INVESTIGATION OF A NEW METHOD FOR SYNCHRONOUS GENERATOR
LOSS OF EXCITATION PROTECTION

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ABSTRACT

In this thesis, a new proposed method for LOF detection has been further explored and its shortcomings corrected. The detection index has been calculated based on these new modifications. The modifications include a more robust delta estimation technique and a removal of a required algorithm condition. Two methods are used to estimate the rotor angle and both provide a similar estimation. The first method depends on the integration of the rotor speed over time, while the second method is based on equations presented in a published paper.

Moreover, the algorithm was tested on both a 2-bus system and the IEEE 9-bus system (The simulation model was built using a Real Time Digital Simulator (RTDS)) to investigate the detection time, security and reliability of the proposed method.

The algorithm was then tested under various operating conditions. The advantages and drawbacks of the proposed algorithm are discussed in the thesis.

DEDICATION

I dedicate my dissertation work to my family and many friends. I must express my very profound gratitude to my parents and to my siblings for providing me with unfailing support and continuous encouragement throughout my years of study and through the process of researching and writing this thesis. This accomplishment would not have been possible without them. I also dedicate this dissertation to my many friends (Sara, Marym, Mariana and Mohammed) who have supported me throughout the process. I will always appreciate all they have done.

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CHAPTER 1

INTRODUCTION

1.1 Background

Secure and fast protection of power system components should be provided in order to isolate the faulted area and minimize its effects on the nearby areas and maintain system stability. Generators are one of the most important components of the power system.

Problems a generator can face are internal faults, system disturbances or operational hazards. Operational hazards include overvoltage, loss of synchronism, loss of excitation, etc [1]. The excitation system of a synchronous generator is a critical and integral part of the machine's design. The excitation system maintains the terminal voltage within the accepted voltage range by responding quickly to load changes. It may be an AC excitation system (an AC machine as a source of power), a DC excitation system (a DC generator) or a static excitation system (its components are static and supply the field circuit through slip rings).

Generator loss of excitation can be caused by accidental tripping of a field breaker, field open circuit, slip-ring flashover, failure of the voltage regulation system, and loss of excitation system supply [2].

When the generator loses its excitation, its reactive power support will be lost; moreover, it will absorb reactive power from the system which can result in a voltage drop. If the power grid is not able to meet the higher reactive power demand this may lead to a voltage collapse

[3].In addition, generator loss of field will also cause stator overloading and rotor overheating (if synchronism is lost), which will result in a decrease in the generator's life time.

The worst-case condition for generator loss of excitation is when the generator is heavily loaded. In this case, there is a higher probability of machine slipping poles (loss of synchronism) because high load means less system impedance and it will decline the final slip frequency [2].During light loads, the generator may not lose synchronism and will operate as a synchronous generator dependent on the principle of reluctance [4].

There is no determined time length the generator can operate without excitation [2], but in order to avoid possible voltage collapse resulting from reactive power demand and machine damage, secure fast and dependable loss of field (LOF) detection methods are required [3].

1.2 Problem Statement

The conventional detection method, which is based on impedance measurement to detect the loss of field, is the most popular technique for LOF detection. However, it shows mal-operation during some disturbances on the system and thus there is a need for an improved loss of field detection technique that is secure and dependable.

1.3 Objectives

The objective of this research is to investigate the reliability of a new proposed method for generator loss of excitation protection.

1.4 Study Outline

The remaining chapters of this thesis are organized as follows:

- Chapter Two: Loss of field detection techniques are reviewed and the conventional method description is presented.
- Chapter Three: This chapter introduces the methodology of the investigated algorithm along with the modifications proposed.
- Chapter Four: This chapter presents simulation results when testing the algorithm performance on the IEEE9-bus system.
- Chapter Five: This chapter discusses the advantages and the drawbacks of the algorithm. Additionally, some recommendations are presented.

CHAPTER 2

LITERATURE REVIEW

The excitation system supplies the synchronous machine field winding with the field current and controls the field voltage. This is required for satisfactory performance of the power system (maintaining system stability). The excitation system consists of the exciter and automatic voltage regulator AVR.

Loss of excitation affects both the generator and power grid. The generator rotor will be overheated because of the slip frequency on the rotor circuit. Loss of excitation may also cause over-loading on the system transmission lines and transformers because when the machine loses its excitation it will absorb reactive power from the system. This will cause an increase in the reactive power output of the other machines. In a weak system, there is a high probability of system voltage collapse after loss of excitation of highly rated machines as the machines work as induction generators [5].

