Investigating the Impact of Powerformer on Voltage Stability by Dynamic Simulation

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***Abstract*—This paper provides an overview of a dynamic analysis carried out on a modified Nordic test system to determine the impact of the Powerformer on voltage stability. The unique aspects of the Powerformer will be highlighted and the modeling of long-term dynamic elements, especially those pertinent to the study of the Powerformer will be discussed. Overexcitation limiter models created for use in the PTI PSS/E analysis program will be discussed and utilized. The importance of choosing the right value of overexcitation limiter gain will be highlighted and discussed. The impact of the location of the Powerformer and the compensation scheme utilized on the time to collapse following a system contingency will also be highlighted and discussed.**

***Index Terms*—Long term dynamics, power system modeling, power system planning, power system security, voltage collapse, voltage stability.**

I. Introduction

VOLTAGE stability and voltage collapse issues have in recent years begun to pose a undesirable threat to the operational security of power systems. Recent collapses, including the 1996 collapse of the western U.S. grid [1], have highlighted the importance of avoiding generator limiting in order to limit potential voltage instability. The particular importance of the stator current limitation and its contribution to the collapse of a system has also been highlighted [2]. The focus of this paper is a new type of generator, the Powerformer [3], [4], which connects directly to the high voltage bus, and therefore, controls this high side bus's voltage directly. A single line comparison between this Powerformer and a conventional generator is highlighted in Fig. 1 [5].

Potential system support benefits via high side voltage control methods have been highlighted in a number of texts [6], [7], reports [8], [9], and papers [10]–[13].

The Powerformer is able to maintain an overload in its stator windings for a longer period than a conventional generator. This means that Powerformer may provide reactive support for an extended period of time compared to a conventional generator. The benefits of this overload capability in improving voltage stability in the Nordic Test system are a focus of this paper.

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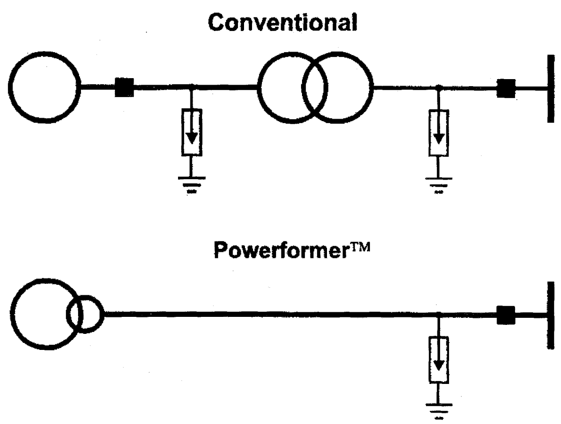

Fig. 1. Comparison of conventional and Powerformer.

II. 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.

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 [14]. This is because these methods do not consider the time dependant aspects of control actions, such as transformer tap changers and generator overexcitation 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 nonconvergence 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 [15]. Dynamic simulation is therefore often used as the benchmark for verifying the results obtained from the power-flow-based techniques.

III. Overexcitation Limiters

The purpose of overexcitation limiters is to ensure that the generator windings are not damaged due to heating caused by excessive current flows. Overexcitation limiters can be installed to limit the currents in both the rotor and stator windings.

TABLE I
FIELD WINDING SHORT-TIME THERMAL CAPABILITY

Time (s)	10	30	60	120
ANSI C50.13 Field Current Ir (% of rated)	208	146	125	112
ANSI C50.13 Stator Current Is (% of rated)	226	154	130	116
Powerformer Stator Current Is (% of rated)	1067	620	444	322

The interaction between rotor and stator limiters is extremely important in the context of system stability and it has been pointed out that rotor limited generator, subject to decreasing voltages can become stator-limited [2]. It has also been pointed out that armature current limiter affects the power system in a more drastic manner than does a rotor current limiter [2]. Delaying stator current limitation will therefore be extremely beneficial.

