

Pilot Protection Based on Amplitude Comparison for Renewable Power Teed Lines

Ke Jia, *Member, IEEE*, Zhe Yang, Yu Fang, Zhengxuan Zhu, Liming Zheng, Tianshu Bi, *Senior Member, IEEE*, and Ali Hooshyar, *Member, IEEE*

Abstract—Fault behaviors of inverter-interfaced renewable energy generators (IIREGs) are quite diverse from those of synchronous generators (SGs). They show the variable system impedance, the limited current and low inertia, so the proportional brake differential protection installed on the transmission line has a high risk of failure for phase-phase failures. To cope with this adaptive problem, a new pilot protection is proposed considering the huge differences in both current amplitudes. Also, an improved criterion is presented for a scenario with a teed line. The existing protection principles focus excessively on the fault current characteristics of IIREGs, so they cannot operate correctly once IIREGs do not output their fault current. This happens when IIREGs produce no power or the circuit breakers exactly reclose on permanent failures. However, the proposed method has good performance for the above cases. The proposed method only requires current amplitude information, and in this case the strict synchronizing measurement is not necessary. Case studies are performed under different fault conditions, and they confirm the proposed method has good performance under different fault conditions. Furthermore, it is also verified using field-testing data.

Index Terms—Current amplitude, inverter-interfaced renewable energy generators, pilot protection, teed line.

I. INTRODUCTION

RENEWABLE energy sources (RESs) have formed an important part of modern power systems to reduce dependence on fossil energy [1], [2]. In order to reduce economic costs, RESs are usually integrated by the collector system within the power plant and then connected to the nearby local substation [3], [4]. It is significant to ensure that the protection installed on the transmission line operates correctly because its failure or malfunction will severely threaten the safety of the power equipment and the stability of the power system [5].

In recent years, photovoltaics (PV) and permanent magnet synchronous generators (PMSGs), which are called inverter-interfaced renewable energy generators (IIREGs), have developed rapidly [6]. IIREGs are integrated with the synchronous grid through power inverters [7]. Due to the inverter's poor ability to resist overcurrent, the fault current limiter (FCL) is equipped with the output of inverters to protect these devices, or the control system based current limiters is used [8], [9]. Affected by the FCL and the control strategies of inverters, IIREGs have huge differences in fault behaviors with synchronous generators (SGs) [10], [11], which primarily represent limited current amplitude, unstable system impedance, and controlled current phase angle [12], [13]. These features cause the traditional protection principles, which are designed according to the fault signatures of SGs, to have adaptive problems [14], [15].

Differential protection must operate within a few tens of ms for internal faults. However, proportional brake differential protection will malfunction because of the controlled phase angle. It has been determined that when the short-circuit capacity for IIREGs equals one quarter of the synchronous grid, the current phase will appear as a high difference and this could be greater than 90° for phase-to-phase faults, which would influence the correct operation of differential protection [16]. In addition, the magnitude of the operating current approaches the restraint current when the fault current from IIREGs are much smaller than that of the grid. This occurrence also causes the sensitivity decline of the proportional brake differential protection [17].

Many new protection methods are proposed to solve the above problems. Reference [18] constructs an equivalent differential impedance using the differential voltage and the differential current, and amplitude characteristics of the differential impedance were utilized to distinguish internal and external faults, but this method has strict requirements related to synchronous data transmission. Reference [19] constructs the differential protection using the magnitude feature of the differential and braking impedances, but it may not operate in the presence of fault resistances. The protection idea of parameter identification was proposed in [20], [21]. This method is based on the difference that whether the first-order derivative of the time-domain differential voltage and the differential current conforms to the capacitance model [21], but the first derivative is significantly affected by higher harmonics, so its performance needs to be improved. The authors in [22],

Manuscript received September 11, 2019; revised December 27, 2019; accepted March 12, 2020. Date of online publication April 30, 2020; date of current version June 2, 2021. This work was supported by the National Key Research and Development Program of China under Grant No. 2018YFB0904104, and by Science and Technology Project of SGCC (SGHB0000KXJS1800685).

K. Jia (corresponding author, e-mail: ke.jia@ncepu.edu.cn), Z. Yang, Y. Fang, Z. X. Zhu, L. M. Zheng, and T. S. Bi are with State Key Laboratory of Alternative Electrical Power System with Renewable Energy Sources, North China Electric Power University, Beijing 102206, China.

A. Hooshyar is with Department of Electrical and Computer Engineering, University of Toronto, Toronto, ON M5S 3G4, Canada.

DOI: 10.17775/CSEEJPES.2019.02220

[23] proposed a traveling-wave-based pilot protection, but the protection requires a higher sampling frequency and is susceptible to transients with lower reliability. In addition, a pilot protection based on the current frequency difference was proposed in [24], but this method is only suitable for the scenario that the Crowbar device of doubly-fed induction generators (DFIGs) was put in operation, instead of IIREGs. Also, the Pearson correlation coefficient and Cosine similarity were utilized to calculate the similarity index between transient currents on both ends, but they will refuse to operate when IIREGs produce low power due to the lack of light and wind or the current breaker recloses with permanent failures.

Since the power-frequency fault current from IIREGs is significantly smaller than the grid-side current for phase failures, this current feature is utilized to constitute a new pilot protection in this paper. This method can deal with failure or reduced sensitivity for proportional brake differential protection for phase failures. Meanwhile, the line length limit was also calculated, considering certain rules. Within this limit, the proposed method can distinguish internal and external failures. It also has good performance when the output power from the IIREGs is at a low level or the current breaker recloses on permanent failures. In addition, for the scenario with a teed line, the adaptability analysis for this protection is also done and the improved criterion is also given. Finally, the proposed method has been confirmed by a real-time digital simulator (RTDS) experiment and field-testing data.

II. CURRENT AMPLITUDE COMPARISON BASED PILOT PROTECTION

A. Basic Principle

As described in Fig. 1, the typical structure of an IIREG includes a source, a power inverter, and a filter together with a step-up transformer. All the IIREGs are connected to the collector line and the produced power are transported through the transmission line. Due to the higher voltage level, the main transformers on both sides of the line are grounded.

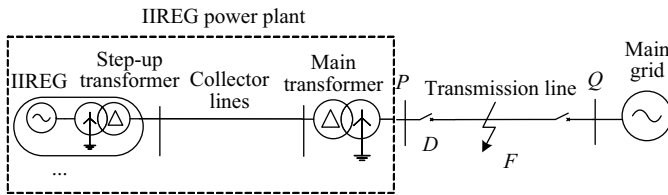


Fig. 1. Simplified topology of the grid with IIREGs.

For a failure at F , its equivalent circuit is illustrated in Fig. 2. As shown in Fig. 2, $\dot{E}_P$ and $\dot{E}_Q$ respectively represent the equivalent IIREG and grid internal potential. $\dot{U}_f$ is the residual voltage of the fault location caused by the fault resistance. Z_P and Z_Q represent the equivalent IIREG and grid internal impedance, and Z_L is the impedance sum of the whole outgoing transmission line. Additionally, λ represents a ratio of the line impedance between the fault location and bus bar on the grid side to Z_L and it ranges from 0 to 1.