Loss-of-excitation may not affect the system immediately but the stator overloading and rotor overheating the generator experiences will decrease the generator's lifetime. Consequently, if the machine continues working in this state for a long period of time the power grid will be adversely affected. Therefore, it is critical to quickly detect generator loss-of-excitation to avoid both generator and system damage.

2.1 Conventional Method

In 1949, the concept of LOF protection using impedance was introduced. Impedance scheme is the most utilized scheme for loss of field detection. During an event of loss-of-field, zone 1 operates under full load conditions while zone 2 operates under light load conditions. In other words, during high loads the impedance trajectory enters the operation zone faster than light loads. Also, zone 2 is considered as a backup for zone 1, and during power swings there is a high probability for the entrance of the impedance trajectory into zone 2. Therefore, a longer time delay is set for this zone to avoid mal-operation. The offset of the protection zones from the origin of the impedance plane is half of the transient reactance ($\frac{X'_d}{2}$). Two methods for LOF detection are presented in the SEL-300G relay manual [6]. The diagrams for both of them are illustrated in figure (2.1).

Figure 0.1 Loss-of-field protection. (a) Positive-offset mho element supervised by a directional element. (b) Negative-offset mho element

$X_d \equiv$ Generator direct-axis reactance.

$X_s \equiv$ The sum of the step-up transformer reactance and system reactance.

$X'_d \equiv$ Generator transient reactance.

The conventional method shows mal-operation during severe stable power swing (SPS) conditions, for instance, a severe fault near the generator [2]. It was reported in a NERC technical reference document that 13 out of 290 generator tripping resulted from LOF mal-operation during such disturbances [3].

2.2 Techniques Proposed

As discussed in the previous section, the conventional method is not reliable during SPS conditions. In addition, it requires a time delay which results in more stresses on the generator and the network. Therefore, other techniques are proposed in the literature in an attempt to overcome such drawbacks.

Reference [2] introduced a new method of LOF detection based on fuzzy set theory. It depends on the concept of the conventional loss-of-excitation detection method, which relies on the variations of the terminal voltage and apparent impedance.

This method trips the breaker when the voltage range is between 0.5-0.8p.u and therefore if the system is strong, it will not work. Its operation depends on the system robustness and it requires a considerable amount of data.

A setting-free approach for detecting loss of field of the synchronous generator is presented in [7]. This approach does not need threshold settings and therefore does not depend on

the system parameters. This approach relies on the resistance variation because it has a fixed polarity during LOF (it remains negative). The equation of resistance variation is as follows:

$$\frac{dR}{dt} = \frac{(1 - k(t)^2) \sin \delta}{(1 + k(t)^2 - 2k(t) \cos \delta)^2} \frac{dk}{dt} X_{tot}(t) + \frac{k(t) \sin \delta}{1 + k(t)^2 - 2k(t) \cos \delta} \frac{dX_{tot}(t)}{dt} \quad (2.1)$$

$$k = \frac{E_{syst}}{E_G}$$

$$X_{tot} = X_G(t) + X_T + X_{Syst}$$

$$X_G \equiv \text{Generator reactance}$$

$$X_T \equiv \text{Transformer reactance}$$

$$X_{Syst} \equiv \text{System reactance}$$

$$E_{syst} \equiv \text{System voltage}$$

$$E_G \equiv \text{Generator internal voltage}$$

This method discriminates between the LOF and a disturbance by setting a time delay before tripping. The performance of the method is evaluated during peak hours, off peak hours and disturbances for a 2-bus system. The results show that it is faster than the conventional method.

In reference [6], a new strategy to detect synchronous generator loss of field is presented. This method primarily relies on the value and duration of the voltage and reactive power variation. The index utilized to detect the loss of field as follows:

$$LOEI = 10^5 [Q^k - Q^{k-1}] [V_T^k - V_T^{k-1}] \quad (2.2)$$

Its performance is compared to both the conventional method and the one proposed in [2] for different loading conditions, generator ratings and system configurations.

The index presented in [6] has difficulty discriminating between SPS and loss of excitation; as a result, a solution is presented in [8]. The discrimination between SPS and LOF is based on the variation of the fast Fourier transform coefficient of the three-phase active power at the relay location. Therefore, the delay associated with the other methods is avoided through an additional threshold value. The second threshold is based on the FFT coefficient of the active power. When the calculated indices from the measured values exceeds the two threshold values, the LOF is detected; otherwise, it shows an SPS condition on the grid.

