FAULT CURRENT CALCULATION IN SYSTEM WITH INVERTER-BASED DISTRIBUTED GENERATION WITH CONSIDERATION OF FAULT RIDE THROUGH REQUIREMENT

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Abstract

The challenge of fault current calculation in a system with inverter-based distributed generation is emphasized by the fault ride through requirement announced in recent grid codes. This paper proposes an algorithm to calculate fault current in such a system. The algorithm adapts the conventional fault calculation technique with the utilization of a power flow-based algorithm. The accuracy of the proposed algorithm is tested by a Matlab/Simulink simulation on a simple system.

Keywords: Fault calculation, Fault ride through requirement, Inverter-based distributed generation, Newton-Raphson, Power flow.

I. Introduction

There have been considerable efforts directed to the development of solution models and algorithm for synchronous, induction, and doubly-fed induction generators with great success and wide application [1]-[4]. However, comparatively fewer solutions have been developed for inverter-based distributed generation (IBDG) which is a package of a distributed generation (DG) and inverters or static power converters. In addition, most publications concerning IBDGs have not received high unanimity. Some authors proposed a model and an algorithm to capture the fault response of IBDG during the fault period but they did not concern the control system of the IBDG [5]. Such algorithm is not convenient to build a calculation tool for setting protective devices that needs the flexibility for many fault cases. The fault response in the time-variant curve fashion of an IBDG has a similar limitation [6]-[8]. Some authors derived IBDG models for fault calculation with deep insight views on the transfer functions of the control system [9]. Unfortunately, those models are suitable for an inverter-only microgrid instead of a grid with parallel operations of the IBDG and the utility source.

In addition, despite being required, according to standard the [10], to physically fast disconnect IBDGs from the grid in a fault event, fault current calculation in systems with IBDG is reasonable to calculate the fault current to catch up with the fault ride-through (FRT) requirements in some new grid codes [11]-[12]. These grid codes require an IBDG to have a capability of passing through a fault signed by voltage at the point of common coupling (PCC). As such, the IBDG continues to feed current during a fault instead of fast shutting down and isolating itself. Therefore, the growing need of both DG owners and distribution companies for more complete studies has motivated the development of solutions to calculate the fault current in the system with IBDGs with consideration of fault ride through requirement.
The objective of this paper is to propose an accurate fault current calculation method in a system with IBDGs, serving for DG impact evaluation and protective device settings of both utility and DG protection systems. The rest of this paper is organized as follows. Section II briefly introduces the fault ride through requirement for a grid connected distributed generation. Then, fault response of an IBDG is firstly analyzed in Section III in order to model this generator for a fault calculation method. Based on this model, Section IV proposes an adaptive algorithm to calculate the fault current in distribution networks with IBDGs with consideration of the fault ride through requirement. This algorithm is validated in Section V by using a time-variant simulation on a simple power system.

II. Fault Ride Through Requirement

Generating plants should make a contribution to network support in not only normal operation but also transient states as an upward tendency. To carry out that mission, generating plants must be connected in an event of network disturbances and contribute a dynamic support to the utility system if possible. The way of passing through the fault or other disturbances, which cause the voltage change at the point of common coupling (PCC), without being disconnected from the network, is called fault ride through capability.

Most grid codes are issued for transmission networks. Some of them, e.g. from Ireland [11] and Germany [12], have specific fault ride through (FRT) requirement for distribution networks to which DGs enveloped by this paper are connected. The FRT and the dynamic network support requirements are briefly summarized in this section aiming to bring the research closer to the industrial practice.

There is usually a distinction between synchronous machine-based DG (SBDG) and other DG types. For instance, German grid code clarifies DG into two type: type-1 and type-2 generating unit. A type-1 generating unit is an SBDG which is connected directly to the network. All others generating plants, e.g. wind turbines, PV systems, fuel cells, are type-2 generating units. General requirements of FRT capability in distribution networks are as the following technical terms.

- to remain connected to the network in the event of network faults.
- to feed a reactive current into the network to support the network voltage during a network fault.
- the reactive power absorbed from the medium-voltage network after the fault have to be less than the absorbed reactive power prior to the fault.

These terms are detailed as FRT curves for all generators and dynamic network support requirement for type-2 generator units.

