IMPACT OF RENEWABLE GENERATION RESOURCES ON THE DISTANCE PROTECTION AND SOLUTIONS

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***Abstract*—Distance relays remain primary transmission line protection for more than a century and significantly evolved to handle issues due to changes in transmission network to meet ever-growing demand e.g. protection of series compensated lines, single-pole tripping and others. Use of the local information to make a trip decision and the backup zone feature makes distance protection an unavoidable choice to protect transmission lines.**

In the recent years, rapidly increasing amount of the renewable generation, including inverter-based resources (IBR) in the grid is presenting new challenges to the line protection. These new energy resources are behaving quite differently compared with a conventional synchronous generation. Also, each country following its own grid code, i.e. different IBR response for the same fault type and system conditions is possible, which is not the case for the conventional synchronous generation. The proprietary nature of the controller design and the flexibility of operating the inverter in different operating modes makes it difficult to predict and evaluate the actual performance of distance and its supervising elements.

In this paper, we discuss the impact of the 'real-controller' operating modes and real world cases on the currents and voltages presented to the distance protection and consequently impact on the characteristics, fault type supervision (FTS), directional elements. We then provide solutions to the problems and introduce the concept of controlled dynamic MHO – an innovative solution for the distance protection in the presence of IBRs and weak sources in general. Power system simulations and real field cases are used to demonstrate solutions to achieve secure and dependable distance protection.

I. INTRODUCTION

Power system network is constantly expanding to meet the ever-growing energy demand. In the last century, contribution to meet this growing demand was dominated by fossil fuel based generation followed by other types like nuclear, gas and hydro. There was a slow shift to clean energy generation like hydro, but still the interconnection to the grid was via the synchronous generators. Although, wind and solar based generation was technically seen as an option, technology advancements and economic factors, limited its wide spread usage. In the recent years, the contribution from wind and solar has significantly increased and it is expected to grow in future.

Additionally, the global commitment to move towards 'Net-Zero' carbon emissions to tackle climate change is the key driver to phase out existing generation based on fossil fuels and move towards renewable energy in energy sector, with wind and solar being predicted as the major contributors. As these renewable energy sources are intermittent i.e. unlike synchronous generation where the speed is constant, wind turbine speed varies with time and it demands for power electronic device to act as an interface.

Initially, line commutated converters (LCC) based on mercury-arc valves were considered as the only option which involves maintenance and environmental issues. Technology evolution replaced mercury-arc valves with thyristor based LCC. Unlike LCC, which relies on natural commutation, voltage source converter technology brings in more controllability, making it a popular choice as an power electronic interface for renewable energy resources.

The global commitment towards climate change and with a new technology paving its way, is driving fast and wide-spread deployment of the renewable generation in recent years. These new technologies, wind (Type-3 and Type-4) and solar with the presence of the power electronic interface is presenting new challenges to the line protection which is the focus of this paper. This is further complicated by the following factors,

- The proprietary nature of power electronic interface controller design,
- Lack of availability of the validated models in simulation packages
- The absence of the global standard causing each country following its own standard resulting in different fault quantities behavior for the same system and fault scenario i.e. fault behavior is not deterministic which is not the case in the conventional synchronous generation.
- Flexibility of operating the power electronic interface in different operating modes, especially Type-4 with VSC which is gaining wide spread deployment

All these factors make it even more difficult to evaluate the performance of distance relays.

This paper discusses the impact of this new renewable generation technology, including inverter-based resources (IBR) on the following,

- Distance characteristics
  - Quadrilateral
  - MHO
- Fault type supervision
- Directional elements

using COMTRADES obtained from the real world and simulation model, which incorporates 'real-controller' design as a black-box.

The paper is organized as follows,

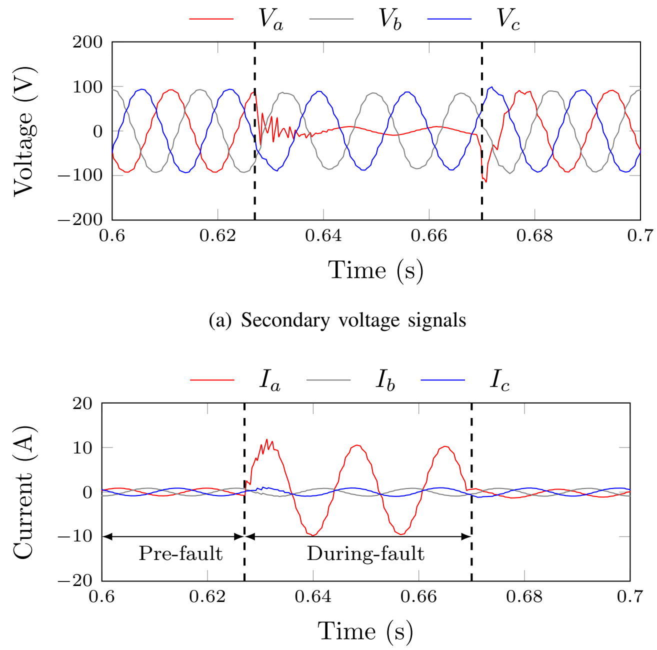
- Section 2 & 3: Section 2 provides overview of the problem by comparing the behavior of the IBR with a conventional generation and in Section 3 we discuss how IBR's can alter the fault signature and the possibilities of having different fault signature for the same fault scenario.
- Section 4: This section provides details regarding power system model which utilizes the 'real-controller' as a black-box model. The outputs from this model in the form of COMTRADE files are considered along with other real world cases for evaluating the impacts and testing the solutions.
- Section 5 & 6: Section 5 & 6 analyzing the impact of the IBR on the distance characteristics i.e. Quad and MHO respectively. Section 6 also provides introduction and details regarding innovative controlled dynamic MHO solution.
- Section 7 & 8: These sections analyzing the impact on the Distance supervisory functions, such as Fault type supervision and Directional elements and provide solutions.
- Section 9: Discusses the impact of the frequency deviation, followed by conclusion in Section 10.

II. Overview of the Problem

The three-phase voltage and three-phase current signals form the basis for any protective relay. Any sophisticated protective relaying algorithm relies on these signals to extract the desired information to make a decision. Fig. 1 shows the voltage and current signals for a real world case. Observing the signal traces one can immediately infer that it is a single phase to ground fault with phase A involved, as we observe a dip in the phase A voltage along with increase in phase A current.

In the case of synchronous generation, these fault traces are dictated by the laws of physics and are a function of the equipment design parameter which is feeding the fault. These equipment design parameters do not vary significantly across the globe, which gives us a deterministic voltage and current signal traces for a given disturbance. Additionally, the relatively slow response of the generator excitation controls and the turbine controls does not change these signals significantly for many cycles during the fault (what we refer as high-inertia generation source), where the relay is expected to make a decision. For more than a century, relaying techniques and algorithms were designed to protect the equipment based on the above mentioned facts.

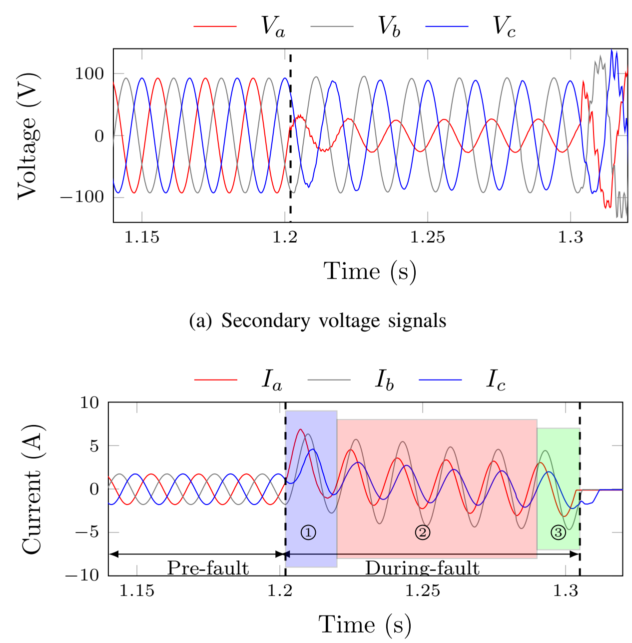
However, in the presence of the IBR, power electronics interfaces the renewable energy source and the grid. This power electronic interface is capable of fast fault current injection, which not only limits the fault current, but also impacts the fault current signatures (what we refer as low-inertia generation source). Fig. 2 shows one such IBR response for a Type 4 wind generator feeding single phase to ground fault AG.



(a) Secondary voltage signals

(b) Secondary current signals

Fig. 1: Real world conventional generator response for the phase A fault



(a) Secondary voltage signals

(b) Secondary current signals

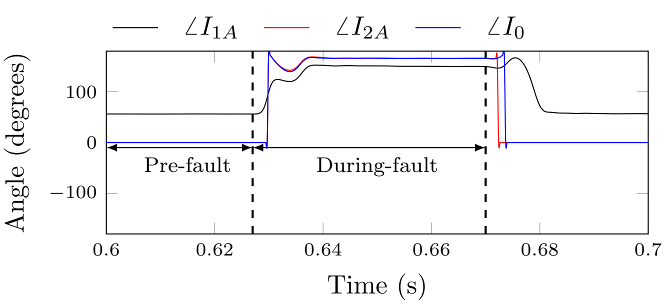
Fig. 2: IBR response for AG fault. Stage 1- disturbance detection, Stage 2: Controller transients, Stage 3:Steady state fault

We can observe that the fault voltage traces shown in Fig. 2(a) do correlate with the conventional generator fault voltage signature (Fig. 1(a)) because the voltage information is dictated by the grid, but the current traces (Fig. 2(b)) do not correlate to the typical fault current signature. This is due to the fact that IBR controller is expected to enter a new operating mode once the disturbance is detected in the stage 1 (Fig. 2(b)). This transition involves controller transients in the stage 2 (Fig. 2(b)) before it settles down (stage 3) into the target value set by the chosen operating mode during fault. Table 1 shows the voltage ride-through performance requirements for the IBR during both balanced and unbalanced faults [1].

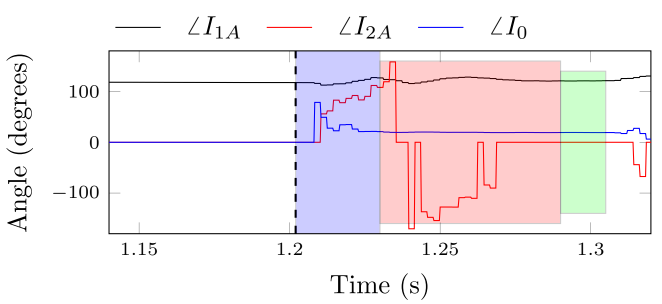
TABLE 1: Performance Requirements

	Wind - Type III	**All other IBR units**
Step Response Time	NA	$\leq$2.5 cycles
Settling Time	$\leq$ 6 cycles	$\leq$4 cycles

As a result, the impact on the phase currents produced by the IBR's is observed in the sequence-components domain. In case of conventional generation, the negative and zero-sequence current quantities are considered as preferred candidates to detect faults, involving ground. More specifically, negative-sequence current, because zero sequence quantity may be influenced by the mutual coupling in the presence of parallel lines. However, in the case of IBR's, the negative-sequence current is not reliable, when compared to the zero-sequence current, because of the presence of the solidly grounded star-delta transformer in front of the IBR is expected to provide reliable zero-sequence current to make a correct decision. Fig. 3(b) shows the sequence components data for the above cases, where the negative sequence current angle changes drastically during the fault (refer Fig. 32(c) for negative sequence magnitude), when the IBR makes its transition from stage 1 to stage 3.



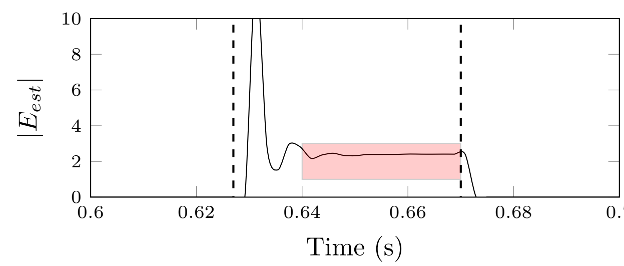
(a) Conventional generation



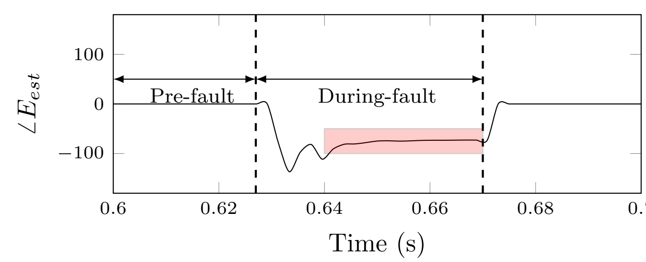
(b) Renewable generation

Fig. 3: Sequence currents
(timing between stages are for illustration purpose only and it depends on the actual controls of the IBR)

It impacts all the elements which rely on the negative-sequence current to make a secure and dependable decision, such as, quad reactance line polarization, ground directional element and others. This also impacts the behavior of dynamic MHO characteristics. The dynamic behavior of MHO characteristic is governed by the chosen polarizing value. With positive-sequence memory voltage as polarization, the dynamic behavior of ground elements is a function of loop currents. Fig. 4 shows the estimated expansion vector (discussed in details in Section VI-3), which is a function of sequence voltages and loop currents for a real world case shown in Fig. 1 for forward AG fault. Two important things to observe: first, the expansion vector stabilizes appropriately within one cycle into the fault resulting in a stable dynamic behavior. Second: as expected, it expands towards the source (inductive) to the third and fourth quadrants as shown in Fig. 5.



