DOI: 10.48011/sbse.v1i1.2210

Modeling and Validation of a Directional Overcurrent Relay as an Island Interconnection Device ⋆

Wandry R. Faria * **Jonas V. Souza** * **Rodrigo B. Otto** ** **Benvindo R. Pereira Jr.** *

* *Department of Electrical and Computer Engineering, São Carlos School of Engineering, University of São Paulo (USP), SP (e-mails: {wandry, jonas.villela, brpjunior}@usp.br)*
** *Itaipu Technological Park Foundation, PR (e-mail: rodrigobueno@pti.org.br)*

Abstract: The growing number of decentralized generators in the distribution systems and the consequent increase in the penetration level in the networks have prompted the inclusion of this scenario in researches involving the planning of electrical power systems. The planning of protection systems for distribution networks considering distributed generators requires adaptations in the approach due to modifications in characteristics of the network, such as passivity and unidirectional power flow. Furthermore, the insertion of generators in distribution networks allows the implementation of new operation methods, such as the possibility of disconnecting some loads from the main feeder and supplying them through distributed generators. The island operation can improve the service continuity indexes, as well as reduce the costs of non-supplied energy. Although the island operation is widely proposed in the literature as a means to improve the system's reliability, the simulation of a protective device to intentionally island a region and the verification of its limitations is not. In this paper, we present the modeling of a directional overcurrent relay through ATP-EMTP, and its employment as a device for island interconnection, analyzing its zone of non-operation. CIGRE 14-bus test system is used to conduct short-circuit tests with the variation of resistance and type of fault applied. The results show the effectiveness of the device, which is able to identify all faults with real impact on the network, placing the region in island operation in less than 20 ms.

Keywords: Distributed Generation, Distribution Power Systems Protection, Intentional Islanding, ATP-EMTP.

1. INTRODUCTION

The search for more reliable networks has been a challenge to the distribution companies (DISCOs) over the last few years, as the rules imposed by regulatory agencies for the maintenance of the concession are becoming increasingly more rigid. In order to meet the indexes required by the regulatory agencies, DISCOs install protection devices in their Distribution Systems (DSs), which, in addition to ensuring the preservation of equipment (*e.g.*, transformers, capacitor banks, and reactors), directly influence the DS's reliability. One of the fundamental reliability indexes is the System Average Interruption Duration Index (SAIDI), which must be kept within pre-established limits that depend on the company's capital investment (Pereira et al., 2018). In this context, the installation of protection and maneuvering equipment is indispensable, since the performance of these devices determines the area affected by a contingency and, consequently, is directly related to the service continuity indexes.

The protection system's central function, besides protecting the network elements, is to ensure that a minimal portion of the network is affected by a contingency. The insertion of several protection devices in series despite increasing the network's reliability leads to the increase of the substation's protection response time, which is contrary to the need for a high-speed action to ensure the grid's equipment safe operation (Silva, 2002). Thus, the insertion of protection devices at strategic points of the DS becomes safely and economically more feasible than to install multiple elements in series throughout the system.

Studies concerning the optimal allocation of protection devices have been published for decades, adapting the method to every change the DSs have been through (Soudi and Tomsovic, 1998; da Silva et al., 2008). However, from the 2000s onwards, the insertion of Distributed Generators (DGs) in DSs has grown, bringing with it the necessity to once again reformulate the studies presented for the protection devices allocation. The allocation of protective devices disregarding the presence of DGs do not contem-

⋆ This work was supported by Itaipu Binacional/UCI and Itaipu Technological Park Foundation - Brazil. The authors also would like to thank the research group "Microgrids and Systems with Distributed Generation by Real Time Simulation" (CNPQ) for the technical support during the work development.

plate the new characteristics of the systems with DGs, *e.g.*, the possibility of bidirectional flow in certain regions of the DS (Kennedy et al., 2016). Another possibility related to the approach of the optimal allocation of protective and maneuvering devices in DS with DGs is the possibility of intentional islanding during contingency situations. In this context, the DGs supply part of the system's loads, that would be disconnected otherwise, thus improving network reliability indexes (Pereira et al., 2018; Heidari et al., 2018).

