Protection System for a Collector Substation That Interconnects an Inverter-Based Resource With a Transmission System

Scott Bruno and Joey Yoklavich
BODEC, Inc.

Eliseo Alcázar Ramírez, Juan Manuel Silva, Aaron Rawlings, and Héctor J. Altuve Ferrer
Schweitzer Engineering Laboratories, Inc.

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***Abstract*—Collector substations of inverted-based resource (IBR) plants receive power through medium-voltage feeders from generation and storage resources, such as photovoltaic (PV), wind, and battery energy storage systems (BESSs). One or two transformers step up the voltage to transmission levels and transfer power to the utility system via a tie line. Collector substations have a high-voltage bus connected to the utility tie line and a medium-voltage (typically 34.5 kV) bus connected to the feeders. Capacitor banks may also be connected to the medium-voltage bus. Substations with two generator step-up (GSU) transformers have two medium-voltage bus sections interconnected through a disconnect switch or a tie breaker.**

This paper describes the protection system developed for the collector substation of a large PV plant to protect buses, GSU transformers, feeders, and capacitor banks. The paper addresses features such as a bus differential scheme with a check-zone function to protect a 34.5 kV split bus, integrated breaker failure protection, and transformer restricted earth fault protection. The paper discusses regulatory compliance with the North American Electric Reliability Corporation (NERC) PRC-024-3, PRC-025-2, and PRC-027-1 standards as applied to PV plants. Finally, the paper describes a bus fault event that occurred during commissioning when the system was initially energized.

I. Introduction

An inverter-based resource (IBR) is any source of electric power that connects to the transmission system through a power electronics interface [1]. IBRs include photovoltaic (PV), wind, and battery energy storage systems (BESSs). IBR system applications have been growing very fast in recent years. In particular, PV systems are increasingly applied in utility, commercial, and residential power systems. In the past two decades, PV generation has grown and continues to grow at record levels, with an average 22 percent annual growth rate [2]. Ten years ago there was only 8 GW of IBRs in the U.S.; the installed capacity was 125 GW in 2023 [2]. PV plant installed cost has decreased from $5 per watt in 2012 to $1.3 per watt in 2022 [3].

PV plant generation capacity is determined by the available footprint. Assessment of a possible PV plant location considers land availability and zoning, irradiance levels, weather, environmental conditions, proximity to water and infrastructure, and various legal restrictions. Economic factors are land cost, incentives, and policies. Incentives from federal, state, and local governments can significantly impact the feasibility of an installation. Other factors are local community support, permitting and approval, technical feasibility of the site, natural disaster risks, and use of government-designated zones.

In the past several years, most PV plants have been combined with BESSs. This combination provides the following advantages:

- Reduces costs by charging the batteries during periods of low energy costs and discharging them during peak demand periods with high energy costs.
- Reduces curtailment during excess power supply periods by charging the batteries, which increases consumption and maximizes the value of the installation to the market.
- Provides increased capacity during peak demand and high-risk periods.
- Provides ancillary services such as fast operating reserves for frequency response, load following, and generation ramping services.
- Provides black-start support after power system blackouts, which can avoid using traditional high-emission sources [4].

Developers, contractors, and utility companies face the challenge of efficiently integrating these installations at a fast pace to keep up with the clean energy goals set forth by the government and electric utilities.

This paper describes the protection system developed in 2022 for a collector substation of a large PV plant to protect buses, generator step-up (GSU) transformers, feeders, and capacitor banks. We first describe the PV plant major components and special protection considerations. Next, we describe the protection system and explain features such as a bus differential scheme with a check-zone function to protect a 34.5 kV split bus, integrated breaker failure protection, and transformer restricted earth fault protection. Then, we discuss the criteria for setting primary and backup protection elements. We also provide an overview of regulatory standards as they apply to PV plants. Lastly, we describe a bus fault event that occurred during commissioning when the system was initially energized. The bus differential (87B) relay tripped in 14 ms; the fault-clearing time was 60 ms.

II. Background

This section describes the major components of IBR plants and, in particular, PV plants.

A. IBR Plants

Fig. 1 depicts a generic example of a renewable IBR plant. The renewable energy source can be a set of PV arrays, a set of wind generators, or a BESS. PV arrays and BESSs produce dc voltage. These sources connect to inverters (IBR units). Wind generators may produce ac voltage or may also connect to IBR units, depending on the generator type.

Several IBR units connect at a common point. An IBR unit transformer steps up the low IBR unit ac voltage to a medium-voltage level.

Medium-voltage feeders transmit power from the IBR unit transformers to the substation GSU transformer that steps up the voltage to transmission levels. A tie line (typically a very short line) connects the IBR plant to the neighboring utility substation.

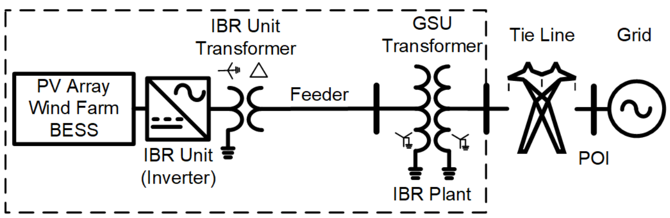

Fig. 1. Example of a renewable IBR plant connected to the power system.

Modern inverters use insulated-gate bipolar transistor switches because of their high controllability [5]. Inverter control algorithms provide voltage, current, active power, and reactive power control. The inverter also controls the quality of the power delivered to the grid.

B. PV Plants

PV generation systems convert sunlight into electrical energy. This conversion takes place in PV cells, which are composed of semiconductor material. Interconnected PV cells compose PV modules.

PV units consist of a set of PV modules connected in series, in parallel, or in a series-parallel arrangement as required to obtain the desired voltage and current levels. The PV modules are interconnected to form strings. These strings are interconnected in a combiner box; the outputs of the combiner box connect to the inverters that convert the dc voltage to ac voltage. The inverter outputs connect to a IBR unit transformer, which typically has delta-connected high-side windings and grounded wye-connected low-side windings.

Fig. 2 depicts a simplified one-line diagram of an example PV plant, which includes the PV units, medium-voltage feeders, and a collector substation with two GSU transformers.

The collector substation generally has one GSU transformer (e.g., 345/34.5 kV or 230/34.5 kV). The GSU transformer rating ranges from 90–250 MVA, and it services as many as ten feeders. The GSU transformer typically has an on-load tap changer for regulating the high-side voltage.

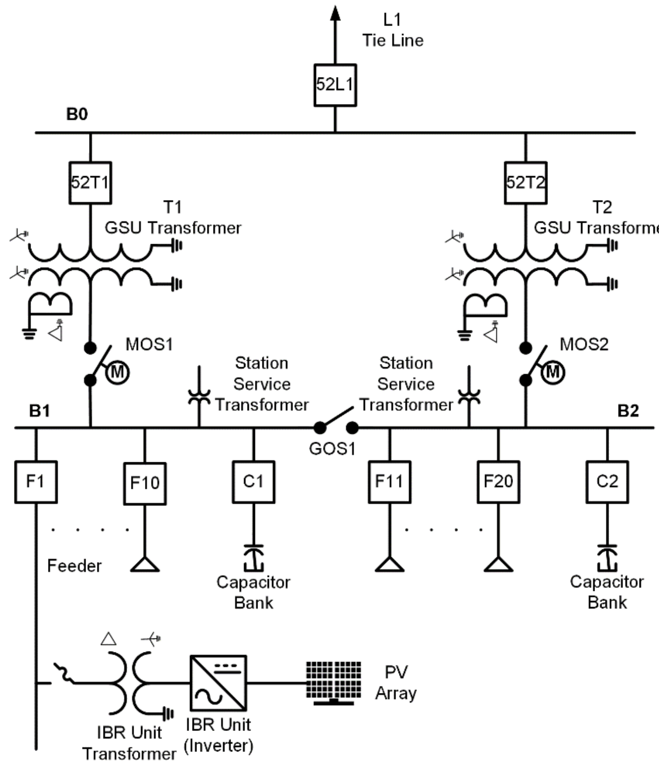

Fig. 2. Simplified one-line diagram of an example IBR plant.

Large PV plants may require two GSU transformers (see Fig. 2), which typically do not operate in parallel. When one transformer is out of service for maintenance or repair, the PV plant power output will be limited to the capacity of the other transformer.