For the fault model of the IIREGs, $\dot{E}_P$ is considered equal to $\dot{E}_Q$, and the fault current of IIREGs is simulated by adjusting

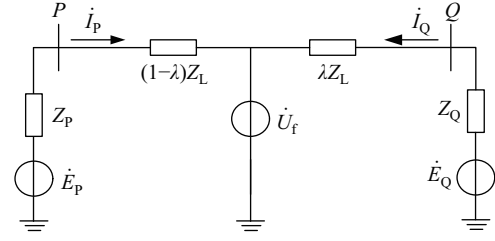


Fig. 2. Equivalent fault diagram for an internal fault.

the equivalent impedance Z_P . This means that Z_P varies for different fault locations. Although RESs are equivalent to the controlled current source in many references [11], [25], which can better reflect their fault characteristics, the equivalent way of the voltage source and a large impedance has a similar effect. In this case, the fault currents can be written as:

$$\dot{I}_P = \frac{\dot{E}_P - \dot{U}_f}{Z_P + (1 - \lambda)Z_L} \quad (1)$$

$$\dot{I}_Q = \frac{\dot{E}_Q - \dot{U}_f}{Z_Q + \lambda Z_L} \quad (2)$$

Since $\dot{E}_P$ is considered to be equal to $\dot{E}_Q$, the current amplitude ratio is expressed as:

$$\frac{|\dot{I}_P|}{|\dot{I}_Q|} = \frac{|Z_Q + \lambda Z_L|}{|Z_P + (1 - \lambda)Z_L|} \quad (3)$$

In general, the fault current from IIREGs is less than twice the nominal current due to the impact of FCLs [25], [26]. Therefore, Z_P is usually much larger than Z_Q . As a result, the numerator in (3) is less than the denominator and the ratio is usually smaller than 1, so the protection criterion is given:

$$\xi = \frac{|\dot{I}_P|}{|\dot{I}_Q|} < \rho_{\text{set}} \quad (4)$$

where $|\cdot|$ means the amplitude of a specific phasor and ρ_{set} represents the threshold of the proposed criterion.

When the system operates normally or an out-of-zone fault appears, the ratio is ideally equal to 1, which exceeds its threshold value. However, the ratio is below the threshold value for internal faults. Due to this huge difference, the internal fault can be reliably identified. The calculation method of the setting value will be detailed in Section II-B.

The proportion of RESs will be increased in the future. In some areas, the short-circuit power from IIREGs may approach the connected system. In this case, the premise that $|Z_P|$ is larger than $|Z_Q|$ will no longer be established and the protection will refuse to operate. Therefore, this criterion must have a certain scope of application. In order to calculate the length limit, the scenario that is most likely to fail to operate (a fault located at bus P, $\lambda = 1$) is analyzed, and (3) is simplified as:

$$\xi = \frac{|Z_Q + Z_L|}{|Z_P|} \approx \frac{|Z_Q| + |Z_L|}{|Z_P|} < \rho_{\text{set}} \quad (5)$$

When the IIREG short-circuit capacity reaches $1/\beta$ of that of the connected grid, Z_P can be considered equal to βZ_Q . In addition, the fault current provided by IIREGs is taken as

a maximum $2I_N$. Based on these conditions, the minimum IIREG internal impedance can be calculated as:

$$Z_{P,\min} = \frac{E_P}{2\sqrt{3}I_N} \quad (6)$$

The rated current I_N is calculated by the IIREG rated power P_N and the line rated voltage U_N . Additionally, E_P is equal to U_N considering the constant internal voltage before and during the fault. The proposed method can operate reliably only when the length of the transmission line should satisfy (7):

$$L < \left(\rho_{\text{set}} - \frac{1}{\beta} \right) \frac{U_N^2}{2P_N z_1} \quad (7)$$

where L and z_1 represent the length and the line positive-sequence impedance of each kilometer, respectively.

B. Setting of this Protection

The transmission line integrated with an IIREG power plant is usually less than 100 km, so it can be taken as a π -type model shown in Fig. 3 [27]. The directions marked in Fig. 3 are the actual directions of currents during normal operations.

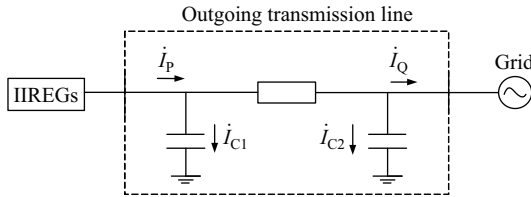


Fig. 3. Current direction when the system operates normally.

According to Fig. 3, the currents on both ends satisfy the following formula:

$$\dot{I}_Q = \dot{I}_P - \dot{I}_{C1} - \dot{I}_{C2} \quad (8)$$

The power factor for IIREGs is close to 1 during normal operations [28]. This means that the phase of the IIREG-side voltage is close to that of the IIREG-side current. The currents marked in Fig. 3 have a phase relationship described in Fig. 4.

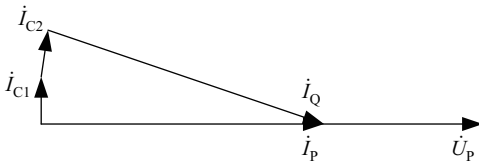


Fig. 4. Current phasor relationship.

The phase angle of $\dot{I}_{C1}$ approaches that of $\dot{I}_{C2}$ due to minor phase angle differences for both sides of the voltages during normal operations. Fig. 4 shows that the IIREG-side current may be slightly less than the one on the grid side. This could cause failure if the threshold value is taken as 1.

Moreover, the DC component of the grid-end fault current will affect the extraction of the fundamental frequency amplitude. Meanwhile, the secondary value measured by current transformers (CTs) also has a certain error. These factors are considered to adjust the threshold value of ρ_{set} :

$$\rho_{\text{set}} = 1 - K_{\text{rel}} K_{\text{np}} K_{\text{er}} K_{\text{st}} \quad (9)$$

where K_{rel} represents the reliability coefficient which is set as 1.2 to 1.3. K_{np} represents the DC component coefficient. When a fast saturation converter is applied in the differential loop, K_{np} can be taken as 1, and when the series resistance is utilized to suppress the unbalanced current, K_{np} ranges from 1.5 to 2. K_{er} represents ten percent of the CT error coefficient. K_{st} represents the homotypic coefficient, and it is 0.5 when the CTs at both ends are the same, and it is taken as 1 when they are different. Based on these factors, its threshold can be set to 0.82, and the above parameters are taken from reference [29].

For asymmetrical ground faults, zero-sequence currents are present. This zero-sequence current can weaken the weak-infeed feature of IIREGs, so the proposed method could not trip the line. However, the zero-sequence directional relay can operate normally for this case, so it can be utilized to form an auxiliary criterion. If the local zero-sequence directional relay and the remote one operate together, then the protection will determine the fault in the zone. The detailed logic of the whole protection is described in Fig. 5.

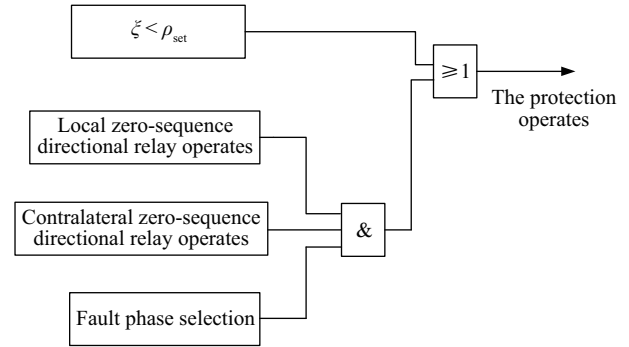


Fig. 5. Detailed operational diagram.

III. PERFORMANCE UNDER DIFFERENT SCENARIOS

A. Operating Performance when the Breaker Recloses

In order to deal with reduced sensitivity or refusal of traditional differential protection, some scholars propose new pilot protection principles using the differences in transient current waveforms on both ends. The Pearson correlation coefficient and Cosine similarity can be used to measure this feature [28], and both equations are as follows:

$$\begin{cases} \text{pearson}(\mathbf{x}, \mathbf{y}) = \frac{\sum_{i=1}^n \left(x_i - \frac{1}{n} \sum_{j=1}^n x_j \right) \left(y_i - \frac{1}{n} \sum_{j=1}^n y_j \right)}{\sqrt{\sum_{i=1}^n \left(x_i - \frac{1}{n} \sum_{j=1}^n x_j \right)^2} \sqrt{\sum_{i=1}^n \left(y_i - \frac{1}{n} \sum_{j=1}^n y_j \right)^2}} \\ \cos(\mathbf{x}, \mathbf{y}) = \frac{\sum_{i=1}^n (x_i \cdot y_i)}{\sqrt{\sum_{i=1}^n x_i^2} \sqrt{\sum_{i=1}^n y_i^2}} \end{cases} \quad (10)$$

where $\text{pearson}(\mathbf{x}, \mathbf{y})$ and $\cos(\mathbf{x}, \mathbf{y})$ are the Pearson correlation coefficient and Cosine similarity of two current waveforms, $\mathbf{x} = [x_1, x_2, \dots, x_n]$ together with $\mathbf{y} = [y_1, y_2, \dots, y_n]$. Additionally, the two coefficients range from -1 to 1 .