(a) Magnitude



(b) Angle

Fig. 4: Conventional generation - Expansion vector (E_{est})

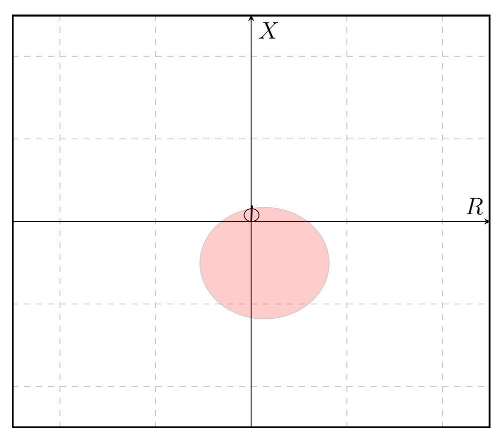
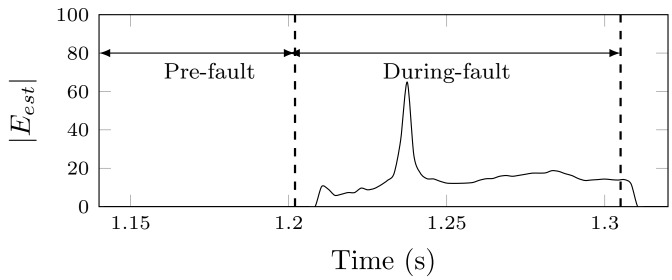
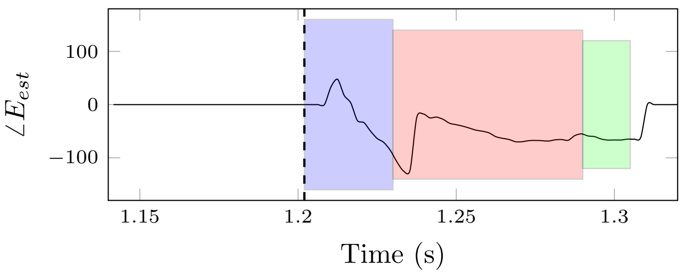


Fig. 5: Conventional generation - Dynamic MHO

Fig. 6 shows the E_{est} for AG forward fault (Fig. 2), but the fault is fed by IBR. In contrast to the conventional case, the MHO expands to the first and fourth quadrants and the source oscillations during the controller transient period in Fig. 6(b) directly translates to swings in MHO characteristic with a reach as a hinge point, resulting in uncontrolled dynamic MHO which is shown in Fig. 7.



(a) Magnitude



(b) Angle

Fig. 6: Renewable generation - Expansion vector (E_{est})

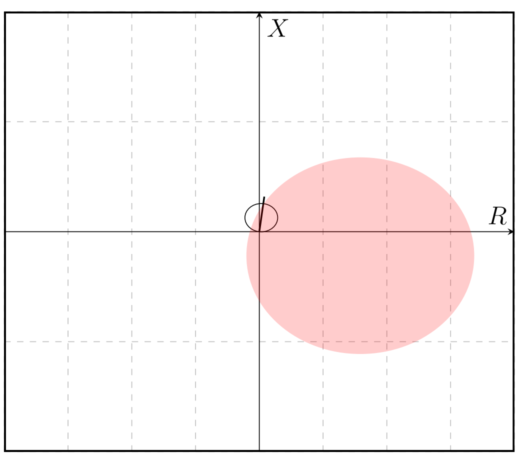


Fig. 7: Renewable generation - Dynamic MHO

Different grid codes impose different performance requirements and operating priority. As a result, the fault current values depends on the control modes and the design parameters of the controller which can vary to meet different grid code requirements. This impacts the conventional current-based relaying algorithms, including distance, directional, fault type supervision which were designed based on the deterministic voltage and current relationship.

III. IBR Modes of Operation - Overview [1]–[8]

In the early days, when the contribution from wind based renewable energy sources was low, it was preferred to trip the wind farms, when the voltage at the point of monitoring below a pre-set threshold. With increase in renewable energy contribution, this may result in cascaded tripping causing generation load mismatch and stability issues. As a result, it has now become a standard requirement (FRT - Fault ride through) for the renewable sources to stay connected during fault and support the system, with a certain exemptions where the IBR is allowed to trip [1]:

- if more than a certain number of successive voltage dips occurs within a 10 second period or when the time duration between successive voltage dips is less than certain duration,
- if successive voltage dip results in IBR self-protection operation.
- if its mutually agreed by transmission system operator and IBR owner

In the FRT period, where the renewable energy sources are expected to stay connected and ride through the fault to support the system, IBR controllers can be programmed to either inject or suppress negative sequence currents as discussed below,

A. Negative sequence suppression mode - Positive sequence reactive current injection only

In this mode, IBR injects positive sequence reactive current, i_{q^+} (Equation 1 - in general) based on the estimated positive sequence voltage V_+ using measured signals from the point of monitoring.

$$i_{q^+} = k_+(0.9 - V_+) \tag{1}$$

B. Negative sequence injection mode

Although suppressing negative sequence looks benificial from equipment perspective, it poses significant challenge to traditional protection elements which is based on negative sequence current information, which will be discussed later in this paper. Recently, standards [1] have mandated to inject a certain amount of negative sequence current. Equation 2 shows the negative sequence reactive current (i_{q^-}) injection which is based on the estimated negative sequence voltage ($V\_$),

$$i_{q^-} = -k_-(V_- - 0.05) \tag{2}$$

C. Mixed sequence injection mode

In this mode, both positive and negative sequence injected are attempted based on the set-points k_+ and k_- and the estimated positive sequence voltage V_+ and negative sequence voltage V_- respectively.

During fault, irrespective of the above modes, the estimated injection values by IBR may be limited by other factors such as,

- available margin in power electronic interface which may be IBR short-term rating - i.e. pre-fault loading
- based on the selected priority,
  - Equal priority
  - Reactive power priority
  - Active current blocking

The desired objective during the FRT can be achieved by choosing one of the operating mode and this brings in multiple options for the utility to choose the particular mode of operation thereby introducing the possibility of having different fault signature for a same fault type at the point of measurement. Table 2 lists few countries and their priority.

TABLE 2: Grid Codes

Country	Priority	Neg. seq.	Remarks
United Kingdom [2]	Reactive power	No specific requirement	–
Belgium [3]	Active or reactive power	Yes	–
Denmark [4]	Reactive power	No specific requirement	90% change in reactive power within 1 second
Finland [5]	Reactive power	Yes with k=2.5	Rise to target within 30-50 ms
Ireland [6]	Active power	No specific requirement	Rise time less than 100 ms
Poland [7]	Reactive power	No specific requirement	90% of additional reactive current in <60ms for symmetrical faults
Spain [8]	Reactive power	Yes with k=3.5 or between 2 and 6	–

This is not the case in conventional synchronous generator where for a particular fault type, fault scenario and system parameters, the fault signature is almost same irrespective of any generator manufacturers and any firmware for field controls. Although, recent standards mandate the injection of negative sequence current, still the IBR's may not replicate the conventional synchronous generator behavior as for Type III the angle of injection can vary during the initial few cycles after fault inception [1].

IV. Power System Model

In the past, staged fault test provided enough confidence to utilities and relay manufacturers to prove dependable operation, however significant cost, time and risk factors are associated with it and only one or few fault cases can be covered. The other option is to pilot test the new relay, as one can observe how the protective relay responds to real world events with reduced risk and cost. The downfall is,

- significantly more time is needed to cover different fault scenarios from the real world events
- pilot testing can be done when we have a dependable and secure primary and backup relays protecting the equipment to monitor the performance of pilot relay. In the case of IBR's, the response of primary and backup relays are questionable due to the lack of deterministic fault signature, which leaves us the option to rely on simulated information.

Modeling plays a significant role in these scenarios not only in replicating the fault scenario close to the real world, but also provides means to mimic the real world behavior for different fault and system scenarios within a short span of time, in a cost effective way and with no or minimum risk. Electromagnetic transient simulation packages provides sophisticated models which have evolved over decades and are mature to mimic the disturbance. These models are validated by comparing the outputs of the simulated models with a real fault waveform.

In the case of renewable energy sources, the availability of analytical model to mimic the stochastic nature of the renewable source pattern helps to analyze interaction between renewable energy source and the grid. However modeling IBR's power electronic interface poses a significant challenge due to the properiatry nature of IBR controller design and lack of availability of validated models. Although many literature's have tried to model the IBR controller behavior to evaluate the performance of the distance relays, considering the operating modes as discussed in the previous section, the reliability of the current values obtained from the simulation models is questionable due to the factors discussed above.

In this paper, COMTRADES obtained from the simulation model [9] which incorporates 'real-controller' as a black box model in electromagnetic transient program were used. Fig. 8 shows the single line diagram of the power system model considered for evaluating the performance of the distance relay.

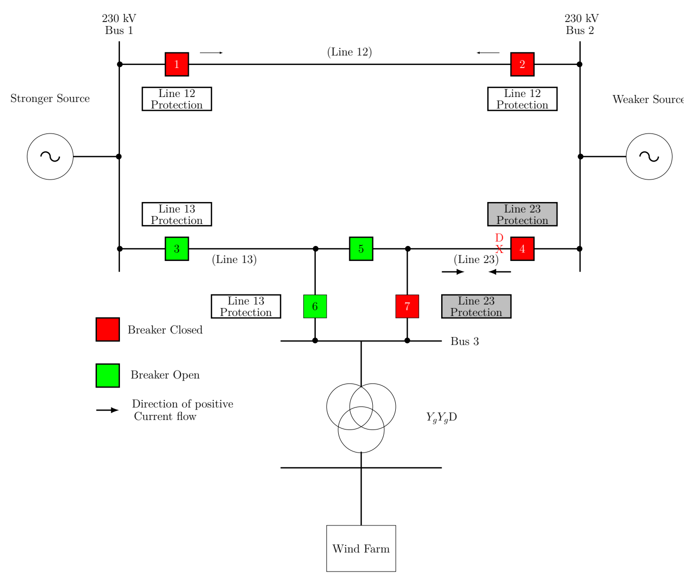


Fig. 8: Power System Model

The system consists of conventional bulk power system as well as renewable energy based power generation. The stronger source which is connected to Bus 1 is connected to weaker source at Bus 2 via transmission line 12. Additionally, it is also connected via transmission lines 13 and 23, which has infeed from the IBR at the point of interconnection, so that generation mix as well as contribution from IBR alone can be investigated. To simulate the response of the later case, circuit breakers 3, 5 and 6 are kept open so that Bus 1 and Bus 2 is connected via line 12 and IBR is connected to Bus 2 via transmission line 23.

The power electronic interface of IBR consists of 'real-controller' models i.e. actual firmware from four different original equipment manufacturers (OEM) as a black box,

- OEM 1: Type 4 wind
- OEM 2: Type 4 wind
- OEM 3: Type 3 wind
- OEM 4: PV Solar

This is then connected to the delta-star step-up transformer which is then connected to the collector bus. The ouput of the collector bus is then connected to the 3- winding step-up transformer which is connected to Bus 3 forming point of interconnection to the grid.

Transmission line 23 is the line of interest, where different fault types as shown in Table 3 are considered at fault location D with each OEM's and the performance of relay controlling breaker 7 is analyzed.

TABLE 3: Fault types at fault location D

Case	Fault Type	OEM
1	AG	1
2		2
3		3
4		4
5	ABG	1
6		2
7		3
8		4
9	ABCG	1
10		2
11		3
12		4
13	AB	1
14		2
15		3
16		4

These COMTRADES are then played to the relay to analyze the performance of distance relay and to test solutions which are discussed in the following sections.

V. Quadrilateral Characteristic

Quadrilateral or polygon characteristic is achieved by combining the output information (using AND gate) from four comparators: top reactance line, bottom directional line, right and left blinders. The top reactance line is obtained by using current as polarizing information. Use of the loop current as polarizing quantity results in static line which may result in over-reaching and under-reaching issues when we have single phase to ground fault with fault resistance R_f in the presence of remote end in-feed $I_R\angle\delta_R$

The presence of fault resistance with remote-end in-feed introduces additional error term causing the zone to overreach or under-reach based on whether the local end is exporting ($\delta_L > \delta_R$) or importing ($\delta_L < \delta_R$) as shown in Fig. 9. The effect is more significant as the fault moves towards the remote end due to increasing $|\frac{I_R}{I_L}|$ ratio, where $I_L\angle\delta_L$ is the local current.