In Pereira et al. (2018) and Peñuela and Mantovani (2013) the authors aggregate the presence of DGs to their allocation method. Additionally, they consider the possibility of island operation, managed through the operation of a protective device with a directional unit. Although the approach proposed in Pereira et al. (2018) and Peñuela and Mantovani (2013) consider the island operation in the mathematical model to reduce the costs of Non-Supplied Energy (NSE), the protective device is not modeled nor tested. Thus, in this paper, we propose the modeling and application of an overcurrent relay with a directional unit as an Island Interconnection Device (IID) aiming to validate their approaches and present its limitations.

2. INTENTIONAL ISLANDING TECHNICS

As proposed in Pereira et al. (2018) and Peñuela and Mantovani (2013), the islanding region can operate connected to the main feeder, in which case there may be power transfer between the DGs and the main grid; or disconnected, where the DGs exclusively supply the power demanded by the loads. The operation of the protective device installed at the Point of Common Coupling (PCC) causes the disconnection of the islanding region from the main feeder. According to IEEE (2003), during a contingency, the DGs must be disconnected in no more than 2 seconds, which means that the IID must act in less than 2 seconds so that the DGs are maintained in operation. The algorithm proposed in Sharma et al. (2017) considers the following types of protection relays for fault detection:

- Voltage unbalance at the PCC
- Voltage drop at the PCC
- Frequency deviation at the PCC
- Overcurrent flowing at the PCC
- Change in the impedance at the PCC
- DG's rate of change of power
- DG's rate of change of frequency

It is essential to highlight that the seven relays mentioned above do not consider the direction of the fault. In this sense, the island is created regardless of the fault location, *i.e.*, whether the fault is inside or outside the islanding region, the protective device will operate, insulating the region from the main feeder. This maneuver does not put in jeopardy the system's safety; if the island is formed with the fault inside, the DG's local protection will operate, disconnecting the DG from the DS and eliminating the current supply to the fault. It is noteworthy to point out that all of the loads in the islanding region would experience energy supply interruption. Considering that it is possible to have protective devices inside the islanding region whose action would reduce the area affected due to a fault inside the islanding region, the IID's operation is not desired, once a possible healthy part of the region would be disconnected from the feeder.

In this context, approaches Pereira et al. (2018) and Peñuela and Mantovani (2013) propose the employment of an IID with a directional unit. Thus, the device sensitizes only for faults external to the islanding region. In this sense, the scenario previously mentioned, where the IID's undesired operation provoke economic and technical negative impacts on the DS, is avoided. The authors propose the use of an automatic recloser with a directional unit as the IID, which we implemented as detailed in the next section (ABB, 2020).

3. DIRECTIONAL OVERCURRENT RELAY

Directional Overcurrent Relays (DORs) consist of the combination of directional and overcurrent units, the latter being inoperative, regardless of the fault current's magnitude, until the directional unit is enabled. Directionality is obtained by voltage polarization, while the protection area is defined by comparing the current angle with the polarizing voltage.

The polarizing voltages magnitudes must be kept close to nominal even in fault situations in order to maintain the voltage reference for the current involved in the fault. In this paper the quadrature bonding (90°) is modeled. In this case, the polarization voltage V_{BC} is used with the phase A overcurrent element. This way, if phase A is involved in a fault, the polarization voltages of this phase (V_C and V_B) are high enough to distinguish directionality. Depending on the connection of the directional relays (30°, 60° or 90°) different polarization voltages can be obtained.

The DOR is modeled on the ATP-EMTP (Center, 1992) platform via the MODELS programming language (Dubé and Bonfanti, 1992) and is composed of the subsystems described below.

3.1 Analog Signal Conditioning

At this stage, the voltage and current transducers are modeled. These subroutines are responsible for reducing the magnitude of the signals coming from the electrical power system. In addition, the signals are subjected to a second-order low-pass Butterworth filter with a cutoff frequency of 1000 Hz to ensure that the highest frequency component does not exceed half the sampling frequency of the digital relay (assuming it is 2 kHz), thus complying to Nyquist's theorem (Weik, 2001).

3.2 Signal Digitalization

In this section, the analog voltage and current signals are sampled, and, through a holder, we ensure that a single analog/digital converter is capable of digitizing all voltage and current measurements of the three phases for a single instant of time. The scanned waveforms are then allocated into a buffer responsible for storing the last measurement cycle.