2.1 Fault Ride Through Curves

The first term is detailed in the fashion of FRT curves, e.g., curves for type-2 generator units from Irish grid code in Figure 1. If voltage at the PCC drops to a value above the borderline, the DG must remain connected to the network. For instance, wind farm power station types B, C, D, and E must remain connected during the first 625 ms if even voltage drops at value of 15%. For the next duration from 625 ms to 1000 ms, if the voltage recovers linearly from 15% to 40%, the wind farm must not be disconnected from the network. After this duration, if the voltage drops at the value less than 80%, the wind farm can be disconnected.
2.2 Dynamic Network Support

The renewable-based generating plants with type-2 generating units are being required to play a role more actively in power systems to which they are connected. One of them is about network support in an event of a voltage drop of more than 10% of the effective value of the generator voltage so that not only remaining connection but also injecting reactive current is required. For instance, Irish and German grid codes require a renewable-based DG to provide reactive current at the low voltage side of the generator transformer with a contribution of at least 2% of the rated current per percent of the voltage drop. It can be assumed that the renewable-based DG supplies a reactive current \( I_G \) of 100% of the rated current \( I_{G,\text{rated}} \) as given by (1).

\[
I_G = I_{G,\text{rated}} \angle (\delta_{VG} - \pi/2)
\]

where \( \delta_{VG} \) is the angle of the generator terminal voltage. The maximization of reactive current shall continue for at least 600 ms or until the distribution system voltage recovers within the normal operational range of the distribution system.

III. Model of an IBDG during Fault

This section firstly analyzes the response of an IBDG during fault with consideration of fault ride through requirement. Based on this analysis, a convenient model of the IBDG is proposed for a fault calculation algorithm in the next section.

3.1. Response of an IBDG during Fault

A typical structure of an IBDG consists of a control system, whose inputs are voltages and currents at the inverter terminal and the PCC, a modulation generator, an inverter, and a filter circuit as shown in Figure 2 [13]-[16]. The primary energy is converted into electrical energy in the fashion of dc voltage directly by PV cells, storage batteries, or indirectly by a package of power generators and rectifiers. The inverter converts this dc voltage into an ac voltage at the appropriate frequency and magnitude, as specified by the power system. The inverter is controlled by signals from a Pulse-width Modulation (PWM) or a Space Vector Pulse-width Modulation (SVPWM) generator.

The IBDG in this paper is controlled by a selected control system as follows. Under normal condition, the power controller estimates the reference current to control at the IBDG...
terminal so that the power output is around the reference value $P_{ref} + jQ_{ref}$. After passing through the current limiter, this reference current is used in the current controller to estimate the reference signal for the PWM generator to control the firing angle of the thyristors inside the inverter. There are two cases that may occur:

- **Case 1**: The reference current after the power controller is under the limit of the current limiter ($I_{thres}$)
- **Case 2**: The reference current exceeds the limit $I_{thres}$.

$$\text{PWM ref}, \text{abc} \quad \text{P}_{\text{ref}} \quad \text{Q}_{\text{ref}} \quad \text{I}_{\text{inv}, \text{dq}} \quad \text{V}_{\text{p}, \text{dq}}$$

Figure 2. Control system with fault ride through capability of an IBDG

In Case 1, the current is controlled so that the output power is around $P_{ref} + jQ_{ref}$, whereas, the current must be limited in Case 2 in order to protect the power electronic devices from thermal damage. The limited current $I_{\text{inv,sat}}$ is designed to satisfy the network support requirement. This means, $I_{\text{inv,sat}}$ lags the voltage at the IBDG terminal by an angle $\theta_0$ ranging from 0 to $\pi/2$. As assumed in [17], the IBDG only responds to the positive-sequence of the IBDG terminal voltage. Thus, the IBDG current is symmetrical even the phase voltages are unsymmetrical. In other words, the IBDG contributes balanced phase currents under both balanced and unbalanced fault conditions. Regarding the absolute value of $I_{\text{inv,sat}}$, the common maximum value is 2 p.u. in IBDG rating. However, most DG operators prefer the rated current $I_{\text{rated}}$ if the IBDG is required to support the maximum reactive current to the system. The limited current $I_{\text{inv,sat}}$ is thus given by (1).