This error can be handled if the top reatance line is tilted by the angle ϕ :

$$\phi = arg\left\{\frac{I_f}{I_A(1+k)}\right\} \tag{3}$$

where,

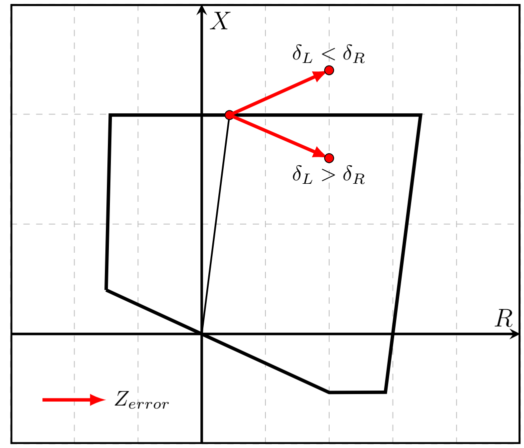


Fig. 9: Quadrilateral Characteristics

- I_f is the fault current ($I_L\angle\delta_L + I_R\angle\delta_R$) which flows through the fault resistance R_f,
- k residual compensation factor ($\frac{Z_{L0}-Z_{L1}}{3Z_{L1}}$)
- Z_{L1} + Seq. line information
- Z_{L0} zero Seq. line information

However, estimation of ϕ needs remote in-feed information and the local relay does not have access to fault current ($I_L\angle\delta_L + I_R\angle\delta_R$) at the fault point. This leads us to the following options,

- Option 1: Replacing I_f with local faulted phase current I_{ph} assuming the $\angle I_{ph} \approx \angle I_f$, but this may result in underreaching and over-reaching issues
- Option 2: Replacing I_f with local zero sequence quantity I_{0L} assuming the $\angle I_{0L} \approx \angle I_f$
- Option 3: Replacing I_f with local negative sequence quantity I_{2L} assuming the $\angle I_{2L} \approx \angle I_f$

Option 2 and Option 3 adapts the reactance line tilting by using zero sequence and negative sequence as polarizing information.

In the presence of IBR, the use of negative sequence polarization is not recommended, specifically when IBR is operated in negative sequence suppression mode. Although the recent German grid code and the draft IEEE P2800 mandate a certain amount of negative sequence injection, the angle of I_2 injection may vary with respect to V_2, as a result zero sequence current information shall be used to polarize the top reactance line provided zero sequence information is reliable. This is obtained using the following checks on I_0 magnitude and angle,

- $|I_0|$ >0.1 pu
- $|\angle I_0 - \angle I_{ph}|$ <50°

However, when zero-sequence information is not reliable, quadrilateral characteristic can be automatically switched to MHO characteristic for reliable operation. Fig. 10 shows a real world case where the zero-sequence quantity is not a reliable candidate for polarizing top reactance line, as the angle between I_0 and phase current is expected to be ideally in-phase and it has violated the angle check.

For a conventional generation, for such scenario, polarization will be automatically switched to negative sequence

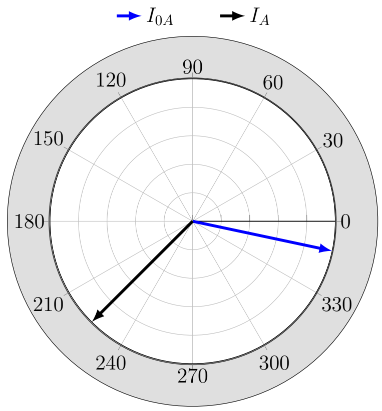


Fig. 10: Real world case - AG fault

provided negative sequence quantity is reliable. After switching, if negative sequence is not reliable quad characteristics will be automatically switching to MHO, instead of further switching to phase current as polarizing quantity with fixed tilt. This is due to the fact that the inherent tilting of MHO during power export or import as shown in Fig. 11 is expected to provide reliable operation when quad characteristics is no longer reliable.

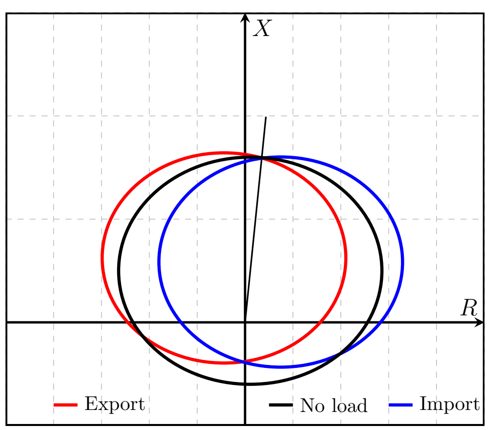


Fig. 11: MHO tilting during power export or import

Adaptive QUAD top reactance line polarization can be achieved as follows,

- Conventional generation
  - best polarization based on system conditions is selected (I_0 or I_2). If both are not reliable then Controlled or Uncontrolled MHO is used. The concept of controlled MHO is introduced in the next section.
- Renewable generation
  - Quad is automatically switched to controlled or uncontrolled dynamic MHO when zero sequence current polarization is no longer reliable.

A. Real World Cases

1) Ground Quad mis-operation with negative sequence sequence polarization in Conventional System: A disturbance in the system resulted in distance ground element mis-operation in phase C. Fig. 12 shows the relay operation where the relay was set to polarize the ground element top reactance line with negative sequence current. Apparent impedance in phase C appears far away from zone 1 reach with all the other QUAD comparators getting satisfied, i.e. right, left and the directional comparators.

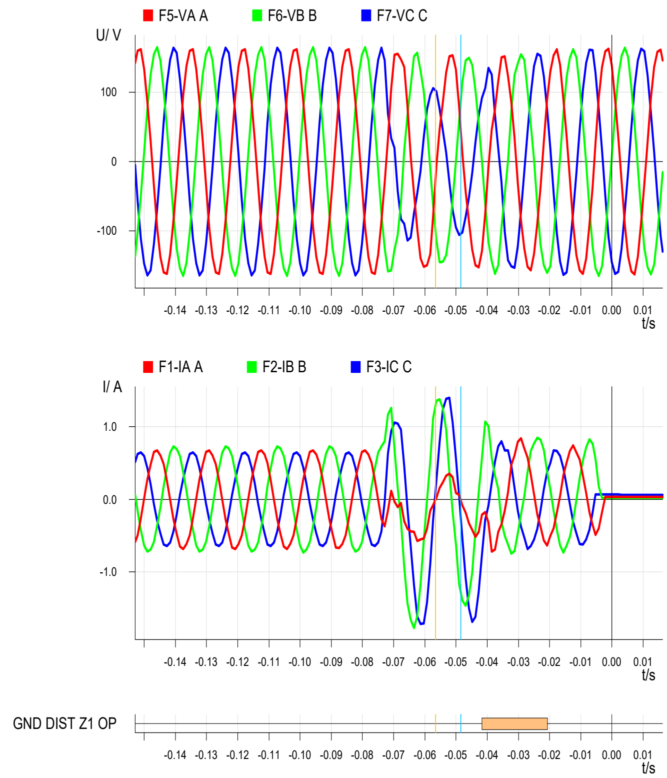


Fig. 12: Ground element mis-operation in phase C with negative sequence reactance line polarization

Observing the sequence information at the time of mis-operation (Fig. 13), reveals that negative sequence current was no longer reliable and zero sequence quantity was more reliable at the time of mis-operation.

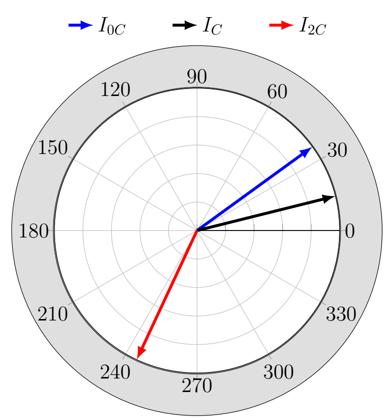


Fig. 13: Real world case - with negative sequence polarization

One of the option is to change the top reactance line polarizing setting to zero-sequence, but it may not be suitable for some other system conditions. The adaptive top reactance line discussed earlier, chooses the best polarization at a particular instant of the time based on the prevailing system conditions.

Fig. 14 shows the performance of relay with adaptive top reactance line, where the disturbance resulted in adaptive top reactance line shifting the polarization from negative sequence to zero-sequence current, as negative sequence is not reliable polarizing quantity and zero-sequence checks are satisfied. This resulted in polarizing the top reactance line with zero-sequence current thereby providing stable and secured operation.

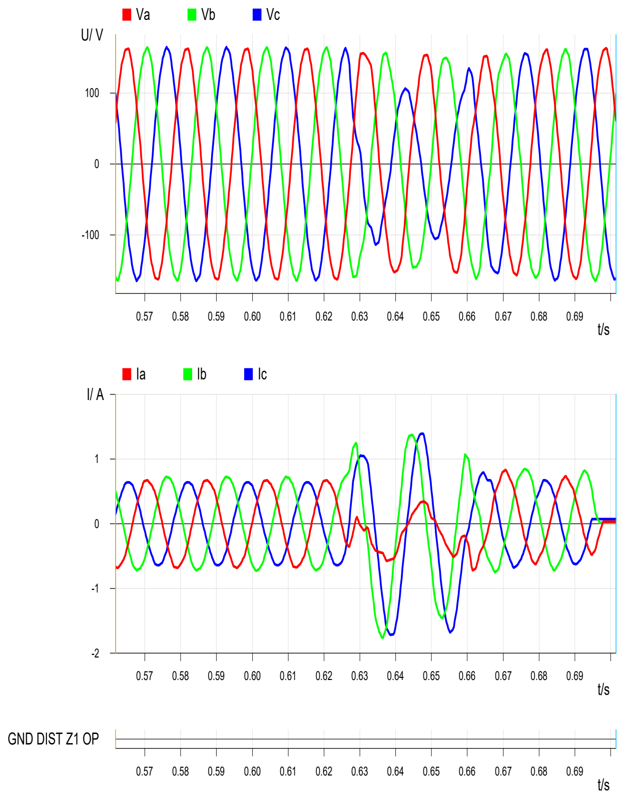


Fig. 14: Ground element performance with adaptive top reactance line polarization

2) Ground Quad mis-operation with both negative and zero sequence polarization in Conventional System: A high-resistance single phase B to ground fault in reverse direction resulted in transient pickup of the forward looking phase A ground element when the breaker behind the relay started opening to isolate the fault. In this case the forward looking relay was polarized with negative sequence current. Fig. 15 shows the forward looking phase A ground element mis-operation. The apparent impedance in this case was also very far from the zone reach with all other QUAD comparators satisfied, i.e. left blinder, right blinder and directional line.

Like the earlier case, one can expect the adaptive top reactance line to shift to zero-sequence current to ensure security, but this is not true, as switching to zero-sequence, first zero-sequence checks on magnitude and angle needs to be satisfied.

Sequence information shows, that both negative sequence and zero-sequence checks fail i.e.quantities are not reliable to

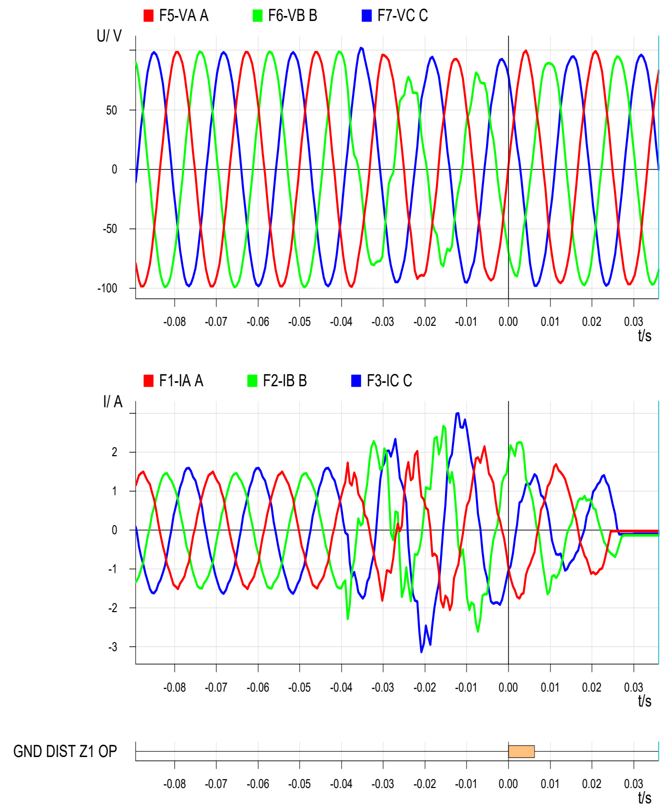


Fig. 15: Ground element mis-operation in phase A with negative sequence polarization

polarize the top reactance line. As the setting was negative-sequence, the excessive tilting resulted in top reactance comparator to get satisfied transiently causing the mis-operation. In this case, even when the relay was set to polarize with zero-sequence current, it is expected to mis-operate.

