Investigating Inverter-Based Resources Impacts on the Transmission Line Protection via Hardware-in-the-loop Simulation

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***Abstract*—Fault responses of inverter-based resources (IBR) are primarily dictated by the control algorithms and are fundamentally different from conventional synchronous generators. Hardware-in-the-loop simulation, commonly viewed as a robust tool for protection setting prototyping and testing, is used in this paper to investigate the impact of a wind farm, with type-4 full converter wind turbines, on the protection of a 345 kV transmission line in Texas, United States. This paper discusses two critical topics in detail: (1) wind farm IBR model development and validation against vendor PSCAD model, and (2) IBR impacts on distance and current differential protection.**

***Index Terms*—Hardware-in-the-loop Simulation, Inverter-Based Resource, Real-Time Digital Simulation, Transmission Line Protection, Wind Farm.**

I. Introduction

Driven by policy changes, renewable energy is poised for explosive growth in the recent decade. As one of the key forms of renewable energy, inverter-based resources (IBR) account for a significant portion of the current and future renewable generation capacity. In the US, for example, with the help of large-scale offshore wind farms and in-land energy storage projects, New York City set forth a carbon-neutral goal by 2050. On the other side of the country, Hawaii has been investing heavily in solar and energy storage IBR to achieve its 100% greenhouse gas neutrality goal by 2045.

A critical part of these renewable energy initiatives is sizeable renewable energy generation projects such as solar farms, offshore wind farms, and utility-scale energy storage projects. These renewable generations are interfaced with sub-transmission and transmission systems via power electronic devices called an inverter. Generally speaking, there are two types of inverters: grid following inverter and grid forming inverters [1]. In regular operation, inverters function in the grid following mode, in which the inverter follows the voltage and frequency references measured at the point of interconnection (POI) using a phase-locked loop (PLL). In the case of black start, the inverter can function in the grid forming mode to establish healthy voltage and frequency for the impacted system.

Inverter dynamic responses, especially fault responses, are fundamentally different from conventional synchronous generators that protection engineers are accustomed to [1], [2]. Typically, the fault current magnitude of an inverter is strictly limited to 1.1-1.5 per unit due to semiconductor thermal limits. Some use a piecewise linear voltage-dependent lookup table to determine the exact magnitude limit to limit the fault current magnitude. In contrast, some cut-off waveforms are above a certain threshold. In addition to magnitude control, the inverter internal control algorithm determines the angle between voltage and fault current, and the angle differs between grid following and grid forming control modes. Additionally, a typical inverter control algorithm limits the negative sequence fault current injection and only produces a balanced fault current in the case of an unbalanced fault. Although the industry and government organizations are working together to establish standards and guidelines for IBR protection, it remains a great challenge for utilities and developers, especially in the case of high IBR penetration.

The impact of IBR on transmission line protection is traditionally studied in electromagnetic transient simulation programs, e.g., [2]. However, similar studies are now being conducted on protective relay hardware, as the test results have better authenticity than pure software simulations. In some studies, the IBR fault responses are first simulated and recorded in an electromagnetic transient simulation program. Then these fault records are played back to the physical relay via relay test kits [3]–[5]. Although this type of study offers great improvements over the software simulation, there are several shortcomings of this type of testing technique: (1) it is labor-intensive to simulate and replay an extensive test plan, e.g., hundreds of test cases. (2) it is impossible to test scenarios that involve cascading events. Therefore, hardware-in-the-loop (HIL) simulation is proposed as a robust alternative for IBR protection testing. HIL simulation is carried out in a computing device that is capable of simulating real-time electromagnetic transient simulation. The simulated power system and inverter electrical dynamics are fed to the physical protective relays via voltage and current amplifiers. The control signals from relays are then interfaced with the HIL computing device via a DC binary circuit, thus creating a loop.

This paper investigates the impact of a wind farm, with type-4 full converter wind turbines, on the protection of a 345 kV transmission line in Texas, United States. The hosting transmission system and the wind farm are modeled in a real-time digital simulation (RTDS) system, and four physical line protection relays are interfaced with RTDS to perform a HIL simulation. The two critical technical contributions of this paper are: (1) this paper shares the best practices and lessons learned of the IBR model development and validation against vendor black box IBR models. (2) this paper assesses the IBR impacts on the transmission line protection via state-of-the-art HIL simulation testing.

