PV Installation Professional (PVIP) Board Certification

NABCEP PVIP

Version Demo

Total Demo Questions: 12

Total Premium Questions: 128

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Topic Break Down

Topic	No. of Questions
Topic 1, Site Analysis	13
Topic 2, System Design	45
Topic 3, Installation	28
Topic 4, Commissioning	9
Topic 5, Operations and Maintenance	13
Topic 6, Safety	20
Total	128

QUESTION NO: 1

A roof has one unshaded southeast-facing plane and one unshaded southwest-facing plane. The design uses two equal-length strings and an inverter with two independent MPPT inputs. Which configuration will best maintain energy production from both roof planes?

A. Connect both strings in parallel to one MPPT input

B. Connect both strings in series to one MPPT input

C. Connect one roof-plane string to each independent MPPT input

D. Install both strings on the southeast-facing plane only

ANSWER: C

Explanation:

Connect one roof-plane string to each independent MPPT input. Modules on southeast- and southwest-facing planes operate at different irradiance levels and often at different maximum-power-point voltages during much of the day. Separate MPPT inputs allow each string to be tracked at its own optimum operating point. Paralleling the unlike strings on one MPPT can force both strings toward a common voltage that is not optimal for one of them. Connecting the strings in series would compound the mismatch and may create an unsuitable operating-voltage range.

QUESTION NO: 2

A listed utility-interactive inverter has a maximum continuous AC output current of 32 A. What is the minimum rating of the AC overcurrent protective device for the inverter output circuit?

A. 30 A

B. 32 A

C. 40 A

D. 50 A

ANSWER: C

Explanation:

40 A is correct. Inverter output current is continuous current, so the AC overcurrent protective device must be sized at not less than 125% of the inverter's maximum continuous output current. The calculation is 32 A × 1.25 = 40 A. A 30 A breaker is undersized for the listed continuous output, while larger breakers are not required by the information given and could require different conductor sizing and equipment verification.

QUESTION NO: 3

A rooftop PV system is being installed on a residential building with a 30-degree tilt angle. The modules are oriented directly south in a location where the solar noon altitude on December 21st is 30 degrees. What is the minimum distance required between two rows of modules to avoid shading between 9 AM and 3 PM solar time, assuming the module height is 3 feet?

A. 3 feet

B. 6 feet

C. 9 feet

D. 12 feet

E. Approximately 10 feet

ANSWER: E

Explanation:

Approximately 10 feet is the correct minimum clear row-to-row spacing when the stated 3-foot module height is treated as the vertical shading height. Designing for no shading from 9 AM through 3 PM means evaluating the lowest solar altitude within that time window, which occurs at the 9 AM and 3 PM endpoints, not at solar noon. On December 21, a 30-degree solar-noon altitude corresponds to an approximate latitude of 36.5 degrees north. At a solar-time hour angle of 45 degrees (9 AM or 3 PM), the solar-altitude equation gives an altitude of about 16.5 degrees. The horizontal shadow length from a 3-foot-high obstruction is calculated as height divided by the tangent of the solar altitude: 3 / tan(16.5 degrees), or about 10.1 feet. Therefore, a minimum practical clear spacing of approximately 10 feet prevents the front row from casting a shadow on the row behind during the specified solar-time period. This uses standard solar-position geometry, including solar declination and hour angle, as described by the NOAA solar-position equations. The December solstice date and the 9 AM-to-3 PM shading criterion are essential inputs to a PV array row-spacing assessment; see the Natural Resources Canada photovoltaic resource for solar-energy design context.

QUESTION NO: 4

A module's Voc is 40V at STC. At -5°C with a coefficient of -0.33%/°C, what is the Voc?

A. 42.0V

B. 43.0V

C. 44.0V

D. 45.0V

ANSWER: C

Explanation:

44.0V is correct. Standard Test Conditions use a cell temperature of 25°C. At −5°C, the temperature difference from STC is −30°C. Because the open-circuit-voltage temperature coefficient is −0.33%/°C, voltage rises as temperature falls: multiplying the −30°C temperature change by the −0.33%/°C coefficient gives a +9.9% voltage change. Applying that increase to the 40 V STC open-circuit voltage gives 40 V × 1.099 = 43.96 V, which rounds to 44.0 V. This cold-temperature Voc calculation is essential in PV system design because the maximum possible series-string open-circuit voltage must remain below the inverter's and all other listed equipment's maximum DC voltage ratings under the lowest expected site temperature. NABCEP's PV Installation Professional credential covers design considerations such as applying module electrical characteristics and environmental conditions to safe system design. See NABCEP PV Installation Professional and the technical discussion of temperature effects on PV module voltage from PV Education.