There are several techniques based on magnetic flux variation in the air gap that have been presented ([9] and [10]) but those techniques have been criticized. This is because in order to measure the machine flux, search sensors coil should be utilized but there is a natural reluctance to install it because it may lead to machine damage [8].

A new method based on PMU measurement in the presence of flexible alternating current transmission system (FACTS) is presented in [11], but this technique needs measurement synchronization and large amounts of information.

The algorithms presented in [6] and [8] start their calculations with the initial condition that the terminal voltage of the machine is less than 0.95p.u. When the system is strong or if there are multiple generators on the same bus, the terminal voltage will not drop to 0.95 and less. This means that the algorithm will never start the calculation and the loss of field will not be detected. Moreover, those methods were not tested on a larger system.

CHAPTER 3

METHODOLOGY

The proposed method for loss of excitation is presented in this chapter. First, the principles on which it is based and the quantities of interest to form a loss of excitation detection index are discussed. Then, upon arriving at the most suitable quantities to use in the index, an algorithm is proposed for detection. Further mechanisms to ensure the index is as robust as possible, and can distinguish between true loss of field and a power swing condition are discussed.

3.1 Loss of Excitation Overview

Consider the equivalent circuit shown in figure (3.1) below:

Figure 0.1 Per-phase synchronous generator equivalent circuit

The active power output is equal to:

$$P = \frac{V_t E_f}{X_d} \sin \delta + \frac{V_t^2 (X_d - X_q)}{2X_d X_q} \sin 2\delta \quad (3.1)$$

$$Q = \frac{V_t E_f}{X_d} \cos \delta - V_t^2 \left(\frac{\sin \delta^2}{X_q} + \frac{\cos \delta^2}{X_d} \right) \quad (3.2)$$

P = active power output

E_f = generator internal voltage

V_t = machine terminal voltage

δ = rotor angle

X_d = d – axis synchronous reactance

X_q = q – axis synchronous reactance

From the previous equation note that the active power output is proportional to the system voltage, sine of δ and the internally generated voltage. Thus, the active power output of the generator will be affected by a loss-of-excitation because the internal generated voltage E_f is a function of the field voltage.

When the generator loses its excitation, the generated voltage decreases and therefore active power slightly decreases for the same value of the mechanical power. This results in a higher rotor angle as shown in figure (3.2).

Figure 0.2 Generator active power – angle diagram

3.2 Detection Index for the Proposed Method

The concept of this method depends on the divergence of the generator's electrical and mechanical quantities from their steady state values after a generator loss of field occurs on the system. To present these variations after the loss of field occurrence, a two bus system is simulated utilizing a real time digital simulator (RTDS).

When the generator loses its field: the reactive power and terminal voltage decrease, active power and current oscillate, while the power angle and speed increase. Voltage, angle and reactive power are utilized to calculate the detection indices because of their fixed polarity during loss of field.

The parameter variations shown in figure (3.4) are for the two bus system presented on figure (3.3). The loading is 90% while the power factor is 0.95 lagging and the LOF is applied at $t=1s$. Notice that the loss of synchronism resulting from the loss of field is not immediate as the generator loses its synchronism after 6 seconds.

Figure 0.32-bus system

Figure 0.4 Generator parameters' (Q , V_t , δ , P and I) behavior after LOF at $t=1$ s

The variation of the electrical quantities (in p.u) can be expressed as an evolving time series as follows:

$$\Delta X(t) = \frac{X(t) - X(t - T_0)}{X_B} \quad (3.3)$$

$T_0 \equiv$ time interval (0.1 second)

$X_b \equiv$ base value

Figure (3.5), (3.6) and (3.7) show the variations of generator parameters for 30%, 60% and 90% of the generator rating respectively. The time interval is considered as 0.1s while the power factor is 0.95 lagging.