The rest of the paper is structured as follows: Section II presents the technical background of the protection and control for wind farms and inverters. Section IV covers the IBR model development and validation. Section IV reports the HIL simulation testing results and analysis. The conclusions are summarized in Section V. Finally, references are given at the end.

II. Protection and Control of the Wind Farm and Wind Turbine Inverters

Fig. 1 depicts a typical wind farm facility that is connected to a high voltage (HV) transmission system. Most wind farms consist of wind turbine generators, a collector system, and a main substation at the POI. Wind turbine generators are usually connected to the medium voltage (MV) collector system via a generator step-up transformer. Depending on the layout of the wind turbine generators, the collector system typically has several radial collector feeders. Underground cables are commonly preferred for collector feeders, but overhead construction may be used for other requirements, e.g., economics, maintenance, soil thermal resistivity, etc. The main substation usually consists of a collector system bus and an interconnection transformer that interface with the HV transmission system. Common interconnection transformer configurations are 1) delta — wye grounded (D-Y), 2) wye grounded — wye grounded with buried delta tertiary (Y-D-Y), and 3) wye grounded – delta (Y-D) winding configurations. The third winding configuration would require an additional grounding transformer at the MV bus. Among all configuration options, the second winding configuration is the most common one [6].

Fig. 2 presents the overall control structure of a typical wind farm. The wind farm plant controller measures the electrical signal at POI and collects measurements from individual wind turbine generators. The plant controller typically supports multiple control modes, e.g., constant power, constant power factor, frequency droop, and voltage droop controls. Despite various control modes, the control interface between the plant controller and individual inverter controllers is the P/Q set point. The plant controller can also trip one or more wind turbine generators if necessary for protection purposes. Based on the P/Q setpoint received from the plant controller, the individual inverter controller generates corresponding gate drive signals for its local semiconductor switching devices.

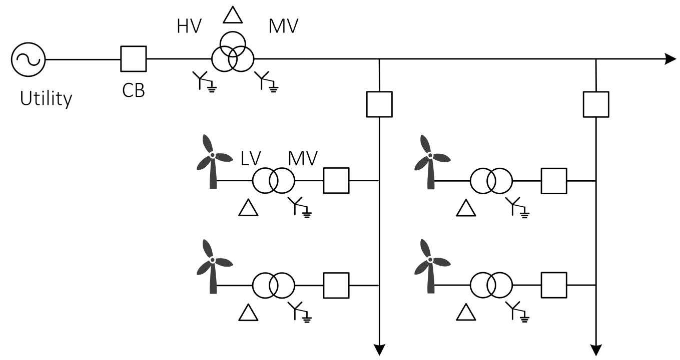

Fig. 1. One line diagram of a typical wind farm.

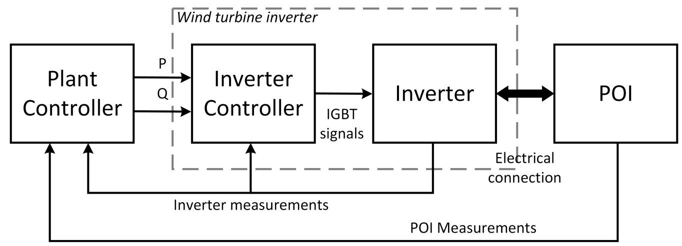

Fig. 2. Typical control structure of a wind farm.

Fig. 3 is a high level control black diagram a typical inverter coupled sequence control scheme. This control scheme has outer active and reactive power control loops and inner active and reactive current control loops. The outputs of the outer loops are active and reactive current set points in the dq-frame, i.e., Id_ref and Iq_ref, which will be taken as reference inputs for the inner current control loops. In addition to power and current control, there are protection control functions, such as high/low voltage ride through (HLVRT), and high/low frequency ride through (HLFRT). Both controls will generate current compensation signals to be added to the input of inner current control loops. At the final stage, the active and reactive current signals are modulated and used to generate gate drive signals for semiconductor switching devices, e.g., an insulated-gate bipolar transistor (IGBT). Note that the coupled sequence control scheme discussed in this section is a typical control scheme used by IBR. The inverter fault current will be balanced despite unbalance fault conditions if the controllers are parameterized properly. Nevertheless, the inverter must inject a negative sequence fault current during a fault in certain regions. To comply with similar regulations, the decoupled sequence control schemes need to be used to control and inject the negative sequence component. Further reading on the decoupled sequence control can be found in [7].

