Solar Access to Public Capital (SAPC)
Working Group

Best Practices in PV System Installation

Version 1.0, March 2015

NATIONAL RENEWABLE ENERGY LABORATORY

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
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C. Doyle
IBTS, Dividend Solar
Austin, Texas

A. Truitt
Acuity Power Group
Denver, Colorado

D. Inda
Clean Power Finance
San Francisco, California

R. Lawrence
North American Board of Certified Energy Practitioners
Clifton Park, New York

R. Lockhart
Acuity Power Group
Wellesley Hills, Massachusetts

M. Golden
Efficiency.org, IBTS
Sausalito, California

NREL Technical Monitor: Michael Mendelsohn

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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

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Disclaimer

The attached Best Practices document was developed through an industry-organizing process convened by the National Renewable Energy Laboratory (NREL). The process was open to a wide array of industry members to get a broad range of perspectives. The document represents the result of long discussions and negotiations on a variety of topic areas of interest to the participating stakeholders. The document does not reflect NREL's or the U.S. Department of Energy's endorsement of any activity or group of activities. Rather, the document is designed to provide a reasonable protocol associated with photovoltaics (PV) system installation supported by the industry stakeholder process in order to improve the energy and cash flow production capability of the PV generating assets in the field.

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Contributors

Johan Alfsen, Quick Mount PV
Mark Berger, NextGrid Technologies
Megan Birney, Wiser Capital
Brian Brookman, Solar Energy Industries Association
Joe Cain, DNV GL
John Dalton, Burnham Energy
Lyleen Dauz, Burnham Energy
Matt Denninger, Advanced Energy Industries
Mike Dershowitz, ModSolar
CJ Desantis, CounterPointe Energy Solutions
Paul Detering, Redwood Insights
Trevor D'Olier-Lees, Standard & Poor's
Christopher Doyle, IBTS, Dividend Solar
Wil Fluewelling, Clean Power Finance
Max Foltz, TRUE South
Todd Fries, HellermannTyton
Whit Fulton, Infinite Invention
Heath Galoway, Sungevity
Matt Golden, Efficiency.org, IBTS
David Hattis, Building Technology, Inc.
C. Todd Himle, Super Anchor Safety
Ron Hooson, Solar Inspectors Hawaii
David Inda, Clean Power Finance
Saul Inda, GAF Solar
Drew Johnson, Burnham Energy
Nick Kasza, Distributed Sun
TJ Keating, SunSpec Alliance
Geoff Klise, Sandia National Laboratories
Sarah Kurtz, NREL
Calder Lamb, Dominion Energy Solutions
Richard Lawrence, NABCEP
Minh Le, U.S. Department of Energy
Kimberlie Lenihan, NYSERDA
Jay Levin, Clean Energy Associates
John Lochner, Locus Energy
Robert Lockhart, Acuity Power Group
Len Loomans, Acuity Power Group
Rich Matsui, kWh Analytics
Michael Mendelsohn, NREL
Jack Meng, Fortune Energy
David Milner, NuGen Capital Dividend Solar
Emeline Minor, Kilowatt Financial
West Owens, SolarCity
Rue Phillips, TRUE South Renewables Inc.
Brian Ray, Hellermann Tyton
Travis Richardson, Sungevity
Sydney Roberts, Southface
Mehrad Saidi, SunSystem Technology
Laks Sampath, NRG Energy, Inc.
Jeffrey Schub, Coalition for Green Capital
Greg Sellers, Clean Power Finance
Aashish Shahani, IBTS
Shawn Shaw, Cadmus
Josh Sturtevant, Distributed Sun
Andrew Truitt, Acuity Power Group, Dividend Solar
Don Warfield, NABCEP
Scott Weicht, Adolfson and Peterson
Chase Weir, Distributed Sun
Roger Williams, Sungevity
Peter Xu, PVAP Expo 2012

Reviewers

Sam Brown, Mercatus
Joe Cunningham, CentroSolar
Ryan Hamilton, Energy Finance Strategies, LLC.
Robert James, DNV GL
Shawn Kerrigan, Locus
Dan Loflin, Locus
Michael Mittleman, MJM Energy Consulting
Selya Price, Clean Energy Finance and Investment Authority
Sydney Roberts, SouthFace
Benjamin Shih, Moody's
Chris Sommerfeld, Sunrun
Jeff Spies, Quick Mount PV
Josh Sturtevant, Distributed Sun
Teresa W. Zhang, PhD, Leidos
Ryan Zwilling, DNV GL

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1 Introduction

1.1 Solar Access to Public Capital and the Installation Subcommittee

The following Photovoltaics Installation Best Practices Guide is one of several work products developed by the Solar Access to Public Capital (SAPC) working group, which works to open capital market investment. SAPC membership includes over 450 leading solar developers, financiers and capital managers, law firms, rating agencies, accounting and engineering firms, and other stakeholders engaged in solar asset deployment. SAPC activities are directed toward foundational elements necessary to pool project cash flows into tradable securities: standardization of power purchase and lease contracts for residential and commercial end customers; development of performance and credit data sets to facilitate investor due diligence activities; comprehension of risk perceived by rating agencies; and the development of best practice guides for PV system installation and operations and maintenance (O&M) in order to encourage high-quality system deployment and operation that may improve lifetime project performance and energy production.

This PV Installation Best Practices Guide was developed through the SAPC Installation Best Practices subcommittee, a subgroup of SAPC comprised of a wide array of solar industry leaders in numerous fields of practice. The guide was developed over roughly one year and eight months of direct engagement by the subcommittee and two working group comment periods.

1.2 Purpose

This Installation Best Practices Guide is designed to improve solar asset transparency for investors and rating agencies, provide an industry framework for quality management, and reduce transaction costs in the solar asset securitization process. The Installation Best Practices Guide is intended to outline the minimum requirements for third-party ownership providers ("Providers"). Adherence to the guide is voluntary. Providers that adhere to the guide are responsible for self-certifying that they have fulfilled the guide requirements.

1.3 How to Use This Document

This document is best viewed on a computer or tablet in order to take full advantage of the embedded, clickable hyperlinks that lead to further information and additional resources. Each hyperlink is fully cited in the References and Resources section beginning on page 23. Relevant definitions used in this document are attached as Appendix A.

