4. STEADY STATE STABILITY STUDIES OF THE ATHABASCA-POINTS NORTH POWER SYSTEM

4.1 Low Frequency Oscillation and Damping

Electromechanical oscillations of low frequency in the order of several cycles per minute are inherent characteristics of power systems with either longitudinal structure or weak tie-lines. The presence of such oscillations has been reported all over the world [21,22.23,24]. Of interest is that the longitudinal type of power systems seems to be more susceptible to poor damping.

Low frequency oscillations are also called system modes. Principally, there are two categories of modes: one is intertie modes associated with one group of generators or plants at one end of a tie-line oscillating against another group at the other end; the other is local modes associated with weakly connected power systems or remote generating units weakly connected to a large power system. Different system modes can occur simultaneously. This coupling among modes makes it difficult to define "cause and effect" relationships in analyzing the dynamic behavior of a multimachine system, especially for intertie-line oscillations [9,25,26,27].

It is recognized that the low frequency oscillations are due to the lack of damping of the system modes. The common remedy for inadequate damping is to utilize additional excitation control by means of power system stabilizers [9,28]. The effectiveness of the PSSs applied to a system depends on their design and on-site tuning. Low frequency oscillations may still occur if the installed PSSs are inappropriately designed and/or tuned. This is specially true in the case that the PSSs are designed according to one-machine infinite-bus system model.

Coordinated PSSs can overcome the drawbacks that exist in PSSs designed based on one-machine system model. Furthermore, coordinated PSSs are more efficient in providing the desired damping and powerful to suppress the low frequency oscillations. This subject will be discussed in Chapter 6.

4.2 System Description

The system under consideration is the Athabasca - Points North power system located in northern Saskatchewan, Canada, reaching from the north-western Charlot River plant to the eastern Island Falls station along an 850 kilometer overhead line operating at 110 kv and 138 kv. A simplified geographic depiction of the system is shown in Figure 4.1 and a single-line diagram of the system showing the main generation and load buses is given in Figure 4.2. Table 4.1 shows a typical load and generation distribution according to geographic area.

There are twelve utility owned hydro generators connected at both ends of the transmission line while loads are distributed along the line. At the eastern end, the system is connected to the Manitoba Hydro system through a rather weak tie-line. The connecting point to Manitoba Hydro system is modeled as infinite bus. The Island Falls plant mainly feeds Flin Flon through a double circuit 95 kilometers long. At normal operation, the power transfer over the double circuit line is about 80% of the total generation of the Island Falls plant.

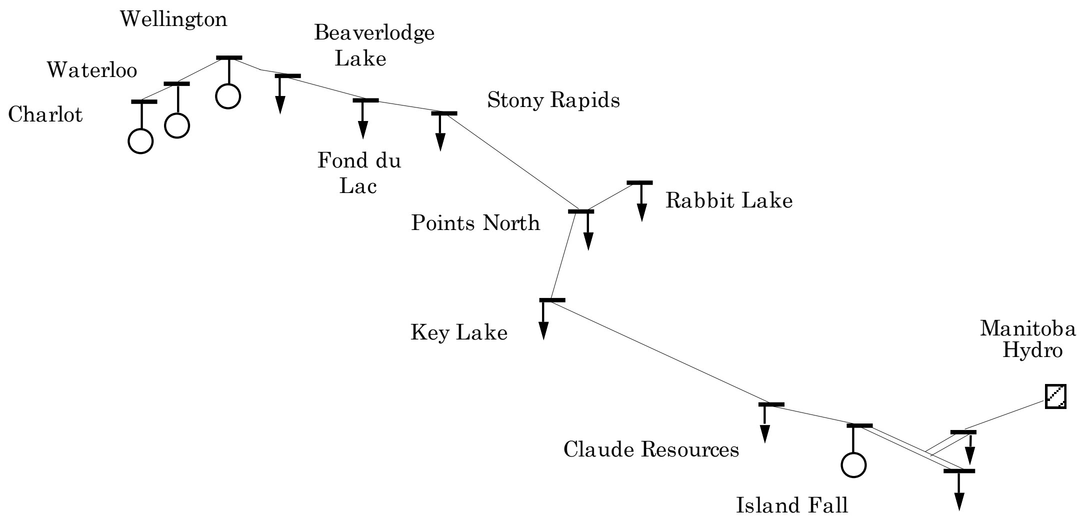

Figure 4.1: Geographic depiction of the Athabasca-Points North Power System.

Generators #1 through #7 are equipped with bus fed static exciters and electrical power input PSSs. Generators #8 and #9 are equipped with bus fed static exciters and accelerating power input PSSs. Generators #10 to #12 are equipped with modified IEEE DC Type 2 rotating excitation.