While it is common to have a rotor overexcitation limiter installed, in a majority of cases, the limiting function on the stator windings is performed by an overcurrent relay. The overcurrent relay instantaneously disconnects the generator from the grid if the stator current becomes excessive. Clearly the case where the relay operates will be more extreme than that of the limiter as it removes the machine completely from service. Although the majority of generators are protected by overcurrent relays, there are a number of cases where a current limiter, rather than a relay protects the stator current, as has been highlighted by Johansson [16]. According to Johansson, overexcitation limiters are used to protect the stator currents at numerous nuclear power plants in Sweden. With this in mind and remembering that the topic of this paper is the Powerformer, its ability to maintain a higher stator current overload capability and the impact of the resultant higher limit level is therefore of particular interest and should be suitably modeled.

The ANSI C50.13 standard [17] 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 I. Agee [18] 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. This situation, of course, does not apply to the Powerformer, which can maintain currents in excess of this standard curve. The relationship between the overload time and the Powerformer's Armature current is given in (1) and the comparison between the conventional curve and the Powerformer curve is shown in Table I and in Fig. 2.

$$\frac{Ia}{Ian} = \sqrt{\frac{75}{4*T}+1}$$
$$\text{Where } Ia = Armature\ Current$$
$$Ian = Rated\ Armature\ Current$$
$$T = Overload\ time\ (min). \tag{1}$$

There are many different types of overexcitation limiter available for use. Each unique style of overexcitation limiter used to limit generator currents will have a distinctly different impact on system operation and stability, as will be shown in this paper. The IEEE has provided an excellent reference on the subject of generator overexcitation limiters [19], as has Mummert [20]. In general, there are two main categories of limiter, "summed" and "take-over." The overexcitation signal, Voel, from the summed type overexcitation limiter, is added to the summing junction of the AVR with the inputs from the voltage compensator (Ecomp), stabilizer (Aux) and the reference signal (Vref). As the Voel signal is normally negative, it has the equivalent effect of reducing the reference voltage value and thereby the excitation of the machine.

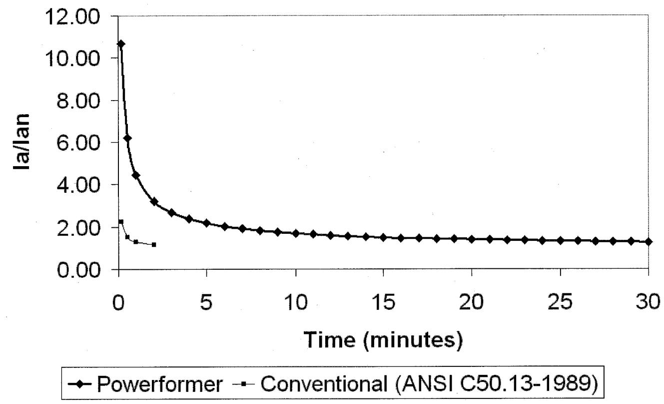

Fig. 2. Comparisons between conventional and Powerformer armature overload capability curves.

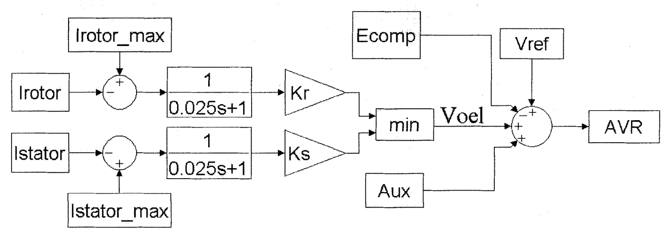

Fig. 3. Diagram of simple "summed" overexcitation model created for use in PTI PSS/E program.

Take-over limiters, on the other hand, replace the main exciter control loop with a loop control integral to the overexcitation limiter. Either Voel, or the output from the summing junction will be passed on the main AVR loop depending on which has the minimum, or most negative, value. This is considered to be the most crucial signal. Unlike the summed-type limiter, the input signal from the main summing junction is taken over until the level of the machine falls below the desired limit.

If the gain of the summed-type limiter is sufficiently high and the bandwidth of the limiter is the same, or higher than the exciter control loop, the operation of the limiter is similar to that of a take-over-type limiter.

