Abstract—This paper provides an overview of a dynamic analysis carried out on the large-scale Queensland transmission network. This paper highlights how decaying voltages and the subsequent hyper-excitation of generators can lead to transient oscillatory instability because of insufficient damping torque. Different levels of voltage compensation have been implemented at critical generators in the model to determine the impact these different control levels may have on the time to voltage collapse following a system contingency.

Index Terms—Power System Modelling, Power System Planning, Power System Security, Long Term Dynamics, Voltage Stability, Voltage Collapse

I. INTRODUCTION

Voltage stability and voltage collapse issues have in recent years begun to pose an undesirable threat to the operational security of power systems. This paper looks at the way in which voltage collapse ultimately leads a system to be oscillatory unstable because of insufficient damping torque. Often when dealing with system instability issues it is common to consider voltage instability and angle stability separately and only consider the extreme examples where angle instability is predominantly a generator issue and voltage instability is predominantly a load issue [1]. The existence of interrelationship of voltage collapse to classical transient stability has however been highlighted in [2]. There is inevitably a proportion of both voltage instability and angle instability in most practical collapses. Vournas et al [3] also point out that the dynamics of synchronous generators cannot be completely separated from voltage stability considerations, because they provide both power and voltage to load buses. CIGRE have illustrated how decreasing system voltage and system collapse, resulting from the restoration of load power by tap changer operation and the limiting of generator currents can, in some cases, lead to transient angle instability [4]. The study performed by CIGRE was on a small ten-bus test system, this paper highlights this particular scenario on the much larger scale Queensland transmission system.

II. QUEENSLAND ELECTRICITY TRANSMISSION SYSTEM

The Queensland power transmission system is a system that can be described appropriately as longitudinal. A long and thin grid system, it stretches over 1700 km in length. The major load centres of this system are located considerable distances from the main sources of generation. Figure 1 provides a good illustration of this longitudinal structure. The forecasted energy growth in the state of Queensland is expected to be around 3.2% p.a. over the next ten years [5]. Subsequently, it is becoming increasingly important to be able to maintain secure operation and suitable voltage levels under a number of crucial system contingencies and to determine maximum capabilities for the transfers between different regions of this system. The large transmission distances involved in the Queensland system mean that voltage stability is one of the major factors influencing the transmission limits between the different regions of this system.

In the Queensland System there are three major regions. The ‘Northern’ region contains mostly hydro generation and some load while the ‘Central’ region contains mostly thermal power generators and a significant percentage of the industrial load in the system. The ‘Southern’ region contains thermal power generators, some pumped storage hydro capacity and the bulk of the residential and industrial loads in the system. The majority of power flows in the system are from the Central region to the Southern region.

The two main contingencies considered in this paper are as follows.

Case 2: Transmission line number 2 between buses 46130 (Ross) and 46350 (Strathmore), in the northern region is tripped.

Case 3: Transmission line between 46200 (Broadsound) and 46290 (Stanwell), in the central region is tripped.

The locations of these contingencies in the Queensland system are illustrated in Figure 1. The power flows in the system model studied are loosely based on a typical summer loading of the system, which in Queensland is higher than the winter loading period. The loading in the Southern and Northern regions have been increased beyond the normal recommended base case in order to ensure that the contingencies studied lead to voltage instability problems.
Figure 1 Diagram of Queensland Electricity System
III. SIMULATION TOOLS

In this paper the results of studies using the PSS/E dynamic simulation package from the Power Technologies Incorporated (PTI) Company are presented. The over-excitation limiter, voltage compensation and tap changing models used in this study are the same as the models described in detail in [6]. The over-excitation models use reference [7] as a guide and have been created to follow the ANSI C50.13 inverse time curves. The ANSI C50.13 standard [8] provides a guide to the minimum acceptable level of temporary current overload capability for the rotor and stator windings. The current overload values are given in Table 1. Agee [9] points out that while the stator current requirements are given it is unlikely that generation owners will operate beyond this curve as most machines are not built with excess armature thermal capability.

Table 1 Field Winding Short-Time Thermal Capability

<table>
<thead>
<tr>
<th>Time (s)</th>
<th>ANSI C50.13 Field Current Ir (% of rated)</th>
<th>ANSI C50.13 Stator Current Is (% of rated)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>208</td>
<td>226</td>
</tr>
<tr>
<td>30</td>
<td>146</td>
<td>154</td>
</tr>
<tr>
<td>60</td>
<td>125</td>
<td>130</td>
</tr>
<tr>
<td>120</td>
<td>112</td>
<td>116</td>
</tr>
</tbody>
</table>

A diagram of the over-excitation limiter model is shown in Figure 2. Only the stator over-excitation limiter component has been illustrated for simplicity, as the rotor limiter is identical in structure to the stator limiter. The minimum, most negative signal from either the stator or rotor limiter is sent to the AVR summing junction.

Figure 2 Diagram of Inverse time curve, ‘summed’ over-excitation model created for use in PTI PSS/E program

- Integrator 1 upper limit = 6, lower limit = 0,
- Integrator 2 upper limit = 1.6, lower limit = 1.05,
- C1=1.04,C2 = 239,C3 = -0.0275, C4 = 0.0275.

