REAL TIME ONLINE EVALUATION OF SMALL SIGNAL SYSTEM DAMPING APPLIED TO POWER SYSTEM STABILIZER COMMISSIONING AND TESTING

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Abstract **– The paper introduces a new recording and online modal analysis system that evaluates small signal damping on power systems. Use of the tool as an aid during the commissioning of power system stabilizers at the Kettle generating station that operates both on the AC as well as the DC networks in the Manitoba Hydro (MH) power system is reported. The paper also reports how the same online modal analysis tool was used to confirm the successful operation of the stabilizers in AC mode through some staged tests. Further, modal analysis results of the measurement system are presented that identify and isolate improperly tuned generator controls that introduce under-damped modes on the Manitoba Hydro power system.**

Keywords – modal analysis, modes, power system stabilizer, oscillations, damped, damping ratio, decay time, eigen analysis.

I. INTRODUCTION

Power systems with long transmission lines connecting centers of load and generation can be particularly prone to electromechanical resonance. Without effective control of damping, the system may reach an operating condition where oscillations become negatively damped, leading to system separation or collapse. Damping control is achieved largely through the application of Power System Stabilizers (PSS).

Since risk of electromechanical resonance severely constrains AC power transfers in the northern section of the Manitoba Hydro grid, PSS was fitted to a hydro generator in the region. A new technique for continuously monitoring the effectiveness of the PSS in damping oscillations was used during the commissioning and over the following year.

II. BACKGROUND

A PSS control loop is applied to a generator in order to provide damping torque to oppose electromechanical resonances. As shown in Fig 1, the control loop feeds generator power, speed or angle (or a combination of these) through gain, filtering and phase shift control blocks, to apply a modulated signal to the AVR reference input [1]. The modulation applied to the AVR input results in the voltage at the generator terminals being modulated in such a way as to dissipate the energy of electromechanical modes in system loads.

Effective stabilization is obtained by appropriate choice of location of the stabilizer, and by design of the parameters of the phase lag and gain blocks [2]. These are determined in offline simulation studies and applied to the controller in commissioning. However, there are a number of uncertainties involved in this process:

- Successful tuning requires an accurate system model, including accurate load modeling.
- Verification of the PSS setup based on conventional commissioning tests tend to reflect the PSS action on local modes, while the effectiveness of damping of inter-area modes is not easily verified.
- While the robustness of the design (its effectiveness in a wide range of operating conditions) can be investigated by modeling studies, it cannot be verified by conventional measurement techniques.

The measurement technique presented in this paper addresses the above problems associated with conventional PSS design and testing. The measurement system provides estimates of damping of all the significant modes, based on analysis of small perturbations that are always present in signals acquired from the power system [3]. It is possible to confirm the effectiveness of the damping of inter-area modes as well as local modes. Moreover, since a continuous record of modal parameters is available, it is possible to verify the robustness of the design through all operating conditions experienced. Using this information, the PSS parameters can also be fine tuned, and the effectiveness of the new configuration confirmed during system tests and normal operation.

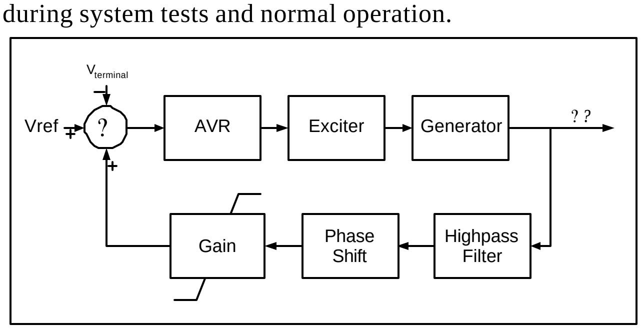

Fig 1. Typical PSS Control Loop

III. MANITOBA HYDRO POWER SYSTEM

Manitoba Hydro is a provincially owned Crown Corporation. 12 hydro-electric and 2 thermal generating stations produce the electricity generated and distributed by MH. With over 18,500 km of power lines ranging from 33kV to 500kV AC, as well as 1,800 km of 500kV DC, MH serves a customer base of approximately 400,000, spanning over a vast geographic area of 650,000 km^2. With roughly 5,000 MW of capacity, nearly half of the power is exported through high voltage interconnections to Saskatchewan, Ontario, and the U.S.