Generally, the high- and medium-voltage buses have a single-bus single-breaker arrangement with no equipment redundancy for a failed breaker or cable. In substations with two GSU transformers, the medium-voltage bus is sectionalized with a disconnect switch or a tie breaker.

As mentioned, feeders (typically underground cables) transfer power from the PV unit transformers to the GSU transformer(s). Typically, one feeder can service as many as eight PV unit transformers. The PV plant generally has a capacitor bank connected to each medium-voltage bus for reactive power compensation at the substation level.

PV plants may have various grounding methods, which depend on the GSU transformer connection. For example, in the Fig. 2 system the GSU transformer has a solidly grounded wye connection on the medium-voltage side. In some PV plants, the GSU transformer wye-winding has low-resistance grounding to limit ground fault current in the medium-voltage system. When the GSU transformer low-side winding has a delta connection, the system is typically grounded through a zig-zag transformer.

C. Tie Line and Point of Interconnection

The neighboring utility owns the tie line. The point of interconnection (POI) is the utility-side tie-line terminal, as shown in Fig. 1. In some PV plants, the utility builds a small control enclosure in the substation switchyard that houses the tie-line protection, control, and metering (PCM) system panels. The resulting additional utility investment increases the cost of the overall installation. In other PV facilities, the plant control enclosure houses the tie-line PCM panels. In this case, the utility typically defines the protection requirement at the POI to comply with their own line protection standards and relay types.

PV plants are often built close to utility substations. As a result, tie lines are generally short (in some cases, only hundreds of feet long). Line current differential (87L) protection is a good solution to protect these lines, but using bus protection relays is an alternative solution. Tie-line protection is outside the scope of this paper.

D. Behavior of IBR Units During Short Circuits

The response of IBR units during short circuits is different from that of synchronous generators; see Table I [6] [7]. The inverter control strategy dictates the inverter short-circuit response [6] [8].

TABLE I
SHORT-CIRCUIT RESPONSE OF SYNCHRONOUS GENERATORS AND IBR UNITS

Items	**Synchronous Generators**	**IBR Units**
Current Magnitude	8 pu* or greater	1.5 ~ 3 pu†, depending on inverter design
Current Angle	Lags voltage by 90°	Can lag or lead voltage
Positive Sequence	Yes	Yes
Negative Sequence	Yes	Depends on inverter design
Zero Sequence	Yes	No

* Value is for thermal units according to [8].

† Value is from [7].

During normal operation, the inverter controls the output current in magnitude and angle. This action allows control of active and reactive power outputs and ensures that reactive power output remains within the maximum and minimum limits.

The inverter control continuously balances the phase voltages and currents. Consequently, the inverter behaves as a constant positive-sequence current source during normal operation and for three-phase short circuits. For unbalanced faults, the inverter control tries to balance the currents, which affects the negative- and zero-sequence current contributions to the fault [7].

Equation (1) defines the inverter short-circuit contribution.

$$I_{SC} = k_{SC} I_{RATED} \tag{1}$$

where:

I_{SC} is the short-circuit current contribution at the inverter terminals.

I_{RATED} is the inverter-rated current.

k_{SC} is a factor that depends on the inverter design. Typically, $k_{SC} \le 3$ [6] [7].

Inverter modeling is an ongoing research topic. The main inverter modeling approaches for short-circuit analysis in systems with IBRs are the following:

- Thevenin equivalent model.
- Full Norton equivalent model.
- Voltage-controlled current source (VCCS) model.

These inverter models are presently available in commercial software. The preference today is to use the VCCS model [9] [10]. These modeling approaches represent inverters as a positive-sequence current source for balanced faults. For unbalanced faults, the negative-sequence current contribution depends on the inverter design; the zero-sequence current contribution typically equals zero (see Table I).

III. PROTECTION SYSTEM

Fig. 3 shows the one-line diagram of the collector substation discussed in this paper, which includes the following components:

- Two 345/34.5/13.8 kV GSU transformers.
- Five 34.5 kV feeders, three connected to BUS-100 and two connected to BUS-200 (we show one feeder per bus for simplicity).
- Two 34.5 kV capacitor banks (one on each bus section).

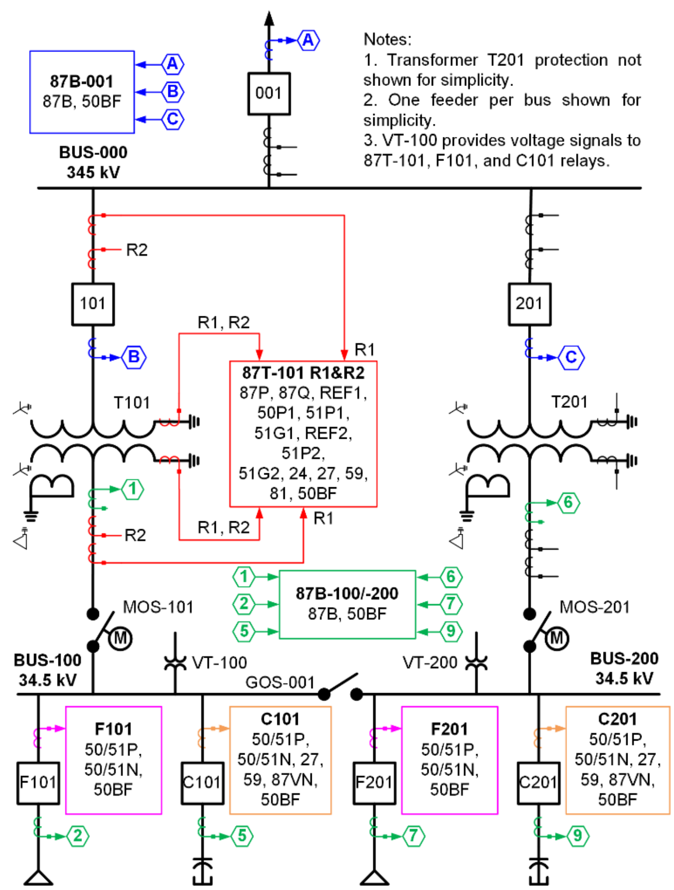

Fig. 3. Collector substation protection system.

Fig. 3 also illustrates the collector substation protection system, which includes the following protection schemes:

- High-side bus protection (87B-001 relay).
- Low-side bus protection (87B-100/-200 relay).
- GSU transformer protection (87T-101 R1 and 87T-101 R2 relays).

- Feeder protection (F101 and F201 relays).
- Capacitor bank protection (C101 and C202 relays).

Fig. 3 does not show the tie-line relays because the neighboring utility is responsible for them.

A. Bus Differential (87B) and Integrated Breaker Failure (50BF) Protection

The collector substation has two multifunction bus protection relays that provide the following functions:

- 87B protection
- 50BF protection

The 87B percentage-restrained elements have an adaptive dual-slope characteristic; they provide sub-cycle operating times for bus faults. These elements are secure for the following conditions:

- External faults with heavy current transformer (CT) saturation.
- Presence of CT subsidence current after clearing an external fault.
- Open- or short-circuited CTs.

The 87B elements provide low operating time for external-to-internal evolving faults.

Fig. 4 shows the 87B element adaptive dual-slope characteristic. In this figure, I_{OP} is the operating current and I_{RT} is the restraining current. O87P is the minimum pickup setting. Slope 1 and Slope 2 are setting values. An external fault detector controls the slope value. Slope 1 is active during normal conditions and internal faults. Slope 2 activates for external faults.

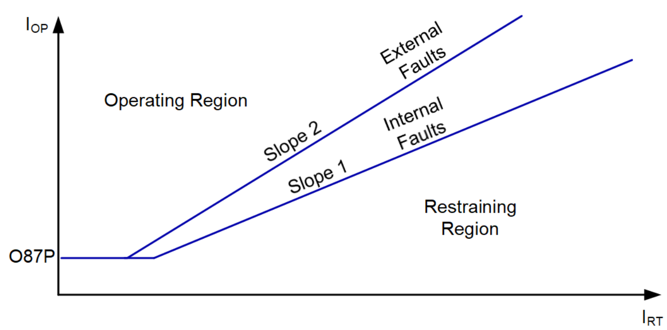

Fig. 4. 87B element adaptive dual-slope characteristic.

