# 5. TRANSIENT STABILITY STUDIES OF THE ATHABASCA-POINTS NORTH POWER SYSTEM

## 5.1 Introduction

Transient stability of a power system is the stability of the system with respect to large disturbances, such as, short circuit, tripping of a transmission line or generating sets. The final operating condition may be quite different from the pre-disturbance operating condition due to alternations made to the configuration of the system. If there is a loss of synchronism of one or more generating sets, the system is transiently unstable.

Transient stability involves both the configuration of the system and its operating condition. It is, therefor, necessary to define the pre-disturbance operating condition and to completely specify the disturbance for studying the transient behavior of the system,

The investigations reported in this chapter were based on the system configuration of Figure 4.2 with all the existing controllers being present. However, load flow conditions may be changed for stability simulations under various situations. The purposes of these investigations were to:

1. evaluate the most severe disturbances the system could withstand;
2. determine the critical clearing times for different disturbances to be used as guide lines in designing protection schemes; and

3. define possible corrective measures to be applied in the system to prevent loss of synchronism.

In order to facilitate the analysis and presentation of simulated results of a stability study of a large power system, generators in the system can be grouped according to their coherency [32]. The dynamic behavior of the generators in a coherent group is assumed to be similar. The total coupling factors [33] can be utilized in this grouping process. Instead of analyzing all the generators in the system, a representative generator is selected from each coherent group and its dynamic behavior is studied.

This coherent grouping process is covered in more detail in Chapter 6. The results are quoted here for the convenience of presenting the simulation studies in this chapter. There are seven generators at Island Falls. Generators #1, #2, #3 and #7 were in group one. Generators #4, #5 and #6 were in group two. Generators #8 and #9 were in group three. Generators #10, #11 and #12 were in the last group. Generators in the last group do not have stabilizers and slight differences between their controllers also exist. Their rated capacities are also quite different, however, they behave in the very similar ways.

One or more representative generators from each group are selected each time when computed results are presented. It should be noted that the presented results are still identified by generator numbers, not by group numbers. It is not always necessary to have all the representatives being selected in a single result presentation.

## 5.2 Operating Procedure of APNS

As the APNS was interconnected from two smaller systems, i.e., the Athabasca System and the Points-North System, at the Points-North switching station, and due to the special arrangement of the circuit breakers in the system as seen from Figure 5.1, the stability of the system following a large disturbance depends on how much power is being transferred through the tie-line between the two systems, i.e., line 30-33 in Figure 4.2, and where the disturbance is located.

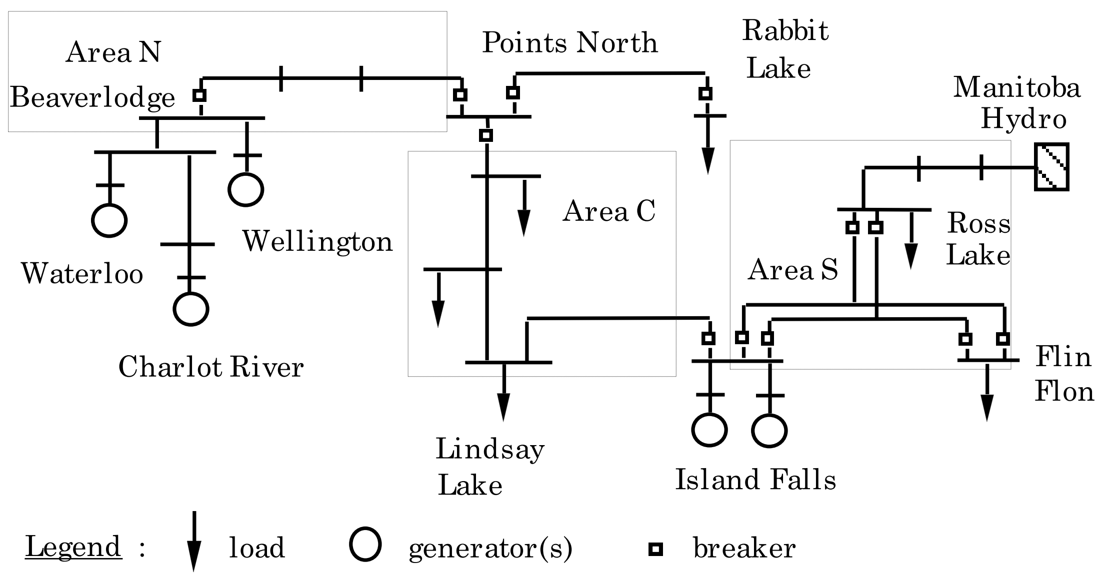


**Figure 5.1:** Simplified single line diagram of APNS.

For instance, if a disturbance is located on the transmission line from Island Falls to Points-North, the circuit breakers at both ends of the line will trip to isolate it. In this case, if there is only a small power transfer over the line 30-33, the Athabasca System and part of the Points-North System can be saved following the disturbance.