The HLVRT and HLFRT control in the inverter are typically implemented using a pair of piece-wise linear functions to specify allowed tripping time. As shown in Fig. 4, the over-

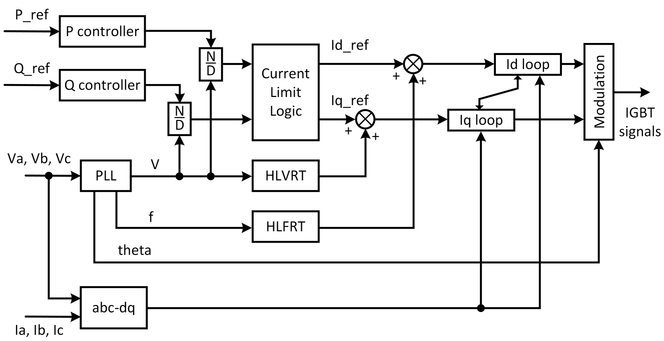

Fig. 3. Typical inverter coupled sequence control scheme.

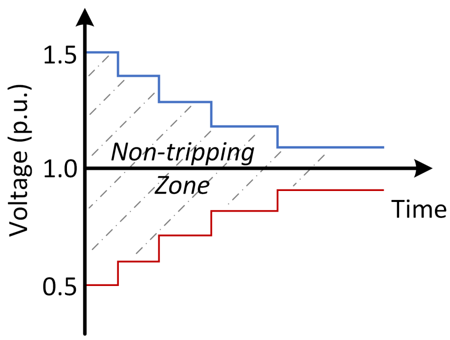

Fig. 4. A typical high/low voltage ride through setting.

voltage and low-voltage conditions and their corresponding allowed tripping time are defined. The over-voltage ride through (HVRT) curve in blue and the low-voltage ride through (LVRT) curve in red enclose the non-tripping zone. These curves can be configured to meet regional regulatory requirements.

To protect the inverter semiconductor switching devices, the inverter output current is strictly limited to 1.0 – 1.5 per unit value. A common inverter voltage-dependent current limit setting is presented in Fig. 5, which is a module called "Current Limit Logic" that is depicted in Fig. 3. The inverter can be configured to prioritize active or reactive current based on the application. For example, if the inverter prioritizes active current, the maximum active current $I_{p,\max}$ can be obtained using the blue curve in the Fig. 5. Then the reactive maximum will be calculated as $I_{q,\max} = \sqrt{1.15^2 + I_{p,\max}{}^2}$, assuming the maximum allowed apparent current is 1.15 per unit. If the reactive current is prioritized in the control setting, the reactive current maximum $I_{q,\max}$ can be looked up in Fig. 5, whereas the active current limit will be calculated accordingly. Note that limiting maximum current to zero in extremely low/high voltage conditions is not uncommon. As a result, the inverter will have zero power output despite that they are still electrically connected to the grid. This is commonly known as momentary secession.

The wind turbine inverters are protected by their local HLVRT, HLFRT, current limit logic, and proprietary protection logic implemented by vendors. The MV collector system is traditionally protected by non-directional 50/51 (instantaneous

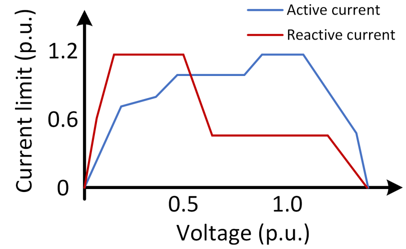

Fig. 5. A common inverter voltage-dependent current limit setting.

and time delay overcurrent) phase and ground elements since the collector feeder resembles the radial distribution feeders. However, a directional element may be required for collector feeders with both redial and network characteristics [8]. The protection for setup transformer, interconnection transformer, and MV bus follow the conventional protection principles. For brevity, this paper will not discuss them in detail.

III. IBR Model Development and Validation

A. Introduction of Vendor IBR Model

In the previous Section II, we have discussed that the inverter technology offers an unprecedented level of control on the fault responses. Therefore, in IBR protection studies, it is critical to model the inverter control scheme faithfully as well as properly parameterize the controller so that the simulated inverter response correlates to the actual inverter. Nowadays, it is common for IBR vendors to deliver compiled PSCAD models to customers for protection and interconnection studies. This type of compiled PSCAD model is also known as "black box model" given that the compiled portion is not visible to the end-user. This is purposefully done to protect the vendor's intellectual property and any proprietary data. In some cases, these black box PSCAD models contain so-called actual inverter controller code that one can find on the physical inverter. Some vendors choose to only conceal the controller modules, whereas some vendors prefer to conceal the entire model, i.e., both controller and inverter electrical design.