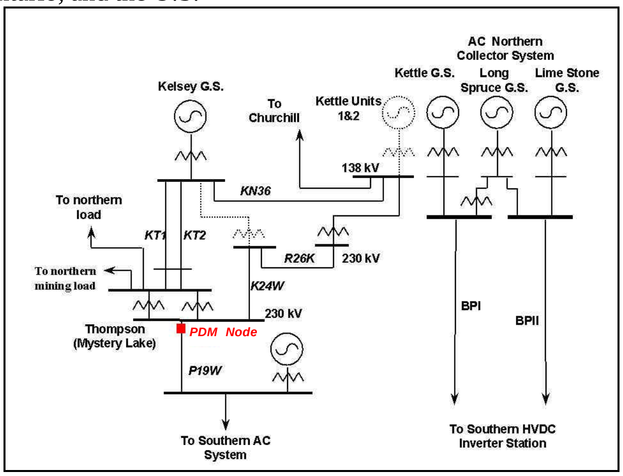

Fig 2. Simplified single line diagram of the Manitoba Hydro northern AC system.

The Kettle generating station, referred to in the abstract is shown in Fig 2. Kettle and Long Spruce together with Limestone supply power to the Henday and Radisson rectifier stations and are situated on the Nelson River in northern Manitoba. These three hydro generating stations are connected through the DC link and operate in asynchronism to the rest of the Manitoba AC system network. However, several times a year, during planned maintenance of the HVDC system, one or two of the twelve Kettle generator units are connected to the AC network. The generated power is then transferred to the south on the only available AC corridor, the P19W 230kV transmission line.

IV. POWER DYNAMICS MANAGER (PDM)

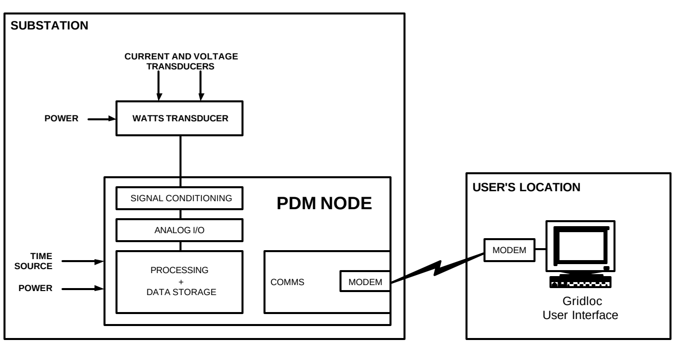

Fig 3. Block diagram of the PDM system used

The Power Dynamics Manager (PDM) was developed by Psymetrix Limited. The PDM system comprises:

- data acquisition of continuous power system values, in this case, a power measurement sampled at 10Hz.
- analysis of the small perturbations in the system measurements to obtain mode frequency, amplitude and damping estimates in the frequency range 0.04-4Hz. The analysis is carried out on 3-minute data windows, updated every 5 seconds.
- data communication and archiving
- user interface with capability for online, real-time viewing, alarm reporting, and historical review.

A number of views from the user interface are shown in Figures 4 to 7. Fig 4 shows the acquired power signal, zoomed to show the small-signal perturbations. Fig 5 shows a locus plot of the dynamic parameters for one mode, with the latest mode amplitude and decay time indicated by the arrowhead, and approximately 5 minutes of history indicated by the tail of the locus. The user settable alarm and alert boundaries for the mode are also shown in this view. If the trace enters an alert or alarm region, the associated tab changes color to indicate the condition, and an alarm output may be linked to a control room annunciation system. Fig 6 shows a record of the damping in terms of mode decay time for one mode. Fig 7 shows a mode amplitude histogram, in which clusters of modal analysis results can be observed, indicating the modes present on the system. This view also displays the user-defined frequency band configuration, which determines the range of frequency of the modes reported in each locus plot.