$$I_{\text{inv,ref}} = \frac{P_{\text{ref}} - jQ_{\text{ref}}}{V_{G}^*} + j\omega C_f V_{G}$$

(2)

Providing that the dynamic network support requirement is considered, the IBDG is controlled to inject a fully reactive current $I_{\text{inv,sat}}$ into the utility system to satisfy the DSOs
requirement. Consequently, the IBDG is only modeled by the dependant current source in parallel with the filter capacitor \( C_f \) as shown in Figure 3. The limited current is defined by (3) where \( 0 \leq \theta_0 \leq \pi/2 \). In case of fully reactive support, \( \theta_0 = \pi/2 \).

\[
I_{\text{inv,sat}} = |I_{\text{rated}}| \angle (\delta_{vp} - \theta_{vp})
\]

Figure 3. Model of an IBDG under fault condition

\[
I_{\text{inv,sat}} = |I_{\text{rated}}| \angle (\delta_{vp} - \theta_{vp})
\]  

Although the FRT requirement requires the reactive current injected to Bus \( p \), the current controlled before the capacitor \( C_f \) as shown in Figure 3 can be acceptable. This is because the difference between current before and after the \( C_f \) is small. The inclusion of \( C_f \) in the model is to reflect more accurately the operation of the IBDG.

**IV. Fault Calculation Algorithm**

The flow chart of the adaptive fault calculation can be represented by Figure 4 (a). This algorithm is based on the conventional technique which is short of taking the IBDG into account. The adaptation comes from the stage of calculating the positive-sequence voltages as explained by Figure 4 (b). After estimating all sequence currents at the faulted bus based on the sequence network connection, sequence voltage at all buses are determined independently based on the corresponding sequence network. Line currents are then calculated from the three sequence components based on the superposition method.

The adapted section compared to the conventional fault calculation technique is detailed in Figure 4 (b). This algorithm starts with forming a sequence network connection, which is circuited from positive, negative, and zero-sequence networks and based on what the fault type is. Unlike the conventional technique, the sequence network connection here is modified so that the positive-sequence network is not replaced by an equivalent impedance; whereas, the circuit consisting of the equivalent zero-sequence impedance \( Z_0 \), the equivalent negative-sequence impedance \( Z_2 \), and the fault impedance \( Z_f \), is replaced by an equivalent impedance \( Z_{eq} \). In case of a three-phase fault, only positive-sequence network is used and \( Z_{eq} \) is equal to \( Z_f \). Another example is illustrated in Figure 5 where \( Z_{eq} \) is determined by (4).

\[
Z_{eq} = \frac{Z_{kk}^2 \left(Z_{kk}^0 + 3Z_f \right)}{Z_{kk}^2 + Z_{kk}^0 + 3Z_f}
\]  

System representations such as lines and transformers are similar to those in the conventional method. However, all loads of the system should be represented by constant impedances based on the prefault voltages in order to reflect the effect of voltage on load demand during fault. The IBDG is modeled as a PQ source in the first iteration and occupies in only the positive-sequence network as modeled in Fig. 4. The model is switched to a current source (3) if one of the two conditions (5) and (6) occurs.
Positive, negative and zero-sequence networks
Modified sequence network connection
Power flow algorithm
Positive voltages
Voltage and current at the fault point
Line currents
Same as the conventional fault calculation

Figure 4. Adaptive fault calculation

(a)

(b)

Positive, negative and zero-sequence networks
Modified sequence network connection
Power flow algorithm
Positive voltages
Voltage and current at the fault point
Line currents
Same as the conventional fault calculation

Figure 5. Modified sequence network connection for a double line-to-ground fault

\[ |I_{ref}| \geq |I_{thres}| \]  \hspace{1cm} (5)

\[ |V_{PCC}| < |V_{limit}| \]  \hspace{1cm} (6)

where \( I_{ref} \) is the reference current expected at the output of the IBDG and given by (2); \( I_{thres} \) indicates the threshold current of the control system of the IBDG as detailed in [17], \( V_{PCC} \) indicates the positive-sequence voltage at the PCC of the IBDG, and \( V_{limit} \) indicates the voltage limit accepted for a normal condition.