Two different overexcitation models have been developed for use in the PTI PSS/E power system simulation program. A simple "summed"'-type overexcitation limiter has been created which acts, without delay, to reduce the excitation and bring the currents (rotor or stator) below a given set limit value. A diagram of this model is shown in Fig. 3.

The difference values between the rotor and stator currents and their set limit values are sent to a logic switch. These difference signals are limited so that only negative values are sent. The minimum, or smallest, value of the two signals input into the logic switch is then sent from the switch to the summing

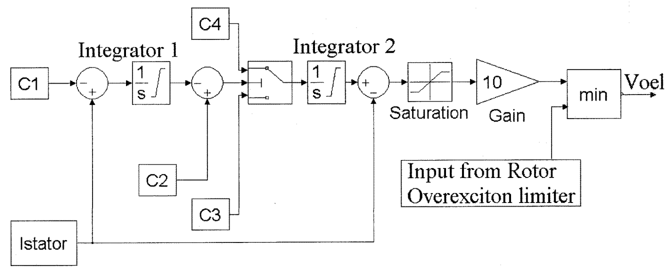

Fig. 4. Diagram of inverse time curve "summed" overexcitation model created for use in PTI PSS/E program.

junction of the AVR and subsequently acts to reduce the excitation. This model is similar to models used by the Cigré taskforce on long-term dynamics [21] and by Johansson *et al.* [22]. The major difference between this model and those used by Cigré and Johansson is that unlike these models, which act as "take-over" overexcitation limiters, the simple model created acts as a "summed"-type limiter. This model can be made to act in a similar manner to a take-over limiter by making the gain sufficiently high.

A second overexcitation limiter model, for use in the PSS/E program, has also been created which acts to follow the ANSI C50.13 inverse time curves. A diagram of this model is shown in Fig. 4. Only the stator overexcitation limiter component has been illustrated for simplicity, as the rotor limiter is identical in structure to the stator limiter. Just as with the simple summed limiter, the minimum, most negative signal from either the stator or rotor limiter is sent to the AVR summing junction.

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

The model values shown above and in Fig. 4 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 overexcitation curve. As shown in Table I, 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 overexcitation limiter.

Unlike the simple overexcitation model shown in Fig. 3, this controller does not act instantaneously to reduce the excitation, instead operating after a time delay dependent on how far the current (rotor or stator) is above a given value. If the current is sufficiently high though (greater than 1.6 times rated), the excitation will be reduced without delay in a manner similar to the first simple limiter.

This model has been formed using [19] as a guide. If the value of stator or rotor current is above a given value, constant C1, the timing integrator designated "Integrator 1" in Fig. 4 begins to ramp up from its initial value of zero. When the output from this integrator goes above the value of constant C2, the switch will send a signal to the second integrator to ramp down at the rate indicated by constant C3. When the output from this integrator exceeds the value of the current, the output from the summing junction will become negative. Once the signal becomes negative, it will be passed by the gain/saturation limiter combination on to the exciter's summing junction in the same manner as the simple limiter. Note how if the signal is greater than 1.6, the signal will immediately go negative and the excitation will be ramped down.

In order for the limiter model to satisfy the Powerformer stator overexcitation curve, the following model values in the stator limiter component are substituted with those shown previously

- Integrator 1 $\text{upper limit} = 240$;
- Integrator 2 $\text{upper limit} = 2.0$;
- $\text{C2} = 239$, $\text{C3} = -0.0015$, $\text{C4} = 0.0015$.

IV. Voltage Compensation – High Side Voltage Control

The "COMP" line drop compensation model used by PTI in their PSS/E simulation analysis software package has been used in this paper. The signal from this compensator, Ecomp, is determined by (2)

$$Ecomp = |Vterm - jXcomp * Iterm|. \tag{2}$$

VTERM and ITERM are the values of the terminal voltage and current, respectively. ECOMP is the compensated value of the desired voltage set point. This is normally equal to the voltage set point unless compensation is required. The value of XCOMP is the equivalent reactance that needs to be placed between the control point and the terminal. This is equivalent to putting a 1:1 ratio transformer between the generator terminals and the high voltage bus. A negative reactance value will result in the voltage being controlled effectively at a point inside the generator windings. As the loading on the generator increases, and therefore, ITERM increases, the value of ECOMP will increase and the excitation signal will decrease.

