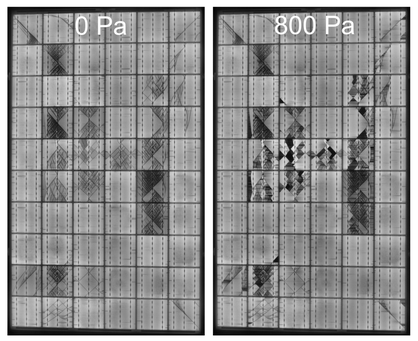


Module with no prior mechanical stress

Regime with no new cracks formed and a majority of existing cracks opened up



~7% Reduction in Power



~2.5% Reduction in Power

- **Work has begun to identify the regime in which a majority of cracks open up, without generating new cracks.**
- **The regime may change based on the cell type and module construction as well as the support. In this PCO test work we use a full perimeter support to generate a more uniform loading profile across the module area**
- **A pressure of 800Pa was identified as an appropriate load condition for the modules used in this PCO test work.**

Snail Trail Impact on Solar PV Module Performance

NREL/SNL/BNL PV Reliability Workshop 2017

Saurabh Chatterjee, Yun Lee & Matt Kumpunen — Panasonic Enterprise Solutions Company (PESCO), USA

Panasonic

INTRODUCTION

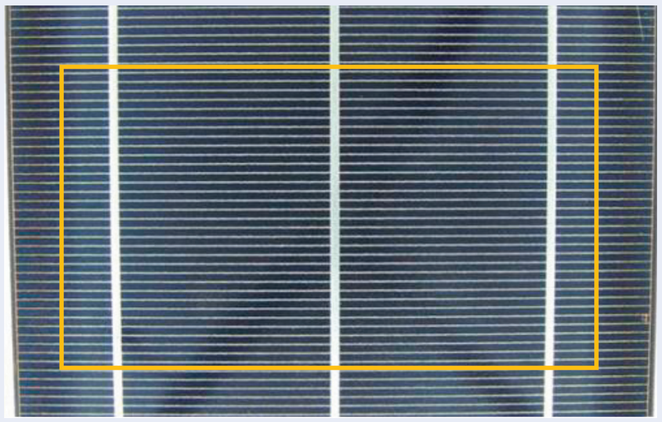
"Snail trails" are linear discolorations that appear on some solar modules, sometimes in association with micro-cracking. Their prevalence and impact on system performance over time are not well understood, representing an important area of inquiry relevant to manufacturer warranties, operations and maintenance teams, and others in the solar value chain. This research investigates the root cause and corrective action of premature module defects observed at projects primarily in the southwest United States. Typically, polycrystalline silicon module manufacturers would support an annual module power degradation rate of 0.7%, starting year two (2) after in-field deployment. Any long-term power degradation exceeding what is warranted by a module manufacturer can have a significant financial impact for the customer and diminish confidence in the technology for future acceptance and deployment. This poster discusses snail-trail-like formations observed in the field on modules, typically within their first two years of operation. We review appropriate sample sizes and durations and explore various accelerated testing protocols to capture any long-term performance degradation. Finally, we contemplate various in-field testing on installed modules under load, such as front and back visual inspections, thermal imaging, and I-V curve measurements to determine any initial power degradation that may deviate from what is warranted by the manufacturer.

METHODOLOGY

1. SAMPLE SIZE

Assume a sample size of 16 modules:

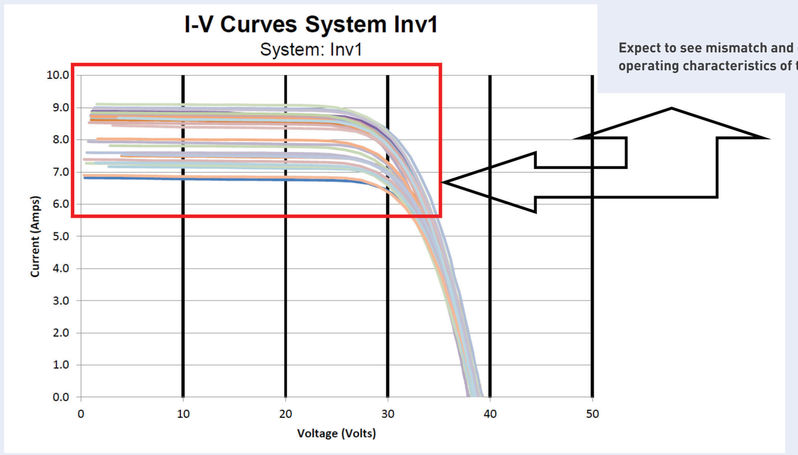
- 10 modules with defects due to snail trails are divided into two batches; **Batch A** and **Batch B** each contain 5 modules
- 5 modules without snail trails or other defects comprise **Batch C**
- 1 new, defect-free module serves as a control



Source: Snail Trails: root cause analysis and test procedures, SiliconPV: March 25-27, 2013, Hamelin, Germany

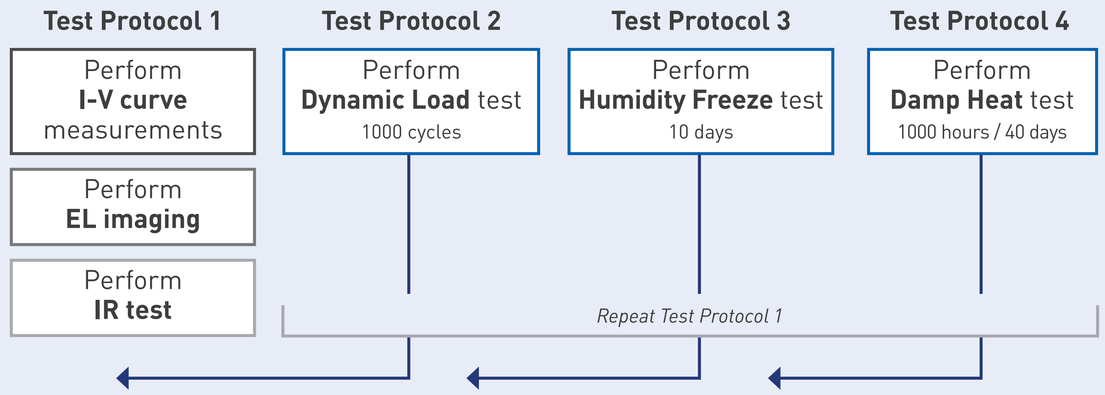
2. INITIAL TESTING – IN-FIELD TESTING

- Perform a front and back visual inspection of **Batch A** modules
- Capture thermal (infrared) images of damage on **Batch A** modules
- Perform I-V curve measurements on **Batch A** modules under load
- Repeat these procedures on **Batch C** modules
- Compare results between batches to capture any abnormalities



3. FINAL TESTING – CONTROLLED LAB TESTING

- If initial in-field testing shows improper power degradation for **Batch A** modules, proceed with the following guidelines to test **Batch B** modules and determine potential power degradation over the life of the project



- During the test process, perform measurements on the control module to capture measurement inaccuracies

CONCLUSIONS

- As utility-scale solar PV developers, engineers and asset owners, we present this test protocol to further our understanding of in-field solar PV module durability, reliability and performance.
- When performing tests between samples, we propose testing samples that all come from geographical locations that experience similar atmospheric conditions.
- This poster is limited to polycrystalline technology; we would like to expand our understanding of module defects with other module technologies.
- Our understanding is that Dynamic Load testing will not induce any new cracks; it will only make existing cracks wider and longer.
- The Damp Heat test induces moisture into cracks to help determine failure; the 1000-hour Damp Heat test should replicate a module's 25-year product life under environmental conditions experienced in the United States.
- We look forward to further development of standards that fully address testing protocols in relation to PV module reliability.
- We ask the community if the recommended hours for accelerated testing per our controlled lab testing protocols adequately capture module lifetime failure.
- We also ask the community if the tests outlined by the test protocol make economic sense from an industry standpoint.

Effects of Nameplate Assignment – How Important is it in Determining Energy Delivered Relative to the Effects of Variable Operating Conditions?

Markus Schweiger, Matthias Heinze, Werner Herrmann, Christos Monokroussos
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markus.schweiger@de.tuv.com, http://www.tuv.com/solarpower

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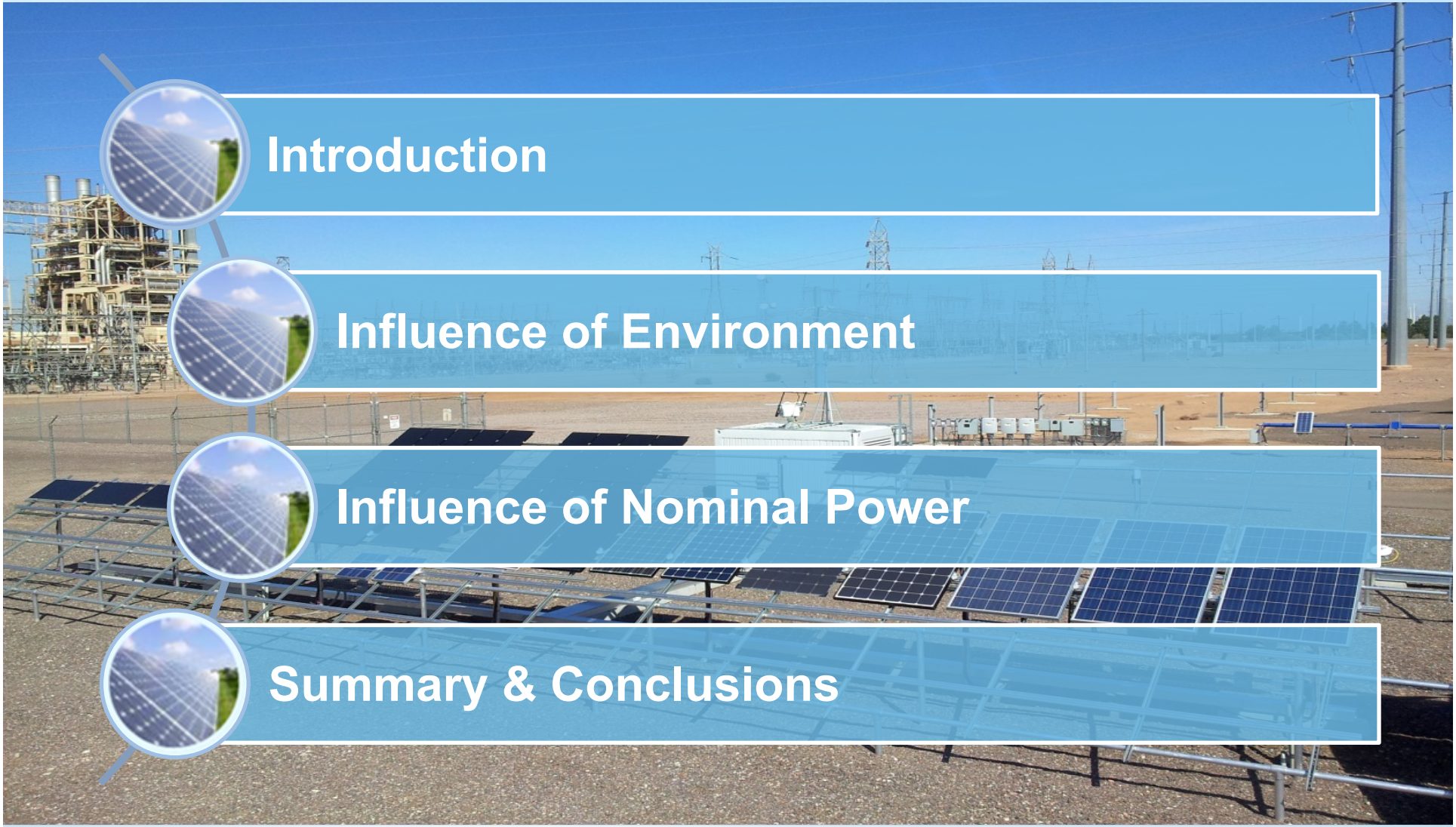
Contents



Introduction

Influence of Environment

Influence of Nominal Power

Summary & Conclusions

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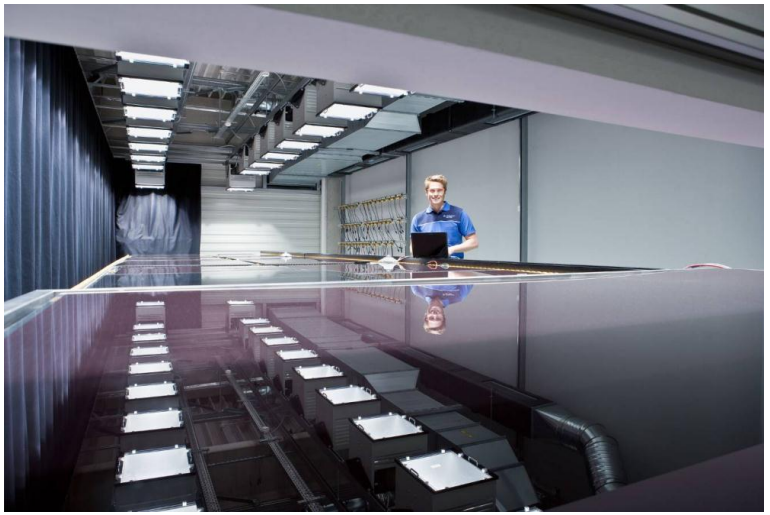
Indoor PV Testing Capacities TÜV Rheinland

- TÜV Rheinland operates 7 accredited solar laboratories: Germany, India, Taiwan, Japan, China, USA, South Korea
- Global network of more than 200 solar experts
- More than 30 years of experience in PV
- World #1 in PV component qualification and PV power plant assessment



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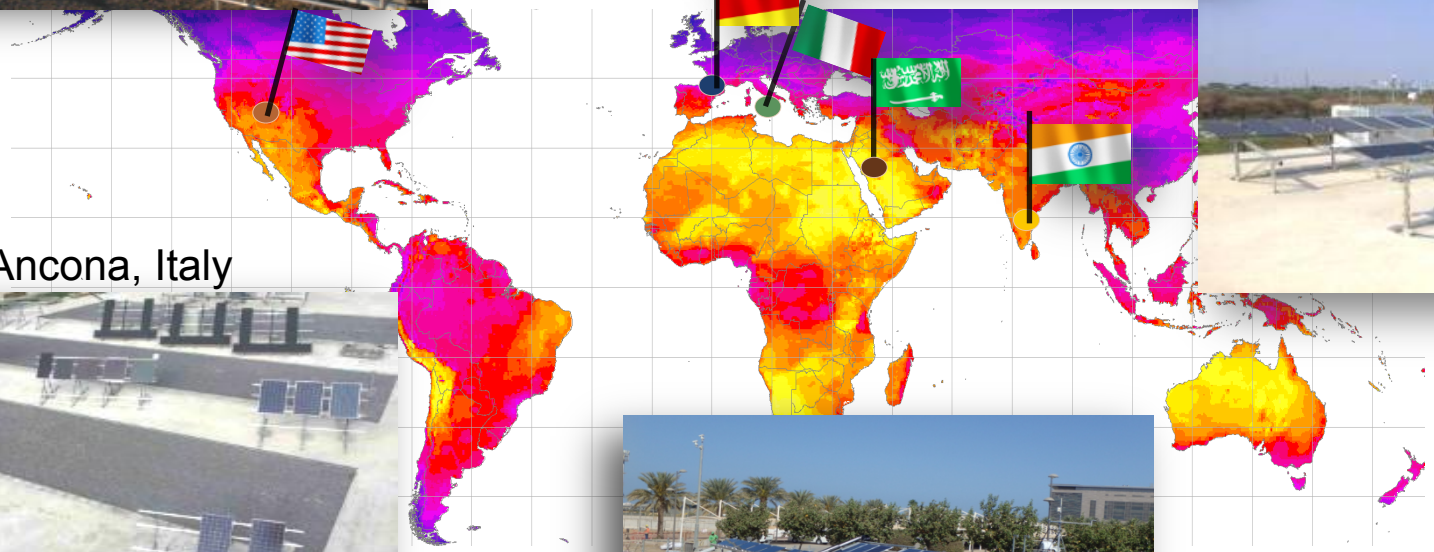
Global Outdoor Test Facilities TÜV Rheinland

1. Tempe, Arizona

3. Cologne, Germany

4. Chennai, India



2. Ancona, Italy

5. Thuwal, Saudi-Arabia

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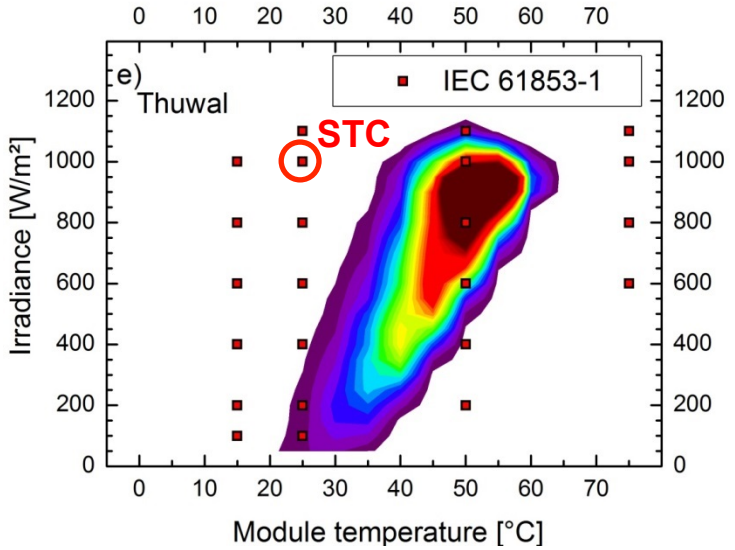
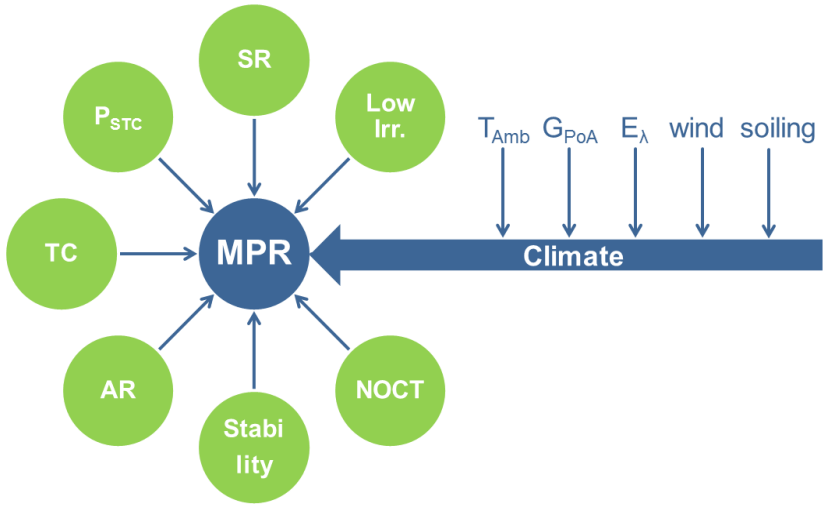
Factors Affecting the Performance of PV Modules

- **Sales price of PV modules** is correlated with nominal output power P_{STC}, which is referenced to standard test conditions (STC) only.
- Real **outdoor conditions differ from STC** and depend on the climatic conditions at the location of the projected power plant.
- Solar cells and PV module technologies show **specific performance characteristics.**
- **High uncertainty** of energy yield prediction by computer simulation tools.
- **Test standard** IEC 61853 Parts 1 – 4: "Photovoltaic (PV) module performance testing and energy rating" **not all parts published yet.**
- **Additional influence due to LID and output power binning**





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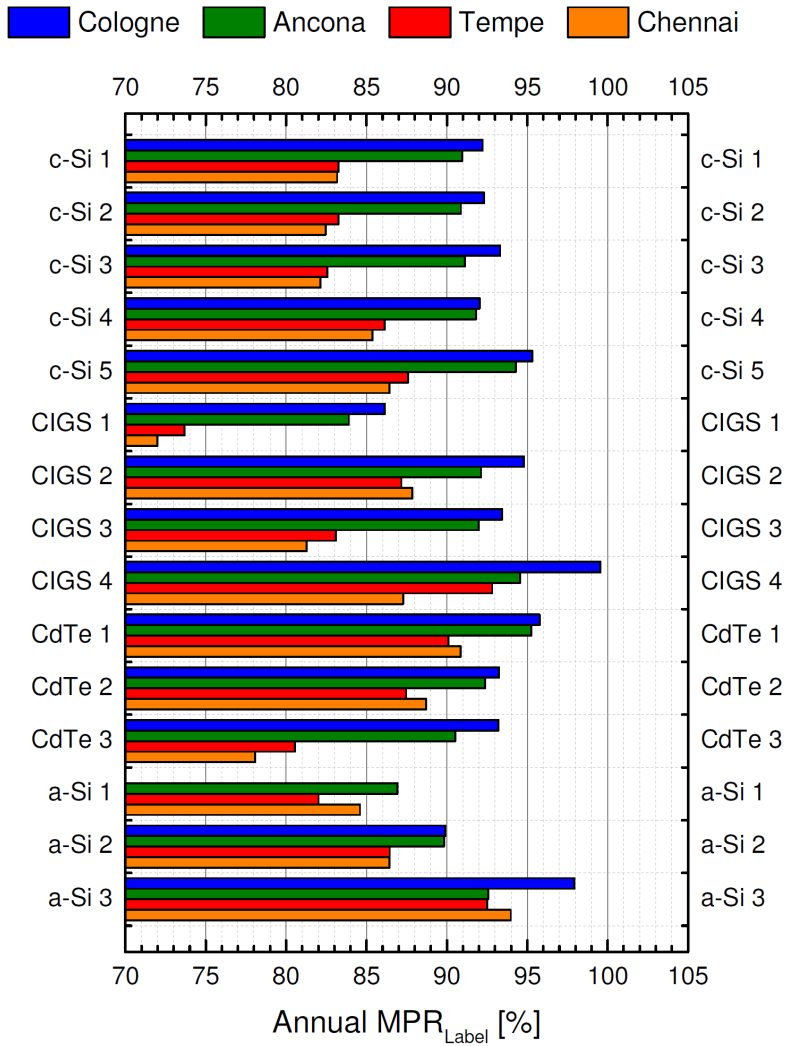
Outdoor Measurements: Module Performance Ratio (MPR)



- **23%** spread in Chennai (tropical)
- **21%** spread in Tempe (semi-desert)
- **14%** spread in Cologne (moderate)
- **12%** spread in Ancona (mediterranean)

$$MPR = \frac{\left(\sum_{1Year} P_{MAX}\right) / P_{STC}}{\left(\sum_{1Year} G_{POA}\right) / 1000 Wm^{-2}}$$

(Operating efficiency of PV modules in the range of 6.7% to 18.4%)

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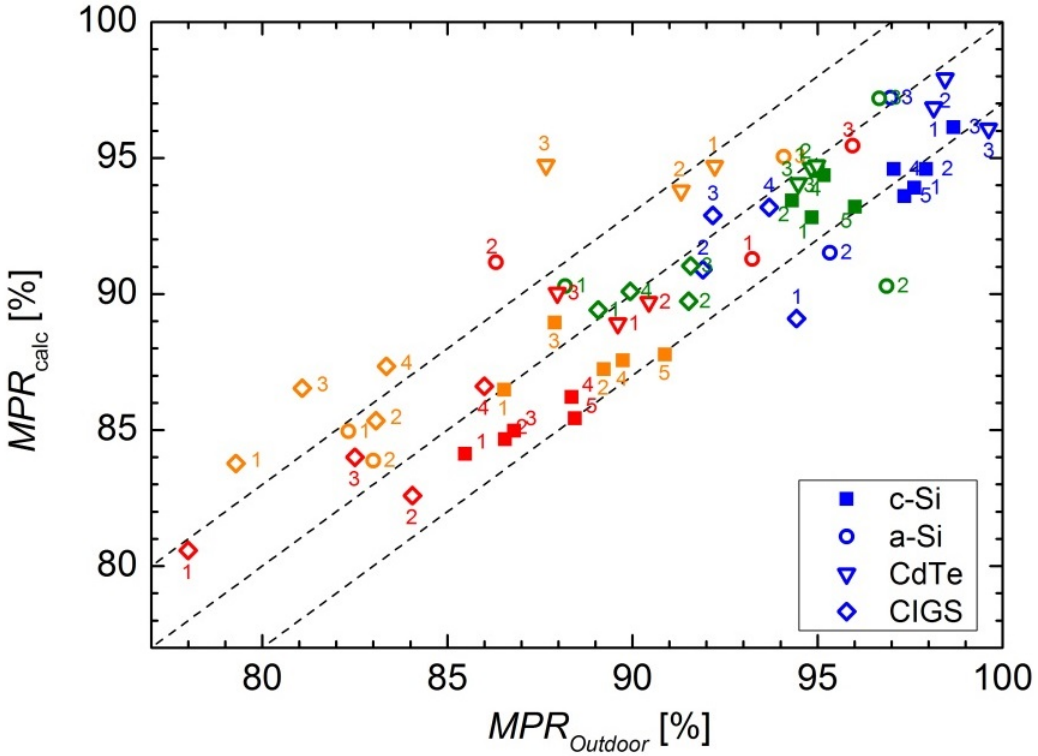
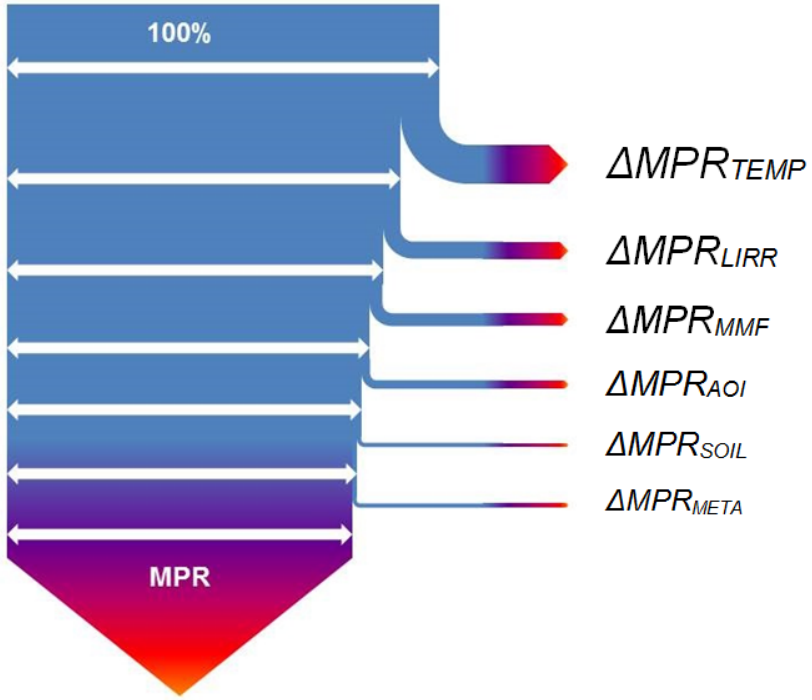
Approach: Linear Performance Loss Analysis (LPLA)

$$MPR = \frac{\left(\sum_{1Year} P_{\max}\right) / P_{STC}}{\left(\sum_{1Year} G_{PoA}\right) / 1000 Wm^{-2}} \overset{!}{=} 1 + \Delta MPR_{TEMP} + \Delta MPR_{LIRR} + \Delta MPR_{MMF} + \Delta MPR_{AOI} + \Delta MPR_{SOIL}$$





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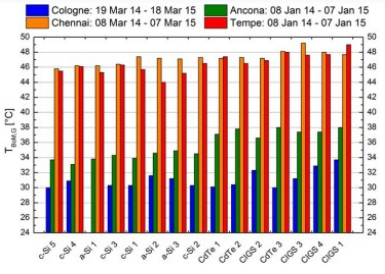
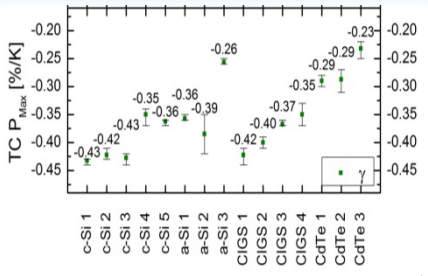
MPR can be estimated by reference climate data sets and energy rating measurements in the laboratory within ±3%:

Weighted Operating Temperature

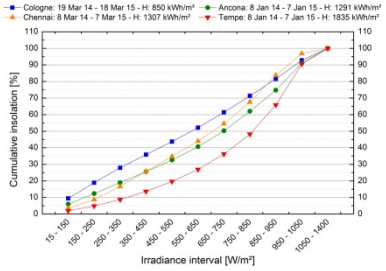


Temperature Coefficient

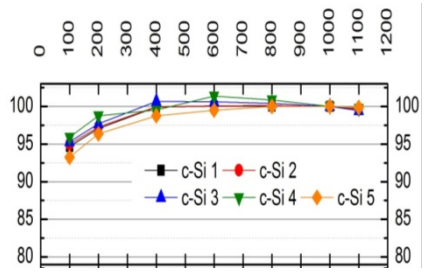


MPR$_{Estimated}$ =

Low Irradiance Profile



Low Irradiance Behavior

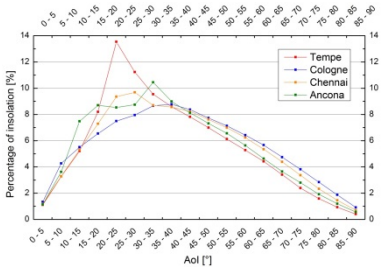


+

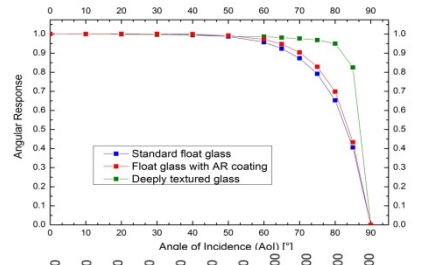
$\Delta MPR_{Temperature}$

$\Delta MPR_{Low\ Irradiance}$

Angular Irradiance Profile



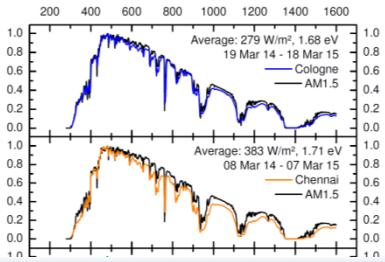
Angular Response



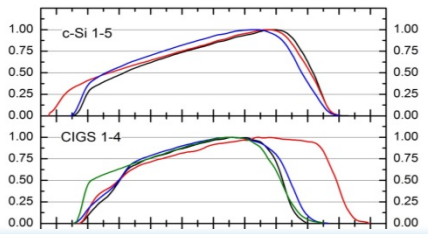
+

$\Delta MPR_{Angular\ Effects}$

Average Spectral Irradiance



Spectral Response



+

$\Delta MPR_{Spectral\ Effects}$

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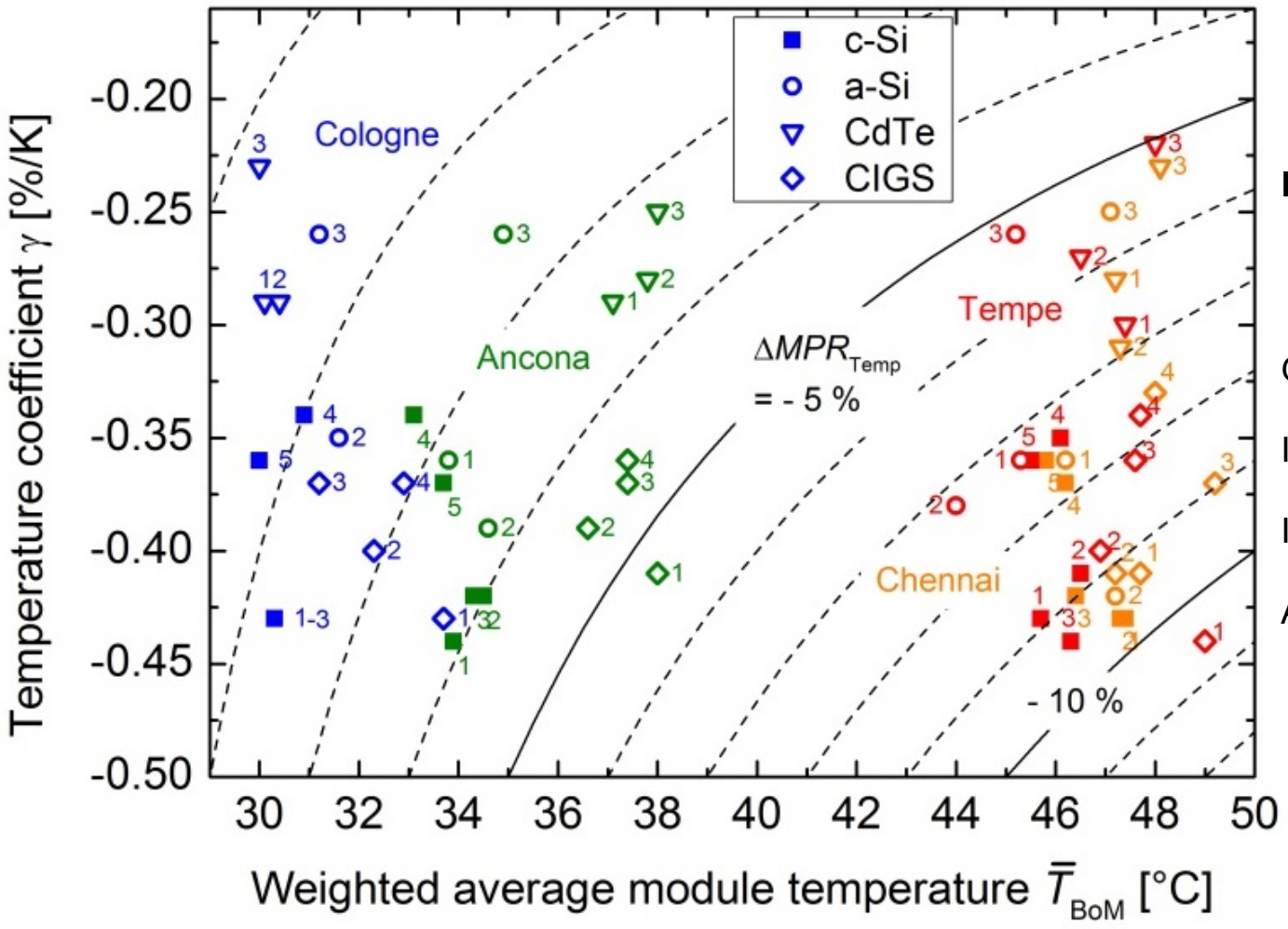
Example: Temperature losses of different technologies in different climates



Location	Energy yield loss due to module temperature
Germany	-1.2 % to -3.7 %
Italy	-2.6 % to -5.3 %
India	-5.3 % to -9.6 %
Arizona	-5.1 % to -10.6 %

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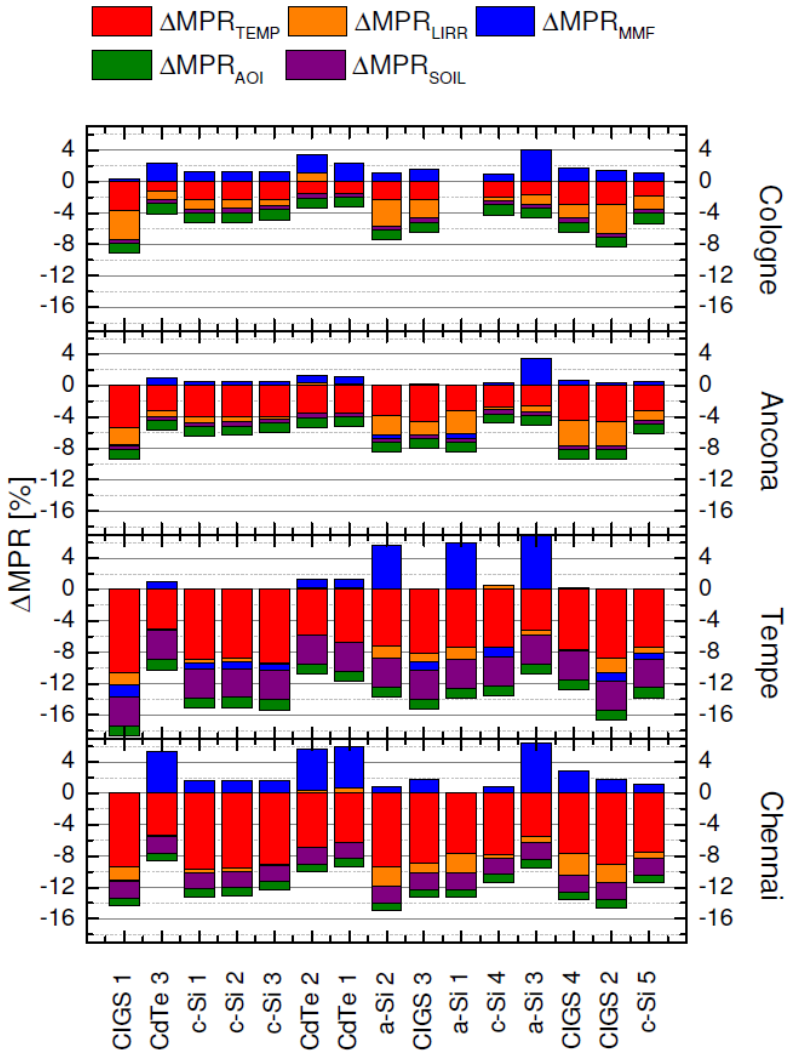
Quantifying the Impact on Energy Yield by LPLA



- Highest avg. module temperature in Chennai 42.4°C → ΔMPR_{TEMP}: -5.3% to -9.6%
- Low irradiance behavior most pronounced in Cologne → ΔMPR_{LIRR}: +1.1% and losses of -3.6%
- Spectral impact ΔMPR_{MMF} mostly positive and high for CdTe technologies with a spectral gain of up to 5.3% (Chennai)
- Max. ΔMPR_{SOIL} observed in Tempe → -3.7% soiling loss per year
- ΔMPR_{AOI} greatest in Cologne with -3.5% for standard float glass

(Further details: http://ietdl.org/t/5oURb)

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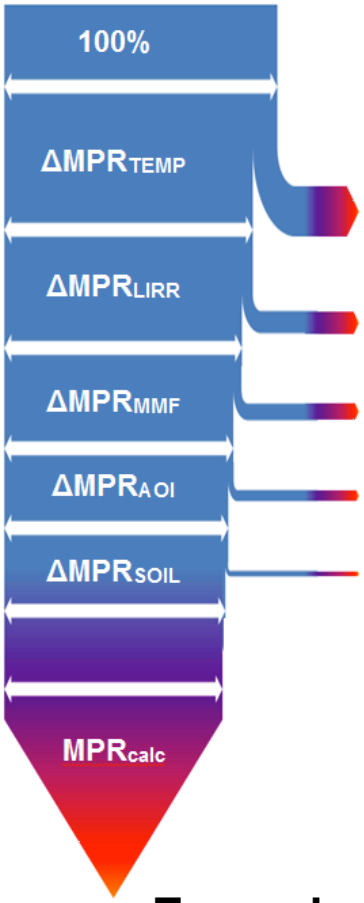
Quantifying the Impact on Energy Yield by LPLA



	c-Si 1				CdTe 1				CIGS 4			
	Cologne	Ancona	Tempe	Chennai	Cologne	Ancona	Tempe	Chennai	Cologne	Ancona	Tempe	Chennai
ΔMPRTEMP	-2.3%	-3.9%	-8.9%	-9.6%	-1.5%	-3.5%	-6.7%	-6.2%	-2.9%	-4.5%	-7.7%	-7.6%
ΔMPRLIRR	-1.2%	-0.8%	-0.4%	-0.5%	0.0%	+0.2%	+0.3%	+0.6%	-1.7%	-3.2%	+0.2%	-2.9%
ΔMPRMMF	+1.3%	+0.5%	-0.8%	+1.6%	+2.3%	+0.9%	+1.1%	+5.3%	+1.8%	+0.7%	-0.1%	+2.8%
ΔMPRAOI	-3.5%	-2.4%	-2.0%	-2.9%	-3.5%	-2.4%	-2.0%	-2.9%	-3.5%	-2.4%	-2.0%	-2.9%
ΔMPRSOIL	-0.5%	-0.5%	-3.7%	-2.1%	-0.5%	-0.5%	-3.7%	-2.1%	-0.5%	-0.5%	-3.7%	-2.1%
	-6.2%	-7.2%	-15.9%	-13.5%	-3.1%	-5.4%	-11.1%	-5.3%	-6.8%	-9.9%	-13.4%	-12.7%
MPRcalc	**93.9%**	**92.8%**	**84.1%**	**86.5%**	**96.9%**	**94.6%**	**88.9%**	**94.7%**	**93.2%**	**90.1%**	**86.6%**	**87.3%**

Example: CdTe 1 generates 88.9/84.1-1= 5.7% more energy than c-Si 1 in Tempe

→ The investor gets 5.7% more yield for the same STC power.

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Verification of power output and stability

$$MPR = \frac{\left(\sum_{1Year} P_{\max}\right) / P_{STC}}{\left(\sum_{1Year} G_{PoA}\right) / 1000 Wm^{-2}} \overset{!}{=} 1 + \Delta MPR_{TEMP} + \Delta MPR_{LIRR} + \Delta MPR_{MMF} + \Delta MPR_{AOI} + \Delta MPR_{SOIL}$$

IEC 61215-1: Power output verification: P_{max}(Lab) ≥ P_{max}(Nameplate)
(considering measuring uncertainties, production tolerances and LID effects)

IEC 61215-2: Criterion definition for stabilization (3 measurements):

$$(P_{\max} - P_{\min}) / P_{average} < x$$

Standard	Scope	Irradiation dose Initial stabilization	Irradiation dose final stabilization	Stabilization criterion x
IEC 61215-1-1	c-Si	2 x 5kWh/m²	not required	1%
IEC 61215-1-2	CdTe	2 x 20kWh/m²	2 x 20kWh/m²	2%
IEC 61215-1-3	a-Si	2 x 43kWh/m²	2 x 43kWh/m²	2%
IEC 61215-1-4	CIGS	2 x 20kWh/m²	2 x 10kWh/m²	2%

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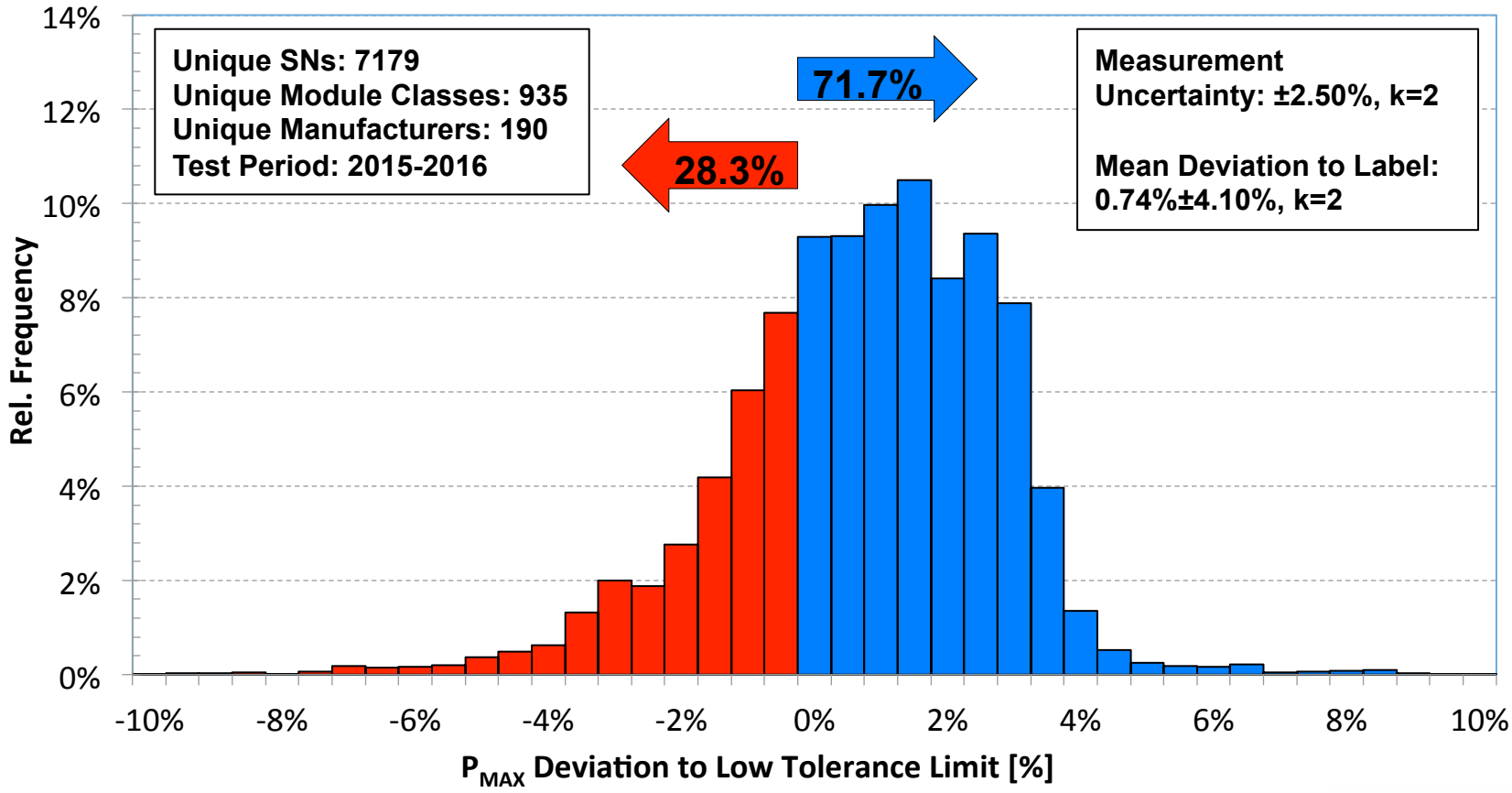
Verification of power output and stability

Reliability of Power Rating and Labelling - Laboratory Experience from Measurements at STC - Modules are typically not solarized (LID not included)



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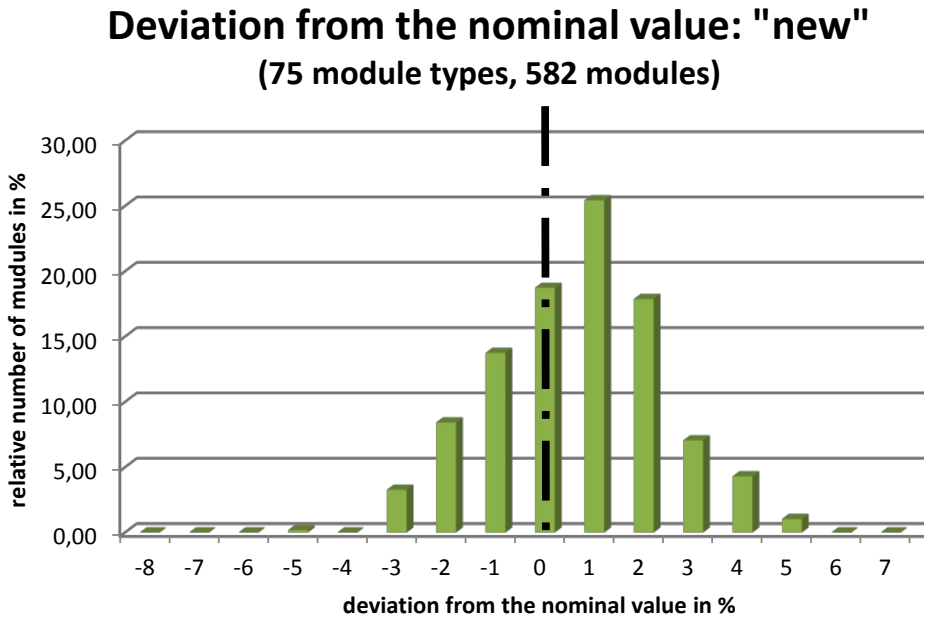
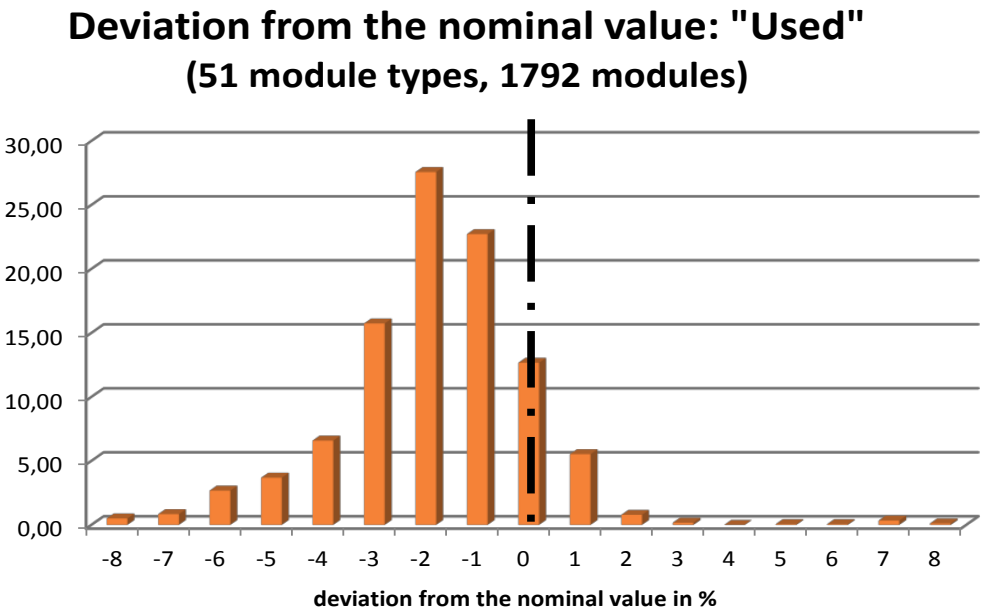
Verification of power output and stability

Significant number of modules underperforms at STC tests due to:

- Production tolerances
- Light induced degradation (LID)
- Binning policy (Manufacturing Sorting)
- Measuring uncertainty





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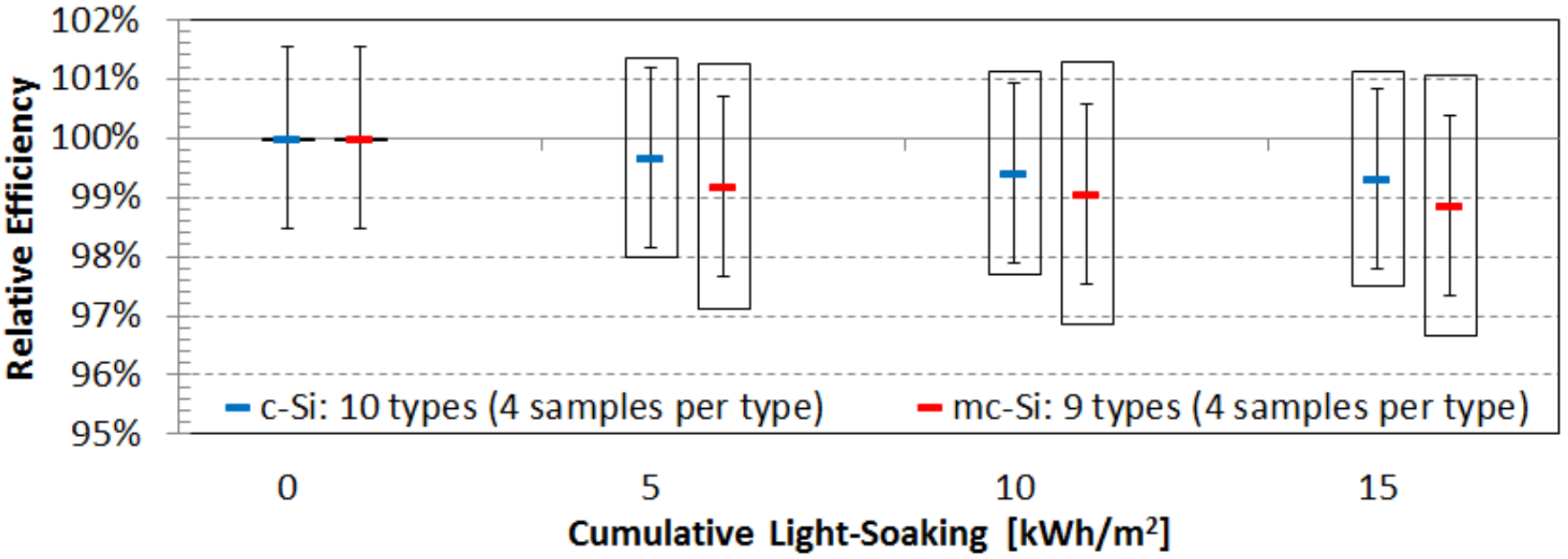
Verification of power output and stability: LID

- Variation of relative efficiency (to initial) against cumulative irradiation dose for different c-Si and mc-Si module types at STC.
- Boxes represent the standard deviation of technology variation (k=2) and error bars the measurement uncertainty.
- All samples considered in this work passes the stabilization criteria in accordance with IEC 61215-1,-1-1,-2 standards.



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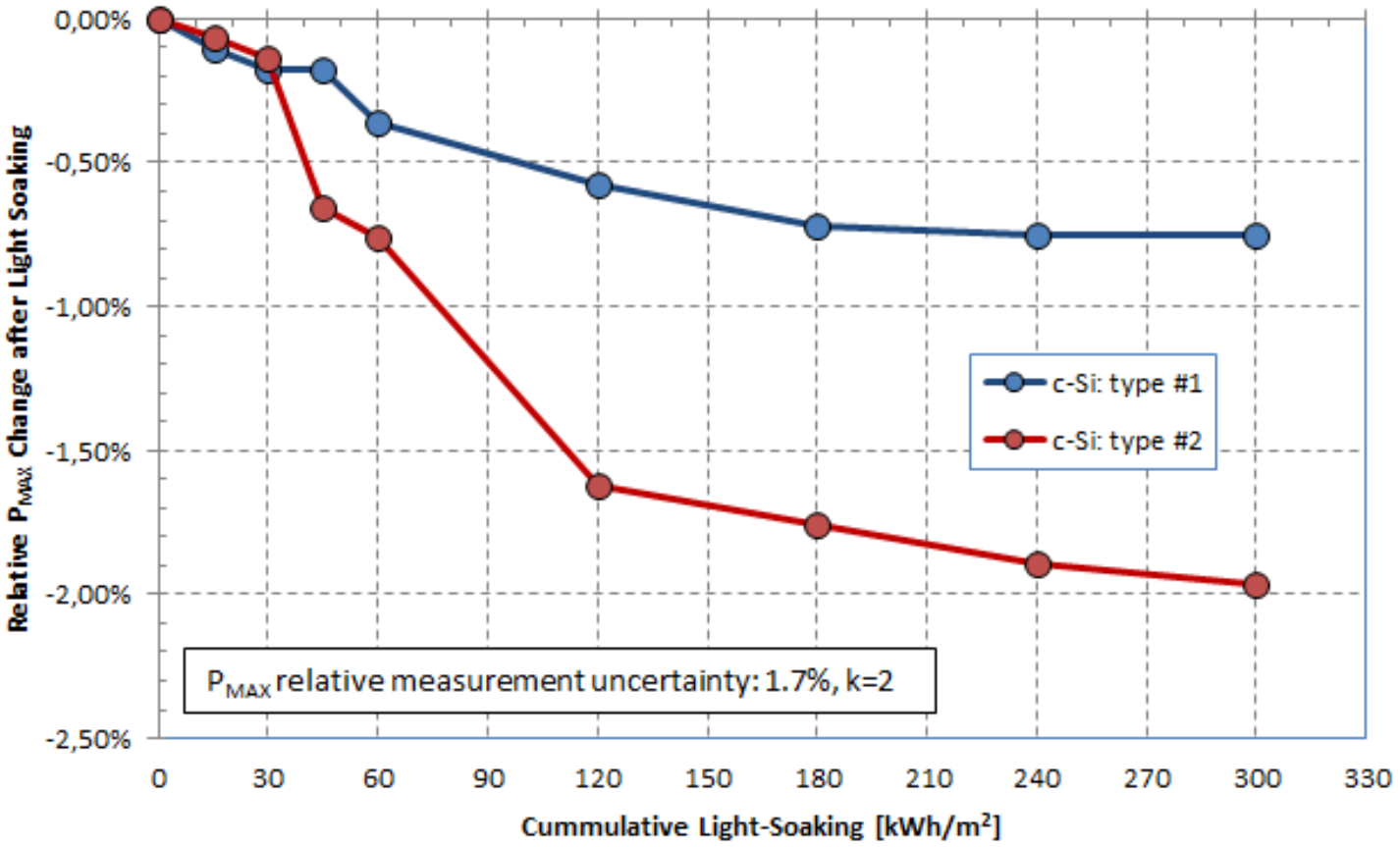
Verification of power output and stability: LID

- But some samples show long-term LID effects:



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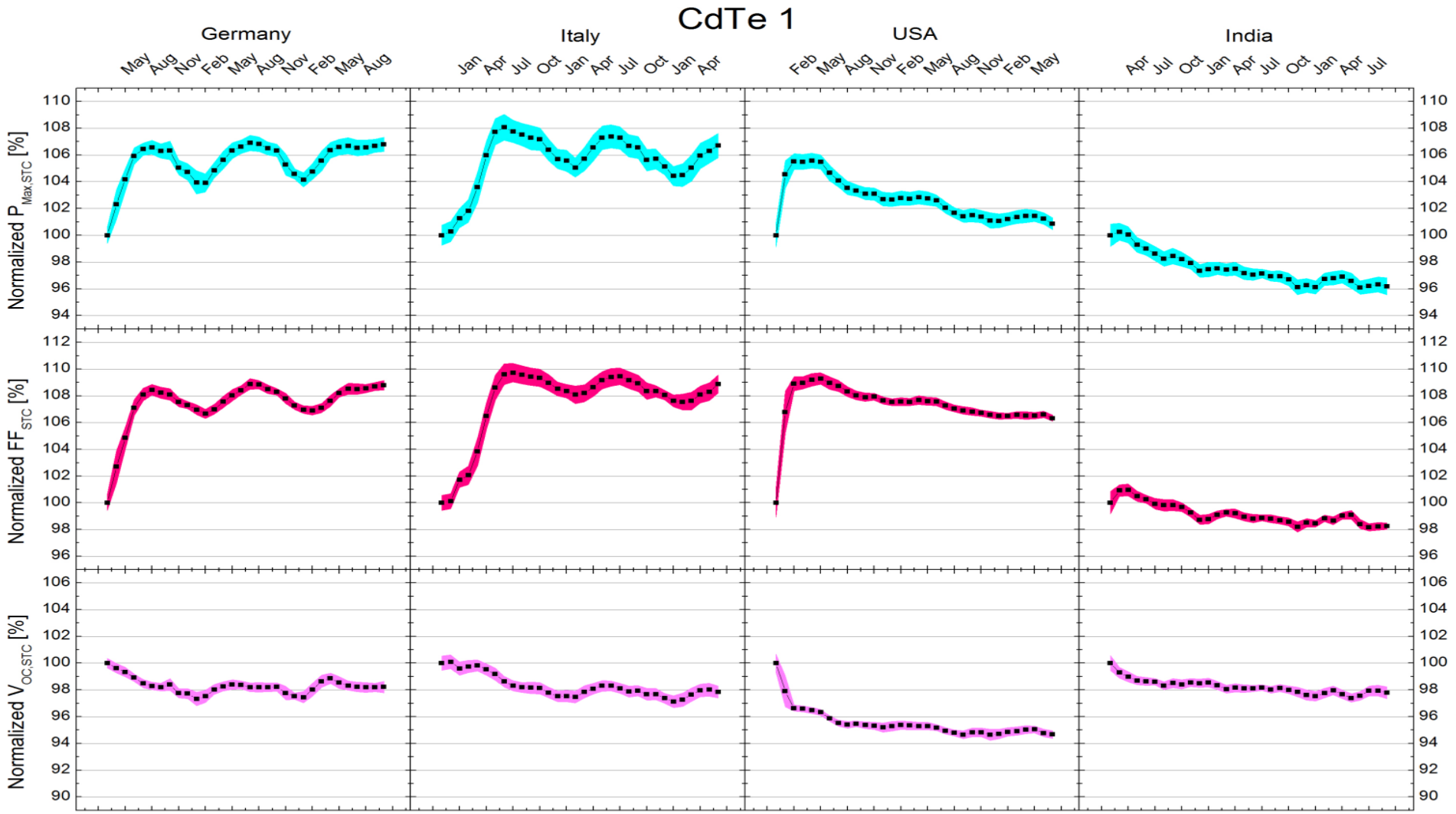
Verification of power output and stability: Metastabilites

$$\Delta P_{Max} = P_t / P_{t=0} - 1$$



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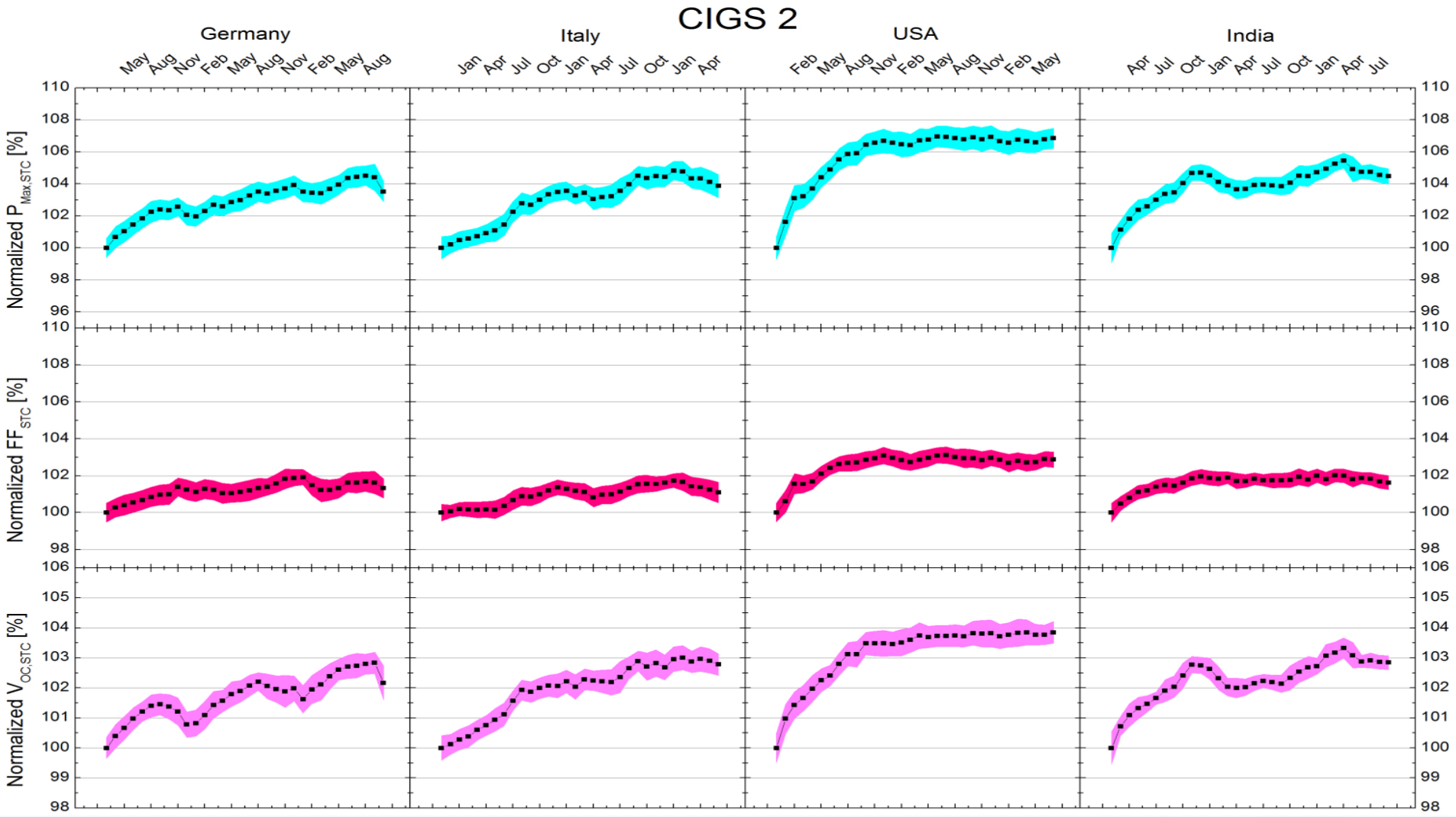
Verification of power output and stability: Metastabilites

$$\Delta P_{Max} = P_t / P_{t=0} - 1$$



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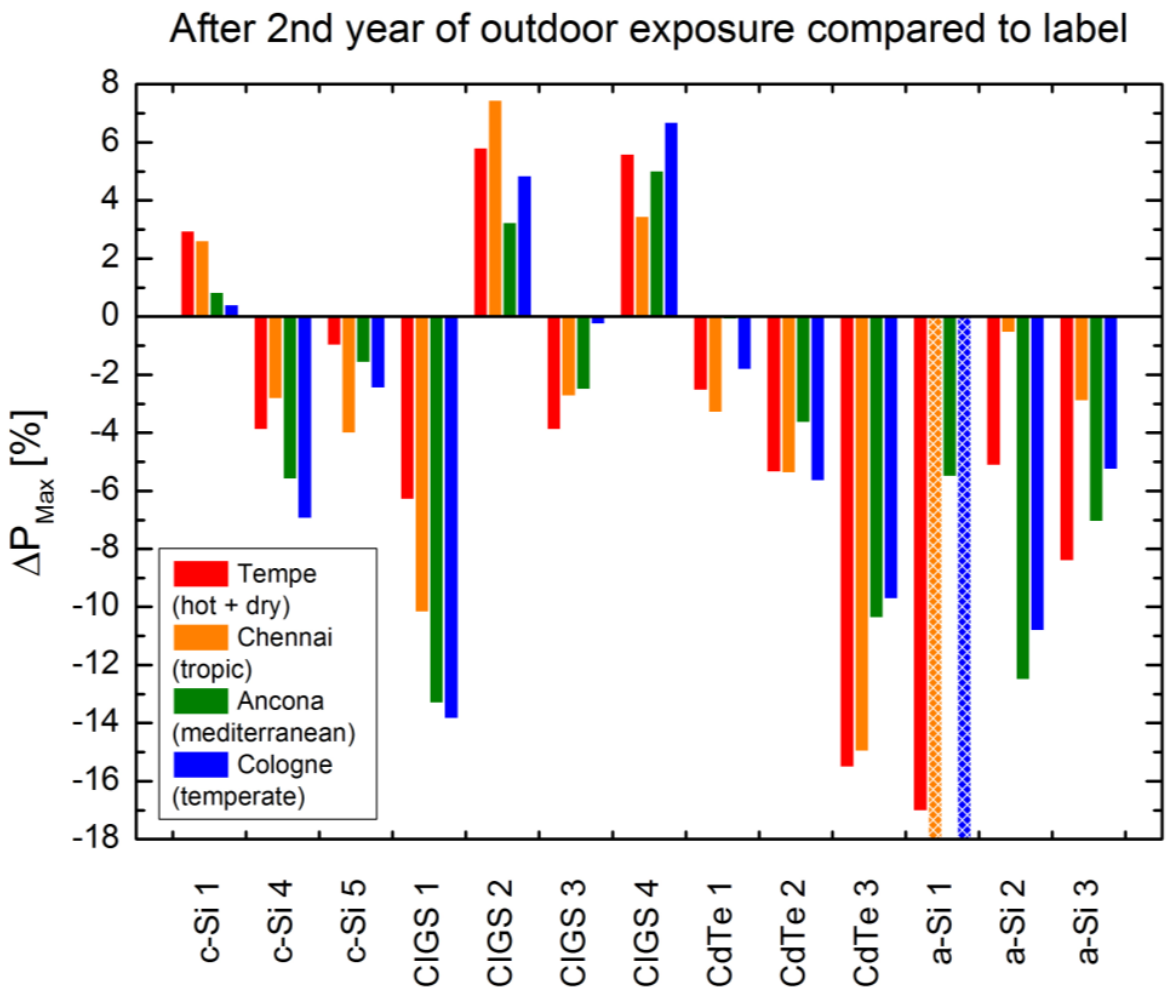
Verification of power output and stability: Metastabilites



- Significant stabilization mechanisms for all technologies detected
- Customers demand: Stabilized output power must be ≥ stated output power
- Strong deficits of some manufacturers detected

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Summary

Effect on energy yield delivery for optimal mounting conditions:

Effect	Impact on yield	Description
Temperature	-1.2% to -10.6%	Climate, module design and technology related
Low irradiance behavior	+1.1% to -3.6%	Related to climate and manufacturer
Spectral effects	up to +5.3% (CdTe)	Related to climate and technology
Angular losses	up to -3.5%	Front glass and climate
Soiling	Max. -3.7% measured in Tempe	Front glass and location
LID	up to -2% (c-Si)	Different metastabilities for thin-film
Nameplate Assignment	Typical range ±4%	Various reasons (see slide 14)

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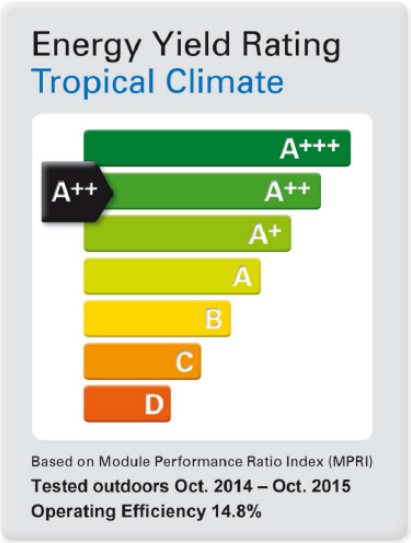
Conclusions

- The influence of climatic impact factors on the energy yield of different PV module technologies is significant for the return of the investment.

→ We are able to rate, quantify and compare the gain or losses of environmental impact factors due to technological differences of PV modules in different climates.

- The nominal power is “investor-friendly” when the average stabilized STC value is higher than the stated value on the label without showing any long-term degradation.

→ We are measuring the nominal power within an uncertainty of ±2.5% and are able to trace the stability of the nominal power indoor & outdoor within less than ±1.7%.



Performance surveillance in different climates is very important for quality control of PV modules - All yield relevant effects are considered in the **TÜV Rheinland energy rating label.**

Conclusions

Thank you
for your attention!

ACKNOWLEDGEMENT: This work is supported by the German Federal Ministry for Economic Affairs and Energy (BMWi) as part of contract no. 0325517B.

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References

[1] W. Herrmann: Solar simulator measurement procedures for determination of the angular characteristic of PV modules, 29th EU PVSEC, Amsterdam, 2014.

[2] IEC 61853-1, Photovoltaic (PV) module performance testing and energy rating - Part 1: Irradiance and temperature performance measurements and power rating, 2011.

[3] IEC 61853-2, Photovoltaic (PV) module performance testing and energy rating - Part 2: Spectral response, incidence angle and module operating temperature measurements (IEC 82/774/CDV), 2013.

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[5] IEC 60904-8, Photovoltaic devices - Part 8: Measurement of spectral responsivity of a photovoltaic (PV) device, 2015.

[6] Schweiger, M.; Herrmann, W.; Gerber, A.; Rau, U. (2016): Understanding the Energy Yield of Photovoltaic Modules in Different Climates by Linear Performance Loss Analysis. Submitted in IET Renewable Power Generation.

[7] IEC 60891: `Photovoltaic devices. Procedures for temperature and irradiance corrections to measured current voltage characteristics´, 2013.

[8] IEC 61646: `Thin-film terrestrial photovoltaic (PV) modules - Design qualification and type approval´, 2013.

[9] Schweiger, M., Herz, M., Kämmer, S., Herrmann, W.: ` Fabrication Tolerance of PV-Module I-V Correction Parameters for Different PV-Module Technologies and Impact on Energy Yield Prediction´. 29th European Photovoltaic Solar Energy Conference and Exhibition, Amsterdam, 2014, pp. 3227 - 3230.

[10] Schweiger, M., Bonilla, J., Herrmann, W., Gerber, A., Rau, U.: `Performance Stability of Photovoltaic Modules in Different Climates´, manuscript in preparation.

[11] Herrmann, W., Schweiger, M.: `Soiling and self-cleaning of PV modules under the weather conditions of two locations in Arizona and South-East India´. 42nd Photovoltaic Specialist Conference (IEEE PVSC), New Orleans, United States, 2015, pp. 1-5.

[12] M. Schweiger, W. Herrmann: Energy rating label for PV modules to improve energy yield prediction in different climates, 30th European Photovoltaic Solar Energy Conference and Exhibition, September 2015, Hamburg, Germany.

Module tester spectral classification: Focus on industrial silicon modules

Ronald A. Sinton, Harrison Wilterdink, Wes Dobson

Sinton Instruments, Boulder, CO, 80301, USA

Problem Statement

- Traditional classification of module-tester spectrum (A, B, C of IEC 60904-9) does not correlate with measurement quality (spectral MMF, from IEC 60904-7)[1,2,3,4,5,6]

"No benchmarking of solar simulators is therefore possible based only on the spectral match information" [3]

Despite this quandary, the spectral classification is prominent in marketing of module-test equipment and referenced in IEC standards and therefore can't be ignored

This presentation: Conformity vs. accuracy and functionality

Technical discussion

[1] IEC 60904-9:2007 (Ed. 2) §5.1. "Solar simulator performance requirements"
[2] W. Herrmann *et al.*, "Advanced Intercomparison Testing of Testing of PV Modules in European Test Laboratories," in *22nd EU PVSEC* (Milan, 2007).
[3] W. Herrmann and L. Rimmelspacher, "Uncertainty of Solar Simulator Spectral Irradiance Data and Problems with Spectral Match Classification," in *27th EU PVSEC* (Frankfurt, 2012).
[4] W. Herrmann, "Advances in Spectral Irradiance Analysis of Solar Simulators," in *26th PVSEC* (Singapore, 2016).
[5] C. Monokroussos et al., "IEC 60904-9 Spectral Classification and Impact on Industrial Rating of c-Si Devices," WCPEC-6, 23rd-27th November 2014, Kyoto, Japan
[6] C. Monokroussos et al., "Impact of Calibration Methodology into the Power Rating of c-Si PV Modules Under Industrial Conditions," 28th EU PVSEC (Paris, 2013), pp. 2926 – 2934.

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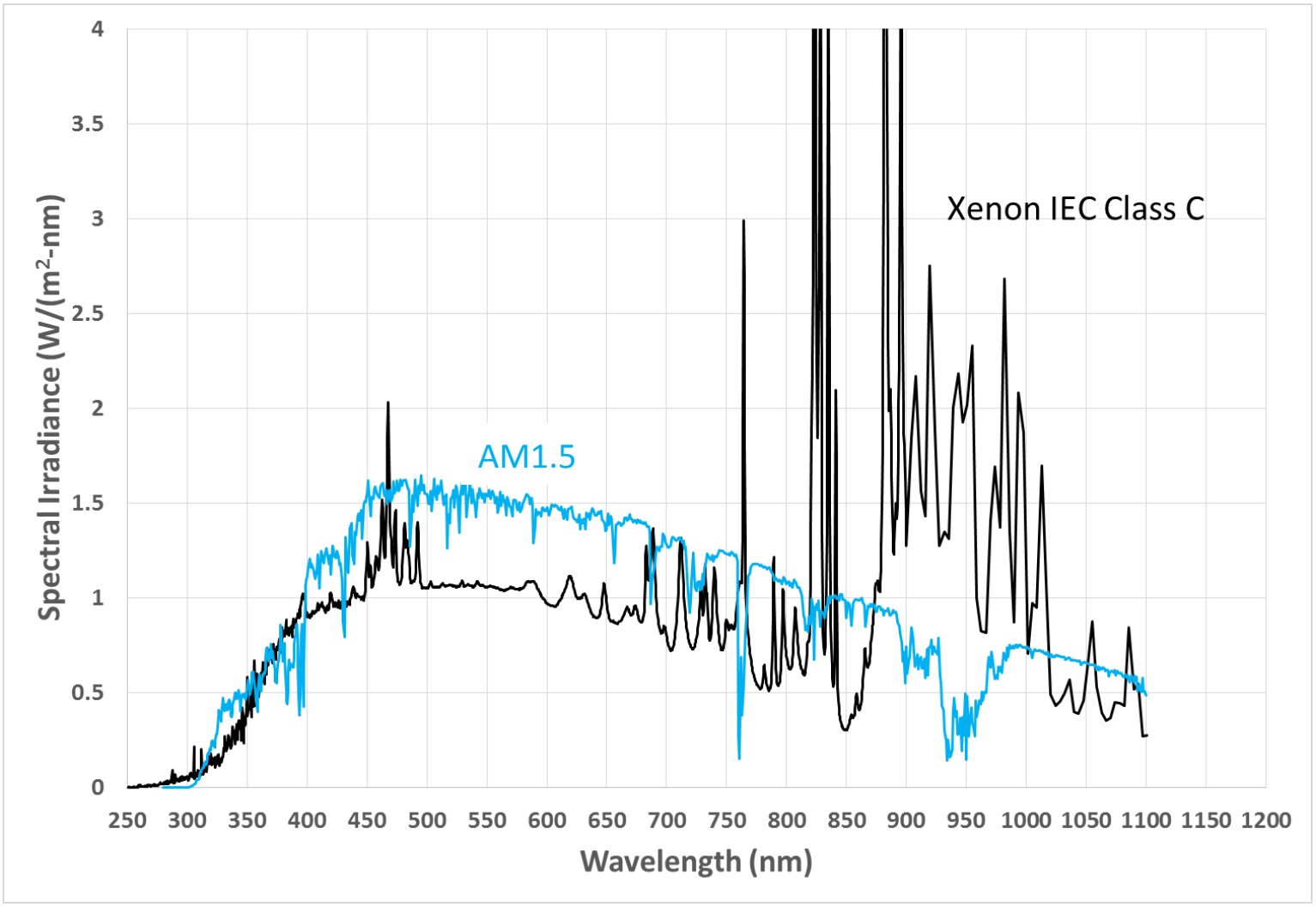
Spectral Irradiance Examples: AM1.5 and Xenon



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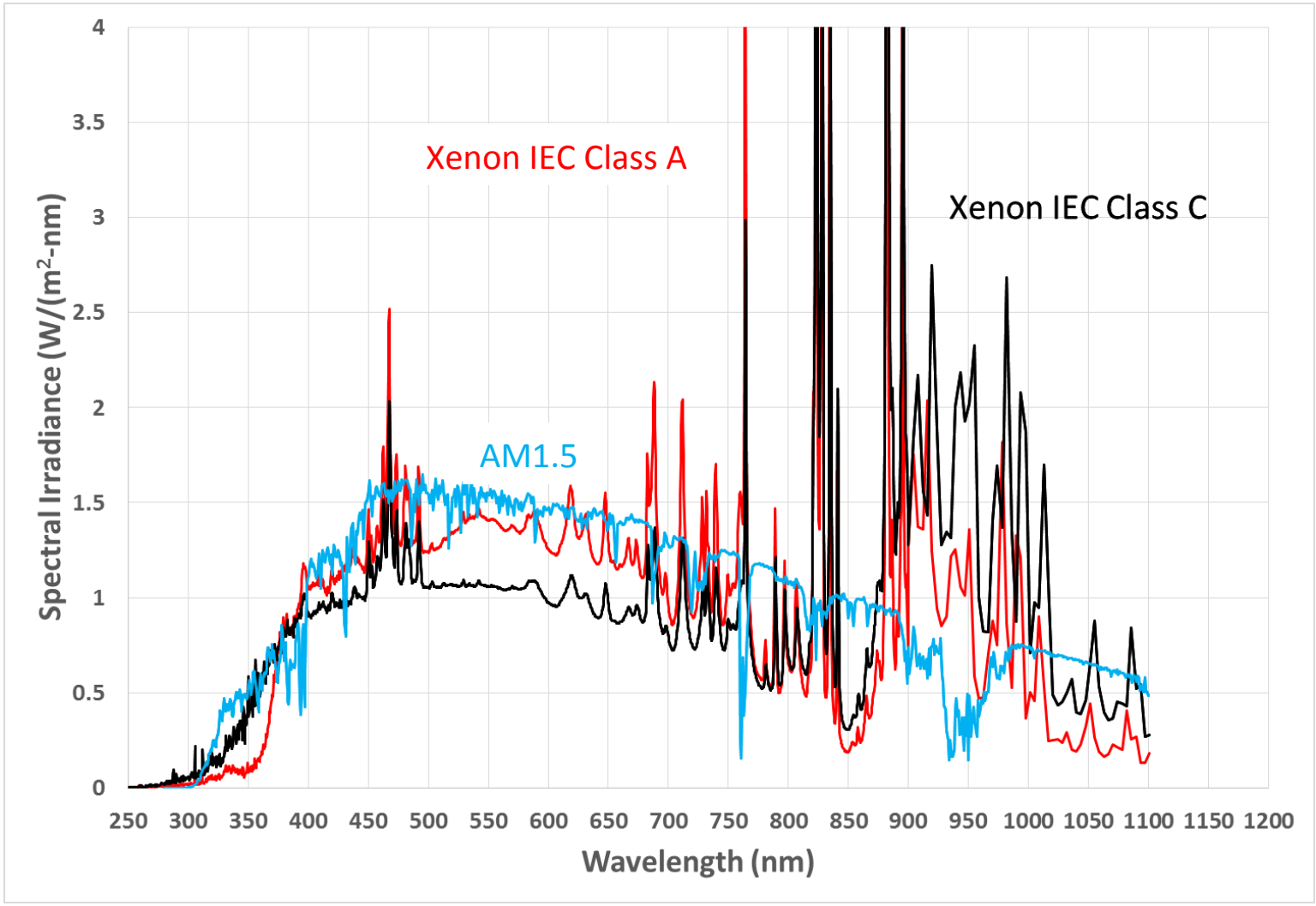
Filtered Xenon (Class A)



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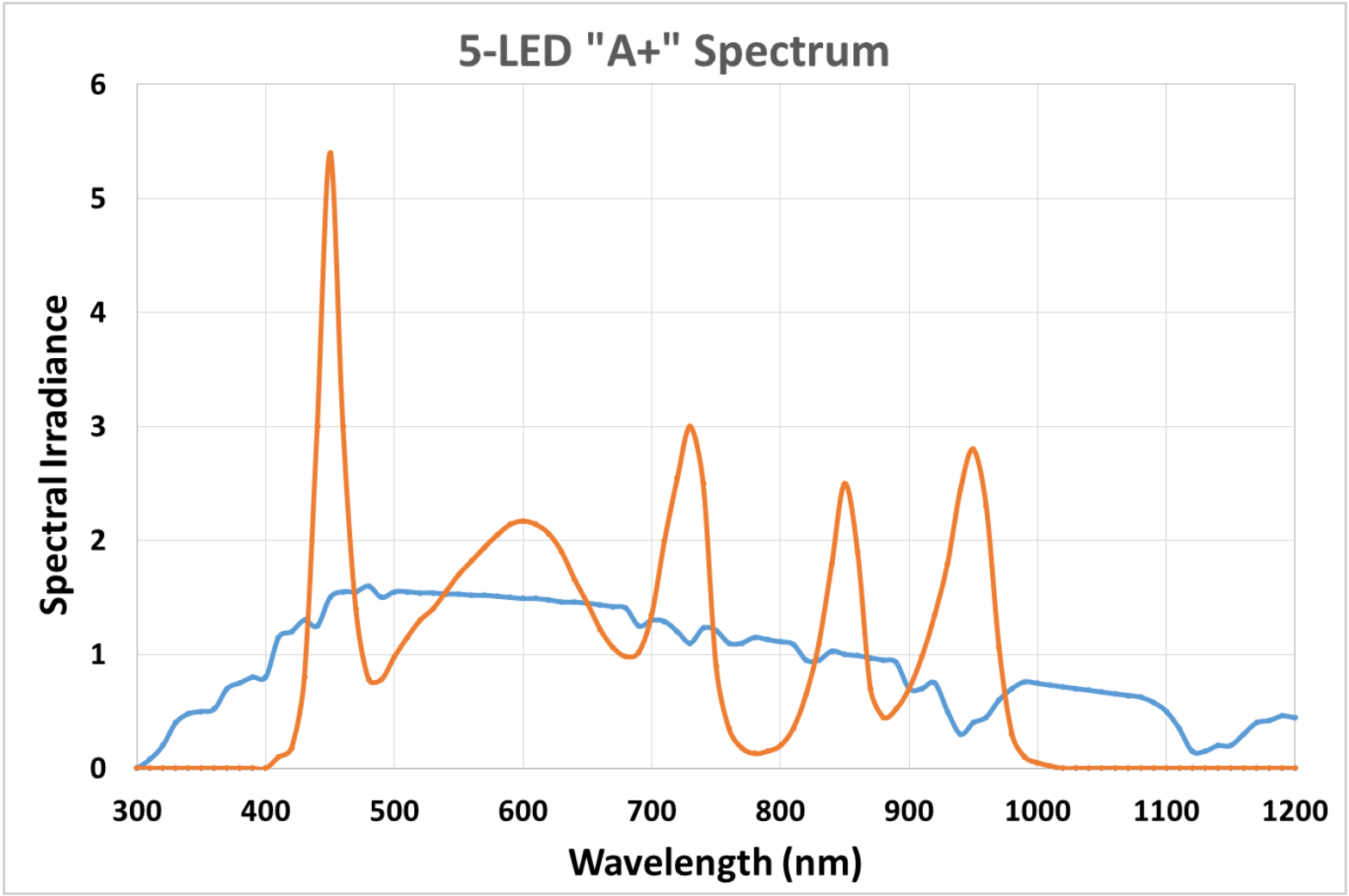
5-LED (“Class A+”)



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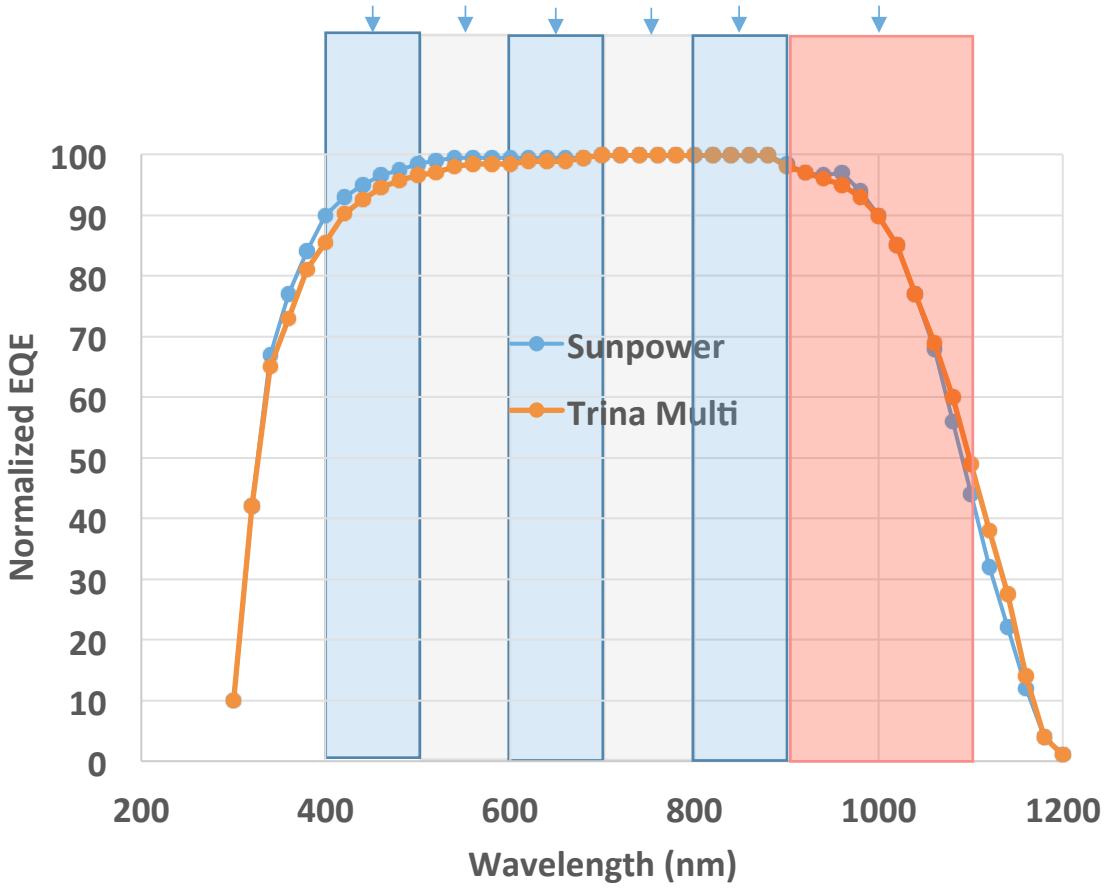
NREL EQE Data: 2 Record Modules

6 spectral bins in IEC standard 60904-9:2007 (Ed. 2)



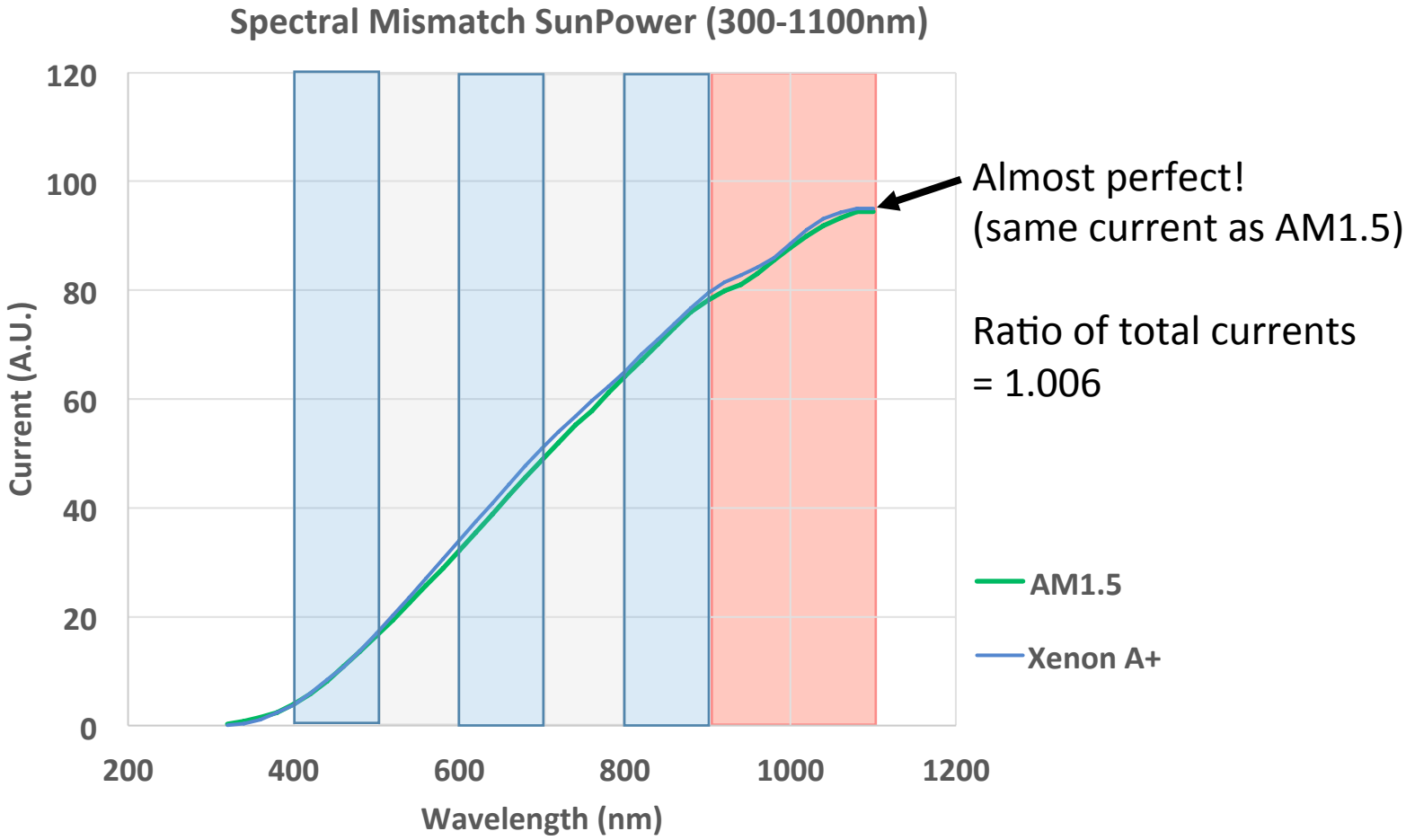
IEC: % energy per bin

Sinton instruments

M. Green *et al.*, "Solar Cell Efficiency Tables," in *Progress in Photovoltaics* Vol. 24, Issue 1, pp. 3 – 11, November 2015.

DOI: 10.1002/pip.2728
http://onlinelibrary.wiley.com/doi/10.1002/pip.2728/full#pip2728-fig-0002

Spectral MMF Calculation (Cont. Xenon “A+”)



Almost perfect!
(same current as AM1.5)

Ratio of total currents
= 1.006

- Methodology:
  - Perfect reference cell (EQE = 1 from 300-1100 nm).
  - Integrate Photons*EQE to find current
  - Spectral range: 300 – 1100 nm

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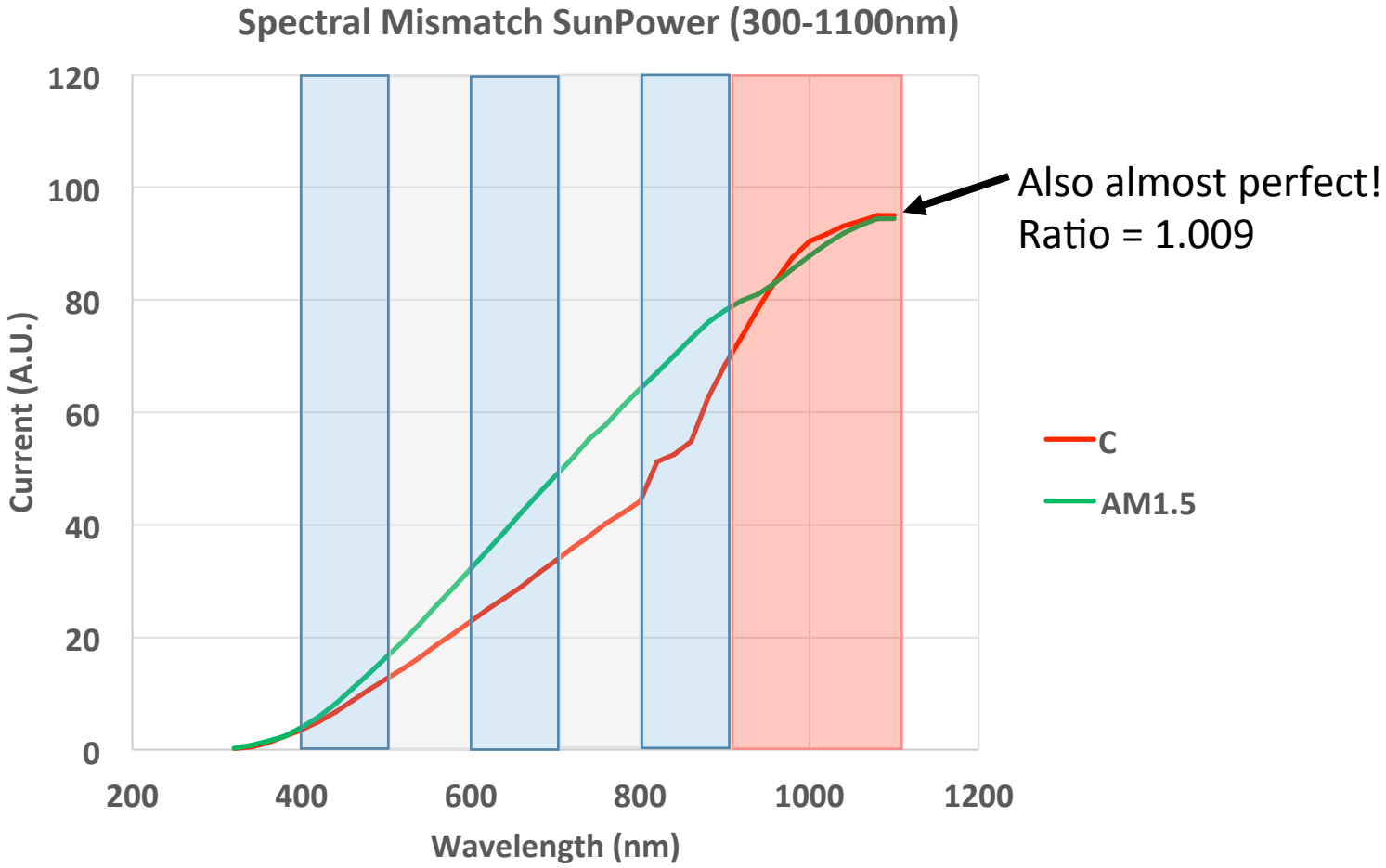
Unfiltered Xenon (Class C)



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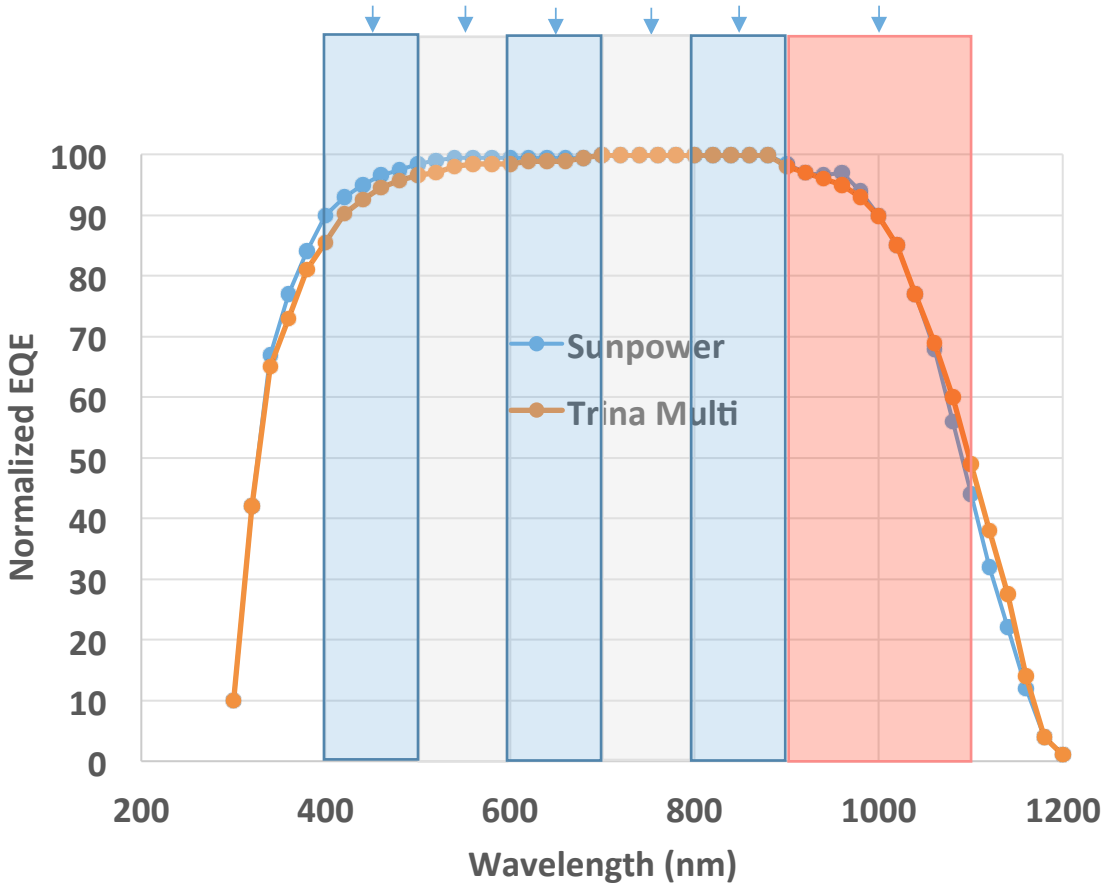
NREL EQE Data: 2 Record Modules

6 spectral bins in IEC standard 60904-9:2007 (Ed. 2) (energy bins)



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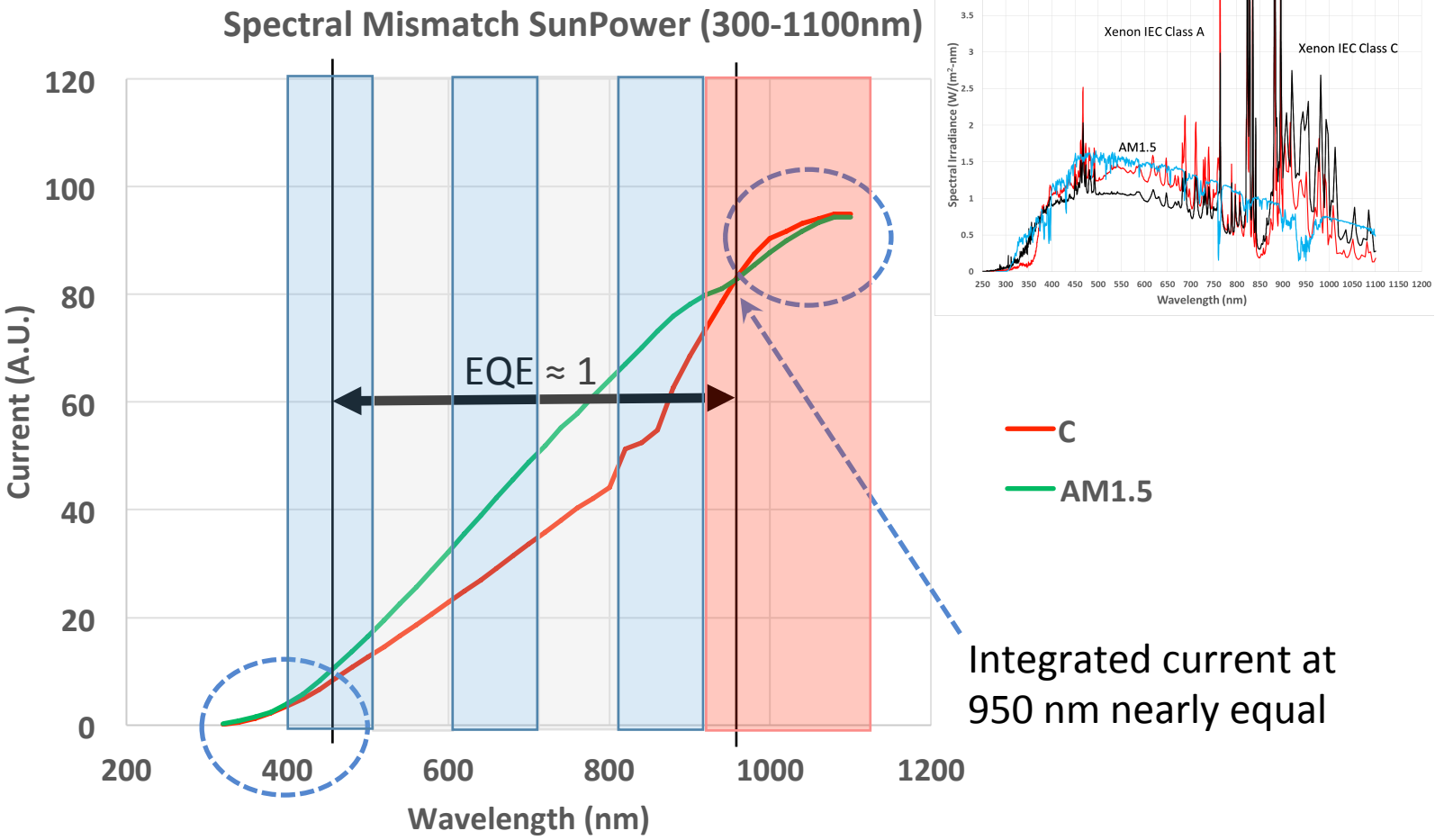
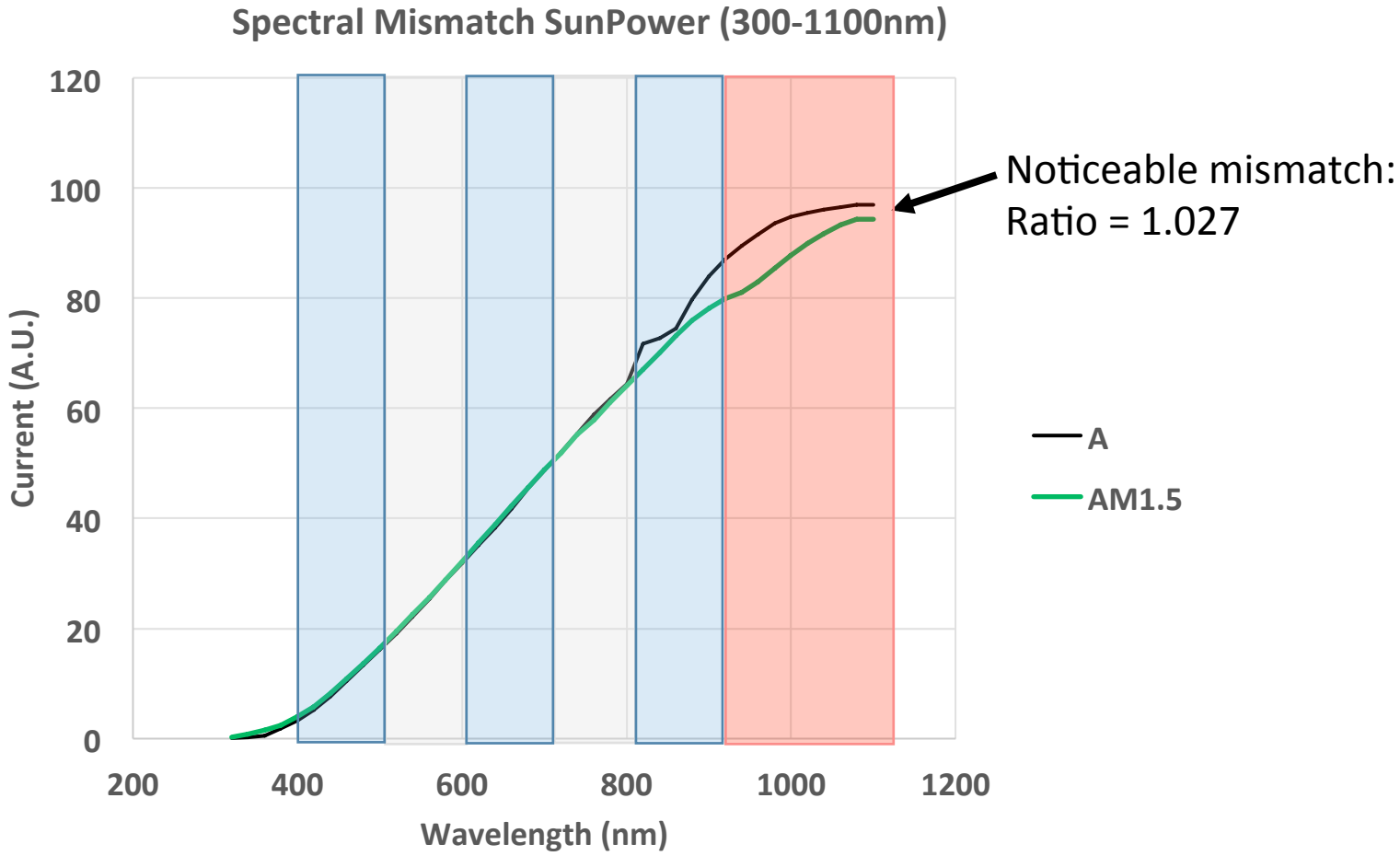
How can a Class C tester work so well?



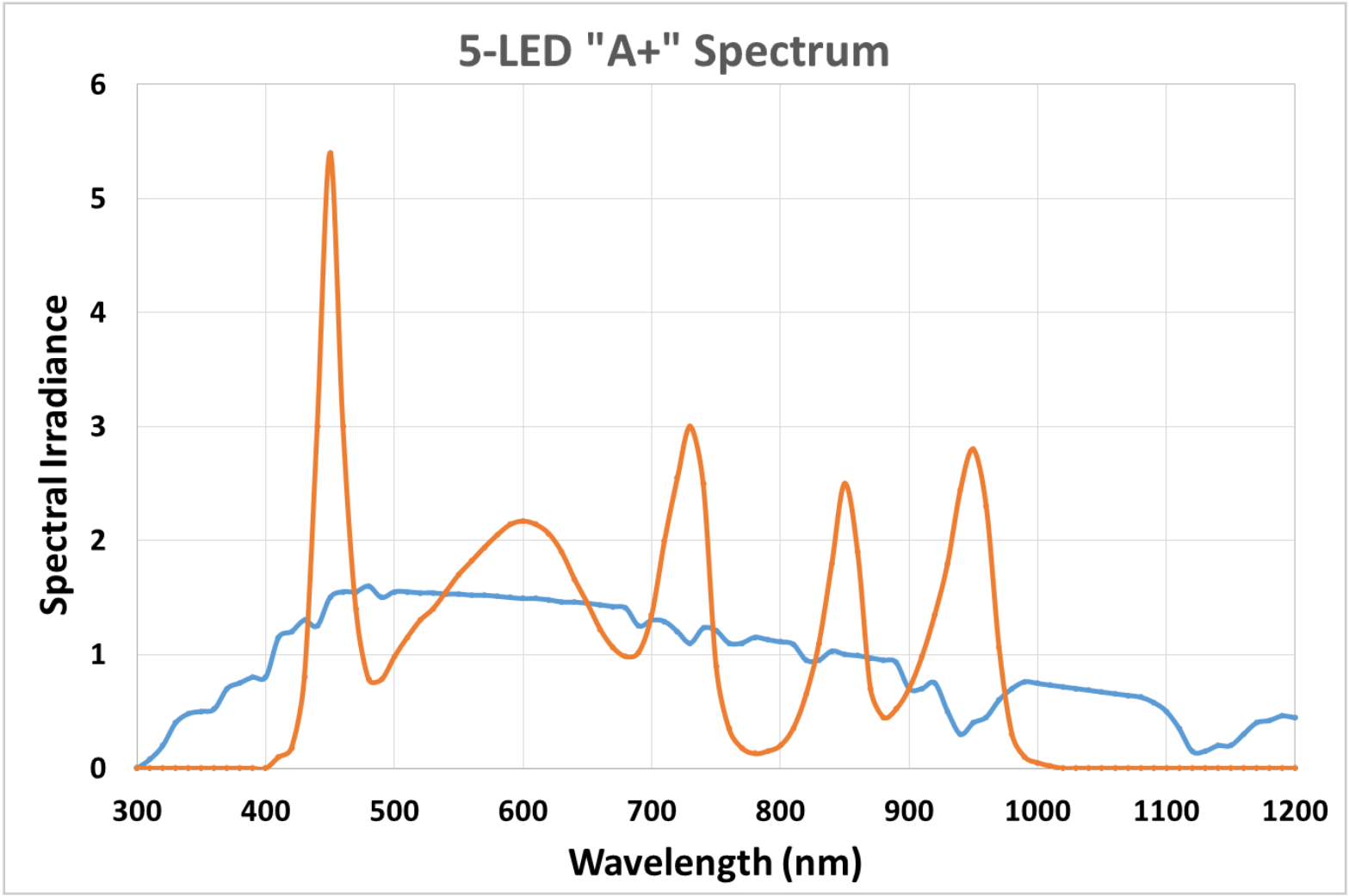
- Photon distribution is nearly perfect where EQE < 1 (dashed blue circles).
- Between these regions EQE ≈ 1, so only the integral matters (dashed blue arrow).
  - (Device does not strongly distinguish between photons at 500 vs. 900 nm).

Filtered Xenon (Class A)



- Diagnosis: too much photogeneration near 900 nm.
  - Total irradiance (900 – 1100 nm) is Class A; but most incoming photons are near 900 nm, where EQE ≈ 1.
  - Overestimates total current; tester less sensitive to spectral response variations from 1000 – 1100 nm.
- This is typical of most filtered Xenon A and "A+" module testers (see spectral data [3]).

5-LED (“Class A+”)



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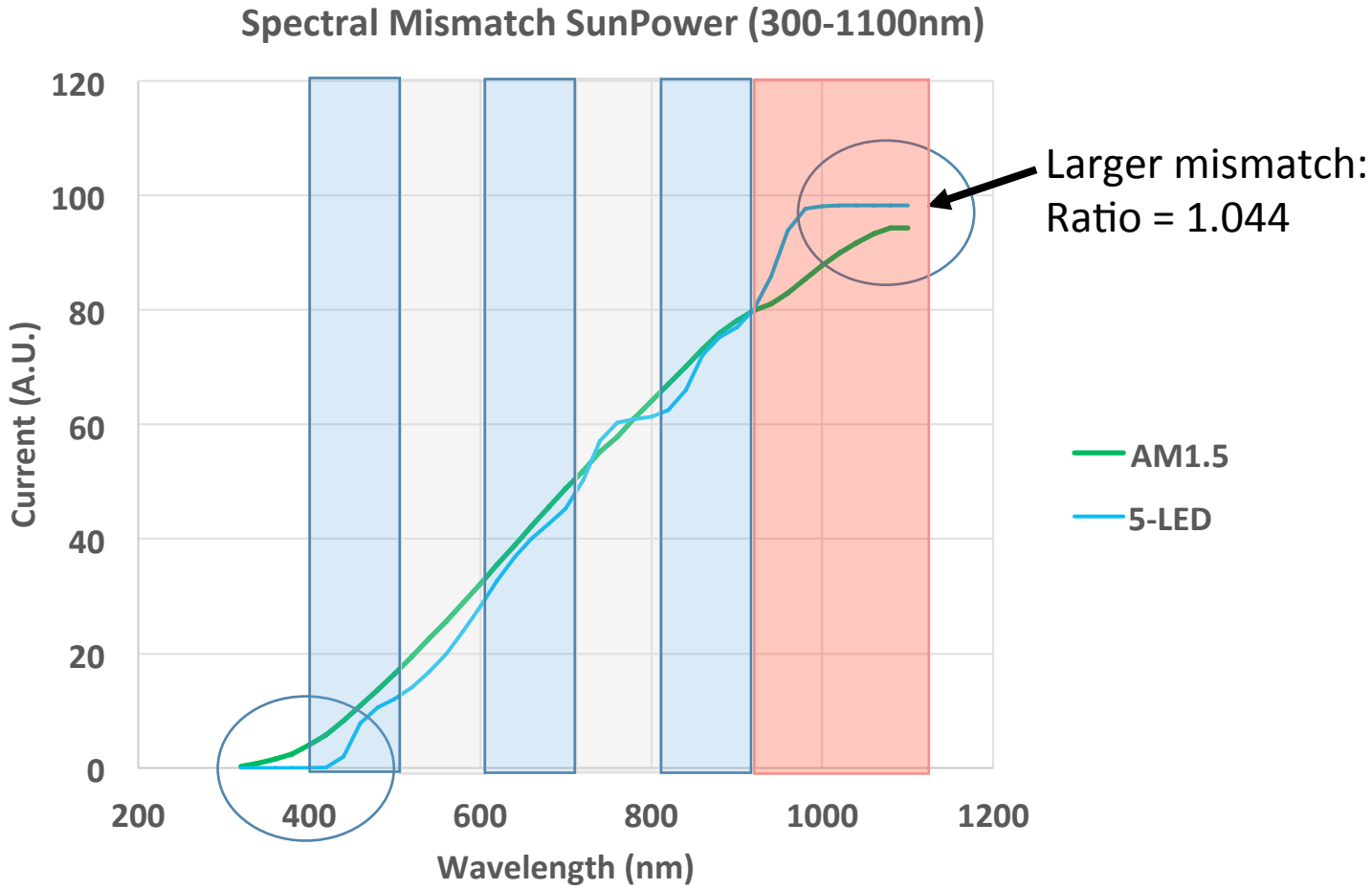
5-LED ("Class A+"): No photogeneration from 980 – 1100 nm!



- Diagnosis: too much photogeneration near 900 nm (same as filtered Xenon Class A, but much more pronounced).
  - Overestimates total current; tester *completely insensitive* to spectral response variations from 1000 – 1100 nm.
  - Similar problem from 300 – 430 nm.
- Issue is invisible when classifying tester with the wide bins of IEC 60904-9.
  - But becomes apparent when analyzing impact on any particular PV technology (e.g., silicon).

Summary of Results for MMF 4 Cases

		Perfect Ref Cell (EQE=1) 300-1100 nm	
Type	Class	SunPower Mono	Trina Multi
Xenon	C	1.009	1.008
Xenon	"A^+"	1.007	1.006
Xenon	A	1.027	1.025
5-LED	"A^+"	1.044	1.041
AM1.5		1	1

- Measurement quality not related to IEC-60904-9 spectral class. This conclusion agrees with the standard & many previous papers on the topic. The standard can incentivize inaccuracy!
- Class C can be more accurate than Class A (or unofficial "Class A^+")!
- A^+ simulators are as prone to mismatch error as any other class

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Power Measurement: No difference!

		Perfect Ref Cell (EQE=1) 300-1100 nm		High eff ref cell 300-1200 nm		Matched ref module	
Type	Class	SunPower Mono	Trina Multi	SunPower	Trina	SunPower	Trina
Xenon	C	1.009	1.008	0.996	0.995	1	1
Xenon	"A+"	1.007	1.006	1.000	1.000	1	1
Xenon	A	1.027	1.025	1.006	1.003	1	1
5-LED	"A+"	1.044	1.041	1.009	1.003	1	1
AM1.5		1	1	1	1	1	1

Name-plate power independent of spectral class!

Using best practice in industry (matched reference module) A-C spectral classification will give identical results!

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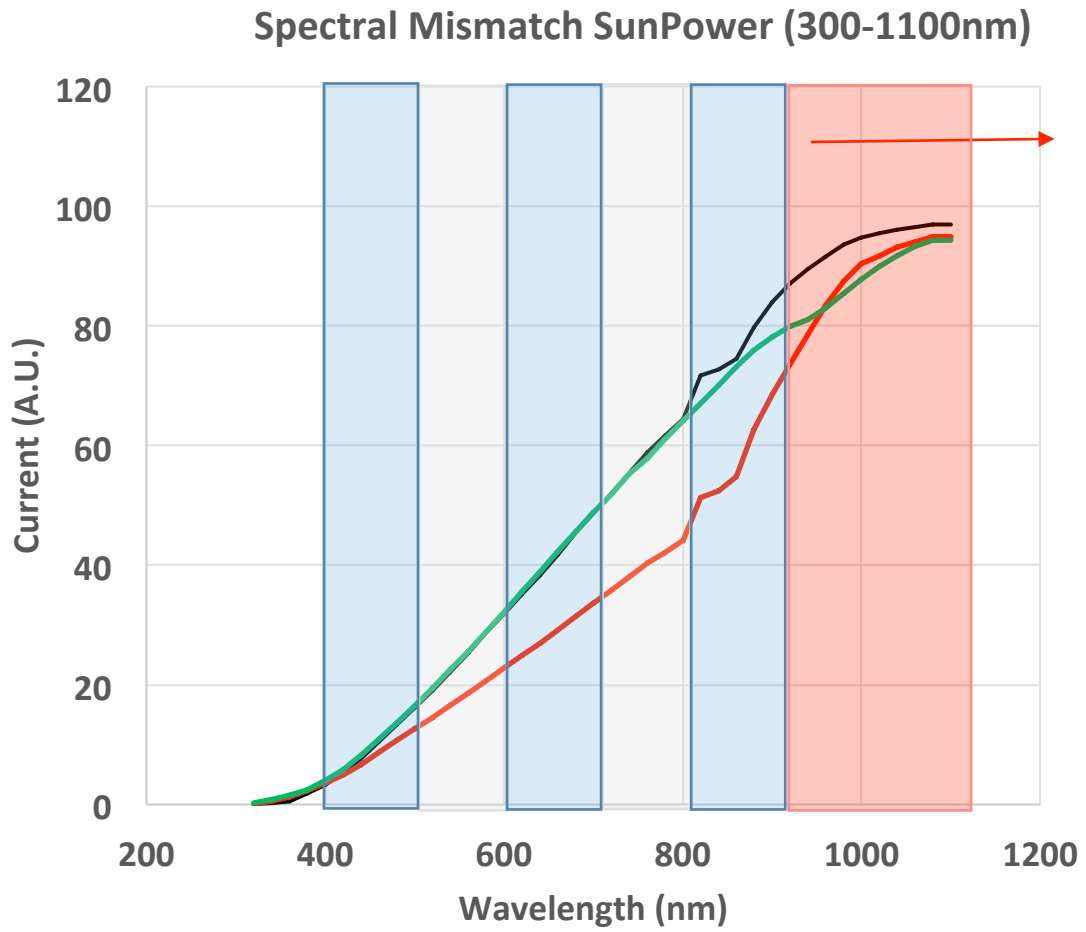
Xenon, filtered to Class A, often WORSE than Class C!



Problem: Wide bin in region where Si EQE goes from near 100%-0%.

This is typical of many filtered Xenon A and "A+" module testers (see spectral data [3]). Multiple C spectra have also given the result shown here

Problem with 60904-9: Solar cells see photon bins, not energy bins, and wide bins that span vast changing EQE of the DUT cause huge DUT Isc differences invisible to 60904-9 depending on where photons are in the bin. Accuracy evaluation requires material-specific EQE.

Blunt Opinionated Conclusion

- IEC 60904-9 classification does not correlate with accuracy, repeatability, ease of use, or cost effectiveness

Conformity ⇏ Accuracy

Optimize accuracy:

Capacitance (high eff solar cells)

Device physics and software analysis

Angular acceptance

→ Matched reference cell (module)

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Blunt Opinionated Conclusion: Details

- Misuse of IEC 60904-9 imposes costs on the industry without obvious benefit.
  - Classification is misleading. Meaningless arms race to claim A^+ for marketing purposes.
  - Very accurate purpose-built simulators can be severely punished by 60904-9
    - ("Class C" of shame)
  - Arbitrary "rules" constrain simulator design for accuracy and cost effectiveness.
- The goal should be metrics for accuracy. Why discourage innovation?
- IEC 61215 (type testing) bans "C", declares "A" infallible. Both statements are technically false. Revise ASAP with technically-accurate provisions.
- References to AAA, CBA, etc. could be deleted from standards or supplemented. Certificate of applicability? (accuracy, repeatability, uncertainty for the specific purpose)
- For the particular case of spectral classification, closeness to the "6 magic numbers" does NOT insure good performance. A^+ concept, in particular, is not especially useful.

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Acknowledgements:

The authors would like to acknowledge interesting discussions and/or data exchange with:

Werner Herrmann (TÜV Rheinland Group)
Christos Monokroussos (TÜV Rheinland Group)
Tony Sample (EC Joint Research Center)
Karsten Bothe (ISFH Germany)
All the customers from 20 years enabling our expertise

However, the authors alone are responsible for the potentially controversial conclusions.

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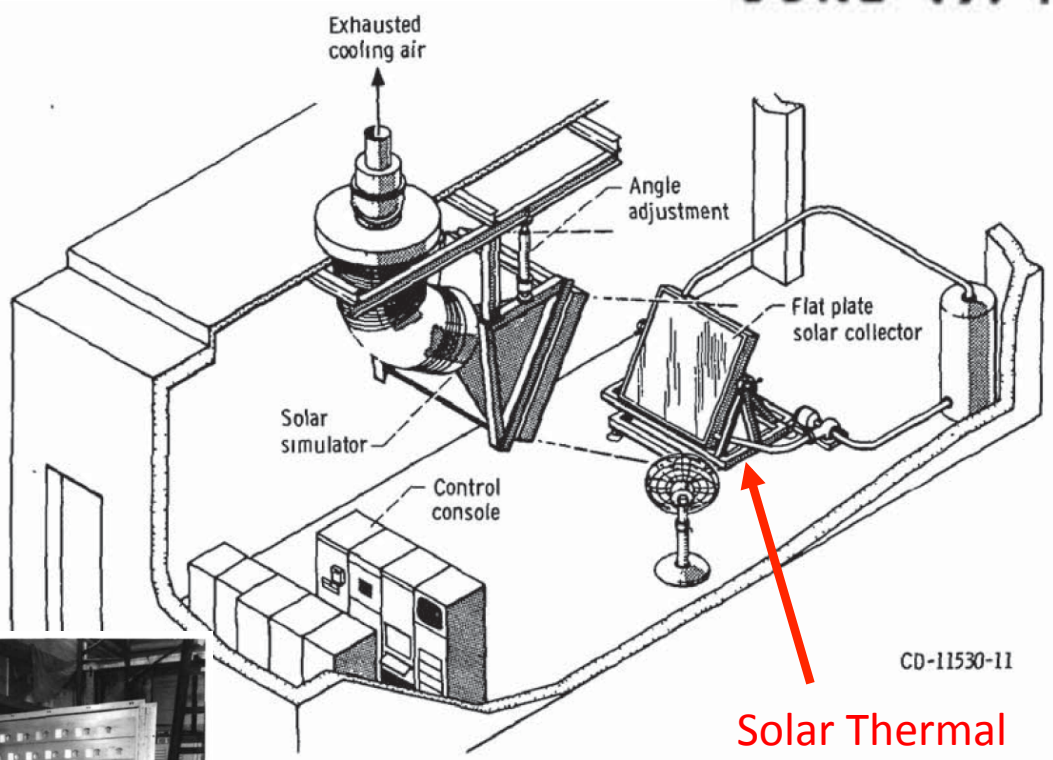
History: NASA publication 1974

TABLE I. - PERCENT ENERGY IN WAVEBANDS

Wavelength, Δλ, μm	Lamp voltage				Air mass 2
	90	105	120	117	
	Prototype lenses				
	Old	Old	Old	New	
	Percent energy				
0.3 - 0.4	0.4	0.8	0.7	0.3	2.7
0.4 - 0.7	44.1	48.0	50.8	48.4	44.4
0.7 - 1.0	31.0	30.4	30.0	29.5	28.6
1.0 - ---	24.5	20.8	18.5	21.8	24.3

JUNE 1974



Solar Thermal

Figure 1. - Indoor test facility.

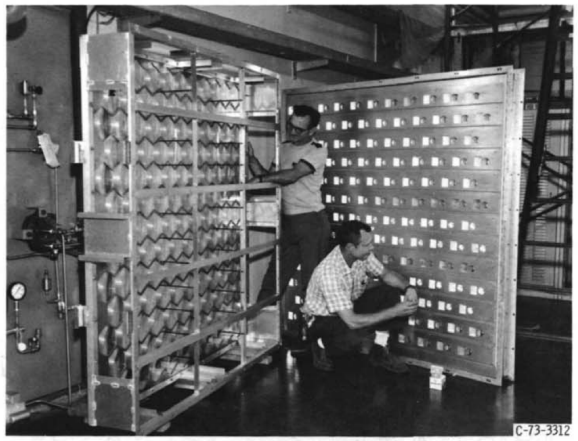


Figure 3. - Lens and lamp sections before assembly.

NASA TECHNICAL MEMORANDUM

059

NASA

Sinton instruments

LID effects and long term stability in PERC solar modules

2017 NREL PV Module Reliability Workshop

Max B. Koentopp

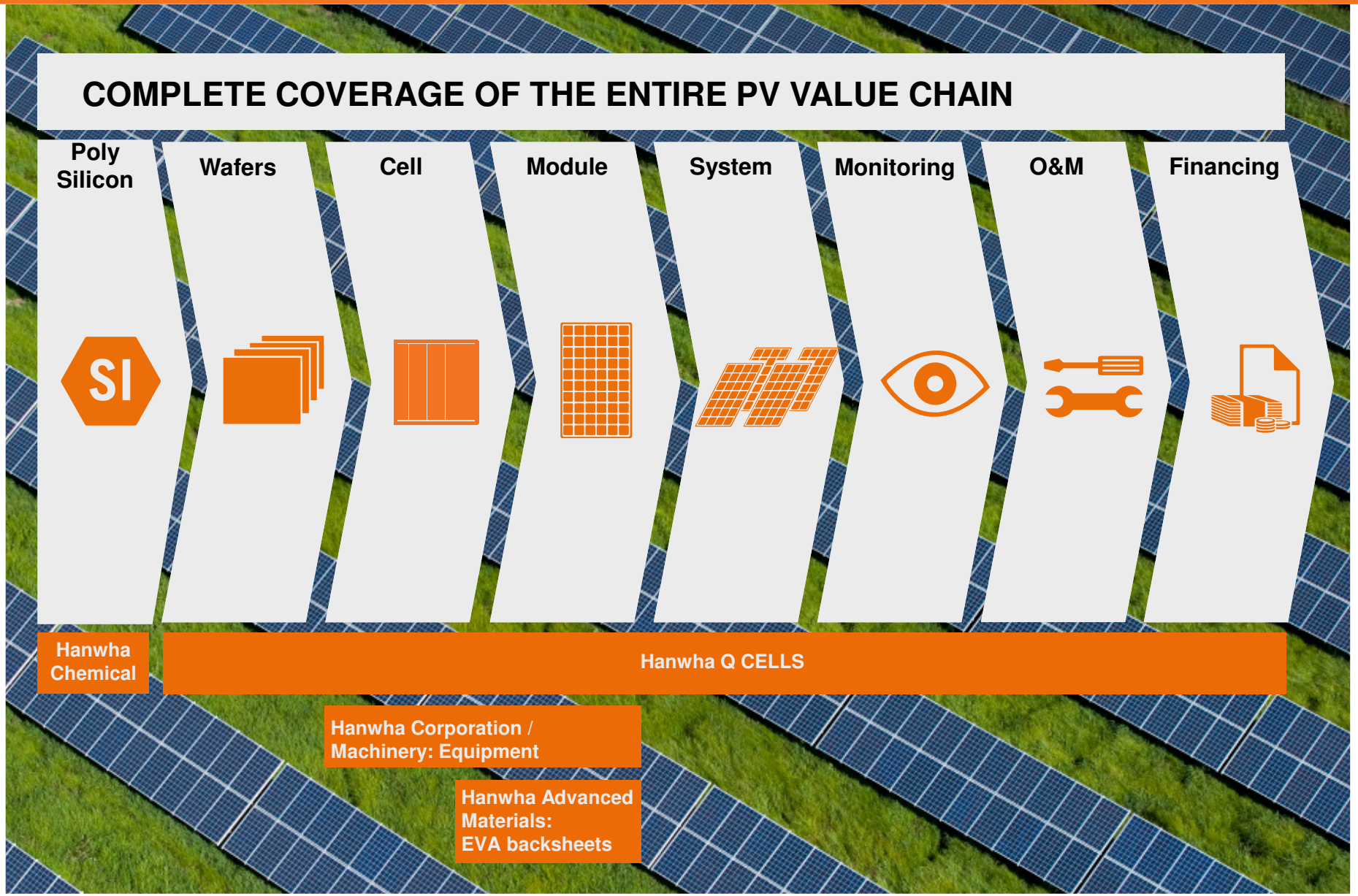
Hanwha Q CELLS

CONTENTS

- **Introduction**
- **Characteristics of light and elevated temperature induced degradation in mc-PERC**
  - Timescale
  - Influence of excess charge carrier concentration
  - Influence of temperature
  - Current injection vs light
  - Impact of wafer supplier
- **Testing for light and elevated temperature induced degradation**
- **Outdoor Results**
- **Mono PERC**
- **Summary and Outlook**

INTRODUCTION
HANWHA GROUP PV VALUE CHAIN

Hanwha Q CELLS



INTRODUCTION
GLOBAL SETUP OF R&D AND PRODUCTION

Germany
- **Global R&D Center (>210)**
- Global QM
- Module Test Lab

Korea
- Capacity (2016YE):
  Cell 1,400MW
  Module 1,600MW

Engineering
- Continuous improvement
- Module Test Lab

Malaysia
- Capacity(2015YE):
  Cell 1,700MW
  Module 1,600MW

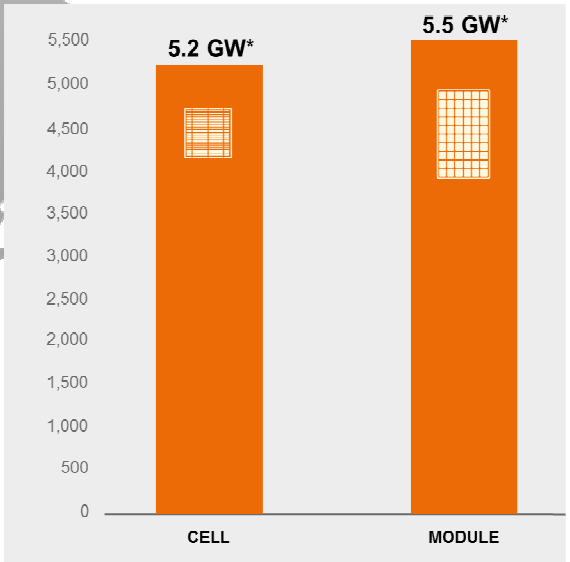
Engineering
- Continuous improvement

China (LYG)
- Capacity(2015YE):
  Ingot 1,400MW
  Wafer 900MW

Engineering
- Crystallization
- Continuous improvement

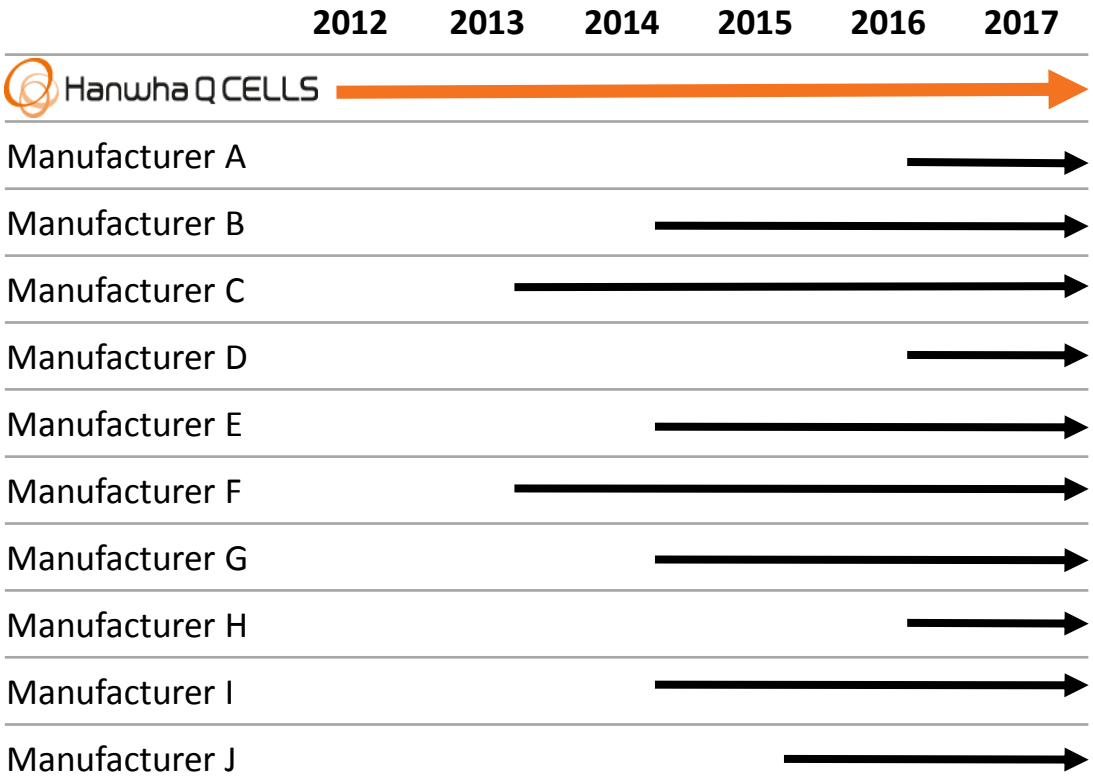
China (QD)
- Capacity(2015YE):
  Cell 2,100MW
  Module 2,100MW

Engineering
- Continuous improvement
  - Product development
  - Module Test Lab



* As of end of Q1, 2016

INTRODUCTION
PRODUCTION EXPERIENCE WITH PERC



- Hanwha Q Cells with **longest PERC production experience** of all PV manufacturers
- Hanwha Q Cells with **largest PERC production capacity (> 3.5 GW)**

Source: PV-Tech : Solar Intelligence, Oct. 2016 (Report 2016/3), Solar Media Limited, 2016

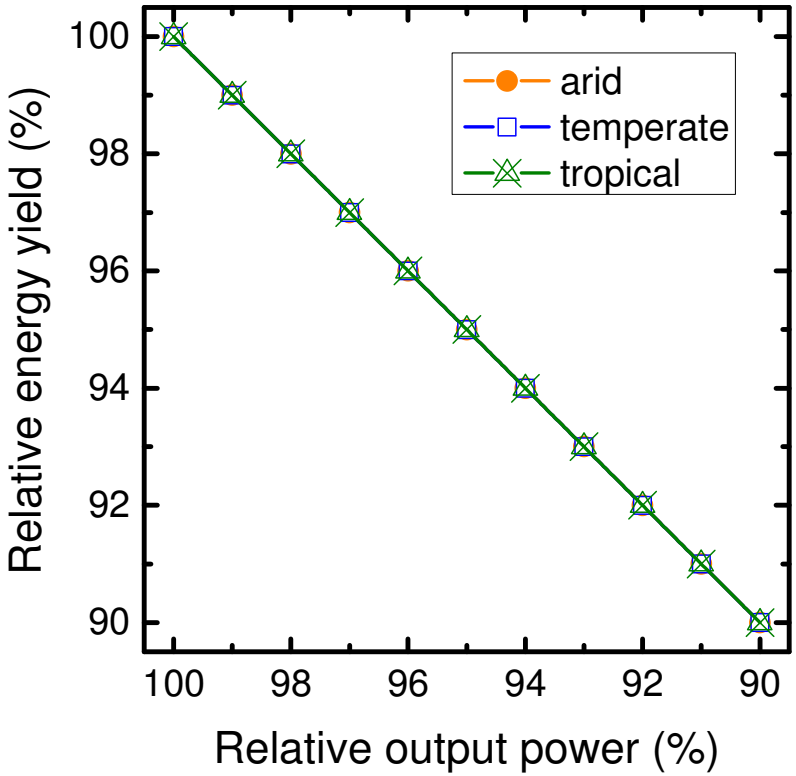
NAMEPLATE AND YIELD

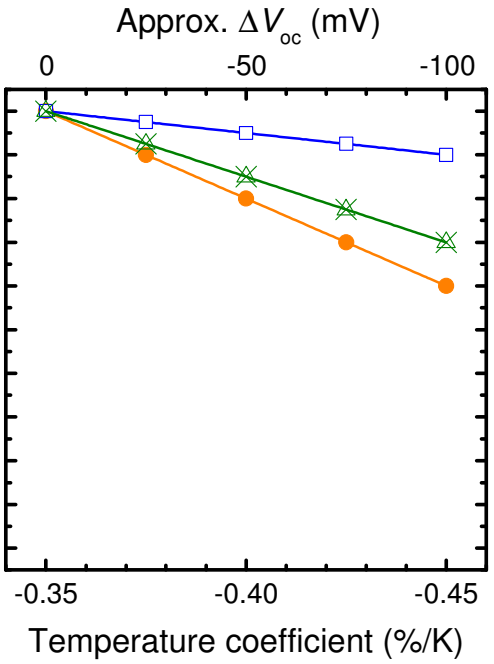
Highest impact on yield & LCOE:

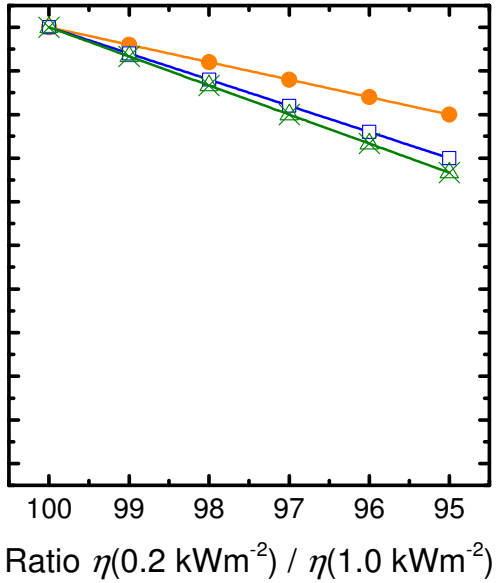
- Nameplate / STC performance
- LID effects
- PID effects

Less impact on yield /LCOE:

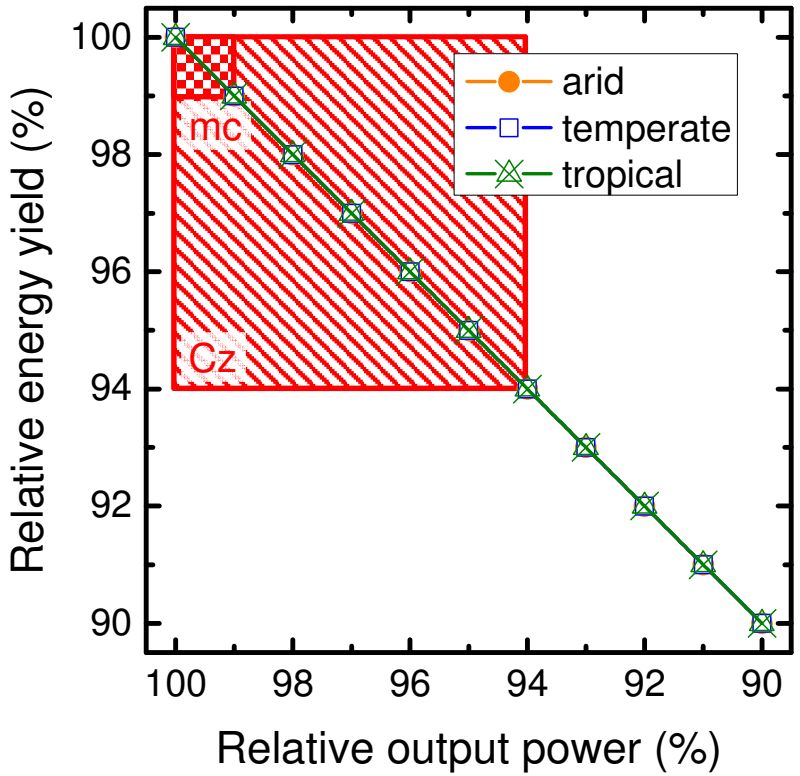
- Temperature coefficient
- Weak light behavior







DEGRADATION MECHANISMS IN PERC

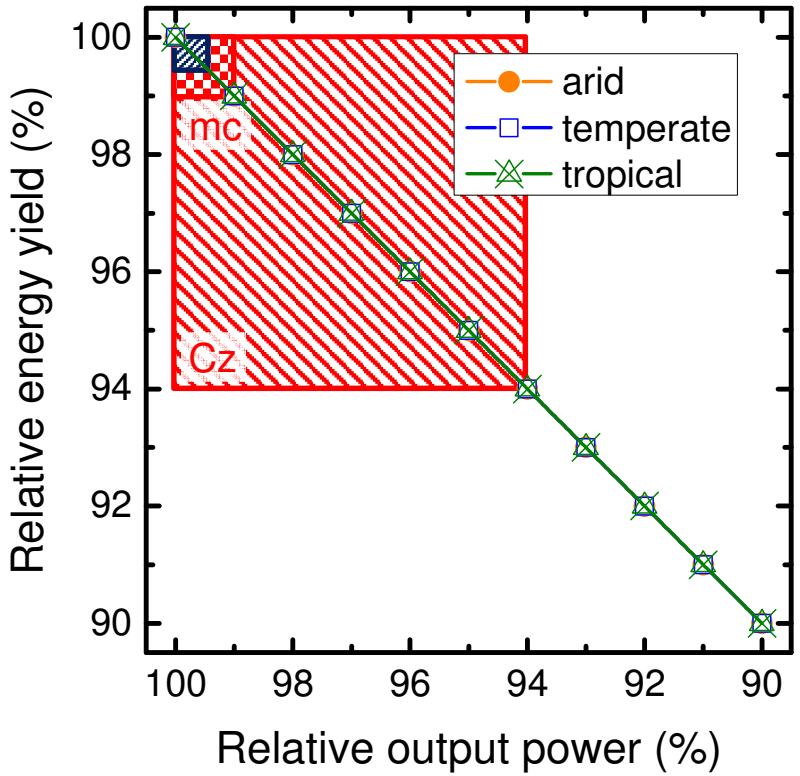


Degradation mechanisms

- **BO complex**[1,2] : mainly p-Cz, up to ~ 6 %

[1] S. Rein *et al.*, in: Proc. 17th EUPVSEC, 1555–1560, Munich, Germany, 2001.
[2] J. Schmidt and K. Bothe, Phys. Rev. B **69**, 024107, 2004.

DEGRADATION MECHANISMS IN PERC



Degradation mechanisms

- **BO complex**[1,2] : mainly p-Cz, up to ~ 6 %
- **FeB/Fe_i**[3,4]: mono and multi, ~ up to ~1 %

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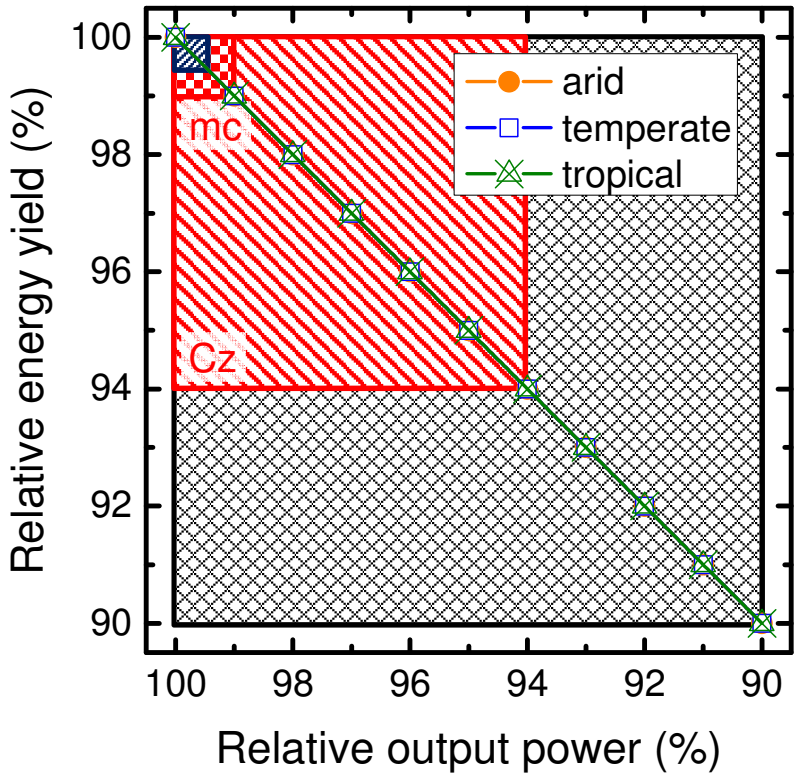
[3] D. H. Macdonald *et al.*, J. Appl. Phys. **95**, 1021, 2004.
[4] S. Rein and S. W. Glunz, J. Appl. Phys. **98**, 113711, 2005.

DEGRADATION MECHANISMS IN PERC

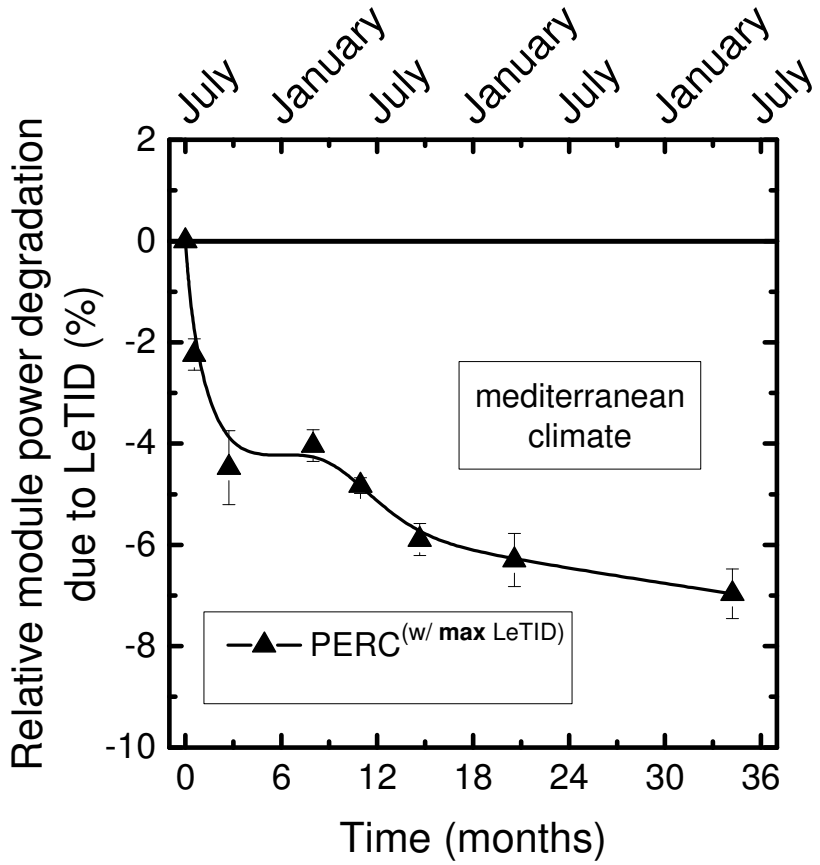


Degradation mechanisms

- **BO complex**[1,2] : mainly p-Cz, up to ~ 6 %
- **FeB/Fe_i**[3,4]: mono and multi, ~ up to ~1 %
- **LeTID**[5-7]: multi PERC, up to ~ 13 %

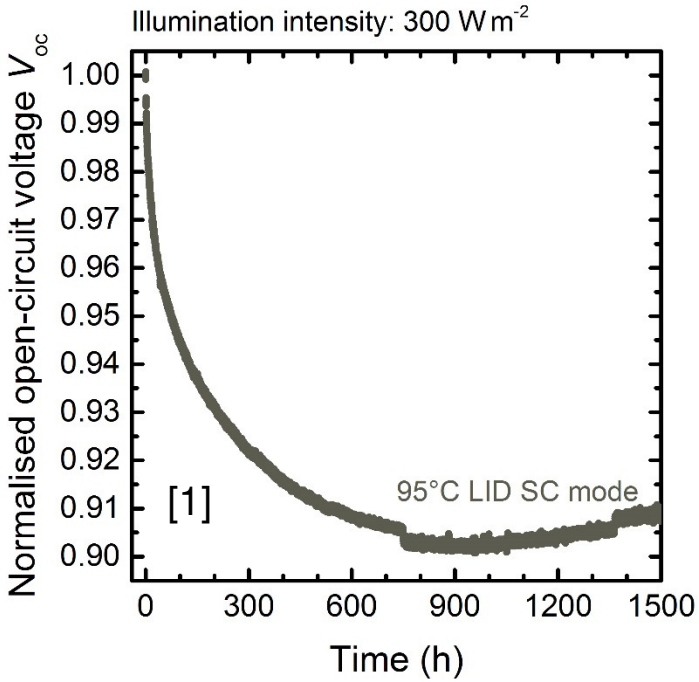
[1] S. Rein *et al.*, in: Proc. 17th EUPVSEC, 1555–1560, Munich, Germany, 2001.
[2] J. Schmidt and K. Bothe, Phys. Rev. B **69**, 024107, 2004.
[3] D. H. Macdonald *et al.*, J. Appl. Phys. **95**, 1021, 2004.
[4] S. Rein and S. W. Glunz, J. Appl. Phys. **98**, 113711, 2005.
[5] K. Ramspeck *et al.m* in Proc. 27th EUPVSEC, 861–865, Frankfurt, Germany, 2012.
[6] F. Fertig *et al.,* phys. stat. sol. (RRL) **9**, 41–46, 2015.
[7] F. Kersten *et al.,* Sol. Energ. Mat. Sol Cells **142**, 83–86, 2015.

CHARACTERISTICS OF LeTID:
TIMESCALE IN HOT CLIMATE (CYPRUS TEST FIELD)



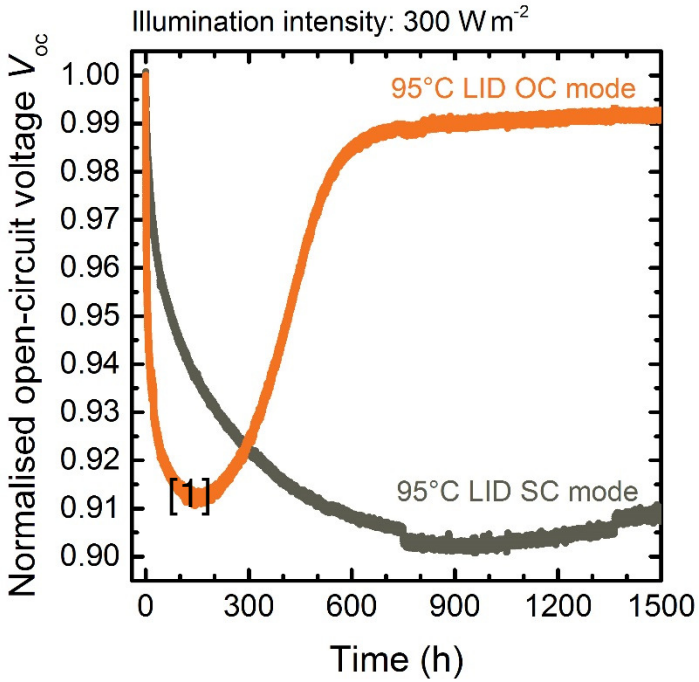
- Degradation takes several years to fully develop even in hot Mediterranean climate of Cyprus

CHARACTERISTICS OF LETID:
TEMPERATURE AND INJECTION LEVEL



[1] F. Kersten *et al.* "Degradation of multicrystalline silicon solar cells and modules after illumination at elevated temperature," Sol. Energ. Mat. Sol Cells **142**, 83–86, 2015.

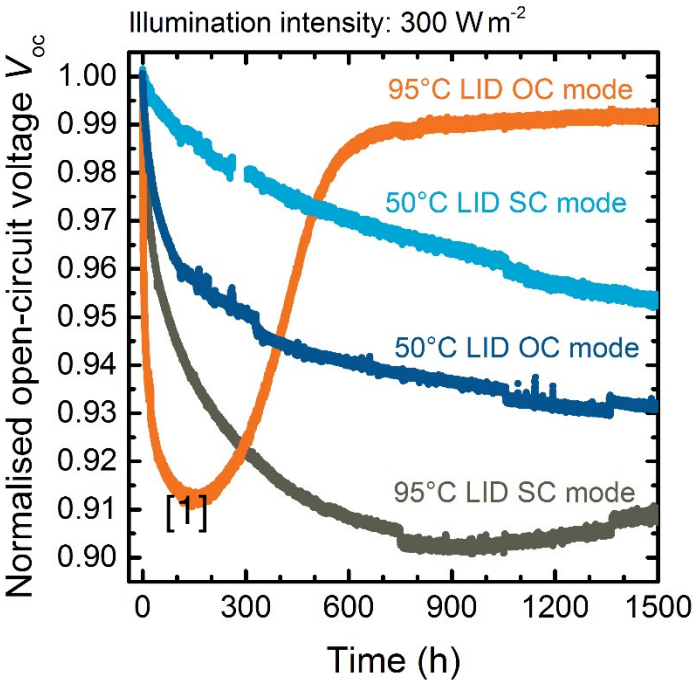
CHARACTERISTICS OF LETID:
TEMPERATURE AND INJECTION LEVEL



- Formation rate increases with injection level
- LeTID features a regeneration phase

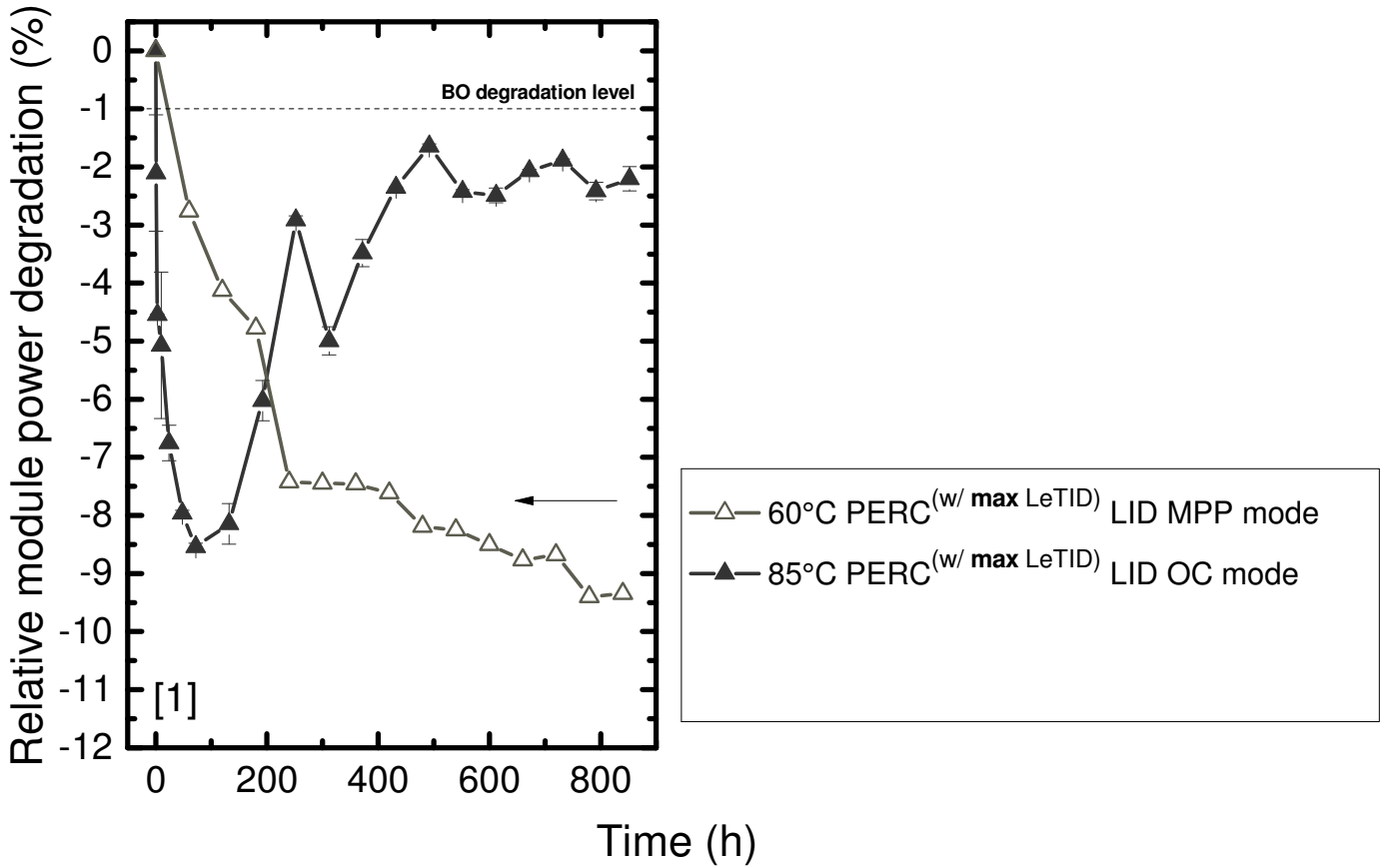
[1] F. Kersten *et al.* "Degradation of multicrystalline silicon solar cells and modules after illumination at elevated temperature," Sol. Energ. Mat. Sol Cells **142**, 83–86, 2015.

CHARACTERISTICS OF LETID:
TEMPERATURE AND INJECTION LEVEL



- Formation rate increases with temperature
- LeTID -- Light and elevated Temperature Induced Degradation
- Takes several hundred hours to develop

LeTID ON MODULE LEVEL
Mpp VS OPEN CIRCUIT CONDITIONS



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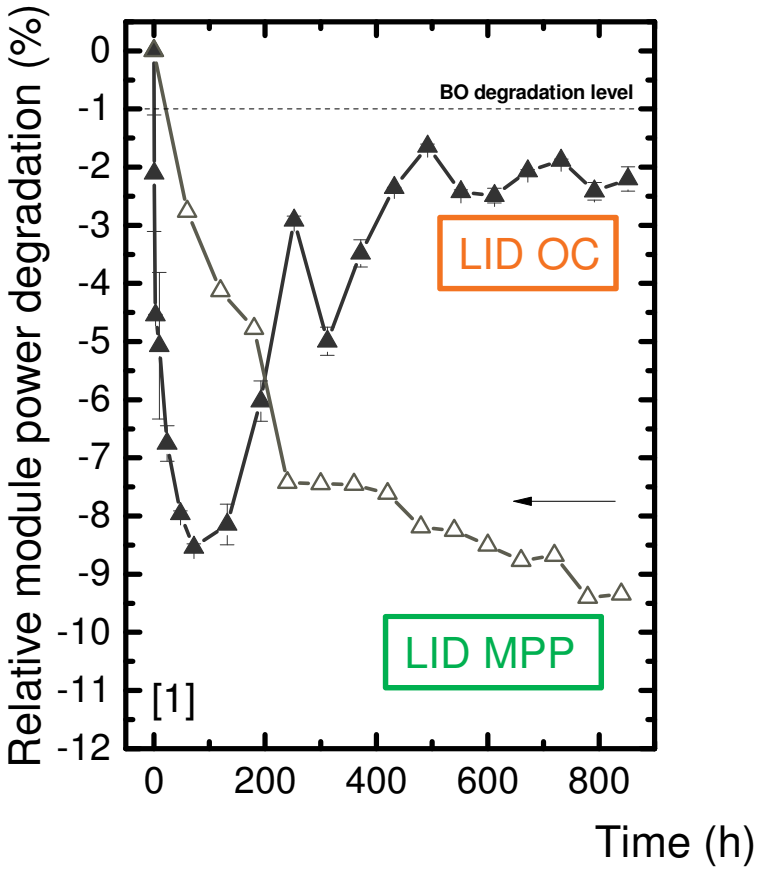
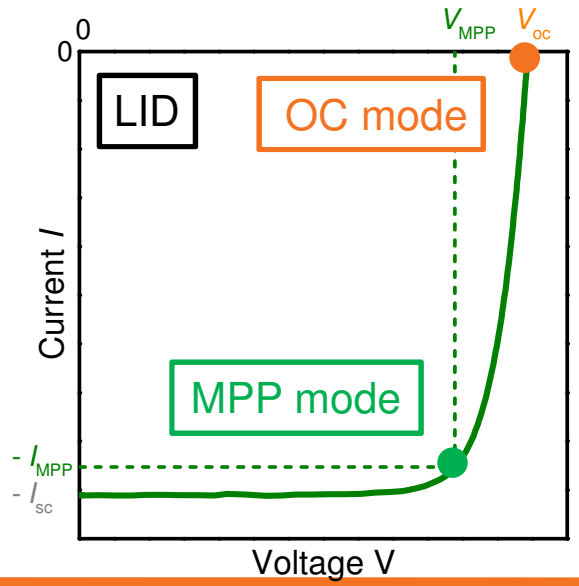
LeTID ON MODULE LEVEL

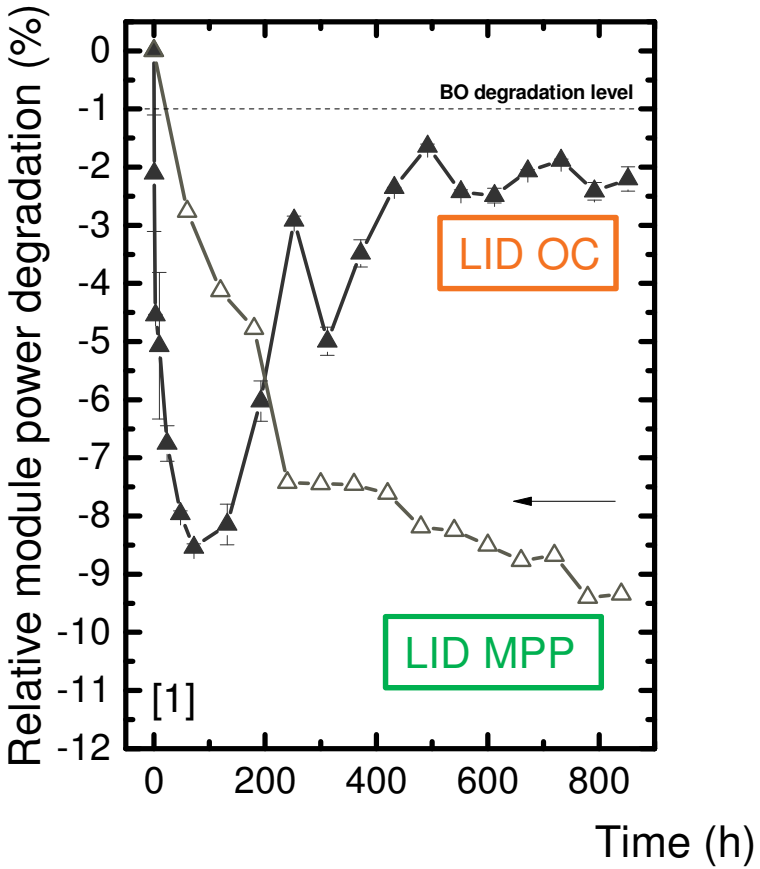
Mpp VS OPEN CIRCUIT CONDITIONS

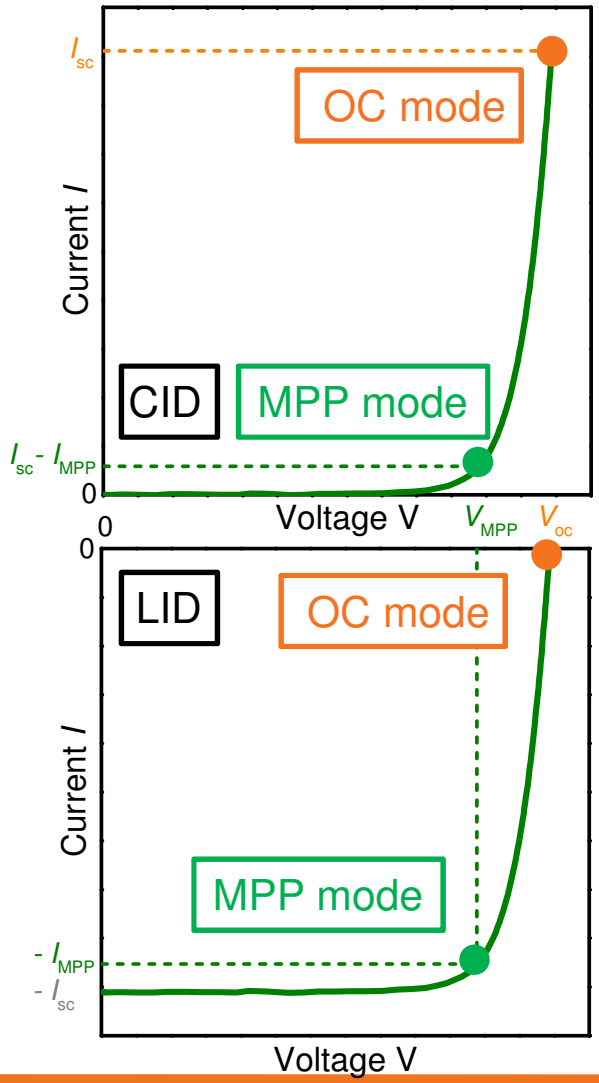




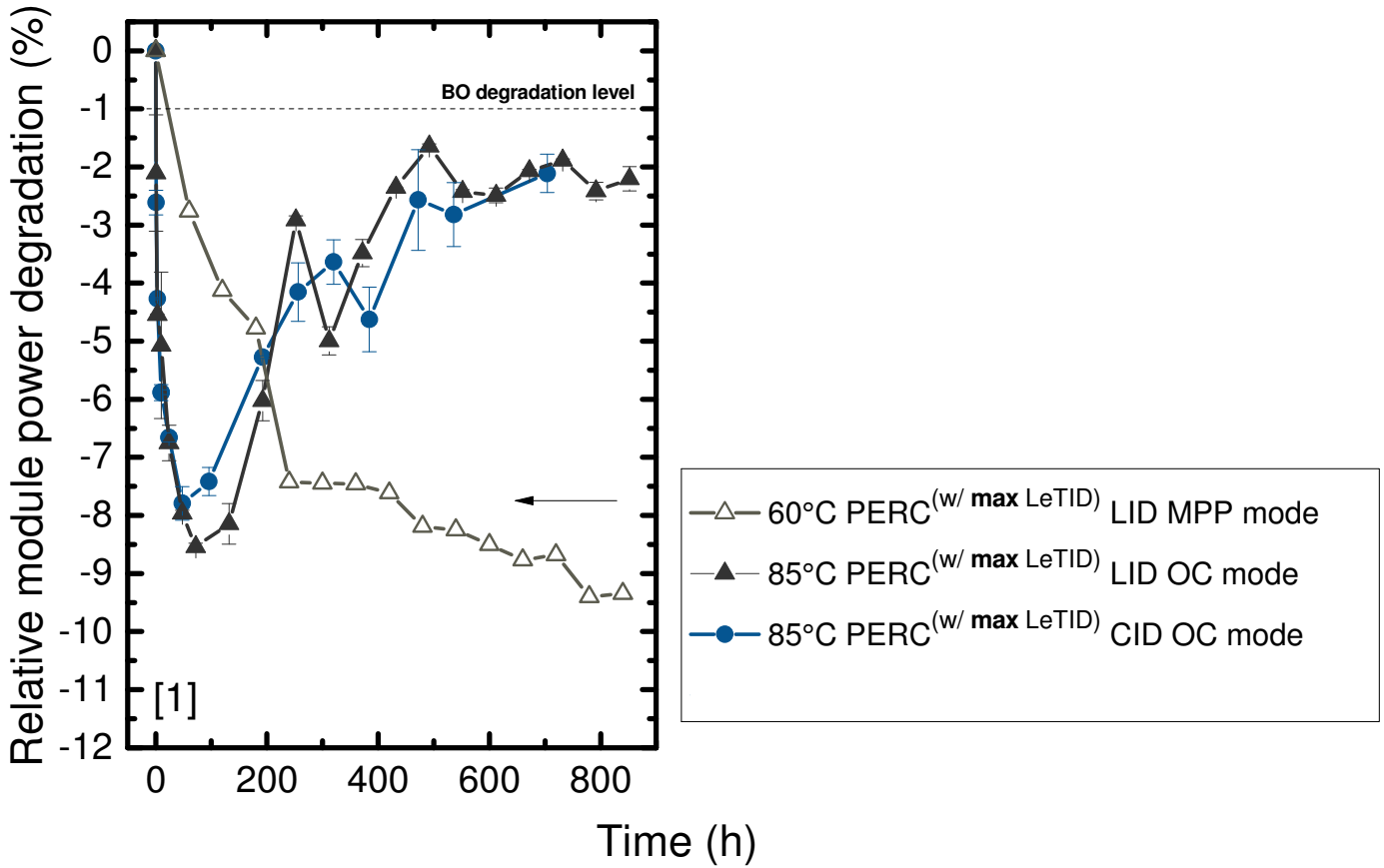
LeTID ON MODULE LEVEL

Mpp VS OPEN CIRCUIT CONDITIONS





LeTID ON MODULE LEVEL
CURRENT INJECTION VS LIGHT INDUCED



LeTID ON MODULE LEVEL
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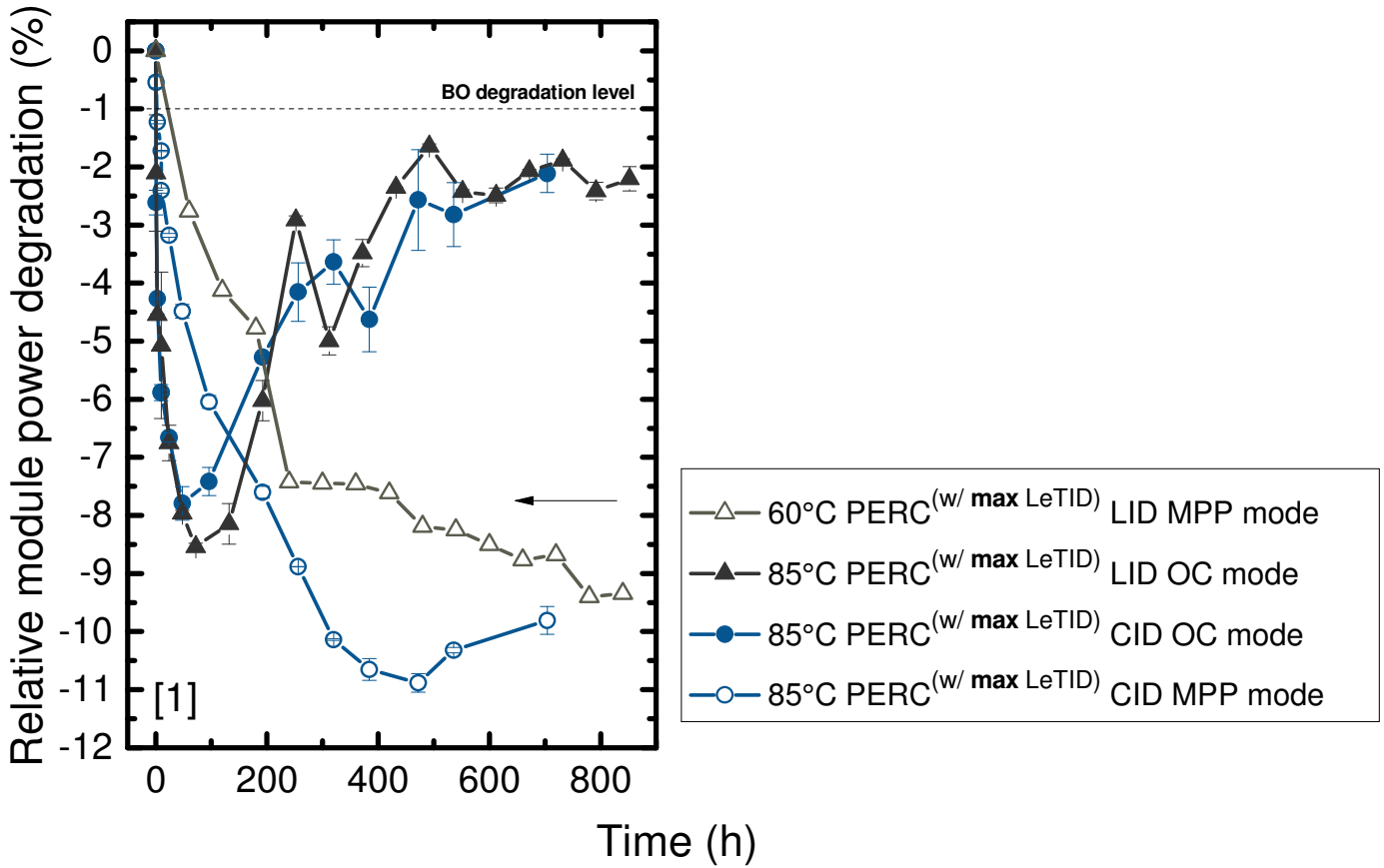

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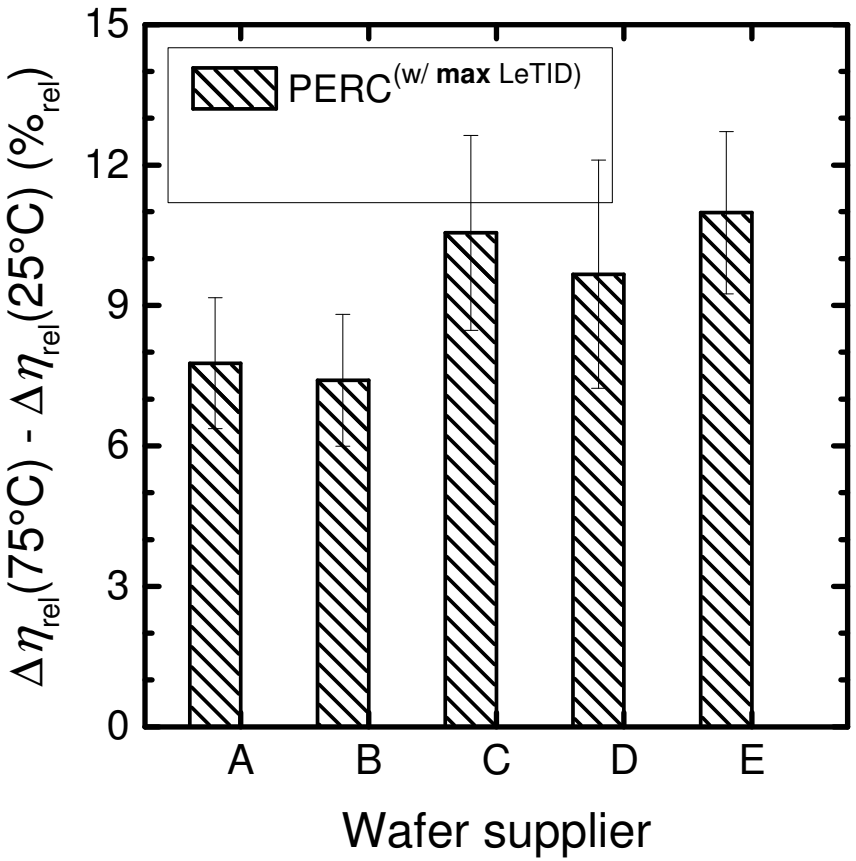
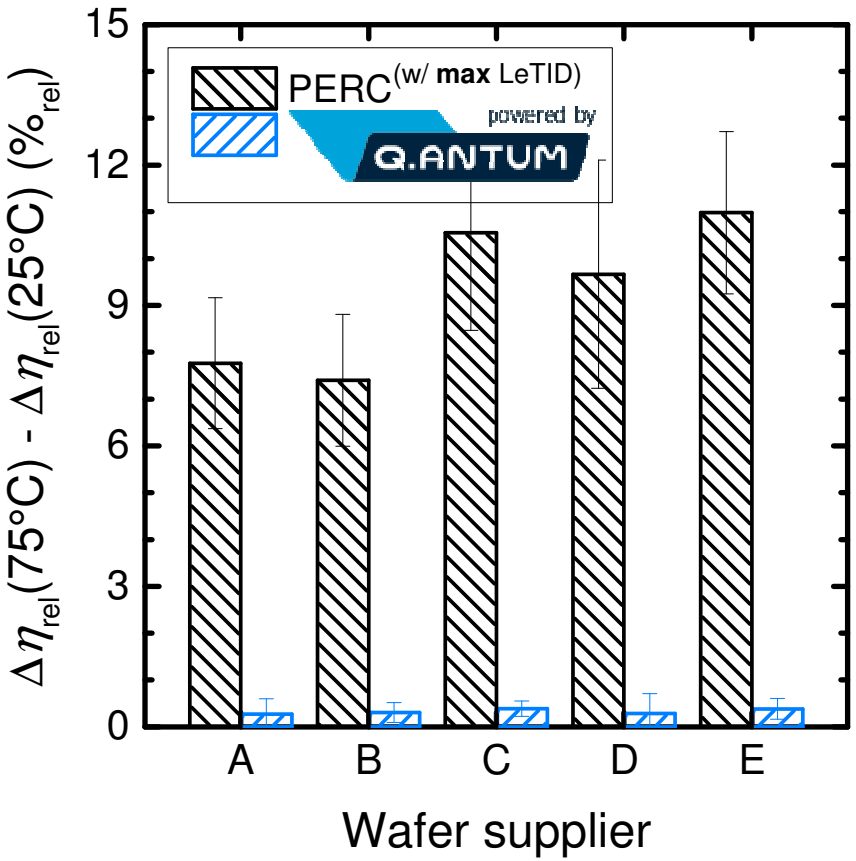
IMPACT OF WAFER SUPPLIER
SUPPRESION OF LeTID



- Full bricks from five suppliers
- Every wafer supplier shows significant LeTID
- LeTID suppressed by **Q.ANTUM Technology**

IMPACT OF WAFER SUPPLIER
SUPPRESION OF LeTID



- Full bricks from five suppliers
- Every wafer supplier shows significant LeTID
- LeTID suppressed by **Q.ANTUM Technology**

CHARACTERISTICS OF LeTID

Summary

Characteristics of light and elevated temperature induced degradation

- Occurs at elevated temperatures (>50 °C)
- Is characterized by degradation of Isc, Voc, Pmpp followed by slow recovery over time
- Is caused by excess carriers → can be induced either via illumination or current injection
- Is a slow process that takes hundreds of hours in lab and up to many years in the field
- Speed depends on injection level and temperature

Target/Scope of an LeTID test

- Stabilization of module before durability test? → not feasible due to cyclic nature and test duration
- Detection of excessive degradation feasible.
  - What is excessive?
  - How accurately do we need to determine the max. degradation?