The admittance matrix \( Y_{bus} \) of the modified sequence network connection is performed similarly to the \( Y_{bus} \) formulation in a power flow algorithm. Newton-Raphson iteration technique is employed to compute positive-sequence components of bus voltages. The Jacobian matrix is computed based on the formulated \( Y_{bus} \). At IBDG bus, the diagonal elements are adapted as follows. The Kirchhoff Current Law at Bus \( p \) can be expressed as (7).

\[ I_p = \sum_{q=1}^{n} Y_{pq} V_q \]  \hspace{1cm} (7)
On the other hand, the current $I_p$ can be computed by using (8).

$$I_p = \frac{P_p - jQ_p}{V_p} \angle -\delta_p + \left| I_p^{\text{inv.sat}} \right| \angle \alpha_p$$  \hspace{1cm} (8)$$

where $\alpha_p$ is the phase of the current source representing the IBDG; $V_p\angle\delta_p$ is the polar form of the voltage at Bus $p$; $P_p+jQ_p$ is the entering power estimated at Bus $p$ (not including IBDG power). Assuming that the phase of $I_{\text{inv.sat}}$ lags $V_p$ by an angle $\theta_p$, this relation can be expressed as (9).

$$\alpha_p = \delta_p - \theta_p$$  \hspace{1cm} (9)$$

Substituting (7) for $I_p$ and (9) for $\alpha_p$ in (8), and separate the real and imaginary parts, the estimated active and reactive power at Bus $p$ are given by (10) and (11), respectively.

$$P_p = \sum_{q=1}^{n} |V_p||V_q||Y_{pq}| \cos(\theta_{pq} - \delta_p + \delta_q) - |V_p||I_p^{\text{inv.sat}}| \cos \theta_{0p}$$  \hspace{1cm} (10)$$

$$Q_p = -\sum_{q=1}^{n} |V_p||V_q||Y_{pq}| \sin(\theta_{pq} - \delta_p + \delta_q) - |V_p||I_p^{\text{inv.sat}}| \sin \theta_{0p}$$  \hspace{1cm} (11)$$

Obviously, the IBDG representation as a current source causes the diagonal elements of submatrices $J_2$ and $J_4$ to be changed as shown in (12)-(13).

Diagonal elements of the submatrix $J_2$:

$$\frac{\partial P_p}{\partial |V_p|} = 2 |V_p||V_q||Y_{pq}| \cos \theta_p + \sum_{q\neq p}^{n} |V_q||Y_{pq}| \cos(\theta_{pq} - \delta_p + \delta_q) - |I_p^{\text{inv.sat}}| \cos \theta_{0p}$$  \hspace{1cm} (12)$$

Diagonal elements of the submatrix $J_4$:

$$\frac{\partial Q_p}{\partial |V_p|} = -2 |V_p||V_q||Y_{pq}| \sin \theta_{pp} - \sum_{q\neq p}^{n} |V_q||Y_{pq}| \sin(\theta_{pq} - \delta_p + \delta_q) - |I_p^{\text{inv.sat}}| \sin \theta_{0p}$$  \hspace{1cm} (13)$$

After switching an IBDG to a current source, the algorithm restarts because the bus admittance matrix needs updating with $C_f$ and the Jacobian matrix needs changing in the diagonal elements. The maximum number of restarting is equal to the number of IBDG in the system. Direct results from the algorithm are positive-sequence voltages at all buses including the faulted bus $k$.

The circuit comprising $Z_0^{kk}$, $Z_2^{kk}$, and $Z_2$ is firstly solved with the known $V_1^k$ to obtain all sequence components of the fault current $I_f^k$, $I_1^k$, and $I_2^k$ at the fault bus $k$. From this stage, calculation of negative and zero-sequence voltages at all buses is in a similar way to the conventional fault calculation because the IBDG does not participate in these sequence networks. Combining with the positive-sequence voltages that have been obtained from the algorithm, bus sequence voltages are used to compute line sequence currents. Lastly, these line sequence currents are superposed to generate line currents during fault.
V. Case Study

This section utilizes the proposed algorithm in Section III to test a simple system with an IBDG. The accuracy of the result is validated by a simulation using Matlab/Simulink. The simulation illustrates the fault ride through capability of the IBDG during fault.