V. Transformer Tap Changers and Load Dynamics

Just as the operation of generator limiters must be considered in long-term analyses, the operation of transformer taps and load dynamics including load restoration brought about by tap changer operation must also be considered. The load dynamics used in the study of the modified Nordic system are the same as those used by Cigré in their report on long-term dynamics [21]. The loads are therefore both voltage and frequency dependent. The PSS/E standard "OLTC1" tap changer model was chosen for the purposes of the simulation as this model allows the modeling of transformer taps to control system voltage. This tap changing model incorporates an integrator timer that ignores brief self-correcting voltage fluctuations by only operating when the voltage has been outside the desired operating band more than it has been in, by a time greater than a set delay value. A further delay between subsequent tap changing operations can also be set.

VI. Modified Nordic Test System

In this paper, the results of dynamic simulation analyses performed for a number of contingencies on the Modified Nordic Test System will be presented. This test system is based on the Cigré Nordic test system [21] and differs from this standard test

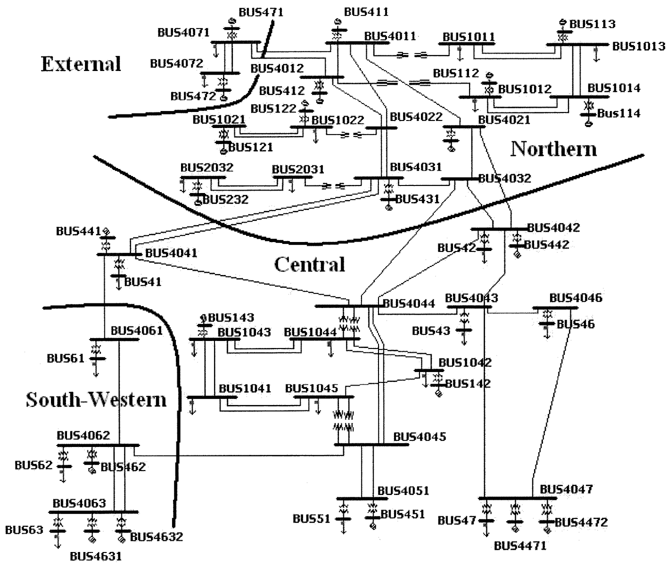

Fig. 5. Modified Nordic test system.

system in one area only. The step-up transformers in this modified system have been modeled externally and the reactive limits of the generators increased in the load flow data to allow for the additional losses in the transformers. This has been done to ensure an accurate indication of the loading limit of the buses in the system is obtained in the static, load flow-based analyses. It has been found in previous investigations that accurate loading limit results cannot be obtained if the transformers are modeled internally [23]. The Modified Nordic Test System is shown in Fig. 5. The three main contingencies considered in this study are the same as that used by the Cigré task force 38.02.08 on long term dynamics [21].

Case 1: generator at bus 4472, in the "central" region, is tripped;

Case 4: transmission line in the "northern" region, between buses 4011 and 4021 is tripped and generator at bus 112 is tripped 0.1 s later;

Case 14: generator at bus 462, in the "south-western" region, is tripped.

In this modified Nordic Test System, there are four major regions. The "northern" region contains mostly hydro generation and some load while the "central" region contains mostly thermal power generators and a significant majority of the load in the system. The "southwest" region is somewhat loosely connected to the rest of the system, containing some generation and load. The "external" region is connected to the northern region and contains a mixture of load and generation and the flows from the external region to northern region are small compared to the flows between other regions. The majority of power flows in the system are from the northern region to the central region.