If a disturbance is located on the transmission line from Points-North to Beaverlodge, the five remote hydro generators in the Athabasca System will pull out of synchronism as the line trips out. On the other hand, the load at Rabbit Lake will be supplied from Island Falls plant.

A disturbance on one of the double circuit lines from Island Falls to Flin Flon will trip off that faulted line and bring the power transfer on the other line to the upper limit of its transfer capacity.

## 5.3 Parameters of Power Components and Controllers

As explained in Chapter 3, parameters of power components and controllers are passed to the TSSP coordinator through data files in transient stability studies These parameters include the following categories: machine data, excitation system data, speed governing and turbine system data and power system stabilizer data. For the APNS, these data were generously provided by the SaskPower. This section denotes some important points worth noting for easy reading of and referring to the system data provided in the form of data file in Appendices A, B and C. Detailed description of the data files is given in the TSSP users manual [3]. Please note that all the symbols used here are universal and self-explanatory. A complete list of these symbols can be found at the beginning of this thesis.

### 5.3.1 Machine Data

The required data for machine modeling are in a form commonly found in manufacture's data sheets. If a generator is modeled by a *two axis model with subtransient*, the following data records are entered.

$Generator\ \#, Model\ \#$
$M_{base},\ H,\ r_a,\ x_\ell$
$x_d, x'_{do}, x''_{do}, x_q, x''_{qo}$
$\tau_{do}, \tau'_{do}, \tau''_{do}$
$D, S_{1.0}, S_{1.2}, -1\ /\ or\ D, A_G, B_G$

If the generator is modeled by an *one axis model with transient*, the data records entered are similar to the above. Those items with a double prime (") are not entered. For an infinite bus modeled as a large generator, only the generator number, model number (#0) and a system capacity (100 MVA, for instance) are entered. At the end of each data record, a slash ( / ) is placed to end the record.

Saturation is approximated by an exponential function (see Appendix E). Alternatively, the two constants, $A_G$ and $B_G$, can be used in the function or the saturation at terminal voltage 1.0 and 1.2 pu, $S_{1.0}$ and $S_{1.2}$, respectively, can be used to compute the two constants by placing a ' -1 ' option in the data record.

The format of data input for the three generator models discussed above was used in the studies reported in this thesis. Other machine models, i.e. *two axis model with transient only* and *one axis model*, are also available in the TSSP, as has been explained in Chapter 3.

### 5.3.2 Excitation System Data

For each excitation system model, a model number is assigned to identify it. The assigned numbers are shown in Table 3.1. The input data record follows a format similar to that in the machine data input. As an example, the data records for a modified DC type 2 excitation system are:

$Exciter\ \#, Model\ \#$
$K_A, K_E, K_F$
$T_C, T_B, T_A, T_E, T_F$
$V_{MIN}, V_{MAX}$
$A_E, B_E / \text{ or } E_1, S_1, E_2, S_2, -1$

Saturation of an excitation system is treated in a fashion similar to that of a generator (see Appendix E).

### 5.3.3 Speed Governing and Turbine System Data

As has been explained in Chapter 2, all six steam turbine systems and their speed governor models recommended by IEEE [6] are available in TSSP. As they are not used in this study, they are not covered in detail here. The speed governor and turbine system for hydro generators can be simulated by two models, the accurate model and the simplified one. Both of which were used in the studies reported in this thesis. As an example, the data records to be entered for the simplified model of a hydro generator's speed governing and turbine system is of the following format:

$Generator\ \#, Model\ \#$
$T_W, T_1, T_2, T_3$
$K$
$P_{MIN}, P_{MAX}$

### 5.3.4 Power System Stabilizer Data

The IEEE standard PSS model [5] and another two SaskPower PSS models identified as IEEESN and IEEEST are incorporated in TSSP and were used in the studies reported in this thesis. Presented below are the data records for IEEEST PSS, where 1,2,3 or 4 are identifiers of the input signals:

speed deviation, terminal voltage deviation, electrical power or accelerating power, respectively. $A_1$ is the time constant of the filter of the PSS with power input. The function of the filter here is to block torsional interaction.

*Stabilizer #, Model #*
*1,2,3 or 4*
$A_1$
$T_1, T_2, T_3, T_4, T_5, T_6$
$K_S, P_{MIN}, P_{MAX}$

Data records for IEEESN PSS and IEEE standard PSS are similar to those of IEEEST PSS. Exact records to be entered for each of these models are given in [3]. Table 3.1 of Chapter 3 shows the available PSS models and their assigned identifying numbers used in TSSP data file.