PROPOSED TEST SEQUENCE

Test procedure

- **Use current instead of light** to stress module →minimize cost and effort
  Injection level comparable to maximum power point conditions.

- **Determine level of LeTID**
  or
  minimum in degradation curve
  → several rounds of current stress with

- Use a **temperature that allows test in reasonable time** without risking to miss minimum.

parameters

Climatic cabinet with power sources to inject current into modules

Current level $\mathbf{I_{test} = I_{sc} - I_{mpp}}$

Test for **one week**

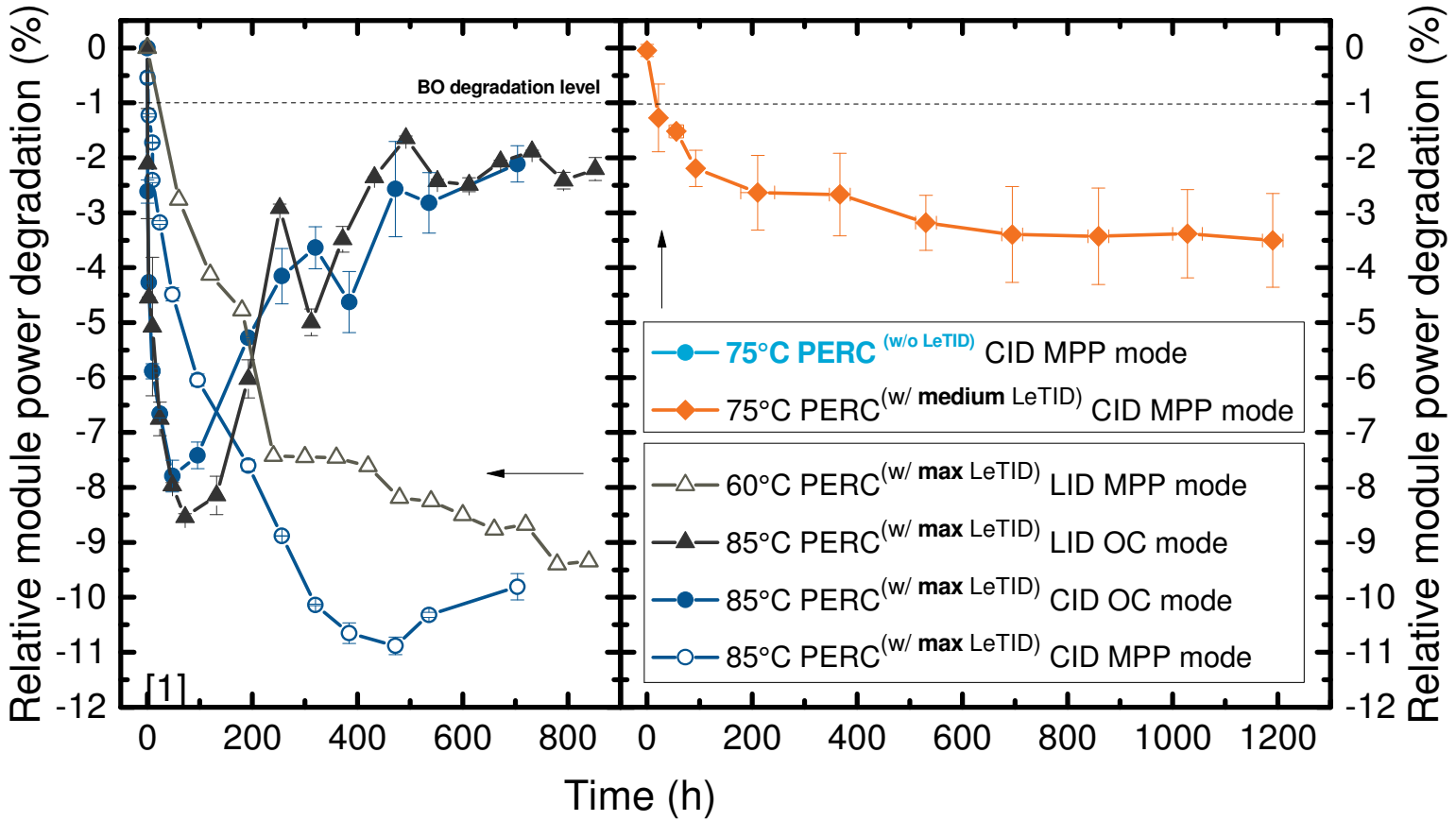
or

Stress **4 days** at a time, Pmpp measurements in-between.Repeat until <1% change

75 °C

IEC TS Standard Proposed by IEC 61215 Amendment team. Volunteers?

TESTING FOR LETID



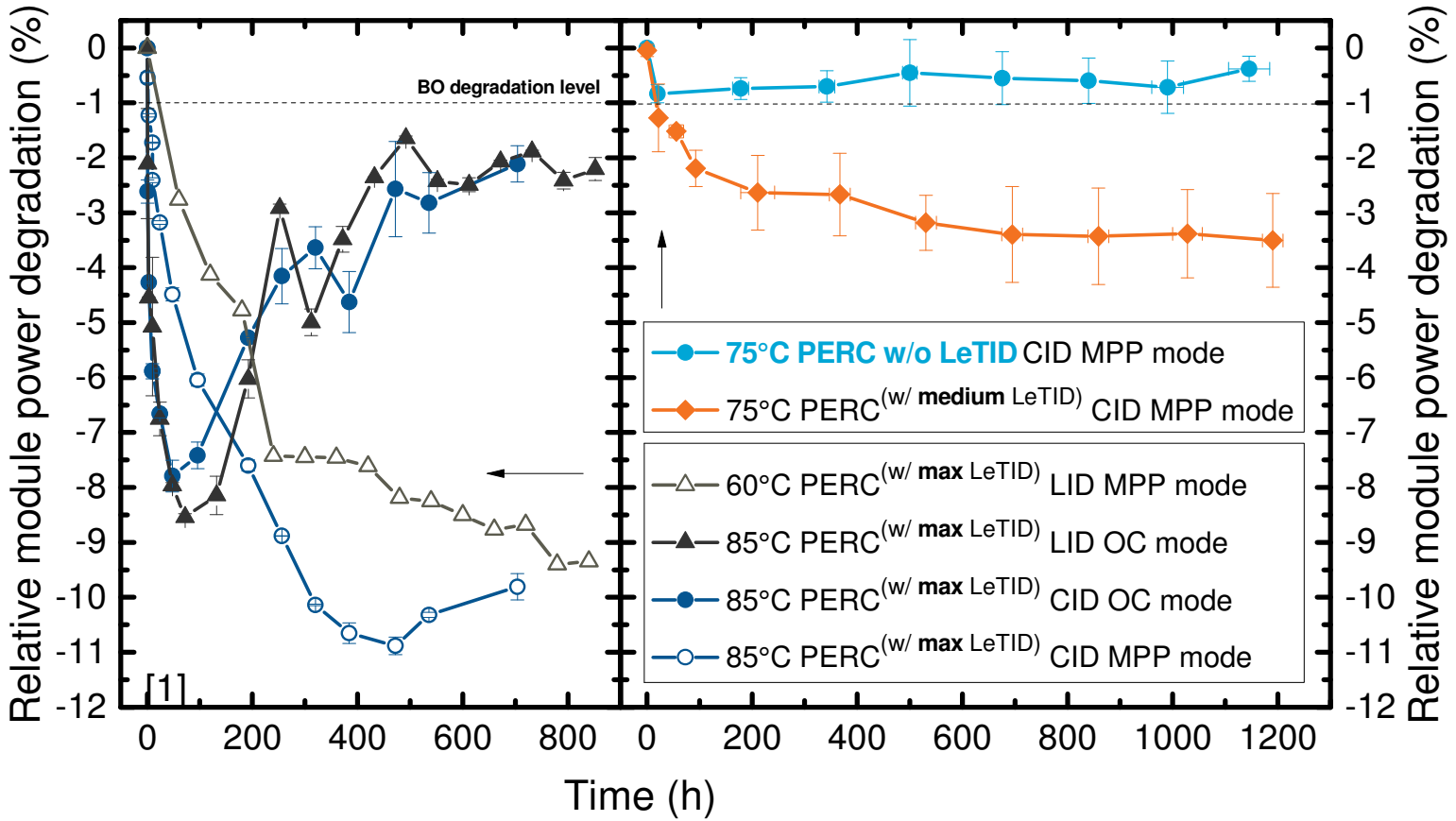
LeTID TEST PROPOSAL

CID at 75°C in MPP mode

- identify power losses due to LeTID at a reasonable speed,
- Avoid missing the minimum

[1] F. Kersten *et al.* "Degradation of multicrystalline silicon solar cells and modules after illumination at elevated temperature," Sol. Energ. Mat. Sol Cells **142**, 83–86, 2015.

TESTING FOR LETID



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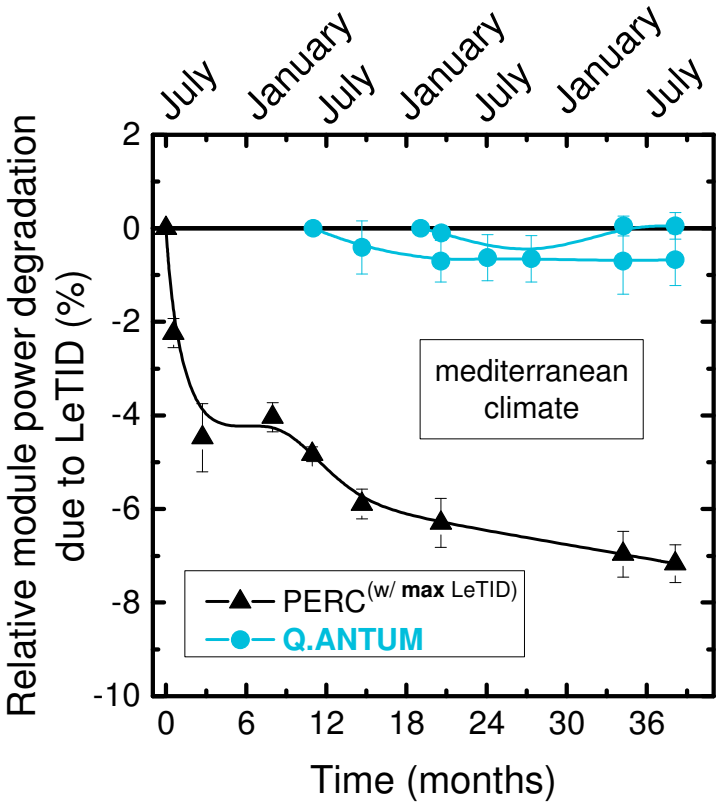
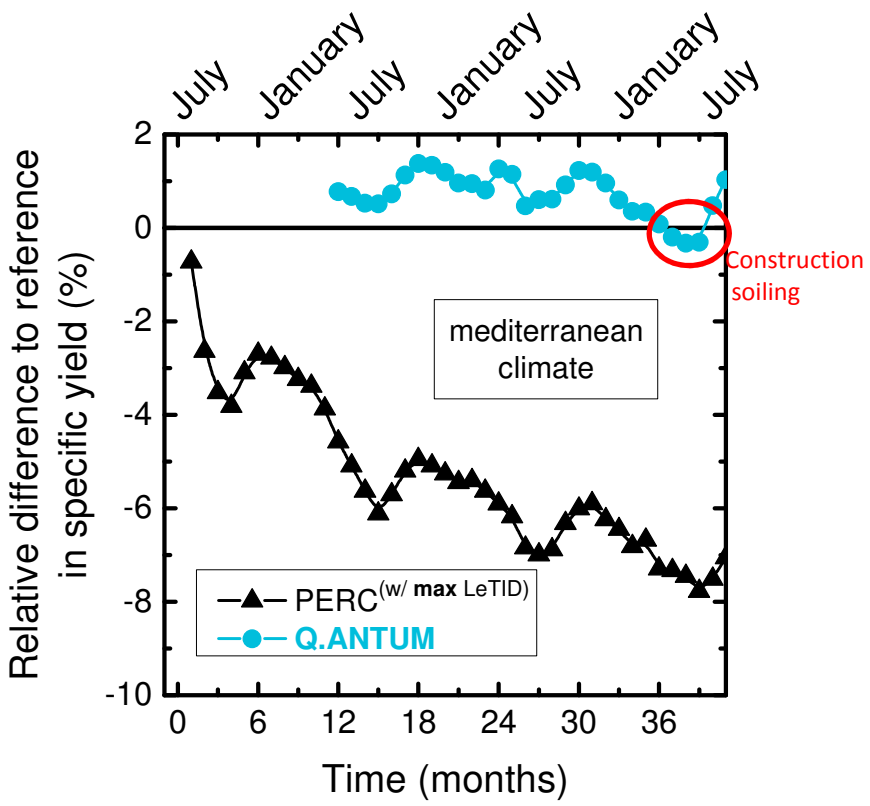
LeTID
OUTDOOR TESTING IN CYPRUS OVER 3.5 YEARS





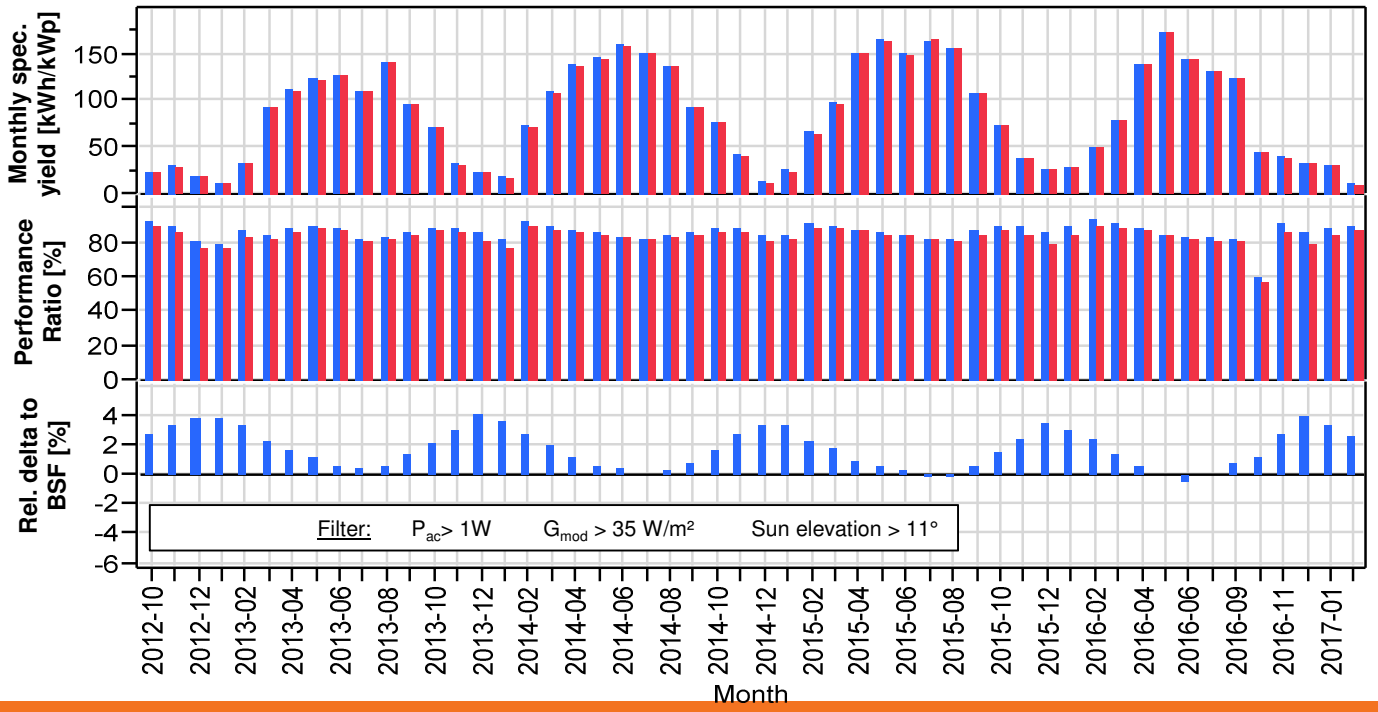
- LeTID takes months to develop and can significantly reduce energy yield
- **Q.ANTUM Technology** suppresses LeTID permanently in the field
- 3.5 years without degradation

TEST FIELD AT GERMANY

Q.ANTUM-TECHNOLOGY VS STANDARD-BSF

Hanwha Q CELLS

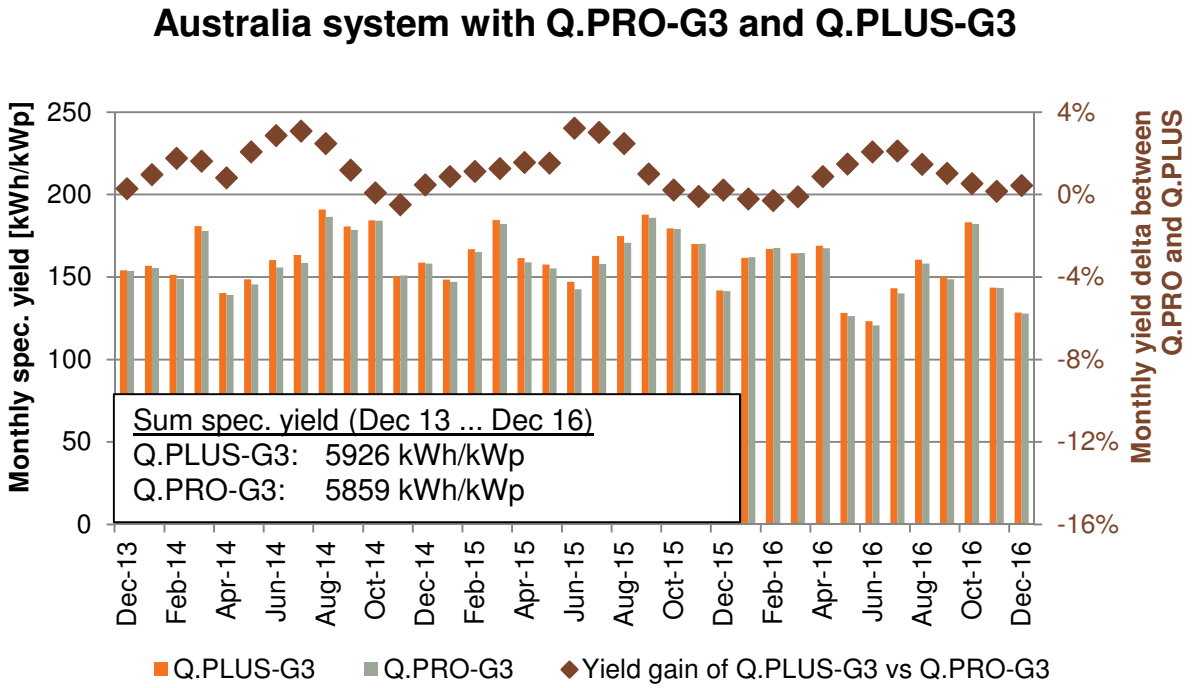
Monthly specific yield & performance ratio comparison between Q.ANTUM and BSF



- **No degradation observed over 4 years**
- **1.7% more spec. yield of system with Q.UANTUM technology compared to standard BSF-system**

TEST FIELD AT ALICE SPRINGS (AUSTRALIA)

Q.ANTUM-TECHNOLOGY VS STANDARD-BSF



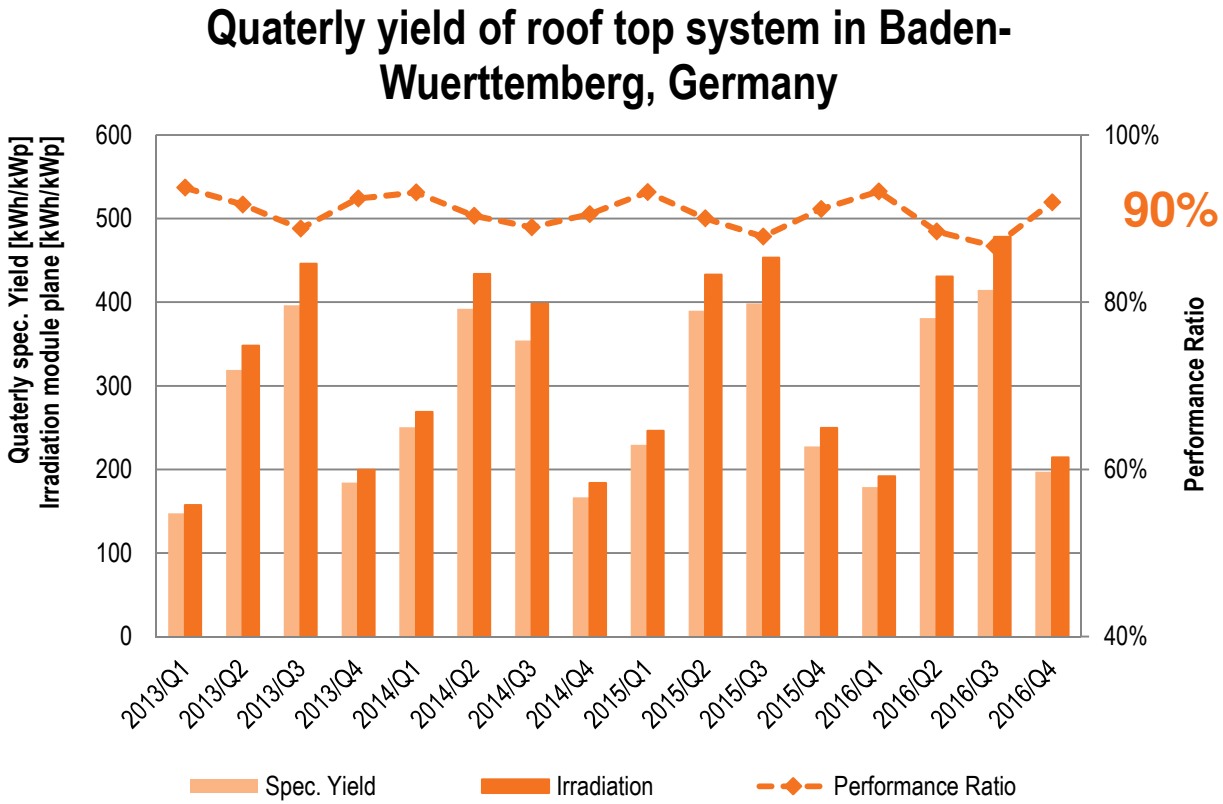
- **No degradation observed over 3 years in hot desert climate**
- **1.2% more specific yield of Q.PLUS compared to BSF**

More information at http://dkasolarcentre.com.au/

REFERENCE SITE AT GERMANY

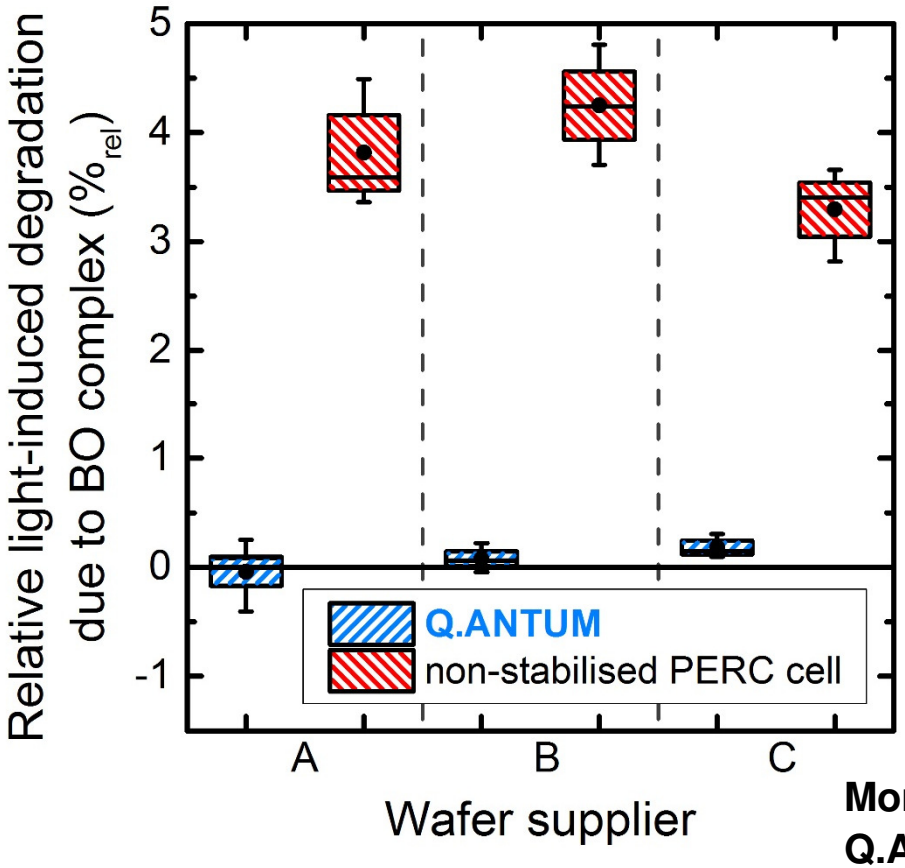
OLDEST Q.ANTUM REFERENCE SITE

Hanwha Q CELLS



- **Stable performance at high PR levels 4 years → no degradation observed**
- **Quarterly performance ratios vary seasonal around 90%**

LIGHT INDUCE DEGRADATION IN Cz PERC



BO caused LID in Cz

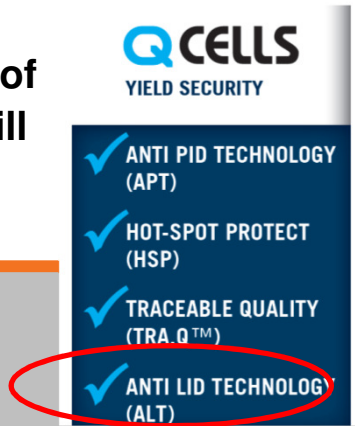
- LID typically ~ 4% dependent on B and O concentration / wafer supplier
- **Q.ANTUM mono Technology** suppresses LID by permanent deactivation of Boron-Oxygen complexes for different wafer manufacturers

Long term stability at elevated temperature

- **Q.ANTUM mono Technology stable**
  Current induced degradation test
  1200h @75°C 1A shows stable power

Superior Q.ANTUM mono 1st year warranty of 98 %

More information to LID and stability of Q.ANTUM on Cz silicon substrates will be presented at the SiliconPV conference



SUMMARY

- **Described characteristics of light and elevated temperature induced degradation**
  - Occurs at temperatures >50 °C
  - Is caused by excess carriers → can be induced either via illumination or current injection
  - Speed depends on injection level and temperature
  - Is a slow process that takes hundreds of hours in lab and up years in the field
- **Proposed test conditions for detection of LeTID**
  - Current induced degradation at 75 °C with $I=I_{sc}-I_{mpp}$
- **Showed that LeTID is suppressed by Q.ANTUM Technology for all wafer materials**
- **Showed that modules perform stable for many years in the field**
  - More than 3 years in Australia and Cyprus without degradation
  - More than 4 years in Germany without degradation
- **Presented Cz PERC results showing stable deactivation of Light Induced Degradation → more detailed results on stable performance of Cz PERC at upcoming Silicon PV**

THANK YOU

2017 NREL PV Module Reliability Workshop
Max B. Koentopp, F. Kersten, M. Schütze,
M.B. Strobel, E. Herzog, J.Müller, D. Buss, F. Fertig

Hanwha Q CELLS

NREL/SNL/BNL PV Module Reliability Workshop

Tuesday afternoon second discussion:

Light-induced degradation (LID):

Do we need to worry about LID later in life for PERC modules that have been treated to remove the effects of LID? Q-cells' treatment is anticipated to be useful throughout the lifetime of the module (they have tested to 6000 hours), but other treatments may not last as long.

When LID has been removed, application of 1000 h of damp heat may cause new susceptibility to LID, so should we apply current during the damp heat test? Q-cells treatment is stable to damp heat, so addition of current during damp heat is not recommended, especially if it might cause recovery of a module that has degraded under light exposure. The damp heat test for thin-film modules now allows an option for applying current, but it is unclear what effect this would have for silicon modules that might experience LID. Each module type may need to be checked to understand the effects of damp heat with and without current flow.

IEC Working Group 8 (WG8) is drafting a standard for testing cells for LID. It may be useful to align the work of WG8 and WG2, but the tests at the cell and module level may differ and the appropriate test depends on the origin of the LID. For B-O defects, the effect is quick (in one day), but other LID can be slower – in some cases PERC modules have been observed to take 4 years to reach the minimum before beginning to recover. If the temperature is increased, then changes will take place faster. At 75°C, a week or two may be enough. When defining a standardized test, it should be kept in mind that different modules behave differently. For example, five types of modules may be differentiated according to:

- n-type heterojunction (HIT)
- n-type interdigitated back contact (IBC)
- p-type mono
- p-type multi
- p-type back-surface field (BSF)

Even within these types, the resistivity and background defects will vary. We should be tracking the cell type in all studies to better understand the degradation effects.

What should a system owner know about LID to predict performance? The vendor should know how the modules will respond to various conditions, but independent verification from an independent test lab can be used to verify the statistics.

Accurate measurement of power:

Ron Sinton's description of how simulator rating for spectrum is not indicative of measurement accuracy was accepted as persuasive. The most important thing is for the company to know how to do the measurement and apply corrections

appropriately. Using matching reference cells/modules is an easy directive to follow for improving accuracy.

PVQAT TG1 update

Status and implementation of IEC 62941

Mar.1, 2017

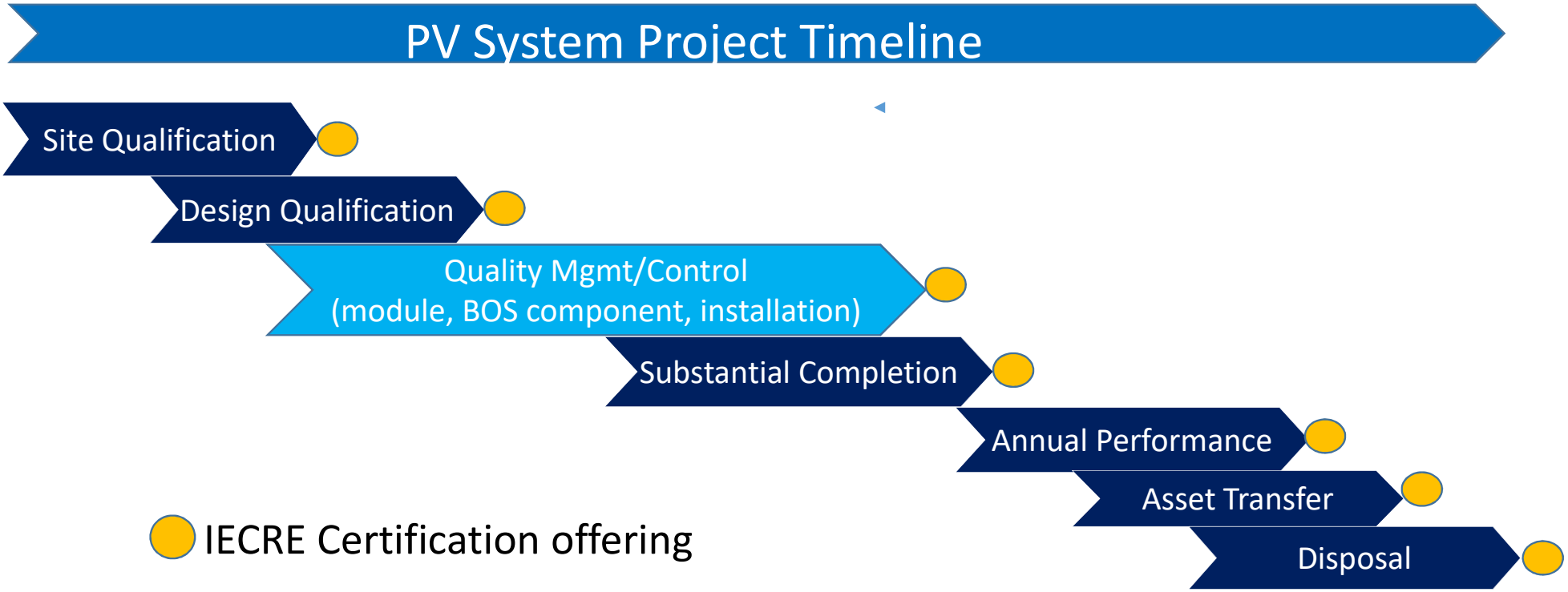
Masaaki Yamamichi(AIST), Govind Ramu(SunPower),
Sarah Kurtz(NREL), Goerge Kelly(Sunset Technology), Wei Zhou(Trinasolar)

IEC TS62941

Terrestrial photovoltaic (PV) modules - Guideline for increased confidence in PV module design qualification and type approval

- Published January 2016
- Consistency with Design, Manufacturing, and Warranty
  - Collection of best practices from within and across the industry
  - Foundation requirements from ISO9001 Quality Management systems requirements
- Key elements include:
  - Design lifetime aligned with the stated warranty
  - Control of key materials and processes to meet the design lifetime
  - Control of monitoring and measuring, Traceability, Change control, Continual improvement and corrective action
- IECRE is preparing for start of their certification

PV System Project and IECRE Certificates



PV-OMC Operational Documents OD405

- TG1 worked to draft pv-omc OD405 documents to implement IEC TS62941.
- Three documents were reviewed in IECRE adjudication process and published Sept., 2016. See details at,

  http://www.iecre.org/documents/refdocs/
- OD405 consists of the three parts to facilitate internationally consistent auditing around the world.
  - ✓ **Requirements for certification of a quality system for PV module manufacturing**
  - ✓ **Audit Checklist**
  - ✓ **Requirements for PV Factory Auditor**

Part 1: Requirements for certification of a quality system for PV module manufacturing

- Quality management system requirements
- General requirements
- Audit Process
- Audit Sampling and Audit time
- Auditor selection
- Stages of audit
- Pass/Fail criteria of IEC TS 62941

Part 2: Audit Checklist

- 235 questions corresponding to requirements defined in IEC TS62941

IEC TS62941		Question ID	Audit Question	Auditor Notes
Section	Statement of requirement			
7.3	Measurement of module performance before shipment shall be to a recognized standard such as IEC 60904-1 using a defined reference spectrum such as the AM1.5 Global Spectrum defined in IEC 60904-3.	211	Is the module performance measured before shipment according to a recognized standard such as IEC 60904 series?	
		212	Is the module performance measurement referenced to a defined reference spectrum such as the AM1.5 Global Spectrum defined in IEC 60904-3?	

Part 3: Requirements for PV Factory Auditors

- PV Factory Auditor; Trainee, Auditor, Lead Auditor, Principal Auditor
- PV Factory Auditor's scope and responsibilities
- Qualifications, authorization and registration of PV Factory Auditors
- Certification Body responsibilities
- Maintenance of auditor qualification
  - Retraining and written test
  - Review of auditor performance
- Promotion or disqualification of auditors
- Auditor certification renewal

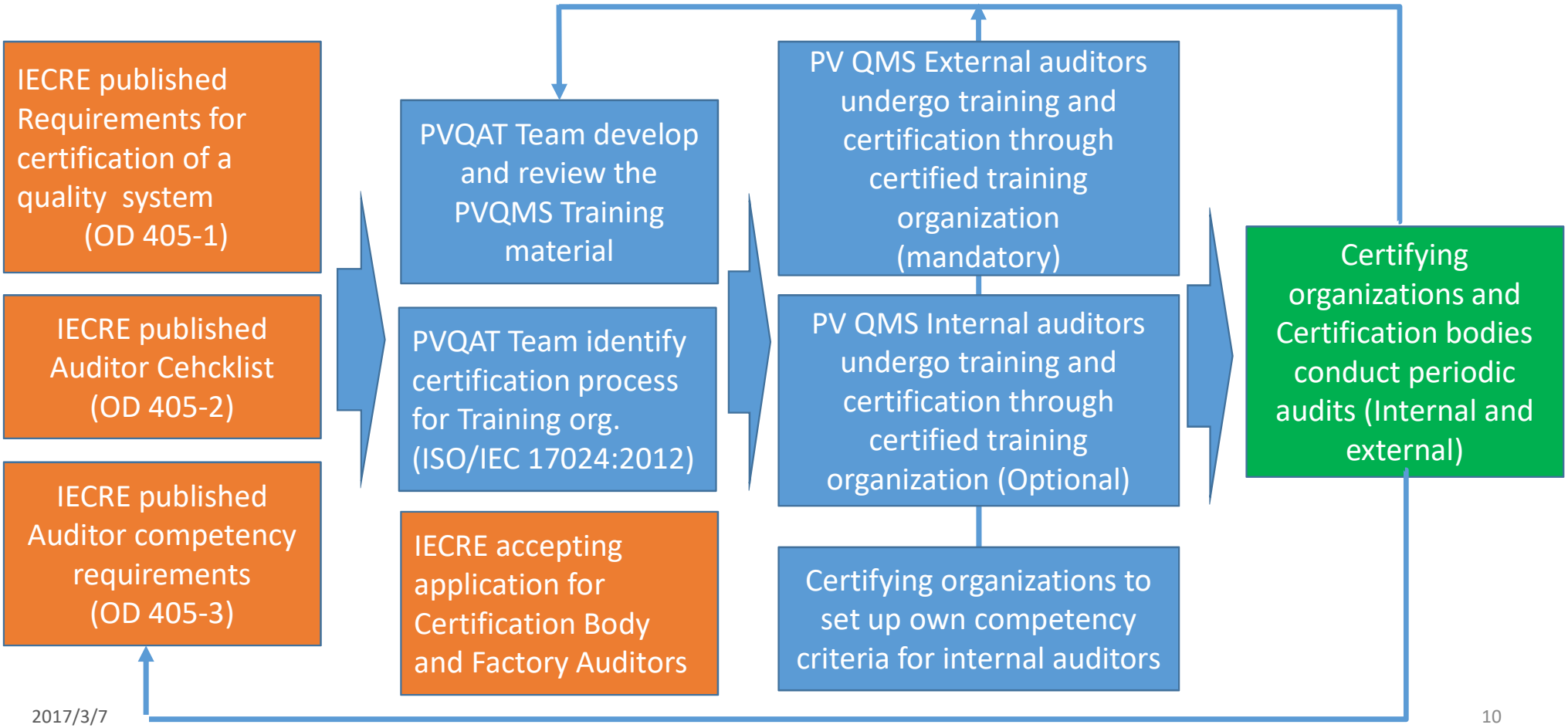
PV Factory Auditor Qualifications Table (abstract)

Auditor's Grade	Educational Background	General Work Experience	Solar Work Experience	Auditor Training	Auditor Experience
Trainee	Univ.degree/ Colleage diploma Certified master/craft-man, engineer	4 yrs	2 yrs	ISO9001 auditor training OR IEC TS62941 auditor training	None
Auditor	Same as above	4 yrs	Same as above	Same as above	4 full management system audit
Lead Auditor	Same as above	4 yrs	Same as above	2 yrs direct experience with IEC 62941 preferred	Auditor level auditing PLUS 3 full management system as a lead auditor
Principal Auditor	Same as above	8 yrs	Same as above	4 yrs direct experience with IEC 62941 preferred	6 yrs as a lead auditor

IEC TS 62941 PV QMS Training Materials

- developed as a training material to PV QMS auditors on IEC TS 62941 requirements.
- covers only the supplementary requirements in this standard.
- How to share/release the Training Materials under discussion
- Auditors are required to be knowledgeable and experienced in the foundational ISO 9001 requirements, quality tools, basic statistical techniques and internal quality auditing process.
- Additionally auditors require experience from PV module manufacturing

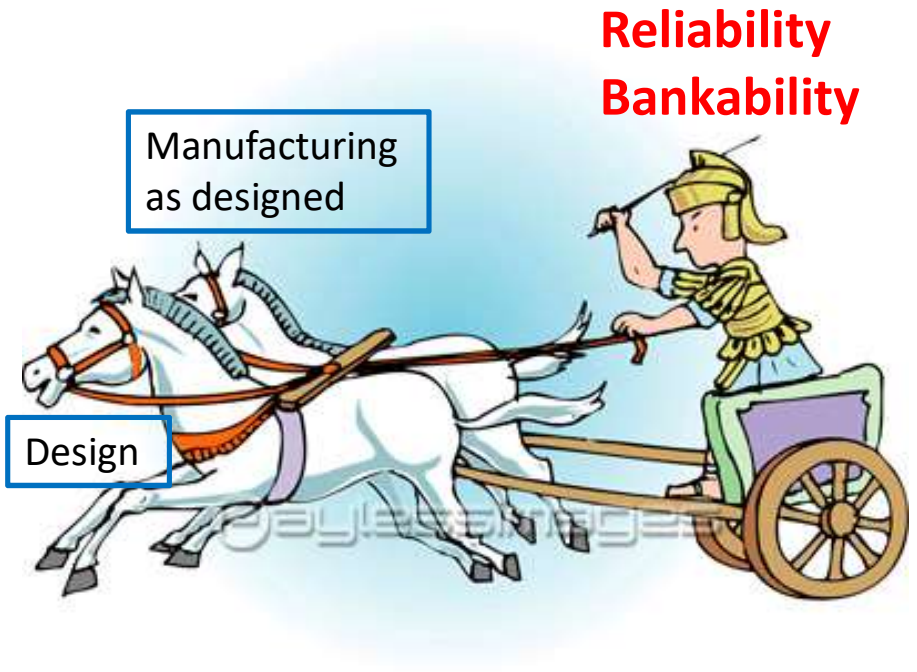
IECRE PV Module QMS Certification



Summary

- TG1 drafted pv-omc documents to implement IEC TS62941.
- IECRE is preparing to audit PV module manufacturer's quality control system to issue Certificate.
- Training materials are being developed to help make the implementation more consistent and of high quality
- Accreditation for organizations and individuals who will do factory audits offered through IECRE – for application process see: http://www.pvqat.org/news/#iec62941

Thank you for your kind attention



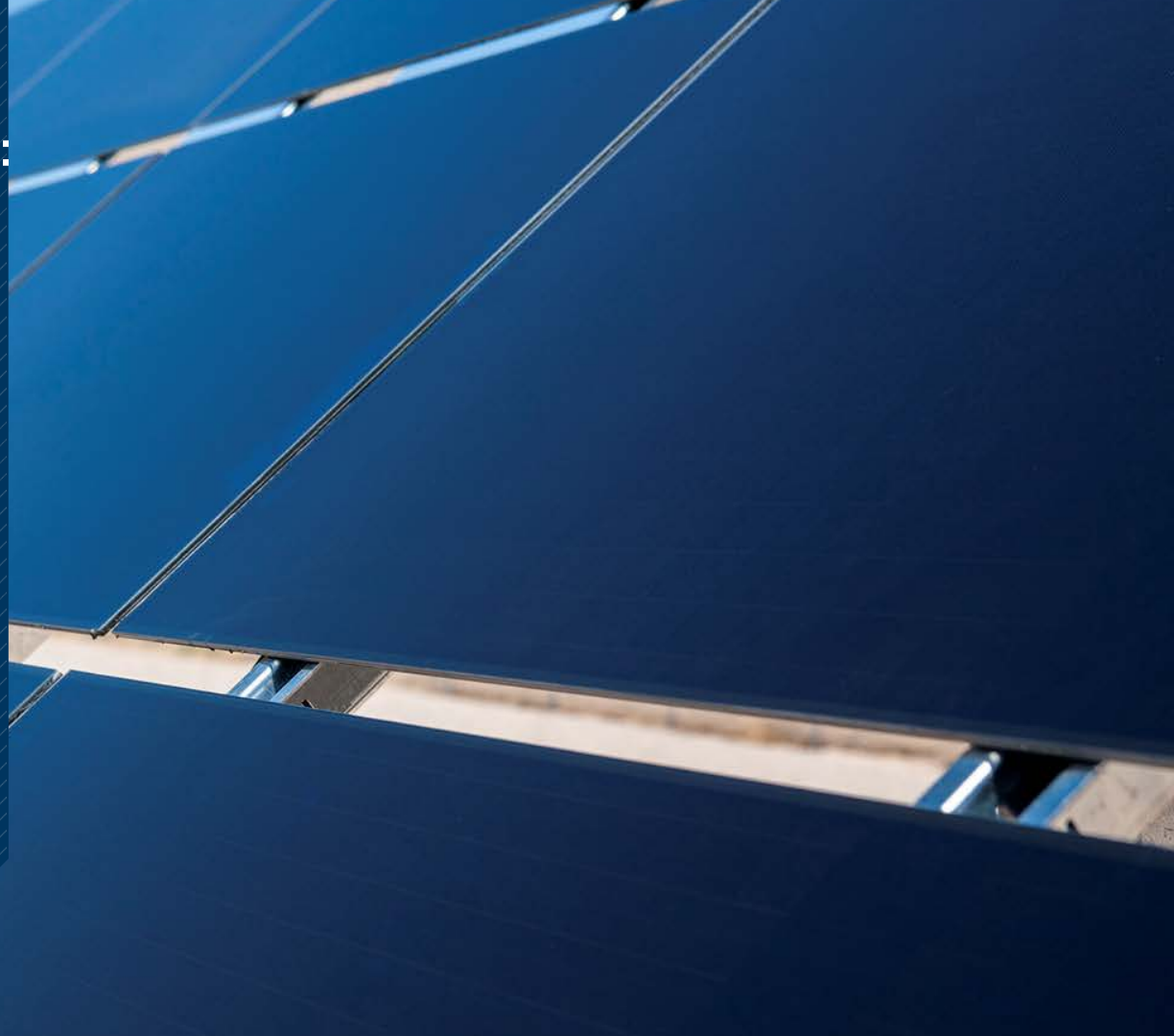
PV RELIABILITY WORKSHOP

PVQAT TG -10 STATUS UPDATE: PV CONNECTOR ASSEMBLY

MARCH 1 2017
LAKEWOOD, CO

BRYAN SKARBEK [Team Leader]
Manager – Test Operations
First Solar, Mesa, Az

First Solar®



ACKNOWLEDGEMENTS & THANKS TO THE MANY PARTICIPANTS OF PVQA - TG10

OBJECTIVE OF PVQAT TASK GROUP 10 – PV CONNECTOR ASSEMBLY

- The PVQAT Task Group 10 has been focused on identifying the different types of field failure modes that are associated with PV Connectors, building an FMEA to identify high risk items and developing a realistic field correlated test plan.
- The Task Group consists of 38 members with representation from system integrators, test labs, module manufacturers, connector manufacturers, micro-inverter manufacturers, material suppliers etc.
- The work from this task group, along with the test results of the project, will be communicated to the PV standards committees for their review and inclusion into future or updates to current standards.

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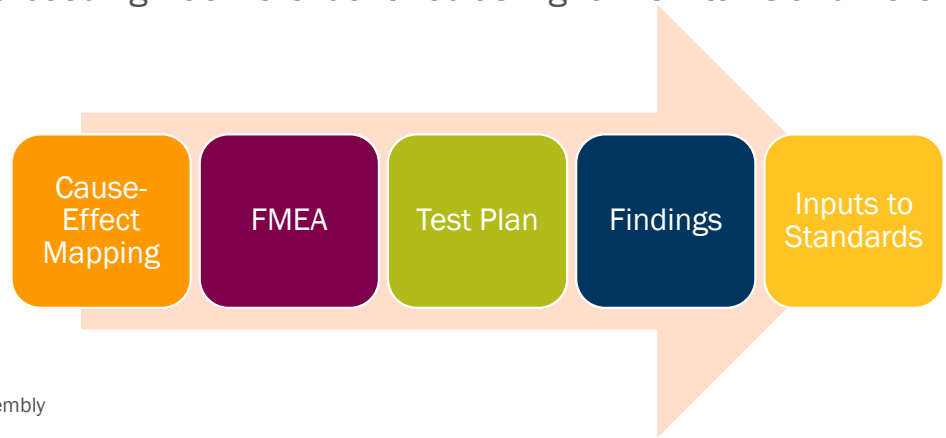
APPROACH

- Task Group 10 had several brainstorming sessions to populate a Fishbone Diagram with the different types of failure modes typically found on PV Connector assemblies and interface to cables. The failure modes are categorized by Man, Machine, Method, Design (Material) and Environment.
- The Fishbone diagram was used to populate the causes in a Failure Modes and Effects Analysis (FMEA). The FMEA was scored jointly by the members of the task group to determine the Severity, Occurrence and Detection & Risk Priority Number (RPN) is the product of these three scores.
  - Items with RPNs exceeding 200 were identified as higher risk items and were included in the test plan.



Source: PVQAT TG -10 : PV Connector Assembly

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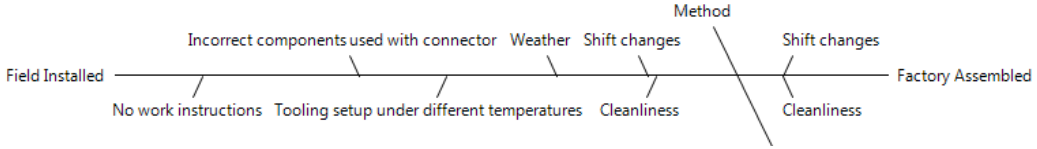
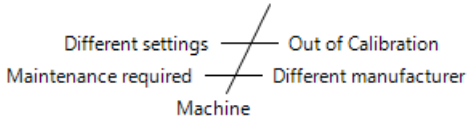
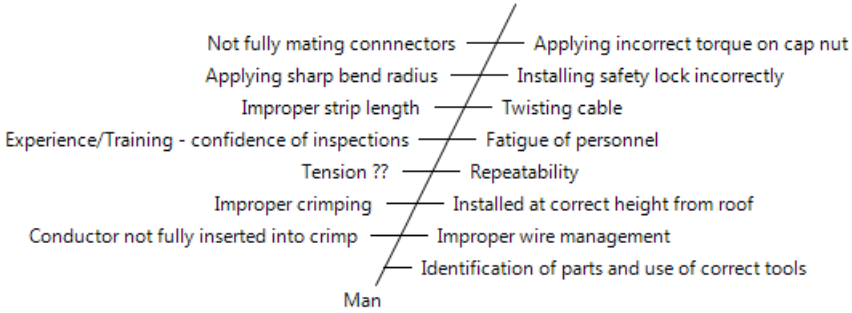
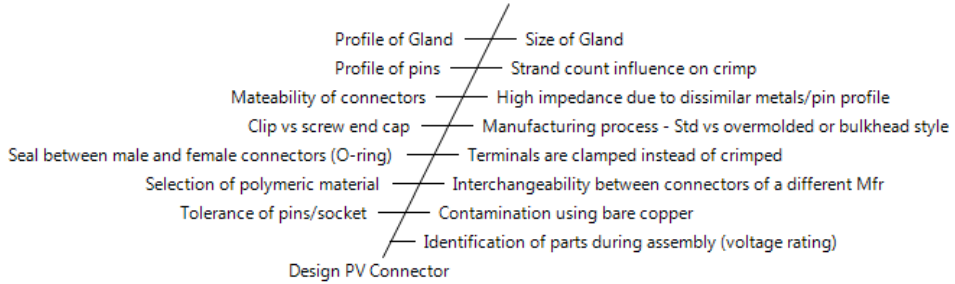
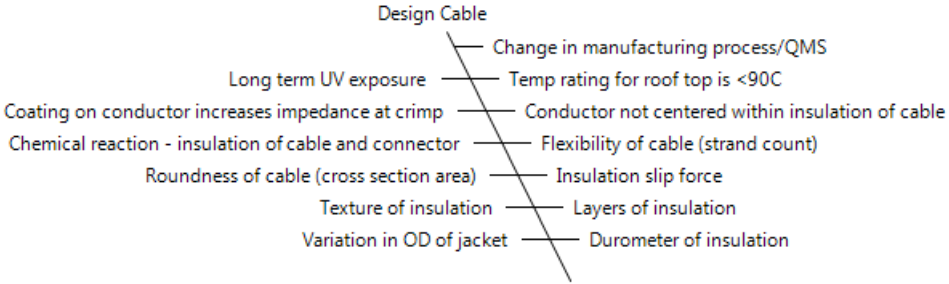
CAUSE AND EFFECT ANALYSIS (FISHBONE DIAGRAM)

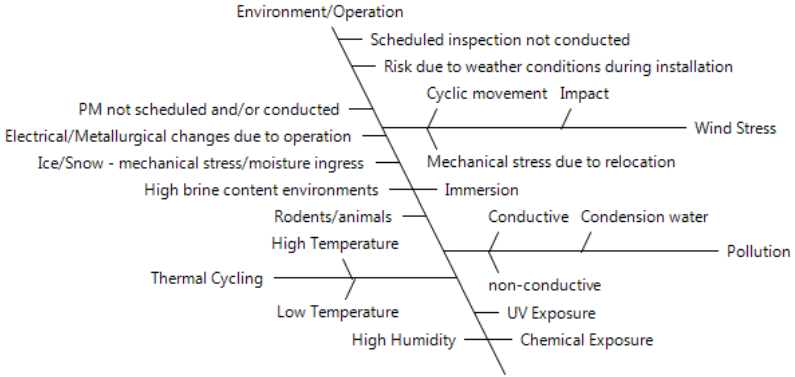












Source: PVQAT TG -10 : PV Connector Assembly

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HIGH RISK ITEMS [INADEQUATELY COVERED BY CURRENT STANDARDS]

- [Safety] Fire hazard\ Shock Hazard
  - Arc flash [Series Arc, Ground Fault]
    - Connector gives false positive of full engagement/lock,
    - Insulation failure\ Embrittlement\ Cracking
    - Withdrawal force exceeded by normal use conditions
    - Rodent attack
  - Wire is pulled out of Connector (Bad Crimp)
    - Cable insulation displacement – thermal expansion/contraction, frost heave, low insulation slip force
    - Cable to Connector interface mismatch (OD tolerance, insulation durometer <> Torque values)
    - Wrong cable (strand #, flexibility,)
  - Excessive leakage currents
    - Improper torque value on end caps
    - Degradation of insulation
    - Handling/ Cable twisted /Bend Radius during shipment, handling, installation
    - Material TCE mismatch (Over molds, connectors)
    - Shape of cable (Unfilled, roundness, surface texture)
  - UV Robustness
    - Carbon Black filled vs. colored polymers (Tinuvin)

- [Performance] Open Circuit
  - Connector disconnects easily
    - Locking ineffective.
    - Delamination of metal coatings
  - Corrosion
    - Moisture Ingress
    - Chemical Attack
    - Dissimilar metals
  - Insufficient wire management
  - Improper Guidance.
    - Secured on both ends (Taught cables)
  - Pollution (Dust ingress)

- Workmanship
  - Assembly
    - Correct Tools, Tool Settings, Calibration, Length (Strip, Insert)
    - Strand loss
  - Installation
    - Bend Radius
    - Locked in Cable Stress
    - Locking pin reversed
    - Exposure of Open/Unmated connectors
    - Cable strain (slack, taught), weight support capacity

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TEST PLAN (A: CONNECTOR PAIR ASSEMBLIES)

TEST PLAN

Connector Pair Assembly UCET Test

Total Qty of Samples per Vendor: 250

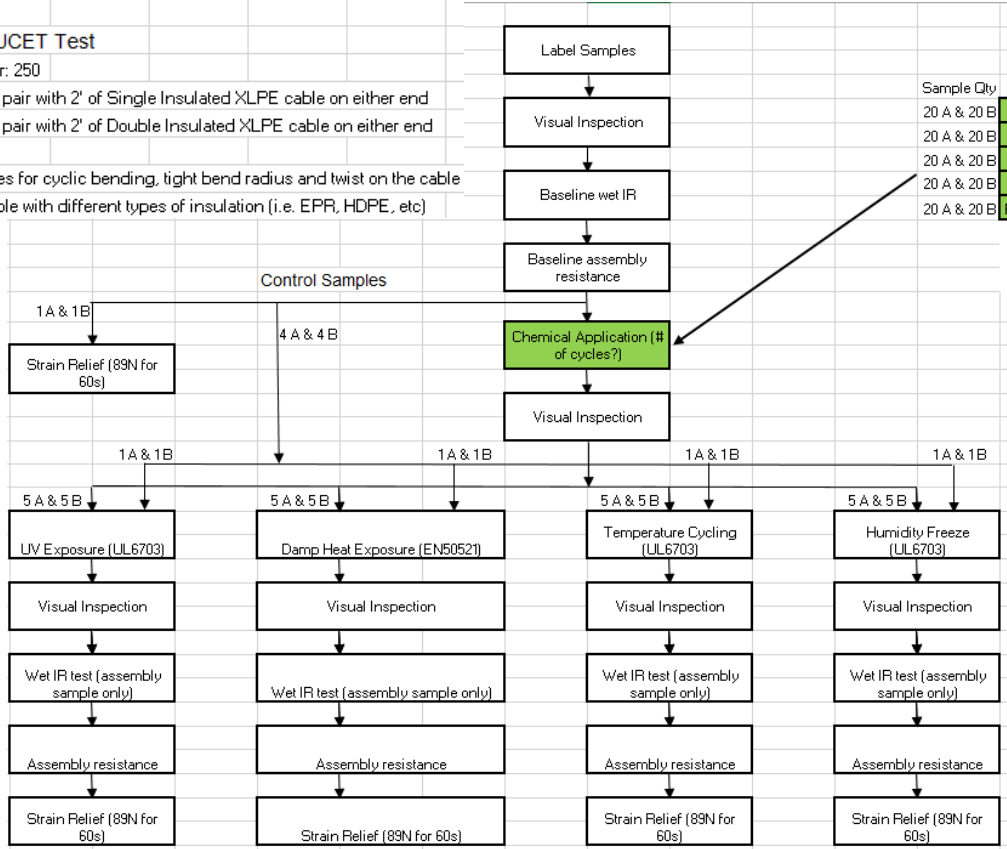
Sample A (Qty - 125): Connector pair with 2' of Single Insulated XLPE cable on either end

Sample B (Qty - 125): Connector pair with 2' of Double Insulated XLPE cable on either end

Phase II testing:

1)Include a test sequences for cyclic bending, tight bend radius and twist on the cable

2)Include samples of cable with different types of insulation (i.e. EPR, HDPE, etc)



Sample Qty		Exposure category (1 - high exposure, 5 - low exposure)	Notes:
20 A & 20 B	Alkaline Solution	1	
20 A & 20 B	Ozone	1	
20 A & 20 B	Ammonia	1	
20 A & 20 B	ZnCl2	1	Galvanized Zinc coating exposure
20 A & 20 B	Flower-of-Sulphur (FoS)	1	Sulphur test run in lieu of MFG

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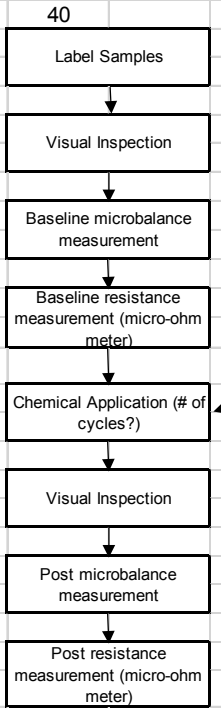
CORROSION ROBUSTNESS TEST PLAN (B: METALLIC PIN COUPONS)

Metallic Coupon Test

Total Qty of Samples per Vendor: 250

Sample: male and female pin assemblies mated together



Sample Qty		Exposure category
		1 - high exposure
		5 - low exposure
40	Alkaline Solution	1
40	Ozone	1
40	Ammonia	1
40	ZnCl2	1
40	Flower-of-Sulphur (FoS)	1

Notes:

Galvanized Zinc coating exposure

Sulphur test run in lieu of MFG

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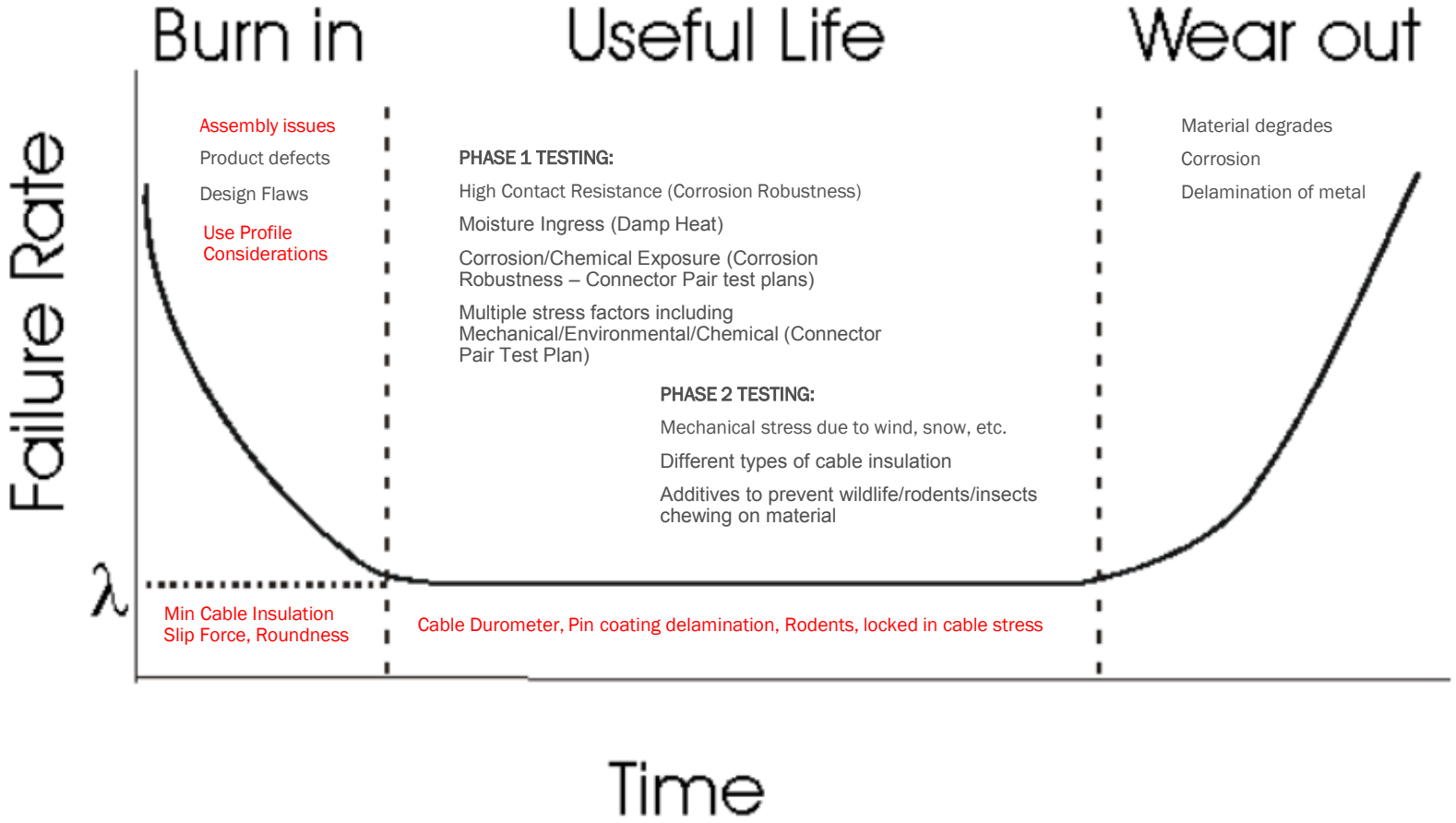
FAILURE MODES DURING LIFE CYCLE OF CONNECTOR – UNDER CONSIDERATION



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Not currently considered in Test Regime

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NEXT STEPS

Focus for upcoming PVQAT Meetings:

1) Discuss Possible Additional Tests:
    a. Cycling Bending
    b. Cable insulation Slip Force
    c. Cable Durometer change with time
    d. Locked in cable stress (twist)
2) Rodents – How to deal with this problem in PV connectors and cables?
3) Develop Workmanship Guidance Standard?
4) Testing
    a. Request samples from PV connector manufacturers for testing
    b. Determine who and where testing will be performed
    c. Develop a schedule for the test plan
    d. Conduct testing & Review results

Ask to Industry:

1) The PVQAT Task Group 10 is asking for volunteers to actively participate in the group.
2) Contribute samples and test resources to support testing.
3) The task group is seeking failure mode and failure rate data on field vs factor installed connectors.

Please contact Bryan Skarbek (Bryan.Skarbek@firstsolar.com).

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TG4 Update: Diodes, Shading

Climate and mounting specific accelerated test development

Vivek Gade — Jabil, representing the Americas
Narendra Shiradkar — Jabil, representing the Americas
Paul Robusto — Miasole, representing the Americas
Hubert Volz – Multi-Contact Essen, representing Europe
Yasunori Uchida — JET, representing Japan
Xian Dong — Zhongshan University, representing China
Chandler Zhang — Trina Solar, representing China

PVQAT
International PV Quality Assurance Task Force

History

- 2011:
  - Task Group 4 reviewed testing standards and identified potential gaps
  - Accuracy of diode technical data sheet. Qualification tests that ensure reliability.
  - *Electrostatic Discharge (ESD) susceptibility.*
- 2012:
  - ESD testing HBM, MBD, IEC Model
  - Extended bypass diode tests. *HTRB and thermal cycling testing*
  - *Statistical and Weibull*
- 2013:
  - IEC 62916, NWIP Bypass diode electrostatic discharge
  - Thermal runaway tests and runaway models.
- 2014:
  - IEC 62916 TS ESD Technical Specification CD was under review.
  - IEC 62979 Ed1.0, NWIP on Thermal Runaway was approved.
- 2015:
  - IEC 62916 TS ESD Technical Specification CDV
  - IEC 62979 Ed1.0, Thermal Runaway CD was out for vote.
- 2016 and ongoing:
  - IEC 62916 TS ESD Technical Specification DTS approved in April awaiting publication.
  - IEC 62979 Ed1.0, Thermal Runaway FDIS stage.

European Task Group 4 Update

Heat Dissipation Requirements for Junction Boxes

Hubert Volz has recommended that the silicon Schottky bypass diodes be operated at maximum of 120 ^{o}C because of following two reasons:

- To avoid thermal runaway failures
- To avoid high diode temperature adversely affecting durability of module encapsulant.

He performed preliminary heat management calculations to arrive at heat sinking requirements in order to hold the silicon Schottky bypass diode temperature at such low value (max. 120 ^{o}C)

- The results indicated a massive heat sink requirement of the size ~ 1’ x 1’.
- Clearly, this would lead to impractically large size junction boxes.
- Therefore, as long as silicon Schottky diodes are being used, they will be operated at higher than 120 ^{o}C temperatures under certain usage conditions.

According to European group, it is time to replace the silicon Schottky bypass diodes with different, more robust devices. One possibility is use of NMOS bypass elements.

European Task Group 4 Update (Continued)

ESD Protection for Bypass Diodes

- Bypass diodes do not have ESD protection which often results in failures in production or field.
- There is comparatively more awareness now at module production facilities regarding ESD, however, diodes in outdoor deployed modules remain vulnerable to failure by ESD due to nearby lightning strikes etc.
- Hubert Volz believes that ESD test needs to be included for junction box approval like IEC 61000-4-2.
- If manufacturers claim a capability of resistance against ESD, the ESD-level should be described with an EMI-standard (Electromagnetic Interference).

Other Focus Areas / Proposed Work

- Finite Element based thermal simulations of junction boxes including convection.
- Simulation of the micro climate of building facades for BIPV applications. The junction box approvals are not tested for facades and it is not clear if the heat management of junction boxes works well in BIPV operation mode.
- To measure the temperature rise of the encapsulation foil of the solar modules when a solar junction box is in bypass mode.

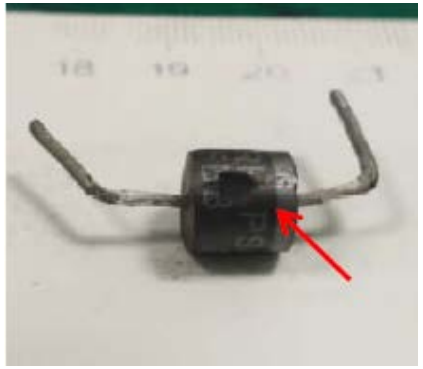
Chinese Task Group 4 Update

Failure Analysis of Field Failures of Bypass Diodes

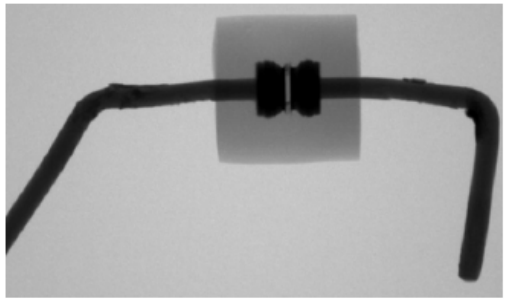
- Chandler Zhang discussed the results from detailed failure analysis of several silicon Schottky bypass diodes returned from field. All diodes had failed in short circuit except Case 3 that resulted in open circuit failure as the diode eventually cracked in half.
- The root cause of diode failures was not known, but a lightening strike was suspected.

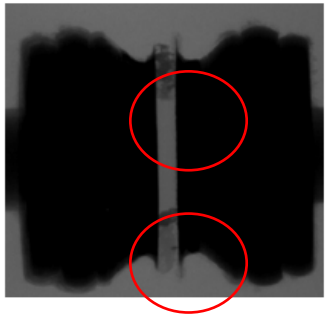
Case 1

Visual: Chipped Epoxy



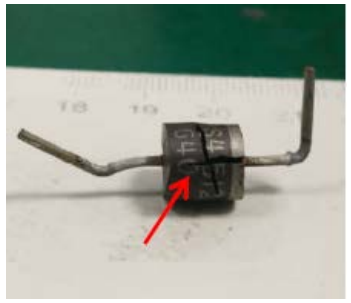
X-ray: Failure sites detected



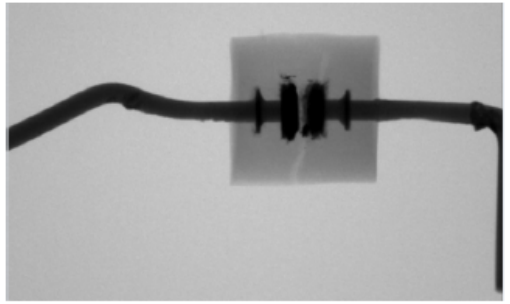


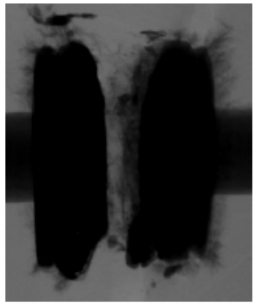
Case 2

Visual: Cracked Epoxy



X-ray: Significant heat damage





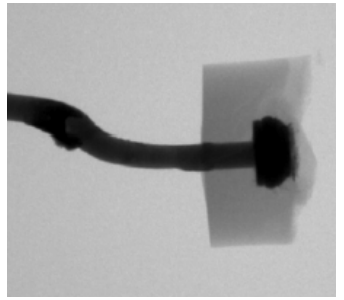
Case 3 Details:

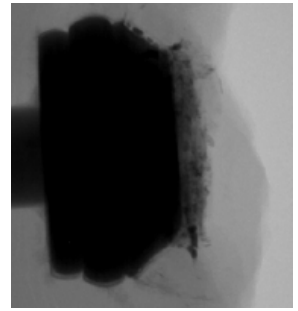
- Thermal damage indicates diode probably failed in short circuit to begin with.
- However, eventually overheating resulted in open circuit failure as diode was cracked in half.

Case 3

Visual: Cracked in half

X-ray: Significant heat damage





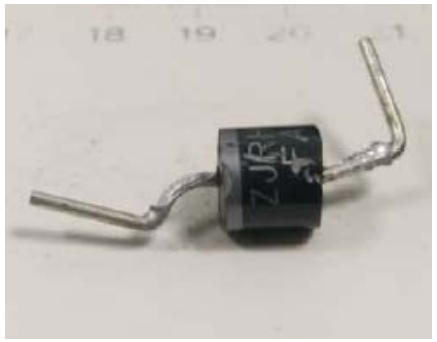
PVQAT

International PV Quality Assurance Task Force

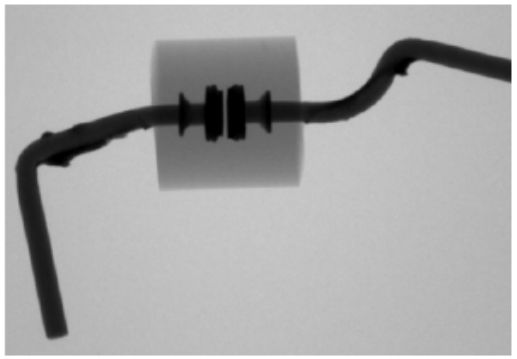
Chinese Task Group 4 Update (Continued)

Case 4

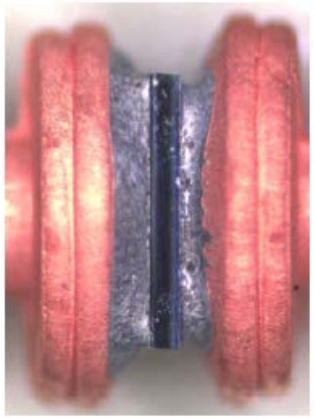
Visual: No Burn Marks



X-ray: No Failure Sites Detected

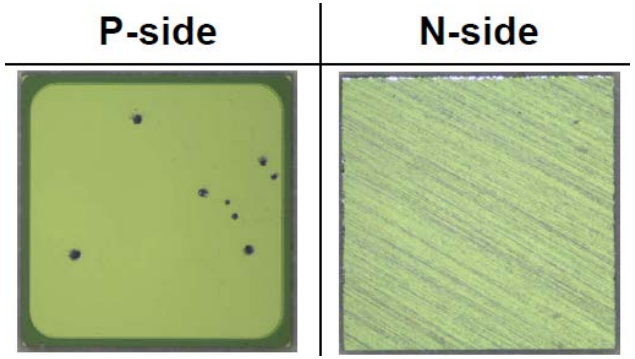


Chemical Decap: No metal residue seen on die edge



- Nothing was seen in visual image or X-ray.
- No metal residue was seen on the side of the die after chemical decap.
- The only failure signatures: ‘Burn Marks’ could be seen on die surface after die-attach and wire lead removal.

“Burn marks” seen on die surface



Chinese Task Group 4 Update (Continued)

Lessons Learned from Field Failure Analysis

- Same event that caused failures in these diodes could manifest it's signatures in various forms.
- Some are obviously seen in visual images, some are visible only under X-ray, some can only be seen as metal residue on die edge after chemical decap, while for some, die attach and wire lead removal is necessary.
- It is necessary to perform failure analysis on as many samples as possible in order to avoid drawing conclusions from limited sample set that is non-representative of entire failed population of samples.
- Thermal runaway susceptibility analysis developed by the US diode group can be used to assist in determining possibility of thermal runaway being the event that triggered failures.
- We need to analyze more field failures in order to create a database of failure signatures and possible causes leading to failure.

Japanese Task Group 4 Update

Compilation of Comments on CD: “BD Thermal runaway test (IEC62979FDIS)”

Key points:

- The module temperature clause modified as follows: 90 ^{o}C for roof mounted modules while 75 ^{o}C for rack mounted modules.
- The two part thermal runaway test proposed by US group (first assessment based on datasheet followed by actual thermal runaway test only if required) was deemed out of scope of the proposed IEC62979CD.
- The suggestion to change reverse voltage to a reduced value of 0.7 x Voc at STC because of lowering of Voc at higher temperatures was rejected citing necessity for safety margins.
- The mandatory duration for passing forward current changed from 1 hour to “40 mins AND until Tlead stabilizes” in order to reduce test duration.
- The test is mainly aimed at Schottky diodes. P-N junction diodes are exempt from the test because of their low reverse leakage currents and capability to withstand high reverse voltages without undergoing thermal runaway.

US Task Group 4 Update: Failure Analysis of Field Failures

Thermal Runaway Testing

- Thermal runaway testing was performed on 11 Jbox designs for rack and roof mounted modules. Significant number of Jbox designs were deemed susceptible for thermal runaway for high Isc modules. (More details in following slides).

Diode Field Temperature Modeling: Revising Bypass Diode Test

- A model for calculating diode temperature in field from TMY data was developed and based on that, revisions to the existing bypass diode test in IEC 61215 were suggested. (More details in following slides).

Failure Analysis of Field Failures

- Failure analysis is being performed by NREL and Jabil on 3 field failed samples of axial silicon Schottky diodes.
- Some failure signatures are similar to what Chinese TG4 has identified while in some short-failed samples, it is proving difficult to identify any failure signatures at all.

High Temperature Forward Bias Test

- Diodes may be forced to work in forward bias continuously / for a long time in their useful life due to partial shading or cracked cells.
- Diode field temperature modeling combined with HTFB testing can be used to arrive at minimum service life for diodes under HTFB failure mechanism in various end use environments. More information on this will appear in IEEE 2017.

US Task Group 4 Update: Thermal Runaway Testing

- A setup for performing simultaneous thermal runaway testing on 7 different Jboxes/modules was developed.
- Thermal runaway test was performed on 11 commercial Jboxes. The samples included Jboxes with and without pottant, with surface mount and axial silicon Schottky diodes.
- Out of the 11 designs of Jboxes tested, 6 failed the thermal runaway test for rack mounted modules (T_{module} = 75 ^{o}C) while 10 failed the thermal runaway test for roof mounted modules (T_{module} = 90 ^{o}C). Module Isc was 10 A.
- Several high efficiency modules have short circuit currents more than 10 A and with upcoming bifacial modules, Isc is expected to further increase.
- This indicates there is need to revise the existing Jbox designs by incorporating low leakage current Schottky diodes and / or using low thermal resistance Jbox designs such as those with surface mount diodes and pottants.

US Task Group 4 Update: Calculating Diode Temperature in Field

- A model developed using thermal and electrical considerations.
- Model assumptions verified experimentally in field deployed modules (rooftop array in Florida).
- Model is useful except in cases where current is varying erratically due to rapidly changing partial shade.

$$I = AA^{*}T^{2}e^{\left(\frac{-q\varphi}{kT}\right)}\left(e^{\left(\frac{q(V-IR_s)}{kT}\right)}-1\right)$$

Schottky Diode Model

Temp vs Power in Field

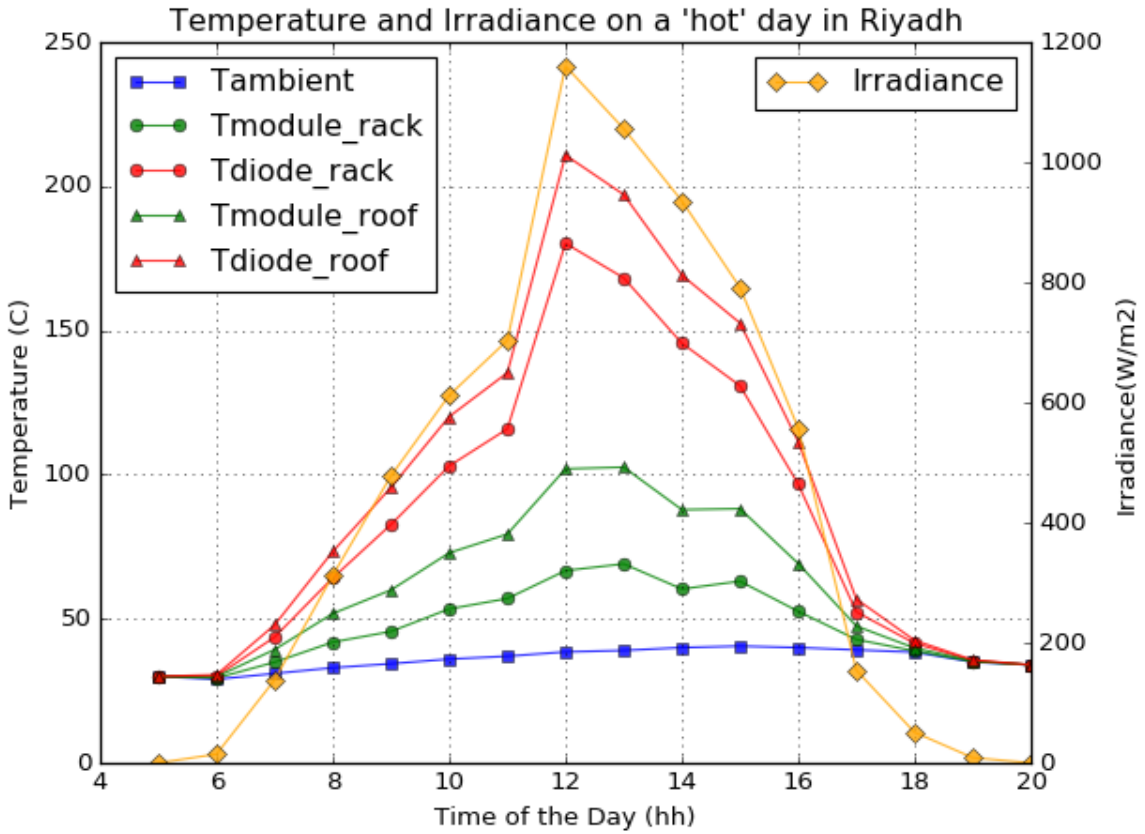
$$T = T_{amb} + R_{th} \times (I_f \times V_f)$$

1D Thermal Conduction Model

Nonlinear Equation for Diode Temperature

$$T - T_{amb} - R_{th} \times \left(I_f \times \left(\frac{kT}{q}\log\left(1 + \frac{I_f}{AA^{*}T^{2}e^{\left(\frac{-q\varphi}{kT}\right)}}\right) + I_f \times R_s\right)\right) = 0$$

US Task Group 4 Update: Data for a Day in Riyadh, Roof Mounted Modules



- Module temperature was calculated using Sandia model.
- Current through diode is stronger driver of diode temperature than the module/ambient temperature.
- Similar calculations performed for 17 climatic zones in the world, for 2 mounting configurations and various thermal resistances and module short circuit currents.
- Assumptions: Rth = 30, Isc = 9.5 A, a representative diode ‘B’ with close to industry average reverse leakage current.

US Task Group 4 Update: Limitations of Existing Qualification Test in IEC 61215

- The filed maximum temperature and temperature during bypass diode test at Isc, 75 ^{o}C were compared to study the effectiveness of existing bypass diode test.
- The existing test was found to yield satisfactory results for rack mounted modules in all climates and roof mounted modules in temperate / cold climates.
- However, the test was found to have high likelihood of yielding false positives or false pass for modules in hot climates and roof mounted configuration.
- Thus a case was made to revise the bypass diode test for high temperature end use environments.

US Task Group 4 Update: Developing New Test Criteria for Bypass Diode Test

- Simulations were run for diode ‘B’ with industry average reverse leakage and Riyadh, roof mount.
- 12 bypass diode test scenarios were simulated each identified uniquely by Isc multiplier and ambient temperature. (Isc multiplier varied between 1 and 1.25 while ambient temperature varied from 75 ^{o}C to 100 ^{o}C in steps of 5 ^{o}C).
- Preliminary assessment showed that a revised condition of 1.25 x Isc at 90 ^{o}C module temperature could be a viable candidate. However, it still had some issues with non-zero false negatives.
- After presenting these results at the WG2 meeting via teleconference, following suggestions were received: i) Run the simulation for different types of diodes ii) Change the current multipliers in bypass diode test to see a slightly less harsh test could yield acceptable results.

US Task Group 4 Update: Developing New Test Criteria for Bypass Diode Test

- 36 bypass diode test scenarios were simulated each identified uniquely by Isc multiplier and ambient temperature. (Isc multiplier varied from 1 to 1.25 in steps of 0.05 while ambient temperature varied from 75 ^{o}C to 100 ^{o}C in steps of 5 ^{o}C).
- For each bypass diode test scenario, a sample space of 36 scenarios was constructed by varying the Isc from 8 A to 10.5 A in steps of 0.5 A and thermal resistance from 15 K/W to 40 K/W in steps of 5 K/W.
- Percentage of true fail/pass and false fail/pass out of 36 was reported for 3 types of diodes. Diode A has highest reverse leakage current, B has close to industry average while C has least.
- The goal was to minimize the false fail and false pass for hot climate of Riyadh and for roof mounted modules. The condition of 1.15xIsc, 100 ^{o}C seemed to meet the requirements for all 3 types of diodes.

US Task Group 4 Update: Developing New Test Criteria for Bypass Diode Test

- The condition of 1.15xIsc, 100 ^{o}C was recommended to John Wohlgemuth for high temperature bypass diode test, who made a remark in IEC 62892.
- It was also found that it is necessary to have two tests: one for rack mounted modules / moderate climates and another for roof mounted modules / hot climates. As it would not be possible to have close to zero false pass and false fails using just one test for all types of climates and mounting configurations.
- Therefore, it was decided to leave the existing test in IEC 61215 as is and suggest a revision in the upcoming IEC 62892.

US Task Group 4 Update: High Temperature Forward Bias Test

- Diodes may be forced to work in forward bias continuously / for a long time in their useful life due to partial shading or cracked cells.
- Using Arrhenius activation energies provided by diode manufacturers, diode field temperature modeling and environmental chamber HTFB testing on reasonable amount of samples, it is possible to estimate equivalent of accelerated test in various end use environments (climates of deployment and mounting configurations).
- Based on the amount of environmental chamber HTFB testing performed before any diode failures are seen in a reasonable amount of samples (~10) , it is possible to determine minimum service life of bypass diodes in worst case HTFB operation mode for various climates of deployment and module mounting conditions.

Acknowledgement

- Thanks to
  - All the International teams for the update.
  - Support from NREL team John W. ,Sarah K., and Peter H.
  - Narendra Shiradkar, Jabil for leading the testing efforts in US.
  - Jabil Management support.

Questions and Discussion Points

- There have been some reports of diode field failures in rack mounted systems. However, more diode failures due to thermal reasons are expected to be found in hot climates and for roof mounted modules.
- Is anybody working on field inspection of rooftop PV systems?
- Module Level Power Electronics (MLPE) manufacturers had indicated they have seen plenty of diode failures. Can any of that data / samples be shared for further failure analysis?
- Failure analysis of field samples indicates large number of samples need to be analyzed before field failures can be linked to a possible root cause.
- Do we perceive a need for NWIP on High Temperature Forward Bias Operation?
- Any data from field evaluation programs being run currently?
- Volunteers within US to run experiments and further validate results are needed.
- Case of “over heating” bypass diodes leading to Backsheet discoloration?

https://www.pv-magazine.com/2016/09/09/when-bypass-diodes-overheat_100026057/

RCPV Research Center for Photovoltaics

AIST

NREL PV Reliability Workshop, 2017

2017/3/1

International Workshop on the Sustainable Actions for "Year by Year Aging" under Reliability Investigations in Photovoltaic Modules

SAYURI-PV Workshop Report

Tadanori Tanahashi
RCPV, AIST (Japan)

Thanks to all presenters and participants !!!

110 Participants

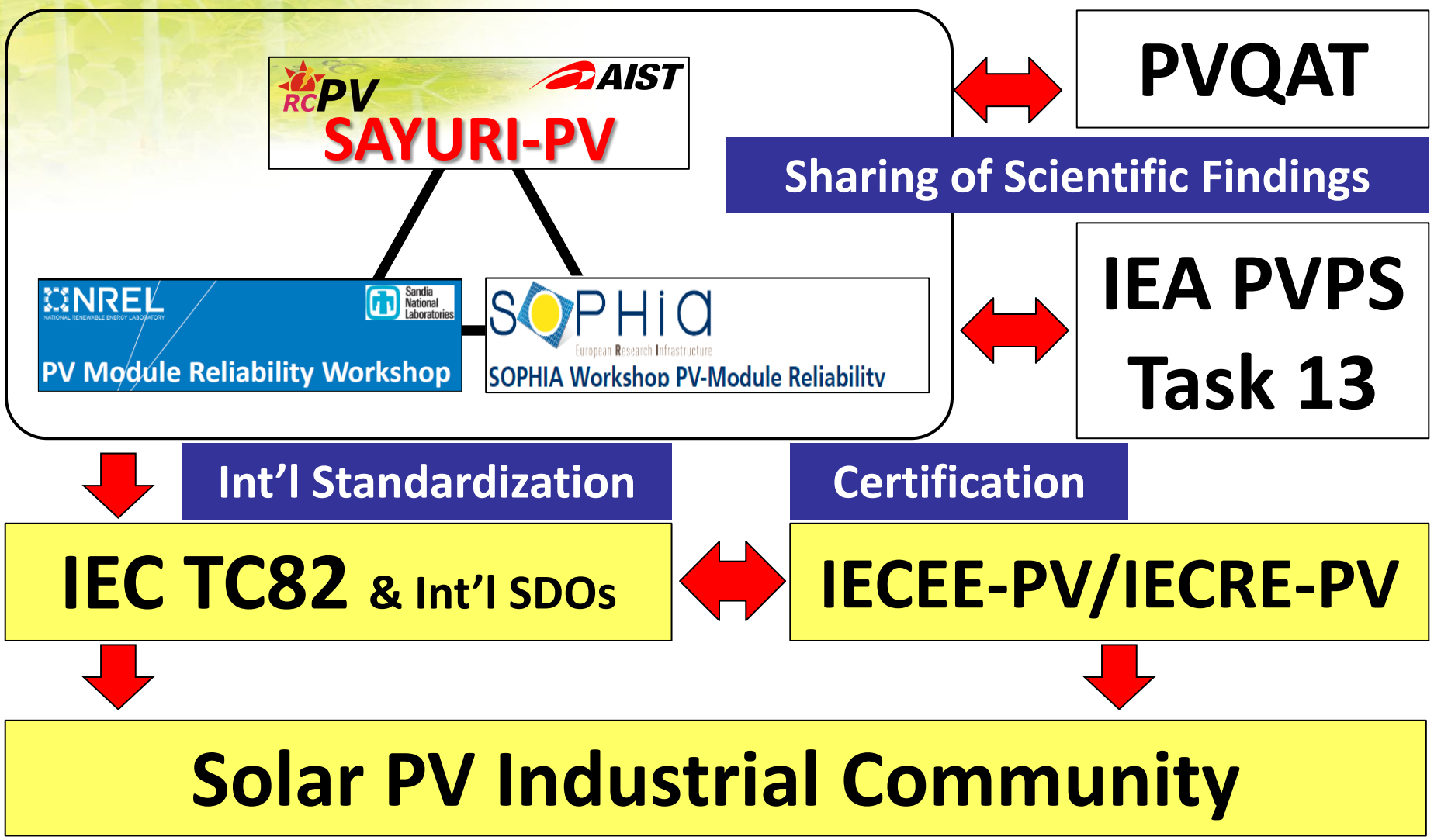
22 Oral Presentations & 20 Posters

SAYURI-PV 2016

Scope of SAYURI-PV Workshop

- **to Share the Information**
  - ***on*** **the Most Recent Scientific Findings for PV Module Reliability**
  - ***toward*** **Global PV Community**
  - ***in cooperation with*** **NREL PVMRW & SOPHIA WS**
- **to Contribute to the Development of Useful International Standards**
  - ***by*** **the Scientific Findings for PV Module Reliability**
  - ***to*** **IEC TC82 & IECEE / IECRE**
  - ***in cooperation with*** **PVQAT & IEA PVPS Tasks**
- **to be a Hub Workshop in Open Innovation Structure**
  - ***to lead*** **Epoch-Making Investigation**
  - ***on*** **the Scientific Research for PV Module Reliability**

International Initiatives for PV Module/System Reliability



SAYURI-PV 2016 TOPICS

Yuzuru Ueda (Tokyo Univ. of Science),
“Long term performance analysis of various PV modules in Hokuto mega-solar”

SAYURI-PV 2016 TOPICS

Interesting Presentations:

Shen, H., et al. (Changzhou Trina Solar Energy, China)

"The influence of different climate on module's performance"

Reliability test in **hot and humid** environment (HAST)

Reliability test in **hot and dry** environment (ML, TC, and TS)

Shioda, T. (Mitsui Chemicals, Japan)

"PV modules' reliability deployed in Japanese PV power plant from viewpoint of encapsulant"

Recent trend of formulation from **additive analysis** (2014 vs. 2015)

Ishikawa, Y. , et al. (NAIST, Japan)

"A characterization by using laser-based technique for failure Si PV modules"

Reduction of carrier lifetime in the defect area with long-term PID

and all presentations.

The electronic proceedings of SAYURI-PV 2016 will be open for free access, from April, 2017.

Please visit:

https://unit.aist.go.jp/rcpv/cie/workshop/2016_SAYURI-PV/presentation/program.html

RCPV Research Center for Photovoltaics

2nd International Workshop on the Sustainable Actions for "Year by Year Aging" under Reliability Investigations in Photovoltaic Modules

SAYURI-PV 2017

Save the Date !!

November 11 – 12, 2017

Kyoto or neighboring city, Japan

SAYURI-PV 2017 will be held in Kyoto, as *a* *Satellite Meeting of PVSEC-27*.

SAYURI-PV 2017: Nov. 11-12, 2017

Registration Fee: Free , Language: English

Latest information (will be uploaded in April, 2017) :
https://unit.aist.go.jp/rcpv/cie/index.html

Contact us at: sayuri-pv-sec-ml@aist.go.jp

PVSEC-27: Nov. 12-17, 2017

Information in detail: http://pvsec-27.com/

RCPV Research Center for Photovoltaics

SAYURI-PV 2017 Topics

***Program Chair*: Prof. Y. Ishikawa (NAIST, JP)**

In the 2nd Workshop in 2017,
we focus on *the evaluation methods of materials* (including PV cell, polymers, metallization, and others) *to assure the long-term reliability of PV modules*, including the efforts toward their standardization.

Date: November 11 – 12, 2017
Venue: Kyoto or neighbouring city, Japan
Latest information (will be uploaded in April, 2017) :
https://unit.aist.go.jp/rcpv/cie/index.html
Contact us at: sayuri-pv-sec-ml@aist.go.jp

Save the Date !!

SAYURI-PV 2017

November 11 – 12, 2017
Kyoto or neighboring city, Japan

We look forward to seeing you in this November!!!

SOPHIA-MODULE RELIABILITY WORKSHOP #7

HTTPS://WWW.PV-RELIABILITY.COM

Bengt Jaeckel for Michael Köhl

Fraunhofer Institute for Solar Energy Systems ISE

SOPHIA Module Reliability Workshop

Fraunhofer ISE, April 27 – 28 2017

www.ise.fraunhofer.de

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Topics of the workshop - overview

- ***New applications*** **of PV-modules providing new challenges for performance and durability assessment**
- ***Innovative devices*** **providing new challenges for performance and durability assessment**
- **Underestimated *stresses***
- **New *testing equipment***
- **New *combined cycles* provide new options and challenges for durability assessment**

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Topics

- **New applications of PV-modules providing new challenges for performance and durability assessment**

as there are the usage of albedo by bifacial PV-modules, the combination of PV-modules with solar-thermal collectors (PVT) and the integration into building envelopes (BIPV or BAPV).

- **Innovative devices providing new challenges for performance and durability assessment**

as there are hetero-junction PV-cells, organic PV, bifacial cells requiring new measurement and testing set-ups and procedures.

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Topics

- **Underestimated stresses**

  Sandblasting

  Bio-Contamination

  Thermo-Mechanics ⇔ Dynamic Mechanics

  Spectral sensitivity of polymers

- **New testing equipment**

  Multi-Stress cabinet for laminates

  Combi-Tester for devices

  Multi-Stress chamber for modules

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Topics

- **New combined cycles provide new options and challenges for durability assessment**

Most of the standardized type approval tests are performed for on single stress factor only. Nature is different. Degradation modes based on combined stress factors are neglected. On the other hand, the combination of different stress factors like Ultraviolet light, temperature, thermomechanical stress based on temperature cycles, mechanical stress, humidity, pollutants and soiling correlating the natural abundance, or to control the stress levels is a big challenge. The questions how to realize such combi-tests or to simulate them by applying sequential stress tests or to carry out representative tests on a mini-module level are to be discussed.

- Which Combined Test Sequences are proposed?
- What are the results?
- What could be standardised?

More information and registration

https://www.pv-reliability.com

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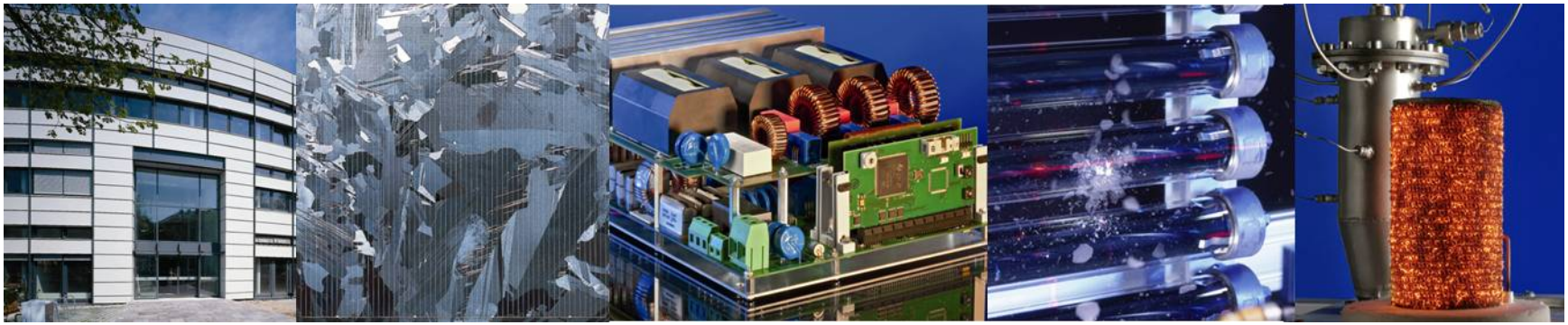
Thank you for your attention!

and the European Commission for funding



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Measurement Uncertainty: A new holistic approach to reduce the pain of uncertainty!

B. Jaeckel[1], J. Arp[2], B. Mihaylov[3] und R. Gottschalg[3]

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[3]Centre for Renewable Energy Systems Technology (CREST), Wolfson School of Mechanical, Electrical and Manufacturing Engineering, Loughborough University, Leicestershire, LE11 3TU, UK, R.Gottschalg@lboro.ac.uk

Motivation:

Measurement uncertainty (MU) is a major obstacle when evaluating modules in a PV plant for compliance with warranty conditions. PV power plants are rated and typically paid for based on their installed nameplate DC capacity. With PV module prices falling by 30% [1] in 2016 alone, the cost of capital plays an increasingly important role in the overall systems' cost. Financing costs are strongly affected by the perceived risk. One of them is the delivered DC capacity. Regardless of which party the risk is allocated to, it increases the overall project cost. To reduce this risk, for large enough projects, a batch of modules is typically tested to confirm DC nameplate performance. Typical MU's are from 2.5% to 3% [2-5].

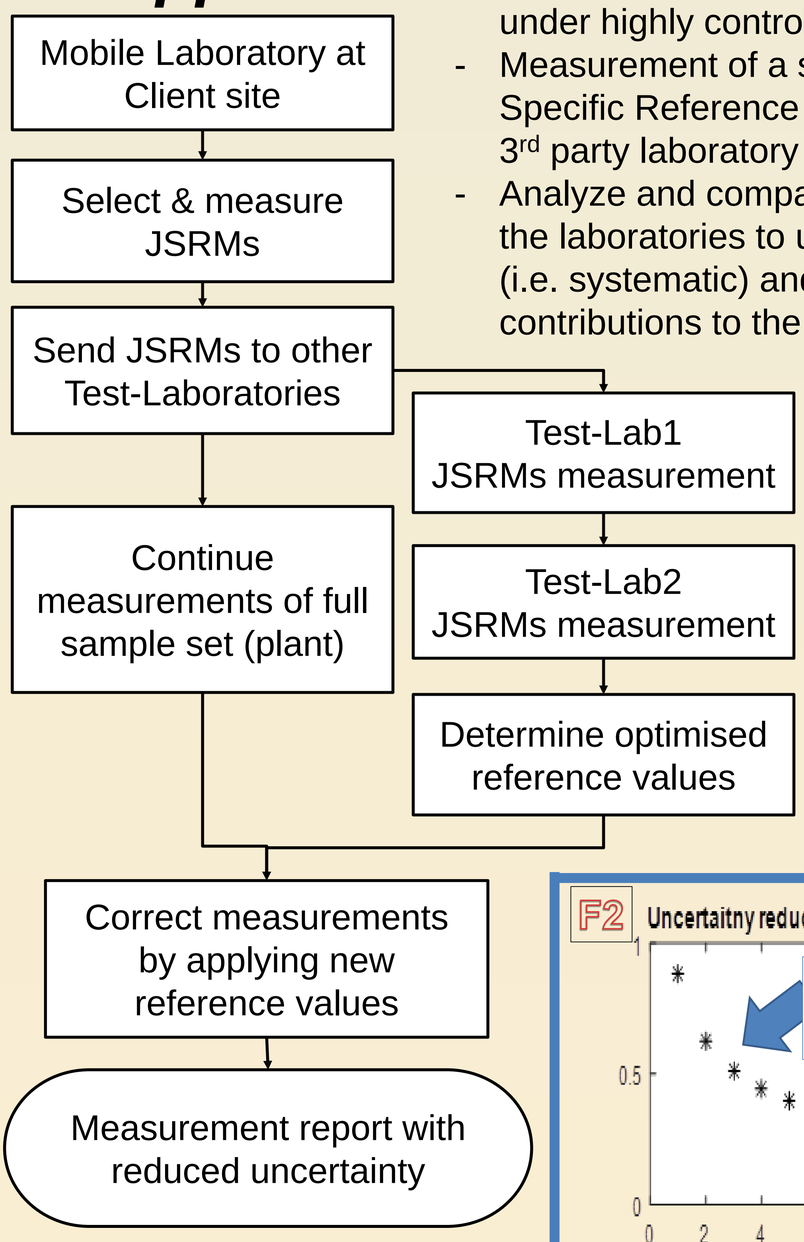
Based on the measurements and their given MU's real installed DC (typically measurement values minus MU's for risk reduction) capacity is calculated and the installer is basically only paid for what he delivered, including risk mitigation. That means that high uncertainties will lead to a lower price based on the definition on how uncertainties are treated within the calculations. Example:

For a 10MWp power plant a 1% higher measurement uncertainty equates to approx. 50.000€ lower system price.

Within this presentation we will show a new holistic approach to significantly reduce the measurement uncertainty (MU), actually almost half it, while keeping costs down and by that increase the value of the PV power plant asset.

Approach:

- measurement of batches of modules in the field under highly controlled conditions
- Measurement of a subset of JSRMs (Job Specific Reference Modules) in an accredited 3rd party laboratory
- Analyze and comparison of all MUs between the laboratories to understand the persistent (i.e. systematic) and volatile (i.e. random) contributions to the total MU.



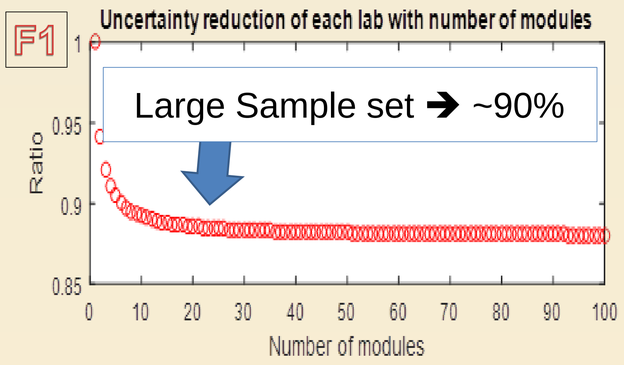
Results:

- From a field measurement campain with k modules a subset of j JSRMs is selected
- Measurement of these j JSRMs in n labs with different calibration chain
- The total MU per Lab is given by

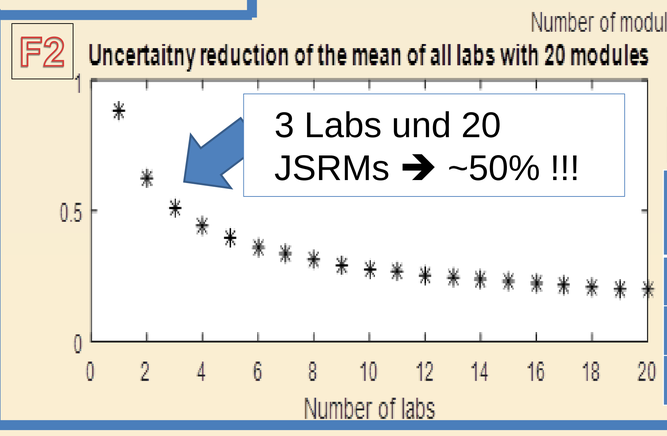
$$u_r^2(\overline{x_i}_{lcor}) = \frac{u_r^2(R_i)}{j} + \frac{u_r^2(R_i)}{\mathrm{k}} + \sum_{i=1}^{n} w_i^2 u_r^2(\overline{x_i})$$

- ➔ This will lead to a MU reduction of approx. 10% (see figure F1 below)
- Measurement in n labs with a certain number of j JSRMs will lead to a more significant decrease in total MU (see figure F2), results from the lab uncertainty study (see table Tab1) and measurement results in figure F3.

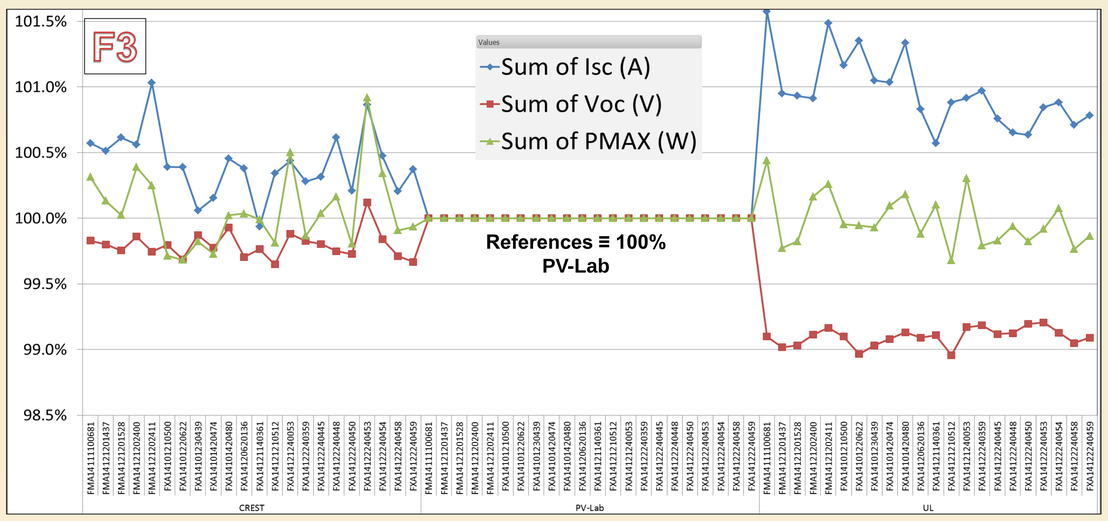
F1



F2



F3



Tab 1

Labor	MU (k=2) in %	$U_r(S_i)$	$U_r(R_i)$	Weights (w_i)	Without Correlation in %	With Correlation in %
Lab 1	**2.7**	1.21	0.65	0.33	**2.5**	**1.5**
Lab 2	**2.6**	1.09	0.70	0.41	**2.2**	**1.5**
Lab 3	**3.0**	1.39	0.58	0.25	**2.8**	**1.5**

Summary:

- MU is a Key-Parameter for Risk-assessements
- Low MU's lead to better Financing
- Multi-Lab-Approach: Several Labs measure a subset of PV Modules
- Reduction of total MU from ~3% to **1.5% ≈ Half of standard MU's**

Literature:

[1] B. Gallagher, "US PV System Pricing H2 2016 : System Price Breakdowns and Forecasts," 2016
[2] W. Herrmann et al, "PV Module Output Power Characterisation In Test Laboratories And In The PV Industry – Results Of The European Performance Project," in 25th EUPVSEC/WCPEC-5, 2010, pp. 3879–3883.
[3] Y. Hishikawa et al, "Round-robin measurement intercomparison of c-Si PV modules among Asian testing laboratories," Prog. Photovoltaics Res. Appl., vol. 21, no. 5, pp. 1181–1188, 2012.
[4] D. Dirnberger et al, "Progress in photovoltaic module calibration: results of a worldwide intercomparison between four reference laboratories," Meas. Sci. Technol., vol. 25, no. 10, p. 105005, 2014.
[5] B. Mihaylov, et al, "Results of the Sophia Module Intercomparison Part-1: STC, Low Irradaince Conditions and Temperature Coefficients Measurements of c-Si Technologies," in 29th EUPVSEC, 2014, pp. 2443–2448.

Underwriters Laboratories

PVLABGERMANY

Loughborough University

Comparison of weathering test chamber light source spectra & preliminary results of PV encapsulant aged with metal halide light source

Mark Alessandro[†], Emre Unsal[†], Doug Vermillion[‡]
[†]Avery Dennison, [‡]Eye Lighting

Abstract

Lifetime expectancy of a photovoltaic (PV) device is 25 to 30 years, ideally with no change in the performance. Manufacturers continuously strive to improve product durability and reliability through recommended tests, and proprietary in-house testing. Outdoor exposure testing is essential for validating long-term product performance, but the use of accelerated testing is necessary for expediting the evaluation process. Many varieties of weathering test chambers are utilized to accelerate and/or simulate the effects of natural outdoor weathering through controllable laboratory conditions. These chambers use a combination of temperature, humidity, water spray and artificial light to replicate natural outdoor conditions.

The most significant difference between the weathering test chamber options is the type of light source used to simulate solar energy. Chambers are available that utilize full spectrum xenon lamps, or UV spectrum fluorescent lamps. Both xenon and fluorescent lamp systems are typically operated at one to three sun equivalence to solar irradiance. Depending on the failure modes of the materials and light sensitivities, corresponding chambers are utilized to test the materials. However, the acceleration factors of these chambers are still lacking the speed required by the PV industry.

A more recent development in the weathering chambers is the use of metal halide lamps that also provide predominantly UV spectrum. Some metal halide chamber lights sources provide up to twenty five-sun equivalent solar irradiance making them a good alternative of new generation test chambers for the PV industry.

Experimental and Materials

The spectra of the Xenon-Arc, Fluorescent UV and Metal Halide light sources were measured with a StellarNet spectrometer (model CXR-SR-50) equipped with a F600-UVVIS-SR 2m fiber optic cable. Results are shown in Figure 2 between 250-800 nm. Measurements were taken at the same plane as the samples would get exposed to.

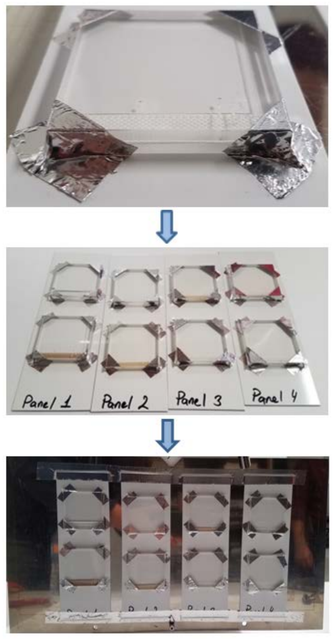


Figure 1 shows the 2” x 2” silica/polymer/silica sandwich samples provided by NREL. These samples were mounted on white painted aluminum panels using metal tapes on the edges. 2 samples per composition tested (EVA-C, EVA-D, EVA-E and TPU). Individual panels were taped on the panel holder that goes inside the metal halide test equipment. The chamber was set to run 1500 W/m^2 between 295-450 nm at 65°C and 30 % RH. Color L, a, b values of the samples were taken daily to track for the color change and yellowing. b* values were reported at Figure 3.

Figure 1: NREL samples tested

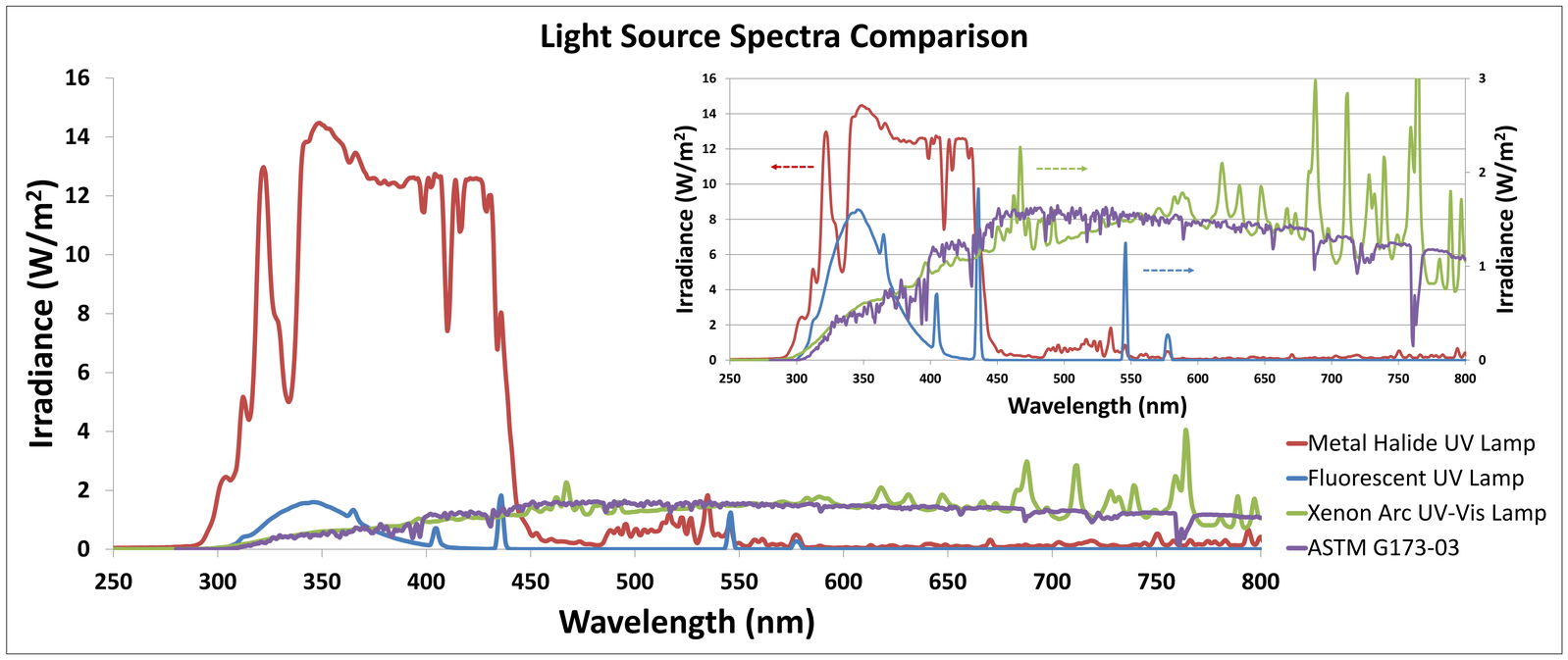


Figure 2: Comparison spectra of Xenon-Arc, Fluorescent UV and Metal Halide light sources. Data collected with Stellar spectrometer. ASTM G173-03 Reference sunlight spectra is also added to the graph.

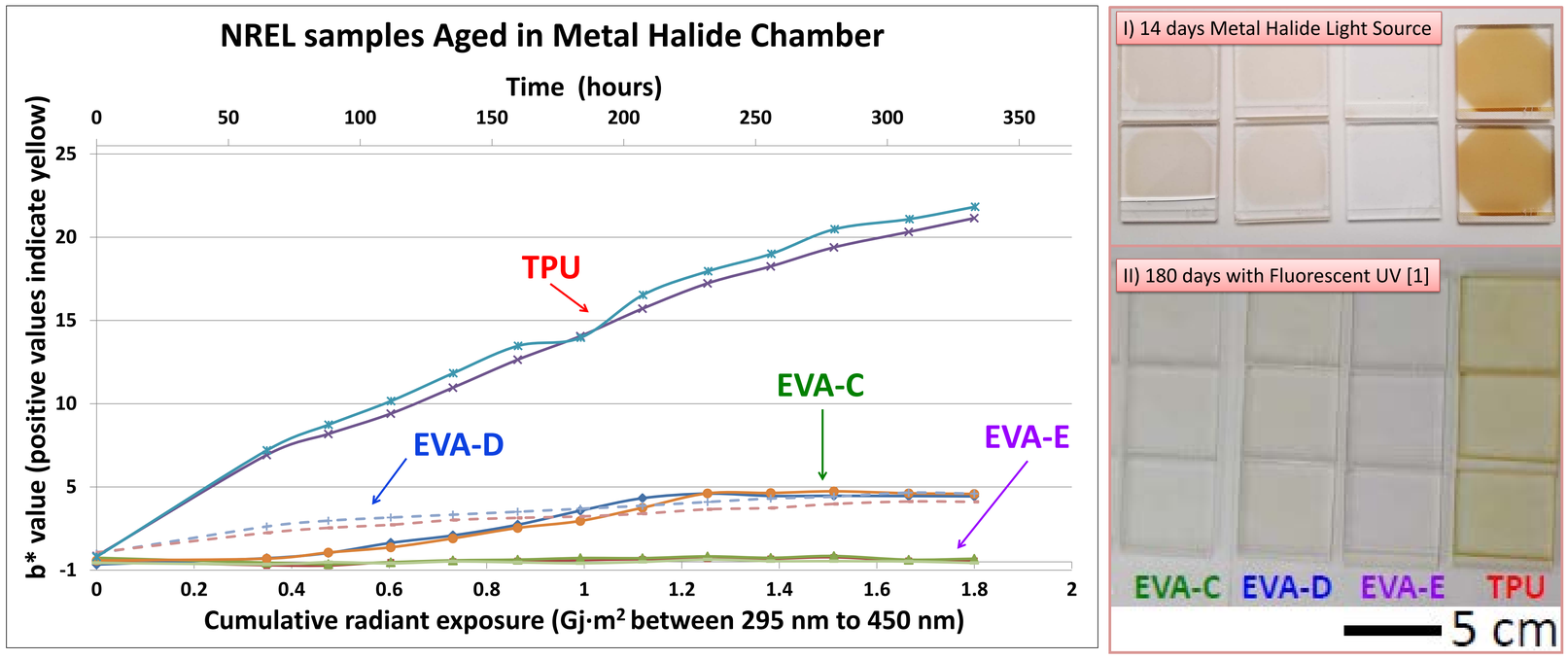


Figure 3: Graph shows the b trend as the samples age. Positive values indicate samples getting yellower. Measurements were taken once a day for 14 days, at the center of the samples. Pictures at the right shows the visual appearance of the samples at the end of the test. #I shows the results after 14 days of exposure inside the Metal Halide light source chamber. #II shows the results after 180 days of exposure of samples inside Fluorescent UV light source chamber[1].*

Results

All samples tested yellowed and showed increase in b* value, except EVA-E. TPU showed a linear increase over time. EVA-D yellowed early in the test and entered in a steady state behavior. EVA-C yellowed at a later stage and leveled off at the same b* value as EVA-D sample.

Conclusions

Spectra of different light sources were compared. Metal halide light sources exhibit very high intensity in the 295-450 nm range compared to Xenon-Arc and Fluorescent UV light sources. Samples aged using metal halide light source showed similar degradation behavior as samples aged in fluorescent UV light source at a much shorter time (180 days vs. 14 days). Providing up to twenty five-sun equivalent of solar irradiation predominantly in the UV range (295-450 nm), metal halide light chambers have a strong potential in becoming new generation of test chambers for the solar PV industry.

[1] 2015 NREL Conference Paper NREL/CP-5J00-63508 “Degradation in PV Encapsulation Transmittance: An Interlaboratory Study Towards a Climate-Specific Test” Miller, D.C. et. al.

CSI: Combined Stress with In-Situ Measurement Testing

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ABSTRACT

In order to optimize long-term stability of PV modules, their degradation behavior should be understood and minimized. Therefore, we have designed and built combined stress degradation setups, in which humidity, temperature, illumination and electrical loads are all used as combined stress on solar cells and modules. These setups also allow real-time monitoring of the electrical properties of the samples. We propose that the setups presented in this study are large improvements compared to the standard IEC tests, due to the combined exposure parameters as well as in-situ monitoring. These properties therefore greatly improve the predictive value of accelerated lifetime experiments.

INTRODUCTION

We believe that qualitative and quantitative understanding of the degradation mechanisms can best be obtained under combined stress conditions, combined with real-time monitoring of their properties, which results in combined stress testing with in situ measurements (CSI). CSI enables:

1. Applying combined stresses on the module and its materials, showing the same failure modes as in the field and showing the accelerating/decelerating effect.

2. In-situ performance measurement shows the real-time degradation behaviour over time.

BACKGROUND

Accelerated lifetime test procedures from the IEC-61215 should ideally tell the industry and potential customers whether the requirements related to long-term performance stability are met.
However, the consensus among researchers is that current IEC-61215 accelerated lifetime tests are mainly used to identify early failures, and are not a valid prediction method for lifetime and end-of-life failures.
Furthermore, the official IEC tests do not focus on the fundamental understanding of the degradation process within a module. However, knowledge of the degradation mechanisms and the possibility to link these with the observed failure modes is very important. The conditions in the laboratory are meant to rapidly identify degradation effects in the field, however, these chosen conditions might actually lead to failure modes that do not occur in the field. Therefore, a large number of accelerated lifetime studies with variation in degradation conditions and sample composition is required to really predict module field performance.

METHODOLOGY

1. Preparation of own Test Samples, if facilities are present

2. Analysis of the solar cells before degradation - measure the ex-situ IV performance of the samples to determine the electrical parameters and the external quantum efficiency (EQE) for the exact current density and wavelength dependent absorption.

3. Placement of the samples into sample holders which are specifically designed to withstand the harsh conditions during the climate tests. Place the sample holders on the sample rack inside the hybrid degradation setup, which allows electrical contact between the solar cells and the measurement tools outside the setup.

4. Execution of the degradation experiment by switching on the solar simulator, heating the climate chamber, and turning on the humidity. Leave the samples in the setup for 100 to 1000 hours while measuring the IV curves.

5. Analysis of solar cells by plotting the IV parameters as a function of the exposure time and/or by measuring the IV performance, or taking microscopy pictures.

6. Definition of the failure mechanisms, modes and their impact on long-term stability of the samples by combining all the data.

SETUP

RESULTS

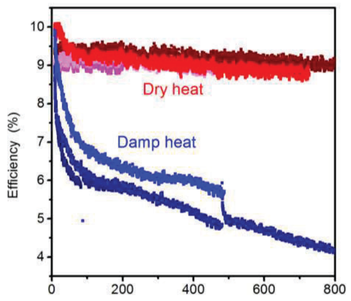

Figure 1.

Figure 1: The development of the efficiency of non encapsulated CIGS solar cells as a function of exposure time to illumination plus dry heat (red) and damp heat (blue) taken at elevated temperatures.

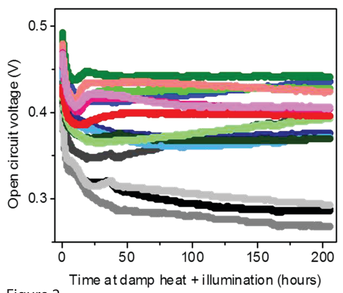

Figure 2.

Figure 2: Evolution of the cell efficiency of non-encapsulated as a function of time at various voltages. Grey, blue, green and red curves indicate cell exposed to -0.5V, 0V, ~VMPP and open circuit conditions respectively. These parameters are obtained at elevated temperatures, while the room temperature efficiencies are around 50% higher.

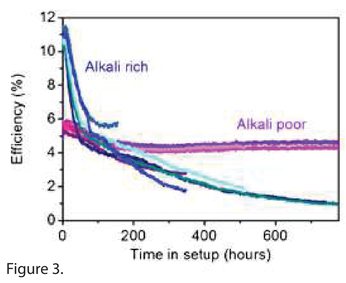

Figure 3.

Figure 3: Evolution of the efficiency and shunt resistance of two types of non-encapsulated CIGS solar cells exposed to damp heat plus illumination. The pink and purple lines represent the alkali poor samples, while the blue lines represent the alkali-rich samples. The values were obtained at elevated temperatures, while room temperature efficiencies are 30-80% higher.

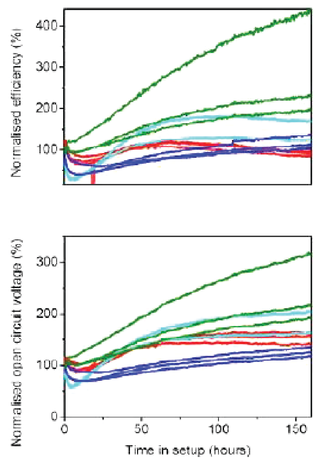

Figure 4.

Figure 4: Evolution of normalized open-circuit voltage and efficiency of four types of non-optimized unencapsulated CZTS solar cells as a function of time in the setup taken at elevated temperatures. Every color depicts a different type of CZTS solar cell.

CONCLUSION

We propose that the setups presented in this study are large improvements compared to the standard IEC tests, due to the combined exposure parameters as well as in-situ monitoring. These properties greatly improve the predictive value of accelerated lifetime experiments.

The four main advantages compared to 'standard' tests are the following capabilities:

- Multi-stress exposure testing (i.e. temperature, humidity, illumination and electrical biases).
- Possibility for the tuning of stresses in order to simulate local climates (e.g. desert or polar conditions).
- Possibility for the tuning of electrical changes, e.g. to simulate effects of partial shading.
- Real-time monitoring of the PV performance, allowing simpler and faster testing, while also better understanding of the degradation mechanisms. It also allows stopping the tests directly after the occurrence of a failure, allowing both direct failure analysis and reduced testing time.

It is therefore proposed that lifetime studied with the presented setups can greatly improve the qualitative and quantitative understanding and prediction of long-term stability of solar cells and modules.

ACKNOWLEDGEMENTS

The authors would like to thank everyone who contributed to the project: TNO/Solliance, Eternal Sun, Delft university of Technology, M2I, Hielkema Testequipment and ReRa solutions.

WANT TO KNOW MORE ABOUT THE SETUP?

Check the QR-code for more info.

WANT TO KNOW MORE ABOUT SPIRE?

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Field Inspection of PV Modules: Quantitative Determination of Performance Loss due to Cell Cracks using EL Images

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[2]Indian Institute of Technology Bombay, India
[2]Arizona State University, USA

Introduction

- Under forward bias condition, the radiative recombination of charge carriers causes light emission from the solar cells. The intensity of this emission can serve as indicator of the solar cell health.
- The dark areas in the EL images can be due to various reasons like cracks, metallization problems, shunting and/or other defects in the bulk semiconductor.
- Current commercial cells are very thin and large, and also the modules are large in size, with glass-polymer construction (instead of glass-glass), all of which makes the cells in the modules susceptible to cracks.
- We present an approach to quantitatively correlate the cell cracks with the performance loss through a correlation between statistically processed EL images and short-circuit current and quantum efficiency data.

Characterization Techniques

- Electroluminescence Imaging was performed to detect the defective (inactive) areas in the selected module. It was done indoors in a dark room with the module under forward bias . The EL image is shown in Fig. 1.
- Cell Quantum Efficiency Measurements were performed at various spots on 3 different solar cells (highlighted in Fig. 1 in red). For this measurement, the backsheet of the module was cut and contact was made to the cell interconnect ribbons.
- Current-Voltage (*I-V*) measurements of individual cells of the entire modules were carried out by accessing the cell terminals as that of the QE measurement.

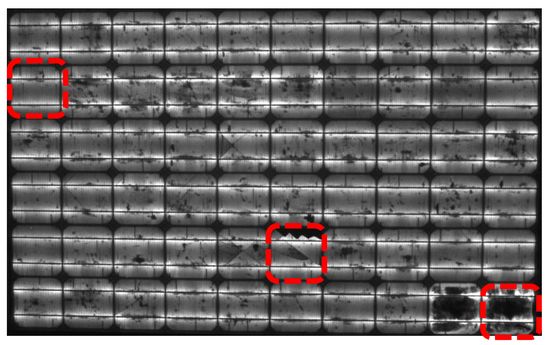
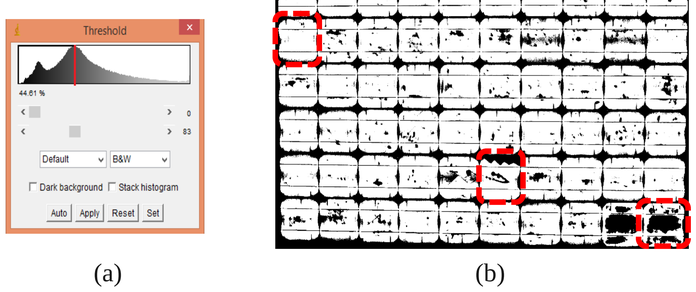


Fig. 1 Original EL image of the PV module (220 Wp rating)

Image Processing

- Threshold function of Image J is used to convert the EL image into a binary image, in which black areas indicate the inactive area of the module (ref Fig. 2).



(a) (b)

Fig. 2. (a) Threshold function in Image-J, showing the histogram of the original EL image and its modal intensity (highlighted using red line), which was used as the threshold limit, and (b) resultant image after thresholding.

- Each solar cell is divided into 3 zones, demarcated by the busbars (indicated as A,B and C in Fig. 4), and the percentage active area in each zone is calculated from the binary image.

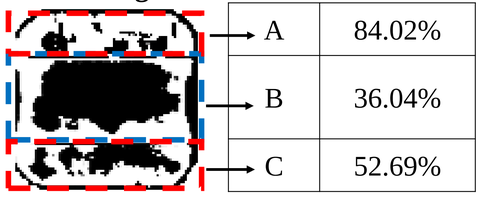


Fig. 4. Processed EL Image, showing the active area in each zone of cell #1 (bottom right highlighted cell in Figs. 1 and 3)

- Quantum efficiency is measured at 30 different points in each of the 3 zones and the average value of these 30 points is considered as representative for that zone. Fig. 5 shows this data for cell #1.
- The short circuit current for the respective zone is estimated from the short circuit current density calculated from the representative (average) QE plot, as per the following relation:

$$I_{sc,\,zone} = J_{sc,\,zone} \times \text{Area of the zone} \quad \ldots.(1)$$

- An I_{sc} reduction factor is then calculated by using the following relations:

$$\textit{Ideal}\ I_{sc,zone} = \text{Module } I_{sc} \times \text{Zone area/ Solar cell area} \quad \ldots.(2)$$

$$\%I_{sc} = I_{sc,zone} / \textit{ Ideal } I_{sc,zone} \times 100\% \quad \ldots.(3)$$

Results and Discussions

- The representative QE curves for cell #1 (Fig. 5) clearly shows that the inactive area degrades the output current.
- The short circuit current density (J_{sc}) estimated from the average QE curve is used to calculate the effective $\%I_{sc}$. It is plotted against the active area of the respective cell zone in Fig. 6, wherein we can see a linear relation between the two.

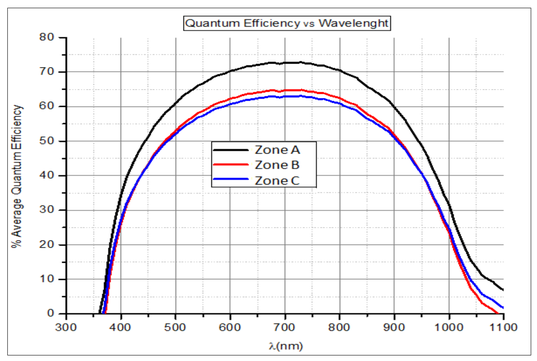


Fig. 5. Average QE curves for various zones of cell #1.

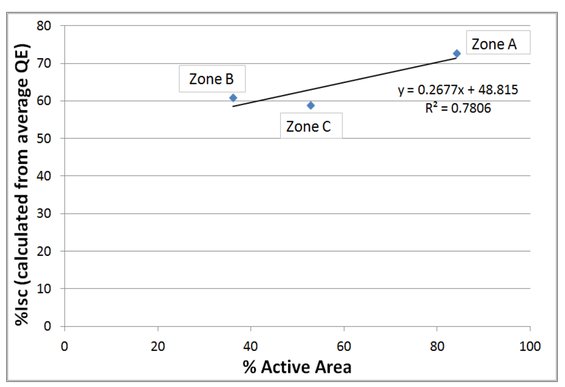


Fig. 6. Plot of estimated $\%I_{sc}$ versus active area of cell #1.

- Fig. 7 shows that the short circuit current derived from the QE measurements is quite close to the actual measured short circuit current for two cells (cells 16 and 50), but there is a significant difference for the 3rd cell (cell 1).
- This difference can be attributed to severe shunting in addition to cell cracks. The cell shunting is observed in this module as it was previously subjected to a short PID (potential induced degradation) test.

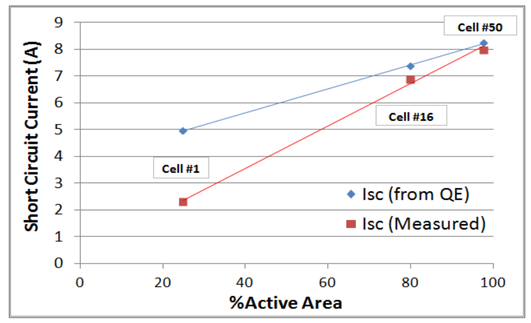


Fig. 7. Short circuit current (Isc) based on integrated QE and direct measurements, plotted against the percentage active area of cell

- The actual measured I_{sc} values of all the cells in the module are plotted against the %Active Area in Fig. 10, and we can clearly see that there is a very strong correlation between I_{sc} and %Active Area.

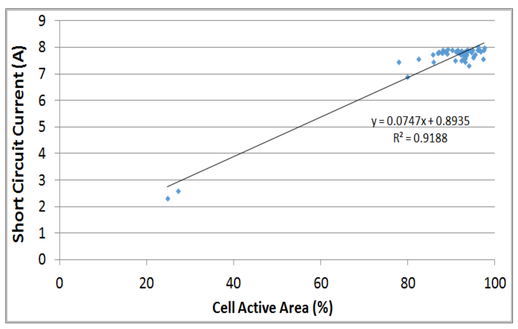


Fig. 8. Short circuit current based on actual measurements versus the percentage active area of the solar cell

Conclusions

- Electroluminescence imaging is an important tool for identification of such inactive areas, but it is often considered as only a qualitative tool.
- We have attempted to quantify the defective areas provided by the EL images, and found an excellent correlation between the remaining active cell area and the short circuit current.
- equipped with the proper image processing tool, it is possible to use EL imaging for quantification of defective area in PV modules, and determination of its impact on module's output power.

References

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Acknowledgements

This paper is based upon work partly supported under National Centre for Photovoltaic Research and Education (NCPRE), through funding from MNRE, Govt. of India, and partly under the US-India Partnership to Advance Clean Energy-Research (PACE-R) for the Solar Energy Research Institute for India and the United States (SERIIUS), funded jointly by the U.S. Department of Energy (Office of Science, Office of Basic Energy Sciences, and Energy Efficiency and Renewable Energy, Solar Energy Technology Program, under Subcontract DE-AC36-08GO28308 to the National Renewable Energy Laboratory, Golden, Colorado) and the Government of India, through the Department of Science and Technology under sub-contract IUSSTF/JCERDC-SERIIUS/2012 dated 22nd Nov. 2012.

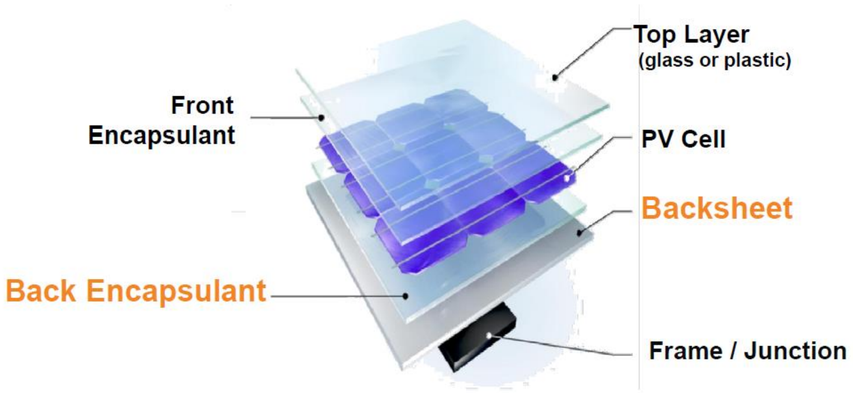
Polyolefin Solutions for Driving Reliability

Lisa Madenjian, Brian Habersberger
Dow Elastomers

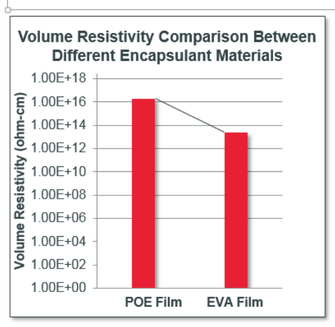
As the PV industry is continuing to drive toward lower levelized cost of energy, technology improvements that affect the day-one performance are essentially mature and offer increasingly marginal benefits. On the other hand, quality improvements achieved by the use of durable, cost-effective materials that both extend module lifetime and improve performance over that lifetime offer significant returns for modest investment. The numerous benefits of polyolefin materials in encapsulant and backsheet design will be discussed and compared to incumbent materials.

Typical Construction of Rigid c-Si PV Module

Requires Back Encapsulant + Backsheet

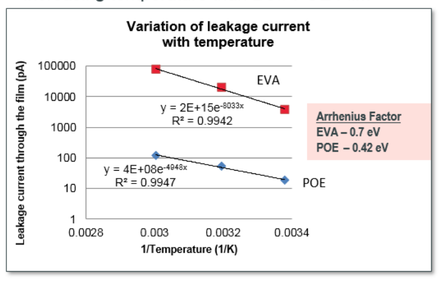


Dow Polyolefin Film: Advantages in Electrical Properties



Dow POE Film has three orders of magnitude higher electrical insulation compared to EVA Film

- Dow POE Film has two to three orders of magnitude lower leakage current vs. EVA Film
- Slope is 1.5X higher for EVA Film vs. POE Film
- Leakage current of EVA Film is more sensitive to increasing temperature than Dow POE Film



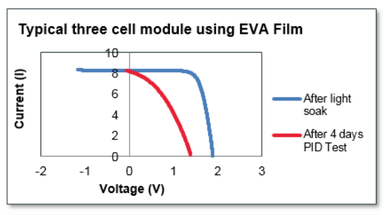
Typical Physical Properties of Encapsulant Films

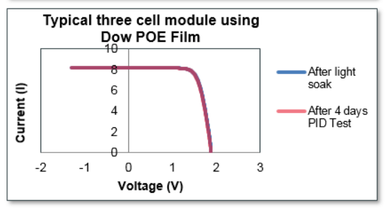
	Dow POE Film	EVA Film
Optical Transmission (%)	>92 [a]	93 [a]
Refractive Index	1.475	1.455
Volume Resistivity (ohm-cm) @ 23ºC (73.4ºF)	>2.00E+16	2.50E+13
Dielectric Strength (kV/cm)	601	444
Thermal Conductivity (W/m-K)	0.291	0.246
Water Vapor Transmission Rate (g/m^2-day) @ 38ºC (100º F)	3.3	34
Adhesion to glass (N/cm) [b]	171	123

[a] Average value from 450-1050 nm, 18 mil film
[b] Laminated at 150ºC (302ºF), 3 min vacuum, 7 min pressure; 180º peel test, glass thickness = 3 mm, strain rate = 2 inch/min

Dow POE Film Has Significantly Less PID vs. EVA Film

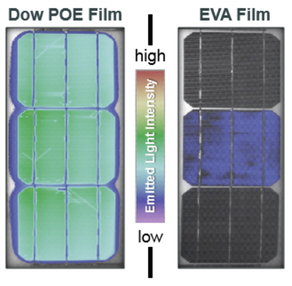
Potential Induced Degradation (PID) Test at -1000V, 60˚C, 85% RH for 4 days





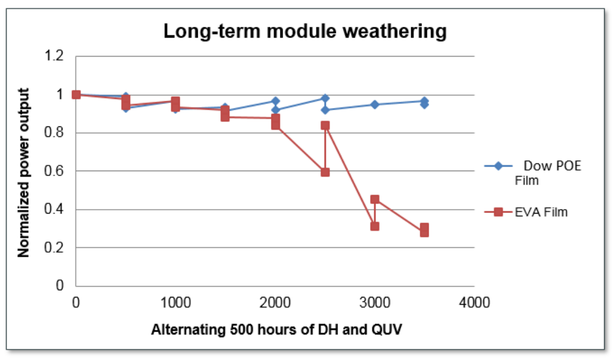
Film Used in Module:	Power loss after PID Test at -1000V, 60˚C, 85% RH for 4 days
EVA-Based Film	>60%
Dow POE Polyolefin Film	<1%

Electroluminescence Measurements After PID Test



POE Films Provide Enhanced Power Retention

Module using POE Film retains power during alternating cycling of Damp Heat and QUV exposure over 7000 hours of total exposure



Modules Using Dow POE Films Retain More Power

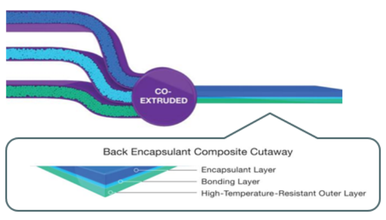
A three-year field test in Florida showed that:
Modules using EVA Films lose 3X more power vs. those using Dow POE Films

Film Used in Module:	Dow POE Film	EVA Film
Power Degradation Rate (%/year)[a]	0.74	2.46

[a] Based on study carried out over three years at the outdoor test facility of Florida Solar Energy Center (FSEC).

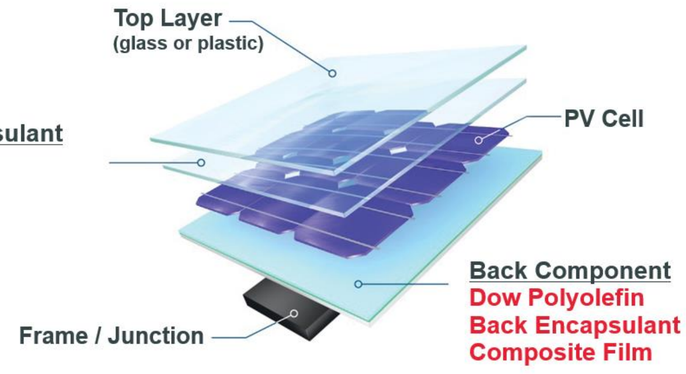
Dow Polyolefin Back Encapsulant Composite Films

- **Improved processing efficiency and logistics**
  - Integrated solution with "2-in-1" PO encapsulant + PO backsheet functionality
  - Eliminates lamination steps and rejects (shrinkage, cell movement, wrinkling)
  - Reduces materials handling and inventory. Improves working capital
- **Improved performance, efficiency and service life**
  - Improved bonding and adhesion, eliminates delamination
  - Excellent electrical insulation
  - Excellent moisture stability and weatherability



Simplified Construction of Rigid c-Si PV Module

Uses a "2-in-1" back composite to serve as back encapsulant + backsheet



Typical Physical Properties - Back Component Materials

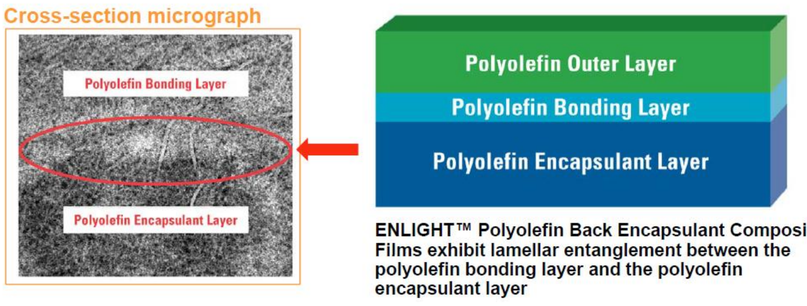
Property	Competitive Typical Film	ENLIGHT™ Polyolefin Back Encapsulant Composite Film
Interlayer peel strength (N/cm) Before Damp Heat [a] After 4000 hours	>4 N/A[b]	>15 to destruct > 15 to destruct
Water Vapor Transmission Rate (g/m^2- day) @ 38ºC (100º F)	2.5 - 4.0	1.1
% Reflectance @ 430 nm	>85	≥92
Relative Thermal Index (RTI)	>105ºC	125ºC
Volume Resistivity (Ohm-cm)	1x10^{11}-1x10^{17}	~2x10^{15}

[a] Temperature 85ºC (185ºF); Humidity 85%; 4000 hours
[b] Could not measure competitive films at 4000 hours due to brittleness

Special Bonding

- Bonds between film layers exhibit lamellar entanglements with very diffuse interfacial boundaries provided by the PO bonding layer
- The integrity of the PO bonding layer significantly increases interlayer bond strength and reduces the potential for interlayer adhesion failures

Cross-section micrograph



ENLIGHT™ Polyolefin Back Encapsulant Composite Films exhibit lamellar entanglement between the polyolefin bonding layer and the polyolefin encapsulant layer

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EVALUATION OF COLOR CHANGES IN PV MODULES USING REFLECTANCE MEASUREMENTS

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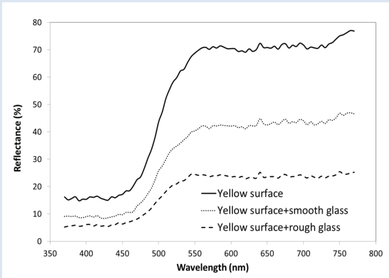
2017 NREL/SNL/BNL Photovoltaic Reliability Workshops
February 28-March 2, 2017
Lakewood , CO
Poster session 3- 51

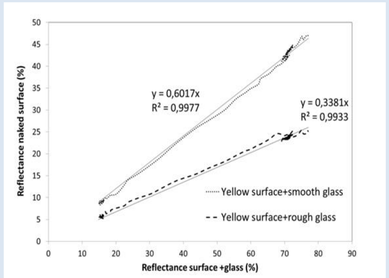
ABSTRACT: It is explored the use of reflectance and related magnitude Yellowing Index (YI) as an indicator of PV solar module surface color change and degradation. While spectrometric quantities as transmittance have been used as a measurement of separated encapsulant and backsheet characteristics, in the present paper reflectances of the surface of real PV solar modules in use are analyzed. We found that $45^0/45^0$ and hemispheric reflectance and associated Yellowing Index can be used indistinctly in certain cases as a good indicator of superficial color changes.

COLOR CHANGES IN PV SOLAR MODULES

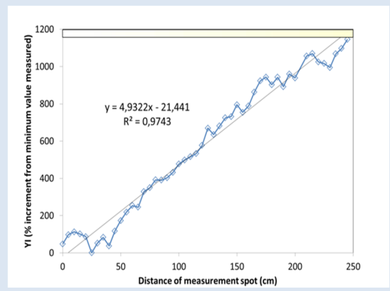
YELLOWNESS INDEX AND 45º/45º REFLECTANCE IN SURFACES + GLASS



Reflectance of a naked yellow paper surface, the yellow surface plus a rough glass and the yellow surface plus a smooth glass.

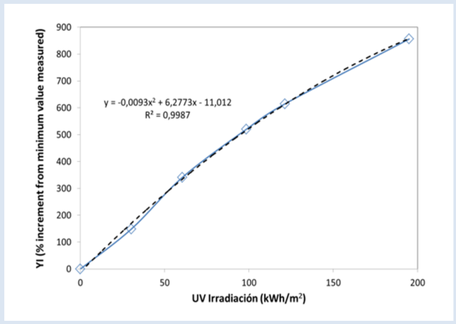


Relation between reflectance of a naked yellow surface and the same surface plus a smooth glass and a rough glass.



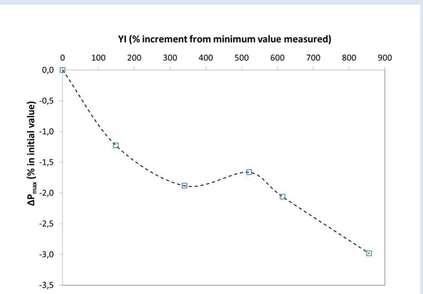
Change of YI in a printed sheet of paper showing a gradual change of color from white to yellow.

YELLOWNESS INDEX FROM HEMISPHERIC REFLECTANCE vs UV DOSE

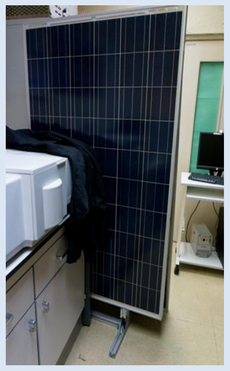


Change of YI in selected spot of a PV solar module situated between two cells. The PV solar module was submitted to an Ultraviolet test in a UV chamber, reaching 195 kWh/m2 of ultraviolet light

Change of maximum power (in % of the initial value) of a PV solar module vs YI. Spot situated between two cell. The PV solar module was submitted to an Ultraviolet test in a UV chamber, reaching 195 kWh/m2 of UV light

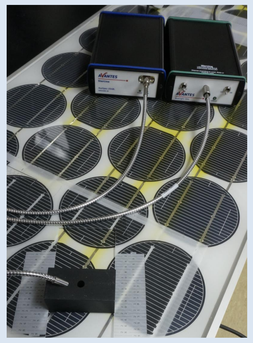


YELLOWNESS INDEX: HEMISPHERIC OR 45º/45º REFLECTANCE?



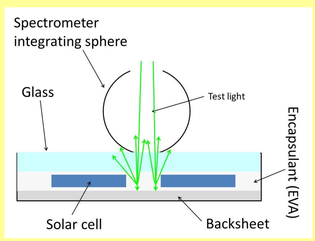
Measurement of hemispheric reflectance of a PV solar module using a optomechanical spectrometer that incorporate a integrating sphere.

Difficult in the field

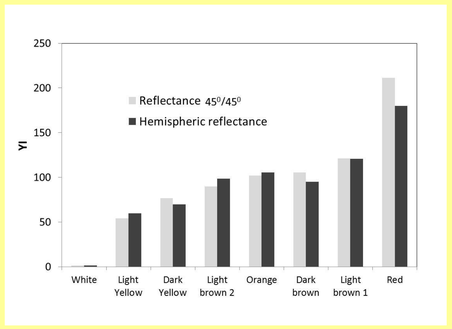


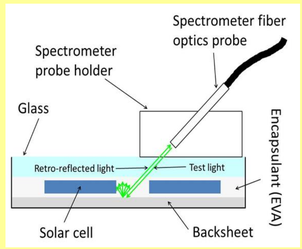
Measurement of 45/45 reflectance of a PV solar module using a fiber optic spectrometer.

Easy everywhere

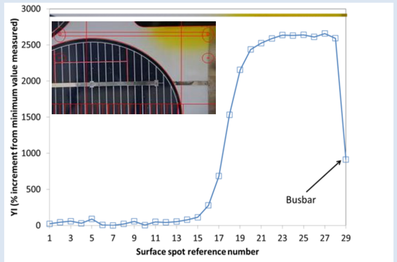


Similar results



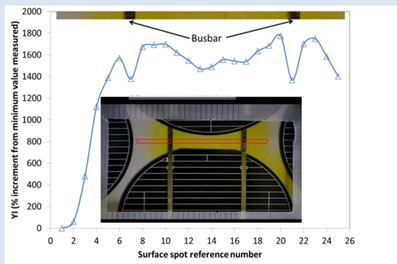


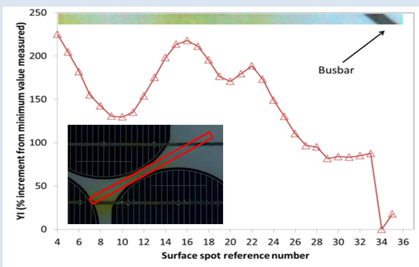
YI AND 45º/45º REFLECTANCE IN PV SOLAR MODULES



Change of YI in a region of a PV solar module. Point 29 corresponds to the measurement of reflectance in a busbar.

Change of YI in a region of a PV solar module. Points 7 and 22 corresponds to the measurement of reflectance in busbars.





Yellowing index in a region of a PV solar module. Points 34 correspond to the measurement of reflectance in a busbar.

CONCLUSIONS: Low cost fiber optic portable spectrometric system are adequate for performing the measurement in field, without disassembling the PV solar module nor using noncommercial samples. A hemispheric reflectance measurement performed using optomechanic spectrometer supply similar results but is tricky to use in real installations.
The presence of a glass between the surface to be measured and the spectrometer is evaluated using $45^0/45^0$ reflectance measurement, finding that naked surface reflectance signal is proportional to glass interposed reflectance signals in the two cases analyzed (smooth and rough glass).
It is found that both hemispherical and $45^0/45^0$ reflectance can be used to describe drift in YI. The advantage in measuring $45^0/45^0$ reflectance is that it can be done easily with portable equipment and that it permits to localize and choose precisely the spot to be measured.
Naked eye color surface differences can be described numerically by measuring YI in PV solar modules that shown differential surface coloration.
It is presented a case in which color change of the surface of a PV solar module submitted to a UV test is well describe using hemispherical reflectance and shown a single mathematical correlation between YI drift and UV dose in one hand and YI versus maximum power in other hand

This work has been partially funded by Spanish Ministry of Economy and Competitiveness (MINECO) under the Plan Nacional de I+D+i, Project CONFIANZA-FV (Ref.: ENE2012-38632-C02-01) and by the Mobility Program for Professors and Researcher in foreign Centers of the Spanish Ministry of Education, Culture and Sports (MECD), 2016 call.

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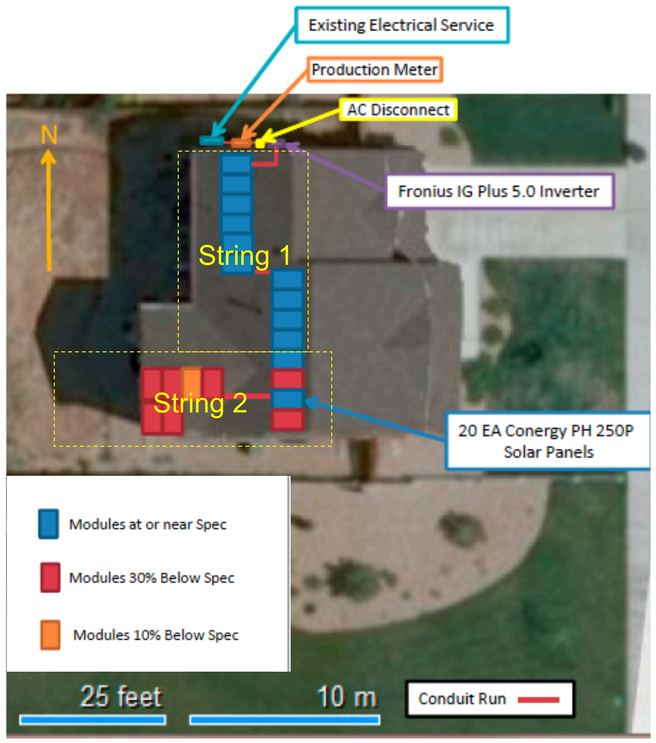
Failure Analysis to Identify Thermal Runaway of Bypass Diodes in Fielded Modules

Chuanxiao Xiao,[1] Yasunori Uchida,[2] Steve Johnston,[1] Peter Hacke,[1] John Wohlgemuth,[1] Mowafak Al-Jassim[1]

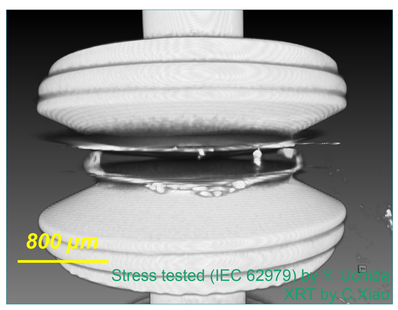
[1] National Renewable Energy Laboratory, Golden, CO, 80401, U.S.A.
[2] Japan Electrical Safety & Environment Technology Laboratories

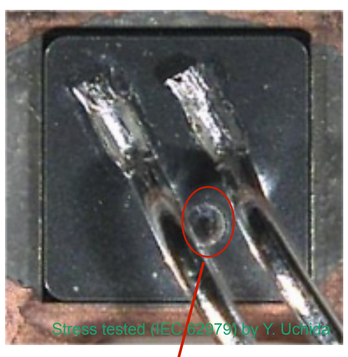
Background & Introduction

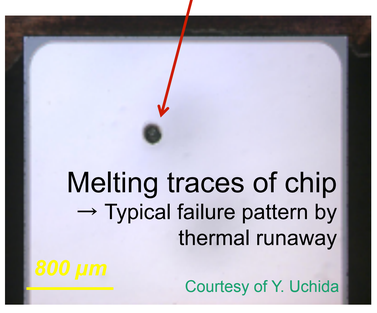


- **Two 10 module strings, one of which has South and West facing modules. This string had many bypass diode failures (shunting) with module power loss as shown.**
- **Did these diodes fail by thermal runaway?**
- **IEC 62979 ed 1 (draft) "Photovoltaic module bypass diode thermal runaway test" was applied on unfailed diodes from these modules. No failure seen.**
- **We performed failure analysis on the field-failed bypass didoes to determine if the failures resemble thermal runaway, a lighting strike, electrostatic discharge, or other overheating?**
- **Failure analysis of short-circuited diodes from fielded modules to show thermal runaway has not yet been demonstrated.**

Lab-stressed thermal runaway diodes







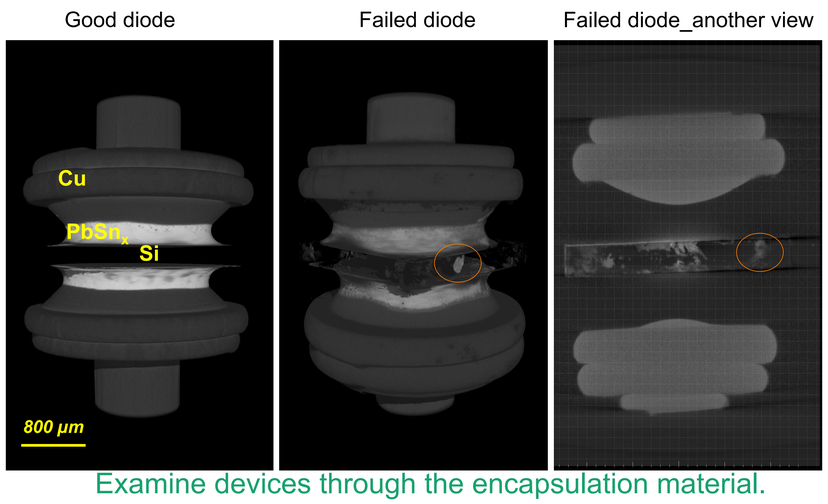
- **Two diodes that we examined that failed by thermal runaway by the IEC 62979 (draft) test showed melted solder and migrated metal (Pb) on the diode edge faces (above). Etch back shows evidence of burns or residue on the chip face (right).**

Experiment

1. ***Bypass diode recuperated from fielded modules in a rooftop installation to determine the failure mechanism***
2. ***X-ray tomography to identify shunt locations without breaking encapsulation***
3. ***Unencapsulate the package, use dark lock-in thermography to study the locations identified by X-ray tomography***
4. ***Aqua Regia etch the diode to expose silicon piece***
5. ***SEM/EDS and optical microscopy to image suspicious shunt locations***

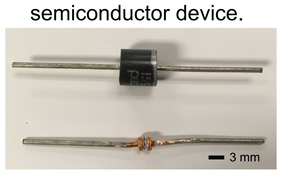
Results & Discussions

X-Ray Tomography

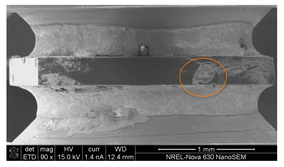


Examine devices through the encapsulation material. Obvious particles observed on silicon surface, similar to the lab-stressed diodes.

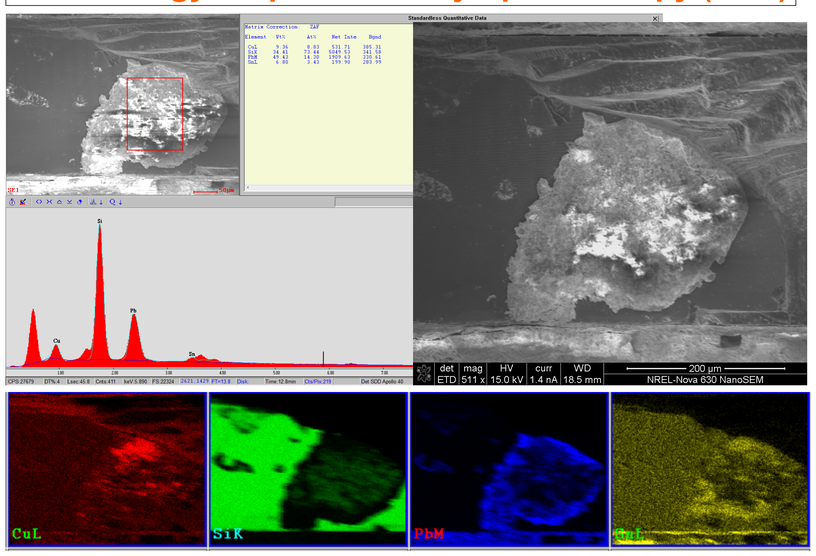
Mechanically remove the encapsulation to expose the semiconductor device.



SEM

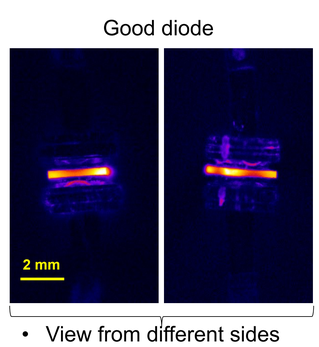


SEM Energy-Dispersive X-ray Spectroscopy (EDS)

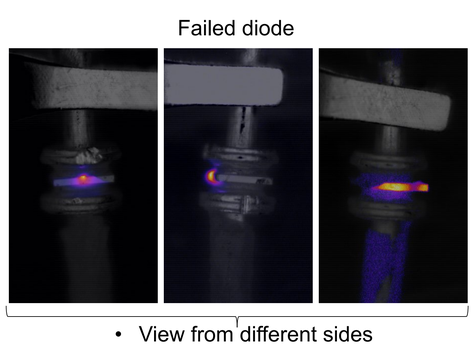


- High resolution imaging to examine defects and identify materials.
- ***Obvious Pb-rich phase, appears to be melted solder.***

Thermal Imaging & Lock-In Thermography

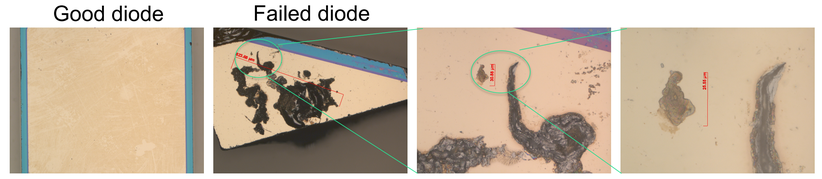


- View from different sides
- Uniform heating in forward bias

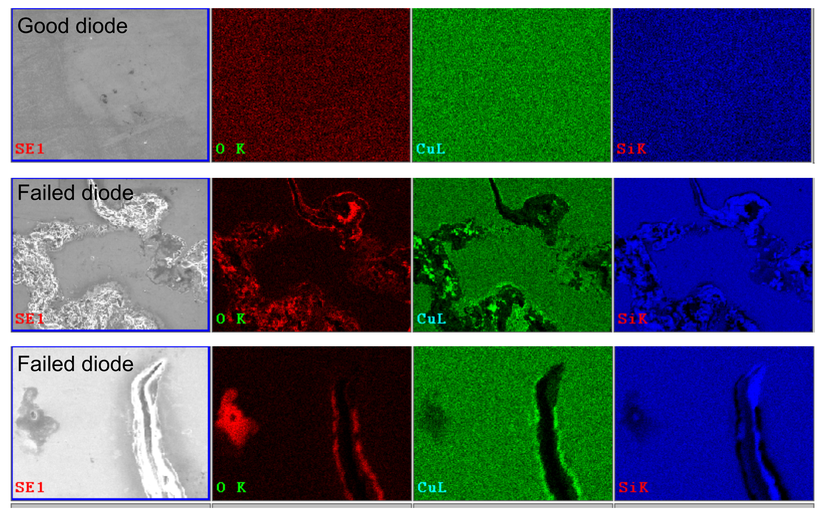


- View from different sides
- Nonuniform heating.

Optical images after acids etch away metal, do EDS



On the failed diode, some etching showed patterns like burn residue; more etching showed pitting, reaction product are more soluble than Silicon.



Oxygen rich surface on areas that had burn residue.

Conclusions

- **The field-failed diode showed similar characteristic of thermal runaway, specifically XRT evidence of migrated metal;**
- **1) Observed burn marks on silicon surface like those lab-stressed for thermal runaway;**
  2) Reaction products are more soluble than silicon, surface is oxygen rich.

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Module Accelerated Stress Testing and Comparison to Field Performance

W. Gambogi, T. Felder, B.L. Yu, S. MacMaster, K. Stika, K. Roy Choudhury and T. John Trout
DuPont, Wilmington, DE, USA

Stresses to PV Modules in the Field

Fixed accelerated stress test conditions commonly used in qualification testing do not address the synergistic stresses observed in the field.

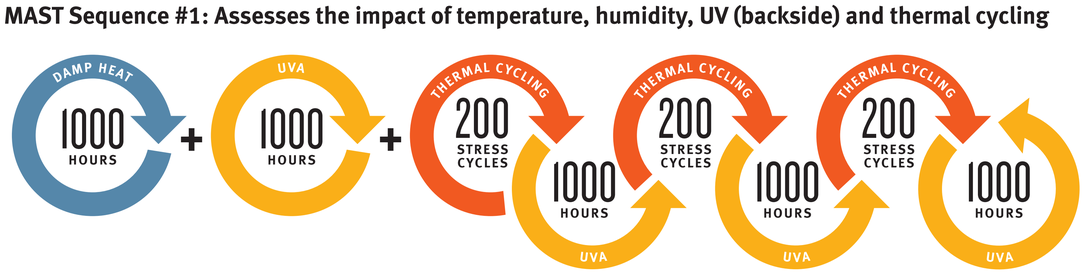
DuPont has developed a set of sequential stress tests to assess the durability of PV modules using important stress conditions in the field: temperature, humidity, UV and thermal cycling. Performance under these module accelerated stress tests (MAST) is compared to the field.