QUESTION NO: 5

A rooftop PV array has conductors running through a conduit exposed to sunlight on a roof with an ambient temperature of 40°C. The conduit is 2 inches above the roof surface. What is the NEC temperature adjustment factor for 90°C-rated conductors?

A. 0.87

B. 0.91

C. 0.96

D. 1.00

E. 0.58

ANSWER: E

Explanation:

The correct temperature adjustment factor is **0.58**. NEC rooftop-conduit temperature adjustment requirements account for the additional heating that occurs when raceways are installed above a sun-exposed roof. For a conduit located more than 1/2 inch and not more than 3 1/2 inches above the roof surface, the applicable rooftop temperature adder is 30°C. Because the stated ambient temperature is 40°C, the conductor ampacity correction must be based on an effective ambient temperature of 70°C (40°C + 30°C). In the NEC ambient-temperature correction-factor table, 90°C-rated conductors at an ambient temperature range of 66°C through 70°C use a correction factor of 0.58. This factor is applied to the conductor ampacity otherwise permitted by the applicable ampacity table, while still observing terminal-temperature limitations and all other PV conductor sizing requirements. The National Electrical Code is published as NFPA 70; the rooftop temperature-adder provisions and ampacity adjustment tables should be verified against the edition adopted by the authority having jurisdiction. See NFPA 70: National Electrical Code and NABCEP's PV Installation Professional certification information.

QUESTION NO: 6

A 15 kW array has a PR of 0.88 and 1600 kWh/m²/year insolation. What is the annual output?

A. 19,800 kWh

B. 21,120 kWh

C. 22,440 kWh

D. 24,000 kWh

ANSWER: B

Explanation:

21,120 kWh is the expected annual energy output. A standard preliminary PV-energy estimate multiplies the array's DC nameplate capacity by the annual plane-of-array irradiation, expressed as equivalent peak-sun-hours, and by the performance ratio: 15 kW × 1,600 kWh/m²/year × 0.88 = 21,120 kWh/year. In this calculation, 1,600 kWh/m²/year corresponds numerically to 1,600 peak-sun-hours per year at the reference irradiance of 1 kW/m². The performance ratio of 0.88 accounts for aggregate real-world system losses relative to ideal nameplate operation, such as temperature effects, inverter conversion losses, wiring losses, soiling, module mismatch, and availability. Therefore, the result represents annual AC energy expected after applying the stated overall system-performance factor, assuming the provided insolation is applicable to the array plane and no additional derates are required. This simplified relationship is consistent with industry PV production-estimation methods, in which incident solar resource and system losses are fundamental inputs. See NREL's PVWatts Version 5 Manual and the NREL solar photovoltaic resources for PV energy-modeling context.

QUESTION NO: 7

A 20 kW array has a measured output of 16 kW at 800 W/m² irradiance. What is the performance loss due to irradiance?

A. 10%

B. 20%

C. 25%

D. 30%

ANSWER: B

Explanation:

20% is correct because the array's 20 kW nameplate rating is conventionally stated at Standard Test Conditions, including an irradiance of 1,000 W/m². Irradiance of 800 W/m² is 80% of the STC irradiance level. For this simplified calculation, PV array power is treated as directly proportional to irradiance, so a 20 kW array would produce 20 kW × 0.80 = 16 kW at 800 W/m². The reduction from the STC-rated output is 20 kW − 16 kW = 4 kW. Expressed as a percentage of the 20 kW rating, the irradiance-related reduction is 4 kW ÷ 20 kW × 100 = 20%. The measured 16 kW exactly matches the output expected from irradiance alone, so this question is identifying the reduction relative to the array's STC nameplate output, rather than an additional operational loss at the measured irradiance. NREL explains that PV module ratings use standard test conditions and that field output varies with conditions such as solar irradiance: NREL PV Module Characterization. The standard-test-condition irradiance value of 1,000 W/m² is also described by the PV Education standard test conditions reference.

QUESTION NO: 8

A PV system is designed with a 48V battery bank and a 5 kW inverter. The load requires 20 kWh/day, and the system must have 2 days of autonomy with a maximum depth of discharge (DoD) of 50%. What is the minimum battery capacity required in Ah?