Equations (2) and (3) define the 87B element operating and restraining quantities.

$$I_{OP} = \left|\bar{I}_1 + \bar{I}_2 + \ldots + \bar{I}_n\right| \tag{2}$$

$$I_{RT} = \left|\bar{I}_1\right| + \left|\bar{I}_2\right| + \ldots + \left|\bar{I}_n\right| \tag{3}$$

where:

$\bar{I}_1, \bar{I}_{2\ldots}\bar{I}_n$ are the differential zone boundary currents.

Fig. 3 shows two 87B schemes. One scheme protects the 345 kV bus (BUS-000); the other scheme protects the 34.5 kV bus sections (BUS-100 and BUS-200). The 87B relays create the following protection zones:

- A 345 kV zone bounded by the line-breaker CT labeled "A" in the figure, and by the 345 kV transformer-breaker CTs (labeled "B" and "C").
- Two 34.5 kV zones, each bounded by a set of 34.5 kV transformer CTs (1 or 6), the feeder-breaker CTs (2 or 7), and the capacitor-bank-breaker CTs (5 or 9).

The bus protection relays also provide 50BF protection for all breakers in the differential zones. 50BF provides faster fault clearing for breaker failure events than remote backup protection, which mitigates power transformer and other equipment damage and enhances power system stability.

1) 87B Main Differential Protection Zones

Fig. 5 shows the main differential protection zones of the 87B-100/-200 relay that protects the 34.5 kV BUS-100 and BUS-200. The relay creates three zones for each bus section (one per phase), as follows:

- Zone 1: BUS-100 A-phase
- Zone 2: BUS-100 B-phase
- Zone 3: BUS-100 C-phase
- Zone 4: BUS-200 A-phase
- Zone 5: BUS-200 B-phase
- Zone 6: BUS-200 C-phase

The collector substation GSU transformers do not operate in parallel. The bus-tie group-operated switch GOS-001 is normally open. When one transformer is taken offline, the operator manually closes the switch to transfer the feeders connected to the 34.5 kV bus of that transformer to the adjacent transformer.

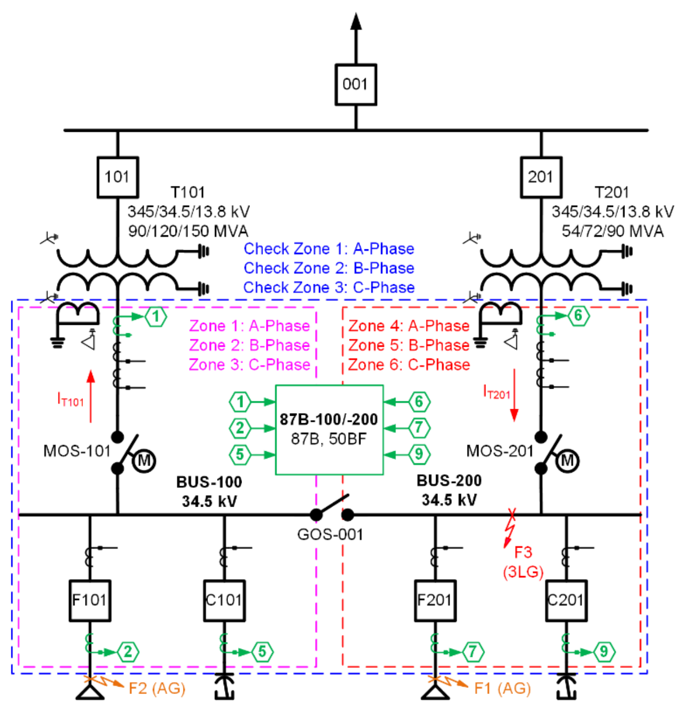

Fig. 5. Protection zones of the 87B-100/-200 relay that protects BUS-100 and BUS-200.

The relay needs to merge the BUS-100 and BUS-200 main differential zones when GOS-001 closes. Because of the absence of GOS-001 position status information, an operator acts on a relay front-panel pushbutton to signal that GOS-001 closed. Then, the relay merges the differential zones using internal logic. A relay front-panel LED informs the operator that the zones merged.

When GOS-001 closes, the relay merges the differential zones as follows:

- Zone 1: BUS-100 and BUS-200 A-phase
- Zone 2: BUS-100 and BUS-200 B-phase
- Zone 3: BUS-100 and BUS-200 C-phase

When the bus zones merge, the relay disables Zone 4, Zone 5, and Zone 6.

2) 87B Check Zones

87B relays use check zones to ensure security in reconfigurable bus arrangements. An independent differential element that monitors the overall current balance for the entire bus provides the check-zone function.

As shown in Fig. 5, the 87B-100/-200 relay check zones are bounded by the 34.5 kV transformer CTs (1 and 6), the feeder-breaker CTs (2 and 7), and the capacitor-bank-breaker CTs (5 and 9). The purpose of these check zones is to prevent incorrect 87B protection operation for external faults when a discrepancy exists between the GOS-001 status and the pushbutton status (e.g., because of a human error). The relay creates the following check zones:

- Check Zone 1: BUS-100 and BUS-200 A-phase
- Check Zone 2: BUS-100 and BUS-200 B-phase
- Check Zone 3: BUS-100 and BUS-200 C-phase

Check Zone 1 element supervises Zone 1 and Zone 4 elements, Check Zone 2 element supervises Zone 2 and Zone 5 elements, and Check Zone 3 element supervises Zone 3 and Zone 6 elements.

Table II shows two examples of external A-phase-to-ground (AG) faults (F1 and F2 in Fig. 5) that would cause incorrect 87B protection operation if not supervised by a check zone. For these two faults, we assume that the operator manually closed GOS-001 but forgot to act on the pushbutton. As a result, the relay does not merge Zone 1 and Zone 4. Zone 1 and Zone 4 elements may operate incorrectly for both faults because they interpret the unmeasured outgoing current to either BUS-100 or BUS-200 as a differential current (i.e., they interpret the external faults as internal). Check Zone 1 would declare these faults as external and not allow an 87B operation. If this check zone is not available, as shown in Table II, the 87B relay may operate incorrectly for either fault.

TABLE II
87B PROTECTION OPERATION FOR EXTERNAL FAULTS

Fault	Pushbutton Zone Merging Selection	Zone 1	Zone 4	Check Zone 1
F1 (AG)*	Not merged‡	Operates	Operates	Not available
F2 (AG)†	Not merged‡	Operates	Operates	Not available

* Fault F1 (AG): T101 in service, T201 out of service, GOS-001 closed.

† Fault F2 (AG): T201 in service, T101 out of service, GOS-001 closed.

‡ Pushbutton selection disagrees with GOS-001 status.

To ensure dependability, the check-zone sensitivity must be equal to or greater than that of the supervised main differential zones. In particular, the Slope 1 setting of the check-zone differential element must ensure sensitive detection of internal faults when both transformers are in operation (with GOS-001 open).

Engineers typically apply the same Slope 1 settings to the main differential zone elements and the check-zone elements. However, in the Fig. 5 system, the main-zone elements and the check-zone elements measure different restraining currents for internal faults with GOS-001 open. Therefore, the main-zone elements and the check-zone elements require different settings.

Considering the different rated capacities of Transformer T101 and Transformer T102, the greatest difference between the restraining currents of the main-zone and check-zone elements occurs when:

- A three-phase fault occurs at BUS-200 (Fault F3 in Fig. 5).
- Transformer T101 is fully loaded and has the maximum fault current contribution from the feeders connected to BUS-100.
- Transformer T201 is unloaded and receives no contribution from the feeders connected to BUS-200.

Fig. 6 shows the fault loci measured by the BUS-200 main-zone differential element and the check-zone differential element for different current contributions to Fault F3. The square dots represent Fault F3 with the maximum current contributions; the round dots represent Fault F3 with the minimum current contributions.