Sequential Test Sequences

DuPont has developed three sequential test protocols by combining the following critical stresses:

- Damp heat exposure (1000h) consistent with >25 years outdoor exposure for backsheet hydrolysis damage
- UV exposure (260 kWh/m^2) to simulate the equivalent exposure in the field due to albedo
- Thermal cycling (600 cycles) provides mechanical stress that assesses the impact of materials' properties changes on physical integrity

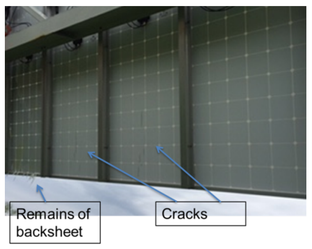
MAST Sequence #1: Assesses the impact of temperature, humidity, UV (backside) and thermal cycling

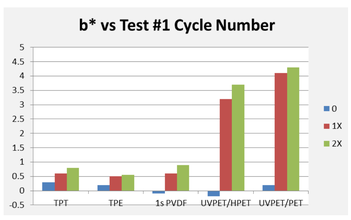


1000 Hours in a Humidity Chamber
Amounts to 25+ years worth of stress

600 Thermal Stress Cycles
Mimics thermal stresses seen in the field

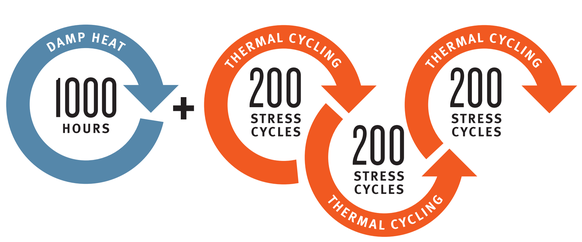
4000 Hours in a UVA Chamber
Amounts to 24 years worth of UV stress



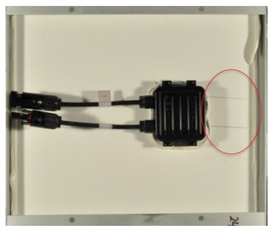


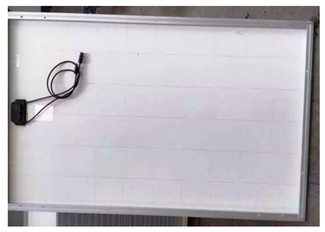
- Single-sided PVDF backsheet (left center) cracking along busbar ribbon
- Single-sided PVDF backsheet cracking in the field (left)—the cracks develop in the MD direction of the PVDF film and propogate preferentially along busbar ribbons
- Yellowing in PET modules from the field (right center) and after MAST sequence #1 including UV exposure from the backsheet side

MAST Sequence #2: Assesses the impact of temperature, humidity and thermal cycling



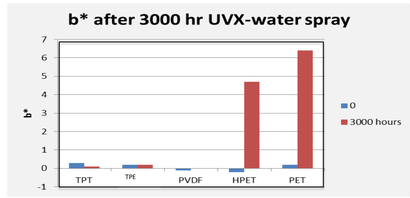
MAST Sequence #2: Assesses the impact of temperature, humidity and thermal cycling (continued)

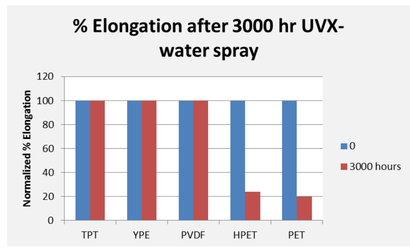




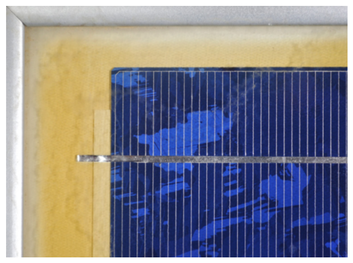
- Cracking of PA mini-module after DH/TC (left) and cracking of PA backsheet in the field (center and right)

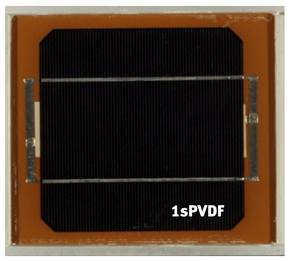
MAST Sequence #3: Weathering (Xenon Exposure and Water Spray)

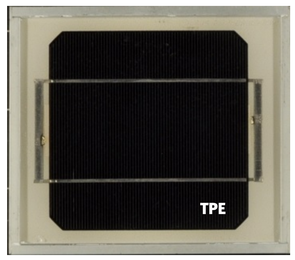




- Yellowing and loss of mechanical properties was observed in two commercial PET backsheets exposed to xenon weathering with air side water spray







- Front side yellowing in the field (left) for 1sPVDF backsheet occurred within less than five years
- Yellowing in single-cell modules with single-sided PVDF backsheet (center) with weathering exposure (90C BPT) and front side UV exposure of ~4 years equivalent exposure in Arizona—no yellowing of TPE backsheet after the same exposure (right)

Conclusions

- Sequential stress tests show defects observed in the field.
- Application of sequential test protocols is an effective approach to assess the impact of materials' degradation in the field.
- Comparison modules using PVF-based backsheets did not show degradation after MAST exposure.

+130 Over the last 9 years, DuPont has introduced more than 130 new Solamet® pastes designed to boost solar panel power output.

+30 YEARS Tedlar® film is the only backsheet material proven to protect solar panels for 30+ years in all weather conditions.

+50% More than half of the world's 900 million solar panels installed since 1975 have DuPont materials in them.

+5 TRILLION DuPont materials have been time-tested in >5 trillion panel-hours of solar installations across the globe since 1975.

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Recent Failures of Backsheets in Fielded PV Modules and their Relation to Material Degradation

Kaushik Roy Choudhury[1], William Gambogi[1], Thomas Felder[1], Alexander Bradley[1], Katherine Stika[1], Steven MacMaster[1], Lucie Garreau-Iles[2], Hongjie Hu[3] and T.-John Trout[1]
(1) DuPont, Wilmington, DE, USA; (2) Du Pont de Nemours International S.A., Geneva, Switzerland; (3) DuPont (China) Research & Development and Management Co. Ltd., Shanghai, P.R.C.

Assessing Material Performance in the Field

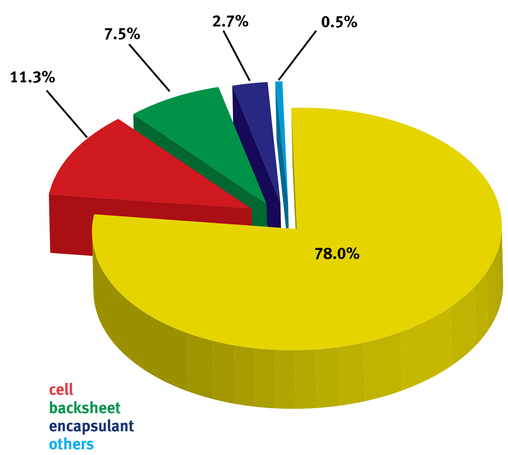
Global program assessing fielded module performance using visual inspection, thermal imaging and FTIR spectroscopy

- Number of fields inspected: 197 with panel output of 453 MW
- Total defect rates ~22%; backsheet defects ~7.5%

Representative modules from the field obtained for further analysis

1 Non-destructive analysis (IV, EL, thermal imaging, electrical insulation)

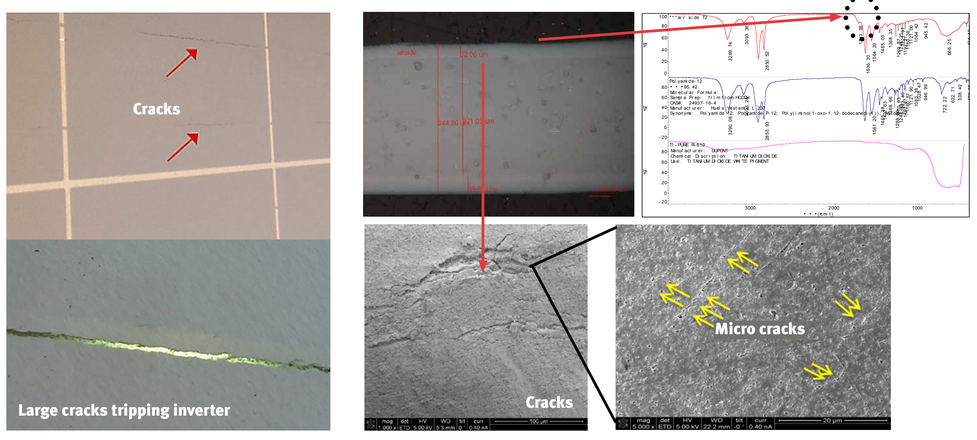
2 Destructive analysis (coring, optical microscopy, SEM, IR spectroscopy, X-ray, GC-MS, ion chromatography, nano-indentation, mechanical properties)



Field Results Show Cracked Polyamide-based Backsheets

Case 1

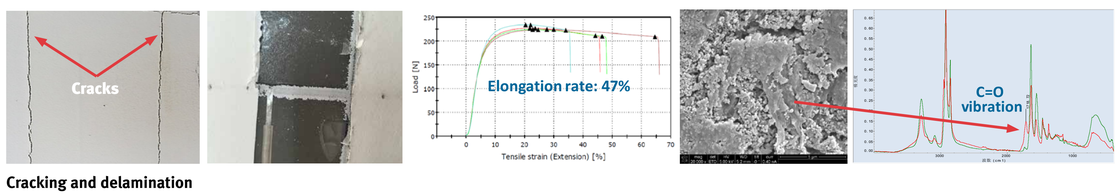
- Service time: 2 years
- Location: China
- Backsheet: 32µm PA / 270µm PA + glass fiber / 40µm PA
- FTIR indicates degradation of airside PA layer
- SEM indicates mini and micro cracks on the airside



Chalking and cracking

Case 2

- Service time: 5 years
- Location: Europe
- Backsheet: 28µm PA / 290µm PA + glass fiber / 30µm PA
- Modules fail wet insulation test: safety risk
- Numerous pores and defects on cracked surface
- C=O vibration stronger than control; PA degradation
- Significant yellowing of degraded inner layer



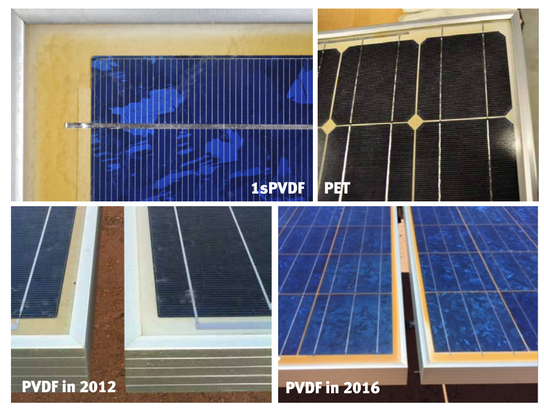
Cracking and delamination

Field Results Show Increased Yellowing of Inner Layer of PVDF and PET-based Backsheets with Time

Inner layer yellowing of single-sided PVDF backsheets (left, <5yr in multiple locations) and PET-based backsheets (right, 4yr in Arizona, USA)

Same field in Arizona, USA inspected in 2012 and 2016:

- In 2012, 1% of modules showed front-side yellowing
- In 2016, 100% of modules show yellowing; 15% had severe yellowing



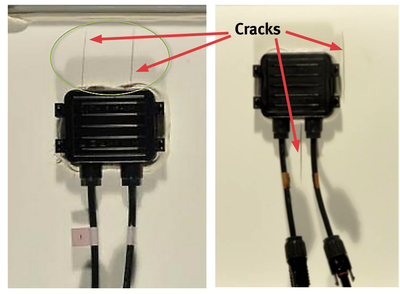
Comparison of Field Data to Accelerated Testing

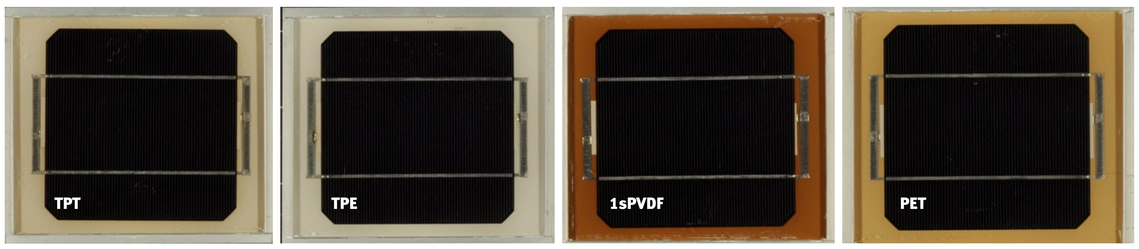
- Single-cell mini-modules with commercial polyamide-based backsheets (AAA) showed yellowing (Δb* = 4.1) and developed cracks in two different accelerated tests:

  a) DH1000/2xTC200

  b) DH1000-2x(UVA1000/TC200)

- Yellowing in single-cell modules with weathering exposure (90C BPT) and front side UV exposure of ~4 years equivalent exposure in Arizona





Conclusions

- Stresses of UV and moisture in the field can lead to degradation of polymeric material resulting in yellowing on the front and back of the module.
- This degradation can also result in loss of mechanical properties leading to cracking and delamination of the backsheet.
- Properly designed weathering exposures and test cycles of full structures can predict performance changes that match field performance.

+130 Over the last 9 years, DuPont has introduced more than 130 new Solamet® pastes designed to boost solar panel power output.

+30 YEARS Tedlar® film is the only backsheet material proven to protect solar panels for 30+ years in all weather conditions.

+50% More than half of the world's 900 million solar panels installed since 1975 have DuPont materials in them.

+5 TRILLION DuPont materials have been time-tested in >5 trillion panel-hours of solar installations across the globe since 1975.

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Survey of Mechanical Durability of PV Backsheets

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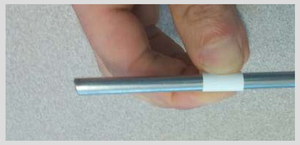
[2]Atlas Material Testing Technology LLC, Mount Prospect, Illinois 60056
[3]Loughborough University, Leicestershire, UK

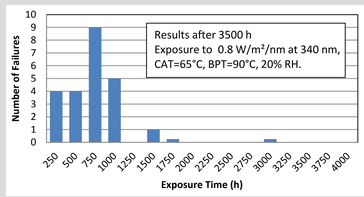
The ability to maintain mechanical properties after applied environmental stress is a good indicator for long term durability of a backsheet. This work surveys a set of 55 materials, some of which are known to fail in the field. While the complete study examined optical reflectance characterization, tensile testing, dielectric testing, and a mandrel bend test, this paper focuses on the mandrel bend test method. All eight of the transparent samples failed. A polyamide based material known to fail in the field did not fail the bend test. It is believed that the field failure is due to an interaction with the encapsulant and/or the cyclic mechanical exposure experienced in the field. When cracks occur, they happen predominantly in the polyethylene terephthalate for transparent materials or the "E" layer for opaque films, not in a fluoropolymer layer.

- *An extended backsheet study was conducted to evaluate the effect of the weathering test over a broad range of materials. Here we want to get an understanding of how backsheets behave in general.*
- *A total of 55 materials were obtained from a number of different sources and is believed to have some replicates.*
- *For some materials we were told the class of materials used along with the thickness, but for others no information was given.*
- *FTIR-ATR was used to classify the air and cell-side surfaces of the backsheets. This was used to determine the composition of unknown materials and to verify the composition of materials with a reported composition.*
- *Backsheet Material Classification (55 samples)*
  - *Air Side*
    - *One sample was a polyamide known to fail in the field.*
    - *36 samples had a fluoropolymer on the air side.*
      - *13 where PVF*
      - *5 were PVDF*
    - *16 samples had PET on the air side.*
    - *Two samples with Polyethylene*
  - *Cell-Side*
    - *27 had a low-vinyl acetate EVA*
    - *18 had a fluoropolymer on the backside*
      - *These all had fluoropolymers on the air side too*
      - *3 of these were PVF*
    - *5 had PET*
    - *4 with a polyolefin*
    - *One polyamide*

Experimental Methods included tensile testing, a mandrel bend test, transmittance and reflectance measurements

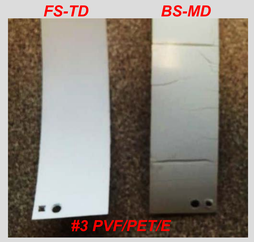
- Bend test samples were mounted on a metal substrate to restrict backside UV exposure.
- Samples are bent around a 6.35 mm diameter mandrel in both directions.
- Testing is conducted every 250 h till failure occurs.
- Usually the cracks are seen, but sometimes you can only hear the cracks forming.
- Tensile testing was also conducted separately with rectangular coupons.

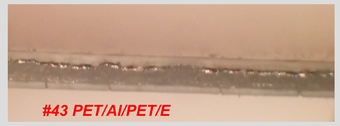




Cracks were almost always confined to the "E" layer.

- Cracks never start in a fluoropolymer layer.
- PET layers only crack when used in transparent backsheets.
- Cracks often dominate in the transverse direction, but never dominate in the machine direction indicating residual strain in the Machine direction.
- Two films showed delamination.
- The majority of the cracks were confined to the E layers.

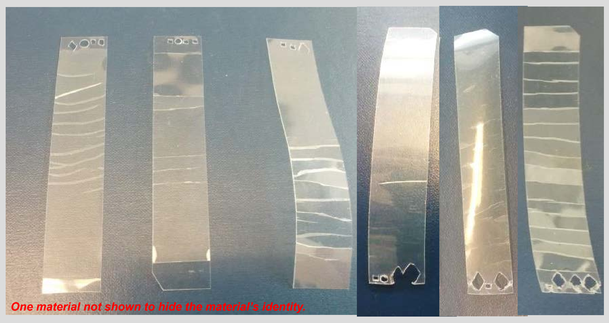




All 7 of the clear samples failed

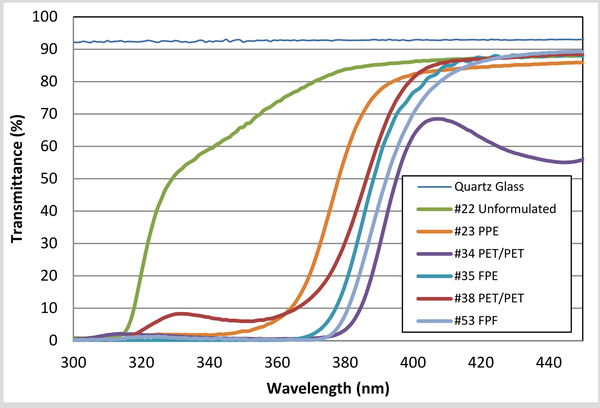
None of the unpigmented PETs were able to withstand exposure for more than 750 h.
This may be a concern for bifacial modules with these films.

#38 RR-UVPET 250 h *#37 RR-PET 250 h* *#22 Unstabilized PET 250 h* *#35 FPE 500 h* *#23 PET/PET/E 500 h* *#53 FPF 750 h*



One material not shown to hide the material's identity

The use of UV absorbers was not sufficient to protect transparent PET films.

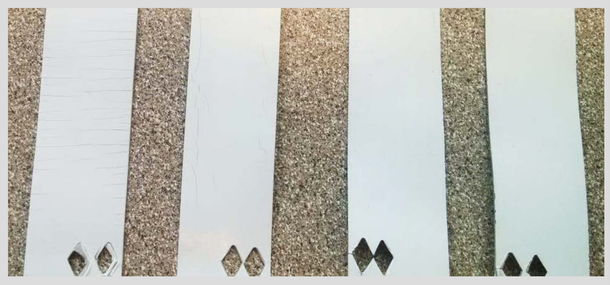


It is not known which layer had the UV aborber in it, but most likely it is in the PET layer.

Sometimes the cracks are predominantly in the transverse direction or were seen first on the machine direction samples.

#8 PVF/Al/PET/E
Cracks in "E" layer only.
Cracks dominate in the Transverse direction.
This is typical behavior, residual strain significantly affects cracking.

BS-MD *BS-TD* *FS-TD* *FS-MD*

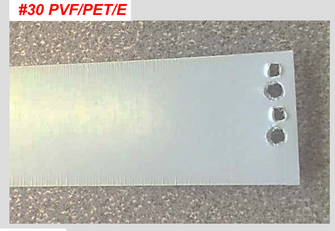


In 8 materials, the cracking initiated from the sides in the "E" layer.

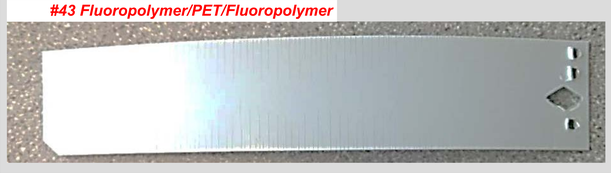
Many samples had cracks that were initiated from the sides of the samples propagate across the samples.

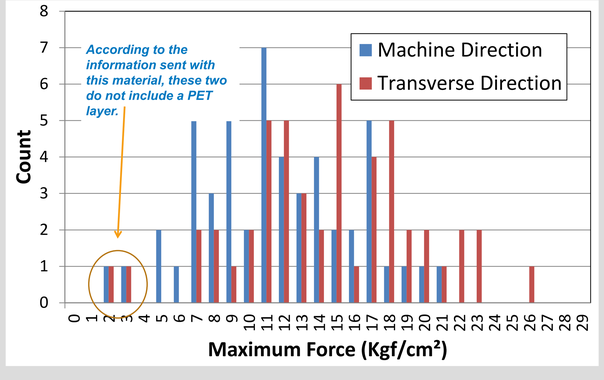
This brings up the question of damage to the edges contributing to failure, but similar damage would be seen in a production module also.

#30 PVF/PET/E

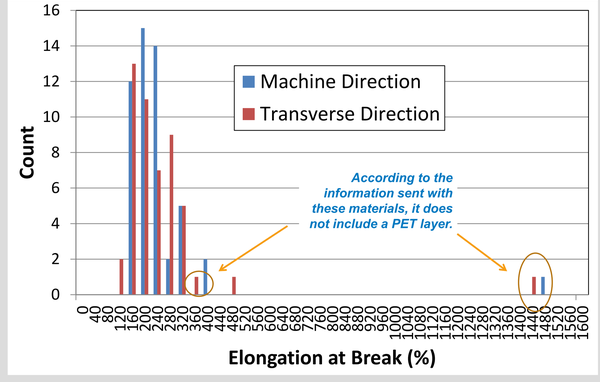


#43 Fluoropolymer/PET/Fluoropolymer





There is a very large relative spread in the maximum force. Attributable to the varying thickness of PET and the other layers in the backsheet films. (This is for unexposed films)



All the PET containing backsheets had similar elongation at break; therefore, evaluating elongation at break may only evaluate degradation of PET. (This is for unexposed films)

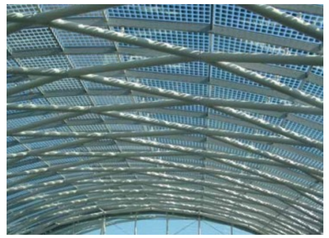
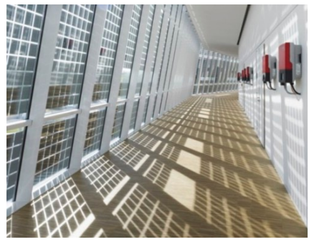
Conclusions:

- *All of the clear/transparent samples have cracked in under 750 h UV exposure. Failure was always in the PET layer even with some UV blocking absorber.*
- *No fluoropolymer layers have cracked unless a PET layer cracked too.*
- *The majority of failures were in the E layer leaving the PET layer intact.*
- *Most failures happened in the first 1000 h of UV exposure.*
- *The polyamide material known to fail in the field did not fail in this test. It may be a shrinkage issue or a material incompatibility that is not manifested when testing a bare film.*
- *Tensile testing is highly dependent on the PET core layer.*

Acknowledgements:

- *We would first of all like to thank all the members of the weathering committee for providing feedback and for providing materials for the study. Through them news of what we are doing got out to a large number of people enabling us to assemble a large collection of 55 backsheet materials.*
- *A special thanks goes out to Emily Parnham and Sophie Pain for tensile strength measurements.*
- *This work was supported by the U.S. Department of Energy under Contract No. DE-AC36-08-GO28308 with the National Renewable Energy Laboratory.*

- *Emily Parnham, Sophie Pain, Nancy Phillips, Xiaohong Gu, Anthony Whitehead, David Burns, Bill Gambogi, Rene Eugen, Shin Watanabe, Jiang Zhu, Sean Fowler, Tom Earnest, Chris Flueckiger, Takao Amioka, Ryuhei Metabi, Laura Bruckman, Roger French, Juergen Jung, Marina Temchenko, Paul Robusto, Marc Brandenburg, Shuying Yang, Greg Obrien, Amy Lefebvre, Michael Koehl, Kurt Scott, Bill Brennan, Toshiaki Hayashi, Gerhard Kleiss, James Bratcher, Ryuhei Metabi, Arnd Roth.*

Development of a Single Layer Clear and White PV Backsheet

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Abstract

Currently, multilayer white backsheets are the industry standard for the back layer in a PV panel. However, with the recent drop in price and greater availability of bifacial cells, the demand for an economical clear backsheet is likely to grow. In today's market, the cost of a clear backsheet is significantly higher than a white backsheet which is our primary motivation for developing a single layer, cost-effective option. At Soliculture Inc., we have initiated reliability testing of a single layer polymeric clear backsheet for standard PV panels with promising results to date. In the past, our team has successfully developed, put into commercial production, and installed in the field (up to 2 years) a transparent backsheet with luminescent dye for use in glass greenhouses.

Industry Standard

Currently, clear solar panel backsheets are made with three layers: encapsulant primer / polyethylene terephthalate / protective layer. Most products are now available for $3 to $5 per m^2

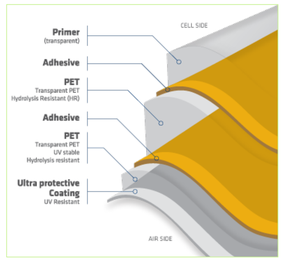


Figure 1. Transparent Backsheet Construction from Coveme

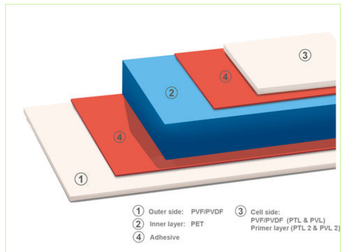


Figure 2. Transparent Backsheet Construction with Tedlar from Krempel

Single Layer Backsheet

Development of a single layer PV backsheet has the potential to both decrease costs and increase reliability since most backsheet failures occur within the layers of the backsheet and by delamination of the backsheet from the glass.

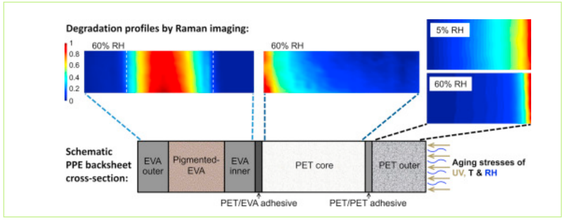


Figure 3. Degredation Profiles of inner backsheet layers by Raman imaging (http://dx.doi.org/10.1016/j.solmat.2015.09.021)

Reliability Testing

Exposures

- Damp Heat
  - 85°C and 85% humidity
  - 1000 hrs
- High UV, Low Heat
  - 6.25 W/m²/nm UVA
  - 40°C
  - 1000 hrs
- Medium UV, High Heat
  - 1.37 W/m²/nm UVA
  - 70°C

Tests

- Peel Tests
  - Adhesion
- Tensile Tests
  - Tensile strength
  - Elongation
- Optical Tests
  - Visual
  - Transmission

Tensile Strength

Tensile strength of the test film is only slightly affected after 1000 hours of damp heat.

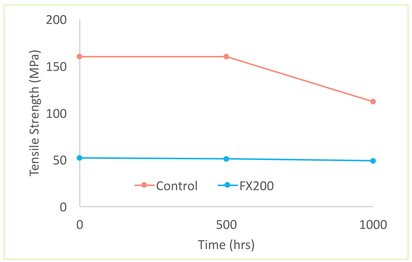


Figure 4. Tensile strength of new film before and after damp heat aging at 80°C and 80% humidity.

Adhesion

The test film out-performs the control in adhesion to EVA after 1000 hours of exposure to damp heat.

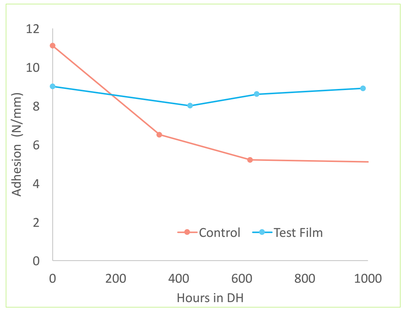


Figure 5. Effect of damp heat aging (80°C and 80% humidity) on adhesion to EVA.

Optical Properties

Transmission through the test film remains high (less than 3% change) after UV exposure and damp heat aging.

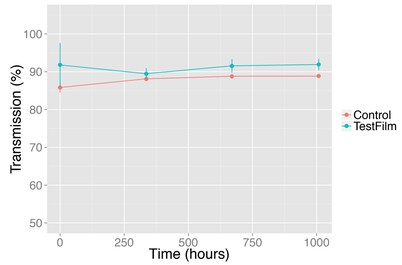


Figure 6. Transmission through film after high UV (low heat).

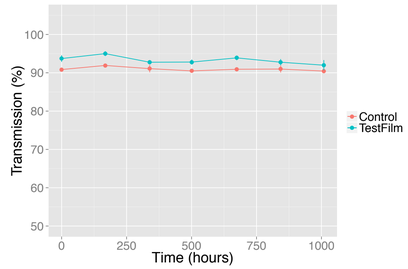


Figure 7. Transmission through film after medium UV (high heat).

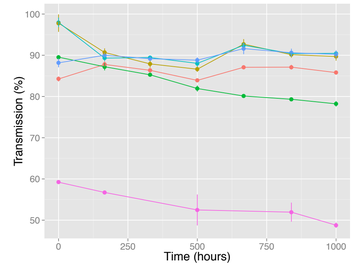


Figure 8. Transmission through film after damp heat aging.

Encapsulation Performance after Three Years in the Field: A Comparison of Hot/Humid and Hot/Dry Climates

Eric J. Schneller[1], David C. Miller[2], Onkar Shinde[1], Sai Tatapudi[3], Govindasamy Tamizhmani[3], and Neelkanth Dhere[1]

[1]*Florida Solar Energy Center, University of Central Florida, Cocoa, FL*

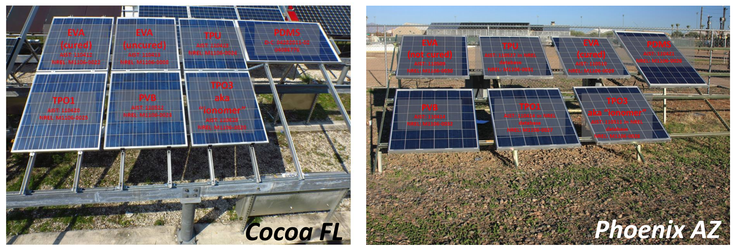
[2]*National Renewable Energy Laboratory, Golden, CO*

[3]*Arizona State University, Phoenix, AZ*

Introduction

Seven different encapsulation materials (thermoplastic EVA, thermoset EVA, PDMS, PVB, thermoplastic polyolefin 1, thermoplastic polyolefin 2, and TPU) were used in the fabrication of modules that were deployed in Cocoa, FL and Phoenix, AZ. The modules were originally used to examine mechanical creep in emerging encapsulant materials, including thermoplastics [1, 2, 3]. The goal of the present and more extended study, however, is to document the performance over time and screen for encapsulation specific degradation modes in two unique climate zones: hot/humid, and hot/dry. Through nearly three years of deployment, several unique features were observed in the modules. This work will distinguish differences observed to date between the different encapsulants. Specifically, "snail trail" features have been observed for the TPU (Cocoa and Phoenix) and PVB (Cocoa only) as well as premature discoloration of the thermoplastic EVA (Cocoa only). Additional features, including shattered front glass, hot spots, a failed solder joint, and delamination of the backsheet have been observed on specific modules. A timeline of when these features were observed and the impact they have on performance will be presented. Comparison of the performance and degradation between the sites is expected to provide insight on the use of modules in extreme (hot) climates.

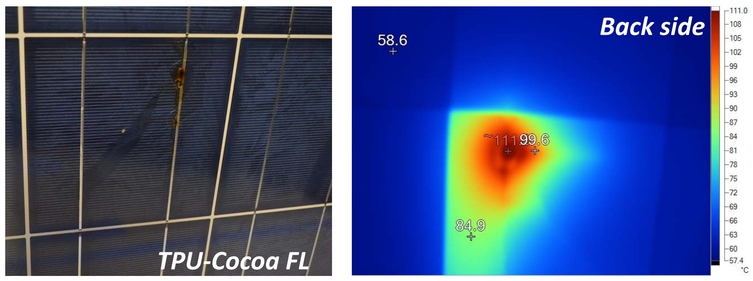
[1] Kempe *et. al.*, Energy Sci. Eng., 4 (1), 2016, 40-51
[2] Kempe *et. al.*, Energy Sci. Eng., 3 (6), 2015, 565-580.
[3] Moseley *et. al.* , NREL/TP-5200-52586, 2011, 1-20.



Images of both sets of modules with each of the encapsulant types identified.

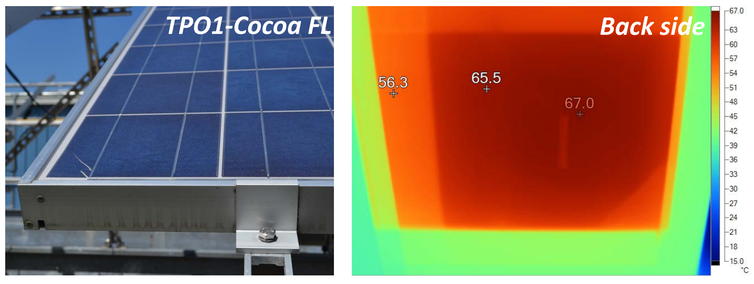
Degradation External to Encapsulation

Interconnect Failure



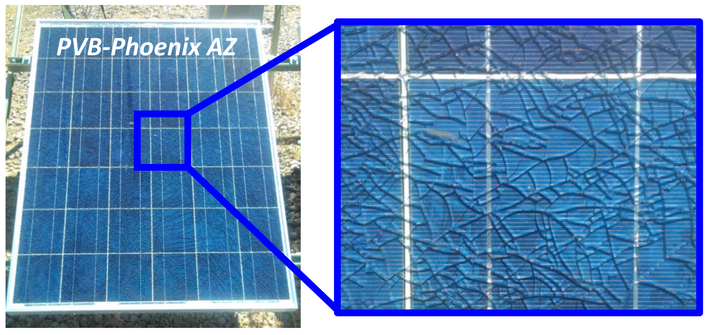
An interconnect failure occurred after a few months in the field. Near solar noon, the temperature regularly exceeded 100 ºC. This has lead to severe degradation of the packaging, including browning of the encapsulant, delamination, and blistering/yellowing of the backsheet. Solder bond failure may result from worksmanship during module manufacture; solder fatigue is subject to the properties of the encapsulantion.

Cell Fracture (Before/During Encapsulation)



During module fabrication, one of the cells in the TPO1 module fractured. The different phase transition temperatures and mechanical stiffness may require different conditions (relative to EVA) during module lamination. Because this region of the cell is electrically isolated, the cell is mismatched within the string and module. The fractured cell is regularly 5-10 ºC hotter than the rest of the module.

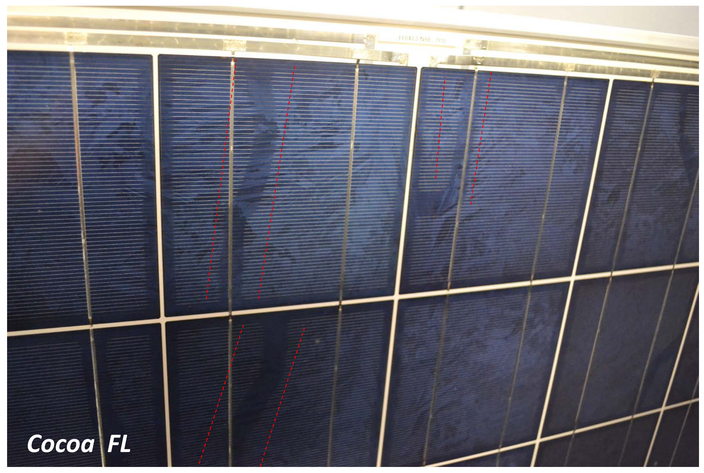
Shattered Front Glass



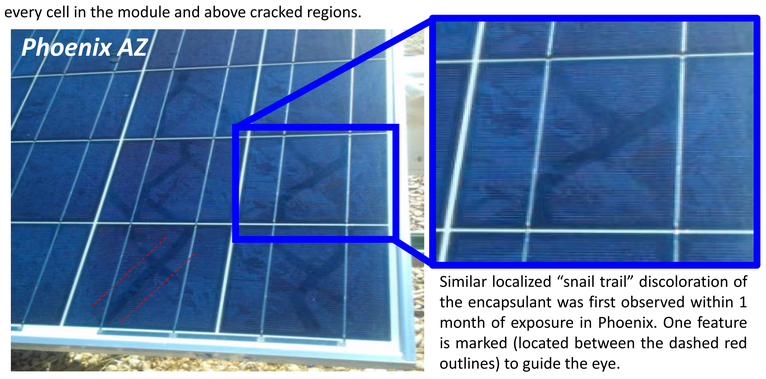
Within the first month of field aging, the front glass of the PVB module shattered. No evidence of impact is evident for the module. The damage may follow from stress within the module (the PVB formulation used is more rigid than EVA, which may retain residual stress after lamination especially when a frame is present).

Degradation Related to the Encapsulation

TPU - "Snail Trails"

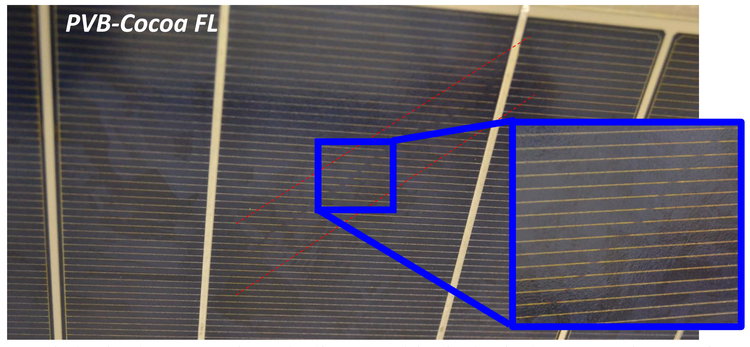


Localized "snail trail" discoloration of the encapsulant was first observed after 6 months of exposure in Cocoa. Such features (located between the dashed red outlines) are now clearly visible at the edge of every cell in the module and above cracked regions.



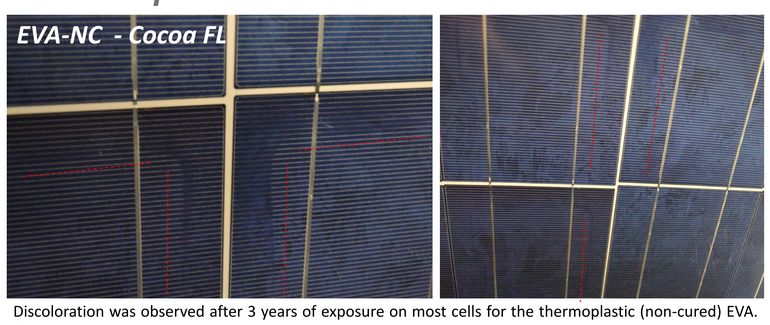
Similar localized "snail trail" discoloration of the encapsulant was first observed within 1 month of exposure in Phoenix. One feature is marked (located between the dashed red outlines) to guide the eye.

PVB - "Snail Trails"



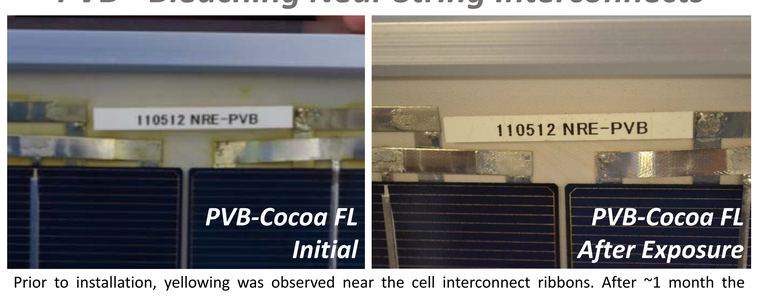
A single discolored region was observed in the PVB module. The discoloration appears along a crack on only one cell. This defect was observed after 3 years of exposure.

Thermoplastic EVA - Premature Discoloration



Discoloration was observed after 3 years of exposure on most cells for the thermoplastic (non-cured) EVA. The discoloration occurs approximately 1 inch from the edge of the cell (dashed red outlines in images). In this study, the same EVA formulations maybe compared for discoloration in hot/humid and hot/dry climates.

PVB - Bleaching Near String Interconnects



Prior to installation, yellowing was observed near the cell interconnect ribbons. After ~1 month the yellowing reduced significantly. After several months, the yellowing disapeared completely.

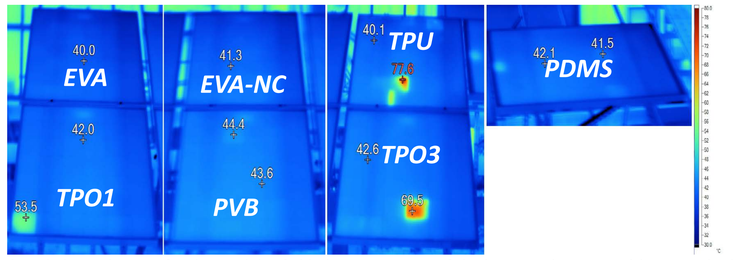
Performance Degradation

Each module was connected to a fixed load resistor during field aging. The performance of each module was measured at 1 year intervals during this project. The tables below shows the relative change in the PV performance parameters (performance at 3 years divided by the original performance). Performance measurements were performed using a solar simulator. The major changes in performance are a result of non-encapsulant related failures (*i.e.,* interconnect failure, cell fracture). No significant performance loss is observed for any of the noted encapsulant degradation (*i.e.,* snail-trails). Even for the TPU in which severe "snail trails" were observed, no significant loss in short-circuit current was observed.

Change in Performance Following 3 Years Exposure in Cocoa FL

Encapsulant Type	Site	Power	Isc	Voc	Ipeak	Vpeak	Fill Factor
EVA	Cocoa FL	0.995	0.990	0.996	0.995	1.000	1.009
EVA-NC	Cocoa FL	1.005	0.995	0.991	1.010	0.995	1.018
TPO3	Cocoa FL	0.864	0.993	1.002	0.944	0.915	0.868
TPO1	Cocoa FL	1.002	0.999	0.996	1.005	0.997	1.007
PVB	Cocoa FL	1.010	0.995	0.995	1.014	0.996	1.020
TPU	Cocoa FL	0.906	0.993	0.989	0.875	1.036	0.923
PDMS	Cocoa FL	0.984	0.973	0.998	0.977	1.007	1.014

Table of performance metrics relative to their original value after 3 years of exposure in Cocoa. Changes exceeding 5% are highlighted in red and notable changes less than 5% in magnitude are highlighted in yellow.

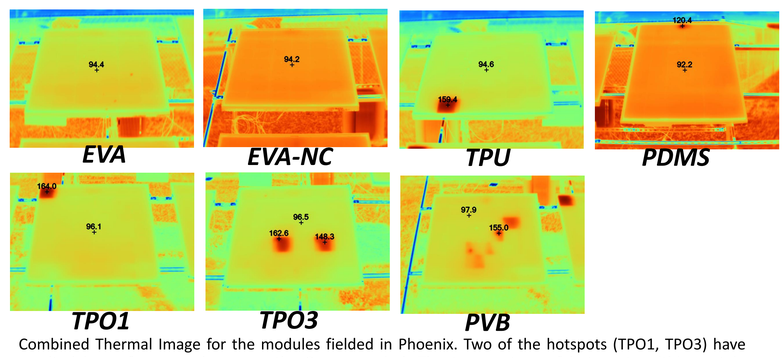


Combined Thermal Image for the modules fielded in Cocoa. Two of the hotspots (TPO1, TPU) have resulted in performance loss over the 3 year period. The temperature scale has been synchronized between the images, and the temperature of hot spots within certain modules is indicated.

Change in Performance Following 3 Years Exposure in Phoenix AZ

Encapsulant Type	Site	Power	Isc	Voc	Imax	Vmax	Fill Factor
EVA	Phoenix AZ	1.026	1.023	1.010	1.007	1.019	0.993
EVA-NC	Phoenix AZ	0.997	0.988	1.011	0.984	1.013	0.999
TPU	Phoenix AZ	0.999	1.010	0.997	1.008	0.991	0.992
TPO1	Phoenix AZ	0.859	0.864	1.004	0.864	0.995	0.992
PVB	Phoenix AZ	0.721	1.046	0.986	0.786	0.917	0.698
TPO3	Phoenix AZ	0.936	1.042	0.993	0.899	1.042	0.904
PDMS	Phoenix AZ	0.732	1.114	0.967	1.055	0.695	0.679

Table of performance metrics relative to their original value after 3 years of exposure in Phoenix. Changes exceeding 5% are highlighted in red and notable changes less than 5% in magnitude are highlighted in yellow.



Combined Thermal Image for the modules fielded in Phoenix. Two of the hotspots (TPO1, TPO3) have resulted in performance loss over the 3 year period. The temperature of hot spots within certain modules is indicated.

Summary

Seven different encapsulation materials were examined a field study in Cocoa, FL and Phoenix, AZ. Degradation modes external to the encapsulation (including interconnect failure, cell fracture, and shattered front glass) as well as degradation modes related to the encapsulation (including snail trails, premature discoloration, and photobleaching) were observed. To date the most significant loss in module performance has followed from degradation external to the encapsulation, which is typically correlated with hot spots within the module.

Future

The field study is anticipated to continue for 5 cumulative years. At that point, the modules will be subject to additional examination (including electroluminescence characterization, which may be compared to the EL images of the modules prior to the field study). Further failure analysis might be compared to that of the glass/glass modules examined in the original creep study [1].

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

PVQAT TG3: Proposed PID pass-fail requirement for amendment to IEC 61215, other TG3 status and combined stress testing

Peter Hacke, NREL

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

PVQAT – TG3: Humidity Temperature Voltage

PID

- Crystalline Silicon PID
  - Shunting: PID-s
  - Delamination: PID-d
- Thin film PID
  - Test method consideration
  - TCO corrosion

TG3 Activities Japan, Germany, “Combi-testing”

- Japan PVQAT, tadanori.tanahashi@aist.go.jp
- Germany PVQAT, michael.koehl@ise.fraunhofer.de
  - Contact in USA: peter.hacke@nrel.gov

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62804-1 PHOTOVOLTAIC (PV) MODULES – TEST METHODS FOR THE DETECTION OF POTENTIAL-INDUCED DEGRADATION Part 1: Crystalline Silicon

Procedures to test and evaluate the durability of crystalline silicon photovoltaic (PV) modules to the effects of short-term high-voltage stress including potential-induced degradation (PID)

PID-shunting (PID-s) & Polarization

Test methods

a) Testing in damp heat using an environmental chamber

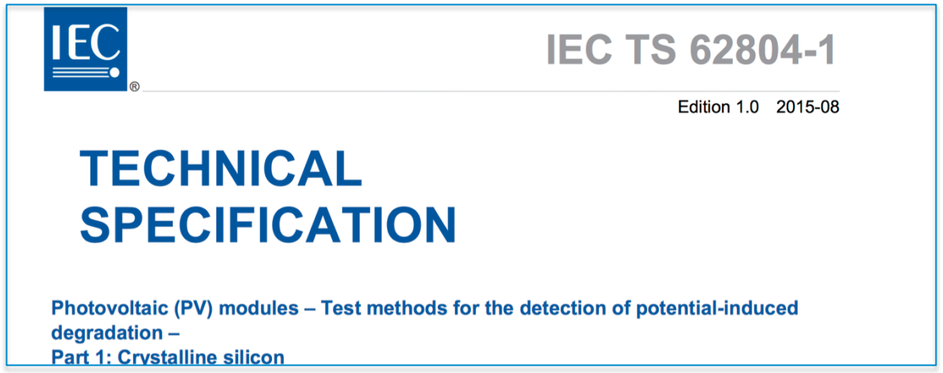
severities represent the minimal stress levels for detection of PID

- **60°C / 85% RH / + & – V_{sys} 96 h**
- **65°C and 85°C for further acceleration**

b) Testing in dry using Al foil

severities represent the minimal stress levels for detection of PID

- **25°C / <60% RH / + & – V_{sys} 168 h**
- **50°C and 60°C for further acceleration**


IEC TS 62804-1

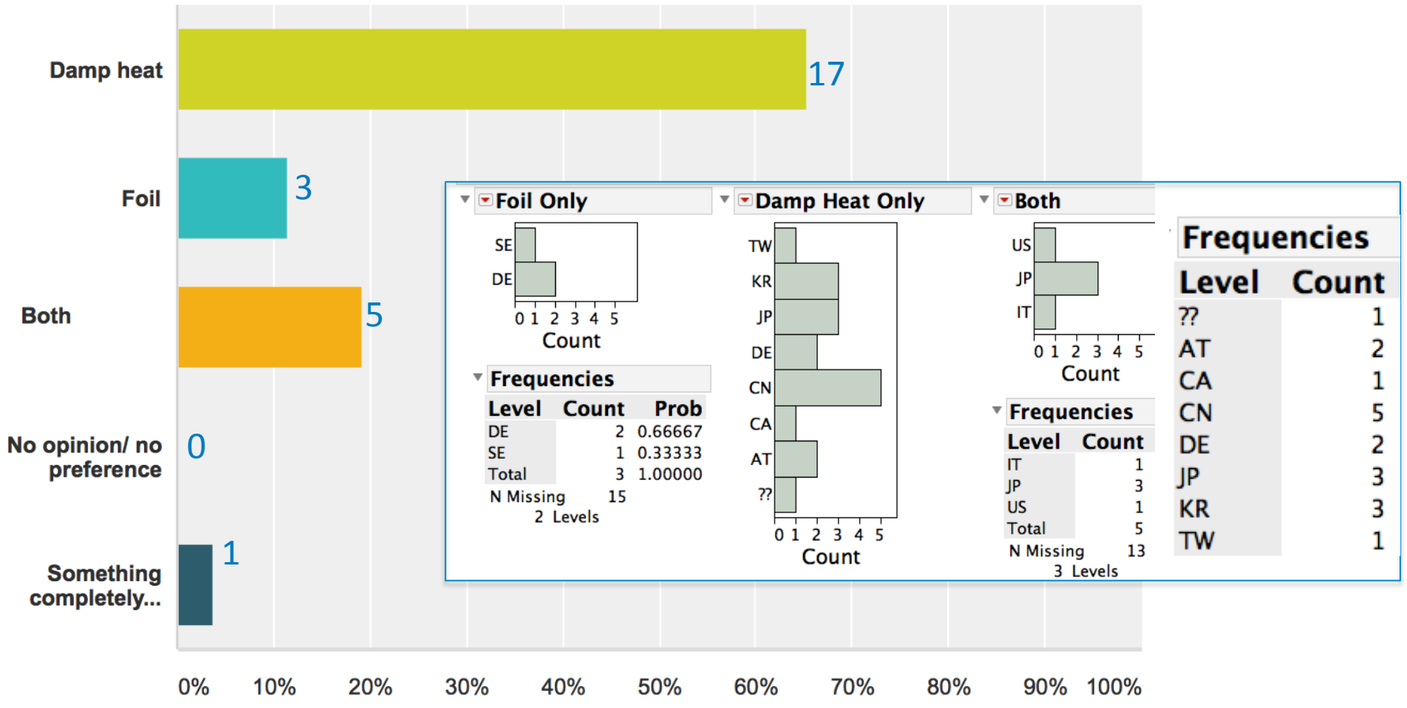
Edition 1.0 2015-08

TECHNICAL SPECIFICATION

Photovoltaic (PV) modules – Test methods for the detection of potential-induced degradation –
Part 1: Crystalline silicon

Foil versus Damp Heat

Non-binding survey to IEC TC 82 WG2 for preferred method:
Foil vs. Damp heat:



Choosing the stresses and levels

Model approach

- M. Topič, F. Sculati-Meillaud, A. Virtuani, Ch. Ballif, Modeling potential-induced degradation (PID) in crystalline silicon solar cells: from accelerated-aging laboratory testing to outdoor prediction, Proc. of 32nd EUPVSEC, Munich, Germany, p. 1558-1563, (2016).
- J. Hattendorf, R. Loew, W.-M. Gnehr, L. Wulff, M. C. Koekten, D. Koshnicharov, A. Blauaermel, J. A. Esquivel, "PID in monocrystalline silicon based modules: an acceleration model", *Proceedings of the 27th EUPVSEC,* pp. 3405-3410, Frankfurt, 2012.
- C. Taubitz, M. Schütze, M. Kröber, M. B. Koentopp, "PID: model calculations and correlation between laboratory tests and outdoor occurrence", *Proc. of the 29th EUPVSEC*, pp. 2490-2494, Amsterdam, 2014.
- P. Hacke et al., "Elucidating PID Degradation Mechanisms and In Situ Dark I–V Monitoring for Modeling Degradation Rate in CdTe Thin-Film Modules," in IEEE Journal of Photovoltaics, vol. 6, no. 6, pp. 1635-1640, Nov. 2016
- H. Nagel, R. Pfeiffer, A. Raykov and K. Wangemann, Lifetime Warranty Testing Of Crystalline Silicon Modules For Potential-Induced Degradation, *Proceedings of the 27th EUPVSEC,* pp. 3163 - 3166, Frankfurt, 2012.
- S. Koch, J. Berghold, B. Abdullah, C. Hinz, P. Grunow Prediction Model for Potential Induced Degradation Effects on Crystalline Silicon Cells 29th European Photovoltaic Solar Energy Conference and Exhibition, pp. 3327 – 3333 (2014).

Accelerated test vs. Field approach

- Confirm that modules that pass the PID test don't degrade by PID in the field.
- Confirm that modules that significantly fail the test fail in the field

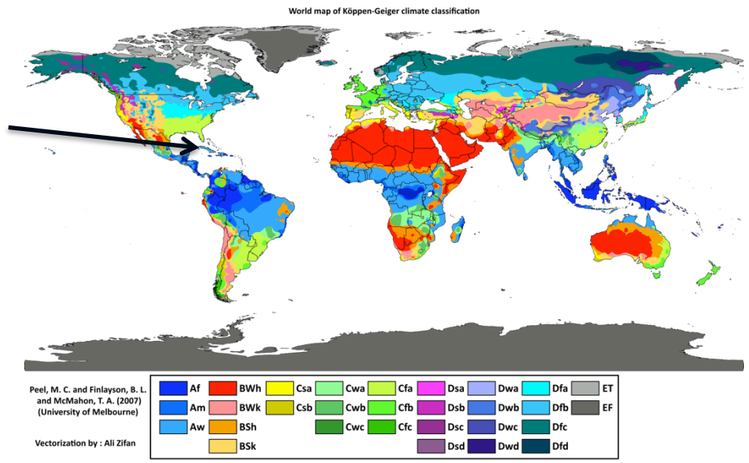
Accelerated tests have simplifications

- Light may accelerated or decelerate PID
- Natural PID recovery may or may not occur depending on the BOM, temperature, and other factors
- History matters: After a PID and PID recovery cycle, the PID resistance may go up

Choosing the stresses and levels

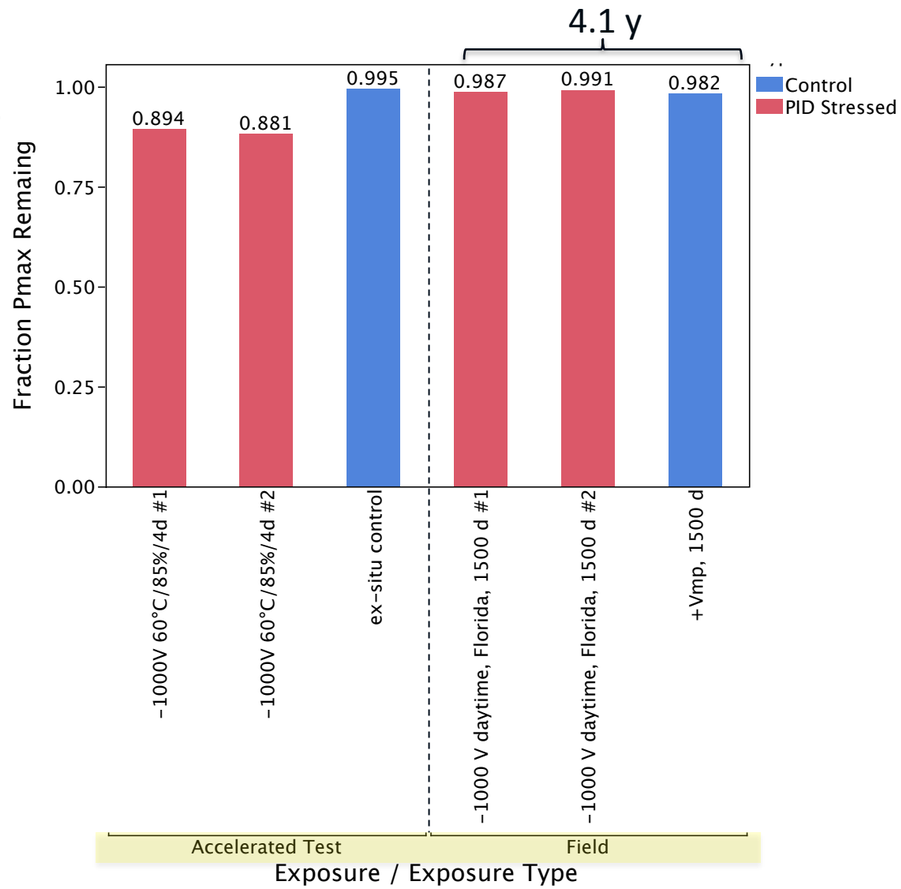
Chamber vs. Field

Humid subtropical/tropical monsoon



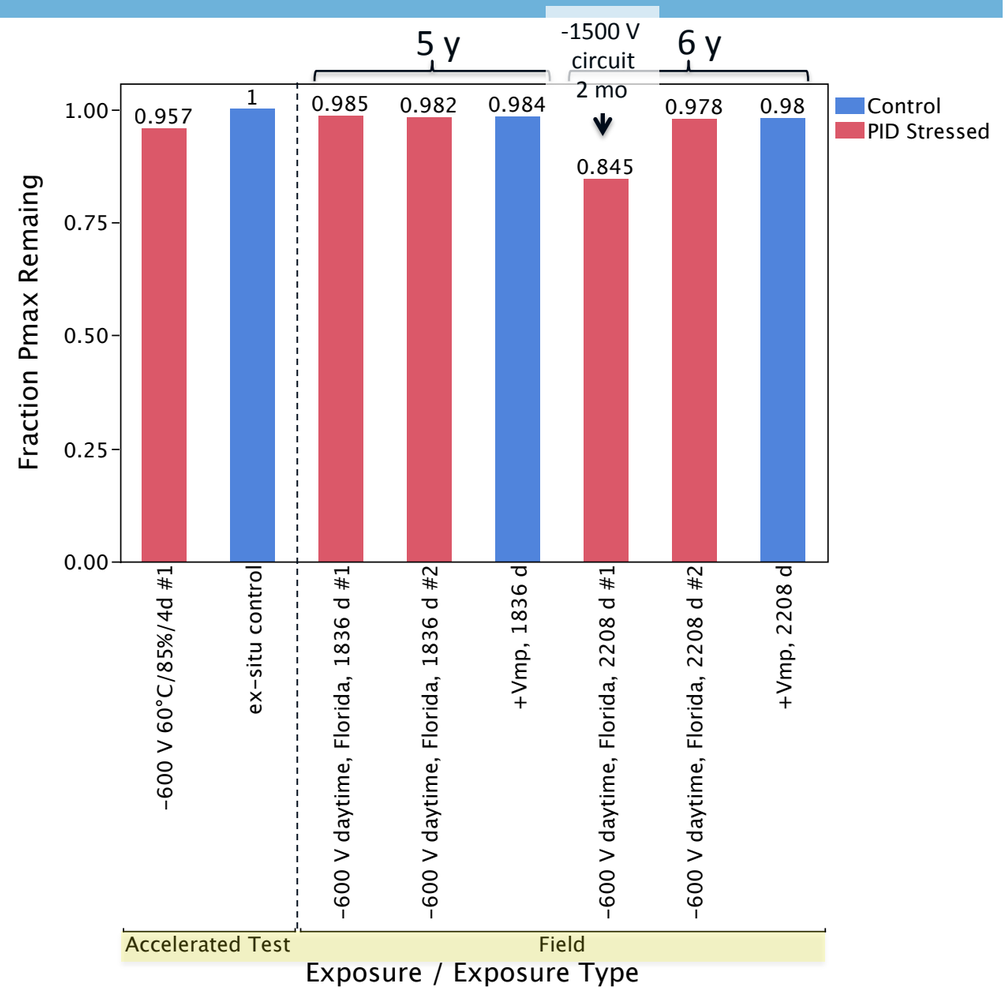
60°C/95%RH/96h/-Vsys test versus 4.1 years in the field

- **C-Si modules** exposed to -1000 V/ 60°C/85%RH/96 h (4 d) degraded 11.5%.
- Fielded replicas in Florida (-1000 V variable, daytime) show no degradation in 1500 d (4.1 y).

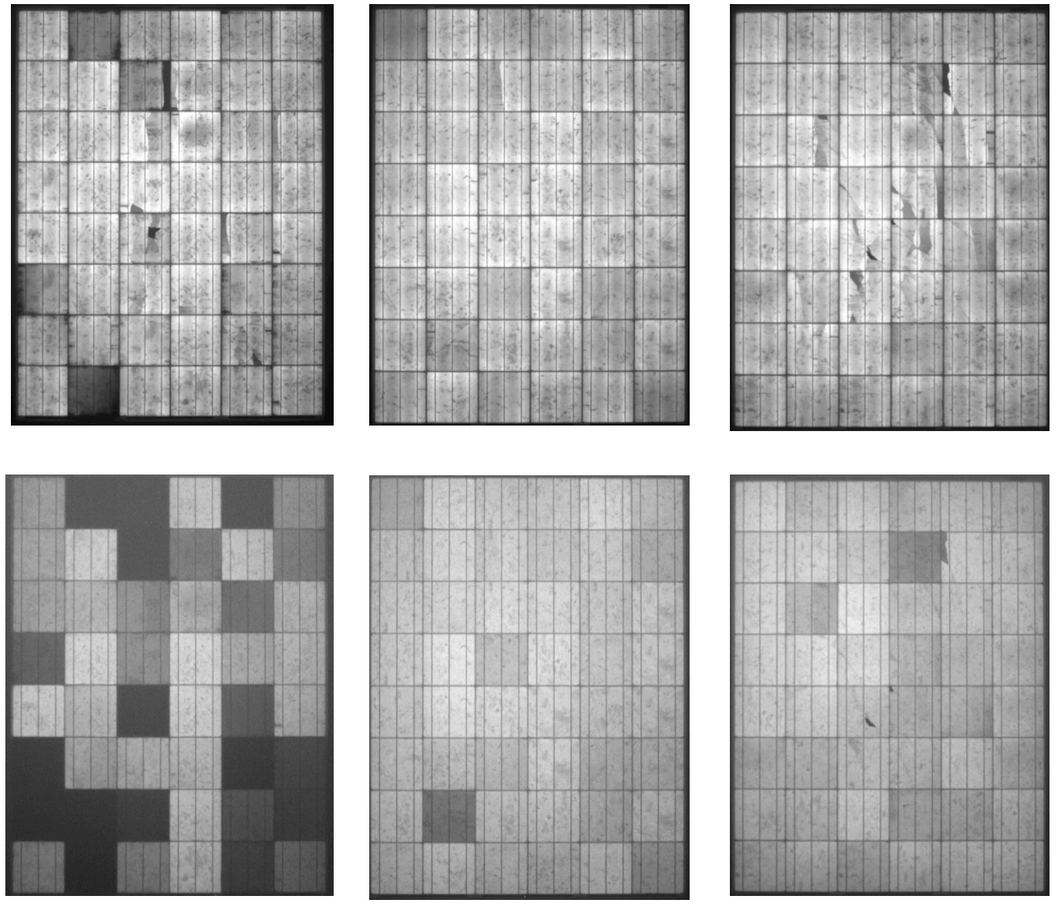


60°C/95%RH/96h/-Vsys test versus 5 & 6 years in the field

- **C-Si modules** exposed to -600 V/ 60°C/85%RH/96 h (4 d) degraded 4.3 %.
- Fielded replicas in Florida (-600 V variable, daytime) show no degradation in 1836 d (5 y).
  - Degradation in 2208 d (6 y).

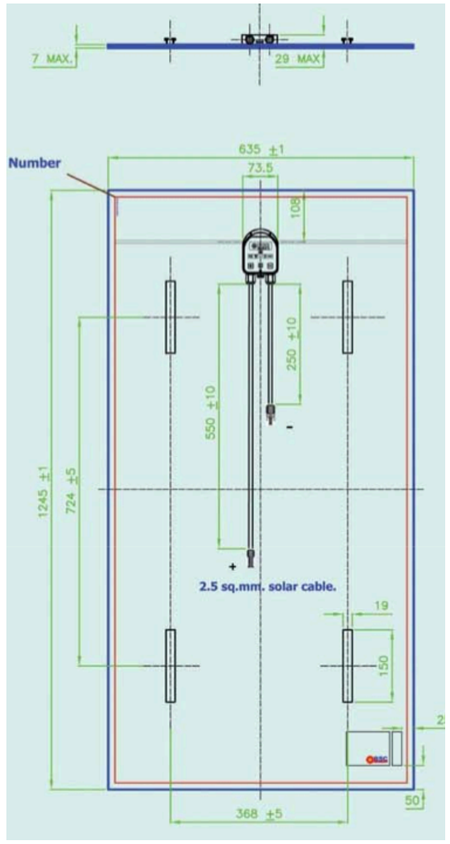


6 years in the field Florida
(passes 60°C/95%RH/96h/-Vsys at ΔP < 5%)



Thanks:
Eric Schneller

Module mounting & design

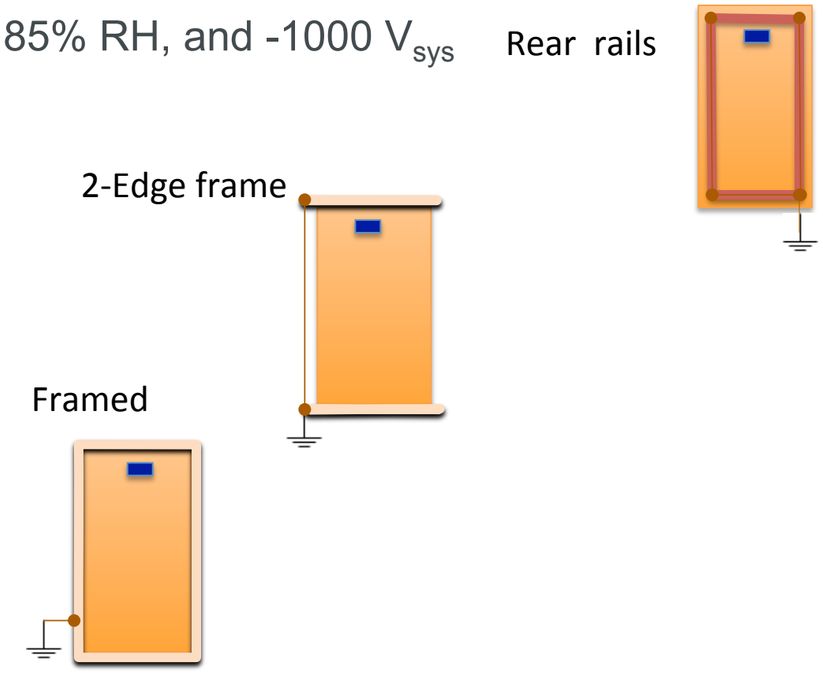


- Bangkok solar a-Si module with rear rail mounting

- Trina solar c-Si module with rear rail mounting

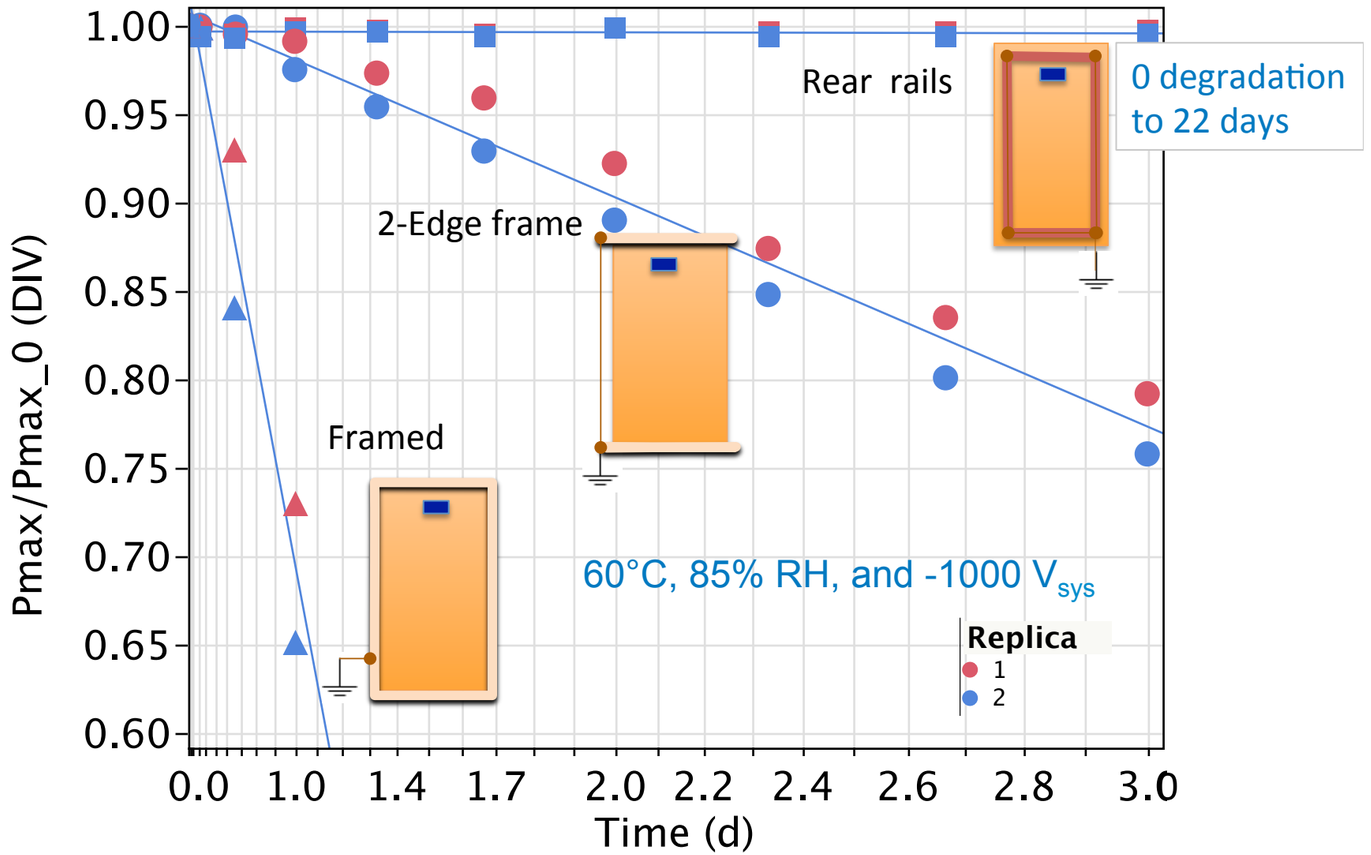
Effect of module design: chamber

- Original commercial and two modified designs (3 replicas each)
- Subjected to 60°C, 85% RH, and -1000 V_{sys}



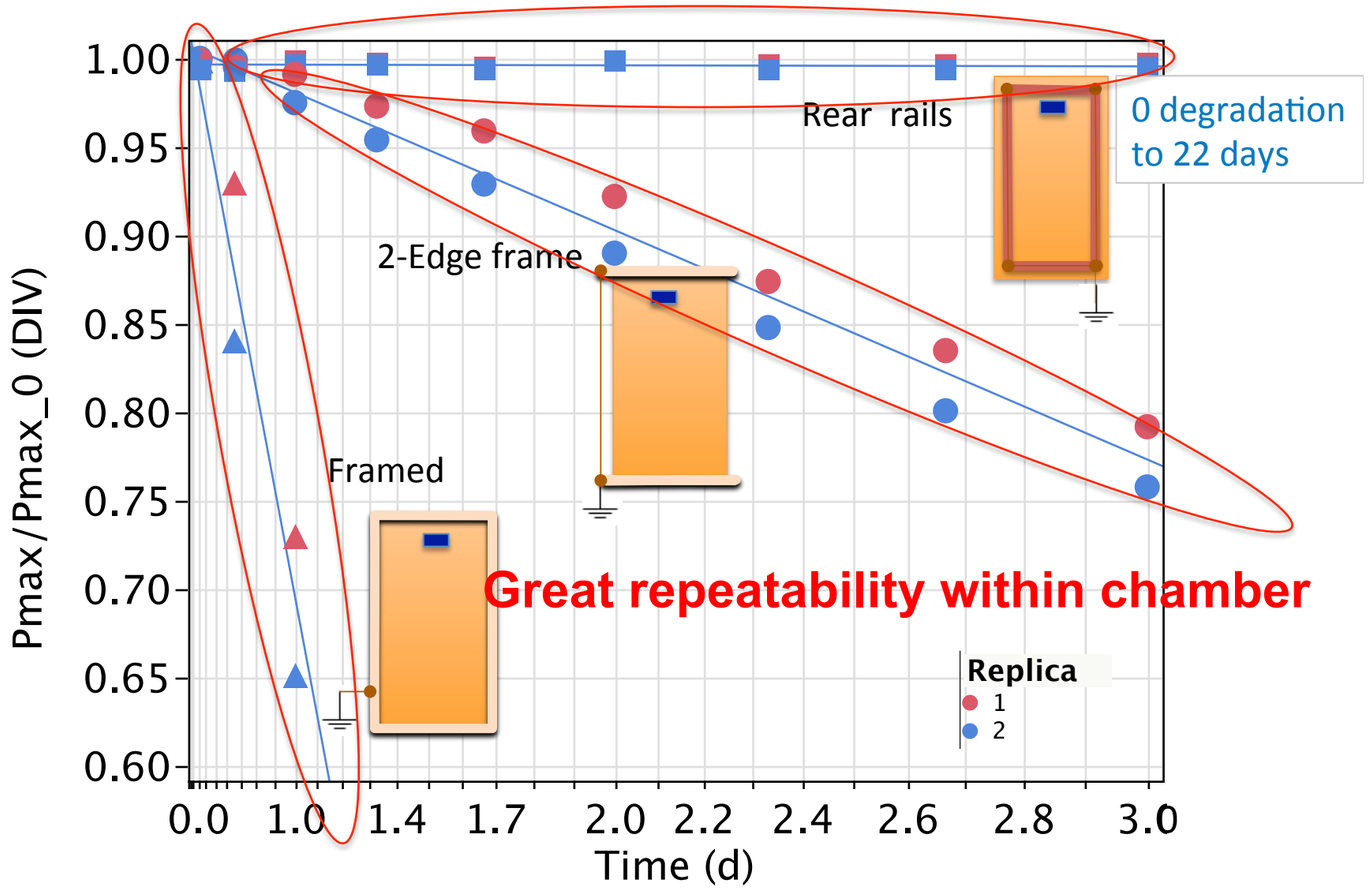
First phase of this experiment published: *Hacke et. al. PiP (2013)*

Effect of module design: chamber



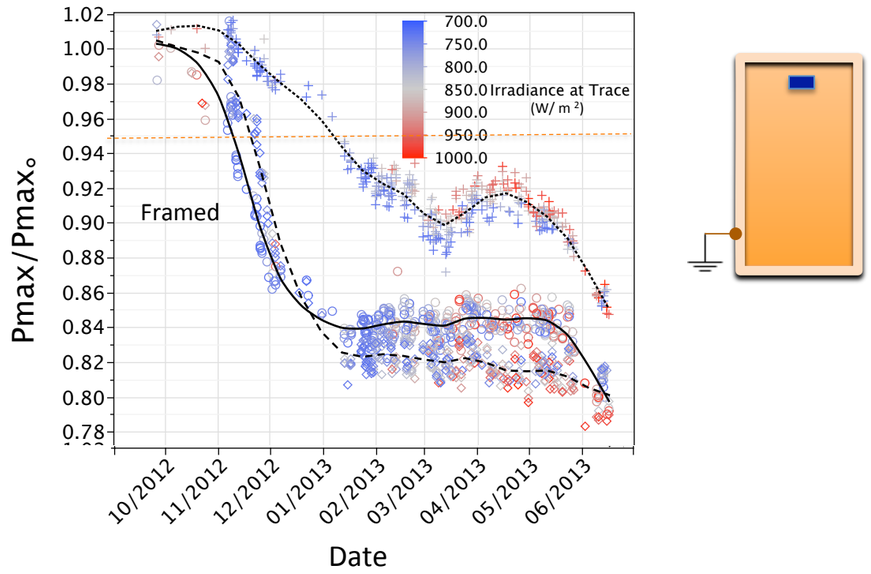
2- Edge frame and framed modules **fail >5%** relative in 96 h, rear rail module passes

Effect of module design: chamber

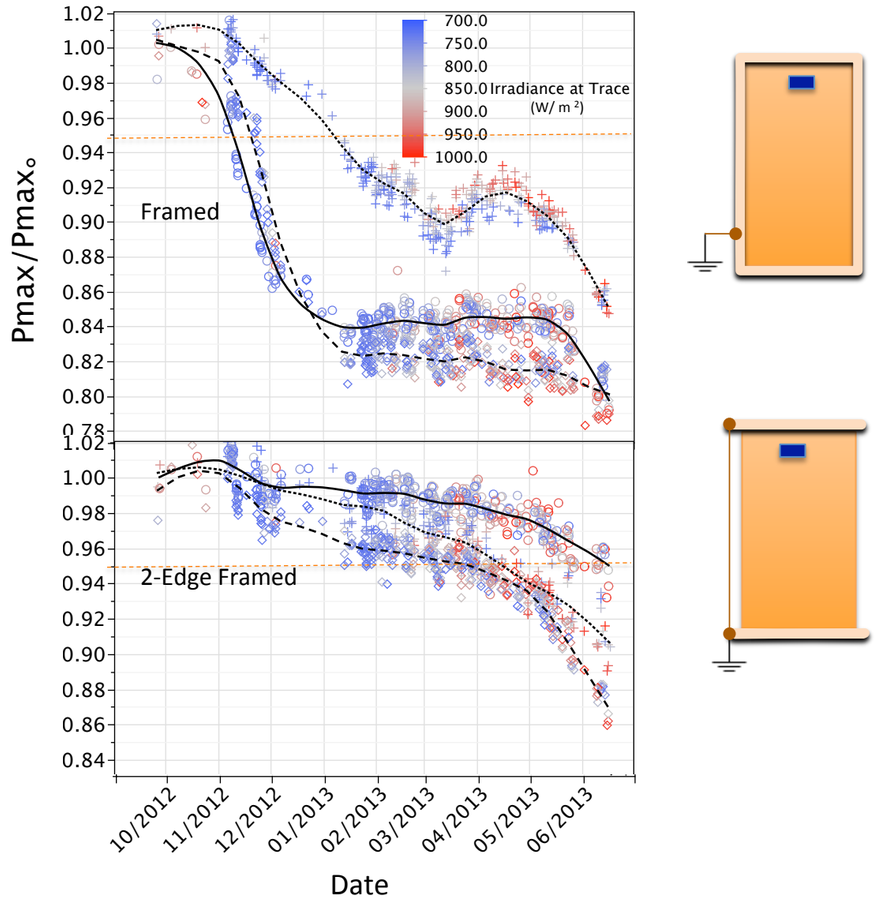


2- Edge frame and framed modules **fail >5%** relative in 96 h, rear rail module passes

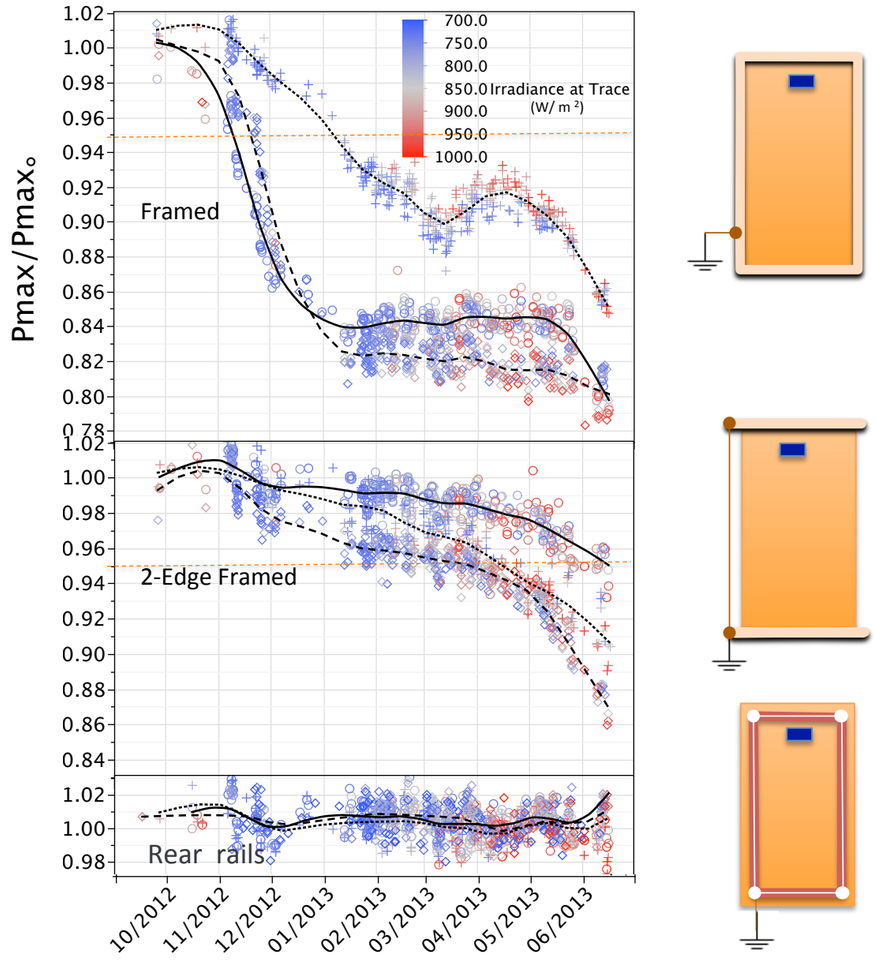
Effect of module design: field



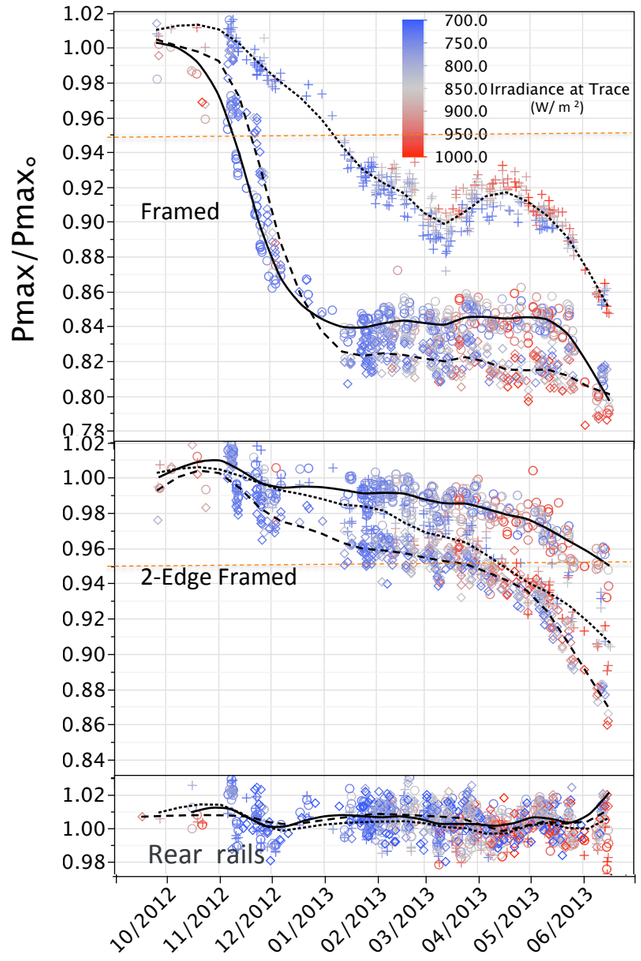
Effect of module design: field

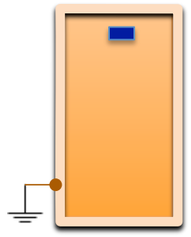


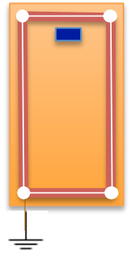
Effect of module design: field



Effect of module design: field

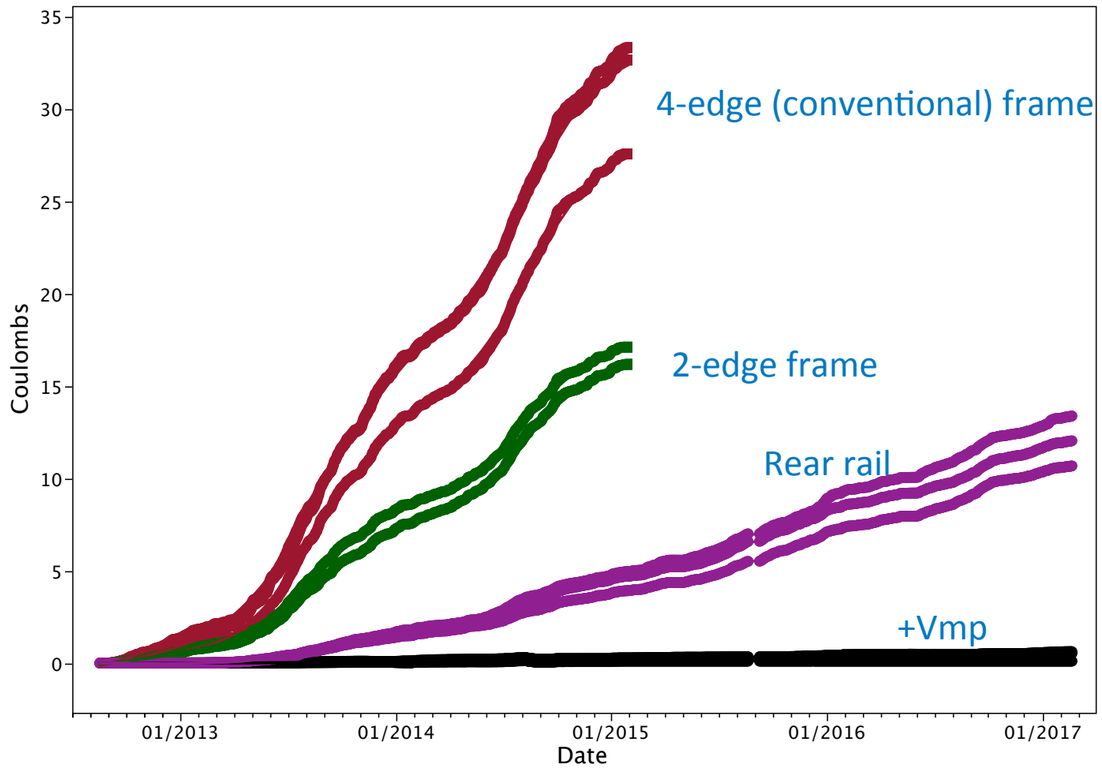




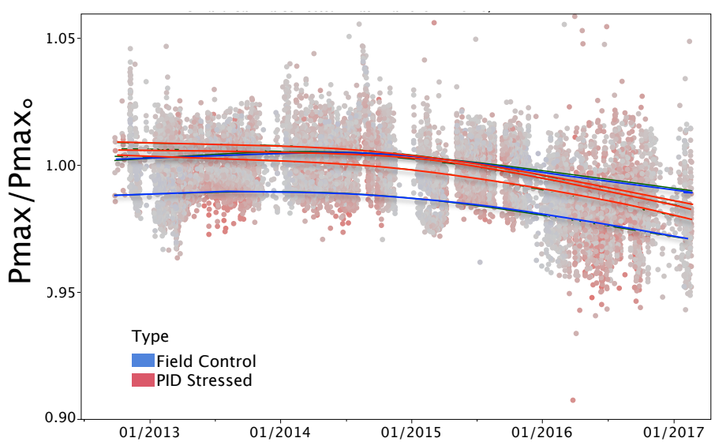


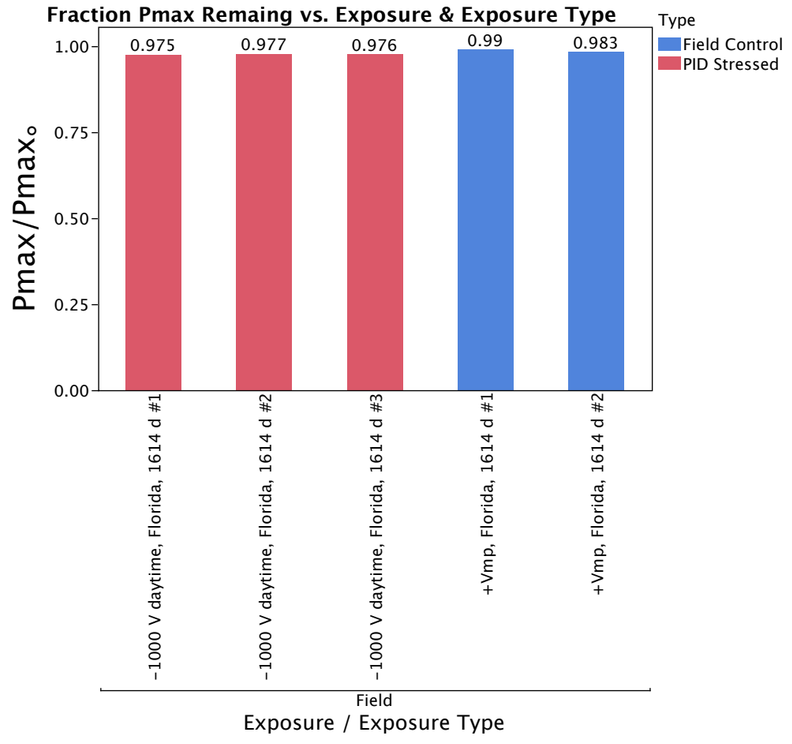
- The designs that fail the **−Vsys, 60°C/85% RH** test fail in the field
- The design that passes the draft standard survives undegraded in the field so far
- Al foil test cannot differentiate the PID performance of these designs

Effect of module design: field – coulombs



-1000 V rear rail modules 4.2 years in the field





Choosing the stresses and levels

What do the results mean?

- **IEC 62804-1 level of 60°C, 85% RH, 96 h ±V_{sys} appears to differentiate modules for PID resistance in the Florida environment (4 y-6 y tests)**
- 3 module types with 20 (total) modules in experiment
- Aggregating stress factors
  - Near the coast (salt air)
  - At rated V_{sys}
    - no system derating for low temperature,
    - no loss of voltage dude to module heating
    - At 1 sun it is at Vsys.
  - Horizontally mounted modules (water and soil collects)
  - Most real system in the USA run at lower stress w.r.t. PID
- *Other climates may be more stressful*

IEC 61215 ed. 3 Amendment 1 draft levels

Potential Induced Degradation Test (MQT 21)

- **Contacting the surfaces with a conductive electrode**
  - **Module temperature: 25 °C ± 1 °C,**
  - **Less than 60 % relative humidity,**
  - **Dwell: 168 h;**
  - **Voltage: module rated system voltage and polarities**

- M. Schütze et. al, EUPVSEC 2011
- H. Nagel et. al., EUPVSEC 2011

…

- **Chamber Method**
  - **Module temperature: 85 °C ± 2 °C,**
  - **85 % ± 3 % relative humidity,**
  - **Dwell: 96 h**
  - **module rated system voltage and polarities**

- ET Solar, “ET Solar Modules Achieve "PID Free” (2012)
- SunEdison ‘Silvantis’, 96 hours, 85 C, 85% relative humidity
- Jinko Solar, 85 C, 85% relative humidity (2013)

…

- **Requirements**

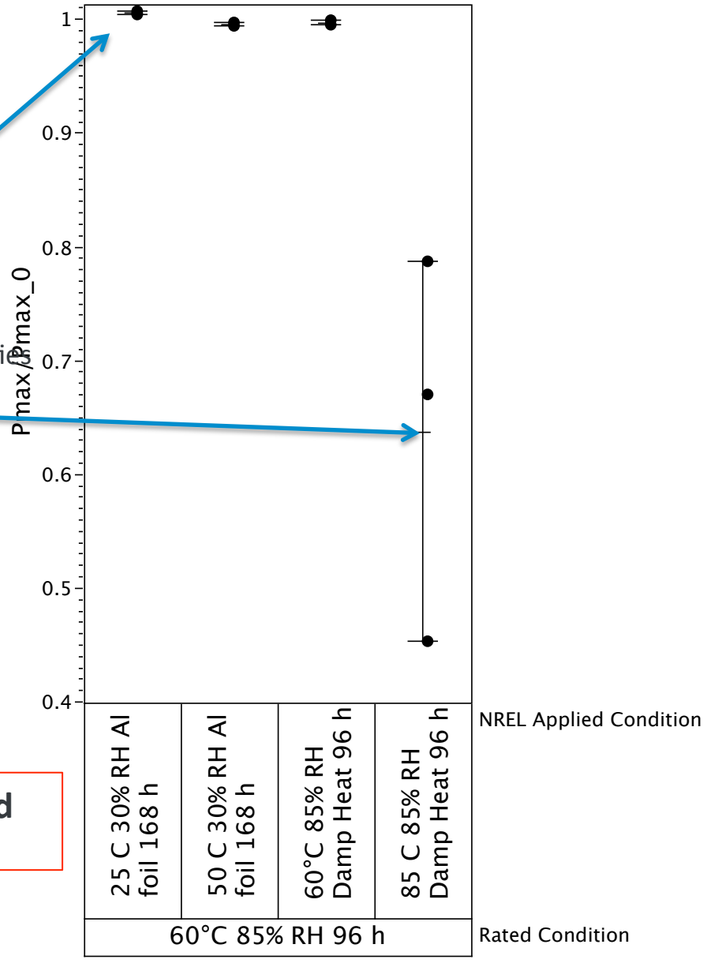
A. Maximum power (MQT 02) per Gate 2 Clause 7.2.2 from IEC 61215-1 **(< 5% degradation)**.
B. No evidence of **major visual defects**, as defined in IEC 61215-1 Clause 8.
C. Wet leakage current shall meet the same requirements as for the initial measurements.
D. Power loss at low irradiance (MQT 07) of less than **5%** after the voltage stress test.

Comparison of test conditions

Potential Induced Degradation Test (MQT 21)

- **Contacting the surfaces with a conductive electrode**
  - Module temperature: 25 °C ± 1 °C,
  - Less than 60 % relative humidity,
  - Dwell: 168 h;
  - Voltage: module rated system voltage and polarities
- **Chamber Method**
  - Module temperature: 85 °C ± 2 °C,
  - 85 % ± 3 % relative humidity,
  - Dwell: 96 h
  - module rated system voltage and polarities

More comparisons on test conditions required



PVQAT – TG3: Humidity Temperature Voltage

PID

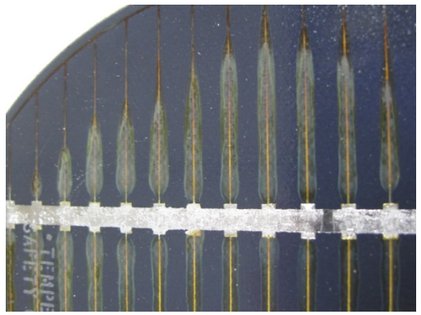
- Crystalline Silicon PID
  - Shunting: PID-s
  - Delamination: PID-d
- Thin film PID
  - Test method consideration
  - TCO corrosion

TG3 Activities Japan, Germany, “Combi-testing”

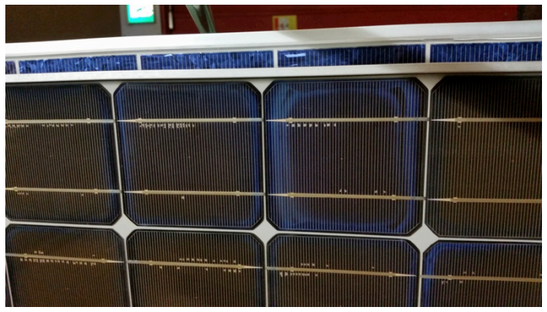
- Japan PVQAT, tadanori.tanahashi@aist.go.jp
- Germany PVQAT, michael.koehl@ise.fraunhofer.de
  - Contact in USA: peter.hacke@nrel.gov

To develop required test protocols, PVQAT identified field failure modes that occur in module types that have passed the qualification test (IEC 61215)

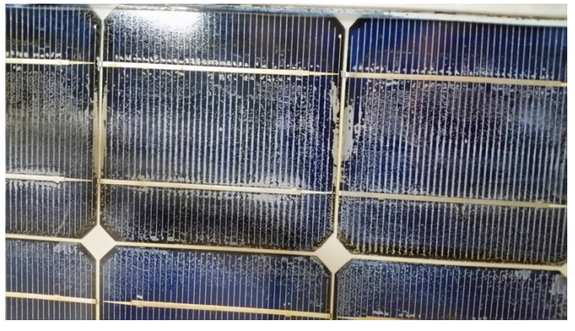
- **Corrosion at cell metallization accompanied by delamination of the encapsulant (review by Prof. Mani, ASU)**



Arco solar



(Sandia)



(AIST)

Similar delamination in the literature

JPL (Mon, 1984) forward biased at 100 mA while exposed to 85°C/85% RH 180 days.

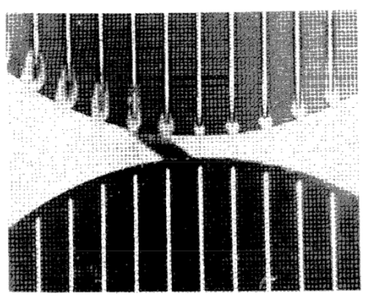
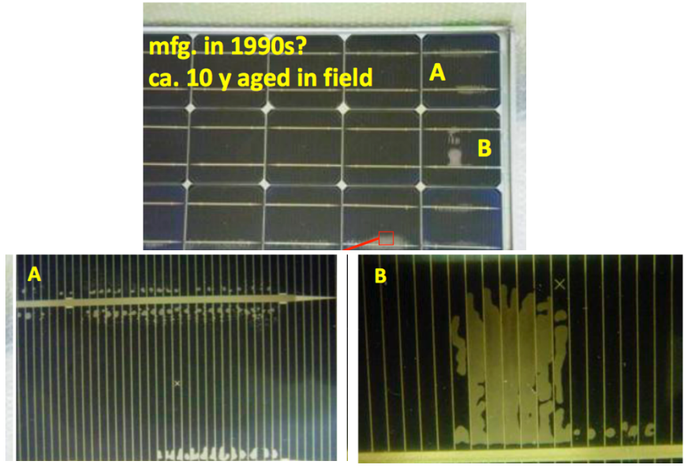
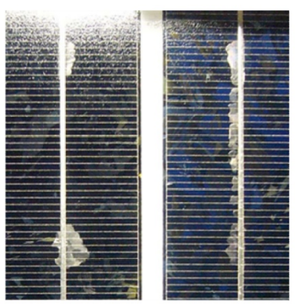


Figure 2. Solar-Cell Electrochemical Corrosion

AIST (Matsuda, 2012) finding **TiO_2** catalyzing reactions leading to delamination





3 UV: -20/75°C 125 Cycles (250 h)

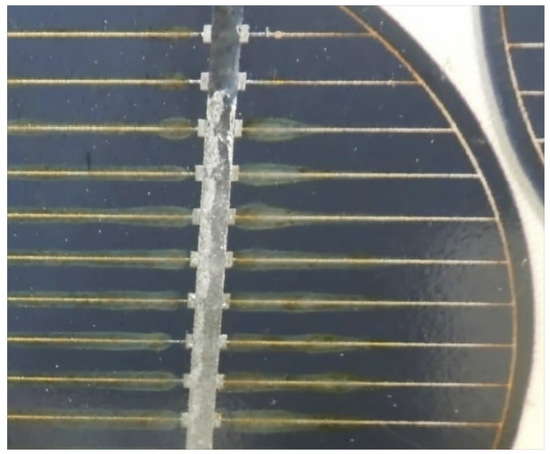
(Module) Temperature Cycling Protocol

75°C, 0 / 3 UV 1 h → **-20°C, 0 UV 1 h**

3 UV: -20/75°C 75 Cycles (150 h) -> Delamination
0 UV: -20/75°C 75 Cycles (150 h) -> No Delamination

"R&D of Characterization Technology of Solar Cells (FY2006-FY2009) Final Report ", NEDO 2010.
Via T. Tanahashi PVQAT TG 3

Delamination at Ag grid fingers



Grid-finger-centric delamination

- **Catalysis at Ag suspected**

  See Yu-Chen Shen presentation: **Electrochemical Mechanisms of Leakage-Current-Induced Delamination and Corrosion in Si Photovoltaic Module**

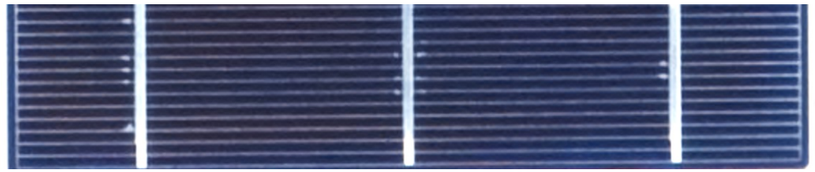
  - Under negative bias, water is reduced, OH- and H_2 ($2H_2O+2e^- \leftrightarrow H2(g)+2OH^-$)
  - Under positive bias, water is oxidized to H+ and O_2 ($2H_2O-4e^- \leftrightarrow O2(g)+4H^+$)

To develop required test protocols, PVQAT identified field failure modes that occur in module types that have passed the qualification test (IEC 61215)

Test protocol development

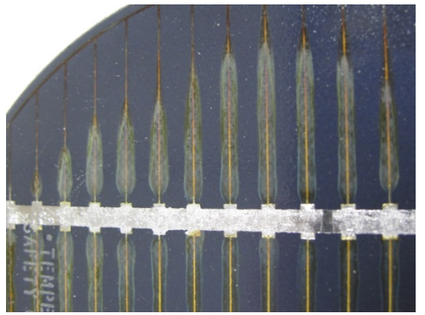
Stress test

1) IEC 61215 85°C 85% RH 1000 h +
2) 72°C 95% foil ground, -1000V **156 h** PID stress

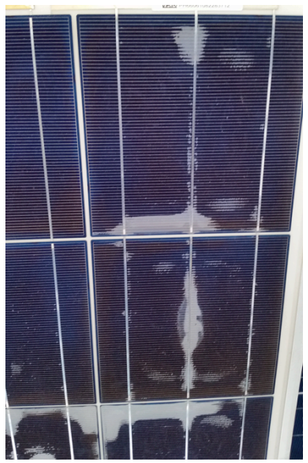


Field equivalent

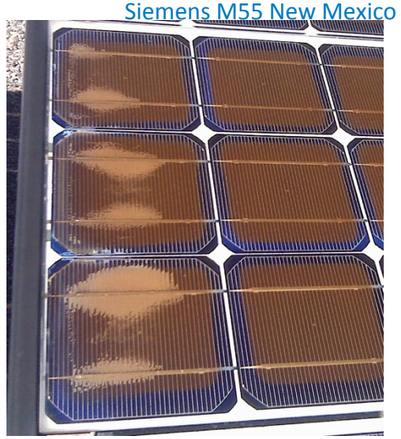
Arco Solar



3) Additional 72°C 95% foil ground, -1000V **136 h** PID stress



Siemens M55 New Mexico



Excessive current transfer associated with the delamination

Results of the DH + PID sequential stress test on four commercial modules

Module #	Delamination	Power Loss	Current (A) (-1000 V)
1	No	Yes	$6.4 \cdot 10^{-5}$
2	No	Yes	$2.6 \cdot 10^{-5}$
3	Yes	Yes	$4.4 \cdot 10^{-4}$
4	No	No	$7.9 \cdot 10^{-7}$

Factors that we believe contribute to this delamination are:

1. The IEC 61215 **damp heat** stress test **reduces the adhesion** between the encapsulant and the cells.
2. PID stress tests, with negative voltage bias applied to the cell circuit, attracts **Na to the cell, which also decreases the adhesion** between the cell and the encapsulant.
3. Electrochemical reactions, **products such as H_2 and O_2 or OH ions**. These generated gasses can cause bubbles and delamination.

PID-delamination tech spec - New work item proposal

82/1203/NP

NEW WORK ITEM PROPOSAL

Proposer	Date of proposal
Secretariat of TC 82	2016-09-08
TC/SC	**Secretariat**
TC 82	USA
Date of circulation	**Closing date for voting**
2016-11-11	2017-02-03

A proposal for a new work item within the scope of an existing technical committee or subcommittee shall be submitted to the Central Office. The proposal will be distributed to the P-members of the technical committee or subcommittee for voting on the introduction of it into the work programme, and to the O-members for information. The proposer may be a National Committee of the IEC, the secretariat itself, another technical committee or subcommittee, an organization in liaison, the Standardization Management Board or one of the advisory committees, or the General Secretary. Guidelines for proposing and justifying a new work item are given in ISO/IEC Directives, Part 1, Annex C (see extract overleaf). **This form is not to be used for amendments or revisions to existing publications.**

The proposal (to be completed by the proposer)

Title of proposal

Photovoltaic (PV) modules - Test methods for the detection of potential-induced degradation - Part 1-1: Delamination for crystalline silicon PV modules (proposed IEC 62804-1-1 TS)

☐ Standard	☒ Technical Specification

Scope (as defined in ISO/IEC Directives, Part 2, 6.2.1)

This part of IEC 62804 defines procedures to test and evaluate for delamination associated with potential-induced degradation–delamination (PID-d). This technical specification is to evaluate for the delamination mode attribuable to high current transfer under negative system voltage bias because of low module package resistivity. Factors driving the delamination are reduced adhesion after damp heat exposure, sodium accumulation at the cell surface further reducing adhesion, and cathodic gas evolution at the cell metallization driven by the negative voltage potential in the active cell circuit.

Approval				
P-Members Voting	**P-Members Approving**	**Approval %**	**Criteria**	**Result**
29	29	100	>50%	APPROVED

PVQAT – TG3: Humidity Temperature Voltage

PID

- Crystalline Silicon PID
  - Shunting: PID-s
  - Delamination: PID-d
- Thin film PID
  - Test method consideration
  - TCO corrosion

TG3 Activities Japan, Germany, “Combi-testing”

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- Germany PVQAT, michael.koehl@ise.fraunhofer.de
  - Contact in USA: peter.hacke@nrel.gov

PID for thin film modules

82/1238/CD

COMMITTEE DRAFT (CD)

PROJECT NUMBER:	
IEC TS 62804-2 ED1	
DATE OF CIRCULATION:	CLOSING DATE FOR COMMENTS:
2017-01-20	**2017-04-14**
SUPERSEDES DOCUMENTS:	
82/1042/NP, 82/1082A/RVN	

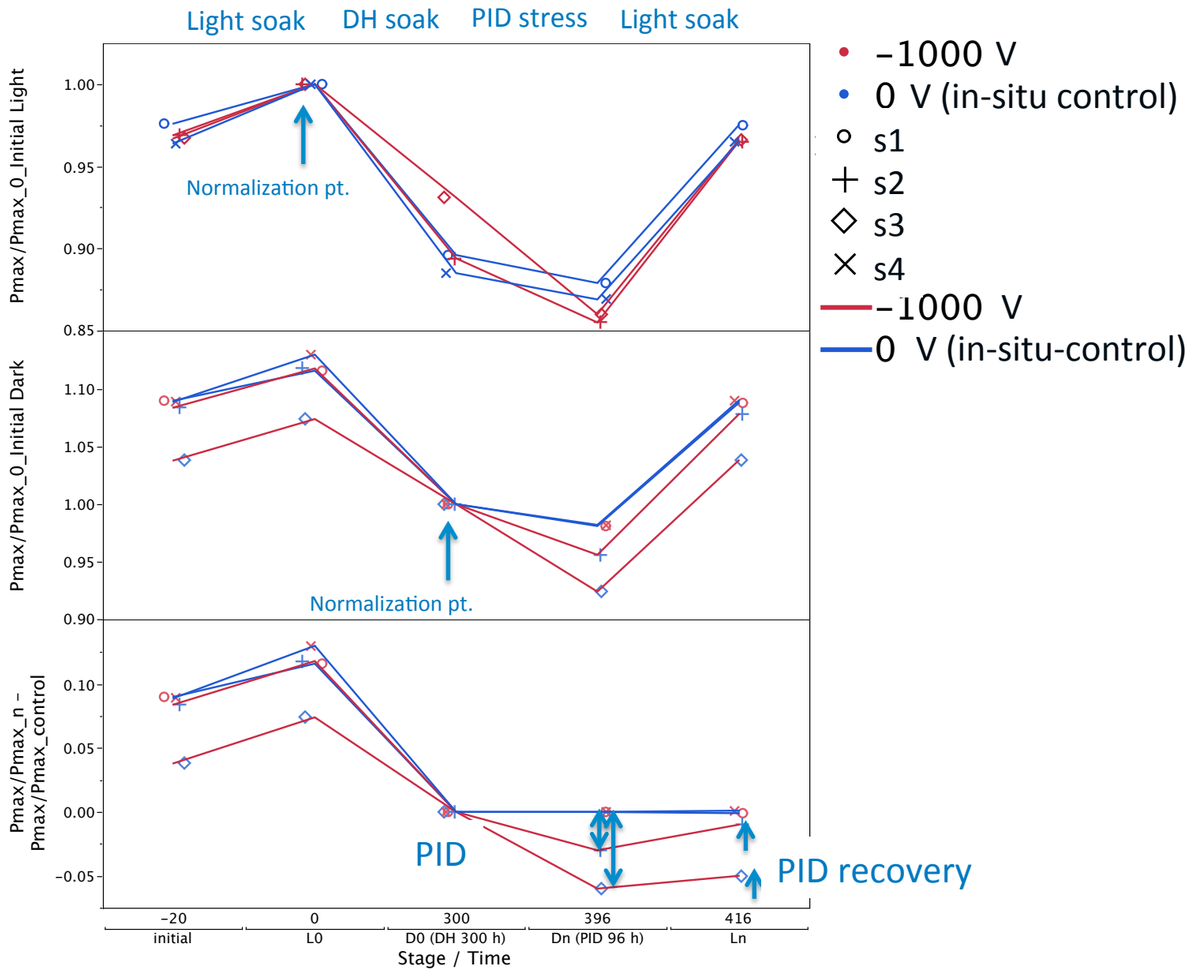
PHOTOVOLTAIC (PV) MODULES – TEST METHODS FOR THE DETECTION OF POTENTIAL-INDUCED DEGRADATION

Part 2: Thin-film

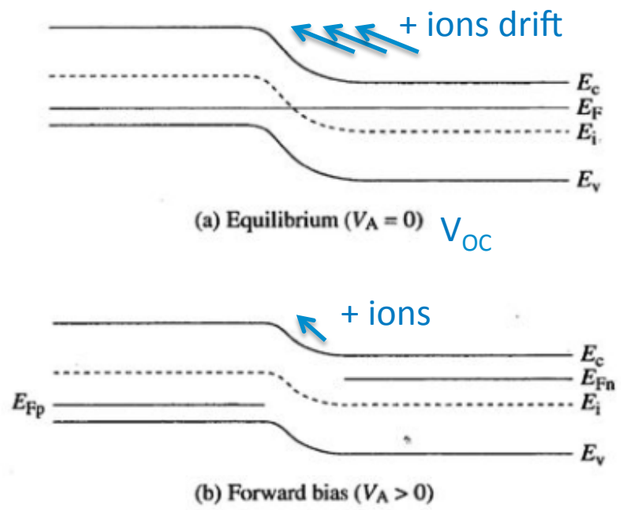
PID for thin film modules

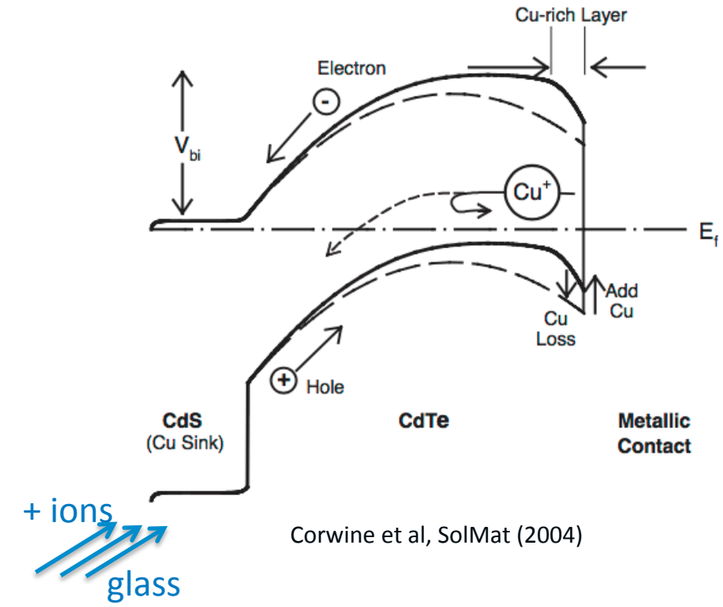
- **Focus now is on defining the method for test**
  - Convolution with metastability
  - Short term test vs long term test
    - Power loss (i.e. shunting)
    - Corrosion (delamination, series resistance)
  - 85°C/85% RH/ ±Vsys condition, durations not specified
- **Then, basis for tests**
  - Coulombs (field vs chamber) *Lechner- ZSW, Weber- PI-Berlin*
  - Time (field vs chamber acceleration)
  - Consideration of effects of humidity vs. not
  - Copy crystalline silicon

PID for thin films results depend on how you view



Junction Bias effects in thin film modules, e.g., CdTe





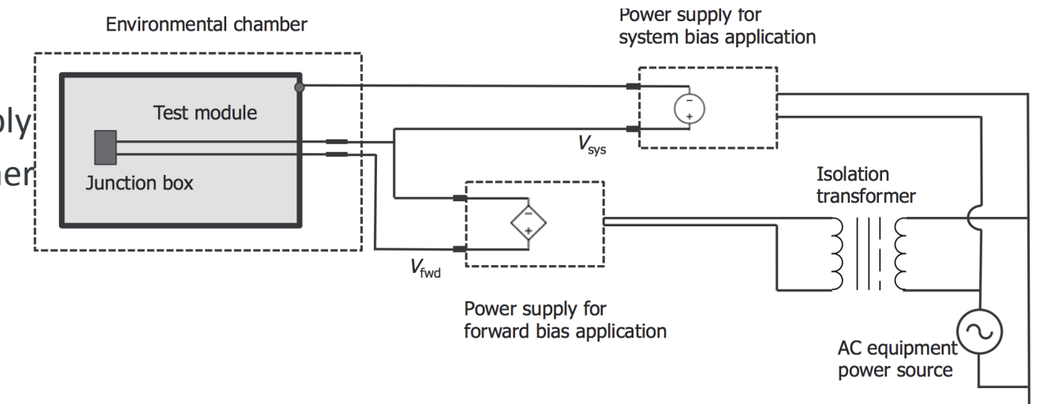
Corwine et al, SolMat (2004)

- Junction bias can affect Cu^+ migration & degradation, as it can Na^+ migration, so there is the option to bias the junction during testing
  - Or use light

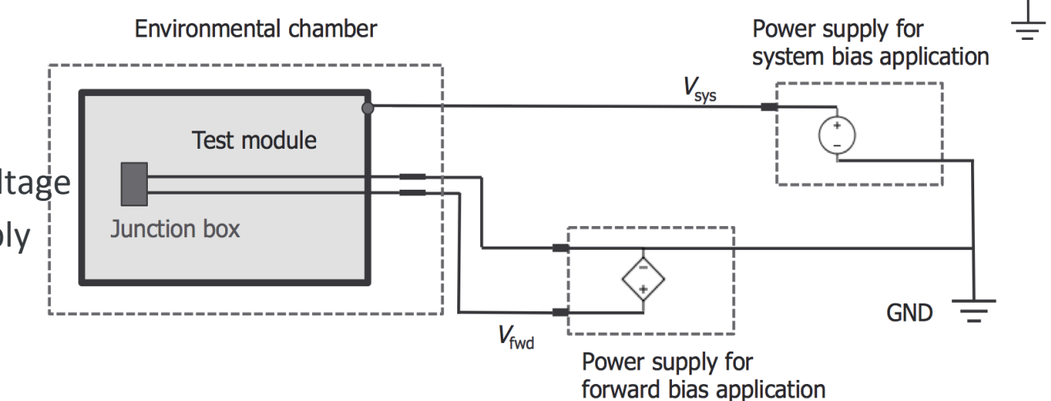
Junction Bias effects in thin film modules: methods

- Circuits to forward bias modules while under bias (option)

Forward bias power supply an an isolation transformer



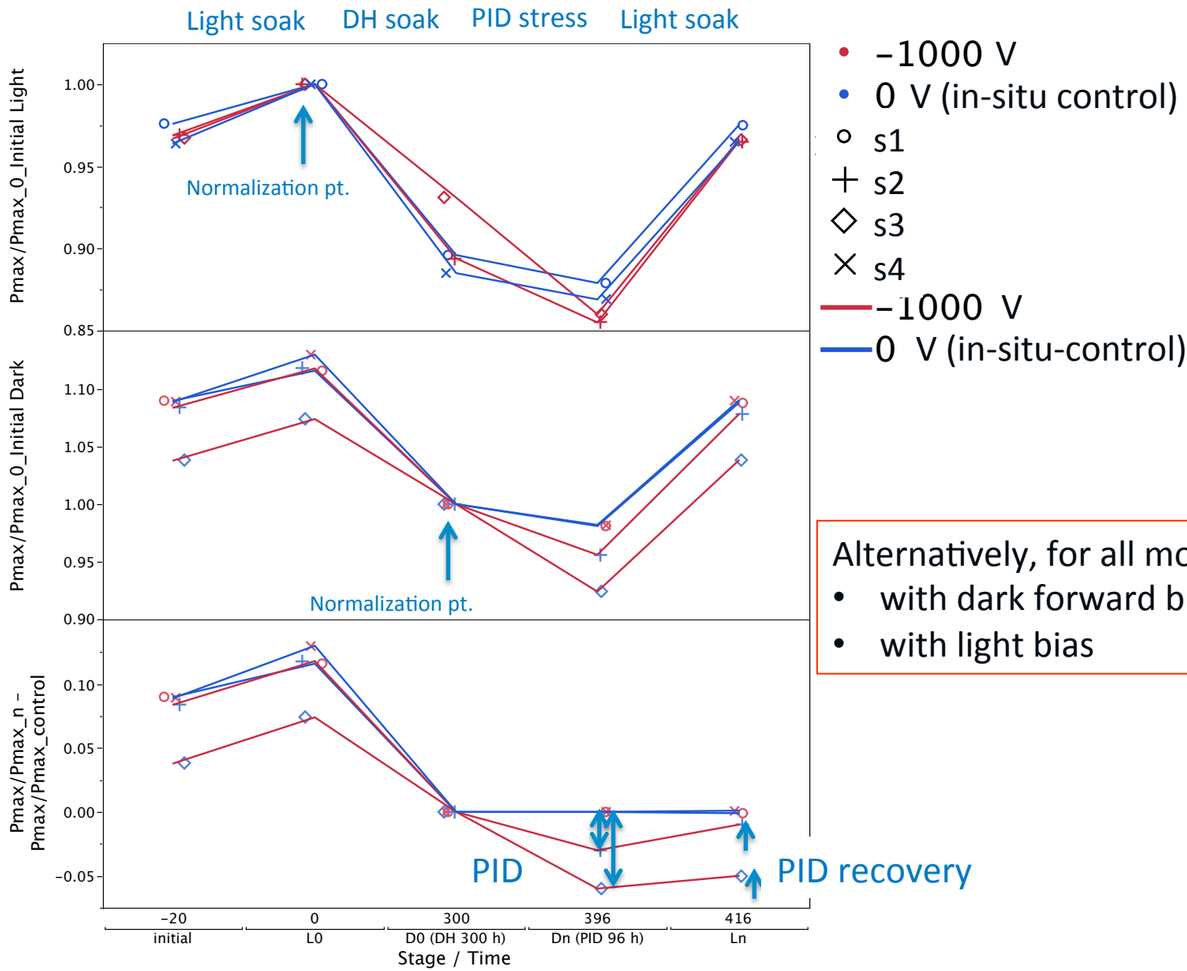
Module frame at high voltage
Forward bias power supply tied to ground



- *Caution*: Dark forward bias current at elevated temperature itself may cause degradation; alternative option to do under low light.

Hacke, J Photonic Energy (2015)

PID for thin films results depend on how you view



Alternatively, for all modules
- with dark forward bias
- with light bias

PVQAT – TG3: Humidity Temperature Voltage

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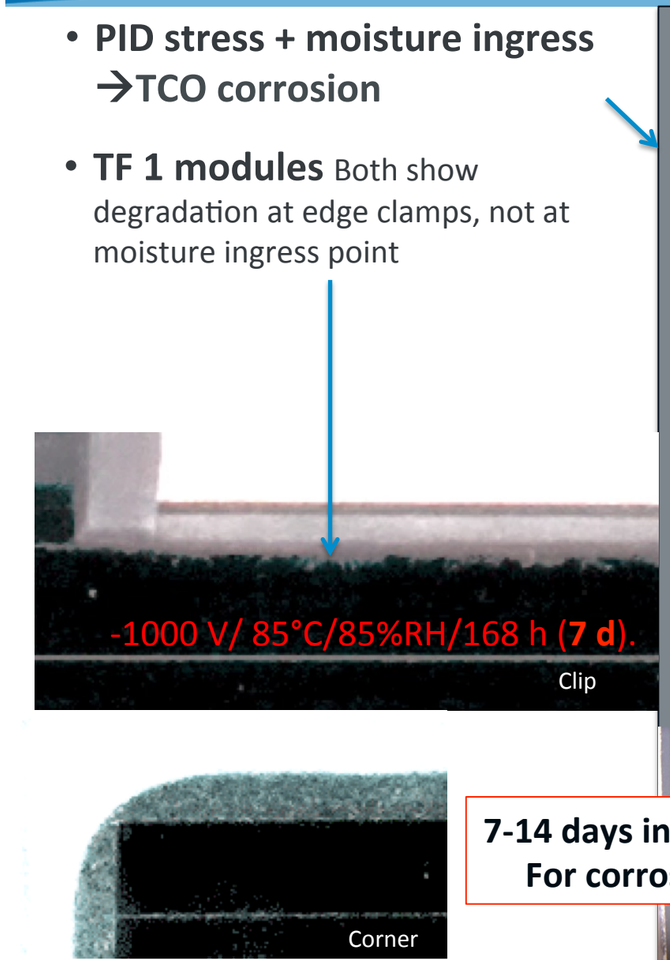
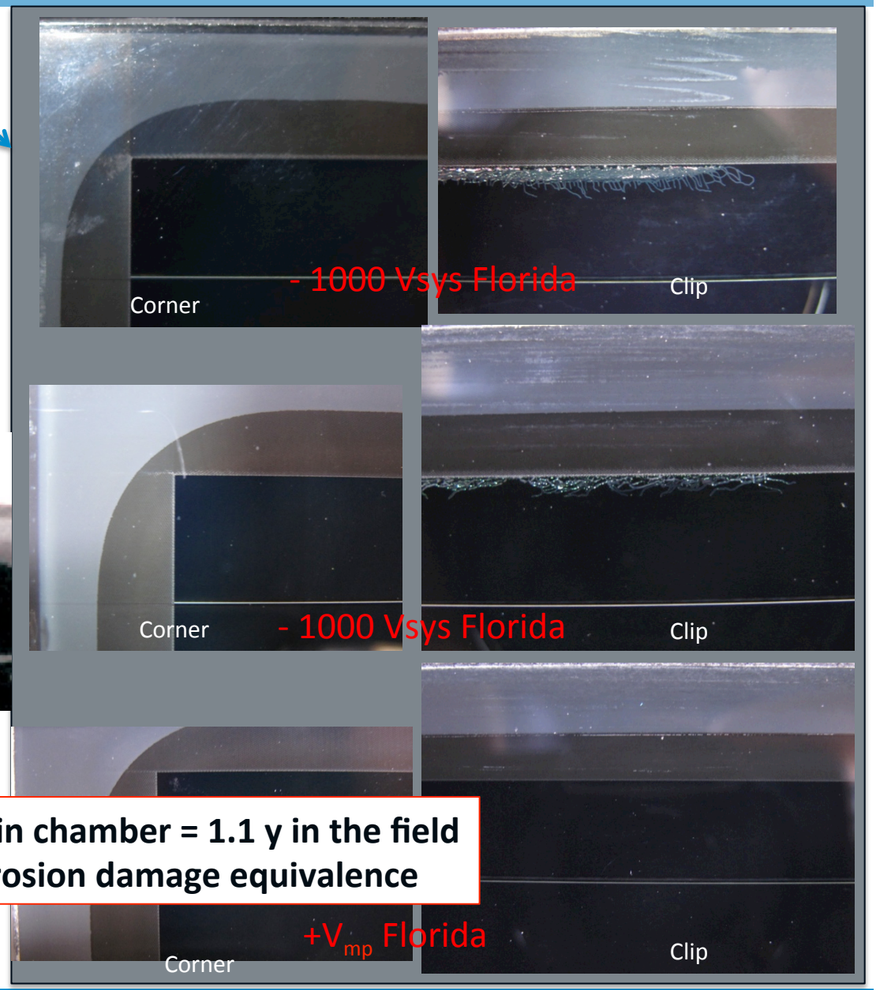
85°C/85%RH/168 h/-Vsys test versus 1.1 y in the field

- **PID stress + moisture ingress →TCO corrosion**
- **TF 1 modules** Both show degradation at edge clamps, not at moisture ingress point



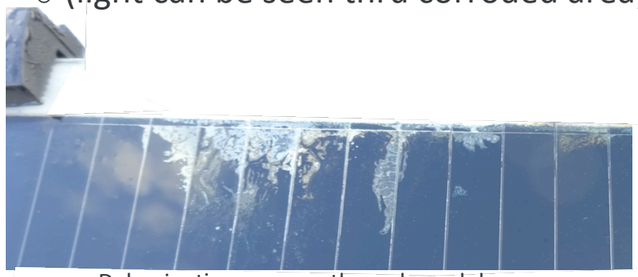


7-14 days in chamber = 1.1 y in the field
For corrosion damage equivalence

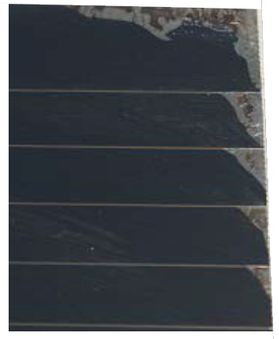
85°C/85%RH/1200 h/-Vsys test versus 2 y in the field

- **TF 2 modules** exposed to -1000 V/ 85°C/85%RH/1200 h (50 d)
  - Small amount of corrosion concentrated near edge clamps

- **TF2 modules** Fielded, -1000 V_{sys} Florida 2 y
  - (light can be seen thru corroded area)



Delamination, can see through module



India

All-India Survey of Photovoltaic Module Reliability: 2014

~7 weeks in chamber did not sufficiently show corrosion damage that manifested in ~2 y in the field (sample size small**)**

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PVQAT-JP: TG-2/3/5 Joint Meeting (Feb. 2, 2017)

- Targeted Failures in Combi-/Sequential-Testing:

PV Module Performance: *Delamination / Cell Crack – Snail Trail / Corrosion*

PV Module Safety Issue: *Crack of Backsheet*

- Identification of Cause(s) of Delamination

Experience: *Delamination is observed even at the recently installed PV systems.*

Delamination: *"Infant mortality" failure?* **or** *Wear-out failure?*

Caused by *Design Process?* **or** *Manufacturing Process?*

ex. Additives of Materials/Cells(Ti)? or Lamination Temp?

ex. Matching of Materials (Polymer-Metal Adherence….)?

- Reported Findings

Targeted Failure	Test Methods [Candidate(s)]	Priority
Delamination	UV – High Temp. / TC Combined Test DH – High Sys. Voltage Sequential Test (NREL)	***We should discuss on*** - Severity of Failure Performance Safety Both Issues - Reproducibility - Cost of Testing incl. Equipments - Duration of Testing - Novel Materials - etc….
Cell Crack (Snail Trail)	Cyclic (Dynamic) ML – TC Seq. Test Mechanical (Bending) Load at Low Temp. **Snail Trail: we have no data*	
Corrosion (Acceleration)	UV – DH Sequential Test DH – TC Sequential (Alternative) Test	
Crack of Backsheet	DH – TC Sequential (Alternative) Test **It has been also reported by DuPont*	

PVQAT – TG3: Humidity Temperature Voltage

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Michael Koehl

Fraunhofer Institute for Solar Energy Systems ISE

Combi tests = all stress factors act on the same samples

Simultaneous uniform acceleration with all stress factors is impossible

Sequential application of different stress factors is possible

Repetition of test-cycles enables interaction of different degradation modes

Initial test sequence:

- 1000 h 85°C / 85% rh
- 100 TC -40°C / +85°C
- 500 h combined DH/UV @ ~85°C module temperature

Following test cycles:

- 500 h 85°C / 85% rh
- 100 TC -40°C / +85°C
- 500 h combined DH/UV bei @ ~85°C module temperature

Study rates, acceleration factors, appropriate levels for

- Radiation (UV)
- Temperature (thermal conductivity)
- Humidity (permeation from the back-sheet into encapsulant in front of the cells)

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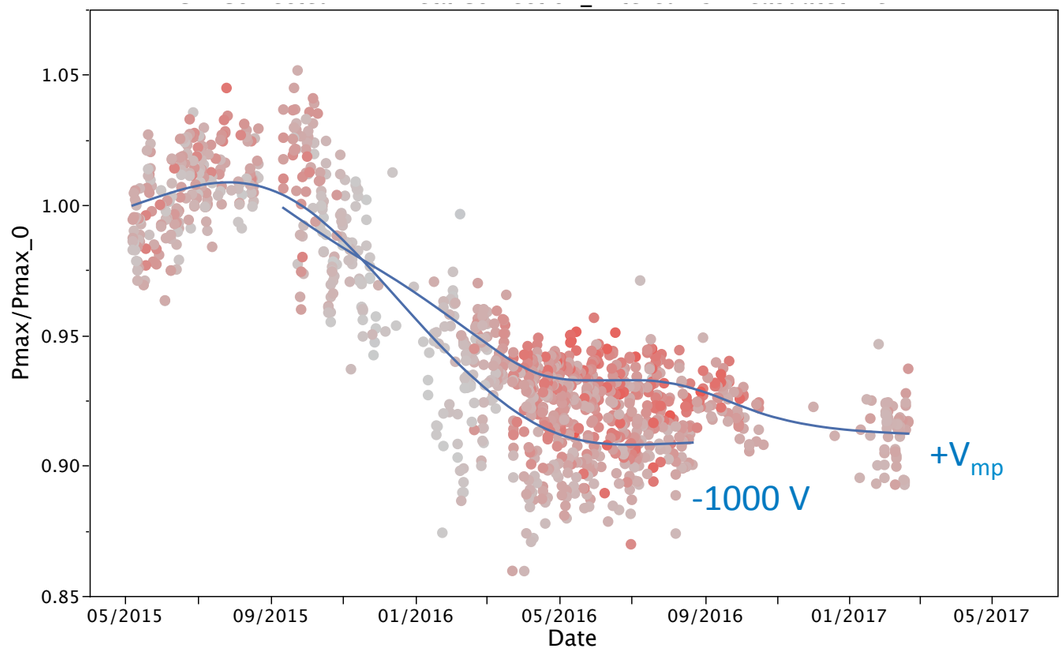
Summary

- For IEC 61215 ed.3 Amendment 1: more comparisons between damp heat and foil method needed
  - Additional field studies in hot-humid climates needed
- PID-delamination Tech Spec project started, more studies to determine appropriate levels will be beneficial
- PID-thin film, focus on test method now
  - Evaluation with respect to in-situ control
    - Light or current bias?
  - Deconvolution with metastability
  - More study sought to input eventual tests levels
- General understanding that to reproduce field failures, combination of environmental stress factors necessary

Thank you !

www.nrel.gov
NREL
NATIONAL RENEWABLE ENERGY LABORATORY
NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

CIGS POWER LOSS



Inconclusive difference between PID stressed and self-biased sample

PVQAT

International PV Quality Assurance Task Force

PVQAT TG5: "UV Weathering Standards Development Within the PV Industry"

Sean Fowler, Xiaohong Gu, David Miller, Nancy Phillips

PV Reliability Workshop

Denver West Sheraton

March 1, 2017, 10:25-11:10

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

PVQAT TG5: Overview

- Scope: UV weathering

I. Introduction - David Miller (NREL)

II. Weathering questions/activities/insights/standards (panel format)

A. Current questions & issues – Nancy Phillips (DuPont)

B. Overview of active research efforts - David Miller

C. Insights from recent studies - Xiaohong Gu (NIST)

D. Past, present & developing standards in the industry - David Miller

III. The future of UV weathering tests - Sean Fowler (Q-Lab Corp.)

IV. Discussion – (PVRW 2017)

Nancy Phillips (DuPont)

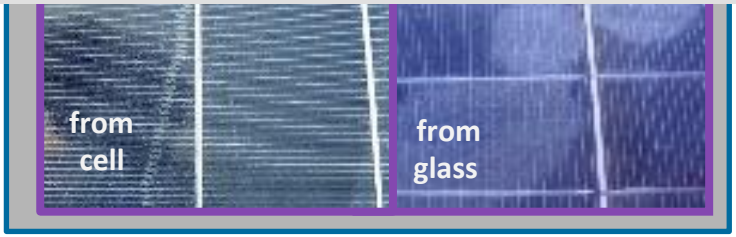
Topic Areas:

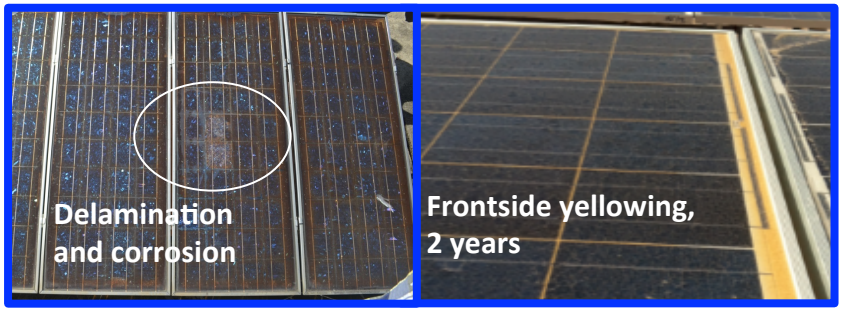
Overview

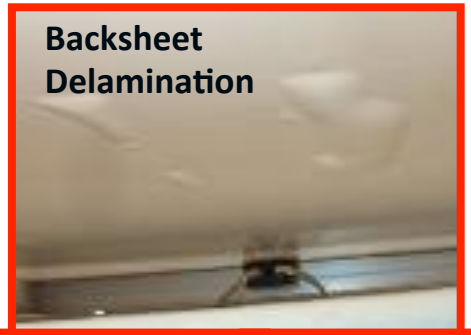
- Relevance
- 62788-7-2 Snapshot

Areas of discussion

- Field conditions
- Artificial Weathering Exposures
- Post-weathering evaluation Methods
- Specimen geometry
- Validating the results







Progress/Questions/Issues: 62788-7-2 (DTS)

62788-7-2 Component Weathering (DTS)

Contents:

- Menu of
  - Exposures
    - Light sources, set points
    - Exposure times
  - Sample Specimen Designs
- Tutorial on how these were derived

Referencing Documents (in progress):

- *Component Standards*
  - 62788-1-x (Encapsulants)
  - 62788-2 (Backsheets)
  - 62788-5(?) (Edge Seals)
- *Module Standards*
  - 61730 AM 1
  - 62892 series: Climate Specific Testing
  - NWIP: Guidelines for Testing PV Modules for High T Operations

Method A: Xenon exposures

	Chamber Air T (°C)	Black Panel T (°C)	Irradiance (W/(m²·nm)) @ 340 nm	Relative Humidity (%)
A1	45	70	0,8	20
A2	55	80	0,8	20
A3	65	90	0,8	20
A4	75	100	0,8	20
A5	85	110	0,8	20

62788-7-2
Exposures

62788-n
Property Evaluation Methods
Reference 62788-7-2 for exposures

n: 1: Encapsulants
2: Backsheets
5 Edge Seals

61730 AM1
Pass/Fail Requirements
Reference 62788-7-2 (exposures)
Reference 62788-2 (test methods)

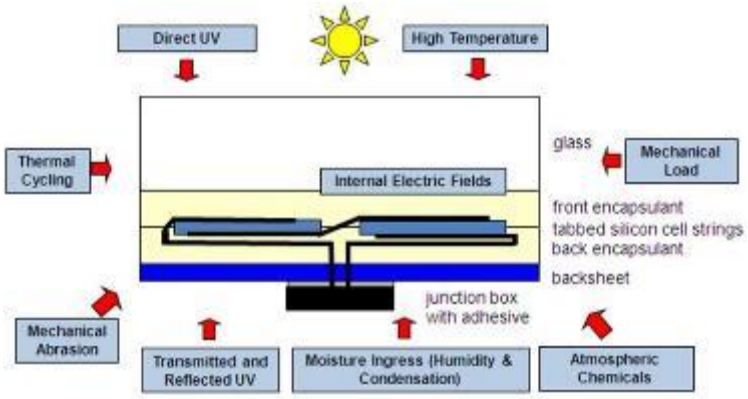
Also:
- 62892- Climate Specific
- NP "Testing for High T"
- ??

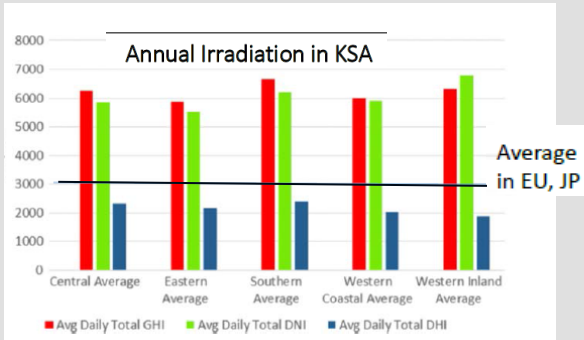
Progress/Questions/Issues: Field Conditions

1. **How to define and describe relevant field conditions?**
   - **Environmental conditions**
     - Different stress set in different environments: reference climate data:
       - Parameters and values defined for various climates
       - Thermal Cycling stress
   - **Conditions at the module**
     - T(module) elevated over T(environment)
     - RH(environment)≠RH(module).
     - Backside irradiance levels

2. **How to approach the variety of climate/mounting configurations?**
   - Combination of different climates and mounting result in very different stress sets
   - Climate/Mounting differences to be handled by Referencing Standards
   - 62788-7-2 Ed. 1 provides options

Environmental Stresses in the Field





Annual irradiation is nearly double as compared to temperate regions

Saudi Arabia, and temperate

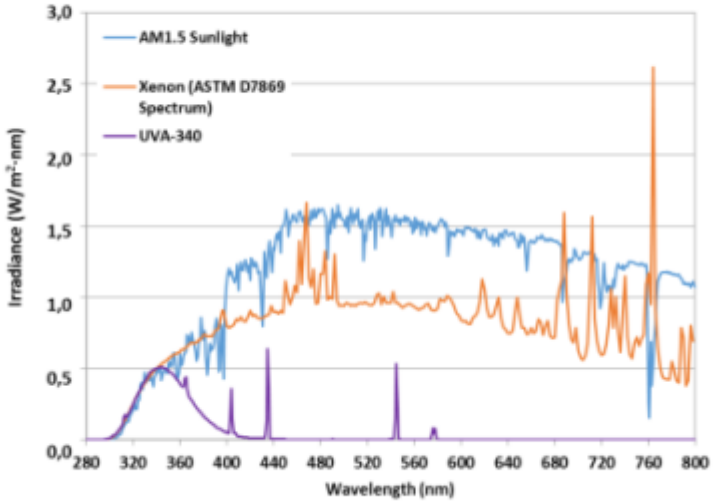
Absolute extreme value of Temperature: 55°C

اطلس مصادر الطاقة المتجددة
Renewable Resource Atlas

Kondo, PVMRW 2016

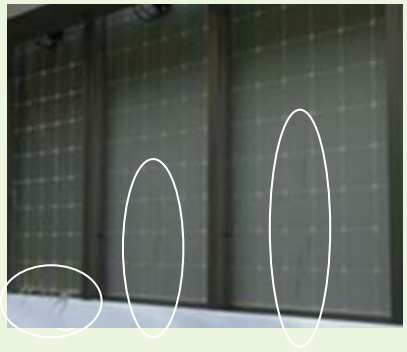
Progress/Questions/Issues: Artificial Exposures

1. **Why not use existing Weathering Standards?**
   - Higher acceleration desired
   - Exposure T lower than application T
2. **Light (Source/Level/Exp. Time)**
   - "Total UV dose": all pathways to a UV dose NOT equivalent
   - Material-dependent response to Light Source and Irradiance Levels
     - Reciprocity
     - Action Spectrum
3. **Temperature, Humidity**
   - HIGHER temperature, LOWER RH to match field stresses
   - Physical capabilities of weathering devices
4. **Cycling stress**
   - Slow change, or thermal shock
   - Temperature range
5. **Combination of stresses**
   - Important to have some kind of mechanical stress in conjunction with thermal and photolytic stresses (BAKE, then SHAKE)



Module after:
a) DH 1000 hours
b) UVA 1000 hours (65 kW/sqm)
c) TC 200 cycles

NO cracks before TC 200

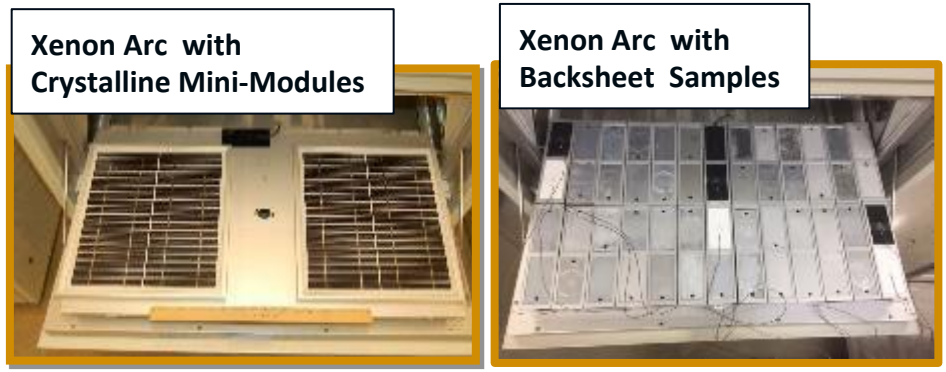


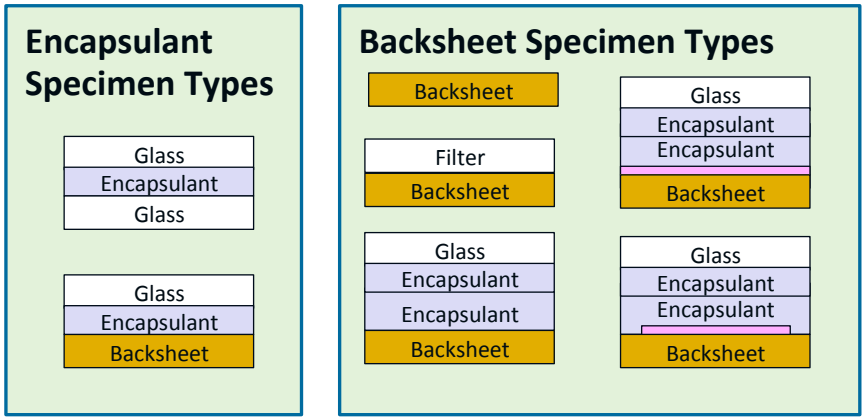
Fielded Module
4 years

Progress/Questions/Issues: Specimen Design

1. **Component v. Module exposures**
   - Performance of *package* is what's important
   - Long-term environmental testing representative of > 10 years impractical for modules
   - Use of known-stable packaging materials adds confidence
   - Building the Reliability story through combined module/ component testing

2. **Component Specimens - Design**
   - Performance of materials alone v. a representative environment
   - Qualification of individual components w/ multiple packaging partners
   - Ability to measure relevant physical properties of materials after exposure

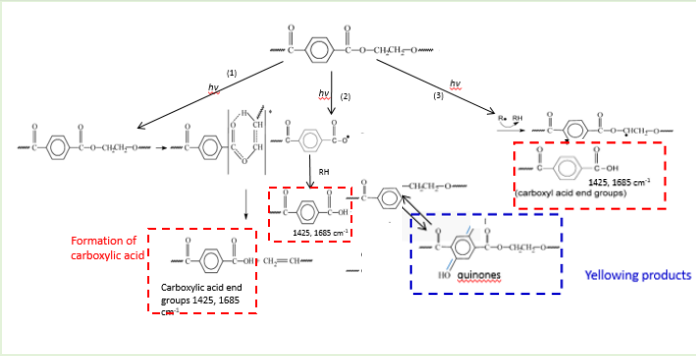




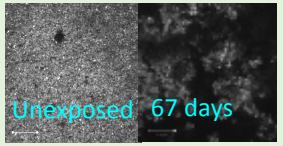
7

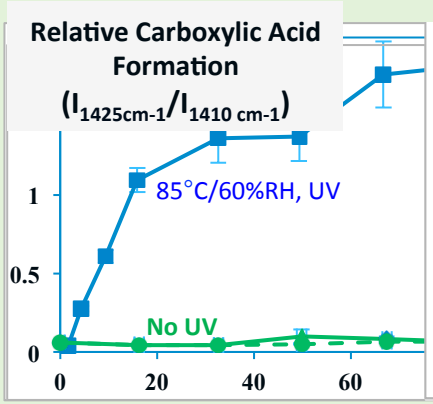
Progress/Questions/Issues: Evaluation Methods

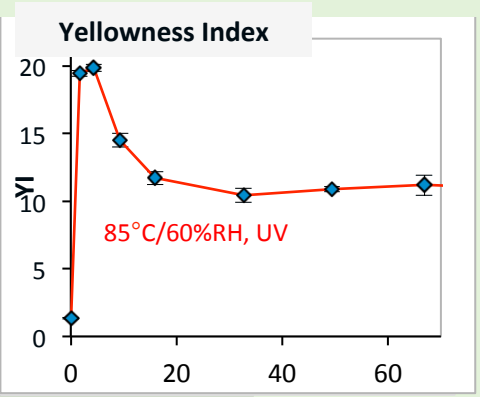
1. **Degradation Modes**
   - Relating module degradation to component properties
   - Component degradation affects module safety and performance
2. **Relevant properties to test after exposure**
   - Ideal: materials unchanged after exposure
   - Measure changes due to:
     - Chemical (breaking of bonds)
     - Physical (morphology)
   - Early indicators v. property requirements
     - Optical properties (color, transparency)
     - Dielectric properties
     - Mechanical properties
     - Spectroscopic information
3. **Test methods**
   - Mechanical properties tests
     - Tensile, % elongation
     - Bend test
     - Nano-indentation
4. **Pass/fail requirements**
   - Predicting degradation levels at end of Service Life



NIST exposures 85 °C/60% RH



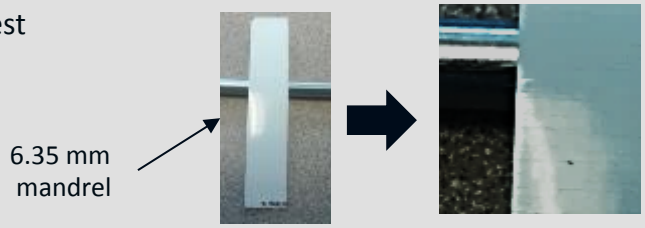




Mechanical Property Measurement

- Tensile/%Elongation
- Nano-indentation
- Bend Test

Bend Test



David Miller (NREL)

There are four regional TG5's.
Each group focusing on different supporting activities (experiments).
You may participate/follow more than 1 of the groups. ☺

- TG5 Americas. Contact: David.Miller@nrel.gov

- TG5 China. Carol Chen: chenxinx@cei1958.com

- TG5 Europe. michael.koehl@ise.fraunhofer.de
  Reference (backsheet study): Koehl et. al., Proc Euro PVSEC, 2015.

- TG5 Japan. Tsuyoshi.Shioda@mitsui-chem.co.jp
  Note: working on encapsulant dc lamination with TG2 & TG3

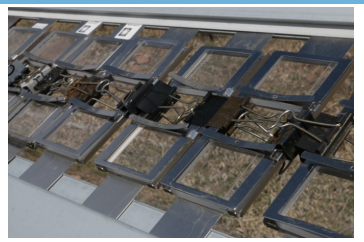
See: http://www.pvqat.org (PVQAT effort)

also: http://pvqataskforceqarating.pbworks.com (minutes, references, attachments, meeting recordings)

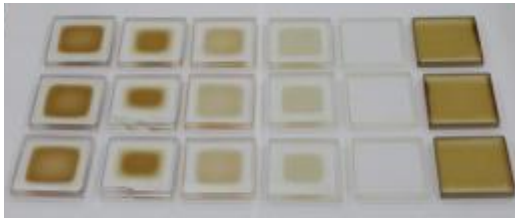
PVQAT TG5: Research efforts

TG5 Americas, study 1
Considerations: type artificial UV source, temperature, humidity, natural weathering, E_a…

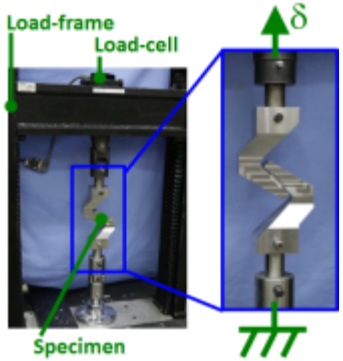
- Discoloration of encapsulants
- Attachment strength of encapsulants
- Strength & adhesion of edge seals



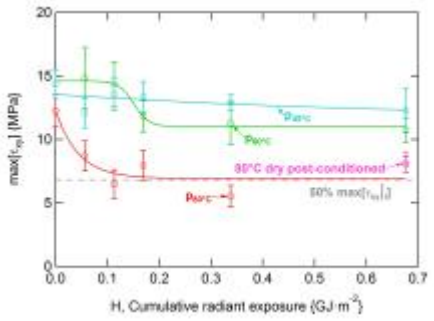
Specimens on outdoor rack, in Golden, CO at NREL.



Specimens after 618 MJ·m^{-2} in Xe chamber, at Fraunhofer CSE.



Compressive shear test used to examine the attachment of EVA.



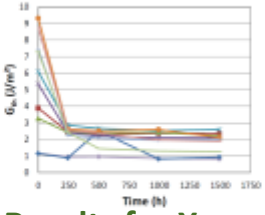
Change in strength of attachment with Xe weathering at 3M.

TG5 Americas, study 2
Will examine repeatability and reproducibility of IEC 62892-3 discoloration of Xe aged contemporary encapsulants.

- Participants needed

(Test starts spring 2017).

Schematic and photo of wedge specimen (edge seals).

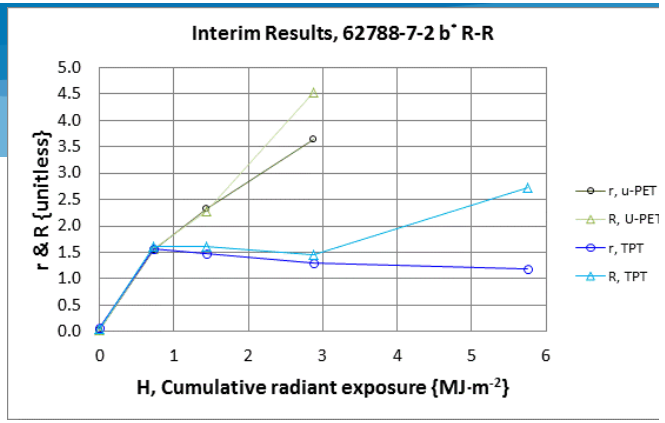


Results for Xe aged wedge specimens.

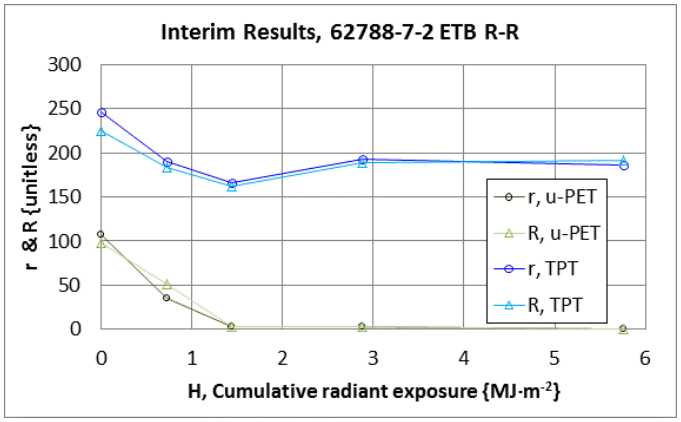
References:
Miller et. al., Proc IEEE PVSC 2016, 33. http://www.nrel.gov/docs/fy17osti/66681.pdf
Miller et. al., Proc IEEE PVSC, 2015, 972. http://www.nrel.gov/docs/fy15osti/64628.pdf.
Kempe et. al., Proc SPIE, 2016, 9938-03.

IEC 62788-7-2: Research efforts

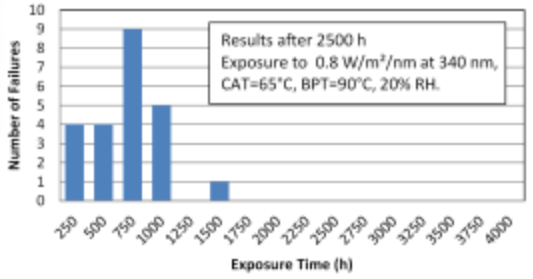
- Quantify repeatability & Reproducibility of the emerging weathering standard on backsheets.
- 9 participanting groups, 5 models Xe chamber, IEC 62788-7-2 test condition A3.
- Materials: TPT backsheet, PET (unstabilized, UV stabilized, White TiO_2).
- Parameters: **b* color**, **elongation to break**, tensile strength, chemical damage (FTIR), breakdown voltage, **mandrel bend test**
- Also: temperature of weathering specimens.
- Also: focused examination of 55 additional materials.
- Contact: Emily.Parnham@gbr.dupont.com



repeatability and Reproducibility (r & R): change in color (b*) for unstabilized PET & TPT.



repeatability and Reproducibility (r & R): Elongation To Break (ETB) for unstabilized PET & TPT.



Implementation and early results for mandrel bend test.

Other Weathering Studies (Outside PVQAT)

•NIST consortium

"Developing Reliability-Based Accelerated Laboratory Tests for Service Life Prediction of PV Materials and Systems"

Examining backsheets, encapsulants (coupon specimens)

Factors: bandpass filters, UV intensity, moisture, temperature

References: Gu, et. al., SOLMAT, 144, 2016, 289-299

Contact: xiaohong.gu@nist.gov

•PREDICTS1

-UV weathering/adhesion of CPV encapsulants

-Fracture mechanics method, like IEC 62788-6-3 (Nick.Bosco@nrel.gov).

-Reference: Cai et. al., SOLMAT, 157, 2016, 346-353.

-Contact: Pr. Reinhold Dauskardt <rhd@stanford.edu>

•PREDICTS2

"Backsheets: Correlation of Long-Term Field Reliability With Accelerated Laboratory Testing"

-Examining veteran modules from multiple climate zones & some artificial weathering

-Contact: Kenneth.P.Boyce@ul.com

Xiaohong Gu (NIST)

Xenon

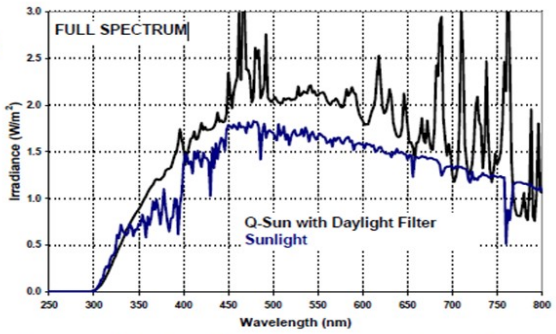
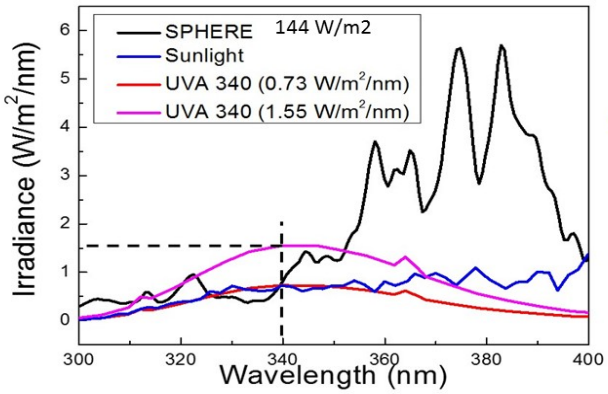
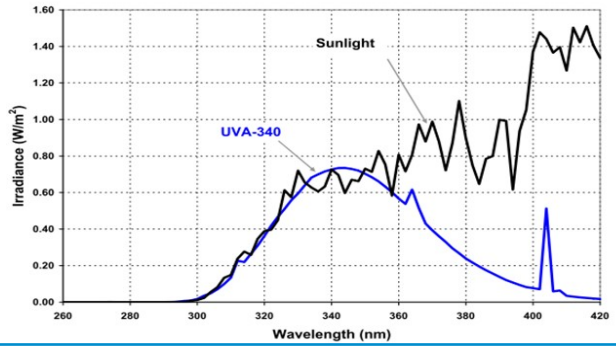


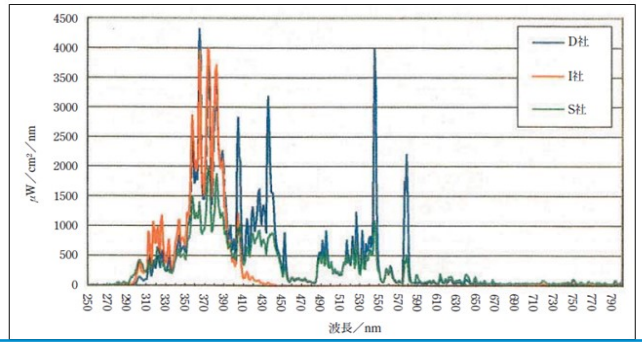
Figure 10a - Daylight Filters and Sunlight Full Spectrum



SPHERE

QUV-A





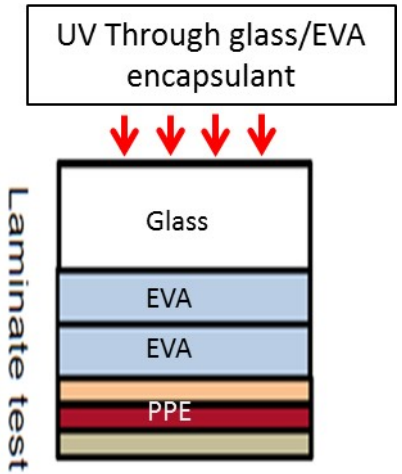
Super UV (Metal Halide)

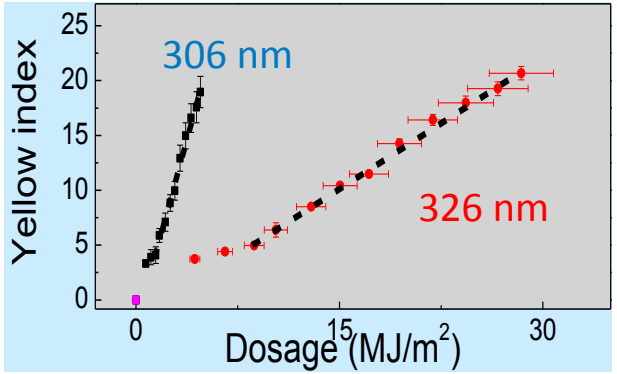
Not all weathering devices are the same; not all UV lights are the same

- Wavelength sensitivity
- UV irradiance effect
- Temperature
- Humidity
- Sample preparation, geometry, & preconditioning

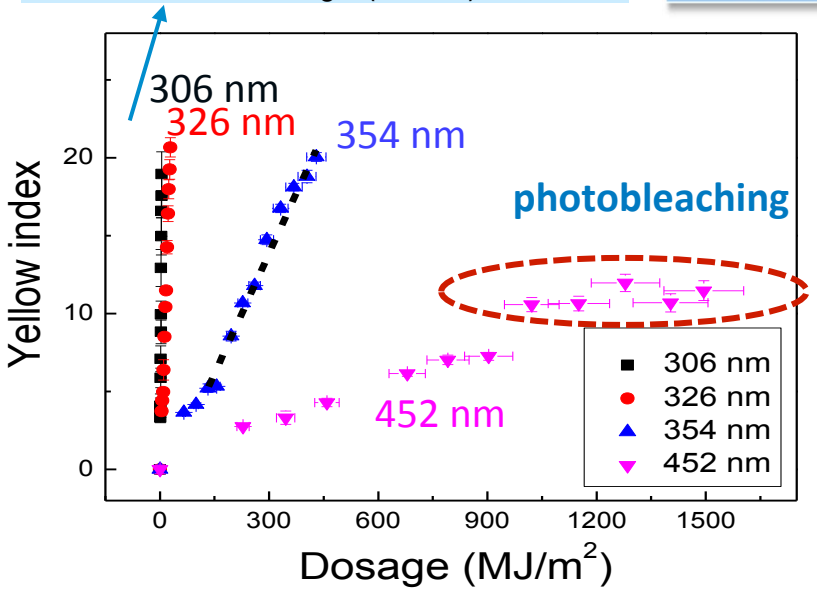
Effect of UV Spectral Wavelength on Yellowing Index of Glass/EVA/PPE Backsheet

NIST SPHERE
Glass/EVA/PPE system
UV/85°C/dry

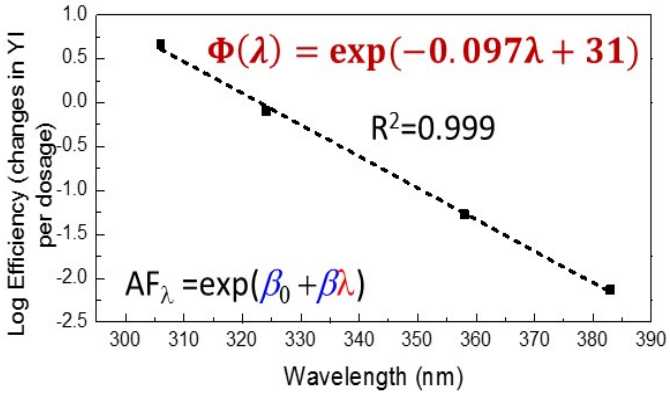




Wavelength (nm)	Pseudo-rate constant (m^2/MJ)	Relative Efficiency
306 ± 3	4.56	580.9
326 ± 6	0.80	101.9
354 ± 19	0.053	6.7
452 ± 80	0.0079	1



Action Spectrum for increase in YI

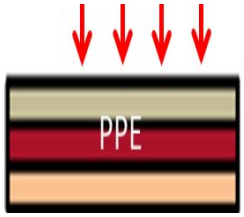


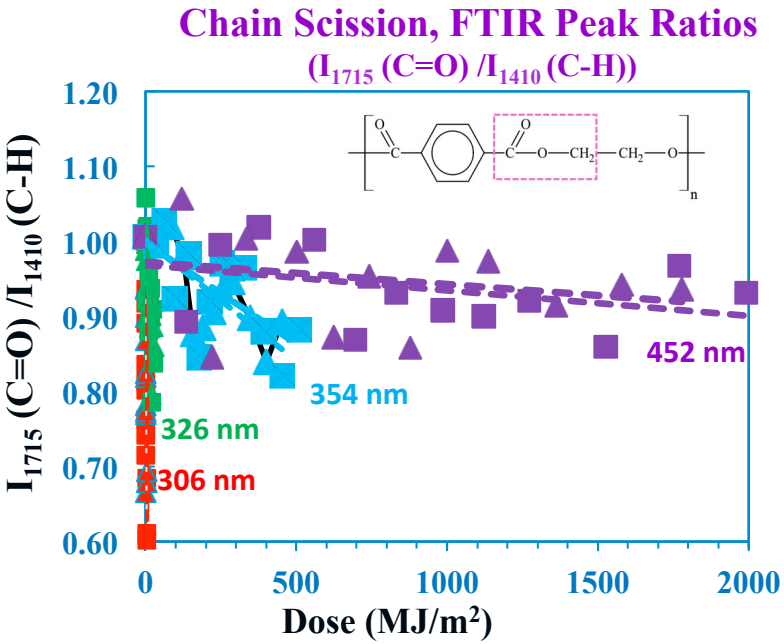
Varying wavelength range with narrow band pass filters, (306 ± 3) nm, (326 ± 6) nm, (354 ± 19) nm and (452 ± 80) nm.

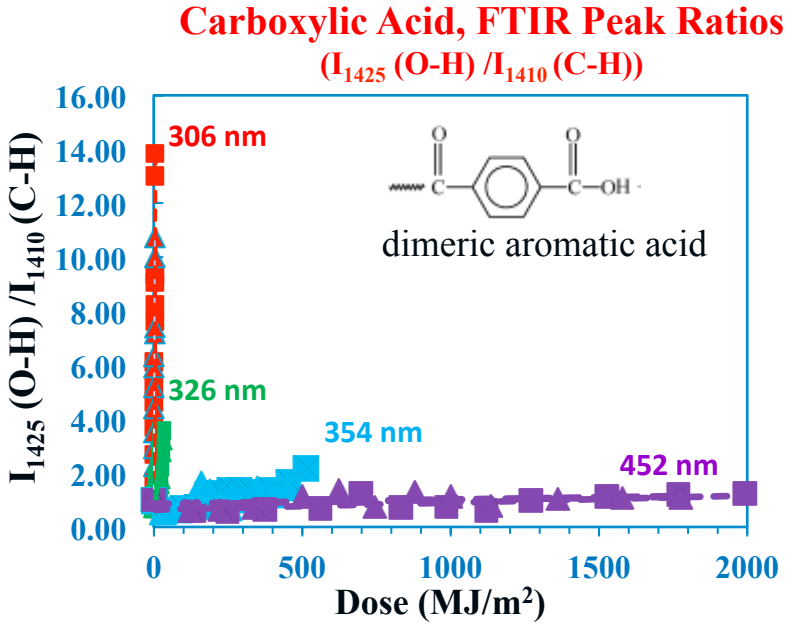
- ✓ Shorter wavelength leads to a higher yellow growth at the same dosage.
- ✓ Increase of YI under 452 nm slows down and then fluctuates at late stage, indicating a photobleaching effect.

➢ An exponential dependence between yellowing and wavelength is obtained.

Effect of UV Spectral Wavelength on Chemical Changes of PET Outer Layer in A PPE Backsheet







Chain Scission Acid Formation

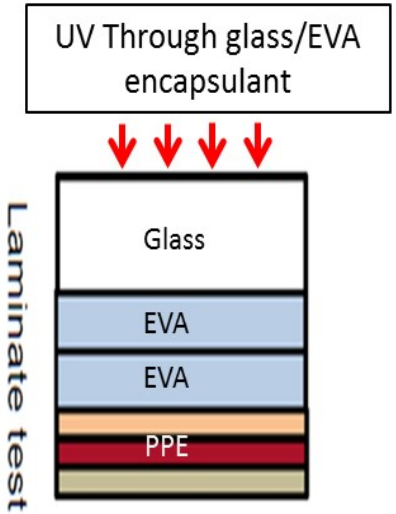
Wavelength (nm)	Relative Efficiency I_{1715}/I_{1410}
306	2706
326	208
354	9
452	1

- A shorter wavelength leads to a higher rate of chemical changes.
- PET is extremely sensitive to short UV wavelength around 300 nm.

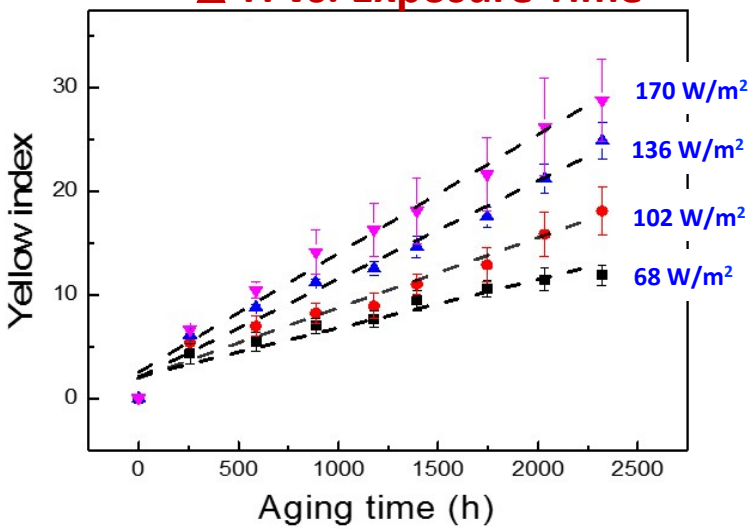
Effect of Light Intensity on Yellowing Index of Glass/EVA/PPE Backsheet

(85 °C/dry)

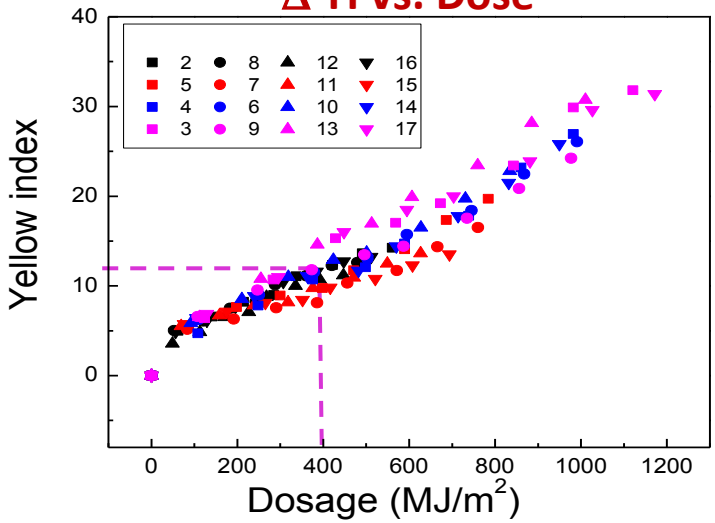
Glass/EVA/PPE system
UV/85°C/dry
NIST SPHERE



Δ YI vs. Exposure Time



Δ YI vs. Dose



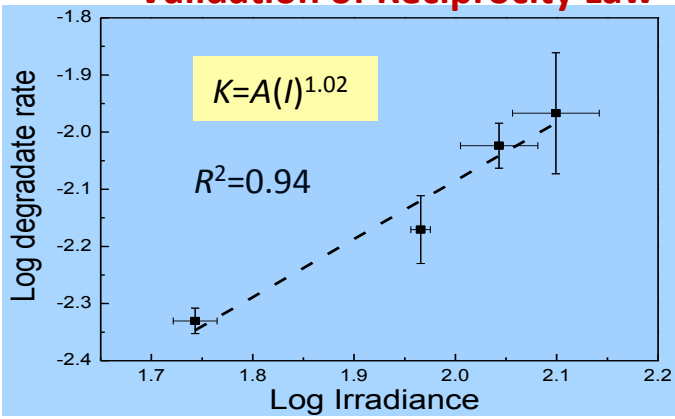
- **Varying light intensity with 40, 60, 80, and 100 % of ND filters (300-400 nm)** → 68, 102, 136, 170 W/m², specifically through filters on specimens

1) A higher light intensity leads to a faster yellowing growth.

2) A quasi-linear relationship is observed for the yellow index-aging time plot.

3) For a given damage, the required dosage is similar at different light intensities.

Validation of Reciprocity Law

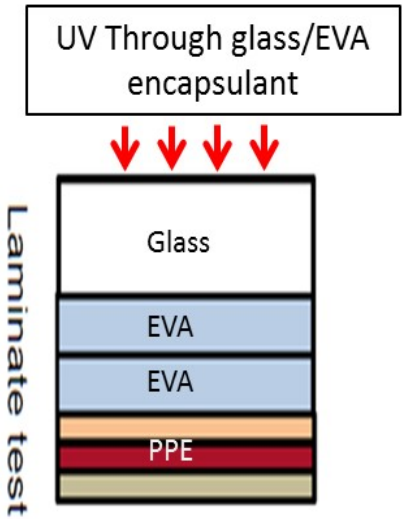


➢ **Reciprocity Law appears to be obeyed.**

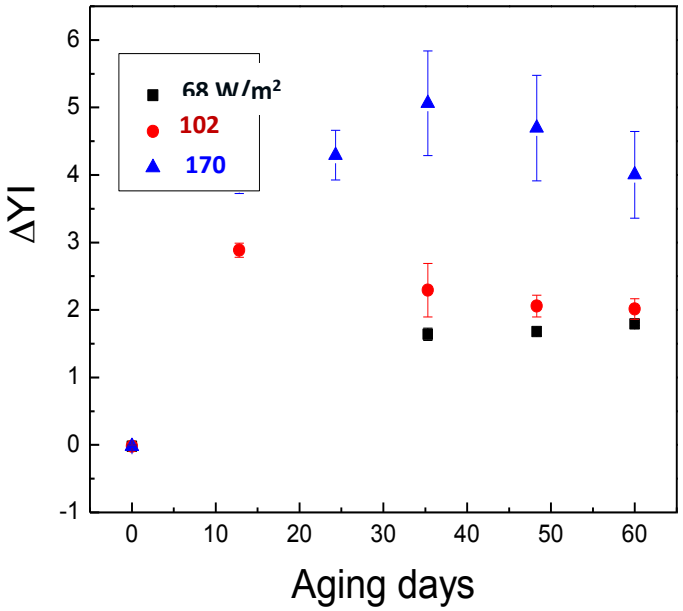
- *Within the studied range of irradiance, same yellowing can be achieved by a shorter exposure time with a higher irradiance, or a longer time with a lower irradiance as long as the dosage is same.*

Effect of Light Intensity on Yellowing Index of Glass/EVA/PPE (65 °C/dry)

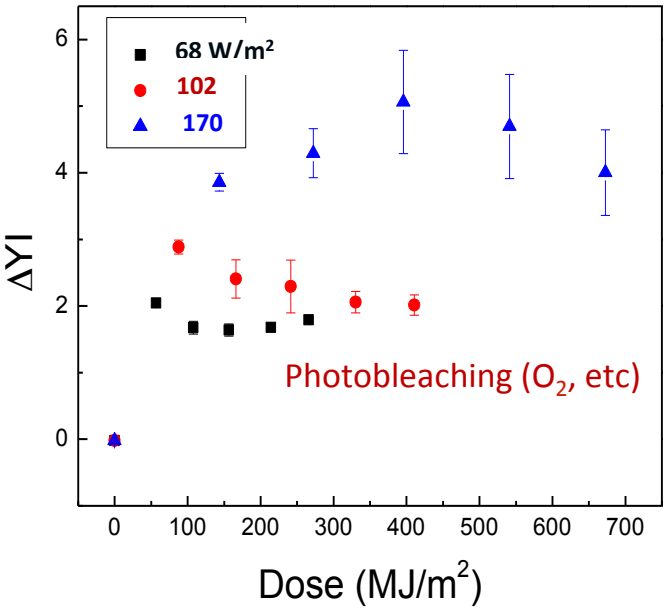
Glass/EVA/PPE system
(65 °C/dry)
NIST SPHERE



Δ YI vs. Exposure Time



Δ YI vs. Dose



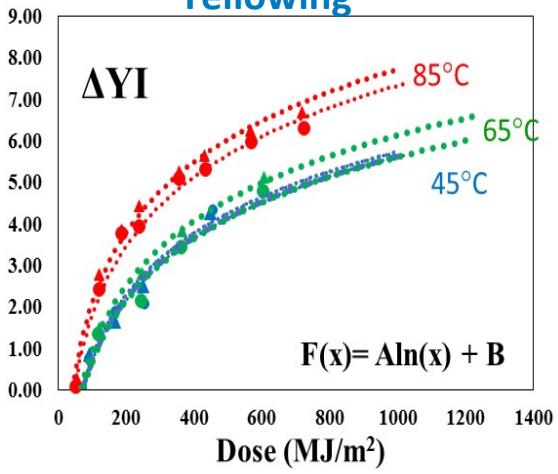
- **Varying light intensity with 40, 60, 80, and 100 % of ND filters (300-400 nm)** → 68, 102, 136, 170 W/m², specifically through filters on specimens

- YI increases initially and then decreases with aging time.
- Basically, a higher light intensity leads to a faster yellowing growth.
- It seems that **Reciprocity Law is not obeyed** for YI change of laminates under UV/65°C/dry due to dominance of photobleaching.