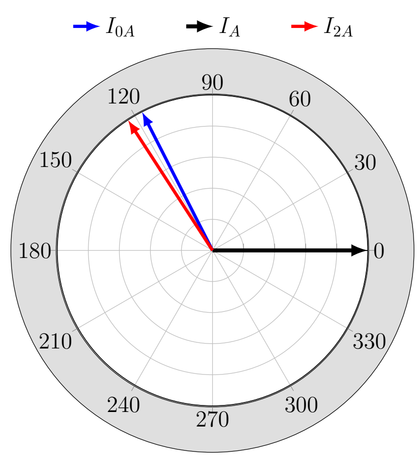


Fig. 16: Real world case - with negative sequence polarization

As both the sequence currents are not reliable, the adaptive top reactance line shifts to MHO to ensure security. Fig. 17 shows the relay events with adaptive top reactance line, where the ground distance has changed the characteristics internally from Quad to MHO dynamically to ensure security.

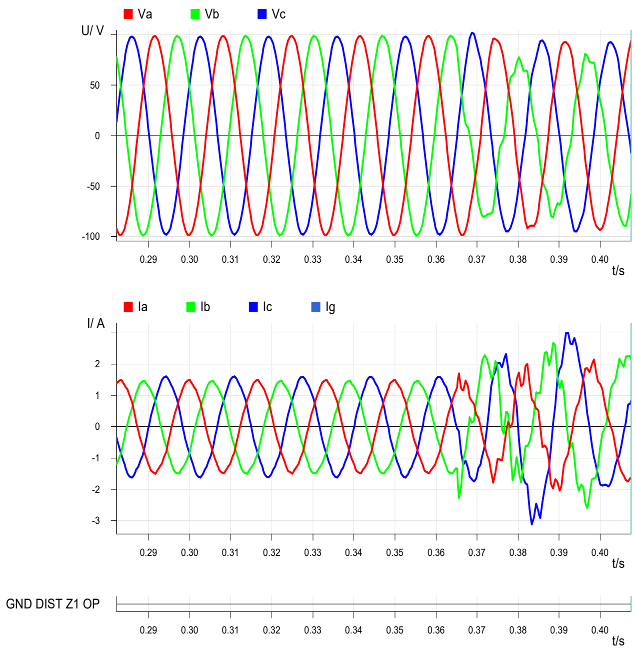


Fig. 17: Ground element performance with adaptive top reactance line polarization

VI. MHO CHARACTERISTICS

Unlike Quad which relies on multiple comparators to make a decision, MHO uses a single comparator, which compares S_1 and S_2 to make a decision. This comparator can be either voltage based where the current information is transformed into voltage using replica impedance or current based comparator where voltage information is mapped to current. Equation 4 and 5 provides information about voltage based comparator, where the input quantities are carefully chosen to achieve MHO characteristic,

$$S_1 = IZ - V \tag{4}$$
$$S_2 = V_{pol.} \tag{5}$$

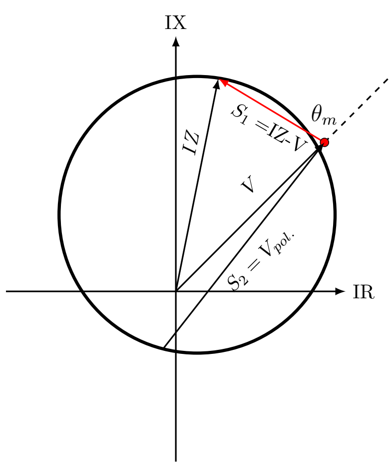


Fig. 18: MHO Characteristics - polarized with voltage other than self-polarized

where V_{pol} is the polarizing voltage which plays an important role in shaping the characteristic.

The phase comparator uses the S_1 and S_2 information to estimate the angle θ_m between the two quantities to make a decision, i.e. when θ_m is less than 90 degree, respective element is asserted. This century old MHO polarization approach was initially based on the faulted phase voltage (V_F), which provides static characteristics, this later evolved to use the following as polarizing inputs to achieve dynamic characteristics,

- cross-polarization (V_C) or
- positive sequence polarization (V_1) or
- memorized phase voltage (V_{FM})
- memorized cross voltage (V_{CM})
- memorized positive sequence voltage (V_{1M})

This dynamic characteristics shown in Fig. 18 provides better resistive reach especially for faults close to the local end and the dynamic behavior depends upon the chosen polarizing information. Although, many options, as listed above were available, polarization based on memorized voltage was quite popular, due to the fact that it provides reliable polarizing information in case of three phase close-in fault. Electro-mechanical designs were having limitations in utilizing the memorized voltage, as it decays with time, resulting in new characteristics as time evolves. This is shown in Fig. 19 where the characteristics slowly shrinks as time evolves for forward fault making it difficult to detect close-in high resistance faults.

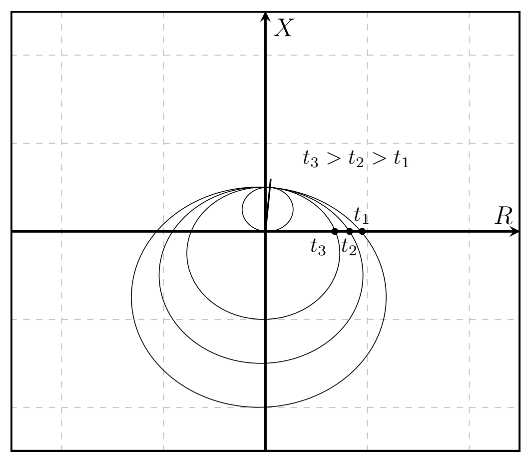


Fig. 19: MHO Characteristics - polarization with decaying memory

With the evolution of technology i.e. the introduction of digital relays, it broke the barrier where the memorized voltage is held for a selected duration resulting in a characteristics which does not change as time evolves. Additionally it also provides the flexibility to mimic the electro-mechanical relay behavior in digital relays.

With a phase, cross and positive sequence voltage as a choice for the memorized voltage, memorized positive sequence voltage polarization is a preferred choice, as it can provide maximum resistive reach coverage. However, this becomes an issue for weak systems (like IBR), where the expansion can be huge.

1) Real world wind farm case:
Fig. 20 shows a real world wind farm case where zone 1 overreached and caused mis-operation. Fig. 21 shows the estimated expansion vector for the forward fault. It can be observed that the angle constantly drifts as time evolves. The estimated angle (Fig. 21(b)) was in the third quadrant at time t_1 and it moved to fourth quadrant at t_2 causing the MHO to slowly drift from third to fourth quadrant.

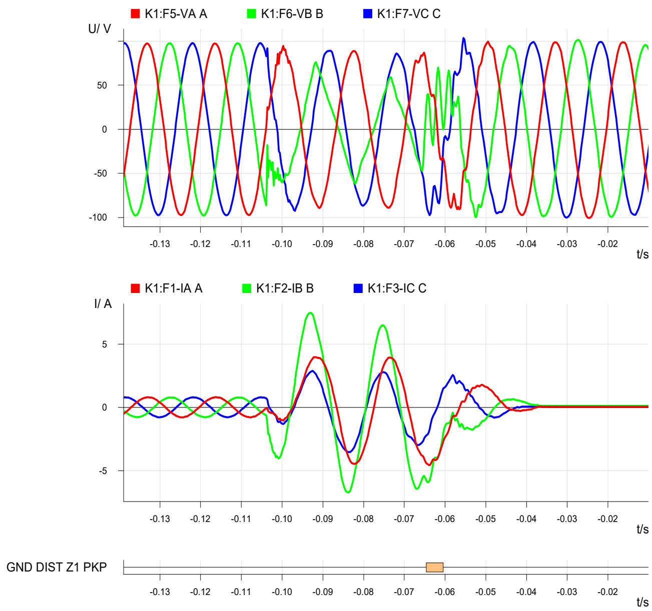
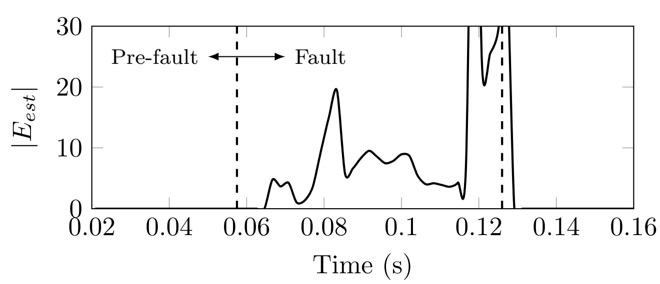
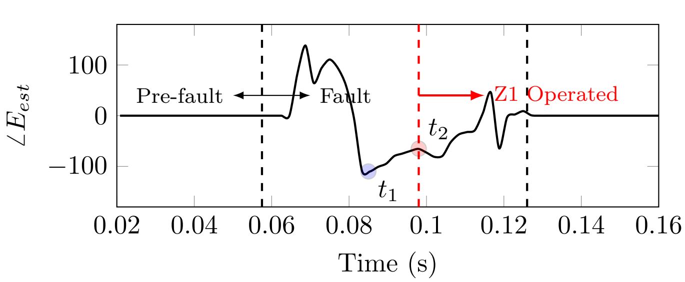


Fig. 20: Zone 1 Ground element overreach



(a) Magnitude



(b) Angle

Fig. 21: Estimated expansion vector E_{est}

The MHO drift is shown in Fig. 22, where during the time t_1 the huge expansion was occurring in the third quadrant and the comparator was not satisfied, which explains why the zone 1 initially did not operate. At the time of zone 1 operation i.e. at t_2 MHO drifted to fourth quadrant causing mis-operation.

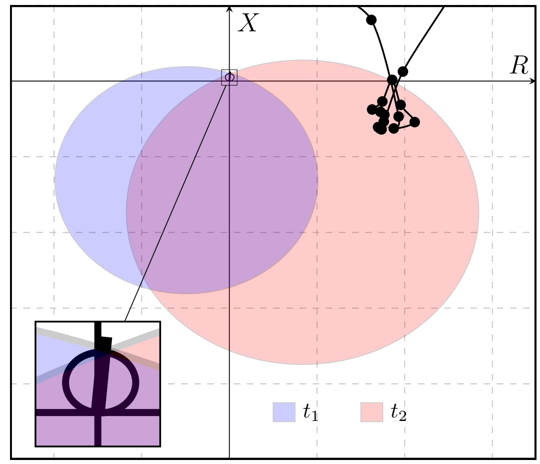


Fig. 22: Uncontrolled MHO causing ground Z_1 to misoperate

2) Simulation case with a 'Real Controller':
An interesting case, where for a remote-end forward phase to phase fault at location D in Fig. 8, the zone 3 in relay at breaker 7 which was configured as reverse looking, picked up for this fault.

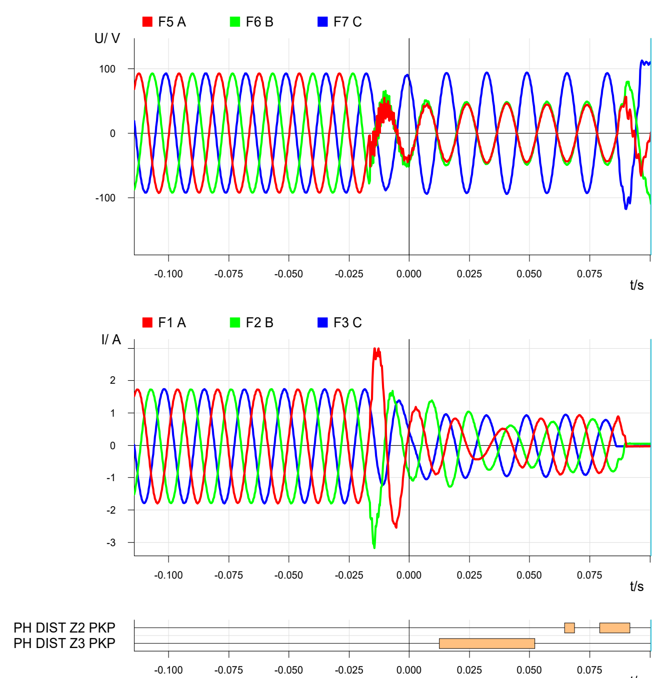
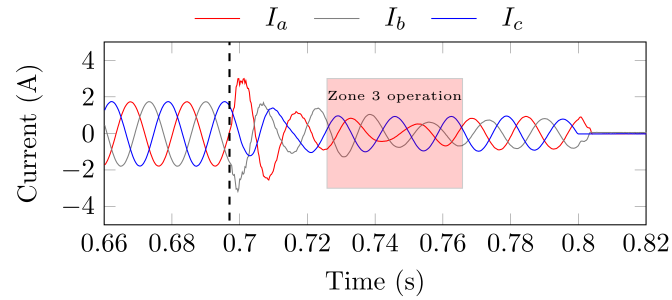
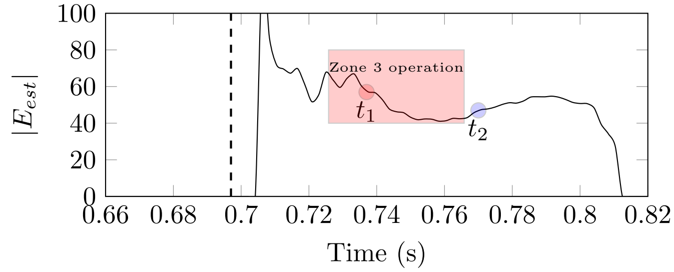


Fig. 23: Reverse phase zone mis-operation for remote-end forward fault

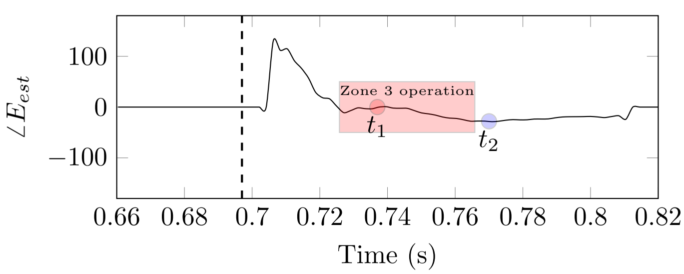
This is a serious concern and it can only happen when both the characteristics and directional comparators agree that it is forward fault. The reason why directional gave wrong decision and how to overcome it, is discussed separately in directionality section. In this section, we will concentrate only on the characteristic and the reason why wrong decision was declared as the reverse zone MHO which is dynamic is expected to secure the operation. Fig. 24 shows the current and E_{est} for the considered fault type and the region where Zone 3 mis-operated. Two points are considered, one inside the zone 3 operated area t_1 and another outside the zone 3 operated area t_2.