5.1 Tested System

The simple system has one IBDG connected to Bus 4, which is a low voltage bus of a step up transformer. The system is depicted by a single-line diagram in Figure 6. System parameters are as follows.

- **Grid:** $V_1 = 6$ kV, $Z_{sc,grid} = 0$ Ω, $Z_{line1} = 0.72 + j2.7$ Ω, $Z_{line2} = 0.5 \times Z_{line1}$, $P_{load} + jQ_{load} = 1 + j0.5$ MVA
- **Transformer:** 0.80 MVA, 6kV/380V, Yn/D11, $R = 0.002$ p.u, $X = 0.08$ p.u (in transformer rating).
- **IBDG:** $S_{nom}=0.55$ MVA, $P_{ref} = 0.5$ MW, $Q_{ref} = 0$ MVar, $I_{thres} = 1.5$ p.u., $I_{inv,sat} = 1$ p.u., (in IBDG rating), $C_f = 900$ μF, $L_f = 0.85$ mH.

![Figure 6. Simple system with an IBDG](image)

5.2. Results from the Simulation

The Simulink is employed to simulate the system in Figure 6. At time $t=2$ s, a double line-to-ground fault occurs at Bus 3 through a ground impedance $Z_f=0.2$ Ω. The following sections explain the system model and prefault conditions before showing the fault current results obtained from a Simulink simulation.

5.2.1 Power System Model in Simulink

The IBDG has a selected control system in Figure 2. Four main elements inside the Simulink model are line, transformer, transmission system, and load. They are represented as follows.

A line is simply represented by an impedance. This impedance is simulated by a resistor in series with a reactor in the Simulink. Their parameters are in Ohm and Henry, respectively. In order to convert the reactance $X$ of the reactor into the corresponding inductance $L$, the power frequency $f=50$ Hz should be used. Therefore, lines 1 and 2 are simulated by ($R_{line1} = 0.72$ Ω; $L_{line1} = 8.6 \times 10^{-3}$ H) and ($R_{line2} = 0.36$ Ω; $L_{line2} = 4.3 \times 10^{-3}$ H), respectively.

The transformer in this power system is a two winding transformer. The low voltage winding is connected in delta and the high voltage one is connected in grounded-wye. The YnD11 connection indicates that the voltage at the delta winding leads the respective one at the wye winding by 30 degrees. The parameters in transformer rating of each winding is $R=0.001$ p.u. and $L=0.004$ p.u.

The transmission system is assumed to be infinitive. This means, the short-circuit...
impedance of the system is $Z_{ac,grid} = 0 \, \Omega$. In another word, voltage at Bus 1 is remained $1\angle 0^0$ p.u. during both normal operation and fault condition.

Load is represented by a constant impedance to reflect the change of load power following the change of voltage. The voltage used to convert the constant power model into constant impedance is generally the nominal voltage. However, the voltage obtained from a power flow program under prefault condition can model the load with higher accuracy than using the nominal voltage.

### 5.2.2 Prefault Condition

Voltages at Buses 2, 3, and 4 are obtained from a power flow program for the prefault condition. Load under this condition is modeled as a constant power of $1+j0.5$ MVA. Results in phase-phase rms value are as follows.

- Bus 2: $V_{2pre} = 5.65 \angle -1.64^0 \, \text{kV}$
- Bus 3: $V_{3pre} = 5.46 \angle -3.82^0 \, \text{kV}$
- Bus 4: $V_{4pre} = 357.96 \angle 31.59^0 \, \text{V}$

Voltage at the load bus 3 is $5.46 \angle -3.815^0$ kVrms. The respective load impedance is $23.8493+j11.9246 \, \Omega$. Thus, it is represented in Simulink by a circuit comprising a resistor $R_{load} = 23.8493 \, \Omega$ in series with an inductor $L_{load} = 0.038 \, \text{H}$.