3.3 Digital Signal Processing

Through the application of the discrete Fourier transform (DFT), the voltage's and current's fundamental components for the three phases are estimated. Filtering the fundamental component is essential to distinguish a short circuit, which characteristically has fundamental frequency phasors with high magnitudes, from an electric machine energizing situation, which presents fundamental frequency components with magnitudes close to the nominal ones.

3.4 Acting Logic

From the phasors estimated by the discrete Fourier filter, the angular difference between the phasors of the phase currents and the polarization voltages (V_{AB}, V_{BC} and V_{CA}) are calculated. The currents' phasors magnitudes are verified and, if an overcurrent situation is verified, combined to the verification of the direction of the current as flowing from the island region into the distribution system, the relay acts, placing the region in island operation. Figures 1, 2, 3 and 4 point out the differences in the angles' behavior for faults applied inside and outside of the islanding region at 1s.

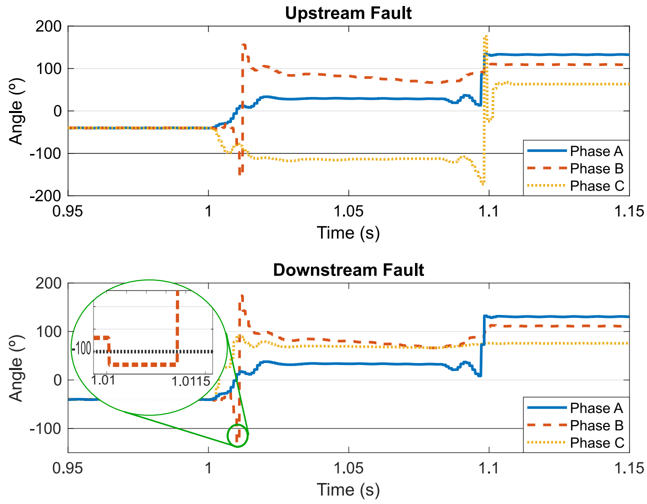

Figure 1. Angle Behavior for Single Phase Fault (Faria et al., 2019)

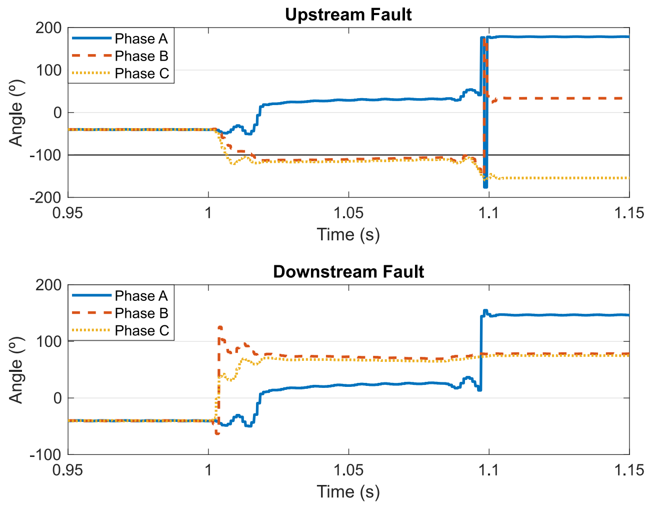

Figure 2. Angle Behavior for Two Phase Fault (Faria et al., 2019)

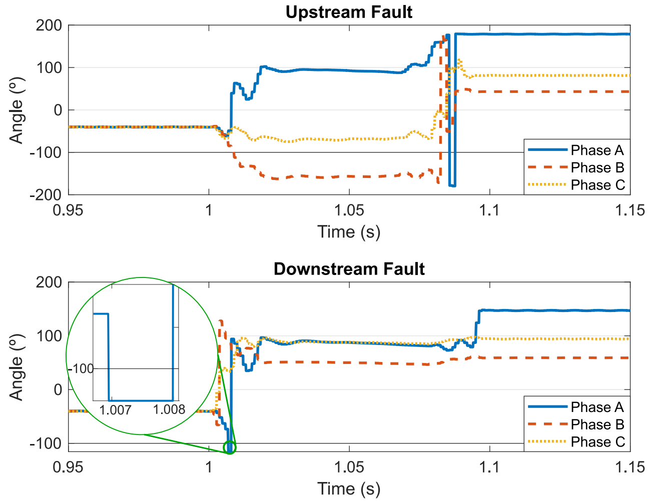

Figure 3. Angle Behavior for Two Phases to Ground Fault (Faria et al., 2019)