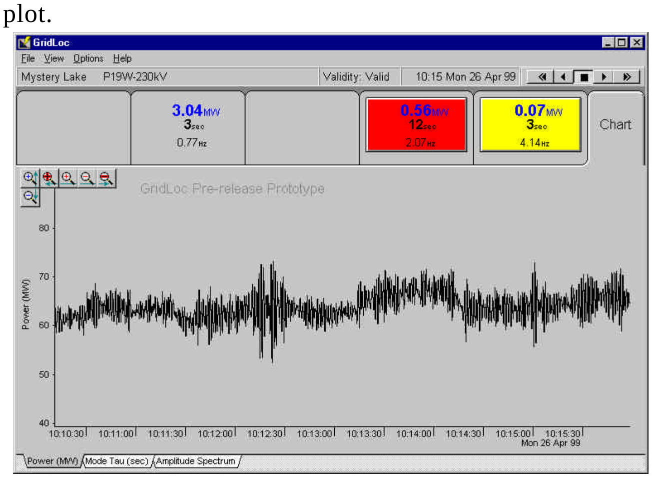

Fig 4. Transmission line power level and dominant modes

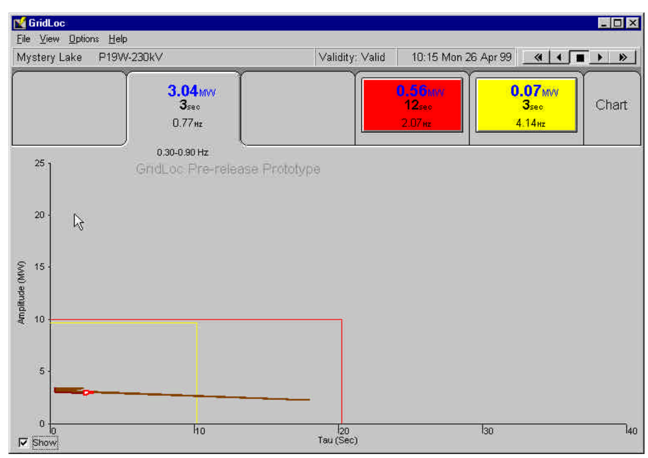

Fig 5. Locus plot of the 0.77 Hz mode

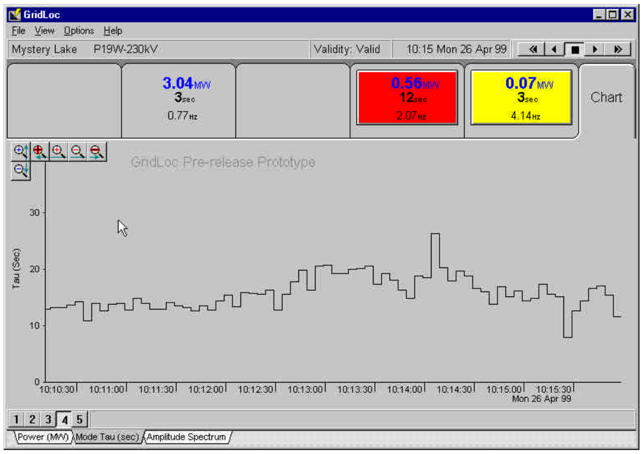

Fig 6. Decay time of the 2.07Hz mode.

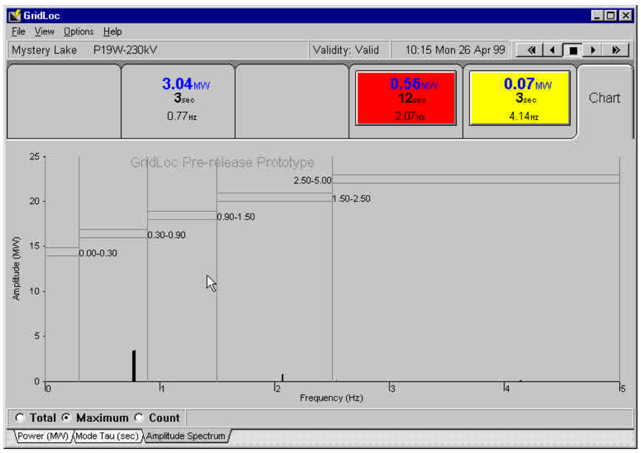

Fig 7. Amplitude histogram of modes within user specified frequency bands

V. MAPP CRITERIA

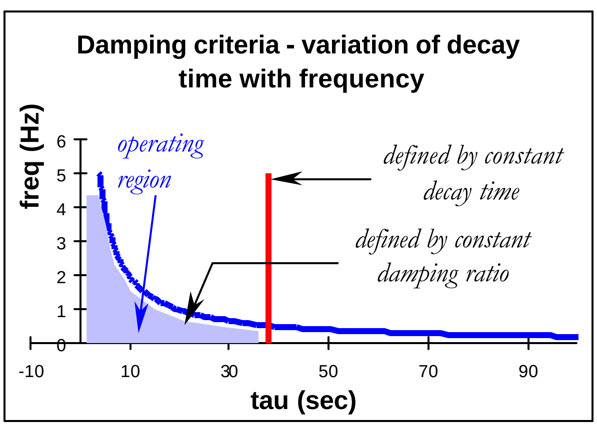

Fig 8. Allowable decay times for modes of different frequencies: MAPP criteria.