Typically, a wind farm consists of many wind turbines generators. Modeling individual wind turbine generator inverters requires a significant amount of computational power. The simulation step size needs to be low enough to accommodate the simulation fidelity of fast switching power electronics devices. In most cases, without the help of parallel simulation, such simulation case is too computationally expensive to run. Therefore, it is common for the vendor PSCAD model to include only one inverter and an interconnection transformer with a scaling factor. By tuning the scaling factor, the model can emulate the collective behavior of the wind farm. Such practice is typically considered sufficient for interconnection studies and protection studies on the adjacent transmission system.

B. IBR Black Box Model Development and Validation in RSCAD

To perform HIL simulation with protective relay hardware in the RTDS, users need to develop an equivalent inverter model in the RTDS native modeling software called RSCAD. This is a very challenging task as the reference model is a black box. Tremendous model probing and tuning efforts are required to achieve a closely matching RSCAD inverter model. Conceptually, one needs to first create probing cases in PSCAD; observe the model responses; and make educated guesses of the internal control structures. Once the controller structure is decided, one can manually or programmatically tune the control parameters to get a matching response. For example, one can use scripting tools to perform parameter sweep simulation and sensitivity analysis. However, we found that it is counterproductive if one directly starts with fault response tuning and matching. Because the inverter fault response is a combination of normal control response and protection function response, the number of control parameters at play can be overwhelmingly large, e.g., 50 – 150 parameters. It is extremely difficult to isolate the key contributing parameters. Based on our experience, we found that it is better to adopt a multi-stage tuning and validation strategy:

1) Quasi-steady-state response validation.
2) Fault transient response validation.
3) and System interactions validation.

The main objective of the first quasi-steady-state response tuning and validation stage is to achieve a good matching response of normal controls and slow reacting protection controls. For example, under normal conditions, one can make random step changes to the inverter inputs, i.e., P and Q set points. In this situation, the protection ride through and voltage-dependent current limiting logic are not contributing to the controller output. This experiment will help narrow down the control parameters to measurement filter time constant, PID gains, signal saturation and ramp rate limits, etc. The next step in this stage is to fix the P/Q input and vary the inverter terminal voltage to create over and under voltage conditions. In this experiment, users can isolate the control variables to HLVRT function and voltage-dependent current limit logic. Similar experiments can be done to probe and tune the HLFRT function.

In the second fault transient response tuning and validation stage, the main objective is to fine-tune the fast-reacting protection controls. For example, as shown in Fig. 3 HLVRT and HLFRT controls typically have a feedforward control loop. In this experiment, users can focus on tuning the filter time constant, feedforward gain, deadband, and activation thresholds related to the ride through functions, since the rest of the normal control loop is fine-tuned in the first stage.

The first two stages require the user to conduct experiments using the wind farm model connected to a fixed voltage source simulating an infinite bus. This will help to reduce the system-level interactions, e.g., power flow, sub-synchronous oscillation, etc. Once the first two-stage validation is done,

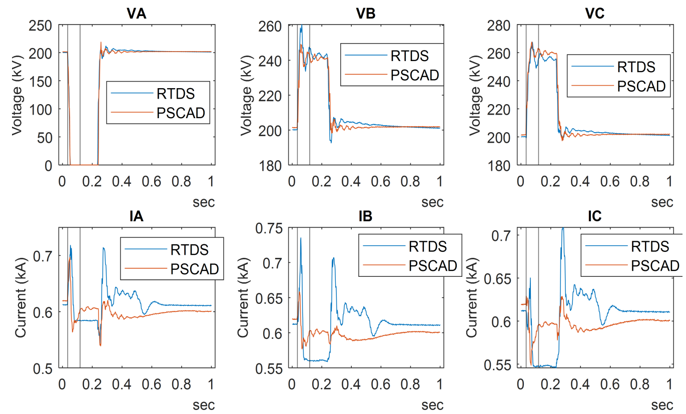

Fig. 6. A phase to ground fault simulation comparison between PSCAD and RTDS.

the user is encouraged to connect the wind farm model to a known system model and perform model tuning at a system level. For example, users can apply internal and external faults on adjacent buses and transmission lines. In addition to fault analysis, users can also adjust the system power flow and voltage level to examine the wind farm plant controller response.