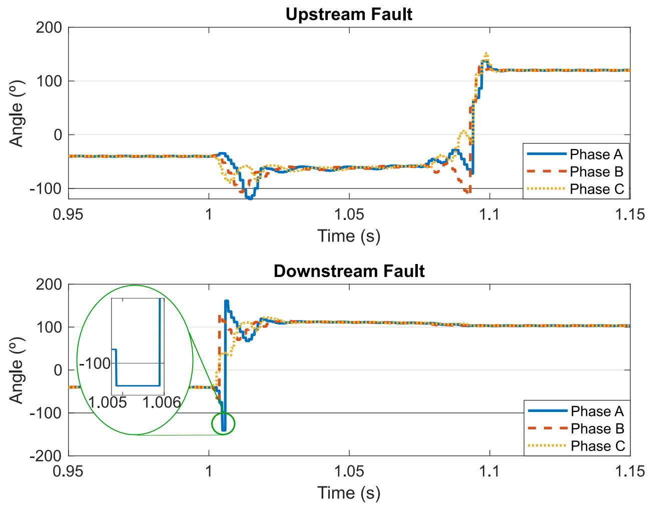

Figure 4. Angle Behavior for Three Phase Fault (Faria et al., 2019)

The actuation angle behavior for faults outside the islanding region (direction for which the relay must act) has values lower than $-100°$ for at least one of the phases, regardless of the type of fault, for more than 5ms, which is not observed for faults in the other direction. Thus, when at least one of the operating angles is less than $-100°$ for a period higher than 5ms, and additionally at least one of the observed phase current magnitude is higher than the user-defined pick-up current, the situation is characterized as a fault for which the relay must operate.

4. TESTS AND RESULTS

The CIGRE 14-bus distribution system is used in the simulations (CIGRÉ, 2014). A 5 MVA generator is connected at bus 5. The DG is capable of supplying power to the adjacent buses (4 and 6). A fundamental point to highlight is the implementation of the DG's controllers. In this paper, we consider a synchronous machine and model its speed and voltage controllers. Thus, the results presented in the next subsections are a closer match to the real operation. The implemented directional overcurrent relay