The alarm and alert boundaries of the GridLoc user interface software were set on the basis of the Mid-Continent Area Power Pool (MAPP) criteria for the limits of allowable oscillations on the power system. Fig 8 shows the allowable decay times for modes of varying frequencies. The MAPP criteria for amplitude is defined as 10% of the power delivered.

VI. OFFLINE SMALL SIGNAL SYSTEM STUDIES

In the mode of operation where a single Kettle generating unit is isolated onto the northern AC network, (as described earlier) the Manitoba Hydro system has periodically experienced voltage and power oscillations around 0.5Hz. The oscillations have typically occurred during high southern power transfers, some of which have been captured on the disturbance recorders located on the P19W 230kV line. In some instances these unstable oscillations have led to loss of customer loads and isolation of generators. This undesirable condition needed to be rectified before more Kettle units could be released for AC duty as planned, which would evidently make the oscillations worse.

Subsequent studies comprising small signal analysis and time domain stability analysis [1] have reported the presence of under damped inter-area and inter-plant modes of oscillation in the northern AC system. Stabilizers were added to the two generators at Kettle that go on AC duty, as a result of these studies. Stabilizers are also proposed for units at another generating station, Kelsey, in order to control these oscillations.

In light of the above, when the project was undertaken to evaluate the online PDM system, the obvious choice of location for the PDM Node was Mystery Lake (the northern terminal of the P19W line) as shown in Fig 2.

VII. ONLINE MODAL ANALYSIS FIELD RESULTS

A. KETTLE PSS COMMISSIONING TESTS

Two of the Kettle generators that were meant to operate on the Manitoba Hydro DC system are now operated both on the DC and AC systems as a result of the enhancement to the Nelson River transmission system. The stabilizers of these units were replaced with IEEE standard PSS2A type stabilizers. They are designed and set to accommodate dual operation on the AC and the DC collector systems [1]. The AC settings are specifically tuned to mitigate the inter-area and inter-plant modes. These modes are causing instability of the system, especially during high power transfer levels on the AC system from north to south.

Usage of the online modal analysis equipment during the commissioning of the Kettle stabilizers on the northern Manitoba Hydro network is reported in this section. The discussion is limited to the performance of the stabilizer when the Kettle units are on AC duty because the modal analysis was done on the AC system.

As reported in [1], in addition to the standard frequency response tests and the reference step-disturbance tests in order to verify the model transfer functions and confirm the damping performances respectively, the stabilizer gain was varied while maintaining the same power flow on the P19W transmission line. This was intended for performance confirmation with the aid of the PDM system.

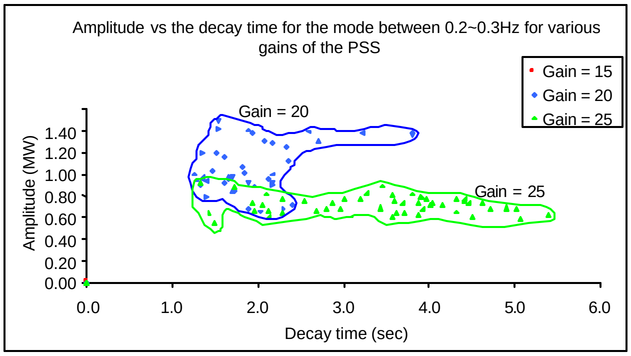

Fig 9. Scatter diagram of the dominant mode between 0.2 and 0.3 Hz for varied stabilizer gains.

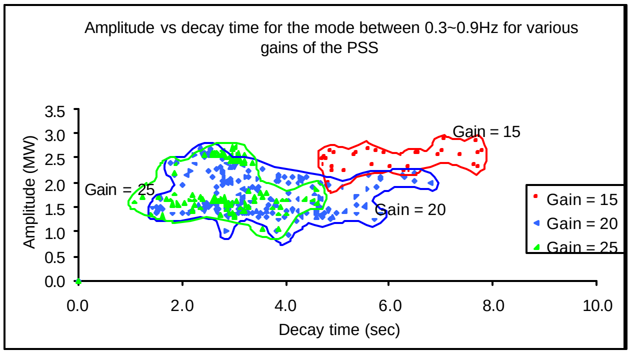

Fig 10. Scatter diagram of the dominant mode between 0.3 and 0.9 Hz for varied stabilizer gains.