It can be concluded from (10) that the Pearson correlation coefficient and Cosine similarity will be equal to 0/0 if one

of the current waveform sequences is 0. This situation occurs when the breaker recloses with permanent failures. At this point, these methods cannot trip the line, while the proposed method has good performance.

Taking Fig. 1 as an example, if the breaker on the IIREG side recloses with a permanent failure, a fault current from IIREGs will be detected, whereas the grid-end current equals zero. As a result, the given criterion will fail to operate. However, the breaker on the grid end usually recloses first in the engineering because of the weak capacity to resist the overcurrent for power electronics. Under this circumstance, the current on the grid side will be much larger than that on the IIREG side, so the proposed method will trip the fault line. With similar logic, it can also operate in the case of the IIREG weak output power due to the lack of light or wind.

B. Operating Performance for the Teed Line

In order to save the power corridor and increase the delivery capacity, sometimes two or more RES power plants are connected by a teed line. Fig. 6 illustrates its simplified topology.

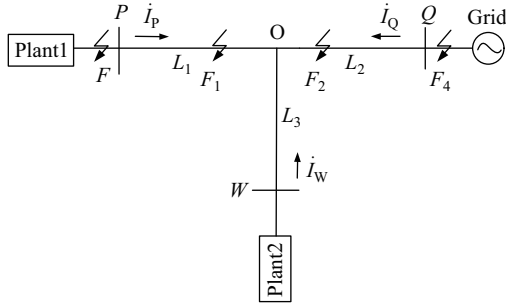


Fig. 6. Simplified topology for the teed line.

As shown in Fig. 6, plant 2 and plant 1 are connected at the middle of the outgoing line. L_1 , L_2 and L_3 respectively represents the length value of lines PO, OQ, and OW. All the marked directions in Fig. 6 are the reference positive directions in the protection field.

The addition of plant 2 will cause the current on the P side to be less than that on the Q side. As the capacity of plant 2 increases, the protection may malfunction. During normal operation, the current phase of plant 1 is substantially equal to that of plant 2, so the protection will malfunction in theory when the rated capacity of plant 2 reaches 18% of that of plant 1 due to the setting value of 0.82. Therefore, the criterion must be improved.

After plant 2 is connected, the current relationship during normal operation satisfies:

$$\dot{I}_P + \dot{I}_W = -\dot{I}_Q \quad (11)$$

In order to ensure that the criterion will not malfunction, the quantities on both sides of (11) are taken as their corresponding module values. At this time, $|\dot{I}_P + \dot{I}_W|$ involves phasor transmission, which increases the communication pressure. To reduce the requirement for communication, the criterion is considered to be rewritten as:

$$\xi = \frac{|\dot{I}_P| + |\dot{I}_W|}{|\dot{I}_Q|} < \rho_{\text{set}} \quad (12)$$

First, the performance of (12) for external faults (point F_4 in Fig. 6) is analyzed. According to the properties of the absolute value inequalities, (13) is obtained:

$$|\dot{I}_P + \dot{I}_W| = |\dot{I}_Q| \leq |\dot{I}_P| + |\dot{I}_W| \quad (13)$$

Therefore, the expression of the value ξ is given as:

$$\xi = \frac{|\dot{I}_P| + |\dot{I}_W|}{|\dot{I}_Q|} \geq 1 \quad (14)$$

It can be seen from (14) that the improved criterion will not malfunction when the system operates normally or an external fault occurs at F_4 .

In addition, for external faults at point F , the phasor relationship is satisfied by:

$$\dot{I}_W + \dot{I}_Q = -\dot{I}_P \quad (15)$$

Considering the properties of the absolute value inequalities, there is:

$$|\dot{I}_W + \dot{I}_Q| \geq |\dot{I}_Q| - |\dot{I}_W| \quad (16)$$

Combining (15) and (16), the value ξ could be written as:

$$\xi = \frac{|\dot{I}_P| + |\dot{I}_W|}{|\dot{I}_Q|} \geq 1 \quad (17)$$

It is clear from (17) that the protection will also not malfunction. Similarly, it can be proved that the protection will not malfunction for the external faults in other locations.

Figure 7 illustrates the fault equivalent diagram for an internal fault at F_1 .

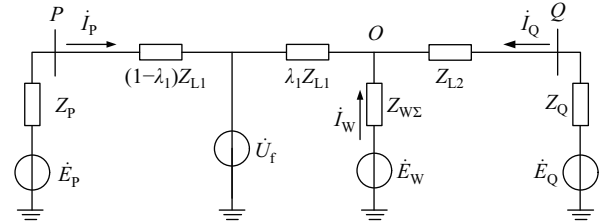


Fig. 7. Fault equivalent circuit.

In Fig. 7, Z_{L1} and Z_{L2} are the positive-sequence impedances of the lines L_1 and L_2 , respectively, λ_1 can be calculated using the line impedance between the fault location and the dot O divided by Z_{L1} , and $Z_{W\Sigma}$ is the sum of the internal impedance Z_W of the plant 2 and the impedance Z_{L3} of the line L_3 .

It is clear from Fig. 7 that the grid-side fault current can be calculated as:

$$\dot{I}_Q = \frac{\dot{E}_Q - \dot{U}_f}{(Z_{L2} + Z_Q + \lambda_1 Z_{L1}) \left(1 + \frac{\lambda_1 Z_{L1} (Z_{L2} + Z_Q)}{Z_{W\Sigma} (Z_{L2} + Z_Q + \lambda_1 Z_{L1})} \right)} \quad (18)$$

In (18), since $\lambda_1 Z_{L1}$ is only a small part of the transmission line, it must be much smaller than $Z_{W\Sigma}$. On the other hand, $Z_{L2} + Z_Q$ is also smaller than $Z_{L2} + Z_Q + \lambda_1 Z_{L1}$. Therefore, the denominator is approximately equal to $Z_{L2} + Z_Q + \lambda_1 Z_{L1}$, and the W branch has little impact on the grid-side fault current.

To study its applicable range, the worst scenario where both plant 1 and plant 2 can output the maximum short-circuit current is considered, and both fault current values are:

$$\begin{cases} |\dot{I}_P| = \left| \frac{\dot{E}_P}{Z_{P,\min}} \right| \\ |\dot{I}_W| = \left| \frac{\dot{E}_W}{Z_{W,\min}} \right| \end{cases} \quad (19)$$

According to (19), (20) can be given as:

$$|\dot{I}_P| + |\dot{I}_W| = \frac{|\dot{E}_P|}{|Z_{P,\min}|} = \frac{|\dot{E}_P| \cdot (|Z_{P,\min}| + |Z_{W,\min}|)}{|Z_{P,\min}| \cdot |Z_{W,\min}|} \quad (20)$$

It can be seen from (20) that $|\dot{I}_P| + |\dot{I}_W|$ at this time can be equivalent to the maximal short-circuit current when plant 1 and plant 2 are connected in parallel on the P bus, so the constraint of (7) is still true, but P_N is the sum of the capacity of two plants, $L = L_1 + L_2$ or $L = L_3 + L_2$, and the above two cases must satisfy (7).

The analysis of the fault at point F_2 in Fig. 6 is similar to the analysis of point F_1 . Under this circumstance, L_2 must satisfy the constraint condition of (7) but this condition is inevitably satisfied under the premise that $L_1 + L_2$ satisfies (7).