## 5.4 Transient Stability Studies

As has been explained in Section 5.2, any fault that initiates trips on the transmission line from Island Falls to the northern end will separate the system into two or more parts, while a fault on one of the double circuit lines will trip that circuit, leaving the integrity of the system intact. The overall system stability is dependent on the disturbance under study. Therefore, the investigations reported in this section were conducted according to the location of a fault. In order to facilitate reference, the system was divided into three geographical areas as shown in Figure 5.1. The northern area is abbreviated as Area N, the central area as Area C and the southern area as Area S.

If a fault is located in Area N, that area will be lost after the fault clearing. The objective is to examine whether Area C and Area S were stable or not. If a fault is located in area C, the stabilities of Area N and Area S are investigated. If a fault is located in Area S, the integrity of the system will be intact and the overall stability is studied.

### 5.4.1 Disturbances in Different Geographic Areas

1. Fault in Area N

It was assumed that there was a three phase to ground (3LG) fault on the line from Points North to Stony Rapids (line 37-46 near bus 37 in Figure 4.2). The fault was cleared by opening the circuit breakers of the line after 6 cycles. As there was no autoreclosure, Area N was lost after fault clearing. All the rest of the system was supplied by Island Falls plant. Figure 5.2 shows that generators #8 and #10 were accelerating while generators #1 and #4 displayed small oscillations. Each generator represents the group it belongs to.

It can be concluded that groups 3 and 4 would pull out of synchronism and Area N would be lost. The generators at Island Falls would supply the loads in both Areas C and S.

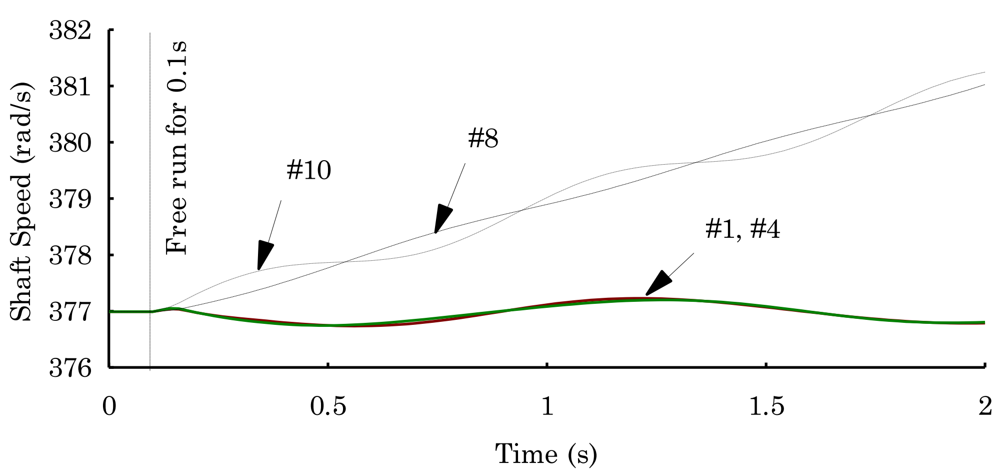

**Figure 5.2:** Machine shaft speed versus time. 3LG fault near Points North. Generators in Area N pull out of synchronism.

2. Fault in Area C

A fault on the main transmission line in Area C would separate the system into three parts. The center area would be lost. The stability of the other two areas would depend on the operating condition at the time of disturbance. It was assumed that there was a 3LG on the line from Island Falls substation to Lindsay Lake ( line 18-21 nearby bus 18 in Figure 4.2) for a duration of 6 cycles. The fault was cleared by opening the line. Figure 5.3 shows the speed response of two typical generators. In fact, all the generators in groups 3 and 4 would behave the same way as generator #8 that was decelerating and eventually would pull out of synchronism. The generators at Island Falls would oscillate severely. This was because the fault was close to the terminal of the generators at this plant.

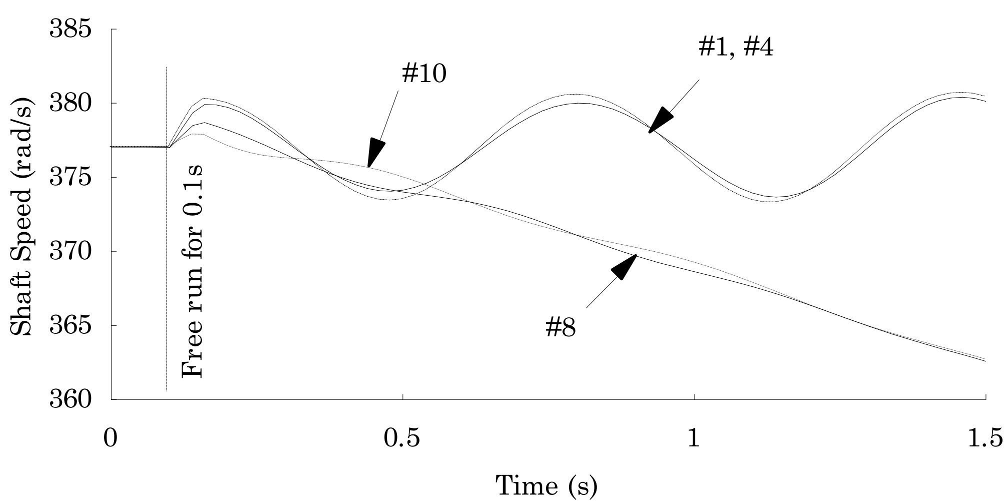

**Figure 5.3:** Machine shaft speed versus time. 3LG fault near Island Falls. Generators in Area N would pull out of synchronism.