(a) Current



(b) —E_{est}—



(c) $\angle E_{est} Angle$

Fig. 24: E_{est} for phase to phase fault

At t_1, it is clear that MHO characteristic sensed this forward fault as reverse, and to understand the reason behind such operation, E_{est} information was used to plot the dynamic MHO behavior. Fig. 25 helps to visualize the reason behind such operation. It can be observed that, at t_1, the reverse zone 3 drifted significantly and moved into the first quadrant, which makes the comparator to see the forward fault in reverse direction.

At t_2, where zone 3 has dropped off, it can be because of either characteristics or directional element or over-current supervision not having a common decision to declare the fault. Looking into the current signals, the possibility of over-current supervision is ruled out and it can be because of either the characteristics or directional element. Again the use of E_{est} provides us with useful information to visualize the behavior of MHO at that instant of time and we can observe from Fig. 25 that the MHO drifted back towards third quadrant making the decision to drop-off, which co-relates with the actual relay behavior.

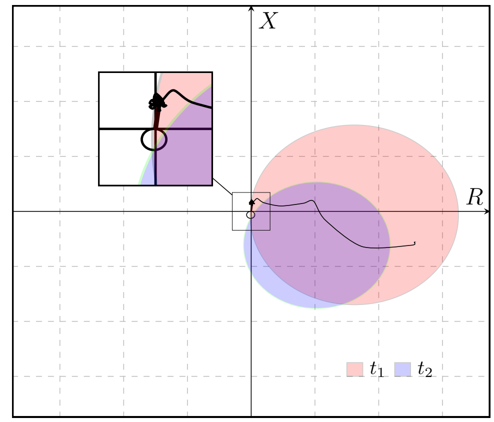
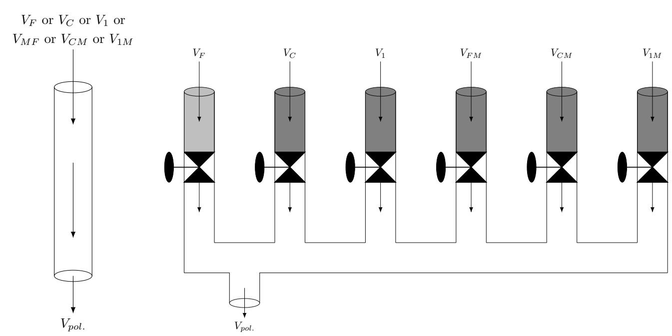


Fig. 25: Uncontrolled MHO causing reverse phase Z_3 to misoperate

The considered cases shows that in the presence of IBR's MHO behavior is uncontrolled and it can move to any quadrant, which typically does not happen in conventional generation except where the characteristics flips out when source to line reach impedance ratio (SIR) is very high.

3) Controlled Dynamic MHO (Patent Pending): The uncontrolled dynamic behavior which is observed in the previous sub-section was mainly due to the selection of polarizing voltage used in equation 5, which was used to overcome the limitations of static characteristics. The polarizing voltage plays a crucial role in shaping the dynamic MHO characteristic. This polarizing quantity can be either single or dual. With single polarization, only one information is used at any instant of time, for e.g. we may switch from V_{1M} to V_1 depending upon the system conditions as shown in Fig. 26(a). and with dual polarization any two information is mixed to form a polarizing information as shown in Fig. 26(b).



(a) Single (b) Dual

Fig. 26: Single and dual polarization

The concept of dual polarization was first introduced by [10] where different signals can be mixed to create a polarizing signal, for e.g. the valve corresponding to V_F can be opened fully and the valve corresponding to V_1 can be opened partially. This brings in the flexibility of controlling the MHO manually by properly selecting and scaling the inputs to the dual polarization scheme. However, the manual control of the valves which corresponds to the scaling factor provides only fixed control and the resulting dynamic characteristic cannot handle the issues due to drifting MHO which is observed in the presence of IBR's.

To overcome this limitation, the concept of controlled dynamic MHO was introduced using the dual polarizing scheme as shown in equation 6, where X and Y are the input voltage polarizing quantities. G and P are the scaling factors which corresponds to valve opening in Fig. 26(b), for e.g. G = 1 and P = 0.3 in equation 6 represents value corresponding to input X is fully opened and value corresponding to input Y is partially opened by 30%. Additionally, making one of the scaling factors to zero helps to switch from dual to single, thereby, bringing in the full flexibility in the polarization to control the dynamic MHO.

$$V_{pol.} = G \cdot X + P \cdot Y \tag{6}$$

For a given choice of dual mix, the G and P values are automatically estimated and used in equation 6 which is then applied to one of the comparator input (equation 5) to achieve control on the dynamic characteristic. In-order to estimate the G and P scalars, first E_{est} is calculated for the considered polarization. Equation 7 and 8 shows the E_{est}, which is estimated by the relay for ground and phase elements with positive sequence memory voltage polarization i.e. single polarization and this principle can be extended to any considered polarization.

$$E_{est,ground} = \frac{V_2 + V_0 - I_1 \cdot Z_{s1}}{I_{Loop}} \tag{7}$$

$$E_{est,phase} = -Z_{s1} \tag{8}$$

where, V_2 and V_0 are negative and zero sequence voltage respectively. I_1 is the postive sequence current, Z_{S1} is the positive sequence source impedance and I_{Loop} is the loop current. This information is then used along with the user defined deterministic characteristic as shown in Fig. 27 to estimate the values of G and P.

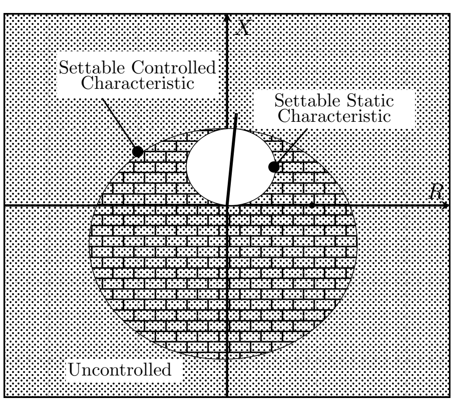
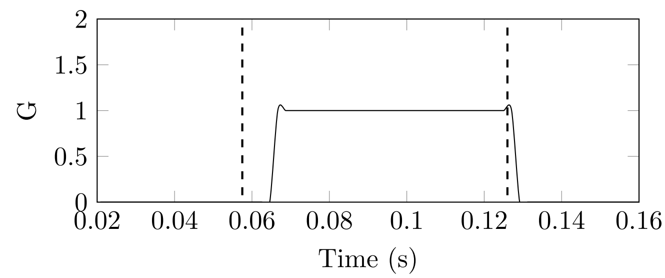


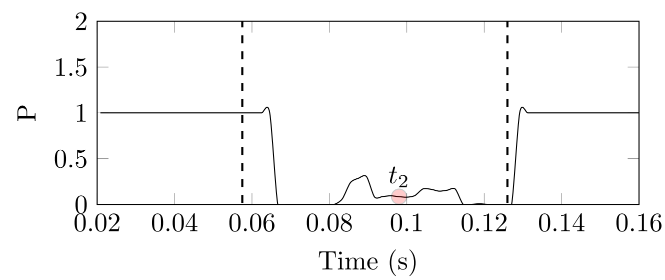
Fig. 27: Controlled Dynamic MHO

If the dynamic MHO characteristic is inside the user defined deterministic characteristic, the values of G and P are driven in such a fashion that the characteristics is not controlled i.e. single polarization based on V_{1M} is used so that it provides the best maximum expansion as possible. When the dynamic characteristics lies outside the defined deterministic characteristic, polarization is switched to dual and the P values are estimated such that the resultant characteristic based on the new dual polarized V_{pol} lies within the defined area at every instant of time.

Fig. 28(a) and Fig. 28(b) shows the estimated G and P with V_F acting as input X and V_{1M} acting as input Y for the discussed real world case Fig. 21.



(a) Estimated G



(b) Estimated P

Fig. 28: Estimated G and P for the real world case

As soon as the actual characteristics is deviating from the defined characteristic, polarization is switched to dual as indicated by G and controlled MHO tries to control the dynamic MHO with estimated P values. The corresponding controlled MHO plot at the time of mis-operation (t_2) is shown in Fig. 29.

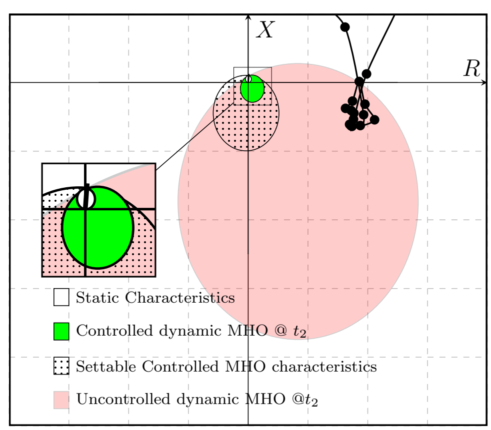
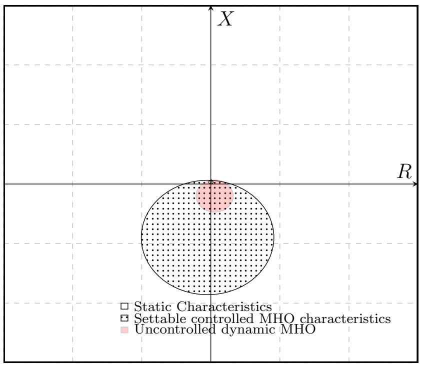


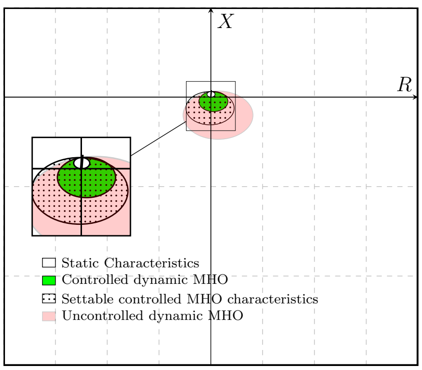
Fig. 29: Controlled Dynamic MHO at t_2

The controlled dynamic MHO tries to shrink and adjust based on the settable characteristics, thereby ensuring security.

This approach is not limited to renewable source, but also applicable to conventional generation. Revisiting the real-world case (Fig. 5), the behavior of controlled dynamic MHO is again based on the defined characteristic. Fig. 30(a) shows the behavior of controlled dynamic MHO allowing the MHO to expand in an uncontrollable fashion when the actual MHO lies within the settable characteristics.



(a) Uncontrolled MHO



(b) Controlled MHO

Fig. 30: Controlled dynamic MHO in the presence of conventional generation

However, when the settable characteristics is less than the actual expansion, controlled dynamic MHO tries to control the MHO behavior by pulling it back as shown in Fig. 30(b)

VII. Fault Type Supervision

Distance characteristic MHO or Quad, is inherently not secure and it needs many supervising elements to secure its operation. Fault type identification is one such supervision to supervise ground and phase distance elements and is responsible for the following important protection and control tasks, in addition to other tasks.