1.4 Guide Overview

There is no one-size-fits-all solar deployment strategy. Firms have unique value propositions, customer acquisition strategies, distribution channels, and technical specifications. The framework for the guide includes: 1) Contractor Qualifications, 2) Provider Best Practices, and 3) O&M.

The "Contractor" is identified as the Contractor of record for the installation of a solar PV system. The "Provider" is identified as the system owner or financing firm that originated the transaction. In many cases, these two parties could be the same firm.

The Installation Best Practices applies to one- and two-family dwellings, townhomes, and Group R-2, R-3, and R-4 buildings (as categorized by ICC) three stories or fewer in height above grade with a separate means of egress and their accessory structures.

2 Contractor Qualifications

The residential solar PV value chain takes on many shapes with regard to third-party ownership. The *Contractor* is the formal installer "of record" of a solar PV system. The *Provider* is identified as the system owner or financing firm that originated the transaction. In certain cases, the Contractor and Provider are the same entity.

The Contractor is responsible for on-site system installation based on the intended design, equipment specifications, and local authority having jurisdiction (AHJ) requirements. In many ways, the Contractor has the greatest impact on the quality of the asset in terms of homeowner safety and actual system performance. Contractors utilized by finance Providers should meet the minimum requirements set forth in Section 2.

2.1 Work History

The installation Contractor shall have a work performance experience that demonstrates its ability to install safe and reliable solar PV systems. The Contractor must provide the number of systems and total kW installed (mandatory) for each year of experience to demonstrate transparency regarding work experience. The Contractor can demonstrate this experience through one of the following:

- ☐ 3 years of company work experience installing residential solar PV systems *or*
- ☐ 5 years of personnel work experience installing residential solar PV systems *or*
- ☐ At least 5 inspections performed on previously installed systems (random sampling) with an at least 80% passing score for all five systems. Scoring metrics shall be developed by the Provider.

> **Work History**
> It is important to de-risk the system installation quality by requiring participating Contractors to have adequate work experience. PV systems are complex, with electrical (DC and AC) and mechanical systems (mounting) that also require an understanding of structural requirements (weight, wind, snow). However, established and experienced contractors with a strong team could install PV systems successfully though they may lack the years of experience specific to PV. It is understood that highly experienced PV contractors may not be available in all markets or geographic areas.

2.2 Financial Transparency

Contractors shall provide documentation that communicates the financial solvency of the installer. Documents should be kept on file by the Provider. Sample documents include:

- ☐ Audited financial statements
- ☐ Bank references
- ☐ Supplier references.

The purpose of these references is to demonstrate that the installation Contractor is/was not in financial distress at the time of installation. Installation Contractor financial distress could have a negative impact on the level of system quality.

Financial Solvency
Financial strength of a Contractor is a critical factor in helping financiers to manage construction and performance risk. Contractors in financial distress may not be reliable in workmanship quality or in meeting procurement or installation timelines. While Contractors may accept risk under contract, they also should be financially capable of providing remedy for those risks.

2.3 Health and Safety

A Contractor should create and maintain a health and safety manual which establishes appropriate rules and procedures concerning workplace safety, including rules related to: the reporting of health and safety problems, injuries, and unsafe conditions; risk assessment; and first aid and emergency response. Some examples of typical rules and procedures follow below.

Health and Safety
This requirement outlines basic standards for worksite safety to mitigate construction risk and potential liability during the construction phase.

- ☐ Contractor Site Supervisor completed a minimum of Occupational Safety and Health Administration (OSHA) 30-hour Construction Industry training, and all site personnel completed a minimum of OSHA 10-hour Construction Industry training
- ☐ Additional training should be supplemented to provide sufficient knowledge for installers to identify hazards, provide corrective actions, and prevent reoccurrence specific to solar PV systems
- ☐ All site personnel must be equipped with complete personal protective equipment (PPE) and trained on any specific hazards associated with their jobs
- ☐ Contractor Site Supervisor completed a Job Hazard Analysis (JHA)
- ☐ Contractor Site Supervisor completed a jobsite orientation with all workers onsite.

The Contractor must maintain an OSHA total case incident rate (TCIR) of 5.00 or less or a similar rate based on a substantially equivalent, accepted measure used to report workplace injuries.

2.4 Insurance

A Contractor must maintain current and appropriate business insurances, including liability insurance, workers' compensation insurance, and commercial vehicle insurance. Coverage should include:

Insurance
The standard addresses minimum expectations based on current practices in the industry.

- ☐ General liability - $1,000,000 per occurrence, $2,000,000 aggregate, *and*
- ☐ Workers' compensation - $1,000,000 each accident, each employee, policy limit
- ☐ Insurance policies should name the Provider and any intermediaries as additional insured(s) and certificate holder(s).

2.5 Personnel Qualifications

2.5.1 Contractor Site Supervisor Qualifications

Personnel Qualifications

It is important to de-risk the system installation quality by requiring participating staff workers with adequate professional and trade credentialing. A Site Supervisor is the onsite Contractor lead who is responsible for implementing the PV system as designed, per equipment manufacturer requirements, in a safe and durable manner. From time to time, a Site Supervisor will have to make decisions that will be unique to a particular project and could affect system safety, quality, and performance. This role will require a strong foundation for good decision making and quality implementation of design specifications.

The Contractor Site Supervisor or designated responsible party should have one of the following professional certifications:

- ☐ North American Board of Certified Energy Practitioners (NABCEP) Certified Installation Professional *or*
- ☐ Licensed electrician (master or journeyman).

Some Contractors or Providers may have proprietary training and education programs that are more specific to the job duties performed by their personnel, which may meet or exceed training and experience requirements for the certifications above. In these instances, the internal training can be used as a substitute for the certifications listed above. Additional certifications that installation personnel may hold to ensure a high level of quality workmanship and safety include:

- ☐ Roof Integrated Solar Energy (RISE) Certified Solar Roofing Professional
- ☐ Underwriters Laboratories (UL) Certified PV System Installer
- ☐ NABCEP PV Entry Level Exam
- ☐ Licensed electrician (apprentice)
- ☐ Proprietary technology training offered by an original equipment manufacturer.

2.6 Trade Licenses

The Contractor should have all professional and trade licenses required by the state and local AHJ. Required solar PV licenses can be found through the Interstate Renewable Energy Council's (IREC) Solar Licensing Database.