A. 417 Ah

B. 833 Ah

C. 1000 Ah

D. 1667 Ah

ANSWER: D

Explanation:

1667 Ah is the minimum nominal battery-bank capacity. First, the required autonomy energy is the daily load multiplied by the required days of autonomy: 20 kWh/day × 2 days = 40 kWh of usable stored energy. Because the design limits battery discharge to 50% depth of discharge, that 40 kWh may represent only one-half of the battery bank's nominal stored energy. The required nominal storage is therefore 40 kWh ÷ 0.50 = 80 kWh, or 80,000 Wh. Battery capacity in ampere-hours is determined by dividing nominal watt-hours by nominal battery-bank voltage: 80,000 Wh ÷ 48 V = 1,666.7 Ah. Since a minimum capacity is requested, this is rounded up to 1667 Ah before selecting an available battery configuration, with practical design also considering applicable temperature, aging, charge/discharge-rate, and manufacturer-capacity adjustments. The stated 5 kW inverter rating affects power capability, but it does not change this energy-storage calculation. NABCEP identifies energy-storage and system-design knowledge as part of PV installation professional competence; see NABCEP's PV Installation Professional certification page. For the relationship between battery voltage, current, and power, see Victron Energy's battery technical information.

QUESTION NO: 9

A module's Isc is 9A at STC. At 600 W/m² irradiance, what is the expected Isc?

A. 5.4A

B. 6.0A

C. 6.3A

D. 7.2A

ANSWER: A

Explanation:

5.4A is correct because a PV module's short-circuit current (Isc) is approximately proportional to plane-of-array irradiance, assuming cell temperature and other conditions remain unchanged. Standard Test Conditions use an irradiance of 1,000 W/m². An irradiance of 600 W/m² is therefore 600/1,000, or 0.60, of the STC irradiance. Multiplying the module's STC short-circuit current by this irradiance ratio gives 9 A × 0.60 = 5.4 A. This proportional relationship is a useful field-estimation principle: irradiance has a strong, nearly linear effect on PV current, whereas voltage changes much less with irradiance and is more notably affected by cell temperature. The calculation concerns Isc specifically, so it uses the rated short-circuit current rather than a module's operating current, such as Imp. PV performance references describe irradiance as a principal input to the module current-voltage relationship and identify STC as the common 1,000 W/m² reference condition. See Sandia National Laboratories' PV Performance Modeling Collaborative module I-V guidance and the National Renewable Energy Laboratory photovoltaic resources.

QUESTION NO: 10

A PV technician is installing a 6.5KWac inverter using a 40A backfed breaker. The single line shows a 200A panelboard with a 200A breaker, but the installer finds that the panelbord actually has a 150A main breaker. Which of the following is the CORRECT installation option?

A. Replace the 200A panel with a 150A panel.

B. Install a 30A backfed circuit breaker.

C. Change the main circuit breaker to a 200A unit.

D. Complete the installation as noted above.

ANSWER: D

Explanation:

Complete the installation as noted above. is correct because the panelboard bus rating remains 200 A, while the installed main overcurrent protective device is 150 A. For a load-side PV interconnection, the NEC busbar calculation permits the sum of the panelboard main breaker rating and the PV backfed breaker rating to be no greater than 120% of the busbar rating, subject to applicable conditions such as locating the PV breaker at the opposite end of the bus from the main breaker. Here, 150 A plus 40 A equals 190 A. This is below 240 A, which is 120% of the 200 A panelboard bus rating. Therefore, the 40 A PV breaker is permitted by this calculation even though the main breaker found in the field is smaller than the main breaker shown on the single-line diagram. The technician should verify the panelboard's actual bus rating from its labeling, ensure the backfed breaker is listed for the panelboard and properly retained as required, and install the interconnection in accordance with the approved design and applicable code requirements. See NFPA 70, National Electrical Code and the NABCEP certification resources.

QUESTION NO: 11

A module's STC power is 300W, with a temperature coefficient of -0.40%/°C. At 65°C, what is the power loss percentage?