Table 4.1: Load and generation distribution(MW)

Area	Load	Generation	Deficit
North	0.5	23	22.5
Center	34	0.0	-34
South	75	97	12

4.3 Load Flow Study in Steady State

Presented in this section is a load flow study of the system under normal operating condition with off-peak demand. The fast decoupled load flow (FDLF) algorithm was employed to perform the study.

The system data used in the FDLF program is listed in Appendix A.1 in the data file named ***pqlf.inp***. The following points should be noted in reading the data file ***pqlf.inp***, the single-line diagram of Figure 4.2 and the load flow results given in Appendix A.2:

1. The Manitoba Hydro bus was assigned as the *slack* bus and its voltage magnitude was fixed at 1.05 per unit with a zero degree voltage angle. The voltage angles of all other buses in the system were referred to this *slack* bus. The numbering of the *slack* bus is arbitrary but in this system it was the last bus.

2. The SVC was treated as a voltage controlled bus, i.e., PV bus with injected active power being zero. The given value of the voltage magnitude will be dependent on the voltage regulation at that area of the system and the availability of reactive power the SVC can either generate or absorb. In this study, the voltage magnitude at this bus was fixed at 1.02 pu.

3. Floating buses do not require any data input. This was taken care of internally in FDLF.

4. All network parameters were referred to a 100.0 MVA base. Provision is, however, made to allow the use of a different system base MVA. All generations, loads and line powers are in nominal values (MW and

MVA), though per unit values can also be used in this program. Voltage is always in per unit and voltage angle in degrees.

The detailed results of the load flow study are given in Appendix A.2. The following observations can be made from the study:

1. About seventy four percent of the total generation at Island Falls is transferred to Flin Flon. The power transfer over line 30-33 is about 1.2 MW.
2. The line charging (reactive) power accumulates along the transmission lines and flows towards Island Falls where two reactors are installed.
3. The voltage profile of the system can be summarized as follows: the voltage at the north-western area is about 1.04 per unit; the SVC at Rabbit Lake keeps the voltage in this area about 1.0 per unit; and the voltage at the southern area is also about at rated voltage of 1.0 per unit.

4.4 Eigenvalue Analysis

It is a common practice to employ eigenvalue analysis to study the nature of system modes of a power system [29,30]. A positive real part of an eigenvalue indicates a negatively damped mode; a zero real part indicates an undamped mode; and a negative real part indicates a positively damped mode. A negatively damped or undamped mode needs to be controlled to ensure stable system operation.

It should be noted that the eigenanalysis conducted in this section and functional sensitivity studies conducted in the next section were under the assumption that no PSSs were in service. The purpose of the study was to identify the best sites for PSS installation.

4.4.1 Computation of Swing Modes

Two operating conditions for eigenvalue analysis were considered: the normal operation and the operating condition where one of the double circuit line was tripped. Table 4.2 summarizes the results, including the eigenvalues, frequencies of swing modes and their participating generators for both situations.

Table 4.2: Eigenvalues of APNS

Mode No	One Line Tripped σ, ω	f(Hz)	Normal Operation σ, ω	f(Hz)	Participation Generators
1	0.216, 5.919	0.94	0.183, 6.102	0.97	8,9,10
2	0.246, 9.050	1.44	0.249, 9.710	1.55	1,2,3,4,5,6,7
3	0.010, 10.973	1.75	0.010, 10.895	1.73	8,9
4	-0.058, 11.298	1.80	-0.060, 11.219	1.79	12
5	-0.065, 11.840	1.88	-0.066, 11.759	1.87	11,12
6	0.157, 12.326	1.96	0.161, 12.225	1.95	7
7	-0.053, 12.380	1.97	-0.054, 12.300	1.96	10,11
8	0.094, 12.623	2.01	0.100, 12.535	2.00	1,2,3
9	0.105, 12.625	2.01	0.112, 12.536	2.00	2,3
10	0.104, 14.192	2.10	0.107, 14.106	2.09	1,2,3,4,5,6,7
11	0.079, 14.807	2.20	0.083, 14.684	2.18	4,5,6
12	0.094, 14.809	2.20	0.098, 14.687	2.18	5,6

It was found that the participating generators in each swing mode under both cases were unchanged while swing mode λ_1 by which three remote generators oscillate, became more negatively damped with the line tripped out. One of the most negatively damped modes, λ_2, and one of the second most negatively damped modes, λ_{10}, are intertie modes, by which all the seven generators at Island Falls oscillate together against the infinite bus. The other modes are either negatively damped or poorly damped.