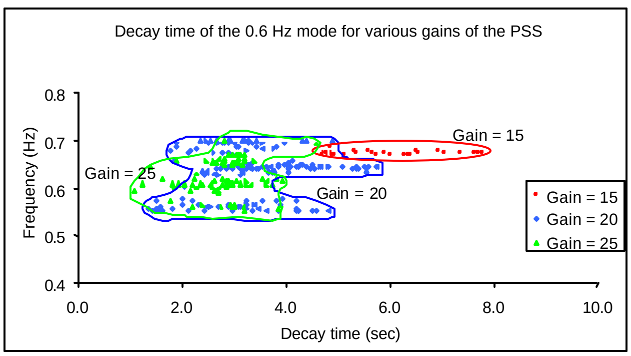

Fig 11. Frequency vs Decay time of the dominant mode between 0.3 and 0.9 Hz for varied stabilizer gains.

The scatter diagram in Fig 9 shows the decay time of the modes that were captured via the MW measurement of the transmission line P19W for the various gains of the stabilizer at the Kettle generating unit. These results show that the dominant mode within the frequencies 0.2 and 0.3Hz lies around 0.25Hz and that the amplitude of the mode is marginally improved with the increase in the stabilizer gain. However the decay time of the 0.25Hz mode is not greatly affected. The plot also shows that this mode disappears when the gain of the PSS is set to 15.

The plot in Fig 10 is for the oscillations falling in the band of 0.3 to 0.9 Hz. It is apparent from the plots that the increased PSS gains moved the modes to the left, indicating improved damping. Also from the wide spread of the dominant mode on the frequency axis (as seen in Fig 11), it was apparent that there is more than one mode present in this frequency band. This observation led to a further investigation of the modes within this band of frequencies, mostly because the new stabilizers on the Kettle units 1 and 2 are designed and tuned to control the modes within this range, which are controllable from the Kettle generating station.

The results of these tests in the frequency band of 0.3 to 0.9 Hz were reclassified into newly defined sub bands of 0.4~0.5 Hz, 0.55~0.7 Hz, 0.7~0.82 Hz. This microanalysis revealed the presence of three different modes in the range that were fairly close in magnitude. However, they were well damped.

The other dominant modes observed during the test fell approximately at frequencies 1.0Hz and 2.0Hz. Analysis showed the PSS gain to have a marginal effect on damping of the mode at 1.0Hz. Oscillations at 2.0Hz were unaffected.

Thus, the online modal analysis complemented the standard commissioning tests of a power system stabilizer, not only by confirming the damping of the tuned frequencies but also by ensuring that no other undesirable oscillations, outside its tuned frequencies are excited.

B. KETTLE PSS STAGED TESTS

The following test procedure was set up to evaluate the effect of the new stabilizers on the Kettle units on AC, using the PDM online modal analysis device. Some data during the test were also obtained from the SCADA system and the recorders that were set up at the Kettle generating station.

Test#1: A single Kettle generator unit on AC system with the stabilizer in-service: test data collection for about an hour.

Test#2: A single Kettle generator unit on AC system with the stabilizer in-service. A 5% step increase in generator voltage was to be created by operating the exciter response test switch for 5 seconds at the beginning of the test hour. Data collection to follow for approximately an hour. This step response test was intended to excite the 0.7Hz mode on the system.

Test#3: A single Kettle generator unit on AC system with the stabilizer off: test data collection for about an hour. The power level on P19W had to be maintained at approximately 70MW and the total power flow south of Ponton (southern terminal of line P19W) limited to around 170MW as determined by the offline studies.

Test#4: A single Kettle generator unit on AC system with the stabilizer off. A 5% step increase in generator voltage to be created by operating the exciter response test switch for 5 seconds at the beginning of the test hour. Data collection to follow for approximately an hour.

As the tests progressed, it was clear that Test#4 was unnecessary and risky for the power levels that were prevalent at the scheduled time for the test. Therefore in place of the final test the stabilizer was re-instated and the data collection was continued for a further 40 minutes at the same power flow conditions.

In Test#1, with the stabilizer in-service and approximately 70MW power flow on the P19W line, the 0.7Hz inter-plant mode was reported by the PDM system with mode decay time typically under 4 seconds. The mode amplitude was typically around 3MW.