The model values shown above and in Figure 2 are used in both the rotor limiter and the stator limiter models and have been set up so that they satisfy both stator and rotor ANSI C50.13 curves. This means that for while the curve is set up to closely match the rotor standard curve it is slightly conservative with regards to the stator over-excitation curve. As shown in Table 1 the stator curve allows for slightly higher per unit values of current at any given time compared to the rotor. The similar values were used for ease of operation and it was felt that as the stator curve was within the standard it would be an adequate, if slightly conservative, representation of a stator over-excitation limiter.

The PSS/E standard ‘OLTC1’ tap changer model was chosen for the purposes of the simulation as this model allows the modelling of transformer taps to control system voltage.

While load flow based techniques are the most commonly used voltage stability analysis tools a case has been put forward, with some justification, that the results of these load-flow based methods may be somewhat pessimistic [10]. This is because these methods do not consider the time dependent aspects of control actions, such as transformer tap changers and generator over-excitation limiters nor do they account for the restoration of voltage dependent loads following a system contingency. It is also important to note that while the maximum power transfer capability of the system is normally assumed to coincide with a zero determinant of the load flow Jacobian matrix it is also important to note that the non convergence of the load flow solution can sometimes be due to a numerical phenomenon of the solution technique being used. Sauer and Pai highlight this situation by pointing out that there have been many cases cited where Guass-Sidel routines converge when Newton-Raphson routines do not [11]. Dynamic simulation is therefore often used as the benchmark for verifying the results obtained from the power-flow based techniques and is the focus of this paper.

IV. CONTINGENCY ANALYSIS

A. Case 2

Figure 3 illustrates the variation in voltage following a case 2 contingency for a select set of five buses. These select buses have been chosen because they are located in different, distinct regions of the Queensland system and are located on the high voltage 275kV backbone of this system as shown in Figure 1. Bus 46320 is located in the Northern region, bus 46110 is located in the border region between the Northern and Central regions, bus 46070 is located in the Central region and buses 46360 and 46030 are located in the Southern region of the Queensland system.

Figure 3 Case 2 contingency, voltage variations at select buses
A voltage collapse and subsequent transient instability incident occurs in the northern region, as indicated in Figure 3 by the collapse and subsequent uncontrolled oscillations of the bus voltages at buses 46320 and 46110.

Note from Figure 3 that while the oscillations are growing in magnitude the voltage collapse continues as illustrated by the fact that the minimum point of the oscillation decreases quicker that the magnitude of the oscillation would allow.

In order to understand how the decay in voltages in the Northern region leads to oscillatory instability it is useful to look at the field voltages (Efd) of the Northern generators at Karreya, Barron Gorge and Collinsville and the susceptance values of the two major Northern SVCs at Ross and Nebo.

In a typical generator exciter arrangement input signals from the over-excitation limiters (Voel), the stabiliser (Aux), the reference signal (Vref) and the feedback from the bus voltage through the voltage compensator (Ecomp) are added to the summing junction of the AVR, which in turn outputs a field voltage signal (Efd). The inputs have the impact of changing the value of the field voltage signal.

Figure 4 illustrates the variation in Efd, and conversely susceptance, at one unit in each of the northern generation and SVC locations following the contingency. All of the field voltages and susceptance values except for the Nebo SVC, located in the border region, show distinct changes in value following tap changes in the system. Figure 4 shows that the field voltage of the Kareeya 4 unit, which is representative of the other units at Kareeya is especially effected by the changes in tap and that the oscillations associated with the tap changes take longer and longer to dampen out as the excitation increases in value until the last change in tap occurrence at which point the system undergoes growing oscillatory instability.

Figure 5 shows the variation in Kareeya unit 4 exciter parameters following the case 2 contingency. Note in particular how the auxiliary signal (Aux) from the unit’s stabiliser gets progressively worse as the excitation level, Efd, begins to climb and eventually hits and swings between its limiting values of 0.5 and –0.5 per unit at the point at which the system becomes unstable. The operation of the taps in the system act to improve the voltage level on the subtransmission and distribution system and have the effect of both increasing the voltage dependent loading and decreasing the voltage on the transmission side. As a result the voltages in the system decline and more reactive power must be sourced to maintain acceptable voltage levels. This leads to increased excitation in the Northern generators and the Kareeya generators in particular. At these increased levels the damping torque of the stabiliser is not adequate to provide stabilisation and dampening of the system oscillations following disturbance. The stabiliser signal is simply not large enough to have a satisfactory impact on the comparatively larger field voltage signal. This is a perfect example of how voltage collapse can lead a system into a state of transient oscillatory instability.