4.4.2 Factors that Affects Damping

It is shown in the previous section that the damping of various swing modes without PSSs is quite poor. In order to achieve improvement in dynamic stability by additional excitation control, the effects of the existing automatic voltage regulators (AVR) on damping were examined. Figure 4.3 shows that the damping deteriorates when the excitation gains increase from 40% to 120%. Note that a mode that does not change with the AVR gains is not shown in the figures. Figure 4.3 also shows that modes λ_3 and λ_4 are barely sensitive to the changes of AVR gains while modes $\lambda_1, \lambda_2, \lambda_6, \lambda_8$ to λ_{12} are sensitive. These sensitive modes involve generators #1 to #9 mainly on which PSSs are already installed.

The effects of speed governors on damping were found to be negligible as shown in Figure 4.4. This might be due to the large equivalent time constants (T_1>30s) as used in the general model for hydro speed governing system and small generator capacity (18 MVA at Island Falls). The only exception is that swing mode λ_1 is sensitive to changes of speed governors.

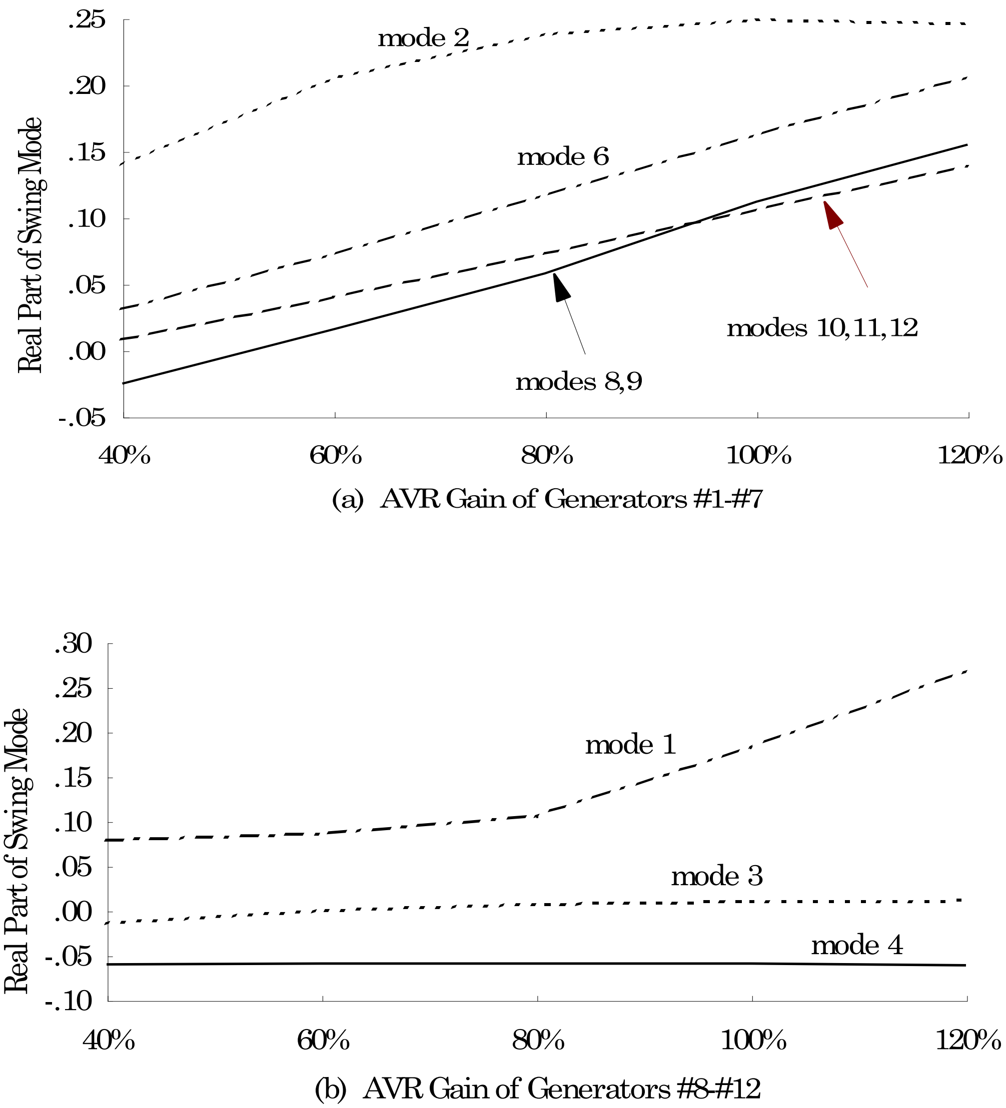

Figure 4.3: Damping versus AVR gain

4.5 Functional Sensitivity Studies

Functional sensitivity studies [31] were performed to find out what control devices affect the dynamics of the system the most. The analytical method is based on the conventional sensitivity concept. Instead of computing the sensitivity in regard to a parameter, sensitivity in regard to a transfer function of a control device was computed. In this manner, the overall effects of the device upon an index of interest, such as the damping of a particular swing mode, could be evaluated.