Figure 0.5 Variations of generator parameters during LOF (30% loading)

Figure 0.6 Variations of generator parameters during LOF (60% loading)

Figure 0.7 Variations of generator parameters during LOF (90% loading)

Various permutations of the electrical quantities are multiplied together for better detectors as expressed in equation (3). K_G is an amplified quantity to increase the detection index value and it depends on the index parameters.

$$\text{LFDI}_{X_1, X_2, \dots, X_N} = K_G \prod_{i=1}^N \Delta X_i \quad (3.4)$$

$$K_G = 10^{2N+1} \quad (3.5)$$

Figure (3.8) depicts the different indices for 30% loading conditions and 0.95 power factor, using double or triple parameters between V, Q and δ . Notice that the indices have a fixed polarity.

Figure 0.8 Various loss of field detection indices (LFDIs) using double and triple parameters

Observe that $LFDI_{V,Q}$ shows the least variation while $LFDI_{Q,\delta}$ presents the highest variation comparatively. This thesis will investigate the index $LFDI_{V,Q,\delta}$.

All parameters used to calculate indices are measurable except for delta. It is estimated based on the equations referenced in [12] as:

$$\delta = \frac{P}{\left[\frac{V_t^2 * (P_1 \cot \delta_1 - Q_1)}{V_{t1}^2} \right] + Q} \quad (3.6)$$

$P \equiv$ terminal active power.

$Q \equiv$ terminal reactive power.

$V_t \equiv$ terminal voltage

Subscript 1 $\equiv$ steady state values.

The following equation (6) is used to calculate steady state rotor angle (δ_1):

$$\delta_1 = \tan^{-1} \left(\frac{X_q I_t \cos \varphi - R_a I_t \sin \varphi}{E_t + R_a I_t \cos \varphi + X_q I_t \sin \varphi} \right) \quad (3.7)$$

The second estimation method relies on the integration of the generator speed to calculate the rotor angle, and has been used for further confirmation of the above calculation.

$$\Delta \overline{w_r} = \frac{\Delta w_r}{w_0} = \frac{1}{w_0} \frac{d\delta}{dt} \quad (3.8)$$

$$\delta = \int_0^t 2\pi f (\Delta \overline{w_r}) \quad (3.9)$$

The rotor angle was estimated and plotted using the two methods for different loading conditions. Figure (3.9), (3.10) and (3.11) illustrate the rotor angle for 30%, 60% and 90% respectively for the 2-bus system.

Figure 0.9 Estimated rotor angle for 30% loading

Figure 0.10 Estimated rotor angle for 60% loading

Figure 0.11 Estimated rotor angle for 90% loading (loss of synchronism after 6 s)

3.3 Nodal injections in a Simplified System Model

The algorithm detects loss of field when the index exceeds a predefined value (threshold) for a specified time (T_{max}). The flow chart of the proposed algorithm is shown in figure (16). The threshold value is determined according to the system conditions that lead to the minimum variations of the generator parameters when LOF occurs on the system.

1) Loading level:

As shown in figure (3.12) the LFDI increases with loading level. Because the 30% loading results in the minimum LFDI it will be considered as the worst case.

2) Power factor value:

Figure (3.13) depicts the variation of LFDI for different power factors -1, 0.8 lead and 0.8 lag. Note that when the load absorbs reactive power (high inductive load) from the system it will lead to higher value of LFDI compared to the state when the system power factor is leading (capacitive load). Therefore, leading power factor is considered as the minimum index condition.

Figure 0.12 Effects of power loading level on $LFDI_{\delta, Q, V}$

Figure 0.13 Effects of power factor value on $LFDI_{\delta,Q,V}$

3) No of units on the bus:

In the case when there are many units on one bus and one of the units loses its field, the other units tend to hold up the bus voltage. Therefore, there will be less variation on the terminal voltage and a minimum LFDI value. A maximum number of units on the bus is considered the case which causes minimum LFDI.

Figure 0.14 Effects of number of units on $LFDI_{\delta,q,v}$

The selection of time interval T_0 in equation (5) is based on two considerations. T_0 should not be too small that there will not be enough variation, and not too large as it will lead to a time delay in LOF detection.