Figure 6 illustrates the variation in voltage following a case 3 contingency for the buses described in the case 2 contingency studies. A voltage collapse and subsequent transient instability incident occurs in the northern region, and in the border region between the Northern and Central regions as indicated in Figure 6 by the collapse and subsequent uncontrolled oscillations of the bus voltages at buses 46320 and 46110 and the small collapse observed in the voltage at bus 46070 in the Central region. Figure 6 shows that at some time shortly after the 20 seconds mark the voltage at bus 46320 appears to drop. The cause of this was found to be the tripping by an out of step relay of the 55MW Barcaldine Unit. The loss of synchronism of this unit and its impact on the system, like its size in comparison to the system capacity, is relatively small and once the unit is tripped the system settles out fairly quickly to a slightly lower value.
Figure 6 Case 3 contingency, voltage variations at select buses

Just as with the case 2 contingency, in order to understand how the decay in voltages in the Northern region lead to oscillatory instability if is useful to look at the field voltages (Efd) of the Northern generators and the susceptance values of the Northern SVCs. Figure 7 illustrates the variation in Efd, and conversely susceptance, at one unit in each of the northern generation and SVC locations following the contingency. All of the field voltages and susceptance values except for the Nebo SVC show distinct changes in value following tap changes in the system. Figure 7 shows that the field voltage of the Kareeya 4 unit, which is representative of the other units at Kareeya is especially effected by the changes in tap and that the oscillations associated with the tap changes take longer and longer to dampen out as the excitation increases in value until the last change in tap occurrence at which point the system undergoes growing oscillatory instability.

Figure 7 Case 3, Northern generator Field Voltage (Efd) and Northern SVC susceptance (pu)

Figure 8 shows the variation in Kareeya unit 4 exciter parameters following the case 3 contingency. Just as with the case 2 contingency it would appear that the high level of field excitation and inability of the stabiliser to provide sufficient damping torque lead the system to lose control and become oscillatory instable.

Figure 8 Case 3, Kareeya unit 4 exciter parameters

C. Voltage Compensation

Different values of compensation were used on the Kareeya generators to observe the impact these different values might have on the time to collapse and subsequent transient instability. The results of this study are shown in Figure 9.

Figure 9 Case 2 contingency, bus 46320 variation for different compensation values

The voltage at bus 46320 has been chosen for illustration purposes as this voltage, amongst all of the other voltages observed for the contingency, displayed the greatest extent of the collapse. The value of Xcomp is the equivalent reactance that needs to be placed between the control point and the terminal. The value of the Xcomp parameter can be varied to allow the control point to be either internal or external to the terminals. If Xcomp is negative the controlled point is outside the terminals by the amount of the compensation. If Xcomp is positive the controlled point is inside the terminals by the amount of the compensation. The signal from the compensator, Ecomp is determined by (1).

$$E_{comp} = |V_{term} - jX_{comp} * I_{term}|$$

(1)
Vterm and Iterm are the values of the terminal voltage and current respectively. Ecomp is the difference between the actual terminal voltage and the calculated voltage at the desired control point. The signal from the compensator is negatively summed into the exciter loop and as such an increase in the signal value has the effect of reducing the field voltage signal.

As shown in Figure 9 the more negative the Xcomp value used is, and therefore how far the control point is within the generator terminals, the better the time to collapse becomes. Having the point within the terminals means that the control of the bus voltage is less stringent at the higher loading condition.

To illustrate how varying the compensation value can have an impact on the time to collapse Figure 10 illustrates the differences in field voltage and stabilizer signal when the different values of compensation are used. The field voltage for the base case (Xcomp = 0.03 pu), labelled (A) in the diagram is clearly higher than the case where the compensation value Xcomp is equal to -0.1 per unit, labelled (B) in the diagram. This is because the Ecomp signal is higher and the excitation signal is reduced. The Efd variation following the changing of a tap also appears reduced when a compensation of Xcomp equal to -0.1 is used. This lower excitation means that the stabiliser is able to provide the necessary damping torque for a longer period of time than for the base case. Note how the stabilizer signal for the base case, labelled (C) reaches its limits sooner than for the case where Xcomp is equal to -0.1, labelled (D) in the diagram.

**Figure 10 Case 2, Kareeya unit 4 excitation parameters for different compensation values**

**V. CONCLUSIONS**

This paper has highlighted how decaying voltages and the subsequent hyper-excitation of generators can lead to transient oscillatory instability because of insufficient damping torque. It emphasises the point that long-term voltage instability phenomena and transient instability phenomena are, in general, interrelated and therefore not completely independent of each other. It has been shown that in the case of certain system contingencies in the Queensland system it was preferable to let to control of the system voltage be less stringent, via the use of voltage compensation. An improvement in the time to collapse following a system contingency was possible via use of this voltage compensation.

**VI. REFERENCES**


**VII. BIOGRAPHIES**

Craig Anthony Aumuller was born in Cairns, Australia in 1974. He graduated from James Cook University, Australia in 1996 with a Bachelor of Engineering (Honours). Since graduation he has worked at the Callide B Power Station and at Connell Wagner, an Australian based international consulting engineering firm. He has completed PhD research at the University of Queensland, Brisbane, Australia and is currently working as a lecturer at James Cook University, Townsville, Australia. His interests include power systems planning, analysis and control.

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