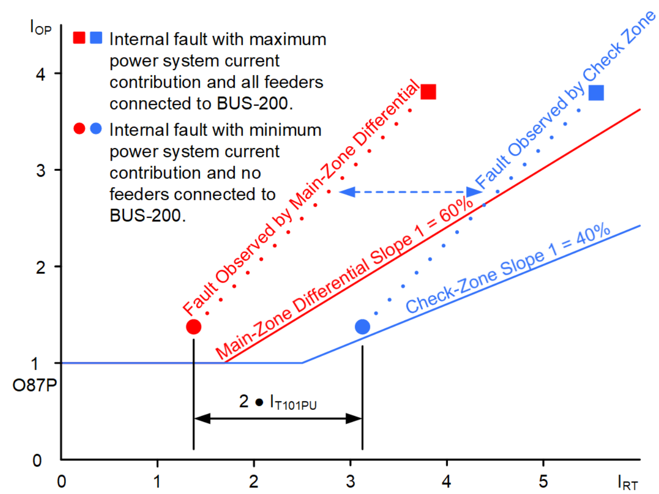

Fig. 6. The BUS-200 differential element and check-zone element measure different restraining currents. Their fault loci are shifted. Their Slope 1 characteristics need different settings.

The BUS-200 differential element measures equal operating and restraining currents ($I_{OP} = I_{RT} = I_{T201}$) for this internal bus fault. As a result, the fault locus measured by the BUS-200 differential element is a straight line starting at the origin of coordinates with a 100 percent slope.

The check-zone differential element measures the same operating current as the BUS-200 element, but it measures a higher restraining current ($I_{OP} = I_{T201}$; $I_{RT} = 2 \bullet I_{T101} + I_{T201}$). As a result, the fault locus measured by the check-zone element is a straight line parallel to the BUS-200 element fault locus. The shift to the right equals the value of the additional restraining current 2 • I_{T101}, as shown in Fig. 6.

Fig. 6 also shows the differential element Slope 1 characteristics. The BUS-200 element Slope 1 has a 60 percent setting. With this setting, it detects all internal BUS-200 faults (the fault locus falls completely in the operation region). Fig. 6 shows that setting the check-zone Slope 1 equal to the main differential Zone 1 setting (60 percent) would cause the check-zone to have no sensitivity to detect minimum current faults. Setting Slope 1 to 40 percent solves the check-zone sensitivity problem.

Let us examine the procedure to calculate the check-zone Slope 1 setting. Equations (4) and (5) express the per-unit phase current contributions from the low side of Transformer T101 and Transformer T201 for a fault at BUS-200.

$$I_{T101\_PU} = \frac{I_{T101}}{CTR_{T101} \bullet TAP_{T101}} \quad (4)$$

where:

I_{T101_PU} is the per-unit low-side phase current contribution of Transformer T101 for a fault at BUS-200.

I_{T101} is the low-side phase current contribution of Transformer T101 for a fault at BUS-200 in primary amperes.

CTR_{T101} is the ratio of low-side Transformer T101 CTs.

TAP_{T101} is the normalization factor of the low-side Transformer T101 terminal.

$$I_{T201\_PU} = \frac{I_{T201}}{CTR_{T201} \bullet TAP_{T201}} \quad (5)$$

where:

I_{T201_PU} is the per-unit low-side phase current contribution of Transformer T201 for a fault at BUS-200.

I_{T201} is the low-side phase current contribution of Transformer T201 for a fault at BUS-200 in primary amperes.

CTR_{T201} is the ratio of low-side Transformer T201 CTs.

TAP_{T201} is the normalization factor of the low-side Transformer T201 terminal.

Equation (6) expresses the check-zone Slope 1 characteristic.

$$I_{OP\_CZ} = \text{Slope } 1_{CZ} \bullet I_{RT\_CZ} \quad (6)$$

where:

I_{OP_CZ} is the check-zone operating current.

I_{RT_CZ} is the check-zone restraining current.

Slope 1_{CZ} is the check-zone Slope 1 setting.

Equations (7) and (8) express the check-zone operating and restraining currents for this BUS-200 fault (see Fig. 5).

$$I_{OP\_CZ} = I_{T201\_PU} \quad (7)$$

$$I_{RT\_CZ} = 2 \bullet I_{T101\_PU} + I_{T201\_PU} \quad (8)$$

Substituting (7) and (8) in (6), and adding a dependability margin, we obtain the check-zone Slope 1 setting expression shown in (9).

$$\text{Slope } 1_{CZ} = \frac{m \bullet I_{T201PU}}{2 \bullet I_{T101PU} + m \bullet I_{T201PU}} \quad (9)$$

where:

Slope 1_{CZ} is the recommended check-zone Slope 1 setting.

m is a dependability margin (we recommend using 0.5–0.6).

By using check zones to supervise main differential zones and properly setting check-zone Slope 1, we provide a good balance between dependability and security of the 87B element for the application described in this paper.

3) 50BF Protection

50BF protection is enabled in all zone protective relays. In each relay, all zone protection elements tripping the breaker provide 50BF initiate (BFI) signals; when the relay declares a breaker failure condition, it issues a tripping signal to all adjacent breakers required to clear the fault.

This arrangement increases dependability by providing the 50BF function in different relays. Each relay provides the 50BF function if it provides zone protection.

This arrangement is simple in design. It does not use external BFI signals. Therefore, it reduces the risk of human errors and noise-induced spurious BFI signals. Reference [11] provides further information.

As an example, Fig. 7 shows the 50BF implementation in the 87B-100/-200 relay and the F101 feeder relay. In each relay, the 50BF logic receives a BFI initiation bit from the internal zone protection elements.

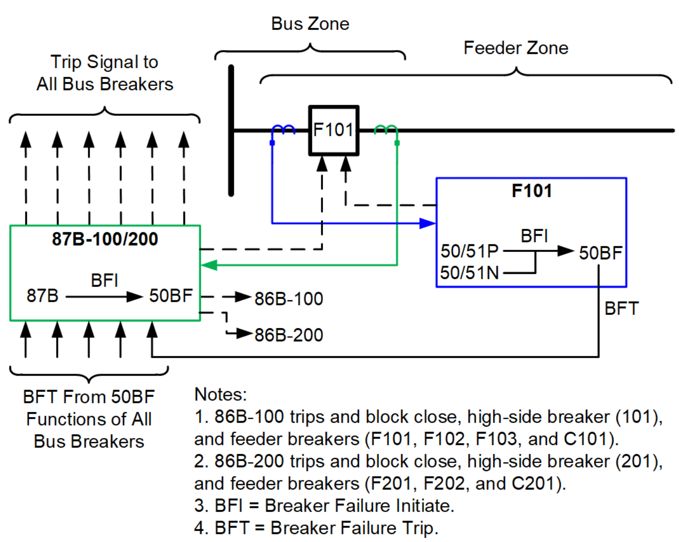

Fig. 7. 50BF implementation in the bus differential and feeder relays.

When a fault occurs in the bus zone, the 87B-100/-200 relay routes the 50BF tripping (BFT) signals to the backup breakers using its multiple contacts. Additionally, the 87B-100/-200 relay routes the BFT signals to the lockout relay 86B-100 and/or 86B-200, which trip(s) the corresponding breakers and blocks their closing.

When a fault occurs in the feeder zone, the F101 feeder relay sends the tripping signal to the breaker and internally sends the BFI bit to the 50BF logic. If the breaker fails to open, the F101 feeder relay sends a tripping command to the 87B-100/-200 relay. This relay then routes the tripping command to the corresponding breakers and lockout relays to isolate the fault.

B. GSU Transformer Protection

The GSU transformer is the most critical component of the substation, with the longest lead time and highest cost. It is common for developers to purchase these transformers years in advance.

We use dual-redundant multifunction relays for protecting each GSU transformer. Fig. 3 shows the GSU transformer relays; they include the following protection elements:

- Phase differential (87P)
- Negative-sequence differential (87Q)
- High-side restricted earth fault (REF1)
- Low-side restricted earth fault (REF2)
- High-side instantaneous phase-overcurrent (50P1)
- High-side phase time-overcurrent (51P1)
- High-side ground time-overcurrent (51G1)
- Low-side phase time-overcurrent (51P2)
- Low-side ground time-overcurrent (51G2)
- V/Hz (24)
- Under-/overvoltage (27/59)
- Under-/overfrequency (81)
- 50BF

The 87P differential zone is bounded by the high-side breaker CTs and the low-side transformer CTs. The 87P element provides primary protection for faults inside the tank and for the cable between the high-side breaker and the GSU transformer. The percentage-restrained 87P element has an adaptive dual-slope characteristic controlled by an external fault detector (see Fig. 4). The unrestrained 87P elements provide high-speed operation for high-current internal faults. The relay has three types of unrestrained differential elements: filtered, raw, and waveshape-based. The raw and waveshape elements do not require user settings.