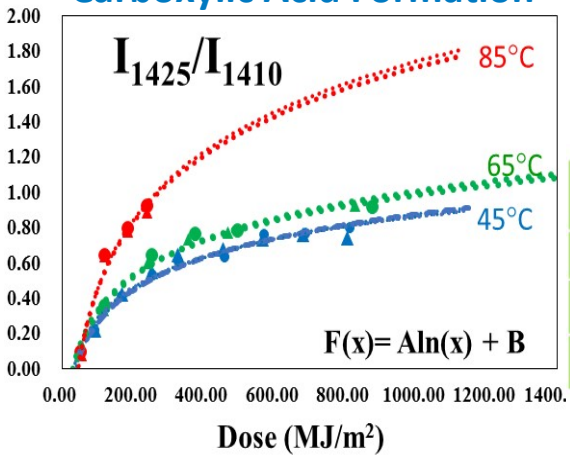
  - *A shorter exposure time X A higher irradiance ≠ A longer time X A lower irradiance*

Temperature Effect on ΔYI and Carboxylic Acid Formation of PET Outer Layer in A PPE Backsheet (UV/dry)

Yellowing

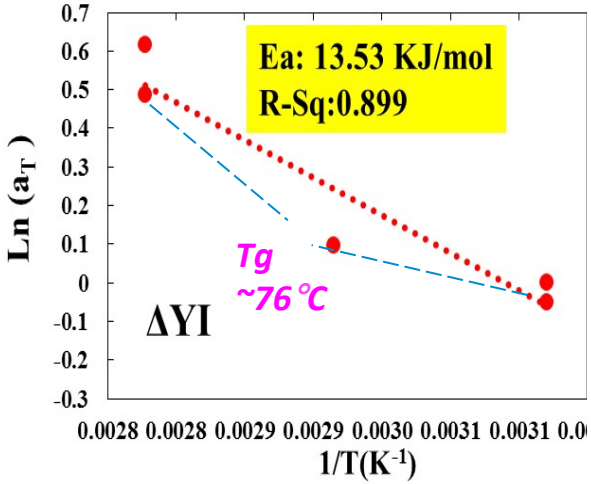


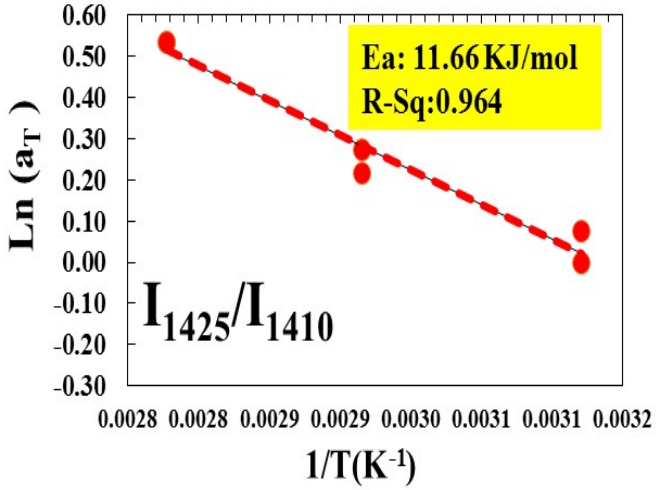
Carboxylic Acid Formation



Acceleration Factors for Yellowing and Carboxylic Acid formation

T (° C)	a_T (YI)	a_T (I_{1425}/I_{1410})
45	1.0	1.0
65	1.0	1.5
85	1.7	3.3





$$k = Ae^{-E_a/RT}$$

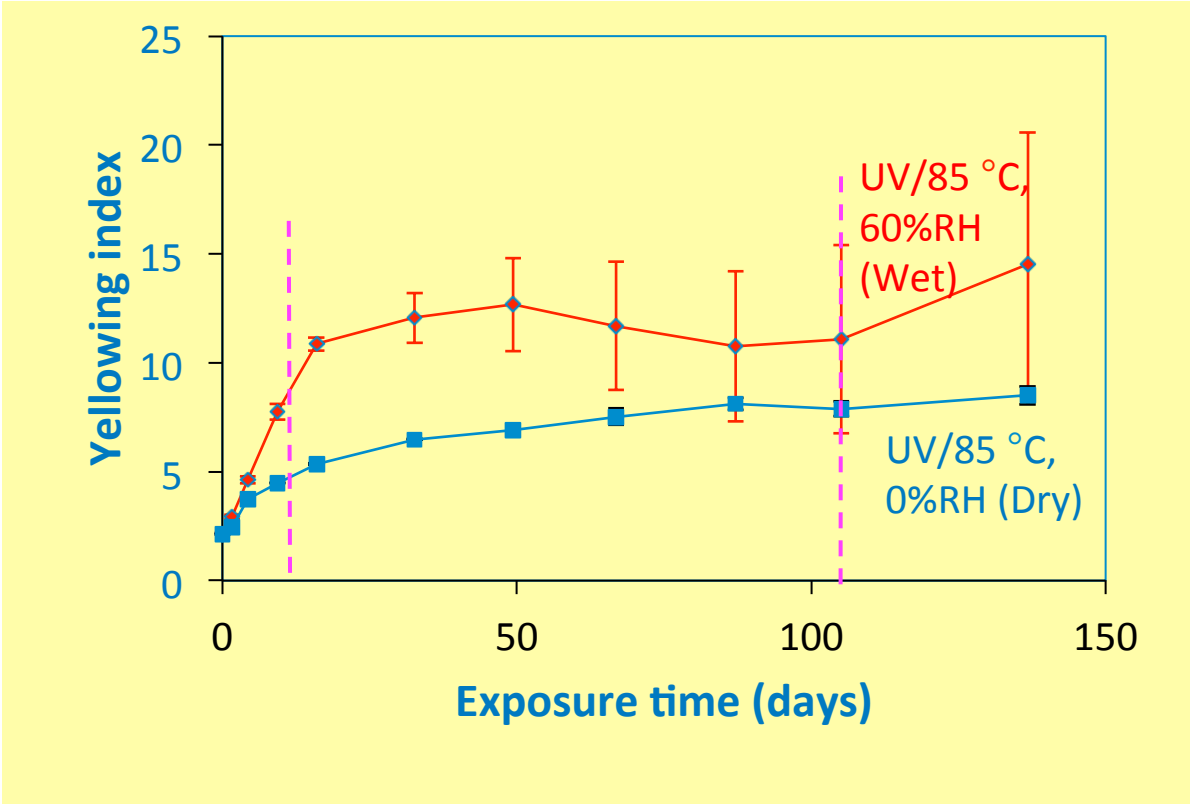
$$\ln a_T = \ln\left(\frac{D_{T1}}{D_{T2}}\right) = \frac{E_a}{R}\left(\frac{1}{T_1} - \frac{1}{T_2}\right)$$

- The effect of temperature does not always obey a doubling rule.
- Need to consider the phase transition temperature when testing the temperature effect.

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

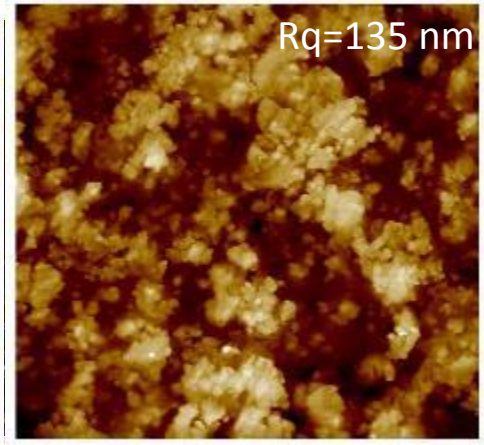
Humidity Effect on Yellowing and Morphological Changes of PET Outer Layer in A PPE Backsheet (UV/85 °C)

Yellowing Index of PPE PET Outer Layer



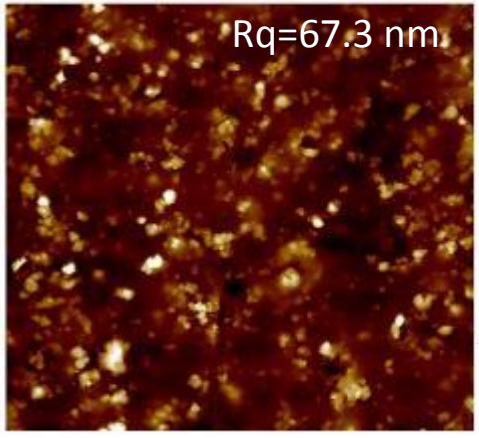
AFM Topographic Images of Aged PET Outer Layer

wet



20 µm x 20 µm

dry



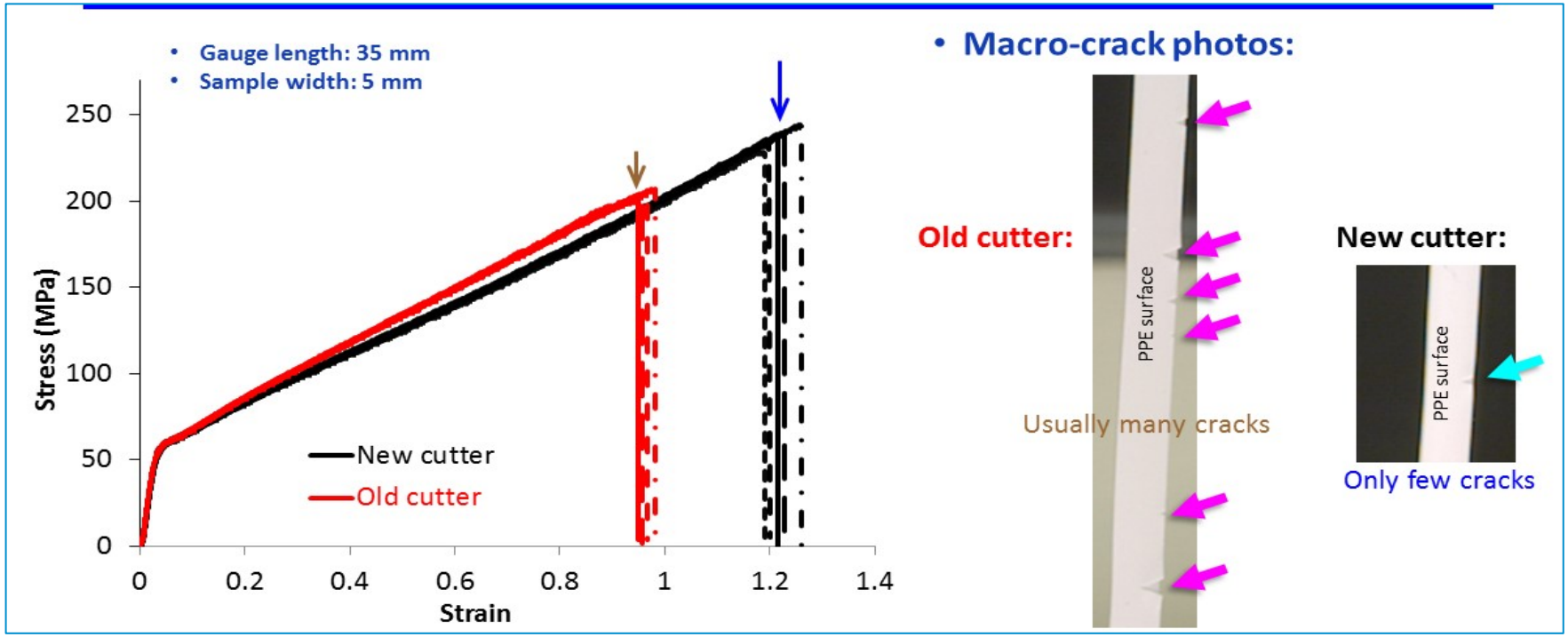
20 µm x 20 µm

- In UV/wet condition, the discoloration and morphological changes of PET-PPE occurred more quickly than in UV/dry condition.
- Pitting/Cracks appeared earlier in UV/wet condition than in UV/dry condition.
- UV/85° C, 105 d

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Sample Preparation Effect on Accelerated Laboratory Testing of Backsheets and Encapsulants

- **Old vs. New Cutter for Tensile Test Sample Preparation**



- **Additional examples:**
  - **Sample exposure geometry (Large sample vs. Small sample)**
  - **Lamination vs. Non-lamination**
  - **Single layer film vs. Multilayer film**
  - **Coupon vs. Module**
  - **Preconditioning vs. Non-preconditioning**
  - **……**

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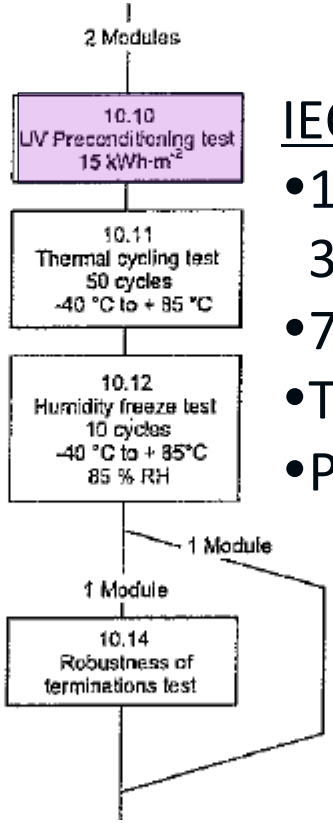
David Miller (NREL)

Precondition before TC & HF. Identify UV susceptible materials & interfaces.
Module test (typically UVA-340 flourescent or metal-halide sources).



IEC 61215-1 ed. 1 (1993) 10.10

- UV test identified, but details not defined.

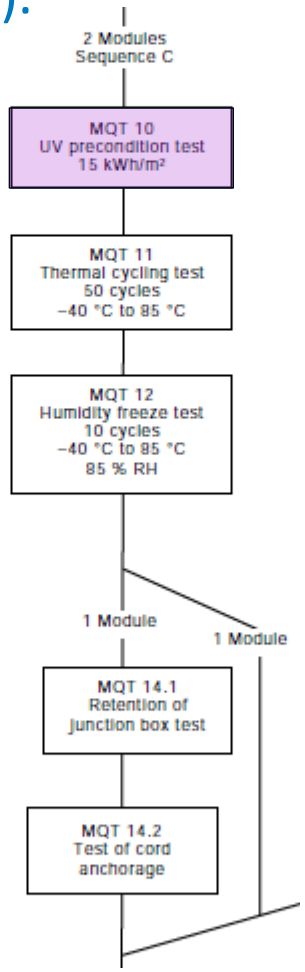
IEC 61215-1 ed. 2 (2005) 10.10

- 15 kWh·m^{-2}, @ H=250 W·m^{-2} ±15% in 280–385 nm
  33%<H within 280 nm–320 nm.
- 71 MJ·m^{-2} TUV, ~53 days AM1.5G
- T_{module} 60±5°C
- Pass/fail: no major visual defect, ΔP <5%, verify insulation resistance

IEC 61215-1 ed. 3 (2016) MQT 10

Similar UV weathering & sequence, except

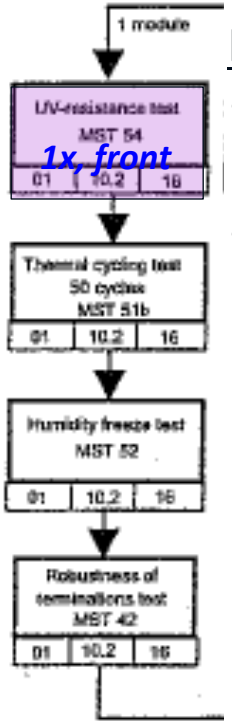
- H evaluated from 280–400 nm
  3%<H<10% in 280 nm-320 nm.
- 54 MJ·m^{-2} TUV, ~40 days AM1.5G



Test sequence in 61215 ed. 2 containing 10.10 (UV preconditioning)

Test sequence in 61215 ed. 3 containing MQT 10 (UV preconditioning)

Weathering Standards: IEC 61730 (The Other Present Test)



Module test sequence in 61730-2 ed. 1.

Edition 1 (2004)

- 61730-1: materials must be UV resistant and fulfill ANSI/UL 746C (applies to polymers exposed to direct sun)
- 61730-2: 10.10 in **61215-2 ed. 2** (~53 days TUV AM1.5G)

Sequence: UV→TC50 →HF10 →robustness terminations

Criteria: visual inspection, maximum power, dielectric withstand tests

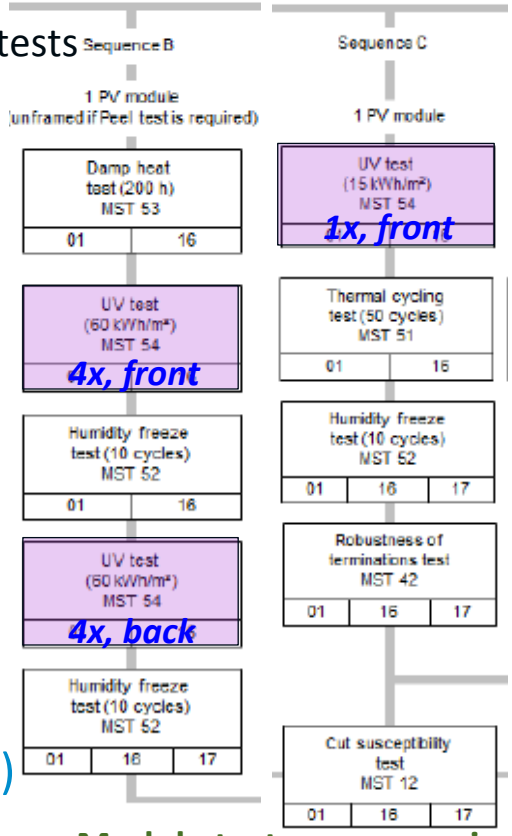
Edition 2 (2016)

- 61730-1: "Polymeric materials shall be durable to weathering stress occurring in the application" (Requirements not well defined *or* component specific)
- 61730-2: **IEC 61215-1 ed. 3** MQT 10 test

  Parrallel sequences

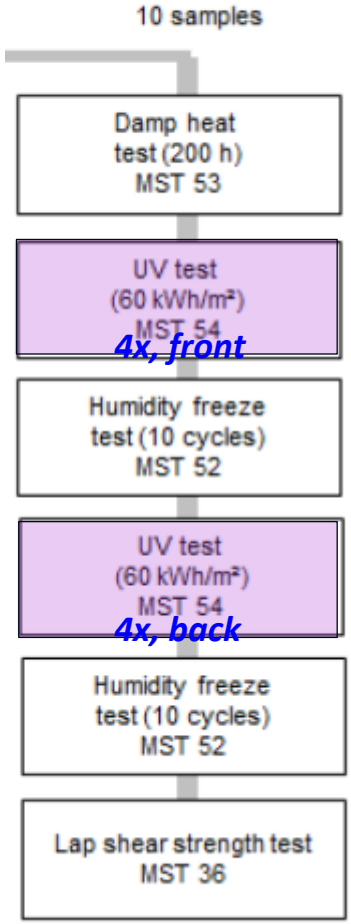
  Irradiate **front then back** of modules

  1x or 4x dose (~40 or ~160/1600 days TUV AM1.5G)



Module test sequences in 61730-2 ed. 2.

Weathering Standards: IEC 61730 (The Other Present Test)



Coupon test sequence in 61730-2 ed. 2.

61730-2 Edition 2 (2016)

- 61730-2: **IEC 61215-1 ed. 3** MQT 10 test

  Test sequence for **coupon specimens (Cemented Joints)**:

  DH200→UVf4x→HF10→UVb4x→HF10→lap shear

  Irradiate **front then back** of coupons

  4x dose (~160/1600 days TUV AM1.5G)
- Criteria: mechanical **lap shear test** ($\Delta\tau_{xy} \leq 50\%$)

61730-1 Edition 2, Amendment (in development)

- 61730-1: **coupon specimens** durable to **IEC 62788-7-2** 596.7 MJ·m^{-2} TUV, **~1.1/11y AM1.5G**
- Applied for Relied Upon Insulators (backsheets, Cemented Joints)
- Criteria: **visual inspection, breakdown voltage** mechanical attachment strength (lap shear)

Weathering Standards: IEC 62788-series (Developing Tests)

- Other industries address materials issues using coupons. "Don't need the whole car to qualify the UV durability of just the paint"

- IEC 62788-series addresses packaging materials & components. Purposes include: datasheet reporting, material acceptance, process control, R&D, and weathering.

- Encapsulants, backsheets, edge seals have most active efforts.

- IEC 62788-7-2 (UV weathering tests) referenced in IEC 61730's ed 2.

Taxonomy of the materials & component standards series.

green text = standard is published
black text = active
blue text = placeholder

62788-1	**Encapsulants (David Miller, NREL)**
-1	Overview, relationship of contained tests to 61730 and 61215, and data sheet (David Miller, NREL)
-2	Volume resistivity (Mike Kempe, NREL)
-3	Not used
-4	Optical transmittance (David Miller, NREL)
-5	Change in linear dimensions ("shrinkage", David Miller, NREL)
-6	EVA degree of cure (David Miller, NREL)
62788-2	**Backsheets (Jürgen Jung, Agfa)**
-1	Overview, relationship of contained tests to 61730 and 61215, and data sheet (Jürgen Jung, Agfa)
-2	DC breakdown voltage (Bernt-Åke Sultan, Borealis)
62788-3	**Adhesives (TBD)**
-1	Overview, relationship of contained tests to 61215 and 61730, and data sheet
-2	Rail bonding
62788-4	**Pottants (TBD)**
-1	Overview, relationship of contained tests to 61730 and 61215, and data sheet
62788-5	**Edge Seal (Mike Kempe, NREL)**
-1	Overview, relationship of contained tests to 61215 and 61730, and data sheet (Mike Kempe, NREL)
-2	Edge seal durability (Mike Kempe, NREL)
62788-6	**General Tests, Tests that apply to multiple components (TBD)**
-1	Overview, relationship of contained tests to 61730 and 61215, and data sheet
-2	Moisture permeation and water absorption (Mike Kempe, NREL)
-3	Material & component adhesion (Nick Bosco, NREL)
-4	Wet leakage
62788-7	**Environmental Stress Tests (Nancy Phillips, DuPont)**
-1	Overview, suggested application of weathering tests
-2	UV weathering (Nancy Phillips, DuPont)
-3	*Other stress tests or sequential tests: ?Damp Heat?, ?Thermal Cycling?, ?Humidity Freeze?, ?Water Spray?,... or ??*
-4	Sand abrasion

Weathering Standards: IEC 62788-7-2 (UV Weathering)

Approach

- Weather coupons using higher fidelity UV radiation than required for modules.
- Coupons allow greater cumulative dose (1000, 2000, 4000 hour durations).
- Multifactor (*UV, T, RH*) applied in steady state

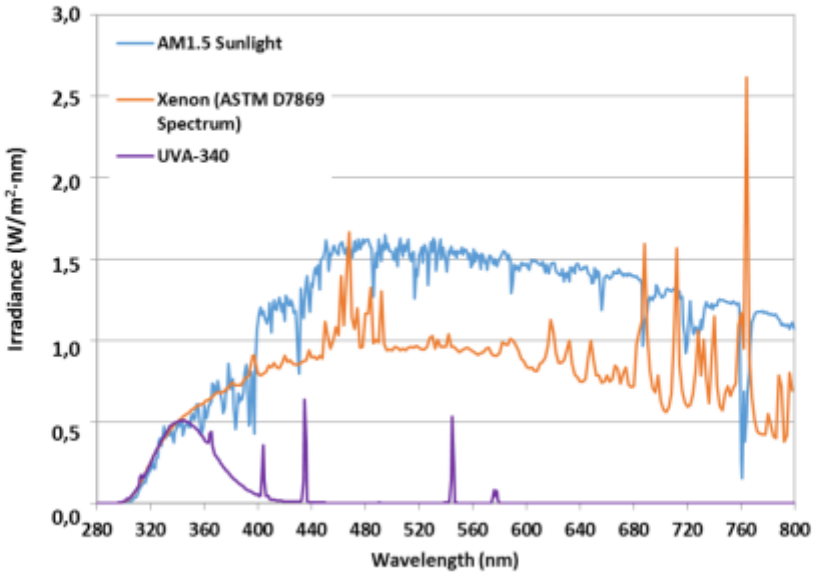
Condition #	Chamber Air Temperature (°C)	Black Panel Temperature (°C)	Irradiance (W/(m²·nm)) @ 340 nm	Relative Humidity (%)
A1	45	70	0,8	20
A2	55	80	0,8	20
A3	65	90	0,8	20
A4	75	100	0,8	20
A5	85	110	0,8	20

Proposed weathering conditions for Xe chambers.

Implementation

- Other (referencing) standards would identify:
  - -Specimen geometry.
  - -Exposure from a menu of options in 62788-7-2.
  - -Product requirements (pass/fail), if applicable.
- Xe chamber is reference method.
- UVA-340 fluorescent chamber may also be used.

Verify your results!



Comparison of terrestrial solar (AM1.5G), Xenon (daylight filter), and UVA-340 fluorescent spectra.

Sean Fowler (Q-Lab Corp.)

"Predictions are difficult, especially concerning the future."

"No generalization is worth a damn, including this one."

Weathering testing is a decision-making tool, not a time machine

- Reduces RISK
- Moves development and quality directionally toward better durability

Sean Fowler
Weathering & Corrosion Technical Director
Q-Lab Corporation

Test Categories & Uses

Accelerated Test Type	Result	Test Time	Results compared to	Research? Development? Certification?
Quality Control	Pass / fail	• Defined • Short	Material specification	Certification & Research
Qualification / validation	Pass / fail	• Defined • Medium - long	Reference material or specification	Certification & Development
Correlative	Rank-ordered data	• Open-ended • Medium	Natural weathering (Benchmark site)	Development
Predictive	Service life Acceleration factor	• Open-ended • Long	Natural weathering (Service environment)	Development & Warranty Contracts

Existing Standards – What types are they?

ISO 4892-2, ASTM G155, ASTM D2565

- Scope of 4892-2 implies it is a correlative test
  - But correlation has not been established for any particular material or benchmark weathering site
  - Default test parameters include "102/18" test which developed out of hardware designed ~100 years ago
- In ASTM terminology, these are "Standard Practices"
- Default test parameters are optional
  - IEC 62788-7-2 falls within scope and requirements

Most commonly used as ***qualification tests*** with defined duration and pass/fail criteria in a specification

Existing Standards – What types are they?

IEC 60068-2-5

- Intended to determine heat build-up of electronic components exposed to sunlight
- Not originally intended as a weathering standard
  - Although it is believed to be one by many
  - Missing important information for conducting weathering tests
  - Work in progress to make it one by referencing ISO 4892-2
- Similar to MIL-STD-810G section 505.5

Most commonly used as a ***qualification test***

Industry Examples of ***Correlative Standards***

Automotive (historical)

- Fluorescent UVB lamps 1970s-1980's
  - Good rank order correlation for coatings from that era
  - Durability of coating systems improved 10x
  - False positives of new systems resulted in early failures
- SAE J1960, 1989 (replaced by J2527 in 2003)
  - Correlated to Florida weathering
    - Color/gloss of early automotive clearcoat/ basecoat systems
  - Color and gloss durability improved 10x
  - Delamination, cracking not accurately replicated; warranty issues

Correlation broke down as material technology changed

Today these are:

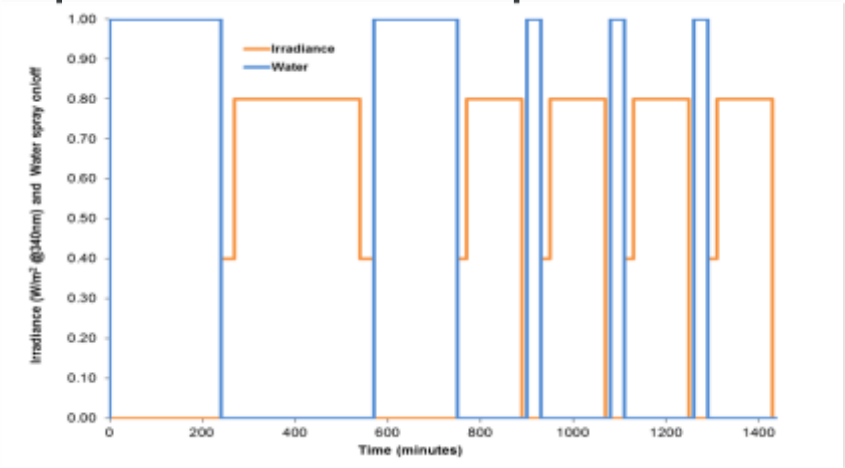
Quality Control & Qualification

Tests

Industry Examples of ***Correlative Standards***

Automotive (today)

- ASTM D7869
  - Improved spectral match of xenon arc optical filter
    - *– Leveraged in 62788-7-2*
  - Higher irradiance speeds up tests (compared to J1960/J2527)
    - *– Same irradiance used in 62788-7-2*
  - Redesigned water spray cycle replicated water uptake of coatings in Florida
  - Ford uses it for material Qualification



Industry Examples of *Correlative Standards*

"VSI Cycle" PVC Siding (building cladding material)

- Fluorescent UV test correlates to 3 year outdoor test for color retention
- Decreased temperature during UV function
- Increased condensation temperature to maximize moisture absorption

EN 927-6 Wood Coatings & Stains

- Fluorescent UV test with enhanced moisture
  - Long duration condensation for conditioning substrate
  - Frequent intermittent water spray for surface erosion
- ASTM D7869 mimics and compresses this cycle

Lessons

There is no general weathering cycle that works for everything

Most standards are either ***Quality Control*** or ***Qualification*** tests

A few standards are designed to accelerate material specific stressors and provide good correlation

- *Correlative standards must be validated before assuming correlation when applied to another application*

Future Work

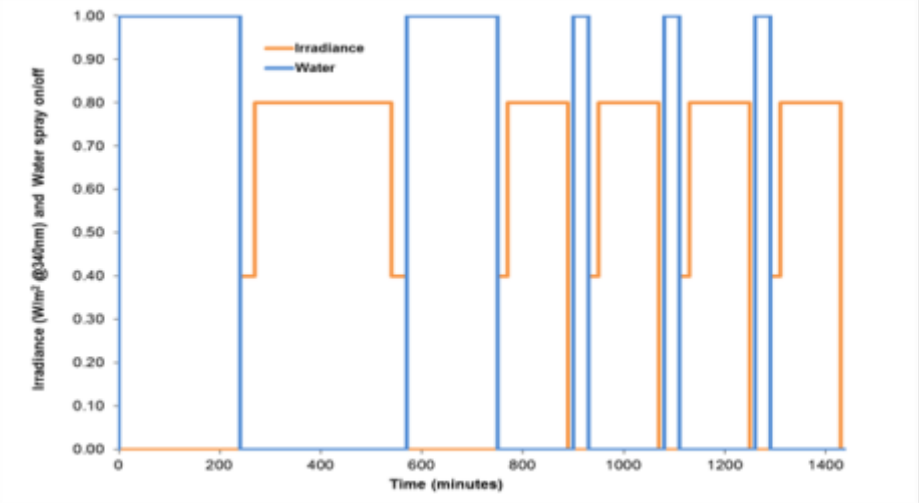
First edition of 62788-7-2 is a ***qualification*** test for materials

- Not enough outdoor data to verify correlation
- Test conditions are steady state, agreed upon as a starting point
- But it does provide key stressor missing from existing IEC standards

We can create a ***correlative*** test as a future generation ***qualification*** test by including additional stresses

- Water spray
  - Thermal cycling
  - Surface erosion
- RH Fluctuations
- Dark time
- Next edition may not have robust correlation data but it will move in that direction

Example weathering cycle



References

"Test Method Development for Outdoor Exposure and Accelerated Weathering of Vinyl Siding Specimens," Fowler & Quill, Q-Lab Technical Article LW-6039

"A Reliable Artificial Weathering Test for Wood Coatings," Podgorski, Arnold, Hora

"Understanding, Optimizing, and Measuring Water in Xenon Arc Accelerated Weathering for Automotive Exterior Coating," Nichols, Misovski, Henderson, Smith, Boisseau, Pattison, Quill, Q-Lab Technical Article LX-5032

"Accelerated Weathering Testing for the 21st Century," Fowler & Quill, Q-Lab Technical Article LX-5018

Articles available at www.q-lab.com

PVRW Audience (Everyone)

Questions from the audience?

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Discussion (Questions to the Audience)

- What *methods* or *test sequences* are not presently addressed in the PV standards that need to be considered?

Are the stress exposures, stress sequences, or property evaluation tests presented today adequate to address industry needs?

- What should be the pass/fail criteria (property and level) for the weathering tests?

What specimens (modules/coupons) should be examined?

- Are the appropriate evaluation characteristics/properties all identified and well defined with established test methods, e.g., 62788-series?
- What *materials* or *components* are not presently addressed in the PV standards that need to be considered?
- Does the equipment needed specimens (modules & coupons) exist (or common enough) that can operate at the temperatures specified in the needed standards?

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Discussion (Questions to the Audience 2)

- The correlation of laboratory stress testing with field results is reduced with shorter exposure times: can you tolerate 1000 h, 2000 h, 4000 h (6 month) duration tests or can you accept more false positive or false negative results?
- Benchmarking using natural weathering (e.g., 2-5 years in Miami & Phoenix) is -*required*- in other industries (auto, paint,…). Is that appropriate for PV? Could benchmarking results be incorporated into a "reliability report", e.g., the CSA proposal?
- What UV degradation modes are you seeing in PV installations? What are the associated dominant weathering factors (source spectrum, action spectrum, reciprocity, temperature, humidity, sample preparation)?

Show of hands: is temperature or humidity a strong factor (that needs more consideration)?

- Is more work required to identify and document the application relevant field conditions?

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Discussion (Questions to the Audience 3)

- Will UV weathering ultimately be addressed in/moved to the standards? 61730? 61215?
- Where should different climates be addressed in the standards?
- What is needed for an enhanced weathering durability protocol?

Show of hands vote to indicate demand for: safety, quality control, qualification, correlative, and/or predictive tests?

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Proposal for Testing for High Temperature Operations

John Wohlgemuth

2017 NREL PVMRW

March 1, 2017

Effects of Higher Temperatures

- Experimental evidence that modules degrade faster and fail more frequently when operated at higher temperatures – See for example reports by:
  - Dirk Jordan (NREL) and Mani (ASU)
  - Kato (AIST) showing high failure rates for rooftop systems.
- Many chemical reactions are thermally activated.
- Bosco (NREL) showed that the maximum stress caused by thermal cycling occur at the highest operating temperatures.

Limitations in today's Tests

- The standard tests for qualification and safety do not address higher operating temperatures.
- Both IEC 61215 series for module qualification and IEC 61730 series for module safety have scope limited to general open air climates generally defined as ambient temperature between -40 °C and + 40 °C.
- Each has only 1 set of test sequences at specified test conditions.
- These tests were designed for evaluating performance in open rack mounting in moderate climates.
- They were not designed for the hottest places on earth nor for mounting with limited cooling like on roof tops.

What can we do?

- There are tests within the standards that can (and should) be performed at higher temperatures if the modules are to be deployed at higher temperature.
- Standards we are looking at:
  - IEC 61215 – Module Qualification
  - IEC 61730 – Module Safety
  - IEC 62790 – Junction Boxes
  - IEC 62852 – PV Connectors

Options

- We could modify all 4 standard series.
  - This would likely take quite awhile.
  - It would probably complicate the standards themselves.
- We could prepare a Technical Specification (TS) providing guidance on how to modify the tests in all 4 documents.
  - Because it is a TS it would take less time.
  - It would not effect the present standards so today's product qualifications would not be impacted.
- WG2 decided to follow the Guidance TS route.

Status

- New NWIP prepared and circulated by IEC CO.
- Vote, comments and appointment of project team is due March 3.
- USTAG discussed on Monday at annual meeting.
- Covers IEC 61215, IEC 61730, IEC 62790 and IEC 62852
- This TS will provide guidance on:
  - How to determine the maximum operating temperatures that the module and components will experience in particular ambient conditions and mounting systems.
  - How to modify the testing specified in the reference standards in order to qualify the product (module or component) for operation at temperatures higher than specified in those standards.

What is in the document

- Who determines what temperatures to rate the product at.
- How to determine the test temperatures based on where the product is going to be used.
- What tests should be modified for higher operating temperature.

Who Decides what Temperature to Use?

- **Module manufacturer**
  - Typically they will define what temperature is selected as the Maximum PV Module Operating Temperature (T_{CON}) for the qualification and safety certifications.
  - The tests detailed in this document are then performed using the temperature selected.
  - Since they will likely want to minimize the number of tests performed, selection of a Maximum PV Module Operating Temperature (T_{CON}) is likely to be based on the highest expected operating temperatures for which their modules are designed or for which they can pass the tests.
- **Installers, integrators, system owners, etc.**
  - They need to determine what maximum operating temperature the modules they install are likely to experience in their system(s).
  - They should procure and use a module type that has been tested using a Maximum Module Operating Temperature (T_{CON}) that is at least as high as the expected maximum module operating temperature.

Finding the Maximum Module Operating Temperature

Two choices:

1. If a maximum module operating temperature is already known from field data, you may use this value directly as the maximum module operating temperature (T_{CON})
2. The maximum module operating temperature (T_{CON}) can be determined in the following manner:
   - Determine the highest ambient temperature routinely observed at the particular location you are interested in.
   - For open rack mounted PV modules, the normalized measured maximum PV module operating temperature can be assumed to be 90 °C or that measured during the temperature test (IEC 61730-2, MST 21). The difference between this new $T_{MAX\ AMB}$ and 40°C is added to either 90 °C or the temperature measured during the Temperature Test to achieve the new Maximum PV Module Operating Temperature (T_{CON})
   - For any mounting system besides open rack that has restricted air flow reducing the cooling, the Temperature Test (MST 21) shall be performed with the module mounted in the same way as it will be in the application. The procedure of MST 21 is then followed, resulting in a value for the measured module temperature (T_{OBS}) at a particular measured environmental temperature (T_{ENV}). Then use the following equation:

$$T_{CON} = T_{OBS} + (T_{MAX\ AMB} - T_{ENV})$$

High Temperature Testing Guideline

IEC 61215

- Hot Spot Test – Change 50°C to T_{CON} - 10°C
- UV Preconditioning - Change 60°C to T_{CON} - 10°C
- By-pass Diode Thermal Test - Change 75°C to T_{CONBOX} - 10°C
- Thermal Cycle Test – Change -40°C to +85°C to -40°C to T_{CON}

IEC 61730

- Same as for 61215
- Materials Creep Test – At 105°C or T_{CON} whichever is higher

High Temperature Testing Guideline

IEC 62790 for Junction Boxes

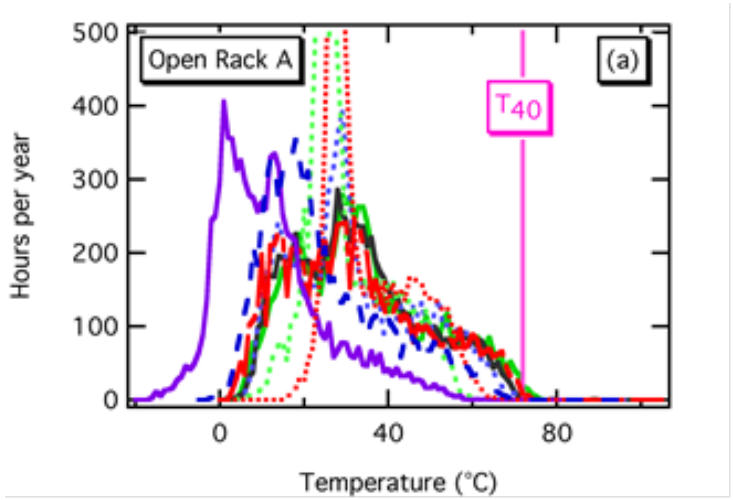
- Thermal cycling – Increase upper limit from 85°C to T_{CONBOX}
- Weather Resistance Test – Change from 65°C to T_{CONBOX} - 10°C
- Ball pressure test - Change from 90°C to T_{CONBOX}
- Resistance against ageing – Change from 90°C to T_{CONBOX}
- Bypass diode thermal test - Change 75°C to T_{CONBOX} - 10°C

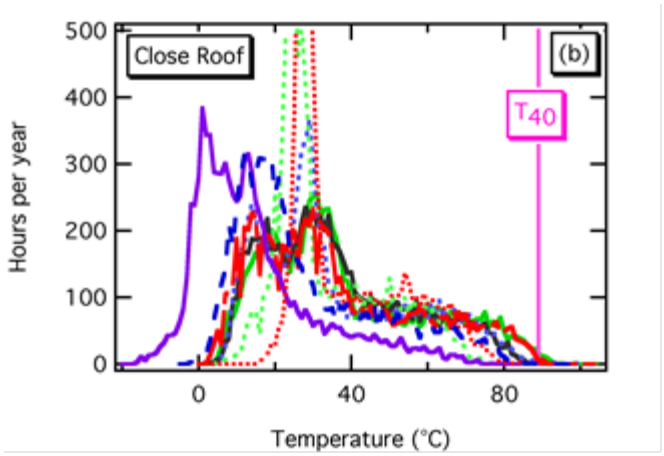
IEC 62852 for Connectors for DC-application in PV systems

- Change of temperature - Increase upper limit from 85°C to T_{CONC}
- Weather resistance the Black standard temperature shall change from 65 °C to T_{CONC} - 10 °C.
- RTE (RTI) or TI test of the PV connector materials shall be performed at T_{CONC}.

Where did -10° come from

- We are looking for temperature that the module will see for considerable time.
- Looking at module temperature graphs you see that modules spend a very small amount of time at their highest temperature.
- Dropping back 10°C results in many more hours of exposure.
- Is there a better way to do this?





Summary

- Proposal for “Guidelines for Qualifying PV Modules, Components and Materials for Operation at Higher Temperatures” has been prepared.
- First review of National committees must be completed this week.
- Now is perfect opportunity to provide feedback and input since project team will begins its work on the CD soon.

NREL/SNL/BNL PV Module Reliability Workshop

Wednesday morning discussions:

Bypass diodes: After Vivek Gade's presentation, a number of questions were raised and suggestions made:

• Many diode failures are caused by lightning – it could be useful to consider about how to improve the lightning protection

• When diodes fail shorted, they are easy to detect, but detecting them when they are open-circuited is more difficult. How can we get data to identify how common the open-circuit failure is?

• Specifically, as modules leave the factory, the diodes could be failed in an open-circuit state; this should be checked. We don't know whether the open-circuit failure mode is common.

Weathering test: The ASTM D7869 standard has been found to be useful by other industries and was referred to positively by the speakers, why was this not used in the proposed weathering for PV? ASTM D7869 starts with a steady state test, then applies a more complex cycle. The panelists cited two primary reasons: First, it would be too big of a change in one step and, second, there is not clear evidence that PV materials weather the same as auto materials or building sidings. It has happened that a test that was very helpful for one class of materials was used to qualify new materials without checking to see if the test results correlated with field results. The result was deployment of product that failed in the field. When developing the new weathering definition, the committee used as much of ASTM D7869 as would be agreed upon, but the portions that caused dissent were left out. Specifically, the ASTM D7869 specification for the Xenon source spectrum was adopted, but the complex temperature, humidity and spray weathering cycle were not.

High-temperature test:

• The proposed test measures the operating temperature of the module with the assumption that the module temperature is fairly uniform. What if there are hot spots, would you adjust all of the test temperatures to reflect that hot-spot temperature? No, the high-temperature test does not attempt to test the whole module at a temperature that reflects the hot-spot temperatures. Instead, when it's desired to test a module for higher temperature operation, the hot-spot test (which intentionally places some cells in reverse bias) is done at a higher temperature to reflect the higher ambient temperature.

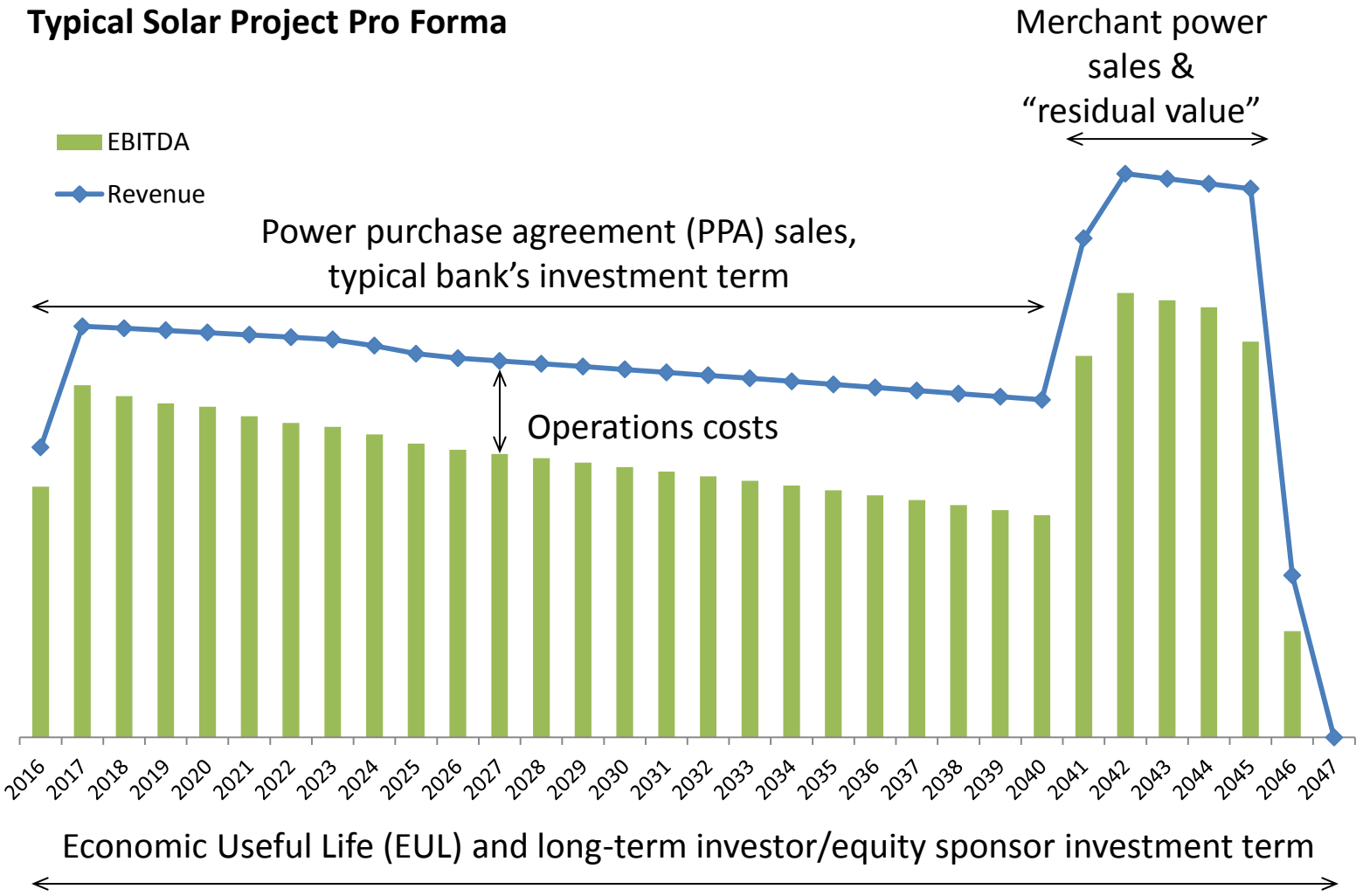
• If you'll be testing to higher temperatures, will we have customers requesting to have tests done at a dozen different temperatures? Don't we want to provide a small number of options? Maybe round to the nearest 5 degrees? There's no reason for the standard to limit it. In the beginning, we anticipate that the customer and the test lab will negotiate the temperature with the test lab charging more if the requested temperature is difficult to implement. Eventually, the community will probably select just one or two higher temperatures to use.

• Not all of the test temperatures are increased by the same amount – it's important to look at the original intent of each test and increase the test temperature to reflect that. If the values that are currently proposed can be improved upon, this is a good time to provide the committee with that input.
• With this higher temperature testing, are we throwing out STC and NOCT? No, NMOT (which now replaces NOCT) is used as a performance measurement. The high-temperature test is used to define the temperatures used in the stress tests.
• What if a module was designed to run at a lower temperature (for example, by making the backsheet thermally conductive)? If a module operates at a lower temperature, this will be determined during the temperature test and that will affect the temperatures that are selected for higher temperature testing.
• The high-temperature testing addresses hotter operating conditions; what about very cold climates? We know of problems with snow and ice causing damage, but don't know of failure mechanisms that are being caused by very low temperatures – if you see these, please bring them to the community's attention so we can design an appropriate test.

Scientific basis for using a durability protocol to gain confidence in long-term performance of modules

Jon Previtali
Wells Fargo Environmental Finance
NREL/SNL/BNL PV Reliability Workshops
February 2017

Predicting and Protecting EBITDA*: The Motivation Behind a Durability Protocol



* Earnings Before Interest, Taxes, Depreciation and Acceleration

Project evaluation criteria

Credit Risk

- PPA and REC counterparties
- O&M and asset management provider
- Technology warranty providers
- ***All revenues must be contracted***

Operational Risk

- EPC provider experience and quality
- Technology performance (modules, inverters, trackers)
- O&M provider and asset administrator
- Back-up servicing plan
- IE validated energy estimates
- Reserves, insurance, coverage ratios

Contract and Documentation Risk

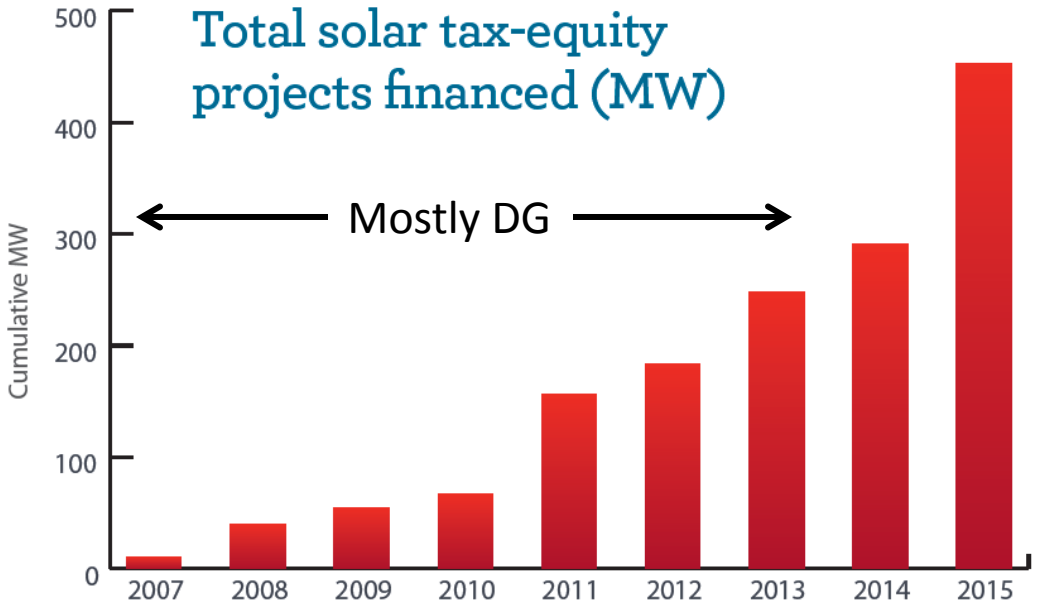
- Industry standard PPA, REC, and other project contracts
- Government, utility, electrical approvals
- Clear real estate documentation
- ***Project must benefit the host customer/ PPA off-taker***

Policy and Regulatory Risk

- Conservative tax structuring
- State incentive program diligence
- Reputational considerations
- Public policy support for solar
- Public utility regulations

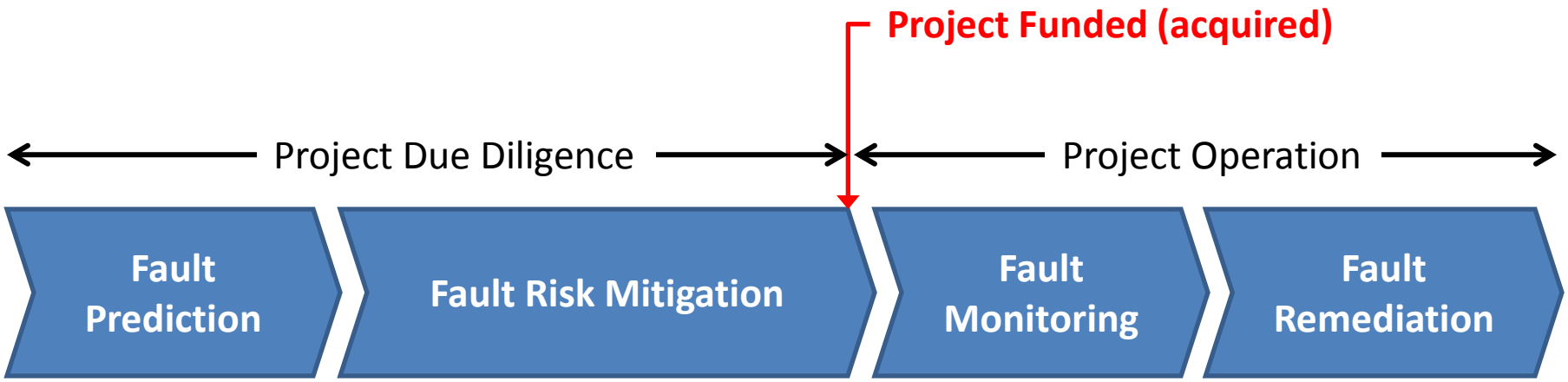
Faults Observed in Field

- Hot spots
  (some due to walking on PowerLight modules)
- PID
- Microcracks
  (due to poor packaging during shipping)
- Bypass diode failures
- J-boxes losing adhesion (BP)
- J-box lid failures and connection corrosion
- Scratched back sheets
  (due to construction handling)
- *Probably more out there*



Portfolio: 300+ DG solar projects, 15 utility scale projects

Using Reliability Testing to Mitigate Risk



- IEC 61215 testing
- Extended testing
- Factory Audits

- Fault characterization: RCA, affected population
- Module rejection & replacement
- Energy yield & price adjustment
- Warranty extension
- Monitoring/testing added to O&M contract
- Module replacement reserve accounts or Letters of Credit

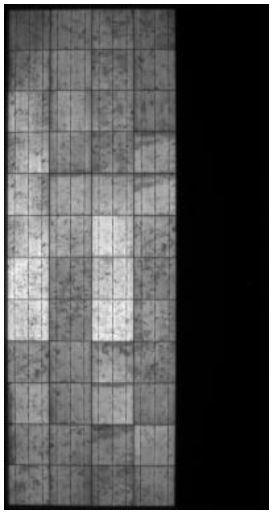
- System performance tests
- Test strings
- Aerial IR imaging
- String/module IV testing

- Warranty claims
- Module replacement
- System decommissioning
- *Looking into power optimizers*

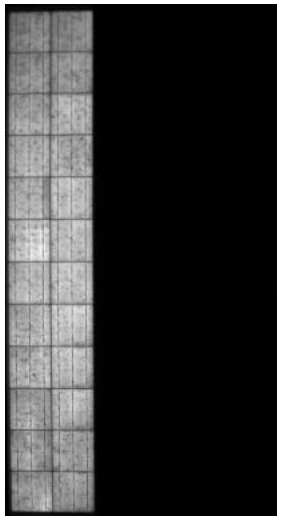
Example 1: Diode Failures

1) Fault Prediction: IEC 61215 + extended testing

Warping / deformation of junction box lid due to excessive heat from Diodes – Post TC400

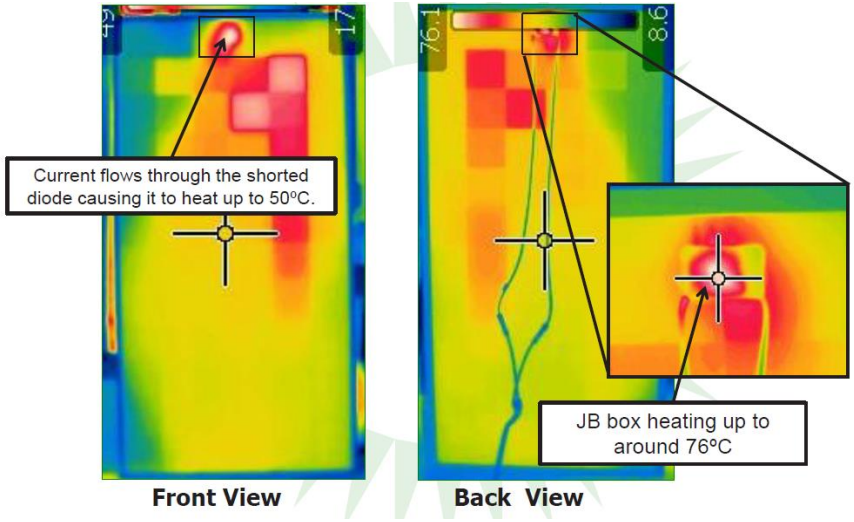


Diode failure at TC400



2-diodes fail at TC600

2) Fault Risk Mitigation: RCA, estimate of yield impact, yearly IR scans, extended warranty including serial defect protection

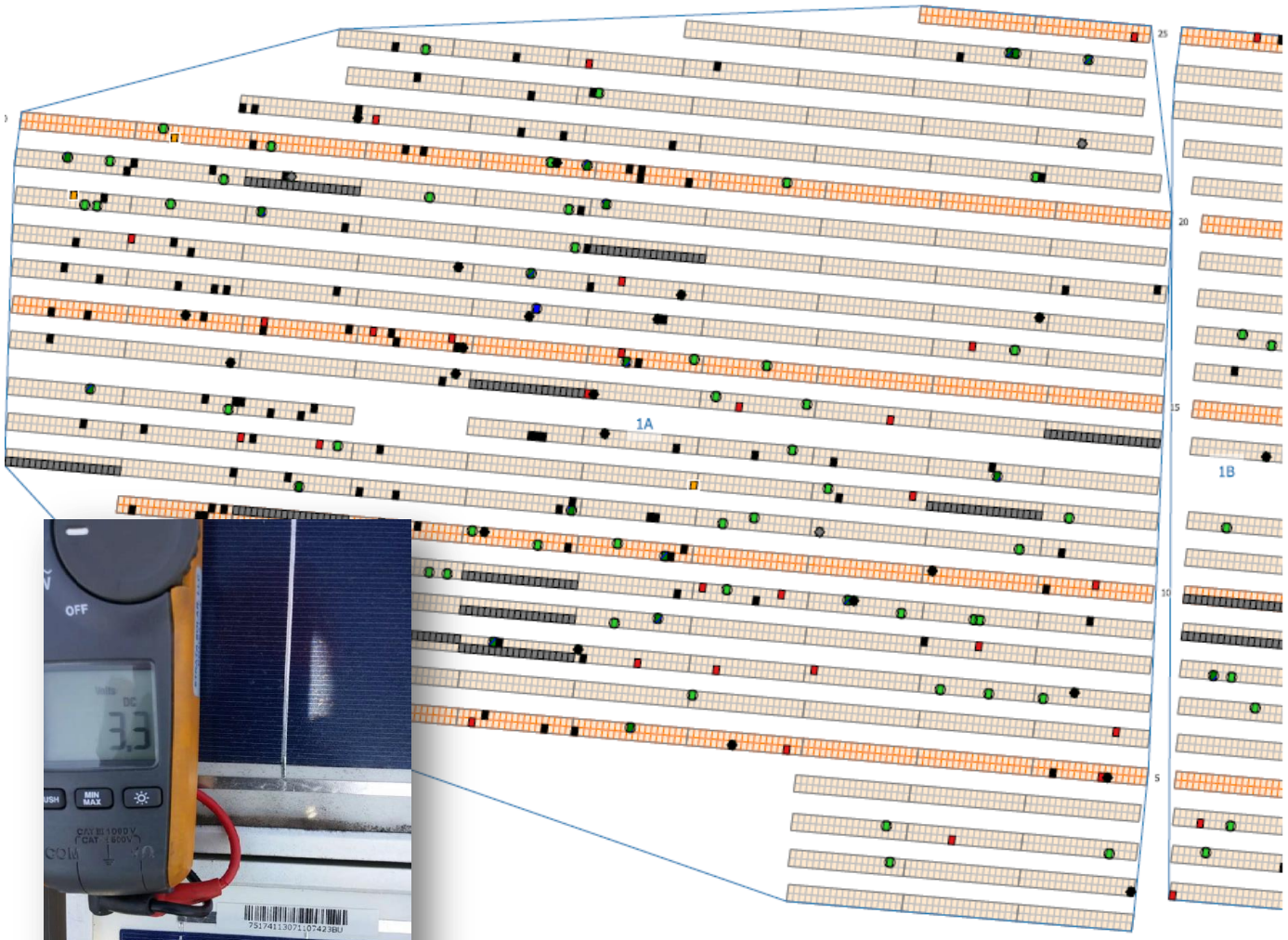


Failed diodes at lab under sun used to inform field technicians doing IR scans

Example 1: Diode Failures

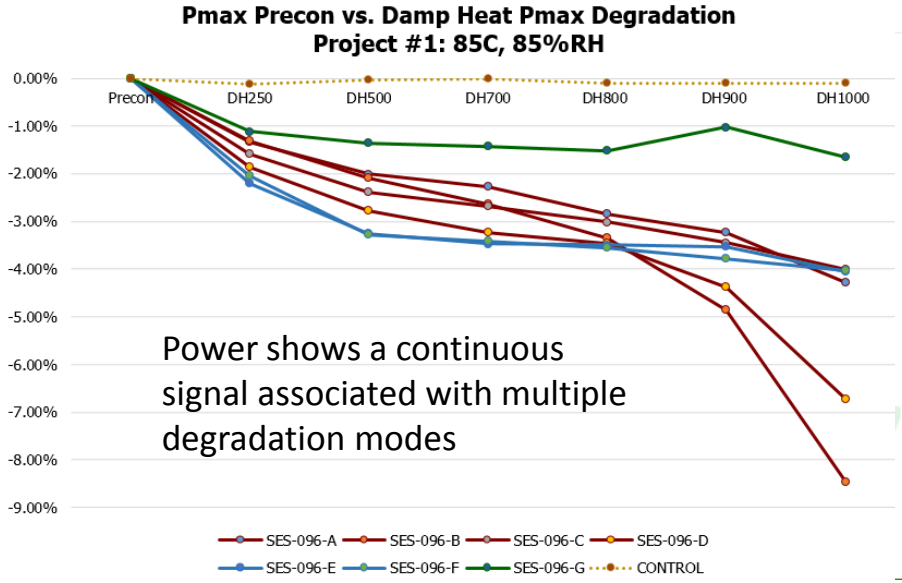
3) Fault Manifestation: 3 years in field, ID'd with IR aerial imaging, confirmed w/field IV tests

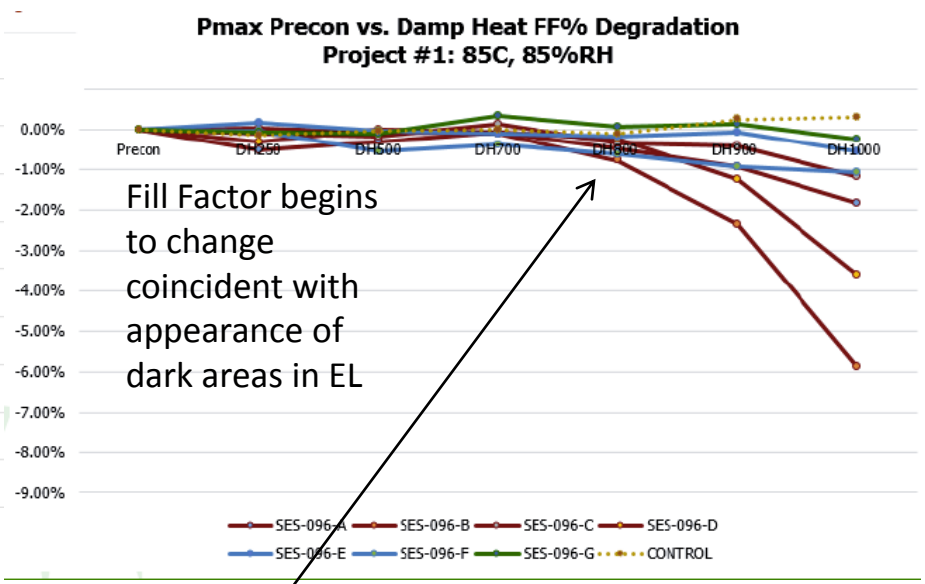
4) Fault Remediation: Serial defect warranty claim

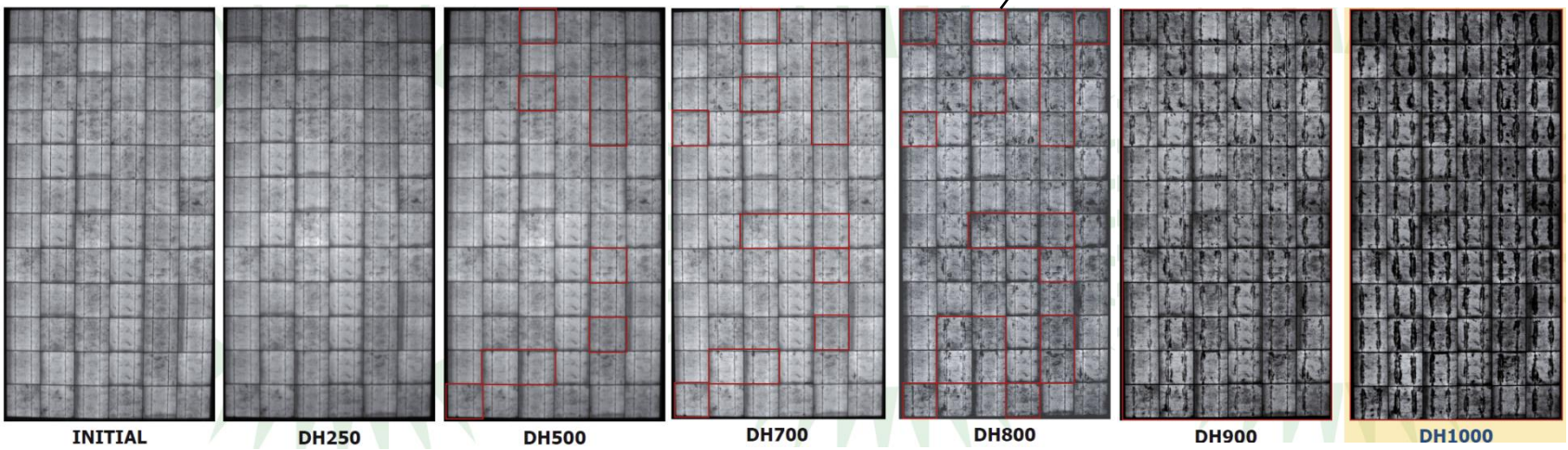


Example 2: PV Cell Corrosion

1) Fault Prediction: IEC 61215 + extended testing + degradation rate testing (as part of mitigation), EL darkening correlating with fill factor loss starting at DH800







Example 2: PV Cell Corrosion

2) Fault Risk Mitigation: RCA, estimate of yield impact via degradation rate test & location-specific modeling, extended warranty, letter of credit, periodic IV test of instrumented sub-array, periodic PR test of project, cash trapped to replace modules if high degradation rate observed.

3) Fault Manifestation: None observed after two years

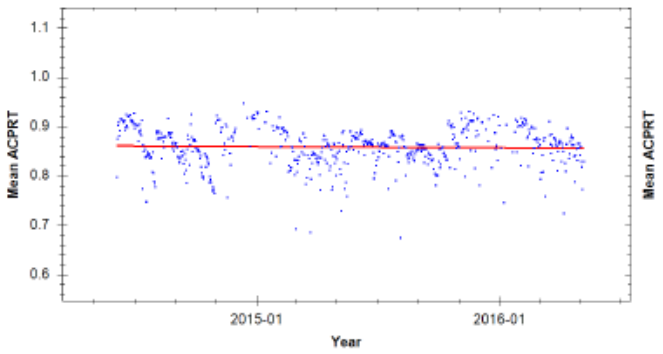
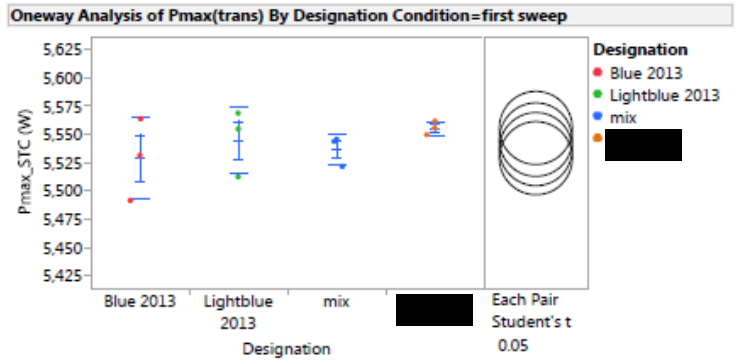


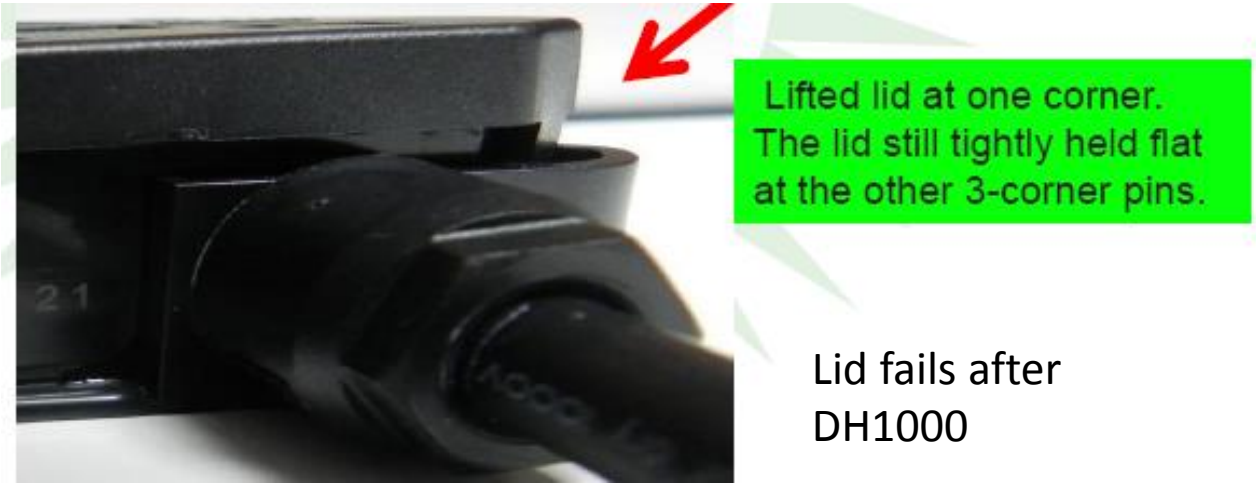
Figure 2. System performance using the ACPRT metric for the [redacted] project [redacted]. The blue points represent daily mean ACPRT values, and the red lines represent linear regression fits to the daily data.

In addition, string-level IV curves were collected to evaluate the performance of the module categories. The data were collected on 2016-03-16 using a Solmetric PVA1000 measurement tool and adjusted to standard test conditions of 1000 W/m^2 irradiance and 25 °C temperature. The performance differences between the groups were found to be less than 0.5%, confirming that accelerated degradation has not been observed.



Example 3: Junction Box Lid Failure

1) Fault Prediction: IEC 61215 + extended testing on two utility scale projects show PPE (polyphenylene ether) junction box lid failure **AFTER** many untested modules are deployed on DG projects...



Lid fails after
DH1000

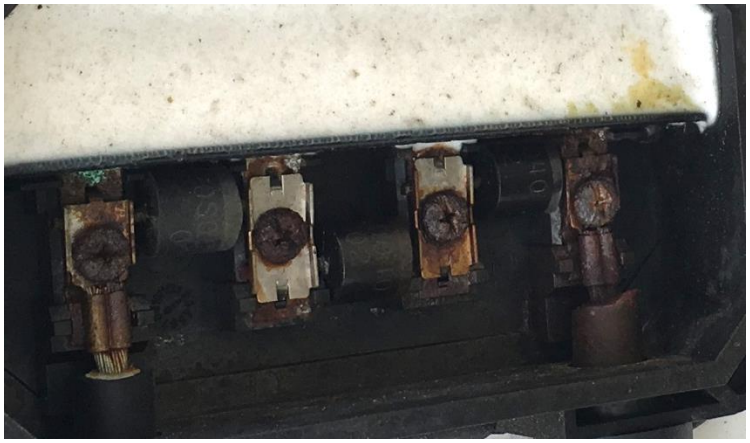
2) Fault Risk Mitigation: RCA, extended warranty, letter of credit, lid redesign, FEA, IE review, replacement, field inspections, *no reliability testing…*

- Safety Factors by measurement:

Pin Material Strength, kg	27.72
Measured old pin force, kg	17.82
Measured new pin force, kg	5.74
Safety Factor, Old Design @ 25C	1.56
Safety Factor, Old Design at 100C	1.38
Safety Factor, New design at 25C	4.83
Safety Factor, New design at 100C	3.45

Example 3: Junction Box Lid Failure

3) Fault Manifestation: Many failed lids observed in original *and* replacement lid



Corrosion probably due to loss of replacement lid.
3-year old rooftop project near CA coast.

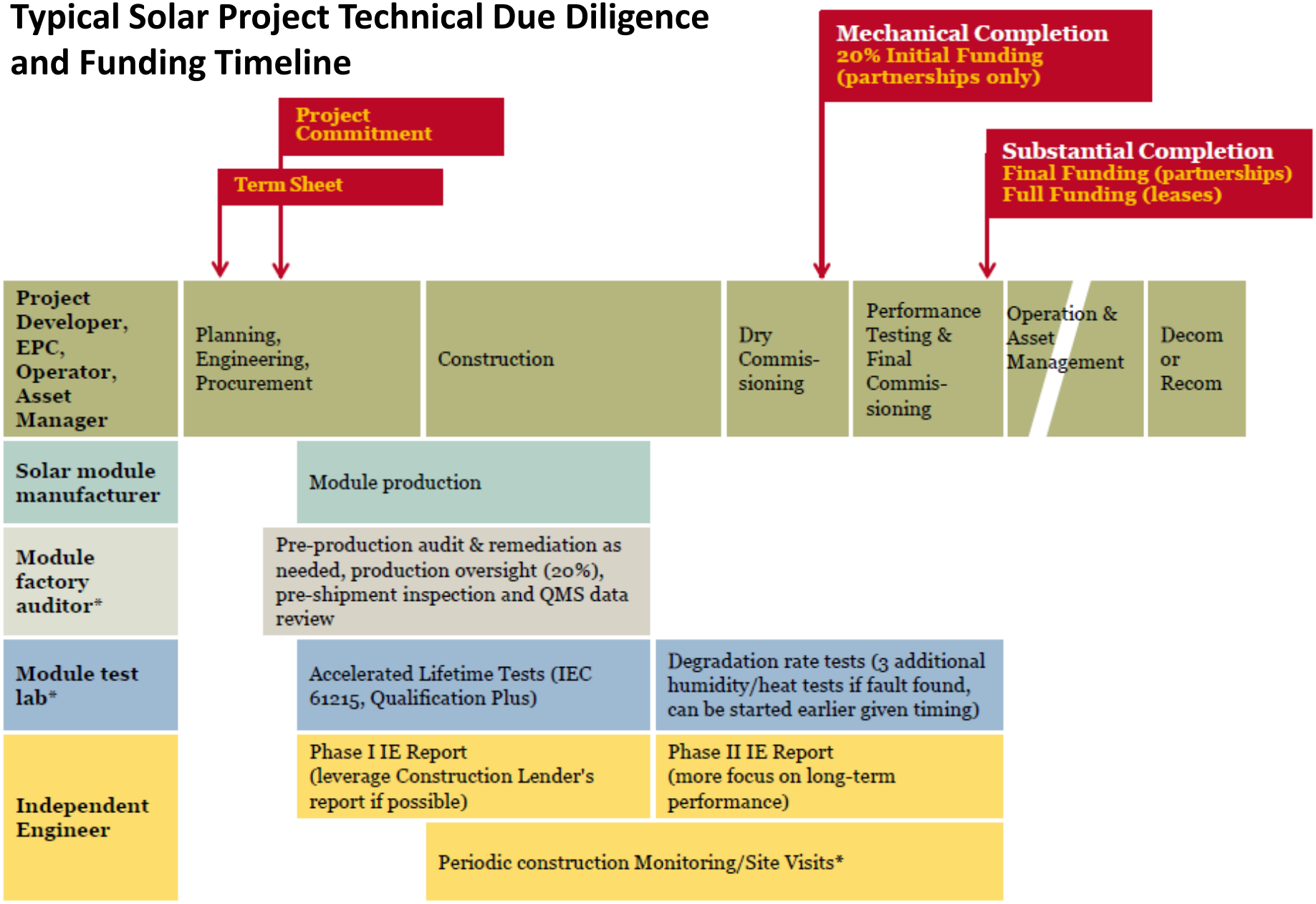
4) Fault Remediation: Lid redesign with new material, reliability testing, replacement, field inspections.

Lid Type	Stress	Amount	N	Failure Rate	
1	DH	1000	23	52%	2014 testing
2	DH	1000	145	2%	2014 testing
2	DH	2000	23	4%	2014 testing
2	HF	20/40	12	0%	RETC
2	HF	60	12	8%	RETC
2	HF	80	12	17%	RETC
2	HF	100	12	25%	RETC
2	TC / HF	50 / 20	20	10%	2014 + RETC
2	TC / HF	100 / 40	10	0%	RETC
4	DH	1000	24	0%	
4	DH	2000	22	0%	
4	HF	20/40/60/80	36	0%	
4	HF	100	10	0%	
4	TC / HF	50 / 20	34	0%	
4	TC / HF	100 / 40	30	0%	

RETC

Appendix:
Typical Solar Project and Module Technical Due Diligence Procedures

Typical Solar Project Technical Due Diligence and Funding Timeline

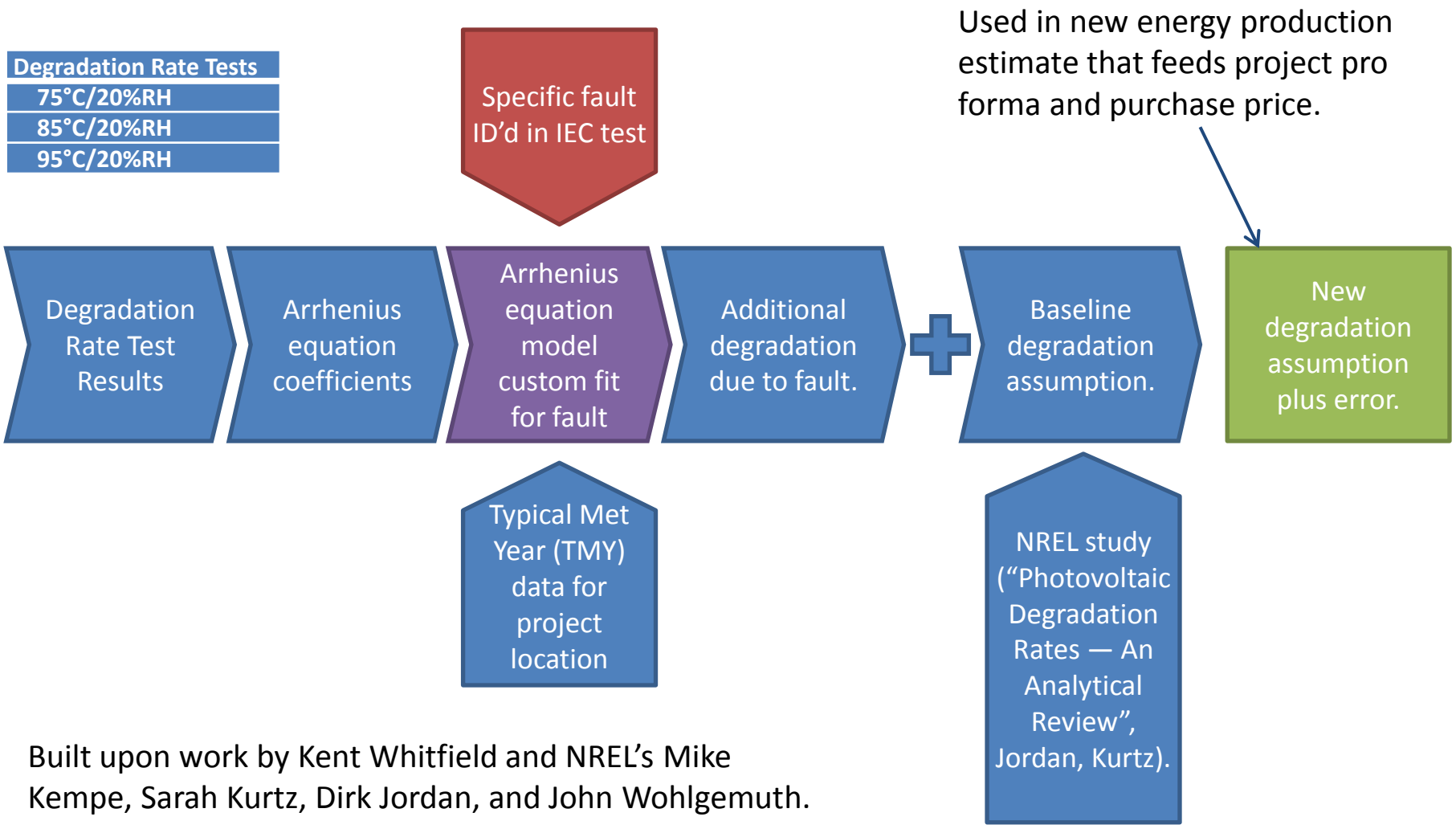


* Sampling techniques used for DG portfolios to reduce cost

Typical PV Module Reliability Testing Protocol
(IEC 61215, extended testing, degradation rate testing)

Weeks	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Days at Lab		7	14	21	28	35	42	49	56	63	70	77	84	91
Manufacturing start	x													
Air Shipment	x													
Sample prep, outdoor preconditioning		x												
Tests														
Wet Leakage Current/HiPot		x	x		x		x	x		x	x			x
Flash Test		x	x		x		x	x		x	x			x
EL		x	x		x		x	x		x	x			x
Visual Inspection		x	x		x		x	x		x	x			x
LID						x								
PAN file validation						x								
TC							200 (IEC)		300					
DH					500			1000 (IEC)		1500				
HF			10 (IEC)		20									
UV					45									
DML							x (IEC)							
PID			x (IEC)											
Bypass Diode Test		x (IEC)												
Degradation Rate Tests														
75°C/20%RH					500			1000			1500			2000
85°C/20%RH					500			1000			1500			2000
95°C/20%RH					500			1000			1500			2000
Reports		Initial Check	Interim 1	Interim 2	Interim 3	Interim 4	Interim 5	IEC		Extended	Special 1 (if needed)			Special 2 (if needed)

Degradation Rate Tests



Built upon work by Kent Whitfield and NREL's Mike Kempe, Sarah Kurtz, Dirk Jordan, and John Wohlgemuth.

Typical PV System Technical Due Diligence Scope of Work

				Ideally Pre-Construction, or Early Construction	Periodic Throughout Construction	Initial Funding (upon Mechanical Completion)	Final Funding (upon Substantial or Final Completion)	Post-Funding
DG Portfolio	Utility Scale Project	Engineering Services (if applicable)	Standard or source of publicly available procedure	Deliverable	Deliverable	Deliverable	Deliverable	Deliverable
1	1	***Project Description***		x		x		
1	1	***Module Factory Audits***						
1	1	Pre-production audit and remediation as-needed		x				
1	1	Production oversight and remediation as-needed (20% of assembly time)		x				
1	1	Pre-shipment inspection		x				
1	1	QMS (quality management system) data review		x				
1	1	***Module Reliability Testing (if needed based on audit)***						
1	1	Baseline IEC testing (95% CL, 5 samples per test leg)	61215	x				
1	1	Extended testing (95% CL, 5 samples per test leg)	Qualification Plus	x				
1	1	NREL degradation rate testing (5 samples per leg, 75C, 85C, 97C/RH 20% until sufficient data for modeling)		x				
1	1	***Equipment and Warranties Review***						
1	1	PV modules		x				
1	1	Inverters		x				
1	1	Racking, Tracker or Parking Structure		x				
1		Data Acquisition System		x				
	1	SCADA System		x				
1	1	Communication Infrastructure		x				
1	1	***Permits and Assessments Review (technical only)***						
	1	Environmental Site Assessment (ESA)		x				
	1	Environmental permit		x				
	1	ALTA Survey						
1	1	Easements						
	1	Utility Scale Interconnection agreement		x				
	1	Conditional Use permit including decommissioning requirement if any		x				
1		Building permits (confirm completion)		x				
1		DG Interconnection agreement (confirm completion)		x				
1		DG risk assessment of secondary studies or system upgrades due to PV penetration in area		x				
1	1	***Contracts Review (technical only, but including review and gap analysis of various guarantees, tests, operating requirements)***						
1	1	PPA		x				
1	1	EPC		x				
1	1	EPC schedule		x				
1	1	O&M		x				
1	1	Asset Management		x				
1	1	Monitoring Service Provider		x				
1	1	Spare Parts List					x	
1	1	Decommissioning		x				
1	1	Site Lease		x				
1	1	Others if needed		x				

Typical PV System Technical Due Diligence Scope of Work (cont'd)

1	1	***Contractors Review***						
1	1	EPC and main subs		x				
1	1	O&M and main subs		x				
1	1	Asset Management including infrastructure (ticketing, billing system, etc.)		x				
1	1	Monitoring Service Provider		x				
1	1	Others if needed		x				
1	1	***Design Review (50% sample with PE stamp review for DG)***						
	1	Geotech report		x				
	1	Civil including earthwork and drainage		x				
1	1	Electrical		x				
1	1	Structural including wind loading (for both ground and roof), structural roof integrity and post pull-out test results for ground (if needed)		x				
1	1	Mechanical		x				
	1	Architectural (for on-site buildings only)		x				
1	1	***Site Review***						
1	1	Site plan including access		x				
	1	System impact, facility or interconnection study		x				
	1	Hazardous waste on-site		x				
	1	Off-site contamination		x				
	1	Endangered species		x				
1		Roof condition		x				
	1	Land condition including flood plane		x				
1	1	***Operational Budget Review (including reserve accounts, confirm rates are "market")***						
1	1	O&M				x		
1	1	Asset Management, reconciled with Managing Partner responsibilities				x		
1	1	Monitoring Service Provider				x		
1	1	Decommissioning				x		
1	1	Others if needed				x		
1	1	***Financial Model Review (pro forma) review***				x		
1	1	Revenue including TOD if applicable						
1	1	Other sources of revenue such as PBI, SRECs.				x		
1	1	Expenses				x		
	1	Review of Curtailment Study (may be performed by third-party)				x		
1	1	***Energy Production Estimate***						
1	1	Solar Resource Assessment				x		
1	1	PAN file creation or confirmation of validation (module)				x		
1	1	OND file creation or conformation and validation (inverter)				x		
1	1	Loss estimation (curtailment, shading, soiling, snow, etc.)				x		
1	1	Load study for non-export systems and loss estimation				x		
1	1	Independent simulation including Inter-Annual Variability and P50, P75, P90, P99 for 1 and 10 years				x		
	1	***Transmission and Curtailment Report***						
	1	Historical and Forward Looking Analysis				x		
	1	Tracking account estimate (for projects settling on LMP market)				x		
1	1	***Site Inspections (on-site or remote)***						
		Small DG Photographic (desktop)/Remote Inspection				x		
	1	Utility Scale Monthly Physical/On-Site Inspection			x	x		
1	1	Physical/On-Site Inspection at Mechanical Completion (50% sample for DG)				x		
1	1	Photographic (desktop)/Remote Inspection at Final Completion				x		

Typical PV System Technical Due Diligence Scope of Work (cont'd)

1	1	***Mechanical Completion Review***						
1	1	Confirmation all major equipment has been installed per plan				x		
1	1	Commissioning tests outlined in EPC, at least including:				x		
1	1	String polarity (if not already covered in short circuit current testing)				x		
1	1	Open circuit voltage and short circuit current testing or the equivalent such as a full coverage IV curve tracer kit or module or system-level infrared imaging audit (if interconnected)				x		
1	1	Grounding continuity				x		
1	1	Megger testing				x		
1	1	***Substantial or Final Completion Review***						
1	1	Confirmation all construction is complete and equipment commissioned per plan					x	
1	1	Performance Test (at least 5 days for DG, 15 days for utility scale at sufficient solar irradiance), e.g. Energy Yield Tests, Performance Ratio Tests or Capacity Test with energy validation	ASTM E2848 (capacity test), *NREL Weather-Corrected Performance Ratio*				x	
1	1	Functional, aka Availability Test (continuous, autonomous operation, at least 5 days for DG, 15 days for US at sufficient solar irradiance)					x	
	1	Confirmation of remote SCADA system functionality at operator's facility via screen sharing with operator.					x	
	1	Confirmation of VPN connection to SCADA system at back-up operator's facility via email from investor's back-up operator					x	
1	1	Confirmation of investor's parallel monitoring feed functionality via email from investor's parallel monitoring service, Industrial Evolution.					x	
1	1	Confirmation that required Continuity of Operations Program (COP) documentation has been uploaded to investor share drive.					x	
1	1	O&M Manual Review					x	
1	1	Punch List Review to confirm no material risk to project operation or pro forma					x	
1	1	List of documents relied open for IE opinion					x	
1	1	***Review Supplemental Reports (and reference in IE reports)***					x	
1	1	Construction monitoring reports			x	x	x	
1	1	Module lab testing reports				x		
1	1	Module factory audit reports				x		
	1	Transmission/Curtailment study				x		
1	1	Insurance review				x		
1	1	Local tax review				x		
1	1	Others if needed				x		
1	1	***Reporting***						
1	1	IE Reports		x				
1	1	Supplemental IE Reports (Bring-downs)				x	x	
1	1	IE Mechanical Completion Certificate				x		
1	1	IE Substantial Completion Certificate					x	
1	1	IE Opinion Letter (sale lease-back only)					x	
1	1	Project Scorecard			x			
1	1	***Meetings and Dialogue***						
1	1	Kick-off		x				
1	1	Periodic meetings (semi-monthly or weekly if needed)			x			
1	1	Discussion and feedback			x			
1	1	***Project Administration and Management***						
1	1	Data Collection (per Project)		x	x			
1	1	Project administration (per Project)		x				
1	1	Project management (per Project)		x	x	x	x	
1	1	***Post-Funding Activity***						
1	1	Confirmation of closing punch list items						x

Thank you from Wells Fargo!

Jon Previtali
Wells Fargo Environmental Finance
415-947-1980
jonathan.m.previtali@wellsfargo.com

EXP450: PV Module Testing Protocol for Quality Assurance Programs – Update

NREL/SNL/BNL PV Reliability Workshop

Cliff Rondeau

March 1, 2017

Topics

- Introduction
- CSA EXP450 Development
- Overview of EXP450 Test Protocol
- Summary

Introduction

- PV module manufacturers currently required to perform mandatory safety and qualification testing to either ANSI/UL1703 or IEC 61730 and IEC 61215
- In lieu of an available ANSI or IEC standard, most PV module manufacturers currently use “private” protocols to perform testing above and beyond the safety and qualification testing, though internal or external 3rd party labs
  - Of particular interest to the investment community as they are looking for a degree of confidence around long-term PV module performance (20-25 years of field life)
- Many of these private protocols share similar characteristics:
  - Extended thermal/temperature cycling testing
  - Extended humidity freeze testing
  - Extended damp heat testing
  - Dynamic mechanical load testing
  - UV exposure
  - PID testing

Introduction

- While these extended protocols may not perfectly represent environmental conditions in the field, they are still found to be useful by manufacturers and investors for several reasons:
  - Provides a comparative evaluation among different manufacturers/designs, BOMs
  - Diagnose potential problems with new manufacturing equipment/facilities against known ones
  - Provides data for ongoing quality monitoring programs after validation testing
- Because of the proliferation of similar private protocols and the demands of investor due diligence, quite a bit of redundant testing is currently occurring.
  - desirable to consolidate the existing protocols into a publicly available protocol that would better serve the marketplace, eliminate redundant testing and enable data to be easily compared across manufacturers and projects.
- Over the past several years extensive research has been done by NREL's PVQAT and IEC TC82 that can inform the design of such a protocol
  - desirable to incorporate this work with a mechanism to update as new developments in the field occur.

EXP450 - Scope

- EXP450 – a protocol outlining PV Module Accelerated Testing
  - Intended user groups: banks, developers, manufacturers and test labs as a publicly available document reflecting industry best practices
- Stand-alone document that is not intended to interact with other safety or qualification standards.
  - maybe some duplicative testing; however, market practices as they currently exist may require independent long-term testing and due diligence by parties not associated with the safety and qualification testing.
- The individual test legs in the EXP450 protocol are intended to use, and build upon as necessary, existing bodies of work in this area.
  - IEC and NREL PVQAT are referred to by reference in EXP450
- EXP450 has a Development Committee convened by CSA to advise on the content of the document and the design of the protocol

EXP450 Development Committee

Name	Company
Laura Bruckman	Case Western Reserve University
Daniel Chang	Jinko Solar
Jim Crimmins	CFV Solar Test Laboratory
Frederic Dross	DNV GL
Ze Guo	CSA Group
Oni Hoque	Silfab
JN Jaubert	Canadian Solar
Sarah Kurtz	NREL
Olga Lavrova	Sandia
Kyumin Lee	CFV Solar Test Laboratory
Ganesh Mani	EDF Renewables
David Meakin	SunPower
Larry Pratt	CFV Solar Test Laboratory
Jon Previtali	Wells Fargo
Ingrid Repins	NREL
Mark Rossetto	MegaCell
Muktha Tumkur	CSA Group
Jim Sorensen	First Solar
John Watts	DNV GL
John Wohlgemuth	NREL
Wenda Zeng	Canadian Solar
Ryan Zwilling	J.P. Morgan

EXP450 - Protocol

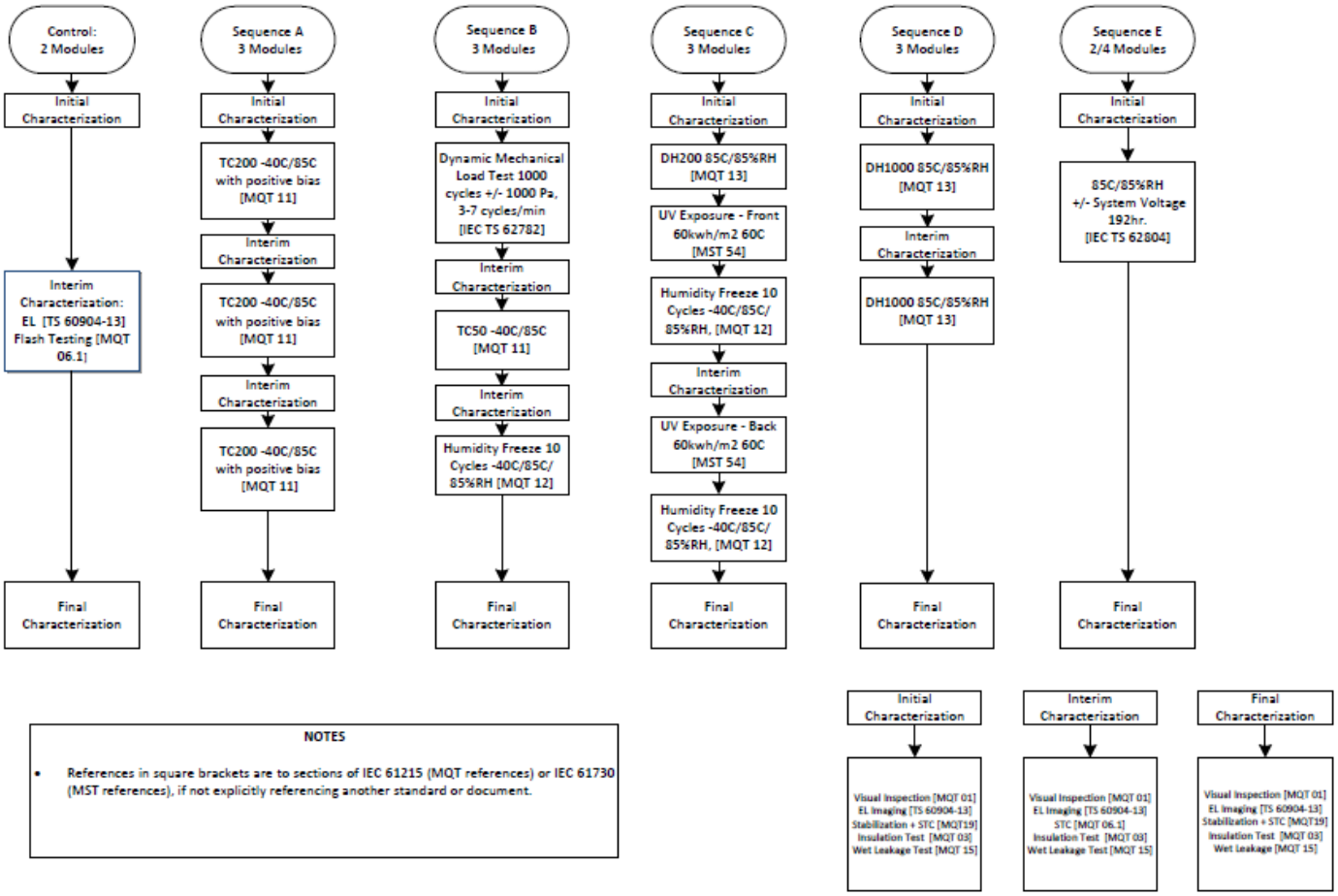
- The EXP450 protocol has been developed by soliciting input from the EXP450 Development Committee members about industry best practices for accelerated PV module testing.
- Work done by NREL and PVQAT including Qualification Plus and Climate Specific Test Protocols have informed much of the protocol development.
- The EXP450 test legs are designed to reproduce failures that have been seen in the field, or potentially could be seen in the field.
  - Test leg durations have been carefully considered to avoid equivalent exposure longer than might be reasonably expected in actual deployment scenarios.
- EXP450 is intended to be used across PV module technology types.
- EXP450 is a portfolio of tests derived from existing IEC and NREL publications and standards.
  - It is designed so that as new test and standards are developed, validated and published they may be adopted into the protocol by reference if approved by the Development Committee. [e.g: rapid TC, ...]

EXP450 – Development Timeline

Milestone	Date
Content development	March 2016 – February 2017
Public review (30 day)	February – March 2017
Comment disposition	March - April 2017
Editing, quality review & final production	May – June 2017
Publication	June 2017

- After publication of the CSA EXP450 Express Document potential future pathways include:
  - 2nd edition of EXP450
  - Bi-national standard for Canada/US
  - IEC PAS or TS development
- It is hoped that discussions may be had at the 2017 NREL PV Module Reliability Workshop with TC82 members around these topics.

EXP450 - Protocol Flow Chart – v3.5



NOTES

- References in square brackets are to sections of IEC 61215 (MQT references) or IEC 61730 (MST references), if not explicitly referencing another standard or document.

Accelerated Tests For PV

Accelerated Stress Test	Failure Mode	Technology
Thermal Cycles	Broken interconnect	Cry-Si & CPV
	Broken cells	Cry-Si & CPV
	Electrical bond failure	All
	Junction box adhesion	All
	Module open circuit – potential for arcing	All
Damp Heat	Corrosion	All
	Delamination	All
	Encapsulant loss of adhesion & elasticity	All
	Junction box adhesion	All
	Electrochemical corrosion of TCO	TF
	Inadequate edge deletion	TF
	Potential Induced Degradation	Cry-Si & TF
Humidity Freeze	Delamination	All
	Junction box adhesion	All
	Inadequate edge deletion	TF
	Insufficiently cured encapsulant	All

"Accelerated Stress Testing, Qualification Testing, HAST, Field Experience – what do they all mean?" – John Wohlgemuth, NREL, 2013. http://www.nrel.gov/docs/fy13osti/58371.pdf

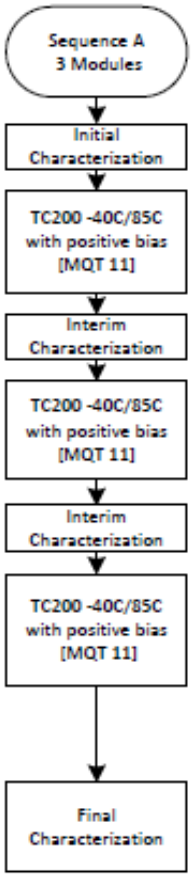
Accelerated Tests For PV

Accelerated Stress Test	Failure Mode	Technology
UV Test	Delamination	All
	Encapsulant loss of adhesion & elasticity	All
	Encapsulant & backsheet discoloration	Cry-Si, some CPV & TF
	Ground fault due to backsheet degradation	Cry-Si & TF
	Degradation of Optics	CPV
Static Mechanical Load (Simulation of wind and snow load)	Structural failures	All
	Broken glass	Cry-Si & TF
	Broken interconnect ribbons	All
	Broken Cells	Cry-Si & CPV
	Electrical bond failures	All
Dynamic Mechanical Load	Broken glass	Cry-Si & TF
	Broken interconnect ribbons	All
	Broken Cells	Cry-Si & CPV
	Electrical bond failures	All

"Accelerated Stress Testing, Qualification Testing, HAST, Field Experience – what do they all mean?" – John Wohlgemuth, NREL, 2013. http://www.nrel.gov/docs/fy13osti/58371.pdf

Thermal Cycling Leg Notes

- The EXP450 Development Committee has recommended an increase in the number of temperature cycles from TC500 (Qualification Plus) to TC600
- At 8 cycles per day, TC600 represents about 3 months of testing time



"Failures of solder bonds and ribbons in the module laminate have dominated the failure Pareto charts in a number of studies. While it is possible that the 0.1%–3% failure rates reported by Degraaff [26] could be infant mortality associated with poor quality control, the high failure rates of this sort reported by Kato [27,28] imply that an improvement in the initial design would be beneficial. Fatigue associated with the mechanical strains encountered during thermal cycling in the field is known to accumulate in a predictable manner. There is some evidence that the 200 cycles required by IEC 61215 corresponds to about 10 years in the field. [31] The increase to 500 cycles was chosen with the intent of aligning the test more closely with product warranties. Many of today's modules can survive far more than 500 thermal cycles, but application of 400 to 800 has sometimes been reported to cause additional failures. [39] Thermal cycling is recommended as one of the longest test times because of the frequency with which this type of failure is still observed in the field."

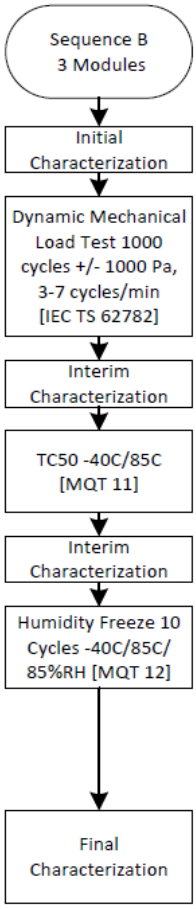
-- Photovoltaic Module Qualification Plus Testing, NREL, December 2013

Dynamic Mechanical Leg Notes

- DMLT1000/TC50/HF10 (Qualification Plus)
- This leg references the Cyclic (dynamic) mechanical load testing from the now-published document IEC TS 62782

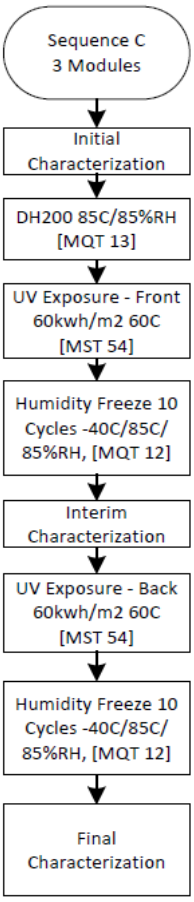
"A reduction in the thickness of silicon solar cells has helped to lower module costs. However, the thinner cells are more prone to fracture, especially during events of extreme mechanical loading. [40-43] Initially, these cracks may not be obvious and may have no effect on performance of the module, but after subsequent thermal cycling, the weakened structure may be more susceptible to failures of metal interconnections between the pieces of silicon. Three studies [40-42] have each shown the value of first applying a mechanical load and then subsequent thermal cycling. The number of cycles and the applied load could be varied, but were chosen to align with the draft standard currently being considered by the IEC. The rate of cycling specified for the test has a very wide spread, reflecting an insensitivity of the test to this parameter because the test is inducing cracks in the silicon and/or in the ribbon interconnections (which are insensitive to dwell time). This test does not attempt to address the creep that occurs in solder bonds during thermal cycling, which are dependent on the cycling frequency."

-- Photovoltaic Module Qualification Plus Testing, NREL, December 2013



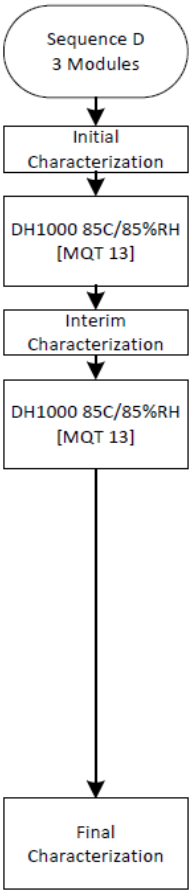
UV60 and Humidity Freeze Leg Notes

- This leg is designed to identify relatively short term failures from UV exposure on both the front and the back side of the module.
- Each side of the module receives a UV dose of 60kwh/m2 and then sequences through HF10. 60 kwh/m2 of UV dose is approximately equivalent to 6 months of field exposure.
- This test leg is identical to Sequence B in IEC 61730-2: 2016. However EXP450 has (3) samples instead of (1) sample in IEC 61730-2: 2016.



Damp Heat Exposure Leg Notes

- DH2000. Most recent research indicates that 2000 hours of damp heat exposure is sufficient for all but the most extreme tropical environments (2x IEC 61215)

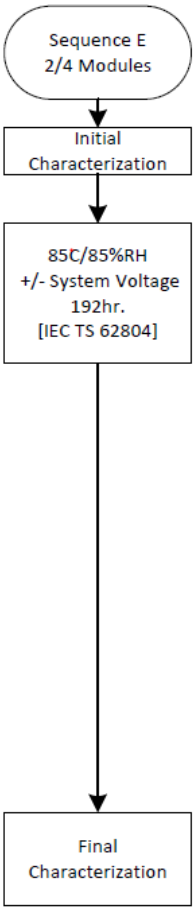


Potential Induced Degradation Leg Notes

- This leg references the published IEC document IEC TS 62804-1 (also Qualification Plus)
- Although manufacturers have made progress in solving this problem, this test is still need

"Although Table 3 does not reflect failures caused by the effects of system voltage, recent data [45] have shown that this mechanism can cause degradation of large systems by tens of percent in a single year. SunPower reported power loss caused by polarization when their modules were operated with a negative ground. [33] They found that the problem could be addressed by grounding the positive end of the system or by redesigning the module. In conventional silicon PV modules, the problem appears in the reverse polarity and is frequently associated with sodium migration from glass. With the introduction of inverters that allow a portion of the system to operate at negative bias with respect to ground, this degradation has become more common. It is easy to reproduce in the laboratory or in individual modules biased as though in a system outdoors. [34,45,46] In general, the problem can be solved for conventional modules by adjusting the chemistry of the silicon nitride layer on the cells, by using a high-resistance encapsulant, or by adjusting the system voltage so that sodium ions present in the glass move away from the cells."

– Photovoltaic Module Qualification Plus Testing, NREL, December 2013



Summary

EXP450 is a document that:

- Intended to provide a level of confidence in the marketplace around the long-term performance of PV modules (fills gap)
- Builds on existing bodies of work (NREL & IEC)
- Flexibility in a publically available protocol to meet the demands of an “evolving” industry

Thank you

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High Sun Irradiance Testing for Understanding Material Life Time Expectation of PV Modules

KYUNG SOO KIM (kskim@kier.er.kr)

Purpose of Experiment

► Many IEC standards are being producing through several years from basic material test to whole product of PV module. Through these, manufacturers can expect their products' expected quality within short time with official test method.

► In a certain point of view, customer would want have real data, mainly maximum producing power, for their purchased PV product that has been exposed to real environment conditions like wind, rain, sun and so on.

► It is known that average maximum power drop is between -0.5% and -1% at moderate condition, yearly.

► Monthly, many newly developed materials for PV modules are adapted and tested based on extended IEC standards. But they are mainly based on temperature and humidity parameters. Still it is greatly needed to use artificial light test method to check PV module's life time and material degradation characteristics and to develop high sun irradiance test

Test Method & Measurement Equipment

Idea & Measurement

► 2cells x 2cells c-silicon PV modules have been connected to electric loader for power consumption under light illumination. And maximum power of module was measured within certain period up to 6000kWh/m^2 at 1 sun intensity. The maximum power changes and EL images characteristics were checked.

► Also using high irradiance condition of 2 sun and 5 sun intensity, we compared its effects with 1 sun test method.

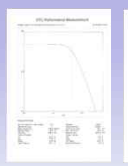
Results & Analysis

Equipment and Test Condition

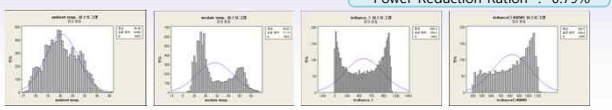
1. 1 to 2 Sun Test Chamber with Temperature Controllable
2. 5 Sun Test Chamber with Temperature Controllable
3. Electric Load
4. I-V Curve Tracer
5. EL Camera
6. Solar Simulator
7. Weather Data for 1 year

1 Sun Level of Intensity Test Results

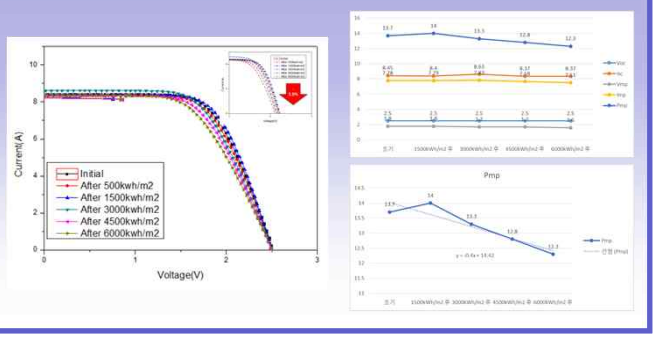
	May	June	July	August	September
Maximum Air Temperature [℃]	48.2	48.7	47.9	47.2	44.3
Minimum Air Temperature [℃]	27.1	29.8	29.5	25.8	24.0
Maximum Module Temperature [℃]	68.5	69.1	66.8	66.3	67.9
Minimum Air Temperature [℃]	24.0	27.1	28.6	26.2	24.3
Highest Irradiance [W/m^2]	1147.8	1073.9	1102.5	1238	1164.7
Daily accumulation Irradiance [kWh/m^2]	7.61	7.05	6.51	7.15	6.76



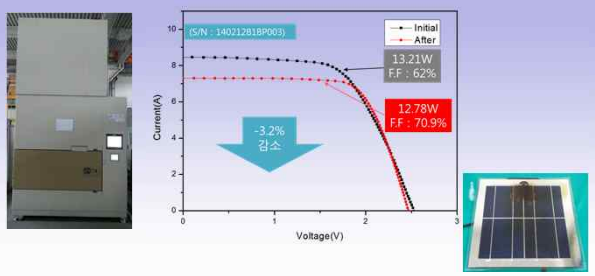
Test Period : 4 Months
Power Reduction Ration : -0.79%



2 Sun Level of Intensity Test Results



5 Sun Level of Intensity Test Results @1440kWh/m2



Conclusion

❖ **Results**

- √ In this study, we conducted high sun level of test to c-solar module from 1Sun to 5Sun intensity level and compared the results.
- √ Considering and adapting real environmental data, 1 Sun test method was proposed and conducted in test chamber.
- √ 2 Sun (2 kWh/m^2) intensity level of test is quite adequate test method for pre-calculating long-term maximum power behavior .
- √ 5 Sun intensity level of test shows the weakness point of material in PV module. We will propose this result as NP in IEC.
- √ This results are under paper working now. So it is not open to publicized until paper published. Only PV-QAT workshop, please!

Presented at the PV Reliability Workshops 2017
28 February - 2 March 2017, SHERATON DENVER WEST HOTEL, Lakewood, Colorado

Overview of PV Project Design Qualification Certificate of IECRE OD-403

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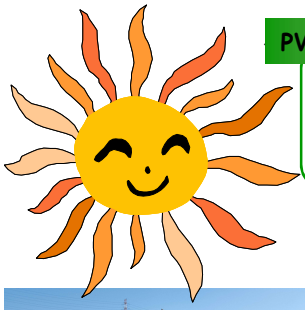
Summary

IECRE PV-OMC is actively working on publishing operational documents. Assessment of a PV system requires oversight of the design and manufacture of the components as well as the design, installation, and operation of the system. So far, PV-OMC has been published OD-401 and OD-402. At the time of commissioning, the plant is confirmed to have been constructed to the original design resulting in a Conditional PV Project Certificate, as described in OD-401. The Annual PV Project Certificate builds on the Conditional PV Project Certificate and is based on a full year of operation so as to quantify the observed performance of the system and document conformance to accepted maintenance procedures as described in OD-402.
In this paper, PV project design issues such as, PV array foundation, PV array support structure, PV array/system performance design, installation and drawing are discussed. Finally, the author introduces the draft of PV Project Design Qualification Certificate.

Input Energy	Feasibility Analysis	Design	Construction	Operation	Maintenance	Remodeling	Recycling/ Disposal
(Meteorological conditions, Irradiation model)	(Site conditions, Power output, Financing)	(Components, Sub-system design)	(Foundation, Assembly, Wiring and Test)	(Commissioning, Performance, Monitoring system)	(Electrical equipment, Failure response)	(System components, Structure repair)	(PV module, inverter, Site)

PV SYSTEM LIFE CYCLE (Over 30 years)

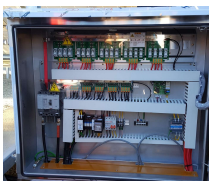


PV array foundation design review

- PV array foundation design
  - Shallow foundation, combined footing
- PV array foundation weight/size and strength calculation sheet
  - Based on soil conditions; compaction/penetration/resistivity/PH/corrosivity/soil moisture

PV array support structure design review

- Support structure configurations
  - Fixed tilt, Adjustable tilt, single-axis tracking, two-axis tracking
- Strength calculation sheet
  - Environmental conditions; wind/snow/thermal expansion/flooding/seismic activity/corrosion
- Material design sheet
  - Steel, SUS, aluminum alloy, Timber
- Legs/foundation fixing bolt size calculation sheet



PV array/system performance design review

- PV module/inverter/components selection sheet
  - Module/inverter/components specification and design sheet
- PV array/system output power calculation sheet
- PV array/system loss calculation sheet

PV array/system installation review

- PV array d.c./a.c. cable length estimation and cable size selection table
- PV array foundation weight/size and strength calculation sheet

PV array/system drawing review

- PV array/system layout configuration drawing
  - array/combiner box/inverter/transformer/switchgear
- PV array/system part lists evaluation
- PV array/system d.c. and a.c. line diagram drawing
- System control configuration/sequence drawing

References

- IEC/TS 62738
  - Section 5.3 Array electrical diagrams
  - Section 5.5 Array physical configurations
  - Section 5.6 Mechanical design
  - Section 7.2 PV array design voltage
  - Section 7.3 Component requirements
  - Section 7.3.4 Cables
  - Section 10. Marking and documentation
- IEC 62548
  - Selection and erection of electrical equipment
  - Section 7.3.4 Cables
  - Section 10. Marking and documentation
- IEC 61724-1
  - Section 9. Calculated parameters

Conclusions

- PV project design should consider civil, mechanical, structural and electrical engineering concepts
- This paper presents the contents of the draft of OD-403
- OD-403 is currently under development with related experts

KPU KOREA POLYTECHNIC UNIVERSITY

Impact of Degradation Rates on Solar PV Project Financials

Rounak A. Kharait, Alex Schneider, Phil Stiles, and Larry McClung | Leidos, Denver, Colorado, 80202, U.S.

Introduction

Impact of degradation rates on long-term solar PV project performance is unknown. For financing purposes, lenders and developers alike select a value of degradation rate based on literature, input from independent engineers, or warranty rates provided by the module manufacturer. Quantifying the impact of different degradation rates on project performance will better inform project finance decisions.

However, determining the precise value of degradation and its trends over the lifetime of a PV project is difficult.

- > Actual useful life data for the latest state-of-the-art technology modules are unavailable.
- > Field measurement is difficult due to low signal-to-noise ratio.
- > The variation of degradation[1] is commonly assumed to be linear, but exponential (and other) variation is an area of ongoing study.
- > Degradation is widely believed to be dominated by a statistical distribution of small “failures” (e.g. hot spots, solder failures) rather than gradual, uniform degradation (e.g. EVA discoloring), making it more difficult to project lab results into field performance.

There are various metrics for quantifying the value of a PV project.

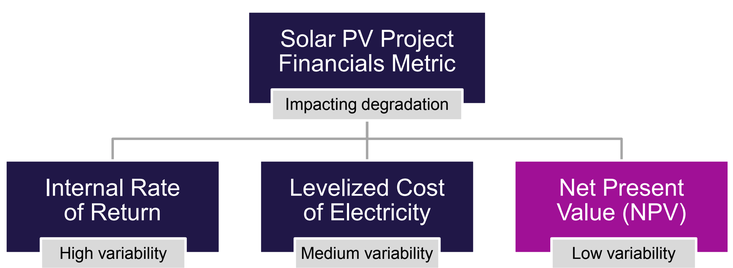


Figure 1. Metrics defining solar PV project financial value

In order to isolate the variability of project cost, tax, and power purchase price factors, NPV was selected as the metric to study impact of degradation rates on PV project financials.

Methods

There are various factors and steps needed to determine NPV:

- > P50 energy estimates to determine project revenues – modeled in PVsyst
- > Degradation rates over 25 years – determined by literature study[1],[2]

Modeling of utility-scale PV project (PVsyst)
- Size: 100 MW-AC
- Location : Mojave, California
- Power purchase price of $55/MWh
- Soiling losses, wiring losses remain constant
- Project life is assumed to be 25 years.

Develop energy estimates for project

Studied modeling configuration variations
- Module type: crystalline and thin-film modules
- Mounting structure type: fixed-tilt and single-axis tracking

Determine range of configurations

Performance impact/sensitivity analysis
- Effect of modeling configurations (crystalline vs thin-film, fixed vs single-axis tracking)
- Effect of DC to AC ratios (low [1.25] to high [1.4])
- Effect of degradation (low [0.5%] to high [1.0%] per year)
- Effect of discount rate (low [2%] to high [3%])

Calculate NPV for selected configurations

Results

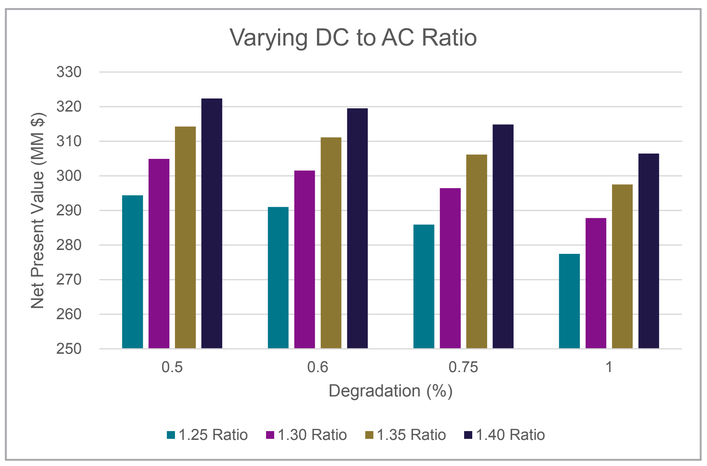


Figure 2. Variation of NPV with degradation with varying DC to AC ratios

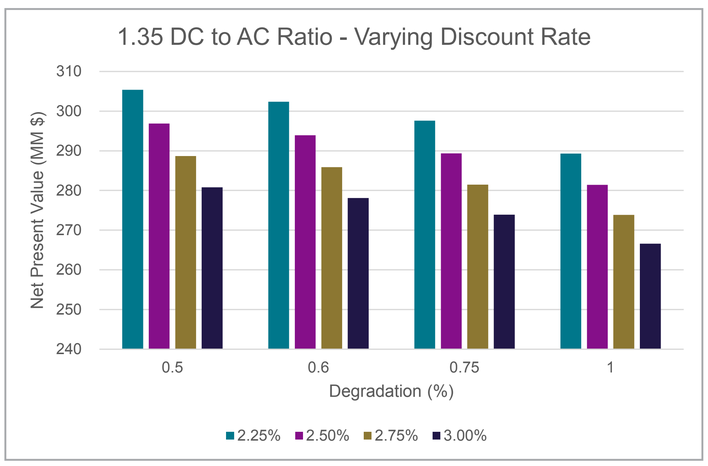


Figure 3. Variation of NPV with degradation with varying discount rates

Sensitivity Analysis

Varying DC to AC Ratio
- For these fixed-tilt designs, the $NPV_{Thin\text{-}film}$ >1.1% $NPV_{Crystalline}$
- For these single-axis tracking designs, the $NPV_{Thin\text{-}film}$ < 0.8% $NPV_{Crystalline}$
- *The difference is due to the lower ground cover ratio for designs with thin-film modules vs. crystalline modules. Different module size and configuration resulted in higher annual plane of array with crystalline modules.*

Varying Discount Rates
- The variation of NPV is inversely proportional to degradation for varying discount rates

Varying Degradation Rate
- $NPV_{0.5\%\ Degradation}$ > 5.8% $NPV_{1.0\%\ Degradation}$

Conclusion and Future Work

- > Selection of actual (single) value degradation rate is not straightforward.
- > Studies have revealed a non-normal distribution of degradation rates for PV modules, with the median degradation rate for crystalline silicon technologies within 0.5-0.6 percent per year range while the mean was in the 0.8-0.9 percent per year range[1],[2]. (A non-normal distribution is expected, as the degradation is effectively bounded by 0 percent on one side.)
- > Failure modes and rates effect the variation and absolute value of degradation rates for the PV modules.
- > Monte Carlo simulation to arrive at a probability distribution of degradation rates would allow stakeholders to make well-informed decisions for a PV project.
- > In future work, we plan to utilize this probability distribution of degradation rates for various locations in the U.S. to comment on additional variables affecting the financial viability of the PV project.
- > Detailed analysis of operating plant data to measure degradation rates averaged over a large plant.

(1) D.C. Jordan, T.J. Silverman, B. Sekulic and S. Kurtz, PV degradation curves: non-linearity and failure modes, *Progress in Photovoltaics: Re.* Appl. 2016:
(2) D.C. Jordan, S.R. Kurtz, K. VanSant, J. Newmiller, Compendium of photovoltaic degradation rates, *Progress in Photovoltaics: Re. Appl.* 2016: **24:** 978-989

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EVALUATION OF VARIOUS PV MODULE TECHNOLOGIES IN DESERT CONDITION USING WEATHER-CORRECTED PERFORMANCE RATIO

JIM J JOHN, AMMAR ELNOSH, ALYA BIN TOOK, PEDRO BANDA

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ABSTRACT

The performance of 31 photovoltaic (PV) modules with five different solar cell technologies (and three different module construction) is studied in the desert climate of UAE. The type of modules included in the study are monocrystalline silicon (mc-Si), bifacial mc-Si, polycrystalline silicon (pc-Si), CdTe and CIGS. The weather-corrected performance (wc-PR) ratio of these modules are studied for the period of two years. The bifacial mc-Si modules exhibit highest PR with values above 100%. Among the standard silicon technology, mc-Si technology shows the highest wc-PR of 91%, followed by polycrystalline silicon with 86%. The thin-film modules CIGS and CdTe showed wc-PR of 89% and 86%, respectively.

INTRODUCTION

- The middle-east countries are becoming increasingly important markets for photovoltaic (PV) installations.
- According to IRENA, 30%-84% of the GCC countries' renewable energy targets will come from PV and BIPV technologies (approx. 40GW) by the year 2030.
- The module PR (Performance Ratio) measures how effectively it converts the received sunlight into DC energy relative to what would be expected from the STC (Standard Test Conditions) rating of module.
- The PR metric quantifies the overall effect of losses in the module due to: cell mismatch, elevated PV module temperature, reflection from the module front surface, soiling, shading and component failures. Even though this metric is commonly used, it is heavily dependent on the ambient weather.
- The weather-corrected PR (wc-PR) is a metric that can be used to study the performance without the influence of ambient temperature and wind speed. This metric should be more or less constant in a year if the PV modules don't show any significant degradation over this period.

METHODOLOGY

The measurements for this study were performed at the Outdoor Solar Testing Facility of the Dubai Electricity and Water Authority (DEWA) R&D center. The PV module test bed in the outdoor facility operates year round, performing measurements on a set of PV modules, with variety of irradiance and atmospheric sensors. The test bed consists of 31 different modules, of a variety of PV technologies. All modules used in this study are installed at a tilt of 25o with respect to horizontal plane, and cleaned weekly. In between IV curve measurements, the modules are kept at maximum power point and Pmax (Maximum power) values are recorded every 30 seconds. . The data is processed in MATLAB software and several filtering steps are performed to eliminate measurements that do not fulfil several quality criteria. The methodology explained by Dierauf et al [1] is used to calculate the cell temperature and average operating cell temperature. All the temperature parameters were calculated from the measured meteorological data. Wc-PR is calculated for the year 2015 and 2016 from 28 Jan–31 December and 01 Jan–31 December, respectively. In this study, the weather corrected PR is calculated using equation,

$$wcPR = \frac{\sum Y_{dc_i}}{\sum \left[P_{\max} \left(\frac{G_{POA_i}}{G_{STC}} \right) \left(1 - \frac{\delta}{100} \left(T_{cell_typ_avg} - T_{cell_i} \right) \right) \right]}$$

whereYdc-iisthemeasuredDCelectricalenergyyield, where Pmax is the STC power from flash test data, GPOA is the measured plane of array (POA) irradiance, GSTC is the irradiance at STC (1000 W/m2), Tcell_typ_avg is the average cell temperature computed from one year of measured meteorological data and Tcell is the PV cell temperature computed from measured weather data.

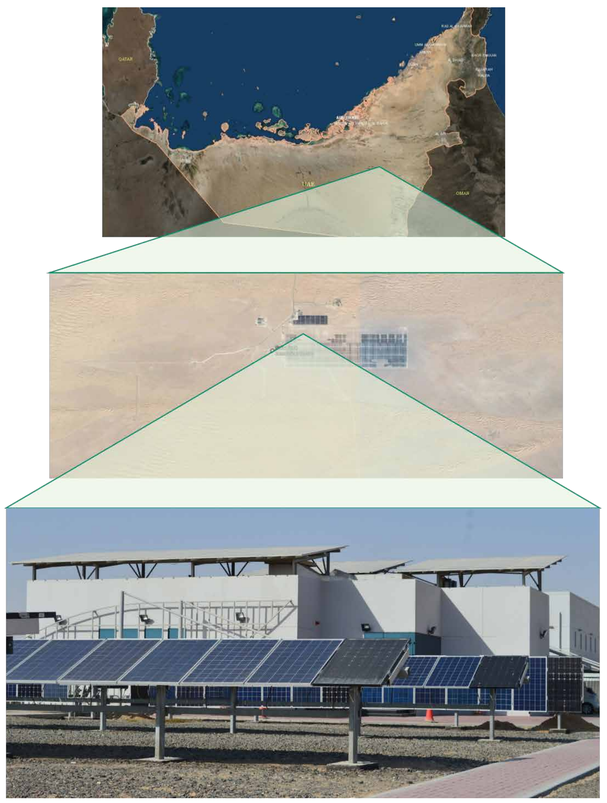

Fig 1. The location of the R&D test facility and MBR Solar park (proposed 5000 MW)

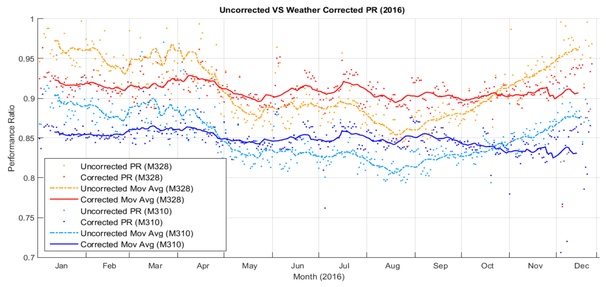

Fig 2. The weather-corrected and uncorrected daily PR of two modules in the PV test bed, plotted for a year.

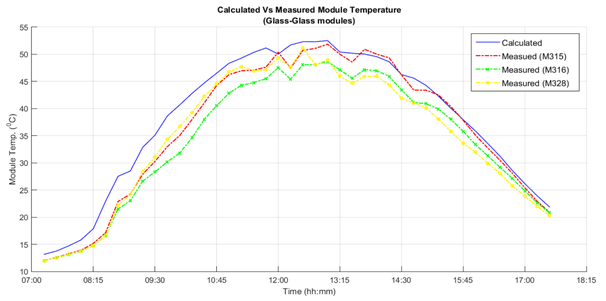

Fig 3. The comparison of the calculated cell temperature and the measured module back temperature of three modules

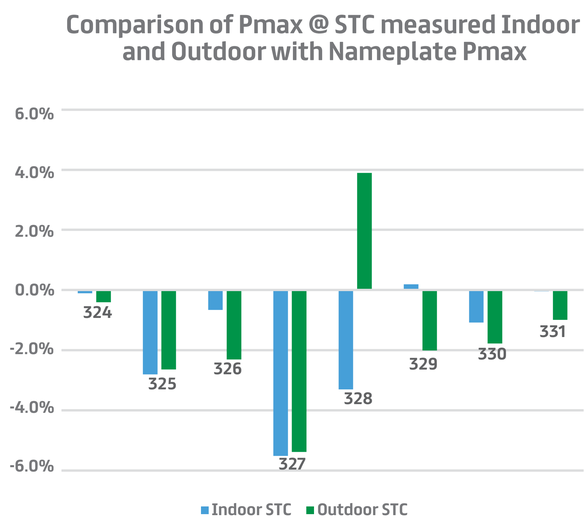

Fig 4. The deviation of STC Pmax measured indoor using a solar simulator and outdoor with the name plate Pmax.

TABLE I: Wc-PR of the PV module technologies for the year 2015 and 2016..

PV Technology	Module ID	PR (2015)	PR (2016)	Construction Type
Monocrystalline silicon	308	86%	86%	glass/EVA/cell/EVA/Backsheet/Frame
	318	87%	87%	glass/EVA/cell/EVA/Backsheet/Frame
	321	86%	87%	glass/EVA/cell/EVA/Backsheet/Frame
	323	84%	85%	glass/EVA/cell/EVA/Backsheet/Frame
	325	NA	87%	glass/EVA/cell/EVA/Backsheet/Frame
	327	NA	89%	glass/EVA/cell/EVA/Backsheet/Frame
	328	NA	91%	glass/EVA/cell/EVA/Glass/Frame
	330	NA	86%	glass/EVA/cell/EVA/Glass/Frameless
	301	99%	96%	glass/EVA/BiFacial/EVA/Glass/Frameless
	313	104%	99%	glass/EVA/BiFacial/EVA/Glass/Frameless
PolycrystallineSilicon	302	84%	83%	glass/EVA/cell/EVA/Backsheet/Frame
	303	86%	85%	glass/EVA/cell/EVA/Backsheet/Frame
	304	85%	85%	glass/EVA/cell/EVA/Backsheet/Frame
	305	84%	84%	glass/EVA/cell/EVA/Backsheet/Frame
	306	84%	83%	glass/EVA/cell/EVA/Backsheet/Frame
	307	85%	85%	glass/EVA/cell/EVA/Backsheet/Frame
	309	85%	83%	glass/EVA/cell/EVA/Backsheet/Frame
	319	85%	84%	glass/EVA/cell/EVA/Backsheet/Frame
	320	86%	85%	glass/EVA/cell/EVA/Backsheet/Frame
	322	82%	81%	glass/EVA/cell/EVA/Backsheet/Frame
	326	NA	86%	glass/EVA/cell/EVA/Backsheet/Frame
	329	NA	86%	glass/EVA/cell/EVA/Backsheet/Frame
	331	NA	83%	glass/EVA/cell/EVA/Backsheet/Frame
	310	86%	85%	glass/EVA/cell/EVA/Backsheet/Frame
	311	85%	84%	glass/EVA/cell/EVA/Backsheet/Frame
	312	85%	85%	glass/EVA/cell/EVA/Glass/Frameless
	314	83%	82%	glass/EVA/cell/EVA/Glass/Frameless
	317	82%	81%	glass/EVA/cell/EVA/Backsheet/Flexible board
	324	NA	85%	glass/EVA/cell/EVA/Backsheet/Frame
CIGS	315	89%	89%	glass/TF/Glass/Frame
CdTe	316	86%	83%	glass/TF/Glass/Frameless

RESULTS AND CONCLUSIONS

- These modules are installed in a hot and dry desert environment. The benefit of using wc-PR over the uncorrected PR is shown.
- The nameplate Pmax values usually have a tolerance of ±2% or ±3% depending on manufacturers. Out of the 8 modules studied, indoor and outdoor measured Pmax of 6 modules were within tolerance band of ±3%.
- The bifacial mc-Si modules exhibit highest PR with values above 100%.
- Mc-Si modules exhibited highest wc-PR (91%) among the non-bifacial PV cell technology. All the standard mc-Si module showed a slight increase in PR (of less than 1%) in the year 2016 in comparison to 2015.
- Most of the pc-Si modules showed almost no change (less than 1%) in PR when compared to the previous year.
- Among the thin-film modules, CdTe module showed almost 3% decrease in PR as compared to 0.7% change in CIGS module technology.
- Further investigation on the measured IV curves is planned for understanding any degradation modes that is introduced during the test period.

References: [1] T. Dierauf, A. Growitz, S. Kurtz, J. L. B. Cruz, E. Riley and C. Hansen, "Weather-Corrected Performance Raio," NREL/TP-5200-57991, 2013.

Presented at NREL PVRW 2017 on Feb 28 - Mar 2, 2017 at Denver, Colorado, USA .

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http://liten.cea.fr/cea-tech/liten | http://www.ines-solaire.org/ | http://www.durabpol.fr/Fault-Diagnosis-of-PV-Plants-by-Aerial-Infrared-IR-Imaging

Early Reliability Issues and Symptoms Evaluated in Four Large PV Plants in Southern France

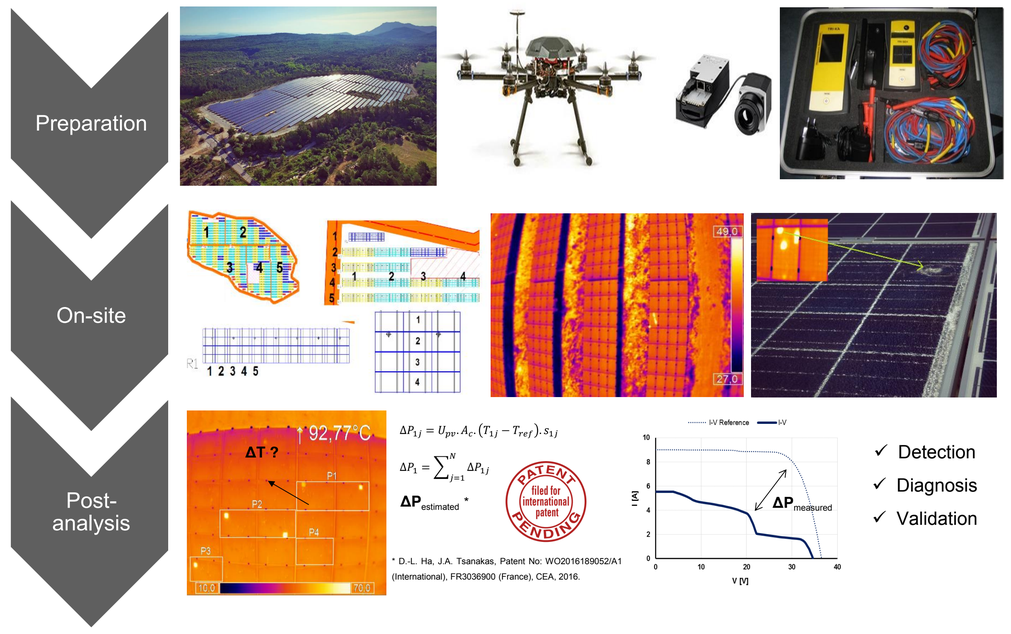
Context – Objectives

We performed **complete diagnostic studies** in **four large PV plants** of overall installed power of **29 MWp**, which were inaugurated in southern France over the last 4 years.

Aerial infrared thermography (aIRT), **I-V characterization** and **visual inspection** measurements were performed in the field, on module and string level.

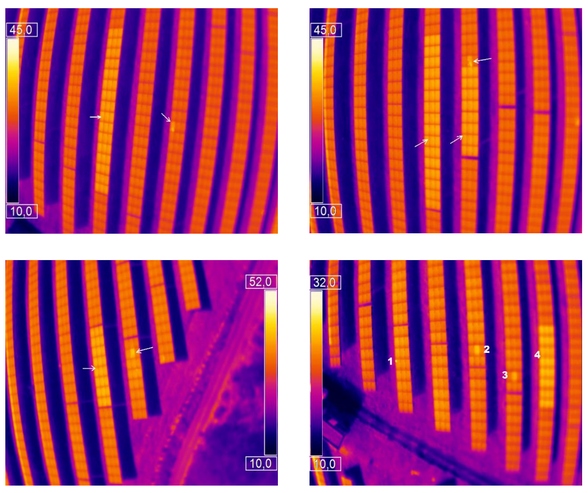
We present here an overview on the main findings of this study, with **key objectives** to:

- Validate the condition of the operating PV modules; electrical, thermal, optical "signatures".
- Diagnose early reliability issues or failures and classify/quantify their symptoms.
- Outline recommendations to the PV operators for on-site (corrective) and/or future (preventive) maintenance actions.



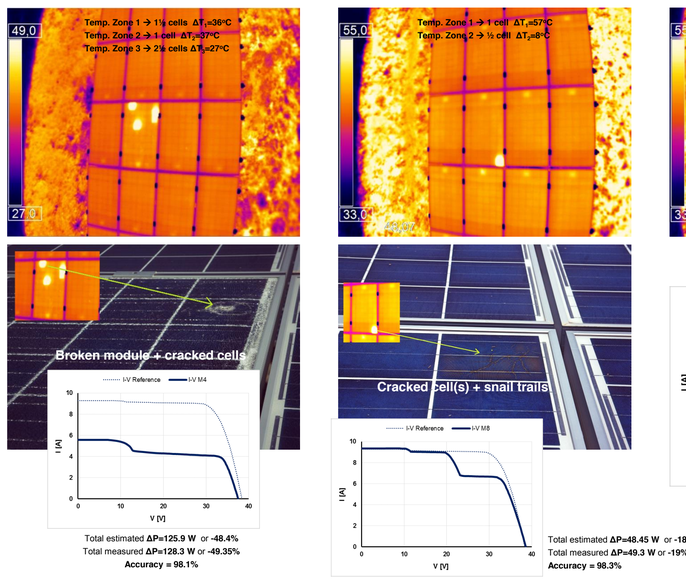
Diagnosed Failures - Symptoms of Reliability Issues

Diagnostic "preview" of PV plant – Large scale analysis
Fast inspection – Identification of "weak" zones for prioritized, detailed diagnosis
aIRT flights >15-20m from the ground → purely qualitative

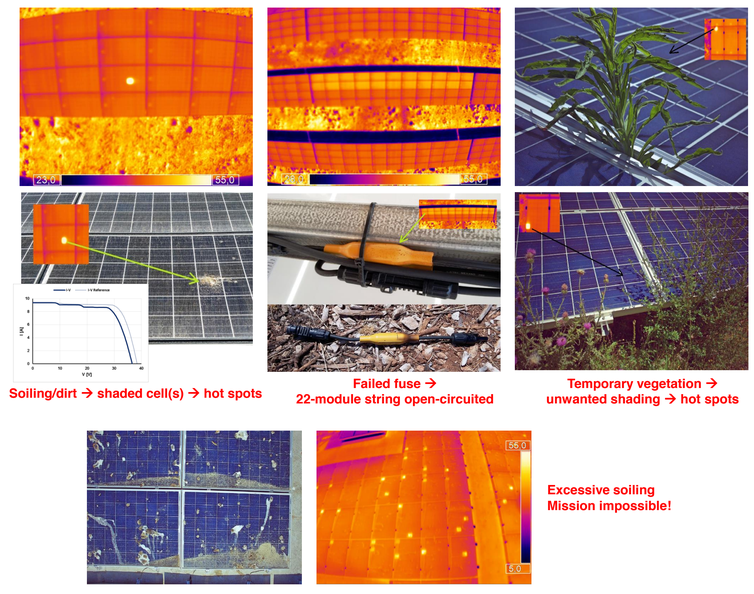


System/module reliability issues and problematic areas are easily identified during preview aIRT.
Typical examples, as indicated above: **inactive PV arrays or strings, excessive soiling/dirt, shading.**

Detailed Diagnosis – Analysis on Module Level
Correlation of thermal and I-V signatures – Classification of Failure Modes – Estimation of PV performance losses
aIRT flights <10m from the ground → min. 5x5 pixels/cell resolution, in line with the IEC 62446-3 TS Ed.1

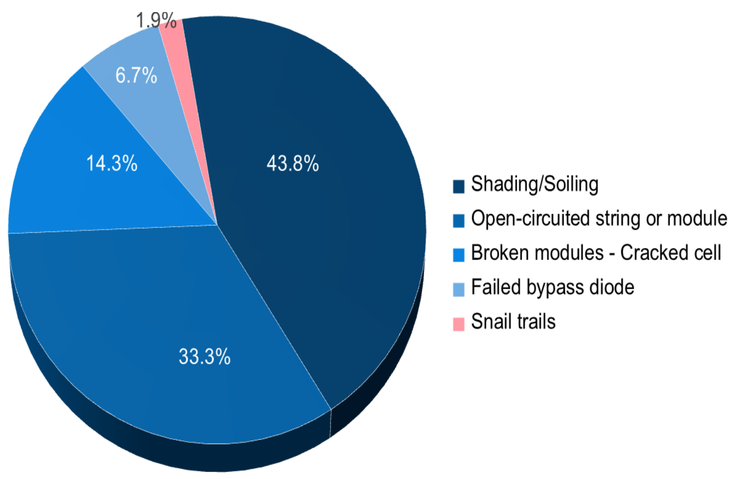


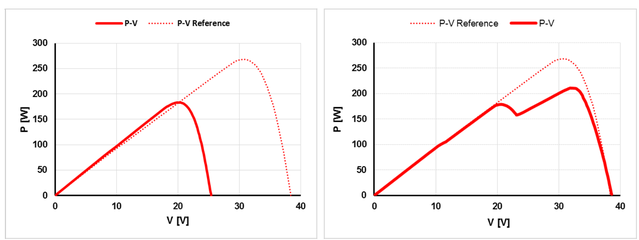
"False" alarms and/or temporary faults on module and system level
Most cases were identified and/or corrected on-site



Overview: Occurrences and PV Losses

- Hot spots due to unwanted shading/soiling and faults on system/string level (e.g. open circuits) were the **two dominant reliability issues**, in terms of occurrence.
- Only 479 modules out of approximately 106,000 installed modules were associated with a temporary reliability issue or failure and, thus, with complete or partial loss in their electrical performance.
- **Fault occurrence rate = 0.45%**, in the first 4 years of operation for these PV plants.





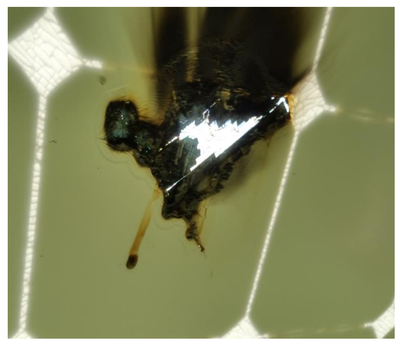
Typical examples of P-V signatures of different failure occurrences:

- Failed bypass diode (submodule inactive)
- Partial shading ("light" case)
- Fractured module glass and/or severe cell cracks.

- The detected faults correspond to **overall power output losses** of approximately **174 kW**, i.e. **0.6%** from the total installed power of the PV plants.
- No yearly degradation rates or LID were taken into account in such calculations.
- Considering that both (primarily) the faults on string level and shading comprise the majority of power output losses, which in principle are recoverable, on-site corrective maintenance was prioritized, even during the inspections.

Key Outcomes – Future Work

- PV plants relatively new → very low fault occurrence rate; reliability issues more related with inadequate maintenance and monitoring.
- No significant optical degradation visible/detectable yet.
- Hot spots: often not "real" faults (e.g. shading, soiling) but may result in severe ΔT>50°C (T_m>85°C) → harsh thermal cycling → risk of follow-up degradation and/or complete failure, even fire (*see Figure*).
- Open-circuited modules and failed bypass diodes: fairly predictable thermal and electrical response: moderate *ΔT* and uniform thermal patterns; but significant power output losses (33% - 100%).
- aIRT particularly promising for fast efficient diagnostic studies in PV plants (typical rates for complete inspections: **3-5 MW/day**)
- **Successful validation of the developed patent**. Estimation of P_{out} losses from the thermal signature of each module. **Accuracy up to 98.3%.**



Perspectives:

- *En route* to an automated navigation-detection-analysis pipeline.
- More failure modes to be explored; e.g. PID, optical degradation.
- aIRT hand-in-hand with the forthcoming IEC 62446-3 TS Ed.1.
- Future challenge: from fault diagnosis ("instant picture") towards **accurate PV energy yield predictions** and better understanding of **failure** (and, thus, **power loss**) **propagation** through the PV lifetime.

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***2017 NREL/SNL/BNL PV Reliability Workshops**, February 28th – March 2nd, Lakewood (CO), USA.*

Toward a drone-based EL and PL inspection tool for PV power plants (DronEL)

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Sergiu Spataru[b], Dezso Sera[b]

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Introduction

Regular inspections of PV installations are essential to ensure the expected ROI.

The frequency of inspection and level of detail is often limited by manpower and cost.

Drone-based automatic inspection will lower the prices, increase quality and speed of large PV power plant QA checks.

Experiments

The first experiments toward an automated drone inspection focus on contactless defect detection such as PL imaging with the sun as light source.

While most of the sunlight absorbed by the PV cell is converted into electricity, part of it recombine emitting light. At ambient temperature, such PL emissions from silicon occur at 1150 nm, near a water absorption range in the solar spectrum, as illustrated in Fig. 1.

Analog and digital filtering methods can be used, limiting the noise from sun and diffuse light for PL imaging.

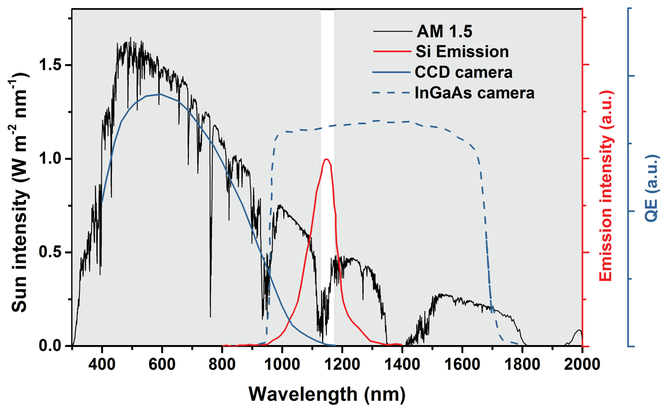


Fig. 1. AM 1.5 sun spectrum and silicon emission peak. The gray areas show wavelengths that should be cut off with the use of optical filters in order to avoid detection of the sunlight. Also shown are quantum efficiencies of a Silicon CCD and an InGaAs detector. Note the ideal range of the InGaAs QE for detecting Si emissions.

Concept

The drone-based inspection tool will combine several techniques such as, infrared (IR), electroluminescence (EL), photoluminescence (PL), and visual imaging.

The PL/EL parameters for panel imaging need to be defined, such as:

- Video/photography processing and filtering,
- Detector exposure time,
- Scanning speed,
- Composition and distance from the solar panel for specific defect detection,
- The equipment to be mounted (payload),
- Operator training.

The concept is sketched in Fig. 2.

Fig. 2. Concept of automated drone inspection.

Indoor PL, EL imaging testbeds have been built within the first month of the project.

DTU Fotonik is home to expert researchers in the fields of optics and imaging techniques. Their knowledge will be harnessed for optimizing the filtering and analysis techniques used in the outdoor testbed.

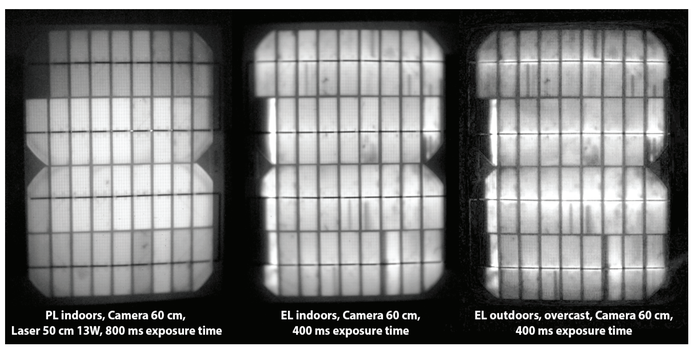


Fig. 3. Indoor PL (left), indoor EL (center) and outdoor EL (right) images of a mono-Si mini-module using an InGaAs camera. The PL/EL methods highlight different types of defects.

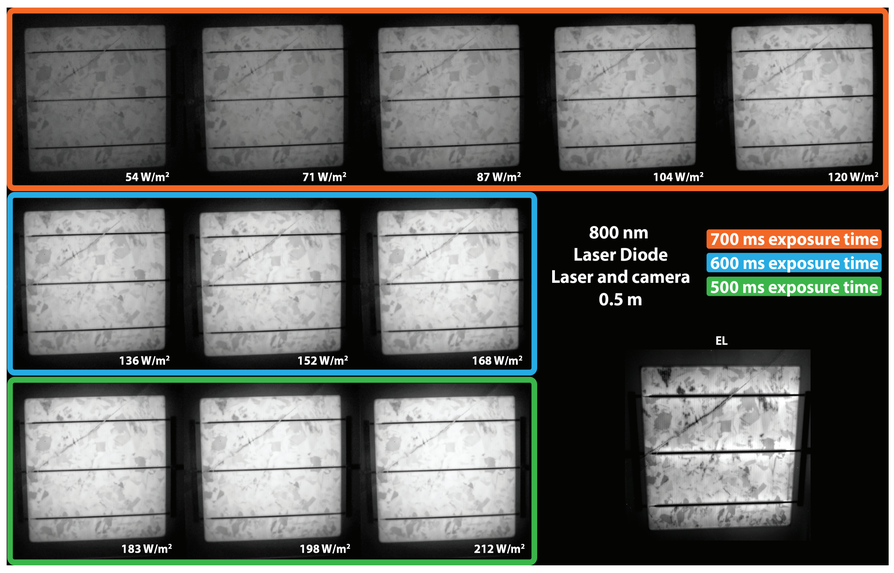


Fig. 4. Indoor PL images of a mc-Si cell exposed to varying laser intensities and exposure times. All images were taken using an InGaAs camera.

Early results

The automatic detection and quantification of the PV module failures will be based on EL/PL intensity histogram analysis (ELID)

Early results show that certain PV failure modes (cell cracks, PID, broken cell interconnects) have specific signatures/impact on the ELID.

We will investigate how different PV failures correlate with the ELID statistics, and define diagnostic algorithms for quantifying the type and magnitude of the failure automatically.

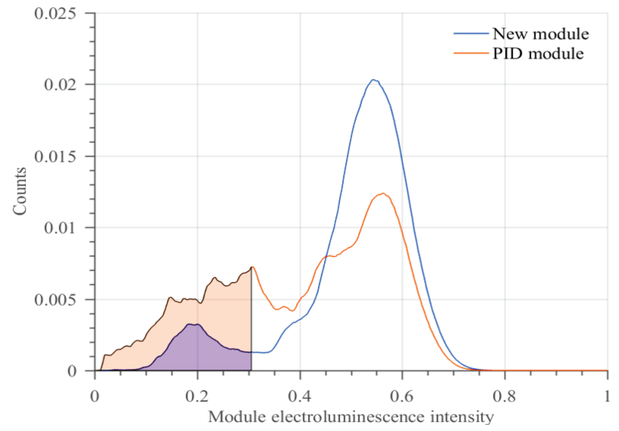
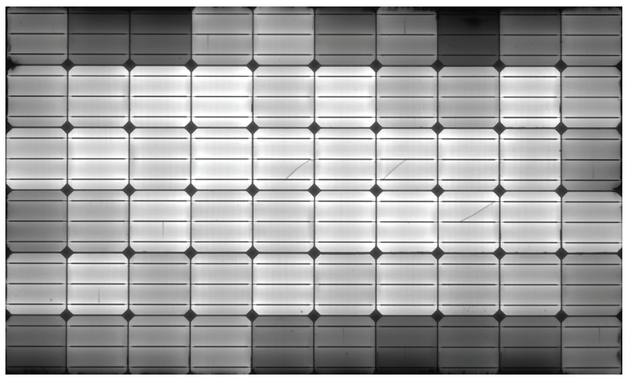
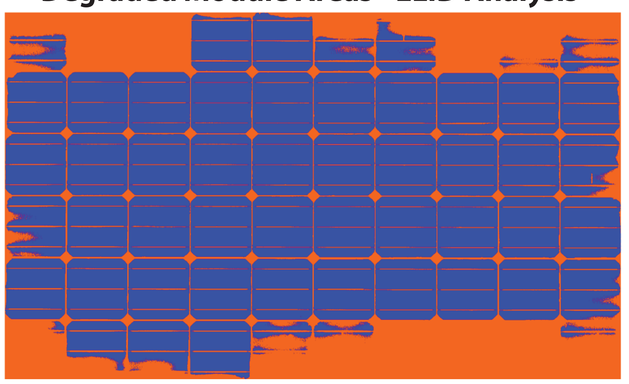


Fig. 5. Normalized module-level EL intensity histograms calculated from the EL images the PV module test sample.

PID Module



Degraded Module Areas - ELID Analysis



Conclusions and Outlook

- The image acquisition parameters for outdoor fast and accurate drone-based imaging tool will be obtained.
- Further light filtering strategies will be addressed.
- PL/EL inspection and multiple wavelength imaging correlation is a step closer to be implemented commercially.

Acknowledgements

The project is funded by Innovation Fund Denmark by project 6154-00012B DronEL – Fast and accurate inspection of large photovoltaic plants using aerial drone imaging.

Innovationsfonden

Partners

Kenergy
SKY-WATCH
SiCon
Silicon & PV consulting
SKIVEKOMMUNE

Statistics for evaluation of >12,000 modules

Frederic Dross, John Watts, Ian Tse
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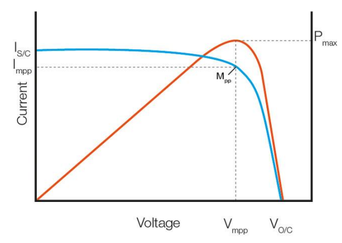
Dirk Morbitzer, Jaime Castro
Sunrun

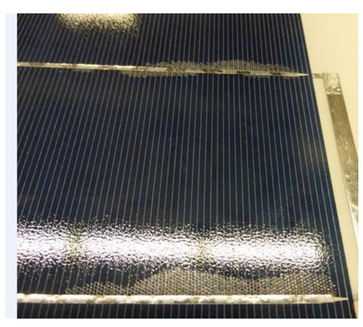
Joe Duncan, Shaun Montminy
SolarBuyer

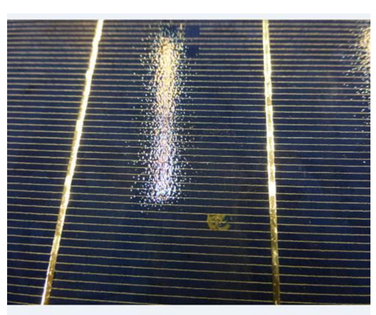
Quarterly Inspection Program for Sunrun fleet



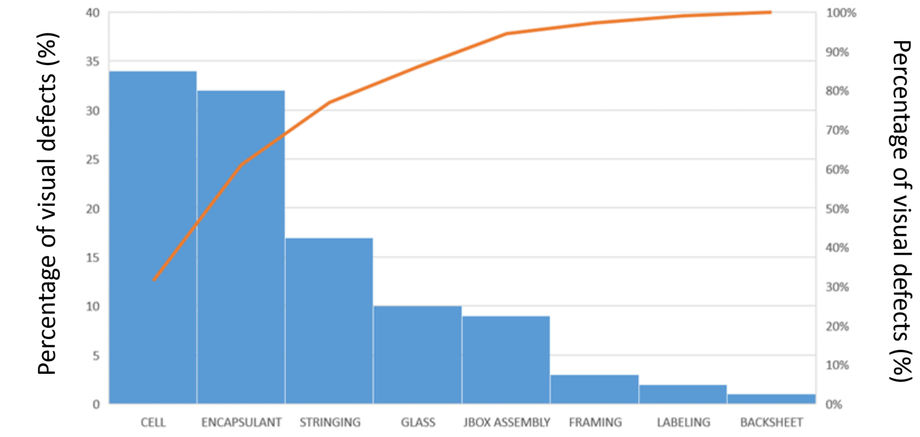
- Visual inspection of the cells, cell connectors, frames, glass, back-sheet, encapsulation, junction box, external cables and connectors.
- Electrical testing including I-V curve, fill factor, P_{mpp}, V_{mpp}, V_{oc}, I_{mpp} and I_{sc}.
- High resolution Electroluminescence (EL) imaging to identify cell micro-cracks, nonfunctioning, cell partitions and other cell-related defects.
- **More than 12,000 modules inspected, from 7 manufacturers, over 2 years.**

Main Results

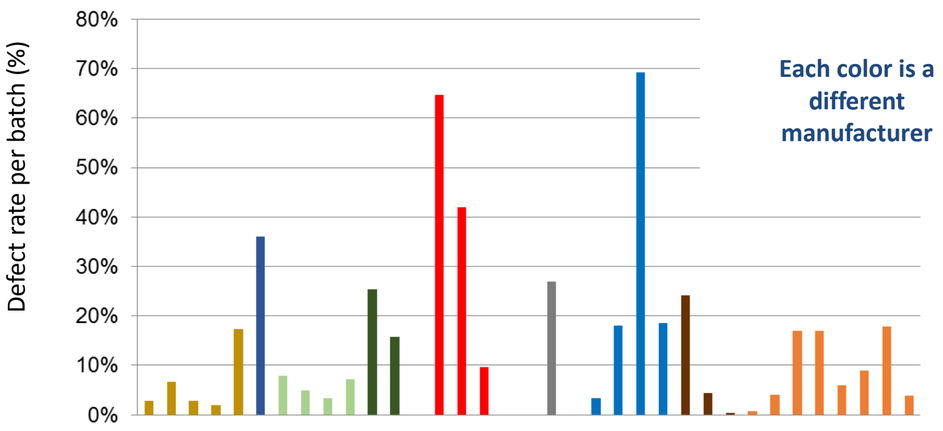




- More than 10% modules show defects
  - ✓ Aggressive criteria to ensure high quality
  - ✓ Most common defect: excessively-cracked cells
- Visual defects distribution:

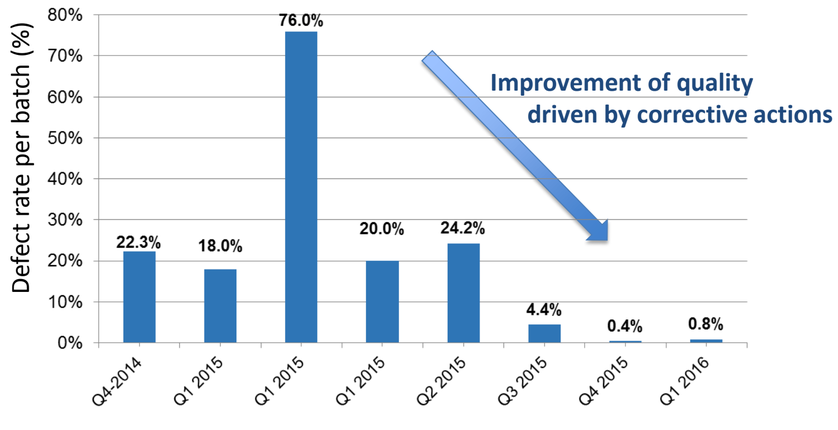


- Some batches are defect-free, while others show up to 70% modules with defects



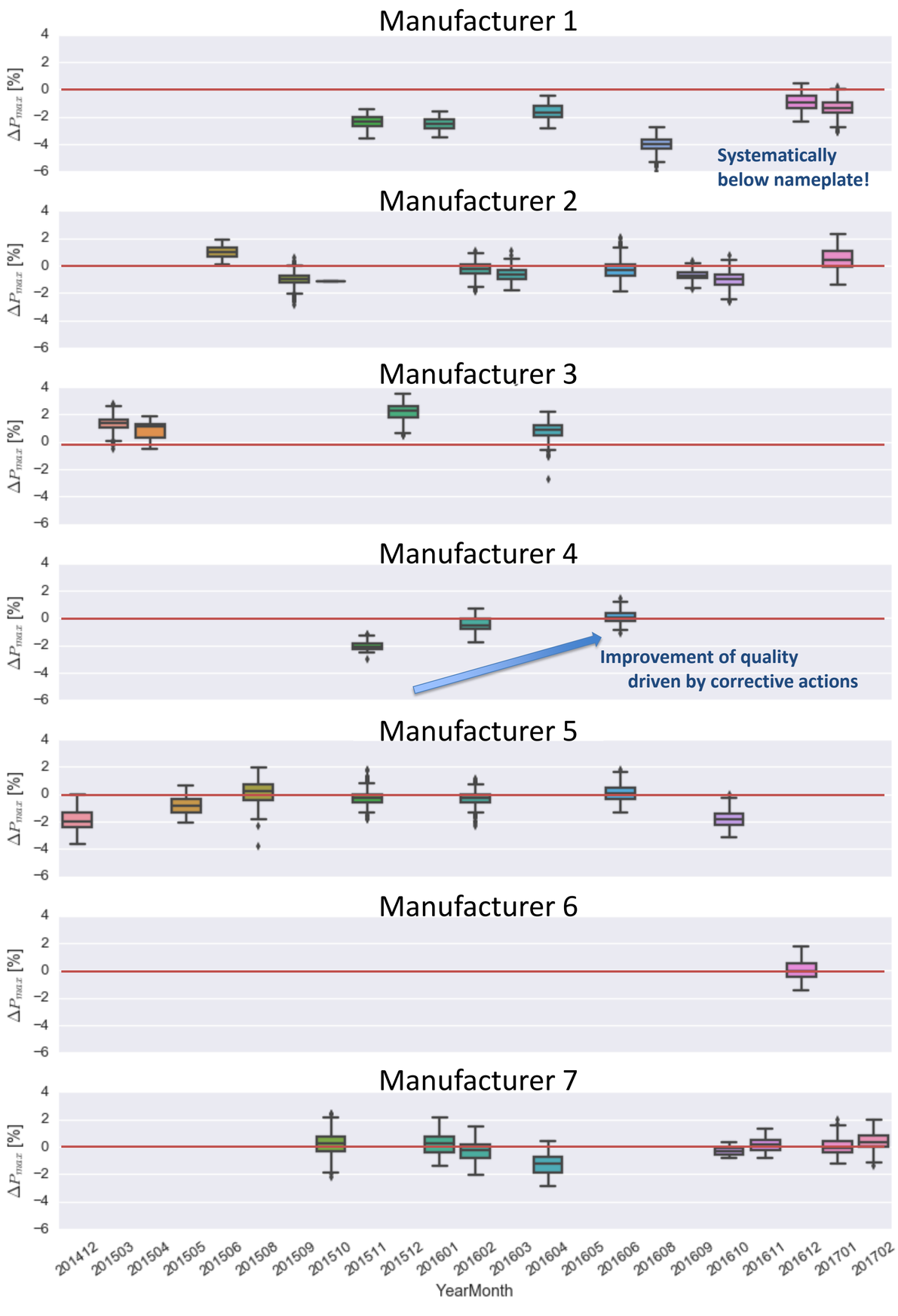
How these results are used

- Quality of supply is monitored and maintained at a desirable level
- Suppliers implement corrective actions and monitoring until the defect rate goes down to acceptable levels



- Results are used in IE reports to facilitate financing of the Sunrun business

- Evolution of P_{mpp} versus Nameplate for the 7 manufacturers
  - ✓ Some manufacturers are well above nameplate, while others systematically fall below nameplate



Presented at the NREL Reliability Workshop 2017, Boulder, Colorado

PV Energy Losses in Snowy Conditions

Introduction

Emily Hardy
EDP Renewables North America
February 2017

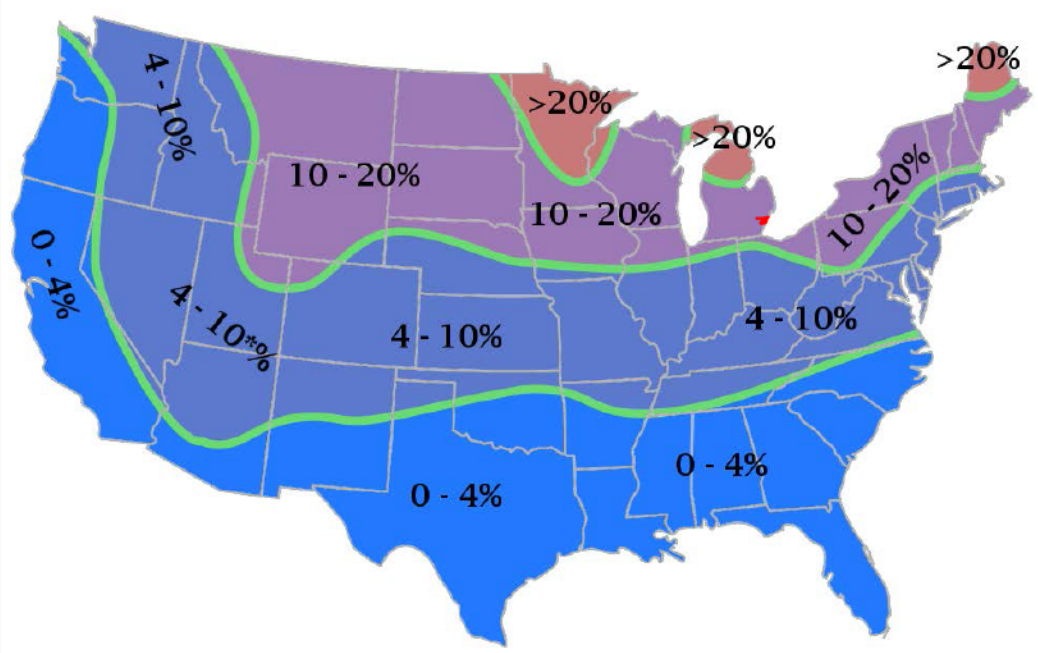
The installation of PV panels in geographic regions, that are prone to heavy snowfall during the winter season, will see a reduction in energy production over those months. Although, the sun's irradiance is naturally lower during this time of year, it is still necessary to estimate these losses in order to properly analyze and predict the annual MWh injected into the grid for the site.

MOTIVATION:
In search of a quick, simple method for calculating losses in production from snow, with minimal data measurements and a reasonable level of accuracy. We are analyzing and predicting the annual net production for multiple solar projects every week, occasionally in areas with heavy snow. It is crucial for us to reduce the uncertainty of these estimates and increase the accuracy of our results.

(1)

Methodology

Analyzed a city with high snowfall totals and publically available data, Detroit, MI.



(2)

1) The map displays general trends and average snow losses as a percentage of the annual production, regardless of the tilt angle of the PV modules. This can be used as a starting point in the absence of further information. According to the map, we can expect snow losses to be in the range of 10%-20% for Detroit, MI. [2]

Methodology

2) A simulated study was performed by NREL to estimate snow losses for major cities throughout the USA. Estimates for annual snow losses in Detroit came to 9.2% for a tilt angle equal to the latitude (~42°N). Tabulated results from a study, for tilt angles of 20°, yield annual losses of 8.4% for this location. [2]

Latitude (42°) = Tilt Angle

City	State	Average Percent Loss	STD Percent Loss
Dayton	OH	7	3.5
Daytona Beach	FL	0	0
Des Moines	IA	10.7	4
Detroit	MI	9.2	3.3
Dodge City	KS	5.1	2.2
Duluth	MN	26.5	5
Eagle	CO	-	-
Eau Claire	WI	19.5	4.8

(2)

20° = Tilt Angle

City	State	Average Percent Loss	STD Percent Loss
Dayton	OH	6.4	3.2
Daytona Beach	FL	0	0
Des Moines	IA	9.7	3.8
Detroit	MI	8.4	2.9
Dodge City	KS	4.7	2
Duluth	MN	23.6	4.5
Eagle	CO	-	-
Eau Claire	WI	17.3	4.4

(2)

Methodology

3) A simple approach to calculate the annual % loss, that only requires monthly average snowfall totals. Results should be rounded to nearest whole number due to simplicity of methodology. [4]

Average Snowfall — Years on Record: 59

	ANNUAL	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
in	32.9	8.4	6.7	5.5	0.9	---	---	---	---	---	---	2.8	8.6

(6)

Inputs:
-Average Monthly Snowfall Totals

Annual % Loss = 0.1 X [Snow Fall (in.)] X $\cos^2$ (tilt) [4]

M3: Detroit, MI Results	
Tilt Angle	**Annual Loss**
20°	3%
30°	3%
42°	2%

Methodology

4) A more in depth analysis can be modeled within NREL's SAM software. This approach, that follow's Marion's Model[3], only requires TMY2 data and estimates the percentage of the PV array that will be covered by snow.[2]

Inputs:
-System Tilt / Configuration
-TMY2 data which includes:

- *Daily Snow Depth Measurements*
- *Hourly POA Irradiance*
- *Temperature*

Note: Snow sliding is considered the primary removal process in this method and does not account for snow melting or wind removal.[2]

M4: Detroit, MI Results			
Tilt Angle	**20 DEG**	**30 DEG**	**42 DEG**
JAN	62.6%	56.6%	45.8%
FEB	35.7%	28.8%	19.1%
MAR	3.8%	3.4%	2.6%
APR	0.0%	0.0%	0.0%
MAY	0.0%	0.0%	0.0%
JUN	0.0%	0.0%	0.0%
JUL	0.0%	0.0%	0.0%
AUG	0.0%	0.0%	0.0%
SEP	0.0%	0.0%	0.0%
OCT	0.0%	0.0%	0.0%
NOV	7.1%	4.8%	2.1%
DEC	30.6%	24.5%	19.8%
ANNUAL	**6.80%**	**6.20%**	**5%**

Methodology

5) A series of equations were developed based on a model that was calibrated using real ongoing measurements.[5]

$$\text{Loss, \%} = C_1 \times Se' \times \cos^2(\text{tilt}) \times GIT \times RH / T_{AIR}^2 / POA^{0.67} \quad \text{Eqn. 3}$$

$$GIT = \text{ground interference term} = [1 - C_2 \times \exp(-\gamma)] \quad \text{Eqn. 4}$$

Where C_2 is a fitted coefficient, and
RH = relative humidity, dimensionless fraction
T_{AIR}^2 = square of average monthly temperature, K, where the squared power magnifies the modeled effect of temperature
$POA^{0.67}$ = monthly plane of array insolation, kWh/m^2, where the 0.67th power moderates the direct effect of radiation
γ = ratio of snow received/snow dissipated =

$$[R*Se'*\cos(\text{tilt})]/[(H^2 - Se'^2)/2*\tan(P)] \quad \text{Eqn. 5}$$

(5)

M5: Detroit, MI Results

Inputs	
Latitude	42°
Snow, in.	40
Tair C	9
Lat-15° POA kWh/m2	1556
Monthly Losses	
JAN	15%
FEB	12%
MAR	7%
APR	3%
MAY	0%
JUN	0%
JUL	0%
AUG	0%
SEP	0%
OCT	0%
NOV	3%
DEC	13%
ANNUAL	3%

(5)

Results

The most important criteria in our search for a method of estimating snow losses for a prospective solar project are:

#1 – Accuracy
#2 – Monthly Loss Breakdown
#3 – Time Required

Method	*Time Required*	*Monthly Losses*	*Annual Loss Estimate*	*Accuracy*
1	None		10% - 20%	?
2	None		8.4% - 9.2%	?
3	Little		2% - 3%	?
4	Medium	✓	5% - 6.8%	?
5	Most	✓	3%	?

Given the results in the table above, methods 4 and 5 are the most appropriate for our needs. The delta in results, between these methods, is significant both on a monthly basis and when estimating total annual net production.

Future Studies

Operational studies need to be performed to identify the methodology that most accurately estimates the losses that are occurring due to snowfall. The challenge is gaining access to useful data.

-Models to be run on operating sites and real output to be compared to modeled output. The goal would be to isolate losses due to snow.

-Installation of two test panels in the region of interest. One would allow snow to slide and melt naturally while the other should be manually cleared of snow during daylight hours. The production from the panels would then be compared to identify the losses caused by snow cover.

(7)

-Installation of snow gauges at prospective sites would be beneficial for site specific data. This is especially true for remote locations that do not have public information available in the vicinity.