A. 12%

B. 14%

C. 16%

D. 18%

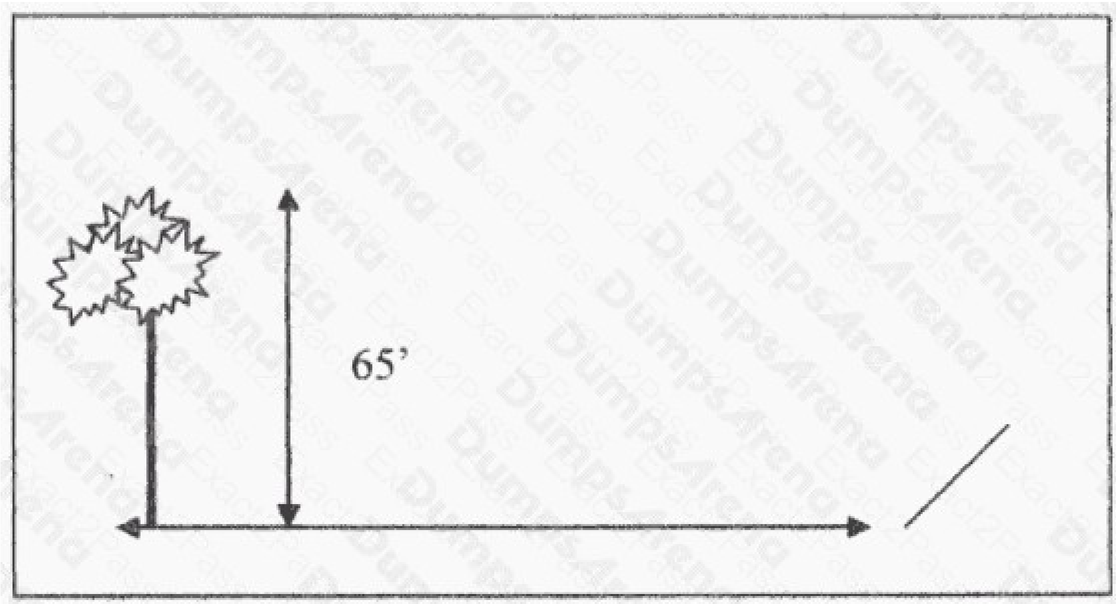
ANSWER: C

Explanation:

16% is correct because Standard Test Conditions (STC) specify a PV cell temperature of 25°C. At 65°C, the module is operating 40°C above its STC temperature. The stated power temperature coefficient is −0.40% per °C, meaning output power decreases by 0.40% of its STC-rated power for every degree Celsius above 25°C. Multiplying the temperature difference by the magnitude of the coefficient gives 40°C × 0.40%/°C = 16% power loss. The negative sign identifies the direction of the effect—power falls as module temperature rises—while the requested loss percentage is conventionally stated as the positive magnitude, 16%. For context, this corresponds to an estimated operating power of 300 W × (1 − 0.16) = 252 W, a reduction of 48 W from the STC nameplate rating. This type of calculation is fundamental to estimating real-world PV production because module operating temperatures commonly exceed the 25°C cell-temperature reference used for STC ratings. See the National Renewable Energy Laboratory solar power resources and the PV Education discussion of temperature effects for further technical context.

QUESTION NO: 12

A PV system is located at 41 N latitude. The sun angle is 23 on December 21 at solar noon. Assuming that the 65 ft tree is directly south of the PV array and will grow 20 ft. over the life of the PV system, what is the MNIMUM distance the tree to the button of the prevent shading?



A. 98 ft.

B. 153 ft.

C. 167 ft.

D. 201 ft.

ANSWER: D

Explanation:

201 ft. is correct because the tree’s mature height must be used for a lifetime shading evaluation. Its current height of 65 ft plus the anticipated 20 ft of growth yields a design height of 85 ft. At solar noon on December 21, the stated sun altitude is 23°. With the tree directly south of the array, its shadow projects north toward the array. The required horizontal separation to keep the shadow from reaching the bottom of the array is determined using the right-triangle relationship: horizontal distance = object height ÷ tan(sun altitude). Thus, the required distance is 85 ft ÷ tan(23°), which equals approximately 200.3 ft. Because the installation must meet or exceed the calculated clearance, the minimum whole-foot answer is rounded up to 201 ft. This type of calculation uses solar altitude, rather than azimuth, because altitude establishes the ratio between an object’s vertical height and its horizontal shadow length. Accounting for foreseeable vegetation growth is also necessary because shading can materially reduce array energy production over the PV system’s service life. Solar-position terminology and calculation concepts are described by the NOAA Solar Calculator; NABCEP identifies site assessment and shading analysis as core PV installation-professional knowledge in its PV Installation Professional certification materials.