The 87Q element provides sensitive primary protection for low-magnitude faults, such as turn-to-turn faults. The external fault detector blocks the 87Q element to prevent its misoperation on the fictitious negative-sequence differential current caused by uneven CT saturation for three-phase faults.

The 87P and 87Q elements are secure for magnetizing inrush current using independent even-harmonic restraint (87P) and common even-harmonic blocking (87P, 87Q). Combining these two methods provides high security and speed without sacrificing dependability. Additionally, these elements use waveshape-based inrush detection to improve security when the differential current harmonic content is low. The 87P and 87Q elements are secure for transformer overexcitation conditions using independent fifth-harmonic blocking.

For ground faults close to the neutral of grounded wye transformer windings, a small portion of the winding is shorted to ground. The small change in the winding does not have a substantial impact on the transformer operation and does not significantly change the phase currents. However, these faults must be quickly detected and isolated because the ground current circulating through the shorted turns can be very high and can cause considerable damage to the transformer. The 87P element is not sensitive to these faults because of the low-magnitude phase current changes. Restricted earth fault (REF) elements respond to the neutral current, thereby reliably detecting ground faults close to the transformer neutral. Reference [12] provides a detailed explanation of the REF element operation principle, settings, and commissioning.

In the collector substation 87T relays, the REF1 and REF2 elements provide sensitive detection of ground faults close to the neutral on the solidly grounded, wye-connected GSU transformer windings. These elements perform phase comparison of the neutral current and the zero-sequence current at the transformer terminals. An instantaneous overcurrent element that measures the neutral current supervises the REF element phase comparators. The REF1 protection zone is bounded by the high-side breaker CTs and the high-side transformer-neutral CT. The REF2 protection zone is bounded by the low-side transformer CTs and the low-side transformer-neutral CT.

The 50P1 element receives current from the high-side breaker CTs and provides protection for severe transformer internal faults.

The 51P1 element receives current from the high-side breaker CTs and provides backup protection for GSU transformer through-faults. It also provides time-delayed backup to the 51P2 element for faults at the medium-voltage bus and the cable between the GSU transformer and the medium-voltage bus. The 51P1 element also provides time-delayed backup to the 87P and the sudden-pressure relay for internal faults inside the tank.

The 51G1 element receives current from the high-side neutral CT and provides backup protection for ground faults on the high-side winding and for system ground faults.

The 51P2 element receives current from the low-side transformer CTs and provides primary protection for GSU transformer through-faults. It also provides backup protection for faults at the medium-voltage bus and the cable between the GSU transformer and the medium-voltage bus, and backup protection for feeder faults.

The 51G2 element receives current from the low-side neutral CT and provides backup protection for ground faults on the low-side winding, bus ground faults, and feeder ground faults.

The 24 element provides primary GSU transformer overexcitation protection [13].

The 27, 59, and 81 elements provide backup protection to the IBR units according to PRC-024-3 [14], as described in Section V.A.

The high-side breaker 50BF protection provides faster fault clearing to mitigate GSU transformer and other equipment damage.

C. Feeder Protection

Fig. 3 shows the feeder relays. They include the following protection elements:

- Instantaneous phase-overcurrent (50P)
- Phase time-overcurrent (51P)
- Instantaneous residual overcurrent (50N)
- Residual time-overcurrent (51N)
- 50BF

The 50P and 51P elements provide primary protection for feeder phase faults. The 50N and 51N elements provide primary protection for feeder ground faults. Additionally, the 50BF protection ensures faster fault clearing to mitigate damage to the GSU transformer and other equipment.

D. Capacitor Bank Protection

The collector substation has externally fused ungrounded single wye-connected capacitor banks. Fig. 3 shows the capacitor bank relays; they include the following protection elements:

- Neutral voltage differential (87VN)
- Instantaneous phase-overcurrent (50P)
- Phase time-overcurrent (51P)
- Instantaneous residual overcurrent (50N)
- Residual time-overcurrent (51N)
- Undervoltage (27)
- Overvoltage (59)
- 50BF

The 87VN elements provide primary protection against capacitor unit failures, capacitor unit fuse malfunction, and cascade failures that can cause extensive damage and may create a safety hazard if the bank is not tripped quickly. The 50P and 51P elements provide primary protection against capacitor bank phase high-current faults, and the 50N and 51N elements protect against capacitor bank ground high-current faults. The 27 element detects loss of system voltage and trips the capacitor bank breaker to prevent capacitor bank reenergization with a trapped charge. The 59 element protects the capacitor bank against abnormal system overvoltage conditions. Finally, 50BF protection ensures faster fault clearing to mitigate damage to the GSU transformer and other equipment.

IV. Protection Setting Criteria

A. 87B Relay

1) 87B Main Protection-Zone Elements

To ensure security, we set the 87B minimum pickup (O87P) to the nominal bus current to prevent operation for normal load current if one CT is open-circuited, short-circuited, or disconnected from the relay. To ensure sensitivity, we check that the minimum internal fault current is greater than O87P. Additionally, we check that the primary current for a fault on the secondary of the in-zone station service transformer is greater than O87P.

Slope 1 is active for normal conditions and internal faults. For internal faults, the fault locus as observed by the 87B element is a straight line with a 100 percent slope. To ensure sensitivity, we set 87B Slope 1 to 60 percent.

Slope 2 is active for external faults. We set 87B Slope 2 based on the worst-case effective CT transient dimensioning factors described in [15]. These factors serve to verify that the CT is adequate considering the maximum through-fault current and the connected secondary burden. The remanence dimensioning factor (K_{REM}) is equal to 3, and the transient dimensioning factor (K_{TD}) is equal to 2.8. Considering these factors, we set Slope 2 to 80 percent.

2) 87B Check-Zone Elements

We set the 87B element minimum pickup (O87P) to the same value as that of the 87B main protection-zone elements.

We set Slope 1 to 40 percent, as explained in Section III.A. We set Slope 2 to the same value as that of the 87B main protection-zone elements.

3) 50BF Elements

We set the 50BF current detector with the maximum possible sensitivity to dependably detect the minimum fault current. A typical setting is 0.5 A secondary. We set the 50BF time delay to 0.15 s. This delay considers the breaker maximum fault-clearing time, the 50 element reset time, and a security factor. We apply these 50BF settings to all relays of the collector substation.

B. GSU Transformer Relay

1) Differential Elements

The 87P and 87Q elements have the adaptive dual-slope characteristic shown in Fig. 4.

To ensure sensitivity, we set the 87P minimum pickup (O87P) to 0.2–0.3 pu of transformer-rated current at base MVA. To ensure sensitivity, it is also important to select proper CT ratios. Reference [16] provides guidelines on transformer differential element settings and CT selection.

Slope 1 must accommodate the steady-state and proportional sources of mismatch in the differential current. We set Slope 1 to 25 percent.

We set 87P Slope 2 based on the worst-case effective CT transient dimensioning factors described in [15]. The remanence dimensioning factor (K_{REM}) is equal to 3, and the transient dimensioning factor (K_{TD}) is equal to 3.5. The maximum through-fault current value to use depends on the differential protection-zone arrangement. In this application, the high-side zone boundary is a single-breaker arrangement. In this case, the through-fault current to consider is the low-side three-phase fault current. This current is limited by the transformer impedance. A typical Slope 2 setting is 75–85 percent.

We set the second- and fourth-harmonic blocking elements to 15 percent. We set the fifth-harmonic blocking element to 35 percent.

We set the 87P filtered unrestrained element pickup equal to the greatest of two values: the transformer maximum inrush current or the maximum fictitious differential current resulting from uneven CT saturation for three-phase through-faults. We estimate the transformer inrush current at eight to ten times the transformer-rated current at base capacity. To determine the maximum through-fault current for this single-breaker arrangement, we consider a low-side three-phase bus fault (assuming an infinite bus source). Assuming that one CT saturates 50 percent, the fictitious 87P differential current equals 50 percent of the maximum through-fault current. A typical setting of the 87P filtered unrestrained element pickup is 8–10 pu of the transformer-rated current at base MVA rating.