- Ensuring security - Blocking distance elements
  - Block ground distance elements for phase to phase to ground faults
  - Block phase distance elements for single phase to ground faults
- To identify the correct fault type and to assist single-pole auto-reclosing schemes to trip the correct pole

Different types of FTS exists [11] which are mature and have proven track record in the field for many decades. In this paper, symmetrical component based phase selector is used as a representative for current based FTS to analyze the impacts, as other current based variants e.g. delta current based phase selector, is expected to have similar behavior.

1) Ensuring Security - Blocking distance elements: The importance of securing ground distance during phase to phase or phase to phase to ground fault is explained anlaytically in detail [11]. In-order to block the ground distance element during phase to phase or phase to phase to ground fault and allow the ground distance elements only during single phase to ground fault, sequence plane is used to supervise the ground and phase distance elements. This plane uses negative sequence and zero sequence current information to make a decision as shown in Fig. 31, where the red region represents the security and the green region represents the dependability.

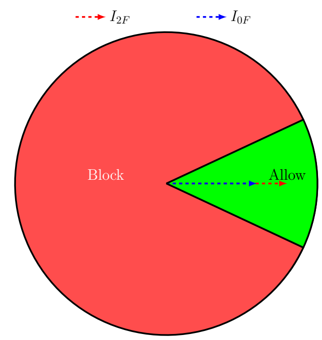


Fig. 31: Fault type supervision for phase to ground and phase to phase to ground faults

The ground distance elements are released when the angle difference between I_{2F} and I_{0F} is less than 50° (suppressed during open pole condition), i.e.,

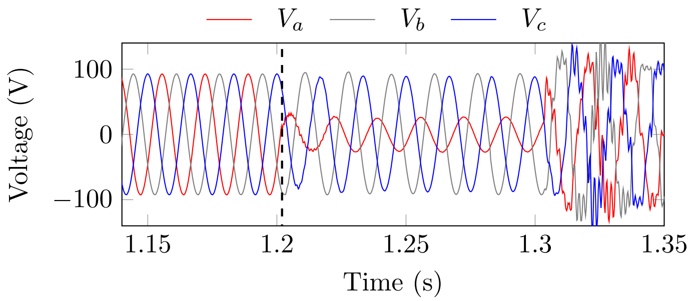
- AG element is released if, $|I_{0F} - I_{A2F}| < 50°$
- BG element is released if, $|I_{0F} - I_{B2F}| < 50°$
- CG element is released if, $|I_{0F} - I_{C2F}| < 50°$

Similarly, phase elements are released if, (in addition to other voltage related checks [12],

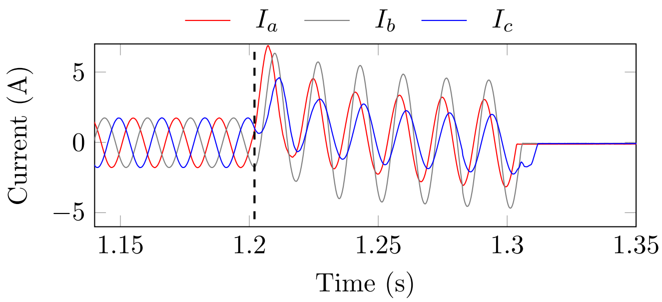
- AB element is released if, $|I_{0F} - (I_{A2F} + 120)| < 70°$
- BC element is released if, $|I_{0F} - (I_{B2F} + 240)| < 70°$
- CA element is released if, $|I_{0F} - I_{C2F}| < 70°$

In-order to analyze the impact due to IBR, Case 1 from Table 3 is considered. Fig. 32(a) and Fig. 32(b) show the voltages and current traces for single phase to ground fault AG. In the case of conventional synchronous generation, a quick scan of fault current traces would give us a immediate clue regarding the fault type and faulted phases, but in the case of IBR, it does not give us any information that it is a AG fault type, which is unusal.

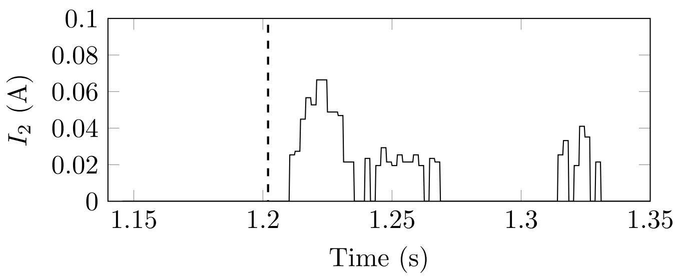
For an AG fault, it is well known from symmetrical component theory that $|I_1| = |I_2| = |I_0|$ for radial feeder and it depends on the respective sequence network current distribution factor when remote-end in-feed is considered. Fig. 32(c) shows the negative sequence current magnitude, where it can be observed that I_2 current is suppressed (forced to zero), i.e. this OEM controller is trying to operate in negative sequence suppression mode as discussed in Section



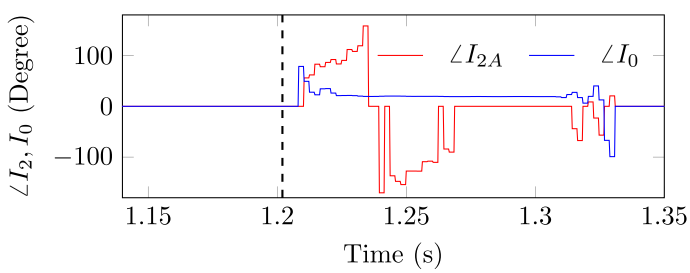
(a) Voltage signals



(b) Current signals



(c) Negative sequence magnitude



(d) Negative and zero sequence current angles

Fig. 32: Single phase to ground fault - AG

III. The angle information is forced to zero as the negative sequence information is suppressed. Additionally, Fig. 32(d) shows that the $\angle I_{A2}$ is not stable during the period where IBR is trying to act and control, however $\angle I_0$ is stable as expected as in negative sequence suppression mode, zero sequence information is not controlled by IBR.

Fig. 33 shows the performance of ground element supervision in the presence of IBR, where for fault $\angle I_{2A}$ moves in all quadrant during the AG fault, thereby blocking the ground distance element AG for AG fault leading to dependability issue. When we focus only on ground distance element operation, it gives us misleading information, i.e. delayed ground element operation, but actually, it is a false information ($\angle I_{2A} = 0$) which is releasing the ground elements.

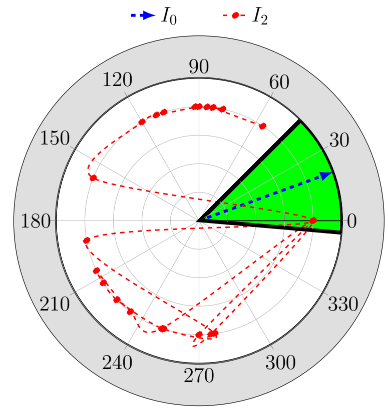
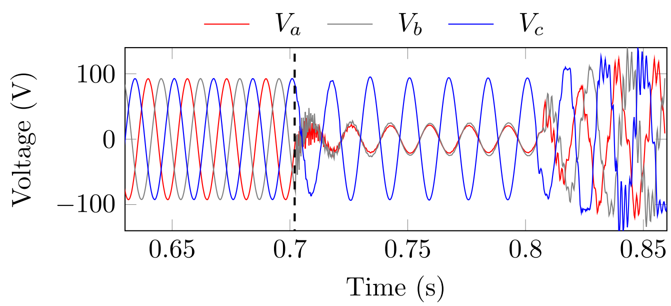
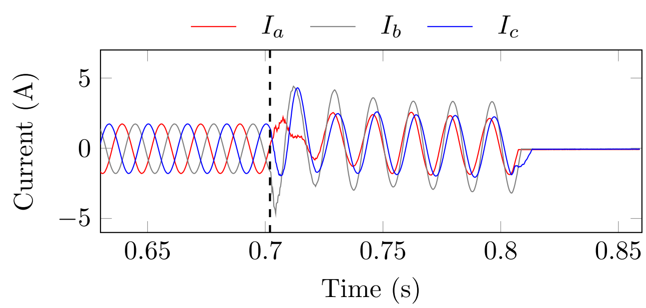


Fig. 33: Ground FTS - Current based for AG fault

Looking into the other dimension i.e. security, Case 5 from Table 3 is considered. Fig. 35 shows the performance during ABG fault whose voltage and current traces are shown in Fig. 34(a) and Fig. 34(b) respectively.



(a) Voltage signals



(b) Current signals

Fig. 34: Phase to phase to ground fault - ABG

For phase to phase to ground fault, the ground elements should be blocked i.e. $|I_{0F} - I_{2F}| > 50°$ and it should lie outside the green region, but from Fig. 35, it is observed that for a certain duration of time, it falls within the green region, thereby allowing the ground elements to operate for phase to phase to ground fault causing security issues.

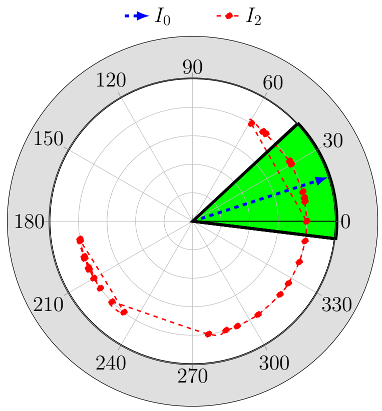


Fig. 35: Ground FTS - Current based for ABG fault

Upto this point, what we have seen is the performance related to ground elements. To understand the performance of phase element supervision, same Case 1 is considered as phase elements are expected to be blocked during AG fault i.e. FTS-AB and FTS-CA should not be asserted as AB and CA elements involves faulted phase. Fig. 36 shows the performance of phase element FTS and it can be observed that both AB and CA elements (light gray) are allowed to operate for a short period i.e. elements are not blocked resulting in security issues.

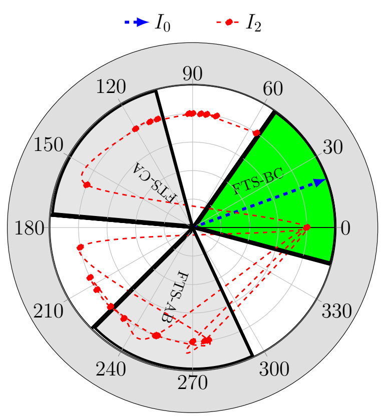


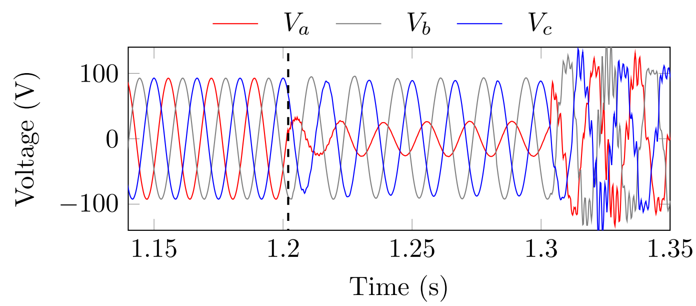
Fig. 36: Phase FTS - Current based for AG fault

From the above investigation, it indicates that ground FTS are prone to security and dependability issues and phase FTS are prone to security issues, as a result current based sequence plane decision is no longer a right candidate for lines fed by IBR's.

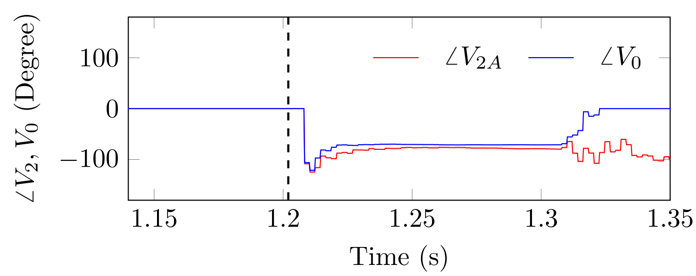
2) Solution to secure distance elements: Any sophisticated protection algorithm relies on two basic inputs analog voltages and currents. The possibility of having different fault current signature for the same fault type and system conditions e.g. different IBR owner can have different slope setting or different priority mode as discussed in Section III (still adhering to the standard) makes it difficult to come up with a new current based FTS to cover all possible fault signatures.

In order to overcome this, voltage based FTS is proposed as this is not new to distance relays where voltage based FTS will be used when current signals are not reliable [12]. Changes in slope setting (equation 1 and 2) and with certain priority modes may improve the voltage profile, but still the desired quantity is embedded in the voltage signal.

Fig. 37(b) shows voltage based sequence quantity for the same Case 1 AG, and it is observed that the quantity is stable in both zero sequence and negative sequence network. Fig. 38 shows the performance of voltage based ground FTS with both sequence information falling within the limit angle 50° there by ensuring dependable operation, i.e. releasing the ground element AG for single phase to ground fault.