3 Provider Best Practices

3.1 Defined Quality Management Plan

The Provider shall have a quality management plan that includes all elements of the company's customer service policy and other quality assurance practices. The plan should be distributed to all company employees and contain documented statements of a quality policy and quality objectives, also referred to by ISO 9001:2008 as a Quality Manual. A Quality Management Plan should include:

- ☐ System equipment specifications
- ☐ System equipment testing
- ☐ Inspection protocol/inspector qualification
- ☐ Design best practices
- ☐ Providers' installation guidelines with explicit quality standards
- ☐ Safety policies
- ☐ System commissioning
- ☐ Upstream and downstream QA activities with explicitly defined corrective action protocols
- ☐ O&M.

> **Quality Management Plan**
> The existence of a robust QA/QC plan demonstrates a strong commitment by the contractor to building quality PV systems, and to encourage that culture throughout its organization. This also demonstrates a strong value for professionalism within the contractor's organization. A strong QA program will help organizations to better manage their internal processes and deliver the level of services likely expected by PV investors.

3.2 Usage Data

The Provider is responsible for analyzing the customer's utility bills from the start of the contract and through at least one prior year, including electrical usage and current rate structure. It is vital that usage and rate structure data is included in the system design to ensure that the customer receives a system that is well-suited to that particular situation in order to maximize the system's economic impact.[1] Utility bill analysis may be contracted out by the Provider.

3.3 Site Data

The Provider is responsible for gathering relevant site-specific information such that the PV system designer can design a PV system appropriate for the application. The Provider should ensure that system design and feasibility estimates are made using reliable data. A possible guide in gathering data is the NABCEP Resource Guide, which addresses many of the key factors and current industry best practices regarding PV system design. Below are brief summaries of major

[1] See Section 2.1 of the NABCEP PV Installation Professional Resource Guide for further guidance on assessing customers' energy usage.

design topics, with references to existing documentation that provide further detail. Relevant information from the following list should be noted on the construction plans submitted for permit application.

General Site	**Roof**	**Structure**	**Electric**	**New equipment locations**
Building footprint	Dimensions	Local design wind speed (and source of info)	Service type and size, MSP main busbar, and breaker size	Inverter
Distance to property lines	Locally required minimum roof setback dimensions from ridge, hips/valleys[2]	Local ground snow load (and source of info)	Service panel make and model	Conduit run
Age of roof covering[1]	Type of roof covering	Design roof snow load	Availability of breaker spaces	PV modules
Age of home	Underlayment type and lap dimensions	Framing lumber dimensions	Meter location relative to home	Service disconnect
Easements, restrictions, open permits	Roof condition – covering, sheathing, framing	Rafter or truss spacing		Monitoring equipment
	Obstruction locations[3]	Max. rafter span or longest truss top chord panel length between struts		
	Safety or liability considerations	Lumber species and grade[4]		
		Sheathing thickness and type		

[1] To avoid unnecessary cost to the Provider or the homeowner, the roof covering should have sufficient life remaining such that reroofing is unlikely to be needed during the contract term. Document any existing roof issues based on customer input.
[2] From 2012 IFC or local AHJ.
[3] Vents, equipment, skylights, satellite dishes, snow guards, roof heaters, etc.
[4] Indicate whether identified in field or assumed.

Additional site data to be recorded includes:

- ☐ Roof information:
  - Dimensions
  - Locally required minimum roof setback dimensions from ridge, hips/valleys (from 2012 IFC or local AHJ)
  - Type of roof covering (e.g., composition shingle, tile, standing seam metal)
  - Underlayment type and lap dimensions
  - Roof condition (roof covering, sheathing, and roof framing)

- Location of obstructions (e.g., vents, equipment, skylights, satellite dishes, snow guards, roof heaters)
- Safety or liability considerations like falling snow and ice near access points (e.g., snow guards)

- ☐ Structural information including:
  - Local design wind speed and source of information (e.g., ASCE 7, local AHJ)
  - Local ground snow load and source of information (e.g., ASCE 7, local AHJ)
  - Design roof snow load (indicate any snow load reductions)
  - Framing lumber dimensions (e.g., 2x6 nominal, 2x4 rough sawn)
  - Rafter or truss spacing (e.g., 24" o.c.)
  - Maximum rafter span, or longest truss top chord panel length between struts
  - Lumber species and grade (indicate whether identified in field or assumed)
  - Sheathing thickness and type (e.g., ½" OSB, ½" plywood)
- ☐ Electrical information:
  - Service type and size, MSP main busbar, and breaker size
  - Service panel make and model
  - Availability of breaker spaces
  - Meter location relative to the home
- ☐ Potential locations for new equipment including:
  - Inverter
  - Conduit run
  - PV modules
  - Service disconnect
  - Monitoring equipment.

Refer to Section 2.2 of the NABCEP PV Installation Professional Resource Guide for further guidance on collecting appropriate site data. Additional information can be found in Solar Energy International's Solar Electric Handbook and Jim Dunlop's Photovoltaic Systems.

3.4 Solar Resource Measurement

The Contractor shall perform a shade analysis for each project using a Solmetric Suneye, Solar Pathfinder, or similar industry-accepted measurement tool. For each unique array tilt, orientation, or module type used, the Contractor shall evaluate at a minimum the corners of each array, and possibly more if the array is large enough where a shade obstacle could impact the center without impacting the corners of the array. For each portion of the array, the Contractor will calculate a total solar resource fraction (TSRF) and provide a calculated TSRF for the overall array. This will be done by weighting each portion's TSRF by its proportional capacity to the entire array as stipulated by the resource measurement tool manufacturer.

Refer to Section 2.2.3 of the NABCEP PV Installation Professional Resource Guide for further guidance on performing an accurate shade analysis.

3.5 Production Estimate

There are multiple tools for estimating PV system production, with more options becoming available every year. The key features for a tool include accurate weather data, shading functionality, adjustable system derate factors, component hardware selection, and monthly energy production estimates.

3.5.1 Estimating Tools

Popular tools for production estimates are estimating algorithms like PVWatts or more complex simulating software like PVsyst, Clean Power Estimate, or Energy Pariscope.

- ☐ PVWatts v4 (NREL) online calculator: uses PVWatts v1 algorithm but offers newer weather data sources (TMY3, 10km Grid)
- ☐ System Advisor Model (NREL): includes PVWatts v1 algorithm.