3. Fault in Area S

Any fault in Area S is of the most concern. This is because eighty percent of the generated power at Island Falls is transferred through the double circuit line to Flin Flon of Manitoba Hydro. A fault that trips one of the double circuit lines would bring the power transfer of the other line to its maximum. A three phase autoreclosure device is available and is set to 10 seconds of dead line.

Case I: Suppose that there was a single phase to ground (SLG) fault on line 59-61 for a period of 6 cycles. It was cleared by opening the 3 phases of the faulted line. Reclosure was started in 10s after fault clearing. Figure 5.4 shows typical rotor angle oscillations. It can be concluded that the system would be oscillatory stable. This oscillation may be due to lack of damping and the incompetence of the PSSs at Island Falls. Figure 5.5 shows that the PSS outputs at Island Falls were trivial. A disturbance more serious than the SLG fault studied above would display similar but more severe oscillations.

Voltage responses resulting from the SLG fault are shown in Figures 5.6 and 5.7. As generators #1 to #9 were equipped with fast excitation systems (AVRs), the generator terminal voltage recovered quickly. The field voltage of generators #1 and #4 exhibited changes during the pre-fault period. This was because of the electrical power input PSSs that are always functioning as long as there is generated power output. This field voltage change under normal operation would cause fluctuation of the terminal voltage.

The mechanical power response of hydro generators is usually slow, as illustrated in Figure 5.8. Simulations show that for the SLG fault, the mechanical power is almost unchanged. Further analysis of the speed governing and turbine system is reported in Chapter 6. The electrical power was oscillating due to lacking of damping.