VII. Overexcitation Limiter Model Comparison – Choosing the Right Value of Gain

In the introduction to this paper, the importance of generator overexcitation limiter operation was highlighted. To fully analyze how a power system will act in the case of a system contingency, these system elements must be modeled carefully. In

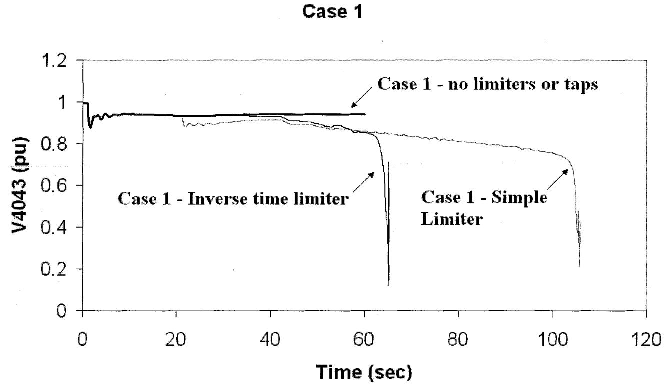

Fig. 6. Case 1 – limiter comparison.

Fig. 6, the variation in voltage at bus 4043 in the Nordic system is shown for the case 1 contingency if the tap changing and generator overexcitation limiter operation are not modeled. In the figure, it is clear to see that the initial system oscillations following the contingency die out after a period of no more than 30 s, after which the voltage appears to settle out to a steady state value.

When the action of the tap changers and generator limiters are taken into account, the result can also be observed in Fig. 6. This figure shows the variation in the voltage at bus 4043 for the case 1 contingency when either of the two different styles of limiter model that have been developed, are modeled. When the simple set time limiter model, shown in Fig. 3, was used, the values of the amplification gain constants Kr and Ks used in this instance were 20 and 2 for the rotor and stator limiters, respectively. These were the values used by Cigré in their report on long-term dynamics [21]. The inverse time curve limiters, shown in Fig. 4, were set up to follow the ANSI C50.13 standard inverse time curve. The delay to the first tap was chosen to be 40 s. The delay for subsequent taps was chosen to be 5 s. This short time period was chosen to speed up the simulation.

Fig. 6 shows that in both of these two different limiter cases after the initial oscillations have died out, the voltages undergo a gradual decline, and that this decline is followed by a final rapid collapse of the bus voltages. As shown in Fig. 6, the voltage collapses sooner for the inverse time limiter. This can possibly be explained by the fact that the amplification gain constant for the stator current inverse time limiter, at 10, is much larger than that of the simple fixed time limiter. Note that a value of 10 or greater is recommended for a model to more closely replicate the action of a "take-over"-type limiter.

To understand how the magnitude of the gain constant chosen can have a crucial impact on the time to collapse, it is useful to focus on the operation of one of the stator overexcitation limiters in the system. The "simple" Fig. 3 style stator overexcitation limiter for the generator at bus 143 operates 20 s after the case 1 contingency occurs. While the value of VOEL is initially larger in magnitude than the error signal, it does not remain so. As the voltage of the generator terminals decreases the value of the error signal increases. The value of stator current for the generator at bus 143 decreases as the limiter acts to reduce the excitation. As the stator current decreases, the difference between the value of the stator current and the limit value also decreases, corresponding to a decrease in VOEL. The value of VOEL reaches a point at which the error signal is greater in magnitude and the stator current is no longer decreased. Although the current has not been decreased below the limit value of 1.05, the current levels out.

Different values of overexcitation gain for the generator at bus 143 gain were tested. It was found that the greater the gain used, the closer the "levelled out" value was to the limit value of 1.05. It must be noted that as the gain is increased, the more oscillatory in response the stator current became in the long term.

When the value of 7.5 is used for all of the stator overexcitation limiters in the system, the time to collapse for the case 1 contingency is reduced compared to the base case. The base-case gain Ks being 2. The greater the gain, the larger the value of the VOEL signal and the more stringently the limiter acts to keep the current below the rated value. The fact that the inverse time curve limiter has a higher gain goes some way toward explaining why the time to collapse is less than for the set time limiter. It is therefore important to point out that when choosing the gain of the overexcitation limiter, that it is sufficiently large to ensure that the current is kept below rated values but not so large as it decreases the time to collapse. This is especially important to remember when dealing with take-over-type limiters. As previously mentioned, a high gain summed-type limiter can replicate these take-over limiters, so the impact on the time to collapse will be similar.