Figure 0.15 Flow chart of the algorithm

The value of the counter is determined according to reference [7], and [8], which state that the time delay depends on the swing frequency. The counter is selected such that it is able to differentiate between a swing condition and a true LOF. The power system swing frequency

range is 0.3-7Hz. In this thesis the minimum value (0.3 Hz) will be considered as the network swing frequency. The longest time period for the expected angle oscillation is then $\frac{1}{0.3}$ s or 3.33 second as shown in figure (3.16). The delta variation will change its polarity after half a cycle or 1.67s. Considering a safety margin of 20% the time delay counter will be 2.0 seconds ($1.2 \times 1.67 = 2.0$ s) to avoid mal-operation resulting from the power swing.

$$T_{max} = \text{delay} \times \text{sampling frequency} = 2 \times 10000 = \underline{\underline{20000}} \text{ (} T_{max} \text{ is dimensionless, = no of counts)}$$

Figure 0.16 Oscillations of $d\delta/dt$ during minimum frequency (slowest time)

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Test System Description

The algorithm was tested on the IEEE9-bus system. This system consists of 3 generators, 3 Loads, 3 transformers and 6 transmission lines as shown in figure 18. Complete system data are tabulated in Appendix A.

The performance of the algorithm has been evaluated on the IEEE 9-bus system for three different operating conditions:

- Normal operating conditions with different loading levels.
- SPS conditions.
- Normal operating conditions with multiple machines connected to bus-2

4.2 Normal Operating Conditions with Different Loading Levels

The IEEE9-bus system is simulated for algorithm assessment. The system is shown below in figure (4.1). Three different scenarios were simulated: 30%, 60% and 90% loading of the generator. In the three cases the power factor is 0.95 lagging and the LOF is applied at time $t=1.0$ s. Note that when applying the loss of field for one generator on an IEEE 9-bus system, the behavior of the electrical quantities (Q , V and δ) is similar for different loading conditions as shown in figures (4.2), (4.3) and (4.4). The sampling frequency is 10 kHz.

Figure 0.3 Generator parameters variations for 60% loading

Figure 0.4 Generator parameters variations for 90% loading

The threshold value is calculated using minimum index conditions as described in the methodology. For this minimum index scenario, active power and reactive power are considered as 0.3 p.u and -0.5 p.u respectively. During threshold calculation, the number of the units on the bus is not considered because there are no multiple units on the same bus for this system. The maximum value of the $LFDI_{V,Q,\delta}$ is 4.686 as illustrated in figure (4.5). Therefore, the threshold value is 20% of the maximum.

Figure 0.5 $LFDI_{V,Q,\delta}$ during minimum index conditions

$$LFDI_{V,Q,\delta} \text{ Threshold} = 0.2 * 4.686 = \mathbf{0.9372}$$

Figures (4.6), (4.7) and (4.8) illustrate the index for different loading conditions (30%, 60% and 90%). The $LFDI_{V,Q,\delta}$ is positive for the three loading conditions.

Figure 0.6 $LFDI_{V,Q,\delta}$ for 30% loading

Figure 0.7 $LFDI_{V,Q,\delta}$ for 60% loading

Figure 0.8 $LFDI_{V,Q,\delta}$ for 90% loading

In case 1 (30% loading) LOF was detected 4.0 s after occurrence by the conventional method while the $LFDI_{V,Q,\delta}$ detected it after 2.1s. During case 2 (60% loading) LOF was detected 5.0 s after occurrence by the conventional method while the $LFDI_{V,Q,\delta}$ detected it after 2.1s. At 90% generator loading the conventional method detected the LOF after 6.0s while the index detected it after 2.1s.

It can be observed that the algorithm detection time is not affected by the loading level of the generator as the detection time is similar during the different loading conditions. Therefore, it

can be concluded that the algorithm is secure and fast for a stable system regardless of the loading level of the machine.

Next, the algorithm performance is tested under a swing conditions since this is the main reason behind conventional relay mal-operation. A stable power swing is defined as an oscillatory disturbance that is controlled by the power system. After the disturbance is removed, the system will remain stable. For example, a fault on any line within the system that is cleared after a designated time will potentially give rise to a SPS.

The detection times for both the conventional scheme and the proposed method are presented in table (4.1). The conventional method detection time is the time difference between the moment the field is lost and the time when the relay output is asserted.

The performance of the index is compared to the conventional method for different operating conditions as shown in table (4.1).

For security evaluation of the proposed index, non-loss of field disturbances are were applied on the simulated system as shown in table (4.2). There were no trip commands generated; therefore the index can be considered as a secure index.