Due to the non-disclosure agreement, we cannot publish vendor-specific information in this paper. Therefore, we cannot present visualizations of the model control structure and tuned model parameters. We can only present generic simulated electrical responses at the adjacent transmission line terminal. In the IBR PSCAD fault simulation, different faults are simulated for 20 cycles at the 345 kV wind farm bus without active fault clearing. The simulated three-phase RMS voltage and currents are recorded, and an example of A phase to ground fault is presented in Fig. 6. In the PSCAD simulation, part of the wind farm is tripped according to vendor-specific protection functions around ten cycles. Therefore, as shown in Fig. 6, after 20 cycles when the fault is removed, the wind farm power output is smaller than the pre-fault values. For our HIL testing, such protection function is not a vital feature to replicate because we expect the transmission line protective relay can detect this fault within five cycles. For transmission system, one would typically want an instantaneous trip (2 cycles for protective relay + 3 cycles for breaker). If the relay cannot detect this fault in the first five cycles, it would likely to fail transient stability requirements. Therefore, the focus is to accurately replicate the first five cycles' fault responses that is enclosed by two vertical black lines in Fig. 6. As a matter of fact, later HIL testing confirms that the 87L element can consistently detect this fault around 2 cycles. Overall, in the first five cycles, the mean absolute percentage error between PSCAD and RTDS simulations is 4.6%.

In addition to the RMS voltage and current comparison, the first five cycles' positive, negative, and zero sequence components of the fault current for both simulations are compared in Fig. 7. One can observe that the inverter controller suppresses negative sequence fault current in spite of the unbalanced A-G

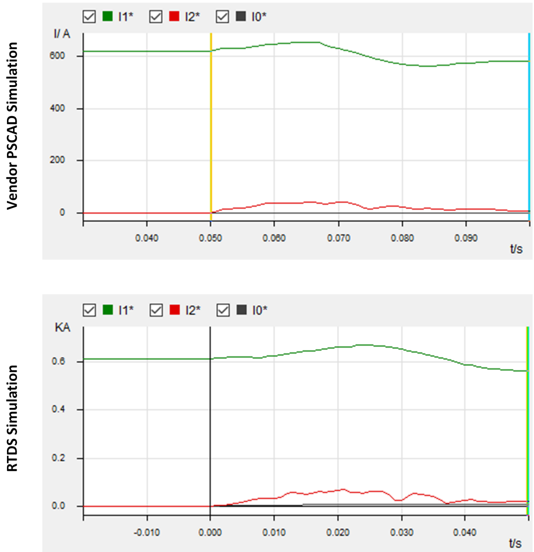

Fig. 7. Fault current sequence component comparison between PSCAD and RTDS.

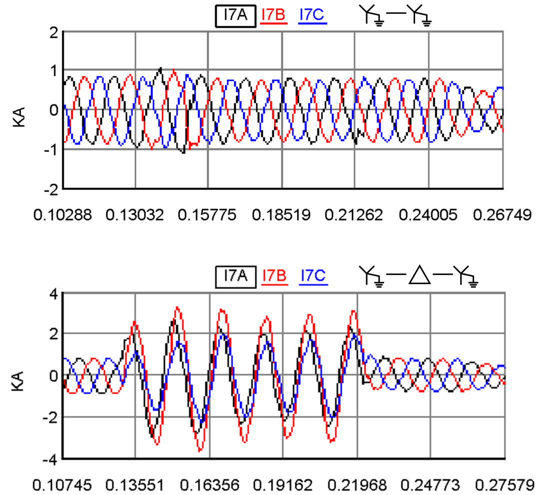

Fig. 8. Interconnection transformer wind configuration effects on fault current during A-G fault.

fault. The zero sequence fault current is also very minimum. This is caused by the Y-Y interconnection transformer used in the comparison study. Overall, the vendor black box inverter fault current signatures are accurately replicated in the proposed RTDS RSCAD inverter model.

C. Lessons Learned from the Model Matching Efforts

In addition to the vendor IBR black box inverter model development and validation experience discussed so far in this section, we would like to share two more important lessons learned during this project.

1) The Rest of the System also Matters: The focus of this protection study is transmission line protection. In this study, we found that the wind configuration of the interconnection transformer plays a significant role in shaping the wind farm fault current. For example, Fig. 8 presents the three-phase instantaneous A-G fault current captured at the high side of the interconnection transformer. The first fault current in Fig. 8 is simulated with a Y-Y two-winding interconnection transformer, whereas the second fault current is simulated with a Y-D-Y three-winding interconnection transformer. One can see that in the Y-D-Y transformer case, the system is able to drive a lot more zero sequence fault current at the transformer high side during this A-G fault. This makes a massive difference to the distance relay when detecting Phase to ground fault. Therefore, it is critical to faithfully model the transformers between the fault and inverter, as they play an essential role in fault current signatures and fault propagation. Besides transformer modeling, depending on studies, e.g., sub-synchronous oscillation, one may want to accurately model the nearby generators, series compensation system, capacitor banks, etc.