VIII. Impact of Powerformer Location on Time to Collapse

The time between subsequent tap changes for the initial simulations, the results for which are shown in the preceding section was 5 s. As mentioned, this relatively small value was chosen to speed up the simulation. The actual value is normally much larger. Smaller values were also chosen by Cigré to speed up their simulations [21]. The tap changer time was increased to 25 s for the next phase of the power system simulations, as this was considered a more realistic value. As Cigré [21] points out, the time between subsequent taps is usually similar to the time delay for the first tap. The initial delay used in the simulations is around 40 s.

In Fig. 7, the variation in voltage at bus 4043 for the case 1 contingency has been observed with the Powerformer installed at select locations in the Modified Nordic test system. The numbers in the figure indicate the position of the bus whose generator has been replaced with a Powerformer. For example, "case 1 431 Pwrfmr" is the response of the system to a case 1 contingency when the generator at bus 431 has been replaced with a Powerformer. No generators have been replaced with Powerformer in the base case.

The overexcitation limiter used in this simulation is the inverse time curve model shown in Fig. 4. In order to replace an existing generator with the Powerformer for comparison purposes, the step-up transformer impedance has been made small enough to be insignificant (less than 1/1000 p.u.) and the inverse time curve for the stator is reconfigured such that it follows the Powerformer curve, shown in Fig. 2, rather than the ANSI C50.13 curve. The advantage of this method is that because the Powerformer was identical in all respects to the conventional generator it was replacing, except for the improved stator current overload capability, meaningful comparisons could be drawn.

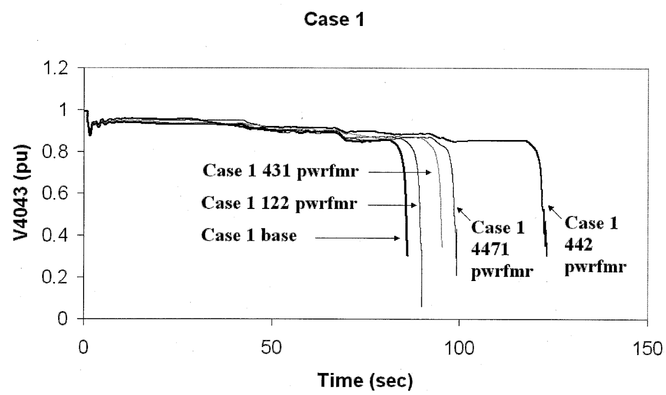

Fig. 7. Case 1, bus 4043 voltage versus time for different Powerformer locations.

The generators replaced by Powerformer were chosen because they were located in geographically and electrically distinct regions of the system.

As can be observed from Fig. 5, the generator at bus 122 is located in the Northern region of the system, as is the generator at bus 431. The generators at buses 442 and 4471 are located in the central region. The generators at buses 431 and 442 are located in the transfer region between the northern and central regions, where the majority of the flows in the system pass through.

Fig. 7 highlights how the position of the Powerformer can have an impact on the time to collapse. The case 1 contingency involves the loss of the generator number 2 at bus 4471. In this scenario, the voltages in the central region collapse. If the Powerformer is located in the same central region, at buses 442 and 4471, respectively, the improvement in the time to collapse is optimum. The Powerformer option at bus 442 provides the best improvement. A static var compensator (SVC) was also placed in the central region at bus 4043 to determine the improvement it might have on the time to collapse. The existing 200-MVAR capacitor bank was replaced with a 500-MVAR SVC. The output from an SVC is dependent upon the voltage of the bus it is controlling. As the voltages in the system begin to fall, the reactive support available from this SVC reduces. It cannot be as supportive as the output from a generator, which is not affected by the voltage at the bus it is controlling. Fig. 8 shows that the time to collapse is improved if the SVC is installed at bus 4043 compared to a Powerformer being located at buses in the Northern region but the time to collapse is not as good as when Powerformer is located at buses in the central region. Fig. 8 also shows how if multiple Powerformer units are installed in the system, the time to collapse can be increased significantly on the base case. When the conventional generators at buses 122, 4471, 431, and 442 were replaced with Powerformer units, the time to collapse was increased from around 90 s to over 300 s.