We set the 87Q element minimum pickup (O87QP) to the same value as that of the 87P element.

The 87Q element restraining current I_{RT} does not comply with (3). Instead, I_{RT} equals the maximum of the zone boundary currents. Slope 1 must accommodate the steady-state and proportional sources of mismatch in the differential current. We set Slope 1 to 35 percent.

2) *REF Elements*

The only setting to calculate for the REF element is the pickup setting 50NP of an instantaneous overcurrent element that measures the neutral current. 50NP must be set greater than the maximum unbalance current (I_{UNB}) and the minimum current required for measurement accuracy (I_{MIN}). For solidly grounded transformers, I_{UNB} is typically considered to be the load unbalance current.

Reference [12] proposes using 30 percent of the bolted three-phase through-fault current as a conservative REF setting for solidly grounded wye windings connected to single-breaker buses. This proposal considers that the $3I_0$ unbalance for a three-phase fault can be significantly higher than the load unbalance. This pickup setting does not affect REF element sensitivity and dependability because zero-sequence current is very high for faults close to the neutral or at any other location in solidly grounded wye transformer windings.

3) *Overcurrent Elements*

We set the 50P1 element pickup equal to the greatest of two values: the transformer maximum inrush current or 125 percent of the maximum through-fault current for a low-side three-phase bus fault (assuming an infinite bus source). This pickup setting meets the requirements specified in PRC-025-2 (Section V.D).

We set the 51P1 element pickup to 220 percent of the transformer-rated current at base MVA rating. This pickup setting meets the requirements specified in PRC-025-2 (Section V.D). We set the time-current curve to coordinate with the transformer through-fault capability curve and with the 51P2 element curve. As a result of this coordination, we set the element time dial to operate in 0.8–1 s for a three-phase low-side bus fault. We use a coordination time interval (CTI) equal to or greater than 0.3 s.

We set the 51G1 element pickup to 20–30 percent of the transformer-rated current at base MVA rating. We check that the element is sensitive enough to detect a single-phase-to-ground fault at the remote bus (the POI). We set the time-current curve to coordinate with the transformer through-fault capability curve. We also set the curve to coordinate with the tie-line 67N element looking to the utility system for a single-phase-to-ground close-in fault, and with the 51G2 element for a single-phase-to-ground low-side bus fault. As a result of this coordination, we set the element time dial to operate in 0.8–0.9 s for a single-phase-to-ground high-side bus fault. We use a CTI equal to or greater than 0.3 s.

We set the 51P2 element pickup to 220 percent of the transformer-rated current at base MVA rating. This pickup setting meets the requirements specified in PRC-025-2 (Section V.D). We set the time-current curve to coordinate with 51P1 and feeder 51P elements for the maximum three-phase low-side bus fault current. As a result of this coordination, we set the element time dial to operate in 0.5–0.6 s for a three-phase low-side bus fault. We use a CTI equal to or greater than 0.3 s.

We set the 51G2 element pickup to 10–20 percent of the transformer-rated current at base MVA rating. We set the time-current curve to coordinate with 51G1 and feeder 51G elements for the maximum low-side bus single-phase-to-ground fault current. As a result of this coordination, we set the element time dial to operate in 0.5–0.6 s for a single-phase-to-ground low-side bus fault. We use a CTI equal to or greater than 0.3 s.

4) *Other Elements*

The 24 element uses a composite V/Hz characteristic with inverse-time and definite-time curves. The 24 element composite curve should coordinate with the transformer overexcitation limit curve and with overvoltage ride-through elements. This coordination ensures that generating resources remain connected during voltage excursions in support of the Bulk Electric System (BES) [14]. When a transformer overexcitation limit curve is not available, refer to Figure 38 of [13], which provides overexcitation limit curves from three different transformer manufacturers.

We set the inverse-time curve to operate in 45 s or less for a V/Hz value equal to 118 percent. We set the definite-time curve to operate in 2 s or less for V/Hz values greater than 118 percent [17].

We set the 27, 59, and 81 elements to comply with PRC-024-3 [14]. These settings ensure that generating resources remain connected during specified frequency and voltage excursions, supporting the BES. Section V.A provides additional information.

C. *Feeder Relays*

We set the 50P element pickup with enough sensitivity to detect phase-to-phase faults at the end of the 34.5 kV feeders. To ensure security, we check that the element is insensitive to low-voltage bus faults in IBR unit transformers. A typical pickup setting is 50 percent of the remote-end three-phase fault current. We set the 50P time delay to 0.1–0.2 s. This delay provides coordination with primary fuses of IBR unit transformers.

We set the 50N element pickup with enough sensitivity to detect single-phase-to-ground faults at the end of the 34.5 kV feeders. The element is insensitive to low-voltage bus faults in the delta-wye-connected IBR unit transformers. A typical setting is 50 percent of the remote-end single-phase-to-ground fault current. We set the 50N time delay to 0.1–0.2 s to provide coordination with primary fuses of IBR unit transformers.

We set the 51P element pickup to 135 percent of the current calculated from the maximum aggregate IBR nameplate MVA output to meet PRC-025-2 as described in Section V.D. We set the time-current curve to coordinate with the transformer relay 51P2 element. We set the element time dial to operate in 0.1–0.2 s for a maximum close-in three-phase fault to ensure coordination with downstream protective devices.

We set the 51N element pickup to 30 percent of 51P pickup. We set the time-current curve to coordinate with the transformer relay 51G2 element. We set the element time dial to operate in 0.1–0.2 s for a maximum close-in single-phase-to-ground fault to ensure coordination with downstream protective devices.

D. *Capacitor Bank Relay*

We set the 87VN alarm element pickup to 50–75 percent of the neutral differential voltage caused by one blown capacitor unit fuse. We set the time delay to 10 s [18].

We set the 87VN trip element pickup to operate at a neutral differential voltage value that is halfway between the number of blown capacitor unit fuses, resulting in the remaining capacitor units experiencing 110 percent (standard duty) rated voltage, and the next lower step [18]. We set time delay to 6 cycles [18].

We set the 87VN high-trip element pickup following the same procedure as for the 87VN element but using 115 percent as a threshold. We set the time delay to 1 cycle.

We set the 50P element pickup to the greatest of either four times the capacitor bank rated current or the inrush current [18]. We set time delay to 6 cycles to coordinate with the capacitor unit fuses. We set the 50N element pickup equal to the 50P element pickup.

We set the 51P element pickup to 125 percent of the nominal capacitor bank phase current. We set the time dial to operate in 0.15 s for a maximum close-in fault to ensure coordination with capacitor unit fuses.

We set the 51N element pickup to 30 percent of the nominal capacitor bank phase current. We set the time dial to operate in 0.15 s for a maximum close-in single-phase-to-ground fault.

We set the 27 element pickup to 50 percent of the nominal capacitor bank voltage. We set the time delay to 5 s.

We set the 59 element pickup to 110 percent (for standard duty capacitor units) of the nominal capacitor bank voltage. We set the time delay to 2 s.

V. Regulatory Standards

PV plants must meet grid interconnection requirements to ensure that the electric power grid operates in a safe, reliable, and stable manner. The interconnection requirements depend on various jurisdictional entities in each country. In the U.S., the Large Generator Interconnection Agreement (LGIA) defines the interconnection requirements between PV plants and local utility authorities.

The LGIA mainly refers to synchronous generators, but it also includes IBRs. The minimum interconnection requirements for IBRs are:

- Active power control
- Voltage and reactive power control
- Primary frequency response
- Fault ride-through capability

Most modern inverters have fault ride-through capability. PV plants using these inverters provide power when the grid needs it. For example, inverters inject reactive power when voltage disturbances occur in the grid.

The following sections describe the interconnection requirements of the North American Electric Reliability Corporation (NERC), utility policy, and the Institute of Electrical and Electronics Engineers (IEEE) applicable to the project described in this paper.

A. *NERC – PRC-024-3*

The purpose of PRC-024-3 is to define protection settings that allow generating resource(s) to remain connected during defined frequency and voltage excursions in support of the BES [14]. Requirement R1 of PRC-024-3, outlined in Attachment 1, Table 2, and Requirement R2, outlined in Attachment 2, Table 1, define the boundaries of frequency ride-through (FRT) and voltage ride-through (VRT) within the Western Interconnection.