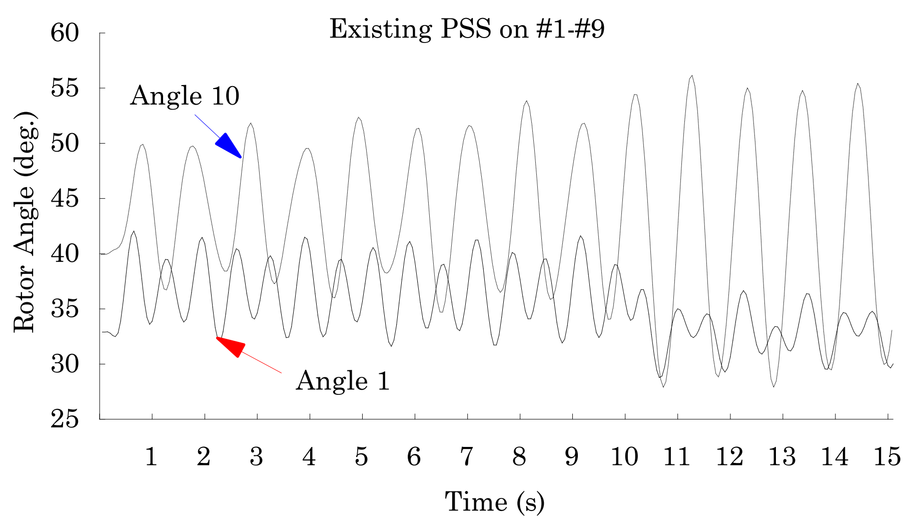


**Figure 5.4:** Rotor angle swings of generators #1 and #10 under the SLG fault. Reclosure in 10s of dead line.

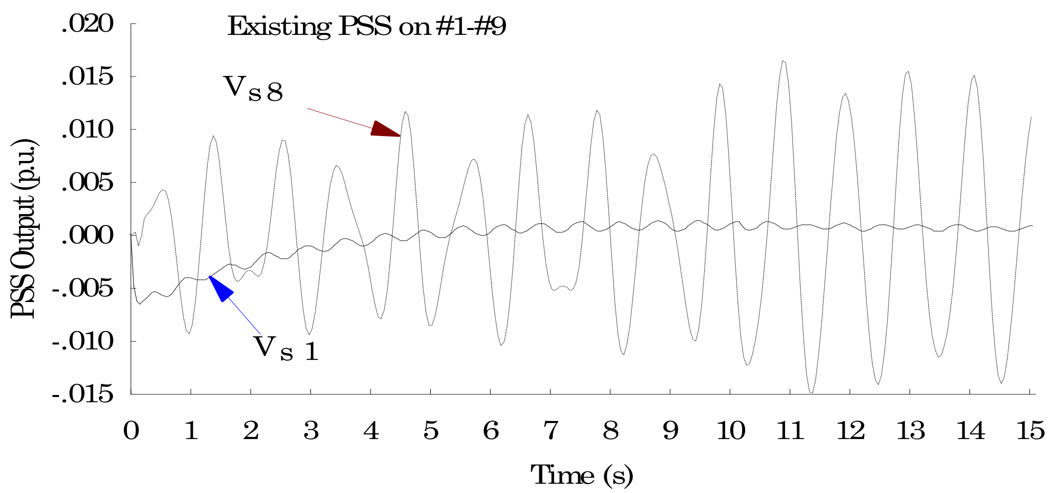


**Figure 5.5:** PSS output voltages of generators #1 and #8 under the SLG fault. Reclosure in 10s of dead line.

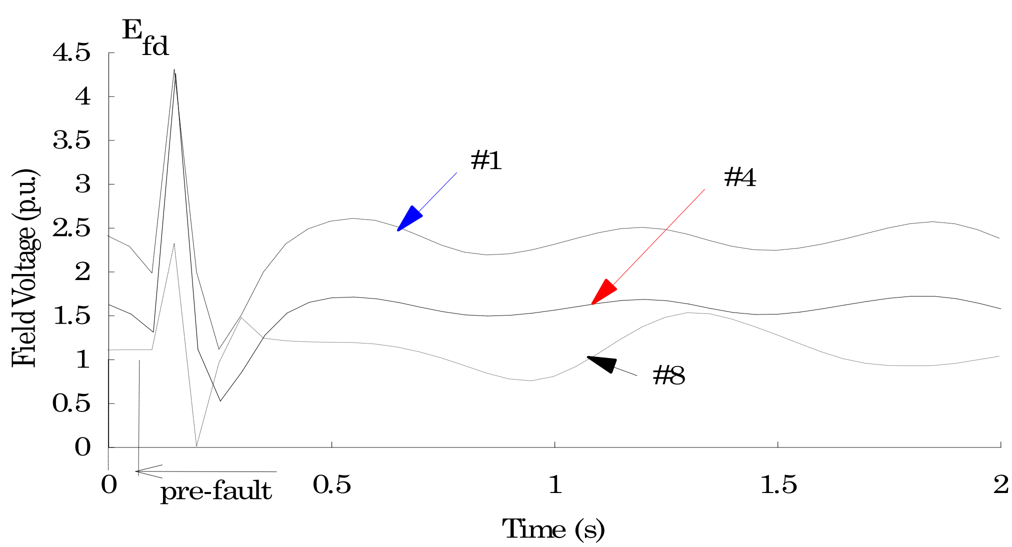


**Figure 5.6:** Field voltage versus time. SLG fault on the double circuit line.

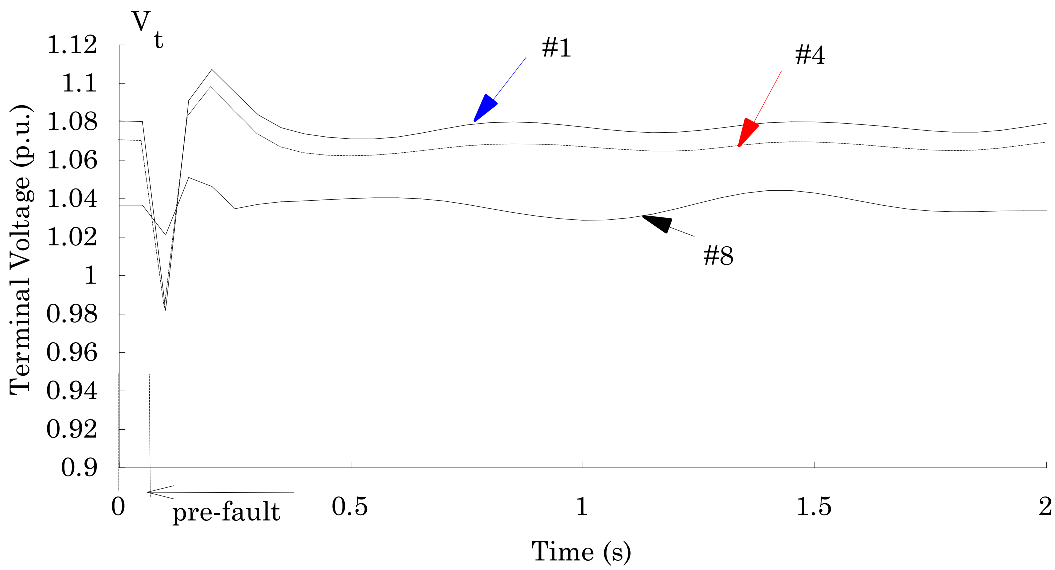


**Figure 5.7:** Terminal voltage versus time. SLG fault on the double circuit line.

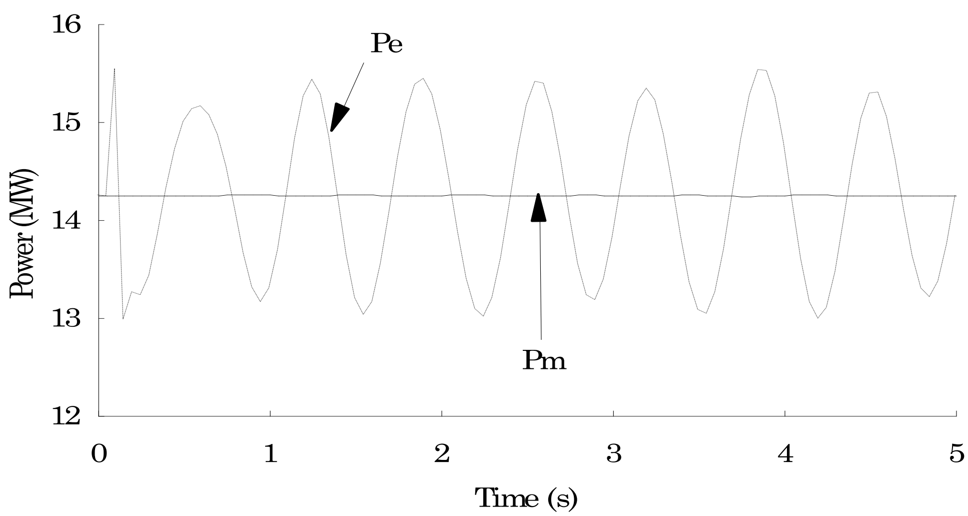


**Figure 5.8:** Mechanical and electrical power responses of generator #5 to the SLG fault.

Case II: Suppose that a three phase to ground (3LG) fault occurs on the double circuit line for 6 cycles. Reclosure is initiated in 10 seconds of dead line. Figure 5.9 shows typical rotor angle oscillations of generators #1 and #10. Comparing to Figure 5.4, we can conclude that the oscillation is much more severe and that the fault has a larger impact on generator #1 at Island Falls as it is closer to the fault. The system is oscillatorily stable but it takes a long time to settle down.

### 5.4.2 The Largest Load Area Is Lost

The main demand in the Athabasca System is located in the Rabbit Lake area. Suppose that there was a three phase to ground (3LG) fault on the line between Points North and Rabbit Lake near Points North ( line 37-38 near bus 37). The fault was cleared in 2.3s without reclosure. The following observations can be made from time domain simulatios.

1. The study showed that when all the loads in this area were cut off after a fault on the line, the system would remain stable with a critical clearing time (CCT) being equal to 2.3 seconds and would be operating at another equilibrium point.
2. More power would be sent to Manitoba-Hydro system through the double circuit lines as shown Figure 5.10.