2) Controller Parameterization is the Key: The PID gains in the inverter controller need to be properly tuned so that the inverter output can be regulated to the desired set points. For example, in Fig. 9 and Fig. 10, we compare the out-of-control response and normal controlled response from two identical Type-IV wind farm but with different PID gains. In Fig. 9, we see that the Id and Iq feedback signals oscillate around the reference signal with an oscillation magnitude of almost 0.5 per unit. The resultant fault current is distorted. According to the sequence component calculation shown at the bottom of Fig. 9, the positive sequence fault current magnitude exceeded the 1.1 per unit limit and went beyond 1.5 per unit. We also see a significant increase in the negative sequence component. In Fig. 10, we see that the Id and Iq feedback signals are closely regulated at references. The resultant fault current is very sinusoidal. The 1.1 per unit positive sequence fault current magnitude is enforced, and the negative sequence current is very minimum. Note that these two controllers all have stable behaviors during normal operations, for example, changing power outputs, switching on/off, changing control modes. However, the controller in Fig. 9 is not fast enough to keep up with the fault conditions.

Typically, in fault conditions, the out-of-control response is inevitable in the first 1 or 2 cycles. Because by design controller will introduce delays. For example, the PLL will need one cycle to capture the phase angle used when generating the modulation wave. Sometimes the measurement feedback signals are filtered using a time constant. All these factors would delay the inverter to catch up with the fault condition. However, after the first 1-2 cycle, the controller should kick in and regulate the inverter outputs.

IV. HIL Testing Setup and Results

The HIL test setup consists of two relays connected to either side of the 345 kV transmission line to be tested. The primary function used to protect the line is line differential protection (87L). The distance element (21) is used as a backup protection method. Fig. 11 contains the one-line diagram of the setup. Note that the wind farm is connected to terminal A.

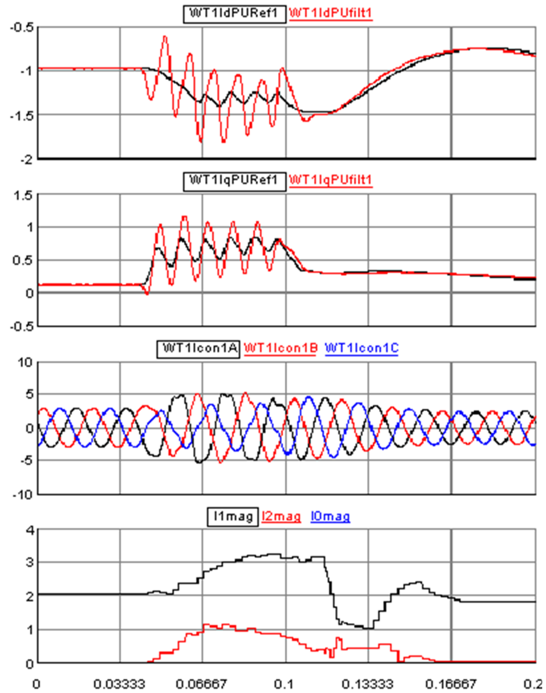

Fig. 9. Inverter out-of-control fault response.

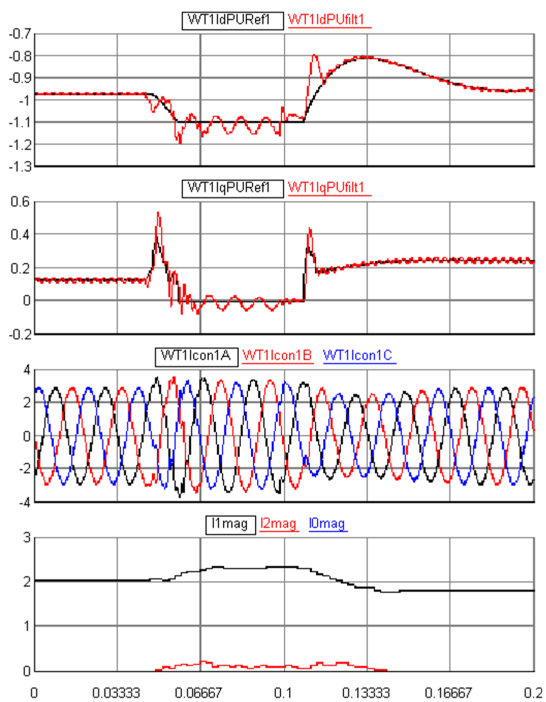

Fig. 10. Inverter normal fault response.