Contractors or third-party designers should not be able to manually change the derate of system components without complete discloser to the Provider. This will avoid third parties manipulating the production estimates in favor of selling a system.

3.5.2 Solar Resource / Weather Data Sources

Weather data sources for all design estimates shall be one of the following:

- ☐ Meteonorm Synthetic Data Sets
- ☐ NREL Typical Meteorological Years (TMY) Data Sets: TMY2, TMY3
- ☐ White Box Technologies CZ2010 for California
- ☐ NREL 40-km gridded data set for United States
- ☐ Clean Power Research 10 km gridded data set.

3.6 System Design

Providers should ensure that system design and feasibility estimates are made using reliable data. NABCEP's Resource Guide addresses many of the key factors and current industry best practices regarding PV system design and can be used as a resource. Below are brief summaries of major design topics, with references to existing documentation, which provide further detail.

> **System Design Factors**
> This section of the standard is based on a significant number of available resources, existing codes and standards, and industry best practices. References to these resources are provided.

The Contractor is responsible for the PV system design, though outsourcing is acceptable provided the details of the design are confirmed onsite. Key factors of PV system design include:

- ☐ System design in accordance to state and local (AHJ) building and safety requirements
- ☐ Accuracy of collected site data (e.g., roof dimensions and slope, existing electrical equipment locations, shade analysis)

- ☐ Proper application of all applicable codes (e.g., National Electrical Code [NEC], International Residential Code [IRC], International Fire Code [IFC])
- ☐ Consideration of customer priorities (e.g., aesthetics, maximizing power production, equipment manufacturer preferences, equipment location preferences)
- ☐ Appropriate level of detail in the design drawings such that the installation team encounters a minimum number of unknown obstacles onsite
- ☐ Proficiency with design software
- ☐ Necessary information for all applicable AHJs for procuring all permits and approvals, which could include:
    - Site plan
    - Electrical diagram (1- or 3-line)
    - Roofing system elevation drawing (including roof type and flashing/attachment)
    - Electrical system details
    - Roof loading details (e.g., design wind speed, design snow load)
    - Installation detail for mounting system stand-off and roof penetration
    - Roof framing details and design checks (e.g., span tables or calculations)
    - Equipment data sheets.

Refer to Sections 2.2, 2.3, 2.5, 2.7, 2.8, and 2.9 of the NABCEP PV Installation Professional Resource Guide for further guidance on proper system design practices. Additional information can be found in Solar Energy International's Solar Electric Handbook and Jim Dunlop's Photovoltaic Systems.

In regions prone to sliding snow and ice, consider using a heavy snow-rated panel and snow guards in specific areas where homeowners are at risk of snow/ice shedding. Examples of sensitive areas for hazards of sliding snow and ice include roofs over building entries, driveways, and decks.

3.7 Equipment Requirements

This section is focused on providing various industry standards to develop a minimum requirement for common components of a solar PV system.

3.7.1 Solar Photovoltaic Modules

Baseline requirements:

- ☐ UL1703 Flat-Plate Photovoltaic Modules and Panels
- ☐ IEC 61215 or UL 61215 Crystalline Silicon Terrestrial PV Modules
- ☐ IEC 61646 or UL 61646 Thin-Film Terrestrial PV Modules
- ☐ ASTM E2481-06
- ☐ Manufactured using an ISO-9001 quality management system

- ☐ Manufacturer should remain willing to participate in third-party audits if required by the Provider or Capital provider.

It is recommended that modules which are resistant to potential-induced degradation (PID) be used for systems where transformerless inverters are used (these systems are ungrounded).

3.7.2 Inverters

For information on inverters, consult UL 1741 Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.

- ☐ IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems
- ☐ IEEE 1547.1 Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- ☐ Inverter installation requirements are governed by the National Electric Code Articles 690 and 705. Article 705, Part II lists requirements of Utility Interactive Inverters, including circuit sizing and over current protection
- ☐ NEC 690.10 lists requirements for standalone system inverters
- ☐ NEC 690.14 provides additional requirements including location of inverters in not-readily-accessible locations
- ☐ NEC 705.12(D) lists requirements for Utility Interactive Inverters
- ☐ NEC 705.40 lists requirements of inverters for loss of primary source of power.

Arc fault protection is required for inverters in jurisdictions subject to NEC 2011 or beyond. It is noted that future requirements, such as those now under consideration in California, may include “smart inverter” capabilities, which allow for remote system shutoff and restart by the utilities.

3.7.3 Racking Systems

For installation criteria for rack mounting PV systems and clamping devices for flat-plate PV modules and panels that comply with UL 1703, see UL 2703 Rack Mounting Systems and Clamping Devices for Flat-Plate Photovoltaic Modules and Panels. It is intended to address product safety concerns for electrical rack mounting systems and clamping devices pertaining to ground/bonding paths, mechanical strength, and suitability of materials.

This standard addresses installation, materials, wind resistance, and fire classification and is intended for installation on or integral with buildings, or for freestanding systems (i.e., not attached to buildings), in accordance with the National Electrical Code, ANSI/NFPA 70, and Model Building Codes.

ICC Evaluation Services has published AC 428, Acceptance Criteria for Modular Framing Systems Used to Support PV Modules. This publication was created to provide the criteria for evaluation of rooftop PV mounting systems for manufacturers seeking a product listing under ICC Evaluation Services. It includes structural design criteria that are useful for designing mounting systems.

3.7.4 Monitoring

To support revenue collection and O&M services, a monitoring system with connectivity (99.5% uptime preferred) to the O&M provider is recommended, including regular performance and availability alerts.

It is preferred that the monitoring system be API compatible with SunSpec Alliance's Best Practices in Solar Performance Monitoring guidelines and Data Structures conforming to the SunSpec Alliance Plant Extract Document to support compatibility of the system lifetime.

Refer to Section 2.6 of the NABCEP PV Installation Professional Resource Guide for further guidance on selecting the appropriate system components.

3.7.5 Electrical Components

- ☐ IEC 62852 – UV exposure for connectors/cables
- ☐ IEC 62790 – UV exposure for junction boxes
- ☐ UL 1565 Wire Positioning Devices
- ☐ NEMA- and/or IP-rated enclosures.