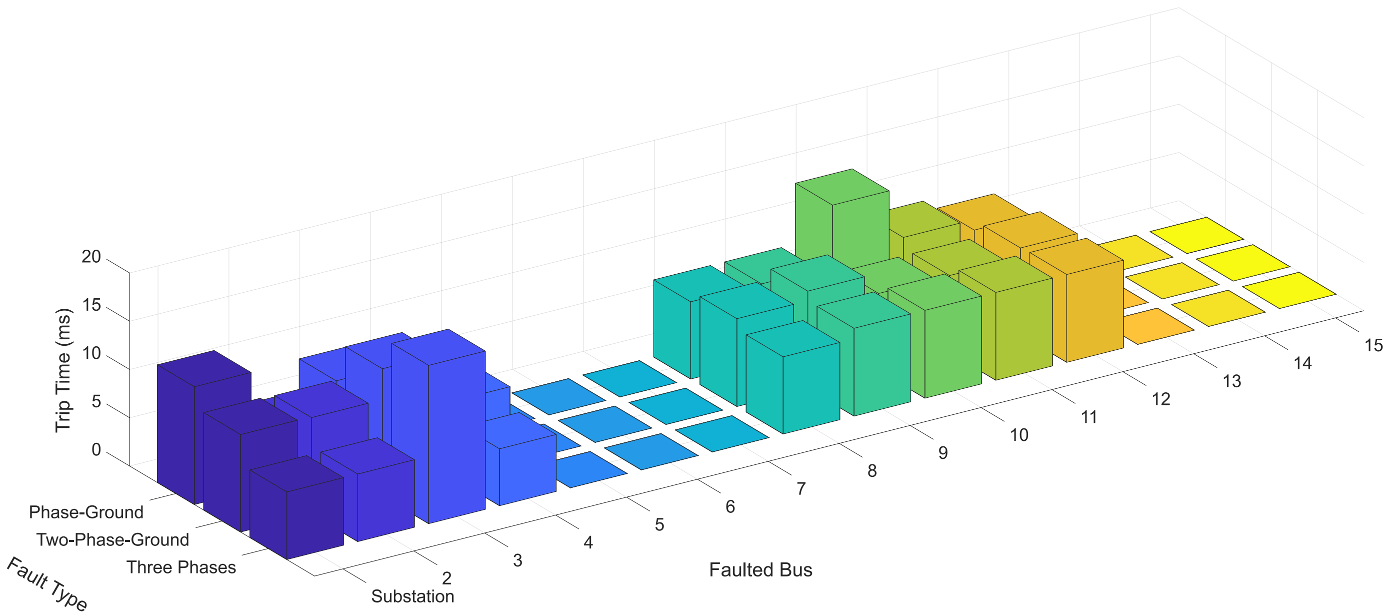

Figure 5. Relay Response to Different Types of Faults

is allocated between buses 3 and 4 in order to intentionally island buses 4, 5, and 6 in situations of faults outside of the region highlighted in Figure 6.

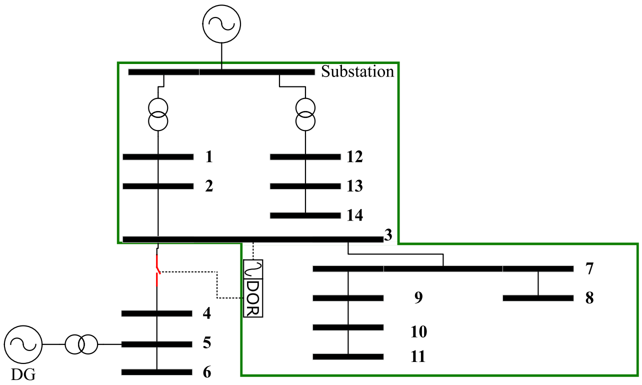

Figure 6. DOR's Protection Zone

As other papers such as Vieira et al. (2008) and Banu et al. (2014) already propose devices to be used as the DG's local protection, this device is not modeled in this work. However, it is crucial to note that the IID must operate faster than the DG's local protection for faults located outside the islanding region.

4.1 Response to Different Type of Faults

In this case study, phase-ground, two-phase-ground, and three-phase faults are applied at all system buses considering a fault resistance equal 1Ω and the relay's instantaneous actuation characteristic. The results are shown in Figure 5.

Since the time for correct interpretation of the fault situation and checking the current direction is 5ms, the cases where the time is less than this value indicates the device's non-actuation. It is possible to verify that faults at buses 4, 5, and 6 do not sensitize the relay, thus guaranteeing the formation of the island only for faults outside the islanding region, as proposed to improve the network's continuity indexes. Buses 12, 13, and 14 are electrically distant from the DG, which can be verified by analyzing the DG current contribution to faults applied at these points, as shown in Figure 7.

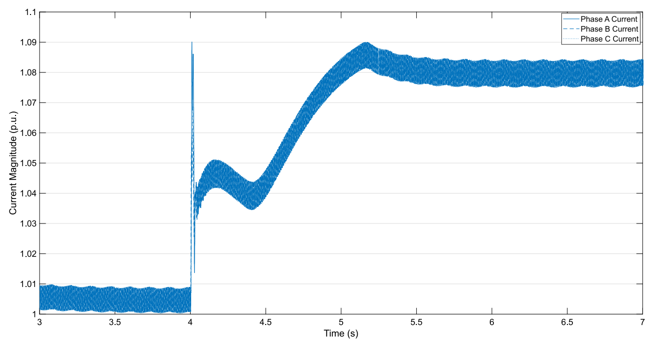

Figure 7. DG's Current Due to a Fault Applied at Bus 12

The DG's currents are increased by 8% due to a fault applied to bus 12, since it is a small amount the relay is not allowed to trip. When faults are applied at buses 13 and 14, the effects on the DG's currents are even fewer.

4.2 Response to the Fault's Resistance Variation

In this approach, the following values are considered for fault resistance: 0.5Ω, 1Ω, 5Ω, 10Ω, 20Ω, and 30Ω. The faults are applied at all system buses, and some of the responses of the DOR are shown in Figures 8 and 9.