References

(1) Horvath, A. “Mother Nature and the Cost of Solar Panels”.
http://blog.clean-footprint.com/solar-energy-articles/mother-nature-and-the-cost-of-solar-panels

(2) Ryberg, D.; Freeman, J. (2015). “Integration, Validation, and Application of a PV Snow Coverage Model in SAM.”
http://www.nrel.gov/docs/fy15osti/64260.pdf

(3) Marion, B.; Schaefer, R.; Caine, H.; Sanchez, G. (2013). “Measured and modeled photovoltaic system energy losses from snow for Colorado and Wisconsin locations.” *Solar Energy* 97; pp. 112-121.

(4) Powers, L.; Newmiller, J.; Townsend, T. (2010). “Measuring and Modeling the Effect of Snow on Photovoltaic System Performance.”
https://www.researchgate.net/publication/251963305_Measuring_and_modeling_the_effect_of_snow_on_photovoltaic_system_performance

(5) Townsend, T; Powers, L. (2015). “Photovoltaics and Snow: An Update From Two Winters of Measurements in the Sierra”.
https://www.researchgate.net/publication/261042016_Photovoltaics_and_snow_An_update_from_two_winters_of_measurements_in_the_SIERRA

(6) http://www.weatherbase.com/

(7) https://www.quora.com/What-happens-to-solar-panels-during-snow-fall

Operando X-Ray Characterization of Photovoltaic Materials

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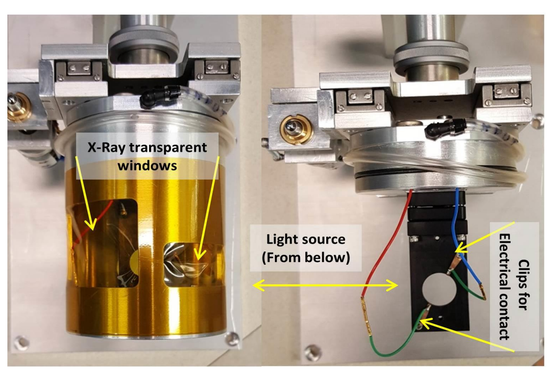
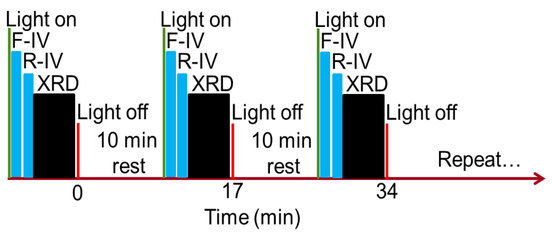
1. Applied Energy Programs, SLAC National Accelerator Laboratory
2. Stanford Synchrotron Radiation Lightsource, SLAC National Accelerator Laboratory
3. National Renewable Energy Laboratory

Abstract: Understanding the structure-function relationship in photovoltaic materials is a key aspect in the optimization of new materials. Traditional characterization techniques often rely on measuring samples before and after synthesis or operation and then the subsequent comparison of these end points. Here we describe a methodology for X-ray diffraction of operational solar cell devices. In this work, we present data investigating the structural tetragonal-to-cubic phase transition in $CH_3NH_3PbI_3$, organic-inorganic perovskite solar cell devices during heating and operation. We hypothesize that the average structure measured by XRD does not dominate the device performance in these devices; rather it is controlled by local ordering, which does not change significantly through the phase transition. We will also comment on the applicability of this technique beyond hybrid perovskite photovoltaics.

Operando Experimental Chamber





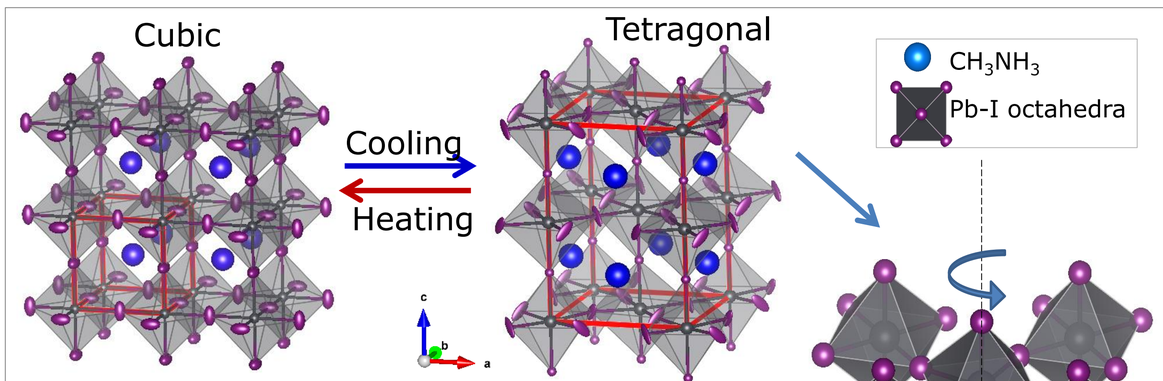
Scans were taken at constant time points

***Operando* Experiment:**
- White LED light (~ 1 Sun)
- Kapton heating tape
- Thermocouple on top of device
- He environment
- 1D and 2D XRD at temperature
- IV curves with light

Current Chamber Capabilities:
- Atmosphere
- Humidity
- Temperature (heating)
- Light
- Electric field bias

Planned Upgrades:
- Mechanical loading
- Larger scale
- High-throughput sampling
- Temperature (cooling)

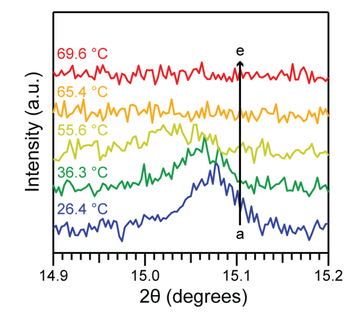
Cubic to Tetragonal Phase Transition

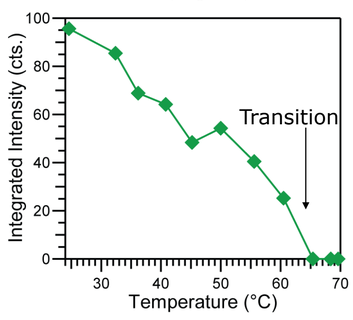


- Cubic-to-tetragonal transition: ~65°C
- Rotation of octahedra leads to a doubling of the unit cell in the a,b-plane
- Octahedral rotation direction alternates between layers, leading to a doubling of the c-axis
- Quarti et al, high temperature phase strongly distorted cubic structure → more tetragonal on the ps time scale

Quarti et al, *Energy Environ. Sci.* 9, 155 (2016)

Device Measurements

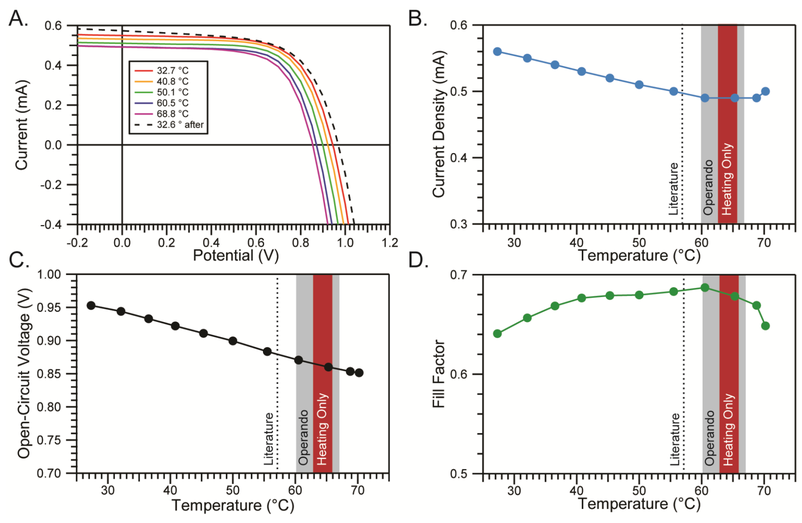




IV-Curves

XRD

- Tetragonal → Cubic transition
- Disappearance of (211) peak
- Transition between 60.5 & 65.5°C



Operando Device Measurements

Summary and Outlook

- Simultaneous, temperature dependent X-ray diffraction and *IV*-curves
- Tetragonal – Cubic phase transition does not impact device performance
  - Measured *operando* and *ex-situ*
- Consistent with Quarti et al picture that the cubic structure is highly distorted
- The local arrangement of atoms is more close to tetragonal
- Local structure dictates the optoelectronic properties in $CH_3NH_3PbI_3$

L. T. Schelhas, J. A. Christians, et al, *ACS Energy Lett.*, vol. 1, pp. 1007–1012, 2016.

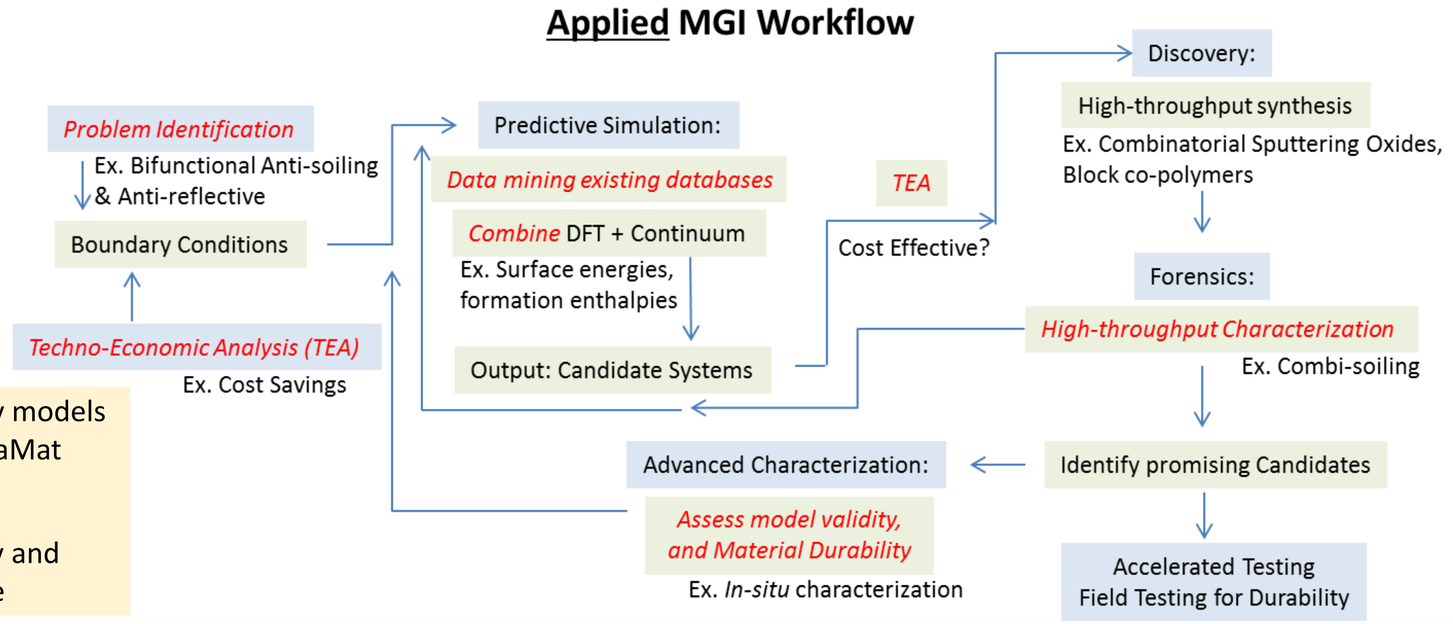
Operando X-ray Diffraction for Accelerated Materials Validation

DuraMAT Durable Module Materials Consortium

"The overarching goal of DuraMat is to **discover, develop, de-risk**, and enable the rapid commercialization of **new materials** and designs for photovoltaic (PV) modules with the potential to improve performance and lifetime while achieving a levelized cost of electricity (LCOE) < $0.03/kWh"

- This *operando* forensics system used for validation of durability models developed by the predictive simulation capability group in DuraMat
- Used to asses material durability during operation
- Use of applied MGI workflow will provide a materials discovery and development methodology that is both rapid and cost effective

Applied MGI Workflow



We wish to thank Tim Dunn, Doug Van Campen, Valery Borzenets, and Samuil Belopolskiy for help with the chamber design and operation.

U.S. DEPARTMENT OF ENERGY | Office of Science | BAPVC BAY AREA PHOTOVOLTAIC CONSORTIUM | Powered by SunShot U.S. Department of Energy

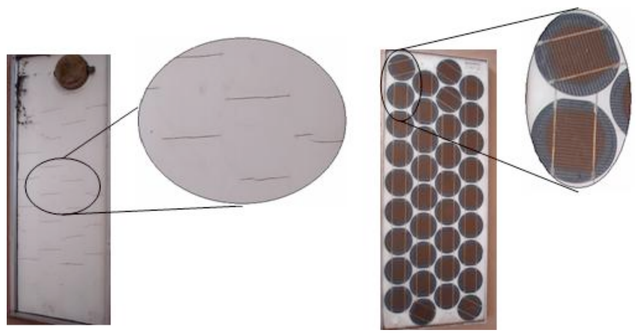
RELIABILITY AND PARAMETER EVALUATION OF PV MODULES WITH 19 YEARS OF USE IN BRASIL'S AMAZON REGION

Lauro de V. B. Machado Neto *and* Antonia Sônia A.Cardoso Diniz
Pontificia Universidade Católica de Minas Gerais - PUC Minas, Belo Horizonte, Brasil

Summary

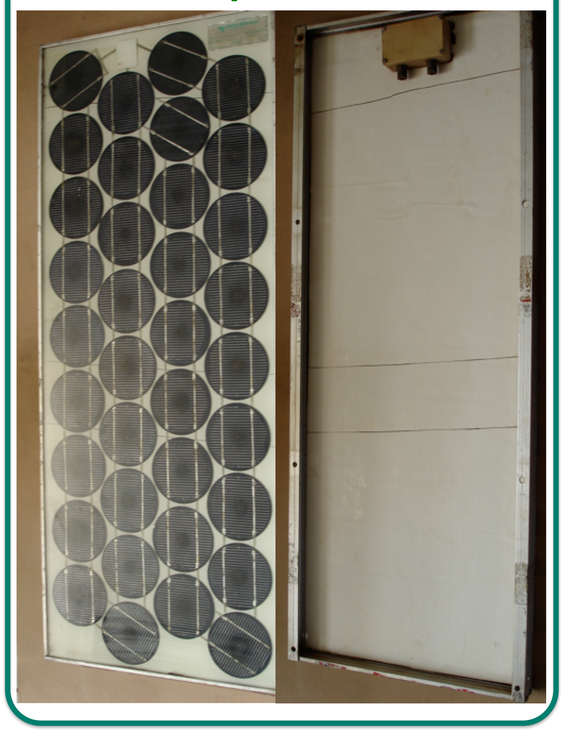
The PV modules are considered a reliability power source for remote systems since the 1970s in Brasil. Embratel, a Brasilian telecommunication company, has 18 telecommunication stations installed in the Amazon region that cover a area of about 900 kilometers square in the rainforest. Each station is fed by PV systems with about 200 modules. For state evaluation of these installations, a sample of 30 modules was removed from various stations and sent to the Laboratory GREEN of the Pontifical Catholic University of Minas Gerais (PUC Minas) for testing. Visual inspection and determination of electric performance are in accordance with procedures of ASTM and IEC. From the measurement of the current and the voltage in outdoor tests, the characteristic IV-curves of each module had been obtained, and parameters estimated using the *non-linear least-square* and *Levenberg-Marquard* methods. Three modules had been chosen for a thermographic evaluation of the 3-main degradation mechanisms.

Visual Inspection



Mechanisms	*Number of Modules*
Browning and bleaching	30
Delamination and bubbles in the back sheet	23
Contact corrosion	13
Corrosion in the junction box	13
Bio film growth	23

Sample 7- 30



Sample 12-30

Sample 18-30

Sample 07 of 30:

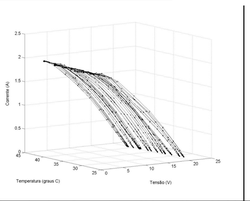
1. Test Conditions

Localization		Solar Conditions		Ambient Conditions	
Latitude	-20°	Date	27/07/06	Air Mass	1,5
Longitude	44°	Time	10:13:00	Wind Speed	1,2 m/s
Standard Meridien	45°	Solar Time	10:10:24	Wind Direction	67°
Altitude	865 m	Solar Altitude	41,91°	Atmospheric Pressure	91,6 kPa
		Solar Azimuth	-144,45°	Ambient Temperature	22,1°C
		Angular Time	-27,40°	Relative Humity	41%
		Module Tilt	48°	Tilted Global Solar Radiation	1027 W/m²
		Module Azimuth	-144,45°	Global Solar Radiation – horizontal plane	700 W/m²
		Incident Angle	0°	Beam Solar Radiation – normal incidence	868 W/m²
		Solar Declination	19,90°		

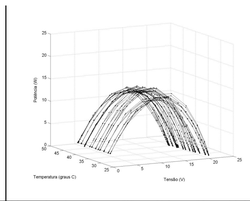
2. Results

Estimated Parameters: Standard Test Condition - Radiation of 1000 W/m², Cell Temperature of 25 °C and Air Mass of 1,5

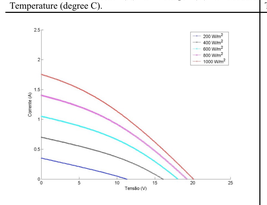
Maximum Power Voltage (V)	10,9	Maximum Power Current (A)	1,0
Open Circuit Voltage (V)	20,1	Short Circuit (A)	1,8
Efficiency (%)	2,8	Fill Factor	0,3
Maximum Power (W)	11,5	Original Rated Maximum Power (W)	35
Degradation (%)	**67,2**		



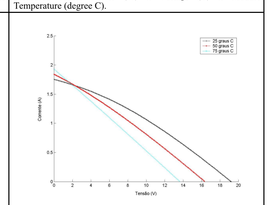
Measured values Current (A) x Voltage (V) x Module Temperature (degree C).



Measured values Power (W) x Voltage (V) x Module Temperature (degree C).

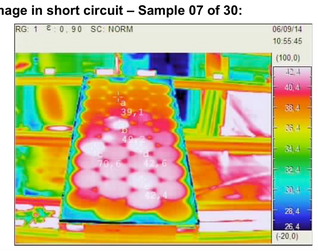


Estimated Current (A) x Voltage (V) for different Solar Radiation (W/m²).



Estimated Current (A) x Voltage (V) for different Module Temperature (degree C).

Infrared image in short circuit – Sample 07 of 30:



Sample 12 of 30:

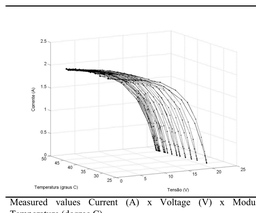
1. Test Conditions

Localization		Solar Conditions		Ambient Conditions	
Latitude	-20°	Date	27/07/06	Air Mass	1,5
Longitude	44°	Time	13:54:00	Wind Speed	1,3 m/s
Standard Meridien	45°	Solar Time	13:51:24	Wind Direction	76°
Altitude	865 m	Solar Altitude	41,69°	Atmospheric Pressure	91,3 kPa
		Solar Azimuth	-143,96°	Ambient Temperature	25,6°C
		Angular Time	-27,85°	Relative Humity	31%
		Module Tilt	48°	Tilted Global Solar Radiation	1005 W/m²
		Module Azimuth	-143,94°	Global Solar Radiation – horizontal plane	654 W/m²
		Incident Angle	0°	Beam Solar Radiation – normal incidence	822 W/m²
		Solar Declination	19,88°		

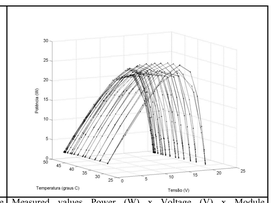
2. Results

Estimated Parameters: Standard Test Condition - Radiation of 1000 W/m², Cell Temperature of 25 °C and Air Mass of 1,5

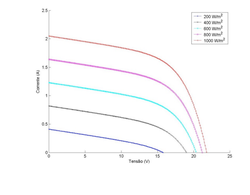
Maximum Power Voltage (V)	16,3	Maximum Power Current (A)	1,6
Open Circuit Voltage (V)	21,8	Short Circuit (A)	2,1
Efficiency (%)	6,2	Fill Factor	0,6
Maximum Power (W)	25,4	Original Rated Maximum Power (W)	37
Degradation (%)	**31,3**		



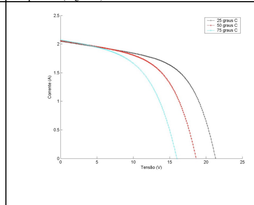
Measured values Current (A) x Voltage (V) x Module Temperature (degree C).



Measured values Power (W) x Voltage (V) x Module Temperature (degree C).

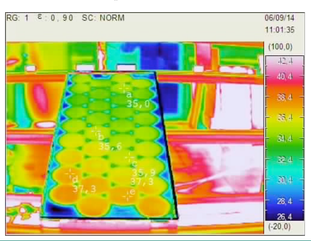


Estimated Current (A) x Voltage (V) for different Solar Radiation (W/m²).



Estimated Current (A) x Voltage (V) for different Module Temperature (degree C).

Infrared image in short circuit – Sample 12 of 30:



Sample 18 of 30:

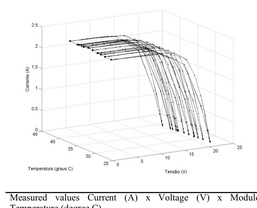
1. Test Conditions

Localization		Solar Conditions		Ambient Conditions	
Latitude	-20°	Date	07/08/06	Air Mass	1,5
Longitude	44°	Time	09:57:00	Wind Speed	2,1 m/s
Standard Meridien	45°	Solar Time	09:54:59	Wind Direction	101°
Altitude	865 m	Solar Altitude	41,73°	Atmospheric Pressure	91,9 kPa
		Solar Azimuth	-138,40°	Ambient Temperature	21,4°C
		Angular Time	-31,26°	Relative Humity	63%
		Module Tilt	48°	Tilted Global Solar Radiation	1122 W/m²
		Module Azimuth	-138,40°	Global Solar Radiation – horizontal plane	744 W/m²
		Incident Angle	0°		
		Solar Declination	17,27°		

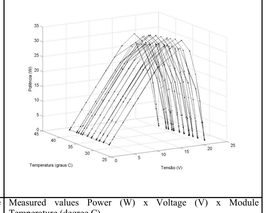
2. Results

Estimated Parameters: Standard Test Condition - Radiation of 1000 W/m², Cell Temperature of 25 °C and Air Mass of 1,5

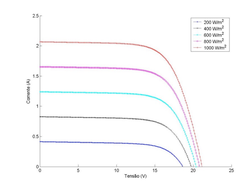
Maximum Power Voltage (V)	15,9	Maximum Power Current (A)	1,9
Open Circuit Voltage (V)	21,2	Short Circuit (A)	2,1
Efficiency (%)	7,2	Fill Factor	0,7
Maximum Power (W)	29,4	Original Rated Maximum Power (W)	35
Degradation (%)	**16,0**		



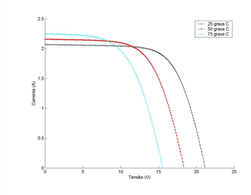
Measured values Current (A) x Voltage (V) x Module Temperature (degree C).



Measured values Power (W) x Voltage (V) x Module Temperature (degree C).

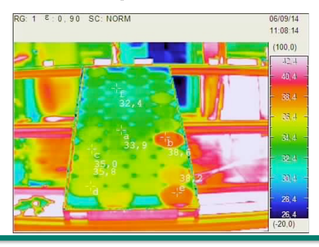


Estimated Current (A) x Voltage (V) for different Solar Radiation (W/m²).



Estimated Current (A) x Voltage (V) for different Module Temperature (degree C).

Infrared image in short circuit – Sample 18 of 30:



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Poster contains no proprietary information

Lessons Learnt from Lab Testing

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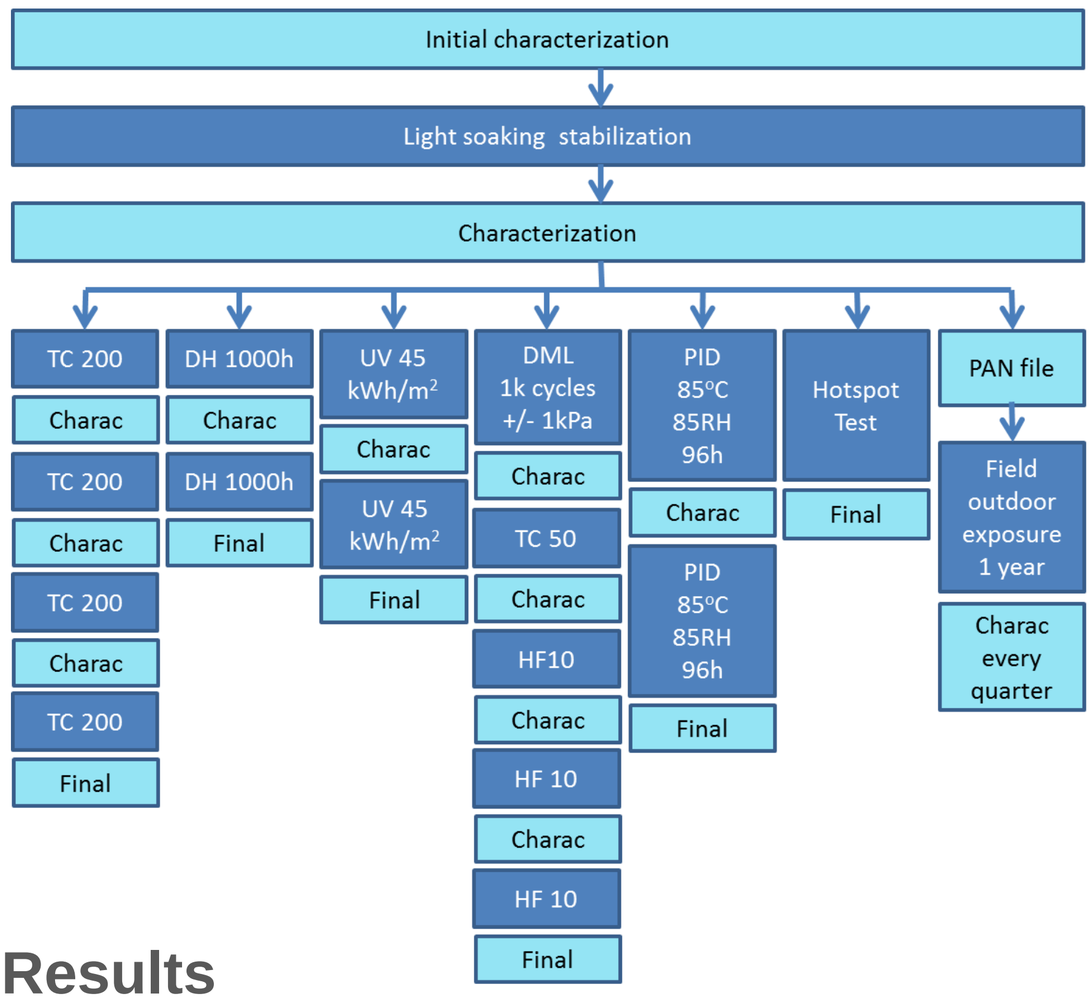
Presented at the NREL Reliability Workshop 2017, Boulder, Colorado

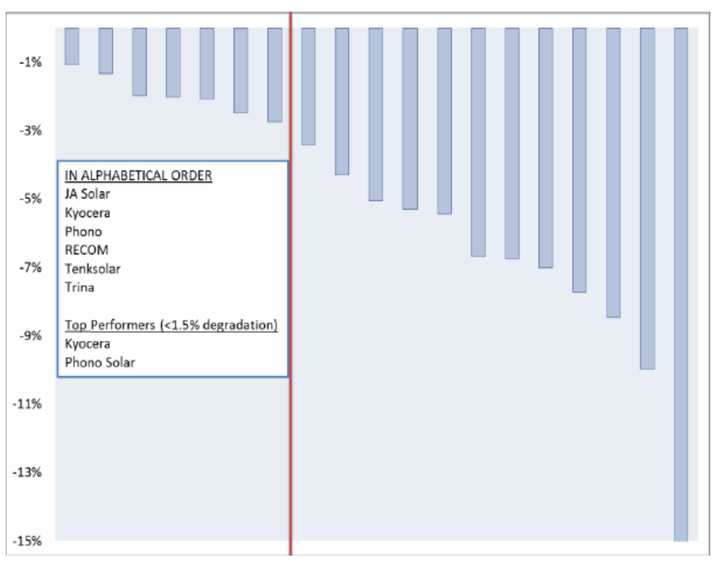
DNV GL Product Qualification Program for modules



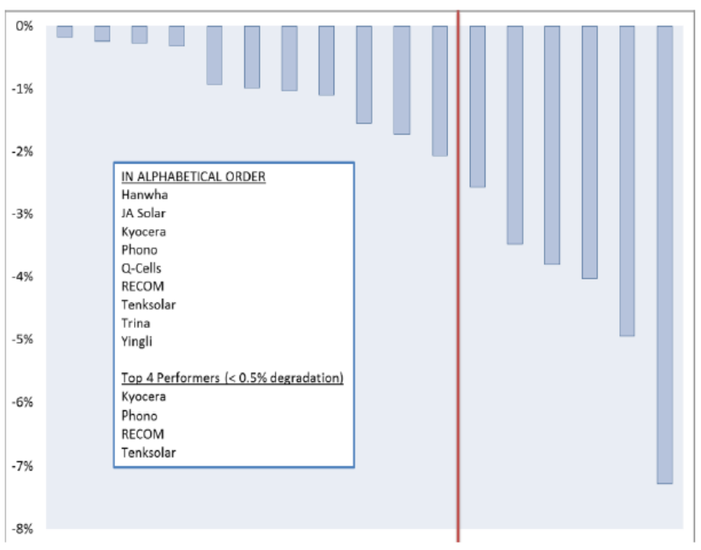
- A network of more than 170 Downstream Partners use DNV GL test data to buy modules
  → 30 GW/year of buying power
- More than 70 Module Qualification Programs to date, from more than 40 manufacturers
  → 50 GW/year of manufacturing power

Results

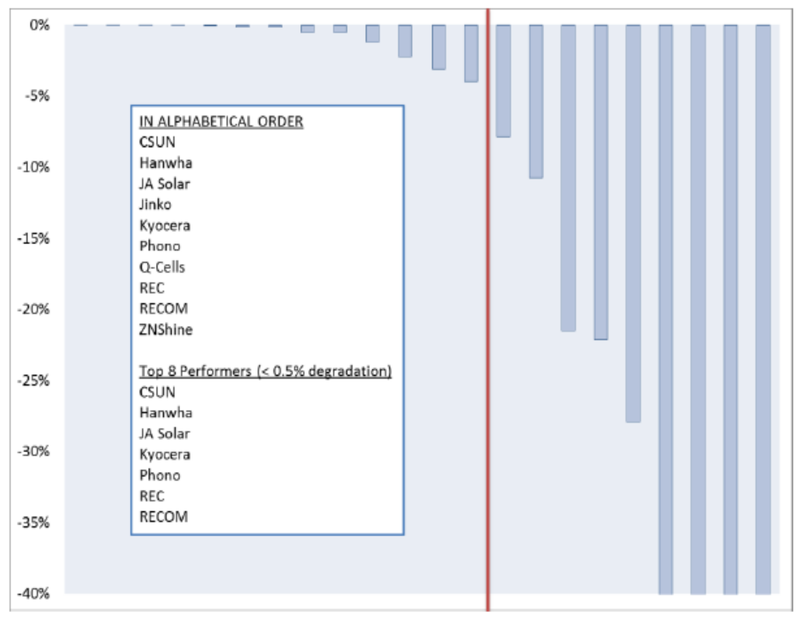
- Degradation observed after 800 Thermal Cycles



- Degradation observed after 1000 cycles of Dynamic Mechanical Load, 50 Thermal cycles , and 10 cycles of Humidity Freeze



- Degradation observed after 100h of PID test

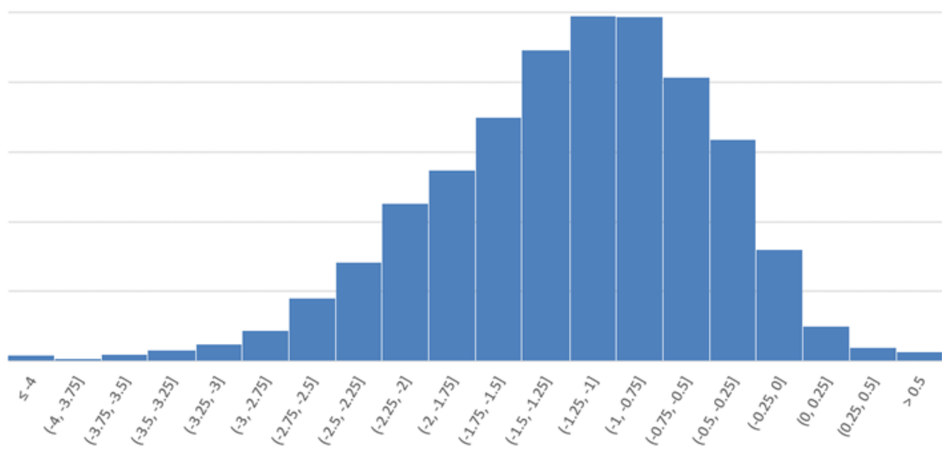


Some statistics

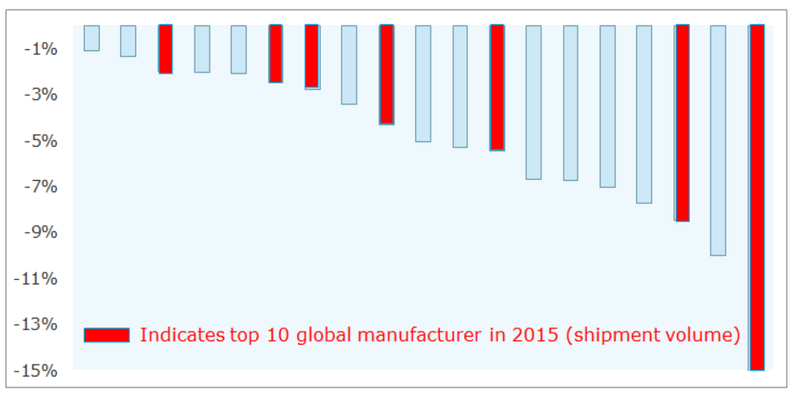
Test	33rd percentile	66th percentile
TC 800 cycles	-3.0%	-5.9%
DML seq.	-0.9%	-3.4%
PID 600h	-1.1%	-5.6%
LID 40 kWh/m²	-0.9%	-1.5%

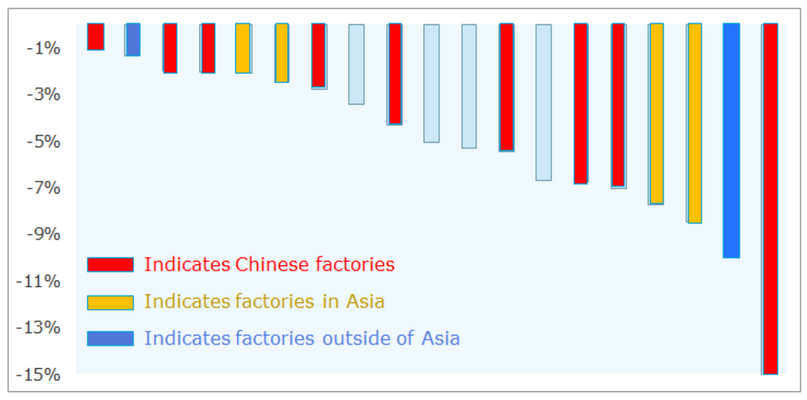
- Disclaimer:
  - ✓ DNV GL Labs probably test on average modules of higher quality/reliability than the global fleet of installed modules
  - ✓ Updated results currently under analysis will be presented in DNV GL-GTM Scorecard 2017

- Degradation observed after 40 kWh/m² outdoors



Looking for correlations





- Little to no correlation found with size of the company and/or location of the factory

Take-aways

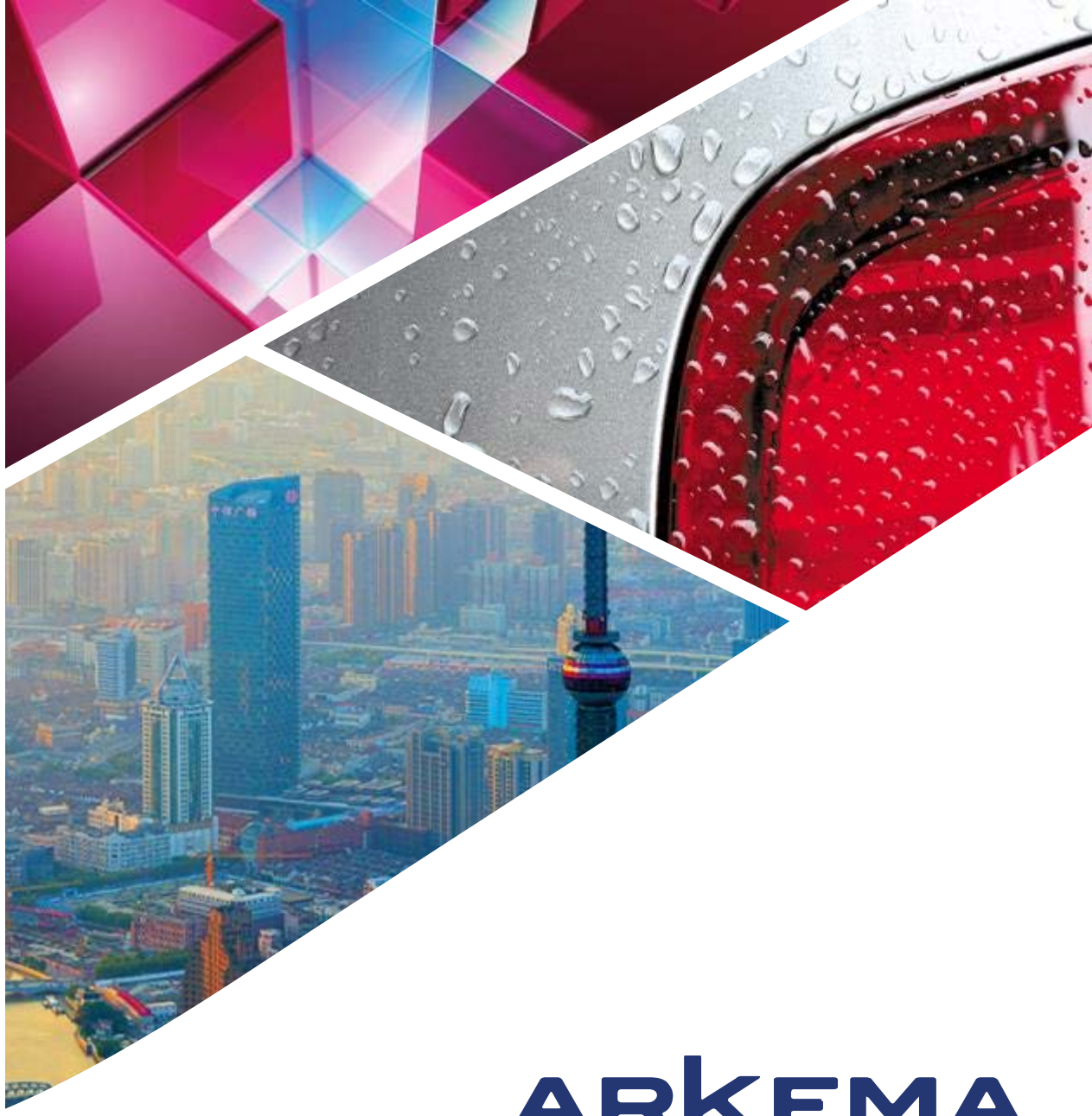
- Comprehensive testing shows a lot of variability among different module manufacturers
- Little correlation to shipment volume or factory location
- The test results are function of the BOM and of the know-how of the manufacturer

WEATHERING OF KYNAR® FLUOROPOLYMERS

FIVE YEAR SOUTH FLORIDA & XENON ARC ACCELERATED WEATHERING

LEADING TO A NEW CHOICE IN CABLE TIES

Gregory O'Brien
Amy Lefebvre
Bryan Douglas
NREL 2017

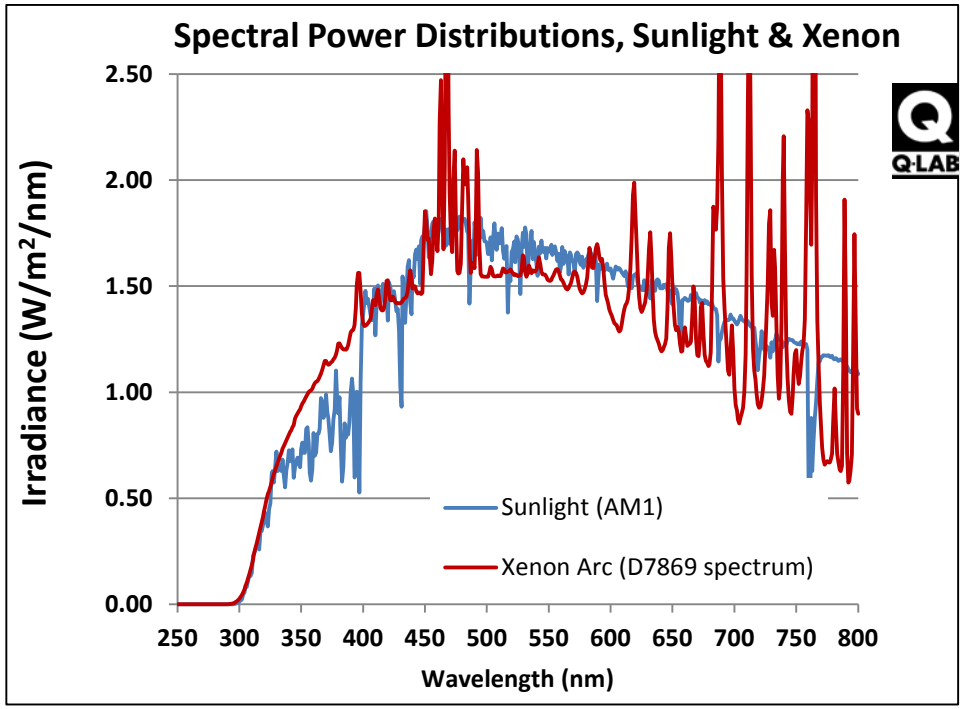


ARKEMA
INNOVATIVE CHEMISTRY

SUMMARY OF THE WORK WEATHERING STUDY PERFORMED

5 year southern Florida exposure

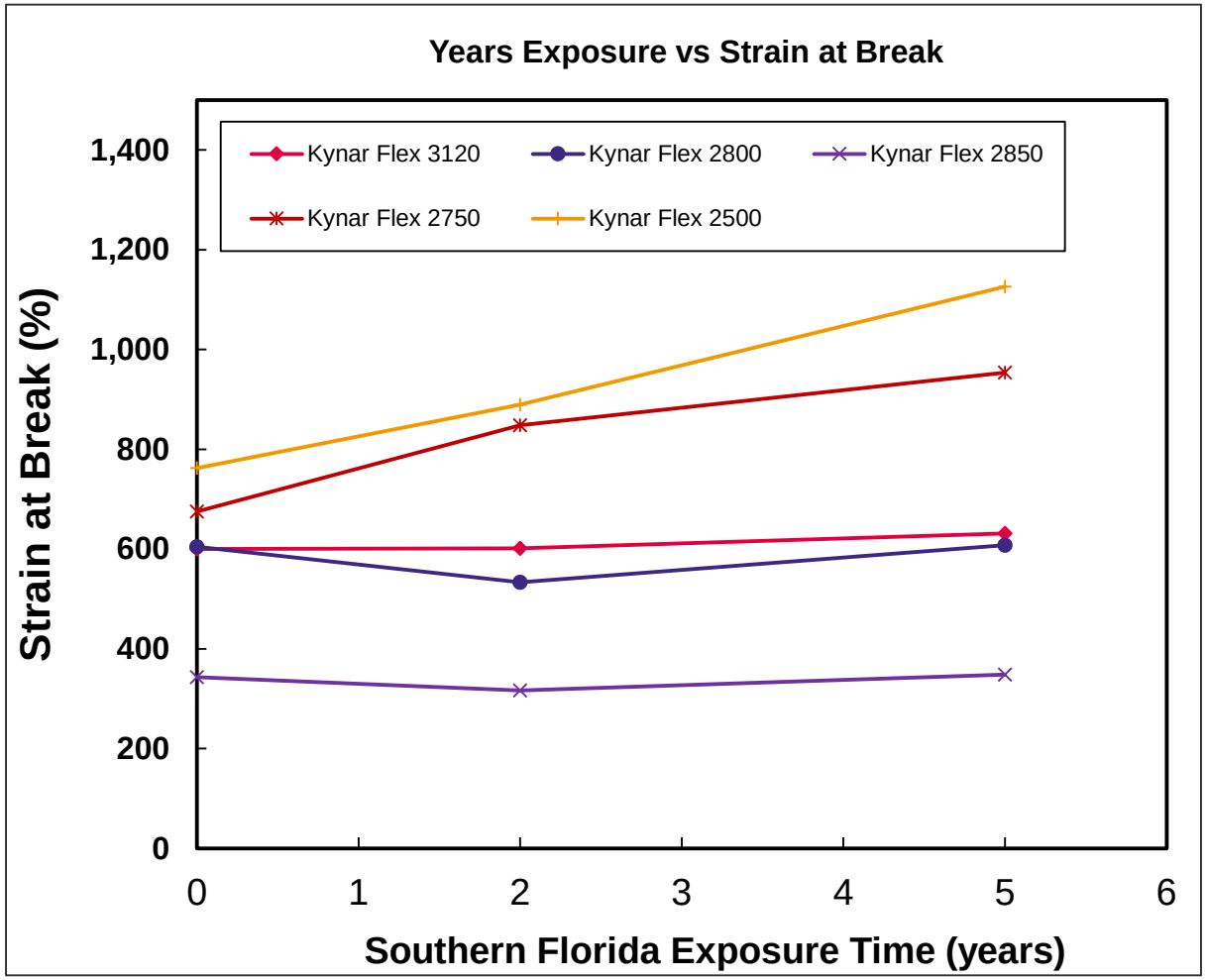
- Extruded Film Samples
- South facing
- 45 degree angle
- Optical testing yearly
- Mechanical Testing at 2 years and 5 years
- Exposures are continuing



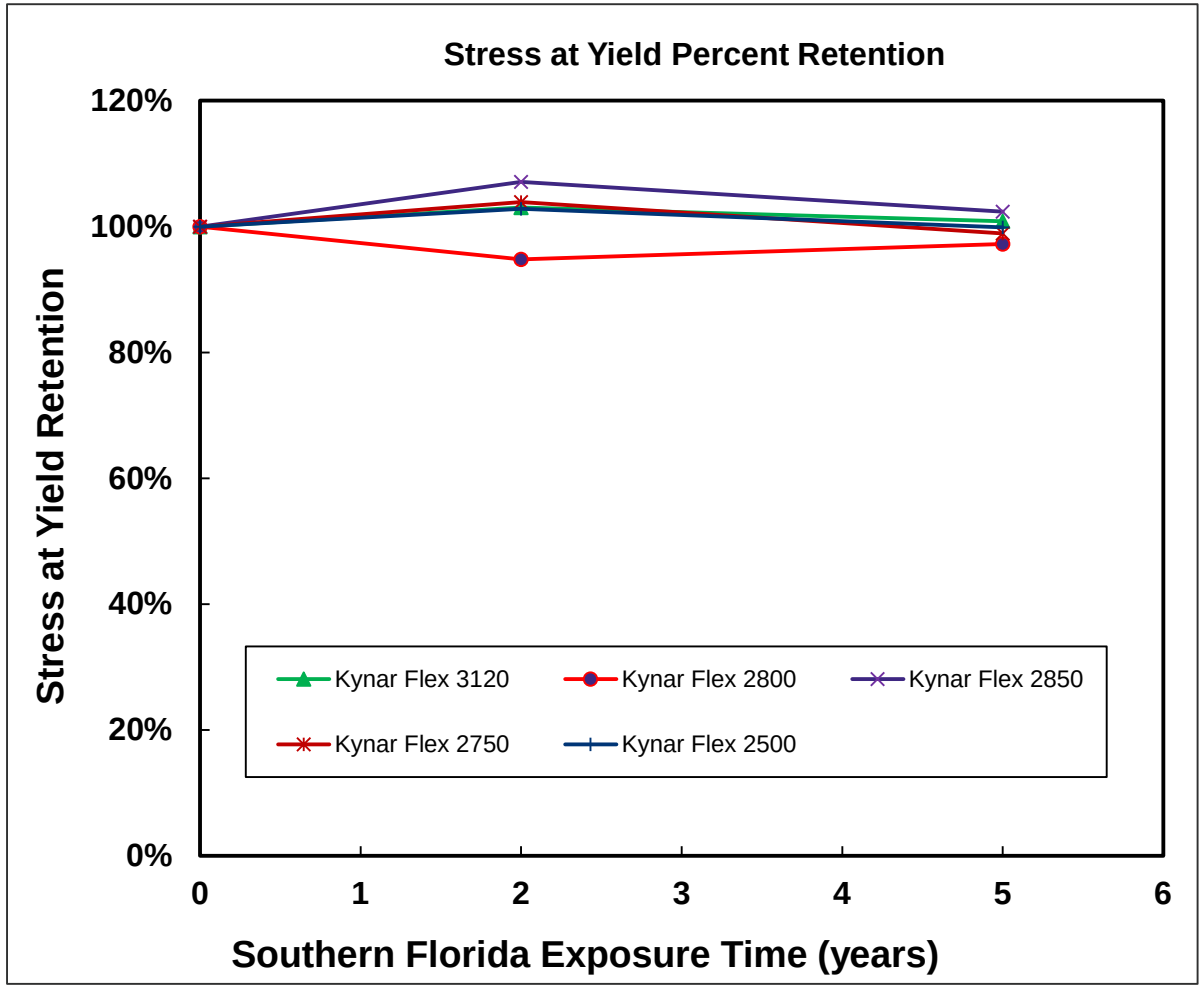
Xenon arc accelerated weathering

- Injection molded tensile bars
- Irradiance at 340 nm of 0.8 W/m²/nm
- Chamber Temperature of 70 °C
- Black Panel Temperature of 95 °C
- Cycle: 102 min light, then 18 min light plus water spray
- Samples tested optically and mechanically at 3000 & 5000 hr

MECHANICAL PROPERTY RETENTION – KYNAR® FILMS – 5 YRS IN FLORIDA



Five years in S. Florida – total UV exposure calculated at 1600 MJ/m2

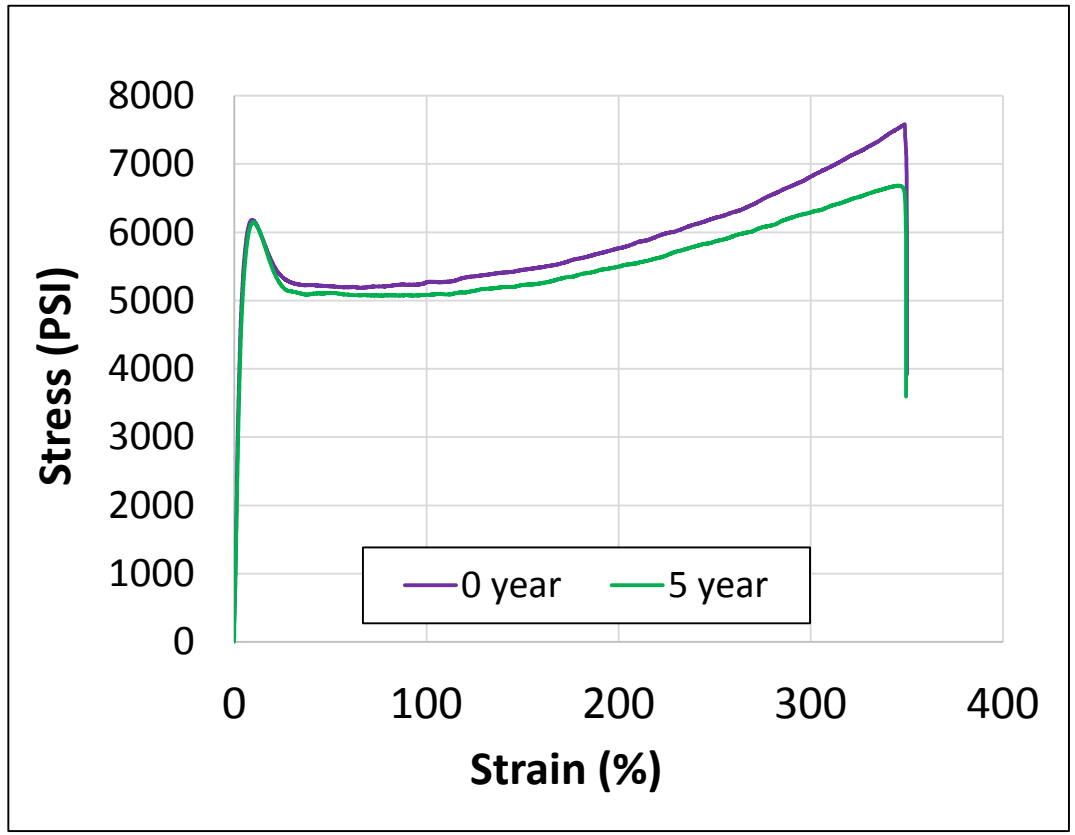


Film Thickness: 50 microns – except Kynar 2500 and Kynar 2750 at 125 microns

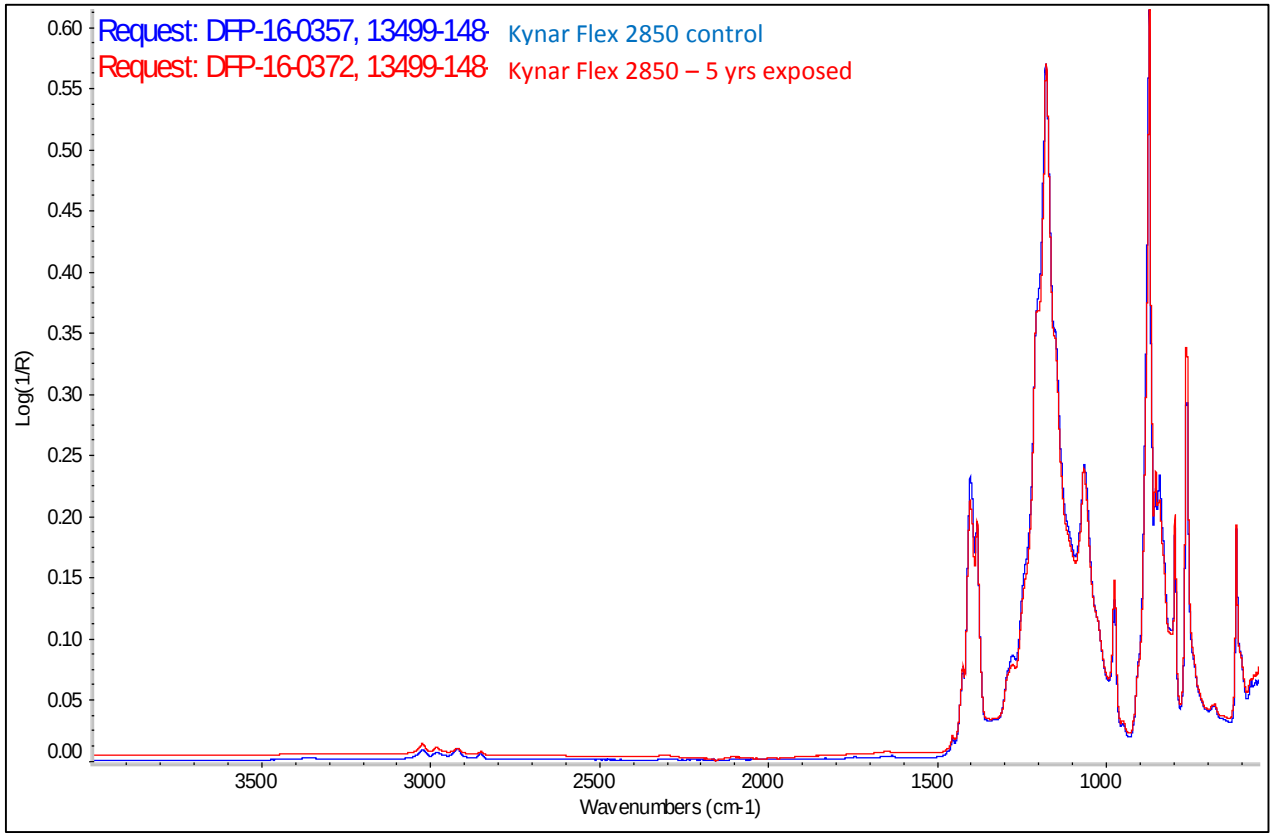
Tensile yield strength maintained at no loss of elongation: UV dosage > 1600 MJ/m^2

MECHANICAL & CHEMICAL PROPERTIES OF KYNAR® FLEX FILMS
BEFORE AND AFTER 5 YEARS OF EXPOSURE IN SOUTHERN FLORIDA

Kynar Flex® 2850 Tensile Stress-Strain



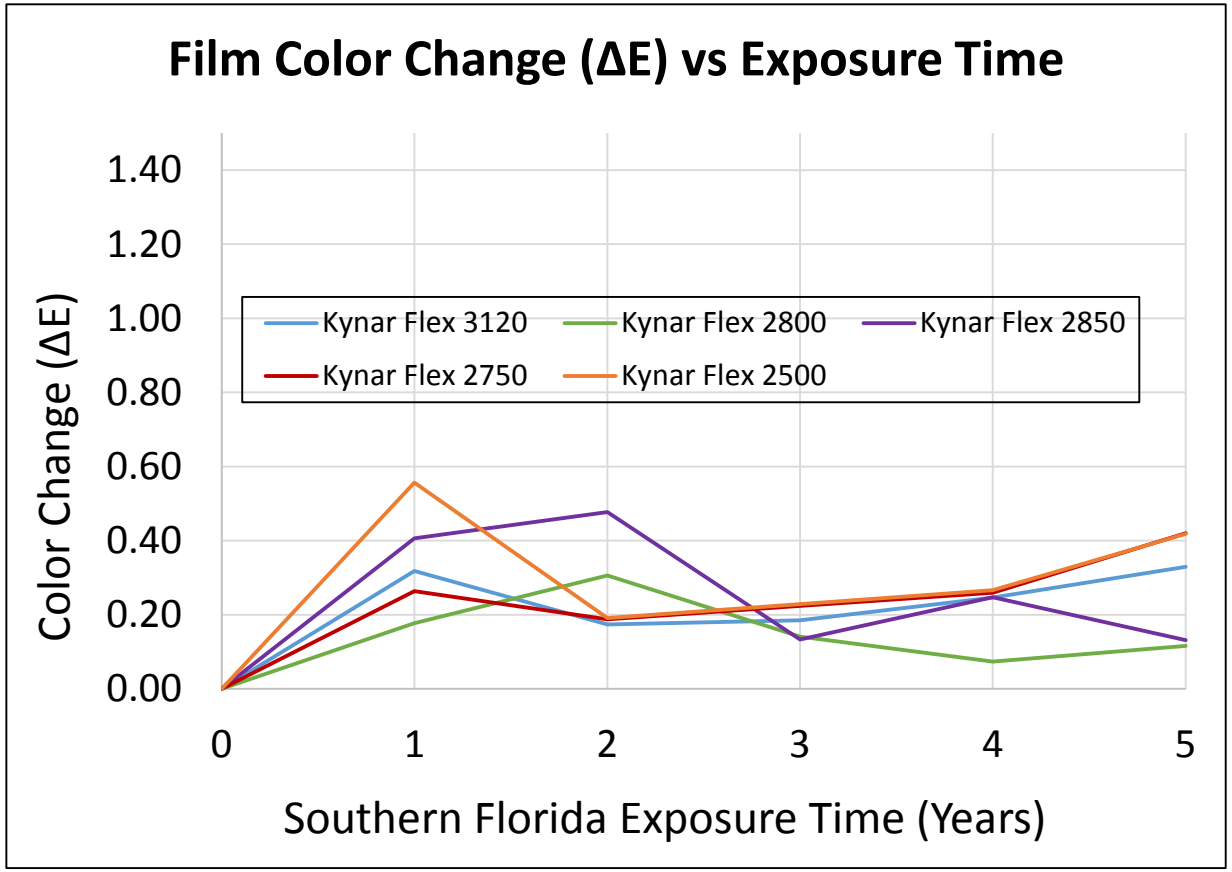
Kynar Flex® 2850 ATR- FTIR

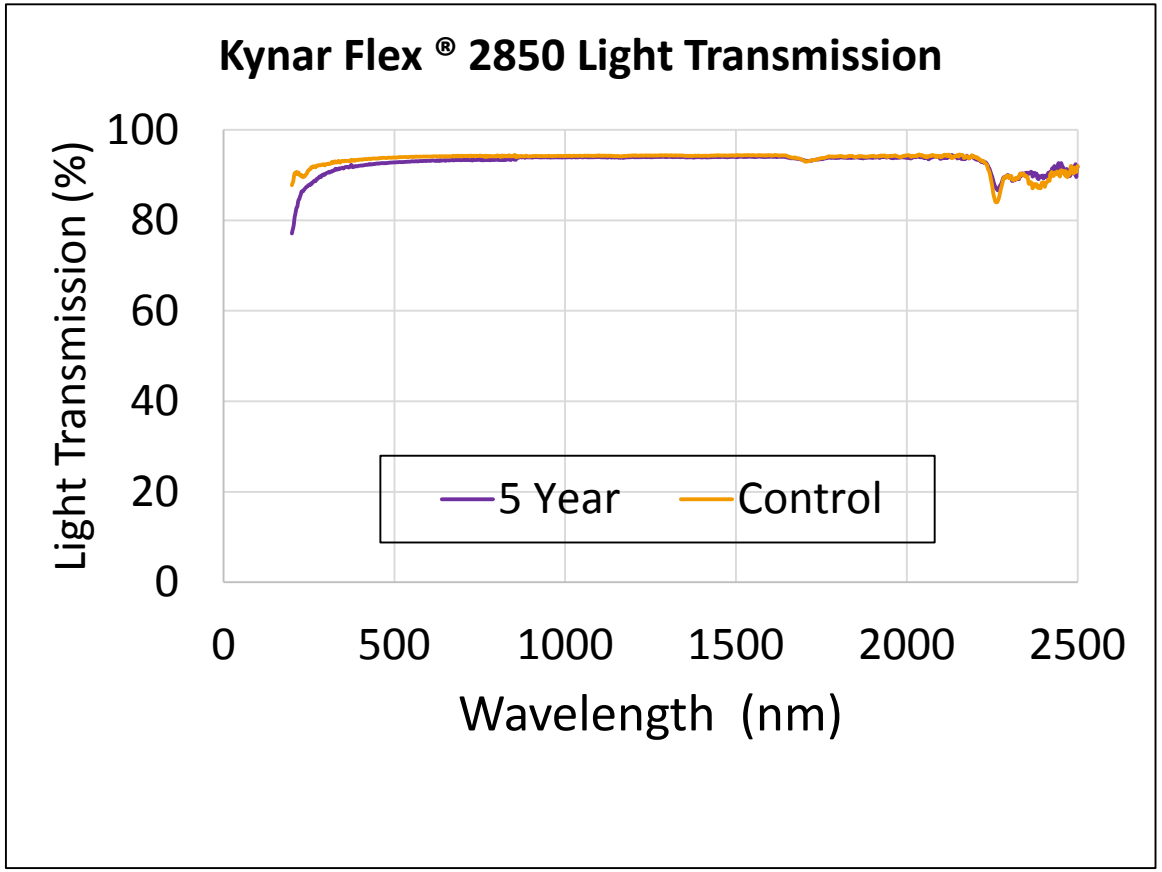


Full mechanical performance is maintained

No UV attack of polymer backbone by FTIR

OPTICAL PROPERTIES OF KYNAR® FLEX FILMS
BEFORE AND AFTER 5 YEARS OF EXPOSURE IN SOUTHERN FLORIDA



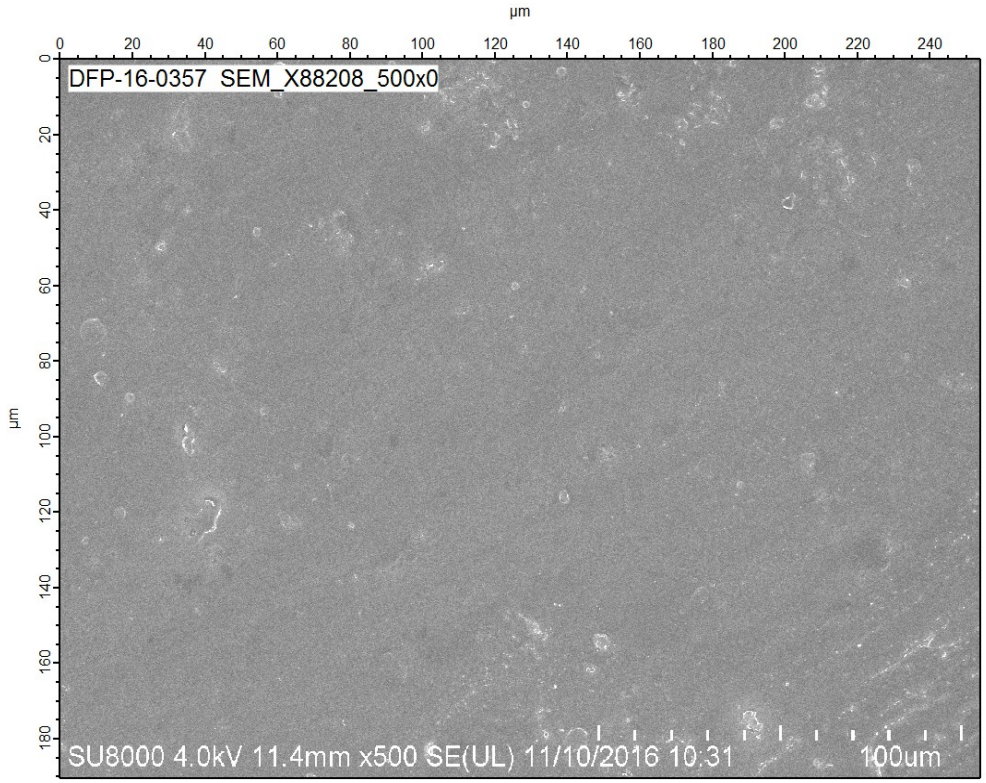


Color change is below the perception limit (< ΔE of 1.5)

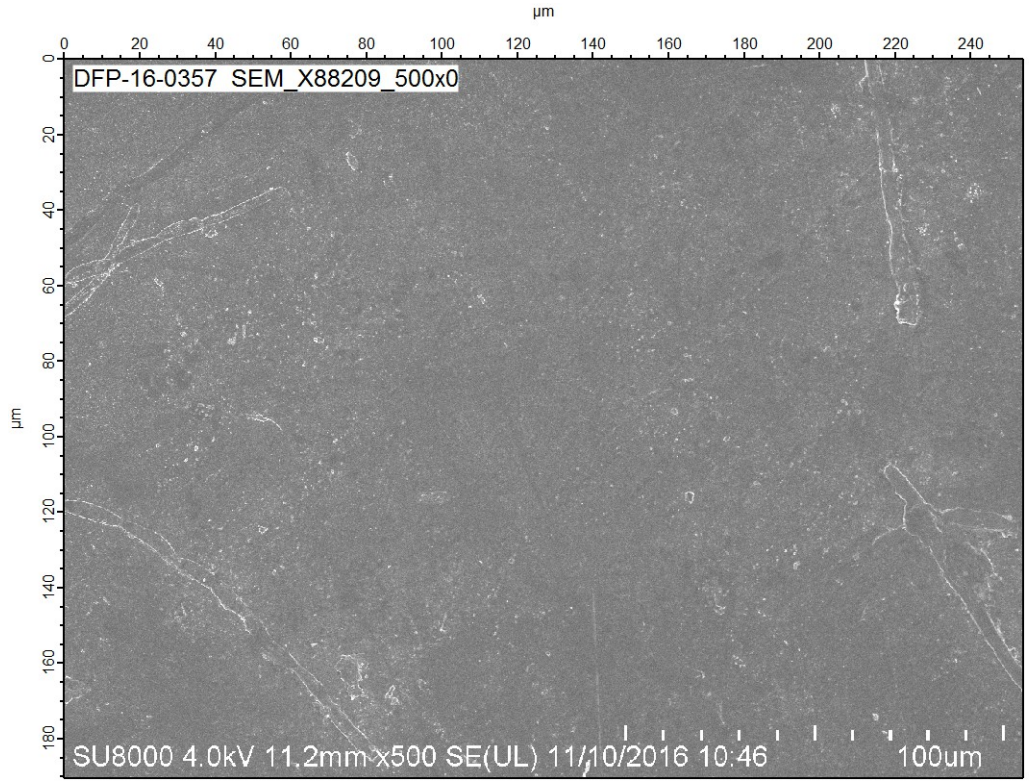
No color change and no significant change is light transmission show UV stability

KYNAR FLEX® FILMS SURFACE PROPERTIES

SEM MICROGRAPH – BEFORE AND AFTER 5 YEARS IN FLORIDA



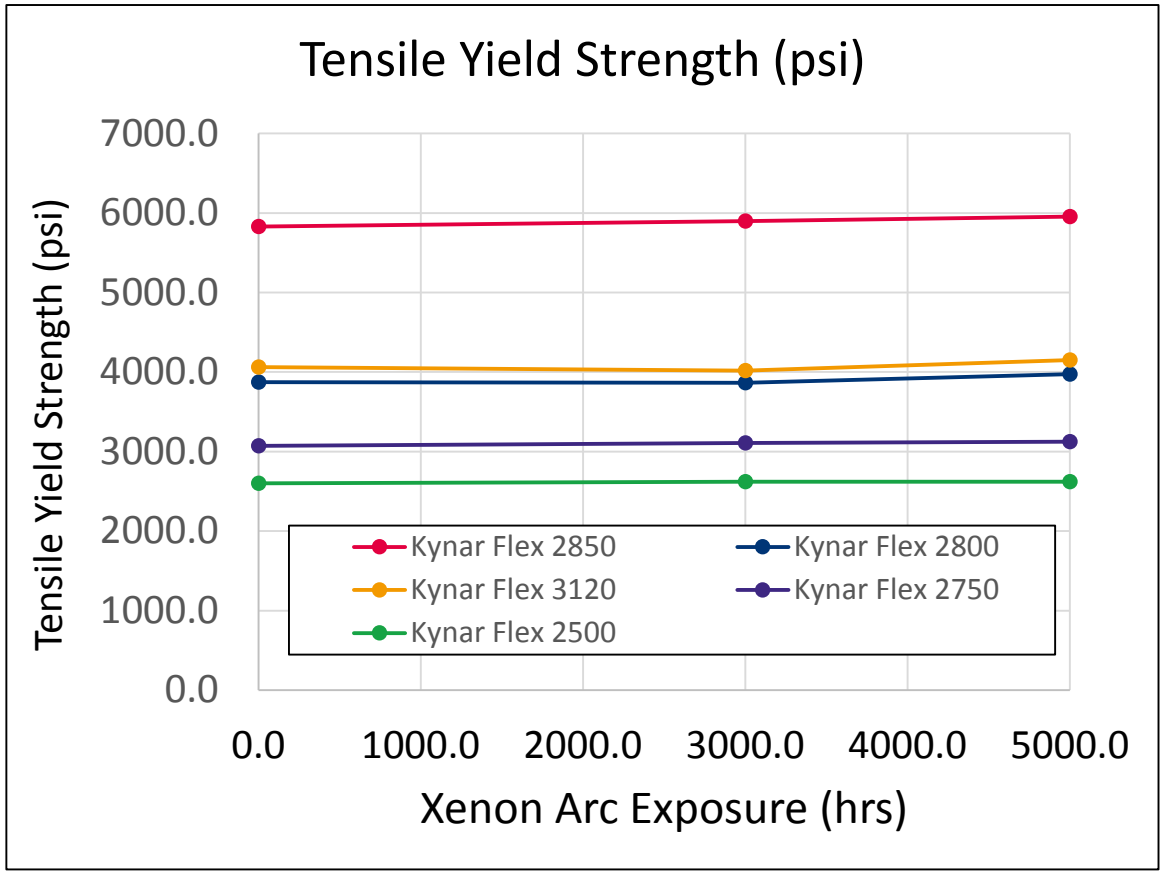
Kynar Flex® 2850
Unexposed Film

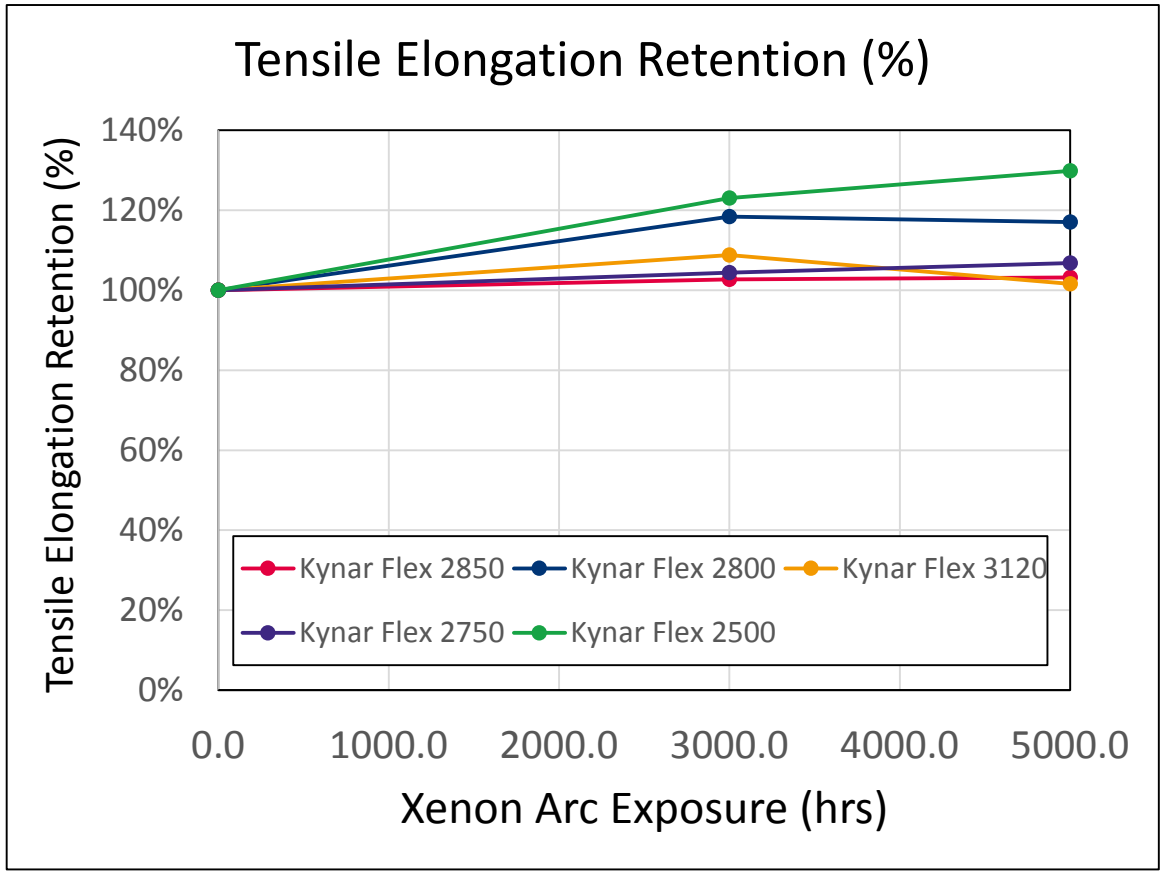


Kynar Flex® 2850
Exposed 5 Years in Florida

No surface erosion or pitting shows the extreme UV resistance of Kynar® Fluoropolymers

MECHANICAL PROPERTIES OF KYNAR FLEX® TENSILE BARS
BEFORE & AFTER 5000 HR XENON ARC ACCELERATED WEATHERING EXPOSURE





Irradiance @ 340 nm of 0.8, 102 min of light with 18 min light & water spray
Chamber Temp = 70 °C , BPT = 95 °C
Samples = ASTM D638 type 1

Results clearly show no embrittlement or degradation in accelerated weathering

MECHANICAL PROPERTIES OF KYNAR FLEX® GRADES OFFERS OPTIONS
STRENGTH AND FLEXIBILITY VARY – BUT ALL OFFER OUTSTANDING WEATHERING

Injection Molded Part Properties

Material	Exposure (hrs)	Stress at Yield (psi)	Strain at Break (%)	Tensile Modulus (psi)
Kynar Flex® 2850	0	5850	44	170,814
	3000	5900	46	178,697
	5000	5950	46	176,375
Kynar Flex® 3120	0	4050	135	117,022
	3000	4025	147	120,136
	5000	4150	137	115,333
Kynar Flex® 2800	0	3875	276	91,435
	3000	3865	327	93,598
	5000	3975	323	89,442
Kynar Flex® 2750	0	3075	353	65,440
	3000	3100	368	64,222
	5000	3125	377	66,292
Kynar Flex® 2500	0	2600	491	46,955
	3000	2625	604	48,524
	5000	2625	638	45,511

Extruded Film Properties

Material	Years	Thickness (µm)	Stress at Yield (PSI)	Stress at Break (PSI)	Strain at Break (PSI)
Kynar Flex® 3120	**0**	**50**	4,470	9,418	600
	5		4,397	6,720	631
Kynar Flex® 2800	**0**	**50**	4,229	9,246	605
	5		4,111	6,759	608
Kynar Flex® 2850	**0**	**50**	5,907	7,233	344
	5		6,048	6,475	348
Kynar Flex® 2750	**0**	**125**	2,870	6,814	675
	5		2,839	7,026	954
Kynar Flex® 2500	**0**	**125**	2,475	6,313	762
	5		2,472	6,562	1,126

A range of stiffness and strength offers component designers options
For applications where extreme weathering performance is critical

STRONG CABLE TIES – FOR EXTREME CONDITIONS

- Kynar® Films have shown outstanding weathering performance in PV backsheets
- Kynar Flex® grades show no changes in properties in outdoor & Xenon weathering
- Extreme weathering resistance, high strength and flexibility offer the designer choice to mold high performance cable ties
- One company – Nile Polymers in offering Kynar® cable ties.

http://www.nilepolymers.com/strong-ty-cable-ties/

Nile

Strong-Ty™ Kynar® Cable Ties

Strong-Ty™ cable ties made from Kynar® PVDF are ideal for environments where combinations of high temperature, chemical attack, radiation or mechanical stress limit other materials. These cable ties are durable and resist abrasion and mechanical damage during and after installation. With minimal flame-spread and smoke-generation Strong-Ty™ cable ties meet the National Electrical Code (NFPA-70A) and UL94V-0 requirements for installation in building plenum.

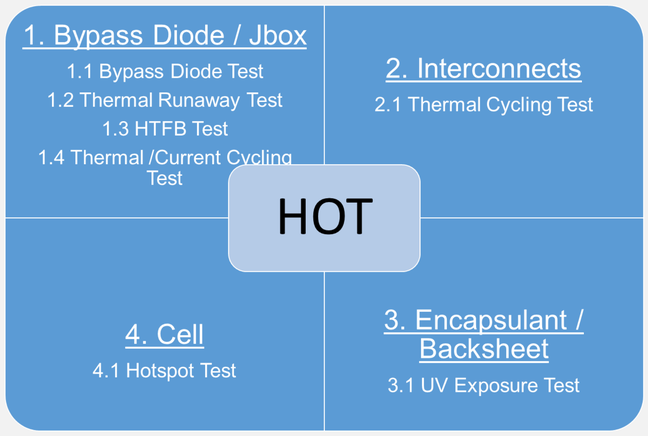
Accelerated Testing of Photovoltaic Modules in Extreme Climates

Vivek Gade, Jared Opalewski, Narendra Shiradkar, and Shesh Vaishnav, Jabil Solar and Environmental Test Center, St. Petersburg, Florida.

High Operating Temperature (HOT) Protocol for Hot Climates

- The stressors and their duration in IEC 61215 protocol are inadequate for modules deployed in extremely hot climates / roof mounted configurations.
- Jabil's High Operating Temperature (HOT) protocol is used to provide enhanced level of confidence in long term reliability for such modules.
- The HOT protocol is based on Jabil's unique know-how on bypass diode / Junction box reliability modeling, 6 years of experience in evaluating reliability of PV modules and the guidelines provided in the upcoming IEC 62892.
- This protocol focuses on following four module components that Jabil has identified to be most susceptible for degradation / failure in the hot end use environments. The components and corresponding accelerated tests are described in the figure below:

The HOT Protocol Architecture



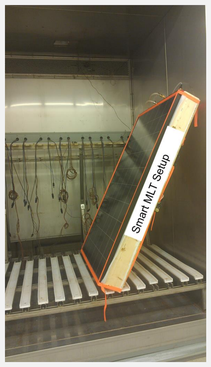
- The HOT protocol uses customized and extended versions of accelerated test tailored to expose specific weak links in PV module designs.
- All of these tests are performed on full size, commercial PV modules while the customers have an option of performing the diode related tests only on junction boxes.
- The maximum temperatures during accelerated tests are determined by first calculating / measuring the maximum module temperature (T_M) and diode temperature for climate of deployment and module mounting configuration of interest.
- By default, roof mounted module configuration in Riyadh, Saudi Arabia is considered to simulate hot end use environment.

- **1.1 Bypass Diode Test:** Test conditions are determined by extensive diode temperature modeling in hot climates followed by optimization for minimizing the possibility of type I and type II errors. Jabil's recommendation is being considered for incorporation in IEC 62892 revised bypass diode test.
- **1.2 Thermal Runaway Test:** Jabil has found that 9 out of 10 Jbox designs tested are susceptible for thermal runaway failures in hot climates especially when used with high Isc modules. The test conditions for this test are more severe than those for rack mounted modules in IEC 62979. Moreover, going beyond the pass / fail criteria, quantitative estimate of how far the diode is operating from thermal runaway point are also provided.
- **1.3 High Temperature Forward Bias (HTFB) Test:** HTFB condition can result from cracked cells or partial shading. Silicon Schottky diodes are especially susceptible to premature failure under such conditions. This test uses Jabil's diode field temperature modeling results, Arrhenius Activation energies from manufacturers and 200 hours of chamber testing at high temperatures to arrive at minimum service life of bypass diodes in continuously ON condition in field.
- **1.4 Thermal / Current Cycling Test:** This test involves procedure similar to Test 2.1. However, the current is passed through the diodes instead of PV modules to simulate real life scenario which can expose the diodes to a ΔT_J of ~ 200 ^oC.
- **2.1 Thermal Cycling Test:** This test is performed similar to the thermal cycling test in IEC 61215 standard; except the upper limit on the temperature is TM ± 2 °C, instead of 85 ± 2 °C. The test is performed for 300 thermal cycles. The module passes the test if the power degradation is less than 5%. The idea is to ensure module interconnects are durable to withstand thermal cycling in hot climates.
- **3.1 UV Exposure Test:** This test is performed similar to the test in IEC 61215 standard; except the module temperature in the UV preconditioning test is (TM– 10 °C ± 5) °C, instead of (60 ± 5) °C and the test is performed for a UV exposure of 90 KWHr.
- **4.1 Hotspot Test:** Solar cells within the module operate at higher temperature in hot climates. Also, they experience higher temperatures during partial shading. This test is performed similar to the test in IEC 61215 standard; except the temperature of the exposure is changed from (50 ± 10) °C to (TM – 10 °C ± 5) °C. The pass criteria are similar to those in current IEC 61215 standard.

Discussion and Conclusions

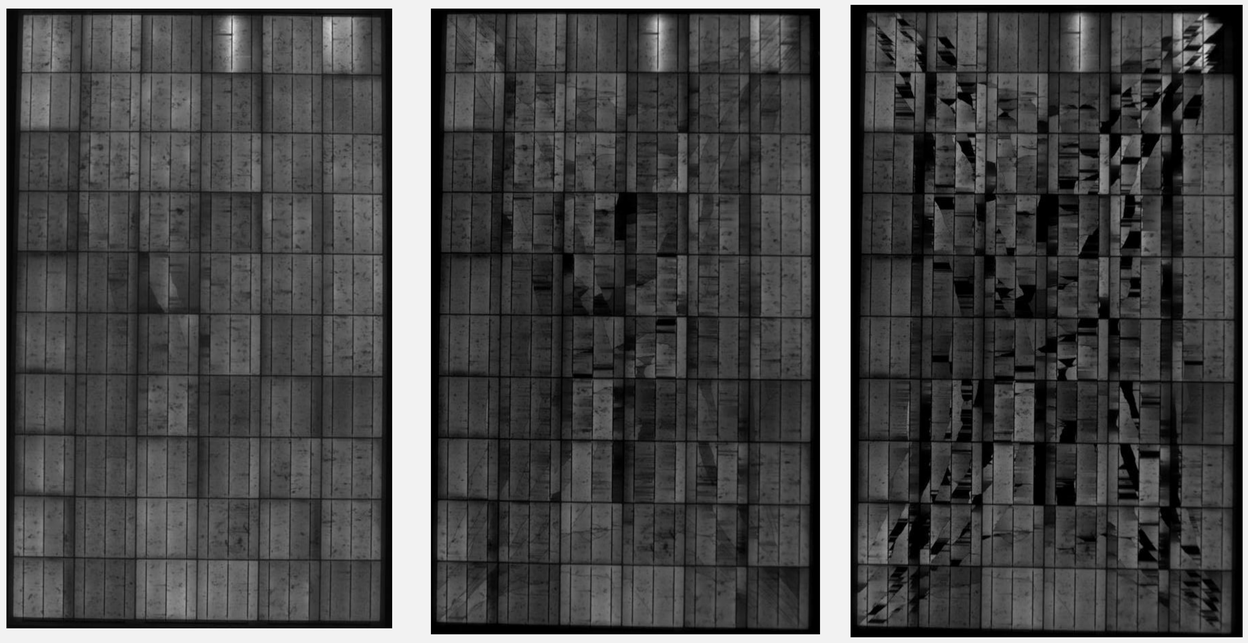
- The HOT protocol is useful to gain higher confidence in long term reliability of PV modules in high temperature end use environments.
- It can be used by module manufacturers during product development phase to develop a reliable module design or by PV project developers to select robust module designs from the market.
- The diode / Jbox related tests in HOT protocol are unique offerings by Jabil and are being used by leading companies involved in module deployments in hot climates / roof mounted configurations.

Mechanical Loading at Subzero Temperatures for Cold Climates



- Field deployed modules are exposed to subzero temperatures during events of snow loading in field. On contrary, mechanical (Snow) load test in IEC 61215 is performed at room temperature.
- When the encapsulant is cooled below it's glass transition temperature (T_g), it becomes stiffer and can cause enhanced cell cracking and associated power loss.
- Jabil's Smart Mechanical Load Setup equipped with capability of in-situ EL imaging is used to assess realistic, worst case snow load damage caused to PV modules at subzero temperatures up to -40 ^oC.
- In this study, performance degradation in a PV module post mechanical loading test (MLT) at 3700 Pa at -40 ^oC is analyzed.

Experimental Results: Post MLT at -40 ^oC



- A condition of 3700 Pa, which is less severe than IEC snow load (5400 Pa) was chosen to see if lower mechanical load at subzero temperature can produce significant power degradation due to cell cracks.
- The module is supported along its frame / perimeter on the Smart MLT setup. A 'X' pattern commonly reported in the literature after MLT can be seen in the EL images.
- Several closed cracks and a few open cracks are observed in the post MLT EL image at no load.
- Smart MLT setup reveals in the post MLT EL image at 1k Pa that the module will experience significant amount of disconnected cell areas if/when the closed cracks open up.

Parameter	Initial	Final	Change
Power (W)	244.53	233.13	- 4.66 %
Fill Factor (%)	73.1	70.8	-3.15%
Voc (V)	37.75	37.4	-0.93%
Isc (A)	8.86	8.8	-0.68%

- Power loss after MLT at 3700 Pa, -40 ^oC was 4.66%. It is highly likely that at IEC snow load conditions (5400 Pa) the module power loss will exceed 5% limit.
- Majority of lost power was due to Fill Factor loss associated with mismatch generated in sub-strings as a result of cracked cells.
- Environmental exposure for such module can cause closed cracks to open up permanently, leading to more power loss.

Discussion and Conclusions

- Modulus of elasticity of EVA considerably increases below T_g, making it stiffer and resulting in enhanced cell cracking even under reasonably high mechanical loads.
- It is important to perform the MLT at -40 ^oC and it is also necessary to study impact of worst case crack opening scenario resulting in disconnected cell areas. Smart MLT setup provides both capabilities.
- Further research is underway to quantify the effects of different encapsulants and module designs on power loss after MLT at -40 ^oC and at room temperature under different loads.

Summary of DC Losses Observed using Aerial Infra-Red Inspection Across >1.6 GW

Rob Andrews and Kristine Sinclair
inspections@heliolytics.com
The 2017 NREL/SNL/BNL PV Reliability Workshops, Lakewood, CO, February 28 – March 2, 2017

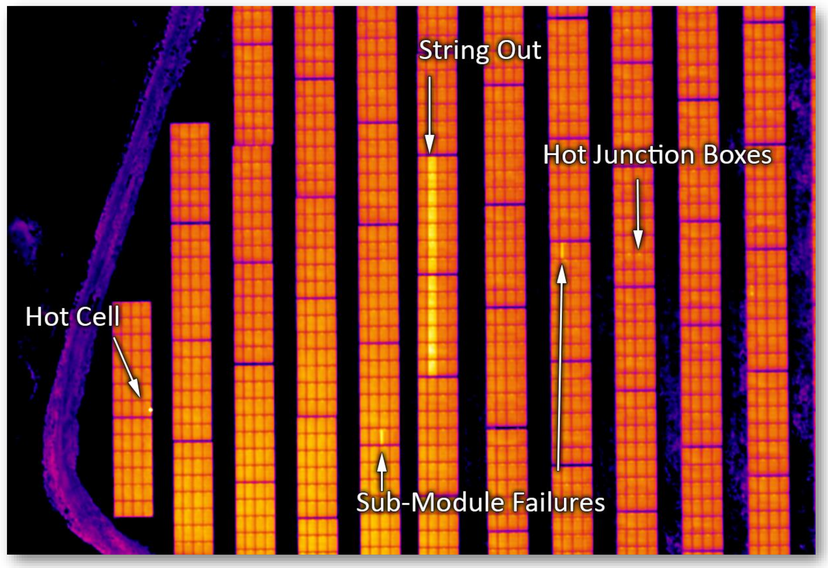
Aerial inspections, which capture infrared (IR) and visible imagery, is a tool offering 100% DC fault detection. Thermal images resulting from aerial IR inspection allow precise identification and mapping of under-performing portions of an array.

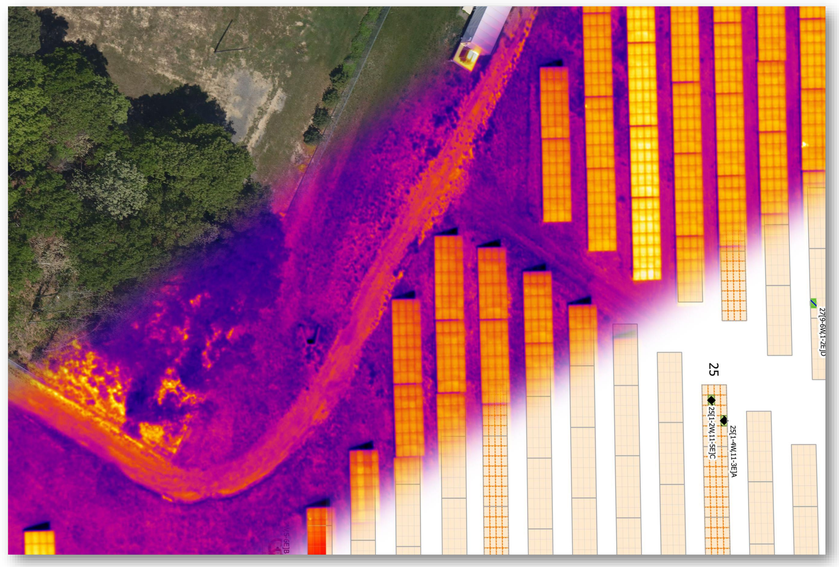
To date, **Heliolytics Inc. has scanned > 2.7 GW** of solar power plants. This work presents a summary of defect rates for a 1.6 GW subset of data.

- North America sites, distributed across 17 states/provinces
- **> 450 sites included, ~ 6 million modules analyzed**
- Sites with a failure rate >10% excluded from analysis
- Duplicate scans of the same site not included

Future work based on a client opt-in **anonymized database** will analyze data based on additional factors, such as site age, module/inverter/tracking technologies, location, DC overrate, etc.

This work will feed into DOE EERE SETO funded project joint with Sandia National Laboratories entitled *"Improvement of System Reliability Models using Measured Reliability Data."* Part of this effort will be to develop a taxonomy to allow for sharing of DC fault information and metadata in a format compatible with the Orange Button initiative.





Causes

Defects Categorized by Component Causing Observation

Electrical Balance of System Issues
- Inverters out
- Combiners out
- Strings out (loose connections, blown fuses, etc.)
- Reversed polarity (mis-wiring)
- Potential Induced Degradation (PID, caused by improper grounding)
- Hot conduits

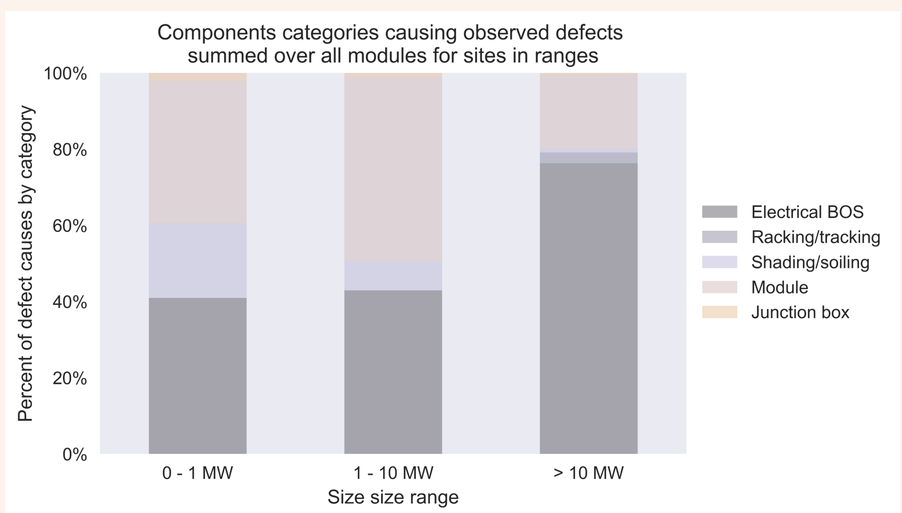
Racking / Tracking Issues
- Broken racking
- Racking misalignment
- Tracking error / misalignment

Shading / soiling Issues
- Surface fouling (localized)
- Surface soiling
- Shading due to vegetation growth
- Shading from adjacent rows
- Shading due to overhead objects
- Foreign objects on surface

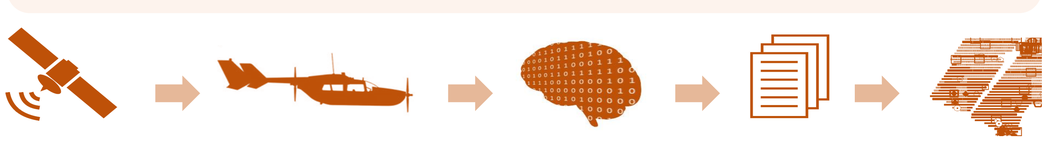
Module Issues
- Relative differences in performance
- Hot modules
- Sub-module hot-spots
- Engaged bypass diodes
- Cell anomalies
- Amorphous hot regions (thin film)
- Missing modules
- Broken modules
- Anti-Reflection-Coating issues
- Fogging (delamination)
- Discolouration

Junction box Issues
- Hot junction boxes

Other Issues (not included in this analysis)
- Erosion / drainage issues on site
- Roof surface hot-spots
- Lighting strikes



Sites grouped into size ranges, defects summed by observation count over all sites in ranges. Of all modules observed to show faults, the proportion attributed to each cause category is presented.



Effects

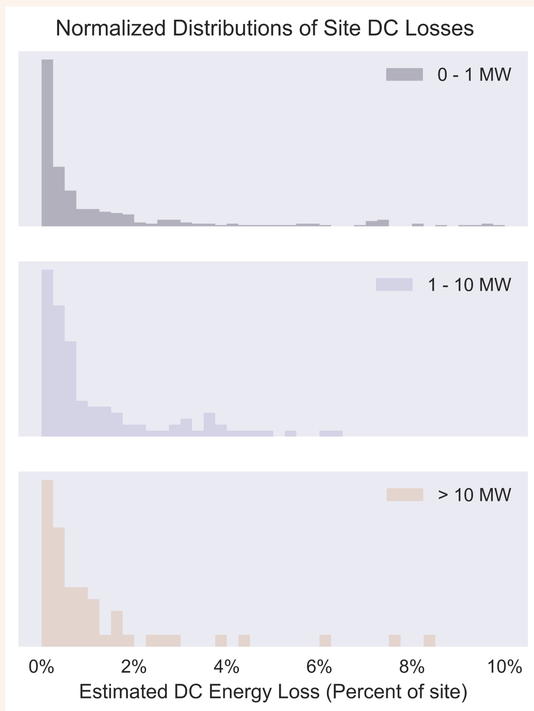
Impact of defects to site energy production

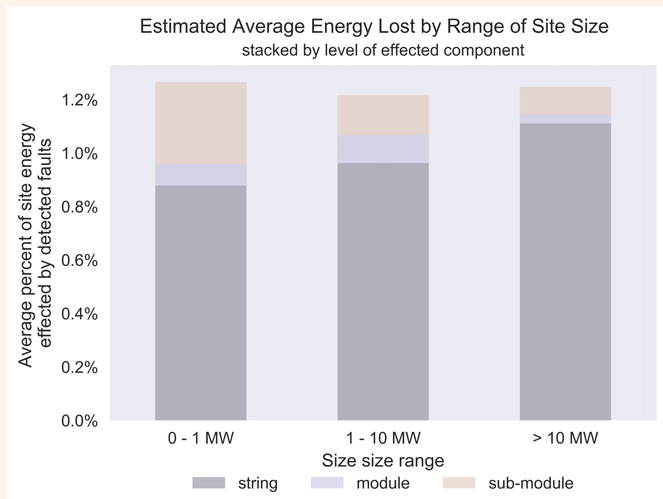
Observed defects given a weighting based on type of issue and severity (temperature) of presentation. Values from 0 – 1 given based on typical impact to power production on a per module basis.
- Ex. Hot conduits → 0, strings out → 1

Site ranges represent Residential & Commercial/Industrial, small Utility scale, and large Utility scale projects. Ranges chosen such that each category contains > 50 sites and a cumulative capacity > 120 MW.

Impacts categorized by level of electrical component effected by defect: String, Module or Sub-module level

	Sub-module	Module	String
Example issues	Cell anomalies, engaged bypass diodes, surface fouling	Low performance, missing modules, fogging	Wiring errors causing reversed polarity, loose connection or blown fuse causing string out
Typical impact to overall DC production	Low to moderate	Moderate	High
Relative ease of remediation	Difficult (module swap, but hard to justify)	Moderate (module swap)	Easy
Comments	Becomes relevant to owners/operators when observed across a large portion of site and/or attributable to a particular production batch – triggers serial defect or performance warranty claim.		"Low-hanging fruit" for owners/operators





Site size Range	Mean Site Size (MW dc)	Impact level of observed DC defects: Sub-module	Module	String	Total
0 - 1 MW	0.4	0.31%	0.08%	0.88%	1.26%
1 - 10 MW	3.5	0.15%	0.10%	0.96%	1.22%
> 10 MW	21.6	0.10%	0.03%	1.11%	1.25%

ENERGY

What does an Independent Engineer look for in a PV Plant?

NREL/SNL/BNL PV System Reliability Workshop

March 1, 2017

Raymond Hudson

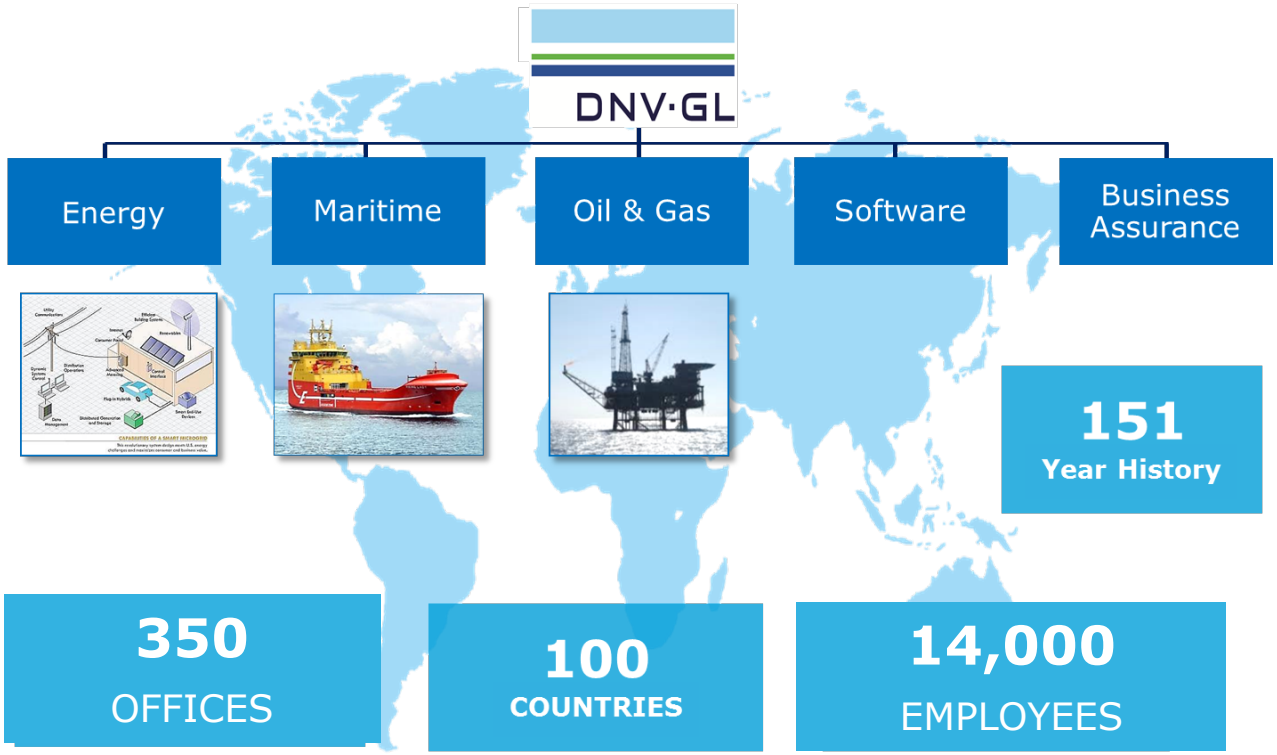
Global Solar Segment Director

DNV GL © 2013

Outline

- DNV GL Introduction
- PV System Landscape
- Independent Engineer Role
- Types of Independent Engineering Projects
- Independent Engineer Scope and Key Elements
- What enhanced reliability data would increase the value of a PV system?
- Conclusion

About DNV GL



DNV GL is the world's largest independent energy & renewable advisory firm.

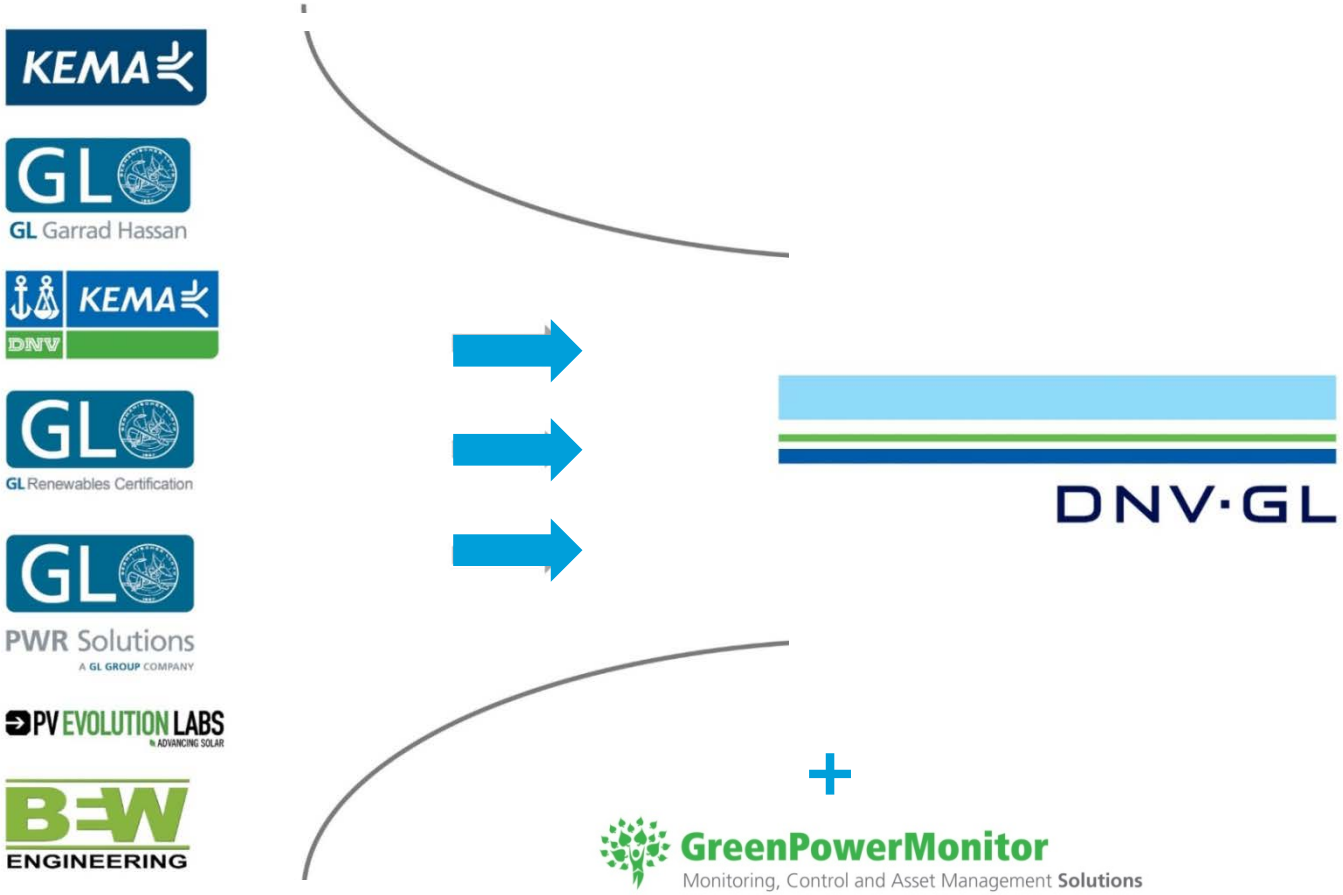
We have over 2500 energy experts.

More than 1000 are focused on renewables.

DNV GL has advised over 5500 solar projects.

DNV GL's Solar Team has considerable experience in many solar aspects

DNV GL has Combined Strengths to Support Energy Customers



DNV GL Offers Services for Solar Projects and Components

Solar Project Lifecycle: DNV GL Solar Services

Project Feasibility

- Feasibility
- Utility Grid Integration
- Component Technology Reviews
- Energy Assessment
- Environmental Permitting

Developers & Equipment Manufacturers & Utilities

System Design & Development / Construction & Commissioning

- Independent Engineering
- Owner's Engineering
- Project Certification
- Module and Inverter Qualification Testing

Developers & Financiers EPCs & Utilities

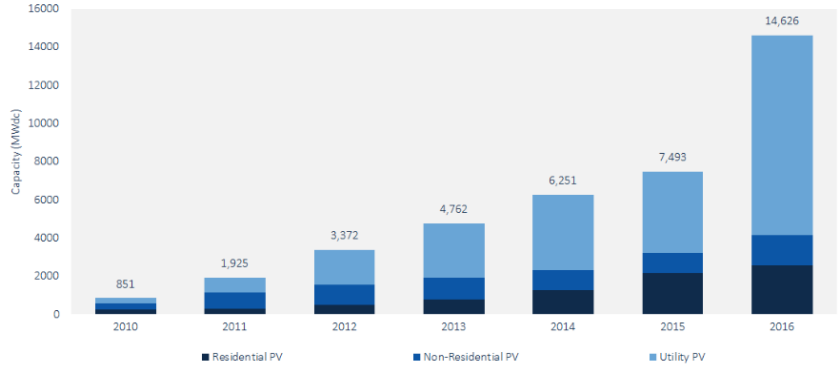
System Operations

- Project Testing
- Forecasting
- Existing Asset Consulting, Refinancing and Decommissioning
- Monitoring, Control, Asset Management

Developers & Owners & Utilities

PV System Landscape

- Installed capacity growing rapidly!
- 76 GW PV capacity installed globally in 2016 ($116B investment)
  - Over 300GW total global capacity (growing for 10 years)
- 14.6 GW PV installed in the USA (95% growth over 2015)
- PV largest new generation source in USA in 2016
  - 39% of new generation capacity solar (29% gas , 26% wind)
- More experienced Financiers/EPCs/Installers/Operators
  - Also many new players
- New technologies being introduced
  - Innovation but potential risks
- Module costs dropping rapidly
  - Reports below $0.40/Wdc
- Inverter costs also dropping rapidly
- Significant pressure to reduce system costs
- It is critical to maintain high PV system quality and performance



Source: GTM Research / SEIA U.S. Solar Market Insight *report*

Independent Engineer's Role

- Provide technical advice to financiers of PV systems
  - Provide opinions about technical system risks
  - Provide technical input to financial models
  - Support sound investment decisions
  - Note that financial models are not standardized
- First PV IE projects in USA 2005
- Larger projects being financed
  - Use same approach as other investments
- Historic Example Nellis AFB 2007 - SunPower
  - 14.2MWdc
  - Tilted tracker
  - Multiple module suppliers
  - Successfully financed at $102M
  - $7.18/Wdc
- Industry and IE have evolved since then

System "Bankability"

- System "Bankability" has a number of elements
- Not formal definition
  - No fatal flaws or major issues
  - Risks identified
  - Meets required codes and standards
  - Within good industry practices
  - Employs high quality components
  - Installed with a high quality process
  - Reviewed and verified independently

- Financier's risk appetite impacts investment decision
  - Vary considerably!
- Independent Engineer focuses on the technical aspects
  - Evaluating and quantifying risks – IE's help

Types of Independent Engineering Reviews

- Individual System Review
  - Utility scale PV systems
  - Commercial and Industrial PV systems
    - Rooftop
    - Ground mount
    - Customer side of meter
- Portfolios of systems
  - Including residential projects
  - Process review instead of individual project
  - Can support "Securitization" – informing ratings agency
- Technology Reviews for key components
  - Modules
  - Inverters and MLPE
  - Tracking and racking systems
  - Key PV system components are not commodities

Types of Independent Engineering Reviews

- New projects
  - From feasibility through operation
  - Opportunity to make changes and improvements
- Operating assets – being acquired
  - Design is fixed
  - Historic operating data available
- Short term owners
  - Build and operate for several years
  - Tax equity driven timing
- Long term owners
  - Concerned about long term operation - 25 years or more!
- New types of projects
  - Community solar
  - Corporate purchases
  - Solar+Storage

Independent Engineer System Scope and Key Elements

- Scope can include items below – not entire menu of services
- Varies as appropriate for specific project
- Safety considered throughout!

Site Evaluation	Design Review
Key Equipment Review	Energy Modeling
Technical Review of Key Contracts	Financial Model Input Review
Site Inspection(s)	Commissioning Review
Final Completion Documentation	Operations

Independent Engineer System Scope and Key Elements

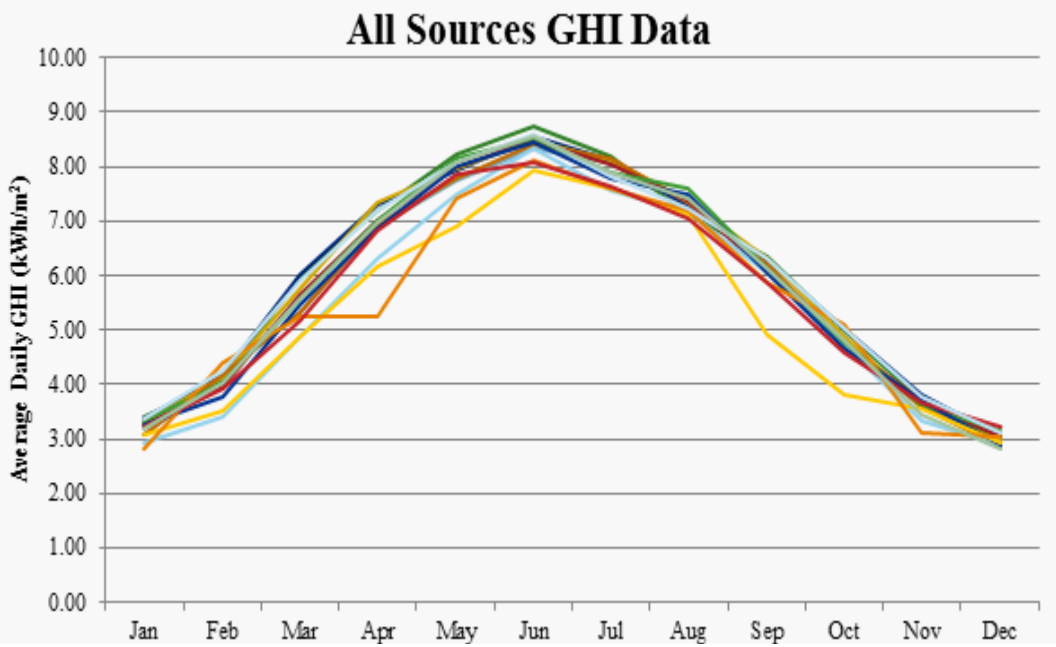
- Site Assessment
  - Anything noteworthy about project site that could be issue
- Design Review
  - Confirm project follows appropriate codes, standards, good industry practices
  - Electrical
  - Structural
  - Civil
  - Geotechnical
  - Environmental
  - May be done by evaluating provided reports
- Key equipment review – **NOT COMMODITIES!**
  - Modules
  - Inverters
  - Tracking/mounting system
  - Balance of System
  - Monitoring system

Independent Engineer Scope - Component Technology Review

- Company overview
- Product evaluation
- Performance evaluation
- **Reliability evaluation**
  - Design for reliability
  - Reliability testing
  - Field history
- Manufacturing capability and process maturity
- Installation and O&M documentation
- Quality systems evaluation
- Standards compliance evaluation
- **Warranty evaluation**
  - Details are important – read it!
- Service and support infrastructure
- Factory and site evaluation

Energy Modeling

- Independent energy prediction is important - unbiased
- Meteorological data
  - Solar Resource and environment
  - Critical in accurately predicting energy production
  - Review and select from available sources – independent selection key
    - Ground stations
    - Satellite sources
- System design details
- Models of components
  - Modules
  - Inverters
  - BOS
  - Critical to be accurate
- AC interconnection
  - Energy calculated for metered point of interconnection



Energy Modeling

- Loss Factors - some key
  - Ohmic
  - Temperature
  - Mismatch
  - Shading
  - Soiling
  - Availability

- Degradation – system level
  - Informed by NREL work and additional system specific information plus additional test and qualification data
- Uncertainty analysis also included
- Downside analysis
  - P50 - P75, P90, P95, P99…
  - Includes resource and other variability and uncertainty
- Combination of standard and customized tools

Independent Engineer System Scope and Key Elements

- Technical review of key contracts
  - EPC Contract – Experienced contractor is important
    - Schedule
    - Budget and contingencies
    - Quality systems
    - System warranties
  - Operations and Maintenance contract review
    - Scheduled maintenance
    - Unscheduled maintenance
  - Interconnection agreement
  - Power Purchase Agreement (PPA) review
    - Price $/MWh (including time of day rates)
    - Possibility of curtailment
  - Offtake Agreement for C&I projects
    - Who will be accepting power on customer side of meter

Independent Engineer System Scope and Key Elements

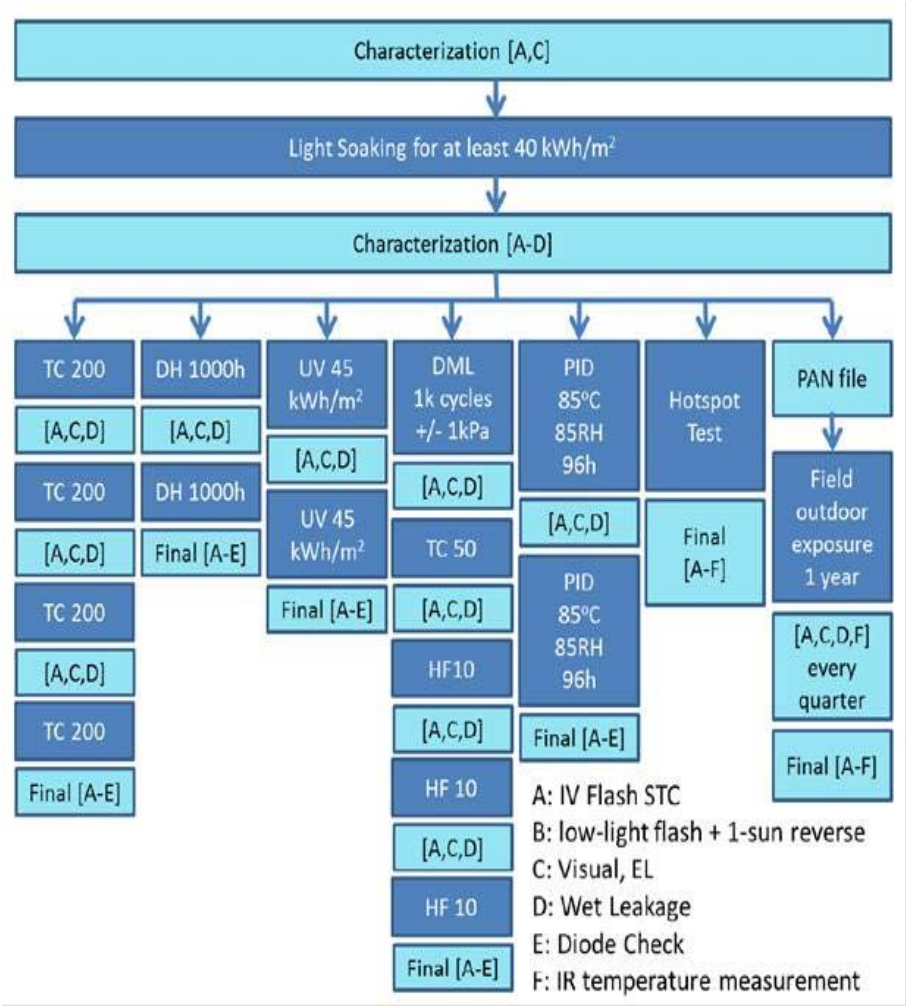
- Financial model technical review
  - Check that technical inputs are correct
  - CAPEX, OPEX, Contingencies
  - Models vary between financiers
- Site inspection(s)
  - Does constructed system match design documents
  - Keep eye out for things inspector from AHJ may have missed
- Commissioning review
  - System testing per EPC contract
  - Capacity, Performance Ratio, Availability test
- Provide closing documents to support funding
- Ongoing operations – quality monitoring system is important
  - Reviewing performance for system and component warranty enforcement

What enhanced reliability data would increase the value of the PV system?

- Reasons to pay more for a PV power plant
  - Increased energy production – more revenue
  - Lower operating costs
  - Reduced risk
- Data that shows higher reliability
  - Accelerated life testing of the type included in standards in place and being developed
- "Holy Grail" would be a test regime that is validated to strongly correlation with failure modes to provide accurate:
  - Component lifetime
  - Component degradation
  - For modules and inverters/MLPEs
- All additional test data is good – especially third party
- For now, qualification programs help – going beyond certification testing

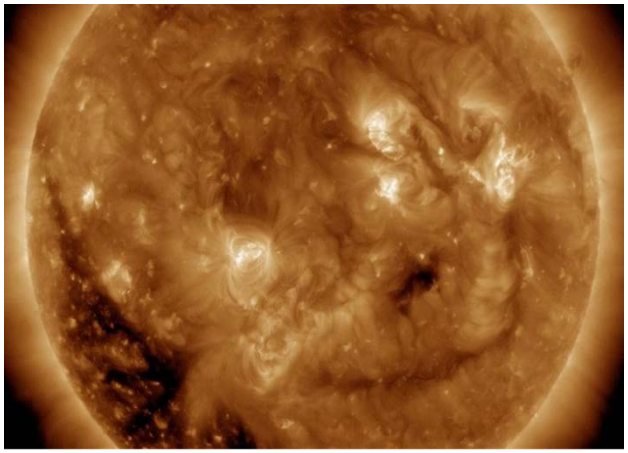
DNV GL Product Qualification Program - Example

- Certification tests are minimum level of testing
  - DNV GL testing shows 6% of modules retested do not pass original certification tests
- Testing beyond certification provides additional reliability and performance information
  - Provides feedback to manufacturers
  - Allows comparison of products
- Modules and inverters
- Must be done for specific products/BOMs
- Specific batch testing is beneficial
- Factory inspections and monitoring also beneficial
- Additional component testing increases IE comfort with the key component and system

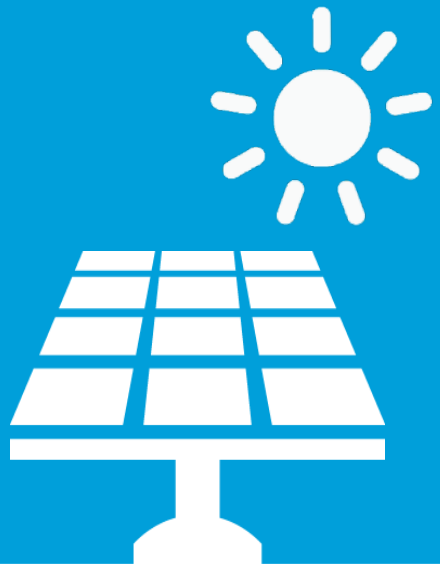


Conclusions

- Independent Engineers are looking for key system characteristics:
  - Operate safely
  - Perform reliably – for expected lifetime
  - Meet energy production expectations
  - Require minimal unplanned maintenance
  - Meet financial goals
    - Cash flow
    - Return on investment
- Help keep the solar industry moving forward!



Thank you!



Presenter:
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SAFER, SMARTER, GREENER

NREL/SNL/BNL PV Module Reliability Workshop

Wednesday afternoon discussions:

IEC 61215:

• Did you (Wells Fargo) find a test for the j-box lid problem that you observed? The j-box lid failure showed up in 1000 h of damp heat testing, so it should have been observed in the IEC 61215 testing, but we usually don't see the data for the IEC 61215 testing.

• Further discussion showed that only a few manufacturers (First Solar being one of them) routinely share the test data from IEC 61215. Because a module can fail a test in IEC 61215 and still pass the certification if the next two pass, effectively a 25% failure rate is considered acceptable. Further discussion questioned whether manufacturers would be willing to share the IEC 61215 data, even under an NDA, though it seems like customers should be able to ask for it.

• DNV GL observes that about 6% of modules don't pass IEC 61215 tests, such as 200 thermal cycles. Perhaps this is not surprising given that IEC 61215 certification allows a failure if the next modules pass.

• Wells Fargo may test 5 or even 7 modules/test leg, which can help to move the confidence level closer to 95%.

• If modules don't pass IEC 61215, the contract may say to reject them.

Extended testing, as proposed in EXP 450: A description of EXP 450 stimulated the following discussion:

• Do the investors support this? A number of individuals spoke up to indicate that their company supported this. The primary reasons cited for supporting it: 1) Would like to see all of the test data for both the IEC 61215 level tests and for the extended tests; 2) Extended testing is now viewed as a best practice by the high-end customers, but there are many different approaches, generating data in different formats and making it hard to compare products tested in different ways. Having a single, standardized extended test protocol would be useful, saving both time and money.

• The EXP 450 tests were chosen to provide stress levels that would correlate with field experience (largely based on publications from NREL and other organizations), however, they are not considered to be "the correct" tests. Rather, they provide a practical set of tests that will be useful to the customer. The number of test cycles could be varied if the community would prefer to change them; the key goal of EXP 450 is not to force a specific set of tests, but to help the industry develop a consensus to use a standardized set in order to reduce costs.

• EXP 450 provides a way to tell a story rather than provide a pass/fail certification.

• EXP 450 does not include component nor materials testing. These are important and should be considered for inclusion. These were discussed by the EXP 450 committee and it was decided to leave them for a different document (from a committee with that expertise); some workshop participants offered to help add them.

• The sampling procedure should also be discussed for inclusion in EXP 450. In fact, sampling was discussed at length by the EXP 450 committee and the conclusion was that it would be best to allow flexibility so that EXP 450 could be executed on randomly sampled modules as part of an ongoing quality assurance system, but could also be applied to batches of modules that were selected systematically to compare process sequences or some other aspect of module properties. An example of an application of EXP 450 is to compare product coming off of two different lines.
• Would the bankers accept EXP 450 testing done by the manufacturer? At least one answer was "yes, if the testing has been audited."

Degradation rates: What degradation rate should be used when completing the pro forma?
• The accelerated tests are not intended to try to quantify degradation rates. The degradation may be non linear and may depend on deployment conditions and weather.
• For some companies degradation rate is likely to be part of the negotiation. Other companies use warranty values as the basis for the assumed degradation. The degradation should include both module and system degradation. Default is typically assumed to be 0.7%/y, but it may be negotiated down to 0.5%/y.
• Only SunPower is known to have modeled and published their anticipated degradation for the lifetime of the module.

Interest rates: What could we do to reduce the risk and be able to negotiate a lower interest rate?
• The interest rate is determined mostly by competition between the banks. The way to bring down the interest rate is to get more banks to compete for projects.
• By law, the interest rates can't drop below the national inflation rate. The market sets the floor on the interest rate.
• Although work we do on quantifying the durability/reliability do not directly lead to lower interest rates, they can indirectly lead to lower interest rates by standardizing terminology and methodology. As more investors join the market, there will be more competition and lower interest rates. This is already starting to happen.
• Better extended testing results does not provide the bank motivation to reduce the interest rate. However, poor test results may eliminate a manufacturer from consideration. There's no benefit to selecting the "best" module, but there's a problem if you're at the bottom.
• Even if default rates were documented to be lower, the interest rate would not be affected. However, the calculation of return on investment might be affected.

Bankability:
• The level of due diligence scales with the size of the project. Projects that would have gotten a detailed review previously may now be combined into larger reviews.
• If we can say that failure rates will be one part per million, will it help? If solid data are available, then less negotiation is needed to define a contract. Being able to quantify failure rates is difficult, but very useful.

• How does DNV estimate soiling rates? They collect data (both from soiling stations and from energy loss) and do literature searches. Their energy production model takes into account the design details.
• Does Wells Fargo validate energy estimates? Wells Fargo does their own calculation to compare with the sponsor and the IE's estimates. If the estimates don't agree, then they get together to compare numbers.
• How does field data help with bankability? Black & Veatch considers a technology established ("proven") once they have at least one year of data at 3 locations. For module manufacturers, they look for companies that have met obligations for 2 years. The manufacturer needs to demonstrate capability to support warranty and O&M obligations for at least 3 years. They also look at failure data, results of accelerated testing, warranty claim information, and what happens when the product warranty expires.
• Is it necessary to have 25 year warranties? Yes and no. The 25-year warranty is desired, but it usually doesn't have a scientific basis, and if the company goes out of business, it may be worthless. Also, warranties vary in scope; customers should always look at what types of problems are covered by the warranty. Inclusion of serial defects in the warranty is useful and a growing trend.
• One could argue that weak warranties are good because they motivate customers to shop around more carefully for a high-quality product and then have fewer failures to address.

Certification:
• The organization giving the certificate should be accredited to document that they are giving a meaningful certificate. Be sure to check this. The list for accredited certification bodies for IECRE can be found at http://www.iecre.org/members/certification/.

Interconnection issues: Upgrades to transmission lines are causing delays to some projects, especially in California. Also, high penetration is causing curtailment when transmission is inadequate or when there is a surplus of power.

Trackers:
• Trackers now are used in close to 80% of projects; this number may have doubled in the last 4 years.
• The tracker mounting can affect the module health.
• The tracker gives 30% more output if it's working.
• Tracker O&M costs can be significant.
• Trackers are often treated like a commodity, but they definitely are NOT a commodity and should not be treated that way.
• IEC Technical Committee 82 has published a qualification test and a safety test for trackers. However, more direct participation from the tracker companies would help improve the standards. Now, the tracker companies are maturing and are more interested in having the standards to differentiate products.

IECRE:

• Standardization of requirements reduces costs and increases confidence.
• The standards need to be implemented consistently.
• IECRE will include review of soil analysis, etc. as part of the design certification.
• IECRE requires consistent implementation of a quality program with field inspections to confirm that the quality program is being administered consistently, but not continuous presence during installation or during manufacturing. Some support was voiced to agree that continuous surveillance shouldn't be necessary.
• Sampling methods are commonly used to determine how many site visits to make. But, should do energy modeling on ALL projects and make sure that every signed document has a verified stamp.
• An advantage can be to have everyone come to do a review at the same time.
• DNV GL and VDE both provide certificates that are similar to IECRE's; are these informing IECRE? Both DNV GL and VDE are participating, though their level of participation in IECRE is greater for wind than for solar. Neither has started using IECRE yet for solar, though DNV has issued the first certificate for wind.
• Both IECRE and Orange Button have the goal of standardizing data formats to help scale the implementation of data collection and analysis.
• It's time to be working on standards that include energy storage.

CENTRAL INVERTER COST OF OWNERSHIP & EVENT ANALYSIS

SYSTEMS RELIABILITY GROUP

SR. MANAGER - SUMANTH LOKANATH

NREL/SNL/BNL – PV RELIABILITY WORKSHOP - MARCH 2017

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AGENDA

- Part 1 - The Case for a Cost of Ownership (COO) Benchmark.
  - Availability drivers
  - Value Proposition
  - Prediction Estimates vs. Actuals
  - Use of the COO Benchmark
- Part 2 - What is driving failures (events) of central inverters
  - Hardware vs. Software impacts
  - Pareto & Factors
  - Root Cause vs. Product Realization Process Step
- Closing Observations & Summary

* COO – Cost Of Ownership

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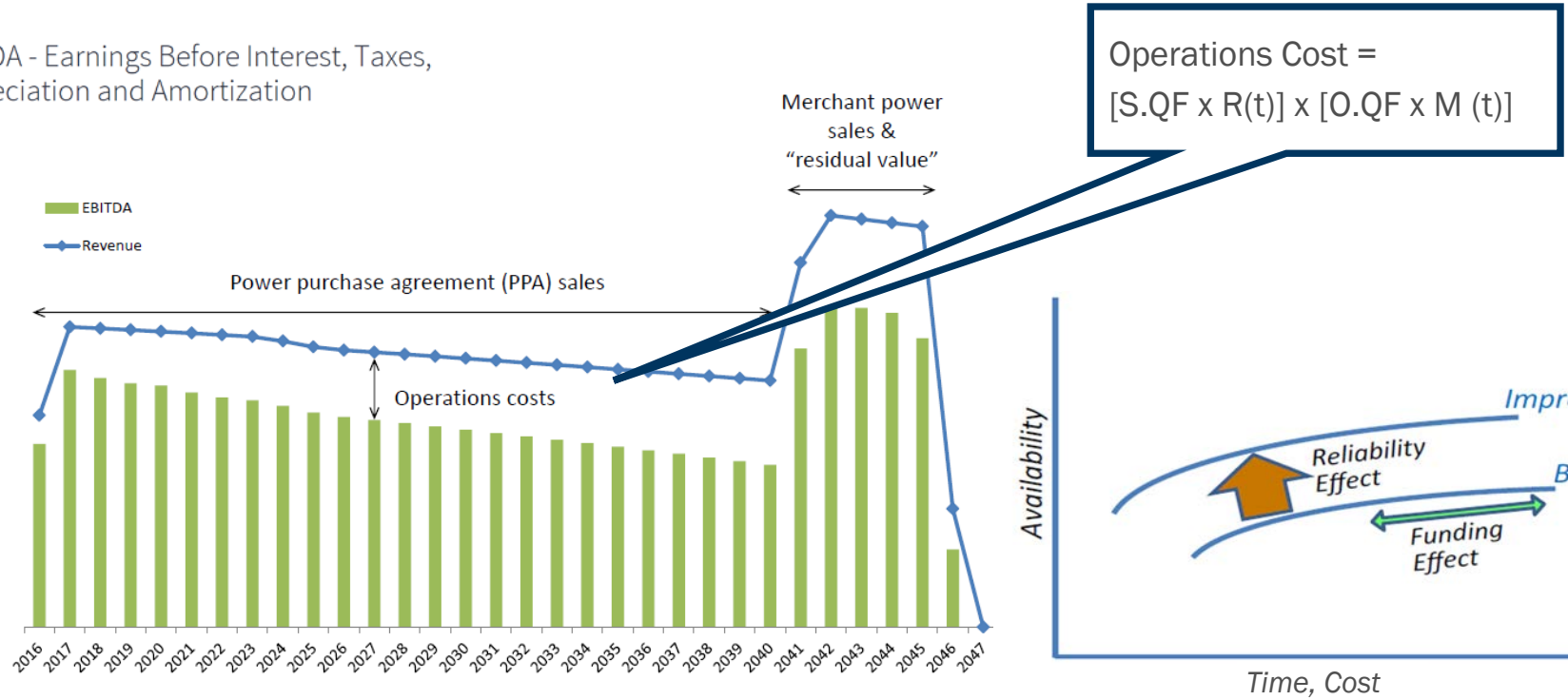
BUSINESS CASE – RISK DRIVEN BY ASSUMPTIONS

EBITDA - Earnings Before Interest, Taxes, Depreciation and Amortization



Typical pro forma for a solar partnership flip.

Source: EBITDA chart courtesy of Jon Previtali, Wells Fargo Bank

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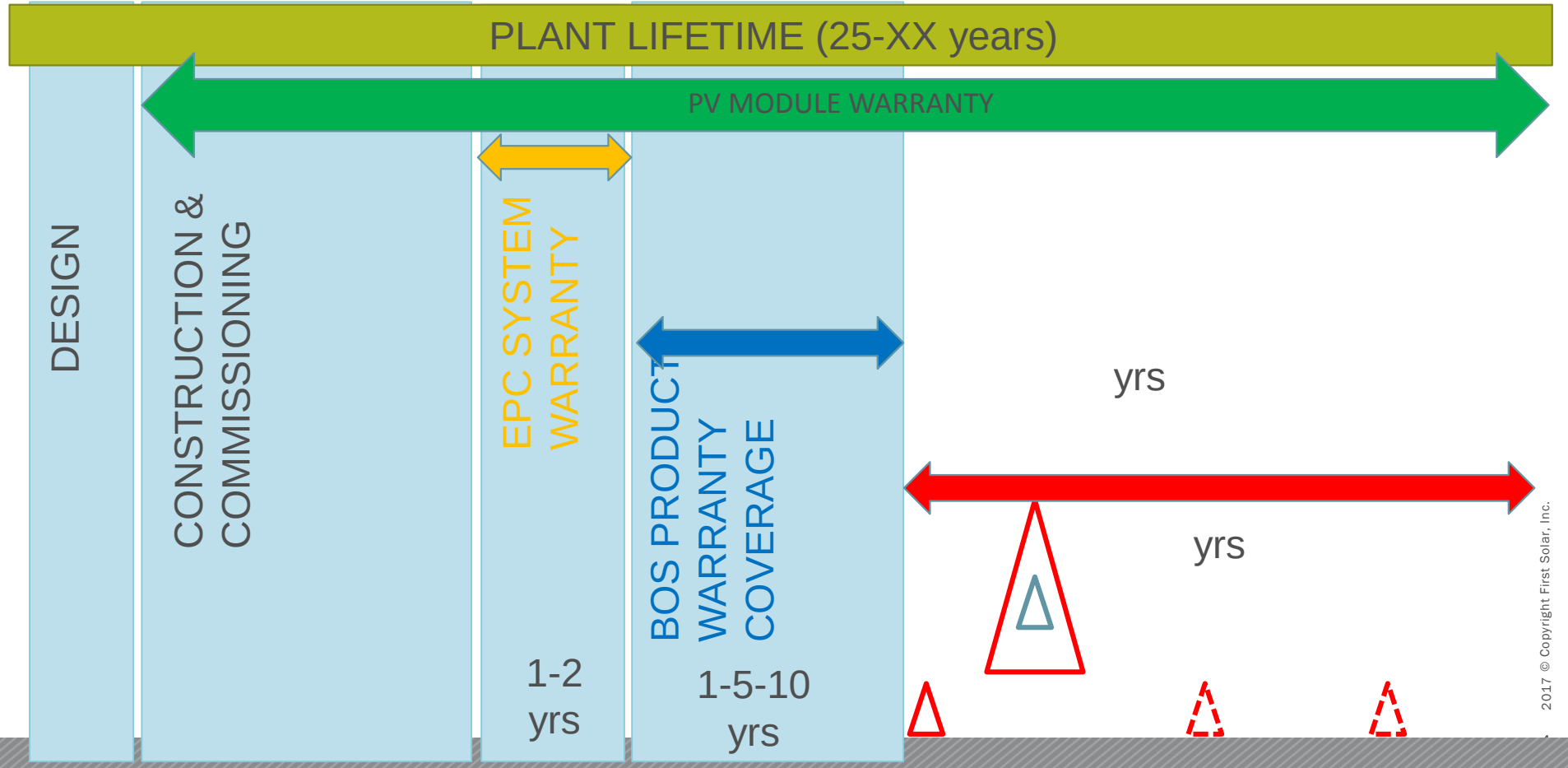
BUSINESS CASE – RISK DRIVEN BY ASSUMPTIONS – CONFIDENCE LEVELS?



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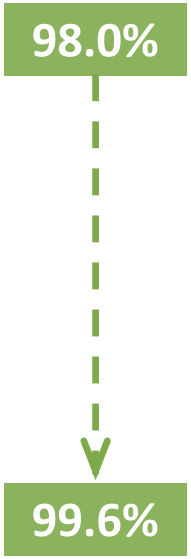
CONSISTENT PERFORMANCE, TRANSLATES INTO VALUE ($$)



Incremental Value of 0.1% Availability (Year 1)	
Base Availability	Marginal Revenue
98.0%	$ -
98.1%	$ 43,000
98.2%	$ 86,000
98.3%	$ 128,000
98.4%	$ 171,000
98.5%	$ 213,000
98.6%	$ 256,000
98.7%	$ 299,000
98.8%	$ 341,000
98.9%	$ 384,000
99.0%	$ 426,000
99.1%	$ 469,000
99.2%	$ 512,000
99.3%	$ 554,000
99.4%	$ 597,000
99.5%	$ 639,000
99.6%	$ 682,000
99.7%	$ 725,000
99.8%	$ 767,000
99.9%	$ 810,000
100.0%	$ 852,000

Incremental Value of 0.1% Availability (Year 1 - 25)	
Base Availability	Marginal Revenue
98.0%	$ -
98.1%	$ 1,075,000
98.2%	$ 2,150,000
98.3%	$ 3,200,000
98.4%	$ 4,275,000
98.5%	$ 5,325,000
98.6%	$ 6,400,000
98.7%	$ 7,475,000
98.8%	$ 8,525,000
98.9%	$ 9,600,000
99.0%	$ 10,650,000
99.1%	$ 11,725,000
99.2%	$ 12,800,000
99.3%	$ 13,850,000
99.4%	$ 14,925,000
99.5%	$ 15,975,000
99.6%	$ 17,050,000
99.7%	$ 18,125,000
99.8%	$ 19,175,000
99.9%	$ 20,250,000
100.0%	$ 21,300,000

Assumptions

Annual MWh	417,410
Plant Capacity (MWp)	100
$/MWh	$ 100

OUR WORLD CLASS O&M Services CONSISTENTLY EXCEED Industry Averages

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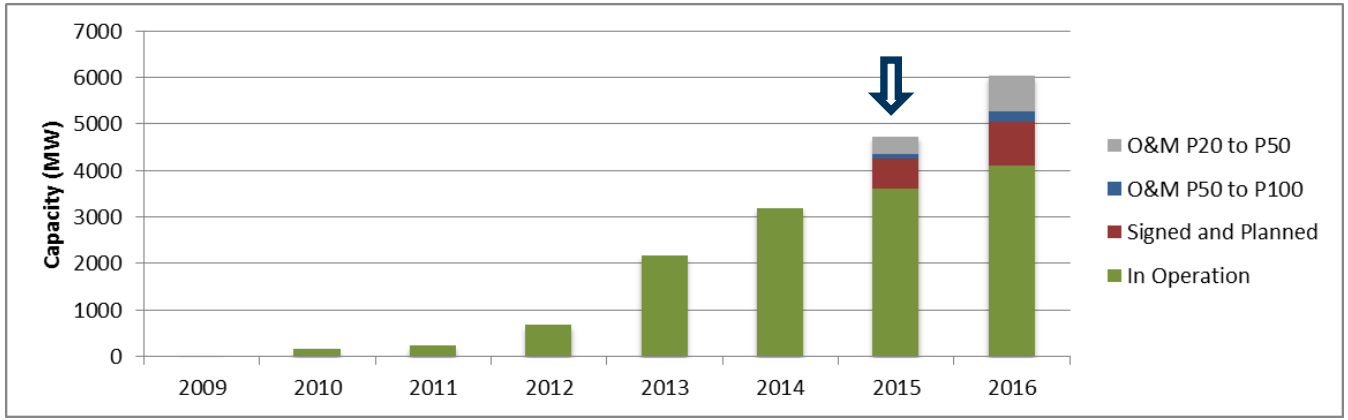
FS FLEET - WORLD CLASS POWER PLANT PERFORMANCE

O&M Fleet History



2014 First Solar O&M Fleet Cumulative Results

Fleet Capacity (AC)	3,160 MW_{dc}
Availability	99.6%
Performance Index (Actual Energy / Expected Energy)	100.3%

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COO COMPARISON – PREDICTIONS BASED ON SUPPLIER PROVIDED ESTIMATES

Cost of Material and Labor;

Does not account for lost of energy revenue.

Modeled COO – Based on Supplier Provided Models

Total Cost of Ownership per Inverter

Note: All costs are cumulative

	Time (Yr)									
Inverter	**1**	**2**	**3**	**4**	**5**	**10**	**15**	**20**	**25**	**30**
Supplier 1	$1,410	$2,407	$3,397	$4,318	$5,221	$9,484	$13,611	$17,651	$21,731	$25,794
Supplier 2	$2,248	$4,444	$6,509	$8,497	$10,438	$19,864	$29,088	$38,187	$47,163	$55,875
Supplier 3	$3,489	$6,808	$9,844	$12,788	$15,683	$30,051	$44,793	$58,334	$72,909	$86,415
Supplier 4	$4,717	$9,546	$14,213	$18,936	$23,696	$47,759	$71,287	$95,247	$119,012	$143,096

Total Cost of Ownership per MW

	Time (Yr)									
Inverter	**1**	**2**	**3**	**4**	**5**	**10**	**15**	**20**	**25**	**30**
Supplier 1	$1,958	$3,343	$4,719	$5,997	$7,251	$13,172	$18,904	$24,515	$30,182	$35,825
Supplier 2	$1,798	$3,555	$5,207	$6,798	$8,350	$15,891	$23,270	$30,549	$37,730	$44,700
Supplier 3	$2,791	$5,446	$7,875	$10,230	$12,547	$24,041	$35,835	$46,667	$58,328	$69,132
Supplier 4	$1,179	$2,386	$3,553	$4,734	$5,924	$11,940	$17,822	$23,812	$29,753	$35,774

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COO COMPARISON - ACTUALS FROM FIELD O&M DATA

Total Cost of Ownership per Inverter

Note: All costs are cumulative

	Time (Yr)				
Inverter	**1**	**2**	**3**	**4**	**5**
Supplier 1	$1,125	$1,458	$1,526	$1,527	$2,008
Supplier 2	$15,637	$15,875	$19,238		
Supplier 3	$3,841	$5,076	$5,088	$5,496	
Supplier 4	$8,319	$12,763			

Total Cost of Ownership per MW

	Time (Yr)				
Inverter	**1**	**2**	**3**	**4**	**5**
Supplier 1	$1,562	$2,025	$2,119	$2,121	$2,789
Supplier 2	$10,425	$10,583	$15,390		
Supplier 3	$2,845	$3,760	$3,769	$4,397	
Supplier 4	$2,080	$3,191			

Red → Actuals >50% from predicted
Orange → Actuals 20-50% higher from predicted
Yellow → Actuals 10-20% higher from predicted
Green → anything lower than predicted or <10% greater.

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KEY FINANCING VARIABLES FOR PV + OPPORTUNITIES FOR FUTURE

Primary Result	PV
Project Size (MW)	20
Installed Cost ($/watt)*	$4.30
Capacity Factor	26%
Generation (Annual MWh)	22,348
Fixed O&M	$10/kW-year
Variable O&M	-

Financing Variable	All-Equity Partnership Flip	Leveraged Partnership Flip	Sale Leaseback	Single Owner
(Tax equity) IRR target year	9	9	20	20
(Tax equity) IRR target	9.0%	11.0%	9.0%	11.0%
Equity closing costs	$300,000	$300,000	$300,000	
Development fee	3%	3%	3%	
Tax investor contribution to equity	60%	98%		
Developer contribution to equity	40%	2%		
Developer operating margin			$20/kW	
Lease payment reserve			6 months	
Debt interest rate (PV)		7.0%		7.0%
Debt term		18 years		18 years
DSCR		1.3		1.3
Debt closing costs		$450,000		$450,000
Debt closing fee		2.75%		2.75%
Insurance (% of installed cost)	0.50%	0.50%	0.50%	0.50%
Analysis period	25 years	25 years	25 years	25 years

For all cases, a 35% federal tax rate, 7% state tax rate, and a 5% sales tax was applied. Ongoing expenses were inflated at a rate of 2.5% per year. Annual insurance costs were set at 0.5% of initial capital costs. All cases also assumed a 30% ITC and MACRS depreciation with 50% bonus depreciation.

Source: The Impact of Financial Structure on Cost of Solar Energy – NREL TP-6A20-53086 March 2012

- Key Influencers:
  - Generation Efficiency
  - Installed Cost
  - Degradation
  - Fixed O&M Costs
    - Labor (CM's, PM's)
  - Variable O&M Costs
    - Availability (Energy vs Time)
    - Unplanned Costs
  - Debt Interest Rate
  - Insurance
  - Salvage Value
  - Depreciation of repair capex

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THE MISSING PIECE- A FAIR PLATFORM FOR DATA DRIVEN RISK AND COSTS

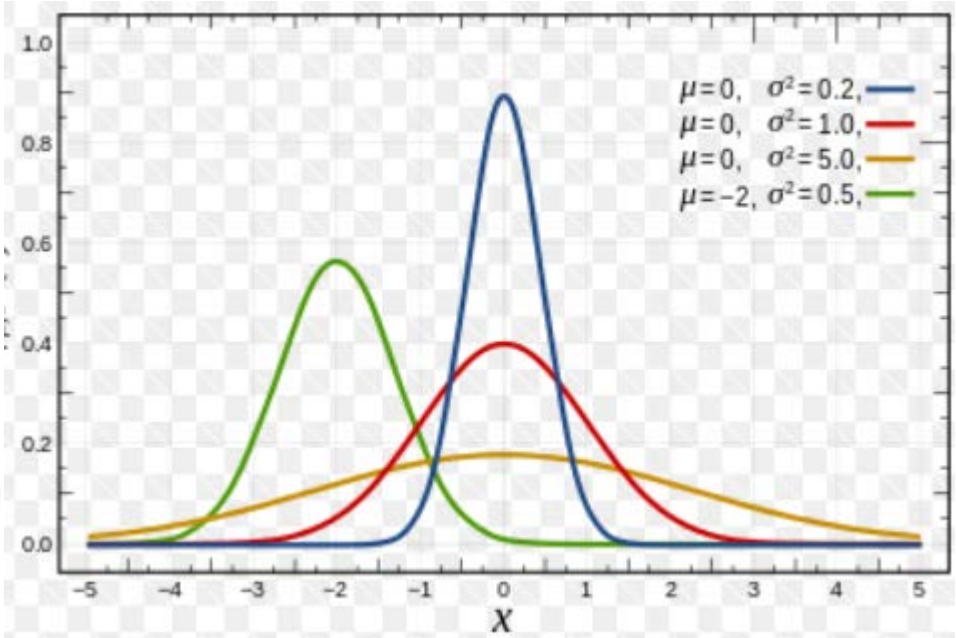

Image: Distributions Courtesy of https://hi.wikipedia.org

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ANALYSIS OF INVERTER EVENTS

- Source of data for Analysis – Failure reports (QCR) based on 8-D process
  - Included various models from 3 major suppliers
  - Failures ranged over ~4 years
  - Total ~400 failure reports analyzed

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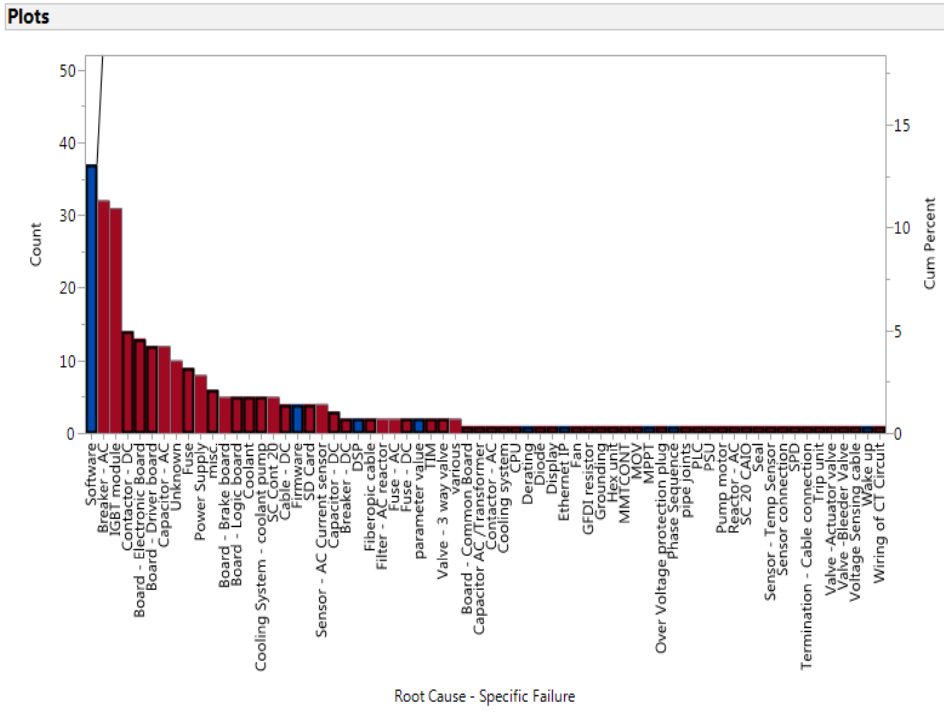
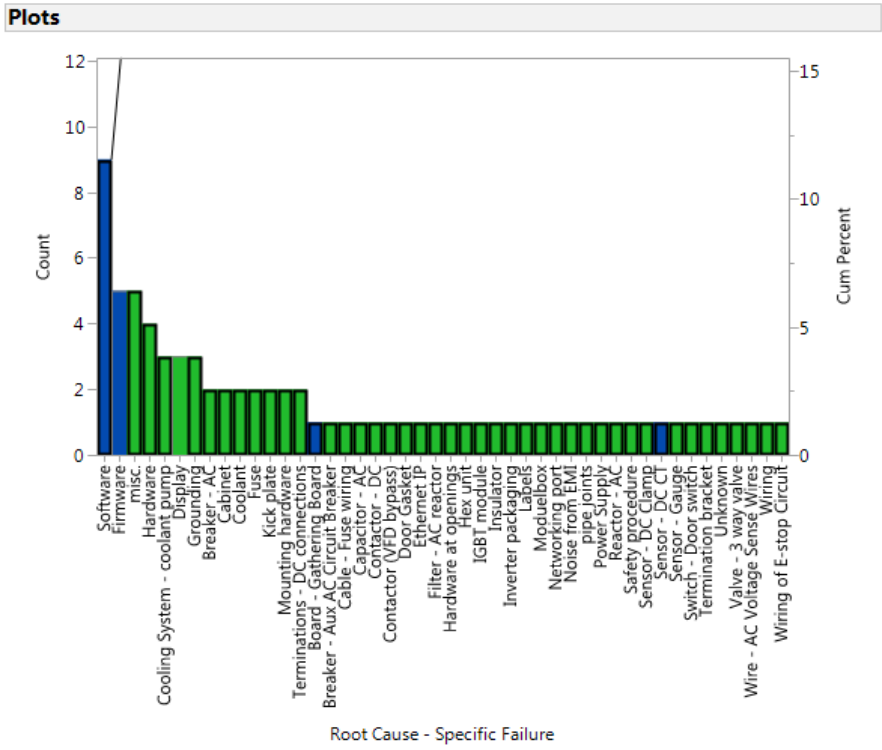
ANALYSIS OF INVERTER EVENTS

FROM QUALITY SYSTEM – BASED ON 8D ANALYSIS OF ~400 FIELD EVENTS

Impact on Energy Availability = YES



Impact on Energy Availability = NO



Software/Firmware Caus

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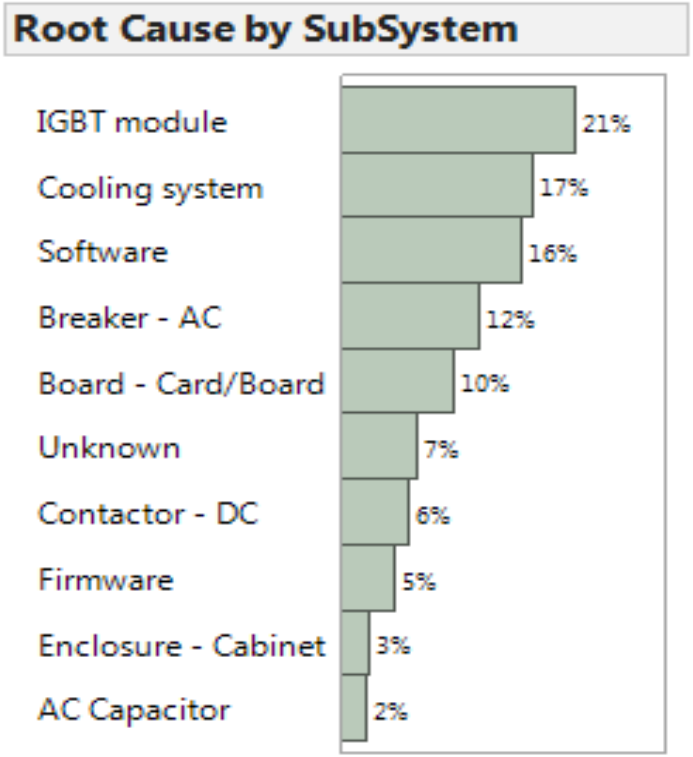
TOP 10 FAILING SUB SYSTEMS



Component / Sub- Systems	Leading Contributors
IGBT Modules	Unknown [27%] – causes across suppliers (Boundary Operating space) Poor Choice of Components [20%] – causes across suppliers Poor Workmanship [11%] – Loose Connections
Cooling	Unknown [24%] – causes across suppliers (Boundary Operating space) Poor Workmanship [38%] – causes across suppliers Poor Choice of Components [11%] - causes across suppliers
AC Breaker	Unknown [18%] – causes across suppliers (Boundary Operating space) Poor Workmanship [54%] – causes across suppliers Poor Choice of Components [6%] - causes across suppliers (dust, noise, voltage)
AC Capacitor	Unknown [15%] – causes across suppliers (Boundary Operating space) Poor Workmanship [62%] – causes across suppliers Poor Choice of Components [23%] - causes across suppliers (harmonics)
Boards	Unknown [44%] – causes across suppliers (Boundary Operating space) Poor Workmanship [18%] – causes across suppliers Poor Choice of Components [14%] – single supplier (Voltage, noise)
DC Contactor	Unknown [13%] – causes across suppliers (Boundary Operating space) Poor Workmanship [57%] – causes across suppliers Poor Choice of Components [25%] – dust, voltage

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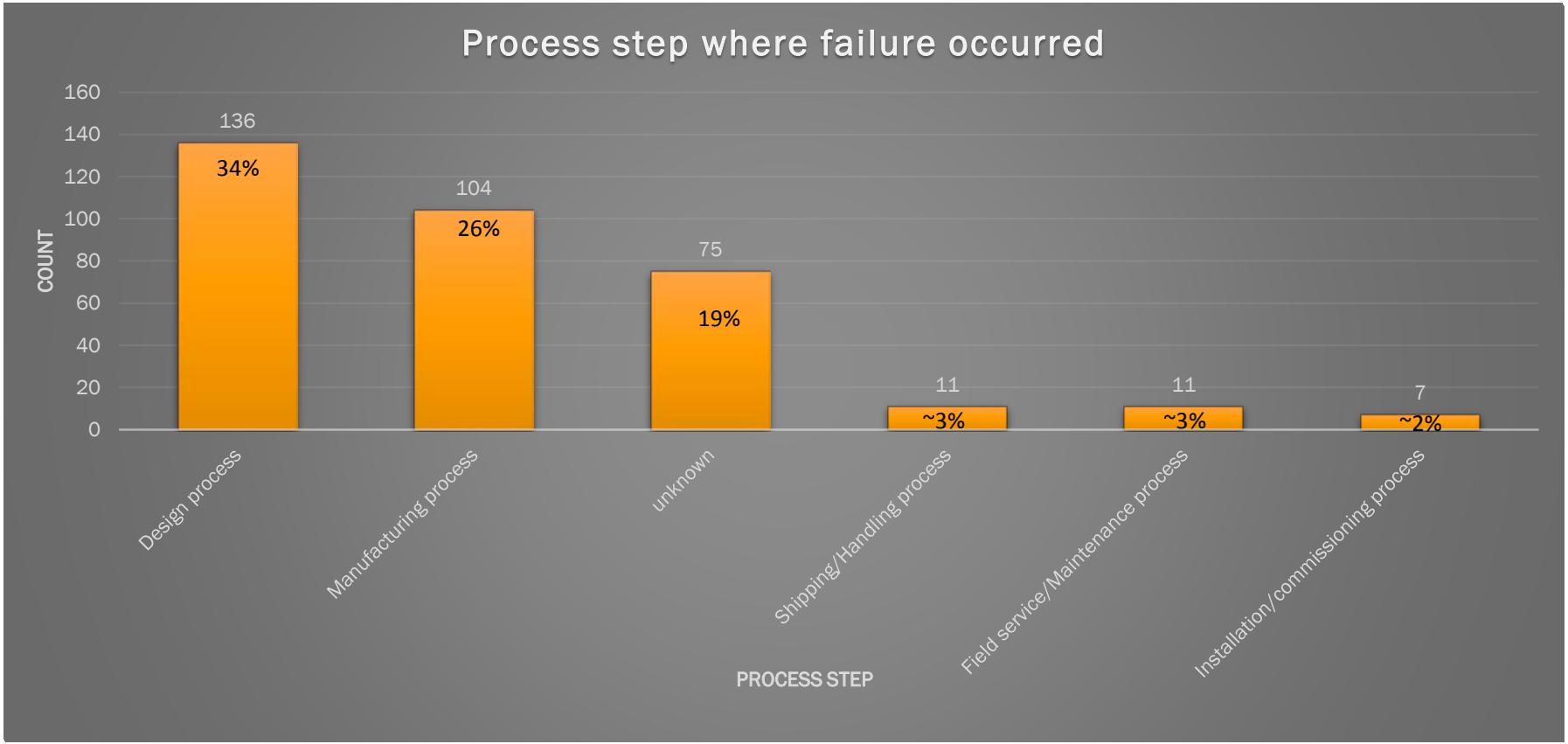
ANALYSIS OF INVERTER EVENTS - WHAT PROCESS NEEDS IMPROVEMENTS?

FROM QUALITY SYSTEM – BASED ON 8D ANALYSIS OF ~400 FIELD EVENTS



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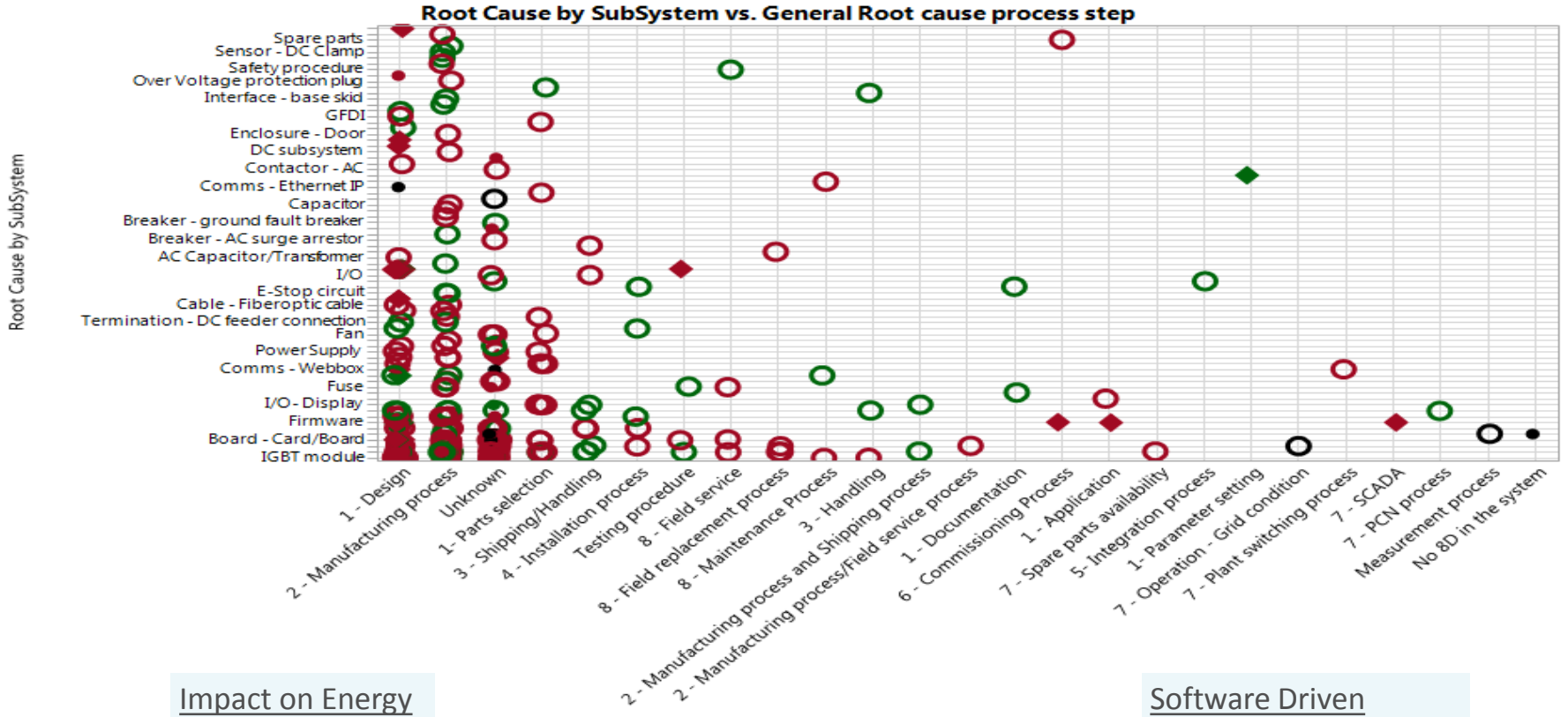
ANALYSIS OF INVERTER EVENTS

Graph Builder



Impact on Energy

Yes – Red Color

No – Green Color

Software Driven

Yes – Filled Diamonds

No – Hollow Circles

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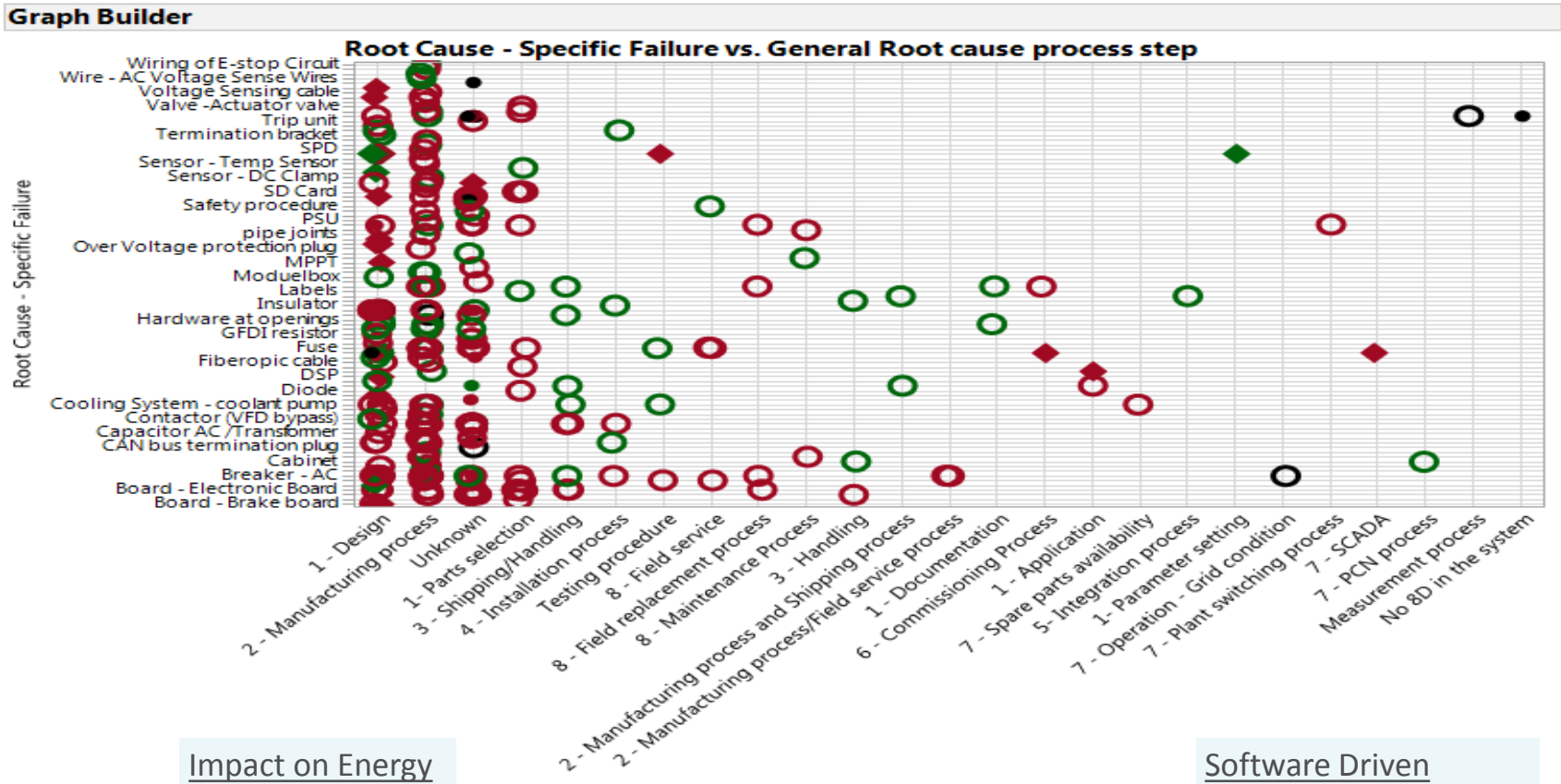
ANALYSIS OF INVERTER FAILURES



Impact on Energy

Yes – Red Color

No – Green Color

Software Driven

Yes – Filled Diamonds

No – Hollow Circles

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OBSERVATIONS & TAKEAWAYS

- Inverters, Switchgear and Transformers are high impact single point failure components in PV power plants.
- Inverters are the single most high failure rate component in PV power plant.
- Software/Firmware driven failure modes have moderately significant impact on Inverters.
- Gaps in Product Quality (Hardware):
  - Active Electronic power components and boards are critical
  - Mechanical components such as Fans, Breakers, Relay, Contactors are next critical group of components
  - Fuse failures are next high impact item (Reliability Failures, not always protection related)
  - Cost of Ownership variances among manufacturers: Lack of benchmarks & platforms in Industry.
- Data indicates inverter failures are driven by insufficient diligence in design for environment, upfront product design, manufacturing process development and product roll outs.
- Current Standards in light of these data appear to be deficient and inadequate for Inverters, Switchgear and Transformers. Qualification and Reliability Standard development efforts should be specifically tailored to address these shortcomings.

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CLOSING SUMMARY

Agenda:

- ✓ Part 1 - The Case for a Total Cost of Ownership Benchmark.
- ✓ Part 2 - What is driving failures of central inverters

Recommendations for Industry:

- ❖ Shift mindset from Transactional to Transformational
  - ❑ Need a benchmark performance measure based on COO to drive optimization across the stakeholders.
  - ❑ Need a neutral stakeholder, fair platform to generate industry meta data to drive improvements via feedback and share value across value chain
- ❖ Shift Test Evaluation & Standards from a Failure Mode to Consequence mindset
  - ❑ Need standards to drive reduction of the top pareto items by impact; Drive Focus priority by
    - ❑ Safety Critical
    - ❑ Generation Impact
    - ❑ Remedy Complexity
  - ❑ Focus on Reliability Growth approaches in field

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PV O&M Cost Model and Cost Reduction

2017 Photovoltaic Reliability Workshop (PVRW)
February 28 to March 2, 2017
Lakewood, CO

Best Practices in PV O&M

- Documents, Analytic Tools and Actuarial Data to reduce cost and improve the effectiveness of O&M

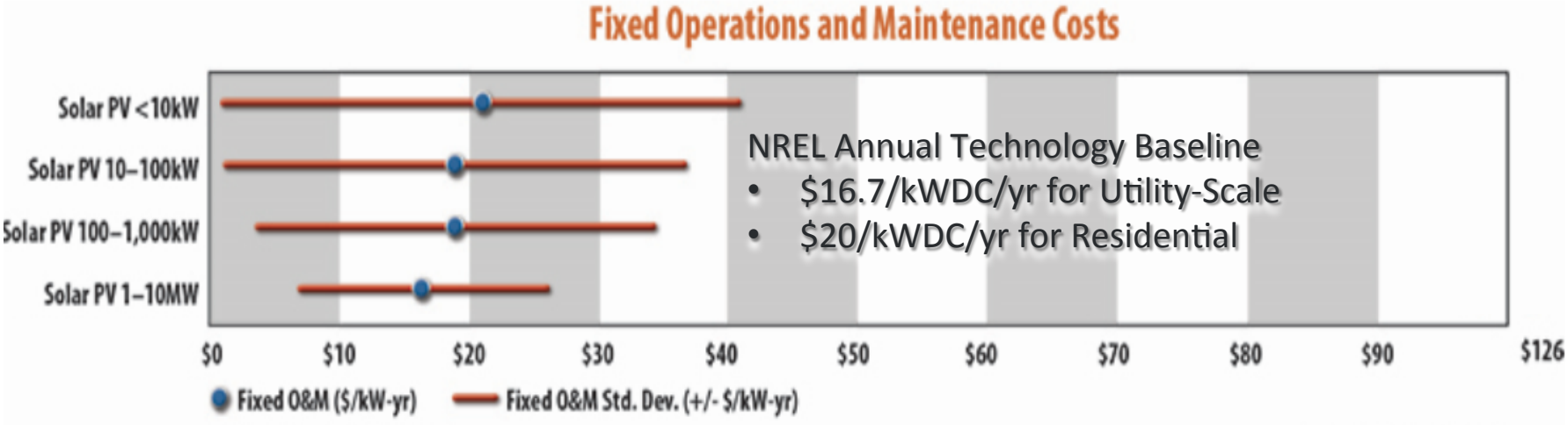
- Working Group (83 people); Mailing List (209 people);
  - email: O_MWorkingGroup@nrel.gov;
  - website: http://sunspec.org/operations-maintenance-workgroup/

- SunShot Support Team:
  - Andy Walker, Travis Lowder, Kari Burman- NREL
  - Geoff Klise, Olga Lavrova- Sandia National Laboratories
  - Roger Hill, consultant
  - Tom Tansy, Jessie Deot, Anil Pochiraju, Bob Fox, SunSpec Alliance
  - Daniel Boff, Ammar Qusaibaty, Christine Nichols- US DOE SunShot Initiative

Classifications Involving PV O&M Costs

Category	Component	Environmental Conditions	Service Category
Administration	AC Wiring	Snow	Administrator
Operations	Asset Management	Humid	Cleaner
Design	Cleaning/Veg	Hot	Designer
Preventive	DC Wiring	Pollen	Inspector
Corrective	Documents	High Wind	Inverter specialist
Decommission	Electrical	Hail	Journeyman electrician
	Inverter	Salt Air	Master electrician
	Mechanical	Diesel Soot	Mechanic
	Meter	Industrial Emissions	Network/IT
	Monitoring	Bird Populations	Pest control
	PV Array	Construction Site Nearby	PV module/array Specialist
	PV Module	Sand/Dust	Roofing
	Roof	High Insolation	Structural engineer
	Tracker		Mower/Trimmer
	Transformer		Utilities locator

Heuristic PV O&M Costs



There is a wide range in the reported data from $0 to $110/kW/year

Often a single annual value is reported $/kW/year or $/kWh

In fact O&M costs do not scale with size (kW) or production (kWh)

Costs vary a lot from year-to-year

Source: FEMP Cost and Performance Matrix , http://www.nrel.gov/analysis/tech_cost_om_dg.html (updated 2/2016)
Annual Technology Baseline, http://www.nrel.gov/docs/fy16osti/66944.pdf (updated 9/2016)

Estimating PV O&M Costs

The PV O&M Working Group concentrated on three estimates related to the cost of delivering a PV O&M Program:

- Annual Cash Flows
- Net Present Value, LCOE
- Reserve Account

The working group has developed a PV O&M Cost Model that can be used to estimate O&M costs.

Weibull Failure Distribution

Q, the probability that a component will fail in any given year, y, is calculated according to the Weibull probability density function.