The performance of the protection scheme is tested for various faults on the transmission line connecting the IBR to the rest of the grid. The following scenarios are considered while testing the system:

- Fault type (TYP): Single line to ground, Double line to ground, Line-to-line and Three phase faults.

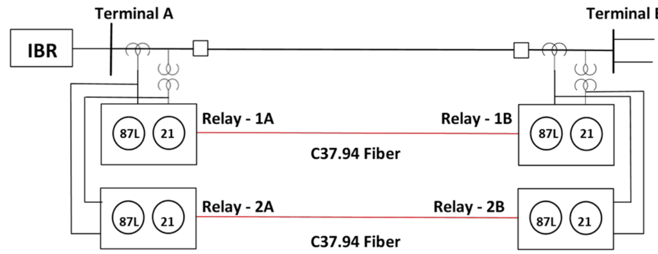

Fig. 11. HIL testing one line diagram.

- Fault location on the transmission line (LOC): Faults at 0%, 50% and 100% of the line length.
- Fault Inception angle (ANG): Various angles ranging from 0 to 180 degrees with respect to the Phase A voltage at Terminal A.
- Fault Resistance (R): 0 or 30 ohms.

Based on the criteria mentioned earlier, a test set consisting of 12 test cases is crafted to evaluate the protection scheme comprehensively. The first set of testing is performed to evaluate the behavior of the 87L element in the presence of an IBR. During this test, relays communicate using a fiber-optic medium. As expected, testing results revealed that the 87L element could consistently clear the fault at around 20 ms. It is clear that the 87L element is not affected by the IBR.

Although the 87L element operated as intended, a backup element is required in the case of communication failure. The 21 element is the backup element in this scheme, and it is also required to be tested. The second set of testing, used to evaluate the backup element, is performed without the fiber-optic communication medium in place to simulate the failure of the 87L element. Hence, the relays should use the backup element (21) to detect and isolate faults. Tab. I tabulates the results of this test with no fault resistance considered.

From the results, it can be observed that the 21 element on terminal B operated as intended since the fault current is driven by conventional generation sources. Terminal B's 21 element trips on zone 1 in the first 8 cases and trips on zone 2 in the latter 4 cases. However, terminal A's 21 element does not operate as intended. Further investigations suggest that the absence of negative sequence current injection and low fault current magnitude caused a fault loop selection error in tested relays. This has been a known issue for the relay manufacturer. The relay manufacturer proposes a potential fix for similar IBR protection issues in [4], [5], which involves the following key setting changes for the relays connected to the terminal with IBR:

- Enabling Week infeed logics (EWFC).
- Updating 50FP and 50RP to improve relay sensitivity.
- Adding customized logic to improve zone 2 reliability.

After implementing the setting changes recommended in [4], [5], improvements were observed in the performance of 21 element for internal ground faults. The presence of zero-sequence currents because of the usage of the Y-D-Y interconnection transformer, coupled with increased sensitivity

TABLE I
IMPACT OF IBR ON THE 21 PROTECTION ELEMENT WITH NO FAULT RESISTANCE.

Case	TYP	LOC (%)	ANG (deg.)	t_{trip}^{1A} (sec)	t_{trip}^{2A} (sec)	t_{trip}^{1B} (sec)	t_{trip}^{2B} (sec)	Comments
1	AG	0	0	Inf.	Inf.	0.024	0.024	1B&2B passed
2	ABG	0	30	Inf.	Inf.	0.033	0.024	1B&2B passed
3	BC	0	60	Inf.	Inf.	0.038	0.028	1B&2B passed
4	ABC	0	90	Inf.	Inf.	0.037	0.027	1B&2B passed
5	BG	50	60	Inf.	Inf.	0.041	0.027	1B&2B passed
6	CAG	50	75	Inf.	Inf.	0.033	0.028	1B&2B passed
7	CA	50	90	Inf.	Inf.	0.036	0.029	1B&2B passed
8	ABC	50	105	Inf.	Inf.	0.035	0.028	1B&2B passed
9	CG	99	120	Inf.	Inf.	0.363	0.356	1B&2B passed
10	BCG	99	135	Inf.	Inf.	0.377	0.356	1B&2B passed
11	AB	99	150	Inf.	Inf.	0.380	0.364	1B&2B passed
12	ABC	99	165	Inf.	Inf.	0.375	0.356	1B&2B passed

of the relay settings, helped detect internal ground faults. However, this solution did not help clear L-L faults for our case. Additional efforts are spent on experimenting with the 27 under voltage protection element. The project team can fine-tune a threshold for the 27 element to operate on solid internal faults. However, the security against external faults is poor, especially in the case of external faults near the opposite terminal.