The variation in voltage at bus 4043 for the case 4 contingency has been observed with the Powerformer installed at the same select locations as for the case 1 contingency in the modified Nordic test system and the result is shown in Fig. 9. Having a Powerformer located in the northern region, where both the line and generator removed for service are located, improves the time to collapse. If a Powerformer or SVC is located in the central region, the time to collapse is actually reduced, despite the additional reactive support available. This situation was also

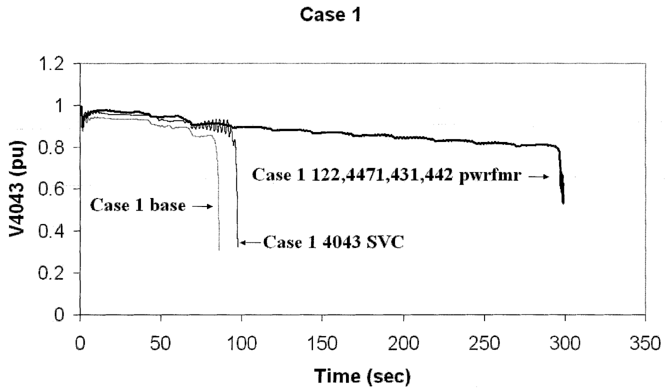

Fig. 8. Case 1, bus 4043 voltage versus time for the addition of an SVC to the system and for multiple Powerformer locations.

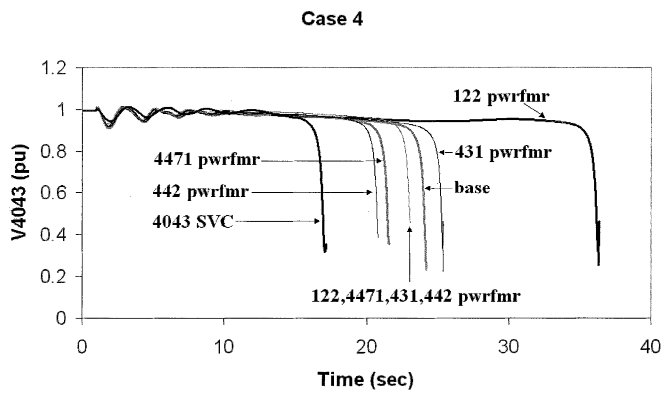

Fig. 9. Case 4, bus 4043 voltage versus time.

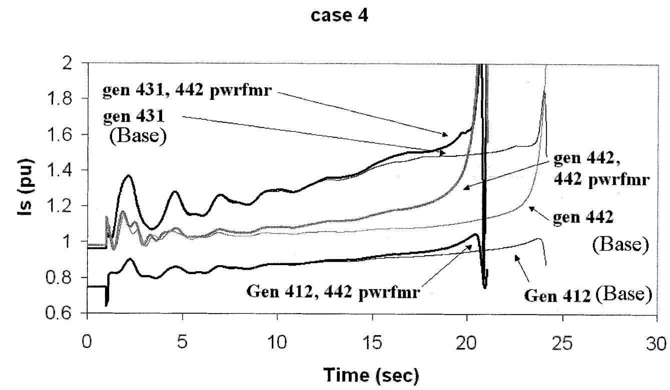

Fig. 10. Stator currents for case 4 contingency.

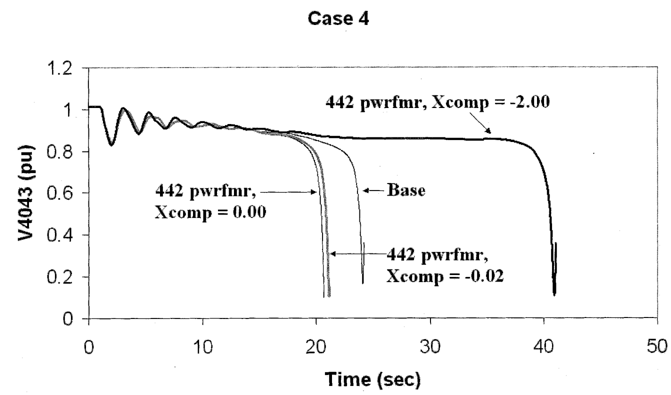

Fig. 11. Case 4, comparison of variation of bus 4043 voltages for Powerformer at bus 442 with/without different values of compensation used.

observed for the case 14 contingency where the time to collapse reduced if the Powerformer is located in the central region.