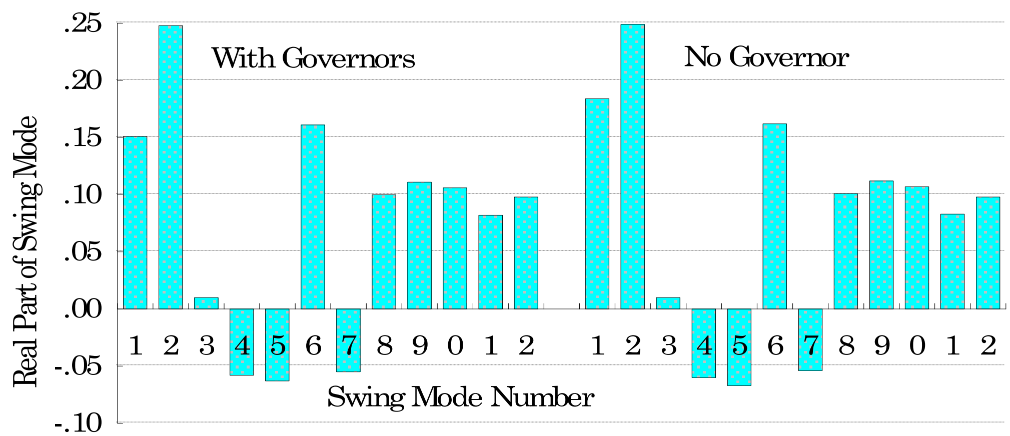

Figure 4.4: Damping Affected by Speed Governor

The discussion of results follows this order: firstly, the effect of the AVR transfer functions is discussed; which identifies those swing modes that are sensitive to AVR devices; secondly, the effect of PSS transfer functions is presented, which is the basis for PSS design discussed in Chapter 6. As the effect of the speed governing and turbine system on dynamics is inappreciably small, it is not discussed here.

The actual parameters of generators and excitation systems were used in computing the functional sensitivities. The objective was to find

$$Sensitivity = \frac{\partial \lambda}{\partial G(\lambda)} \Big|_{\lambda = swing\ \mathrm{mode}} \tag{4.1}$$

where $G(\lambda)$ is the transfer function of a device to be investigated. Tables 4.3 and 4.4 list the functional sensitivities of the swing modes with respect to AVR and PSS transfer functions (TF), respectively. These quantities are only valid near the vicinity of the current operating point and under the limitation that the changes of these transfer functions near the vicinity are not significantly large as compared to the changes of the system modes. However, they do provide quite accurate information for analyzing the effectiveness of existing controllers, such as AVRs, and for determining the most effective sites for PSS installation. It can be concluded from Table 4.3 that only swing modes λ_2,λ_6,λ_8 to λ_{12} are sensitive to the AVR transfer function of generators #1 to #7. Swing mode λ_1 is much more sensitive than swing modes λ_3 and λ_4 to the AVR transfer function of generators #10 to #12. This conclusion is also supported by the results displayed in Figure 4.3. Table 4.4 indicates how sensitive each swing mode is to various PSSs if they are installed at corresponding generators. The best PSS installation sites, as seen in the last row of Table 4.4, are decided based on the magnitude of the functional sensitivity. Usually each mode is coincident with more than one generator due to couplings among generators. To take these couplings into account, a coordinated PSS design procedure is proposed in Chapter 6 of this thesis.

It can be concluded that the results obtained and reported in this section are in agreement with the fact that the actual system is equipped with PSSs on generators #1 to #9 to provide positive damping to the various swing modes.