V. CONCLUSIONS

This paper documents the procedures and results of a HIL protection testing project aiming to assess the impact of IBR on transmission line protection. This paper particularly discusses the challenges of creating matching inverter IBR against the vendor black box PSCAD model and shares the best practices as well as lessons learned of the IBR model development and validation. The validated RTDS IBR model is then used to conduct the HIL protection testing to evaluate the performance of 87L and 21 elements. Overall, our results suggest that the 87L element is not affected by the IBR and can be used to protect the transmission line securely. However, at the line terminal where IBR is connected, the 21 element backup is affected by the IBR. Due to small fault current magnitude and minimal negative sequence fault current, the 21 element cannot detect and clear internal faults. Although several mitigation techniques have been experimented with, the project team did not achieve 100% security on all internal and external fault scenarios. More sophisticated and reliable solutions will be the focus of our future endeavors to mitigate the impact on 21 elements.

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Srinidhi Narayanan Engineer III in Protection, Control & Automation with Quanta Technology, graduated with a master's degree in Electrical Power Systems Engineering from NC State University in 2021. The focus areas of her master's degree included power system protection, transient analysis, and communication and SCADA systems. She has also completed a capstone project as a part of her graduate program, called "Design of Protection Scheme for an Inverter-Based Microgrid Circuit," sponsored by Duke Energy. Srinidhi has more than two years of experience in the electrical power systems industry.

Juergen Holbach Ph.D., Senior Director of Automation and Testing with Quanta Technology, has more than 25 years of experience designing and applying protective relaying. An IEEE member and chairman, he has published over a dozen papers and holds three patents. In 2009, Juergen received the Walter A. Elmore Best Paper Award from the Georgia Tech Relay Conference. Juergen's areas of expertise include automation and protection, transmission protection, real-time digital simulator (RTDS) testing, and International Electrotechnical Commission (IEC) 61850 compliance.

Jeremiah Stevens Senior Advisor/Manager of Protection Studies, Protection, Control & Automation, has over 18 years of power systems experience ranging from planning to operations, substation design, system protection, and substation control. Over the last 12 years, he has focused primarily on system protection—-performing protection studies, designing protection schemes, and setting transmission protective relays.

Michael Cummings P.E., Engineering Director with Dashiell Corporation, has more than 18 years of experience in EHV, HV, and distribution substation design. He received his bachelor of science degree in Electrical Engineering from Louisiana Tech University in 2003. He is a registered Professional Engineer in multiple states, originally licensed in Texas. He continues his career in high voltage EPC projects applying a broad range of experience including design and application of protective relaying systems, equipment specification, and physical design and layout of outdoor substations for various industrial and utility clients.

Randall Rohde PE, PMP, Senior Project Manager with Dashiell Corporation, has more than 15 years of experience in the power and utilities industry. He received his bachelor's degree in Electrical Engineering from Texas A&M University in 2005. He is a registered Professional Engineer in Texas. He began his career in engineering and designing substations for various utility and industrial customers. He now manages high voltage substation and transmission line Engineering, Procurement, and Construction (EPC) projects.

Chenyan Guo P.E., recently joined NextEra Energy Resources as a Senior Manager in Transmission Business Management. She has more than 10 years of experience in transmission planning and operation with Florida Power and Light and Lone Star Transmission. She received her Master of science degree in Electrical Engineering from Texas A&M University in 2011. She is a registered Professional Engineer in Texas.

Noe Encarnacion Operations Manager with Lone Star Transmission, has 15 years of experience on various areas of the power industry including operations, system protection design, controls, automation and SCADA systems. He received his bachelor's degree in Electronic Engineering from Universidad Autonoma Metropolitana Mexico in 2007. He began his career in engineering and design in the renewable power industry. Over the last 5 years, he has focused primarily in operations of high voltage substation and transmission line assets.