IV. SIMULATION ANALYSIS

The experimental testing system shown in Fig. 8 consists of an RTDS simulation system and a universal protection and control platform (UPCP). The simulation system has four components which include RTDS, PWM generator, screen monitor and main controller [30]. The simulation model on the IIREG power plant was built on the RTDS simulation system. All power components are extracted by the discrete Fourier transform (DFT) algorithm and the proposed method is solidified in the digital signal processor (DSP) system of the UPCP [31]. The simulation data is output through the RTDS output cards and then passed to the DSP of the UPSP. The UPCP performs the solidified algorithm according to the simulation data transmitted from the RTDS.

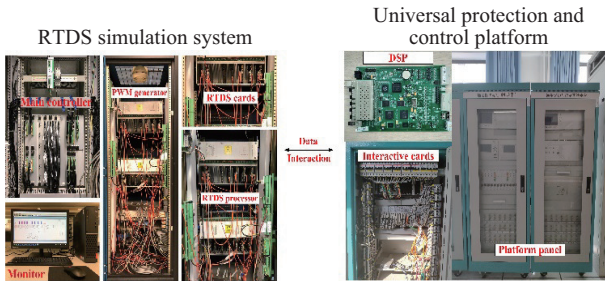


Fig. 8. Testing system based on RTDS.

Proportional brake differential protection and the given criterion are confirmed by case studies performed in the above platform. The fault types are set to a three-phase fault, a phase-B-to-phase-C fault, a phase-A grounding fault and a phase-B-to-phase-C grounding fault, which are marked as an ABC fault, a BC fault, an AG fault and a BCG fault,

respectively. In the simulation model, the total capacity of the IIREGs is set to 495 MW, and the grid impedance is taken as $0.4 + j12.568\Omega$. At this time, the short-circuit capacity of the IIREGs reaches one quarter of that of the grid. According to (7), the length of the line must be limited within 80.44 km. Control objectives of active power and reactive power are $P_0^* = e_d^+$ and $Q_0^* = 1.5e_d^+(0.9 - e_d^+)$, respectively when a fault occurs. Other parameters are shown in Table AI.

A. Proportional Brake Differential Protection

The proportional brake differential protection may fail to operate because of the controlled phase angle of the IIREGs. The restraint value is taken as 0.8, and a failure is set at the midpoint of the line. The performance is given in Fig. 9.

In Fig. 9(a), the phase-C ratio is smaller than 0.8 when a BC fault happens, so the differential protection will fail to operate. Additionally, the three-phase performance will also decline for ABC faults in Fig. 9.

However, the differential protection is not significantly damaged for asymmetric grounding faults in Fig. 9(c), 9(d), and this is because the phase angle difference is smaller than 90° because of larger zero-sequence currents.

B. The Proposed Protection Method

This part is to verify that the proposed protection can trip the line in the above scenario, so the simulation conditions remain unchanged. Fig. 10 illustrates the results under diverse types of faults.

As shown in Fig. 10(a), 10(b), the proposed method has good performance whether there is a BC fault or an ABC fault when the proportional brake differential protection refuses to operate. For a BC fault, fault phases are respectively 0.269 and 0.214. In addition, value ξ approaches 0.260 for the three-phase fault. These values are significantly below the threshold of 0.82, so the protection could operate correctly.

For asymmetric ground faults, the given criteria could trip the line in Fig. 10(c), 10(d), while it may fail to operate because of the zero-sequence current, so the zero-sequence directional pilot protection must be deployed to solve this problem.

To verify the proposed protection systematically, fault locations are 0 km, 10 km, 20 km, 30 km and 40 km away from the bus-P. Table I illustrates the results for the amplitude ratio under different fault locations.

Table I shows that the sensitivity of fault phases is lowest for a fault at 0 km. This is because the fault current from IIREGs is the largest, while the one on the grid end is the smallest at this time. Meanwhile, the given criteria could trip for all phase-to-phase failures.

For asymmetric grounding faults (AG faults and BCG faults) located at 0 km, the value ξ for the given criterion significantly increases in comparison with that for the BC failures or ABC failures because of the large zero-sequence current. This is very detrimental to the protection operation.

The line length must be less than 80.44 km obtained from (7), so the line length is extended from 50 km to 80 km. And the fault location is 0 km. And the fault location is 0 km.

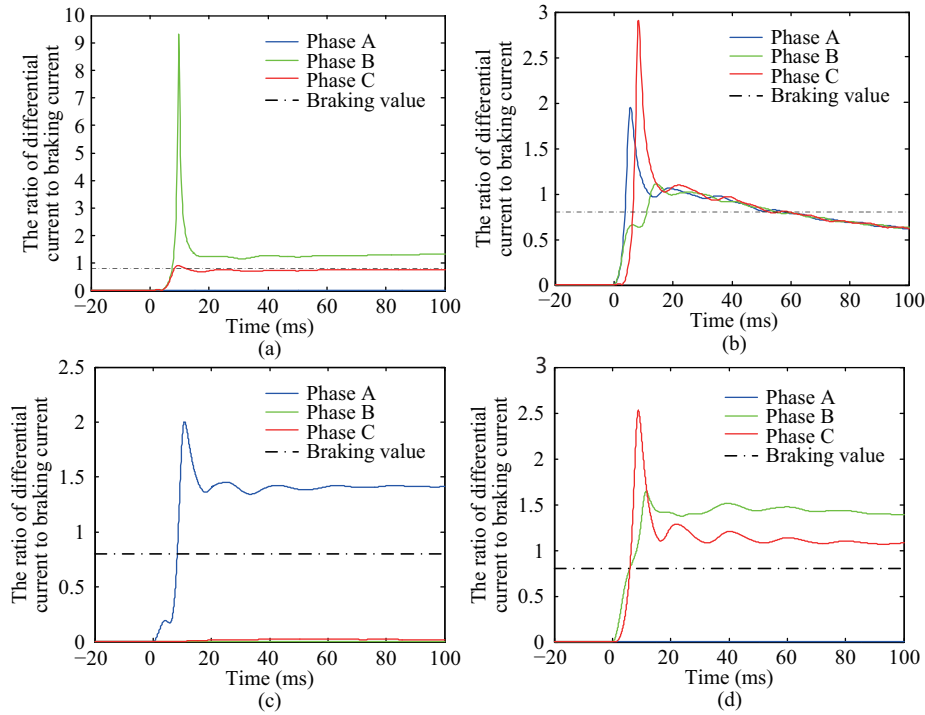


Fig. 9. Differential protection. (a) BC. (b) ABC. (c) AG. (d) BCG.

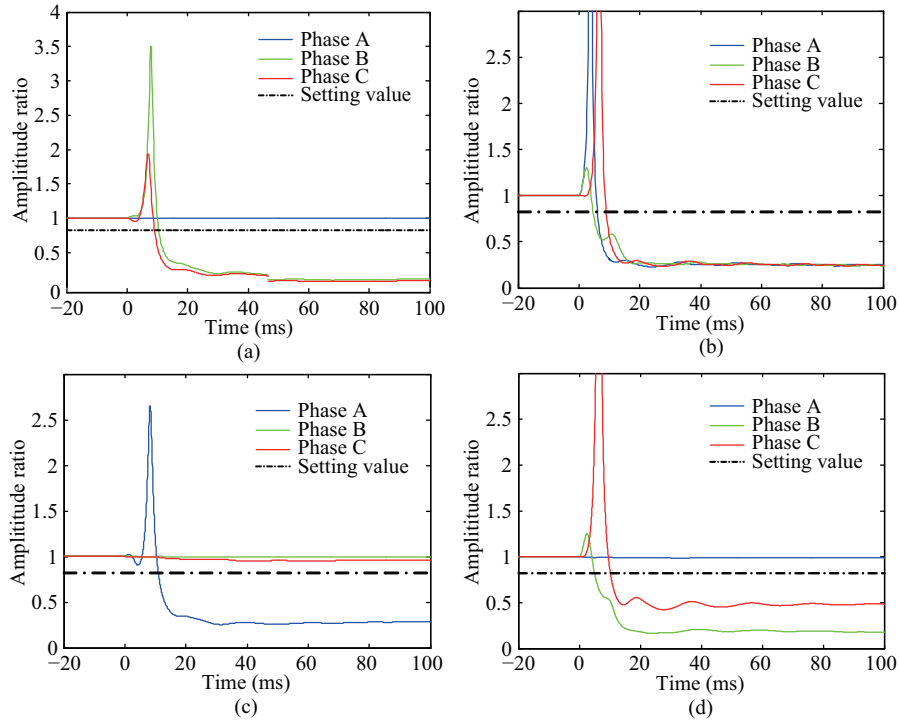


Fig. 10. Given criterion. (a) BC. (b) ABC. (c) AG. (d) BCG.