Table 4.3: Swing mode sensitivity to AVR transfer function

Gen	Swing Mode No											
No	1	2	3	4	5	6	7	8	9	10	11	12
1	0	0	0	0	0	0.02	0	0.27	0	0.06	0	0
2	0	0	0	0	0	0.02	0	0.09	0.18	0.06	0	0
3	0	0	0	0	0	0.02	0	0.05	0.22	0.06	0	0
4	0	0	0	0	0	0	0	0	0	0.04	0.18	0
5	0	0	0	0	0	0	0	0	0	0.04	0.04	0.13
6	0	0	0	0	0	0	0	0	0	0.04	0.04	0.13
7	0	0.1	0	0	0	0.36	0	0	0	0.03	0	0
8	0	0	0.1	0.02	0	0	0	0	0	0	0	0
9	0	0	0.1	0.03	0	0	0	0	0	0	0	0
10	0.6	0	0	0	0.02	0	0.08	0	0	0	0	0
11	0.5	0	0	0	0.12	0	0.03	0	0	0	0	0
12	0.4	0	0	0.09	0.02	0	0	0	0	0	0	0

Table 4.4: Swing mode sensitivity to PSS transfer function

Gen	Swing mode No											
No	1	2	3	4	5	6	7	8	9	10	11	12
1	0	0.03	0	0	0	0	0.02	0.15	0	0.03	0	0
2	0	0.03	0	0	0	0	0.02	0.05	0.11	0.03	0	0
3	0	0.03	0	0	0	0	0.02	0.03	0.13	0.03	0	0
4	0	0.02	0	0	0	0	0	0	0	0.03	0.08	0
5	0	0.02	0	0	0	0	0	0	0	0.03	0.02	0.07
6	0	0.02	0	0	0	0	0	0	0	0.03	0.02	0.07
7	0	0	0	0	0	0	0.1	0	0	0.01	0	0
8	0.05	0	0.15	0.02	0	0	0	0	0	0	0	0
9	0.05	0	0.15	0.02	0	0	0	0	0	0	0	0
10	0.04	0	0	0	0	0.03	0	0	0	0	0	0
11	0.03	0	0	0	0.05	0.02	0	0	0	0	0	0
12	0.03	0	0	0.04	0.02	0	0	0	0	0	0	0
PSS	10		8,9	12	11		7	1	2,3	0	4	5,6

4.5 Time Domain Simulation

Sustained low frequency oscillations are present and observed under small disturbances. For studying the response of the APNS under such a disturbance, it was assumed that a load increase of 1% of the total system capacity took place at Rabbit Lake. Figure 4.5 shows the resulting generator rotor angle oscillations of generators #1 and #8 at Island Falls and Charlot River plants, respectively.

It can be seen from Figure 4.5 that generators #1 and #8 oscillate in opposition to each other. The reason is that as the electrical distance from generators #8 to the location of the disturbance is twice of that from generator #1, the terminal voltage at Island Falls drops more and generator #1 begins to accelerate. On the other hand, generator #8 begins to generate more power to balance the sudden increase of load. All other generators at Island Falls behave similar to generator #1 and the generators at the northern end behave similar to generator #8.

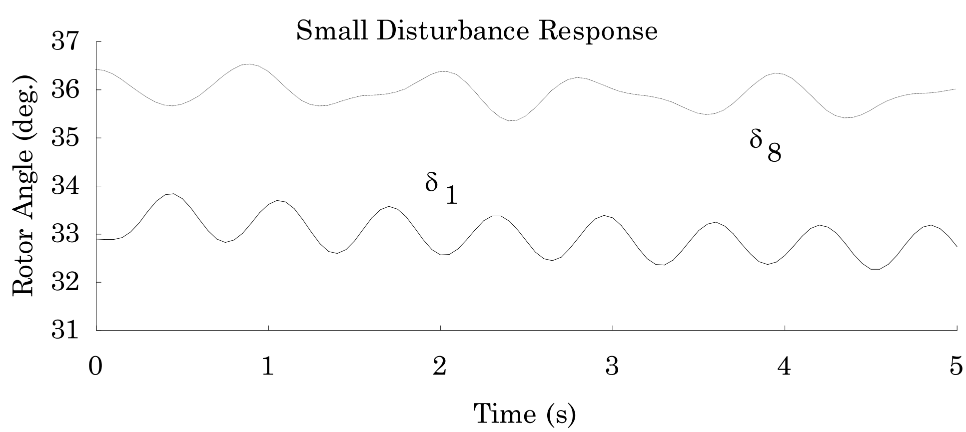

Figure 4.5: Rotor angle response to 1% load increase at Rabbit Lake.

4.6 Summary

In this chapter, an introduction has been given to the problem of steady state stability, i.e., low frequency oscillation and damping. It is understood that the desired additional damping can be provided by the application of power system stabilizers. Then, the description of the system studied in this thesis is given. A load flow study was performed for an off-peak condition. The steady state stability studies of the system were conducted by eigenvalue analysis and sensitivity study technique. The results of these studies were interpreted to obtain the best sites for installing power system stabilizers to provide positive damping. The time response of the system to a small disturbance is presented to demonstrate that more damping is desirable to improve the steady state stability of the system.