B. *Utility Policy*

The utility policy addresses the technical requirements for generation, transmission, and end-user facilities that interconnect with the utility. This policy commonly requires compliance with NERC reliability standards, regional authority reliability standards, and any specific utility reliability requirements.

C. *IEEE Standard 2800-2022*

IEEE Standard 2800-2022 establishes the capability and performance requirements for IBRs interconnected with transmission and subtransmission systems. These requirements include VRT and FRT capabilities, dynamic support of active and reactive power, and system protection [1]. Table 12 and Table 15 show the VRT and FRT boundaries. This standard is not mandatory, but NERC strongly recommends its adoption in areas that do not have specific interconnection requirements.

D. *NERC – PRC-025-2*

The purpose of PRC-025-2 is to define settings of load-responsive protective relays associated with generation facilities. PRC-025-2 recommends settings that prevent unnecessary generator tripping during system disturbances that do not pose a risk of damaging the associated equipment [19].

The standard applies to dispersed generation, such as wind and PV plants, with an aggregate capacity greater than 75 MVA, interconnected at a common point at 100 kV or greater. PRC-025-2 defines IBR installations such as asynchronous generators falling into the dispersed generation category.

PRC-025-2, Requirement R1, Table 1 lists the following relay loadability criteria applicable to IBRs:

- Option 5a: Relays installed on dispersed power producing resources connected to asynchronous generators, including inverter-based installations. In our project, this option covers 51P elements of feeder relays.

- Option 11: Relays installed on the generator side of the GSU transformer connected to asynchronous generators, including inverter-based installations. In our project, this option covers 51P2 elements of 87T-101 R1 and R2 relays.
- Option 18: Relays installed on the high side of the GSU transformer connected to asynchronous generators, including inverter-based installations. In our project, this option covers 50P1 and 51P1 elements of 87T-101 R1 and R2 relays.

The phase-overcurrent elements should be set greater than 130 percent of the current calculated from the maximum aggregate IBR nameplate MVA output at the rated power factor.

E. NERC – PRC-027-1

The purpose of PRC-027-1 is to maintain the coordination of protection systems installed to detect and isolate faults on BES elements, such that these protection systems operate in the intended sequence during faults [20]. This standard is applicable per the BES definition in [21], specifically Inclusion I2.b. The definition encompasses the generating resources, including the generator terminals through the high side of the GSU transformer, connected at a voltage of 100 kV or greater with gross plant aggregate nameplate rating greater than 75 MVA.

The standard identifies the protection elements that are applicable for Requirement R2, and they require the following:

- Using fault current to develop the settings
- Ensuring coordination with other protective devices

For the scope of this paper, the protection elements meeting this standard include 50P1, 51P1, 51G1, 51P2, and 51G2 of 87T-101 relays, as well as 50P, 51P, 50N, and 51N of feeder and capacitor bank relays.

VI. Commissioning Event Analysis

On November 29, 2023, the PV plant owner received authorization from the utility to energize the collector substation (see Fig. 8). Following safe work practices, the utility energized the line. Then, the substation operator closed Breaker 001 to energize BUS-000. After confirming that BUS-000 was properly energized, the operator closed Breaker 201 to energize Transformer T201. Then, the operator opened Breaker 201 according to procedure. Next, the operator closed the GOS-201 switch, then closed Breaker 201 to energize BUS-200.

Upon energization, an AG fault occurred on BUS-200. Fig. 9 shows the waveforms and logic signals captured by the 87B element protecting BUS-200. The 87B element tripped in 14 ms. Breaker 201 tripping cleared the fault in 60 ms. The 87B relay recorded a fault current contribution of 6,175 A from Transformer T201. This event served as a commissioning test for the 87B element, which performed correctly.

We also used the event as a commissioning check of Transformer T201 relays (87T-201, R1, and R2). In particular, we checked the response of REF1 and REF2 elements to validate the REF scheme CT wiring.

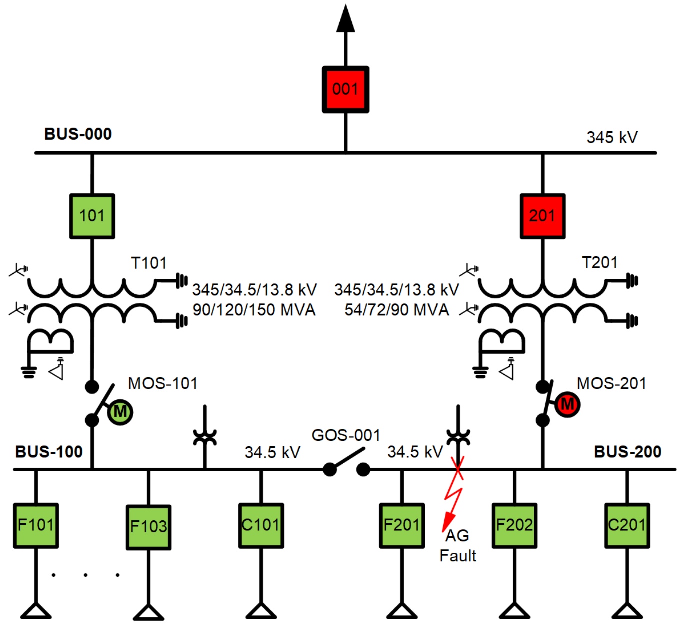

Fig. 8. An AG fault occurred at BUS-200 during energization.

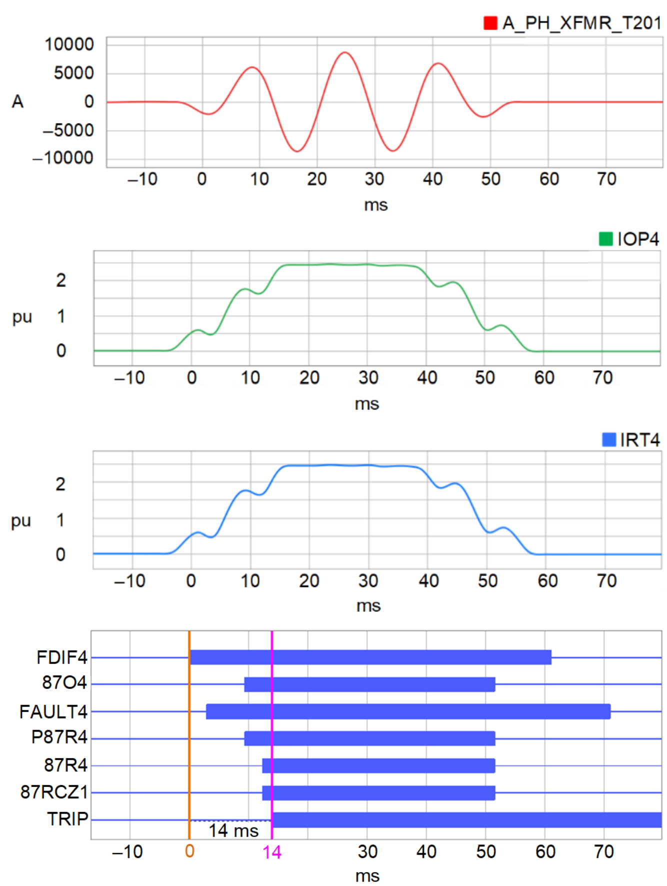

Fig. 9. The event served as a commissioning test for the BUS-200 87B relay. The relay correctly tripped in 14 ms. The total fault-clearing time was 60 ms.

The following are descriptions of the Y-axis digital signals in the bottom image of Fig. 9:

- FDIF4 = Zone 4 filtered restrained differential element picked up.
- 87O4 = Zone 4 restrained differential operating current above O87P.
- FAULT4 = Zone 4 fault detector picked up.
- P87R4 = Zone 4 instantaneous differential element picked up.
- 87R4 = Zone 4 restrained differential element picked up.
- 87RCZ1 = Check Zone 1 restrained differential element picked up.
- TRIP = Relay output trip signal.

Fig. 10 shows the waveforms captured by the Transformer T201 relays. The top graph shows the residual $3I_0$ current measured at the transformer high-side terminals and the $3I_0$ current measured at the transformer high-side neutral. These two currents have equal magnitudes of 610 A and are 180 degrees out of phase. The middle graph shows the residual $3I_0$ current measured at the transformer low-side terminals and the $3I_0$ current measured at the transformer low-side neutral. These two currents have equal magnitudes of 6,143 A and are 180 degrees out of phase. As a reference, the bottom chart shows the voltage signals captured during the event.