### 5.2.3 Double Line-to-Ground Fault (DLGF)

In the case of a DLGF (phases B and C) through $Z_f = 0.2 \, \Omega$, a big dip at phases B and C of the IBDG terminal voltage (Bus 4) occurs. The drop of voltage causes the reference current to increase until it reaches the limit $I_{thres} = 1,772.66 \, \text{A}$ (peak value) and passes the limit at time $t = 2.06 \, \text{s}$. The IBDG is switched to the current source mode causing the IBDG current becomes constant immediately after that with the value of $I_{inv,sat} = 1,181.77 \, \text{A}$ (peak value) as shown in Figure 7. The phase of the IBDG current lags the phase of the positive-sequence component of the IBDG terminal voltage by $90^0$. This lagging phase satisfies the FRT requirement in the case of fully reactive current support.

The voltage characteristics at Buses 4 and 2 are not in the same waveform as illustrated in Figure 8 because of the transformer connection of YnD11. Both voltages at Phases B and C at Bus 2, that is on the high voltage side of the transformer, decrease due to the fault. At Bus 4, which is on the low voltage side of the transformer, the voltage dip at Phase B is bigger than that at phases A and C whose voltages are almost the same as 225 V. Thus, the phase shift caused by the transformer connection should be taken into consideration at the stage of forming the bus admittance matrix.

The fault currents at the faulted bus in this case are shown in Figure 9 where the peak values of the current at Phases B and C are 1,311.25 and 1,228.25 A, respectively. Because the IBDG is controlled in current mode, the power output is no longer maintained the predefined value of 0.5 MW as shown in Figure 10. In addition, the $90^0$ phase lagging of the IBDG current causes the active power output to become zero and the reactive one to increase to 0.34 MVA. Table 1 summarizes results of voltages and currents obtained from the Simulink simulation of the DLGF case so as to easily compare with those from the proposed fault calculation algorithm which will be used later.
Figure 7. Currents from IBDG during a DLGF $Z_f = 0.2 \, \Omega$

Figure 8. Voltages at Buses 2 and 4 during a DLGF $Z_f = 0.2 \, \Omega$

Figure 9. Fault current during a DLGF $Z_f = 0.2 \, \Omega$
Figure 10. IBDG power output based on positive-sequence components during a DLGF with $Z_f = 0.2 \, \Omega$

Table 1. Peak voltages and currents obtained from Simulink

<table>
<thead>
<tr>
<th>Items</th>
<th>Bus 2</th>
<th>Bus 3</th>
<th>Bus 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pos.-seq. voltages</td>
<td>2,638(\angle-3.88^0)</td>
<td>1,414(\angle-9.4^0)</td>
<td>185(\angle25.93^0)</td>
</tr>
<tr>
<td>Phase A</td>
<td>4,266(\angle-3.88^0)</td>
<td>4,119.3(\angle-5.93^0)</td>
<td>216.9(\angle11.4^0)</td>
</tr>
<tr>
<td>Phase B</td>
<td>1,672(\angle131.6^0)</td>
<td>282.57(\angle108.1^0)</td>
<td>125.19(\angle-91.5^0)</td>
</tr>
<tr>
<td>IBDG current</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fault current</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pos.-seq. currents</td>
<td>1,777.6(\angle-64.24^0)</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Phase A</td>
<td>1,777.6(\angle-64.24^0)</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Phase B</td>
<td>1,777.6(\angle-64.24^0)</td>
<td>1,308(\angle162^0)</td>
<td></td>
</tr>
</tbody>
</table>

5.3 Results from the Proposed Algorithm

It is assumed that all sequence impedances are identical for each system component. The computation is performed in per unit with: $\text{baseMVA} = 1 \, \text{MVA}$; base voltage on the high voltage side: $\text{basekV} = 6 \, \text{kV}$; base voltage on the low voltage side: $\text{baseV} = 380 \, \text{V}$. In order to determine the equivalent impedance $Z_{eq}$ for utilizing the proposed algorithm, the system in Figure 6 is represented in the fashions of negative and zero-sequence networks as in Figure 11. For easily comparing with the results from the simulation in Table 1, the load is also modeled as a constant impedance with respect to the prefault voltage obtained from a power flow program.