3.8 Defined Installation Best Practices

3.8.1 Permitting and Inspections

The installer is responsible for procuring all of the necessary permits and approvals for PV system construction and inspection. Permitting processes vary based on the requirements of the AHJ. A model approach (from the solar industry perspective) is spelled out in the Solar America Board of Codes and Standards' (Solar ABCs) Expedited Permitting Practice document, which states and AHJs are encouraged to utilize and/or reference. Though this standard was meant to streamline and bring consistency to state and local AHJ practices, specific requirements for each state may still need to be considered with respect to permitting processes and forms. At the state level, building codes, laws, and policies may vary, as well as laws and practices about how states and local AHJs interact. Through the U.S. Department of Energy SunShot Initiative's Rooftop Solar Challenge, many states and local AHJs have developed and made available state-level permitting guides, recommended practices, and forms. Efforts to document the many individual AHJ solar permitting requirements that are still prevalent can be found on the National Solar Permitting Database and in Vote Solar's Project Permit. Refer to Section 3.1 of the NABCEP PV Installation Professional Resource Guide for further guidance on PV system permitting.

3.8.2 System Construction

The following resources define solar PV installation best practices. Additionally, installations should be compliant with all state, utility, and local AHJ requirements, as well as equipment manufacturers' installation requirements.

3.8.2.1 System Grounding and Bonding

- Proper grounding and bonding is the most important safety element of an installed PV system. Grounding and bonding for PV systems is covered in NEC 690(V), along with many sections of Article 250. Article 690.35 allows ungrounded PV system of any voltage, if conditions are met, particularly ground fault protection (see below). A grounding system consists of Equipment-Grounding Conductors, a Grounding-Electrode System, and a Grounding-Electrode Conductor.

- The purpose for the Equipment Grounding (EG) system is to ensure that there is no hazardous voltage between any exposed metal parts of a system and Earth. If a system is properly "earthed," a barefoot person standing on the ground and touching any exposed metal surface of the system will not experience an electrical shock. All metallic equipment (both DC and AC) should be grounded per the requirements of the NEC and equipment manufacturer. This includes metal raceways, enclosures, mounting hardware, module frames, conduit fittings, etc.
- If there is a Lightning Protection System (LPS) existing on the building, the Engineer of record should make a determination as to whether, and how, to bond the array EG to the LPS main ground.
- It is essential that if a current-carrying conductor of a PV output circuit is grounded (a "grounded system"), that it be bonded to ground at only one point (as per NEC requirements).
- "Ungrounded" systems do not have a bonding connection between a current-carrying conductor of the PV output circuit and ground. They are becoming increasingly common due to lower equipment costs and higher efficiency. Note that the name refers only to the fact that there is no "system ground" (i.e., grounded current-carrying conductor), but all equipment grounding and bonding requirements do still apply.

3.8.2.2 Ground-fault Detection

- A particular hazard still exists for systems using inverters with "fused" ground fault detector interrupter (GFDI) protection, which many string inverters still incorporate (see Solar ABC's Ground Fault Detection Blind Spot for details). The situation of having a blown GFDI fuse, with no defined path for any fault current to earth, can have severe consequences for safety of personnel, structures, and equipment. The industry is gradually moving away from fused ground fault detectors, and toward differential ("residual") current sensors that don't open the path to earth (as with "ungrounded" inverters). And the recent advent of arc-fault detection and interruption protection, as required in the 2014 NEC for ALL systems 80Vdc or more, should safely extinguish any large arcing ground faults.

3.8.2.3 Marking (Labeling) Best Practices

Strict conformance to system marking (or labeling) requirements of PV systems and their components is crucial for the safety of operators, service personnel, emergency responders, and others. PV system general labeling requirements are covered in NEC 2014 690 Ch. VI, as well as specific accompanying requirements throughout Articles 690 and 705. Ideally, all required and desired labeling language is included in the design drawings.

Electrical equipment and components used in PV systems have markings identifying the manufacturer, size, type, ratings, hazard warnings, and other specifications. Equipment markings should never be removed, and all equipment markings must be durable for the environment in which the equipment is installed. Markings must be visible or easily accessible during and after installation.

Field-applied markings are required for certain components and for the inclusive PV system. These markings must be designed to withstand the environment in which they are installed (e.g., "UV rated" for outdoor labels) and permanently affixed to the respective equipment in a manner appropriate for the environment and compatible with the substrate materials. Field-applied markings are required on many types of equipment and components, including (but not limited to) conductors, connectors, conduits, disconnecting means, point of utility connection, as well as special markings for bi-polar arrays, ungrounded arrays, battery storage systems, standalone inverters providing a single 120-volt supply, and other marking as required by codes and local AHJ requirements.

Resources for field-applied markings include:

- ANSI.org, ANSI Z535.4-2011, Product Safety Signs and Labels
- HellermannTyton PV System Labeling Guide
- IBTS Guide to System Labeling.

3.8.2.4 Mechanical Components

Though a PV system's purpose is electrical in nature, it is very important that the components are mechanically installed in a manner appropriate for the local environment. This holds true for all types of installations, but is particularly important for residential rooftop installations due to the load forces to which they may be exposed (e.g., wind and snow), and the potential damage to life or property that could occur if mechanical connections were to fail. Applicable codes for the installation of mechanical components include the International Building Code (IBC), International Residential Code (IRC), and International Fire Code (IFC).

3.8.2.5 Mounting Systems

PV modules are typically attached to roofs via purpose-built metal (usually aluminum) mounting systems. Module mounting systems must be listed for the application and capable of withstanding the uplift (due to wind) and downward forces (e.g., snow-load) to which they could potentially be exposed based on the specific location of the installation. Consider the following important items when installing the mounting system.

- Appropriate weather sealing of all penetrations of the building envelope.
- I-codes guidelines on array setbacks (requirements vary based on roof design).
- Compliance with local guidelines when navigating existing vents or equipment on the roof.
- Comprehension of best practices for working with a given roof covering as per the National Roofing Contractors Association Roofing Manual.
- A balance of customer aesthetics expectations with code requirements and airflow directives from the module or racking manufacturer.
- Assessment of the roof structure (usually via attic or crawl space inspection) for lumber type, dimension, and condition.
- Assessment of the condition of the roof covering. If the roof covering will need replacement before the end of the expected PV system lifetime (20-25 years), the homeowner should consider roof replacement prior to PV system installation.