Table II illustrates the results for the amplitude ratio under different lengths.

Table II shows that the value ξ continually rises with the increase in the line length for BC faults and ABC faults, so the protection sensitivity will decline. When the outgoing transmission line is set to 80 km, the maximum value of ξ is 0.633, which is below the setting value of 0.82. This shows that the calculated length limit is reasonable for phase failures.

However, the phase-C for BCG failures will not operate because of the zero-sequence current. Therefore, zero-sequence directional relays are added.

Fault resistance for phase-to-phase faults is less than 25Ω since it is usually the arc resistance [30]. Therefore, the maximum of the fault resistance is taken as 30Ω . In addition, the transmission line is still set to 80 km, and other conditions remain unchanged.

TABLE I
AMPLITUDE RATIO UNDER DIFFERENT FAULT LOCATIONS

Fault location	Phase	BC	ABC	AG	BCG
0 km	A	0.998	0.384	0.528	0.999
	B	0.396	0.373	0.999	0.442
	C	0.275	0.372	1.000	0.712
10 km	A	0.997	0.305	0.378	0.999
	B	0.333	0.328	0.999	0.393
	C	0.248	0.307	0.997	0.643
20 km	A	0.998	0.253	0.258	0.995
	B	0.269	0.264	0.997	0.171
	C	0.214	0.250	0.998	0.552
30 km	A	0.999	0.214	0.158	0.989
	B	0.213	0.193	0.993	0.098
	C	0.180	0.194	0.995	0.199
40 km	A	0.998	0.153	0.081	0.993
	B	0.159	0.136	0.991	0.088
	C	0.139	0.145	0.992	0.095

TABLE II
AMPLITUDE RATIO UNDER DIFFERENT LINE LENGTHS

Fault type	phase	50 km	60 km	70 km	80 km
BC	A	0.993	0.996	0.993	0.996
	B	0.438	0.473	0.508	0.633
	C	0.271	0.328	0.358	0.373
ABC	A	0.423	0.479	0.541	0.575
	B	0.447	0.480	0.528	0.576
	C	0.449	0.501	0.556	0.585
AG	A	0.570	0.572	0.547	0.671
	B	1.001	0.999	0.999	1.003
	C	1.000	1.002	1.008	1.003
BCG	A	1.001	1.002	1.001	1.006
	B	0.669	0.832	0.833	0.604
	C	0.920	1.169	1.244	1.019

Table III illustrates that the performance of this given criterion will decline with the increase in fault resistance for BC faults and ABC faults. The value ξ reaches 0.760 for a BC fault with 30 Ω , so the protection could still trip the line. This shows that it can still tolerate a certain fault resistance for phase failures even at the length limit boundary.

TABLE III
AMPLITUDE RATIO UNDER DIVERSE FAULT RESISTANCES

Fault type	Phase	0 Ω	5 Ω	10 Ω	20 Ω	30 Ω
BC	A	0.998	0.997	0.996	0.997	0.993
	B	0.633	0.656	0.715	0.743	0.760
	C	0.373	0.376	0.419	0.429	0.455
ABC	A	0.575	0.599	0.654	0.704	0.753
	B	0.576	0.603	0.649	0.695	0.748
	C	0.585	0.606	0.656	0.708	0.742
AG	A	0.671	0.630	0.868	0.992	1.094
	B	1.003	1.002	1.007	1.002	1.008
	C	1.003	1.003	0.996	0.994	0.992
BCG	A	1.006	1.007	1.006	1.007	1.003
	B	0.604	0.809	0.779	0.747	0.734
	C	1.019	1.032	0.950	1.067	0.942

In addition, for AG faults, the value ξ of phase-A is higher than the threshold value 0.82 when the fault resistance is set to 30 Ω , which leads to the failure of the proposed method. Also, all the values of ξ of phase-C for BCG faults are greater than the setting value 0.82 regardless of the fault resistance.

Meanwhile, the given criterion is confirmed under diverse short-circuit capacities. Table IV illustrates different short-circuit capacities and their corresponding length limits and ξ .

TABLE IV
AMPLITUDE RATIO UNDER DIFFERENT LINE LENGTHS

Rated capacity (MW)	Short capacity (MW)	Ratio	Limit (km)	Phase	ξ
247.5	495	1:8	196.15	A	0.943
				B	0.611
				C	0.413
495	990	1:4	80.44	A	0.996
				B	0.633
				C	0.373
660	1320	1:3	51.87	A	0.997
				B	0.625
				C	0.402

BC faults appear at 0 km, and the line length is taken as 200 km, 80 km and 50 km, respectively.

Fault phases can always operate normally under diverse line lengths and integrated capacities, so the length limit calculated by (7) is effective for different rated capacities and short-circuit capacity ratios.

C. Performance for the Scenario with a Teed Line

For the scenario with a teed line, in order to reduce the requirement for communication systems, the properties of the absolute value inequality are utilized to convert phasor calculations into scalar calculations.

Simulation conditions are as follows: $L_1 = 20$ km, $L_2 = 20$ km, $L_3 = 20$ km, and the nominal power of plants 1 and 2 is $495/2 = 247.5$ MW. In order to verify its anti-misoperation performance for external faults, the fault points are set at points F and F_4 in Fig. 6, respectively. Figure 11 together with Fig. 12 shows simulation results for the given criteria.

In Fig. 11, amplitude ratios ξ are always greater than the setting value 0.82 when diverse failures appear at F. Therefore, this proposed method will not malfunction for left out-of-zone faults.

Similarly, it will not malfunction for right out-of-zone faults observed in Fig. 12 for diverse faults at F_4 .

For internal faults, the protection must operate reliably under the condition that the line length satisfies the value obtained from (7). Fault locations are 0 km, 10 km, 20 km, 30 km and 40 km away from the bus-P in Fig. 6, and these failures are all located on the lines L_1 and L_2 . Table V shows the simulation about the improved criteria.