In order to understand why locating Powerformer at a bus in the central region can have a detrimental impact on the time to collapse, it is useful to look at the variation in voltages at buses in the system if the limiters and tap changers are not considered. If the conventional generator at bus 442 is replaced with a Powerformer that the buses in the northern region, 4012 and 4031, settle out to a lower voltage level. On the other hand, the voltages of buses in the central region settle out to higher values.

Fig. 10 shows the change in stator currents for the generator located at buses 412, 431, and 442 when the generator at bus 442 is conventional and when it is Powerformer. Note how the stator currents increase more rapidly for the case where Powerformer is installed. These increased stator currents mean that the limiters will have to operate sooner. In the case of this contingency, it is when these limiters operate that the system voltages collapse. The reactive flows from the central to northern regions, along lines 4042–4032, 4042–4021, and 4041–4031 also increase more rapidly if Powerformer is installed. This is understandable considering that when Powerformer is installed at 442, the voltages in the northern region drop while the voltages in the central region increase as already pointed out.

This situation can be avoided by allowing the central region voltages to drop slightly and/or to maintain less stringent control over these voltages. When a contingency occurs in the northern region, either the set point voltage of the Powerformer could be reduced or the control point of the Powerformer could be pushed back "into" the generator. By setting the compensation reactance to a larger value, the point of control of the generator will be moved further "into" the generator windings and the terminal voltage will be less stringently controlled reducing in value as the loading of the generator increases. Fig. 11 illustrates the improvement in time to collapse possible if compensation is added to the Powerformer at bus 442. When the value of -0.02 is used, there is a small amount of improvement but if -2.0 is used, the time to collapse instead of being worst than the base case is noticeably better. This was also found to be the case for the case 14 contingency.

IX. Conclusions

In this paper, the unique aspects of the Powerformer, from a system voltage stability perspective, have been highlighted. Most important, the stator overload capability of the Powerformer has been examined. The impact of the type of overexcitation limiters chosen on the time to collapse following a contingency has been illustrated. The importance of choosing the right value of gain for the overexcitation limiter model has also been highlighted. The value of the gain must be sufficiently large enough to ensure that the current is kept below rated values but not so large as to decrease the time to collapse.

The impact of location of the Powerformer and its additional overload capability and the impact of the compensation scheme chosen for the Powerformer has also been discussed. In this analysis, it has been shown how the additional stator overload capability of the Powerformer can have an even more beneficial impact of the time to collapse than the addition of reactive compensation in the form of a SVC. It has been shown that in the case of certain system contingencies in the modified Nordic test system, it was preferable to let to control of the system voltage be less stringent, via the use of compensation, if the Powerformer was located in a different region to the contingency.

In this paper, it was highlighted that the Powerformer controls the high voltage bus and that the idea of controlling the high voltage bus is gaining an increasing amount of support [24]. One of the problems with controlling the high voltage bus is that if two or more generators are controlling the same bus voltage, some line drop compensation must be added to avoid undesirable system oscillations and reactive imbalance between the machines [10], [11], [24]. What this paper has illustrated is that in certain cases it is also wise to install voltage compensation so that the level of voltage control is less stringent. The need for less stringent control must be determined for each system individually. It is the aim of this paper to highlight the existence of this condition so that it can be taken into account when considering high side voltage control in a system.

The Nordic test system is a suitable example of a longitudinal system where load is located distant from the generation sources. Information gathered in this paper is therefore reasonably applicable to systems of this type and the reactive overload capability will be of benefit, in general, to any system requiring reactive support. A thorough investigation of the impact of the Powerformer on voltage stability is in progress on a complex large-scale power system and will be reported on in a future paper.

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