- Usage of the appropriate size and type of fasteners for the application, and achieving the proper embedment in the substrate.
- Comprehension of the cause and effect of inter-row shading in tilted arrays, and being able to identify when it may become an issue.
- Comprehension of the span and cantilever limitations of the mounting system.

For further information on PV mounting structure installation can be found in resources such as the NABCEP Resource Guide, Solar Energy International's Solar Electric Handbook, and Jim Dunlop's Photovoltaic Systems.

3.8.2.6 PV Modules

There are a variety of module construction types available today (e.g., metal-framed, frameless, building-integrated, "peal and stick"), but the majority of PV modules used in residential applications are aluminum-framed, poly- or mono-crystalline, glass-enclosed laminates. Regardless of construction type, care must be taken to comply with all manufacturers' instructions concerning the transportation, storage, mounting, grounding, and connecting of the PV modules. Failure to do so could result in voiding of the module warranty, underproduction of the PV system over time, and increased shock- or fire-hazard risk. Important items to consider when installing the PV modules include:

- Awareness of any specific mounting location stipulations from the module manufacturer, which may or may not vary based on the potential wind load at the site
- Understanding of the different module mounting options, such as bolting the module frame to the mounting structure or clamping the frame with the appropriate hardware and compression force
- Appropriate use of fall protection equipment is particularly important during array installation because PV modules tend to be large and unwieldy, presenting elevated risk for installer injury and to workers on the ground if any equipment is dropped. This risk is further exacerbated on steeper roofs
- Knowledge of electrical safety protocols, such as ensuring that homerun conductors are not connected during installation to ensure the safety of any personnel wiring electrical equipment.

3.8.2.7 Systems with Module-level Power Electronics

For future O&M purposes, the serial numbers of module-level power electronics (e.g., power optimizers, microinverters) should be mapped during installation (e.g., Enphase installation guide). There are numerous technology solutions to capturing equipment barcode information through mobile technology, such as SiteCapture.

3.8.2.8 Additional Resources

- International Building Code Section 1504
- PV Racking and Attachment Criteria for Effective Asphalt Shingle Roof System Integration
- A Guide to Photovoltaic (PV) System Design and Installation

- Field Inspection Guidelines for PV Systems
- Photovoltaic Power Systems, 2005 National Electric Code: Suggested Best Practices
- Southwest Technology Development Institute, Codes and Standards Resources
- NABCEP Photovoltaic (PV) Installer Resource Guide
- Best Practices for Solar Photovoltaic Installations – Renewable Energy Vermont Partnership Program
- IEC 62446 Commissioning Standard.
- Green Job Hazards: Solar Energy
- Solar Construction Safety.

3.8.3 Interconnection

Before a PV system is allowed to operate legally, the appropriate utility provider must approve the system for operation. Similar to PV permitting, PV interconnection requirements vary around the country, but are generally based on one or a combination of the following three major interconnection standards:

- ☐ FERC's Small Generator Interconnection Standards (SGIP)
- ☐ California's Rule 21
- ☐ IREC's Model Interconnection Standards.

The interconnection of a distributed generation system, such as a PV system with the local utility, depends upon state regulations and utility policies and practices. Interconnection guidelines and state- and utility-specific rules can usually be accessed by installers through utility websites. Contractual aspects of interconnection include fees, metering requirements, billing arrangements, and size restrictions on the system. Understanding the local utility's requirements is a very important process, and varies for each local utility.

In addition, national and local codes have interconnection and system equipment and labeling requirements so that the system can be easily identified and/or shut off. For example, some states or utilities require an easily accessible external disconnect switch. The NEC governs how the output of a PV system can be connected to the utility in Article 705. The two relevant connections would be:

1. Supply side (similar to installing another service onsite and is usually found for larger installations)
2. Load side (most commonly used for smaller systems and requires a dedicated circuit breaker or overcurrent device with the sum total of overcurrent devices supplying the busbar should not exceed 120% of the busbar rating).

Before investing in a solar PV system, it is wise to apply for interconnection approval as early in the process as possible. This allows added costs or barriers to be factored into the decision to install at a particular location; it can impact decisions about system design. With PV market penetration increasing, there are emerging issues around the need for transformer or other equipment upgrades on local circuits and the question of who pays for this. In the case of nonresidential systems, even more equipment and local circuit considerations may arise, making it unfeasible to install a system at a particular location, or at the intended size. These factors can change the economics of a project and should be identified as early as possible.

Further details on interconnection requirements can be found on the Database of State Incentives for Renewable Energy. Additional information on interconnection requirements can be found on the Freeing the Grid website.

- IEEE 1547 - Standard for Interconnecting Distributed Resources with Electric Power Systems
- IEEE 1547.1 - Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- IEEE 1547.2 - Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems
- IEEE 1547.3 - Guide For Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems
- IEEE 1547.4 - Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems
- IEEE 1547.6 - Recommended Practice For Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks
- NEC 690, 705.

3.9 System Documentation

Providers should store basic homeowner and system information for the term of the initial customer agreement. Data naming methodology should follow the SunSpec Data Dictionary.

Outlining the minimum documentation that should be provided for grid-tied residential PV systems will ensure transparency to investors of basic system components, information on design and installation, and O&M requirements. Additional data representing the consumer credit worthiness is not included in this list.

3.9.1 Required Homeowner Data Points

- ☐ Plant identifier
- ☐ Site owner name
- ☐ Site owner address
- ☐ Site owner city
- ☐ Site owner state
- ☐ Site owner zip code
- ☐ Site owner phone number
- ☐ Site owner email address
- ☐ Activation date.

3.9.2 Required System Design Data

- ☐ Design model
- ☐ Installed DC capacity
- ☐ Derate factor
- ☐ Nominal power rating
- ☐ Module manufacturer
- ☐ Module model
- ☐ Module units
- ☐ Inverter manufacturer
- ☐ Inverter model
- ☐ Inverter units
- ☐ Racking manufacturer(s)
- ☐ Racking model(s).

3.9.3 As-built Photo Inventory

Provider shall maintain a photo inventory of all active systems. Photos may be captured through the installation Contractor, third-party inspector, or in-house personnel. Mandatory photos include at least one (1) onsite photo of the following system components.