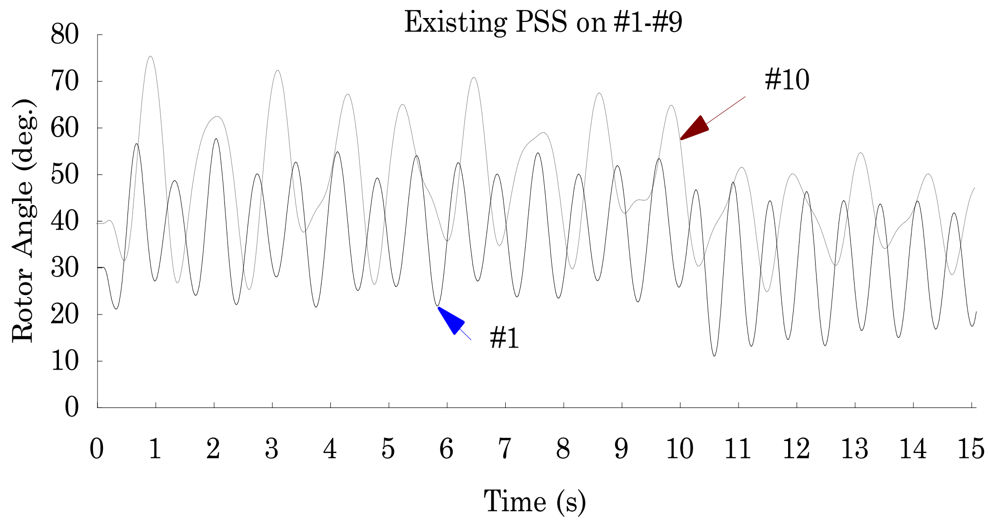


**Figure 5.9:** Rotor angle swing of generators #1 and #10 under the 3LG fault. Reclosure in 10s of dead line.

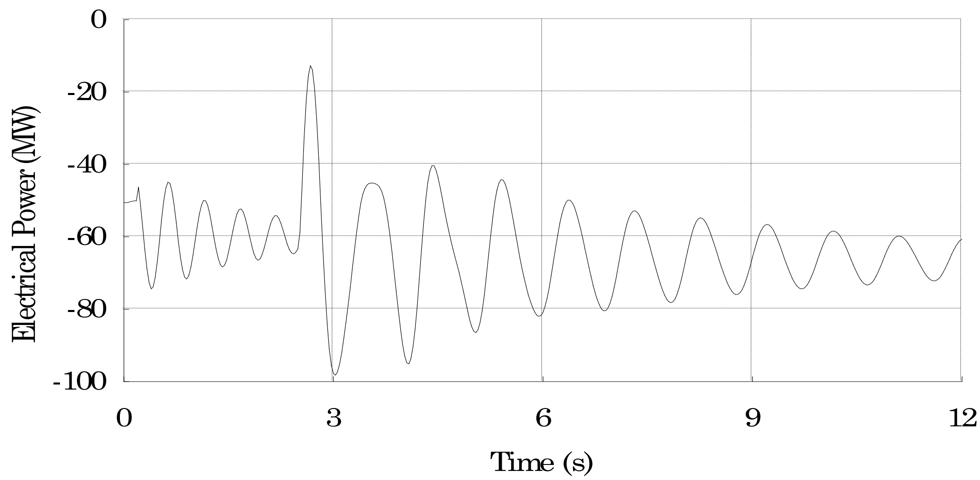


**Figure 5.10:** Transferred real power from Manitoba Hydro to this system. 3LG fault at bus 37 for 2.3s.

### 5.4.3 Symmetrical and asymmetrical Disturbances

1. Effect of Autoreclosure on Stability under 3ϕ Fault

Suppose that there was a three phase to ground fault (3LG) nearby Lindsay Lake on the line between Lindsay Lake and Key Lake ( line 21-26) for 6 cycles. Comparison was made between with and without autoreclosure. Figure 5.11 shows the results obtained.

1). Figure 5.11 shows that the system would be unstable if no autoreclosure were initiated after the fault clearing by opening the line. It shows that the rotor angle of generator #8 would go to negative infinity. Generators #9 through #12 would behave in a similar fashion.

2). Autoreclosure might not be successful if it passed the dead time of 0.4 second. Simulation shows that the system would become unstable if the dead time were set to be 0.41 seconds.

3). If the critical clearing time (CCT) changes, the dead time would also change, but not significantly.

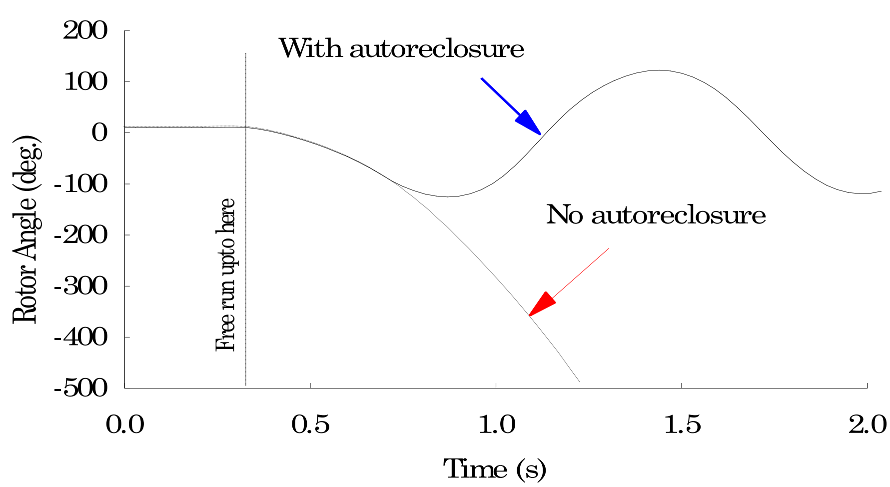


**Figure 5.11:** Rotor angle of generator #8. 3LG fault at bus 21 for 0.1s with and without autoreclosure.

2. Effect of Autoreclosure on Stability under 1ϕ Fault

Case I: If there was a single phase to ground (SLG) fault on the line between Stony Rapids and Points-North nearby Points-North (line 37-46 nearby bus 37). The fault was cleared by opening the faulted phase of the line in 2 seconds. Two simulations were performed with and without reclosure, respectively, as shown in Figure 5.12.

1). The system would still be stable even the CCT is 2s. This indicated that the system could be operating for a longer time with only two phases connected between bus 46 and bus 37 without distorting the stability of the system.

2). Figure 5.12 also shows the situation where autoreclosure is initiated 0.4s after the fault clearing. It can be seen that autoreclosure could-greatly quicken the stabilizing process of the system.