Table 0.1 LOF detection time for both conventional method and proposed algorithm under different loading conditions

Case No	Initial loading		Detection time (s)	
	P (p.u)	Q (p.u)	$LFDI_{V,Q,\delta}$	Conventional
1	0.6	0.25	2.1	7.3
2	0.6	0	2.1	6.3

3	0.6	-0.25	2.1	5.39
4	0.5	-0.2	2.1	4.97
5	0.5	-0.3	2.1	4.48
6	0.5	-0.4	2.1	3.97
7	0.3	0.03	2.1	5.94
8	0.6	0.01	2.1	6.4
9	0.9	0.01	2.1	7.8

Table 0.2 Non-loss of field disturbances

Disturbance	Initial loading		Method	
	P (p.u)	Q (p.u)	$LFDI_{V,Q,\delta}$	Conventional
Unit out (gen3)	0.3	0.1	No trip	No trip
Load out (L8)	0.3	0.1	No trip	No trip
Load out (L6 & L8)	0.3	0.1	No trip	No trip

4.3 SPS Conditions

Two cases were tested to simulate a stable power swing and loss of field. An SPS was simulated by applying a three phase fault at bus 4. The LOF was applied after the fault was cleared.

- Case A

A stable power swing was simulated by applying a fault on bus 3 at $t = 0.78$ s and cleared at $t = 1.0$ s. LOF occurred at $t = 1.0$ s. Figure (26) below depicts V,Q and δ behavior after the SPS.

Figure 0.9 Terminal voltage, reactive power and rotor angle variation during SPS

Figure 0.10 Algorithm detection time during SPS

Figure 0.11 Conventional method detection time

From figures (4.10) and (4.11) the detection time for the proposed index and the conventional scheme is 4.6s and 12s respectively.

- Case B

Another power swing was simulated by applying a fault on bus 4 at 0.9 s and cleared at $t=1.0$ s while LOF occurred at $t=3.0$ s. Figure (4.12) below depicts V, Q and δ behavior after SPS.

Figure 0.12 Terminal voltage, reactive power and rotor angle variation during SPS

Figure 0.13 Algorithm detection time during SPS

Figure 0.14 Conventional method detection time

From figures (4.13) and (4.14) the detection time for the proposed index and the conventional scheme is 5.1s and 12s respectively.

4.4 Normal Operating Conditions with multiple machines connected on bus-2

The number of the generators on bus 2 was increased from one to three and then to four in order to evaluate the algorithm when one of the generator's suffers a loss of field. The system topology is illustrated in figure (4.15). A simulation was performed under normal operating condition with a loss of field on one of the generators at simulation time = 1.0 s.

Figure 0.15 IEEE9-bus system, with 3 and 4 generators at bus 2

From figures (4.16) and (4.17), it can be seen that the rotor angle and reactive power variations have a fixed polarity (Q is negative and rotor angle is positive) while the terminal voltage variations oscillates. This is due to the fact that the other machines (on the same bus) are trying to maintain the bus voltage at 1.0 p.u. Therefore, the index will not have a fixed polarity as shown in figure (4.18). These oscillations will translate into oscillations on the detection index and hence the method will not be able detect the generator loss of field.

Figure 0.16 Generator parameters variation with 3 generators on bus-2

Figure 0.17 Generator parameters variation with 4 generators on bus-2

The oscillations can be avoided by increasing the time interval T_0 , figure (4.18) and (4.19) below show the index when the time interval is 100ms and 300ms respectively.

Figure 0.18 $LFDI_{V,Q,\delta}$ when $T_0=100$ ms

Figure 0.19 $LFDI_{V,Q,\delta}$ when $T_0=300$ ms

Threshold value is calculated as described in the methodology. During the minimum index scenario, active power and reactive power are considered 0.3 p.u and -0.4 p.u respectively. In this new 9-bus configuration, the number of the generators is considered when calculating the

threshold, taking 4 generators as the minimum index condition. The maximum value of the $LFDI_{V,Q,\delta}$ is 16.11 as illustrated on figure (4.18).

Figure 0.20 $LFDI_{V,Q,\delta}$ during minimum index conditions

$$LFDI_{V,Q,\delta} \text{ Threshold} = 0.2 * 16.11 = \underline{\underline{3.222}}$$

Figure 0.21 $LFDI_{V,Q,\delta}$ for 3 generators at bus 2

Figure 0.22 $LFDI_{V,Q,\delta}$ for 4 generators at bus 2

The index is shown in figure 4.21 and 4.22 for both cases (3 and 4 generators on bus 2). Note that the index has a fixed polarity (positive). The algorithm does not trip because the index $LFDI_{V,Q,\delta}$ exceeds the threshold but for less than 2 seconds.