TABLE V
AMPLITUDE RATIO UNDER DIVERSE FAILURES

Fault type	Phase	0 km	10 km	20 km	30 km	40 km
BC	A	0.997	0.995	0.992	0.994	0.994
	B	0.406	0.341	0.272	0.222	0.165
	C	0.282	0.253	0.219	0.182	0.145
ABC	A	0.391	0.327	0.271	0.216	0.159
	B	0.386	0.329	0.263	0.206	0.152
	C	0.381	0.315	0.259	0.193	0.147
AG	A	0.651	0.487	0.384	0.258	0.108
	B	1.016	1.002	0.998	0.995	0.994
	C	1.813	1.323	1.004	0.996	0.987
BCG	A	1.166	1.057	1.000	0.995	0.992
	B	0.842	0.527	0.372	0.174	0.107
	C	0.837	0.728	0.762	0.400	0.180

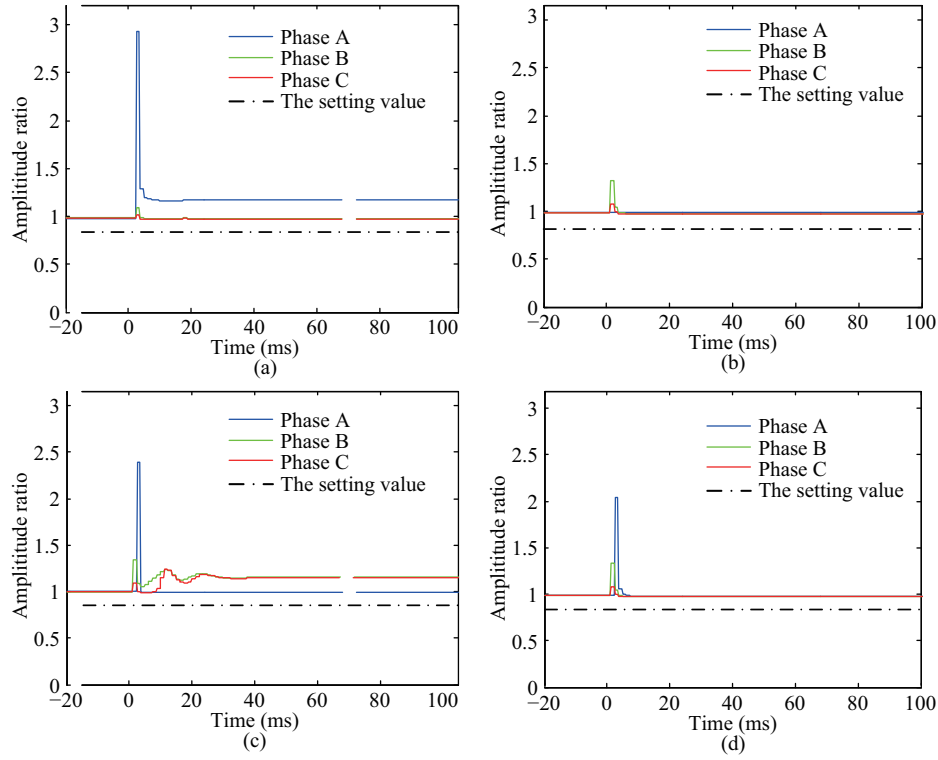


Fig. 11. Performance of this protection for the fault located at F . (a) AG failures. (b) BC failures. (c) BCG failures. (d) ABC failures.

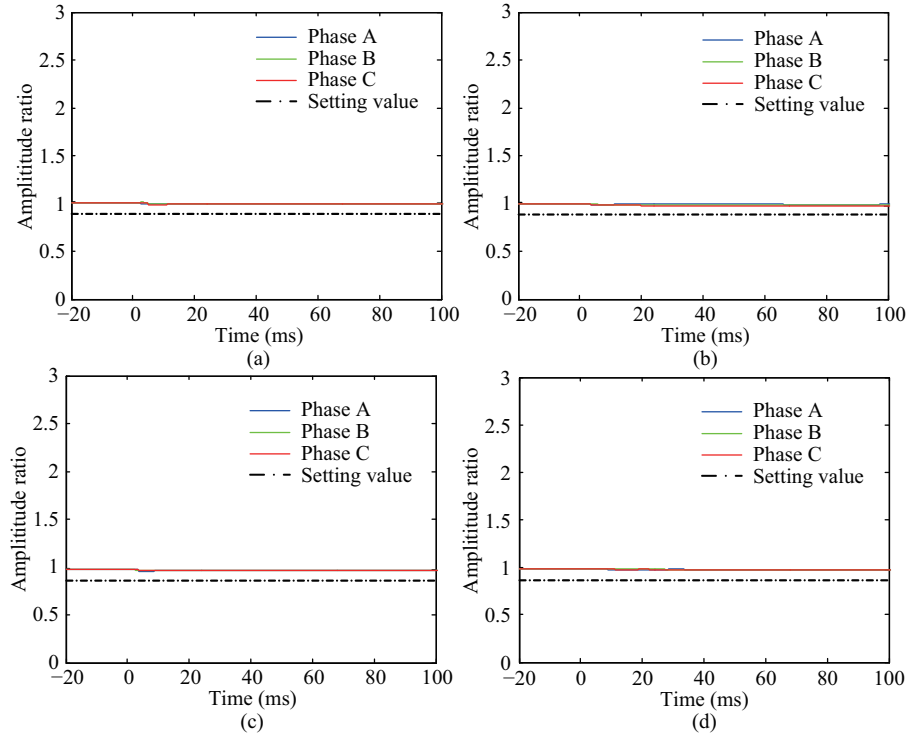


Fig. 12. Performance of the protection for the fault located at F_4 . (a) AG failures. (b) BC failures. (c) BCG failures. (d) ABC failures.

With comparisons between Table IV and Table V, the teed line has little effect on the proposed method for BC failures and ABC failures, which is consistent with the previous theoretical analysis.

In addition, for BCG faults, the values ξ of all the fault phases are greater than the setting value 0.82 when the fault

occurs at the output of plant 1. Under this circumstance, the given criterion will malfunction, so the zero-sequence directional relays must be deployed to work as a compulsory criterion.

To confirm the length limit, L_2 is set to 30 km, 40 km, 50 km, and 60 km respectively. At this time, $L_1 + L_2$ is equal

TABLE VI
AMPLITUDE RATIO FOR DIVERSE LINE LENGTHS

Fault type	Phase	50 km	60 km	70 km	80 km
BC	A	0.996	0.998	0.996	0.998
	B	0.444	0.485	0.512	0.645
	C	0.282	0.332	0.363	0.379
ABC	A	0.454	0.487	0.552	0.582
	B	0.434	0.504	0.546	0.579
	C	0.452	0.509	0.559	0.589
AG	A	0.763	0.768	0.783	0.755
	B	1.017	1.015	1.012	1.011
	C	2.154	2.652	3.511	4.491
BCG	A	1.173	1.139	1.200	1.143
	B	0.868	0.964	0.949	1.098
	C	1.102	1.374	1.304	1.474

to $L_3 + L_2$, and both values range from 50 km to 80 km, and the fault location is at 0 km. Table VI shows results for the improved criteria.

It is clear from Table VI that for BC faults and ABC faults, the improved criterion can operate reliably within the length constraint calculated by (7). The maximum value of ξ is 0.645, which is basically equal to the value 0.633 shown in Table VI, so the calculation of the applicable range is still established for the scenario with a teed line.

In addition, for AG faults and BCG faults, the values ξ are greater than the setting value of 0.82 in many fault scenarios such as a BCG failure at 0 km. This shows that the given criterion is not completely suitable for asymmetric grounding failures.

V. FIELD-TESTING DATA ANALYSIS

We collect three sets of voltage and current data for field testing including a PV substation and two wind farms. For the PV substation in Jiangxi, a BC failure appears on the 35 kV special line. In addition, the Jilin wind farm includes 66 homotypic PMSGs of 1.5 MW, and it presents a phase-C to ground failure (CG) at the 220 kV line. Its topology diagram is similar to that shown Fig. 1. Additionally, the wind farm in Inner Mongolia also has a similar topology diagram to Fig. 1, and a phase-B grounding fault (BG fault) appears on the 220 kV transmission line.

Field-testing data from Jiangxi are utilized to confirm the proposed protection for phase-to-phase failures, and the data from Jilin are applied to confirm that the performance of the IIREG-side zero-sequence directional component is not affected by IIREGs. Their behaviors are illustrated in Fig. 13.

It is clear from Fig. 13(a) that ξ of phase-B (0.02) and ξ of phase-C (0.008) are much lower than the threshold value of 0.82, and they both can operate correctly. In addition, Fig. 13(b) shows that the phase angle detected by the zero-sequence directional relay is stable at around -90° , so the zero-sequence directional relay has good performance.