Based on the measured trip time of each contingency case, Table 1 summarizes the relay's behavior facing different types of faults.

The actual protection zone provided by the designed DOR is presented in Figure 10. The red area marks the region for which the relay does not sensitize (due to the low influence on the DG's currents); on the yellow region, only the faults with low resistance (less than 10Ω) are identified; finally, on the green area, the faults are identified for every tested scenario.

It is worth mentioning that for every scenario in which the DOR acts, the tripping time is less than 20 ms, inferior to the acting time of protective devices used as DG's local protection presented in Vieira et al. (2008) and Banu et al. (2014). Thus, the device operates before the local protection, clearing the fault and maintaining the DG operational.

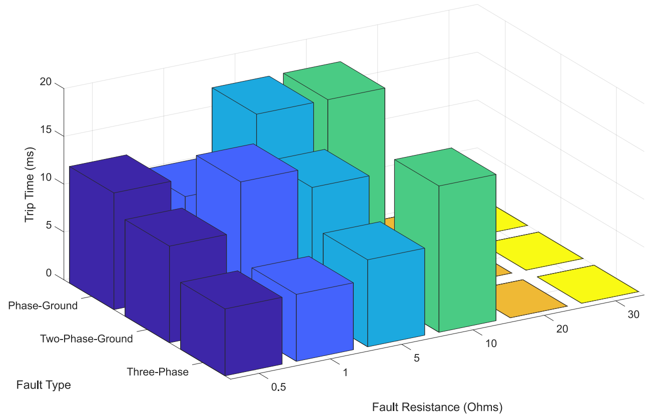

Figure 8. Relay Response to Faults Applied at the Substation

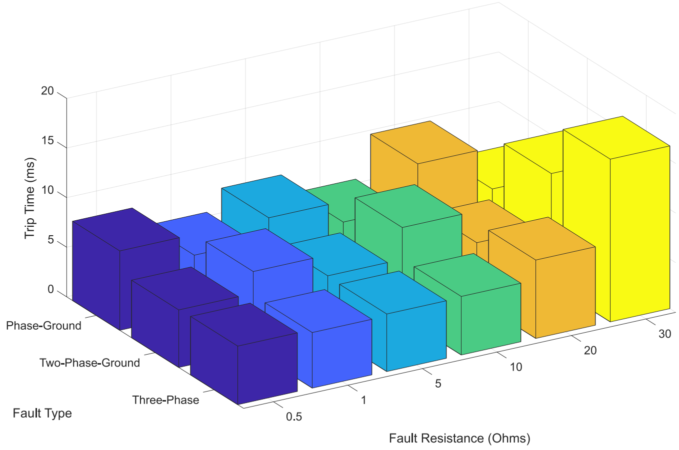

Figure 9. Relay Response to Faults Applied at Bus 3

Table 1. DOR's Tripping Behavior

Fault Location	Tripping Behavior
Substation and Bus 1	Trips when the resistance is no higher than 10Ω
Bus 2	Trips when the resistance is no higher than 20Ω
Bus 3	Trips for every tested fault resistance
Buses 4 to 6	Does not trip for any of the tested fault resistance
Buses 7 to 11	Trips for every tested fault resistance
Buses 12 to 14	Does not trip for any of the tested fault resistance

4.3 DOR's Interaction with the Network's Protection System

It is possible to conclude from Table I and Figure 5 that a 20Ω three-phase fault at the substation node does not

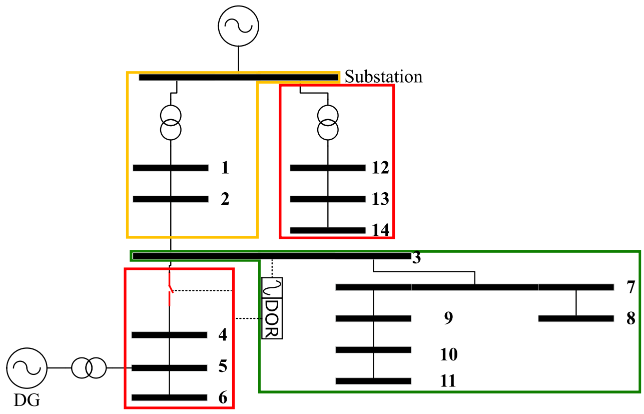

Figure 10. Directional Overcurrent Relay Real Protection Zone

sensitize the DOR implemented in this paper. However, as can be verified in Figure 11, the currents flowing through the DOR during the fault are not high enough to characterize a fault.