(a) Voltage signals



(b) Negative and zero sequence voltage angles

Fig. 37: Single phase to ground fault - AG

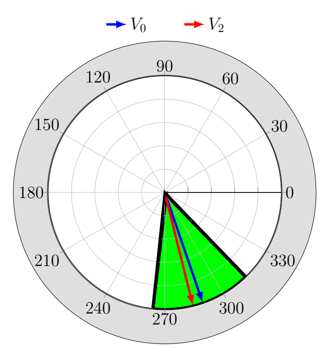
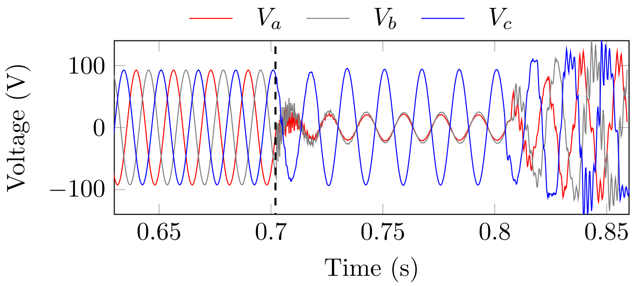


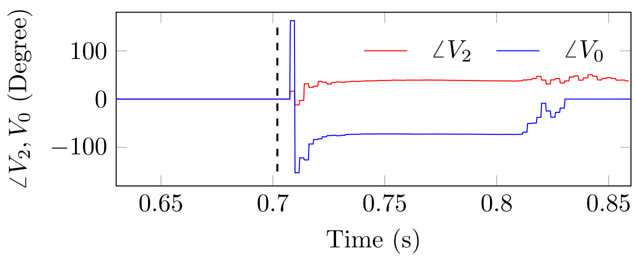
Fig. 38: Ground FTS - Voltage based for AG fault

Similarly, when we consider the security aspect, Case 5 phase to phase to ground fault (ABG) fault (Fig.39(a)) we need to ensure that ground elements are blocked. From Fig. 40 we observe that the limit angle is violated, thereby blocking the ground elements and ensuring security.

Finally, when we look into the voltage based phase FTS considering Case 1 AG fault, from Fig. 41 it is observed that both phase elements with faulted phase involved FTS-AB and



(a) Voltage signals



(b) Negative and zero sequence voltage angles

Fig. 39: Phase to phase to ground fault - ABG

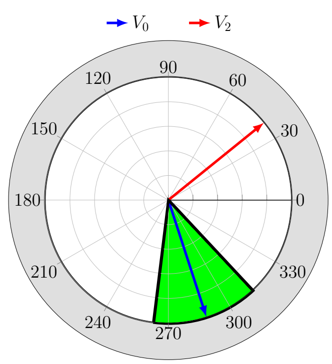


Fig. 40: Ground FTS - Voltage based for ABG fault

FTS-CA are blocked allowing only BC phase element which does not involve the faulted phase.

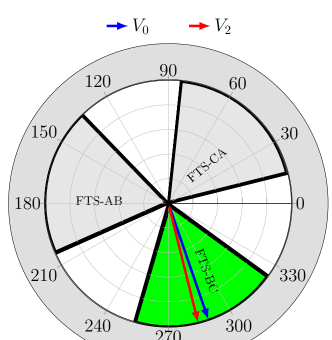


Fig. 41: Phase FTS- Voltage based for AG fault

A. FTS for Single-pole tripping

Single-pole operation demands highly reliable FTS, to eliminate incorrect fault identification that can be made by distance elements or to provide fault type information to elements that are not capable of identifying the fault type, e.g. high-set over-current element. Fault type is identified based on the agreement between two planes, Plane 1 - Positive sequence and Negative sequence (Fig. 42) and Plane 2 Zero sequence vs Neg.sequence (Fig. 43). The latter plane is the same plane which was discussed in the previous subsection.

Inputs to Plane 1 and Plane 2 are current and voltage sequence quantities [12]. When the current is not able to determine the fault type, it automatically switches to voltage based quantity for conventional synchronous based generation.

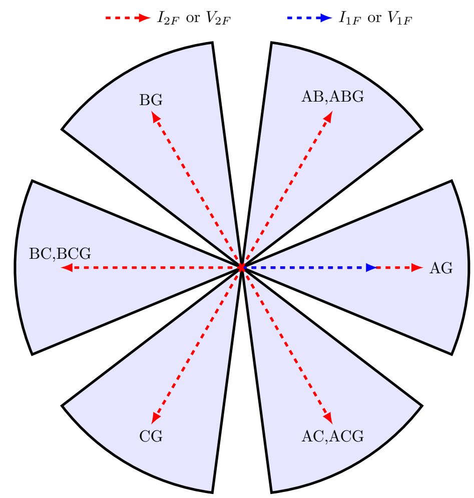


Fig. 42: Plane 1: Pos. sequence vs Neg. sequence

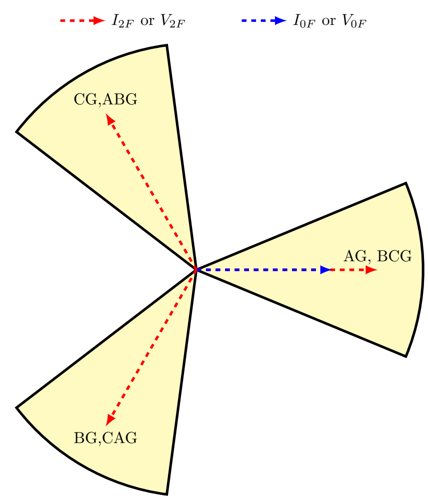


Fig. 43: Plane 2: Zero sequence vs Neg. sequence

In the above subsection we have already seen that current based Plane 2 is not able to provide reliable information and only voltage based Plane 2 provides correct and reliable decision, which means that FTS for single-pole tripping also cannot provide correct and reliable decision as it needs agreement from both planes i.e. to declare AG both planes should indicate AG as faulted phase. As a result, voltage based Plane 1 and Plane 2 is used.

Fig. 44 to Fig. 46 shows the correct identification of different fault types with voltage based FTS which is used for single-pole tripping.

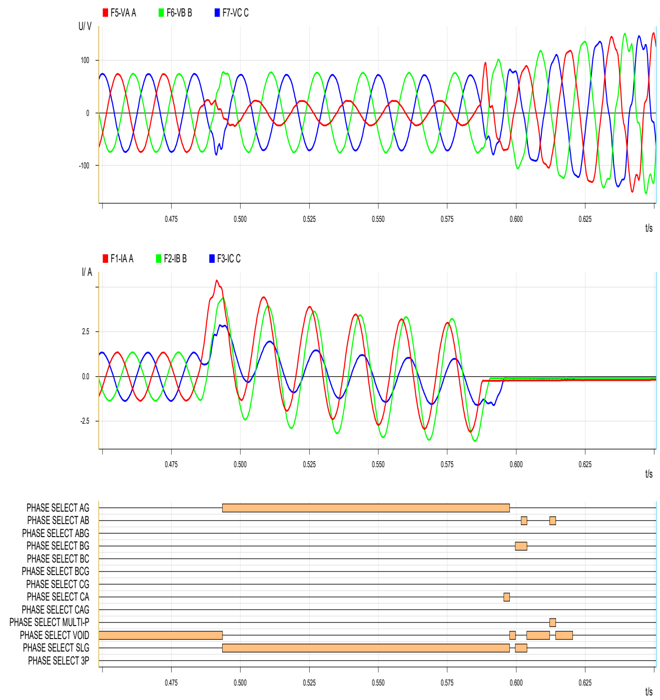


Fig. 44: Single phase to ground fault - AG

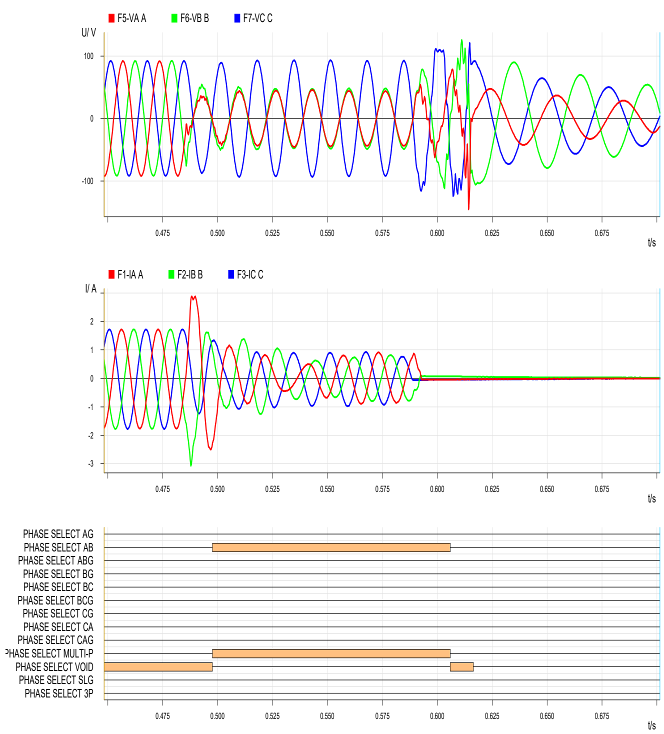


Fig. 45: Phase to Phase fault - AB

VIII. Directional Element

To ensure secure operation, distance characteristics is supervised by directional elements. In addition to supervision, these

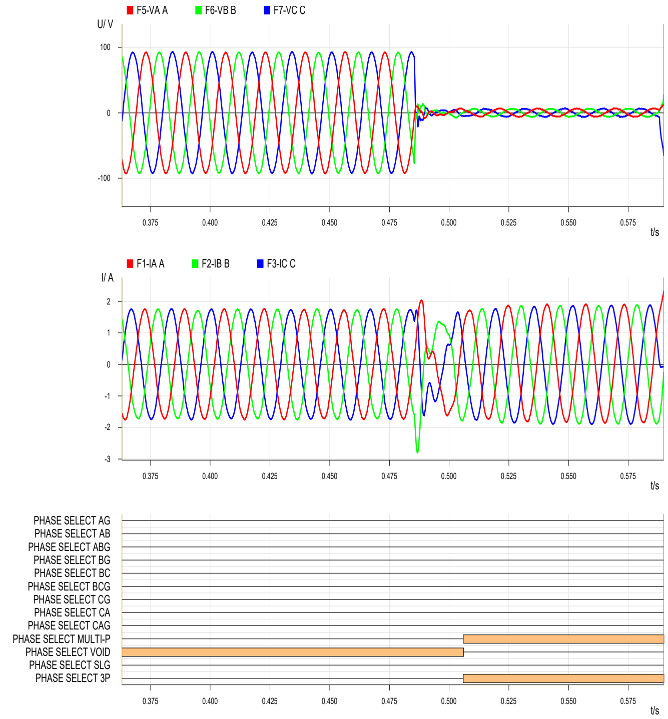


Fig. 46: Three phase fault

directional elements can be used to form a closed boundary for Quad characteristics.

MHO, although is inherently directional, losses it directionality on external phase to phase to ground fault, e.g. reverse phase to phase to ground fault may lead to the forward long reaching healthy phase ground element to mis-operate. As a result, directional element is always used to supervise the distance characteristic MHO or Quad decision by determining the fault direction.

Directional element is achieved by comparing the angle between polarizing quantity and operating quantity, where the polarizing quantity can be,

- sequence quantity (V_2, V_0, V_1, V_{1M}) or
- phase information (V, V_M, cross, cross-memory, $\triangle$V)

and the operating quantity can be,

- sequence quantity (I_2, I_0, I_1) or
- phase information (I, $\triangle$I)

1) Issues with negative sequence current as operating quantity:

To determine the fault direction, negative sequence current quantity is typically preferred for ground elements mainly because it is insensitive to zero-sequence mutual coupling. The use of zero-sequence quantity in-addition to negative-sequence quantity provides enhanced directional integrity for ground distance elements.

Fig. 47 shows the directional characteristics with I_2 and I_0 as operating quantity and positive sequence voltage memory V_{1M} as polarizing quantity. During forward fault, the considered operating quantity is expected to lag the polarizing quantity by the fault loop impedance angle. This fault loop impedance angle when used as a relay characteristic angle for directional element, helps to achieve maximum torque.

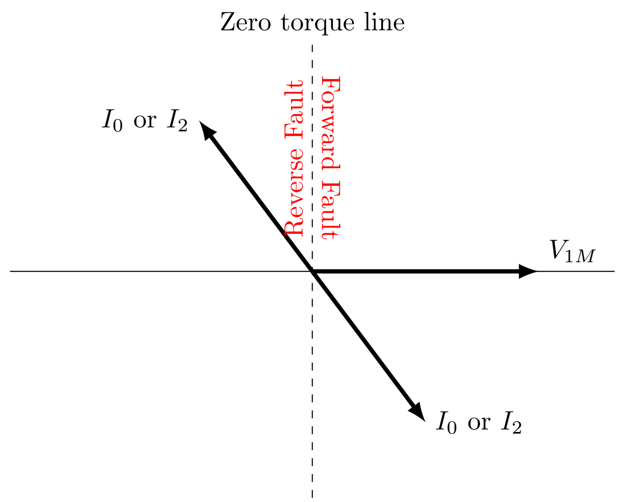


Fig. 47: Dual (I_2 and I_0) memory polarized directional element

However, in Section VII we have already observed that negative sequence current information may be suppressed by IBR depending upon the mode of operation and even if IBR injects negative sequence information, the information may not reliable. As a result for IBR based generation, only directional element based on zero sequence information is used to supervise the distance and negative sequence information is bypassed.