The equivalent negative and zero-sequence impedances of the system viewed from Bus 3 are (0.0376 +j0.0979) p.u. and (0.0219 + j0.0739) p.u., respectively. According to the sequence network connection in Figure 5, these two impedances and three times of the fault impedance ($3Z_f$) can be replaced by an equivalent impedance $Z_{eq} = 0.0194 + j0.0423$ p.u. for the DLGF case. The equivalent impedance is connected to the faulted bus (Bus 3) in the positive-sequence network as illustrated in Figure 12 for applying the proposed fault calculation algorithm.

In this unbalanced fault case, the connection of YnD11 is taken into account by a complex tap setting value $a = e^{j30^\circ}$ for the positive-sequence component and $a = e^{-j30^\circ}$ for the negative-sequence component. The tap setting indicates that the positive-sequence component of delta voltage leads the positive-sequence component of Y voltage by 30 degrees; whereas, the negative-sequence component of delta voltage lags the one of Y voltage by 30 degrees. These tap setting values are input in the data to formulate the bus admittance matrix $Y_{bus}$ of the modified sequence network connection in Figure 12.
During the DLGF, the IBDG is switched to the current source mode with $I_{\text{inv,sat}} = 835.64 \text{ A rms (or 1,181.77 A peak value)}$ at the second iteration. The algorithm restarts and updates $C_f$ to the bus admittance matrix $Y_{\text{bus}}$. The solution is reached after new 7 iterations. After the algorithm converges, the phase of $I_{\text{inv,sat}}$ automatically lags the positive-sequence voltage at Bus 4 by 90 degrees. The power output during this fault case is no longer maintained at 0.5 MW. Currents at the faulted bus (Bus 3) are computed from the positive-sequence voltage at Bus 3 in a similar way to the conventional fault calculation.

Peak values of fault current $I_F$ in Ampere are obtained by multiplying the corresponding per unit value by the base value of 96.225√2 A.

The summary of results from fault calculation for the DLGF is in Table 2. Obviously, the values of elements in Table 2 including fault currents, bus voltages, and currents contributed from IBDG are in close proximity compared with the results in Table 1 that comes from the simulation. For instance, the fault current at phase B at the faulted bus in Table 1 is $1,308 \angle 162^0$ A peak. This value is a little lower than $1,310 \angle 161.6^0$ in Table 2.

![Figure 11. Sequence networks of the simple system with the installation of an IBDG](image)

![Figure 12. Modified sequence network connection for the test system](image)

<table>
<thead>
<tr>
<th>Items</th>
<th>Bus 2</th>
<th>Bus 3</th>
<th>Bus 4</th>
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<td>2,637.6$\angle-3.856^0$</td>
<td>1,413.8$\angle-9.3965^0$</td>
<td>184.8581$\angle25.9894^0$</td>
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<td>Phase A</td>
<td>4,264.3$\angle-3.7^0$</td>
<td>4,117.9$\angle-5.9^0$</td>
<td>216.6162$\angle11.4831^0$</td>
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<tr>
<td>Phase B</td>
<td>1,673.7$\angle131.4^0$</td>
<td>282.6$\angle108.2^0$</td>
<td>125.5671$\angle-91.451^0$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Items</th>
<th>IBDG current</th>
<th>Fault current</th>
</tr>
</thead>
<tbody>
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<td>0</td>
<td>471.0911$\angle108.1834^0$</td>
</tr>
<tr>
<td>Pos. component</td>
<td>$1,181.77 \angle-64.0106^0$</td>
<td>844.2299$\angle-74.7622^0$</td>
</tr>
<tr>
<td>Neg. component</td>
<td>0</td>
<td>2.7516$\angle1.7735^\text{rad}$</td>
</tr>
<tr>
<td>Phase A</td>
<td>$1,181.77 \angle-64.0106^0$</td>
<td>0</td>
</tr>
<tr>
<td>Phase B</td>
<td>$1,181.77 \angle-64.0106^0$</td>
<td>1,310.3$\angle161.6^0$</td>
</tr>
</tbody>
</table>
VI. Conclusion

This paper has proposed an adaptive algorithm for fault calculation in system with IBDG. The algorithm is then validated successfully by the comparison with the time-variant simulation of a simple system. Results obtained from the proposed algorithm and those from the simulation are close in proximity. The algorithm is convenient for calculating fault currents with all fault types. The estimated fault currents can be used to set parameters of protective devices and to check their protection capability.

VII. References