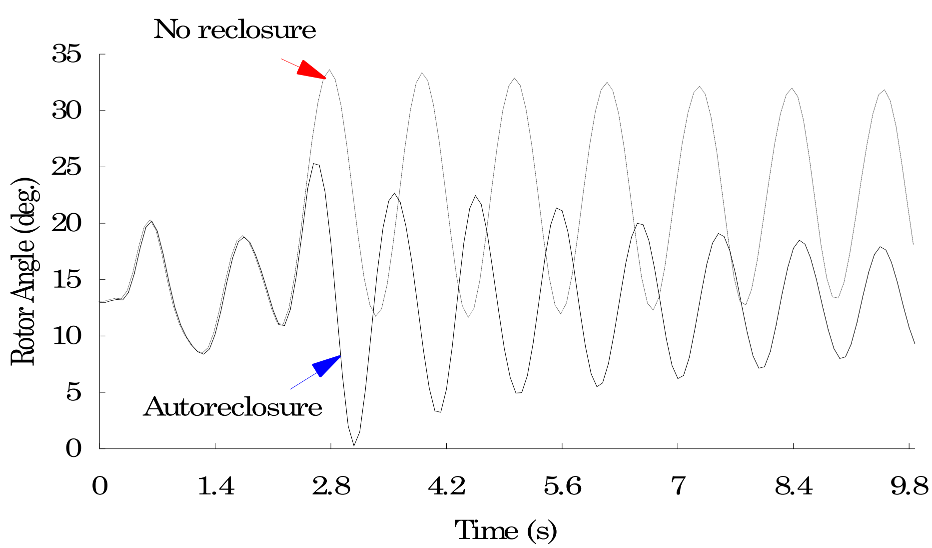


**Figure 5.12:** Rotor angle of generator #8. SLG fault at bus 37 for 2s with and without reclosure.

3). The system would be operating at a new equilibrium point if there were no autoreclosure to restore the system configuration after the fault. Single phase fault clearing by opening that phase is equivalent to increasing the impedance of the transmission line.

Case II: Suppose that a single phase to ground (SLG) fault appeared on the line from Lindsay Lake Tap to Key Lake Tap (line 21-26). The fault was cleared in 6 cycles (0.1s) by opening the faulted phase. Simulated results are presented in Figure 5.13.

1). The system would be oscillatory after the single phase fault was cleared in 1.0s without reclosure.

2). If reclosure was initiated 0.4s after the fault clearing, it would accelerate the restoration of system stability.

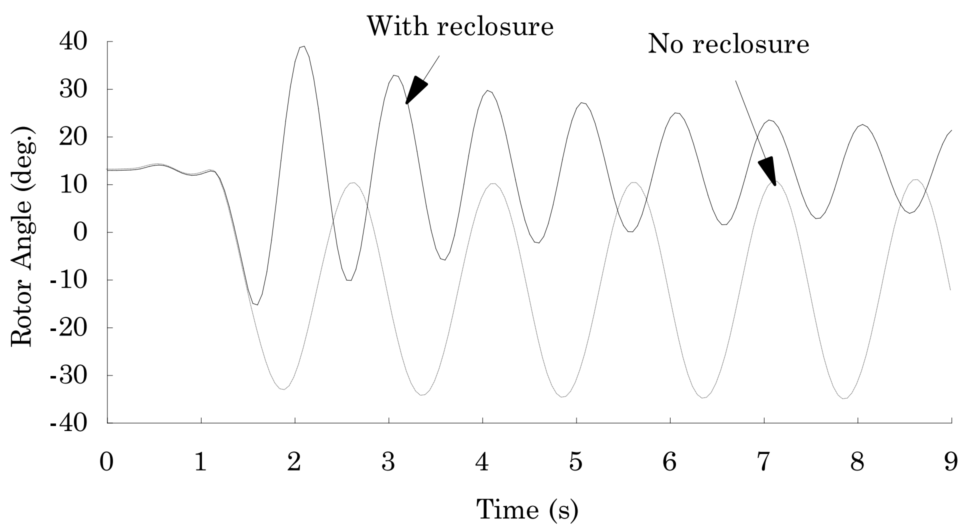


**Figure 5.13:** Rotor angle swing of generator #8. SLG fault at bus 21 with and without reclosure.

## 5.5 Summary

Presented in this chapter are the transient stability simulations of the Athabasca-Points North power system under different types of disturbances at different locations.

Three-phase-to-ground symmetrical faults represent the most severe disturbances and were investigated in greater detail. It was found that three phase faults on the main transmission lines from Island Falls to the northern end of the system would cause instability. Autoreclosure could prevent instability if it could be applied in a timely fashion.

Single-phase-to-ground faults have the highest frequency of happening in a practical power system. Simulations for this system have shown that no severe instability has been observed if the fault can be cleared by opening only that faulted phase in a time delay of normal protection, allowing two phases to be in service for a time period. Autoreclosure could greatly accelerate the process of stability restoration.