2) Issues in setting the phase directional element: The growing contribution from the renewable sources and the advancement in technology has resulted in mandating wind generators to provide reactive power support [13]. Fig. 48 shows the reactive power requirements by UK (blue), Spain (red), Denmark (black), to list a few.

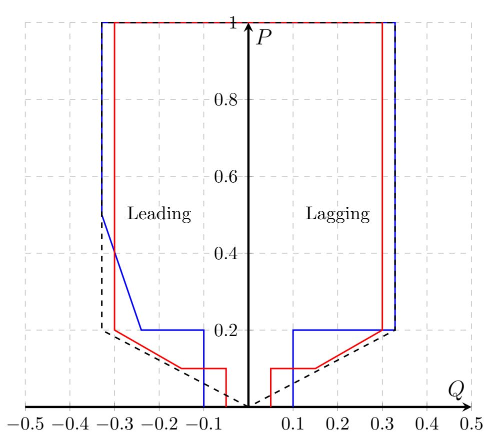
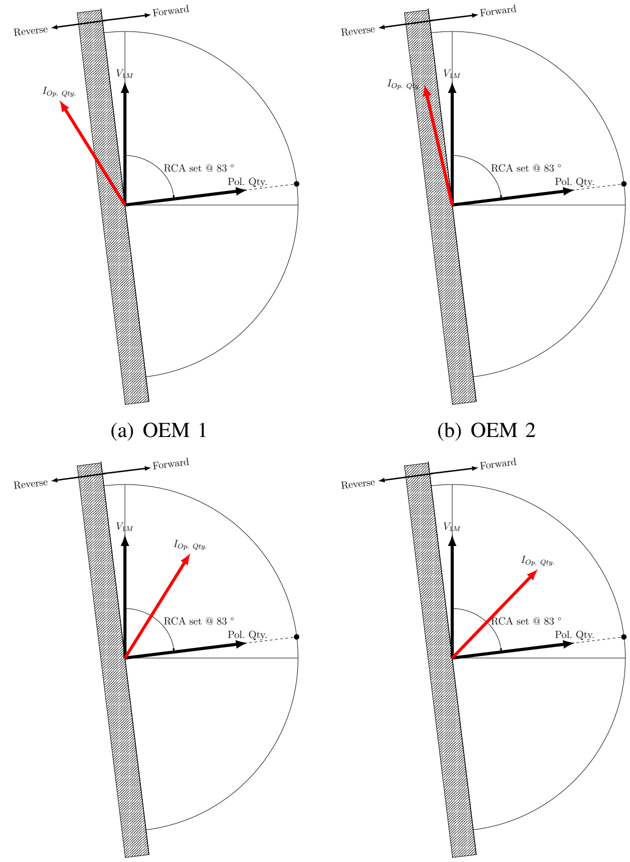


Fig. 48: Reactive power requirements (blue- UK, red-Spain, black-Denmark)

The different reactive power requirements mandated by grid codes and the flexibility of operating the IBR in different modes (Table 2) during the disturbance may result in leading fault currents. This may impact the directional element performance if it is not properly set to handle leading power factor. Fig. 49 shows the behavior of different OEM for the same fault type (i.e. phase to phase fault involving phases A and B) at location D in Fig. 8. In all the four cases, the phase directional was set to handle 7 degree leading to 173 degree lagging loads/fault currents. It can be observed from Fig. 49(a) and Fig. 49(b) where the reverse phase directional element declared the fault as reverse, whereas the actual fault was in forward direction.



(a) OEM 1 (b) OEM 2

(c) OEM 3 (d) OEM 4

Fig. 49: Reverse phase directional element performance for forward fault AB with different OEM (black - polarizing quantity, dashed red - operating quantity, red-operating quantity after directional RCA adjustment)

This is due to the fact that the fault current was leading around 32 degree and 13 degree in OEM 1 and OEM 2 respectively. The phase directional was set to handle only 7 degree leading fault/load currents. This resulted in reverse zone (Zone 3) getting picked up for a remote-end forward fault in the case of OEM 1 (Fig. 50) and OEM 2. Where as, in OEM 3 and OEM 4 the direction was properly declared leading to correct operation of the forward zones.

Unlike, electro-mechanical relays, where the maximum torque can be achieved by properly setting the directional relay characteristic angle, digital or numerical relays brings in the flexibility to achieve uniform torque over an area based on the implementation. As a result, the phase directional element was now set to handle 60 degree leading and 120 degree lagging fault or load currents. Fig. 51 shows the performance of phase

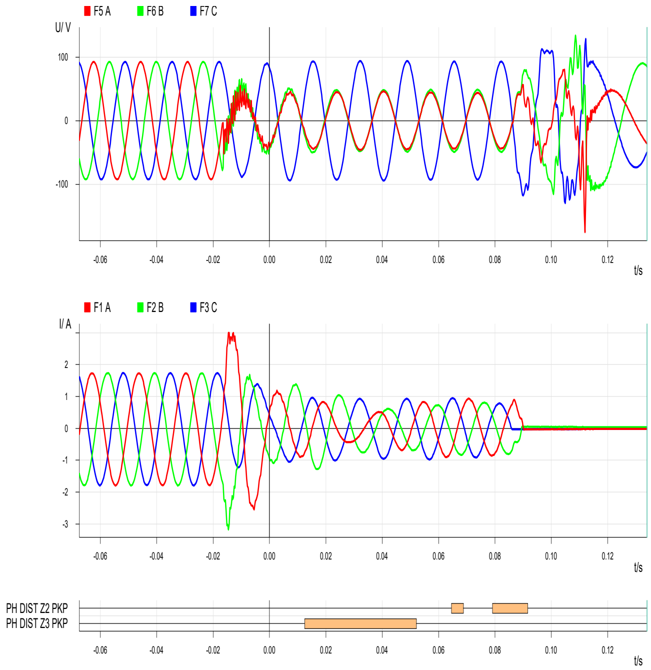


Fig. 50: Relay events for AB fault with OEM 1 - Directional element set to handle 7 degree leading power factor fault/load currents

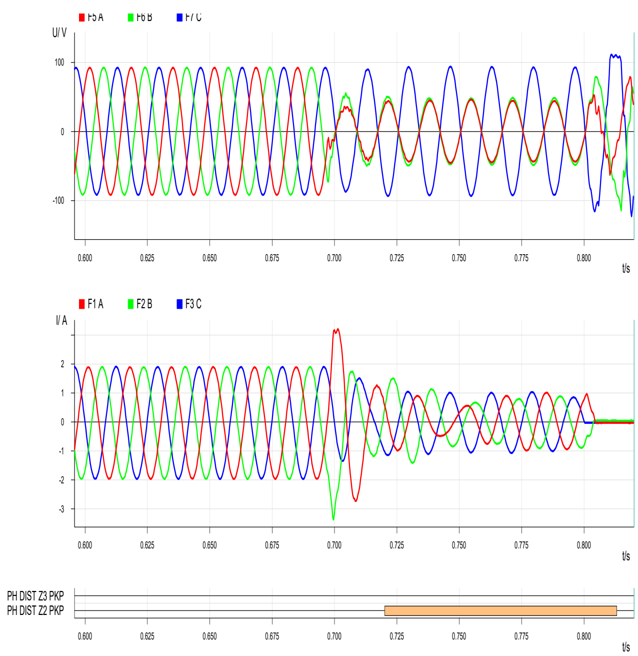
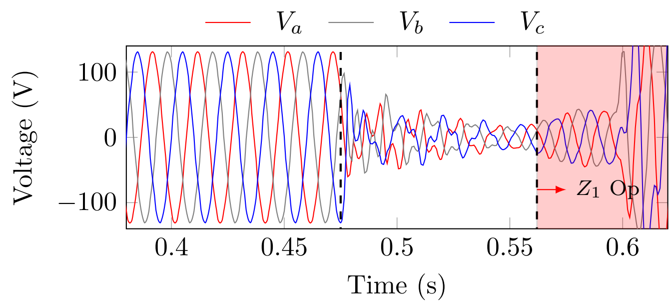


Fig. 51: Relay events for AB fault with OEM 1 - Directional element set to handle 60 degree leading power factor fault/load currents

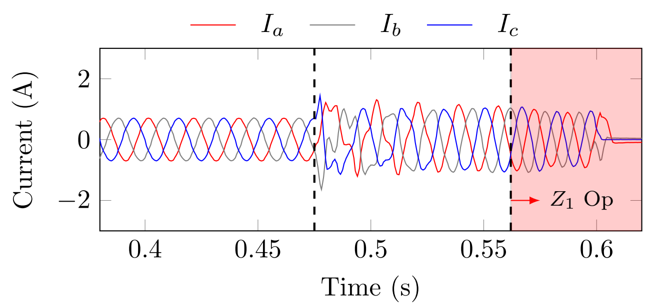
directional element when it is set to handle 60 degree leading fault or load currents. It can be observed that directional comparator makes correct decision and releases the forward looking zone i.e. zone 2.

IX. Frequency

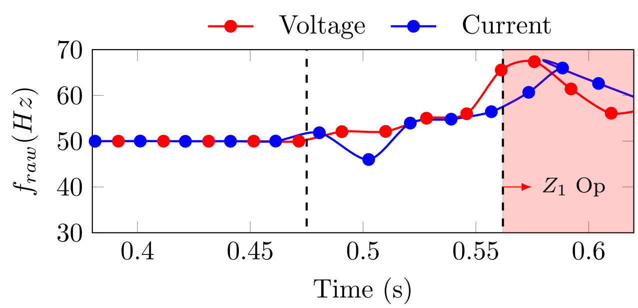
Frequency tracking plays a crucial role and impacts the decision of any protection element which is based on phasor information. The impact on phasor estimation due to off-nominal frequencies are minimized by either resampling or tuning the filter coefficients based on the tracked system frequency. In conventional generation i.e. synchronous machines, the inertia of the rotating shaft restricts abrupt change in frequency during any disturbance. However, in case of renewable generation, more specifically with grid forming IBR's which can decide the frequency, it may vary drastically.



(a) Voltage signals



(b) Current signals



(c) Raw frequency after pre-processing

Fig. 52: Zone 1 mis-operation due to frequency drift

Fig. 52(c) shows the real world case where the frequency was drifting fast in the presence of renewable based generation which resulted in zone 1 mis-operation. The important thing is where the voltage and current signals were having different frequency as shown in Fig. 52(c). Protective relays typically rely on either voltage or current signal to track the frequency and this information is used for either adjusting the sampling rate or tuning the filter coefficients of all the analog channels based on the tracked frequency. Any deviation from this results in phasor magnitude and angle oscillations and it is expected to cause mis-operation.

The problem of under-reaching zone 1 mis-operation can be mitigated by the following options:

- using controlled dynamic MHO which is biased towards security. It overcomes the issues due to frequency excursions for e.g. reverse zone pickup for the forward fault (Fig. 25 and Fig. 50)
- adaptively delaying the zone decision when frequency excursions are detected in either voltage or current or in-between voltage and current signals.

X. Conclusions

This paper has demonstrated the importance of re-looking at the distance protection for protecting lines fed by renewable generation. The major issue is due to the change and variations in fault current signature for faults fed by IBR's. This is mainly due to the flexibility and the choice of operating mode i.e. priority for which the IBR is programmed to operate. Additionally, controller design parameters also have an impact on fault current signature during the transition.

Impact of the above mentioned on the phase currents during fault is directly seen in the sequence components with negative sequence getting impacted more in a specific operating mode. Although standards and grid codes have recently mandated the negative sequence current injection, the quantity may not be reliable during the initial few cycles, especially with Type III wind turbines. This paper discussed how this impacts the fault type supervision and ground distance directional elements which rely on the negative sequence quantity to make a decision and solutions were provided to overcome this problem by using sequence voltage based information for fault type supervision and bypassing the negative sequence directional elements.

It is also not recommended to use negative sequence current to polarize the top reactance line for quad characteristics. In-order to overcome the limitations with zero sequence current polarization, this paper has discussed the advantage of using the quad with best polarization selection, which automatically selects the best polarization at a particular point in time, thereby retaining the adaptive tilting feature and automatically switching to MHO to ensure reliable operation when zero-sequence quantity is no longer reliable.

This paper also discussed the impact of IBR's on the century old MHO behavior and provides interesting insights into unexpected MHO behavior. The reason behind such behavior i.e. uncontrolled dynamic MHO was explained analytically and it introduced an innovative solution "Controlled Dynamic MHO" to overcome the uncontrolled dynamic MHO behavior.

XI. Acknowledgements

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