CHAPTER 5

CONCLUSION

5.1 Conclusion

The two methods used for delta estimation have similar results as presented in the results chapter.

The condition for starting the calculation of the index is when the voltage drops below 0.95 p.u. This condition is not necessarily met in all system configurations. Therefore, it is recommended to eliminate such condition.

The selection of the time interval T_0 is found to affect the algorithm reliability. T_0 should be large enough to guarantee that the voltage oscillations will not affect the index polarity.

The algorithm failed in detecting LOF in the case of multiple machines connected to the same bus. Even though the index did exceed the threshold value, it did not meet the time delay criteria. A swing frequency of 0.3 Hz was used to calculate the time delay. This time delay insured system security during SPS conditions. However, for a LOF in the multiple-machine case, the index did not remain above the threshold value for the required time period. This scenario illustrates the tradeoff between the maximum time delay that guarantees detection of LOF and the minimum time delay required to avoid mal-operation during SPS conditions.

The conventional method will be used as a backup for the proposed method, because the later shows good detection for most of the cases except when there are many generators on the same bus. Moreover, the existence of this case is rare in the actual grid.

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APPENDIX A
IEEE9-BUS SYSTEM DATA

Details of IEEE 9 Bus System:

Sbase = 100 MVA

Vbase = 220kV

Vmax = 1.06 p.u

Vmin = 1 p.u

NUMBER OF LINES = 8

NUMBER OF BUSES = 9

Bus No.	P _G	Q _G	P _L	Q _L	V _{SPC}
1	0	-	0	0	1.04
2	1.63	0	0	0	1.025
3	0.85	0	0	0	1.025
4	0	0	0	0	1
5	0	0	1.25	0.5	1
6	0	0	0.9	0.3	1
7	0	0	0	0	1
8	0	0	1	0.35	1
9	0	0	0	0	1

Table A-1 Bus Data

Bus No.		Resistance (p.u)	Reactance (p.u)	Half line charging Admittance(p.u)
From bus	To bus			
1	4	0	0.0576	0
4	6	0.017	0.092	0.079
3	9	0	0.0586	0
6	9	0.039	0.17	0.179
5	7	0.032	0.161	0.153
7	8	0.0085	0.072	0.0745
2	7	0	0.0625	0
8	9	0.0119	0.1008	0.1045

Table A-2 Line Data

Exciter:

The generator exciter is built externally and its output is inserted to the generator through a breaker which is normally closed and changes its status after designated time. Figure () depicts the exciter block diagram.

Figure A-1 Exciter block diagram

$T_r \equiv$ Voltage measurement time constant

$T_a \equiv$ Voltage regulator time constant

$K_a \equiv$ Voltage regulator gain

$T_f \equiv$ Damping filter feedback time constant

$K_f \equiv$ Damping filter feedback gain

$K_p \equiv$ Proportional gain on voltage limit

$V_{tmax} \equiv$ Maximum static limit on voltage measurement

$V_{tmin} \equiv$ Minimum static limit on voltage measurement

$V_{rmax} \equiv$ Maximum static limit of excitation voltage

$V_{rmin} \equiv$ Minimum static limit of excitation voltage

Parameter	value
T_r	0.02
T_a	0
K_a	400
T_f	0.6
K_f	0
K_p	1
V_{tmax}	7
V_{tmin}	6.9999
V_{rmax}	4.6
V_{rmin}	0

Table A-3 Exciter data

SEL-300G settings:

$$\begin{aligned}
 40Z1P &= \frac{V_{NOM}}{1.73 * I_{NOM}} \\
 40XD1 &= \frac{-X'_d}{2} \\
 40Z1D &= 0 \\
 40Z2P &= X_d \\
 40XD2 &= \frac{-X'_d}{2} \\
 40Z1D &= 0.5
 \end{aligned}$$

VITA

Enass Mohammed was born in Khartoum, Sudan, to the parents of Babiker and Hafiza. Ms. Mohammed received her Bachelor of Science degree in electrical and electronics engineering –power system concentration- in 2010 from University of Khartoum in Khartoum, Sudan. After graduation, she joined Majig for construction Services LTD as an electrical engineer. Ms. Mohammed worked there for 4 years before accepting a graduate assistantship offer from the University of Tennessee at Chattanooga to pursue a Master of Science degree in Electrical Engineering. She was awarded her degree in August 2017.