The equation for the Weibull probability density function is:

$$Q = \alpha/\beta^{\alpha}\ y^{(\alpha-1)}\ e^{(-y/\beta)\wedge\alpha}$$

α = the "shape factor" of the distribution, indicating how spread out the probability of failure is over the years,

β = the "scale factor" of the distribution, indicating over which years of the analysis period the bulk of the failure distribution lies.

Parameters, α and β, are obtained from heuristic failure data

PV ROM (Reliabilty, Operations, Maintenance) database of failure and reliability data; Sandia National Laboratory.

=WEIBULL.DIST(y,α,β,FALSE).

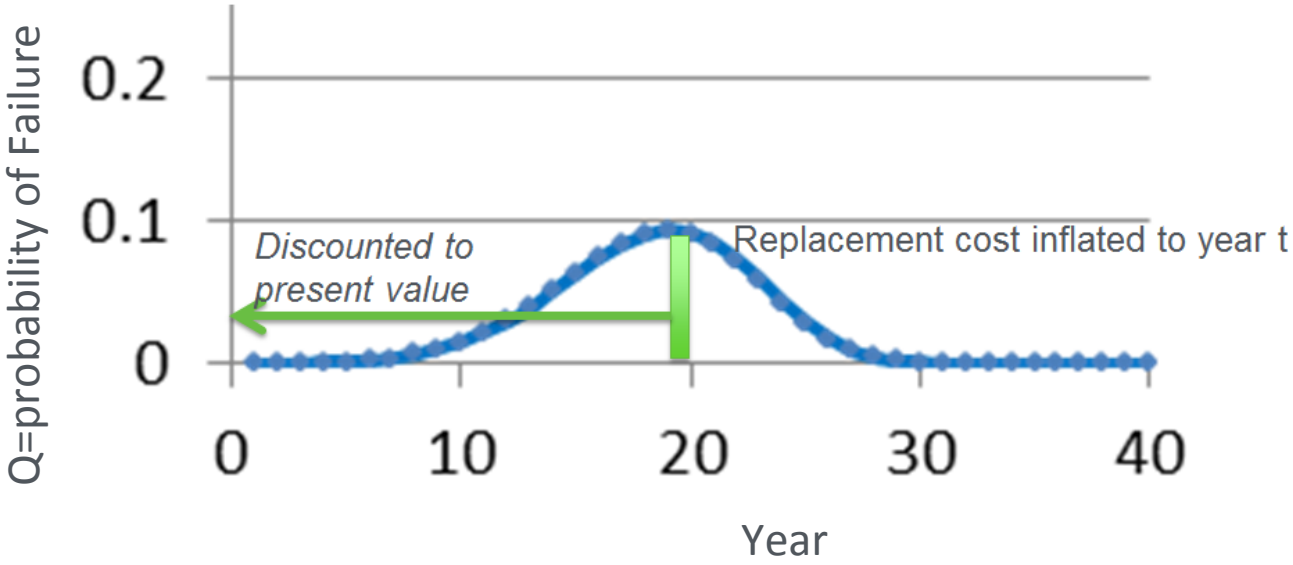
Source: http://reliawiki.org/index.php/The_Weibull_Distribution

Net Present Value of Replacement Cost

$C_{replacement}$ = Cost to replace Component in year 1
Q= probability of failure of component in each year t
d=discount rate (%/year)
i=inflation rate (%/year)
t=number of year

Q=failure probability

Present Value= $\sum t=1^{t=T} C_{replacement} \times Qt \times (1+i)^t / (1+d)^t$



Source of Failure Distributions: Geoff Klise, Sandia National Laboratories; http://energy.sandia.gov/energy/renewable-energy/solar-energy/photovoltaics/pv-research-development-activities/pv-systems-and-reliability/snl-pv-performance-model/

Calculation of Reserve Account - Background

- Weibull distribution of failure gives us a good estimate of life-cycle cost and levelized cost of energy (LCOE), but the method spreads the costs over the years and show a rather uniform average cost per year.

- Financiers are asking for a tool that calculates “maximum exposure”; in other words, what dollar amount of a “reserve account” or “line of credit” would a bank offer to sell to a project?”

- Reserve account is calculated for each year of the analysis period.

Definition of Terms

- P= the probability that a component will not fail in any given year, specific to that year only according to the Weibull distribution of component failure.
- Q= the probability that a component will fail in the same year;
- (P+Q)=1
- R= the desired probability that the reserve account will be sufficient to pay for required replacements in that year.
- N=the number of a certain type of component (for example N=10 inverters, N=500 combiner boxes, or N=50,000 PV modules)

Reserve Account: Start With a Simple Example…

Consider two inverters:
N=2

Replacement Cost (Year 1):
$C_{replacement}$ =$10,000 each

Weibull Failure Distribution:
Mean Interval (years) β=20
Shape Factor α=5.0

In year 20:
P = probability of non-failure
P = 0.908
Q = probability of failure
Q = 0.092

Mind your P's and Q's:
Spare in Reserve for NEITHER of the two inverters:
Reserve Account: $0
P_1P_2 = P^N=(0.908)^2=0.824 (you get this level of availability for free)
Spare in Reserve for EITHER ONE of the two inverters:
Reserve Account=$10,000
$P_1P_2 + P_1Q_2 + P_2Q_1$ = 0.824+(0.908*0.092)* 2 =0.991
Spare in reserve for BOTH of the inverters:
Reserve Account= $20,000
$P_1P_2 + P_1Q_2 + P_2Q_1 + Q_1Q_2$ =0.824+0.300+ (0.092)^2=1.00

Desired Probability that Reserve Account is Sufficient	Reserve Account
0.824	$0
0.991	$10,000
1.000	$20,000

General Polynomial Expansion

Binomial Theorem, 1666, Sir Isaac Newton

$(P+Q)=1$

Total number of components = N
Number of components funded in reserve account=n
For N identical (same P and Q values) components:

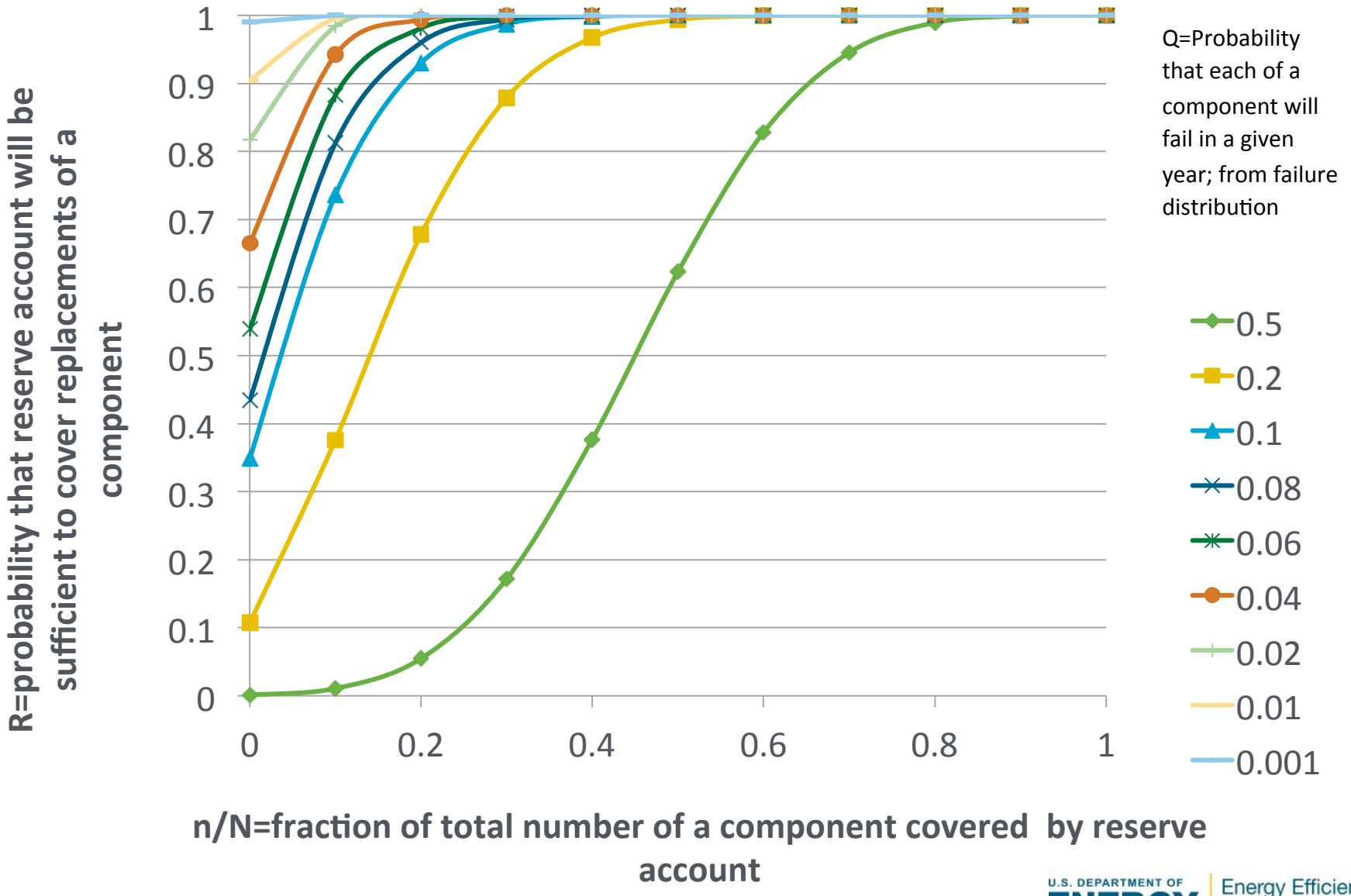
$(P+Q)^N = 1$

$P^N + NP^{N-1}Q + N(N-1)P^{N-2}Q^2/2! + \ldots + Q^N = 1$

Add up the first n+1 terms to find the probability that n components will be operational ($1<n<N$).

Polynomial Expansion form changes with N, and computationally intense to evaluate at large values of N

Reserve account graph



Example Calculation of Reserve Account

In this example we consider 10 components, each with a replacement cost of $1000 in a given year, and with a Weibull failure probability of Q=0.05 in this given year.

The desired probability that the reserve account will be sufficient is R=0.999 (99.9% certainty).

INPUTS

N= 10

$C_{replacement}$= $1,000

Q= 0.05

R= 0.999

The resulting dollar amount to keep in the reserve account to cover failure of this component in the given year is (0.303)*(10)*($1000) or $3,030.

OUTPUTS

Required n/N=0.303 (required fraction of total number of component covered by reserve account in order to achieve desired probability that reserve account will be sufficient in a given year)

C reserve account = $3,030 (amount in reserve account for this type of component in this given year)

Implementation of NPV and Reserve Account in Cost Model

Continue example of two inverters

Inputs

Number of Inverters: 2

Replacement Cost (each): $10,000

Desired Confidence that Reserve Account Sufficient: 0.900000

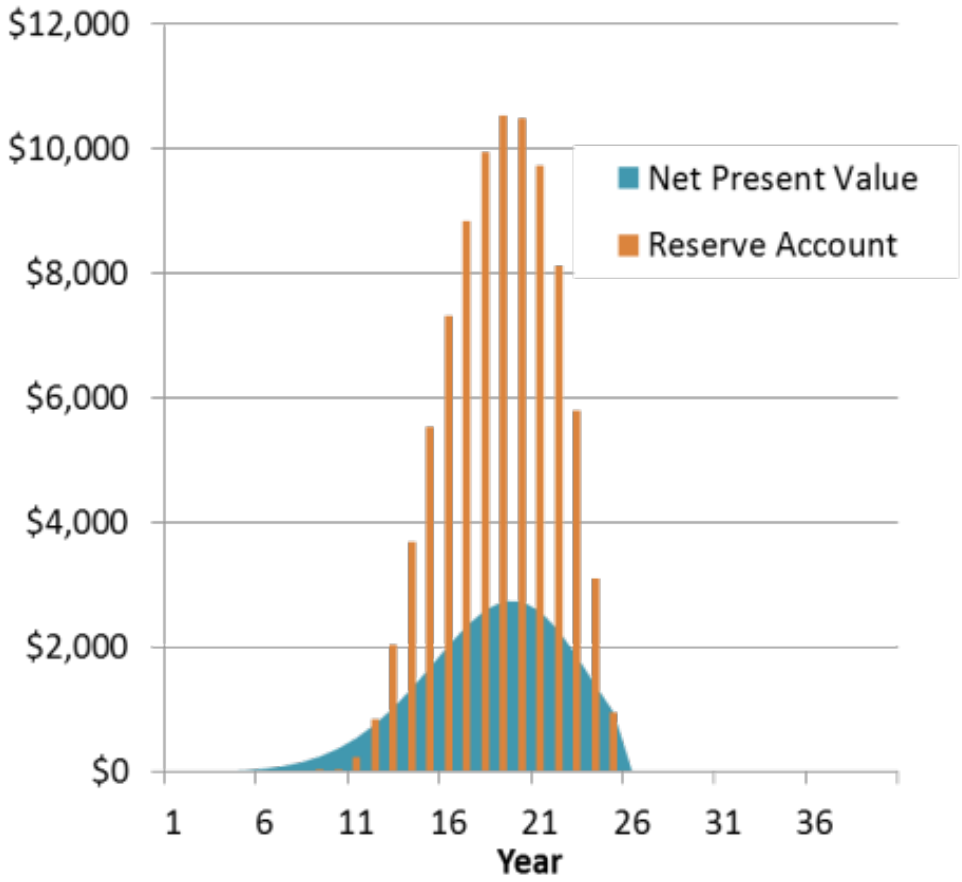
Mean Interval (years): 20.00

Weibull Shape Factor: 5.00

Analysis Period: 25 years

Discount Rate: 7.00% per annum

Inflation Rate: 2.00% per annum



Outputs

Net Present Value of Replacement Costs $8,284 (area under curve)

Maximum Amount Reserve Account $10,501 in year 20

Calculation of Net Present Value and Reserve Account

- Annual Cost and Reserve Account both modified by:
  - Within analysis period?
  - Within warranty period?...type of warranty?
  - Fixed interval or Weibull distribution?
  - Yearly inflation of costs.

- This is done for each measure in the PV O&M Cost Model (PV module replacement, inverter replacement…all) and added up to calculate the total amount in the Reserve Account for each year of the Analysis Period.

PV O&M Cost Model Results (Example)

Inputs

General Inputs		
Analysis Period (Project Life)	25	years (40 max)
Discount Rate	7.00%	% per annum
Inflation Rate	2.00%	% per annum
Desired Confidence that Reserve Covers Cost	0.92	
Working Hours/year	2,080	

System Inputs		
Name of System	Ground Mount Tracking	
Location	Denver, CO	
System Size (kWp DC)	10,000.0	
System Size (Wp DC)	10,000,000.0	
Energy Yield Year 1 (kWh/kWp/year)	1,400.0	
System Installed Cost	$30,000,000	
Module Efficiency	16.0%	
Module Power (W STC)	305	
Array Area (m2)	62500	
Number of Modules	32787	
Module Type/ Degradation	Mono-crystal silicon: 0.36%/year	
Degradation Rate per year	0.0036	
Modules per String	14	
Number of Strings	2342	
Strings per Combiner Box	15	
Number of Combiner Boxes	157	
Combiner boxes per DC disconnect	1	
Number of DC Disconnects	157	
Inverter Type	Central Inverter	
Inverter Replacement Cost/ Wp	$0.190	
Number of Inverters	10.0	
Inverter Capacity (kWp)	1,000.0	
Number of Transformers	10.0	
Inverter Warranty (years)	10.0	
PV Module Product Warranty (years)	20.0	
Other equipment (EPC) Warranty (years)	1.0	
Purchased monitoring contract (years)	0.0	Enter '0' if not applicable

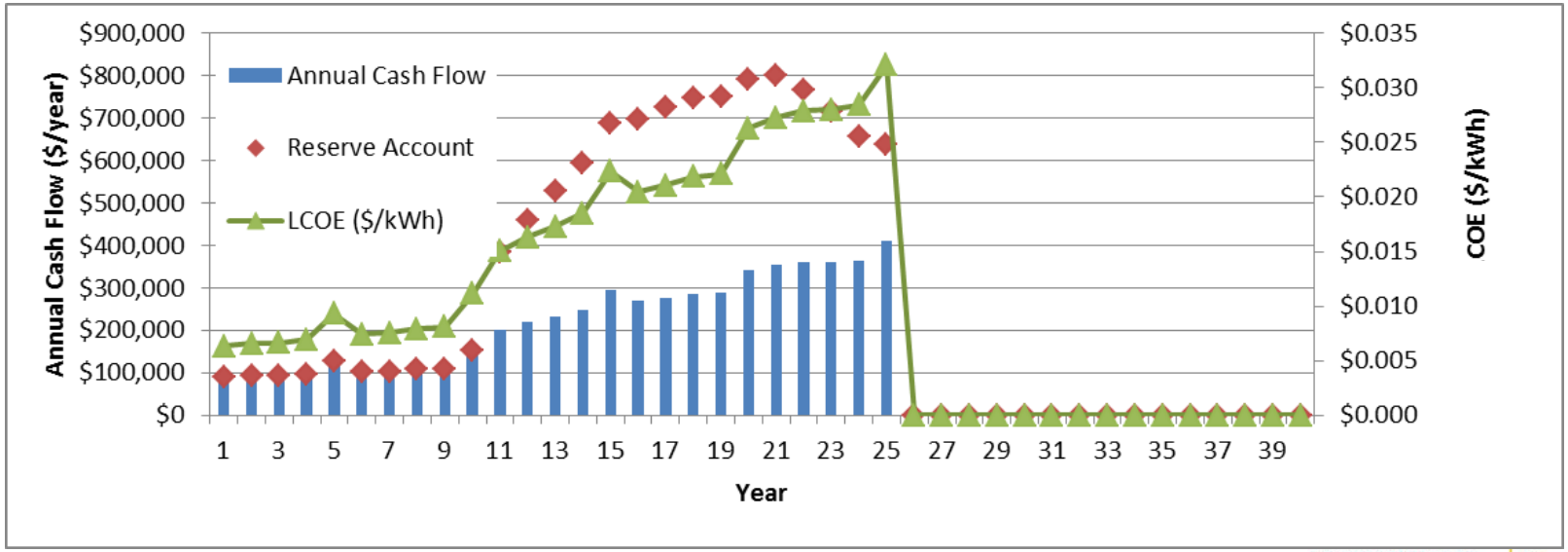
Market Sector	Utility (1 MW)
Mounting Location	Ground Mount
Roof Slope	Sloped, 4:12
Type of Roofing Material	Composite Shingle
Mounting Type	Attached
Inspection technique	Arial
Array Area per Roof Attachment (m2)	2.0
Number of Roof Attachments	31250
Ground Coverage Ratio (GCR)	33%
Site Area (acres)	52.6
Modules/Row	200
Total Rows:	164
Tracking or Fixed	1-axis Tracking
Rows per Tracked Block:(ignore untracked)	16
Total Tracking Blocks:(ignore untracked)	10.2
Foundations per row: (ignore rooftop)	10

Environmental Conditions	
Indicate "1" if condition applies to project, "0" if not applicable	
Snow	0
Pollen	1
Bird Populations	0
Sand/Dust	0
Humid	*Not yet implemented*
Hot	*Not yet implemented*
High Wind	*Not yet implemented*
Hail	*Not yet implemented*
Salt Air	*Not yet implemented*
Diesel Soot	*Not yet implemented*
Industrial Emissions	*Not yet implemented*
Construction Site Nearby	*Not yet implemented*
High Insolation	*Not yet implemented*

PV O&M Cost Model Results (Example)

Example of 10 MW ground-mounted system with tracking

System Name	Ground Mount Tracking
Results	
Annualized O&M Costs ($/year)	$143,760
Annualized Unit O&M Costs ($/kW/year)	$14.38
Maximum Reserve Account	$801,111
Net Present Value O&M Costs (project life)	$2,046,203
Net Present Value (project life) per Wp	$0.205
NPV Annual O&M Cost per kWh (LCOE)	$0.013



High LCOE in Late Performance Period

- Warranties have expired
- Inflation has raised parts and labor prices
- The Weibull failure distributions show high failure rates in later years
- The performance had degraded (0.5%/year)

Results of PV O&M Cost Model (Example) by Component

Example of 10 MW ground-mounted system with tracking

Lifetime NPV by Component Type			
Component	Avg. Cost/Yr	NPV (Life)	% of Total
AC wiring	$2,423	$22,299	1%
Asset Management	$40,082	$436,553	21%
Cleaning/Veg	$41,644	$453,566	22%
DC wiring	$15,265	$123,136	6%
Documents	$3,286	$35,784	2%
Electrical	$1,894	$20,351	1%
Inverter	$72,075	$555,708	27%
Mechanical	$5,607	$53,304	3%
Meter	$19	$205	0%
Monitoring	$72	$783	0%
PV Array	$12,517	$135,644	7%
PV module	$13,439	$72,798	4%
Roof	$0	$0	0%
Tracker	$7,960	$86,694	4%
Transformer	$6,795	$49,377	2%
(blank)	$0	$0	0%
Total	**$223,077**	**$2,046,203**	**100%**

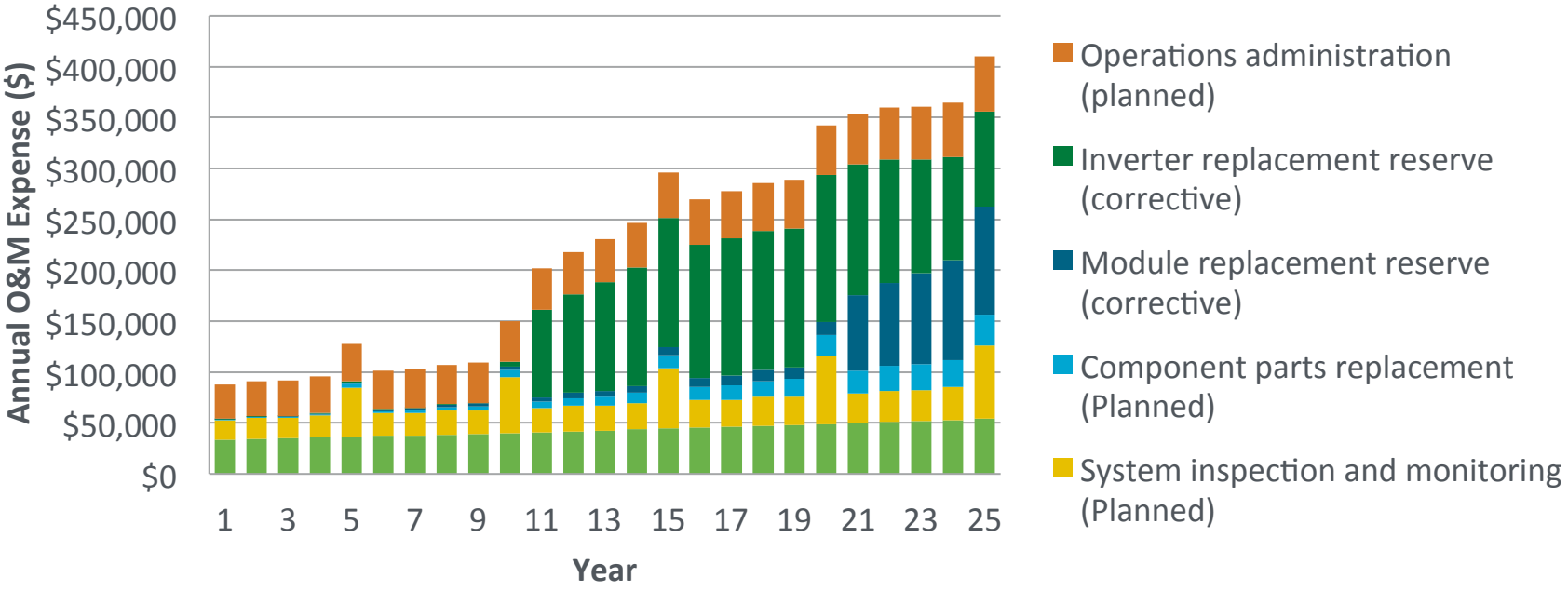
Results of PV O&M Cost Model (Example) by Service Provider

Example of 10 MW ground-mounted system with tracking

Lifetime NPV by Service Type			
Service	Avg. Cost/Yr	NPV (Life)	% of Total
Administrator	$43,424	$472,939	23%
Cleaner	$25,239	$274,892	13%
Inverter specialist	$71,551	$550,944	27%
Inspector	$26,850	$286,646	14%
Journeyman electrician	$17,358	$110,105	5%
PV module/array Specialist	$11,399	$86,393	4%
Network/IT	$186	$1,825	0%
Master electrician	$7,223	$53,383	3%
Mechanic	$1,706	$11,542	1%
Designer	$0	$0	0%
Pest control	$1,702	$18,536	1%
Roofing	$0	$0	0%
Structural engineer	$10	$69	0%
Mower/Trimmer	$16,424	$178,884	9%
Utilities locator	$6	$44	0%
Total	**$223,077**	**$2,046,203**	**100%**

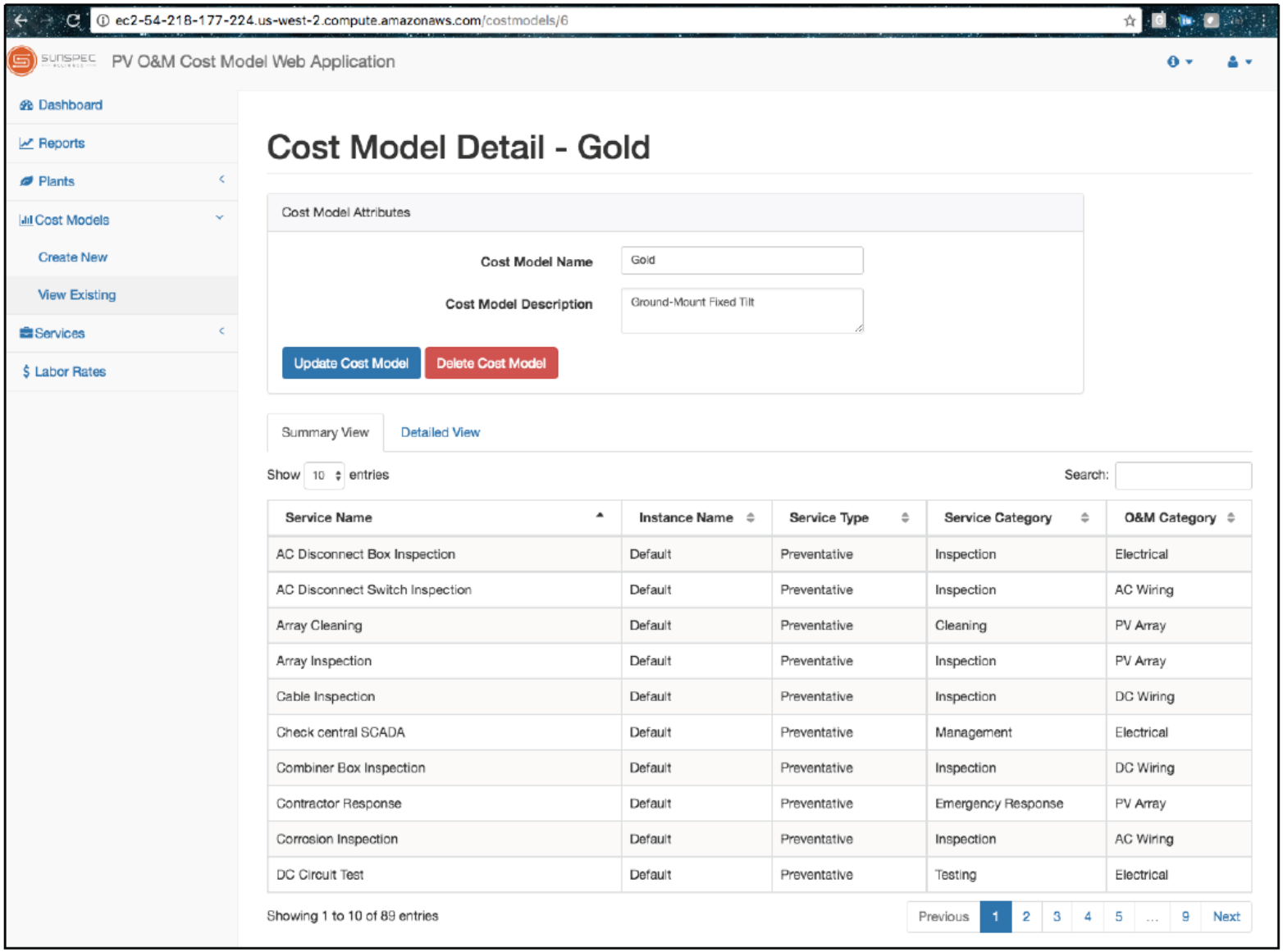
PV O&M Cost Model Results (Example)

Example of 10 MW ground-mounted system with tracking



Mike's Category	Annual $/kW (levelized)
Component parts replacement (Planned)	$0.64
Inverter replacement reserve (corrective)	$4.21
Module cleaning and vegetation management (Planned)	$3.57
Module replacement reserve (corrective)	$1.02
Operations administration (planned)	$3.07
System inspection and monitoring (Planned)	$1.87
TOTAL (per kW cost levelized over the analysis period)	**$14.38**

On-line implementation of PV O&M Cost Model under development by SunSpec Alliance



Source of Screen Capture: Jessie Deot, Sunspec Alliance

Recommendations for Cost Reductions

- Asset Management Software
  - Benchmarking performance
  - Continuous Performance Index
  - Curation and Quality Control on Data
  - Efficient business transactions; lower cost
  - Improved analytics
  - Knowledge management-diagnostics and troubleshooting
  - Keep track of preventative maintenance requirements
  - Calculate predictive or condition-based maintenance.

Recommendations for Cost Reductions

Warranty management practices

- Observe instructions or conditions such as preventative maintenance so you do not **void warranty**
- Curate data to **prove that a module is underperforming**,
- Plan for **labor to remove, ship, and re-install** an underperforming module.
- Try to get a warranty for the manufacturer to "**repair or replace" rather than "supplement**,"
- Consider **Insurance Backed Guarantee (IBG)** that provides that warranty claims will still be processed in the event of the liquidation, receivership, or closure of a dealer

Failure to follow "product box handling and storage requirements" can cause damage when moved and void a warranty

Photo by Andy Walker, NREL

Recommendations for Cost Reductions

- Remote imaging, Aerial Inspection

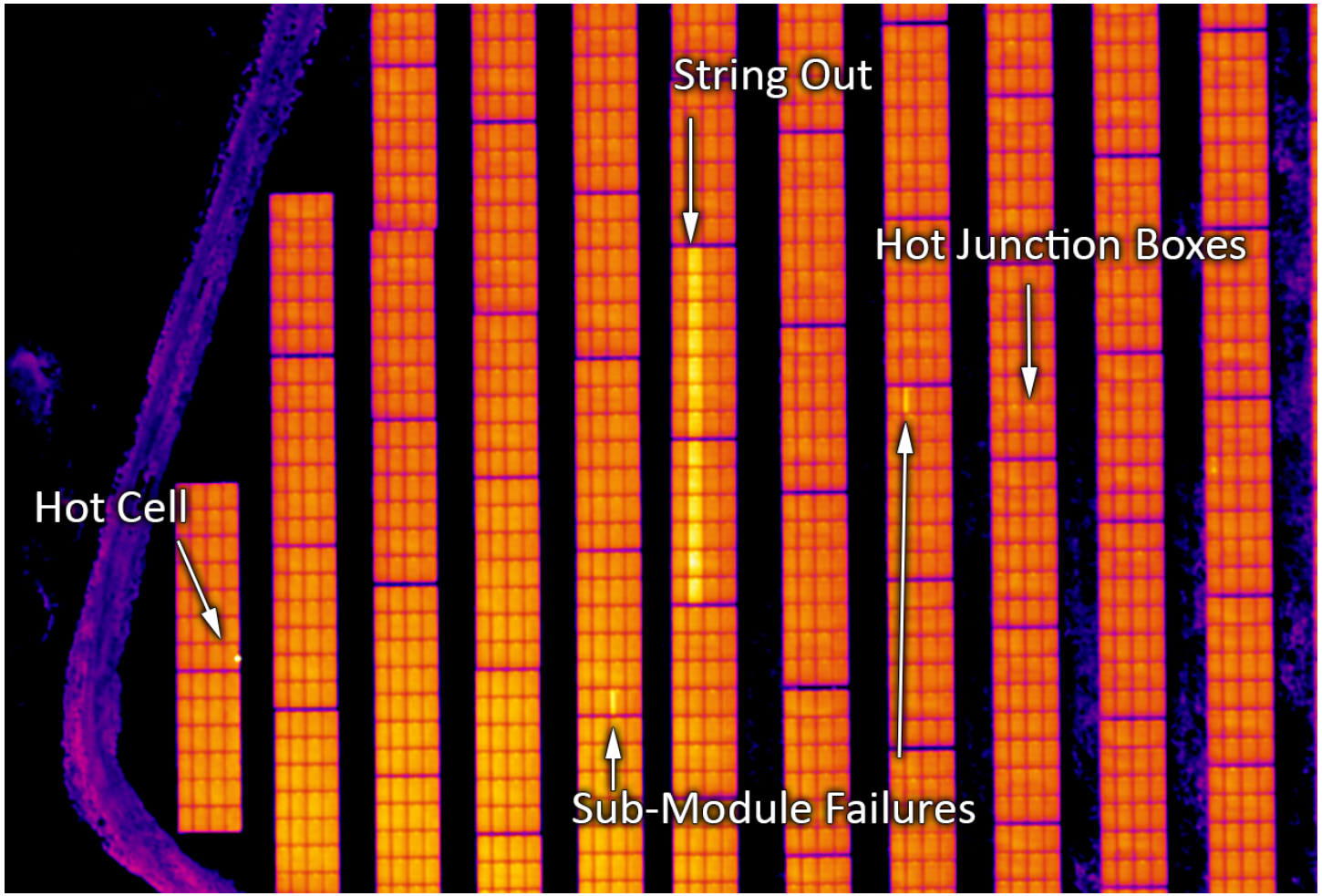


Image by Rob Andrews, Heliolytics

Recommendations for Cost Reductions

- O&M Business Models
  - "The UBER of PV O&M"
  - O&M Cooperative business structures
  - Shared facilities and inventories
- Module-level power electronics
  - Reduced production losses
  - Covers rapid shutdown requirements
  - Detailed data
  - Conventional AC wiring
- Standardization of parts, suppliers, procedures
  - Optimized reserve
  - Remove obsolete inventory and reduce inventory exceeding the maximum stocking level to reduce cost to count, move, store, secure, insure and taxes.

Thank You!

EFFECT OF MULTI-PARAMETER FILTERING ON SOILING LOSS INDEX

NREL/SNL/BNL
PV Reliability Workshops
Lakewood, CO
Feb 28-Mar2, 2017

Ajay Singh (asingh@campbellsci.com) and Matthew Perry (mperry@campbellsci.com)
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INTRODUCTION

Investigation of energy production loss is gaining importance in solar PV plants. The most popular method to do so is comparison of outputs from two identical PV panels. One of these panels is cleaned periodically and the other is allowed to soil under natural conditions. This method is popular due to simplicity of the method. Also use of production size modules avoids any inaccuracies due to differences in technology of modules or even the size, type of framing etc. However the soiling loss calculated using this method suffers from errors due to differences in mounting angles, orientation or angle of incidence during different time of the day. In this paper the authors will present data showing some of these differences. These errors can easily be minimized by limiting the measurements during the solar noon hours, when the solar radiation has almost normal incidence angle on the modules. Data filtering based on irradiance levels can also minimize these errors. Data filtering is also effective in getting some useful data points from a cloudy day.

KEY DEFINITIONS

We begin by a definition of the soiling loss index in terms of quantities that can be measured directly from a PV module. We define *Soiling Loss Index* (SLI) as loss in the irradiance reaching the solar cells. If all other factors are same then this loss is primarily due to the loss in transmission properties of the glass as a result of the soil accumulation. The irradiance is calculated from short circuit current[6] as:

$$G_{eff} = I_{SC} \frac{[1-\alpha(T-To)]}{I_{SC,STC}}$$

Where, G_{eff}: Effective irradiance reaching the solar cells
I_{SC} : measured short circuit current of the module
$I_{SC,\ STC}$: short circuit current at STC
T: back of module temperature
To: back of module temperature at STC, typically 25° C
α: Temperature coefficient of short circuit current.

The soiling loss index (SLI) uses the effective irradiances of a clean reference panel and a dirty test panel, and is defined as:

$$SLI = \left(1 - \frac{G_{eff,Ref}}{G_{eff,Test}}\right) \times 100\%$$

Where, $G_{eff,\ Ref}$ is the effective irradiance calculated from the clean reference panel and $G_{eff,\ Test}$ is the same quantity calculated from the test panel.

EXPERIMENTAL PROCEDURE

Two identical full size PV panels are mounted side by side. The short circuit current is measured on both panels with the a precision current sensing shunt. Back of-module temperatures are also measured using a thermistor. Measurements are performed between sunset and sunrise. The two modules are short-circuited using a solid state relay for about 5 second every 30 seconds. The short-circuit current is measured using a current shunt. Back-of-module temperatures on both modules are also monitored.

An effective irradiance reaching the cells is calculated in accordance with the IEC 60904[5], according to the equation 2 above. An initial offset between the two panels is estimated in the beginning and periodically afterwards each time both panels are cleaned. This offset is applied to the subsequent measurements.

In accordance with IEC 60904, we limit the SLI calculation within one hour of local solar noon and for effective irradiance > 800 W/m². This avoids any differences in soiling loss due to zenith angle of sun, module current dependence on irradiance level or spectral differences. We also use a filtering scheme to filter out any unstable data due to clouds etc. The stability criteria adopted is based on the recommendations made in IEC 60904.

RESULTS

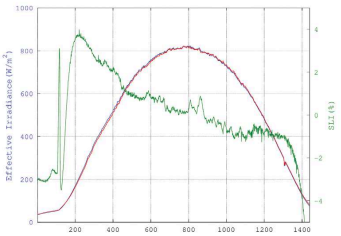

Figure 1: Effective Irradiance as calculated from short circuit current of the PV modules on a clear sky day. The green curve shows the soiling index. The SLI depends on the time of the day.

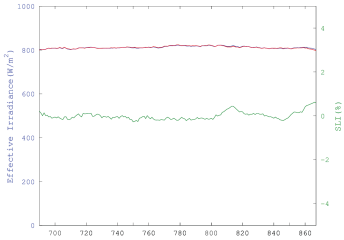

Figure 2: Effective irradiance and SLI during ±1 hour of solar noon and $G_{eff,r} > 800$ W/m². The time of the day dependence is absent during this time.

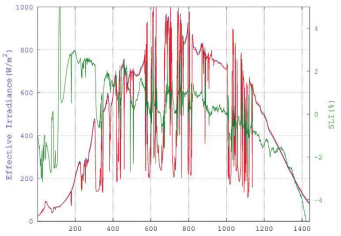

Figure 3: Effective Irradiance and SLI on a cloudy day.

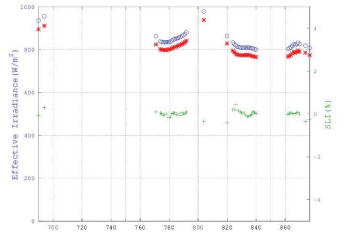

Figure 4: G_{eff} and SLI taken during a cloudy day with $G_{effref} > 800$w/m² during ±1 hour of solar noon.

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For more information on the CRSI2 Soiling Index Datalogger, please visit:
https://www.campbellsci.com/crsi2

The Effect of Soiling on the Performance of PV Modules in a Semi-Arid Area in South Africa

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CONTEXT – OBJECTIVES

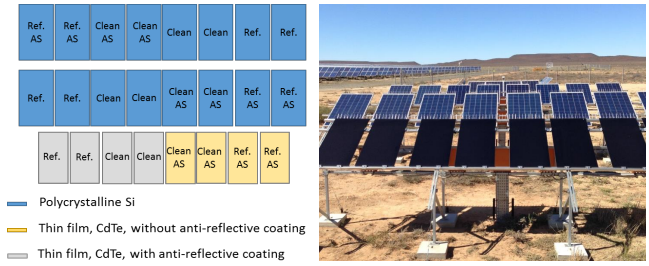
Understanding and quantifying PV performance degradation due to soiling is a key step towards realistic PV energy yield predictions and reduced cost of PV electricity, particularly for arid areas and dusty locations.

We **aim** to investigate and quantify the **impact of soiling** on the power output of PV modules installed in the *Northern Cape* region in *South Africa*, through the following steps:

- Performance evaluation and comparison of regularly cleaned and uncleaned PV modules.
- Assessment of different cleaning schedules and the efficiency of an anti-soiling product in minimizing PV soiling losses.
- Supplementary analysis to: i) quantify dust accumulation and ii) identify variations in transmittance through module glass.

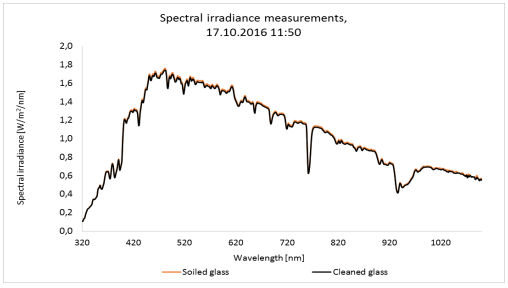
TEST SITE – METHODOLOGY

- At Scatec Solar's 75MW PV plant in Kalkbult, South Africa; including a weather station and 24 PV modules (tilt α=30°, azimuth θ=0°).
- 16 pc-Si modules (255W), 8 thin film (CdTe) modules (100W).



- Half of the modules remained uncleaned (reference samples). For the rest, surface cleaning was applied at 2-week intervals. Half of all modules were treated with an anti-soiling (AS) product.
- Module temperature and I-V measurements, at 10-min intervals.
- Measurements of plane irradiance, relative humidity, wind speed, air temperature and precipitation, at 1-min intervals.
- Analysis period: *May-November 2016*.

TRANSMITTANCE MEASUREMENTS



- Measurements of the spectral irradiance through module glass were performed by means of a spectroradiometer.
- *No significant variations* were identified between clean glass (reference) and glass with 2½-days accumulated dust.

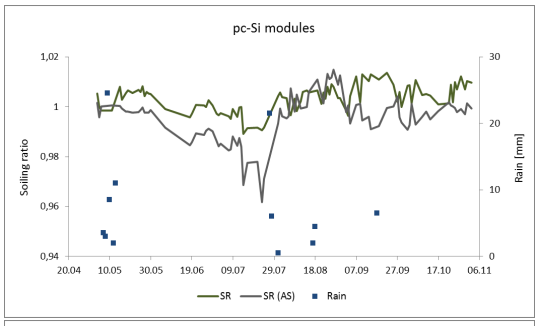
QUANTIFICATION OF DUST ACCUMULATION

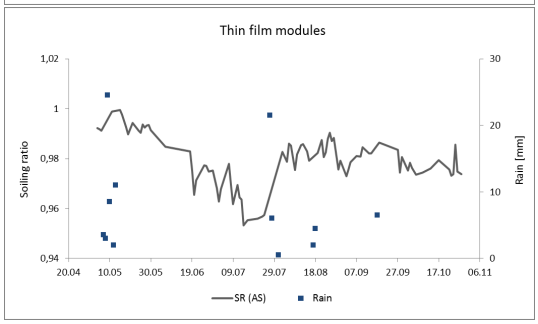
	Soiling levels 14.10.16 [mg/m²]	Soiling levels 15.10.16 [mg/m²]	Daily dust accumulation [mg/m²/day]	Soiling levels 17.10.16 [mg/m²]	Daily dust accumulation [mg/m²/day]
Poly3	57	46	**46**	25	**13**
Poly4	79	39	**39**	43	**22**
Poly5	54	43	**43**	41	**21**
Poly6	50	33	**33**	31	**16**

Example results on soiling levels for four pc-Si modules are given in the above table. The daily dust accumulation is estimated by dividing the soiling levels by number of days since last cleaning. As the airborne dust levels were abnormally high before 15.10.16, the range of **13-22 mg/m²** is suggested as more realistic estimation for the daily dust accumulation.

SOILING LOSSES

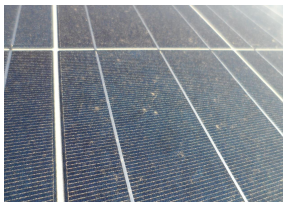
We quantified the performance losses of the tested modules, in correlation with the soiling levels. For this, we defined the soiling ratio (*SR*) as an the temperature-corrected power output ($P_{out,c}$) of the reference modules divided by the $P_{out,c}$ of the regularly cleaned modules.





Preliminary results on the precipitation levels and SR for pc-Si modules with and without AS treatment (upper Figure), and for thin film modules with anti-soiling treatment (lower Figure).

KEY FINDINGS – PERSPECTIVES



- The most significant soiling losses were observed in the winter months (May – July).
- Transmittance measurements and quantification of dust accumulation confirm low soiling levels in October.
- Given the preliminary results, the applied AS product works surprisingly against its purpose increasing the soiling levels.
- Heavy rain has good cleaning effect. Indeed, after rainfalls (end of July), performance losses are completely recovered for the pc-Si and partly recovered for the thin film modules.

Near future objectives of this ongoing work:

- Quantify the annual energy yield losses due to soiling.
- Longer analysis period → more comprehensive conclusions
- Identify trends in the weather and soiling growth-factors.

NREL ***2017 NREL/SNL/BNL PV Reliability Workshops**, February 28th – March 2nd, Lakewood (CO), USA.*

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PV soiling losses: seasonality and predictability

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Background

The accumulation of dust, dirt and particles on the surface of a photovoltaic (PV) module can have a non-negligible impact on the energy yield. Peak losses up to 70% have been reported in literature.

Aim of the work

Identifying the parameters that can best predict the soiling losses at any site: the preliminary results of the investigation on soiling seasonality and predictability are presented.

Key factors

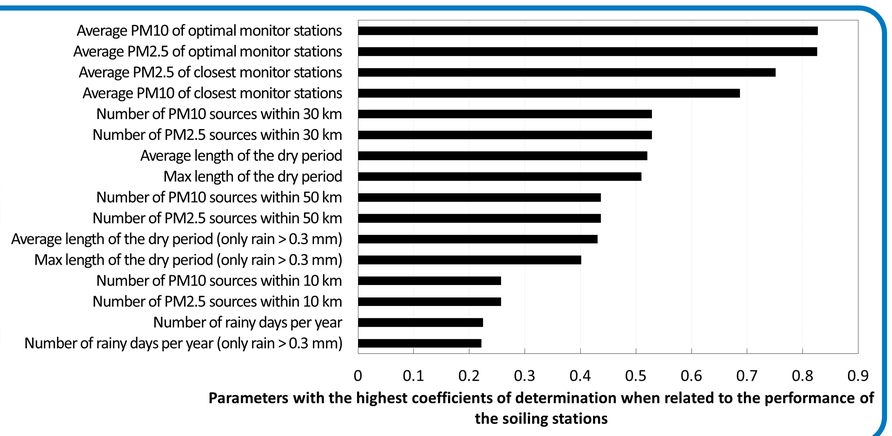
(main site-specific parameters impacting PV soiling)

Methodology

The long-term performance of 20 soiling stations have been compared with 100+ environmental and meteorological parameters.

Results

Local particulate matter (PM) concentrations and some parameters describing the precipitation pattern had significant correlations with soiling.



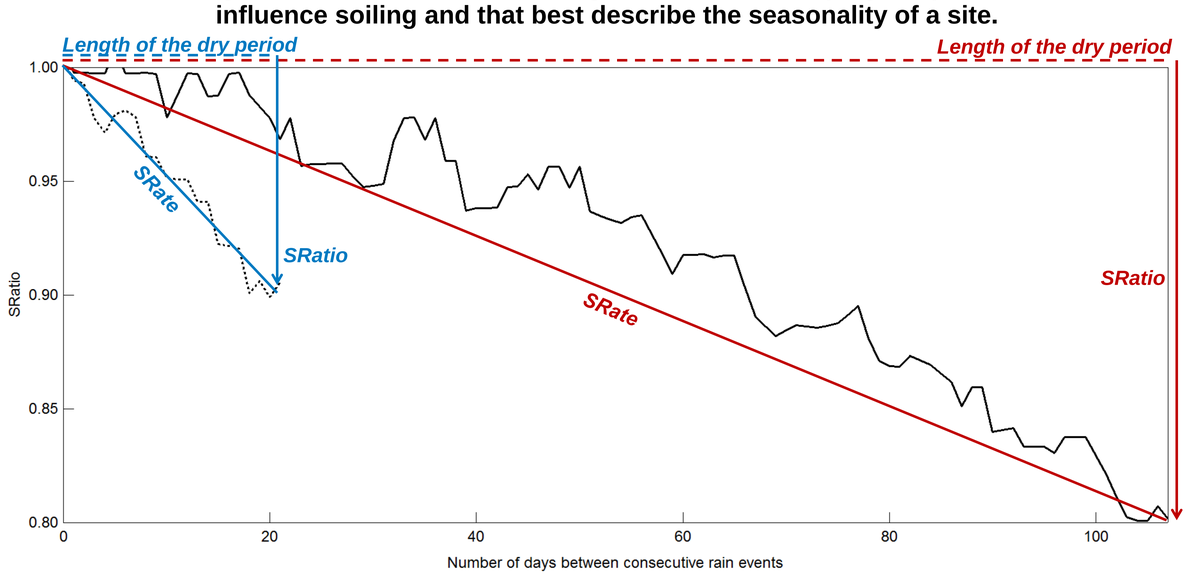
Parameters with the highest coefficients of determination when related to the performance of the soiling stations

Glossary

- **Soiling stations: PV station made of at least two cells and a pyranometer. Each device is regularly cleaned, with the exception of one of the two cells. The outputs of the cells are compared in order to determine the desired soiling metrics.**
- **Soiling ratio (SRatio): ratio between the currents of a soiled and a clean cells. SRatio = 1 for clean conditions, decreasing with soiling.**
- **Soiling rate (SRate): daily variation in soiling ratio.**
- **Particulate matter (PM): solid and liquid particles suspended in air.**
  - **PM10: particulate matter 10 micrometers or less in diameter.**
  - **PM2.5: particulate matter 2.5 micrometers or less in diameter.**

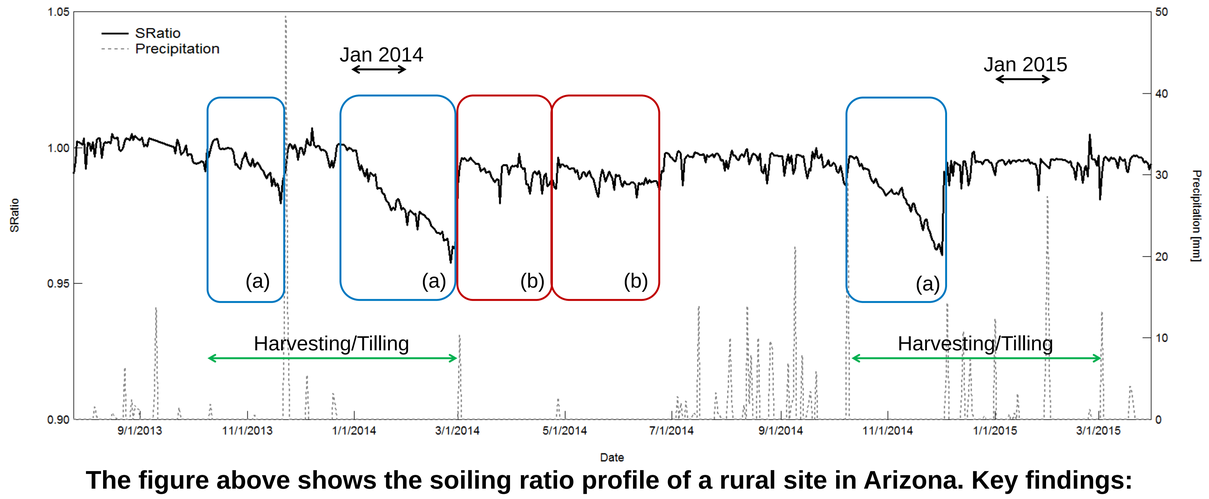
Seasonality

Aim: Determining the seasonal trends in soiling losses and identifying the parameters that most influence soiling and that best describe the seasonality of a site.



The figure above shows two soiling ratio profiles of a Californian site in different seasons:

- **Higher soiling rate periods do not necessarily result in lower soiling ratios: longer dry periods can lead to major losses even if lower soiling rates are registered.**

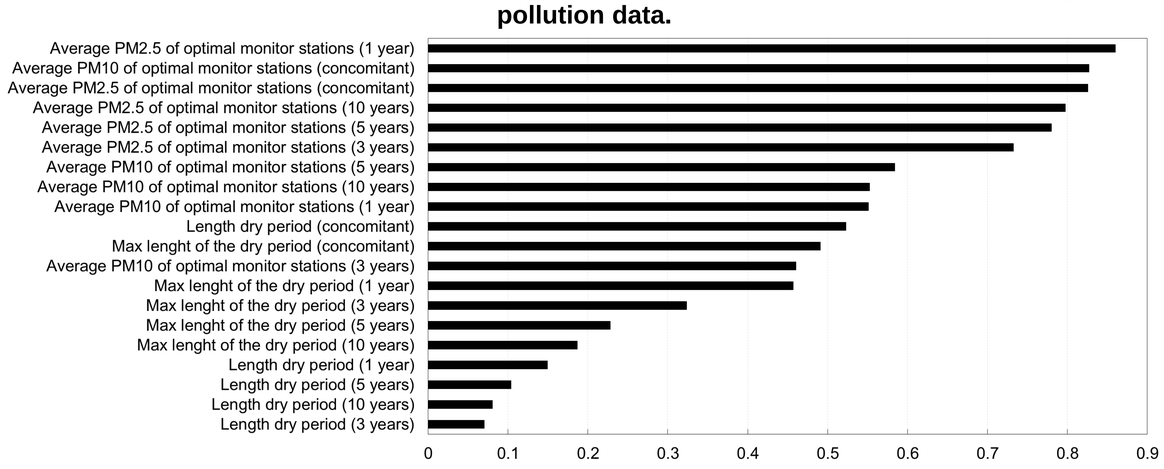


The figure above shows the soiling ratio profile of a rural site in Arizona. Key findings:

- **Strong downward trends between November and February (a), when harvesting and tilling occur;**
- **No major soiling during the dry periods occurring in other seasons (b);**
- **Different precipitation patterns in January 2014 and in January 2015 lead to different SRatios.**

Predictability

Aim: Determining future soiling losses trough the analysis of previous-years' meteorological and pollution data.



Data from previous years with the highest coefficients of determination when related to the performance of the soiling stations. The number of years before the soiling station installation date is reported in brackets.

- **Data from previous years have generally lower accuracy in soiling predictions;**
- **PM2.5 is the most consistent parameter, with high ability ($R^2 > 0.7$) to predict the soiling losses;**
- **The maximum lengths of the dry period are better predictors then the average lengths of the dry periods, if data from previous years are considered.**

Impact

- **Knowing the correlations between local parameters and soiling losses enables the creation of national and international soiling maps. Proving the predictability of soiling through those parameters would help optimizing the design, the operation and the maintenance of PV plants.**
- **The identification of seasonal trends is essential to determine the most adequate cleaning schedule and, thus, to enhance the energy yield, minimizing the maintenance costs.**

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This work was completed under Contract No. DE-AC36-08GO28308 with the U.S. Department of Energy.

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Photovoltaic Reliability Workshop (PVRW)
Lakewood Denver West Sheraton - Denver, CO
February 28th – March 2nd, 2017

PV Module Surface Soiling Studies in Brasil: Program and Research Progress

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Suellen C. Silva Costa,† Pedro Paiva Brito,† Cláudio Dias Campos,† Sergio de Morais Hanriot,† Daniel Senna Costa,†
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PVReliability.org
Confiabilidade de Sistemas Fotovoltaicos

Activities and Objectives

The project **mission** is to enhance ongoing research in solar-PV technology reliability, linking worldwide efforts with those important for the now-growing solar investments in the Brasil markets. The **objectives** include two interrelated areas important to module *surface* reliability and performance—at the very *first* point of interaction for the incoming solar photons:

- **Soiling Science and Technology**: *Creating and validating protocols and procedures; establishing joint test fields in representative climate zones; developing and deploying dust-monitoring stations in key locations where PV installations exist or are planned; collecting samples and monitoring dust-performance relationships, comprehensive dust/soiling chemical and physical analysis, and fundamental adhesive-property characterization (from the microscale); and developing a framework for dust testing standards based on Brasil's specific climate (humidity, temperature, wind, precipitation) conditions.*
- **Coatings and Films for Performance Enhancement:** *Developing, testing and validating nano- and micro-technology-based antireflection and dust mitigation coatings, including novel dual-purpose designs; and initiating materials-design protocols toward the possible discovery of new and improved coatings.*

The program aims to understand, model, and link fundamental physics and chemistry of the soiling process (in its interaction with the module surface) with observed macroscale electrical and optical characteristics of these PV devices.

Physics and Chemistry of Soiling: *Microscale Relationships*

The **chemistry & physical characteristics**[1-4] of dust differ from geographical region to geographical region throughout the *world—even at sites within fractions of kilometers distance of each other*. However, typical dust found on modules from the Gulf desert regions have 80%–90% quartz, primary silicates, and minerals/clays. The samples from rural areas of Brazil typically have 15% or less of quartz and primary silicates, with the majority of the components from secondary silicates, agricultural products, and area-specific minerals. Soluble minerals/organics & components from the fuels (e.g., diesel in samples collected near highways) and soluble minerals/organics can sometimes be detected—factors that can have significant implications for both adhesion & cleaning. These samples have been collected from very different climate zones[4] for comparisons.

Chemistry, composition, location . . .

Table 1. Compositional information on soiling particles collected from module surfaces from several climate zones. Analysis is done on a collection of several milligrams of particles. The EDS data provide information on the volume compositions and the XPS on the near-surface region. The surface concentrations of soluble salts and organics for "B" and the hydrocarbons for "C" are evident in comparing the techniques.

Detected Elemental Species (%)													
Technique	**C**	**O**	**Na**	**Mg**	**Al**	**Si**	**S**	**Cl**	**K**	**Ca**	**Ti**	**Cr**	**Fe**
A. Dry "sand" dominated by primary silicates (Dry desert region in Saudi Arabia interior)													
EDS	5.0	52.5	2.2	2.8	7.6	21.9	ND	0.8	1.7	1.8	0.7	ND	2.8
XPS	6.9	51.1	2.8	2.7	7.4	20.0	ND	1.1	2.1	2.3	0.4	ND	2.7
B. Dry "soil" from temperate and mildly humid region (Belo Horizonte, Brazil)													
EDS	5.3	45.1	2.4	3.8	5.5	9.4	3.9	1.4	1.9	8.5	0.1+	0.3	12.1
XPS	4.3	47.1	3.1	3.9	3.8	8.7	5.1	1.4	2.2	6.6	-	0.4	10.9
C. Particles from highway region exposed to hydrocarbon vehicle emissions–secondary silicates (Brazil)													
EDS	11.2	41.9	1.9	2.4	5.3	11.2	2.1	0.8	1.9	9.2	Trace	0.1	8.2
XPS	19.8	49.8	3.2	2.9	4.9	8.8	6.2	1.2	2.2	10.8	Trace	0.4	6.9

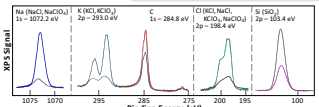
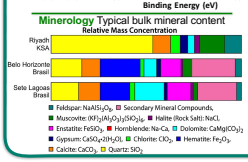


Figure 2. X-ray photo-electron spectroscopy (XPS) data showing signals from Na, K, C, Cl, and Si before (colored) & after sputtering for removal of the surface region (dark grey), indicating the surface accumulation of the soluble minerals.



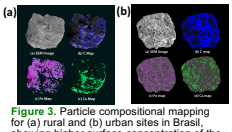
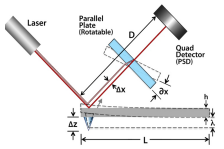


Figure 3. Particle compositional mapping for (a) rural and (b) urban sites in Brasil, showing higher surface concentration of the C (for high-traffic area).[1]

Single-particle adhesion . . .



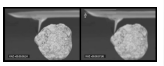
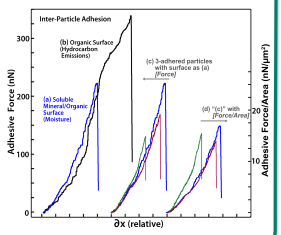


Figure 4. *Left:* Cantilever at start (unbowed) of measurement, and *Right:* Cantilever bowing as the particle is pulled to the left.

Methodology:[1] The deflection of the laser beam from the top of the AFM cantilever measures the bowing of the cantilever, which can be translated directly into the lateral force holding the particle to the surface.

Figure 5. Measured inter-particle adhesion forces for two cases: (a) Particles having soluble mineral/organic surface and exposed to moisture, and (b) particles taken from module exposed to hydrocarbon fumes (high vehicular traffic). (c) and (d) compare force and force/area for three adhered particles having surfaces as in (a). The parameter ∂x is a measure of the bowing of the AFM cantilever that relates directly to the force.[1] Cases correspond to particles in Fig. 2.



Climate Zones, Monitoring Sites, and Partners

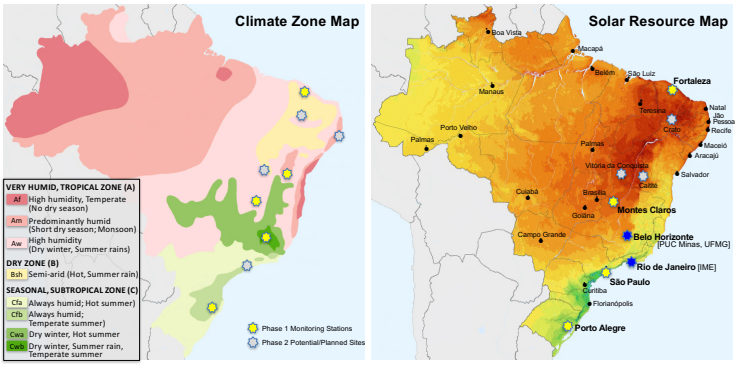


Figure 1. *Left:* Climate zones, based on Köppen-Geiger [Meteorologische Zeitschrift, **15**, 259–263 (2006)], showing chosen first-phase dust-monitoring locations and additional potential monitoring sites (based on climate-zone coverage and priority PV-installation locations).† Monitoring stations have both thin-film and c-Si technologies; *Right*: Collaborating partners (blue suns) and confirmed monitoring sites (blue and yellow suns) shown on solar resource map of Brasil. Other Brasil cities are included for reference.

†*Suellen C.S. Costa et al., "Caracterização Físico-Química da Sujidade Deposita Sobre Módulos Fotovoltaicos Instalados em Zonas Climáticas de Minas Gerais," Proc. VI Congresso Brasileiro de Energia Solar, Apr. 2016.*

Performance: *Macroscale Correlations*

Studies of the shape[4,5] of **the J-V characteristics** are just initiated to examines the relationships among soiling levels/patterns and PV module performance, the climate conditions, and the physical and chemical properties of the soiling particles and surfaces involved. Specifically, these studies focus on the commonly encountered **non-uniform soiling** of module surfaces. These non-uniform accumulations[5] cause a decrease in the power produced, but also result in shading that can cause increased area heating ("hot spots"), leading to module degradation. We have started to examine the effects of non-uniform soiling patterns (categorized as **edge build-up, waves, and blotches**) on the J-V characteristics, documenting changes in **the shape of these characteristics** with the geometry and thickness distributions on the module surfaces. These studies are initially being performed on crystalline Si framed modules. The non-uniform distributions are also related to the temperature distributions—with the temperature mapping evaluated using low-cost (iPhone or iPad based) infrared cameras. Hot spots have temperature increases of more than 15°C in some cases for modules operating under normal sunlight conditions. We have begun careful analysis of the I-V patterns, gaining some indications for *possible* spectroscopic identifications for fundamental model development.

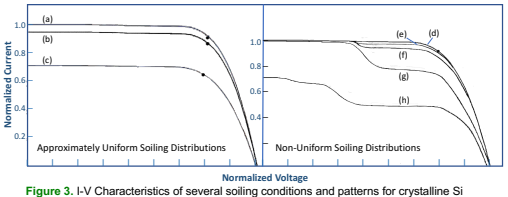


Figure 3. I-V Characteristics of several soiling conditions and patterns for crystalline Si module. Left: (a) for clean module and (b) and (c) 7 gm/cm² and 33 gm/cm² approximately "uniform" soiling, respectively. Right: (d) clean module; (e) medium-level soiling around sides and bottom of frame (edge build-up); (f) higher-level soiling around sides and bottom of frame; (g) high level at sides and corners; (h) with blotch covering several cells near center of module with high-level edge build-up.

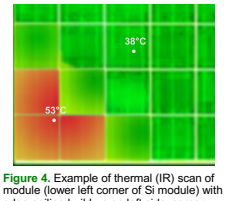


Figure 4. Example of thermal (IR) scan of module (lower left corner of Si module) with edge-soiling build up on left side, corner, and bottom. Three cells have elevated temperature (△T = 15°C) where soiling is highest (corner/frame region).

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Acknowledgements: The authors gratefully acknowledge the support of CAPES for part of this work through "Pesquisa Visitante Estrangeiro," and to Ciência sem Fronteiras that supports the students and postdocs involved with our Brasil dust/soiling reliability project. We also acknowledge the interactions and advice of the *Solar Energy Institute for India and the United States* (SERIIUS), which maintains a strong leading research and development program in soiling and dust research and mitigation. This group is funded jointly by the U.S. Department of Energy and the India Office of Science and Technology in the Ministry of New and Renewable Energy.
Poster presents no sensitive or proprietary information

Using Solar Production Data to Calculate Average Soiling Rates and Characterize the Effects of Specific Weather Events

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Abstract

Soiling of photovoltaic modules by dirt or snow can significantly reduce the energy production of solar power plants, and erode value to investors. Historically, losses due to soiling have been highly uncertain as they rely primarily on pre-determined rates of dirt accumulation, such as those described in the Kimber et. al methodology. This uncertainty is further exacerbated for small-scale projects that don't have soiling monitoring equiperformance metric ent and therefore rely solely on non-empirical methods for estimating soiling rates before construction. To overcome this industry-wide issue, Sol Systems has adopted the methodologies outlined in the paper, "A Scalable Method for Extracting Soiling Rates from PV Production Data" to extract soiling rates based from our operational fleet of more than 50MW across continental USA.

Objectives

This project provides:

1) insight into the real soiling rates extracted from the Sol Systems operational fleet;
2) a means to characterize the effects of specific weather events into visual representations that other C&I portfolio owners could adopt to better predict soiling;
3) and, a framework to recognize soiling-created underperformance using limited monitoring instrumentation that is typical of small PV systems.

Methodology

The methodology used here is a slightly modified version of the process described in "A Scalable Method for Extracting Soiling Rates from PV Production Data". In an effort to further improve accuracy, Sol Systems has placed two filters on the dataset. Both are applied during the interpolation process of the 15 minute data. The first is a clipping filter that is tied to system AC capacity. The second is a minimum plane-of-array irradiance filter which by default is set to 300 W/m^2. Both filters completely exclude the data associated with that point (irradiance and production).

The required inputs for the analysis are:

- PV Instantaneous Power (15min res.)
- POA Irradiance (15min res.)
- Panel Temperature (15min res.)
- Daily Rainfall Totals [1]

The first step is to calculate a daily performance metric for the system. To do this the 15 minute instantaneous power readings must each be temperature corrected to 25 degrees C. Once those values have been calculated, they are then integrated into daily production numbers. Daily insolation is calculated the same way by intergrating the 15 minute irradiance numbers.

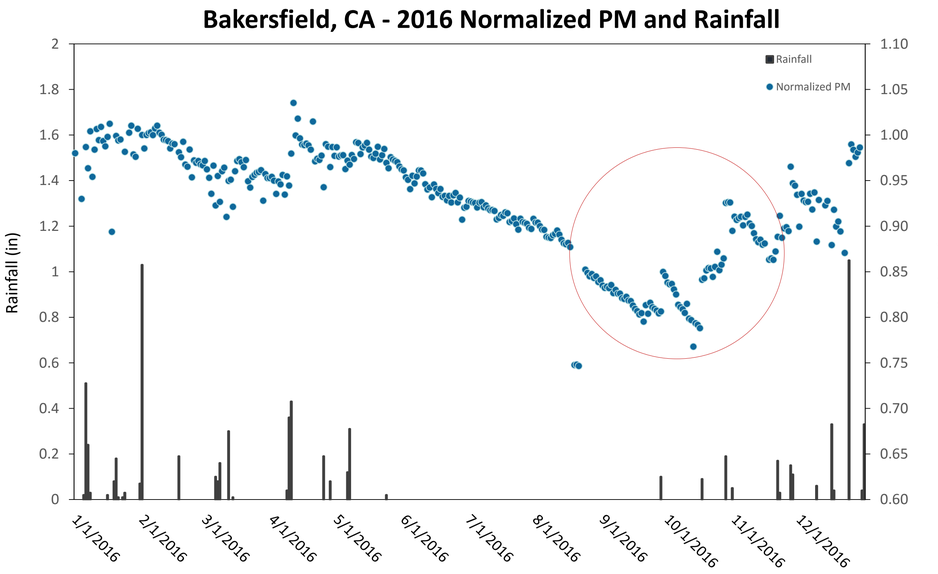
The performance metric is then calculated by dividing the daily insolation into the daily production number. The daily performance metric values are then normalized to the 95th percentile of the calculated performance metric values for that site. This step produces a dimensionless performance metric that is sized to the near peak performance of the system.

To extract the daily soiling rates the performance metric values must be compared to the daily rainfall totals. Extended dry periods will tend to have a continual decline in system performance as soiling levels rise. Periods of two weeks or more without a rainfall event are preferred. The magnitude of the events does not matter. The average rate of change in the daily performance metric values during those periods will correspond to the daily soiling rate.

For each period identified, a Theil-Sen estimator is used to extract the slope of performance metric vs. days. The Thiel-Sen estimator takes the slope between all possible pairs of points in a data set and then returns the median of those values. This method is preferred over a simple linear regression because it better reduces the effect that outliers have on the final soiling rate number. [2]

Results

System Info
Canopy Mounted, 270 Degree Azimuth, 5 Degree Tilt
AC Size: 500kW
DC:AC Ratio 1.20

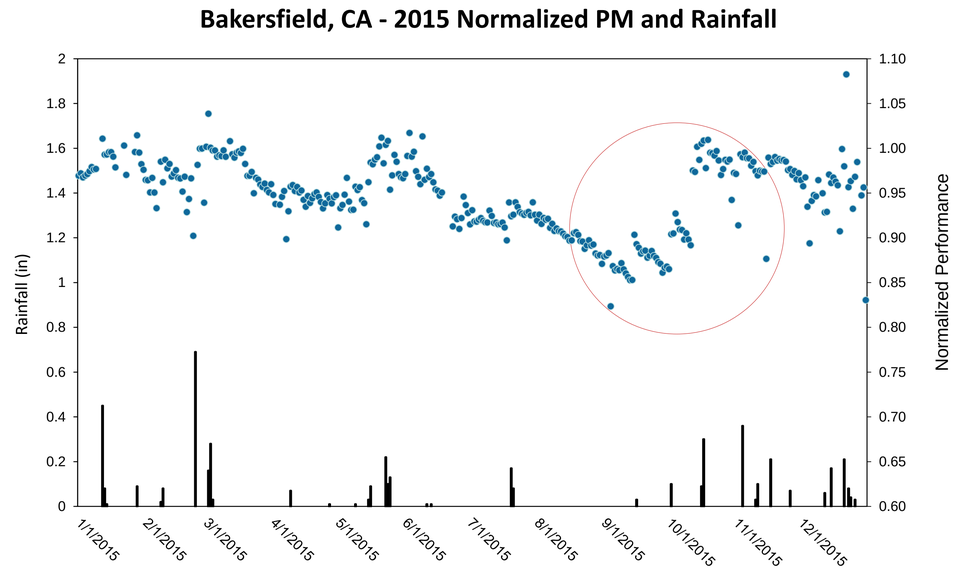


Start Date	End Date	Daily Soiling Rate
February 7, 2016	March 5, 2016	-0.19%
March 16, 2016	April 4, 2016	-0.10%
May 10, 2016	August 17, 2016	-0.11%
August 24, 2016	September 27, 2016	-0.16%
September 29, 2016	October 16, 2016	-0.38%
October 28, 2016	November 20, 2016	-0.28%

Figure 1: Extracted Soiling Rates, 2016

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0.97%	1.33%	4.73%	2.49%	2.29%	6.01%	8.70%	13.79%	18.08%	16.07%	10.00%	6.99%

Figure 2: Average Monthly PM Values, 2016



Start Date	End Date	Daily Soiling Rate
March 3, 2015	April 7, 2015	-0.18%
April 8, 2015	May 14, 2015	-0.04%
May 23, 2015	July 18, 2015	-0.16%
July 19, 2015	September 14, 2015	-0.14%
September 15, 2015	October 1, 2015	-0.19%
October 2, 2015	October 11, 2015	-0.21%

Figure 3: Extracted Soiling Rates, 2015

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2.76%	4.85%	2.93%	6.83%	3.17%	3.27%	8.86%	10.92%	13.89%	5.55%	3.68%	5.85%

Figure 4: Average Monthly PM Values, 2015

- Soiling rates were found to be highly variable over the course of a single year and did not correspond well to the magnitude of or time since the last rainfall.
- Instead the soiling rates seemed to be correlated to the amount of activity in the area, specifically agricultural. The highest daily rates were found in the early spring and late summer/early fall. Circled above in red, the period with the highest average soiling rates typically began around the end of August and went through November. Looking at this site over its entire 4 year operational history October seems to have the highest average soiling rates of any month, whereas September typically saw the lowest average performance metric values.
- Wind direction was also found to have an effect. Northwest winds seemed to increase soiling rates at this location. Upon further analysis of the surrounding area a viable explanation was found. The area to the Northwest of Bakersfield (Figure 5) has large amounts of land being used for growing cotton, almonds, oranges and grapes. The almonds in particular produce significant amounts of dust. It appears that a large portion of the spike in soiling rates at this project location are due to the annual almond harvest. According to the California Air Resources Board approximately 41 pounds of dust are raised from every acre of almonds harvested. For comparison, wheat raises roughly 6 pounds per acre and cotton comes in around 3.5. On top of that almond trees can be harvested up to three times in a single year.

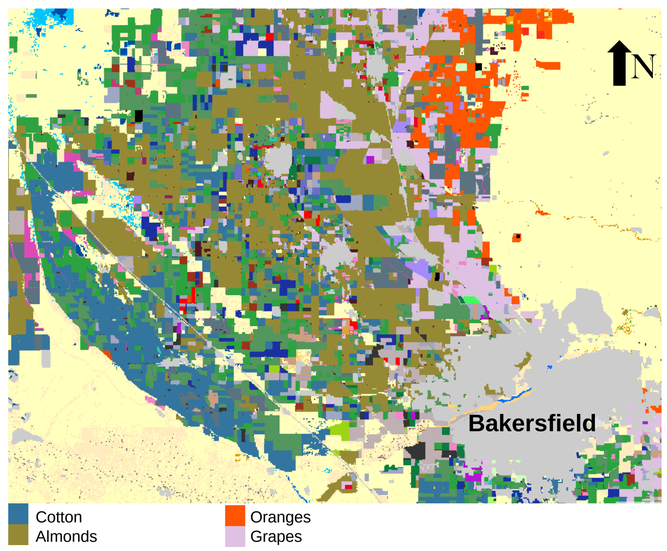


Figure 5: Map of primary land usage to the area Northwest of Bakersfield [3]

Conclusion

The process presented in "A Scalable Method for Extracting Soiling Rates from PV Production Data" has worked well on the data it has been applied to here. Further analysis of the rest of the operating fleet will be completed in the coming year. That information will then be compiled along with the primary use being to improve our current regional monthly soiling profiles. In 2016, Sol Systems assembled a dirt and snow soiling estimator based on work from a number of previous studies in the field. One of the major areas of uncertainty in the calculation is the daily soiling rate which is typically assumed to be a mostly static value throughout the year. With the extracted soiling rates in hand the losses can be more accurately modeled on a seasonal level.

The second use will be to better characterize specific local weather related events. Here we have evidence of the effect that wind directions and local agriculture activities can have on daily soiling rates. More time will need to be devoted to this to gain useful information that could be applied to other projects during the diligence process. The hope is that the analysis of the other sites in the fleet will reveal similar tendencies at other locations. Some other atypical events Sol would like to investigate (and has data on) are: sand storms, freezing rain, heavy fog and even hurricanes.

Finally, Sol would like to incorporate the calculations used here into our Asset Management process. The calculated soiling losses would be used to help identify the economic benefit of a panel washing and at what point in the year it would have the most impact.

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Anti-soiling coatings for PV applications

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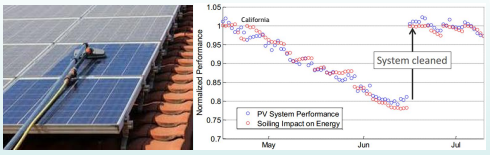
Introduction

With the ambition of becoming the preferred materials solution provider for high-efficiency solar PV modules, DSM has developed innovative breakthrough technologies, which boost the cost/performance ratio of solar energy systems.
For photovoltaic (PV) modules, soiling could be a major issue as it reduces the amount of light that reaches the cells and thus reduces the power output. Dust storms in desert areas can even reduce the output of PV modules by as much as 70%-80% in one hour.
DSM has developed an anti-soiling coating, suitable for use on a front glass sheet of a PV module. The anti-soiling coating has been developed for locations with high soling rates to minimize output loss with reduced number of cleaning cycles. Our anti-soiling coatings also provide anti-reflective functionality to maximize the benefit offered by both technologies. This poster covers lab and outdoor testing of the anti-soiling coating including development of lab tests to simulate outdoor conditions and analysis of outdoor data to demonstrate the anti-soiling effect. A lab test combining dust settling on glass samples and blowing off the settled dust to simulate outdoor conditions will be introduced including initial results with different anti-soiling and anti-reflective coatings.

Justification



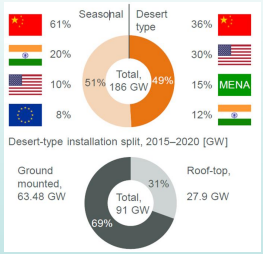
J.R. Caron, B. Littmann, *IEEE J. Photovoltaics*, **2013**, *3*, 336–340.

Soiling of PV modules is a major source of losses in module output, with the highest soiling rates in arid (desert) areas.
Regular cleaning can mitigate the loss in output but increases the O&M cost.

There is a clear market need for technological solutions to lower the speed of soiling and/or to reduce cleaning costs.

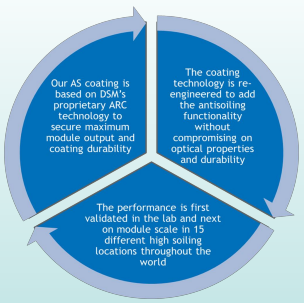
Market need and opportunity

Key countries contributing to desert type and seasonal soling markets, 2015-2020.



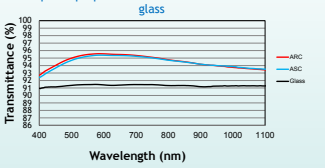
- China is expected to host the majority of soiling installations, both desert and seasonal.
- USA mostly desert type market.
- The MENA region is a major desert type market with mostly ground installations.
- India's seasonal soiling market growth fastest, mostly rooftop segment.
- In total , more than 2/3 of desert type installations are expected to be ground mounted.

Development Approach



Optical performance

Optical properties ASC vs ARC and uncoated glass

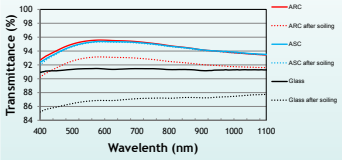


	Average Transmittance (%)	Absolute transmittance gain (%	Relative transmittance gain (%)	Maximum transmittanc e (%)	Position maximum transmittance λ [nm]
Uncoated glass	91.3	-	-	-	-
ARC	94.6	3.2	3.6	95.6	604
ASC	94.5	3.1	3.4	95.4	607

Excellent AR properties: the average relative gain in transmittance is 3.4%, practically identical to that of the DSM ARC coating.

Anti-soiling performance

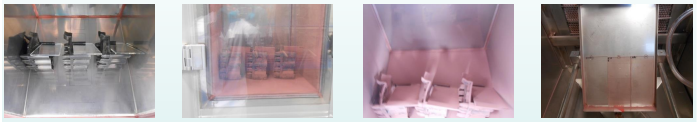
Soiling properties ASC vs ARC and uncoated glass



	Transmittance loss after soiling (%)
Uncoated glass	4.33
ARC	2.26
ASC	0.08

DSM ASC has an almost perfect performance in the standard DSM soiling test - virtually no loss in transmittance

Performance in dust settling test

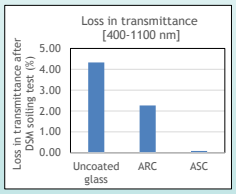


Before soiling | During soiling | After soiling | After exposure to air flow

Sequential testing in dust settling chamber with China sand and exposure to gentle air flow.

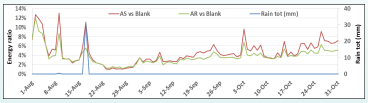
After deposition, all samples area heavily soiled.

After exposure to air flow: ASC is significantly cleaner than ARC, the uncoated glass is most heavily soiled.



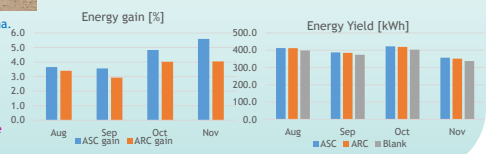
Outdoor performance

Test site TüV Süd Dunhuang China.



3 sets of modules are being tested for 1 year: uncoated, ARC and ASC.

The AS coating consistently outperforms the ARC, average additional output is 1.0-1.2%.



Conclusions

- A lab soling test method has been developed simulating soil deposition and removal by air flow.
- The soiling test method demonstrates a difference in anti-soiling properties between uncoated and coated glass, with the AS coating showing the best anti-soiling benefits.
- In Dunhuang China, the ASC coating consistently outperforms the ARC coating with an average additional output of 1.0-1.2%.
- Correlations between lab test results and real outdoor performances still need to be further verified.
- We are looking for new concepts/methods/equipment for testing soiling performances in the lab.

HEALTH · NUTRITION · MATERIALS

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Thermal Non-uniformity in PV Modules and Plants: Influence on Performance Parameters

Ashwini Pavgi, Jaewon Oh, Joseph Kuitche, Sai Tatapudi, and GovindaSamy TamizhMani
Arizona State University Photovoltaic Reliability Laboratory (ASU-PRL), Mesa, Arizona, USA

Abstract

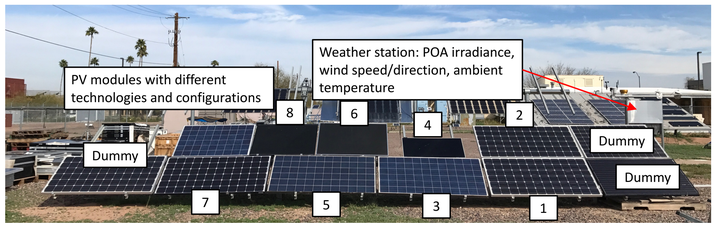
The behavior of temperature distribution of PV cells within a PV module and of PV modules within a PV power plant is presented. The effect of thermal non-uniformity on I-V parameters of three different PV technologies (c-Si, CdTe, CIGS) was investigated. 8% temperature variation between the thermocouples in c-Si and CIGS modules was observed and caused about 2% and 1.5% variations in P_{max}, respectively. On the other hand, about 14% variations in temperature in CdTe module causes about 4% variation in P_{max}. A least temperature non-uniformity was observed from black framed PV module in c-Si technology. ANOVA, a statistical tool, was also used to study the influence of various ambient and design factors on temperature variation. Two PV power plants (fixed horizontal-tilt and one-axis) located in a desert climate of Arizona was investigated for thermal uniformity study. Temperature non-uniformity was observed and visualized by using thermal mapping data of the PV power plant. Additionally, higher average operating temperature of modules was observed for the one-axis tracker based plant as compared to the fixed-tilt based plant, thereby a higher degradation rate and a lower lifetime are expected for the one-axis tracker based modules as compared to the fixed-tilt based modules.

Experimental Setup

Module Level Setup

- T-type thermocouples attached to the backsheet at locations defined in the IEC 61853-2.
- Temperature monitoring under maximum power point tracking (MPPT) condition.
- Multi-curve tracer was used for the I-V measurement and temperature coefficient.

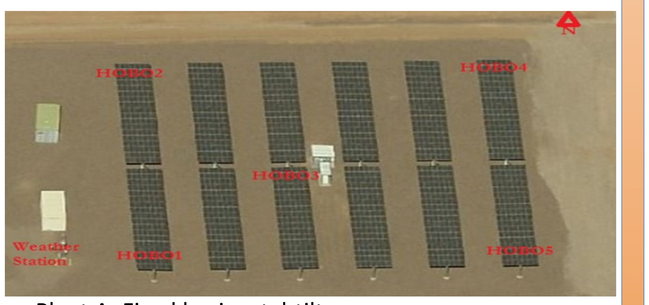
No	Insulation Type	Module Technology
1	Non-insulated	Mono c-Si
2	Aluminum tape covered back sheet	Mono c-Si
3	Frame insulated	Poly c-Si
4	Non-insulated	CdTe
5	Frame and back sheet insulated	Poly c-Si
6	Non-insulated	a-Si
7	Non-insulated	CIGS
8	Black-frame module	Mono c-Si



Outdoor Test Setup

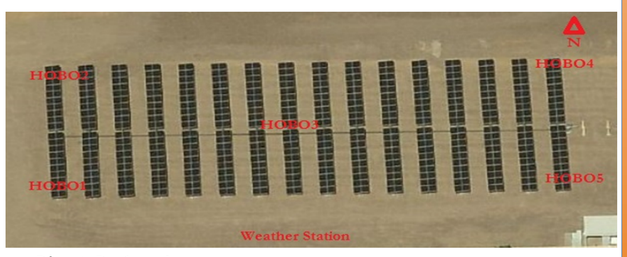
System Level Setup

- Crystalline silicon module power plants were investigated.
- Five data loggers were installed at the northwest (NW), northeast (NE), southwest (SW), southeast (SE) and center locations.
- 4 thermocouples were attached to module at each location in accordance with IEC 61853-2
- MATLAB was used to interpolate and map the temperature values on a grid representative of PV module or a power plant.



Plant A: Fixed horizontal-tilt arrays

- No wind barrier around plant



Plant B: 1-axis arrays

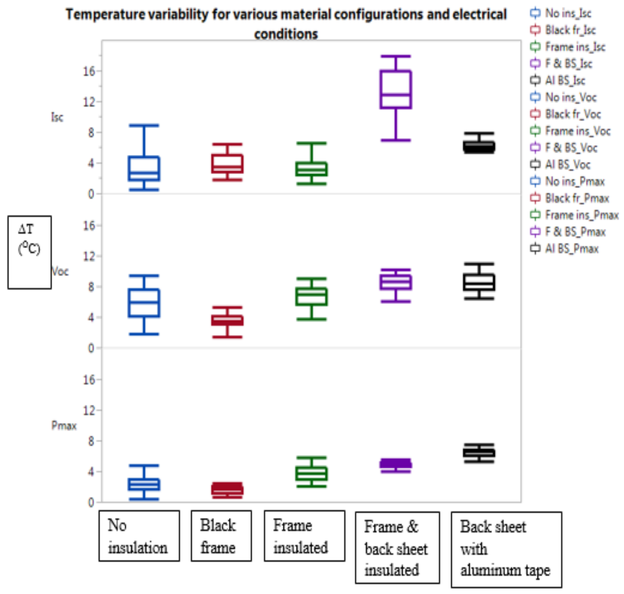
- 4 feet lower ground level having some wind obstruction
- 15 foot high wall on the south side of the 1-axis plant and this wall is about 30 feet away from the array leading to some wind obstructions

Analysis of Variance (ANOVA)

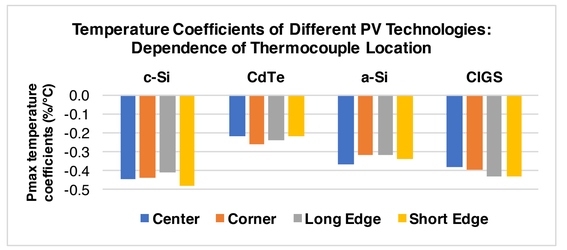
- Fixed effect model was used.
- Module Level: 3 factors (PV technology, electrical condition, and thermocouple locations) with different levels were studied on a clear sunny day (1015 W/m^2)
- System Level: 3 Factors (type of power plant, module locations, and thermocouple locations) with different levels were studied on a clear sunny (940 W/m^2) and cloudy (320 W/m^2) day

Module-level Thermal Non-uniformity

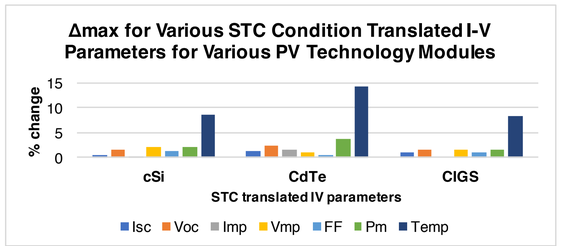
- Temperature non-uniformity depending on thermocouple location and thermal insulation type.
- Observed temperature coefficient non-uniformity depending on thermocouple location.
- Based on ANOVA, all the 3 factors have significant effect on the temperature variation since all the p-values are less than 0.05.



❖ Aluminum tape could be a good solution to improve thermal uniformity provided appropriate measures are taken to lower the operating temperatures.



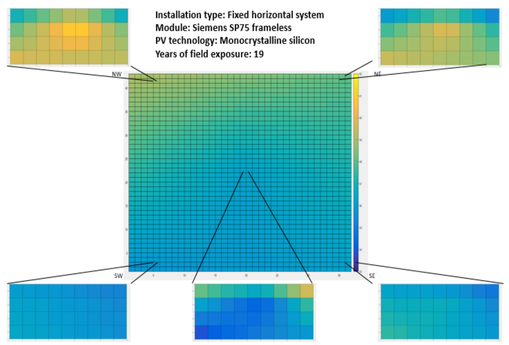
Measured before applying insulation. The temperature coefficient of frameless module (CdTe) experiences the least dependence on the thermocouple location of the module.



Parameters were continuously monitored more than 2 clear sunny days. CdTe module shows higher temperature variation and P_{max} than c-Si and CIGS modules.

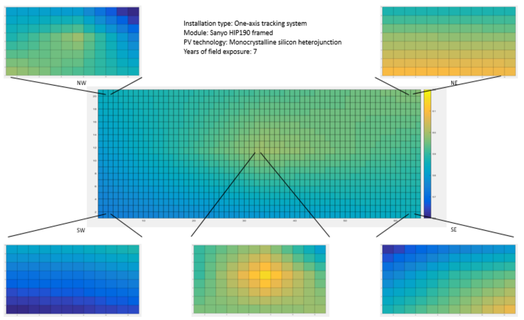
Plant-level Thermal Non-uniformity

- PV plant thermal non-uniformity was observed from both plants.



Plant A: Fixed horizontal-tilt arrays

- Temperature is highest at NW corner of the plant

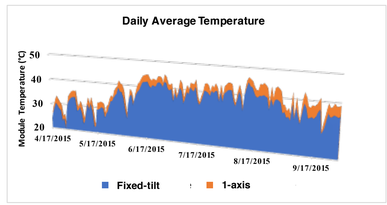


Plant B: 1-axis arrays

- Temperature is highest at center of the plant due to wind obstruction in the plant.

ANOVA

On a clear sunny day, ANOVA indicates that both module location (p: 0.05) and the plant type (fixed vs. 1-axis, p: 0.034) play significant roles in temperature distribution. However, on a cloudy day, only module location (p: 0.031) within a plant plays a significant role in temperature distribution.



The 1-axis plant experienced higher temperature than the fixed-tilt plant.

Conclusion

- At the module level, center cells tend to operate at the highest temperatures and the frameless modules tend to experience more uniform temperatures than the framed modules.
- The module-level thermal non-uniformity can be decreased by the use of black frame or insulating the frame.
- At the plant level, thermal non-uniformity is mainly dominated by the wind direction.

Acknowledgments: This research is based upon work supported by the Solar Energy Research Institute for India and the U.S. (SERIIUS) funded jointly by the U.S. Department of Energy subcontract DE AC36-08G028308 (Office of Science, Office of Basic Energy Sciences, and Energy Efficiency and Renewable Energy, Solar Energy Technology Program, with support from the Office of International Affairs) and the Government of India subcontract IUSSTF/JCERDC-SERIIUS/2012 dated 22nd Nov. 2012.

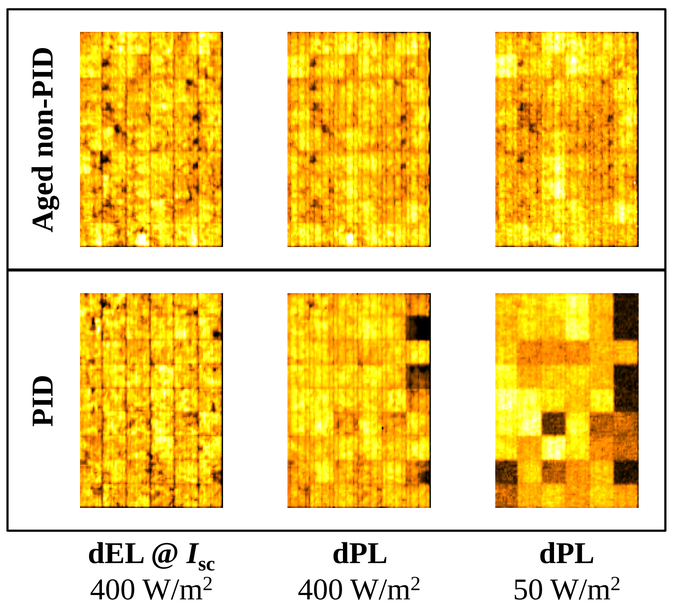
solarzentrum stuttgart

DaySy Daylight EL & PL: Estimates PID Losses in the Field

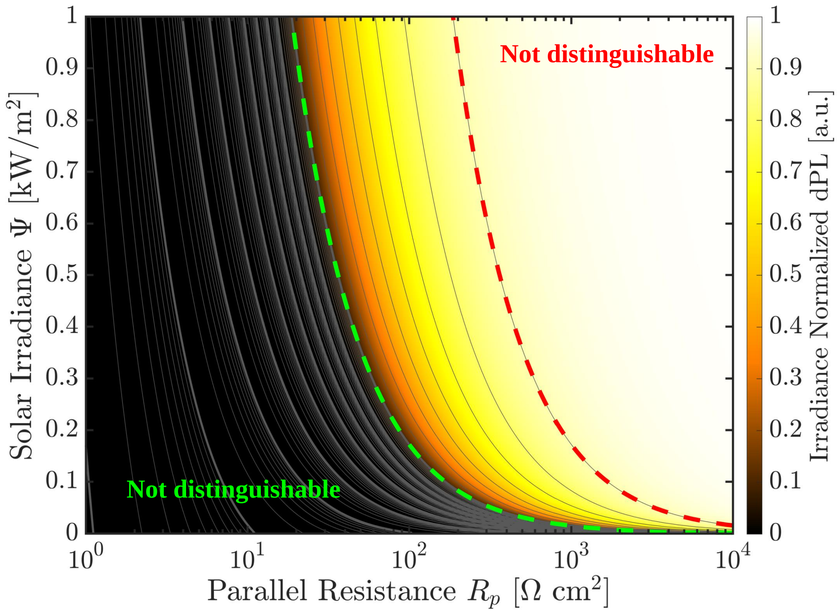
Problem: Potential Induced Degradation (PID) severely deteriorates PV module power output. Until now, PID characterization required lengthy measurements: Either the combination of outdoor nighttime Electro-Luminescence (nEL) detecting PID with daytime IV measurements quantifying the power loss, or the demounting of PV modules and assessing them in a lab.

Solution: DaySy daytime Photo-Luminescence (dPL) detects PID and simultaneously estimates the PV module power loss.

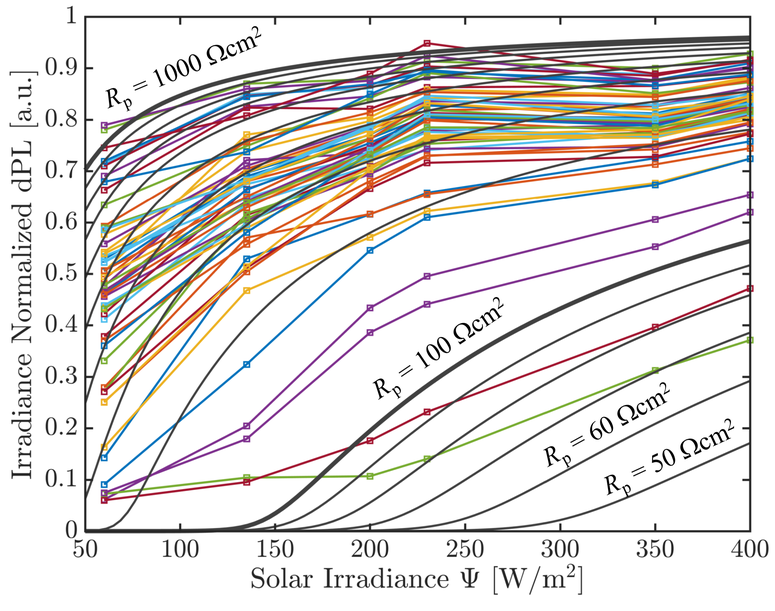
Measurement: Daytime EL & PL



Simulation: dPL Intensity



Extraction of Cell dPL Intensity



Procedure Relative cell efficiency η values are extracted from dPL images in 6 steps:

1. Correct image data: lens shading, lens distortion and projection.
2. Extract averaged luminescence intensity for every cell.
3. Normalize with regard to J_0 using I_{sc} dEL or 1 kW/m² dPL images.
4. Normalize with regard to irradiance Ψ using the least affected cell at Ψ = 50 W/m².
5. Extract R_p by comparison with simulated dPL intensity. The simulation employs the widely used isolated element model.
6. Determine relative cell efficiency with the one diode model.

Relative Cell Efficiency and R_p

η = 73 % 2.36 Ω	η = 68 % 2.04 Ω	η = 93 % 9.85 Ω	η = 83 % 3.91 Ω	η = 96 % 15.73 Ω	η = 72 % 2.33 Ω
η = 89 % 6.19 Ω	η = 78 % 3.02 Ω	η = 98 % 26.33 Ω	η = 99 % 41.09 Ω	η = 85 % 4.23 Ω	η = 81 % 3.39 Ω
η = 79 % 3.16 Ω	η = 82 % 3.68 Ω	η = 99 % 41.09 Ω	η = 78 % 2.91 Ω	η = 74 % 2.48 Ω	η = 93 % 9.91 Ω
η = 84 % 4.09 Ω	η = 85 % 4.24 Ω	η = 89 % 6.04 Ω	η = 72 % 2.31 Ω	η = 80 % 3.27 Ω	η = 81 % 3.48 Ω
η = 85 % 4.28 Ω	η = 76 % 2.76 Ω	η = 86 % 4.75 Ω	η = 82 % 3.71 Ω	η = 81 % 3.50 Ω	η = 87 % 4.96 Ω
η = 84 % 4.06 Ω	η = 71 % 2.23 Ω	η = 91 % 7.52 Ω	η = 79 % 3.18 Ω	η = 81 % 3.42 Ω	η = 99 % 41.09 Ω
η = 90 % 6.32 Ω	η = 77 % 2.82 Ω	η = 95 % 13.73 Ω	η = 88 % 5.26 Ω	η = 88 % 5.27 Ω	η = 92 % 7.81 Ω
η = 90 % 6.30 Ω	η = 85 % 4.26 Ω	η = 91 % 7.50 Ω	η = 85 % 4.35 Ω	η = 87 % 4.86 Ω	η = 97 % 21.68 Ω
η = 80 % 3.33 Ω	η = 99 % 41.09 Ω	η = 76 % 2.70 Ω	η = 88 % 5.63 Ω	η = 67 % 1.96 Ω	η = 78 % 2.93 Ω

Aged non-PID

η = 49 % 1.20 Ω	η = 46 % 1.12 Ω	η = 55 % 1.40 Ω	η = 68 % 2.04 Ω	η = 46 % 1.12 Ω	η = 21 % 0.52 Ω
η = 50 % 1.24 Ω	η = 52 % 1.29 Ω	η = 48 % 1.19 Ω	η = 60 % 1.58 Ω	η = 37 % 0.90 Ω	η = 12 % 0.28 Ω
η = 58 % 1.52 Ω	η = 41 % 1.00 Ω	η = 39 % 0.95 Ω	η = 33 % 0.80 Ω	η = 42 % 1.04 Ω	η = 44 % 1.07 Ω
η = 65 % 1.82 Ω	η = 39 % 0.95 Ω	η = 47 % 1.15 Ω	η = 38 % 0.93 Ω	η = 43 % 1.05 Ω	η = 14 % 0.34 Ω
η = 73 % 2.42 Ω	η = 69 % 2.10 Ω	η = 56 % 1.43 Ω	η = 35 % 0.86 Ω	η = 47 % 1.15 Ω	η = 27 % 0.65 Ω
η = 69 % 2.10 Ω	η = 67 % 1.95 Ω	η = 27 % 0.65 Ω	η = 45 % 1.10 Ω	η = 32 % 0.79 Ω	η = 36 % 0.88 Ω
η = 59 % 1.55 Ω	η = 45 % 1.11 Ω	η = 64 % 1.77 Ω	η = 39 % 0.96 Ω	η = 44 % 1.07 Ω	η = 46 % 1.12 Ω
η = 31 % 0.74 Ω	η = 57 % 1.47 Ω	η = 40 % 0.97 Ω	η = 46 % 1.13 Ω	η = 41 % 1.00 Ω	η = 19 % 0.47 Ω
η = 29 % 0.71 Ω	η = 42 % 1.03 Ω	η = 38 % 0.93 Ω	η = 44 % 1.09 Ω	η = 47 % 1.16 Ω	η = 40 % 0.98 Ω

PID

Supported by:

Federal Ministry for Economic Affairs and Energy

on the basis of a decision by the German Bundestag

Conclusion: DaySy assesses of Potential Induced Degradation (PID) in the field and further simultaneously estimates PID impact on PV module efficiency. Thus, DaySy dEL + dPL immediately detects and quantifies PID in the field.

2017 Photovoltaic Reliability Workshop
March 2, 2017

Inspection methods of PV systems by using UV irradiation

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Motivation

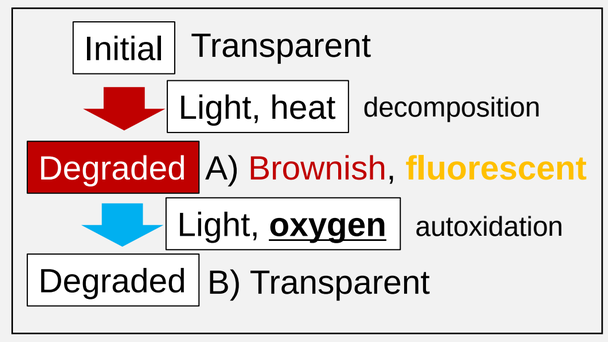
Development of large-scale PV systems attracts increased attention to inspection methods which enable faster, easier and more accurate detection of breakdowns in an early stage. Table 1 shows the aspects of the respective inspection methods. At present, the inspection methods have trade-off between accuracy and speed. Therefore, the speedy and accurate method is required. In this presentation, we propose a new approach which allows for a simple method detecting the failure sources of the modules.

Table1. Inspection methods and their aspects

Methods	Loss of power generation	Accuracy	Speed	Equipment	Cost
String EL	○(at night)	◎	△	△	×
Remote power monitoring	○	△	◎	△	○
Appearance check using drone	△	△	○	△	○
Pulsed light	△	○	×	△	△
Pulsed signal	×	△	×	△	△

Conclusions

We can detect the failure sources of the module by irradiating UV light in the night. In this method, the discoloration of the encapsulant can be estimated by the luminescence intensity of the module under UV irradiation. The appearance changes of the degraded encapsulants are categorized to two different regions; A) fluorescent and B) transparent. This is caused by the mechanisms of autoxidation. In the area without oxygen intrusion (region A), only the thermal and photo decomposition occur, resulting in the generation of chromophore group as an intermediate. In the area with oxygen intrusion (region B), the autoxidation progresses with oxygen, causing further dissolution of the chromophore group. Thus, there are no browning and fluorescence in the area.



Using these characteristics, cell crack, hotspot, delamination and affect of impurity can be detected with this method. This inspection method makes it possible to detect the failure sources of modules in the faster and easier way.

Fluorescence of the encapsulant

To detect failure sources, we took notice of the discoloration of the encapsulant. The appearance changes of the degraded encapsulant has many important characteristics;
1)The degradation of the encapsulant is accelerated by the heat.
2)Some degraded materials in encapsulants cause browning and fluorescence.
3)Fluorescent materials are further dissolved with exposure to air and light.

These characteristics come from the mechanisms of autoxidation.[1, 2] Figure 1 shows the aspects and fluorescence of initial and degraded encapsulants.

In the area without oxygen intrusion(A), only the thermal and photo decomposition occur. Therefore, the chromophore group such as carbonyl group[2, 3] and/or aromatic compounds[4, 5] are likely produced as an intermediate, which makes the area brownish and fluorescent.

In the area with oxygen intrusion(B), the autoxidation progresses with oxygen, resulting in the further dissolution of the chromophore group. Thus, there are no browning and fluorescence in the area.

1)L. Reich and S.S. Stivalas, “Autoxidation of Hydrocarbon and Polyolefins- Kinetics and Mechanisms”, Marcel Dekker, New York (1969)
2)D. J. Carlsson and D. M. Wiles, *J. Macromol. Sci., Chem.*, **C 14**, 65 (1976)
3)N. S. Allen, J. Homer and J. F. McKellar, *J. Appl. Polym.* Sci., **21**, 2261, 3147(1977)
4)A. Charlesby and R. H. Patridge, *Proc. Roy. Soc. London. Ser. A*, **283**, 312, 329(1965)
5)W. Schnabel, *Makromol. Chem*., **180**, 1487(1979)

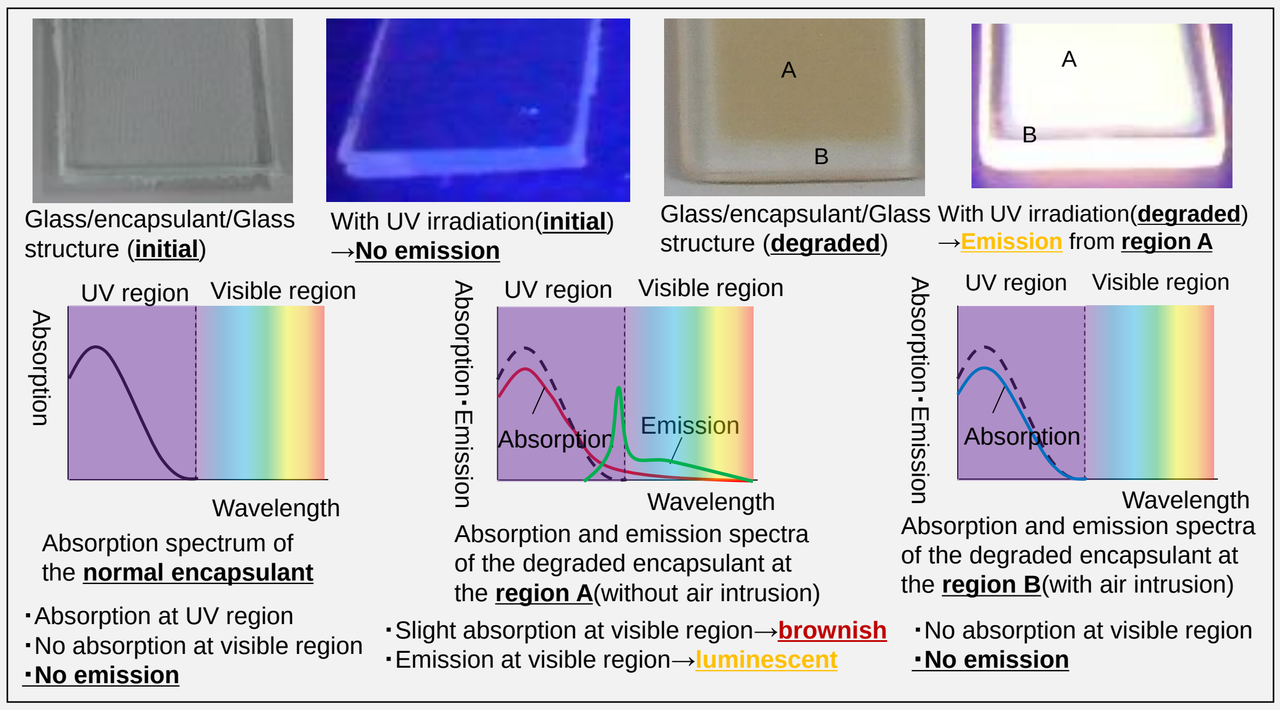


Fig. 1. The aspects and absorption and emission spectra of encapsulants.

Evaluation of failure sources in modules

Using these characteristics, we can detect the degraded area of the module without stopping power generation. In this method, the discoloration of the encapsulant can be estimated by the luminescence intensity of the module under UV irradiation at night. Namely, the photoluminescence of encapsulant is used as a barometer of degradation. Using characteristics 1) and 2), the heated part of the module can be detected. Fig.2(a) shows the picture including the cell causing hotspot. hotspot heats the encapsulant on the cell, causing the strong fluorescence. Fig. 2(b) shows the picture including the cracked cell. Using characteristics 2)and 3), the crack can be easily detected as the dark line because the oxygen intrudes into the encapsulant on the cell through the crack. Similar to the crack, the affect of impurity and delamination can be detected due to the dissolution of the fuorescent material.

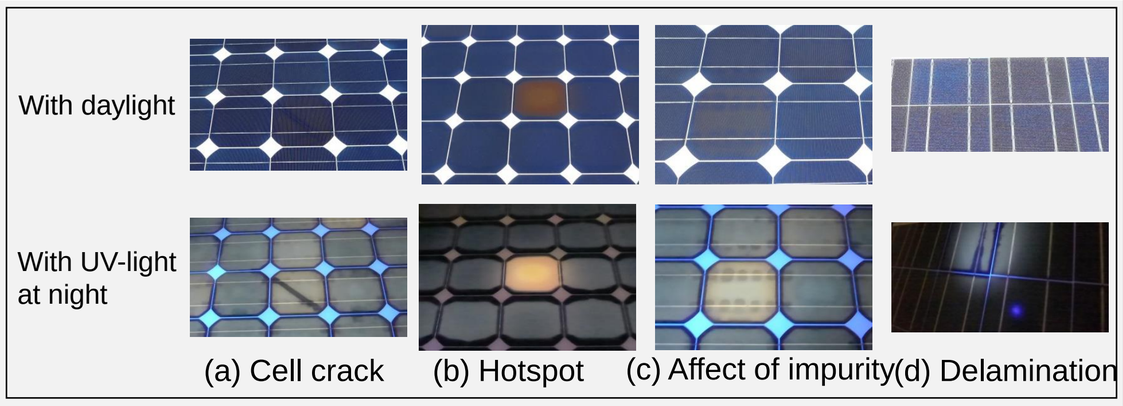


Fig. 2. Degraded modes detected with UV irradiation

The photoluminescence intensity of encapsulants is much higher than that of c-Si, therefore, the requirement of light source intensity is not so high. For example, the UV-LED is preferable for the UV light source. To measure the luminescence clearly, the wavelength of the irradiation light around 380 nm is better due to the low absorptions of the base material and UVA in the encapsulant and the high absorption of the fluorescent materials from degraded encapsulant in the wavelength region. Furthermore, the UV cut filter enables a normal camera to detect the fluorescent image without noises from UV light source. As shown in Fig.3, a combination device of camera, UV source and UV cut filter is a promising candidate for the inspection device. A further combination of drone and the device shown in Fig.3 might be better.

The degradation mechanisms of encapsulant are strongly dependent on the module designing. Table 2 shows the detection sensitivities of the failure modes dependent on module designing. Since the discoloration of the encapsulant often happens when the encapsulant contains UVA, it’s easy to detect the failure modes of the module with UVA. The disappearance of the fluorescent material is caused by air intrusion, therefore, the rear glass or Aluminum-foil-backsheet makes it difficult to detect cell crack and delamination. Since the degradation takes a long time to proceed, the PV system for this inspection method should have been operated for at least one-year, preferably over three-years. At present, most of the installed modules employ UVA and backsheet, therefore, this inspection method is effective for them.

Thus, this inspection method makes it possible to detect the degradations of modules in the faster and easier way. However, it’s difficult to clarify the breakdown because how high the degraded part causes the power loss cannot be estimated. Therefore, this method should be effective with the identification of the broken string, for example, by remote power monitoring. Figure 4 shows the proposal image of this inspection scheme.

Table 2. Detection sensitivities of failure modes dependent on module designing

Additive (organic)	Rear structure	Cell crack	Hotspot	Affect of impurity	Delami-nation
With UVA	Backsheet	◎	◎	○	○
Without UVA	Backsheet	△	△	△	△
With UVA	Glass or Al-backsheet	△	◎	○	×
Without UVA	Glass or Al-backsheet	×	△	△	×
With phosphor	Backsheet	○	△	○	○
With phosphor	Glass or Al-backsheet	△	△	○	×

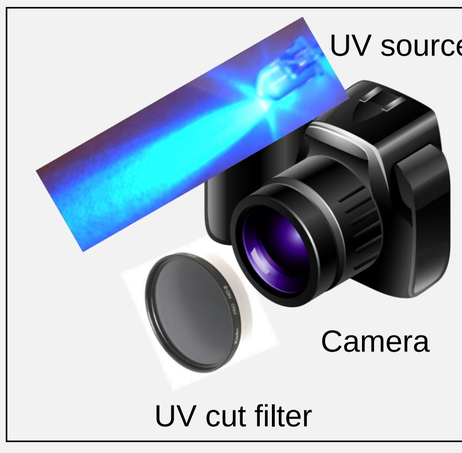


Fig. 3. Image of UV inspection device

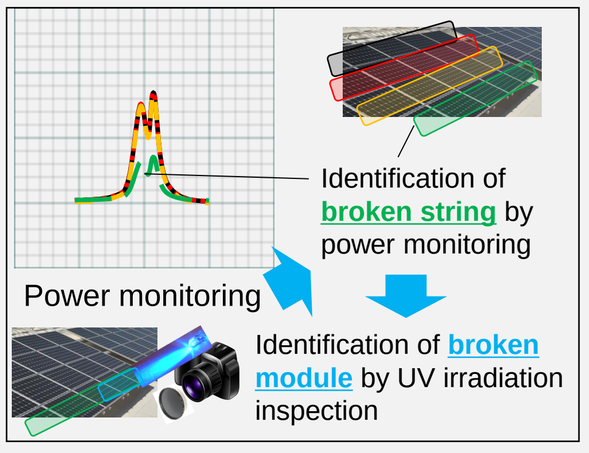


Fig. 4. Image of inspection scheme

Tracker Lifetime Cost
Tracker Reliability, Lifetime and LCOE

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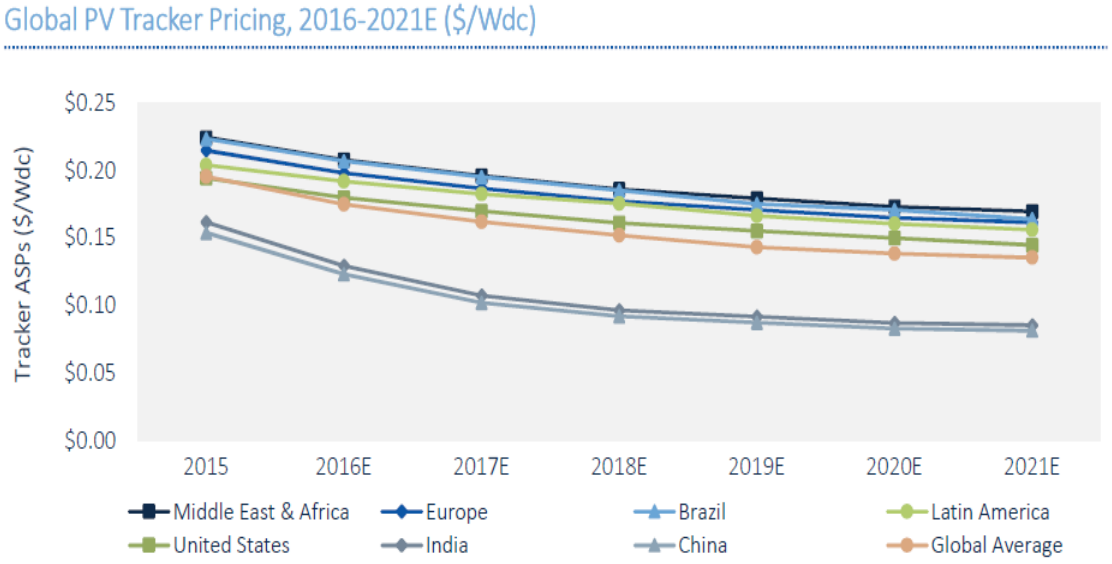
NREL PV Reliability Workshop
February 2017

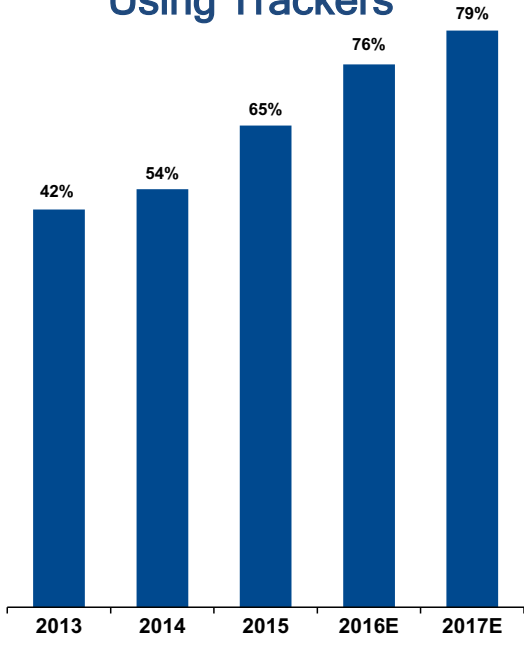
Array Technologies, Inc.

Recent years have brought a mass transition to trackers in utility-scale projects

Tracker Initial Prices are Falling While Demand is Increasing



% of U.S. Ground Mount Projects Using Trackers



Source: GTM Research.

Site LCOE tracker effects

Initial cost is only part of the equation.
How do we quantify these future costs?

$$LCOE = \frac{\text{Lifetime Cost}}{\text{Lifetime Production}}$$

$$\$ / kWh = \frac{(\text{Upfront costs}) + (\text{Lifetime costs}) + (\text{Financing costs})}{(\text{Production})*(\text{Uptime})} \times \text{Risk}$$

Product cost, grading costs, installation.

Scheduled and unscheduled maintenance.

Track record, risk profile, bonding costs.

Site power density, tracker architecture, accuracy

Tracker uptime, # failure points, component reliability.

Probability of major failures, product/site design flaws, product obsolescence.

Tracker lifetime costs are the combination of scheduled and unscheduled O&M

Scheduled maintenance items are planned at fixed intervals for the site:

- Inspections
- Lubrication
- Planned replacements (batteries, seals)
- Module cleaning
- Site mowing

$$Lifetime\ Costs = C_L = C_S + C_U$$

Unscheduled maintenance items are not easily predictable, and require long-term experience to accurately predict:

- Environmental deterioration
- Part quality variations
- Intermittent events – lightning, wind, snow

Scheduled maintenance costs can be calculated easily

One must choose to analyze an entire plant or a sub-set, such as a 1 MW block.

Scheduled Maintenance Cost Formula:

$$C_S = Tk_o \sum_{i=1}^{n} q_i f_i (l_i + p_i + m_i)$$

Variables affecting scheduled costs:

T = plant lifetime

k_o = overhead factor

q = quantity of components affected in the plant

l = labor costs/item

p = part costs/item

m = mobilization costs/item

n = number of distinct O&M tasks in plant

f = frequency of maintenance/time

Unscheduled maintenance costs can vary considerably, and are not easily predictable

Unscheduled maintenance cannot be predicted, but can be modeled using various methods.

Unscheduled Maintenance Cost Formula:

$$C_U = k_o \sum_{i=1}^{n} q_i(l_i + p_i + m_i) \int_0^T f_i(t)dt$$

Weibull distributions (or bathtub curves) are typically considered the best method to approximate the failure rates, f(t), over the lifetime of a product.

Commonly in solar plants, mean time between failures (MTBF) is applied to approximate f(t) as a constant value. This *MAY* be roughly correct, but only if the component life > plant life OR there is already scheduled maintenance to replace the component before failures begin to rise.

This is can be dangerous to assume if the lifetime of a particular component has a risk of being inside the plant lifetime.

Unscheduled maintenance costs can vary considerably, and are not easily predictable

Every component in the system should be considered for this analysis. Some may be found to have such low failure rates that they are negligible.

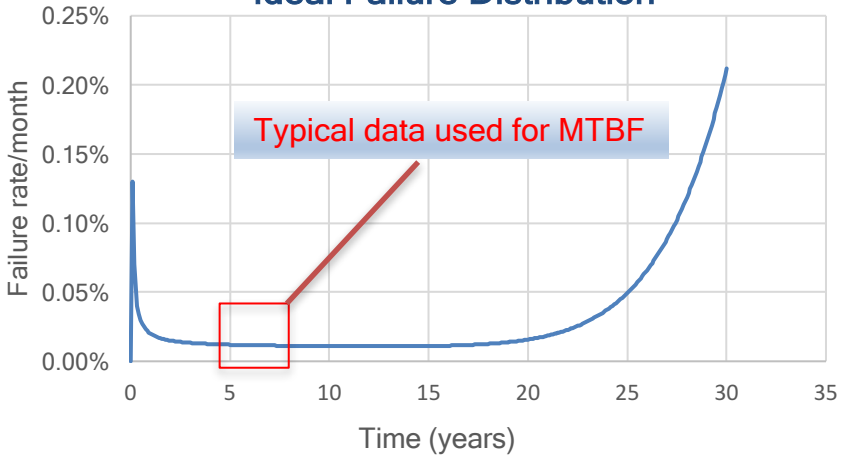
Components with unexpectedly low lifetimes will have higher costs by several orders of magnitude.

Formula for a typical failure distribution:

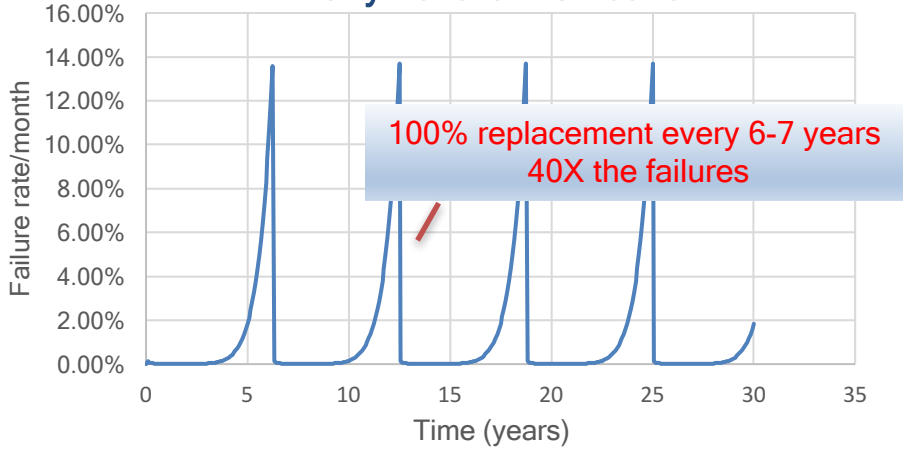
$$f_i(t) = \frac{\gamma_0}{\alpha_0}\left(\frac{t}{\alpha_0}\right)^{\gamma_0 - 1} + f + \frac{\gamma_f}{\alpha_f}\left(\frac{t}{\alpha_f}\right)^{\gamma_f - 1}$$

Initial Random End of life

Ideal Failure Distribution



Early Failure Distribution



Estimating site risks

"Risk" is defined as the potential added cost, as a percentage, that can be estimated as part of LCOE.

Many events are not attributed to normal failures, but are due to unexpected events.

Examples:

- Lightning strikes
- Exceeding design specifications
- Corrosion
- Theft
- Operator error
- Animal infestation
- Wind event

Taken individually, these risks can seem small, but cumulatively, they can cause promising projects to become impaired assets.

Formula for a typical failure distribution:

$$Risk = 1 + \sum event\ probability \times \frac{cost\ of\ event}{LCOE\ costs}$$

Example: Wind event damages a module:

Probability of wind event exceeding site design: 2%
Probability of module being exposed to pressure: 5%
Event probability = 0.02x0.05 = .001 = .1%
Cost of module = $0.60/W
Total LCOE cost = $1.20/W

$$Risk = 1 + 0.001 \times \frac{\$0.60}{\$1.20} = 1.0005$$

How do we apply all of this analysis?

Finally, to add the lifetime costs into the LCOE equation, we set an interval for the analysis, usually one year, and calculate net present value (NPV) of the money that will be spent to maintain the site later for each interval. This reduces the value of the future costs by the discount rate. This is usually assigned by the investor. Risk factors are similarly quantified by interval and reduced.

Net present value for lifetime costs:

$$C_{L,NPV} = \sum_{t=1}^{T} \frac{C_{L,t}}{(1+r)^t}$$

Example spreadsheet

Case 1: High priced component
- Low quantity per site (~1/6500 modules)
- MTBF of 100 years
- High cost to mobilize

Case 2: Low priced component
- High quantity per site (~1/100 modules)
- MTBF of 100 years
- Low cost to mobilize

Case 3: Low priced component
- High quantity per site (~1/100 modules)
- MTBF of 10 years
- Lower cost to mobilize

Case 4: High priced component
- High quantity per site (~1/100 modules)
- MTBF of 10 years
- Lower cost to mobilize

Case 5: High priced component
- High quantity per site (~1/100 modules)
- MTBF of 3 years
- Lower cost to mobilize
- **$20M catastrophic event in year 15!**

		Case 1	Case 2	Case 3	Case 4	Case 5
Plant size	(MW)	100	100	100	100	100
Plant life	(years)	30	30	30	30	30
Overhead	(%)	25%	25%	25%	25%	25%
Quantity	(# parts)	50	5000	5000	5000	5000
Labor cost	($)	300	50	50	50	50
Part cost	($)	1000	10	10	120	120
Mobilize cost	($)	100	30	10	10	10
Frequency	(#/year)	0.01	0.01	0.1	0.333	0.333
Event cost	($)	1400	90	70	180	180
Yearly cost	($)	875	5625	43750	374625	374625
Discount rate	(%)	6%	6%	6%	6%	6%
Total NPV cost	($)	$12,044	$77,427	$602,211	$5,156,650	$13,501,951
	($/kW)	$0.120	$0.774	$6.022	$51.566	$135.020
	(¢/W)	0.01¢	0.08¢	0.60¢	5.16¢	13.50¢

Quantity and Frequency are major cost drivers

Thank you

For access to the spreadsheet shown in the presentation, email jwilliamson@arraytechinc.com

arraytechinc.com

NREL PV Reliability Workshop
February 2017

Array Technologies, Inc.

A COMMERCIAL SYSTEM PERSPECTIVE ON MITIGATING PV SOILING LOSSES

- What is soiling?
- Measurement?
- Effects?
- Mitigation?

NREL Reliability Workshop 2017

Sanjay Shrestha
Swinerton/SOLV Performance Team

WHAT IS SOILING?

COMMERCIAL ASPECT OF SOILING

- Gradual or event based soil build up layer on the array
- Reducing incident energy on the PV array, as a result reducing the output energy
- Temporary and variable degradation mode
- Even a couple of percent can have impact in revenue by hundreds of thousand in a year on Utility scale project
- Conservative soiling model means frequent washing, aggressive will decrease the worth of the project
- Owners/Developers need an accurate soiling loss model in their P50 model
- Soiling assessment almost always results in “let’s wait” and “it depends”

MEASUREMENT

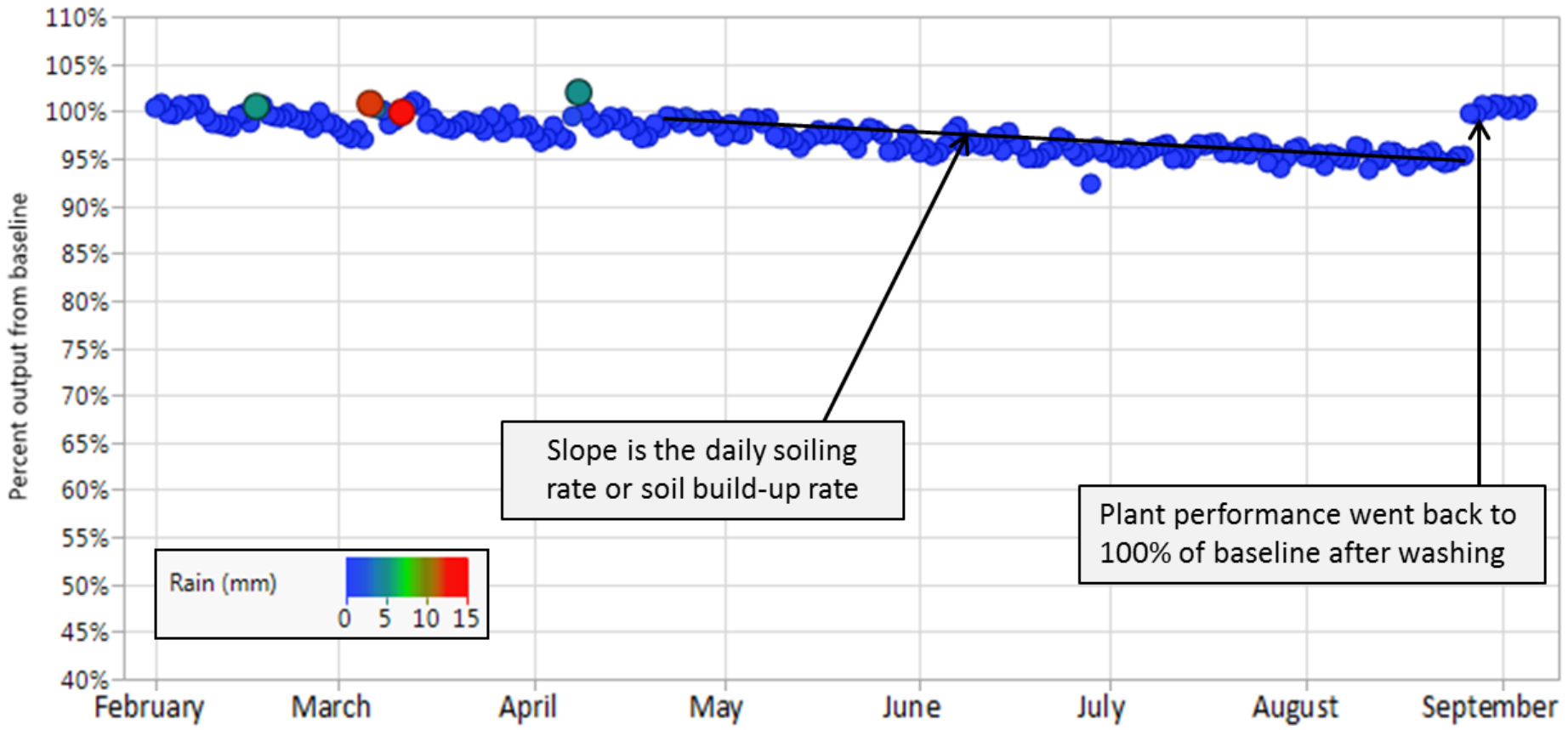
SOILING MEASUREMENT METHODS

- Field IV testing
  - Time consuming
  - User dependent
  - Manual work
  - Expensive test equipment
  - Specific to location
- Soiling Stations
  - Manual cleaning and maintenance
  - Trend analysis
  - Expensive installation
  - Specific to location
- Operational Data
  - Site wide approximate measurement
  - Redundant Measurement
  - Using existing data
  - Trend analysis

Reference
http://www.atonometrics.com/products/soiling-measurement-system-for-pv-modules/

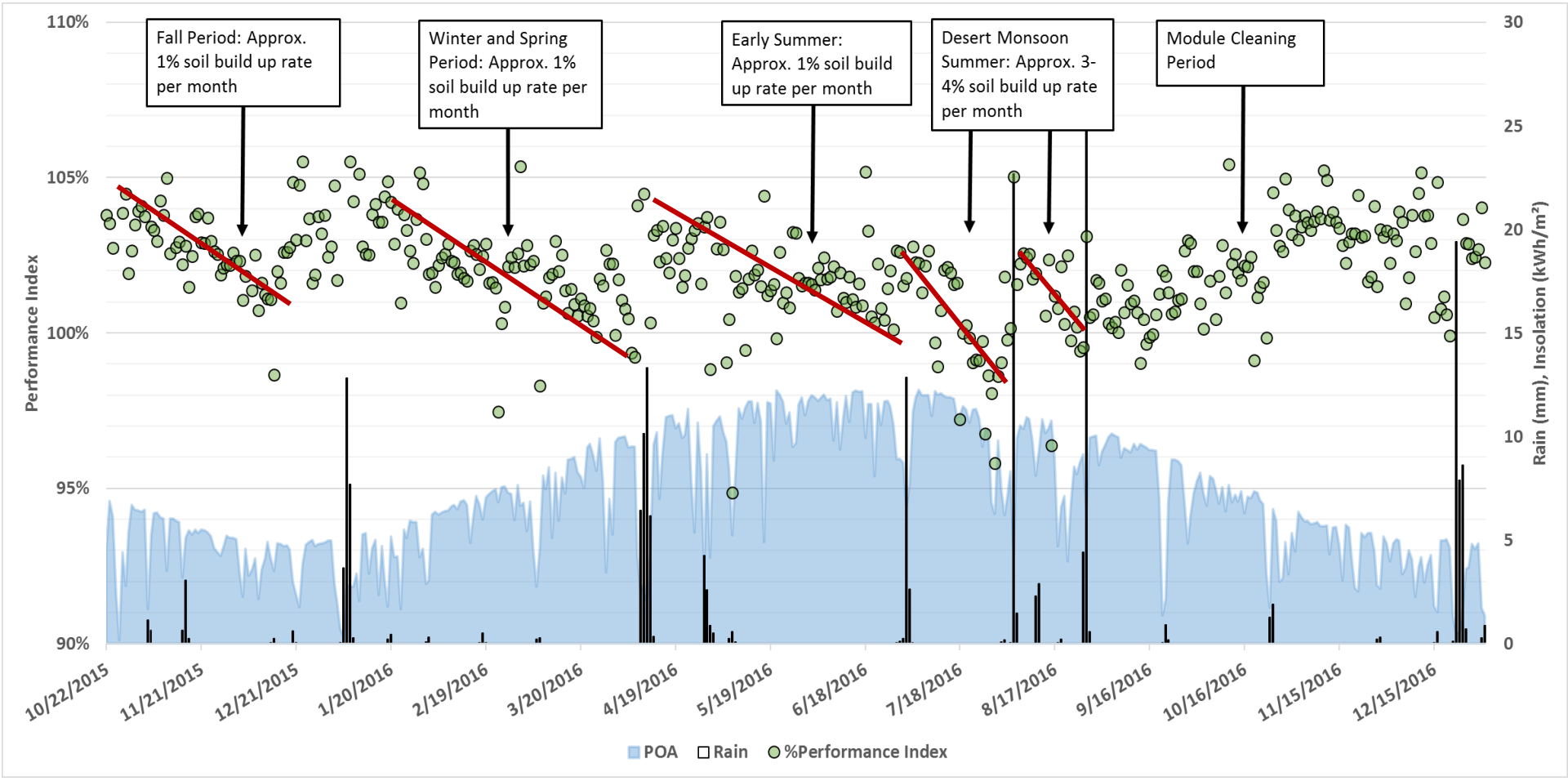
MEASUREMENT

Plant-level baseline data



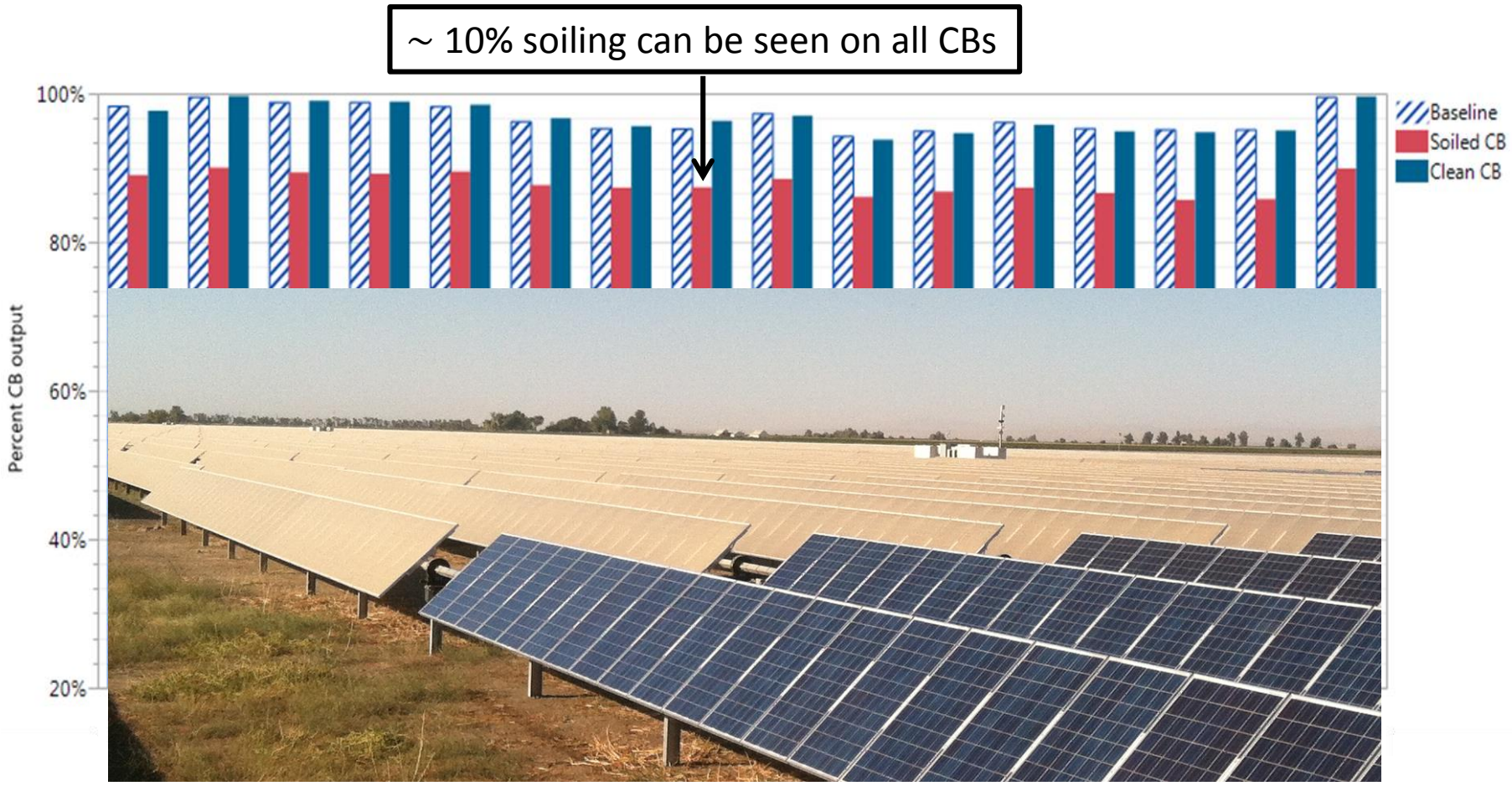
MEASUREMENT

Plant-level baseline data



MEASUREMENT

Combiner-level baseline data



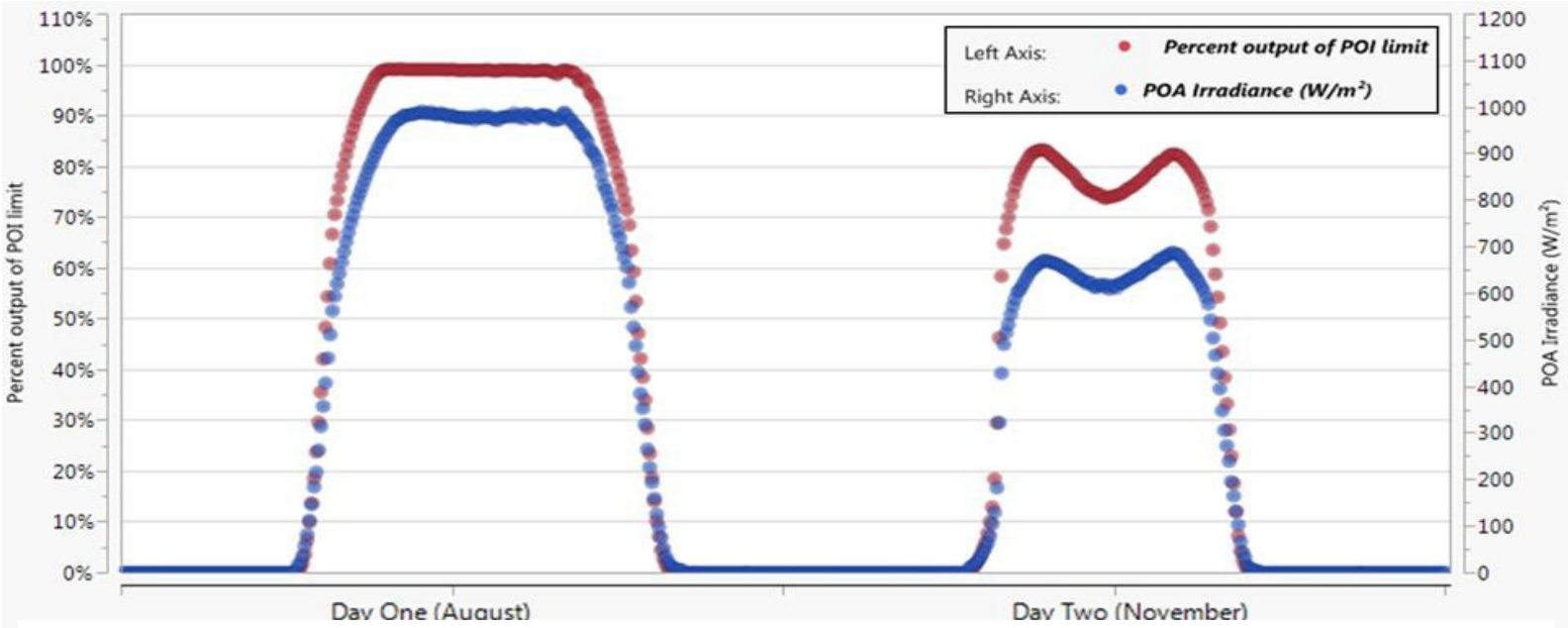
EFFECTS

Is the soiling rate a real representation of lost energy?

- During Maximum power point tracking operation
- Morning and evening hours – less irradiance
- Winter months – less insolation
- DC oversized plant – clipping – no significant effect
- Harvest and planting season – significant drop

EFFECTS

Is the soiling rate a real representation of lost energy?



Two-day operational comparison	Incident Energy	Metered Energy	Energy at MPPT	Energy at full power	ratio	Percent Soiling from baseline	% Lost Energy	Lost Energy due to soiling
	"POA Insolation"	"meter"	"E-mppt"	"E-clipping"	"E-clipping" / "meter"			
	(kWh/m²)	(MWh)	(MWh)	(MWh)	(--)	(--)	(--)	(MWh)
Day One (August)	10.4	193.1	66.5	126.6	65.50%	3.70%	1.30%	2.6
Day Two (November)	5.3	126.5	126.5	0	0.00%	3.60%	3.50%	4.8

MITIGATION

- High DC/AC ratio – recent practice - not recommended
- For fixed tilt installation – at least 10 degrees tilt - recommended
- Smart O&M practices
  - Optimum tracker stowing – utilizing even a slight rain
  - Data analytics – Differentiating between “%soiling” and “%lost energy due to soiling”
  - Optimum wash – knowing schedule of local farmers and cost-benefit of washing
  - Localized soiling – determine and wash only the affected areas – cost effective; this is why sometimes soiling stations can give misleading information

MITIGATION

Thank you!

Sanjay Shrestha
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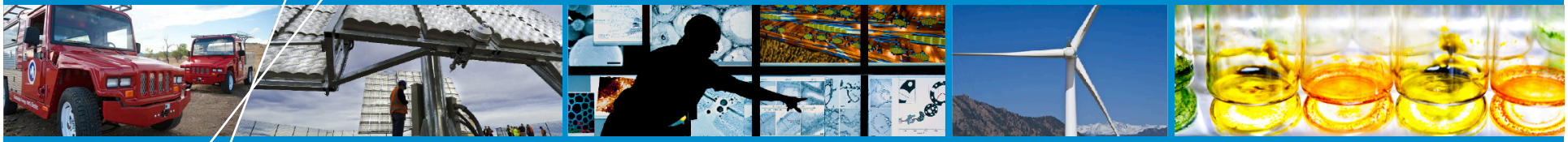
SOLV/Swinerton

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Progress towards mapping out PV soiling losses in the U.S.



NREL/SNL/BNL PV Reliability Workshop

Matthew Muller

March 2nd, 2017

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Outline

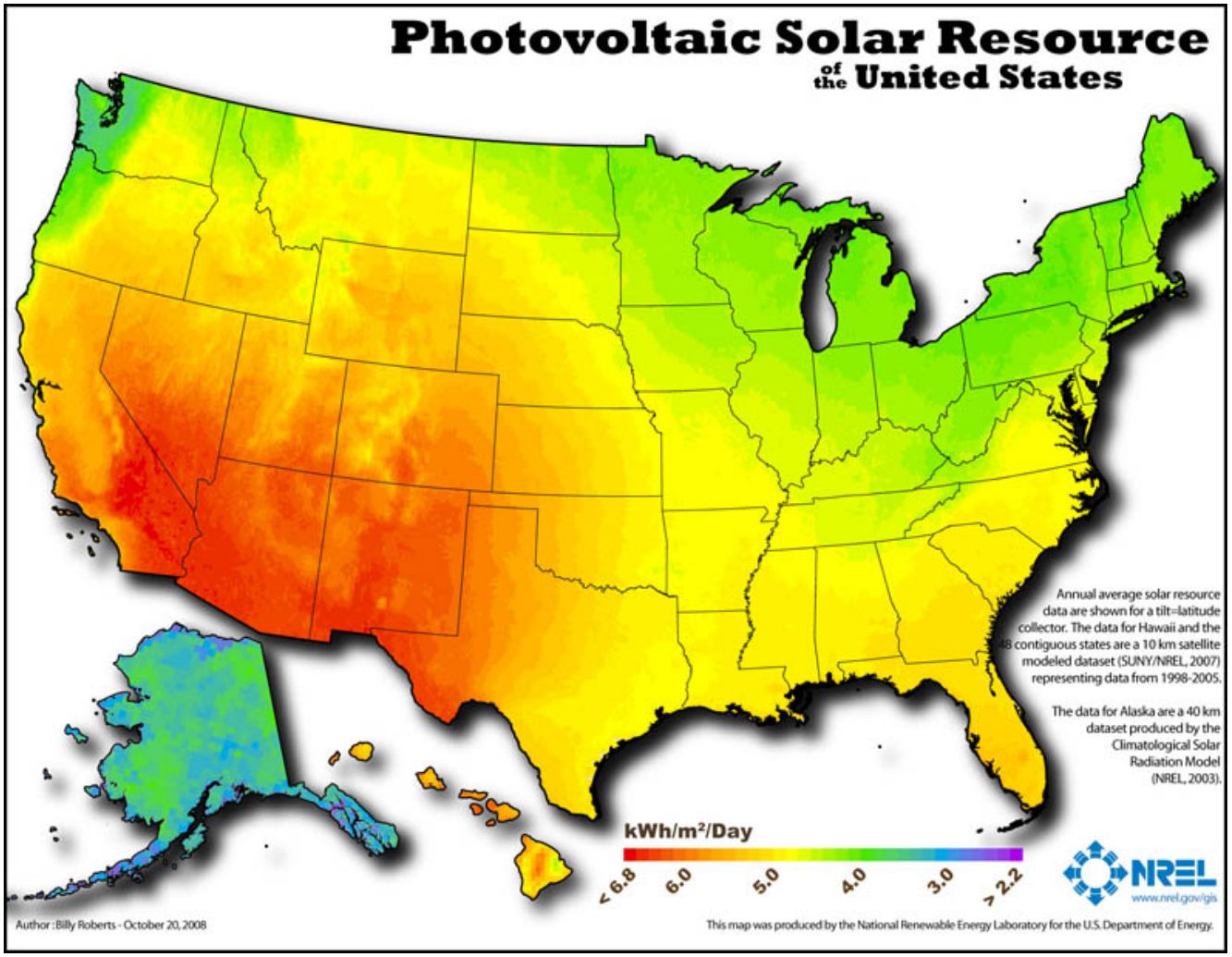
- Project goals in regards to quantifying PV soiling losses
- Progress in parallel approaches targeted at goals
  - Losses from soiling stations
  - Predicting soiling loss variation using alternate data sets
  - Extracting soiling specific losses from PV plant data
- Summary

Project goals: Quantifying Soiling Losses

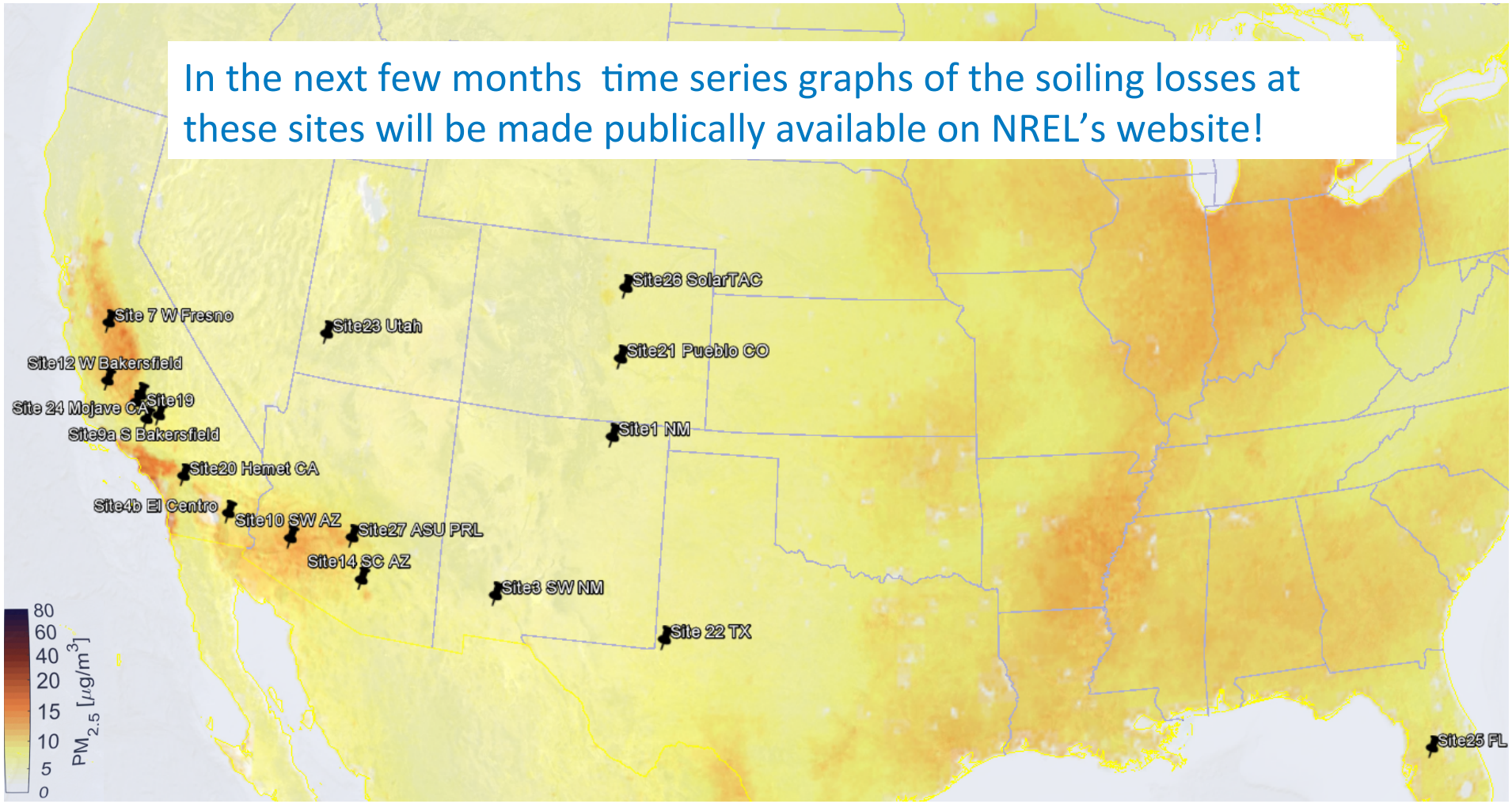
- Soiling = Reduction in PV power output due to soil on the PV surface
- Literature:
  - » Soiling is complex and site specific
    - Adjacent pollution sources, agriculture, geometry like tracking vs fixed tilt, local soil, and more
  - » Efforts to model day-to-day variation in soiling loss →weak results
    - Dust deposition model for one site not easily applied to another site
- Can we go beyond site complexity and distinguish soiling derates for modeling PV performance in Miami FL, Denver CO, Mojave CA, Mumbai India, Dubai U.A.E?
- **THE ANSWER YES!...** We can distinguish between these sites and we are working on systematic methods to achieve this.
- **NREL GOALS:**
  - » Populate maps/make existing soiling loss data publically available
  - » Develop methods/models for quantifying average annual soiling derates at sites where no specific soiling loss data is available

Do these goals have value?

- From day-to-day this solar resource map can be drastically wrong but it still has high value
- Blanket soiling derates of ~ 3% are being applied to the U.S.
- The difference of 1% in a derate can mean millions of dollars for a utility scale PV plant
- It is clear 3% is not broadly correct and we systematically can do better



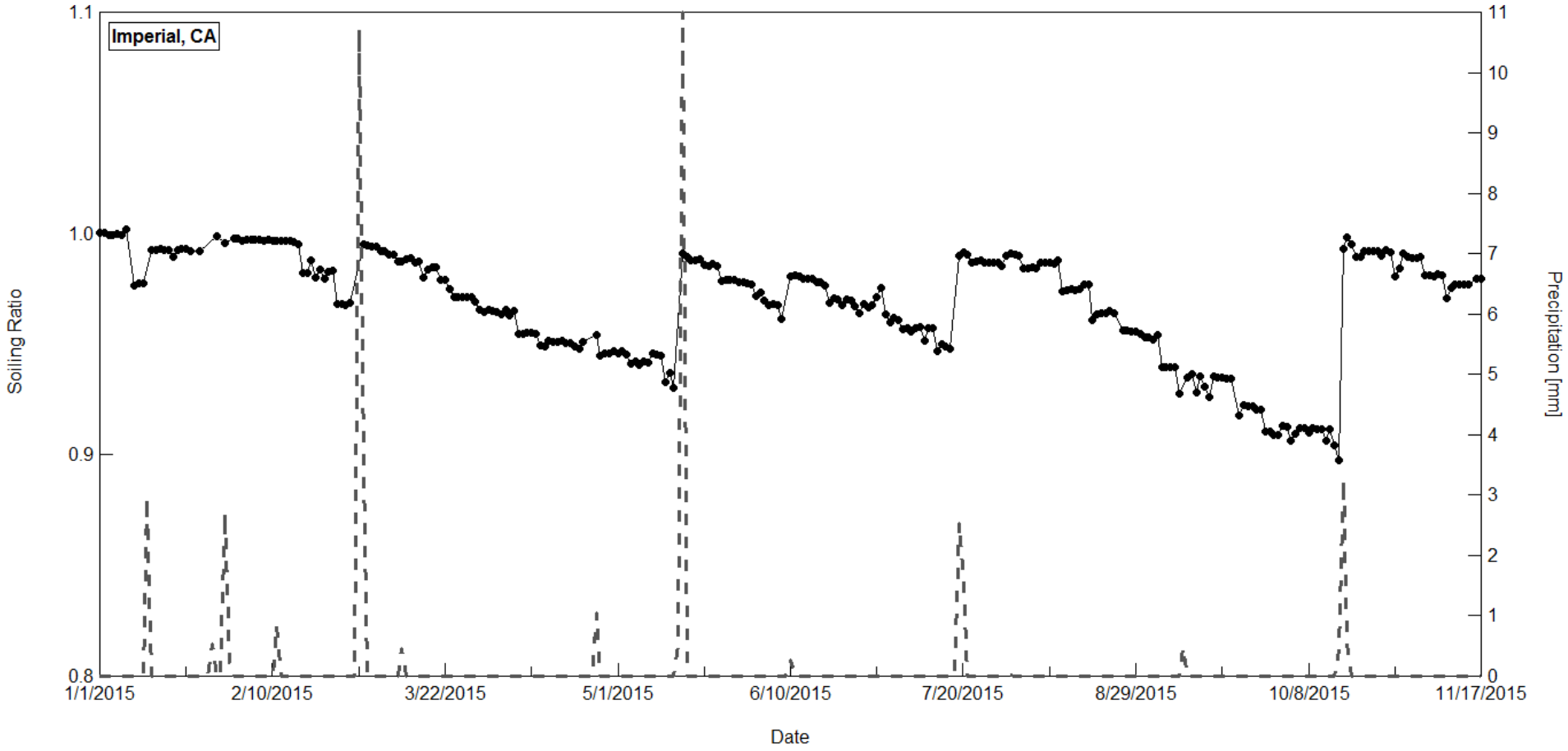
Partners Share Soiling Station Sites (Hawaii not shown)



*Map shading is based on satellite modeling of annual airborne 2.5 micron particulate levels

Soiling Station Data

Daily Soiling Ratio = Isc(dirty)/Isc(clean)



"An Investigation of the Key Parameters for Predicting PV Soiling Losses" Micheli et al. Progress in PV, DOI: 10.1002/pip.2860

- **GOAL: Determine if annualized soiling loss variation from the 20 soiling stations on the previous slides can be predicted from other more readily available data?**

- **Understanding the "key parameters" can then lead to a broader method/model to calculate soiling derates across the U.S. and the world.**

~100 Independent Variables Examined for Predicting Soiling Losses (see paper for complete list)

Site data

Altitude [m]
Time period [days]
Height [m]
Tilt [deg]
Tilt (Numerical)
Tracking
Distance from highway [km]
Distance from dirt road [km]
Distance from ocean [km]
Salt belt state
Fire regime (Binary)
Fire regime (Numerical)
Land cover (Numerical)
Land cover (Binary)
Wind erosion index [tons]
Wind erosion group
Percentage of clay in the soil [%]
Soil pH

Pollution data

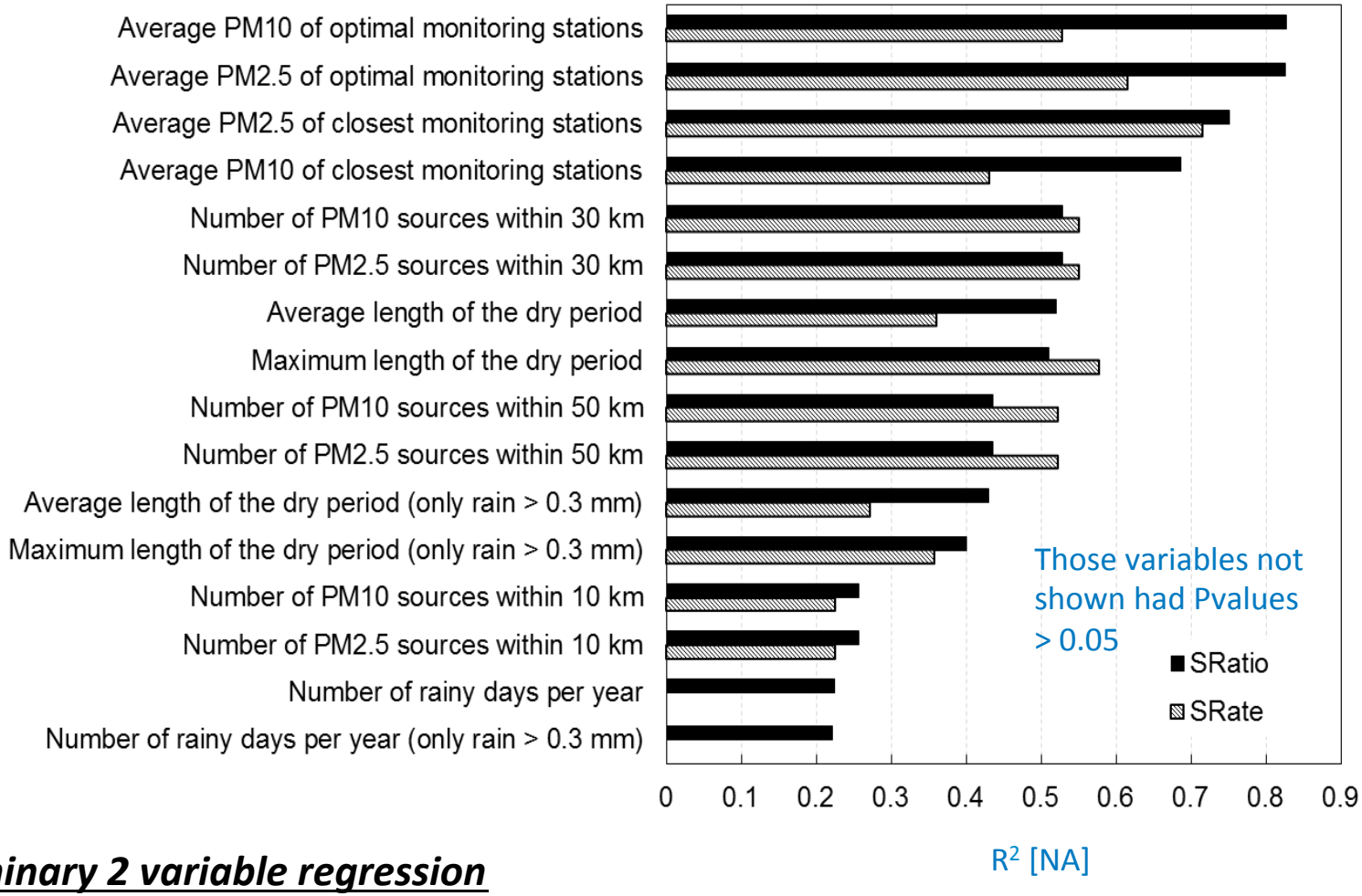
An array of metrics for reporting site PM10 and PM2.5 levels from EPA data
Number of pollution sources within set distance of the site
EPA estimates on the number of tons of emitted pollutant within set distance of the site
Satellite-derived PM2.5 [µg/m3]

Precipitation and meteorological data

Various precipitation metrics for example:
Avg Length of dry period [days]
Maximum length dry period [days]
% rainy days [%]
Number of days with dew cycles [%]
Average RH [%]
Wind speed statistics for example:
Average wind speed [m/s]
Average peak gust [m/s]
Days with peak > 5m/s [%]
Days with peak > 10m/s [%]

Linear Regression Results; Data from 20 Soiling Stations

SRatio = Average(Daily Soiling Ratio) for the entire data collection period
SRate = Rate of change in the soiling ratio for dry periods, per Deceglie 2016 PVSC



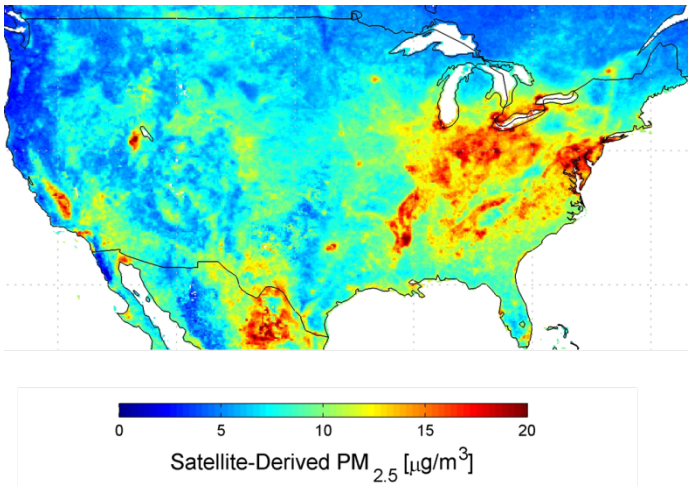
Preliminary 2 variable regression

- PM10 and PM2.5 together predict 88% of the variation in the soiling ratio
- PM2.5 and BinaryDryLength predict 90% of variation in the soiling ratio

Soiling Station Investigation Conclusion

Broadly available data such as:

2.5 Micron airborne particulate average 2001-2006.
Credit: Dalhousie University, Aaron van Donkelaar



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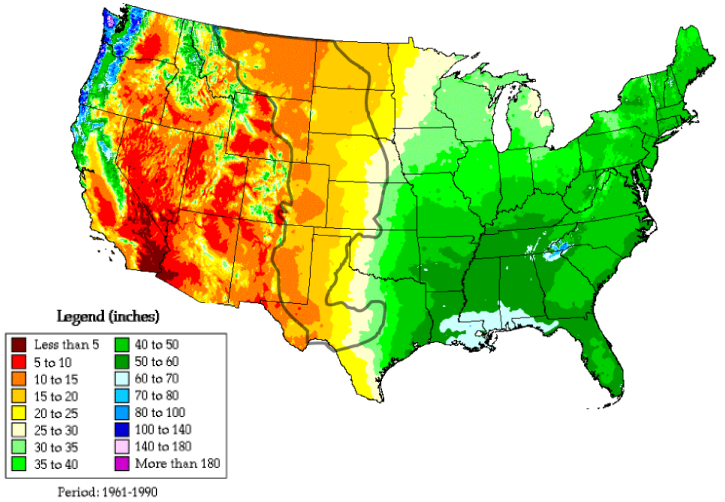
Precipitation Map
Credit: Christopher Daly, PRISM model

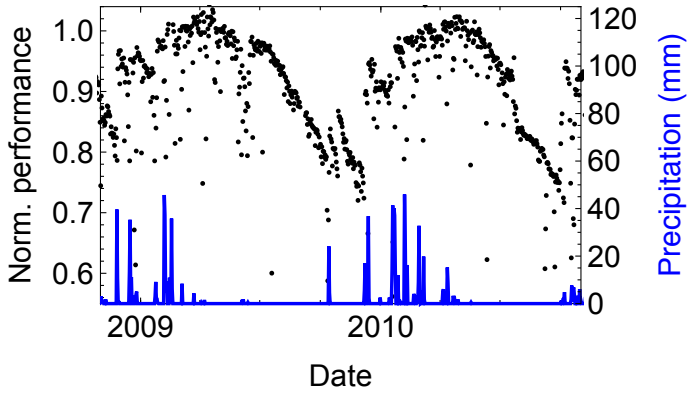


= ***Potential to predict 90% of the variation in annual US soiling losses (create a soiling derate map)***

Note1: The study is being expanded to include more site and international sites
Note2: See the poster by Leo Micheli for more details on this work

Soiling Losses from PV Production Data

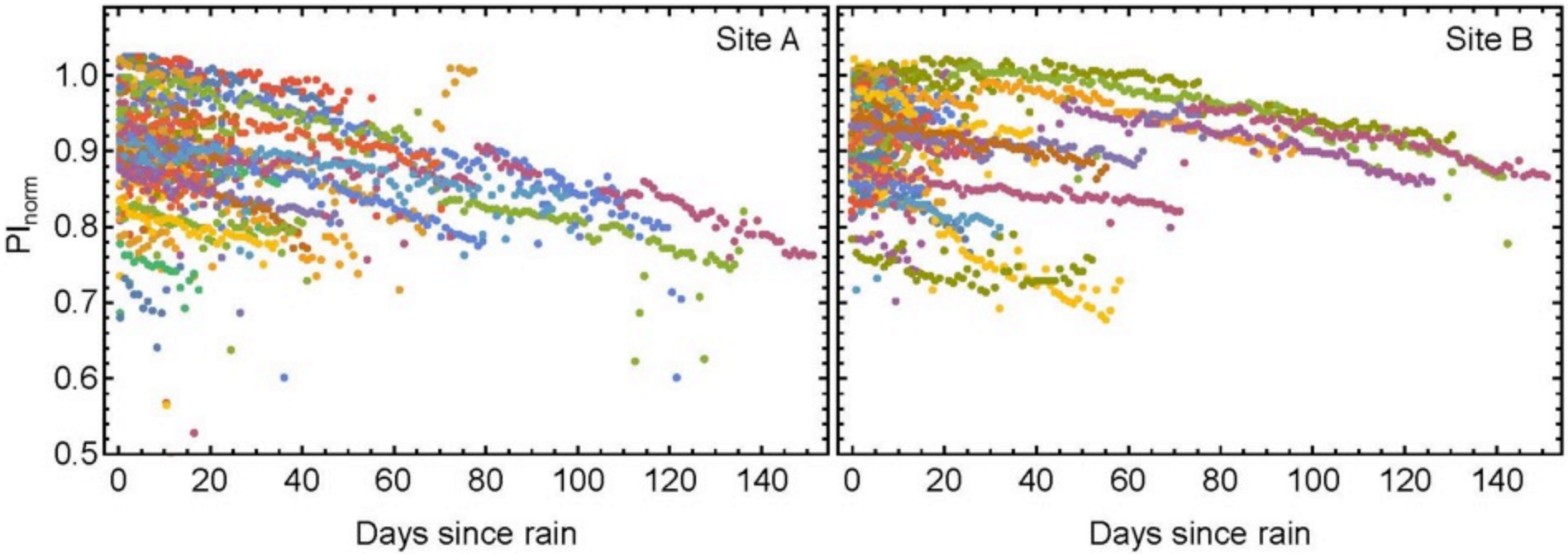
- There are PV plants across the U.S. and the world that inherently contain information about soiling losses



- The performance data also reflects other losses and errors like clipping, uncleaned irradiance sensors, degradation, tracking problems, cleaning events, equipment failures and……..
- Specific details of plant performance are often considered proprietary
- Goal: Determine if soiling losses can be accurately extracted from all other losses and without proprietary information?