It should be noted that there were three different modes with comparable amplitude at frequencies around 0.7, 0.6 and 0.45Hz reported in the amplitude histogram display.

Similar mode amplitude and decay time were observed in Test#2 following the step change in voltage reference, as were observed in Test#1.

In Test#3 with the stabilizer off, it was clear that the 0.7Hz mode was always dominant. With 70MW power flow on the P19W line, the mode decay time was typically around 9 seconds, and the mode amplitude was sustained at 5MW. This clearly confirmed the presence of an under-damped mode at 0.7Hz.

During Test#3, the PDM system reported an excursion of the 0.73Hz mode into the alarm region. Mode amplitude of 4.65MW and decay time of 18 seconds were reported. It also showed a gradual increase in the decay time and the amplitude of the 0.7Hz mode in the absence of the stabilizer. This movement of the 0.7Hz mode prompted the control engineers to re-instate the stabilizer. It was evident from the SCADA information that a drop in the load of a large mining customer caused the degradation of the 0.7Hz mode damping on the system. Following the re-instatement of the stabilizer, the damping of the 0.7Hz mode improved, and the PDM system reported the mode decay time reducing to its typical values, and exiting the alarm region.

In addition to the above observations, the scatter plots of the modes that were present during the test period verify the successful behavior of the stabilizer. Figures 12 to 14 show the scatter plots for the frequencies 0.45Hz, 0.6Hz and 0.75Hz respectively. They also clearly display that the stabilizer controllability is confined to the mode of frequency 0.75Hz, despite the fact that they all fall within its tuned bandwidth. This observation again confirms the offline eigen analysis that ranks Kettle generators highest for the controllability of the 0.7Hz mode. The offline analysis also showed that the other two modes are better controlled from a different generator on the system [1].

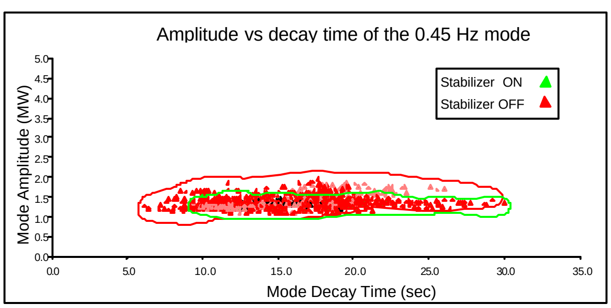

Fig 12. Scatter plot of the 0.45Hz mode during staged tests.

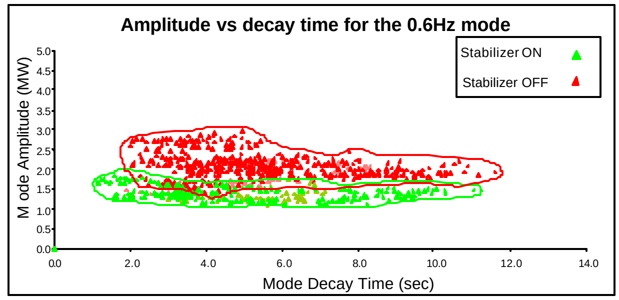

Fig 13. Scatter plot of the 0.6Hz mode during staged tests.

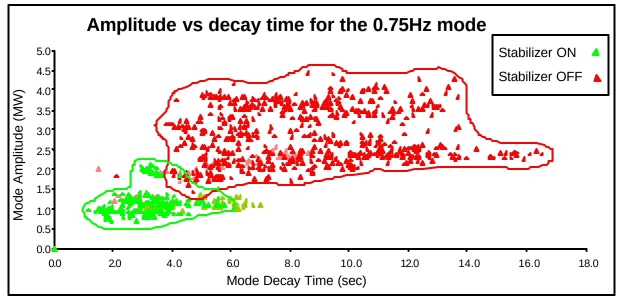

Fig 14. Scatter plot of the 0.75Hz mode during staged tests.

VIII. IDENTIFICATION OF SYSTEM MODES

Archived data collected during the period of the project resulted in roughly a year's worth of modal information on the MH power system. This data was used to review the system dynamics occurring under all of the operating conditions experienced on the northern AC network during the project, and indicates the robustness of the power system stabilization.

Through post-processing the archived data, 624 under damped modal events were identified. A histogram showing the percentage incidence of the events for the various oscillating frequencies is given in Fig 15.