A photo inventory allows the provider to have a strong understanding of onsite conditions and overall level of quality. It will also reduce O&M costs. Photos shall be stored through the life of the service contract and retrievable through customer/address query. Electronic capture and cataloguing of site information is preferred to ensure consistency and accuracy; example technologies include SiteCapture.

Table 1. Required System Photos

Roof (array)	Balance of System
Address Block Overall Array Under Array Array Horizon (shading) Module Nameplate Conduit Runs and Support Junction Box Locations Junction Box Interior Wire Management Flashing of roof penetrations	DC Disconnect location and interior Inverter Location Inverter Nameplate AC Disconnect location and interior Main service panel (cover open) Main service panel (cover closed) Connection to premise's grounding system Production meter Monitoring system Net meter

3.9.4 Additional Information

Copies of additional key information should be provided to the system owner and stored through the duration of the service agreement.

Electrical Design

- ☐ Company name
- ☐ Company address
- ☐ Company phone number, email, website
- ☐ Contact person (contact name, address, phone number).

Structural/Mechanical Design (if provided by mounting equipment manufacturer, list manufacturer information)

- ☐ Company name
- ☐ Company address
- ☐ Company phone number, email, Web site
- ☐ Contact person (contact name, address, phone number).

PV Installer (If more than one company, list for each and note company roles)

- ☐ Company name
- ☐ Company address
- ☐ Company phone number, email, Web site
- ☐ Contact person (contact name, address, phone number).

Electrical Design Documentation

Three-line diagrams are preferred.

- ☐ At minimum, a one-line wiring diagram which includes:
    - General specifications
    - String information
    - Electrical details / inverter information
    - Grounding / overvoltage protection
    - AC system specification
    - Equipment data sheets
    - Warranty information
    - Installation manuals
    - O&M manuals
    - Test results / Cx data.

3.10 Third-party Inspection and Verification

3.10.1 Field Inspection Verification

Providers should verify and measure installed asset quality through a continuous process of third-party field inspection verification (FIV) of the Provider's completed systems. For purposes of this document, a third-party inspector shall mean any technically qualified entity that was not directly involved in the installation or system design process. The third-party inspector can be part of the installation company (e.g., part of the O&M division) or an entirely separate entity. The FIV process includes onsite inspections of completed system installations to verify the systems have been installed to equipment manufacturer specifications, relevant codes, and installation best practices. This process is essential to the checks and balances of solar as an asset class.

Third-party Inspection and Verification

Independent, objective verification of PV system quality, completed by skilled inspectors, is an essential function to help ensure transparency in levels of quality, safety, and performance, and to protect and increase investor confidence in aggregated solar assets.

- To ensure an objective process, the inspector(s) should be a third-party provider, not involved in the design or installation of the inspected system(s)
- Data collected by the FIV is subject to approval from the Provider and may be modified by the Provider upon review
- FIV results should be shared with the Contractor for a continuous improvement process for installation quality.

3.10.2 Third-party Inspector Qualifications

The third-party inspector should have one of the following professional certifications and have specific knowledge of solar PV design and installation.

- NABCEP Certified Installer
- UL Certified PV System Installer
- Licensed Professional Engineer
- Licensed Electrician
- ICC Certified Electrical Inspector and/or Plans Examiner
- Equivalent proprietary training programs.

All inspectors shall have a minimum OSHA 10-hour certification and applicable skills (climbing and carrying ladder, walking on roof surface, etc.) to perform an objective inspection.

3.10.3 Fleet Sampling Method

FIV should be performed using a stratified random sampling method of completed systems per month. The variables used for the stratified, random selection process should include: 1) installation Contractor and 2) asset geographic region. The stratified sampling method ensures that the random sampling collects a statistically meaningful sample population.

The sample population should serve as a statistical representation of the overall population of the Provider's fleet. Quality metrics collected through FIV should be gathered on a monthly basis so that the Provider and Contractor can make continuous adjustments to improve the overall results.

The minimum sampling method shall be no lower than 10%. The 10% sampling can be viewed as statistically significant as a representation of the entire population (fleet).

Additional percentages may be used for Providers to properly mitigate risks. Field inspections may also be supplemented with independent desktop reviews of onsite photos.

3.10.4 Scoring System

The FIV will also result in a system quality scoring metric that can be used as a single quality assessment of the initial installation. The scoring system should numerically quantify the level of risks associated with the safety and performance of the system.

- **Pass/Fail** – For each inspection, a report shall be issued that summarizes the issues identified and provides the Contractor with a list of deficiencies requiring corrective action. The report shall also include the overall QA score.
- **Define System Components** – The sample breakout includes inverter, models, conduit/junction box, AC disconnects, DC disconnects, PV system labeling, grounding/bonding, wire management, roof conditions, flashing, shading, and system layout.

Also see IBTS Sample Inspection Checklist and Scoring Methodology.

4 Fleet Quality O&M

O&M plans rely heavily on accurate and timely data and as such, monitoring ecosystems should be designed to meet those needs for the long term. Hardware, communication, backend meter data management system/support, and data presentation should be well thought out so that all the components work together seamlessly and transfer of responsibility is painless. The requirements below reference documented plans across a fleet of systems, not individual plans per system.

4.1 Documented O&M Program

Documented and maintained O&M plans should be available, along with a preventive maintenance schedule and system or customer-driven alerts for corrective maintenance documented with service histories for each installation. The complete plant history, as-built drawings, installation photos, equipment list, equipment cut sheets, maintenance manuals, warranties and documentation, and equipment serial number inventory should be maintained as part of this plan. The plan should, at a minimum, comply with OEM equipment manufacturers' maintenance and documentation required to keep warranties in force along with preventative and corrective maintenance histories for each installation.

Fleet Quality O&M

To ensure solar assets perform as expected over their lifecycle, O&M programs should include key provisions to address scheduled and corrective maintenance, system monitoring and communications protocols. The committee has outlined the primary O&M considerations and provides standards to address them, along with some available resources.

4.2 System Monitoring

To support O&M, a minimum performance monitoring system with connectivity (99.5% head-end uptime preferred) should be utilized by an O&M provider and include near real-time performance and availability alerts.

It is preferred that the monitoring system provide an open and well-documented API and follow well-documented best practices guidelines and data structures modeled after industry standards, such as SunSpec or the IEP model supported by the DOE.

It is acknowledged that in some limited circumstances, homeowners may prohibit access to gateways. These instances are assumed to be rare and providers shall have appropriate protocols in place to address these instances.