Soiling Rate Extraction, Deceglie et al. PVSC 2016

- Plot of all dry intervals $>\tilde{d}$ for site A and B
  - different color for each unique interval
- Theil-Sen fit for data points in each interval
  - soiling rate is median of all slopes
  - distribution of slopes used to report uncertainty of soiling rate
- Results provided variation in soiling rates for over 30 sites-



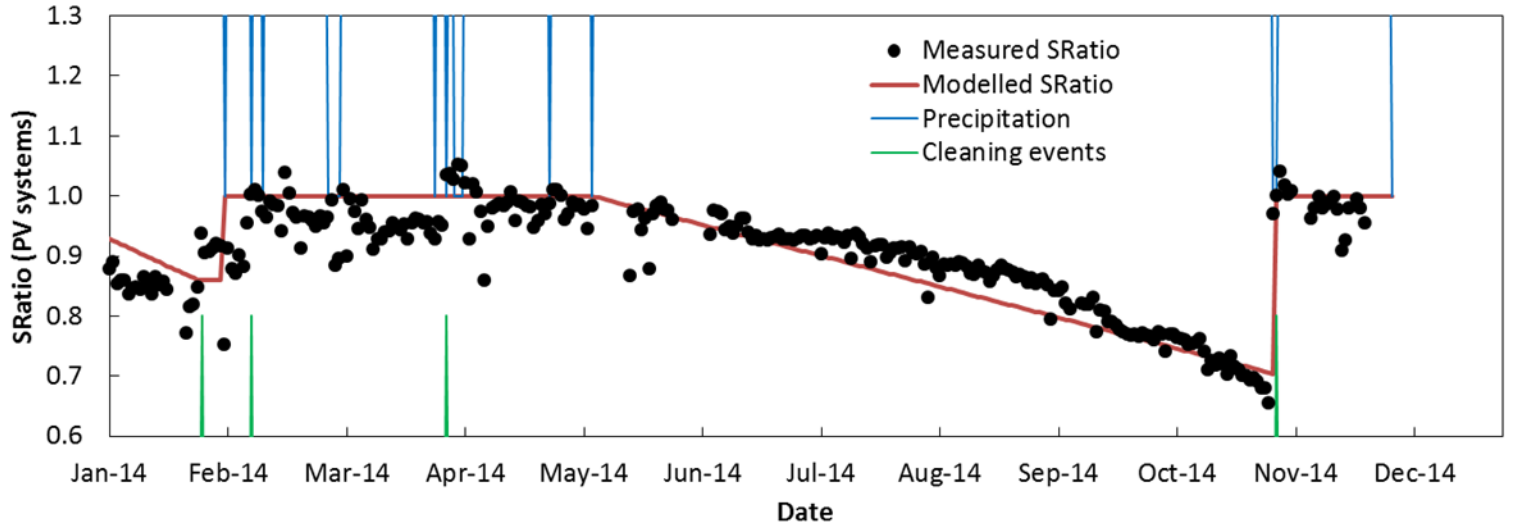
2017, Extracting Soiling Losses

- **Extracting soiling losses are significantly more complicated than extracting soiling rates**
  - Rates stand out in the long dry periods but what happens in the interim periods
  - Energy losses can heavily depend on the interim periods
  - The intercept of each slope for the rate extraction could be ignored but this is not true for energy loss extraction
  - A simple integration of the losses in the performance index over a year includes all other losses

- **Goal: Test an array of methods for extracting soiling losses from PV plant data and compare against soiling station losses at the same location (10 sites available)**

Example Extraction Algorithm PV System Data

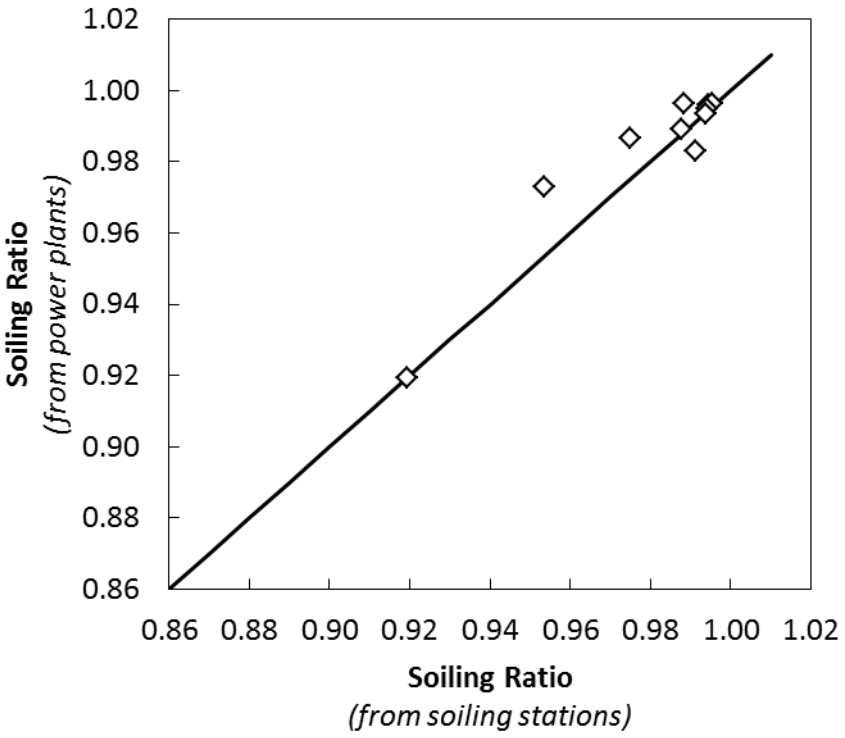
1. Start with temperature corrected daily performance index (call SRatio in graph)
2. Use a rolling median to detect "positive shifts" or cleaning events (green in graph)
   Rolling median minimizes outlier data, rain (blue) assumed to return SRatio to 1
3. Positive shifts or rain events parse the data into distinct soiling periods
4. Fit the data in the each soiling period (Theil-Sen Estimator)
5. If the "positive shift" is associated with rain, count it as real, otherwise carry the loss forward
   Allows us to calculate annual energy impact assuming only natural cleaning
6. Calculate irradiance weighted soiling losses using the red line
7. Note: We are considering various assumptions and variations in the algorithm including options that don't rely on rain data



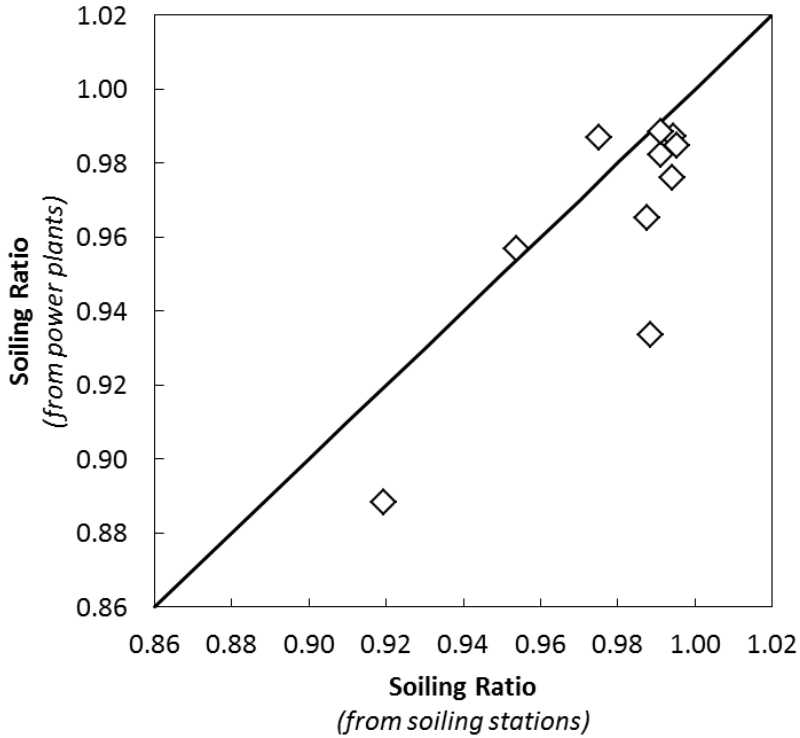
Validation Efforts

- Comparison with data from soiling stations show general agreement
- Different assumptions about precipitation and cleaning explain discrepancies (too early to state one set of assumptions is better than another)

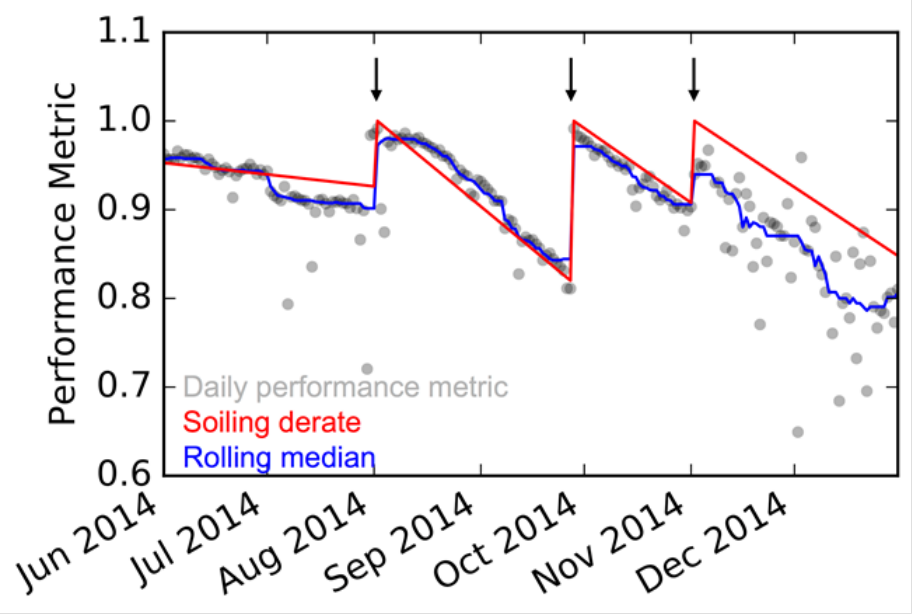
Algorithm including rainfall data



Algorithm ignoring rainfall data



Extracting Soiling Losses from PV Data: Conclusions



- **Algorithm/method to extract soiling impact on energy yield from PV production data**
  - Various assumptions under test
  - Assumptions impact the results
  - Validation under way using soiling station data

- **See poster for further details/developments also PVSC 2017 submission(Deceglie et. al.)**
- **Open challenges:**
  - Reporting a complete uncertainty, not just the uncertainty of slopes in the dry periods
  - Magnitude of performance shift at a cleaning event
  - Use of other irradiance sources e.g. satellite as site irradiance sensors may be soiling
  - Others

Overall Summary

- The industry currently has no systematic method to determine annual soiling derates for new PV sites in the U.S/World
- NREL is examining soiling stations, PV data, and alternate data sources to develop methods to establish derates for new sites
- NREL will be making existing information from soiling stations publically available
- Airborne particulate measurements and precipitation data show potential to predict 90% of the variation in soiling losses at different sites in the US
- An algorithm is under development and validation to systematically extract energy losses due to soiling from general PV system data

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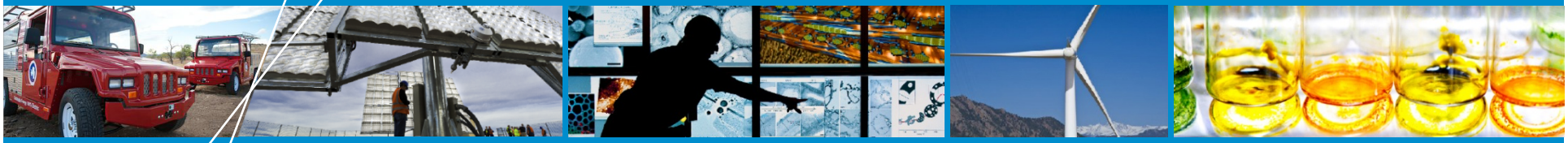
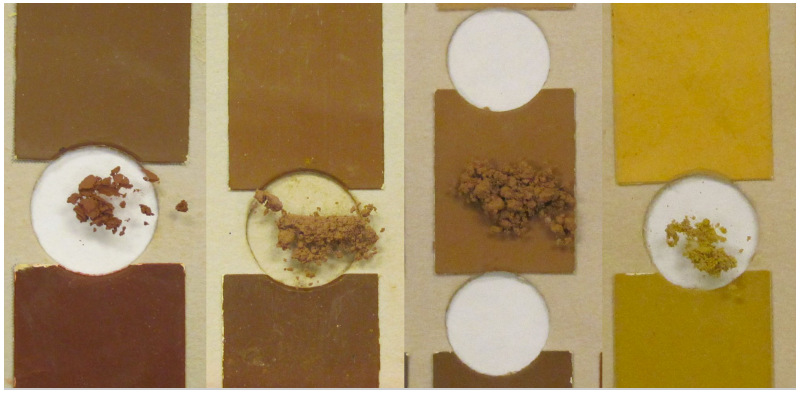
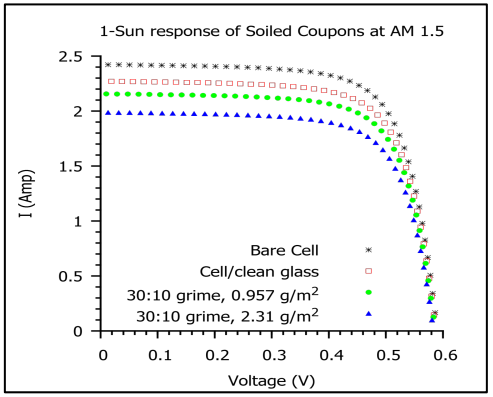


Thank You!

and

Questions?





Overview of Sandia's Soiling Program: Experimental Methods and Framework for a Quantitative Soiling Model

Bruce King

PV Reliability Workshop

2 March, 2017

Sandia National Laboratories is a multi-program laboratory managed and operated by Sandia Corporation, a wholly owned subsidiary of Lockheed Martin Corporation, for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-AC04-94AL85000.

Acknowledgements

Sandia National Labs - Patrick Burton

University of Colorado, Boulder – Liza Boyle, Mike Hannigan

Arizona State University – Govindasamy Tamizhmani (Mani)

DOE Regional Test Centers

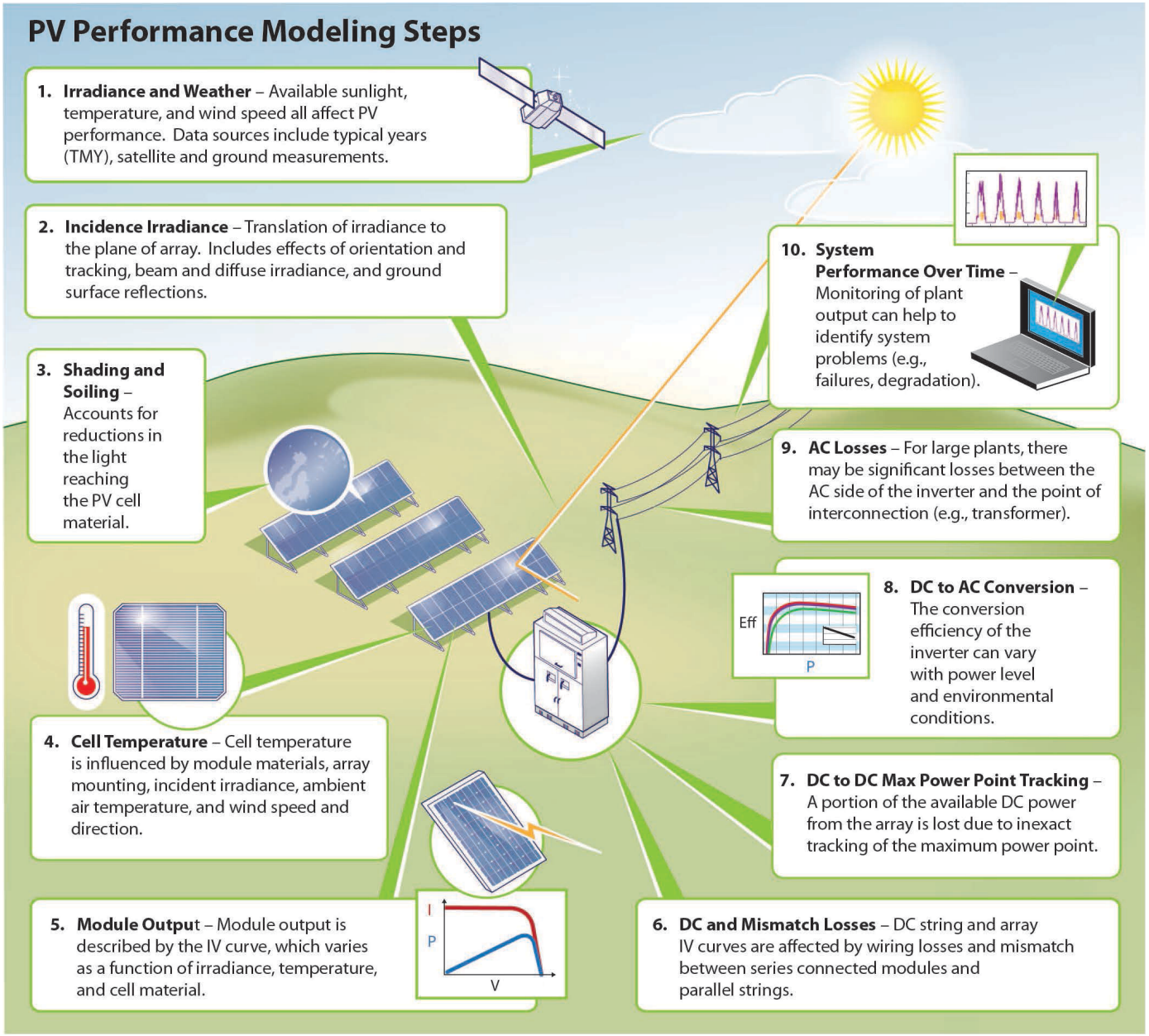
US Department of Energy SunShot Initiative

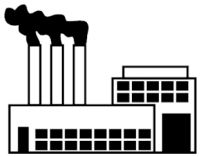
Outline

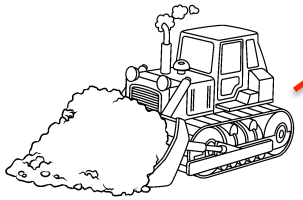
Sandia National Laboratories

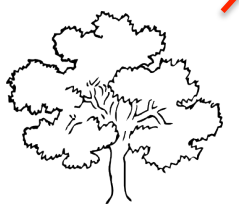
1. Overview of soiling and effects on PV
2. Laboratory Soiling studies
3. Case Study – Evaluation of Anti-soiling coatings
4. Summary

PV Performance Modeling Steps









2. Suspended Atmospheric Particulates

5. Precipitation
- Additional suspended soil
- Soil Patterning
- Natural cleaning

6. Solar input

3. Transport (soiling velocity)
- Wind
- Diffusion
- Gravitational Settling

?

1. Sources
- Wind
- Pollutants
- Construction
- Pollen

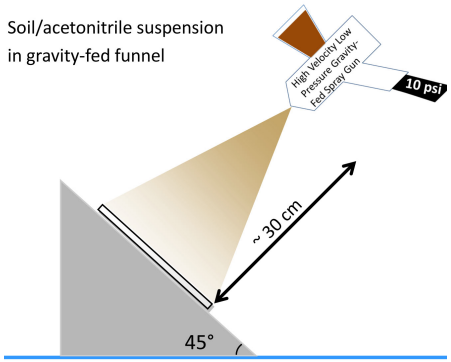
4. Adhesion
- Module surface texture
- Module surface energy
- Tilt angle
- Particle bounce vs stick
- Re-suspension
- Humidity/moisture
- Temperature

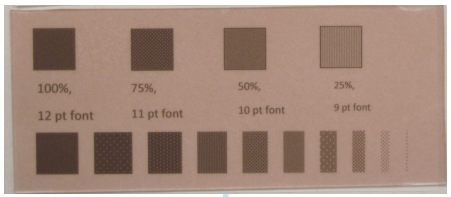
7. Impacts to PV performance
- Normal Incident Attenuation
- Spectral filtering
- Angle of incidence
- Hot spots

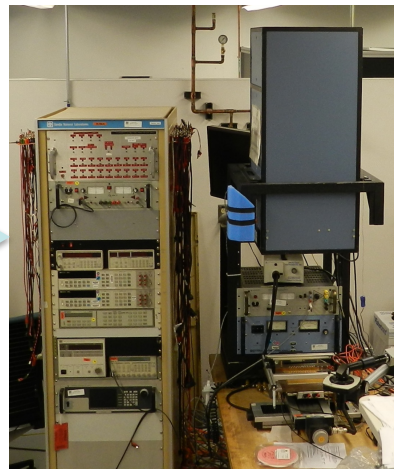
Sandia National Laboratories

Laboratory Soiling – Tools to study fundamental impacts to PV performance

Laboratory Soiling – Methodology and Characterization







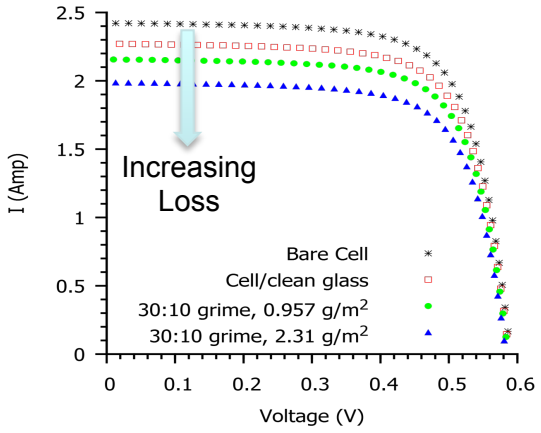
- Traceable soil components are blended to match known natural soil types/compositions.
- Blends are sprayed onto glass coupons at varying loading rates.
- Transmission loss is measured using three different instruments
  - One-sun cell simulator
  - Quantum efficiency
  - UV-Vis spectrophotometer
- **Goals:**
  - Correlate composition to loss; determine the degree to which soil type influences loss
  - Provide a tool to industry to study soiling and soil mitigation

P. D. Burton and B. H. King, "Artificial Soiling of Photovoltaic Module Surfaces using Traceable Soil Components," in *39th Photovoltaic Specialists' Conference*, 2013

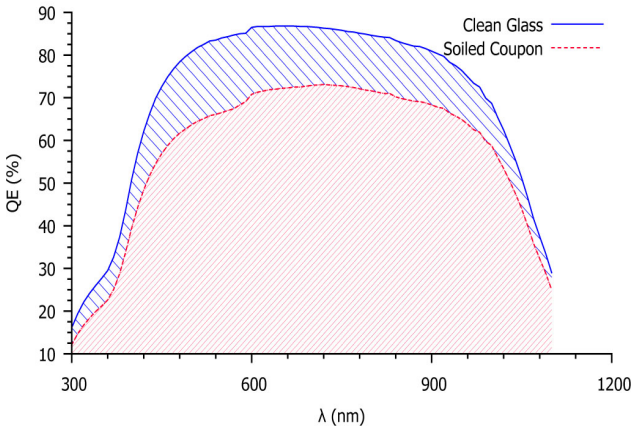
Laboratory Results – Measurement Techniques and Attenuation

Sandia National Laboratories

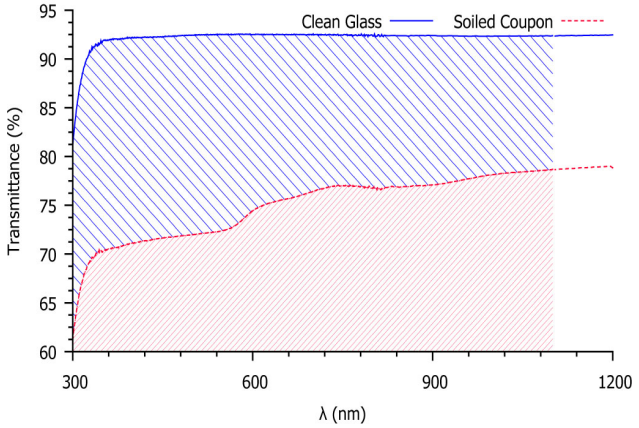
1-Sun Simulator

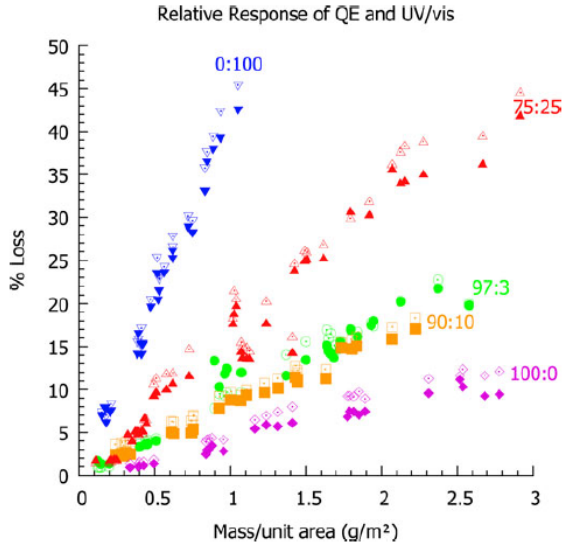


Quantum Efficiency



UV-Vis Spectrometer



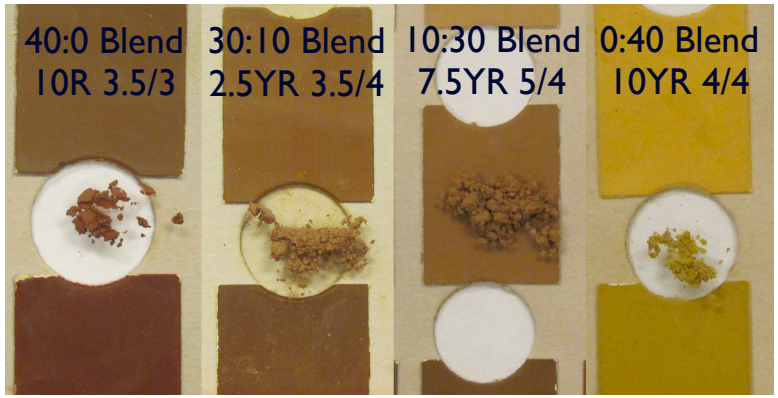


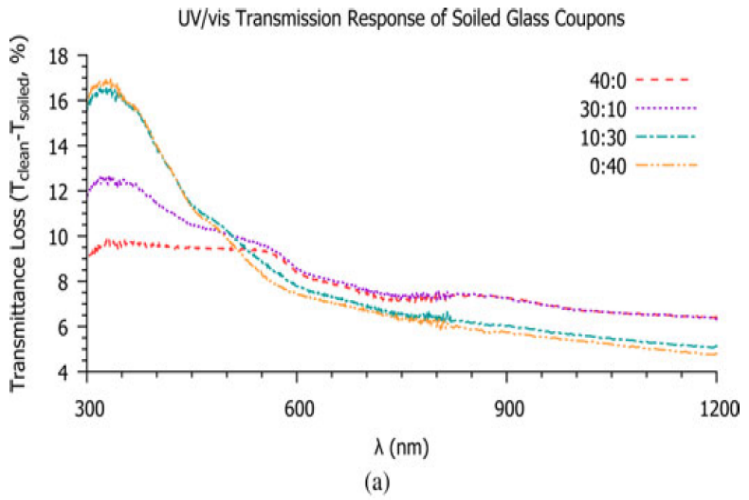
$$Loss = \frac{\int_{300}^{1100} S_{clean}(\lambda)\, d\lambda - \int_{300}^{1100} S_{soiled}(\lambda)\, d\lambda}{\int_{300}^{1100} S_{clean}(\lambda)\, d\lambda}$$

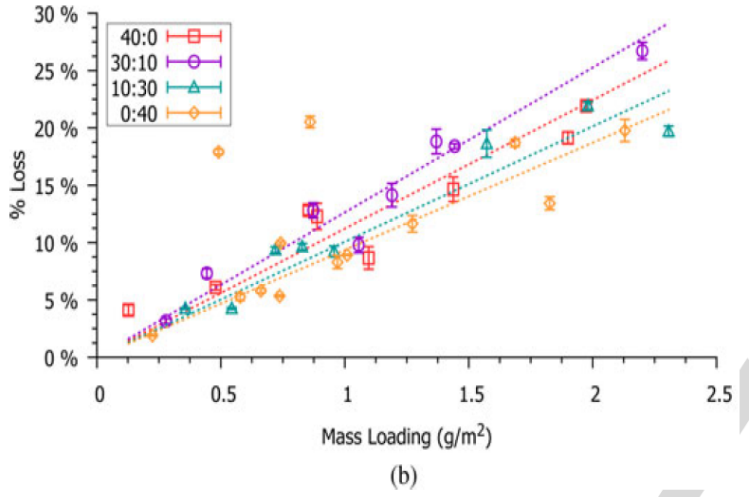
- Demonstrated three complimentary measurement methods
  - Methods based on measuring Transmission Loss correlate very well
- Soils with higher soot content lead to dramatically greater loss

P. D. Burton and B. H. King, "Application and Characterization of an Artificial Grime for Photovoltaic Soiling Studies," *IEEE Journal of Photovoltaics*, 2014

Lab Results – Effect of Soil Composition





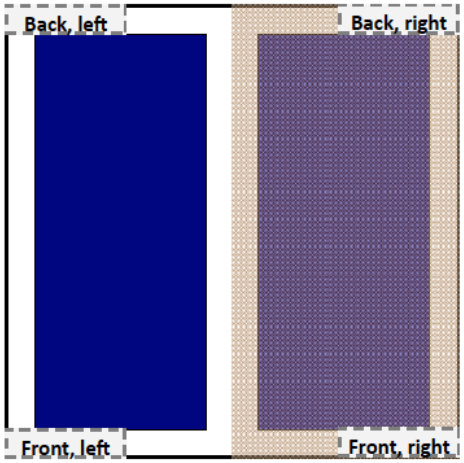


- Developed blends to test compositional effects
  - Four spectrally responsive blends common to the US South West based on iron oxides; hematite (red) and goethite (yellow)
  - Other contents include silica and small levels of carbon
- Soil blends were applied to glass coupons at loading rates up to 2.5 g/m^2, comparable to accumulations seen in nature
- Energy Dispersive Spectroscopy (EDS) indicates that composition is maintained between blending and spraying
- Compositional Effects:
  - Goethite rich soils displayed greater spectral sensitivity, leading to greater attenuation in the blue to UV
  - Hematite rich soils displayed a neutral loss
  - The greatest loss occurred for a blend of the two iron oxides

P. D. Burton and B. H. King, "Spectral Sensitivity of Simulated Photovoltaic Module Soiling for a Variety of Synthesized Soil Types," *IEEE Journal of Photovoltaics,* 2014.

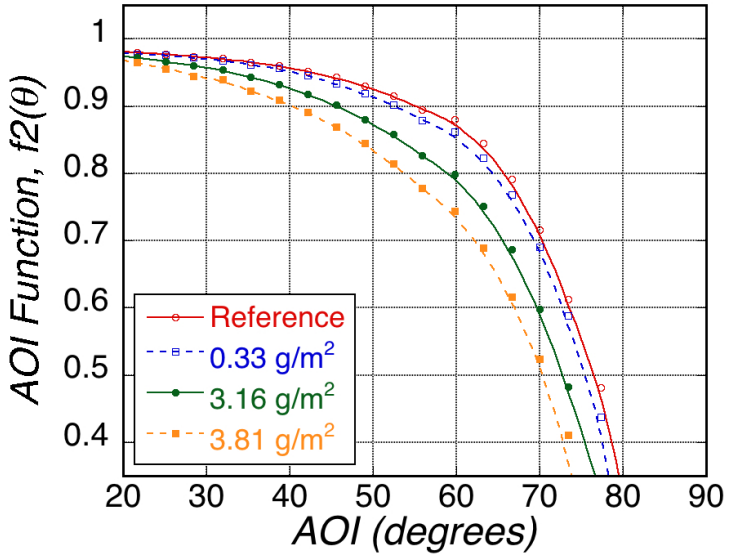
Lab Results – Angle of Incidence

- Synthetic (neutral) soil was applied to one half of custom split reference cell
- Angle of incidence response was measured outdoors on a two-axis tracker
- Low soiling rate (< 0.5 g/m^2) has minimal effect on AOI response compared to a reference curve
- High soiling rate (>3 g/m^2) has a pronounced effect on AOI response
- This effect is **in addition** to attenuation effects and could be a significant consideration for commercial rooftop systems in particular



$$I_{scr} = \frac{I_{sc} E_0}{[E_{DNI} + E_{diff}][1 + \alpha_{Isc}[T_c - T_0]]}$$

$$f_2(\theta) = \frac{\left[\frac{I_{sc}}{I_{scr}}\right]\left[\frac{E_0}{1 + \alpha_{Isc}[T_c - T_0]}\right] - E_{diff}}{E_{DNI}\cos\theta}$$



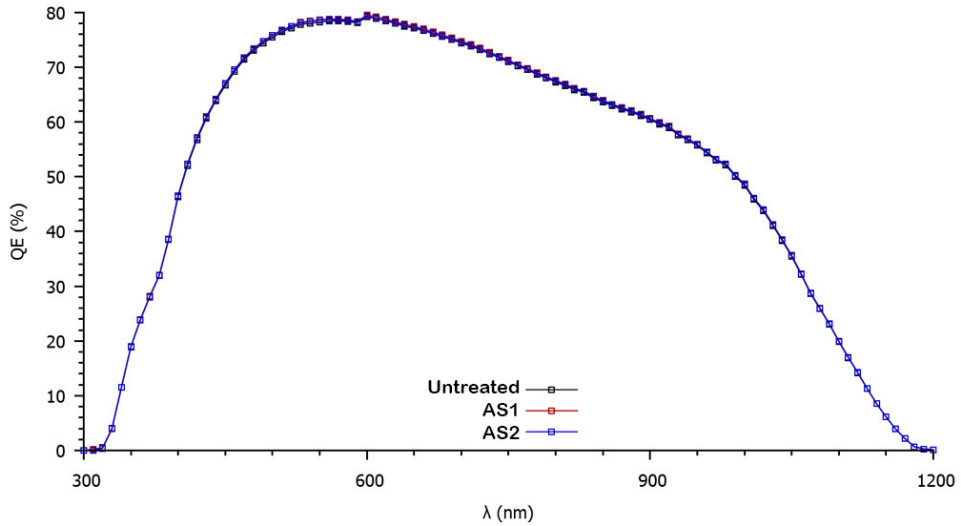
P. D. Burton, A. Hendrickson, S. S. Ulibarri and B. H. King, "Pattern Effects of Soil on Photovoltaic Surfaces", *in preparation*

Sandia National Laboratories

Case Study – Evaluation of Anti-soiling coatings using laboratory methods

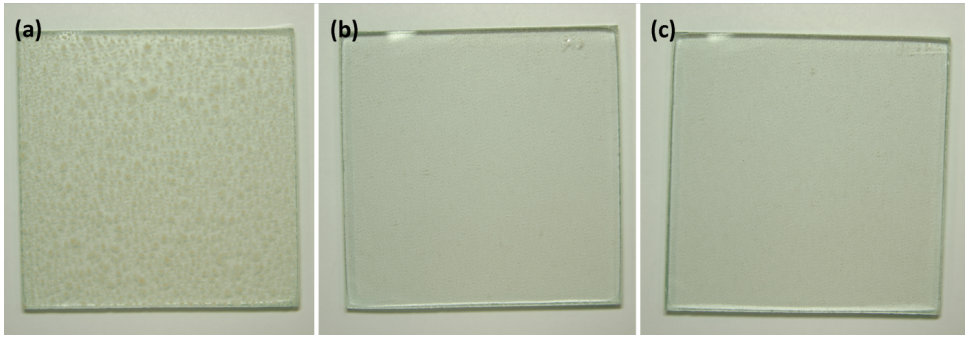
Evaluation of Anti-Soiling Coatings

- Proof of concept lab study to evaluate anti-soiling coatings provided by a glass coating company
- Glass samples with three surface conditions; a) untreated glass (UT), b) AS1 treated and c) AS2 treated.
- Simulated soil (neutral composition, AZ road dust/DI water) was applied using aerosol gun
- Transmission loss characterized using QE method
- Soil release efficiency characterized by simple rinsing and physical wiping
- No initial differences in normal incident transmission were observed between the three surface conditions.

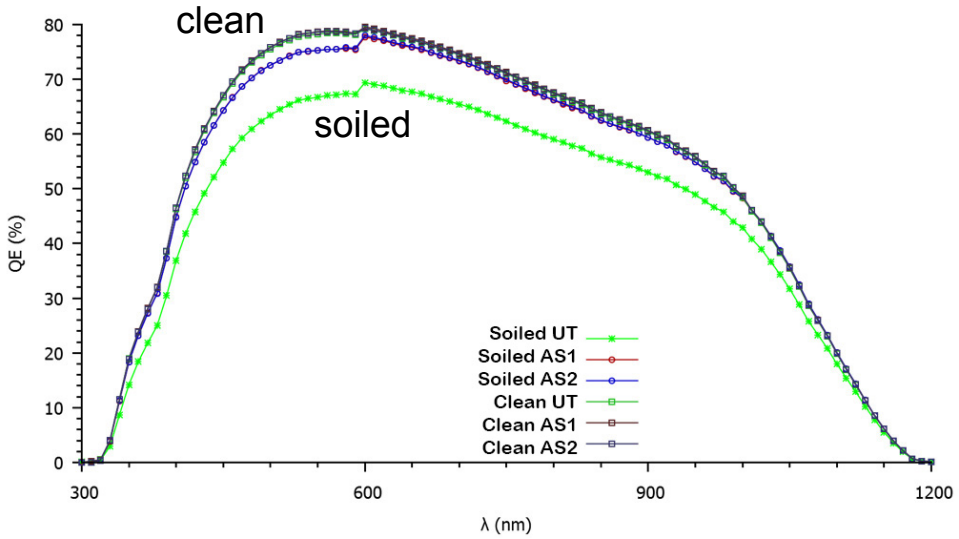


Applied Soil

- Simulated soil (neutral composition, AZ road dust/DI water) was applied at a specific soil coverage of 4.3 g/ m^2, corresponded to heavy soiling.
- Appearance
  - Untreated Sample - coarse, mottled appearance
  - AS1 and AS2 - fine, uniform appearance. Visually, the two treated samples were indistinguishable from each other.
- Attenuation
  - Untreated Sample – significant loss, ~13%
  - AS1 and AS2 – slight loss, ~ 2.5%. As with visual examination, the two treated coupons were indistinguishable from each other.

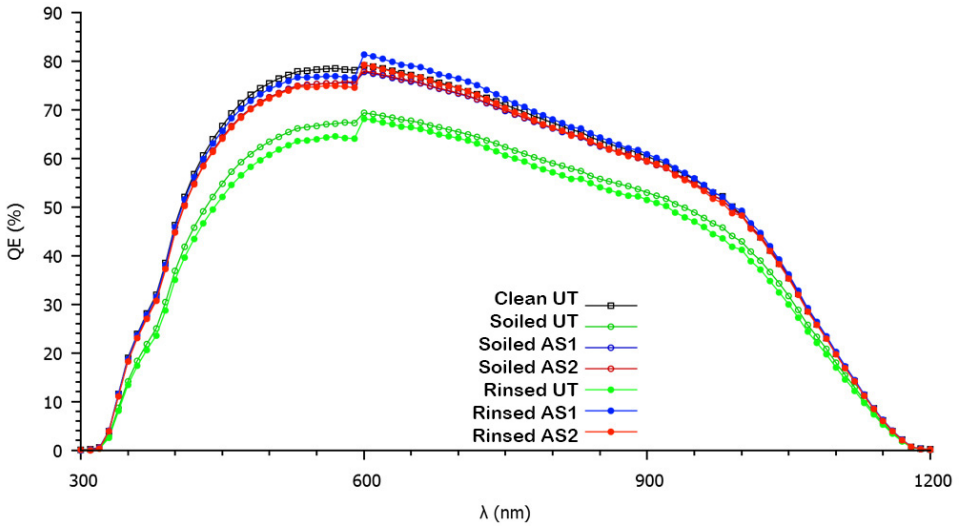


UT AS1 AS2



Release Rate Efficiency

- Two methods
  - DI water rinse
  - Mechanical wiping with a clean clot
- Rinse test
  - Untreated Sample - displayed greater loss after rinsing. Visual examination revealed significant soil redistribution
  - AS1 - recovered fully
  - AS2 - did not recover significantly
  - The untreated coupon actually displayed greater loss after rinsing.
- Mechanical wiping
  - All samples recovered fully



	UT	AS1	AS2
Soiled	-13.3%	-2.6%	-2.3%
Rinsed	-16.2%	0.2%	-2.2%
Wiped	0%	0%	0%

Summary

Sandia National Laboratories

- Repeatable laboratory methods have been demonstrated for studying fundamental impacts of soil on PV performance
- Soil composition has been demonstrated to affect PV performance
  - Higher soot content soils attenuate light to a greater extent than low soot content soils
  - Spectrally responsive pigments may alter the spectrum of light reaching the PV cell
- Significant soil accumulation changes angle of incidence behavior, leading to greater losses than anticipated
- A proof of concept study demonstrated the potential to apply laboratory soiling methods to the study and optimization of anti-soiling coatings
- Side observation: Anti soiling coatings may be beneficial beyond enhancing soil release by promoting more uniform soil distribution on the module surface

Adhesion Mechanisms for Soiling on PV Glass

PV Module Reliability Workshop

Lin Simpson, Helio Mountinho, Craig Perkins, Chun-Sheng Jiang, Mowafak Al-Jassim, Matthew Muller

March 2, 2017

This presentation contains proprietary and business sensitive material, not for public disclosure
NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Contents

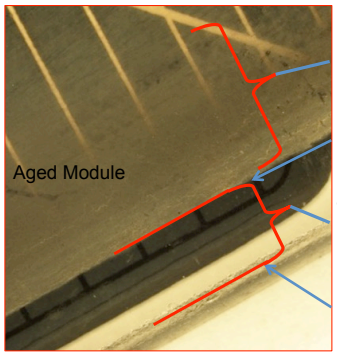
- **Introduction/overview**
  - Soiling Project
  - Mechanisms
- **Initial soiling adhesion mechanisms**
- **Complex soiling mechanisms**
- **Future work**
- **Summary**
- **Acknowledgements**

Introduction/Overview: NREL Project

- **Addressing Soiling: From Interface Chemistry to Practicality**
- **Working with stakeholders and PV community from the outset**
  - ***Welcome collaborations and input***
  - Focus on addressing 3 main problems to decrease LCOE

Outcomes

Coating Deployment Guidelines | Module Coating Standards | Reduce Performance Uncertainty

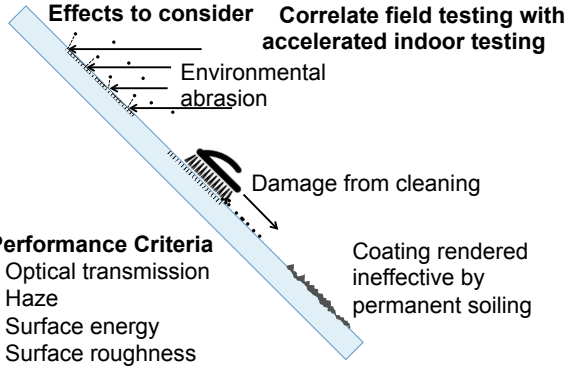


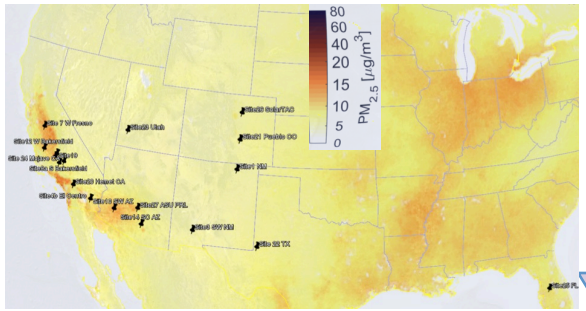
Tenacious deposits at frame edge ~ 1 cm at all module edges

Frame edge

5 mm glass w/ frame removed is clear and does not show soiling

Edge of module/ glass





Lower LCOE: O&M, Finance

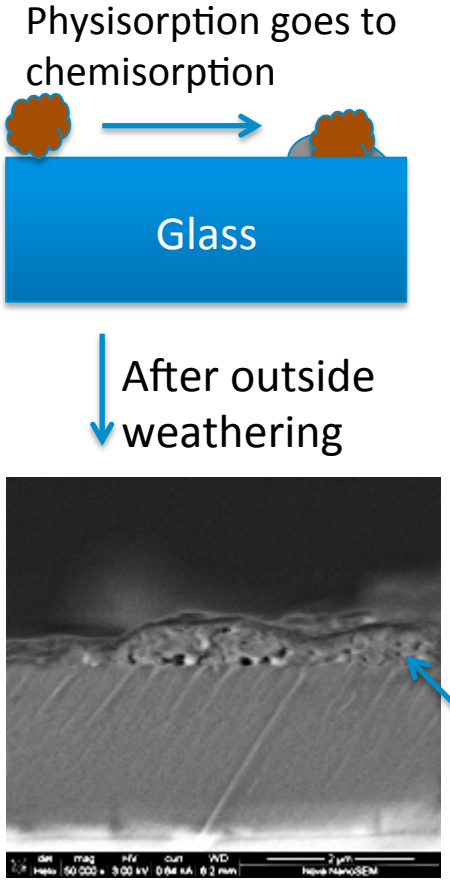
Quantifying Soiling Mechanisms | Evaluate Surface Abrasion | Predict Soiling Rates

Overview

- **Conclusions from literature survey**
  - Early work attempted to address mechanism issues more[1]
  - A lot of work identifies soiling issues, but do not evaluate/identify exact adhesion mechanism[2]
- **To go beyond just "observing" soiling we must systematically evaluate each adhesion mechanism involved at each step.**

Sample Observations:

- **Dust that has been on the surface for a while tends to be harder to remove.**
- **Humidity and dew cycle seem to increase soiling.**
- **One of the main forms of enduring soiling is cementation.**



Sample questions to answer:

- **If gravity or wind brings dust to the surface, what makes it stick?**
  - **Kaz's recent paper[3] places adhesive forces with dust at 10-300 nN: Humidity had big effect.**
- **What role does humidity play?**
  - Reduces electrostatics?
  - **Enables capillary?**
  - **What is relative strength?**
- **What is the effect of surface properties and dust composition?**
  - **Surface roughness?**
  - Surface Energy?
  - Conductivity?
- Is the roughness due to weathering from chemical etching of the glass or surface deposits?

1. e.g.,Cuddihy and Wilis, JPL Pub 84-72 (1984)
2. e.g., Mani and Pillai, Ren. And Sust. Energy Rev. 14, 3124 (2010)
3. Kazmerski et.al., 978-1-4799-7944-8/15/©2015 IEEE

Initial PV Soiling Adhesion Mechanisms

van der Waals may be most important initial adhesion mechanism that holds dust on the surface continuously.

van der Waals
~5 to 1000 nN
Decreases with increased surface roughness

Roughness

Humidity

Capillary
~50 to 10k nN, RH>~30%
Decreases with increased surface roughness

Roughness

Humidity

Capillary forces are a major issue in early morning with dew formation.

Focus on mechanisms unique to PV modules, e.g., cementation due to high PV module temperatures.

Cementation
All mechanisms adhere dust to surface to enable longer term "chemical" bonding

Hydrogen Bonding and Surface Energy

Need to understand and differentiate hydrogen bonding from van der Waals. Understanding critical to the development of mitigation strategies.

Electrostatic
~0 to 1000k nN
Long-range (mm)
Drives ion transport

Static Electricity Humidity

Surface Charge Humidity

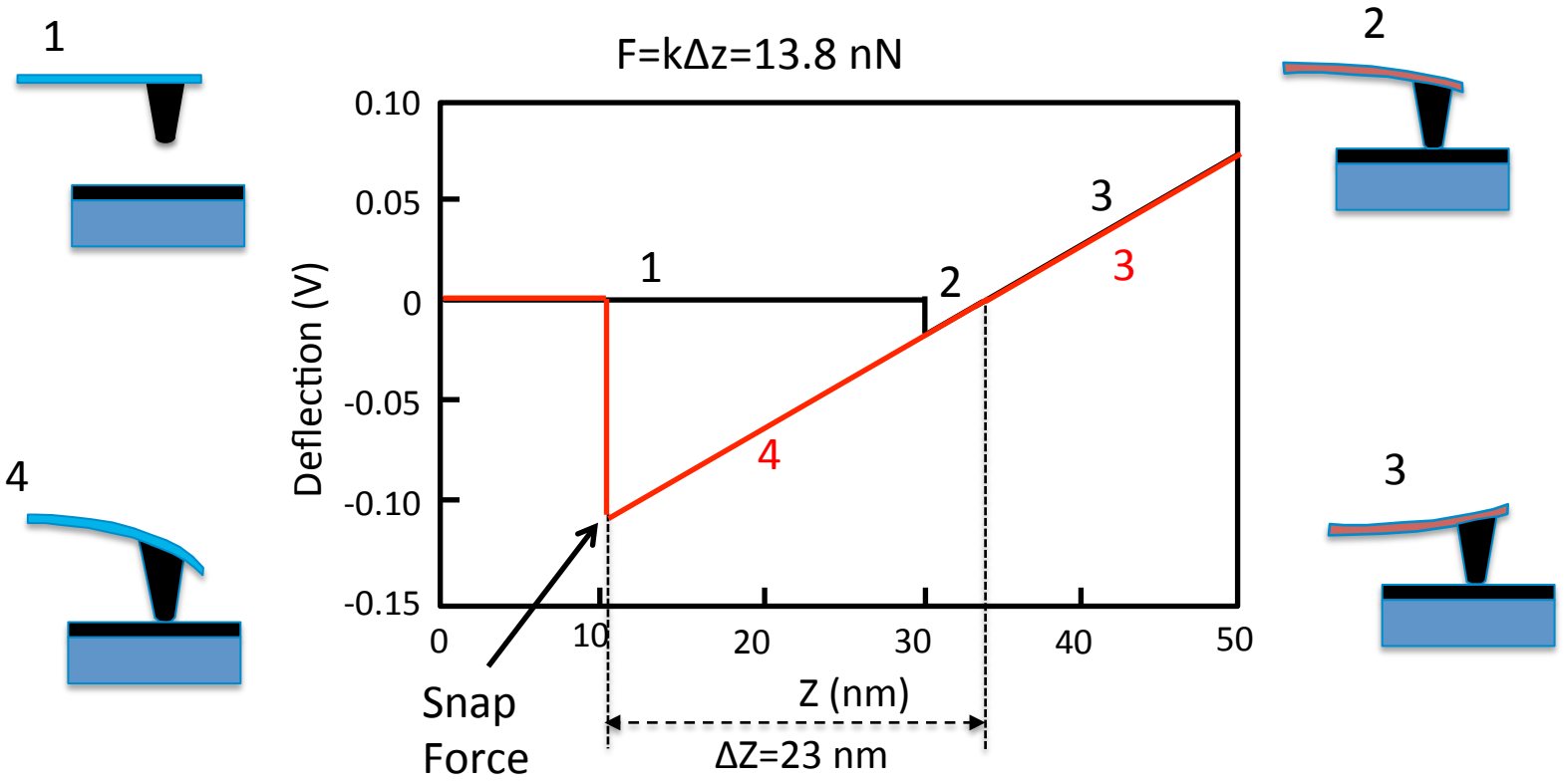
Creates strong induced dipole, multipole, … effects.

Chemical Bonding
Ionic mobility and corrosion

50 to 100°C PV Temperatures

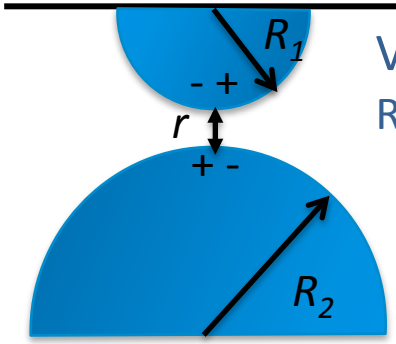
Need to understand how daily cycling with water and heat impacts cementation.

AFM Force vs Distance Measurements



The cantilever deflection signal is transformed into adhesion force by using the cantilever force constant (e.g. 0.6 N/m).

Adhesion Forces: Comparison to Theory



Van der Waals, induced dipole

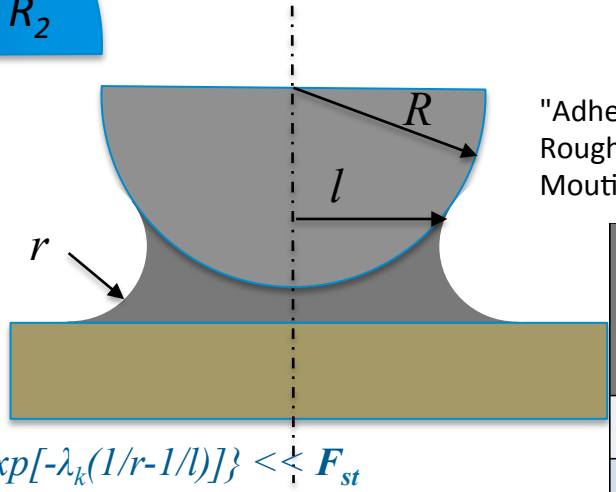
RH: 0%

If $R_2 = \infty$ and $r << R_1 \& R_2$

$F_{vw}(r) = -AR_1 / 6r^2$

Value	Adhesion Force (nN)		
	AFM tip	5-µm sphere	20-µm sphere
Theory*	2.9	238	952
Experiment	6.6	314	684

Capillary Force: F_{cp}



"Adhesion Mechanisms on Solar Glass: Effects of Relative Humidity, Surface Roughness, and Particle Shape and Size." Solar Energy Materials and Solar Cells. H.R. Moutinho, C.-S. Jiang, B. To, C. Perkins, M. Muller, M.M. Al-Jassim, and L. J. Simpson

$Fcp = Fst + Fmc$

$Fst = 2\pi l\gamma$

$Fmc = \pi l^2 p_0 \{1-exp[-\lambda_k(1/r-1/l)]\} << F_{st}$

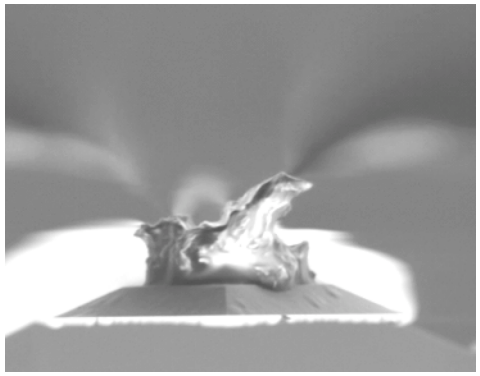
Value	Adhesion Force (nN)	
	AFM tip - RH 40%	20-µm sphere - RH 67%
Theory	5.2	3329
Experiment	18	1920

Trends are good, but more work is needed to understand effects of contact area and to determine a reliable/meaningful value of r for capillary forces.

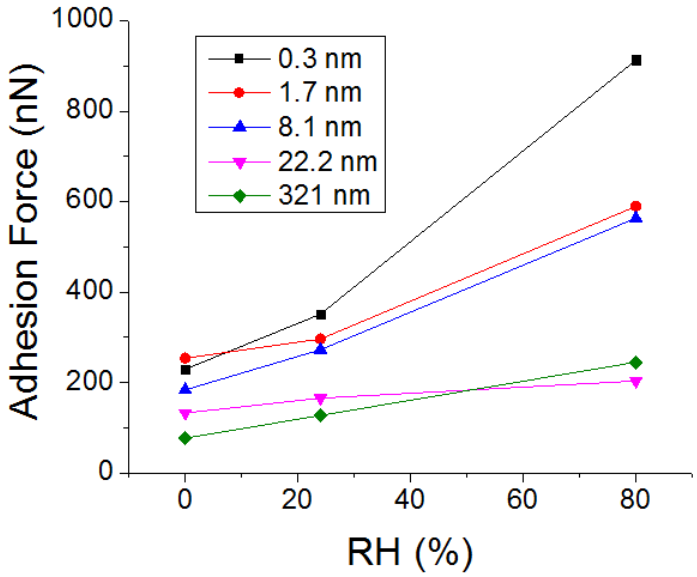
- **vdW and capillary forces are important soiling adhesion mechanisms.**
- **Capillary forces can be stronger than van der Waals.**
- **In general, adhesion increases with particle size and relative humidity, but decreases with glass surface roughness**
- **More work needed to understand interface and high humidity effects.**

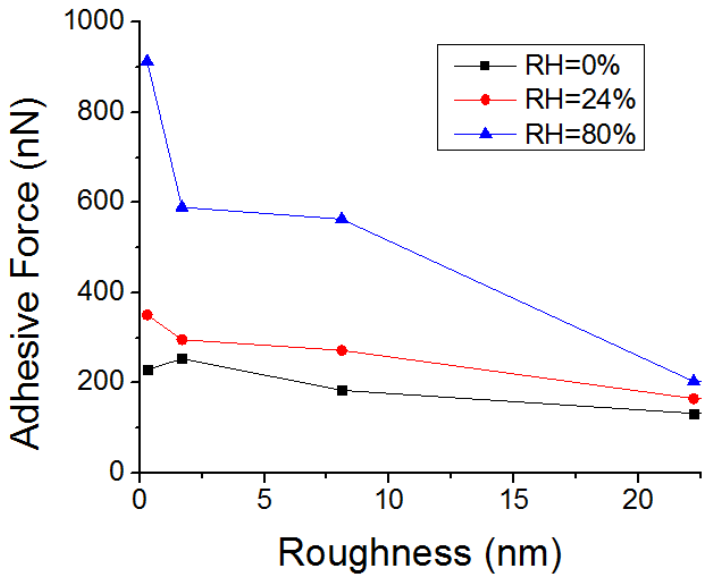
Initial Adhesion Mechanisms: AFM

- **van der Waals and Capillary Forces of Real Dust Particles**
  - Adhesion force as a function of RH and roughness.
    - Results in general agreement with AFM tips and glass sphere baselines.
      - vdW and Capillary adhesion of dust particles between (bracketed) AFM tip and glass spheres
    - Adhesion force increases with increased humidity and decreased surface roughness.
    - Despite large difference in shape and size:
      - vdW main adhesion force at low humidity and rough surfaces.
      - Capillary force dominates only at high humidity on smooth surfaces.
    - Compared to glass spheres, appears to be an increase in adhesion at about 18% RH Suggests that the dust particles may be more hydrophilic than the glass spheres.

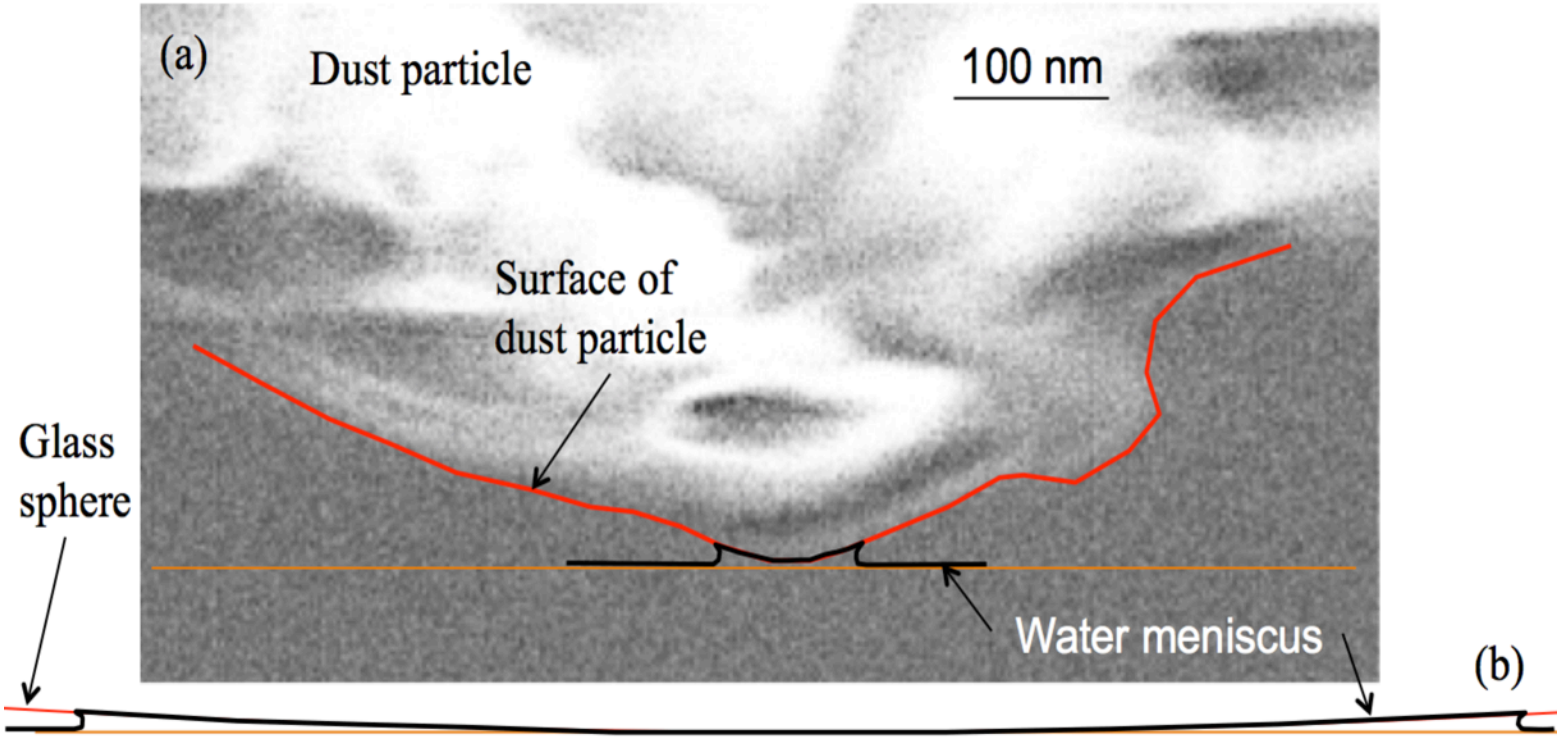


Real dust particle glued to AFM cantilever





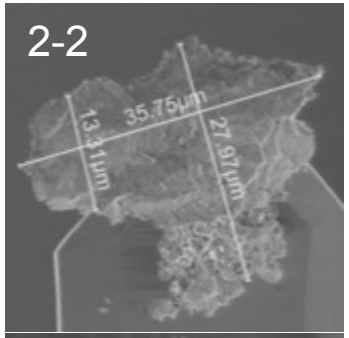
Initial Adhesion Mechanisms: Contact Area

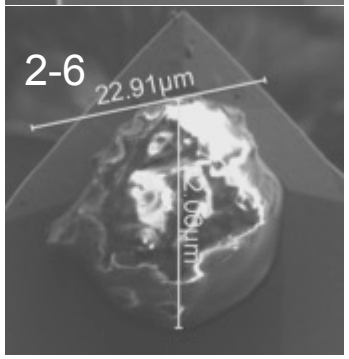


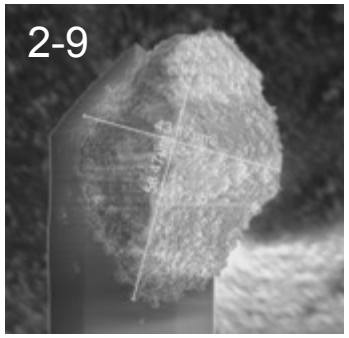
Comparison of the contact area between a glass surface and (a) a real 20-μm diameter dust particle and (b) a 20-μm diameter glass sphere. We are considering a 1-nm thick water layer with a 10-nm thick meniscus due to the relative humidity. The scale is the same for both images.

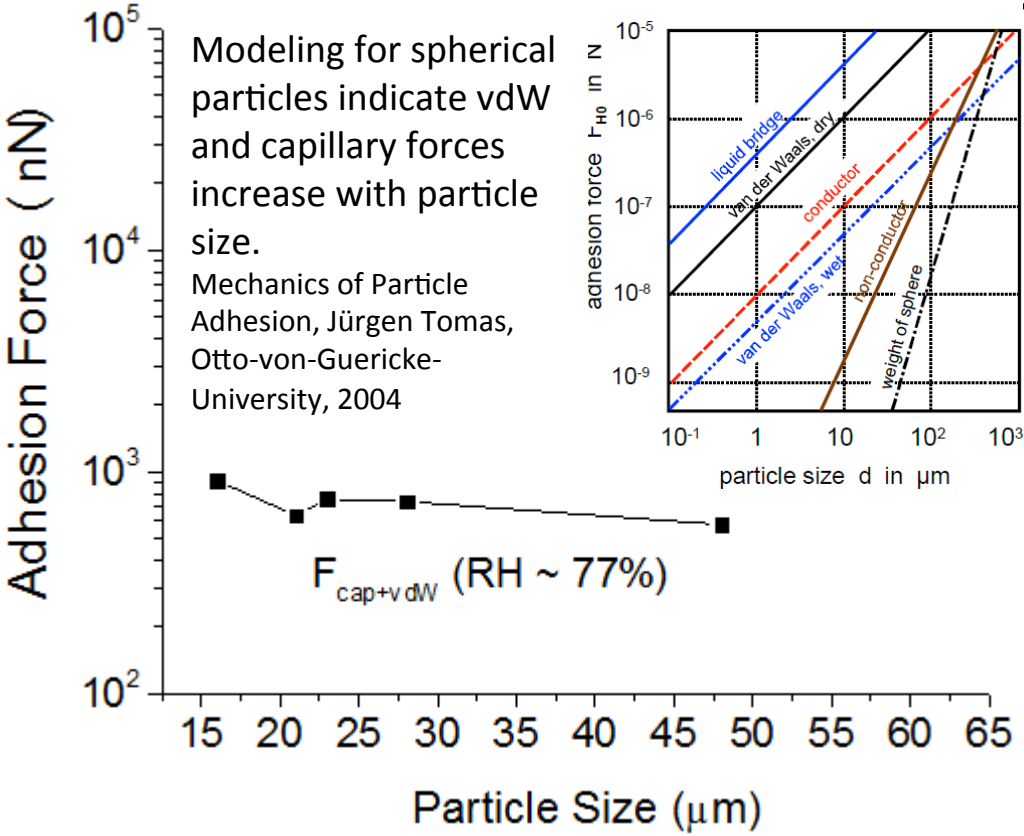
For short range forces (e.g., vdW and capillary) as expected adhesion forces are controlled by surface contact areas; not correlated with particle diameter for real dust particles that have surface roughness.

Initial Adhesion Mechanisms: Different Size Dust Particles



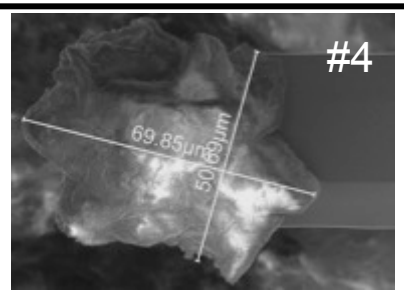


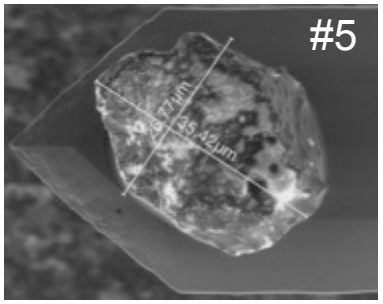


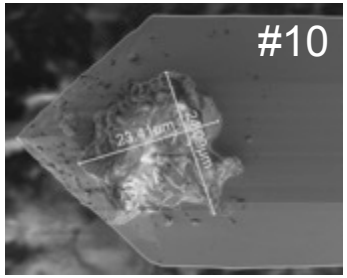


Modeling for spherical particles indicate vdW and capillary forces increase with particle size.

Mechanics of Particle Adhesion, Jürgen Tomas, Otto-von-Guericke-University, 2004





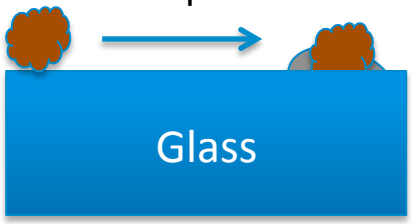


Due to surface roughness, real dust particles have surface contact areas much smaller than expected based on the particle diameter and therefore vdW and capillary adhesion does not increase proportionally as particle size increases.

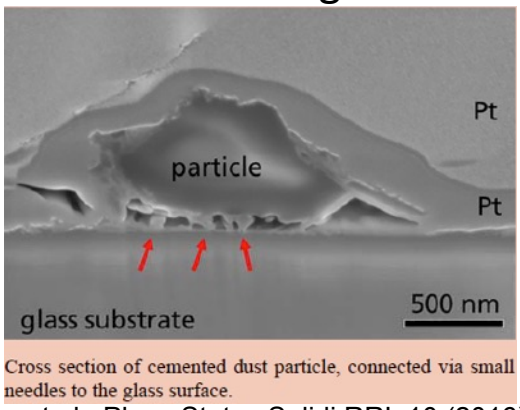
While longer-range forces may increase with the size of real dust; the adhesion of real dust from short-range forces does not increase for larger particles. Explains why larger particles blow off PV.

Complex Soiling Mechanism: Cementation

Physisorption goes to chemisorption?



After outside weathering

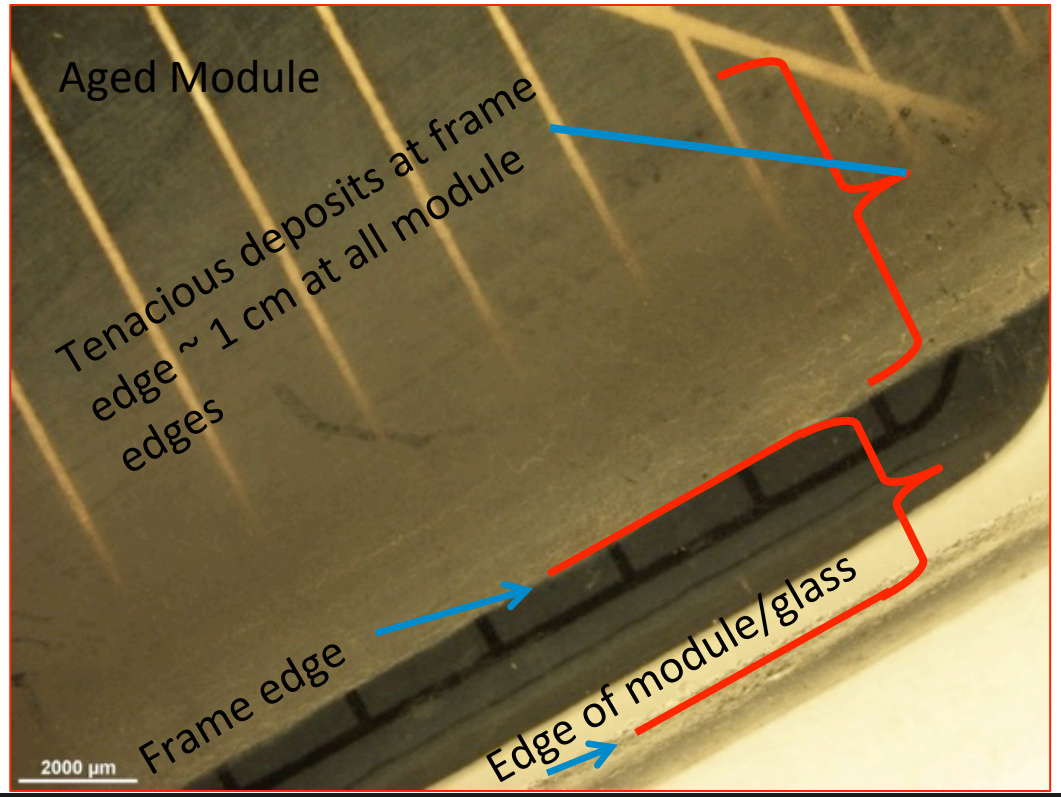


Cross section of cemented dust particle, connected via small needles to the glass surface.

Ilse et al., Phys. Status Solidi RRL 10 (2016) 525

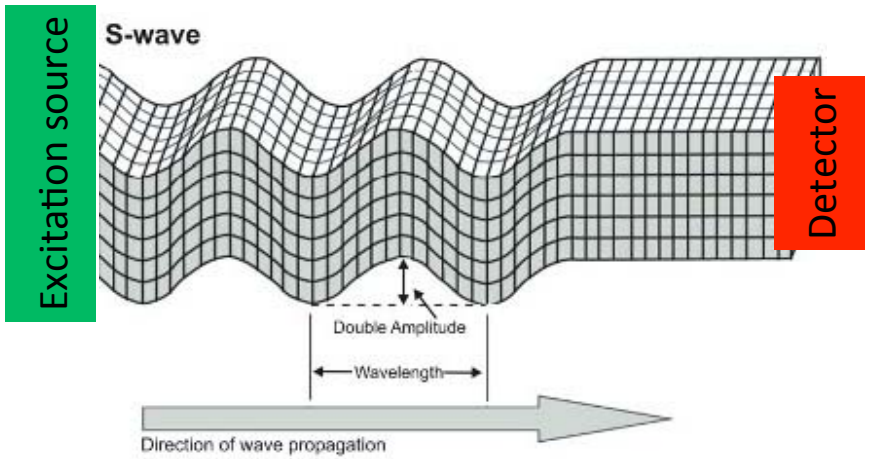
- Must quantify if and what is the chemical bond(s); what is "cemented".
- Reproduce observed cementation in lab.

- **Must define "cementation" and processes involved**
- **Critical to quantify interfacial chemistry**
  - How is Na or other ion migration involved
    - Distinguish between increased physical adhesion and true chemical bonds.
      - Measuring acoustic properties of overlayer (by e.g. QCM) is one way.
  - Surface properties
    - What roll does H-bonds and other corrosion processes play.



Define "Cementation": Use "Cement" Industry

- **What is cementation? Is it a discrete process or is there a continuum?**
  - Cementation is a type of phase transition known as a percolation transition.[1]
  - Whether or not it is first order (abrupt) or second order (continuous) is a matter of debate.[2]
- **Can we detect it?**
  - ***In practice, there is a qualitative, discrete difference between cemented and uncemented particles:***
    - ***Cemented particles transmit shear, uncemented particle ensembles do not.[3]***



Note: no shear waves before "cement" has formed after requisite curing time

Shear waves do not propagate in uncured cements.

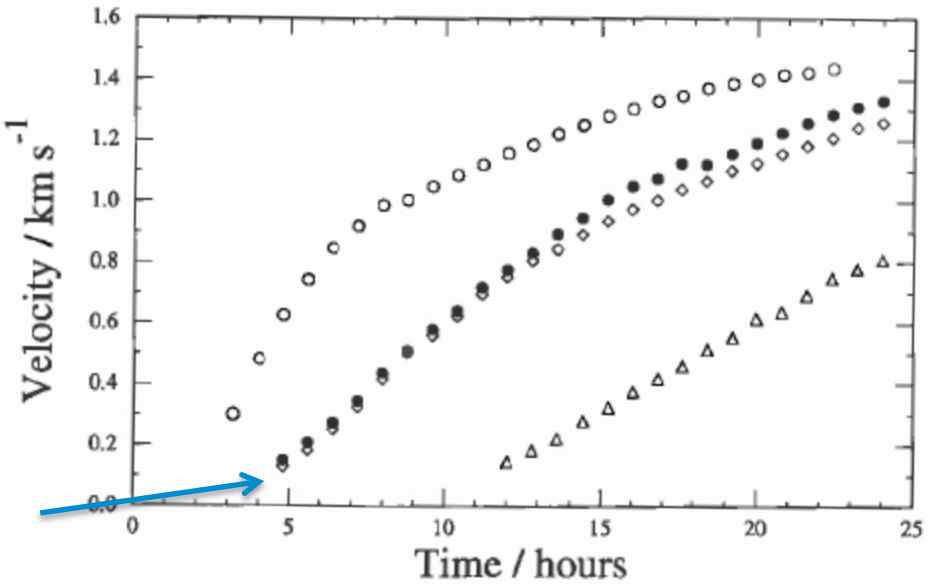


Figure 4 Measured ultrasonic shear wave velocities for de-aerated and rolled Dykerhoff slurries: Dykerhoff + 2% $CaCl_2$ (○), neat Dykerhoff (●), surfactant Dykerhoff (◇) and Latex Dykerhoff (△)

From [3]

1. *Advanced Cement Based Materials* **3** (1996) 94.
2. *Science* **323** (2009) 1453
3. *Ultrasonics* **31** (1993) 147.

QCM to Measure Cementation: Quartz Crystal Resonator to Probe Particle-Surface Interactions

Schematic of QCM-based flow cell[6]

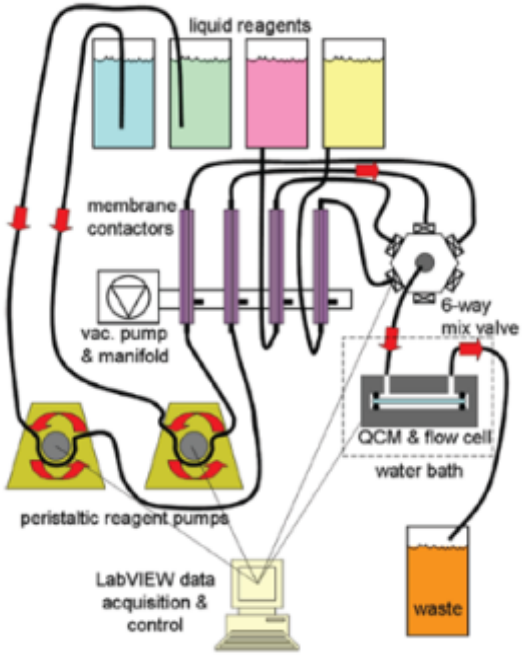
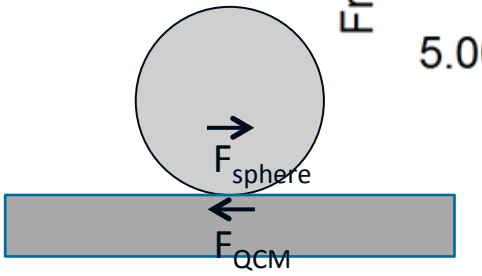
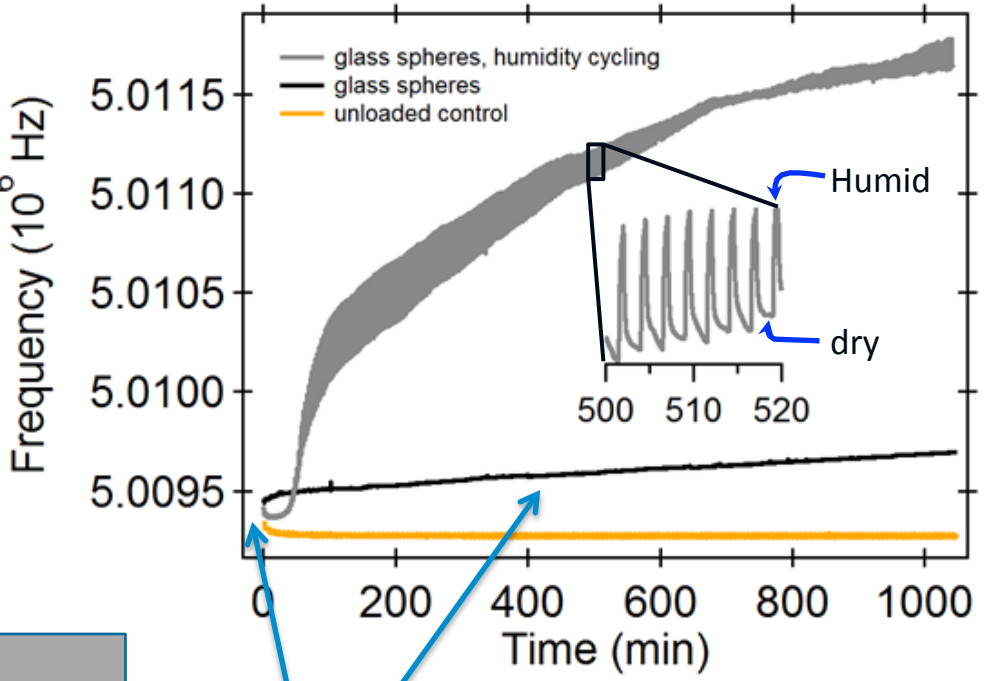


Figure 2. Schematic of our QCM-based flow cell reactor used to probe the quality of SAMs.

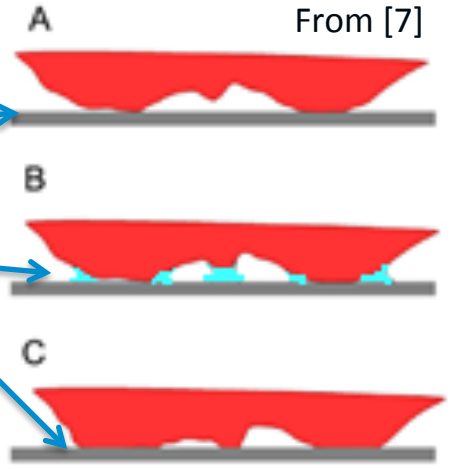
Inertially clamped SiO_2 sphere exerts restoring force on oscillator



Humidity cycling increases rate of aging



From [7]



Positive frequency shift due to increased stiffness of oscillator.[3]

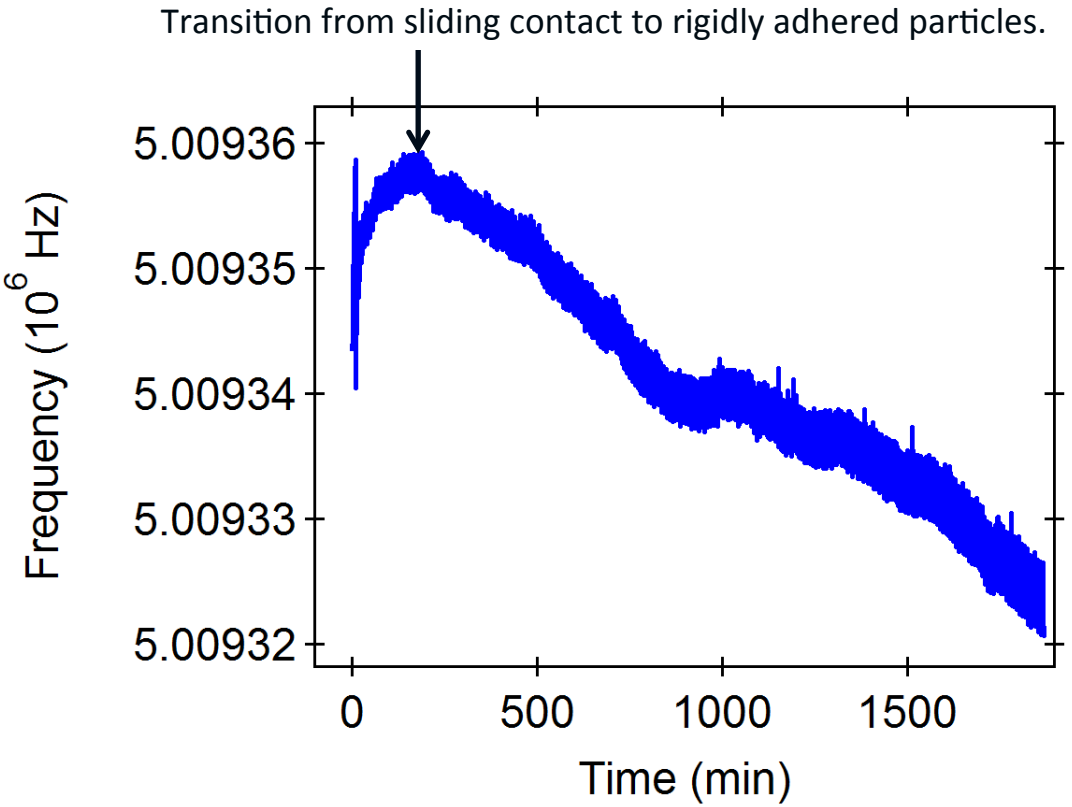
Positive shifts with time due to capillary aging.[4,5]

As humid and dry air are cycled, the interaction between the particles and surface change (age). This leads to more contact area that increases the stiffness (interaction) between the QCM surface and particles; causing the frequency to increase with time.

3. *Anal. Chem.* **82** (2010) 2237: 4. *Nature* **396** (1998) 735: 5. *Phys. Rev. Lett.* **96** (2006) 058301: 6. *J. Phys. Chem. C* **113** (2009) 18276: 7. *Nanotechnology* **26** (2015) 484001

Complex Soiling Mechanisms: Cementation

Onset of cementation is detected in **halite particles on QCM SiO_2 surface** with humidity cycling.



Cycling between humid and dry air causes the halite particles to initially age, as did the silica spheres. However, at some point, the fundamental interaction between the halite and QCM surface transitions to where it transmits "shear."

The formation of rigidly adhered particles marks the formation of cementation. As more particles become cemented the frequency continues to decrease. With cementation detected, we can now quantify the different processes involved.

Future Work

van der Waals may be most important initial adhesion mechanism that holds dust on the surface continuously.

van der Waals
~5 to 1000 nN
Decreases with increased surface roughness

Roughness ↓ Humidity ↓

Capillary
~50 to 10k nN, RH>~30%
Decreases with increased surface roughness

Roughness ↓ Humidity ↑

Key finding: vdW and Capillary adhesion does not increase significantly with particle size for real dust particles.

Capillary forces are a major issue in early morning with dew formation.

Focus on mechanisms unique to PV modules, e.g., cementation due to high PV module temperatures.

Cementation
All mechanisms adhere dust to surface to enable longer term "chemical" bonding

- Studies with controlled modification of surface chemistry.
- Development of simple field tests to augment more complex QCM work.
- Temperature, humidity, and electrostatic dependent studies.

Hydrogen Bonding and Surface Energy

Need to understand and differentiate hydrogen bonding from van der Waals. Understanding critical to the development of mitigation strategies.

Electrostatic
~0 to 1000k nN
Long-range (mm)
Drives ion transport

Static Electricity ↓ Humidity

Surface Charge ↑ Humidity

Creates strong induced dipole, multipole, … effects.

Chemical Bonding
Ionic mobility and corrosion

50 to 100°C PV Temperatures

Need to understand how daily cycling with water and heat impacts cementation.

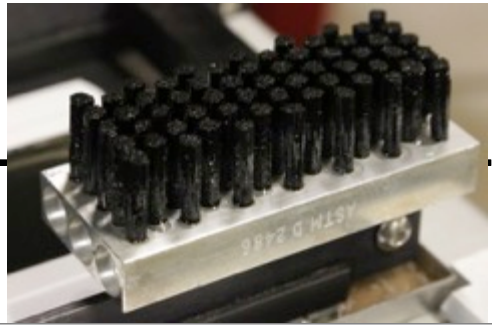
Summary

- **van der Waals and Capillary Adhesion of Dust Particles**
  - Main mechanisms that are present all the time, that are associated with adhesion of dust to PV surfaces.
    - van der Waals forces in dry conditions may have similar magnitude to capillary for smooth surfaces
    - van der Waals and capillary forces are significantly reduced with increased surface roughness, but are significantly increased with contact area. Thus the soiling adhesion is very dependent upon the local topography.
  - Because the rough dust particle surfaces do not provide a good contact area with the glass surface, short distance forces, like van der Waals and capillary (liquid bridge), do not increase in proportion to particle size, as is typically the case with smooth shapes like spheres.
    - i.e., the contract area of rough dust particles does not increase proportionally with particle size.
- **Cementation**
  - Adopted a testable and robust definition of cementation based on the ability of cemented particles to transmit shear.
  - QCM shear oscillators provide a means to study cementation, particle-surface, and particle-particle mechanical properties.
  - Shear forces appear to be an important parameter to measure in soiling studies.
  - Demonstrated onset of cementation with humidity cycling.

Acknowledgements/Thanks

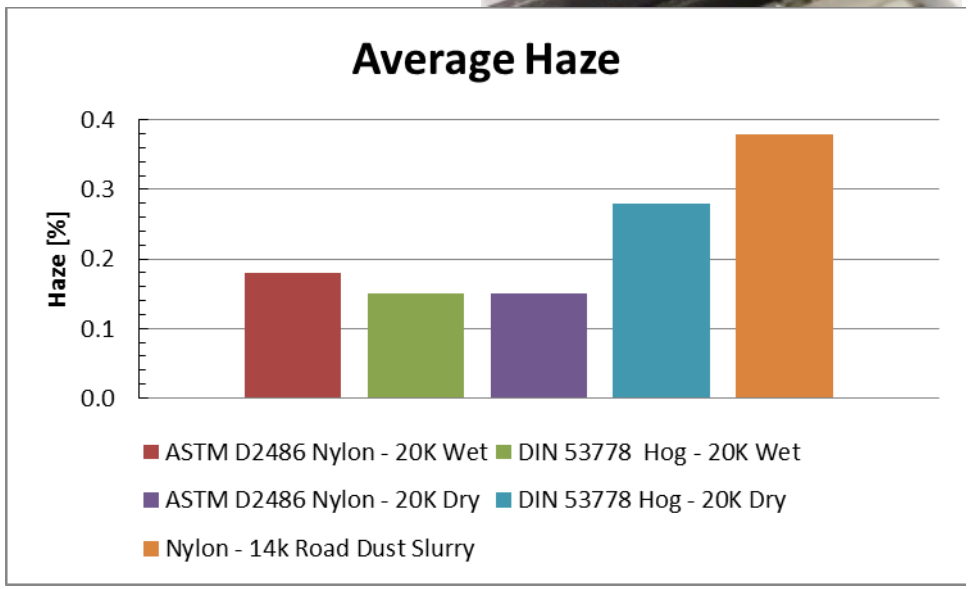
- **NREL Staff**
  - Sarah Kurtz
  - Lin Simpson
  - Matt Muller
  - Mowafak Al-Jassim
  - Michael Deceglie
  - David Miller
  - Helio Montinho
  - Craig Perkins
  - Paul Ndione
  - C.S. Jiang
  - Bobbie To
  - Greg Perrin
  - Paul Basore
  - Nancy Haegel
  - Jen Liebold
  - Jina Martingano
  - Jane Fisher
- **Collaborators**
  - Mike Van Iseghem: EDF
  - Richard Perkins: SunPower
  - Zoe Defreitas: SunPower
  - Mike Anderson: SunPower
  - Mark Lewis: First Solar
  - Markus Gloeckler: First Solar
  - Mark Grammatico: First Solar
  - Marco Aguilar: SunEdison
  - Brian Wildes: SunEdison
  - Christopher Hart: SunEdison
  - John Previtali: Wells Fargo
  - Brenor Brophy: ENKI
  - Tim Narum: 3M
  - Dennis DeCourcy: 3M
  - Dirk Weiss: 3M
  - Pr. Alan Lyons: ARL designs
- **Collaborators**
  - Nicoleta Voicu: DSM
  - Yi Li: DSM
  - Ian Bennett: DSM
  - Milica Mrcarica: DSM
  - Hugo Schoot: DSM
  - Hassan Qasem: DEWA
  - Pedro Banda: DEWA
  - Russ Jones: KACARE
  - Omar Shesha: KACARE
  - Hussain Shibi: KACARE
  - Ben Figgs: Qatar
  - Anil Kottantharayil: SERIIUS
  - Juzer Vasi: SERRIIUS
- **Partners**
  - G. TamizhMani: ASU
  - Alan Sellinger: CSM
- **DOE**
  - Inna Kozinsky
  - Geoffrey Kinsey
  - Rebecca Jones-Albertus

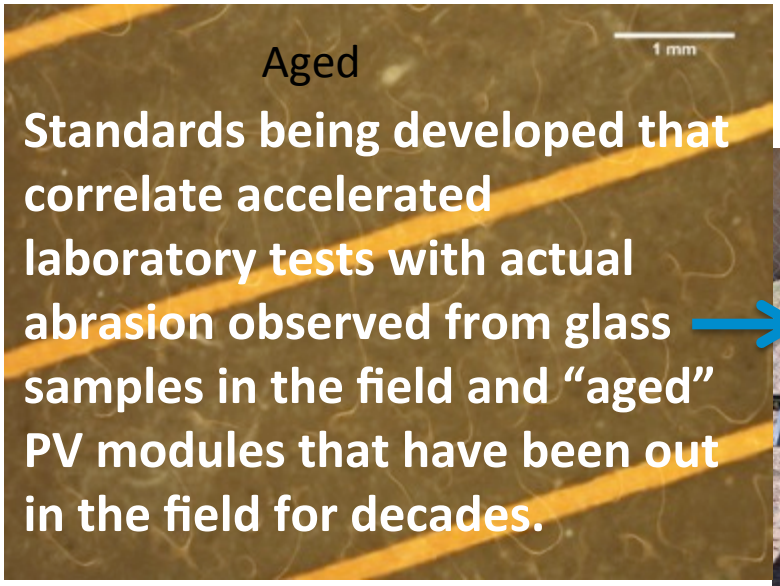
PV Coating Standards



Summary of accelerated testing results:

- As expected brushes themselves do not damage the glass surface
  - Differences in transmittance measurements are within the measurement noise
- Haze values are small and within the noise
  - After 14,000 cycles with AZ slurry a haze is discernable to some eyes
- More test results to come using a slurry with larger dust particles which are expected to cause damage





Standards being developed that correlate accelerated laboratory tests with actual abrasion observed from glass samples in the field and "aged" PV modules that have been out in the field for decades.

Mumbai, IIT
Tempe, AZ
Sacramento, CA
DEWA, UAE
Kuwait (in progress)

May deploy some in Brazil as well

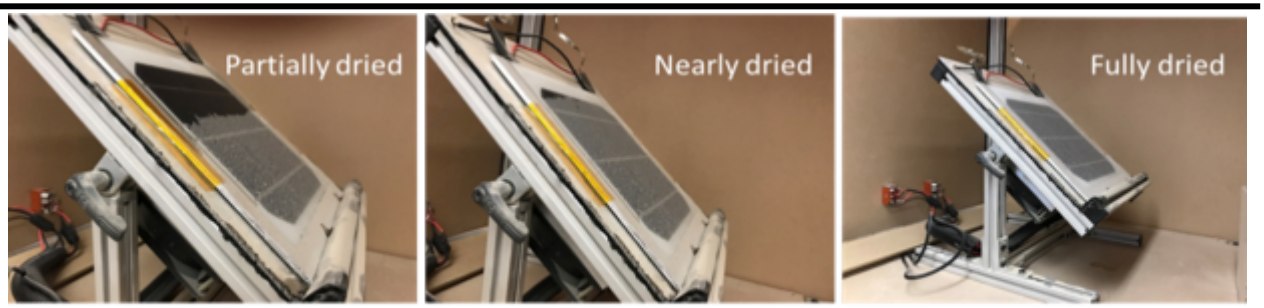
ASU Artificial Soiling Chamber

Inexpensive chamber and dust delivery components.

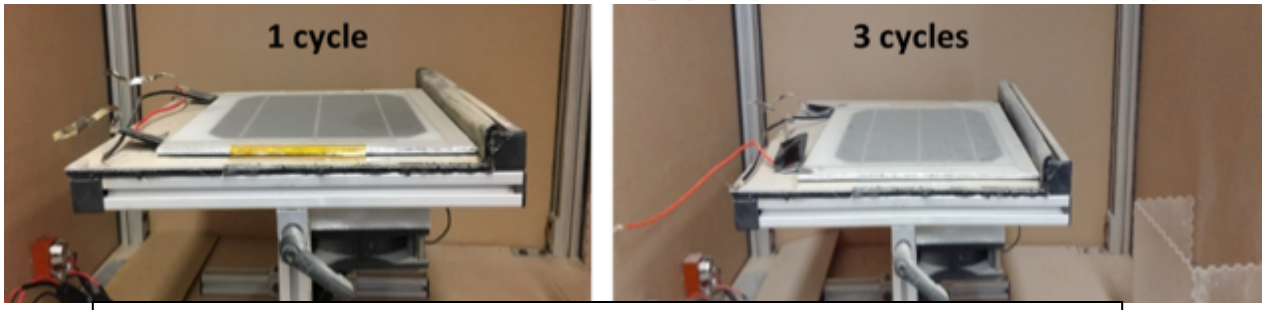
Humidity and temperature controlled to mimic daily dew and heat cycles.

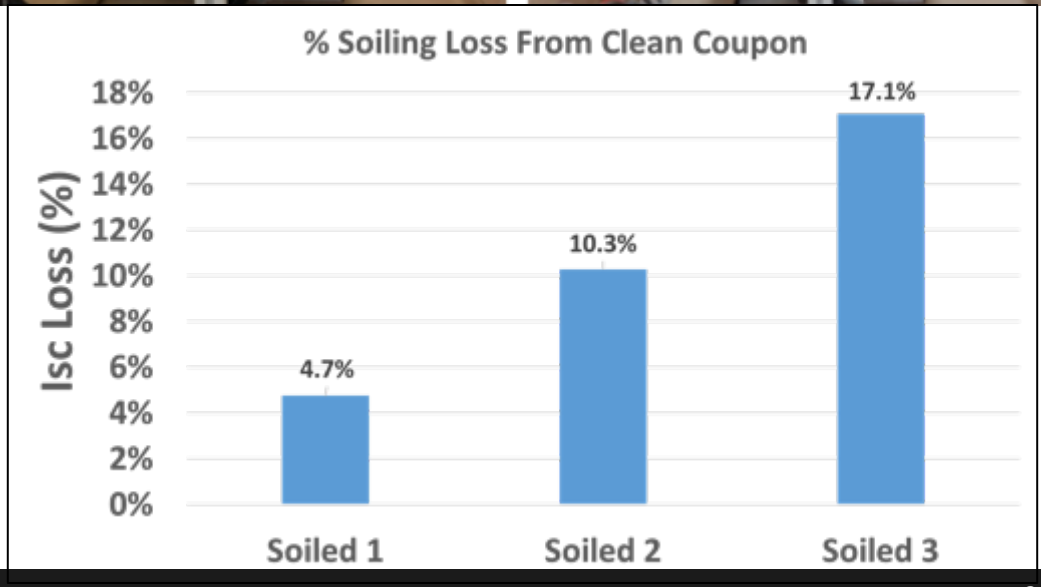
Chamber can deliver reproducible amount of dust (collected from outdoor PV panels) to produce a uniform layer with controlled thickness.

This type of system will be needed to perform accelerated tests associated with PV module coating durability and effectiveness.



Heat conduction visualization – 1 soiling cycle (total time about 5 minutes)





NREL/SNL/BNL PV Module Reliability Workshop

Thursday morning discussions:

Motivating quality: Seeing that someone has won an award for being the best supplier or given recognition for some other reason can be attractive to customers. Could we use this as a way to motivate companies to improve?

Warranties: Read the warranty terms carefully and make sure to follow all of the preventative maintenance for inverters, or the warranty may be voided.

Strings: Why are strings becoming dysfunctional? (More than one study at the workshop reported that energy loss from a system is greater because of whole strings stopping their performance than because of individual modules)

- It has been observed that blown fuses can cause 2% energy loss over the year.
- For new plants, strings are likely to be out because the modules weren't connected properly during construction or because of a broken module. Fuse failures can be 40%-50% of string failures. The fuses may fail when the irradiance spikes because of reflections from nearby clouds, sometimes reaching 1500 W/m^2. Or, they may fail for other reasons. Understanding why the fuses are failing might help to reduce these losses.

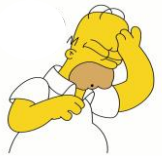
Soiling:

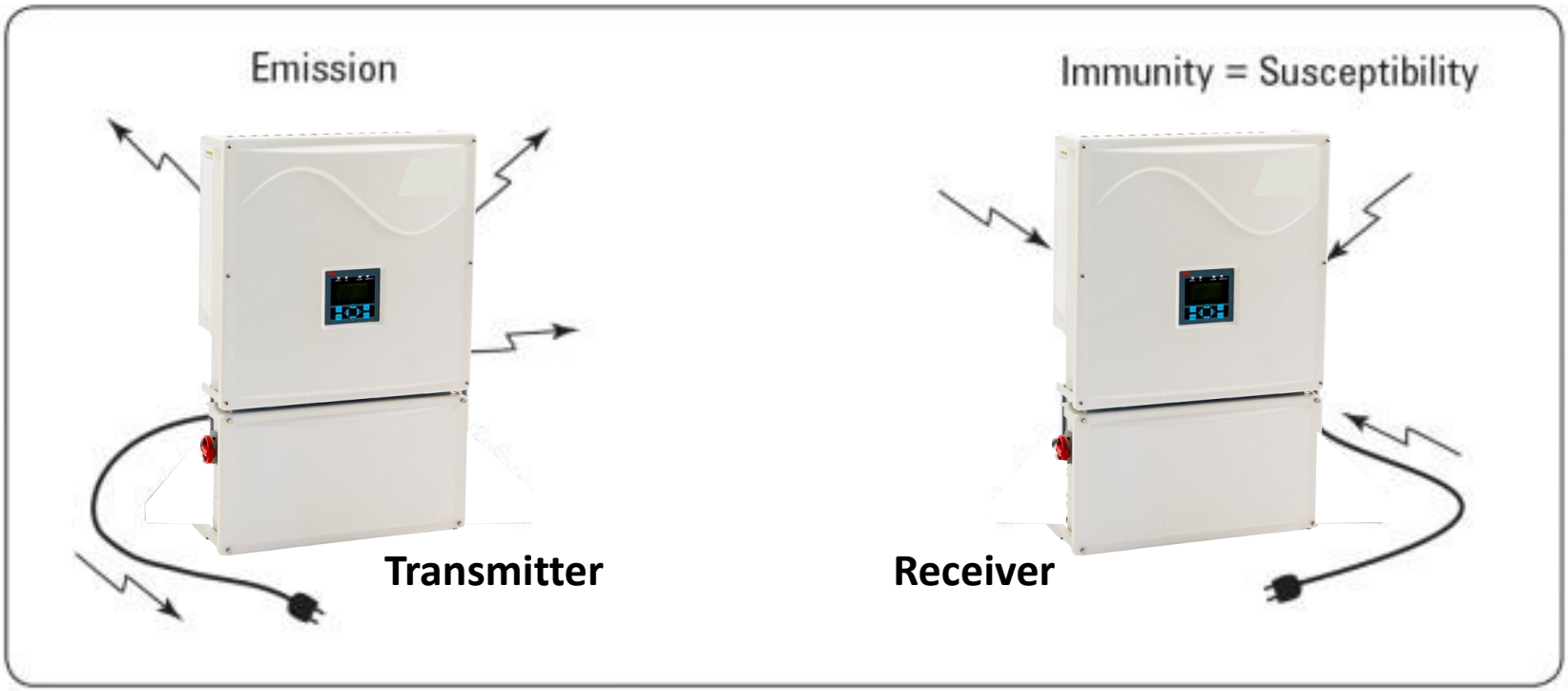
- Would like to understand the extent that cementation will affect the energy loss.
- Would like a standard for how to artificially soil things. There are several tests that have been developed, but they aren't aligned.
- Would like to understand how anti-soiling surfaces are affected by cleaning.

Electromagnetic Interference (EMI) & its Role in Inverter Reliability

(or lack thereof)

(EMI - the forgotten parameter)





Radiated & Conducted Disturbances

Reliability
[ri-lahy-*uh*-**bil**-i-tee]

noun

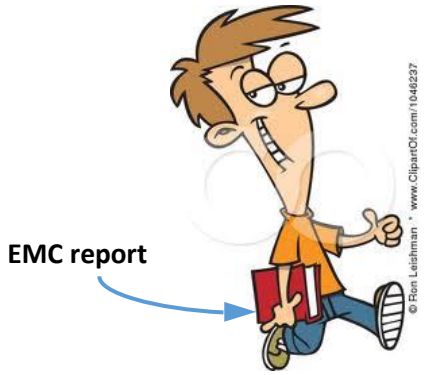
1. the ability of a product or a system to perform as intended (i.e., without failure and within specified performance limits) for a specified time, in its life cycle conditions. *

GOALS for Inverter manufacturers:

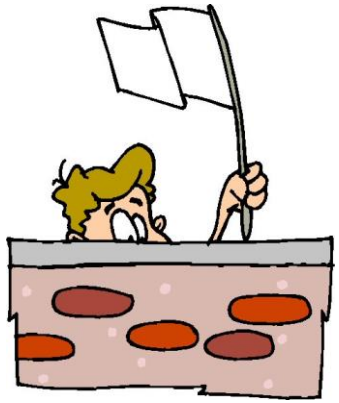
- ✓ Continue to remain Functionally operational
- ✓ Continue to remain compliant to Efficiency specs
- ✓ Continue to remain safe
- ✓ Continue to remain electromagnetically compatible

EMC Past ≠ EMC Present

The fact that one example of a product in serial manufacturing passed an EMC test once upon a time proves absolutely nothing about whether the units being made or sold today would pass that EMC test unless the manufacturer has adequate EMC procedures methods embedded in his QA program.



Past



Present

EU Market Surveillance Authorities assessed 55 micro inverters & optimizers between January and June **2014**.

Only **9%** were assessed as compliant.

Table 1: Number and origin of products		
Country of origin	**Number of evaluated solar panel inverters**	**Level of compliance of assessed administrative and technical requirements during the campaign: number (%)**
China / Taiwan *	19	0 (0 %)
EU / Switzerland	32	5 (16 %)
Other countries**	3	0 (0 %)
Unknown	1	0 (0 %)
All origins	**55**	**5 (9 %)**

* Three products from Taiwan
** One from Israel, and two products from Thailand

54 EUT were assessed for emissions:

67% were found not compliant!

EMC ADMINISTRATIVE CO-OPERATION WORKING GROUP 6th EMC Market Surveillance Campaign 2014
REPORT ON THE 6TH JOINT CROSS-BORDER EMC MARKET SURVEILLANCE CAMPAIGN (2014) SOLAR PANEL INVERTERS (Grid-connected PV inverters and optimisers intended to be used by consumers)

EMI problems with Smart Meters

Some US utility customers have experienced EMI problems with some meters involving high-frequency, low-power radiated emissions from the meters interfering with consumer electronic equipment.

receiver

transmitter

Utilities in Germany, Italy, Sweden and The Netherlands have also reported conducted emissions below 200 kHz from photovoltaic (PV) inverters which caused accuracy problems with the meters installed on the facilities where the PV systems were in use.

transmitter

receiver

Most smart meter companies do not claim compliance to FCC Part 15 nor claim compliance to the EMC directive, despite marking their device with the CE marking.

(Taken from: "Meshing Power Quality and Electromagnetic Compatibility for Tomorrow's Smart Grid", Philip F. Keebler, Energy Utilization – Power Delivery Sector, Electric Power Research Institute (EPRI), pkeebler@epri.com, in IEEE Electromagnetic Compatibility Magazine – Volume 1 – Quarter 2, 2012, http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6244982.)

C 272/30 EN Official Journal of the European Union 26.7.2016

7. ensure that procedures are in place for series production to remain in conformity.

Changes in product design or characteristics and changes in the harmonised standards or in other technical specifications by reference to which conformity of a product is declared must be adequately taken into account.

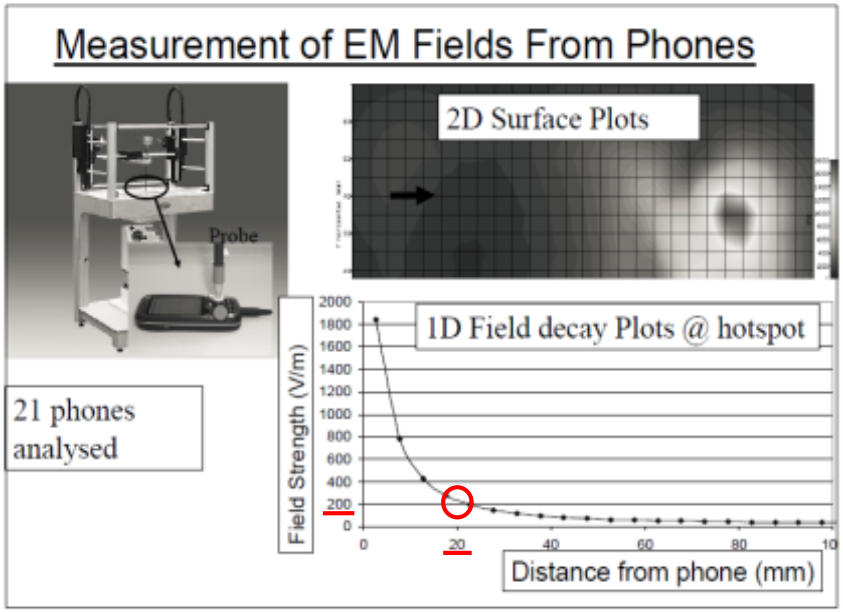
The kind of action to be taken by the manufacturer depends on the nature of changes in the harmonised standards or other technical specifications, in particular whether these changes are material with regard to the coverage of the essential or other legal requirements and whether they concern the product in question. This might require for instance to update the EU Declaration of conformity, change the product design, contact the notified body (109), etc.;

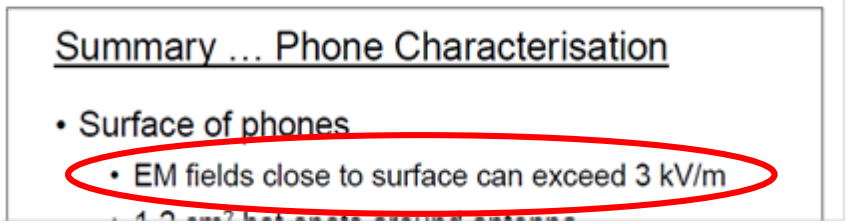
FCC CFR 47 part 2, subpart J states:

§2.1073 Responsibilities.

(a) The responsible party, as defined in §2.909, must warrant that each unit of equipment marketed under a Declaration of Conformity is ***identical to the unit tested*** *and found acceptable with the standards and that the records maintained by the responsible party* ***continue to reflect the equipment being produced*** *under the Declaration of Conformity within the variation that can be expected due to quantity production and testing on a statistical basis.*

Ford Motor Company and Schwarzbeck investigated cell phone EMI & found surprising results.





Immunity Tests Do Not Simulate Real Life Exposure

EMC test methods are designed for accuracy, repeatability, and low cost - and may not simulate real life very well.

For example: most radiated EM field immunity testing is done in anechoic chambers that create an environment unlike every real-life situation.

In real life there will be one or more surfaces reflecting EM fields onto the equipment from a variety of angles.

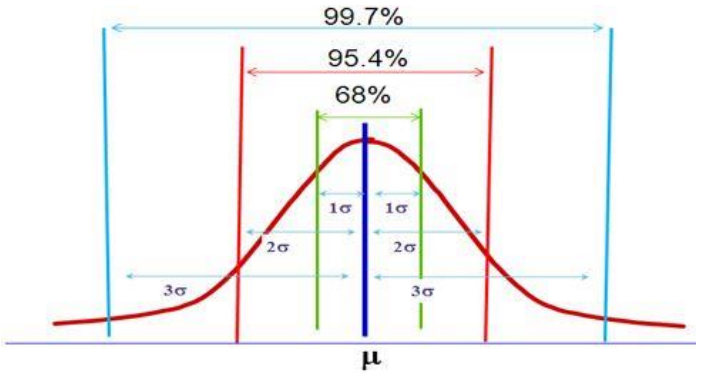
Each type of EM disturbance phenomenon varies according to some statistical parameters.

So where to set the pass/fail **level** for an immunity test, within this statistical variation??

This level is known as the **‘Compatibility Level**', and it is often set at the **two-sigma** level.

This level means that **95%** of the population of events of this type of disturbance can be expected to fall below the test level. But it means that **5%** of disturbances can be expected to be higher than the test level.

Therefore, a one-in-twenty chance of malfunction or failure upon exposure to some EM disturbances could be unacceptable where there could be safety implications or assessing performance/reliability in the field.



SIMULTANEOUS EM DISTURBANCES

In many cases, only one of the multiple EM disturbances "uses up" most of the noise margin in a digital system, so that when a simultaneous disturbance occurs (even a very low level), it can cause a malfunction.

Michel Mardiguian, RF industry expert has shown that when one EM disturbance is applied (e.g. a radiated RF field) the immunity of the equipment to another disturbance (e.g. fast transient bursts) can be seriously compromised.

In his conclusions he stated: *"Speculating that all the worst EMI threats will appear at the same time on a given system would be extravagant. But relying on the belief that certain EMI combinations will never exist could be just as imprudent.*

Why EMC Immunity Testing Is Inadequate For Functional Safety – Keith Armstrong

Michel Mardiguian (author of 'Controlling Radiated Emissions by Design)

Inductors suffer ‘inductance variations’ due to current and temperature which will alter the characteristics of the filter the inductor is used in, affecting the emissions and immunity of the equipment.

An real-life example is a variable-speed motor drive tested for emissions to IEC 61800-3, at **25 °C** and 230Vrms with a light load on the motor.

When retested at **40°C**, 252 Vrms (i.e. 10%) and full load – all within the filter’s maximum ratings, the emissions from the variable speed drive were measured to be **20dB higher**.

Why EMC Immunity Testing Is Inadequate For Functional Safety – Keith Armstrong

Safety testing traditionally considers foreseeable faults (e.g. shorted or open circuited components) to check that the equipment remains safe (e.g. "single fault safety").

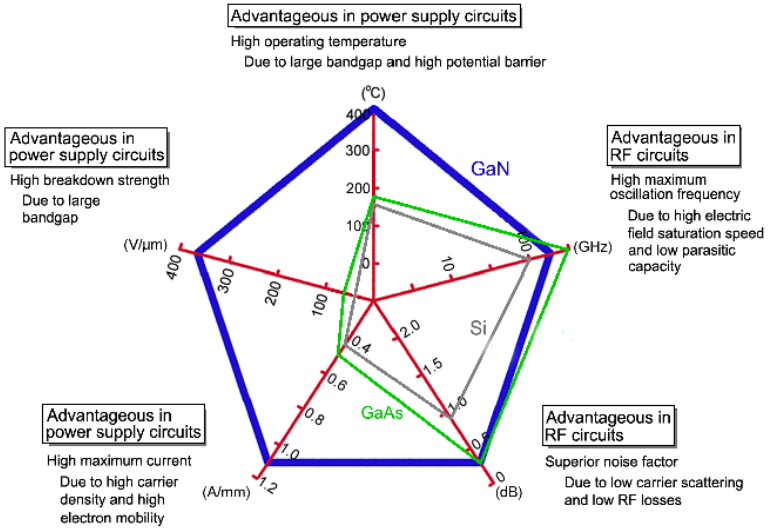
But, as far as we know, no one has ever done EMC immunity testing in a similar way - retesting the EM performance after simulating each foreseeable fault in turn.

And if they tried, their EMC Test Plan would become totally cost prohibitive and impractical.

Why EMC Immunity Testing Is
Inadequate For Functional Safety – Keith Armstrong

In the near future, switching power converters will operate at frequencies 10 to 100 times faster due to the use of Silicon Carbide or Gallium Nitride devices, making them noisier at much higher frequencies.

They will also become significantly smaller in size, cost less, and dissipate less heat, which will considerably increase their use in many applications, including all types of domestic appliances.

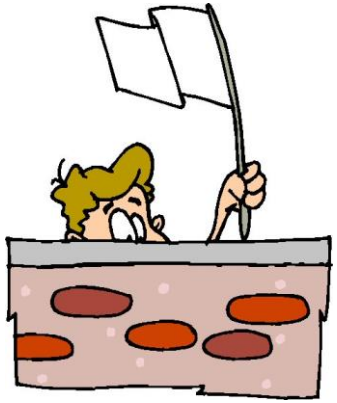


Why Do We Need an IEEE EMC Standard on Managing Risks?
By Keith Armstrong

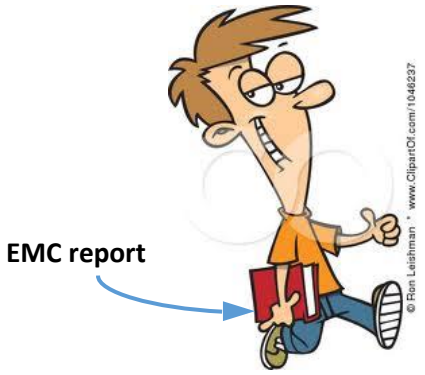
EMC Present = EMC Future

A QA program should involve at least the following:

1. Design to reduce the large variabilities that can occur in EMC performance in serial manufacture due to different components, assembly, or wiring practices to manageable proportions.
2. Control of all changes, production concessions, variants, software bug fixes and upgrades, to ensure that they don't compromise EMC performance.
3. Sample based EMC testing in manufacturing.



Present



Future

IEC 62093: Proposed Approach to Testing Inverters

2017 NREL/SNL/BNL PV System Reliability Workshop

Paul Sochor (TUV Rheinland) and Paul Parker (Sunpower)

March 2, 2017

TÜVRheinland®
Precisely Right.

Outline

- Introduction
- Causes for PV Inverter Failures
- Examples of Premature Failures and Failure Mechanisms
- Concept for IEC 62093 Ed.2
- Discussions

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Introduction

Reliability of PV Inverters

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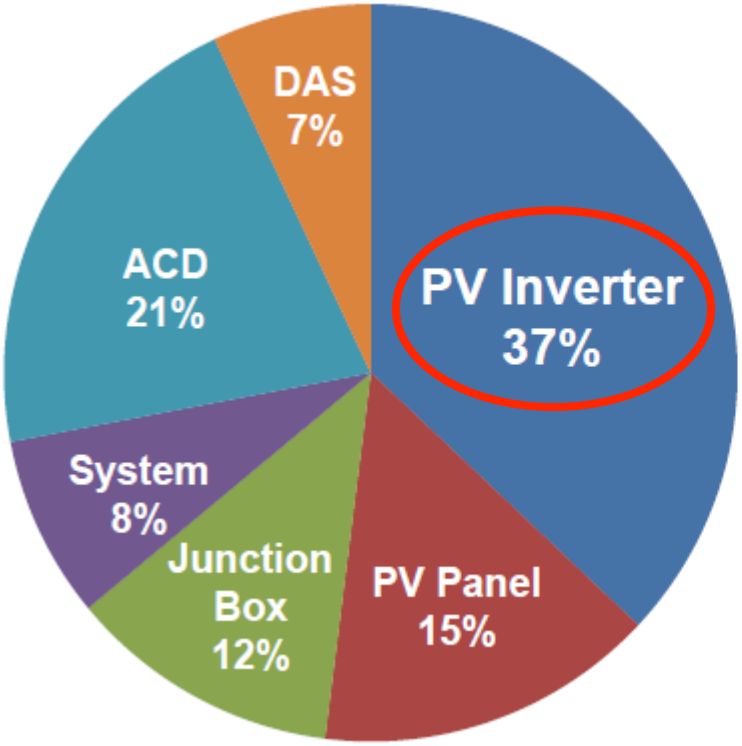
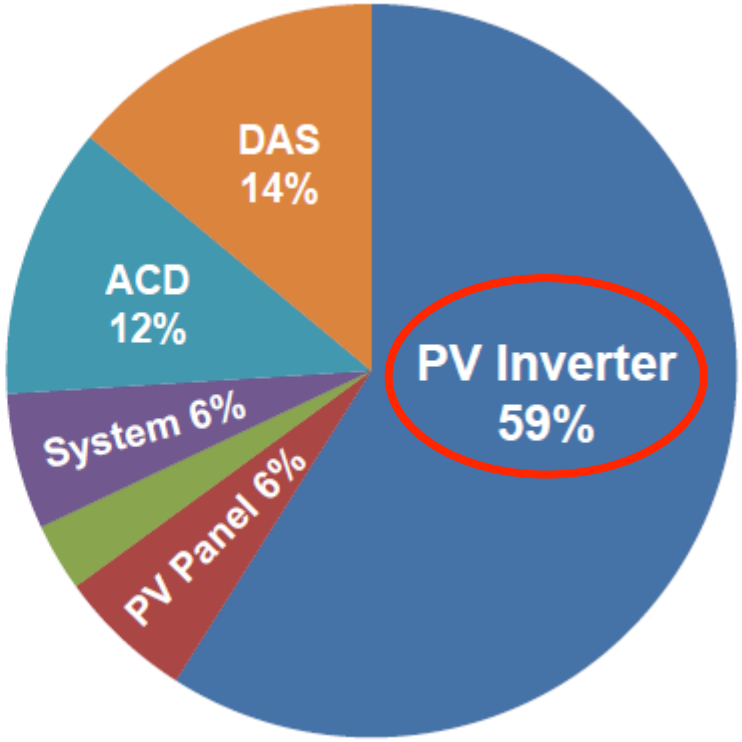
Prevalence of PV System Failures

Utility-scale PV systems with < 5 years of operation



Unscheduled maintenance events



Unscheduled maintenance costs

Sources: Moore, L. M. and H. N. Post, "Five years of operating experience at a large, utility-scale photovoltaic generating plant," Progress in Photovoltaics: Research and Applications 16(3): 249-259, 2008
"Reliability of Power Electronic Systems", Industrial Seminar, F. Blaabjerg, F. Iannuzzo, K. Ma, *IEEE APEC Tutorials, March 2016*

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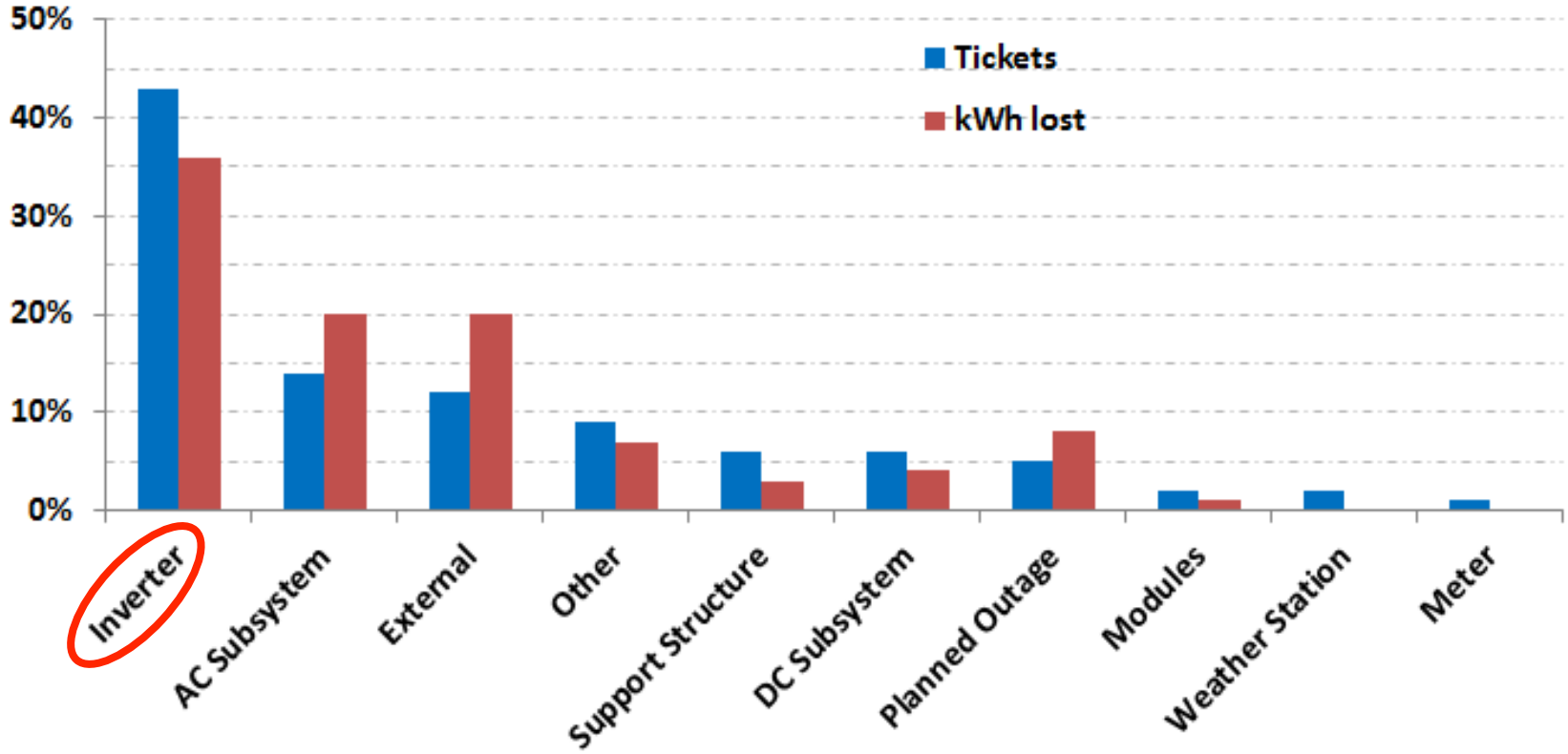
Prevalence of PV Inverter Failures

Fleet of utility-scale PV systems < 5 years of operation



Early stage PV inverter failures are common problem in PV systems

Source: Golnas, A., "PV System Reliability: An Operator's Perspective," *Photovoltaics, IEEE Journal of* , vol.3, no.1, pp.416,421, Jan. 2013

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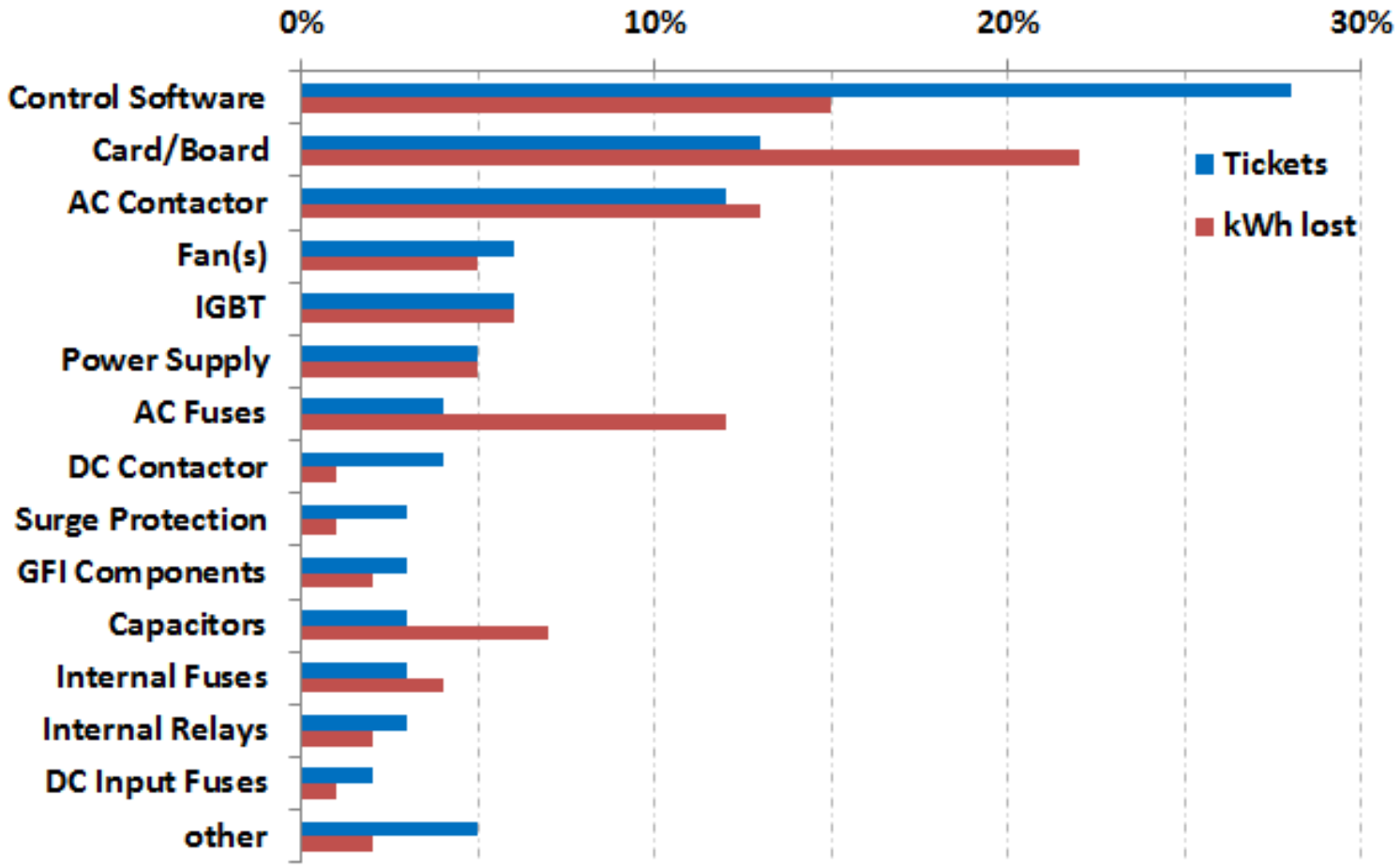
A Closer Look at Reported PV Inverter Issues



Source: Golnas, A., "PV System Reliability: An Operator's Perspective," *Photovoltaics, IEEE Journal of* , vol.3, no.1, pp.416,421, Jan. 2013

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Causes for Inverter Failures

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Causes for Inverter Failures

Major Causes for Failures	Contributing Factors
▪ Design Flaws (design mistakes, insufficient hardware margins, software bugs etc.)	Insufficient design experience Little time invested for testing/debugging
▪ Faulty Components (unproven component technology, high failure rates, large parameter spread)	Process- /Quality-Control at supplier Quality-Control/ vender selection at manufacturer side
▪ Manufacturing Flaws (assembly, soldering, wiring etc.)	Factory-internal process-/ quality control Yield Management
▪ Environmental and Operational Stress (lightning strike, grid transients, hot/cold/humid environment)	Insufficient design durability Unaccounted stresses and stress levels

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PV Power Electronic Converters

"Conventional" Power Electronic Converters (e.g. motor drives)

Typ. Indoor Installation
Controlled Environment

PV Inverter

Outdoor Installation
Harsh Environment

High Environmental and Operational Stress

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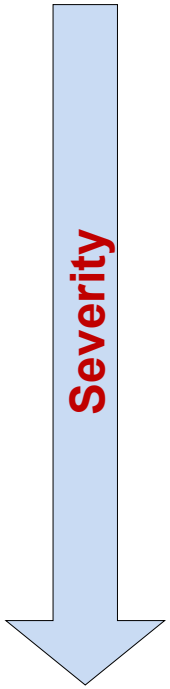
Types PV Inverter Failures



Types of Failures:	Impact	Examples
▪ Soft Failures (due to software bugs)	Operational, but reduced yield	Unexplained shutdowns and restarts, software bugs
▪ Hardware Failures (safe stop, no harm to humans)	Stopped operation (repair /replacement req.)	Various component failures
▪ Safety-related Hardware Failures (with potential harm to humans)	Fire, Electric shock	Ground faults, arc faults, connectors, terminals, internal short-circuit

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Variations of PV Power Conversion Equipment

	Module-Level Power Electronics (MLPE)	String Inverter	Central Inverter
Power Range	< 1 kW	1 kW – 100 kW	> 100 kW
Electrical Output	1-φ AC / or DC	1-φ AC or 3-φ AC	3-φ AC
Weight	< 2-3 kg	< 100 kg	> 100 kg
Installation	Module or rackmounting	Wall- or rackmounting	Free standing electrical enclosure
Examples			

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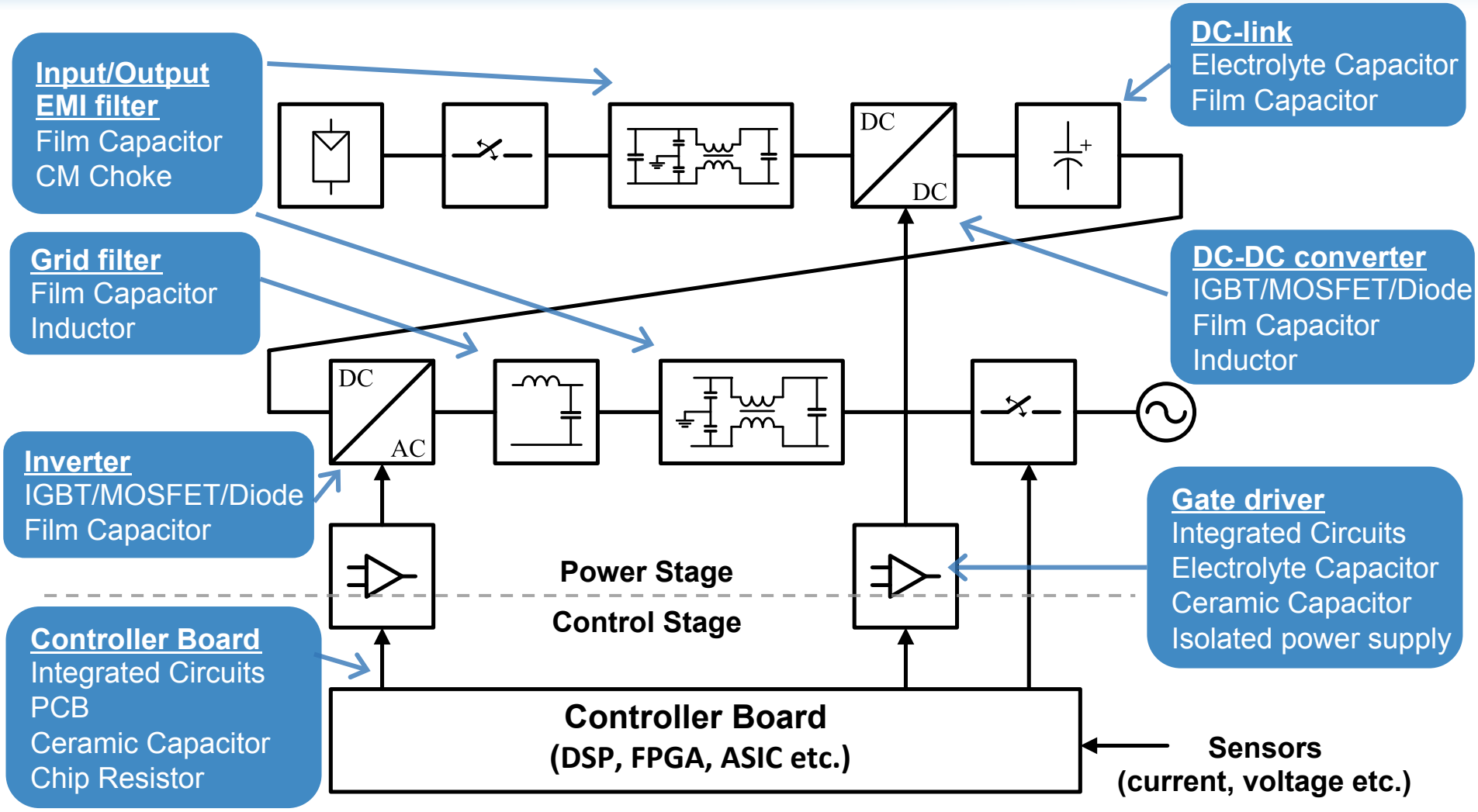
Generic Structure and Components of PV Inverter



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Critical Components

Power Stage (high voltage)	Control Stage (low voltage, low power)
▪ IGBT, MOSFET, power diode ▪ Capacitors (Electrolyte/ Film/ Ceramic, Tantalum) ▪ Magnetics ▪ PCB ▪ Contactors, relays ▪ MOVs ▪ Wires, cables, connectors, terminals	▪ Integrated circuits (ICs) (ASICs, Microcontroller, optocoupler, AD/DA, Op amp, Gate Driver, etc.) ▪ Auxiliary power circuits ▪ Capacitors (electrolyte, ceramic) ▪ Chip resistors ▪ PCB ▪ Connectors, terminals, wires

Other critical components
▪ Mechanical Enclosure ▪ Sealing, potting, adhesives etc. ▪ Cooling system (fans, etc.)

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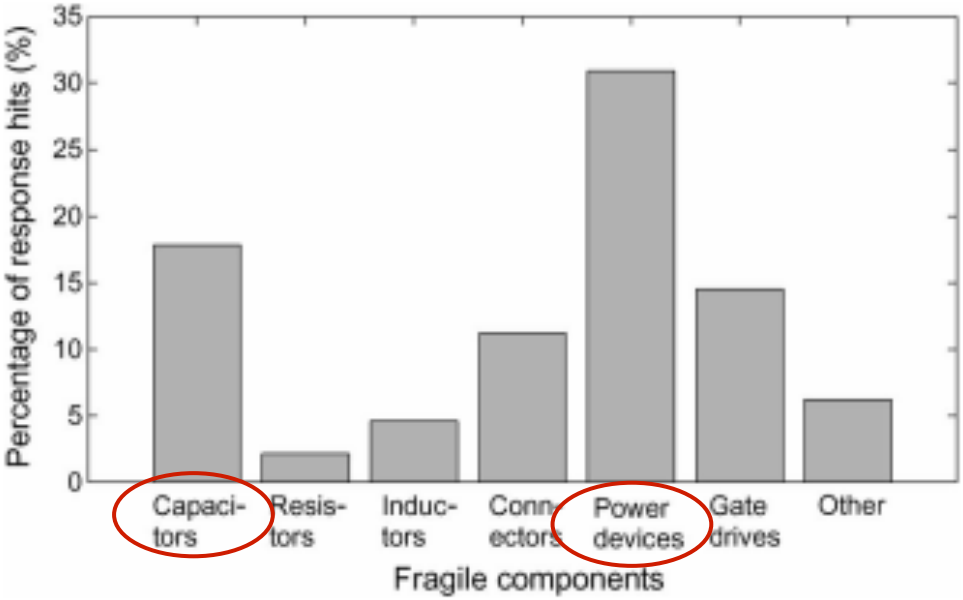
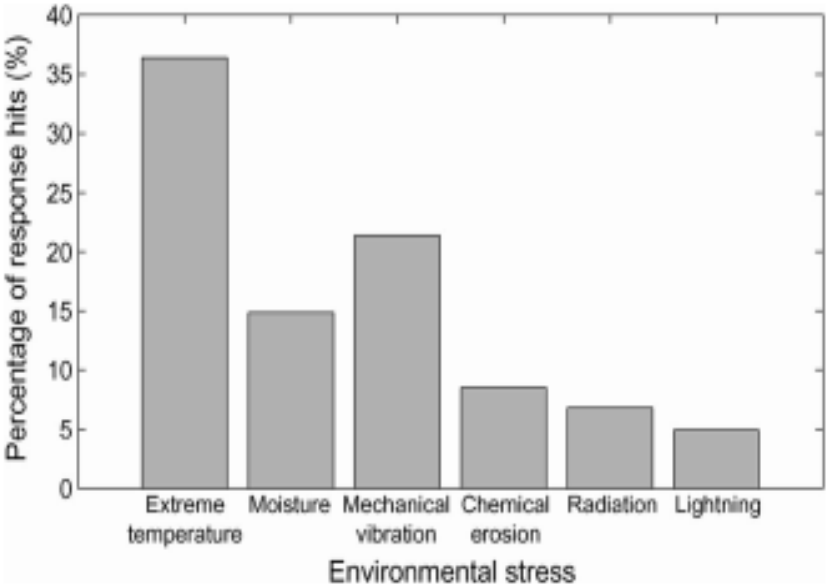
Survey on Reliability in Power Electronics

Weak Points in Power Electronic Systems



Major Stress Factors



Power Semiconductors often identified as weak point

Source: S. Yang et al. *An Industry-Based Survey of Reliability in Power Electronic Converters, IEEE Trans. Power El. VOL. 47, NO. 3, May/June 2011*

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Two Types of Component Failures

	Degradation Failure	Catastrophic Failure
Definition	Component parameters fall out of “acceptable” tolerance	Complete loss of functionality
Example (Capacitor)	Reduction in C Increase in ESR etc.	Short, Open, explosion of capacitor
Example (IGBT, MOSFET)	Change in Threshold voltage, Increase of $R_{ds,on}$, Increase in turn-off time etc.	Short, Open, Gate-oxide breakdown

May induce subsequent catastrophic failure (incl. other components)

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Root-Cause Failure Analysis

Unlike PV modules, PV inverters are highly complex systems consisting of hundreds of components

Faulty components may cause chain reactions

2 Examples

- **Heat**
- **Cold**
- **Ripple Current**

DC Capacitor

Overvoltage

IGBT Short-circuit

- **Volt. Transient**
- **Software bug**
- **etc.**

Gate Driver

Parasitic Turn-On

IGBT Short-circuit

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Examples of Premature Failures and Failure Mechanisms

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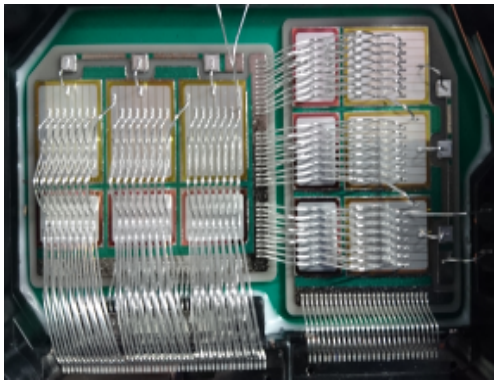
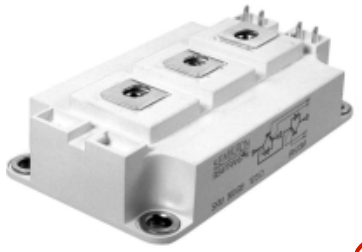
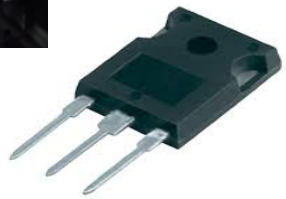
IGBT / MOSFET / Power Diode Failures

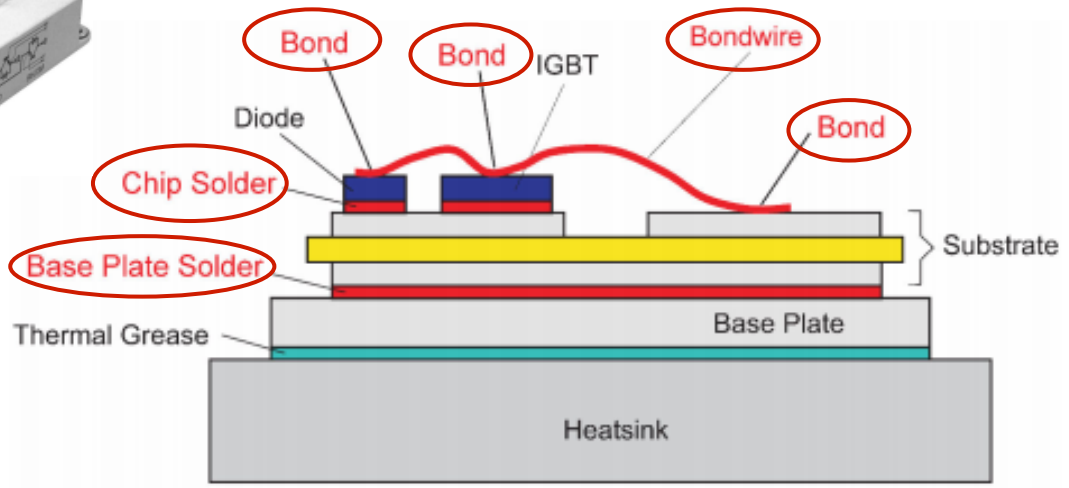
Major Failures	Major Failure Mechanisms	Major Stressors
▪ **Short** ▪ Open	▪ **bond-wire failure** ▪ **solder fatigue** (die & base plate) ▪ Gate-oxide breakdown ▪ Encapsulation failure	▪ **Temperature swing (ΔT)** ▪ **Temperature, Current** ▪ Voltage surge ▪ Mech. Stress







Affected parts:



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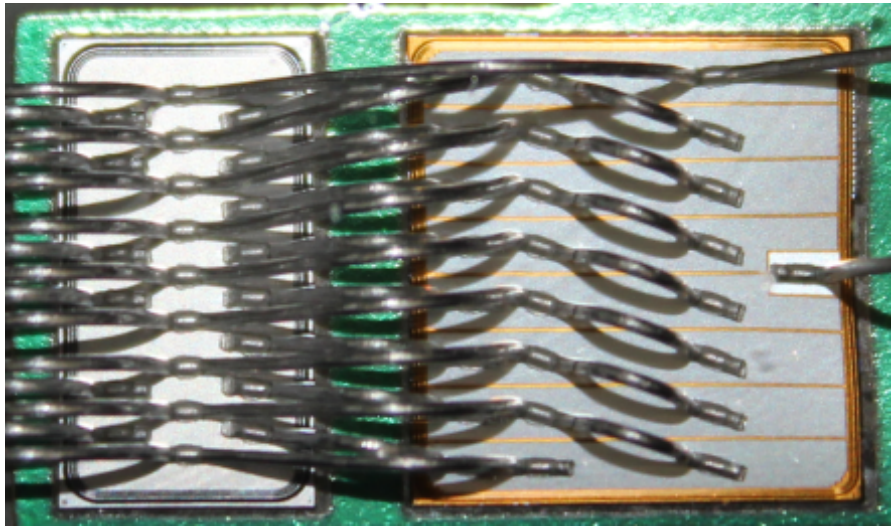
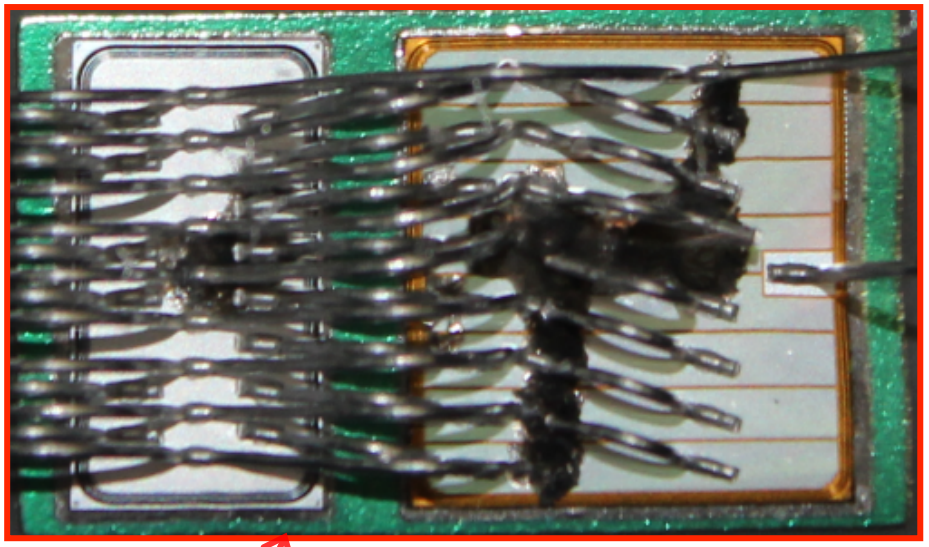
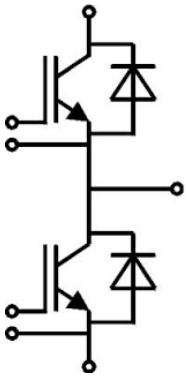
IGBT Failure Example

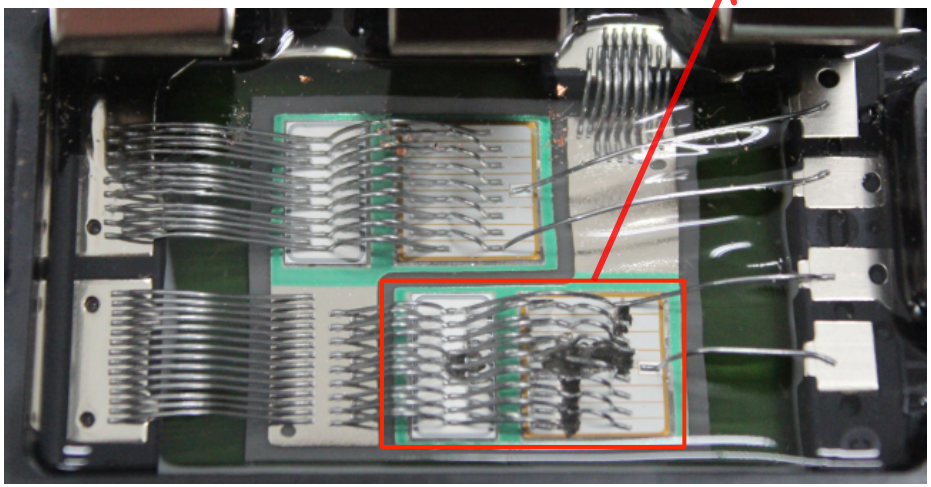


Healthy
IGBT chip



Short-circuited
IGBT chip





IGBT module
(2-in-1)

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Electrolyte Capacitors

Major Failures	Major Failure Mechanisms	Major Stressors
▪ **Open** ▪ Parameter change (C, ESR, etc.) ▪ Short	▪ Electrolyte evaporation ▪ Wire disconnect ▪ Foil damage ▪ Dielectric breakdown ▪ Corrosion	▪ **Temperature** ▪ **Over- /Reverse Voltage** ▪ **Ripple current** ▪ Moisture

Examples:

Exploded dc link capacitor

Electrolyte leakage

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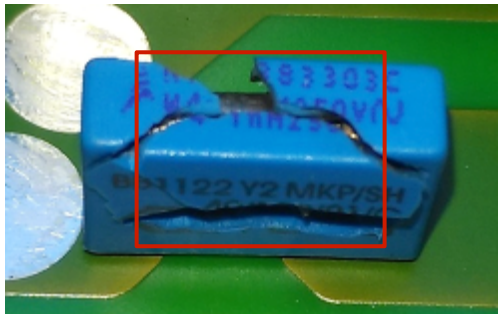
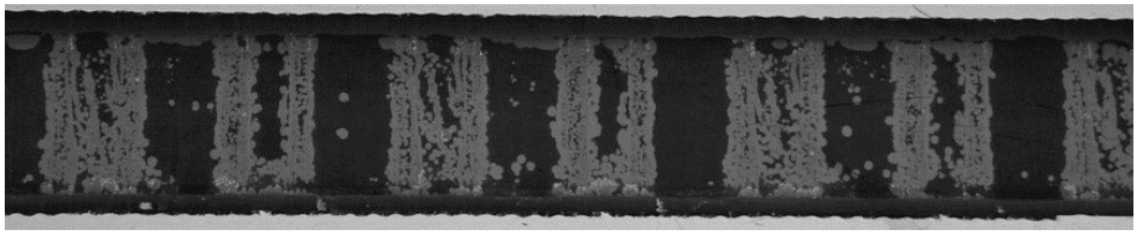
Film Capacitors

Major Failures	Failure Mechanisms	Major Stressors
▪ **Open** ▪ **Parameter change** (C drop etc.) ▪ Short	▪ Dielectric breakdown ▪ Electrode area reduction ▪ Self-heating breakdown (due to high freq. currents)	▪ High temperature ▪ Overvoltage ▪ EMI, ripple current ▪ High humidity

Examples:



EMI filter capacitor cracked after voltage surge



Metalized film corrosion

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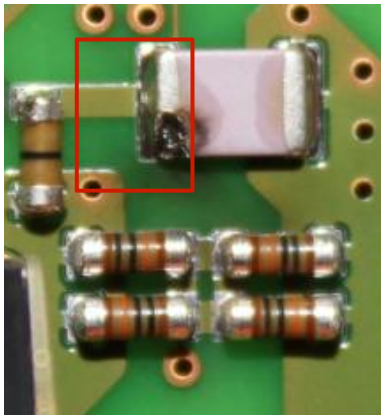
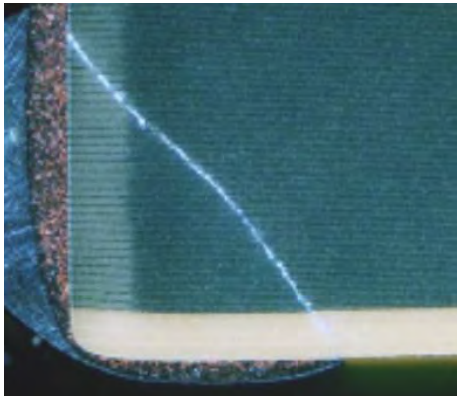
Ceramic Capacitors

Major Failures	Major Failure Mechanisms	Major Stressors
▪ **Short** ▪ Open ▪ Parametric change	▪ Ceramic cracks / body damage ▪ Electrochemical migration ▪ Dielectric breakdown / increased leakage current ▪ Oxygen Vacancy Migration	▪ Mech. Tension/Torque of PCB ▪ Moisture ▪ Contamination ▪ High Voltage ▪ Temperature and dT/dt



dielectric breakdown



typical flex crack through MLC-Cap
(source: Kemet)

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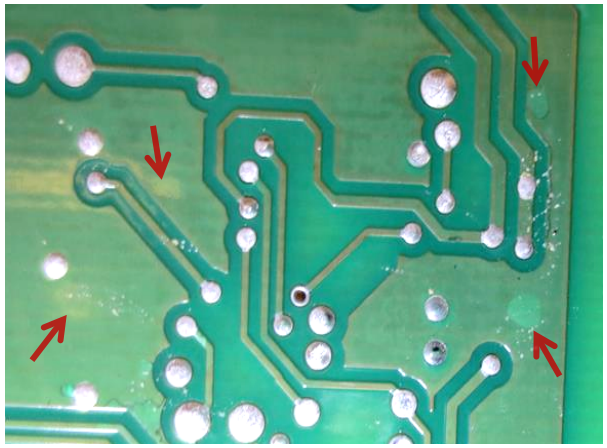
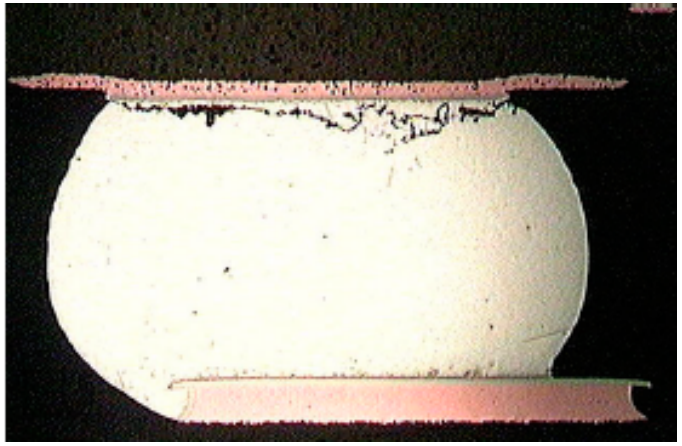
PCB and Solder Related Failures

Major Failures	Failure Mechanisms	Major Stressors
▪ Open or Shorted traces/ layers/ vias ▪ High R/ open solder contact	▪ Conductive Anodic Filament ▪ Insulation degradation ▪ Delamination ▪ Electrochemical Migration ▪ Solder fatigue /cracks	▪ **Moisture** ▪ **Contamination** ▪ Temperature, ΔT ,dT/dt ▪ High voltage ▪ Mech. stress

Examples:



Bubbles / Delamination
Trace corrosion



SMD solder cracks

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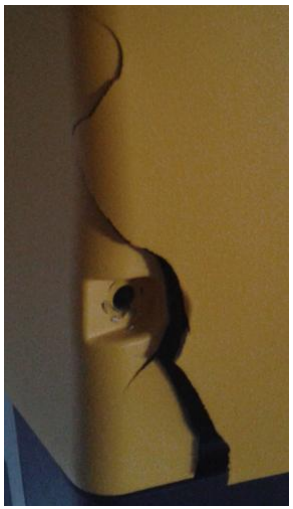
Enclosure Failures

Major Failures	Failure Mechanisms	Major Stressors
▪ Fractures/cracks ▪ Corrosion ▪ Clogged air filter	▪ Galvanic corrosion ▪ Uniform attack corrosion ▪ Corrosion of polymers (discoloration etc.)	▪ Moisture ▪ Vibration ▪ Contamination ▪ UV ▪ Thermomechanical stress



Cracked inverter enclosure

Clogged air filter

Rust on bottom side of PV inverter (installation near coast)

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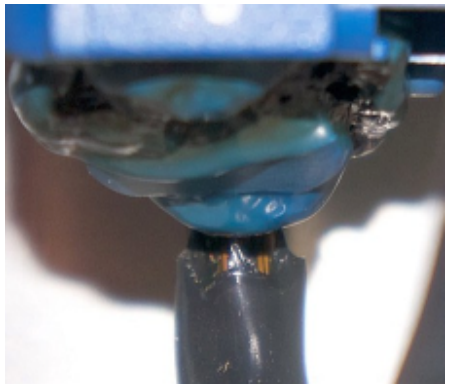
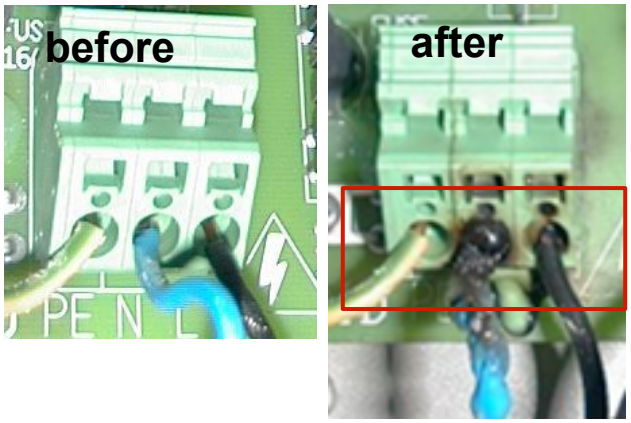
Wire, Cable, Connector and Terminal Failures

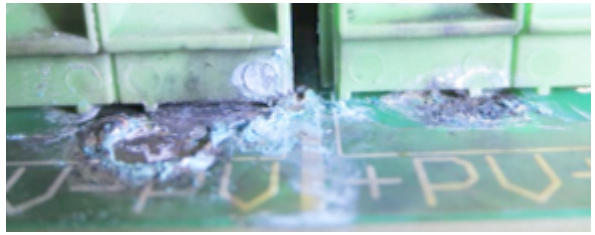
Major Failures	Failure Mechanisms	Major Stressors
▪ Short/ ground fault ▪ Open ▪ High resistance contact ▪ Insulation failure	▪ Corrosion of contact ▪ Fretting of contact ▪ Loss of torque	▪ Moisture ▪ Temperature ▪ Voltage ▪ Mech. stress /vibration



Melted contact (cable - terminal)



Burnt connector terminal



Contact corrosion due to moisture ingress caused arcing on terminal

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Concept for

IEC 62093 Edition 2 (working document)

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IEC Standards for Power Electronic Converters in PV Systems

IEC 61683 (1999) *Photovoltaic systems – Power conditioners – Procedure for measuring efficiency*

EN 50530 (2013) *Overall efficiency of grid connected photovoltaic inverters*

Efficiency

IEC 62109-1 */-2* (2010, 2011)
Safety of power converters for use in photovoltaic power systems
Part 1: General requirements
Part 2: Particular requirements for inverters

IEC 62477-1 (2012) *Safety requirements for power electronic converter systems and equipment - Part 1: General*

Safety

IEC 61727 (2004) *Photovoltaic (PV) systems – Characteristics of the utility interface*

IEC 62116 (2014) *Utility-interconnected photovoltaic inverters – Test procedure of islanding prevention measures*

Grid Connectivity

IEC 62093 Ed.1 (2005) *Balance-of-system components for photovoltaic systems - Design qualification natural environments*

Reliability

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Motivation

IEC 62093 Ed.1 (2005)

Balance-of-system components for photovoltaic systems – Design qualification natural environments

- **Focusing on BOS components (similar test sequence as IEC 61215 for PV modules)**
- **Does not specifically exclude PV inverters, but does not take into account specific failure characteristics of PV inverters**
- **Very low acceptance in industry**

Currently, no comprehensive quality testing standard for PV inverters available

Goal: Standard that helps to eliminate early stage failures of PV inverters

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Objective for IEC 62093 Ed. 2 (working document)

- **Main Objective**
  - Identify possible weak points in the design that may cause early failures
  - Establish baseline design requirements to achieve basic level of durability
  - Improve overall quality of products coming to the market.

- **Requirements**
  - Identify major failures
  - Simple and economic testing in reasonable amount of time
  - Straightforward pass/fail criteria

- **Concept**
  - Physics-of-Failure approach (as with IEC 61215 for PV modules)
  - Accelerated stress tests to induce stresses that cause certain types of failures
  - Test conditions based on inverter size and environmental category (cf. IEC 62109)

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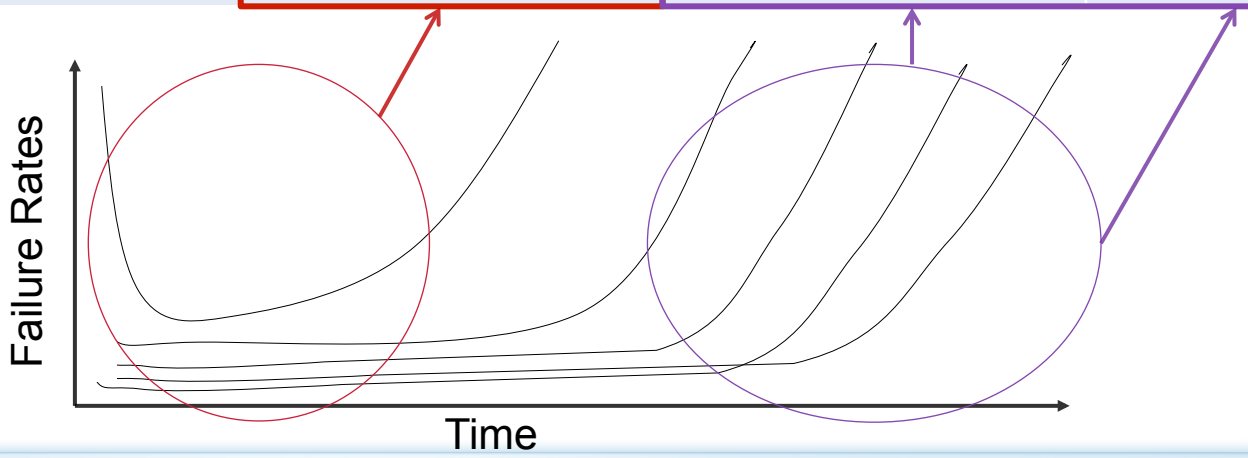
Comparison of Reliability Testing

	Qualification	Comparative	Lifetime
Purpose	Minimum Design Requirement	Comparison of Products	Substantiation of Warranty
Quantification	Pass / Fail	Relative	Absolute
Failure Modes	Early-stage	Wear out	Wear out
Climate / Application	No differentiation	Differentiated	Differentiated
Testing Cost /Time	Moderate	Moderate/ High	High



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Goals Of Qualification Testing

Not Goals

- Assessment of product lifetime
- Identify and eliminate all possible failures in all climates
- Improvement of state-of-the-art products
- Discrimination between products of short and long lifetimes
- Restricted market access to new market entrants

Goals

- Assessment applying baseline quality requirements
- High reliability of identifying and eliminating major early failures
- Improvement of overall quality of products entering the market
- Simple, but strict pass/fail criteria
- Economic testing in reasonable amount of time
- Achieve wide acceptance in the industry

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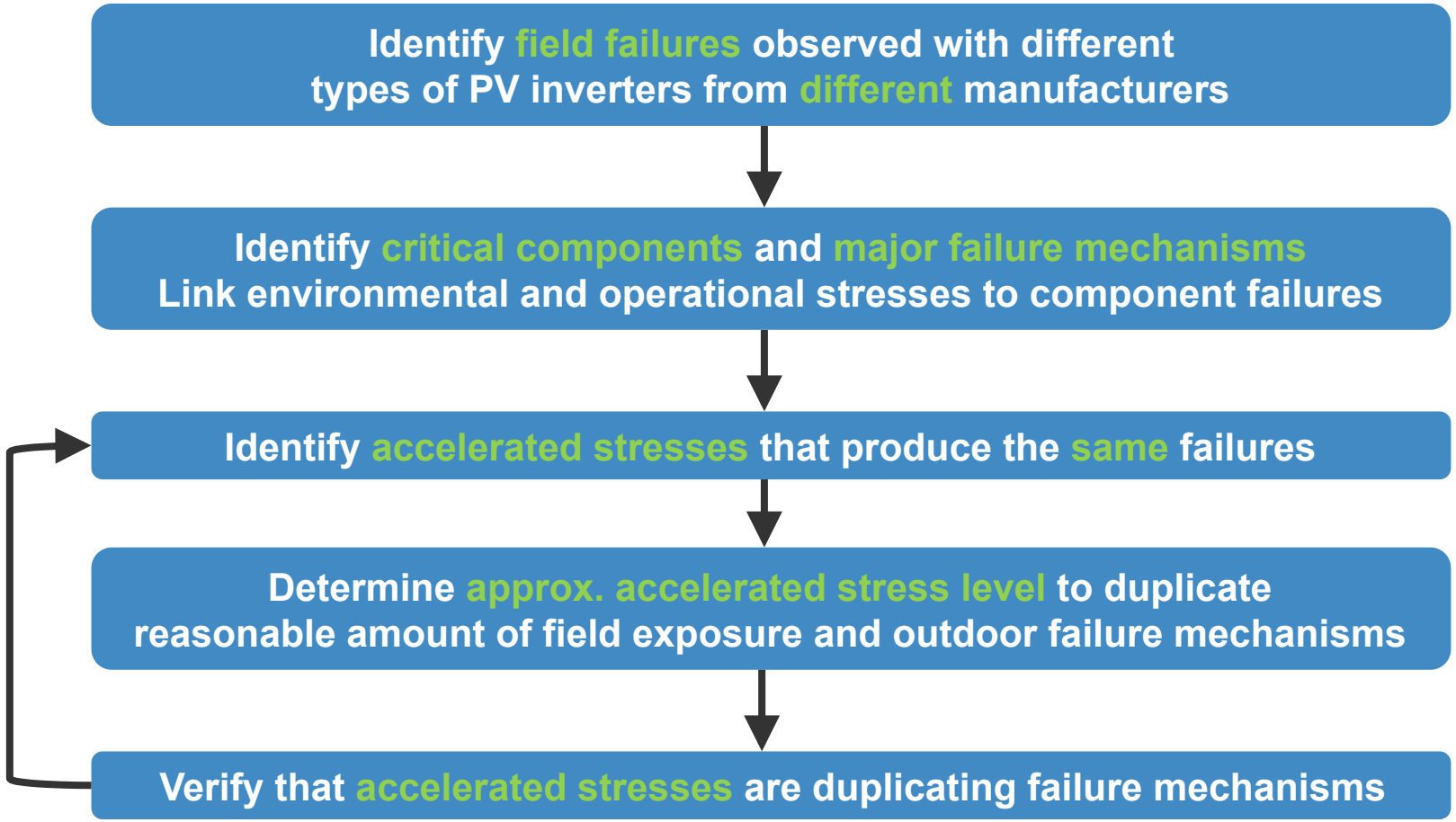
Approach for Development of Qualification Standard

Physics-of-Failure Approach



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IEC 62093 Ed.2 (draft): Test Overview

Category	Test Name	Purpose
Verification Tests	Visual Inspection	Identification of visual defects
	Insulation Test	Identification of insulation problems
	Functionality Test	Verification of functionality
Environmental Stress Tests	Thermal Cycling	Thermomechanical stress
	Powered Dry Heat	Thermal stress
	Damp Heat	Humidity and electrostatic stress
	Humidity Freeze	Humidity and mechanical stress
	Rain Intrusion / Wind-driven Rain	Water intrusion
Optional Stress Tests	Salt Mist	Galvanic corrosion
	Dust and Sand	Ingress of sand/ dust
	Vibration / Shock	Dynamic mechanical stress (transportation)
	Mixed gas/ ammonia corrosion	Chemical corrosion

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Differentiation of PCE Test Requirements

Unlike PV modules, PCE (Power Conversion Equipment, ref. IEC 62109-1) may have highly diverse hardware designs → **Differentiation Required**

Based on size/ power rating		Based on environmental service use:
▪ **Category I:MLPE** (micro-inverter, module level dc-dc converter) ▪ **Category II: string level power electronics** (wall-, or rack-mounted) ▪ **Category III: large-scale power electronics** (free standing electrical enclosures)	×	▪ **Indoor, conditioned** **(climatic class 3K2, IEC 60712-3-3)** ▪ **Indoor, unconditioned** **(climatic class 3K3, IEC 60712-3-3)** ▪ **Outdoor** **(climatic class 4K6, IEC 60712-3-4)** (based on classification in IEC 62109-1)

3x3 Test Matrix

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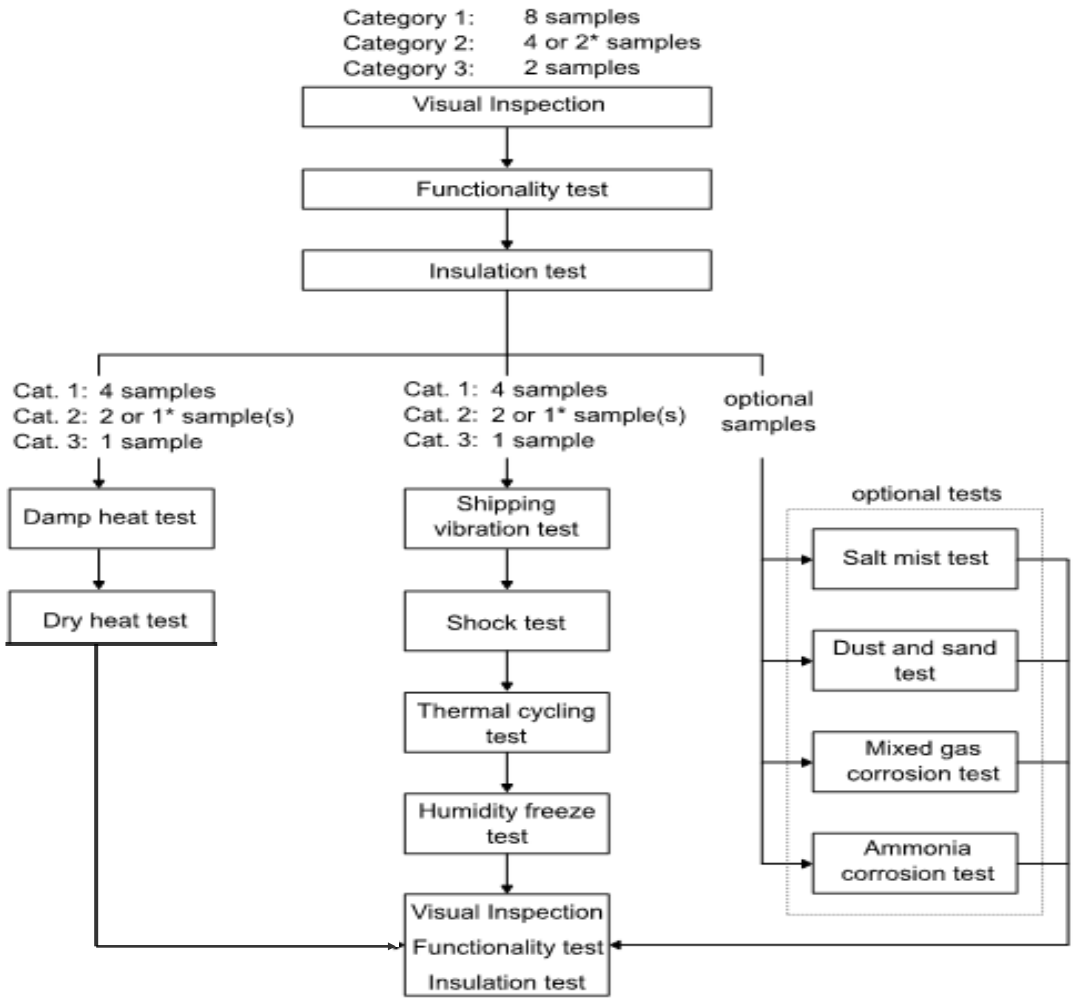
Sampling Plan / Test Sequence



* reduced sample requirement for large cat. 2 PCE (> 50 kVA)

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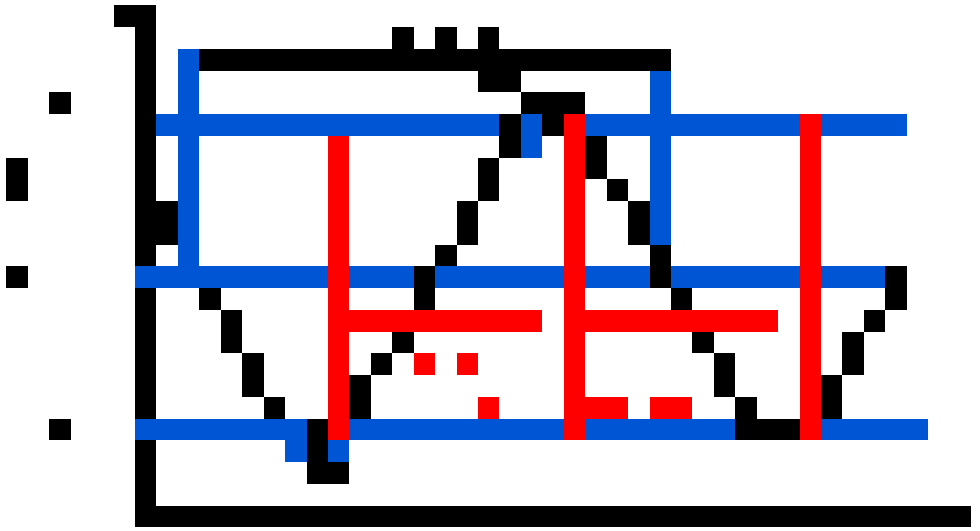
Thermal Cycling

- Ambient temperature cycling under partially powered conditions
- Start-up at low temperatures
- e.g. -40°C to -85°C, 400 cycles



Exemplary Failure	Affected Components
Bond-wire / die attach solder fatigue	IGBT, MOSFET, ICs
Solder joint cracks	PBC mounted devices
Vias	PCB

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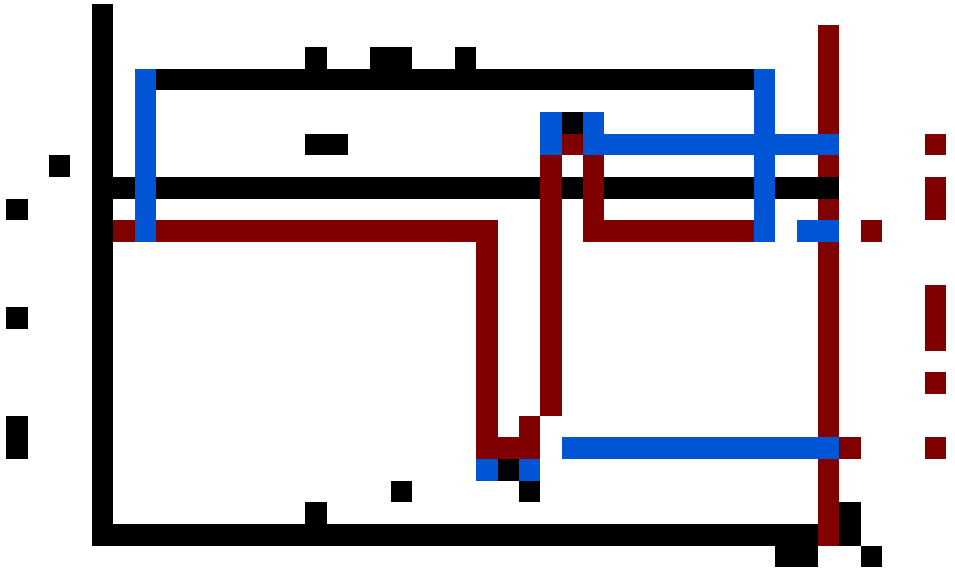
Powered Dry Heat Test

Constant power operation at elevated ambient temperature
With hourly cyclic restarts

Eg. 1000 hrs. at 60°C



Exemplary Failure	Affected Components
Dielectric breakdown	Semiconductors, capacitors
Electromigration	PCBs
Electrolyte evaporation	E-Caps

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Damp Heat Test

High Temperature, High Humidity
Applied Voltage to dc and ac terminals
(very low power operation)

Eg. 1000 hrs. at 65°C/ 85% RH

Exemplary Failure	Affected Components
Corrosion	PCB, PCB-mounted devices, Film Capacitors
Galvanic Corrosion	Metallic enclosure, wires, terminals
Electrochemical Migration	PCB / Components with high E Field
Insulation degradation	Wires, cables, magnetics

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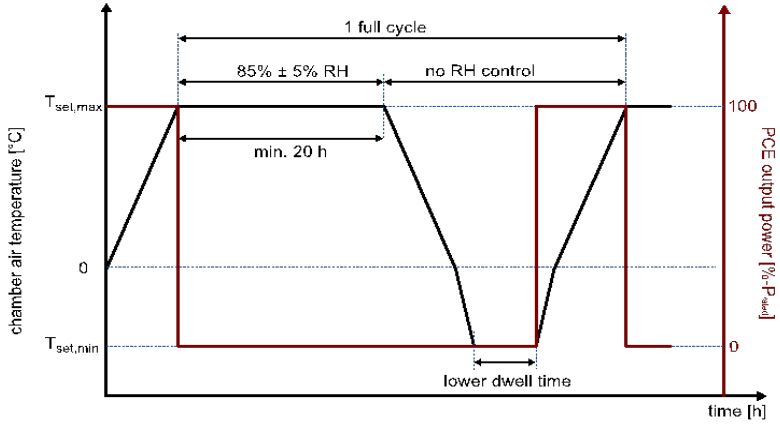
Humidity Freeze Test

Combined elevated temperature and high humidity followed by a freeze cycle.

Eg. 10 cycles. -40°C to -85°C/85% RH



Exemplary Failure	Affected Components
Fractures, Cracks	Mechanical enclosure electronic components
Galvanic Corrosion	Mechanical enclosure, terminals, screws etc.
Condensation related failures (insulation, sealing, passivation etc.)	electric and electronic components

TÜVRheinland®
Precisely Right.

Rain Intrusion / Wind-Driven Rain Test

Objective

To ensure that enclosure of inverter is capable of preventing water running into interior of enclosure following and during heavy rain storm and after opening of doors.
Main focus are large Cat.3 inverters.

Tests req. only for outdoor PCE with < IP65 rating

Rain Intrusion Test	Wind-Driven Rain Test
• 1 h of perpendicular water spray • 15 min of water spray at 45deg tilt from each side	• 30 min of rainfall exposure per side (at 15cm/h rainfall rate and 31 m/s wind velocity)
Test in laboratory environment	Test in laboratory environment

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Precisely Right.