All the modes recorded were between 0.44 and 2.07 Hz, with the 2.07 Hz mode accounting for nearly 64% of the modal occurrences.

The relation between mode occurrence and power transfer patterns was investigated and is shown in Fig 16. The scatter plot shows that most of the modal events occurred when the P19W line loading was lower than 40 MW. In addition, all the 2.07 Hz modal events occurred when the line was loaded below 10 MW. Under these conditions it is unlikely that the Kettle units would have been operating on the AC system.

Scatter plots of the mode frequency versus damping ratio in Fig 17 shows the 2.07 Hz mode to be the most poorly damped. Plotting the mode frequency versus mode amplitude (Fig 18) however, reveals that 2.07 Hz mode is of very low amplitude. The largest mode amplitude of over 25 MW was encountered when 230 kV line H59C tripped and subsequently cross-tripped several generating units. Investigations into the source of the oscillations identified in this project require additional testing and analysis, which are beyond the scope of the paper.

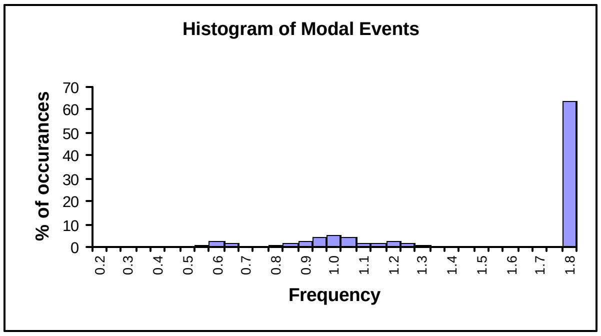

Fig 15. Histogram of modal frequency

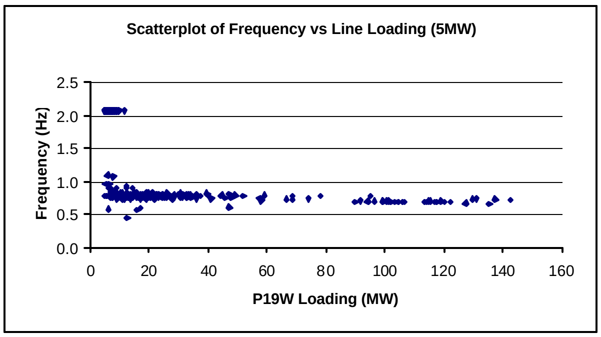

Fig 16. Scatter plot of frequency vs line loading

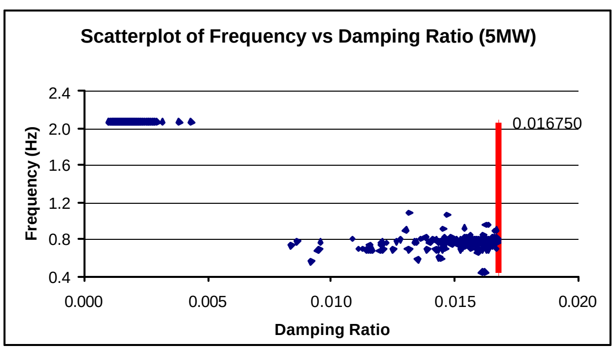

Fig 17. Scatter plot of frequency vs damping ratio.

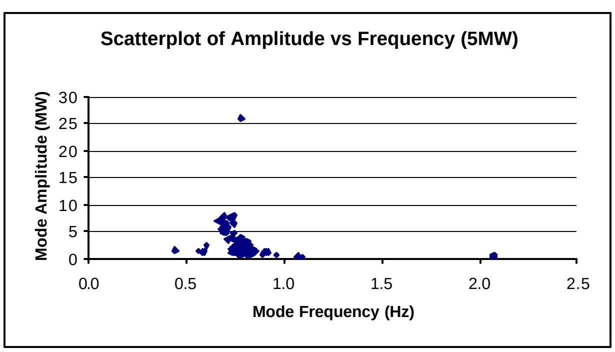

Fig 18. Scatter plot of amplitude vs frequency

IX. CONCLUSION

The online modal analysis device which was monitoring only a single point of the Manitoba Hydro AC network could be used to aid and complement the standard commissioning tests of a power system stabilizer. The tool was also used to confirm the stabilizer's successful operation in damping the inter-area and inter-plant modes. In addition, the online modal analyzer was able to detect other disturbances that were exciting oscillations on the system.

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