To learn more, see SunSpec Alliance's Plant Extract Document.

4.2.1 Hardware

Metering hardware should meet the ANSI C12.20 standard for safety, design, and accuracy (either Class 0.5 or Class 0.2). This specification includes build and design standards for the hardware to withstand typical environmental conditions and accuracy standards that provide revenue-grade data that is suitable for billing and governmental reporting requirements. System data should be collected at a minimum interval of 15 minutes and should be reported daily to an offsite system. Onboard meter storage should be at a minimum of 30 calendar days with the capability to report the interval and accumulation data on a system request. Hardware should also have the ability to report, on event, disaster issues such as power supply loss or metering/system tampering.

4.2.2 Communication

A typical setup has three distinct parts: the backhaul connection from the meter to the AMI (advanced metering infrastructure), the AMI head end itself, and an MDMS (meter data management system). The backhaul connection is IP-based communication over RF Mesh (ZigBee) or cellular (2G, 3G, 4G). In the solar market, cellular is becoming the most common—if not the only—backhaul used. The AMI head end handles all remote commands sent to and received from the meter. This includes reading register and load profile data and energizing/de-energizing the remote disconnects, among others. The AMI head end is also responsible for reporting events such as power loss or tampering alarms. The MDMS is responsible for aggregating the information and interfacing with any line of business applications.

Usually it is best for an established, reliable company to retain control of this infrastructure for the sake of business continuity. In some cases, if that business were to fail, it would mean no production data until a replacement AMI, backhaul, and MDMS could be built and deployed. In the case of cellular, it is important to develop protocols for the portability of cellular service and legal ownership of the cellular connection would also have to be established with the new company to enable the timely restoration before communications with a site could be restored.

4.2.3 MDMS/Support

MDMS and support of the system's data should maintain a 99.5% up time with a suitable disaster recovery plan to restore the system within 24 hours of any critical issue. Data should be stored in its original resolution (e.g., 15-minute interval data) and a copy of the data should be retained for the life of the system without manipulation or combination in any manner. This data should be in increments of at least 15 minutes.

4.2.4 Data Presentation

The end user typically determines data presentation, but at a minimum, the system data should be presented daily, monthly, and annually. Daily feeds should be provided that show the previous day's production, as well as month-to-date and year-to-date values. O&M plans should be built to notify actionable personnel on critical production or safety issues within five days. Complete loss of production and non-communication should be reported on a daily basis. Systems producing lower-than-forecasted volumes should be reported on a weekly or monthly basis; using intervals smaller than a week increase the possibility of false positives and usually do not provide business value.

5 References and Resources

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Appendix A. References to Codes, Standards, and Guidelines

The following references relevant codes and standards that are commonly adopted by the AHJ.

Relevant Codes:

IBC - 2012 International Building Code

1503.2 Flashing
1507.2.9 Flashings
1507.2.9.1 Base and cap flashing
1507.3.9 Flashing
1505.8 Photovoltaic systems
1507.17 Photovoltaic modules/shingles
1507.17.1 Material standards
1507.17.2 Attachment
1507.17.3 Wind resistance
1509.7 Photovoltaic systems
1509.7.1 Wind resistance
1509.7.2 Fire classification
1509.7.3 Installation
1509.7.4 Photovoltaic panels and modules
1511.1 Solar photovoltaic panels/modules
1511.1.1 Structural fire resistance

IRC - 2012 International Residential Code

R903.2 Flashing
R905.2.8.1 Base and cap flashing
R905.2.8.4 Other flashing
R905.3.8 Flashing
R905.16 Photovoltaic modules/shingles
R905.16.1 Material standards
R905.16.2 Attachment
R905.16.3 Wind resistance
M2301.2 Installation
M2301.2.1 Access
M2301.2.2 Roof-mounted collectors
M2301.2.7 Roof and wall penetrations
M2301.3.1 Collectors
M2302.1 General
M2302.2 Requirements
M2302.2.1 Roof-mounted panels and modules

IFC - 2012 International Fire Code

[A] 105.7.13 Solar photovoltaic power systems.
605.11 Solar photovoltaic power systems
605.11.1 Marking.

605.11.1.1 Materials
605.11.1.2 Marking content
605.11.1.3 Main service disconnect
605.11.1.4 Location of marking
605.11.2 Locations of DC conductors
605.11.3 Access and pathways
605.11.3.1 Roof access points
605.11.3.2 Residential systems for one- and two-family dwellings
605.11.3.2.1 Residential buildings with hip roof layouts
605.11.3.2.2 Residential buildings with a single ridge
605.11.3.2.3 Residential buildings with roof hips and valleys
605.11.3.2.4 Residential building smoke ventilation
605.11.3.3 Other than residential buildings
605.11.3.3.1 Access
605.11.3.3.2 Pathways
605.11.3.3.3 Smoke ventilation
605.11.4 Ground-mounted photovoltaic arrays.

NFPA 70 - National Electrical Code

Relevant Standards:

ASCE 7: Minimum Design Loads for Buildings and Other Structures

ASCE 7 is the source of wind loads, snow loads, etc., and the calculation methods that develop the loads from tabled data.

2012 National Design Specification For Wood Construction

Many sections of the NDS are relevant for checking roof framing for the added loads from solar. Span tables are derived from values and formulas in the NDS. It would be misleading to reference only the table that mentions edge distance. Recommend deleting this reference to Table 11.5.1C. Table 11.5.1C - Edge Distance Requirements

UL 1703

UL 2703

UL 1741

Roofing Guidelines and Resources:

PV Racking and Attachment Criteria for Effective Asphalt Shingle Roof System Integration: http://roofingcenter.org/main/Initiatives/pv

NRCA - 2010 National Roofing Contractor Association

Chapter 3: Guidelines Application to Steep-slope Roof Systems

3.9 PENETRATIONS
4.1 Rack-Mounted Photovoltaic Modules Flashings

ARMA - 2006 Asphalt Roofing Manufacturers Association
Chapter 10 Flashings
Soil stacks and vent pipes

TRI - Tile Roofing Institute
http://www.mca-tile.com/downloads/TRIGuide2010.pdf

TRI ICC-Evaluation Report – ESR-2015P
http://www.icc-es.org/Reports/pdf_files/ESR-2015P.pdf.