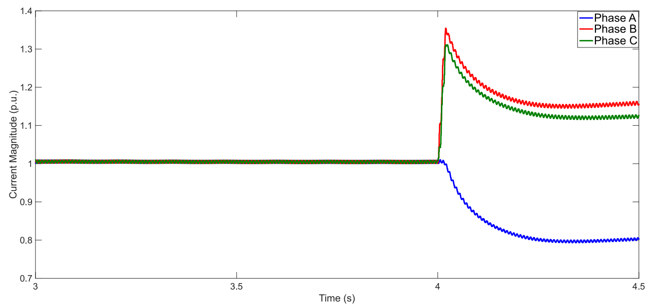

Figure 11. DG's Current for a 20 Ω Fault at the Substation Node without other Protective Devices

Nonetheless, the current flowing through the substation node assumes magnitude superior to 5 times the nominal current, as shown in Figure 12. In this sense, the protective devices allocated at the substation sensitize, eliminating the substation's current supply to the fault. When the substation's protective devices act, the DG's current contribution to the fault increases, as shown in Figures 12 and 13. In this scenario, the current is high enough to sensitize the DOR, placing the region in island mode and clearing the fault.

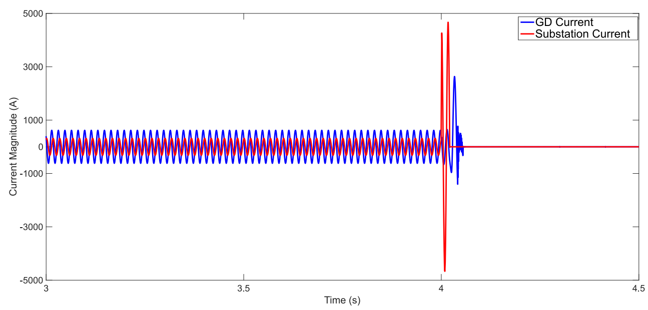

Figure 12. Fault Currents Considering the Substation's Protective Device Actuation

Although Figure 10 and Table I show that the DOR cannot identify every fault within its protection zone, when considered the DOR's interaction with other protective

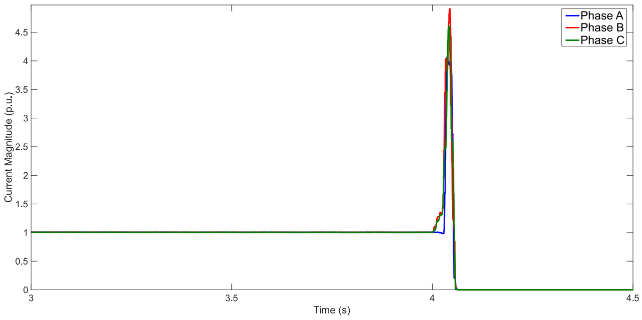

Figure 13. DG's Current for a 20 Ω Fault at the Substation Node with other Protective Devices

devices, the outcome is an efficient protection system capable of clearing all of the simulated fault scenarios.

5. CONCLUSIONS

In this paper, a directional overcurrent relay is modeled using ATP-EMTP's MODELS and tested as a device for intentional islanding. The use of a directional unit allows the region to operate in island configuration only if the system failure is located outside of the island region, in this way the SAIDI and NSE costs can improve. The conducted studies proved the relay's capacity of identifying most of the applied faults, except on cases where the current is not high enough to sensitize the overcurrent unit. Considering the presence and operation of other protective devices, the simulated DOR operates correctly and identifies every fault scenario, placing the region in island operation as intended.

The study considers the variation of resistance and type of fault applied at each bus, and the modeled relay behaved accordingly, tripping for faults upstream and blocking for faults downstream. The most severe faults applied to buses 12, 13, and 14 cause the DG's current to increase by 8%, which is not interpreted as a fault situation by the relay, therefore there is no trip signal.

For every tested scenario, the DOR acts in less than 20 ms, which is faster than the protective devices commonly employed as local protection for DG's. In this sense, the implemented equipment guarantees the correct island formation, not allowing the DG to disconnect when the fault is outside the islanding region nor allowing the island to be formed otherwise.