Field-testing data from Inner Mongolia is utilized to verify the proposed method for grounding faults. Three-phase current waveforms on the IIREG and grid side have been described in Fig. 14(a), and the results of the given criterion are given in Fig. 14(b).

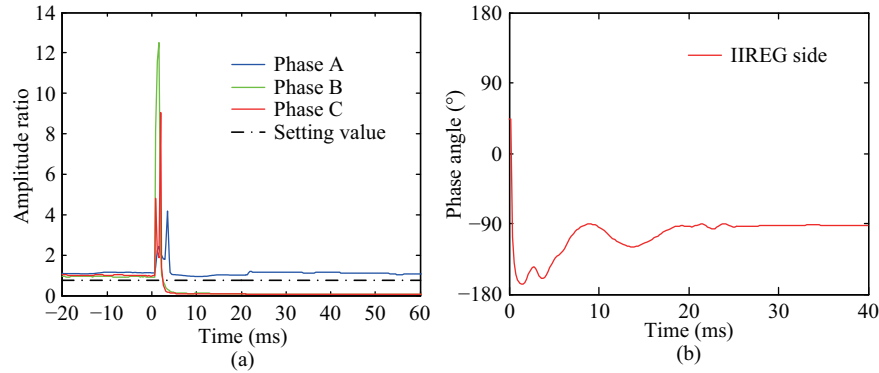


Fig. 13. Field data. (a) Ratio. (b) Zero-sequence directional relay.

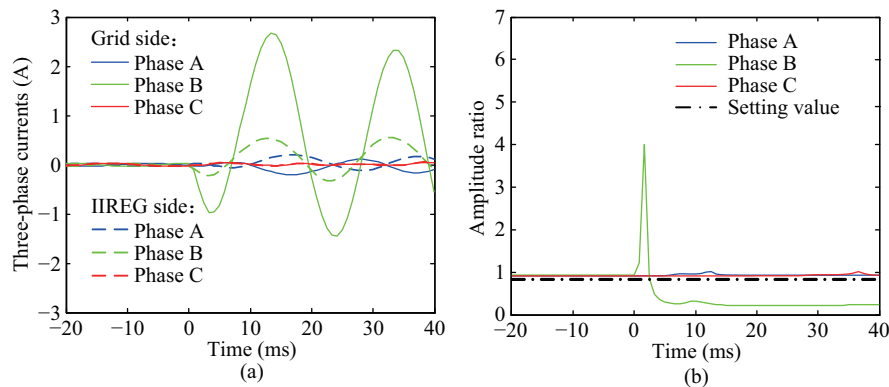


Fig. 14. Field-testing data. (a) Current waveforms. (b) Amplitude ratio.

It is clear from Fig. 14(a) that the faulty phase current is still much larger than the one on the IIREG end, even though the fault current on the IIREG side increases tens of times because of the zero-sequence current. In addition, in Fig. 14(b), the ratio for the faulty phase is equal to 0.297, and the other two are larger than the setting value 0.82, so the given criterion could operate normally.

VI. CONCLUSION

This paper presents a current amplitude comparison-based pilot protection to deal with failure or reduced sensitivity of differential protection for phase failures. This method can be simply achieved in existing relays, so it is cost-effective. In addition, it only needs amplitude information, so it has a lower requirement for communication systems. It could also operate normally for reclosing with a permanent fault and low power output from IIREGs.

Furthermore, the adaptive analysis of the criterion is studied for a feed line, and an improved criterion adapted to this case is given. It still transports magnitude information and exhibits good performance for failures in or out of zone. Simulation results and field-testing data are convincing to support the given criterion.

APPENDIX

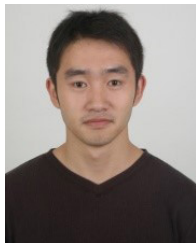
TABLE AI
SIMULATION PARAMETERS

Element	Parameter	Value
Outgoing transmission line	Voltage level	220 kV
	Frequency	50 Hz
	Length	40 km
	Zero-sequence impedance	$0.284 + j0.824 \Omega/\text{km}$
	Positive-sequence impedance	$0.076 + j0.338 \Omega/\text{km}$
	Zero-sequence capacitance	$0.0061 \mu\text{F}/\text{km}$
Main grid	Positive-sequence capacitance	$0.006 \mu\text{F}/\text{km}$
	Equivalent sequence impedances	$0.4 + j12.568 \Omega$
LCL filter	Capacitor	200 μF
	Inductance	1100/924 μH
	Resistance	0.0001/0.0001/0.25 Ω
Main transf.	Rated capacity	500 MVA
	Rated transformation ratio	220/35 kV
	Wire connection	YNd
	Short circuit impedance	6%
Step-up transf.	Rated capacity	1.6 MW
	Wire connection	Dyn
	Short circuit impedance	6.76%
Collection line	Equivalent impedance	$0.11 + j0.129 \Omega$
IIREG power plant	Unit capacity	1.5 MW
	Installed number	330
	Total capacity	495 MW
PI controller	Coefficients of the voltage loop	0.35 p.u.
	Coefficients of the current loop	0.1 p.u.
	Integral time constant	0.01 p.u.
DC bus	Rated voltage	1.2 kV
	Capacitance	4500 μF