Verification Tests

- **Visual Inspection**
  Set of visual requirements to pass
  - Cracks/ dents / corrosion in enclosure
  - Damaged wires
  - Failure of adhesives
  …

- **Functionality Test**
  Test of basic inverter functionality at different operating points

  Note: Pass/fail criteria should be based on functionality and not efficiency

- **Insulation Test**
  To ensure basic insulation requirements after environmental stress tests
  Apply IEC62109-1:2010 clause 7.5.2 / IEC62477-1:2012 clause 5.2.3.4

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Other Failures

Some types of failures are not (fully) covered, some examples:

Software bugs

- Random tripping of protection circuitry
- Communication equipment
- PCE not drawing power as it should, MPPT related issues

Grid-related failures:

- Voltage transients on grid side, lightning strike etc.
- “Dirty” grid/ high harmonic content, high grid impedance etc.
- Repeated low-voltage-ride through

Difficult to cover by standard

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General Discussions

- **Testing profile suitable to detect dominant failures of each PCE category?**
- **Test severities sufficient for each PCE category?**
- **Periodic retest to identify changes to design, component, process**
- **Include cyclic on-off period during Damp Heat test**
  PCE is operated at very low power (< 10% P_{rated})
  - **Long on-period, short off-period (e.g. 3hrs. on, 10 min. off)**
  - **Short off-period, long on-period (e.g. 3 hrs. off, 1 hrs. on)**
- **Modify Humidity Freeze to include Humidity Condensation**
- **Handling of Temperature Cycling Test with large central inverters**
  large thermal mass (>1000kg), long cycling times, possibly long testing times

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Specific Discussion Topics

- **Handling of Temperature Cycling Test with large central inverters**
  large thermal mass (>1000kg), long cycling times, possibly long testing times

Suggestions:

Test in disassembled state	Test as a whole
▪ Faster, cheaper ▪ Tested components: PCBs, contactors, breakers, fuses, IGBT stacks w/ capacitors ▪ Requires multiple smaller chambers ▪ Only few individual components tested ▪ May not be possible with every design ▪ Cannot detect failures exacerbated by applied voltage and current ▪ Requires separate cold start test ▪ Monitoring not possible	▪ Requires large, powerful chamber ▪ Requires large dc power supply ▪ All components experience ΔT ▪ Ramp up assisted by PCE heat dissipation ▪ Ramp down slow, speed up by opening doors, removing cover panels

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NREL
NATIONAL RENEWABLE ENERGY LABORATORY

NREL is a national laboratory of the U. S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

A Stochastic Model for PV System Reliability & Performance in SAM (PVRPM) – LIVE DEMO

Janine Freeman (NREL)
Geoffrey Klise (Sandia)

Abstract

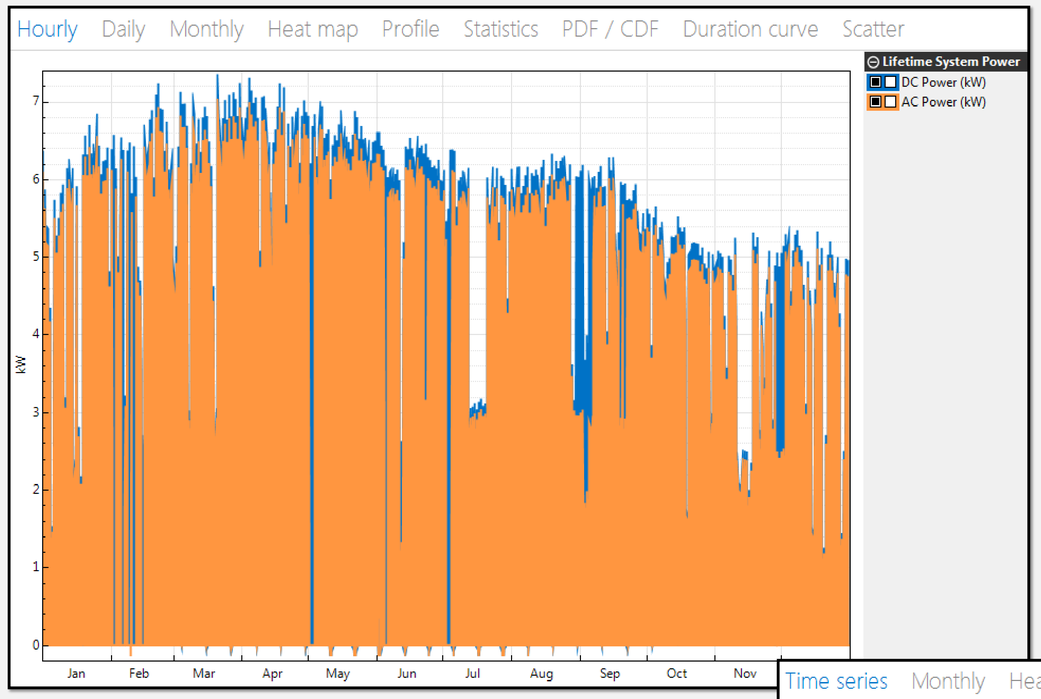
Now showcasing a newly developed Beta version of the Photovoltaic Reliability Performance Model (PVRPM) that has been implemented in the System Advisor Model (SAM). This model samples failure distributions for components in a PV system and predicts failure times, replacement costs, and performance/cost impacts for a more realistic representation of LCOE of PV systems.

Stop by our LIVE DEMO to learn more! Thursday afternoon poster session from 2:45-3:30pm

Interested in Beta testing?

Janine Freeman
NREL
Energy Modeling Engineer
janine.freeman@nrel.gov
303-275-4694

Sample Outputs



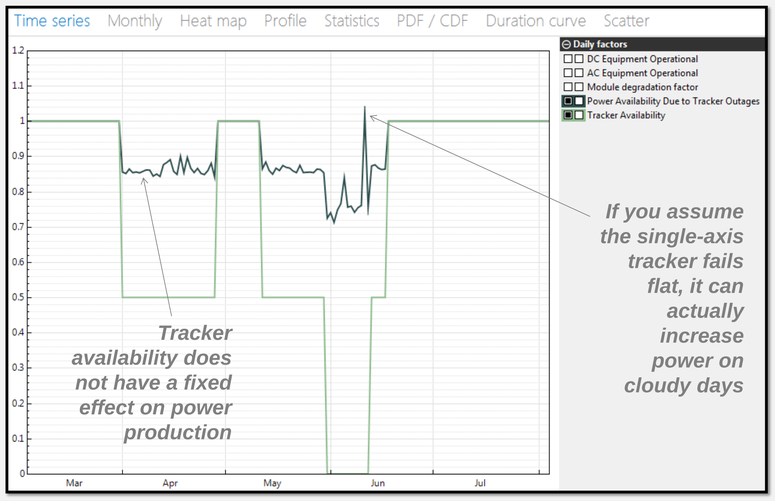
Outputs are available for each realization, or aggregated stochastic results. The user can specify the number of runs, component failure distributions, and the output metrics of interest (confidence intervals, probabilities of exceedance, etc.).

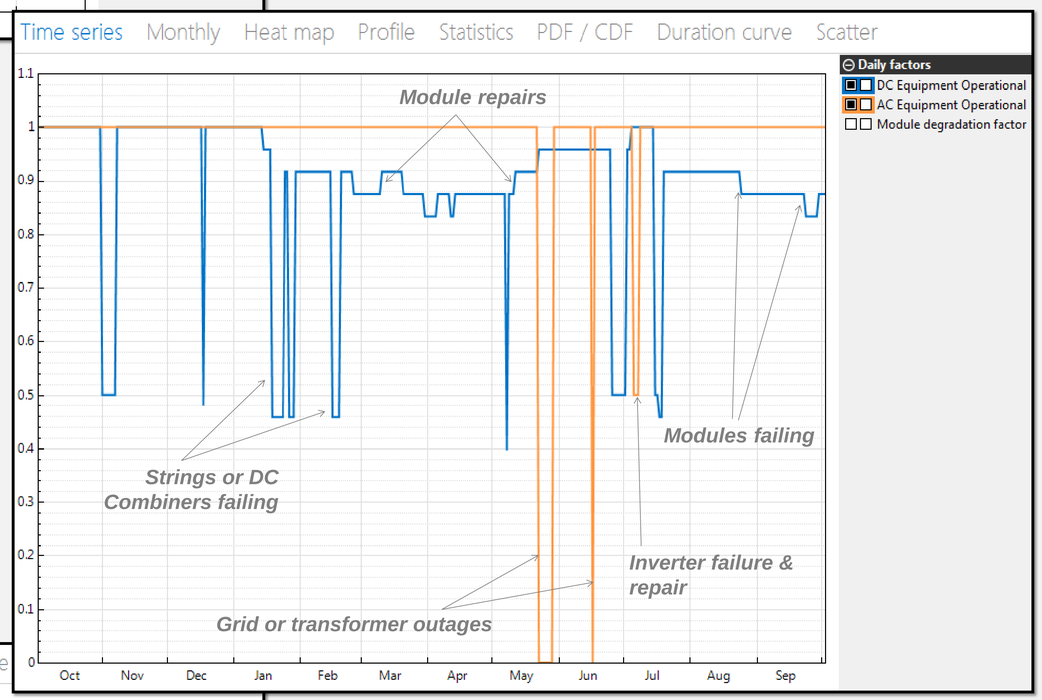
This project is a collaboration of:

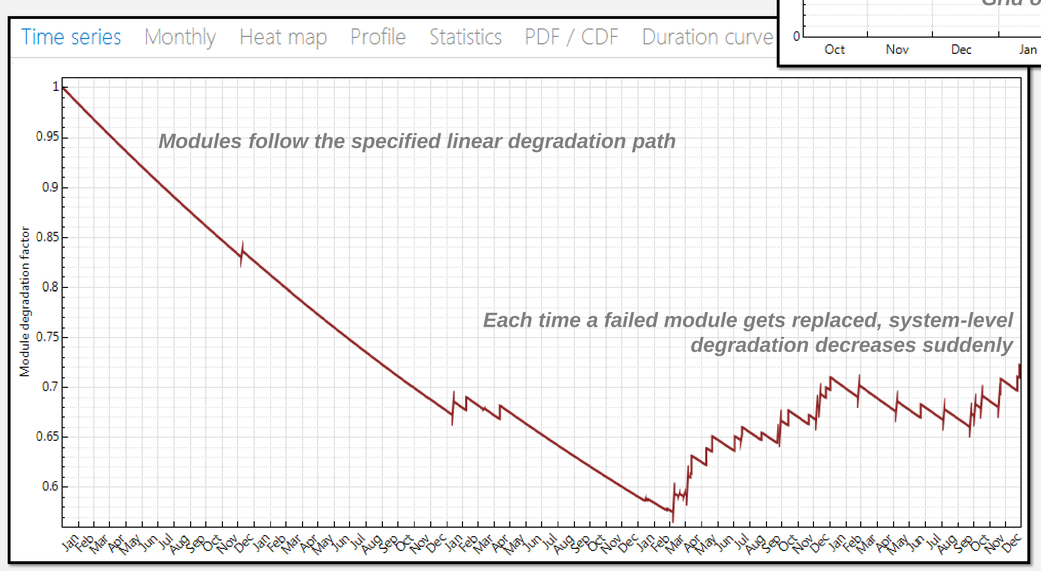
NREL NATIONAL RENEWABLE ENERGY LABORATORY

Sandia National Laboratories

System Advisor Model







Results shown are from a fictitious small system with highly accelerated failure and degradation rates and a short lifetime for demonstration purposes only.

The user can specify the system configuration, the system lifetime, and all of the financial assumptions through the System Advisor Model (SAM) interface.

All calculations are implemented transparently in the SAM LK scripting language.

Supported in part by the U.S. DOE Office of Energy Efficiency and Renewable Energy Solar Energy Technologies Program

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PV System Reliability Workshop
Lakewood, CO
March 1-2, 2017
NREL/PO-6A20-

NREL/SNL/BNL PV Reliability Workshops | Lakewood, CO | Feb. 28 – Mar. 2, 2017

Design for Reliability (DfR) of Power Electronics for PV Systems

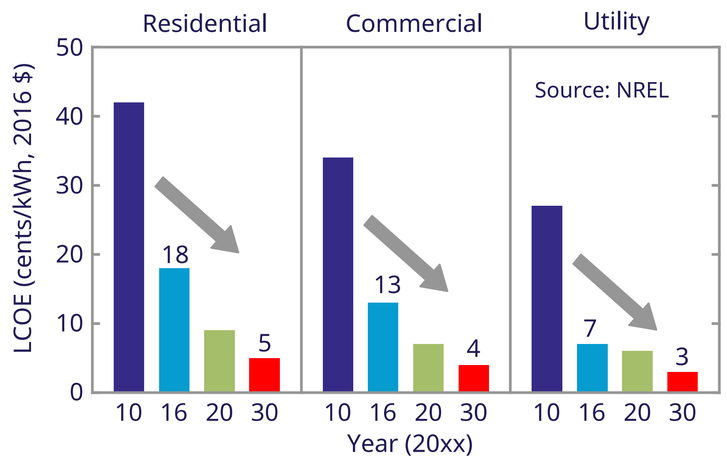
Yongheng YANG, Ariya SANGWONGWANICH, Frede BLAABJERG
Department of Energy Technology, Aalborg University, Aalborg, Denmark

Highlights – Why Do We Need to Design for Reliability?

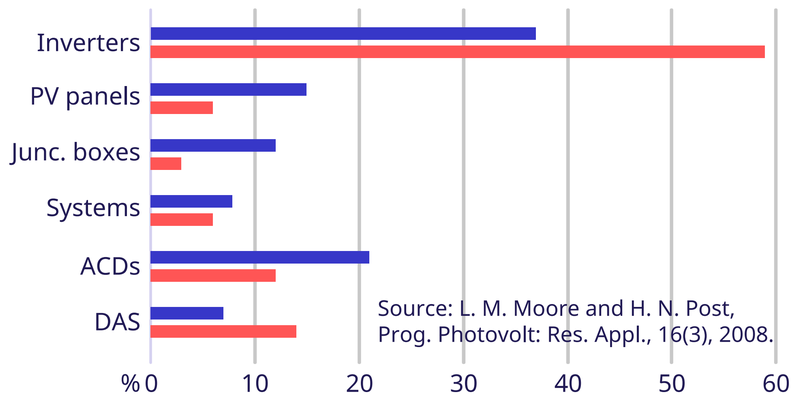
- Power Electronics technology is the key to renewable (including PV systems) integration and utilization
- Efficiency and reliability are two major concerns in the design of power electronics
- Advancements in semiconductors and topological innovations pushed the efficiency above 98%
- **Design for Reliability (DfR) is the way to maximizing the service while lowering the cost**

Demands of High Reliability

Continue to lower the Cost of Energy (COE):



$$COE = \frac{C_{Cap} + C_{O\&M}}{E_{Annual}}$$



Design for Reliability

Design for Reliability structure:

Failure Identification
- Critical components
- Failure mechanisms
- Major stress & strength

Stress Analysis
- Mission profile translation
- Multi-physics stress
- Multi-timescale stress

Strength Modeling
- Component-level
- Accelerated test
- Degradation model

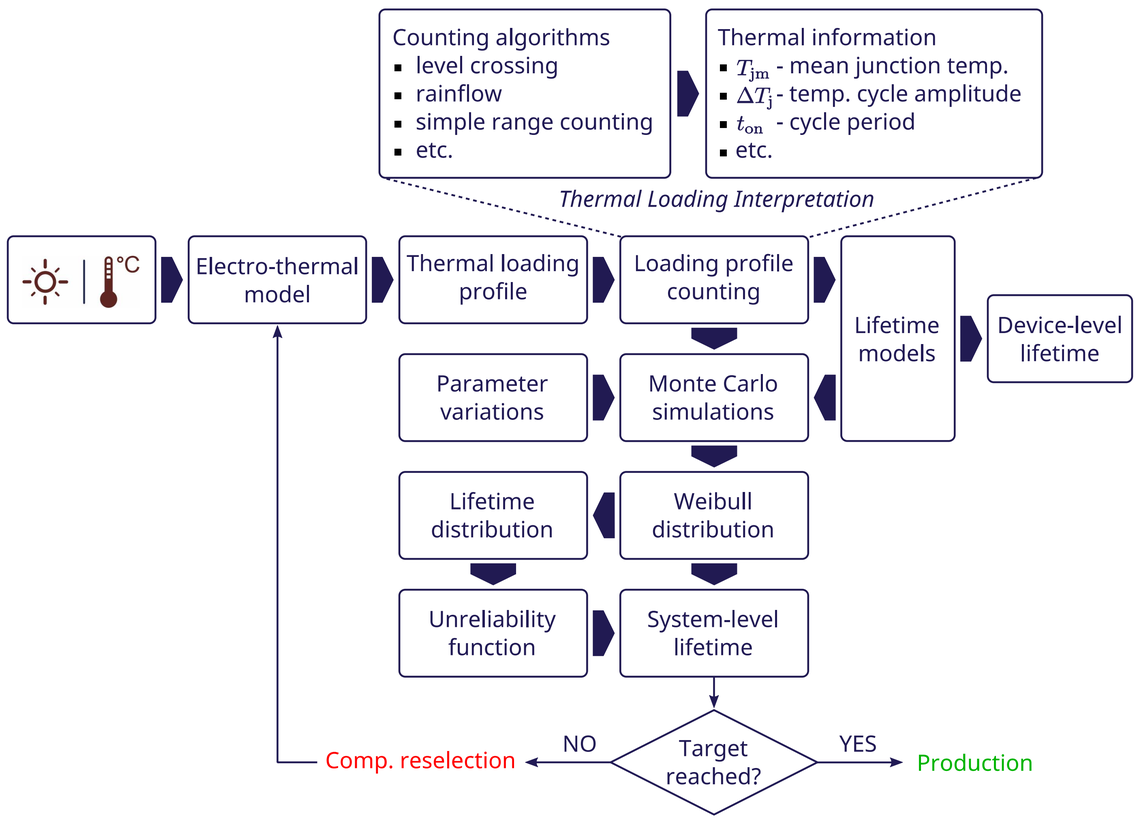
Reliability Mapping
Stress characterization
Variations & statistics
Multi-component system

Reliability Performance

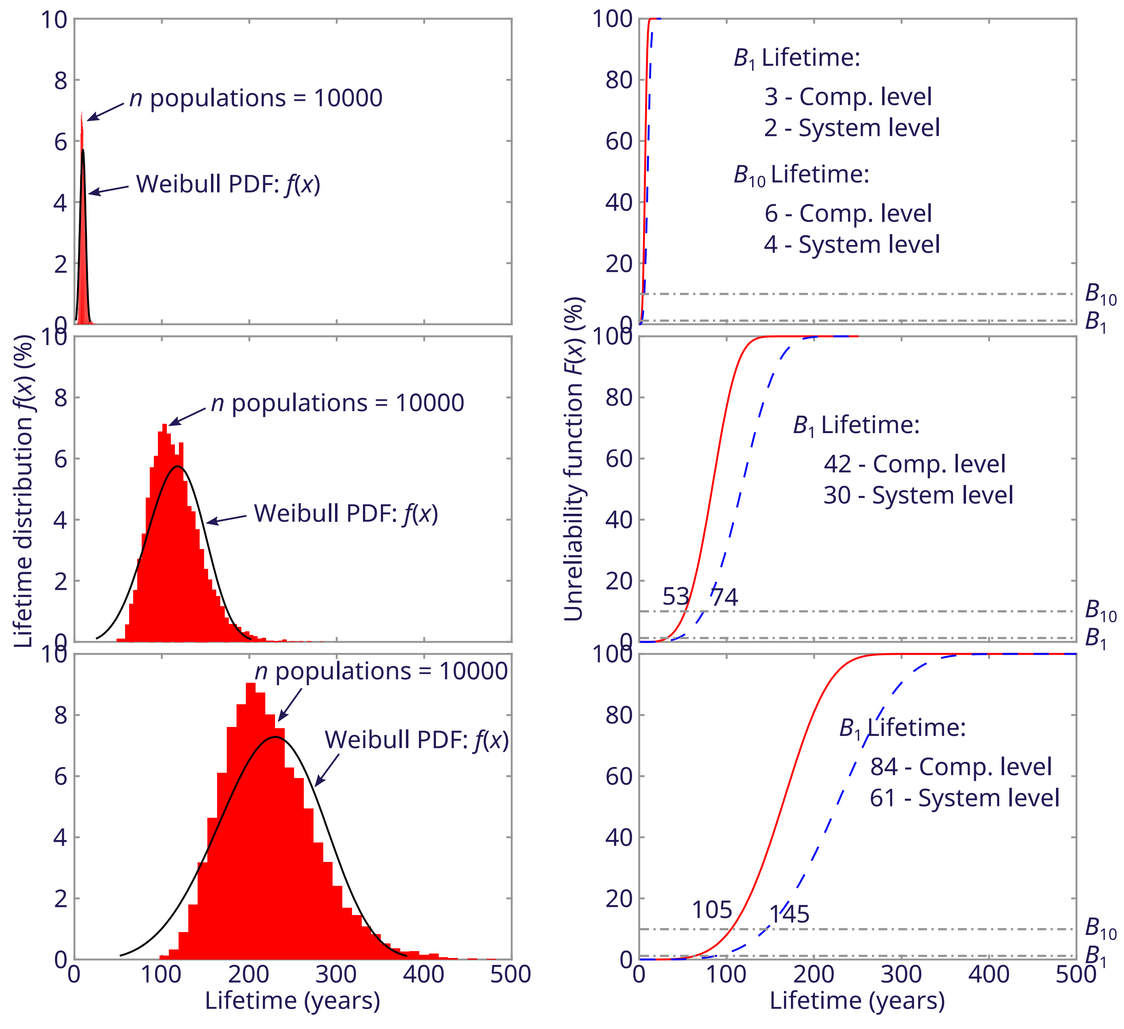
Direct	Indirect
• B_X lifetime	• Thermal loading
• Robustness	• V/I stresses
• Failure probability	• Stress margin

Design Example of A 6-kW 1-ϕ PV System

Design Specifications:
- 25+ years of operation
- A specific mission profile (Aalborg, DK)



Three devices are considered (15 A, 30 A, and 50 A):



B_x lifetime - the time when x% of the population have failed. PDF – Probability Density Distribution.

For more information, please visit the Center of Reliable Power Electronics (CORPE) www.corpe.et.aau.dk

Natural Resources Canada | Ressources naturelles Canada

Degradation Studies of a Photovoltaic System Operating in the Canadian Arctic for 21 Years

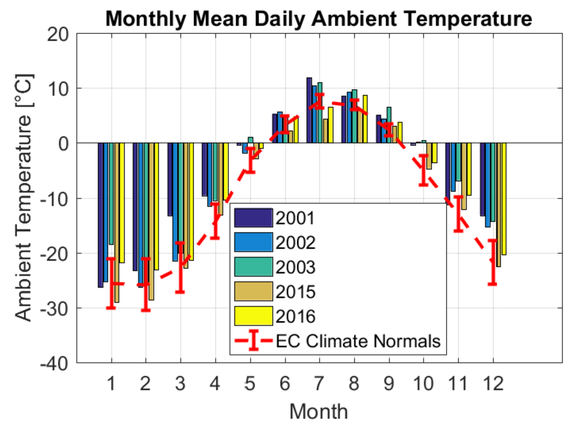
Naveen Goswamy and Yves Poissant, CanmetENERGY

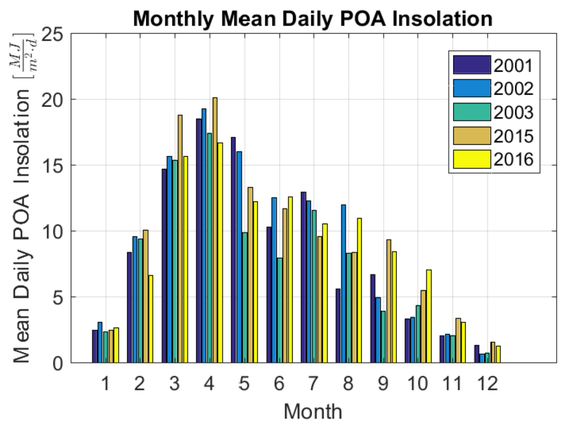
System Overview

3.2 kW_p PV array, Nunavut Arctic College, Nunatta Campus (2016)

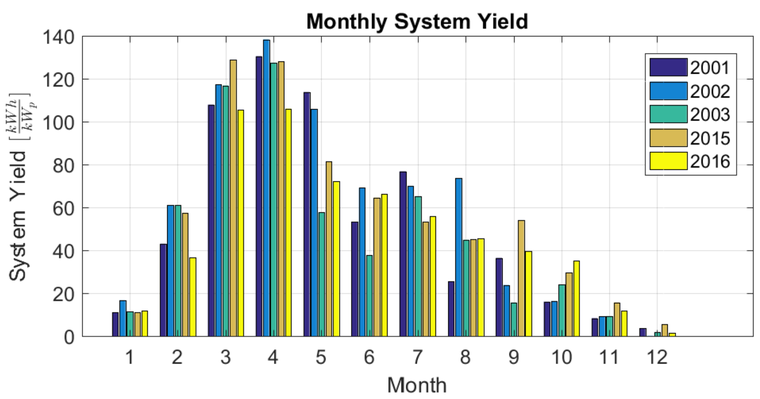
Location:	Iqaluit, Nunavut, Canada
System size:	3.2 kW_p
Number of modules:	69
Initial date of operation:	July 1995
Mounting configuration:	Façade
Azimuth:	30 degrees West of South
Cell type:	Monocrystalline Si
Module Make/Model:	Siemens M55+SM55, Solec S53
Topology:	5 strings of 12 modules connected to a grid-connected central inverter + 9 test modules open-circuited
Inverter Make/Model:	Statpower Prosine 5000 GT 3kW_{AC}

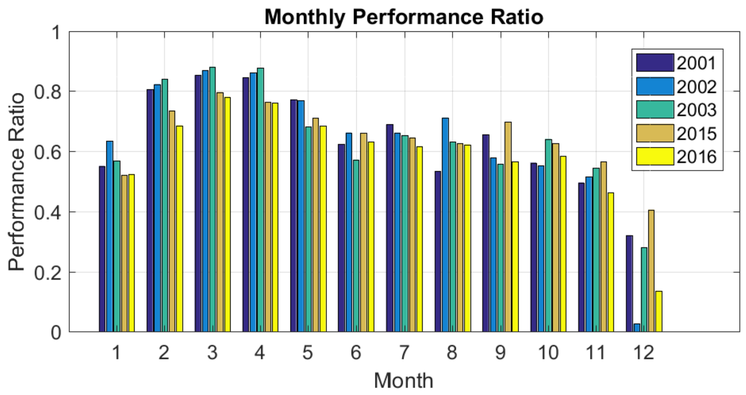
Climate Profile





Performance History





Visual Inspection

All 69 façade mounted modules were inspected in 2014. Based on this, the following points were noted:

- Minor cases of semiconductor/encapsulant delamination (representing less than 0.01% of array).
- Slight discoloration of cells observed.
- Some mounting hardware corrosion was apparent, maybe galvanic or salt-water related.
- Due to the façade mounting and the bulkhead construction bordering the array, the modules are protected from significant precipitation and wind exposure.

Degradation Rates

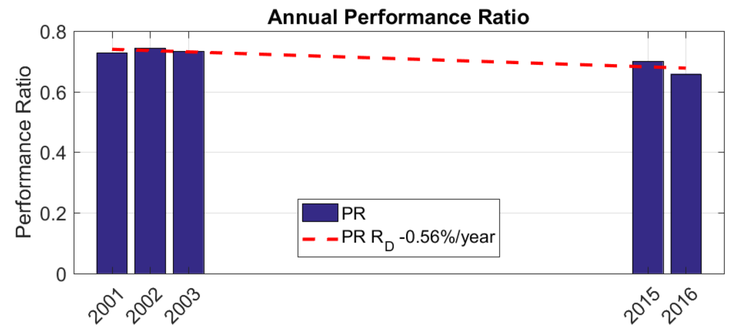
Max Power Degradation Rate

Three Siemens SM55 modules were tested in 1999 before being installed in the open-circuit test-array and again in 2016 after 17 years of exposure. By this method, the mean annual max power degradation rate for those modules ($R_{D,Pmax}$) was **-0.64 %/year**.

MODULE S/N	Max Power 1999 [W]	Max Power 2016 [W]	%Δ	$R_{D,Pmax}$ [%/year]
8791	57.49	51.46	-10.50	-0.62
8768	57.00	50.85	-10.79	-0.63
8447	57.39	50.99	-11.16	-0.66
			Mean $R_{D,Pmax}$ [%/year]	**-0.64**

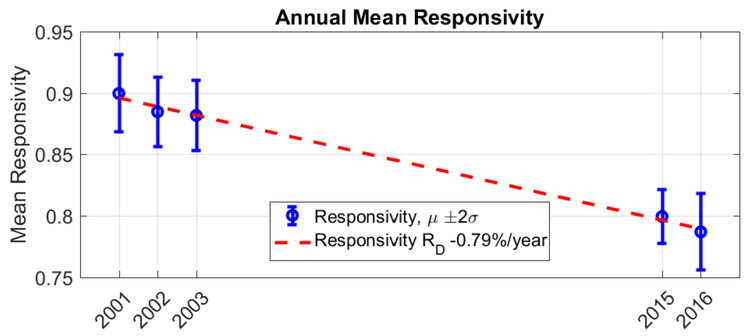
Annual Performance Ratio Degradation Rate

Comparing the Annual Performance Ratios for the years 2001-2003 and 2015-2016, the system degradation rate ($R_{D,PR}$) was **-0.56%/year**.



Annual Mean Responsivity Degradation Rate

Targeting system incident irradiance in the range of 800 W/m^2 and cell temperature corrected to 25 °C, the system degradation rate of the annual mean responsivity ($R_{D,resp}$) was **-0.79%/year**.



Discussion

The Nunavut Arctic College PV system has been operating continuously and autonomously for more than 21 years. Aside from maintenance of the monitoring system, no technical interventions have been required. Previously, CanmetENERGY had been involved with studying this system from a performance perspective [1]. The current analysis provides an examination of long-term degradation of the system.

A visual inspection performed in 2014 revealed negligible issues related to delamination and discoloration of the silicon cells. No junction box separation, backsheet delamination, humidity ingress, corrosion, or evidence of short-circuit or arc faults were observed.

Three different degradation rates (R_D) were empirically derived as follows: (i) Standard Test Condition indoor tests performed with a solar simulator, to determine maximum power degradation; (ii) annual performance ratio degradation; and (iii) annual mean responsivity degradation [2]. These three methods each reveal different values, however all of the rates fall within the range of those expected for x-Si* as documented in the scientific record [3].

* Median degradation for crystalline silicon technologies is in the 0.5–0.6%/year range with the mean in the 0.8–0.9%/year range, as determined by comprehensive meta-study [3].

Works Cited

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[2] PNW 82-1061: Photovoltaic system performance – Part 4: Degradation rate evaluation method (proposed IEC TS 61724-4) (2016).
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Failure detection and classification algorithms for grid-connected PV systems

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(*corresponding author email: livera.andreas@ucy.ac.cy)

INTRODUCTION

- The accurate identification of performance losses and failures in grid-connected photovoltaic (PV) systems is crucial for their further penetration in the energy mix.
- System malfunctions and failures cause a drop in performance yield.
- PV monitoring systems are required to quickly identify design flaws or malfunctions and prevent economic losses [1].
- In this work, failure detection routines (FDR) have been developed in order to identify malfunctions and failures in grid-connected PV systems.

Experimental Setup

- The benchmarked PV system used for the emulation of faults comprises of 4 multi crystalline Silicon (multi c-Si) PV modules, each 250 Wp, and is demonstrated in Fig. 1.

Figure 1: Multi c-Si grid-connected PV system used for the emulation of failures in Nicosia, Cyprus.

- The PV system is connected to a data acquisition platform, which is used for the monitoring and storage of meteorological and PV operational data [2].

Methodology

- The developed FDR consists of two stages: the fault detection and the classification stage.
- The fault detection stage is based on a comparative algorithm that detects discrepancies between the PV system monitored and simulated dc power.
- A failure is identified when the monitored power is significantly lower than the simulated power.
- The power production model used in this work is based on a parametric approach according to the following equation [3]:

$$P_{MPP} = G_{POA}\,(a1 + a2 G_{POA} + a3\,log(G_{POA})) \cdot \left(1 + \gamma(T_m - 25)\right) \quad (1)$$

- In addition, statistical algorithms for identifying local outliers and anomalies were used to verify that a failure occurred.
- For the classification stage, decision trees algorithms that consider the magnitude of the discrepancy, affected parameters, pattern and duration of the fault and cross-referencing with other healthy operational parameters, were implemented for each failure.

RESULTS

- The preliminary results demonstrated that the developed FDR are capable to detect and classify specific operational problems (inverter failure and shading) associated with grid-connected PV systems.
- In particular, the impact of inverter failure to the dc power production is depicted in Fig. 2. The results showed that the actual power production, in February 1st, 2017 (a clear day in Cyprus) at 13:00, was significantly lower than the simulated power production. The comparative algorithm of the detection stage identified power loss and suggested further analysis to classify accurately the failure.

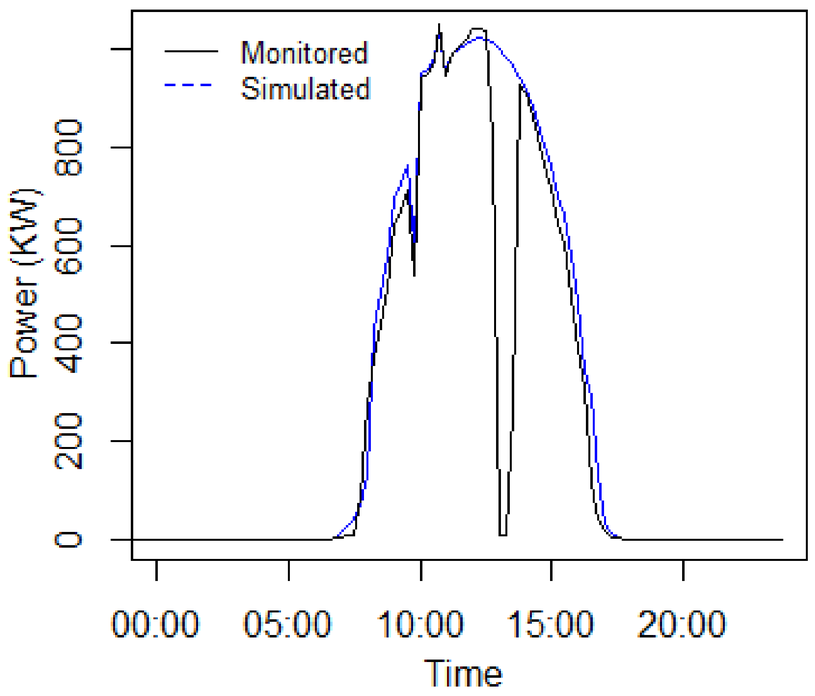

Figure 2: Monitored and simulated power of a PV system during inverter fault introduction.

- In order to verify the identified fault, statistical algorithms were applied on the array voltage, current and power time series to detect anomalies points. An anomaly was detected on the abovementioned date and time and the array voltage time series plus the abnormal point is shown in Fig. 3.

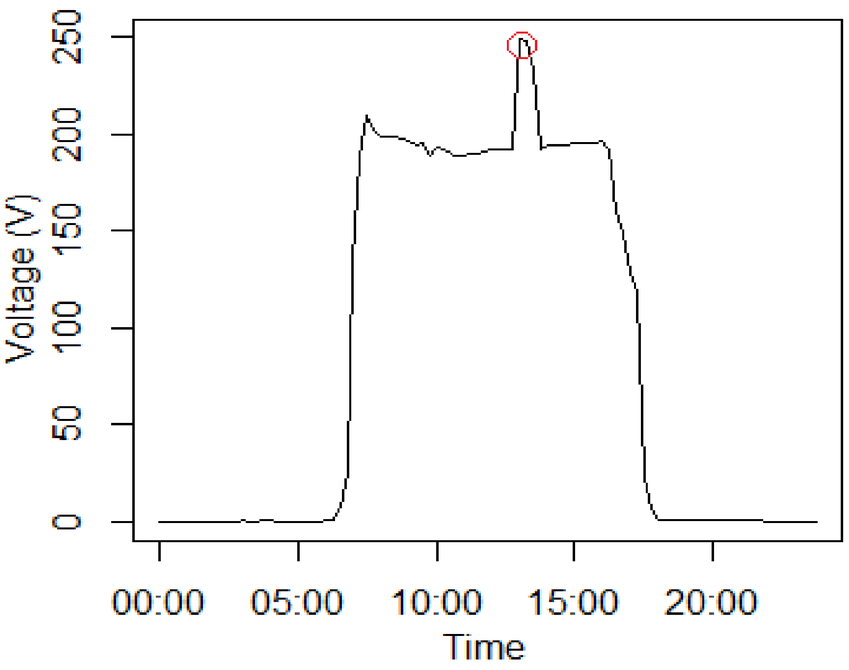

Figure 3: Anomalies detection in seasonal voltage time series.

- Finally, based on the pattern, duration of the fault and the affected electrical parameters (dc and ac power, dc voltage and current), the developed decision trees classified accurately the fault as an inverter defect.
- Furthermore, the shading effect on the produced power was detected and quantified by the developed FDR. Specifically, a repetitive 10 % power reduction was observed for only some hours per day (see Fig. 4).

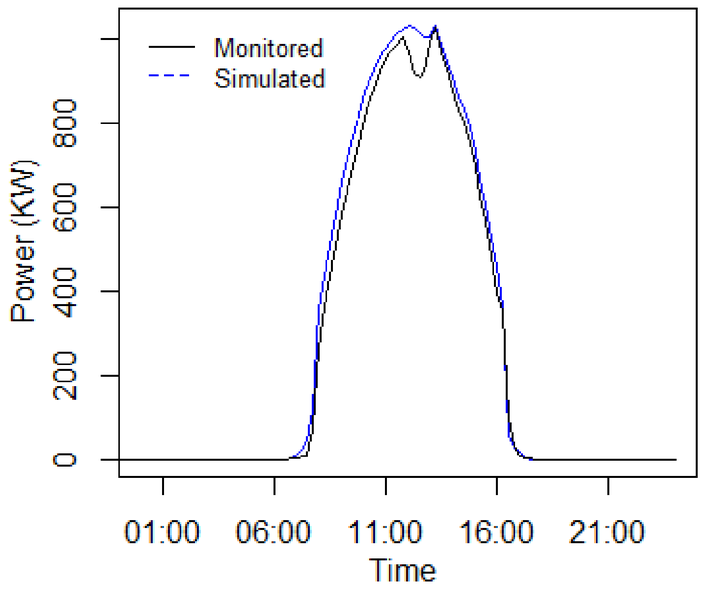

Figure 4: Monitored and simulated power of a PV system during shading introduction.

CONCLUSION

- The preliminary results showed that the developed FDR can detect and quantify specific performance losses and failures in PV systems.
- The developed FDR will be tested against other emulated faults (such as string defects, bypass diode faults and defect control devices) and the sensitivity of the FDR performance to the resolution of data will be examined.
- In order to enable the generalization of this methodology for PV faults detection, the developed FDR will also be tested on acquired data of a large scale PV plant.

ACKNOWLEDGEMENTS

This work was funded through the IPERMON project (KOINA/SOLAR-ERA.NET/1214/08) which was co-financed by the European Regional Development Fund and the Republic of Cyprus through the Cyprus Research Promotion Foundation (DESMI 2009-2010).

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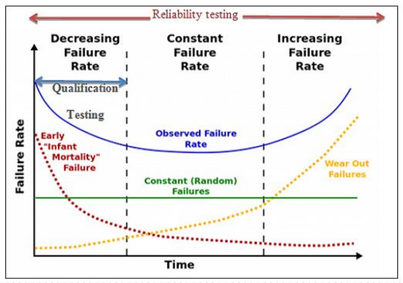
[2] A. Phinikarides, G. Makrides, B. Zinsser, M. Schubert, G. E. Georghiou, “Analysis of photovoltaic system performance time series: Seasonality and performance loss”, Renewable Energy, vol. 77, pp. 51-63, May 2015.

[3] R. Platon, J. Martel, N. Woodruff and T. Y. Chau, Online Fault Detection in PV Systems, in IEEE Transactions on Sustainable Energy, vol. 6, no. 4, 2015, pp. 1200-1207.

Online I-V Scanning and Intelligent Diagnosis on the Faults of the Solar Panels for the Operating Plants

Peijun Shen*, Xin Gu, Juan Hu and Xianmiao Zhang, **Huawei Technologies Co.,Ltd.**

Background



SourceL Connecting PV Module Quality to Field Degradation, **SOLARBUYER**

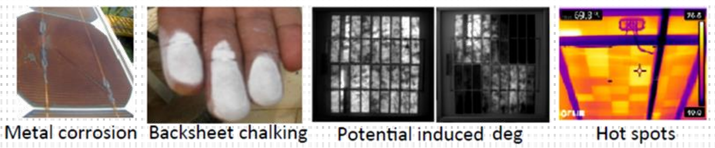
The highest technical risk involved in PV investment is early-life & long-term faults of panels.

TUV:

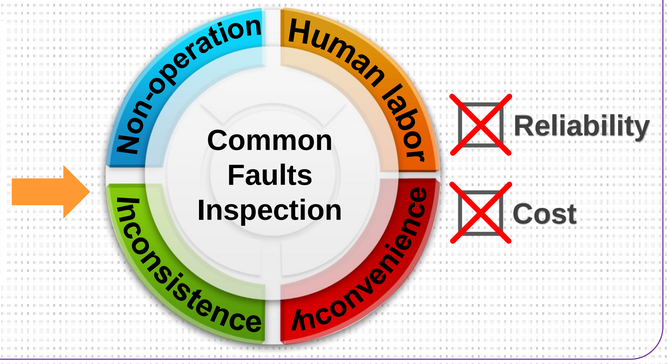
Among 12GW plants, 30% (3.6GW) has severe defects, and 50% (1.8GW) of them result from panels

Mannheimer Insurance AG:

10% of operating solar plants have panel faults



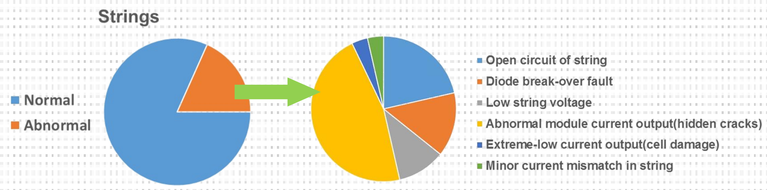
The inspections are usually needed for the plants established at the above natural environments.



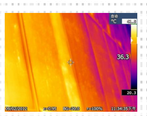
Example

Roof PV plant @ Songshan Lake, Dongguan, Guangdong, China
153 strings composed by Mc-Si panels.
grid-connected for 5 years

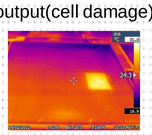
Fault types	Numbers of strings with faults (percentage)
Open circuit of string	6(3.92%)
Diode break-over fault	4(2.61%)
Low string voltage	3(1.92%)
Abnormal module current output(hidden cracks)	13(8.50%)
Extreme-low current output(cell damage)	1(0.65%)
Minor current mismatch in string	1(0.65%)



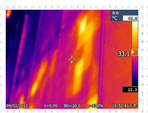
Diode break-over fault



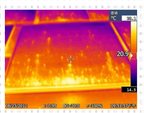
Extreme-low current output(cell damage)



Abnormal module current output(hidden cracks)



Minor current mismatch in string



These faults detected by I-V scanning and diagnosis were confirmed by a following IR test or other tests.

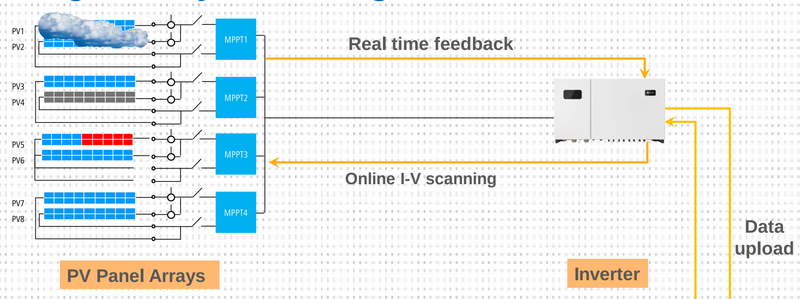
Solution

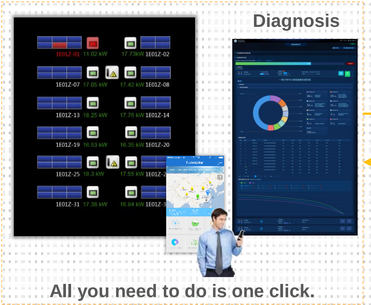
Online I-V Scanning Intelligent Diagnosis

- Unique IV characteristic for each fault
- Quick and precise
- Compatible with Huawei inverter

One-click IV Scanning and Diagnosis

Integrated System Design





Features

- 128 points, one scanning time < 1s
- 0.5% precision
- High consistence (Scanning strings in one array at the same time)
- Full string scanning, detect potential problem in each string
- Auto analysis on the faults
- ~0 energy consumption
- 14 types of panel faults can be recognized

TUV verification

Conclusions

The online I-V curve scanning with intelligent diagnosis on the faults of the solar panels is a string-level one-click solution for the operating plant. This technique can help recognize panel faults with high speed, accuracy and consistency and it also helps locate the solar panel(s) with faults, which provides a promising way for easy and low-cost maintenance for the plants.

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HUAWEI

RdTools: Open-Source Degradation Analysis Toolbox

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2. National Renewable Energy Laboratory -- Golden, Colorado

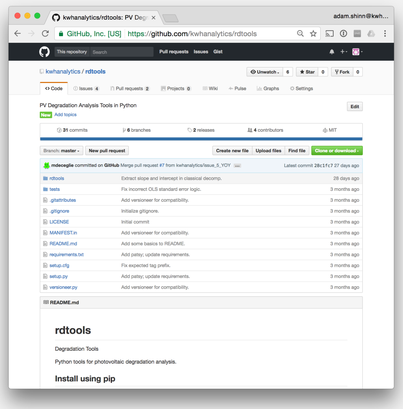
PV Reliability Workshop 2017

Motivation

kWh Analytics Inc. and NREL seek to provide open-source software tools to analytically derive degradation rates of photovoltaic modules and systems. Degradation plays an important role in photovoltaic project finance, affecting the valuation of energy generation for the lifetime of the investment. By open-sourcing degradation analysis code, we hope to foster open collaboration on analytical techniques while providing off-the-shelf tools for researchers, independent engineers, and industry stakeholders. Empowered with analytically-derived degradation rates, we can quantify equipment durability, assess the financial risk of currently operating projects, and provide data-driven input in financial models for future projects.

Degradation Analysis Toolbox

RdTools, hosted on Github is a public code repository. The open source tools are written in Python, a common language for data translation and analysis. Other open-source packages, such as PVLIB-Python and Pandas, are leveraged in this repository. RdTools includes time-series normalization methods to account for weather and seasonality in energy production data, and degradation calculation methods include regression and year-over-year approaches. In this poster we present an outline of current and planned features of RdTools, provide code examples and share initial results from a study that uses RdTools to analyze 10k residential systems.



https://github.com/kwhanalytics/rdtools

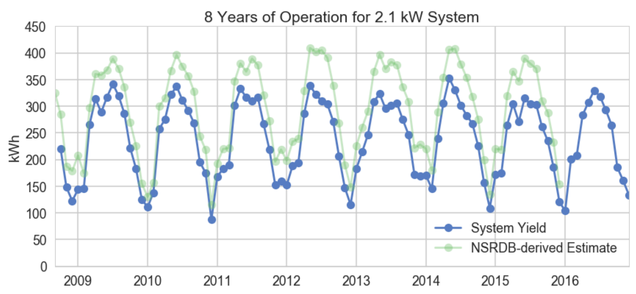
Current and Planned Features

- Normalization Step
  - Performance Ratio
  - PVWatts
  - Sandia Array Performance Model
- Data Filtering Utilities
- Degradation Analysis
  - Ordinary Least Squares[1]
  - Ordinary Least Squares with Classical Decomposition[2]
  - Robust Regression[1]
  - Year-on-Year[1]

[1] D. Jordan, M. Deceglie, S. Kurtz, PV Degradation Methodology Comparison – a Basis for a Standard, *PVSC*, 2016

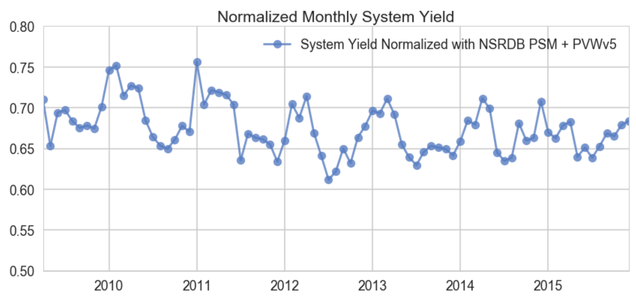
[2] D. Jordan and S. Kurtz, Analytical Improvements in PV Degradation Rate Determination, *PVSC*, 2010

Example: Normalization Step with PVWatts




```
pvw_kws = {
    'poa_global': poa_global,
    'P_stc': system_nameplate,
}

normalized_energy = rdtools.normalize_with_pvwatts(energy, pvw_kws)
```

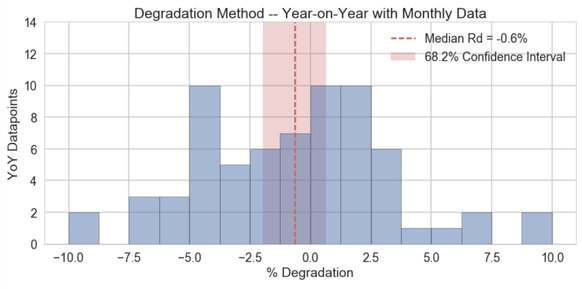


Inputs are system energy and required keywords for the PVWatts module model: plane of array irradiance and nameplate. Input time series variables energy and poa_global can be of differing frequencies.

Example: Degradation with Year-on-Year Approach

```
yoy_result = rdtools.degradation_year_on_year(normalized_energy, freq='MS')

Degradation and 68% confidence interval:
YoY Rd = -0.65% +/- 1.31%
```



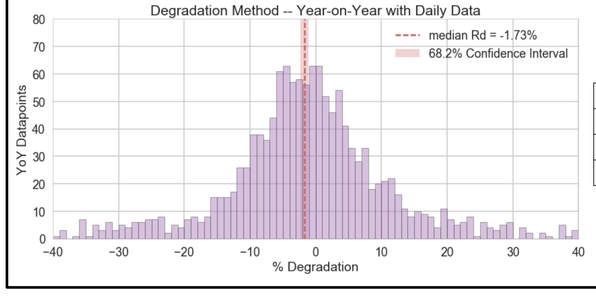
	YoY Result
Rd_median_pct	-0.64545
Rd_stderr_pct	1.31
Rd_CI	(-1.24536, 0.06644)

In this example the monthly time series, normalized_energy, is used as input to the year-on-year approach. Although the analysis lacks sufficient data to create a well-formed distribution, the result falls well within the confidence intervals from the two regression approaches.

For comparison, below is an example of the year-on-year approach applied to different system with 5 years of energy production with daily frequency.

```
yoy_result = rdtools.degradation_year_on_year(normalized_energy_daily, freq='D')

Degradation and 68% confidence interval:
YoY Rd = -1.73% +/- 0.64%
```

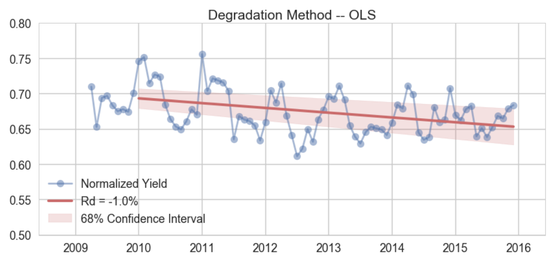


	YoY Result
Rd_median_pct	-1.73154
Rd_stderr_pct	0.57
Rd_CI	(-1.92577, -1.36062)

Example: Degradation with Ordinary Least Squares

```
ols_result = rdtools.degradation_ols(normalized_energy)

Degradation and 68% confidence interval:
OLS Rd = -0.98% +/- 0.57%
```



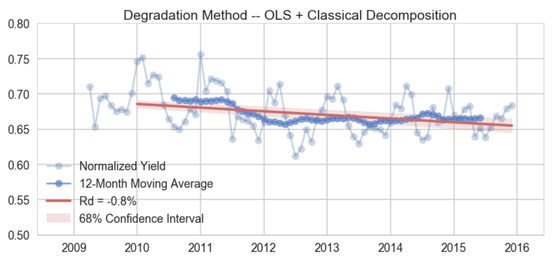
	OLS Result
intercept	0.69344
intercept_stderr	0.00695
slope	-0.00678
slope_stderr	0.00203
rmse	0.02981
Rd_pct	-0.97805
Rd_CI	(-1.26195, -0.69249)

Since regression approaches are sensitive to seasonality, OLS is applied in full-year increments. In this example, the last 6 years of the input time series, normalized_energy, is utilized.

Example: Degradation with OLS + Classical Decomposition

```
ols_cd_result = rdtools.degradation_classical_decomposition(normalized_energy)

Degradation and 68% confidence interval:
OLS+CD Rd = -0.76% +/- 0.22%
```



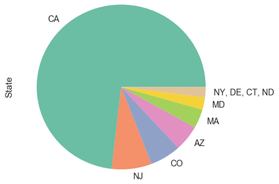
	OLS+CD Result
intercept	0.68558
intercept_stderr	0.00259
slope	-0.00519
slope_stderr	0.00078
rmse	0.0085
mk_test_trend	decreasing
Rd_pct	-0.75671
Rd_CI	(-0.86792, -0.64616)

In this example, OLS is applied to the 12-month moving average of the input time series, normalized_energy. Compared to standard regression approaches, this method is more robust to outliers.

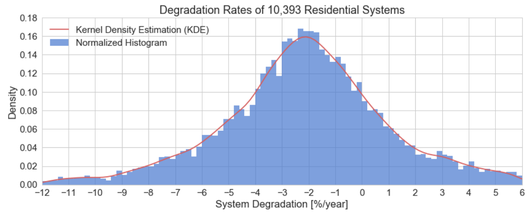
Residential System Degradation Study

In collaboration with NREL, we have applied methods from RdTools to study 10k residential systems from the kWh Analytics database.

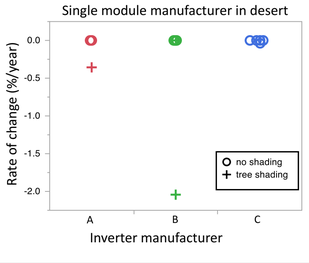
Systems used in this study are primarily located in California, and have operational lifetimes ranging from 2 to 6 years.



Using the year-on-year method, the distribution of degradation rates shows a wide range with a median rate of -2%/yr.



An interesting initial find is the affect of shading in hotter climate. Out of all systems using a single module manufacturer in a desert climate, two show higher rates of degradation and both are subject to shading from nearby trees.



Generalized Degradation Model of Photovoltaic Modules Exposed in Different Climatic Zones

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SDLE
SOLAR DURABILITY AND LIFETIME EXTENSION CENTER

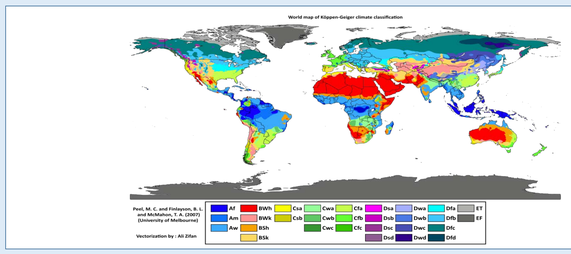
Abstract

Backsheet of PV module
- Provides insulation protection
- Protect cell from harsh environmental conditions

Degradation of photovoltaic backsheets exposed in the real world
- Synergetic result of weathering effect
- Classified by Köppen Geiger climatic zones

Statistical modeling approach
- Requires large amount of data for unbiased analytics
- Predicts degradation of backsheet

Module with polyamide/polyamide/polyamide backsheet
Exposed in Csa (temperate, dry, hot summer) Köppen Geiger climatic zones for 5 years
Severe cracks visually observed



Köppen Geiger climatic zone[1]
- Aim to classify in agriculture
- Group the world wide climate by temperature and precipitation
- Describe the complex conditions by simple letters code
- Incorporated in predictive model as predictor (stress)

[1] https://en.wikipedia.org/wiki/K%C3%B6ppen_climate_classification

*This work made use of the RedCat High Performance Computing Resource in the Core Facility for Advanced Research Computing at Case Western Reserve University.

Large amount of data needed
- For high accuracy of predictive model
- Requires an effective method organize and management data

Data stored in HBase
- As a triple
- Safe and large enough memory size(21Tb)

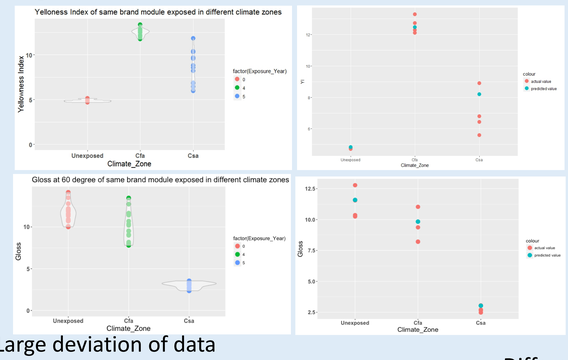
Automatically data transfer to HBase
- Cron job works every 3 hours

Sample Pool

Brand	e7x9krc	55nkgpm	55nkgpm	55nkgpm	55nkgpm	5bo70mr	5w0rpoj	0lkymzd	h6ep23h	92tbqxw	qx2ktvt	z5mu4eo	z5mu4eo
Exposure location	Arizona	New	China	Italy	Colorado	Cleveland	Cleveland	Cleveland	Cleveland	Cleveland	Cleveland	California	California
Climatic zone	Csb	New	Cfa	Csa	Dfb	Dfa	Dfa	Dfa	Dfa	Dfa	Dfa	Csa	Csa
Exposure history	2	0	4	5	6	4	4	4	4	4	4	28 (stored in shed)	28
Out layer material	PVDF	PA	PA	PA	PVDF	THV	PVF	PET	FEVE	PVDF	PVDF	PVF	PVF

13 modules exposed in real-world for different years
5 climatic zones in total
Model developed with subset of whole dataframe

Degradation vs. climatic zone



$YI = 4.8541 + 7.5384C_1 + 3.3865C_2$

- *Adjusted R^2 = 0.8999*

$Gloss = 11.5875 – 1.7544C_1 - 8.5531C_2$

- *Adjusted R^2 = 0.8968*

$C_1 = \begin{cases} 1, & if\ climatic\ zone\ is\ Cfa \\ 0, & if\ climatic\ zone\ is\ not\ Cfa \end{cases}$

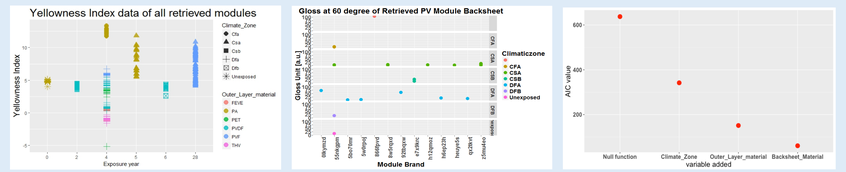
$C_2 = \begin{cases} 1, & if climatic\ zone\ is\ Csa \\ 0, & if\ climatic\ zone\ is\ not\ Csa \end{cases}$

Large deviation of data
- Cracks on modules
- Different measurement location

Satisfied statistical parameters and predicted values

Different change rate
Gloss loss relates to fracture

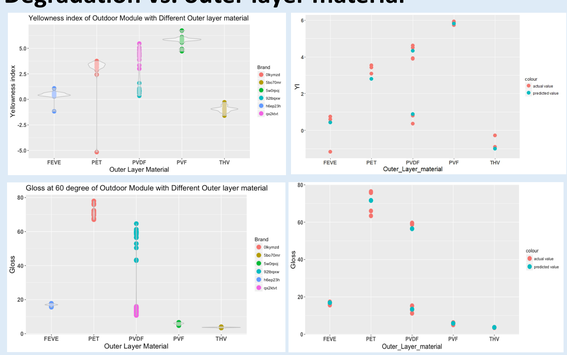
Degradation Model Incorporating Multiple Variables



Model formula:
- YI = Climate Zone + Exposure Year + outer layer material
  - Adjusted R^2: 0.9243
  - p-value: < 2.2e-16
  - Exist singularity due to small amount of data
- Same formula pattern of gloss with YI
  - Adjusted R^2: 0.9935

Adding "climatic zone" term
- Induce largest decrease of AIC value
- Highest statistical significance among those three predictors
- Climatic zone has strong effect on backsheet degradation

Degradation vs. outer layer material



$YI = 2.7912 – 3.7356M_1 + 2.9960M_2 – 1.9552M_3 – 2.3690M_4 + 1.5488M_5$

- *Adjusted R^2 = 0.8642*

$Gloss = 71.6275 - 67.9481M_1 – 65.7456M_2 – 15.1281M_3 – 54.6953M_4 - 58.2031M_5$

- *Adjusted R^2 = 0.9875*

$M_1 = \begin{cases} 1, & if\ out\ layer\ material\ is\ THV \\ 0, & if\ out\ layer\ material\ is\ not\ THV \end{cases}$

$M_2 = \begin{cases} 1, & if\ out\ layer\ material\ is\ PVF \\ 0, & if\ out\ layer\ material\ is\ not\ PVF \end{cases}$

$M_3 = \begin{cases} 1, & if\ out\ layer\ material\ is\ PVDF1 \\ 0, & if\ out\ layer\ material\ is\ not\ PVDF1 \end{cases}$

$M_4 = \begin{cases} 1, & if\ out\ layer\ material\ is\ FEVE \\ 0, & if\ out\ layer\ material\ is\ not\ FEVE \end{cases}$

$M_5 = \begin{cases} 1, & if\ out\ layer\ material\ is\ PVDF2 \\ 0, & if\ out\ layer\ material\ is\ not\ PVDF2 \end{cases}$

Two grades of PVDF
- Acrylic added in PVDF 1

High statistical significance of predictive model
Similar predicted value with real value

Conclusion

Different changing rate of yellowing and gloss-loss
- Of PA backsheet
- Gloss relates to the fracture of PA polymer

Climatic zone plays an important role in backsheet degradation

Generalized linear degradation models were developed
- With non-destructive evaluation data of modules exposed in different climatic zones

Significant statistical parameters
- Such as adjusted R^2 and p-value
- Show a well fitting of data and high predictive accuracy

Multivariable regression model
- Displays strong influence of climatic zone on degradation of PV backsheet

More data required to eliminate singularity

Future Work

Obtain more degradation data
- Including non-destructive characterization data
- FTIR, UV-Vis to understanding chemical change

Including weather data

Cross-correlation these real-world degradation data
- With indoor accelerating data

Research was performed at the SDLE Research Center, which was established through funding through the Ohio Third Frontier, Wright Project Program Award tech 12-004.
This work was supported by the DOE-EERE SunShot award DE-EE-007143.

Impact of missing data on the estimation of photovoltaic degradation rate

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INTRODUCTION

- A key factor that will enable the further penetration of photovoltaics (PV) is the lifetime energy yield assurance [1].
- Accurate evaluation of the degradation rate of PV systems is required [2].
- Measurement outages and missing data affect the degradation rate estimates.
- In this work, the impact of missing data on the estimation of the annual degradation rate of crystalline-Silicon (c-Si) PV systems was investigated.

METHODOLOGY

I. Experimental Setup

- The outdoor PV testing facility at the University of Cyprus (UCY) is shown in Fig. 1.

Figure 1: Outdoor PV test site of the UCY.

- 1 kW_p PV systems of different technologies are operating side-by-side since June 2006.
- The PV systems are connected to a data acquisition platform, which is used for the monitoring and storage of meteorological and PV operational data [3].

II. PV system performance time series and generation of missing data

- The recorded measurements of the global irradiance on the plane of the array (G_I) and the array DC power (P_A) were used to construct the monthly PV array performance ratio (PR) time series.
- The monthly PR time series of the benchmarking PV system used for the performance assessment of different techniques for estimating degradation rate in the presence of measurements outages, is depicted in Fig. 2.
- G_I and P_A measurements were randomly sampled (from 1 to 40 % of the total amount of a 5-year data-set) to select data points which were designated as Missing Completely at Random (MCAR) in order to create unbiased outage periods.
- The missing data points were replaced by "Not Available (NA)" values.

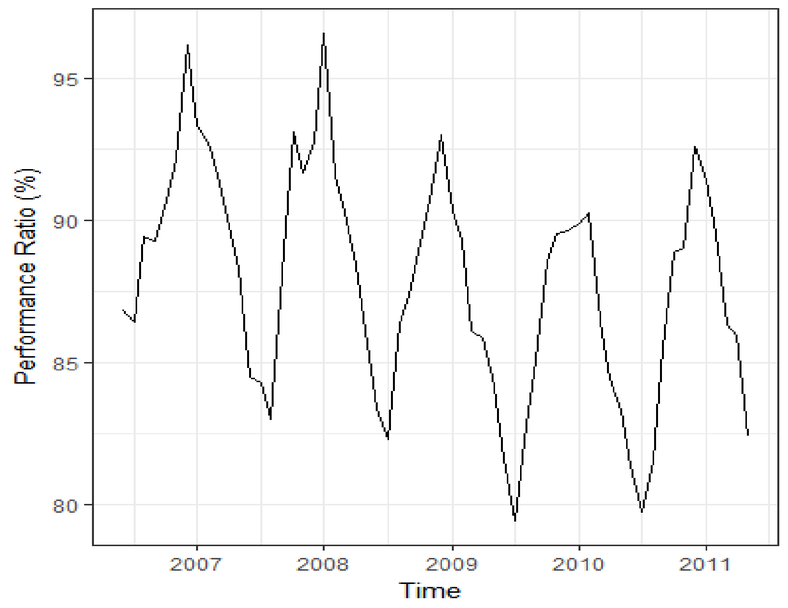

Figure 2: Monthly PV array PR time series over the period of June 2006 to June 2011.

III. Missing data imputation

The missing G_I and P_A data points were treated with missing data imputation techniques and models such as imputation by Linear Interpolation (Linear), Moving Average (MA), Last Observation Carried Forward (LOCF), Kalman Smoothing and State Space Models (Kalman) and Seasonal Decomposition (Seas).

IV. Degradation rate estimation

Linear Regression (LR), Classical Seasonal Decomposition (CSD) and Autoregressive Integrated Moving Average (ARIMA) models, were applied to the constructed monthly PV array PR time series of the c-Si PV system to extract the trend and estimate the annual degradation rate.

RESULTS

The degradation rate estimates for the investigated c-Si PV system clearly demonstrated that missing data can greatly affect the value of the annual degradation rate (see Fig. 3 - 5). In particular, for up to 40 % of missing instantaneous data points, the annual degradation rate estimation compared to initial estimates using the complete 5-year data-set (without missing data), was underestimated by up to 37 %, 35 % and 34 % when using LR, CSD and ARIMA, respectively.

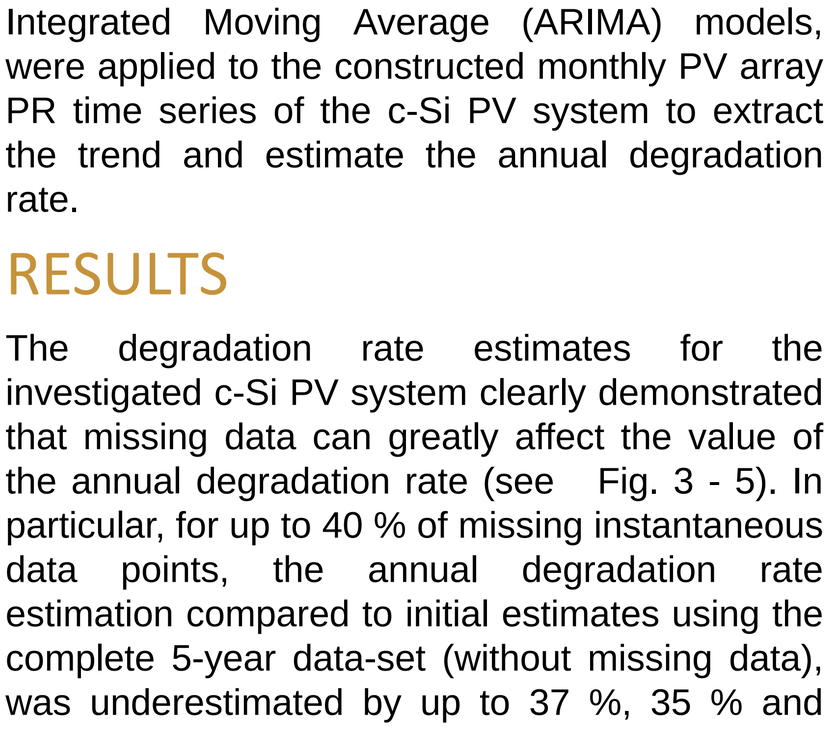

Figure 3: Maximum percentage deviation of annual degradation rate estimated with LR for 1 – 40 % level of missing data.

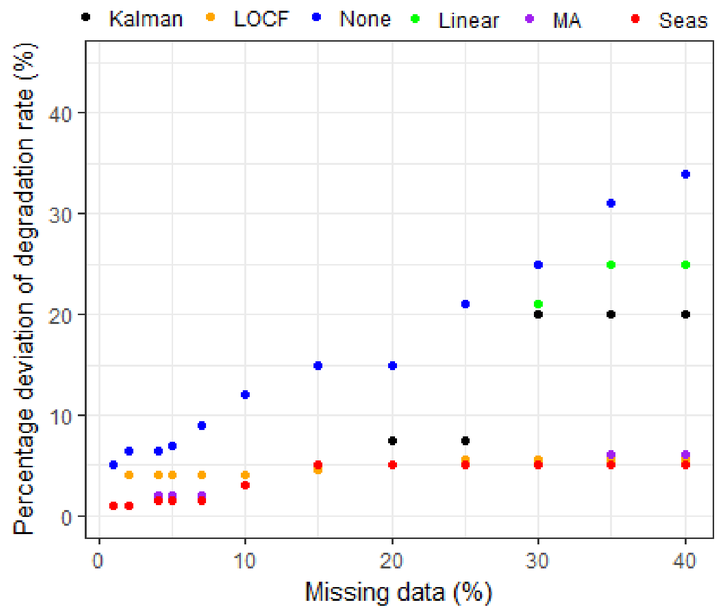

Figure 4: Maximum percentage deviation of annual degradation rate estimated with ARIMA for 1 – 40 % level of missing data.

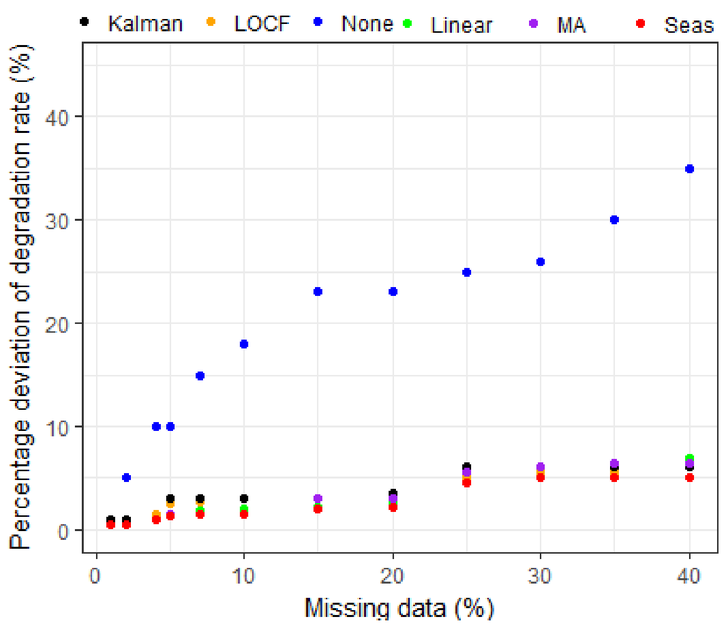

Figure 5: Maximum percentage deviation of annual degradation rate estimated with CSD for 1 – 40 % level of missing data.

CONCLUSIONS

- The application of different imputation techniques resulted in better estimates with best performance exhibited by the Seasonal Decomposition imputation technique.
- The ARIMA model was the most robust method for trend extraction for up to 10 % of missing data, when imputation was not applied.

ACKNOWLEDGEMENTS

This work was funded through the H-Volt PV project (KOINA/SOLAR-ERA.NET/1214/09). The authors would also like to acknowledge the financial support from the Cyprus Research Promotion Foundation.

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[3] A. Phinikarides, N. Philippou, G. Makrides, and G. E. Georghiou, "Performance loss rate of different photovoltaic technologies after eight years of operation under warm climate conditions," in 29th EU-PVSEC, 2014, pp. 2664-2668.

Month-by-Month Analysis of the Power Change Rate of Real World, Outdoor, Photovoltaic Systems Across Multiple Climate Zones

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Solar Durability & Lifetime Extension Research Center, Department of Material Science and Engineering, Case Western Reserve University, Cleveland, Ohio 44106

Introduction:

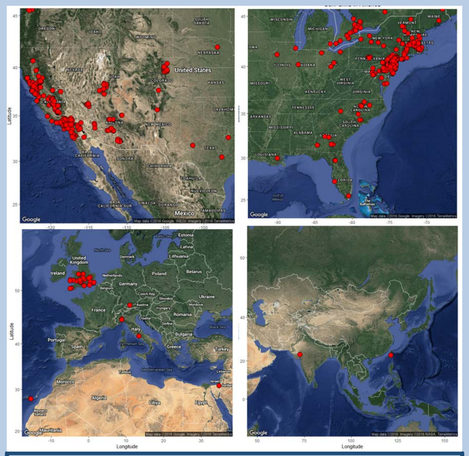
As solar power becomes a more prominent source of energy, it becomes necessary to understand the degradation rates of PV systems over decades long periods of time.

At the Solar Durability and Lifetime Extension (SDLE) Research Center, our goal is to observe real-world power plants and determine their power change rates, as well as the external factors that may be contributing to it, using the Month-by-Month Method.

Data Acquisition and Processing

Global SunFarm Network

- A Global FunFarm Network (GSFN) was established as a data source from real world PV plants
- 5638 total inverters across 787 sites
- 60 module brands
- 13 Köppen-Geiger Climate Zones (KGCZs)



Distribution of sites in the GSFN

E-CRADLE [2]

- A Hadoop/Hbase system for high performance data storage and processing
- Enables the storage and analysis of thousands massive amounts of power data
- Effectiveness has been demonstrated in I-V analytics

The Month-by-Month (MbM) Method

- A standard analysis method was developed to determine the change rate of the systems from the GSFN
- The MbM method uses as little data filtering as possible and can account for non-linear change rate features
- This method is divided into three models (β, ξ, γ)
- Sample Set #1 and #2 were pulled from the GSFN for analysis, Set #1 was 7 PV plants across 5 KGCZs dating back 12-15 years, Set #2 was 655 inverter across 13 KGCZs with an average age of >2 years

Beta (β) Pseudo Month Predictive Model

- Subdivide data sets into 30 day pseudo-months
- Assume that there is so significant degradation within each pseudo-month
- For each pseudo-month, train a model of the power output as a function of the ambient weather conditions (temperature, wind speed, solar irradiance)

$$\textit{Sample Set \#1:} \quad P_{AC} = \beta_{10} + \beta_{11} I_{GHI} + \beta_{12} T_{Ambient} + \beta_{13} W_{windspeed} + \varepsilon_1$$

$$\textit{Sample Set \#2:} \quad P_{AC} = \beta_{20} + \beta_{21} I_{POA} + \beta_{22} T_{Ambient} + \varepsilon_2$$

Xi (ξ) Longitudinal Model

Predicted Power

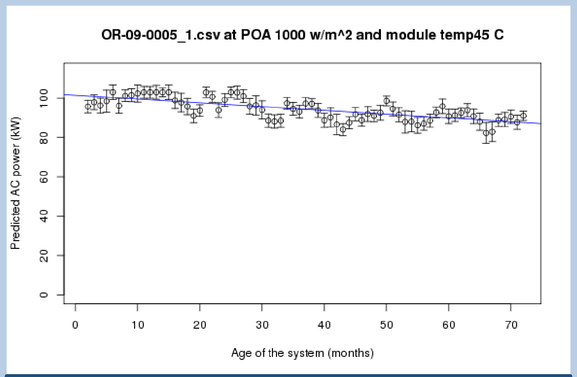
- Standard weather conditions are calculated for each inverter
- Predicted power for each month is calculated by applying the standard conditions to each beta model
- A weighted regression is fit to the power data, based on the uncertainty of each beta model

$$Y = X\xi + \varepsilon$$

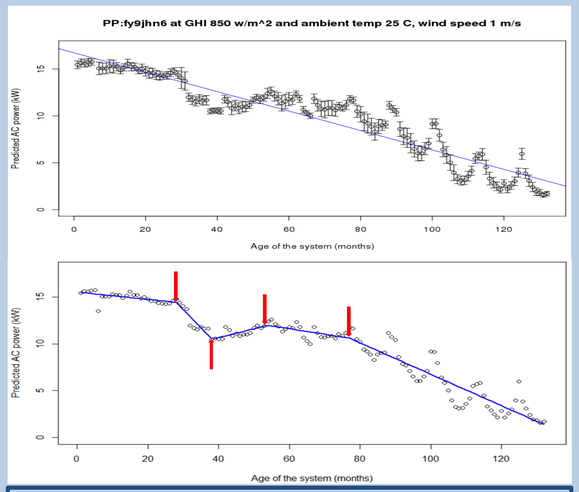
- Power change rate is determined from the slope of the trend

Segmented Regression Fitting

- In many cases a simple linear change rate approximation is not appropriate
- Piece-wise linear fitting can capture unexpected trend features
- Standard operation such as replacement or maintenance can cause segmented changes



Predicted power time-series with a linear trend (Set #1)

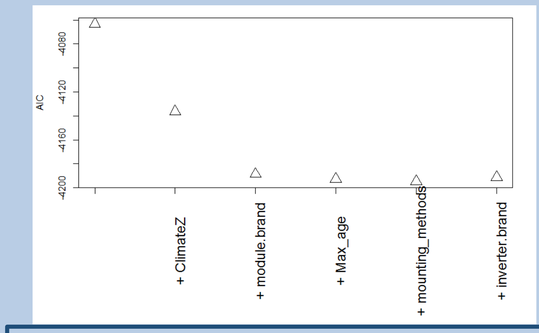


Time-series with linear and piece-wise linear fit (Set #1)

Gamma (γ) Cross-Sectional Model

- The γ model determines the rank order of importance between the change rates of the systems and their metadata variablesAkaike Information Criterion (AIC) used to determine the most influential factor when predicting a system's change rate
- Analysis on Sample Set #2 shows the Köppen-Geiger Climate Zone as most significant, followed by the module brand:

$$-R_d = \gamma_0 + \gamma_{1i} CZ_i + \gamma_{2j} Mod.Brand_j + \gamma_3 MaxAge + \gamma_{4k} Mounting_k + \varepsilon$$



γ model AIC values as metadata variables are added

Conclusions/Future Work

- The MbM method is an effective tool for degradation science
- Climate zone is shown to have a strong impact on a systems' degradation
- Future work will include applying this method to more sample sets of power data

References:

[1] Hu.Yang et al. 'Modeling the Long-term Temporal Change of Power Production for Real-world Photovoltaic Systems" IET Renewable Power Generation, submitted

[2] Hu, Yang, et al. "A Nonrelational Data Warehouse for the Analysis of Field and Laboratory Data From Multiple Heterogeneous Photovoltaic Test Sites." *IEEE Journal of Photovoltaics* 7.1 (2017): 230-236.

[3] Rubel, F.; Kottek, M. Observed and projected climate shifts 1901 -- 2100 depicted by world maps of the Köppen-Geiger climate classification. *Meteorologische Zeitschrift* **2010**, *19* (2), 135–141 DOI: 10.1127/0941-2948/2010/0430.

Acknowledgements:

- This work was supported by the DOE-EERE SunShot award DE-EE-0007140
- Research was performed at the SDLE Research Center, which was established through funding through the Ohio Third Frontier, Wright Project Program Award tech 12-004
- This work made use of the RedCat High Performance Computing Resource in the Core Facility for Advanced Research Computing at Case Western Reserve University

Degradation of different PV module technologies under field conditions in India

B. Bora[1,2], O.S. Sastry[1], R. Kumar[1], B. Prasad[2]

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[2]TERI University, Plot No. 10, Institutional Area, Delhi-110070, India
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Introduction

- PV module power generation prediction for long period of exposure is mainly depends on the degradation rate.
- Jordan & Kurtz studied 2000 degradation rates, measured on individual modules or entire systems, have been assembled from the literature, showing a median value of 0.5%/year.
- However for Indian climatic condition this picture is different.
- The All India Survey 2014 has reported more than 1000 degradation rates and showing an average degradation rate for the so-called 'good' modules is 1.33%/year
- Most of these degradation data is from the instant measurement data

Objectives

- The main objective of this study is to provides the degradation information of multi crystalline silicon, amorphous silicon, HIT, SunPower and thin films PV module in a composite zone of India.
- The degradation rates are calculated from the slope of time line series plot of various PV module types for long time exposure, will be more useful for energy estimation process.

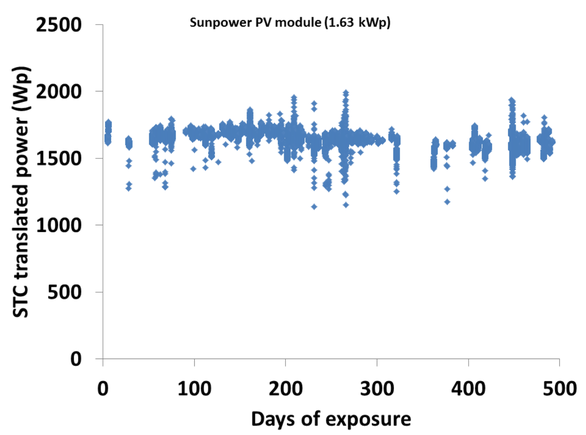
PV system description

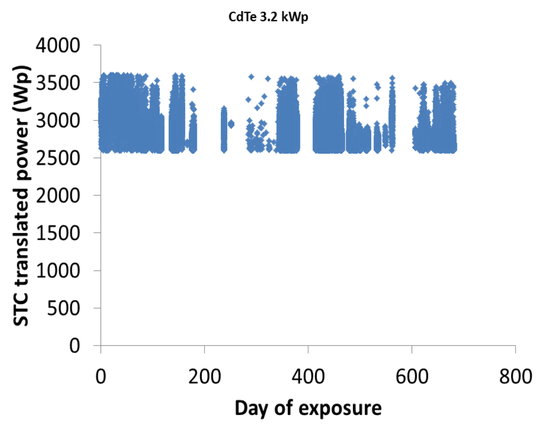
- The test site is National Institute of solar Energy, Gurgaon, India. Comes under composite climatic zone of India.
- Systems are installed in a fixed tilt equal to the latitude of the site.

Technology	Size	With inverter/DC load
Amorphous Si (a-Si)	1.2 kWp	DC load
Sun power Maxeon technology	1.63 kWp	DC load
Multi crystalline Si (m-Si)	1.6 kWp	DC load
HIT	1.68 kWp	DC load
CdTe	3.2 kWp	With inverter
CIGS (single module)	125 Wp	DC load

Results and discussion

- The outdoor performance data of all the technologies are filter out for a intensity range 800-1050 W/m^2. Data sheet temperature coefficient is used for STC translation of power.





Technology	Degradation rate per year w. r. t. nameplate value	Degradation rate per year w.r.t. initially measured data (without treatment)	Days of exposure
Amorphous Si (a-Si)	5.7%	6.9%	699
Sun power Maxeon technology	0.8%	1.5%	492
Multi crystalline Si (m-Si)	2.25%	1.8%	809
HIT	2.2%	3%	729
CdTe	3.1%	2%	681
CIGS	4.8%	4.2%	884

Conclusion

- Degradation rate per year is not constant through out the time of exposure
- Taking of single degradation rate for energy estimation of PV module technologies will lower the accuracy.
- There is difference between the degradation rate w.r.t. nameplate value and initial measurement.
- Data filtration need to be improved for better result with different range of exposure time

Acknowledgement

This research is based upon work supported by the Solar Energy Research Institute for India and the U.S. (SERIIUS) funded jointly by the U.S. Department of Energy subcontract DE AC36-08G028308 (Office of Science, Office of Basic Energy Sciences, and Energy Efficiency and Renewable Energy, Solar Energy Technology Program, with support from the Office of International Affairs) and the Government of India subcontract IUSSTF/JCERDC-SERIIUS/2012 dated 22nd Nov. 2012.

Rapid Shutdown Requirements for 2017 NEC

Presented by:
Bill Brooks, CMP 4

BROOKS ENGINEERING

2017 NEC Statistics for Article 690

- Whole article was reduced from 11,000 words to about 8,000 words.
- Rapid shutdown increased from 133 words to over 1100 words.
- Dc loads, stand-alone systems (ac loads), and battery storage systems have historically been considered part of Article 690. With the advent of a whole new articles on energy storage systems [Article 706], stand-alone systems [Article 710], microgrids [new Part IV of Article 705], and dc microgrids [Article 712]—all these sections were removed from 690.

BROOKS ENGINEERING

690.12 Rapid Shutdown of PV Systems on Buildings.

- PV system circuits installed on or in buildings shall include a rapid shutdown function to reduce shock hazard for emergency responders in accordance with 690.12(A) through (D).

- *Exception: Ground-mounted PV system circuits that enter buildings, of which the sole purpose is to house PV system equipment, shall not be required to comply with 690.12*

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RTU
23

690.12 Rapid Shutdown of PV Systems on Buildings.

Several Significant Changes From 2014:

1. Greatly increased detail of rapid shutdown switch including location and signs
2. Define array zone—within 1' of modules
3. 3 options for reducing shock hazards within the array boundary.
   1. Listed Rapid Shutdown PV Array
   2. Curtail voltage of conductors within array zone to 80V
   3. No exposed metal or conductors in PV array and array more than 8' from grounded metal.
4. Require equipment to be certified for rapid shutdown

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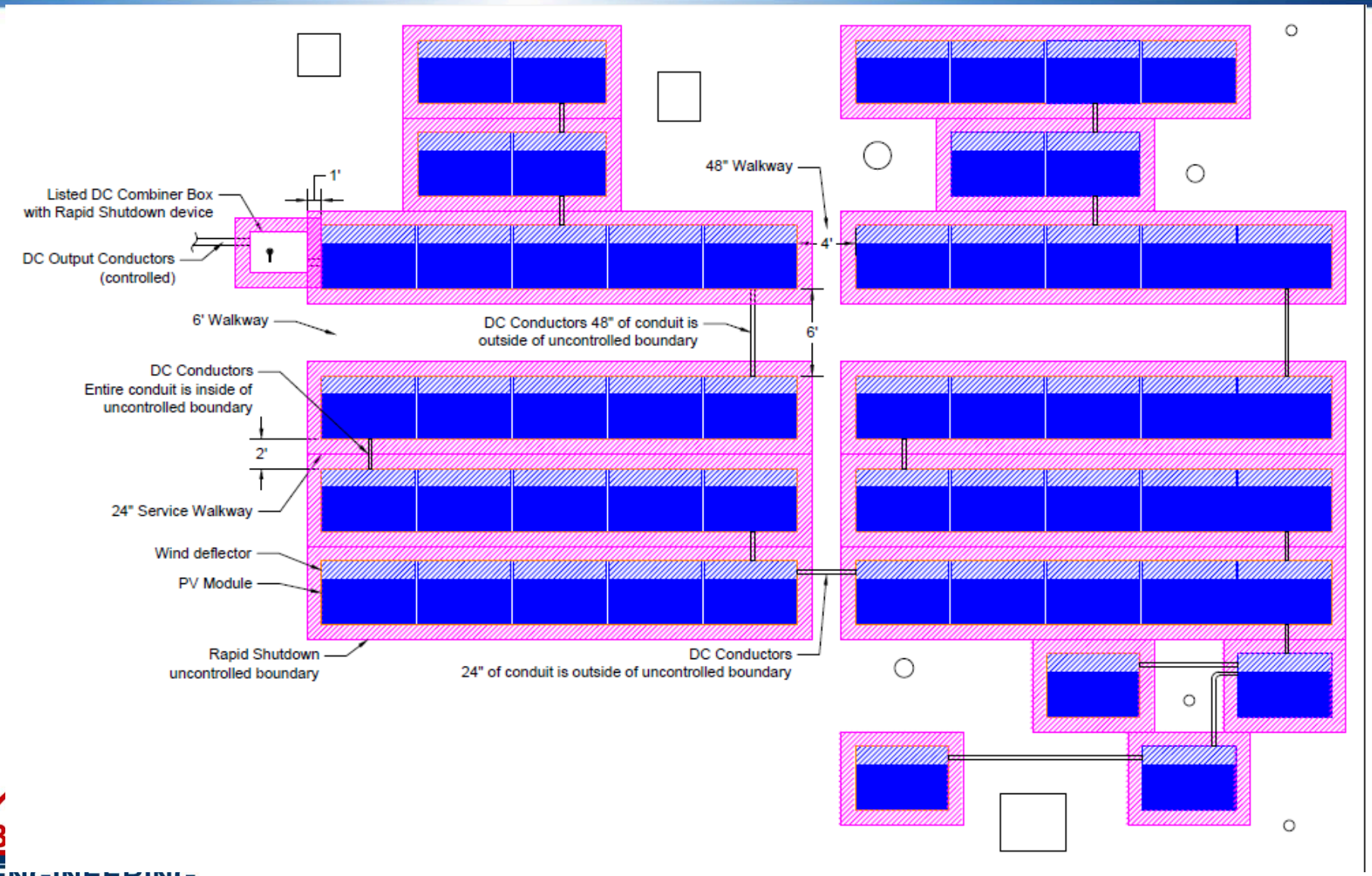
Array Boundary Defined



ENGINEERING

690.12(C)

- The rapid shutdown initiation device(s) shall consist of at least one of the following:
- (1) Service disconnecting means
- (2) PV system disconnecting means
- (3) Readily accessible switch that plainly indicates whether it is in the “off” or “on” position

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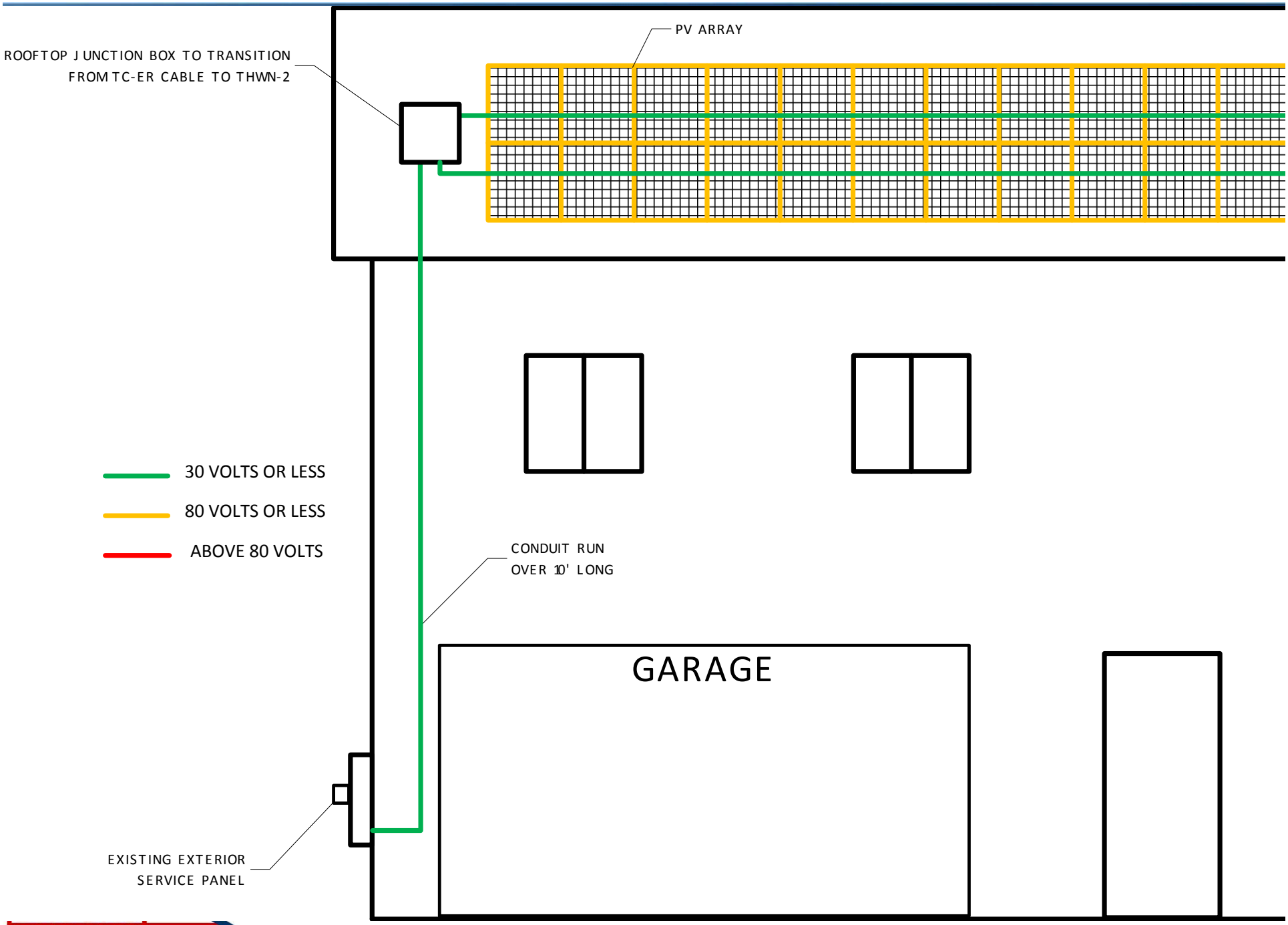

ENGINEERING

690.12(C)

Informational Note: One example of why an initiation device that complies with 690.12(C)(3) would be used is where a PV system is connected to an optional standby system that remains energized upon loss of utility voltage.

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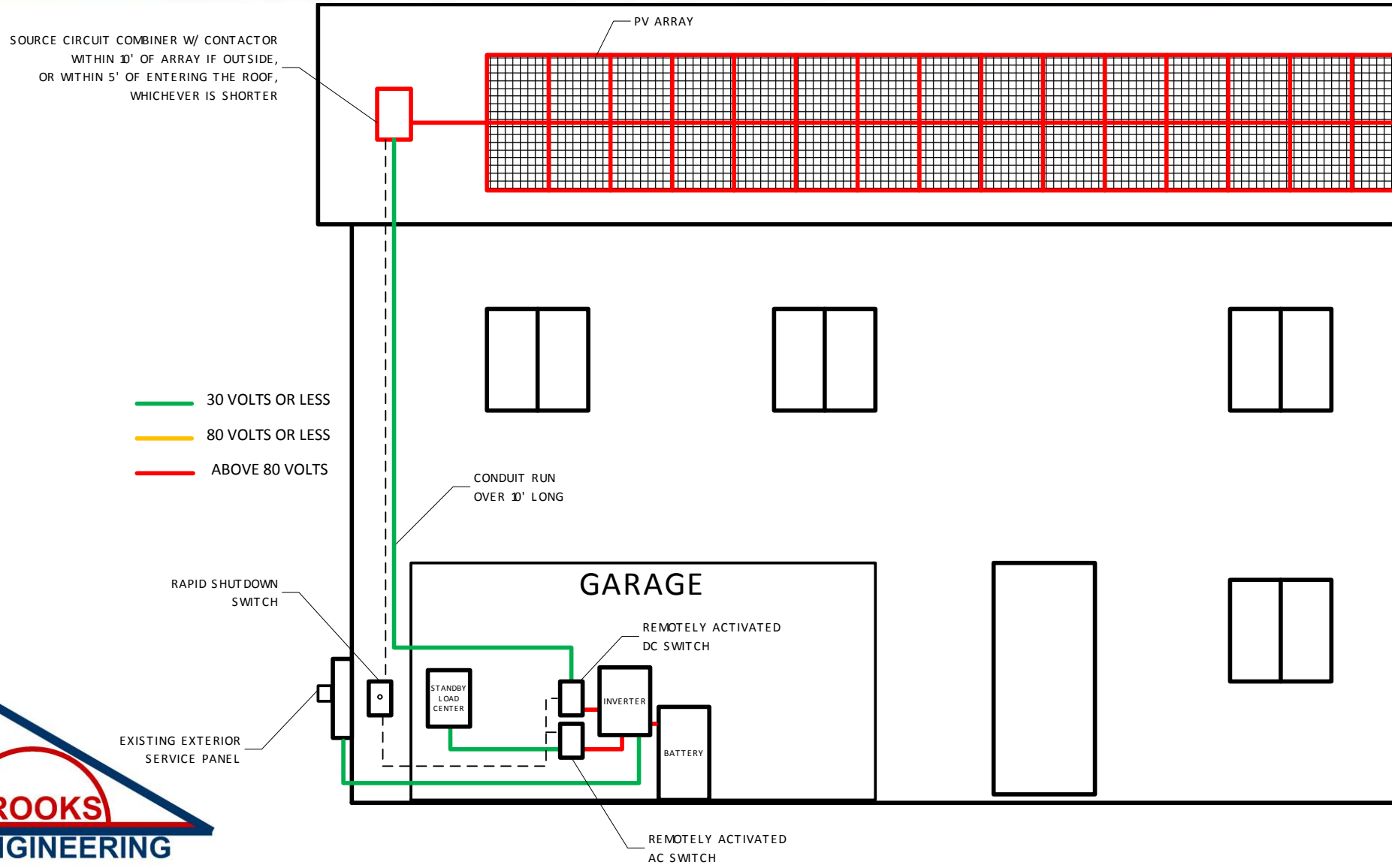
Readily Accessible Switch



BROOKS ENGINEERING

690.12(C) Multiple PV Systems

- Multiple PV systems on a single service

Not more than 6 switches or circuit breakers or combination thereof in a single enclosure or a group of separate enclosures

BROOKS ENGINEERING

690.12(D) Equipment

Equipment that performs the rapid shutdown functions, other than initiation devices such as listed disconnect switches, circuit breakers, or control switches, shall be listed and labeled, and identified for providing rapid shutdown protection.

Informational Note: Inverter input circuit conductors can remain energized for up to 5 minutes with inverters not listed for rapid shutdown.

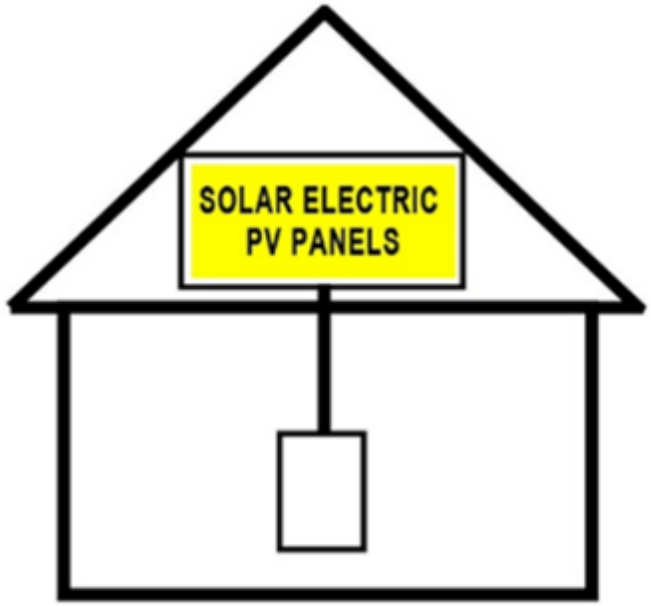
BROOKS ENGINEERING

690.56(C) Buildings with Rapid Shutdown

For PV systems that shutdown the array and conductors leaving the array

SOLAR PV SYSTEM EQUIPPED WITH RAPID SHUTDOWN

TURN RAPID SHUTDOWN SWITCH TO THE "OFF" POSITION TO SHUTDOWN PV SYSTEM AND REDUCE SHOCK HAZARD IN ARRAY



BROOK
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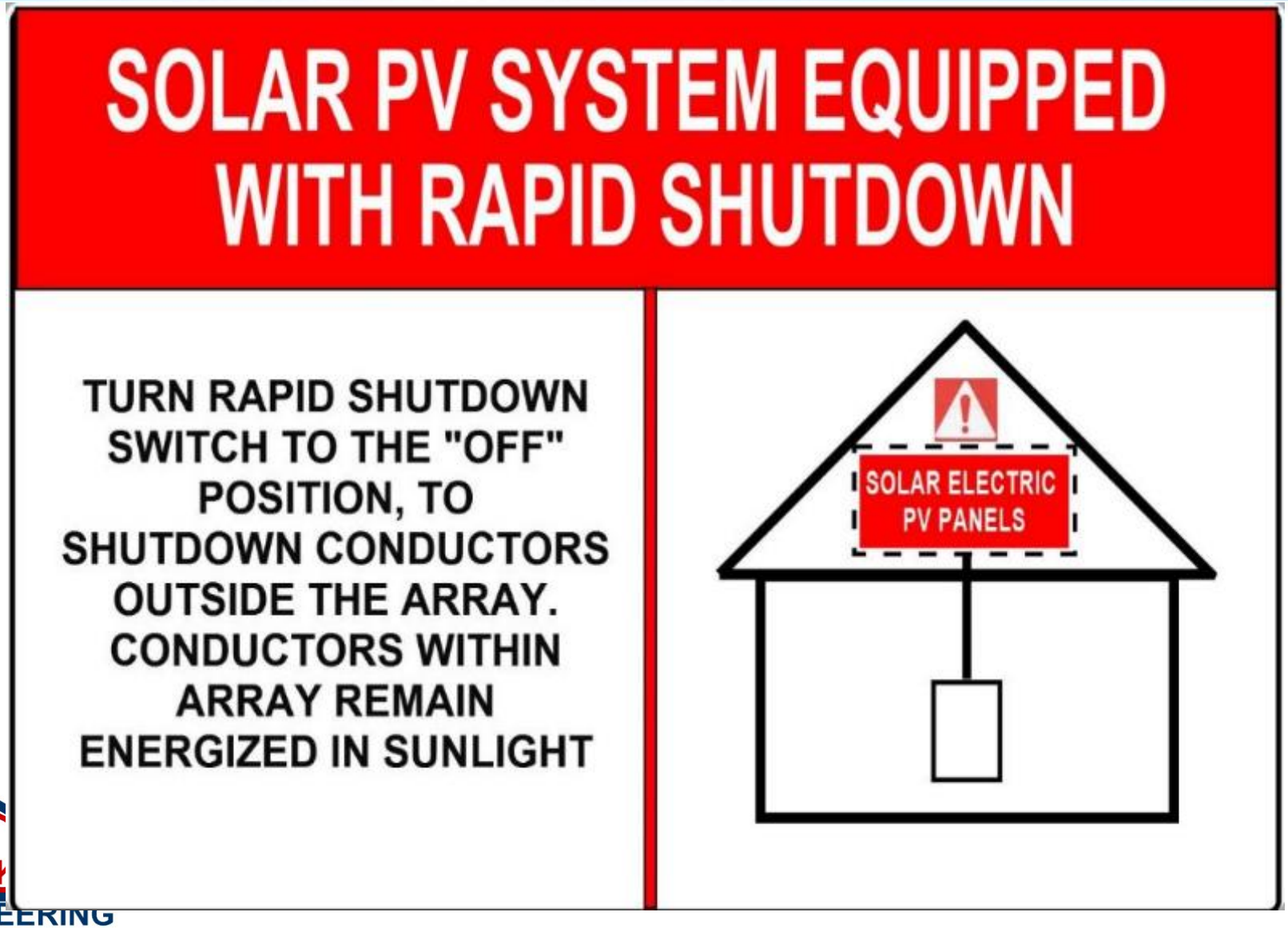
690.56(C) Buildings with Rapid Shutdown

For PV systems that only shutdown conductors leaving the array



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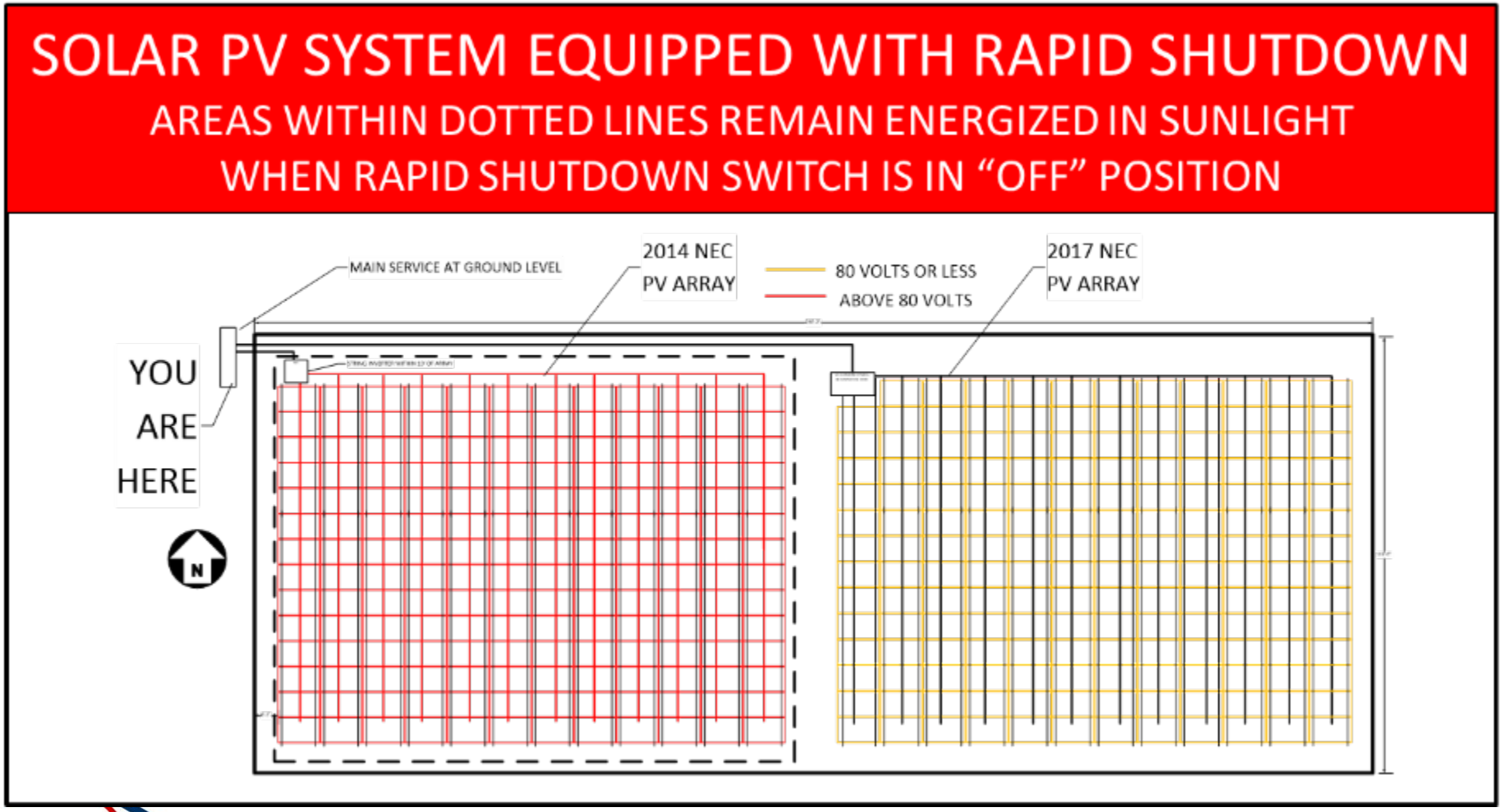
690.56(C) Buildings with Rapid Shutdown

For buildings with both types of PV systems



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690.56(C) Buildings with Rapid Shutdown

A rapid shutdown switch shall have a label located on or no more than 1 meter (3 ft) from the switch that includes the following wording:

RAPID SHUTDOWN SWITCH
FOR SOLAR PV SYSTEM

BROOKS
ENGINEERING

2017 NEC 690.12 Rapid Shutdown Current Compliance Options

1. String inverter located at the edge of the array with dc-to-dc converters or shutoff switching devices at each module.
2. Micro-inverters that segment each module (1-4 PV modules per inverter)
3. Building-Integrated PV array with no exposed metal or wiring and installed more than 8' from grounded metal.

BROOKS ENGINEERING

Key issues yet to be resolved for 2017 NEC version of rapid shutdown

- Standard needs to be developed to certify equipment.
  - Process is wrapping up that is focusing on products for the 2014 NEC and products outside of array boundary for the 2017 NEC
  - As the existing standard process is established for products address outside array boundary, work is starting to develop certification process for listed rapid shutdown PV array products

BROOKS ENGINEERING

NEC 2017 & Rapid Shutdown

CA Matthew Paiss, IAFF Rep to NEC

NREL PV Reliability Workshop, Mar 1, 2017

PV Focus Areas

- **Area #1**
  - **Partnering with IREC to deliver PV training.**
  - **Online and Classroom**
- **Area #2**
  - **Fire Code Setback Modifications 2018 code**
- **Area #3**
  - **Work on Rapid Shutdown Standards**

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Area #1

Training Development & Deployment

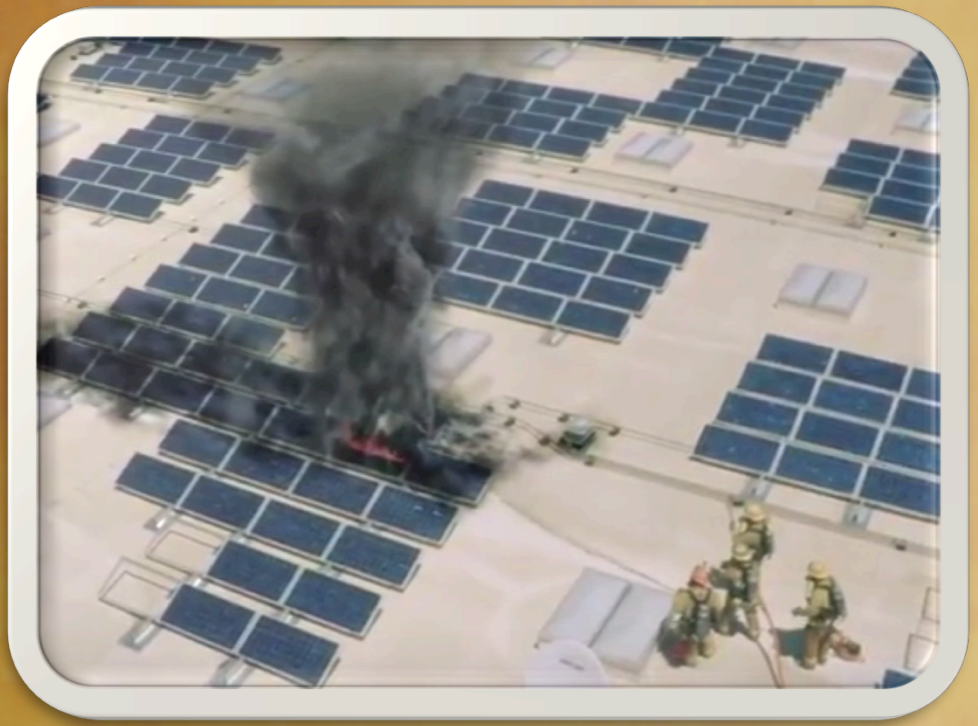
SOLAR PV SAFETY FOR FIREFIGHTERS (ONLINE)

- Online training
- Videos and simulations
- Self-paced/Interactive
- FREE
- Approximately 1300 have completed

IREC
Interstate Renewable Energy Council, Inc.

www.iaff.org/pvsafetytraining

SOLAR PV SAFETY FOR FIREFIGHTERS (ONLINE)



Target audience:

- Firefighters
- Incident commanders
- Training officers
- Fire prevention officials
- No solar knowledge required

Length: 3 hours

IREC
Interstate Renewable Energy Council, Inc.

www.iaff.org/pvsafetytraining

SOLAR PV SAFETY FOR FIREFIGHTERS (ONLINE)

IREC
Interstate Renewable Energy Council, Inc.

www.iaff.org/pvsafetytraining

SOLAR PV SAFETY FOR FIREFIGHTERS (ONLINE)

Simulation Video: Residence with PV

IREC
Interstate Renewable Energy Council

www.iaff.org/pvsafetytraining

Area# 2

Fire Code Setback Mod - 2018 IFC

605.11.1.2.1 Pathways to ridge.

- Two 36” wide pathways on separate roof planes. At least one pathway shall be provided on the street or driveway side of the roof.

605.11.1.2.2 Setbacks at ridge.

- Arrays < 33 % or less of total roof area, a minimum 18” wide setback is required on both sides of a horizontal ridge.
- Arrays > 33% require a 36” ridge setback.

Area# 2

Fire Code Setback Mod - 2018 IFC

605.11.1.2.2.1 Alternative setbacks at ridge.

- Where an automatic sprinkler system is installed within the dwelling and array < 66 % or less of total roof area, a minimum 18” wide setback is required on both sides of a horizontal ridge.

- For arrays > 66% total roof area, 36” ridge setback required.

Area# 3

Rapid Shutdown

Area# 3
Rapid Shutdown

- Issues to resolve:
  - *3 options to meet RSS (each with concerns)*
    - *Listed Rapid Shutdown Array*
    - *Less than 80Vdc within array*
    - *BIPV*

Area# 3
Rapid Shutdown

- Issues to resolve:
  - *Listed Rapid Shutdown Array*
    - *Standard does not exist yet*
    - *Will "Bird on Wire" concept work for damaged array?*
    - *Could result in full Voc array with many paths of conduction.*

Area# 3
Rapid Shutdown

- Issues to resolve:
  - *Less than 80Vdc within array*
    - *Most common method to meet RSS*
    - *Need data on reliability - are fears realized?*
    - *Reduces amount of conductors energized to VOC.*

Area# 3
Rapid Shutdown

- Issues to resolve:
  - *BIPV*
    - *Gives a pass to any BIPV without metal nearby*
    - *No requirement of design, or conductor placement.*
    - *Presents shock hazard if damaged.*

Identification Challenges

- BIPV systems present identification challenges.
  - Can be easily obstructed (low lighting, smoke, snow)
  - Potential for accidental conductor severing during ventilation

Identification Challenges

Is there a PV system here?

How about Here?

Or Here?

Identification Challenges

- Tesla Solar Roof planned to cover 100% of roof.
  - Extremely difficult to identify as PV, or even where PV stops.
  - Will be exempt from RSS - 690.12(B)(2)(3)
- Acceptance more likely with RSS to <50Vdc.
- Will require major shift in tactical approach

Development of New PV Array Level Rapid Shutdown Standard 2017 and Future Steps for 2019

Tim Zgonena
UL LLC

March 2, 2017

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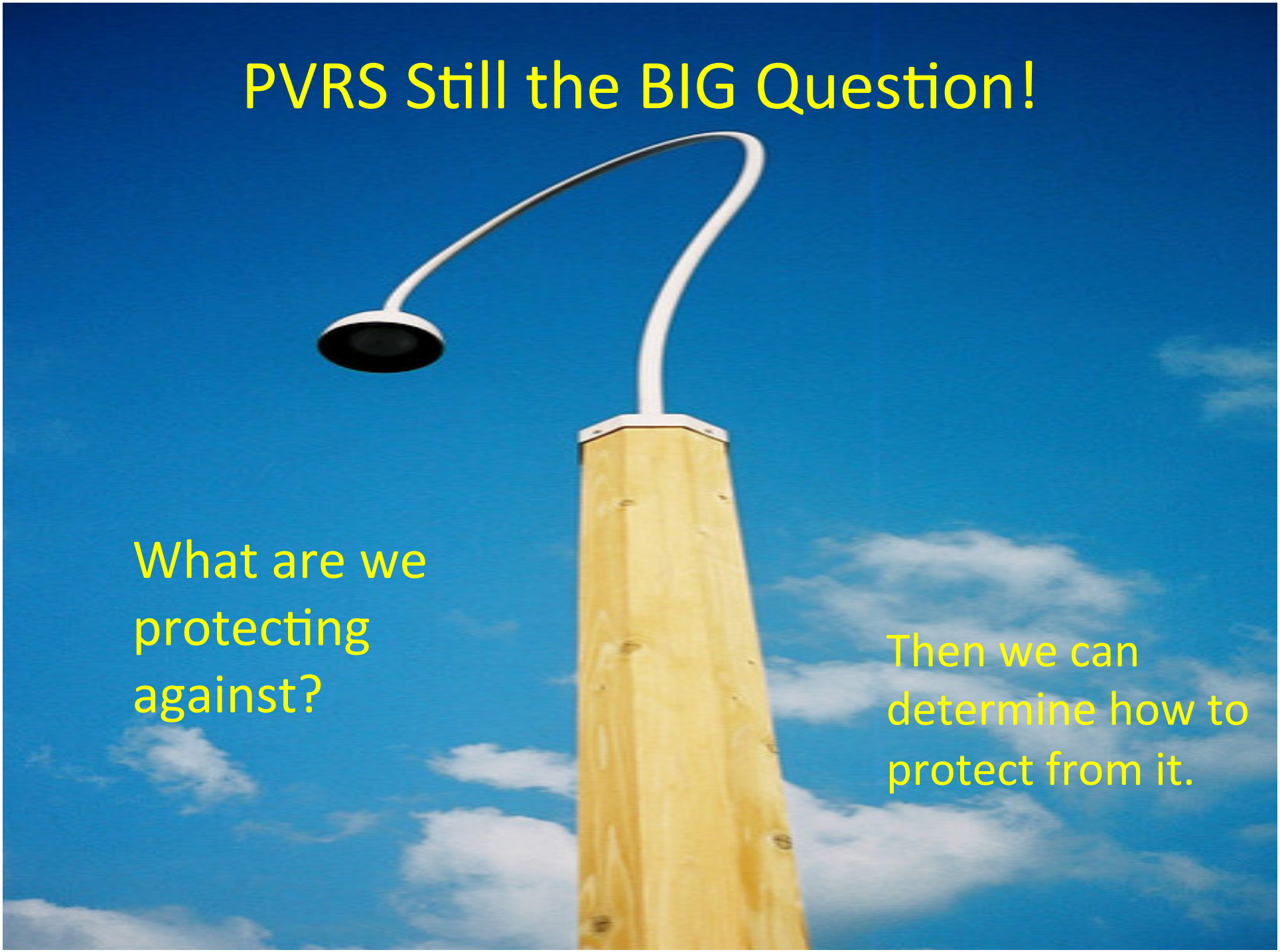
PVRS Still the BIG Question!



What are we protecting against?

Then we can determine how to protect from it.

Where are we now?

- Published PV RSS UL1741 CRD and corresponding UL1741 revision proposal being modified by the UL 1741 STP the consensus process.
- The PV RSS industry task group lead by Larry Sherwood is in the final stages of draft preparation and will be sent to the STP for ballot after the next meeting.

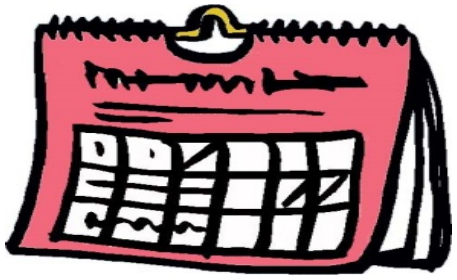
UL 2014 NEC
PV RSS Certification Categories

- **QIJS - Photovoltaic Rapid Shutdown Systems**
  - **UL Certified 3 systems**
- **QIJW -Photovoltaic Rapid Shutdown System Equipment**
  - **UL Certified >20 equipment**
- **QIJW2 - Photovoltaic Rapid Shutdown System Equipment – Component**
  - **>UL Certified 10 components**

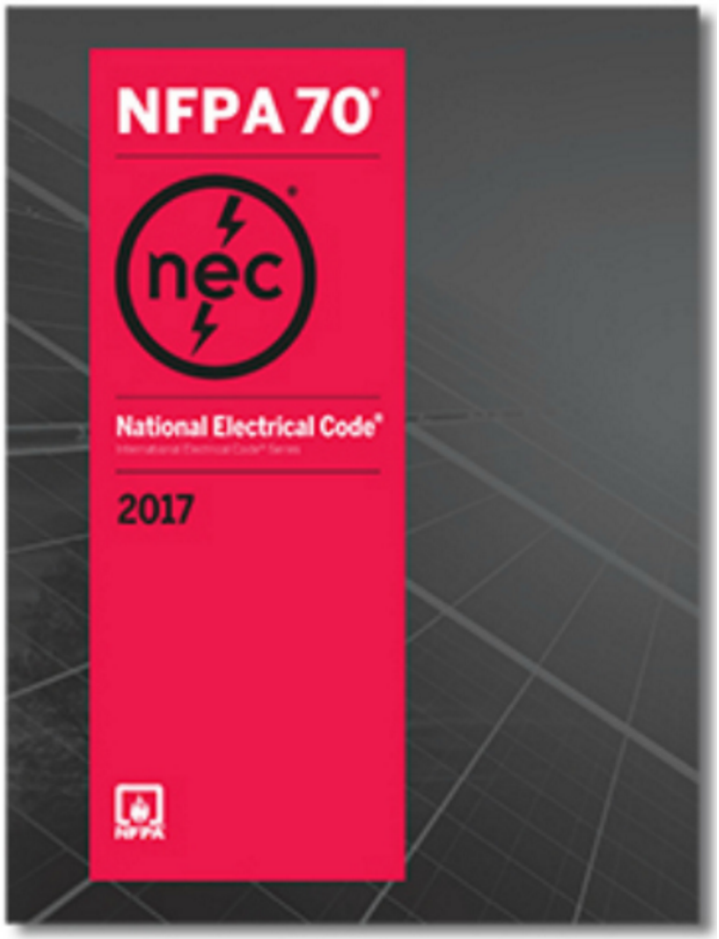
UL STP Timeline to Publish 2014 NEC PV RSS Requirements

- The initial Task Group draft was sent to the STP for comments.
- The task group addressed the comments and revised the draft.
- The task group is in the final stages of the ballot process
- The draft will be sent back to the 1741 STP to start the CSDS 45 day ballot cycle.
- After the ballot is finished the task group will review and respond to STP comments and that may include revisions.
- If there are revisions the draft will be recirculated so the STP can review the final draft and change their vote if they choose.
- Minimum 2/3 affirmative votes to reach consensus.

Likely publication in June 2017.



Development of PVRS Standard for Compliance with the 2017 NEC 690.12



We have 3 Ds!

Destination
Direction
and
Deadline

New science based research and leverage existing technology where we can.

2017 Revisions to NEC 690.12

690.12 revision to include new requirements for rapid shutdown protection internal to a PV array. This is proposal requires the following options;

1) Listed PV array level protection system.
2) 80V, 30 Second Limit for controlled conductors internal to the array.
3) PV arrays with no exposed wiring methods, no exposed conductive parts, and installed more than 8ft from exposed grounded conductive parts or ground.

New Informational note to better explain possible implementations to reduce shock hazards by methods such as limiting access to exposed components that might become energized, reducing the voltage difference between energized components, limiting the electric current that might flow in an electrical circuit involving personnel with increased resistance of the conductive circuit, or by a combination of such methods.

New UL Standard to Address PV Array Protection Related to Fire Fighter Safety and Rapid Shutdown

There is significant agreement and support from PV industry and fire fighters to develop a new consensus safety standard to address PV Array protection including Rapid Shutdown.

Based upon PV industry and Fire Fighter community input, UL is developing a structure/framework for the new standard.

It is critical that we do not make the same mistake again and assume we know the solution to some unknown questions.

New DOE Research Sandia and UL

Expansion on original UL Fire Research to determine;

1. Who needs protection?
2. Protection from what hazards?
3. Under what electrical, environmental and fault conditions?

- Evaluate different configurations of PV .
- Define safe states for PV systems operation under emergency conditions.
- Determine risk of electrical shock in ungrounded, isolated PV arrays.
- Develop a Fire Fighter body impedance values accounting for tools, gear and PPE.
- Fire Fighter tactics and risk scenarios
- Evaluate electrical enclosure protection from firefighting liquids.
- Harmonize safety standards and committee work.

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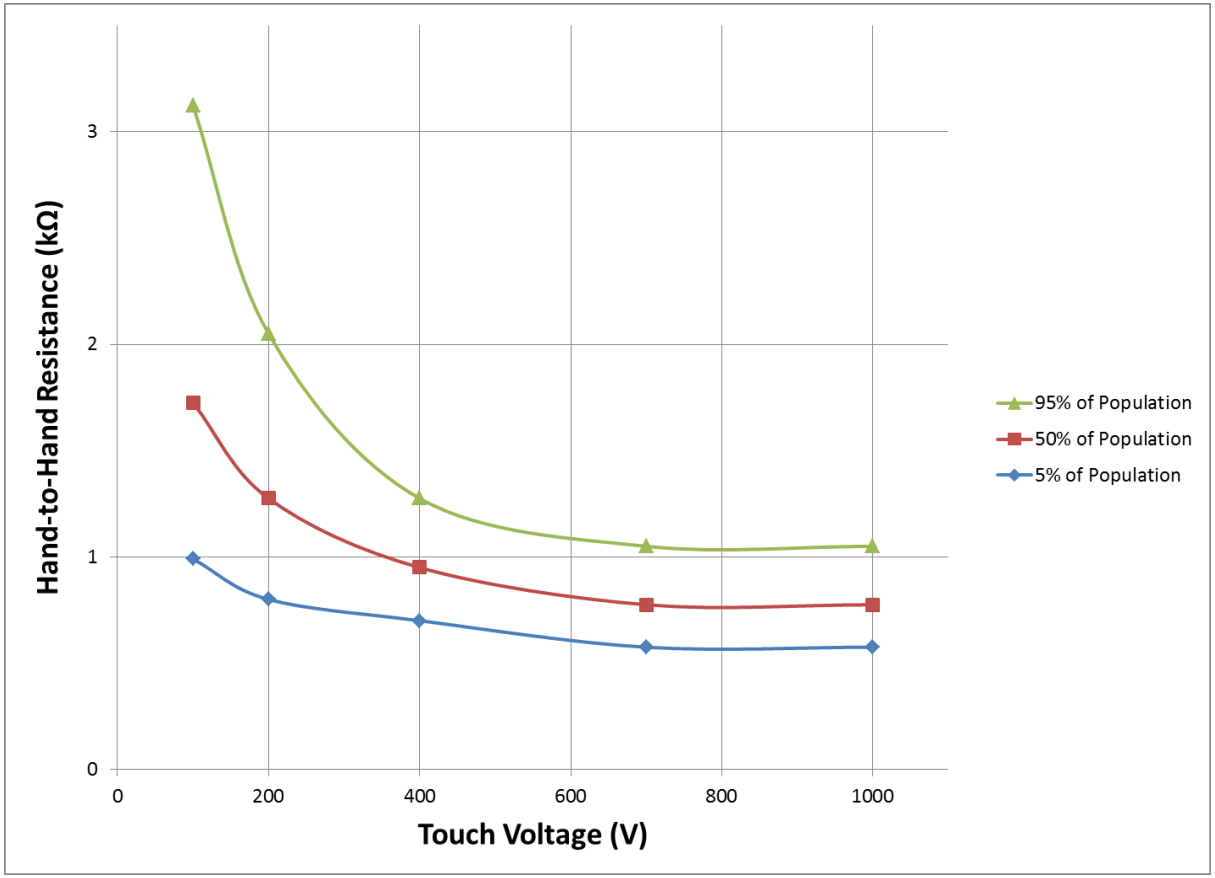
Fire Fighter Body Model Impedance

- Document Search
- Modeling/Simulation
- Actual measurements of fire fighter PPE

IEC 600479 - Effects of current on human beings and livestock,
Table 2 – Total body impedances *Z*T for a current path hand to hand a.c. 50/60 Hz, for large surface areas of contact in water-wet conditions.

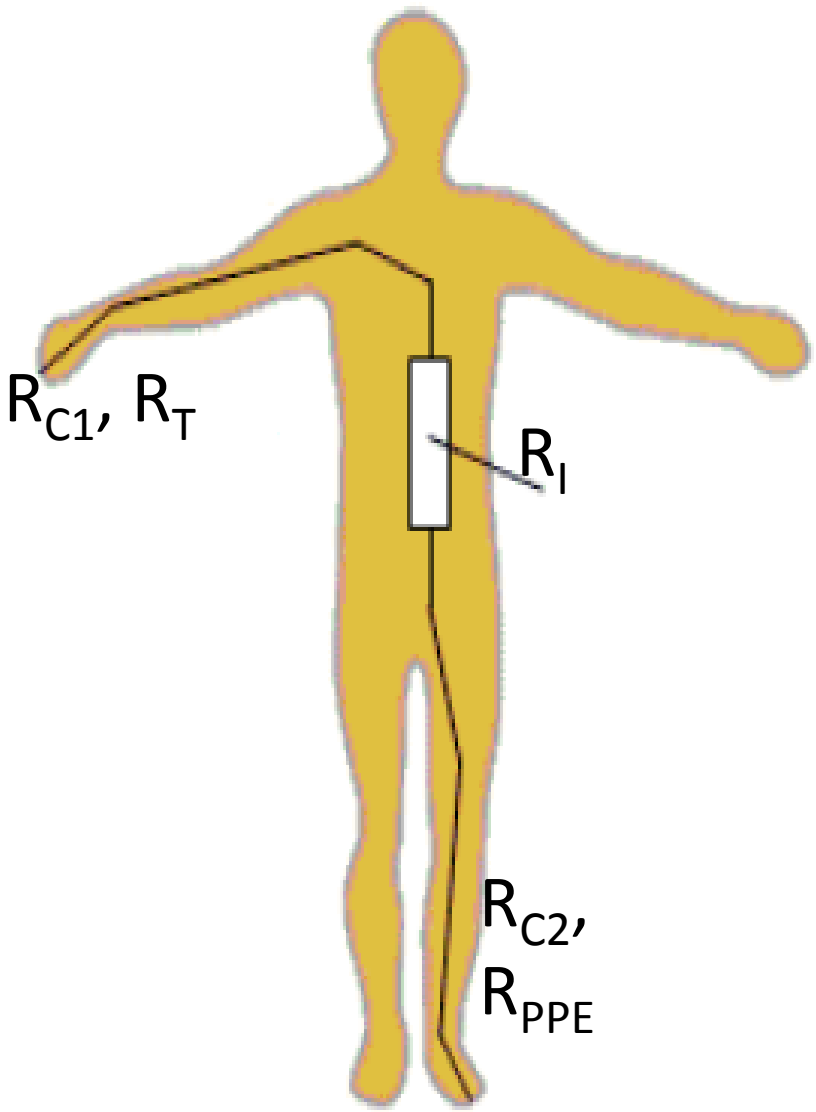


Body impedance depends on:

- Current path
- Touch voltage
- Duration of current flow
- Frequency
- Degree of skin moisture
- Surface area of contact
- Pressure exerted
- Temperature

Body impedance reduces asymptotically with increasing touch voltage.

- **<u>Other values exist for d.c. voltages</u>**



R_{C1}, R_{C2} – Contact resistances (skin)

R_T – Tool resistance

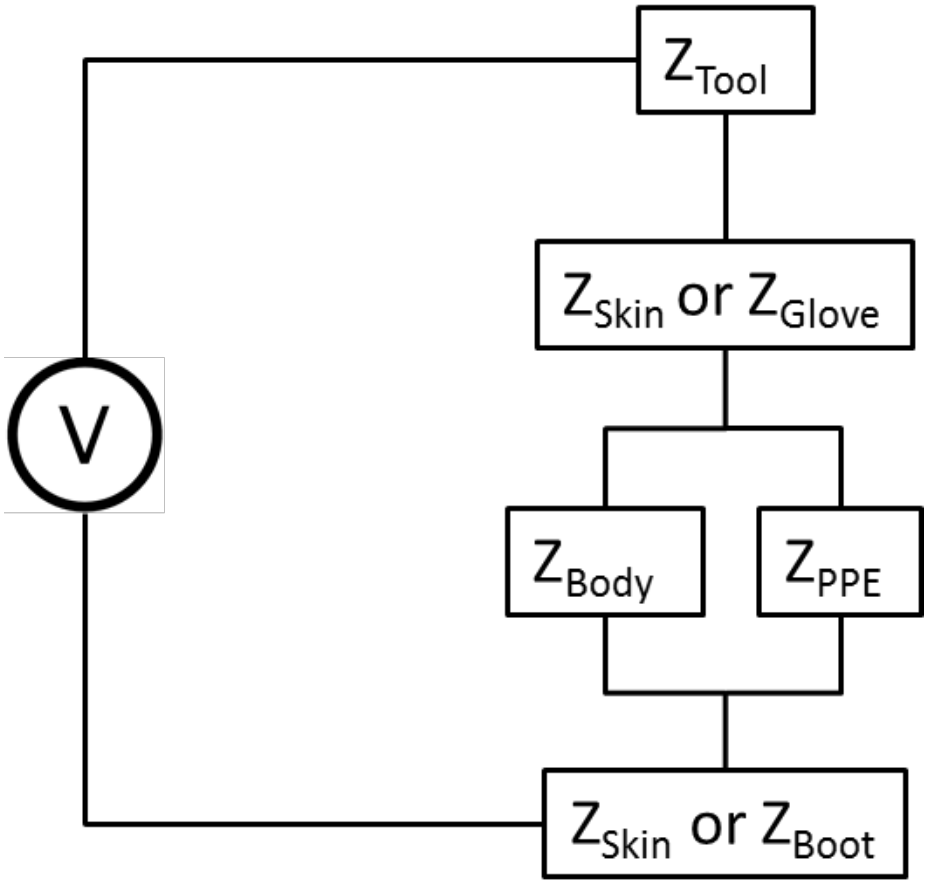
R_I – Internal body resistance

R_{PPE} – PPE resistance

Hand-to-foot impedances are typically 10-30% lower than hand-to-hand.

GIZ, et. al., "Evaluación de los riesgos de incendios en plantas fotovoltaicas y elaboración de planes de seguridad que minimicen los riesgos", March, 2015.

Components of the Fire Fighter Impedance Model



We plan on expanding on the data, based on IEC/TS 60479-1 and other standards, to include:

- PPE clothing
- Tools
- Other relevant factors

These could be evaluated with other variables:

- PPE moisture
- Skin moisture
- Anatomical factors

DC vs. AC factors need to be considered.

Simulated Hazard Currents Based Upon PV System Voltage vs Total Fire Fighter Impedance

- **As array V_{oc} increases**
  - **Danger to personnel becomes larger**
  - **But kW rating has almost no effect in hazard level**
  - **Most current hazard < 150 mA fatality limit, but still not in < 2mA zone**

Current Hazard in (mA)

Array V_{oc} (V)

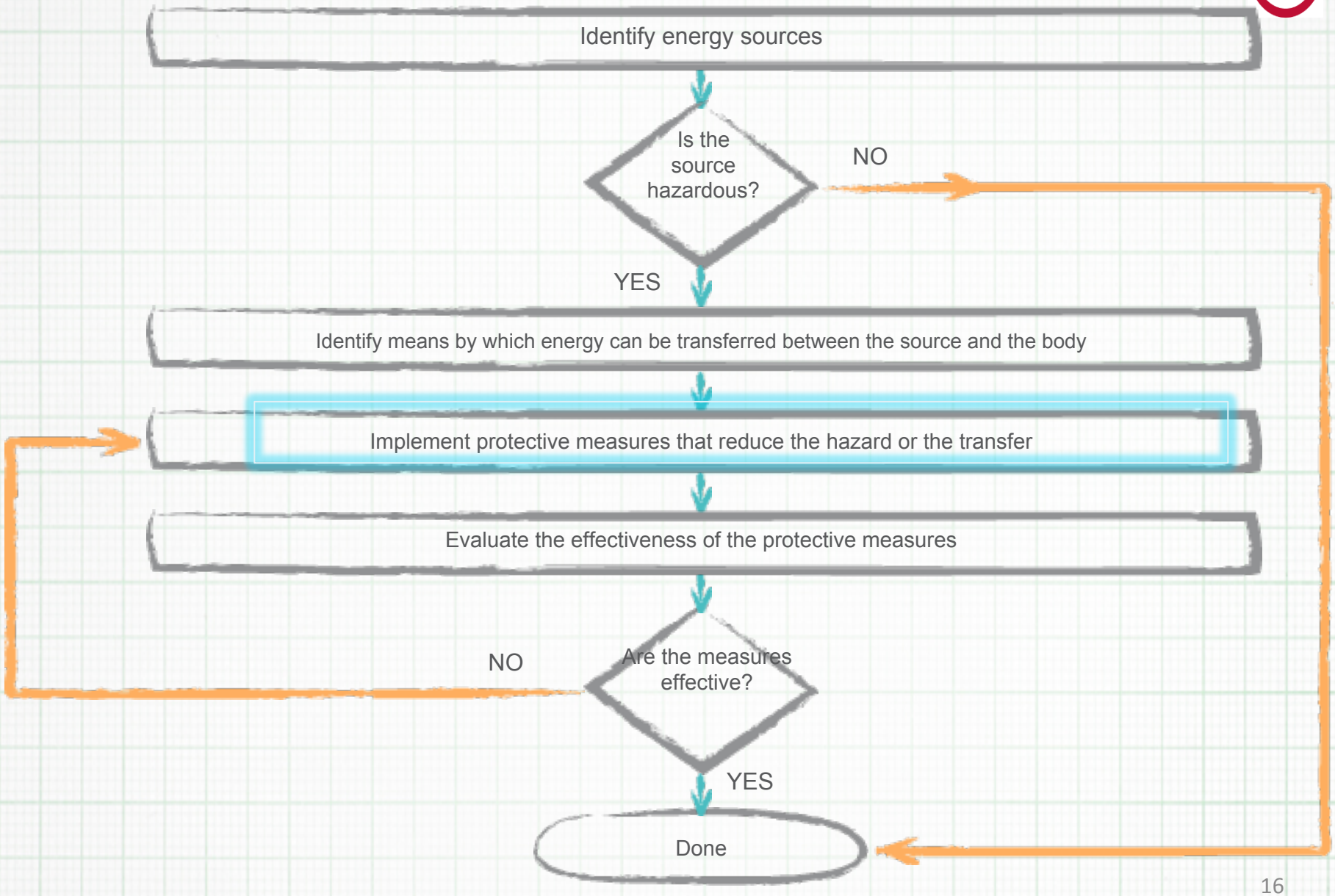
Firefighter Impedance (Ω)	55.8	111.6	167.4	446.4	558.0	669.6	781.2	1,116.0	1,674.0
100	-553.42	-1093.28	-1611.26	-2085.11	-2426.77	-2497.40	-2499.85	-2499.98	-2499.98
600	-92.98	-185.68	-278.10	-370.20	-461.99	-553.43	-644.50	-915.22	-1355.87
1,100	-50.75	-101.42	-152.00	-202.51	-252.92	-303.25	-353.48	-503.59	-751.61
1,600	-34.90	-69.76	-104.58	-139.36	-174.11	-208.81	-243.48	-347.21	-519.18
2,100	-26.59	-53.16	-79.71	-106.24	-132.74	-159.22	-185.68	-264.91	-396.46
2,600	-21.48	-42.95	-64.40	-85.84	-107.26	-128.67	-150.06	-214.15	-320.65
3,100	-18.02	-36.02	-54.02	-72.01	-89.98	-107.95	-125.90	-179.71	-269.17
3,600	-15.51	-31.02	-46.52	-62.01	-77.50	-92.98	-108.45	-154.81	-231.93
4,100	-13.62	-27.24	-40.85	-54.46	-68.06	-81.65	-95.24	-135.97	-203.74
4,600	-12.14	-24.28	-36.41	-48.54	-60.67	-72.79	-84.90	-121.22	-181.66
5,100	-10.95	-21.90	-32.85	-43.79	-54.73	-65.66	-76.59	-109.36	-163.89
5,600	-9.97	-19.95	-29.91	-39.88	-49.84	-59.80	-69.76	-99.61	-149.30
6,100	-9.16	-18.31	-27.46	-36.61	-45.76	-54.90	-64.05	-91.46	-137.09
6,600	-8.46	-16.92	-25.38	-33.84	-42.30	-50.75	-59.20	-84.54	-126.72
7,100	-7.87	-15.73	-23.60	-31.46	-39.32	-47.18	-55.03	-78.59	-117.81
7,600	-7.35	-14.70	-22.05	-29.39	-36.73	-44.08	-51.42	-73.43	-110.08
8,100	-6.90	-13.79	-20.68	-27.58	-34.47	-41.36	-48.24	-68.90	-103.29
8,600	-6.50	-12.99	-19.48	-25.97	-32.46	-38.95	-45.44	-64.90	-97.30
9,100	-6.14	-12.28	-18.41	-24.55	-30.68	-36.81	-42.95	-61.33	-91.96
9,600	-5.82	-11.64	-17.45	-23.27	-29.08	-34.90	-40.71	-58.14	-87.17
10,100	-5.53	-11.06	-16.59	-22.12	-27.64	-33.17	-38.70	-55.27	-82.86

< 2 mA
2 - 150 mA
> 150 mA

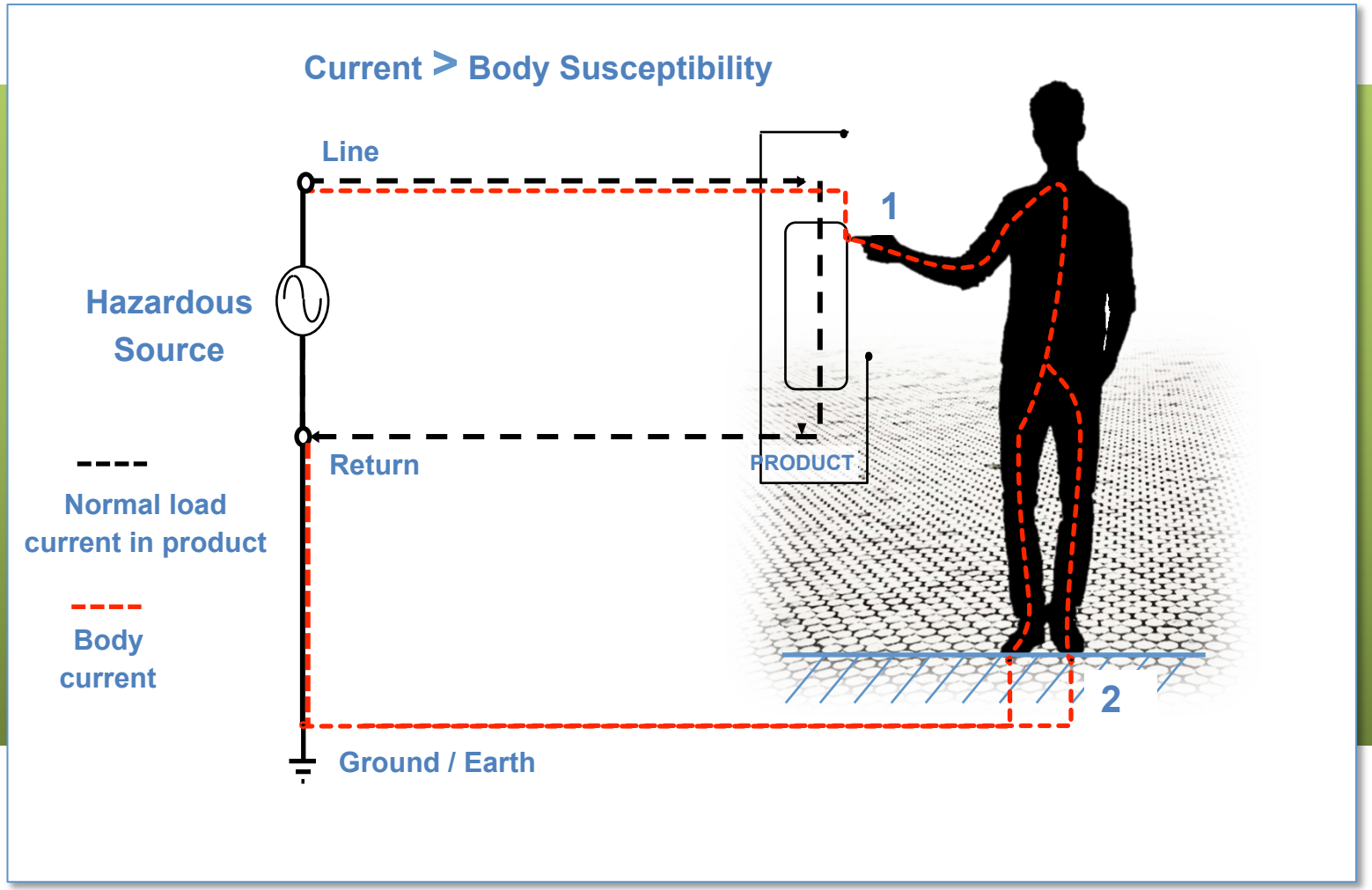
It Is Not Just the Voltage

While limiting voltage is one means to reduce electric shock hazards there are many other ways to reliably reduce shock hazards. This new standard will develop commonly applied other protection methods for this PV Array application in a manner that is based upon engineering and science.

Hazard Based Protective Measures

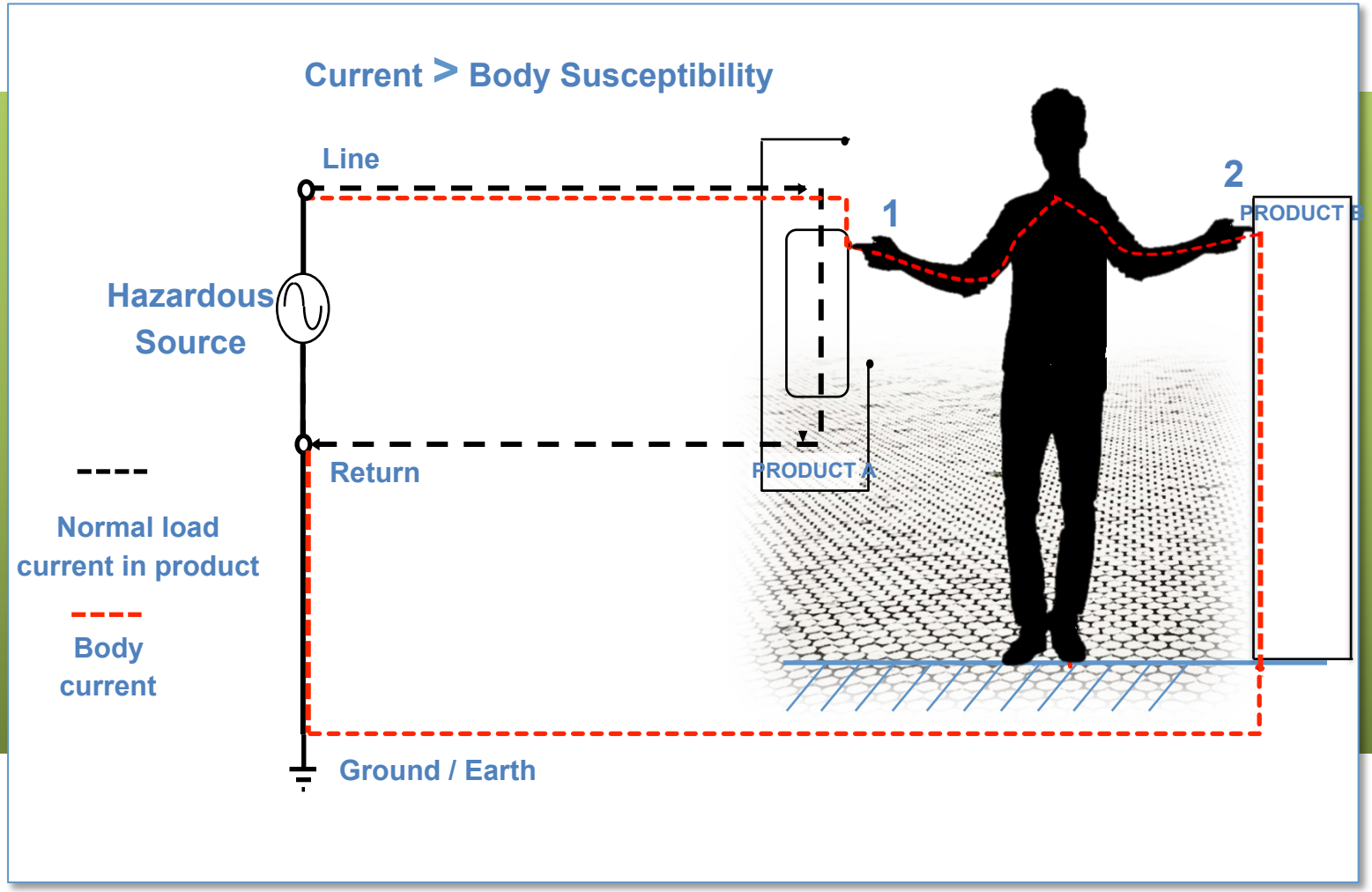


General Safety Objective: No Hazardous Body Current



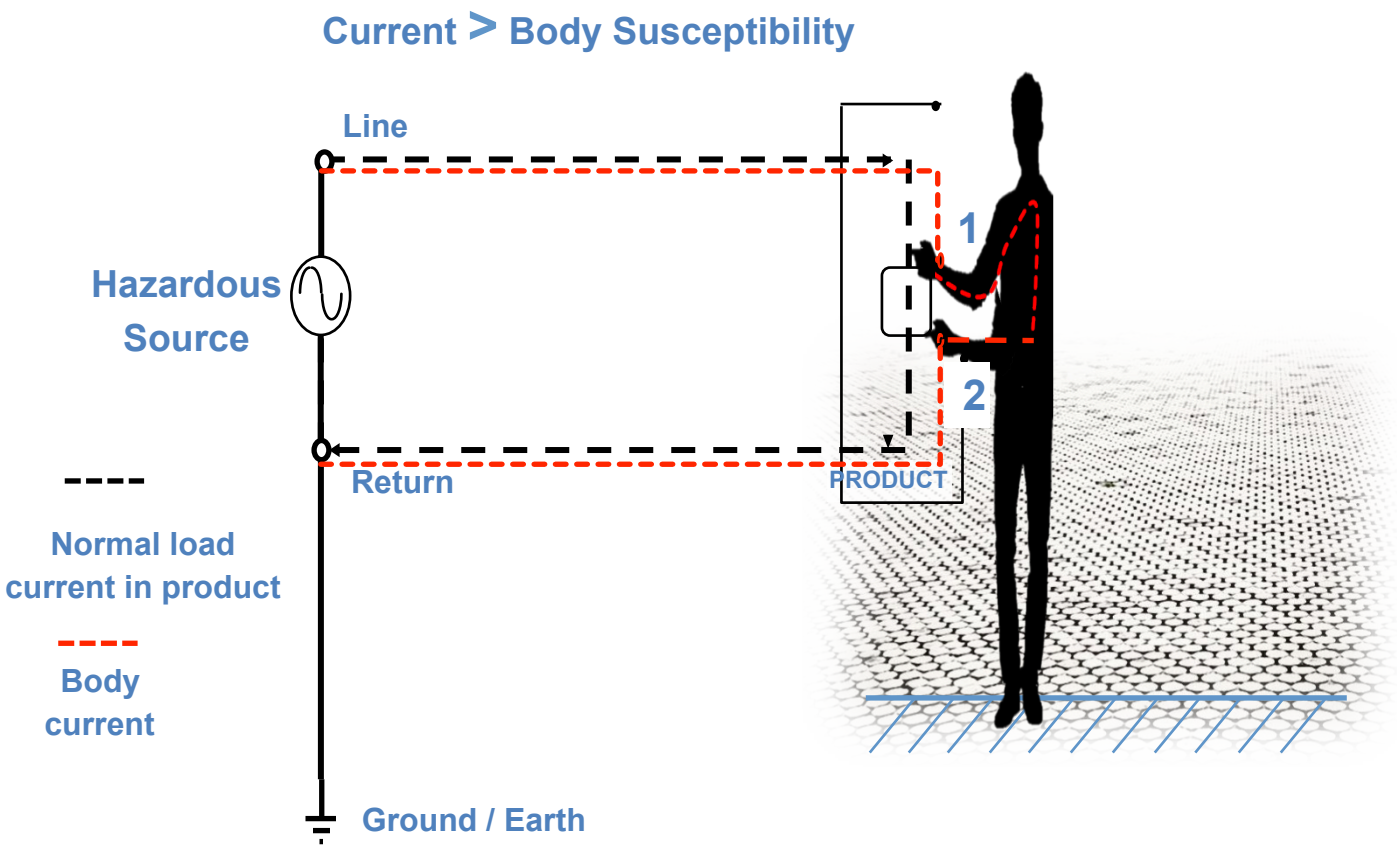
Hazardous body current to be reduced by safeguards

General Safety Objective: No Hazardous Body Current



Hazardous body current to be reduced by safeguards

General Safety Objective: No Hazardous Body Current



Hazardous body current to be reduced by safeguards

Mitigate Electric Shock Injury by Reduction of Energy Transfer to a Person

Safeguard Categories

1. Equipment
2. Personal
3. Site
4. Behavioral

Safeguard Mechanisms

1. Disconnection
2. Attenuation
3. Impedance
4. Deflection
5. Containment
6. Isolation

Goals for New PV RSA Standard

- Develop standard/requirements for PV array RS systems that is:
  - Array /system based (not single solution focused)
  - Science-based
  - Written to address specific defined hazards and safety concerns for fire fighters.
  - Written to define specific normal and abnormal conditions of use.
  - Written to be implementation agnostic so as to allow for a range of product designs, concepts and innovations.
  - Voltage is a real concern, but more importantly is that this document identifies a way to keep the fire fighter out of a hazardous current path

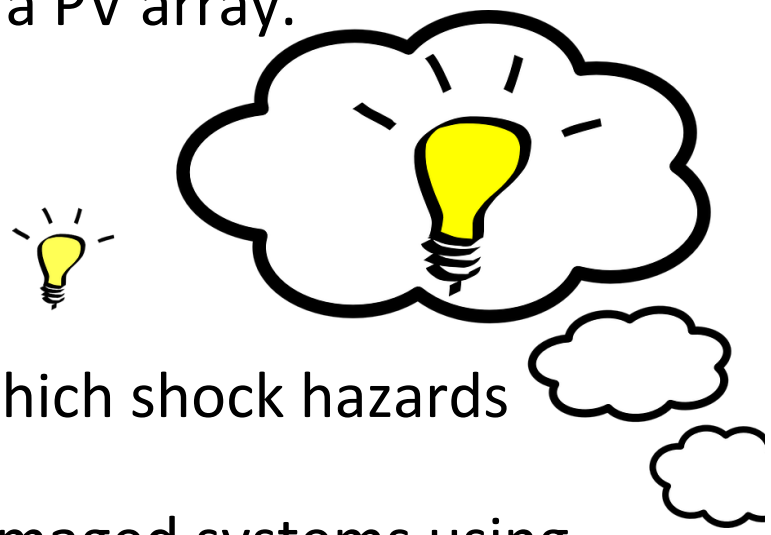
New UL Standard for PV Rapid Shutdown Arrays

- Implementation / Solutions for 690.12 2017 will come in a variety of shapes and sizes.
  - Electrical
  - Mechanical
  - Installation based
  - Combinations there of

- This new standard will make use of the UL1741 electrical PVRS equipment requirements as well as other standards for PV modules UL1703, their installation UL2703, PV wiring UL9703 and more.

New Array Standard Functional Requirement Concepts

- Evaluate equipment and means for providing a reduced level of hazard inside the boundary of a PV array.
  - Limit hazardous body current by:
    - Limited access to live parts
    - Reduce voltage of live parts
    - Limit current through body
    - Combinations of above.



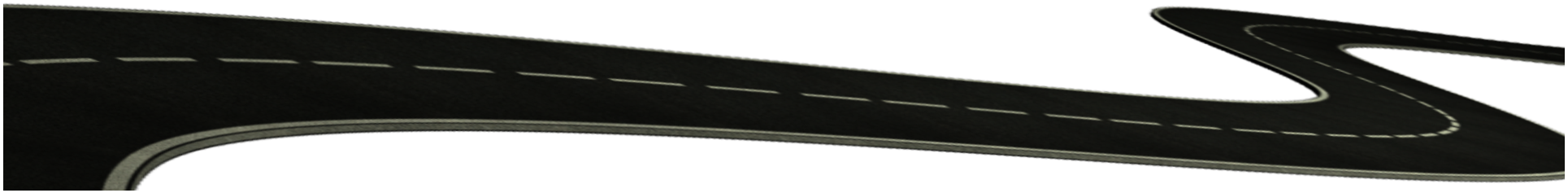
- Specify array damage conditions for which shock hazards must be evaluated.
- Establish an acceptance criteria for damaged systems using risk-based hazard assessment
  - Understanding that hazard elimination is not possible
  - Using established methods from other industries

Developing the Standard

- Establish method of characterizing tolerable level of electrical hazard risk to comply with NEC article 690.12 (2017).
- Specify requirements for undamaged and single point failure conditions
- Specify array damage conditions for which shock hazards must be evaluated
- Define compliance criteria / limits based upon appropriate impedance models of personnel in the context of firefighter operations (body impedance, clothing and gear, tools, etc.)
- Specify tests designed to simulate inadvertent contact with array components by firefighter personnel, based on typical firefighter rooftop operations and associated scenarios for accidental contact.
- Establish a functional safety scoring system

Path Forward for New UL PVRS Standard

- Complete UL 1741 PVRS requirements for 2014.
- Develop a STP for the new standard expand from 1741 electrical task group to include experts from all PV related industries.
- Start up 2017 PVRS task group calls.
- Define what can we do & what can we not do?
- Incorporate results of Sandia / UL research to expand on UL's original PV Fire report.
- Task group efforts
- Voltage and current safety limits for this application.
- Develop educational material Do's and Don'ts



UL to Develop a New STP for PV Rapid Shutdown Systems

PV module mfrs (UL1703)
Electronics (UL1741)
PV rack mfrs (UL2703)
Harness mfrs (UL9703)
PV wire, connector and harnesses (9703, 6703,etc)

Fire Fighting Community
AHJs
Functional safety and risk assessment experts
National labs
Industry experts
Others

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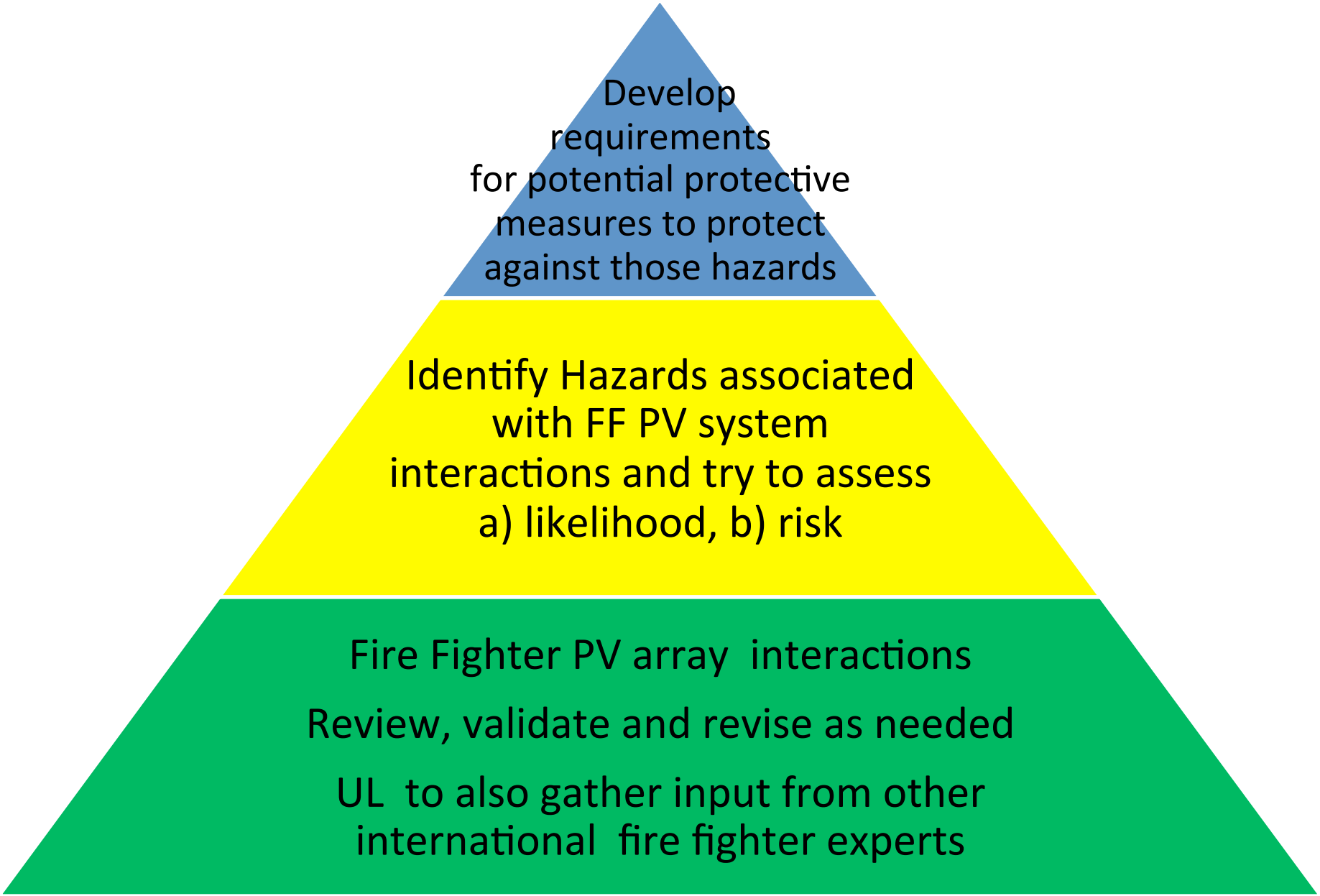
Fire Fighter Interactions with PV Systems



Fire Fighter PV Array Interactions

Fire Fighters have a tough job and they need to make due with the cards they are delt.

While they will not intentionally be cutting through PV modules, it is likely that a fire fighter could make use of a PV array rack system to stabilize themselves while performing their work.

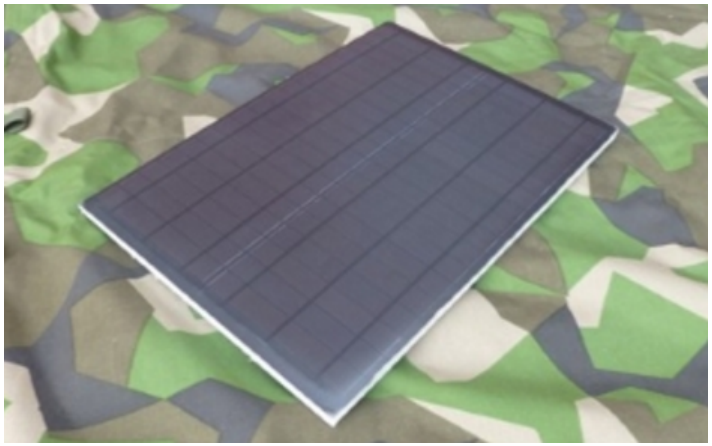
One consideration is to limit access to PV wiring and backs of PV modules.

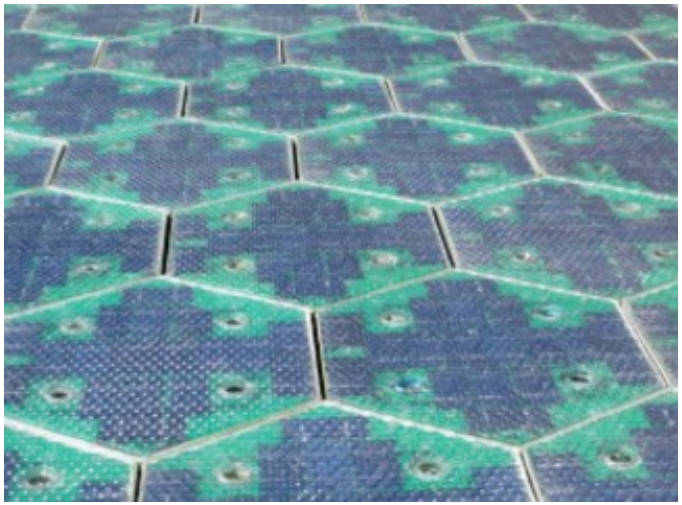
New Generation of Tough PV

Bulletproof solar panels protect military equipment

December 11, 2014

Source: ASM International





Bulletproof Glass In The News – Solar Powered Roads

MAY 15, 2014 / BULLET PROOF GLASS, BULLET RESISTANT MATERIALS

Functional Safety for PVRS

- Levels of protection including both active and passive safeguards
- This methodology will allow a means to address the many "What If" scenarios that could happen in the real world that are unlikely to all happen concurrently.
  - Functional safety
    - Researching other potentially related existing standards
    - System level evaluations is related yet very different from equipment level evaluations.
    - Example Medical – various levels of protection from known hazards for the specific situation with multiple levels of active and passive protection. X-ray machine vs Defibrillator vs Thermometer

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Risk Based Hazard Mitigation Probabilities and Severity

- Criteria for protection depend on probabilities of hazard and harm.
- Yellow areas are the challenge for this standard
- Real world system failure data helpful for validation
- IEC 61508 defines approaches when actual data not available

			Potential Consequences				
			L6	L5	L4	L3	L2
			Minor injuries or discomfort. No medical treatment or measureable physical effects.	Injuries or illness requiring medical treatment. Temporary impairment.	Injuries or illness requiring hospital admission.	Injury or illness resulting in permanent impairment.	Fatality
			Not Significant	**Minor**	**Moderate**	**Major**	**Severe**
Likelihood	Expected to occur regularly under normal circumstances	**Almost Certain**	**Medium**	**High**	**Very High**	**Very High**	**Very High**
	Expected to occur at some time	**Likely**	**Medium**	**High**	**High**	**Very High**	**Very High**
	May occur at some time	**Possible**	**Low**	**Medium**	**High**	**High**	**Very High**
	Not likely to occur in normal circumstances	**Unlikely**	**Low**	**Low**	**Medium**	**Medium**	**High**
	Could happen, but probably never will	**Rare**	**Low**	**Low**	**Low**	**Low**	**Medium**

Numerous Possible Implementation Form-factor for Compliant 2017 690.12 Listed Arrays

- The Term “Rapid Shutdown Array” results in preconceived notions and assumption based on the verbiage in the name.
- Some viable solutions will include features and functions that are not well described using the rapid shutdown terminology.
- Consideration to use a different title for the new standard to better describes the ultimate goal of the protection being provided.
- Different solutions may need different markings and signage.

Options and Confusion

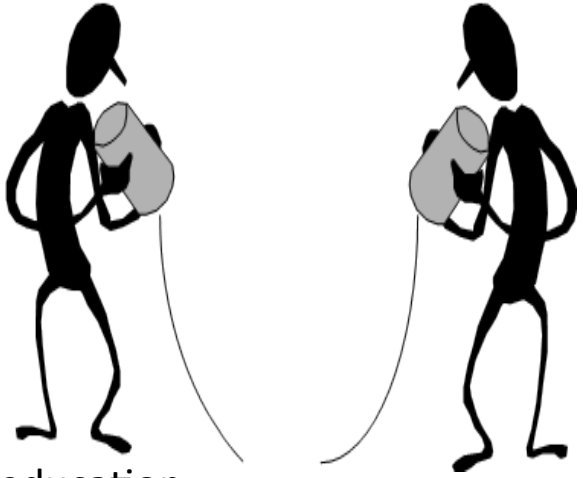
Photovoltaic Emergency Hazard Control Systems

- Does this title better describe our intended goal?

Future Considerations
How do we Address:

- Multi-mode products that do not go off line when the grid is disconnected
- Inverters/converters with multiple input sources or different input sources
- BIPV you can not identify as PV

Fire Fighter Outreach Challenges



- 30k fire department with different requirements and priorities
- Little to no mandatory training and continuing education
- No single communication means to get new training to firefighters

- UL FSRI has 10 full-time staff dedicated to firefighter research and education
- They have covered many firefighting topics including PV Firefighter Safety
- PV is one of hundreds of topics the fire service has to be prepared to deal with during an emergency.

- UL FSRI issued report and FREE online training program in November 2011 and we estimate the program has been viewed by 5% of the fire service. Many more have received the message through various outreach efforts but many do not understand the hazards associated with PV.

- The PV challenges also change and evolve so there is no static target we are preparing them for. There is no baseline PV knowledge the fire service has, it is all across the board. We may have to consider the least common denominator or at least a reasonable substitute.

Thank you

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Task Group Revising the UL CRD/ UL1741 SPT Draft Proposal for PVRS Equipment and Systems for 2014 NEC

- Protection of Emergency Personnel
- Status Indicators, Initiators and Reset Devices
- PVRSS that Includes PV Disconnect Functionality
- Operational Tests for PVRSS Verification of levels – Controlled Conductors.
- Verification Testing of PVRSS at Rated Extremes
- Power Supply Ride Through
- Inverters Certified as PVRSE
- PVRSS and PVRSE Functional Safety Using Solid State Controls
- Functional Safety Standards
- Conditions to be Addressed for a PVRSS/PVRSE
- Environmental Stress Testing (based on UL991)*
- Ratings, Markings and Instructions.

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What is an Array?

- **NEC 2017 Definition**
  - **Array.** A mechanically integrated assembly of module(s) or panel(s) with a support structure and foundation, tracker, and other components, as required, to form a dc or ac power-producing unit.

- **Summarized**

An Array includes all PV equipment, including mounting system and inverters, where constructed together in one location.

We Need a New Name for PVRS

- PVRS is not rapid nor is it shutdown.
- Possible good words to describe the attributes
  - Isolation
  - Protection
  - Array
  - Fire Fighter

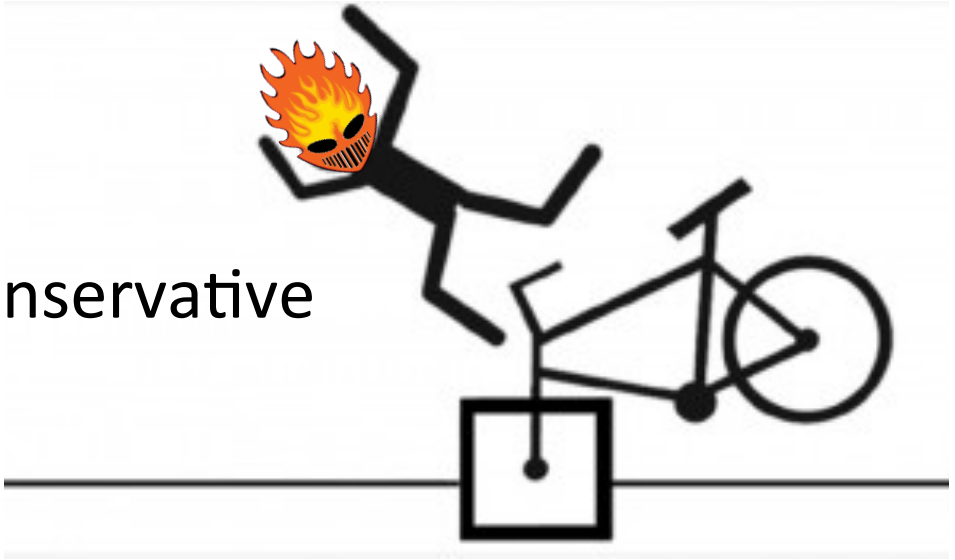
- Some new ideas
  - Fire Fighter Array Protection -FFAP
  - PV Protection System - PVPS
  - Fire Fighter PV Protection System - FFPPS

From UL Fire Research Team

- Do we need to under this R&D project consider and address existing fielded older systems?
- Dissemination and Information - UL has an excellent Fire Fighter network. All major fire magazines are on the advisory board for UL Fire R&D.

Fire! is Fire! is Fire!
Ground Fault or Arc Fault

- US has reached general task group agreement that we should use the 750 Joule energy limit for fire that was developed from PV AFCI research.
- This 750 Joule limit will be applied for PV systems on buildings.
- Adjustable settings.
  - Default setting most conservative



NREL/SNL/BNL PV Module Reliability Workshop

Thursday afternoon discussions:

Accelerated testing of power electronics:

• The statistics often point to the power transistor (or some other electrical component) as the cause of failure, but it may be that this is a secondary failure and that the primary cause is a fan or something else. It can be quite difficult to identify the root cause and identify how to prevent further failures.
• In general, there is an interdependency of mechanisms that makes it difficult to test inverters.
• Are the proposed standards adequate? The draft IEC 62093 is definitely a step in the right direction. It won't catch all of the failure mechanisms, but it will uncover a lot of the failure mechanisms you'll see in the field.
• We also need a QA standard for inverters: Workmanship and quality are paramount.
• It could be useful to define standard use profiles, too. This is something that is not so proprietary.
• EMI is a big issue and will be increasing in importance as we move to more advanced technology.
• Some claim that a sealed inverter doesn't need to be subjected to a dust test, but if you remember when IEC 61215 added the wet leakage test, it made junction boxes get a lot better. Would inverters also be improved if they had to pass a dust test?
• For inverters, the more you try to keep moisture out, the more likely you are to trap moisture inside.
• Modeling is a useful tool to understand moisture.
• We have used an activation energy of 0.79 eV, does anyone know where the number comes from? It's a doubling every 10°C. Al and Cu diffusion have been found to have this activation energy.
• We need to focus on the whole value chain; we should look at the issues of common mode grounding.

Rapid shutdown:

• If a module puts out > 80 V, what are the options for compliance? A listed array; no grounded metal in the area.
• Could you elaborate on some of the "functional safety requirements" that UL will write? When medical products go through functional safety evaluations, they look at the reliability of the hardware and the software and look at the specific risks. We use functional safety evaluations for ground fault and arc fault protection.
• For the 2020 code cycle, will we be able to wrap all requirements into one option? We could try, but there may be push back. Having multiple options is popular.
• You're moving toward a hazard-based approach. Are people supportive? It's managing risk; we don't have a good option otherwise. To the extent that we are successful in reducing risk, they are on board. If we don't blow smoke, they are very open minded.
• Are all devices listed by UL? Interek has certified some.

www.nrel.gov

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