REFERENCES

ABB (2020). *Product guide RER620: Advanced recloser protection and control*. Asea Brown Boveri, 655 Century Point, Lake Mary, FL 32746. URL `https://new.abb.com/medium-voltage/distribution-automation/grid-automation-solutions/products/advanced-recloser-protection-and-control-rer620`.

Banu, I.V., Istrate, M., Machidon, D., and Pantelimon, R. (2014). A study on anti-islanding detection algorithms for grid-tied photovoltaic systems. In *2014 International Conference on Optimization of Electrical and Electronic Equipment (OPTIM)*, 655–660. doi:10.1109/OPTIM.2014.6850940.

Center, L.E. (1992). *Alternative Transients Program (ATP): Rule Book*. EMTP.

CIGRÉ (2014). *Benchmark Systems for Network Integration of Renewable and Distributed Energy Resources: Task Force C6.04*. [Brochures thématiques]. CIGRÉ.

da Silva, L.G.W., Pereira, R.A.F., Abbad, J.R., and Mantovani, J.R.S. (2008). Optimised placement of control and protective devices in electric distribution systems through reactive tabu search algorithm. *Electric Power Systems Research*, 78(3), 372 – 381. doi:https://doi.org/10.1016/j.epsr.2007.03.005.

Dubé, L. and Bonfanti, I. (1992). Models: A new simulation tool in the emtp. *European Transactions on Electrical Power*, 2(1), 45–50. doi:10.1002/etep.4450020108.

Faria, W.R., Oleskovicz, M., Coury, D.V., Otto, R.B., and Pereira, B.R. (2019). Intentional island and dynamic analysis of a microgrid. In *2019 IEEE Milan PowerTech*, 1–6. doi:10.1109/PTC.2019.8810559.

Heidari, A., Dong, Z.Y., Zhang, D., Siano, P., and Aghaei, J. (2018). Mixed-integer nonlinear programming formulation for distribution networks reliability optimization. *IEEE Transactions on Industrial Informatics*, 14(5), 1952–1961. doi:10.1109/TII.2017.2773572.

IEEE (2003). Ieee standard for interconnecting distributed resources with electric power systems. *IEEE Std 1547-2003*, 1–28. doi:10.1109/IEEESTD.2003.94285.

Kennedy, J., Ciufo, P., and Agalgaonkar, A. (2016). A review of protection systems for distribution networks embedded with renewable generation. *Renewable and Sustainable Energy Reviews*, 58, 1308 – 1317. doi: https://doi.org/10.1016/j.rser.2015.12.258.

Peñuela, C. and Mantovani, J. (2013). Improving the grid operation and reliability cost of distribution systems with dispersed generation. *Power Systems, IEEE Transactions on*, 28, 2485–2496. doi:10.1109/TPWRS.2012.2235863.

Pereira, K., Pereira, B.R., Contreras, J., and Mantovani, J.R.S. (2018). A multiobjective optimization technique to develop protection systems of distribution networks with distributed generation. *IEEE Transactions on Power Systems*, 33(6), 7064–7075. doi:10.1109/TPWRS.2018.2842648.

Sharma, M.K., Kumar, P., and Kumar, V. (2017). Intentional islanding of microgrid. In *2017 6th International Conference on Computer Applications In Electrical Engineering-Recent Advances (CERA)*, 247–251. doi:10.1109/CERA.2017.8343335.

Silva, L.G.W.d. (2002). *Alocação otimizada de dispositivos de proteção em sistema de distribuição de energia elétrica*. Master's thesis.

Soudi, F. and Tomsovic, K. (1998). Optimized distribution protection using binary programming. *IEEE Transactions on Power Delivery*, 13(1), 218–224. doi:10.1109/61.660881.

Vieira, J.C.M., Salles, D., Freitas, W., and França, A.L.M. (2008). Um método prático para a definição dos ajustes de relés baseados em medidas de freqüência usados para detecção de ilhamento de geração distribuída. *Sba: Controle & Automação Sociedade Brasileira de Automatica*, 19(2), 199–213.

Weik, M.H. (2001). *Nyquist theorem*, 1127–1127. Springer US, Boston, MA. doi:10.1007/1-4020-0613-6_12654.