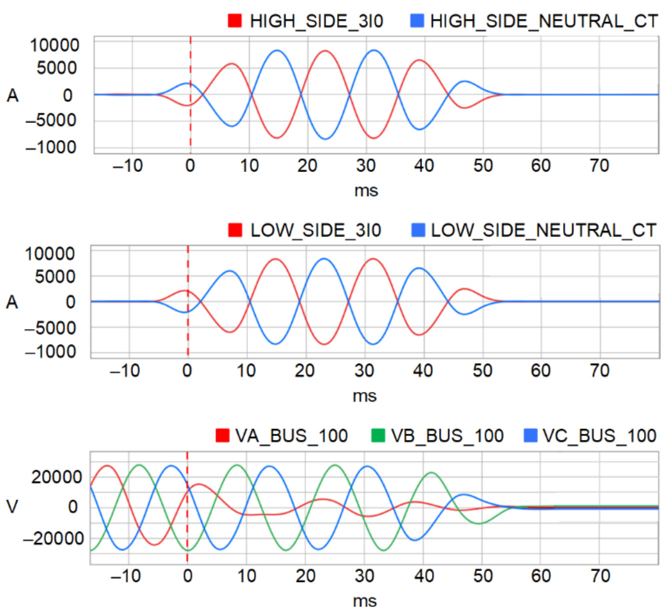

Fig. 10. The event also served as a commissioning test for the Transformer T201 relay. REF1 and REF2 measured equal-magnitude zero-sequence currents shifted 180 degrees.

VII. Conclusion

This paper describes the protection system for a PV plant collector substation. We discuss the use of multifunction relays to protect buses, GSU transformers, feeders, and capacitor banks. The paper provides an overview of PV plants and discusses the protection challenges posed by IBR sources connected to the power system. Inverter control algorithms limit the fault current contribution and affect the sequence component content of fault currents. In addition, power system software designers need to continuously enhance IBR modeling to keep track of the rapidly changing inverter control strategies and algorithms.

We describe a bus differential scheme with a check-zone function to protect a 34.5 kV split bus. In particular, we demonstrate that the check-zone differential element requires a lower Slope 1 setting value than the main-zone differential element to ensure sensitivity in a substation with two GSU transformers. We provide guidelines for the check-zone Slope 1 setting.

We discuss the advantages of integrating 50BF protection in multifunction zone protection relays in a collector substation. Integrated 50BF protection design is simple. 50BF integration enhances security by reducing the risk of human errors and noise-induced spurious BFI signals.

We also show the advantages of applying REF elements to sensitively and selectively protect grounded wye transformer windings against ground faults.

An important protection scheme requirement is redundancy. We implemented a dual-redundant protection system with no single points of failure for the GSU transformers. The failure of any component does not affect the protection system availability.

Large PV plant design and construction pose many challenges, such as involvement of multiple parties, tight schedules, long equipment lead times, and insufficient human resource availability. Sometimes, three or more parties participate in the overall system protection design. The protection criteria outlined in this paper are applicable to similar collector substation installations. Multiple engineering teams can use these criteria as a common base to select protection schemes and calculate settings. These criteria ensure that relay settings comply with regulatory requirements and utility policies.

A lesson learned from this project and other similar projects is the need to design protection schemes and perform protection coordination studies well ahead of time to give stakeholders enough time to review and approve them.

Future projects may include distributed protection systems using protocols that are part of the IEC 61850 standard over a fiber-optic network to decrease costs and installation time. Another possibility is implementing centralized schemes that provide fast, dependable, and secure protection with fewer relays and at a lower cost.

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IX. Biographies

Scott Bruno is a seasoned electrical engineer with 25 years of expertise across diverse industries including oil and gas, mining, utilities, renewables, and industrial electrical power and control systems. His career began as an electrician, providing him with valuable hands-on experience in the field. Scott earned his B.S. in electrical engineering from the University of Utah in 1999. Following graduation, he served as a consulting engineer for several years before co-founding BODEC, Inc. in 2007. As CEO and owner of BODEC, Scott utilizes his extensive background to specialize in design-build projects. He holds professional engineer and electrician licenses in the state of Utah.

Joey Yoklavich has accumulated more than 25 years of expertise as an electrician, electrical/general contractor, and construction manager across commercial, industrial, and government sectors. He holds licenses as a master electrician in multiple states and specializes in bulk handling systems such as belt conveyors, train/truck loadout systems, substations, oil and gas production facilities, hazardous waste disposal facilities, and manufacturing facilities. Joey has personally overseen the design and safe construction of numerous facilities, ensuring they meet both schedule requirements and design specifications.

Eliseo Alcázar Ramírez received his B.S.E.E. from the Oaxaca Technological Institute in 1998 and his M.S.E.E. from Autonomous University of San Luis Potosí in 2015. Upon graduating with his B.S.E.E., he served five years at Comisión Federal de Electricidad (CFE) in Mexico at the Southeastern Distribution Division (SDD). Working with CFE, he was involved in developing supervision, maintenance, installation, and commissioning of protection, control, and metering systems. In April 2004, Eliseo joined Schweitzer Engineering Laboratories, Inc. (SEL). He is presently a senior engineer with SEL Engineering Services, Inc (SEL ES). His professional experience includes devising solutions and performing studies for industrial, distribution, transmission, renewable and conventional generation, and special protection systems like remedial action schemes and microgrids. He has commissioned protection, control, metering and supervision systems, and remedial action schemes. He is an IEEE senior member.

Juan Manuel Silva Zaragoza received his B.S. in electrical engineering from Instituto Politécnico Nacional in 2017 and his M.S. in electrical engineering from Instituto Politécnico Nacional in 2022, presenting a stochastic mathematical programming model for Generation Expansion Planning (GEP) with hydroelectric power as uncertainty. Upon graduating with a B.S., Juan Manuel served in Mexico for two years in the maintenance of large electrical power substations, gaining experience in installation and commissioning of primary equipment. In 2021, he joined Ingeteam in the Mexico office as a protection engineer and participated in the design of protection, control, and metering panels, as well as maintenance and commissioning for the utility company Comisión Federal de Electricidad (CFE) and private companies in the renewable sector. In August 2022, Juan Manuel joined Schweitzer Engineering Laboratories, Inc (SEL) in Boise, ID. He is currently a protection engineer and his professional career includes designing protection, control, and metering panels, and performing electrical protection studies for industrial, distribution, and transmission systems with a special focus on the renewable sector.

Aaron Rawlings received his B.S. in electrical engineering from University of Idaho in 2006 and his M.E. in electrical engineering from University of Idaho in 2022. Upon graduating with a B.S., Aaron served nearly 12 years at Bechtel. He was a senior electrical engineer working on design and protection of large power generation and oil and gas projects across the country. He spent many years in the field supporting project construction and startup. He is currently a protection group lead for SEL Engineering Services, Inc. (SEL ES) in Boise, ID. He has worked on many protection and control upgrade projects in a wide range of industries both domestically and internationally. Aaron is a registered professional engineer in the state of Maryland and an IEEE senior member.

Héctor J. Altuve Ferrer received his B.S.E.E. degree in 1969 from the Central University of Las Villas in Santa Clara, Cuba, and his Ph.D. degree in 1981 from Kiev Polytechnic Institute in Kiev, Ukraine. From 1969 until 1993, Dr. Altuve served on the faculty of the Electrical Engineering School at the Central University of Las Villas. From 1993 to 2000, he served as professor of the Graduate Doctoral Program in the Mechanical and Electrical Engineering School at the Autonomous University of Nuevo León in Monterrey, Mexico. In 1999 through 2000, he was the Schweitzer Visiting Professor in the Department of Electrical and Computer Engineering at Washington State University. Dr. Altuve joined Schweitzer Engineering Laboratories, Inc. (SEL) in January 2001, where he is currently a distinguished engineer and dean of SEL University. He has authored and coauthored more than 100 technical papers and several books and holds four patents. His main research interests are in power system protection, control, and monitoring. Dr. Altuve is an IEEE life fellow.

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