REFERENCES

- [1] M. B. McElroy and X. Y. Chen, "Wind and solar power in the united states: status and prospects," *CSEE Journal of Power and Energy Systems*, vol. 3, no. 1, pp. 1–6, Mar. 2017.
- [2] W. J. Du, J. T. Bi, T. Wang, and H. F. Wang, "Impact of grid connection of large-scale wind farms on power system small-signal angular stability," *CSEE Journal of Power and Energy Systems*, vol. 1, no. 2, pp. 83–89, Jun. 2015.
- [3] V. Miranda, "Successful large-scale renewables integration in Portugal: Technology and intelligent tools," *CSEE Journal of Power and Energy Systems*, vol. 3, no. 1, pp. 7–16, Mar. 2017.
- [4] A. Prasai, J. S. Yim, D. Divan, A. Bendre, and S. K. Sul, "A new architecture for offshore wind farms," *IEEE Transactions on Power Electronics*, vol. 23, no. 3, pp. 1198–1204, May 2008.
- [5] J. H. He, Z. Q. Wang, Q. F. Zhang, L. Liu, D. H. Zhang, and P. A. Crossley, "Distributed protection for smart substations based on multiple overlapping units," *CSEE Journal of Power and Energy Systems*, vol. 2, no. 4, pp. 44–50, Dec. 2016.
- [6] Z. Chen, X. J. Pei, M. Yang, L. Peng, and P. X. Shi, "A novel protection scheme for Inverter-Interfaced Microgrid (IIM) operated in islanded mode," *IEEE Transactions on Power Electronics*, vol. 33, no. 9, pp. 7684–7697, Sep. 2018.
- [7] B. Y. Liu, Q. K. Wei, C. Y. Zou, and S. X. Duan, "Stability analysis of LCL-type grid-connected inverter under single-loop inverter-side current control with capacitor voltage feedforward," *IEEE Transactions on Industrial Informatics*, vol. 14, no. 2, pp. 691–702, Feb. 2018.
- [8] H. Nourmohamadi, M. Sabahi, E. Babaei, and M. Abapour, "A new structure of fault current limiter based on the system impedance with fast eliminating method and simple control procedure," *IEEE Transactions on Industrial Electronics*, vol. 65, no. 1, pp. 261–269, Jan. 2018.
- [9] H. A. Pereira, R. M. Domingos, L. S. Xavier, A. F. Cupertino, V. F. Mendes, and J. O. S. Paulino, "Adaptive saturation for a multifunctional three-phase photovoltaic inverter," in *Proceedings of the 17th European Conference on Power Electronics and Applications*, Geneva, 2015, pp. 1–10.
- [10] L. J. Chen and S. W. Mei, "An integrated control and protection system for photovoltaic microgrids," *CSEE Journal of Power and Energy Systems*, vol. 1, no. 1, pp. 36–42, Mar. 2015.
- [11] R. F. Tao, F. T. Li, W. W. Chen, Y. F. Fan, C. G. Liang, and Y. Li, "Research on the protection coordination of permanent magnet synchronous generator based wind farms with low voltage ride through capability," *Protection and Control of Modern Power Systems*, vol. 2, no. 1, pp. 28, Jul. 2017.
- [12] K. Jia, C. J. Gu, Z. W. Xuan, L. Li, and Y. Q. Lin, "Fault characteristics analysis and line protection design within a large-scale photovoltaic power plant," *IEEE Transactions on Smart Grid*, vol. 9, no. 5, pp. 4099–4108, Sep. 2018.
- [13] A. Hooshyar and R. Iravani, "A new directional element for microgrid protection," *IEEE Transactions on Smart Grid*, vol. 9, no. 6, pp. 6862–6876, Nov. 2018.
- [14] V. Telukunta, J. Pradhan, A. Agrawal, M. Singh, and S. G. Srivani, "Protection challenges under bulk penetration of renewable energy resources in power systems: A review," *CSEE Journal of Power and Energy Systems*, vol. 3, no. 4, pp. 365–379, Dec. 2017.
- [15] J. H. He, L. Liu, F. F. Ding, C. C. Li, and D. H. Zhang, "A new coordinated backup protection scheme for distribution network containing distributed generation," *Protection and Control of Modern Power Systems*, vol. 2, no. 1, pp. 10, Mar. 2017.
- [16] Y. B. Li, K. Jia, T. S. Bi, R. F. Yan, and B. H. Liu, "Analysis of line current differential protection considering inverter-interfaced renewable energy power plants," in *2017 IEEE PES Innovative Smart Grid Technologies Conference Europe*, Torino, 2017, pp. 1–6.
- [17] S. Dambhare, S. A. Soman, and M. C. Chandorkar, "Adaptive current differential protection schemes for transmission-line protection," *IEEE Transactions on Power Delivery*, vol. 24, no. 4, pp. 1832–1841, Oct. 2009.
- [18] T. G. Bolandi, H. Seyedi, S. M. Hashemi, and P. S. Nezhad, "Impedance-differential protection: a new approach to transmission-line pilot protection," *IEEE Transactions on Power Delivery*, vol. 30, no. 6, pp. 2510–2518, Dec. 2015.
- [19] G. B. Chen, Y. Q. Liu, and Q. F. Yang, "An impedance-based protection principle for active distribution network," in *2018 China International Conference on Electricity Distribution*, Tianjin, 2018, pp. 1241–1245.
- [20] X. N. Kang, J. L. Suonan, G. B. Song, and Z. Q. Bo, "Protection technique based on parameter identification — its principle and application," in *2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century*, Pittsburgh, PA, 2008, pp. 1–6.

- [21] X. N. Kang, Z. Z. Wu, J. L. Suonan, and H. You, "Research on pilot differential protection based on parameter identification and suitable frequency band of transmission line model," in *2011 International Conference on Advanced Power System Automation and Protection*, Beijing, 2011, pp. 234–241.
- [22] F. V. Lopes, C. M. S. Ribeiro, J. P. G. Ribeiro, and E. J. S. Leite, "Performance evaluation of the travelling wave-based differential protection when applied on Hybrid Transmission Lines," *The Journal of Engineering*, vol. 2018, no. 15, pp. 1114–1119, Oct. 2018.
- [23] X. Z. Dong, J. Wang, S. X. Shi, B. Wang, B. Dominik, and M. Redefern, "Traveling wave based single-phase-to-ground protection method for power distribution system," *CSEE Journal of Power and Energy Systems*, vol. 1, no. 2, pp. 75–82, Jun. 2015.
- [24] N. Cao, T. H. Ge, and Q. Yu, "Research on main transformer protection of doubly-fed wind farm based on fault current frequency difference," in *2018 Chinese Automation Congress*, Xi'an, China, 2018, pp. 4067–4072.
- [25] J. Keller and B. Kroposki, "Understanding fault characteristics of inverter-based distributed energy resources," National Renewable Energy Laboratory, Golden, CO, Technical Report REL/TP-550-46698, Jan. 2010.
- [26] A. Hooshyar, M. A. Azzouz and E. F. El-Saadany, "Distance Protection of Lines Emanating From Full-Scale Converter-Interfaced Renewable Energy Power Plants—Part I: Problem Statement," *IEEE Transactions on Power Delivery*, vol. 30, no. 4, pp. 1770–1780, Aug. 2015.
- [27] A. R. Bergen and V. Vittal, *Power System Analysis*, 2nd ed., Englewood: Prentice-Hall, 2000.
- [28] K. Jia, Y. B. Li, Y. Fang, L. M. Zheng, T. S. Bi, and Q. X. Yang, "Transient current similarity based protection for wind farm transmission lines," *Applied Energy*, vol. 225, pp. 42–51, Sep. 2018.
- [29] S. H. Horowitz and A. G. Phadke, *Power System Relaying*, 3rd ed., Chichester: Wiley, Research Study Press, 2008.
- [30] S. M. Liu, T. S. Bi, K. Jia, and Q. X. Yang, "Coordinated fault-ride-through strategy for doubly-fed induction generators with enhanced reactive and active power support," *IET Renewable Power Generation*, vol. 10, no. 2, pp. 203–211, Feb. 2016.
- [31] S. Xu, H. Liu, T. Bi, and K. E. Martin, "A high-accuracy phasor estimation algorithm for PMU calibration and its hardware implementation," *IEEE Transactions on Smart Grid*, to be published.



Ke Jia (M'11) received the M.Sc and Ph.D. degrees in Electrical Engineering from Nottingham University, U.K., in 2008 and 2011, respectively and then worked as a Research Fellow until 2013.

He is currently an Associate Professor at North China Electric Power University. His research interests include power system protection and fault location, microgrid automation and renewable energy.



Zhe Yang received the B.S. degree in Electrical Engineering from the Northeast Electric Power University in 2017.

He is currently pursuing the M.S. degree in Electrical Engineering at North China Electric Power University. His research interests include analysis of power systems with renewable energy, power system protection and control.



Yu Fang received the B.Eng. and M.Eng. degrees in Electrical Engineering from North China Electric Power University, Beijing, China, in 2017 and 2020, respectively.

He is currently an Engineer with the State Grid Nanjing Power Supply Company, Nanjing, China. His research interests include analysis of power systems with renewable energy, power system protection and control.



Zhengxuan Zhu received the B.Eng. degree in Electrical Engineering in 2017 from Hefei University of Technology, Hefei, China. He is currently working toward the M.S. degree in Electrical Engineering at North China Electric Power University, Beijing, China.

His research interests include power system protection and renewable energy.



Liming Zheng received the B.S. degree in Electrical Engineering from Sichuan University, Chengdu, in 2017. He is currently pursuing the Ph.D. degree in Electrical Engineering with North China Electric Power University. His research interests include protection and control of power systems with renewable energy power plants.



Tianshu Bi (M'98–SM'09) received the Ph.D. degree from the Department of EEE at the University of Hong Kong, Hong Kong, China, in 2002.

She is currently a Professor at North China Electric Power University. Her research interests include power system protection and control, synchronized phasor measurement technique and its application.



Ali Hooshyar (M'15) received the Ph.D. degree in Electrical Engineering from the University of Waterloo in 2014.

He is an Assistant Professor of the Electrical and Computer Engineering Department at the University of Toronto, Canada. His research interests include protection and control of renewable energy systems and smart grids. Dr. Hooshyar is an Editor of the *IEEE Transactions on Smart Grid* and the *IEEE Transactions on Power Delivery*. He is also the Guest Editor-in-Chief of the Special Issue of the *IEEE*

Transactions on Power Delivery on "Resilience-Oriented Protection, Control, and Monitoring Systems for Power Grids."