IEEE Transactions on Power Systems, Vol. 5, No. 1, February 1990

ADJUSTING CONVERTER CONTROLS FOR PARALLELED DC CONVERTERS USING A DIGITAL TRANSIENT SIMULATION PROGRAM

T. Shome A.M. Gole

Department of Electrical Engineering
University of Manitoba
Winnipeg, Manitoba, Canada

D. P. Brandt R. J. Hamlin

Manitoba Hydro
Winnipeg, Manitoba, Canada

ABSTRACT

A description of how accurate system modelling of a dc system with an electromagnetic transient simulation program can be used to study and correct interbipole oscillations between converters connected into a parallel multiterminal system is given. The paper shows how to decide on the detail of modelling that is required, and demonstrates that it is often not enough to use prepackaged , generic HVDC control models, supplied with these programs. The detail of control models that are used in the electromagnetic simulation programs are shown to have a significant impact, in some cases, on the simulation results. In particular, a case of six hertz oscillations, in the dc currents of two converters on the Nelson River System, is accurately simulated, and it is shown that control modifications suggested by the simulation actually do eliminate the interbipole oscillations.

KEYWORDS

Parallel multiterminal, HVDC, Digital simulation, Electromagnetic transients program, Controls.

INTRODUCTION

Digital programs for simulating transients in HVDC systems and controls have been developed in the past few years [1,2,3,4]. These programs have been used in many general studies to evaluate different control strategies and to study new types of converter circuits. Nyati [5] has used such a program to compare the effect of various voltage control devices at converter terminals. Arabi [7] has looked at different firing strategies for series-tapped HVDC systems. Turanli [6] has studied forced-commutated converters. In most of these studies, generic models of controls were used, and the conclusions of the studies were of a general nature, and not related to any specific operating system. Relatively little has been reported on comparisons between the field tests and the results produced by digital simulation software. Woodford [8] and Ino [9] have made some such comparisons to show that these programs can accurately reproduce the observed results from the field.

89 SM 700-6 PWRS A paper recommended and approved by the IEEE Power System Engineering Committee of the IEEE Power Engineering Society for presentation at the IEEE/PES 1989 Summer Meeting, Long Beach, California, July 9 - 14, 1989. Manuscript submitted September 1, 1988; made available for printing May 23, 1989.

The authors of this paper feel that sufficient experience has been obtained with HVDC system simulation to be able to use the program for analysing disturbances and setting control parameters on operating dc systems. The authors have set up such a model on the EMTDC transient simulation program for the controls and converters of Bipoles 1 and 2 of the Nelson River HVDC transmission system. EMTDC was used to find control settings for the converter controls to eliminate a low frequency interconverter oscillation. While carrying out parallel operation tests at Manitoba Hydro, it was observed that for a certain tap changer ratio on one inverter terminal, an oscillation would develop in which one inverter took more current, for a half period, at the expense of the other. For the next half period (of approximately six hertz frequency), the other inverter took more current. The total current put out by the paralleled rectifiers was constant. It should be noted that the two bipoles were supplied by different manufacturers, and have different controls. It was found that to duplicate the six hertz oscillation using digital simulation, it was not sufficient to use the generic control blocks provided in the EMTDC simulation program. Detailed modelling, almost at the electronic circuit level, was essential.

Many different strategies to solve the problem were investigated, using the EMTDC program, and the easiest appeared to be in the form of changing the time constant of a first order pole control block. In the real system, this was achieved by changing a capacitor to the value suggested in the simulation, which corrected the problem. It was also observed that a different value of capacitor would be required, if one smoothing inductor was out for maintenance. This too was verified in the field.

Thus it is possible for utilities to develop their own system models in-house, using commercially available simulation programs. After some manipulations, between tuning the digital model and field tests, the model, then, can be used as a reliable guide to modelling the controls for other system contingencies.

BACKGROUND

The Nelson River HVDC system of Manitoba Hydro, shown schematically in Fig. 1, has two bipolar dc circuits, which bring power from the generating stations on the Nelson River to the southern load centers over roughly 900 km of terrain. The first circuit, Bipole 1, is rated at ± 463.5 kV, 1800A, and has three 154 kV mercury-arc valve group per pole. Bipole 2 is rated at ± 500 kV, 1800A, and has two 12 pulse thyristor valve groups per pole. Control modifications have been implemented, and high speed switches provided to allow parallel operation of the converters on any one pole on a single transmission circuit, in the event of the unavailability of the other transmission line. The initial paralleling was carried out at low voltage- with one 154 kV Bipole 1 six pulse valve group paralleled to one 250 kV Bipole 2 twelve pulse valve group- to prove control concepts and modifications. During paralleling operation, the 250 kV valve group is operated at a lower voltage, so that both valve groups have the same voltage. These tests were carried out in the summer of 1982 [10]. High voltage paralleling- with the full 463.5 kV of Bipole 1 and one 500 kV pole of Bipole 2- were carried out in 1985 and 1986.

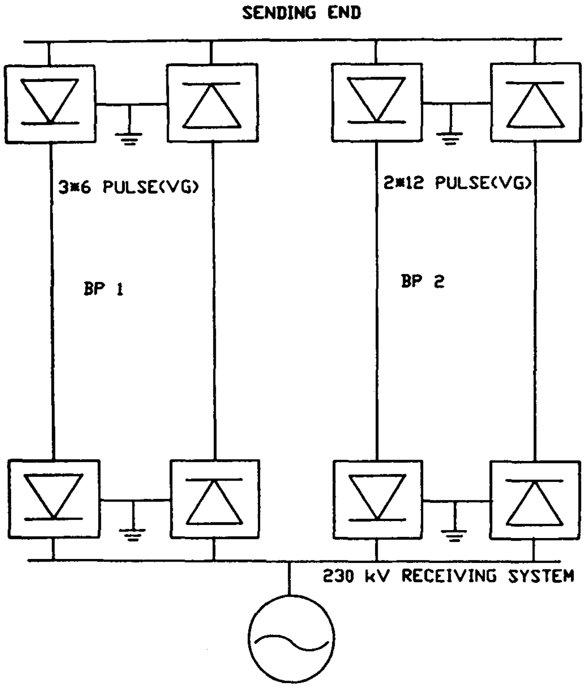


Fig. 1: Nelson River transmission system

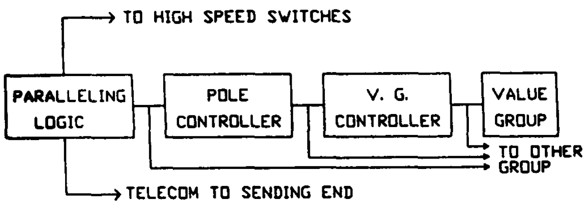


Fig. 2a: Schematic of paralleling deparalleling control

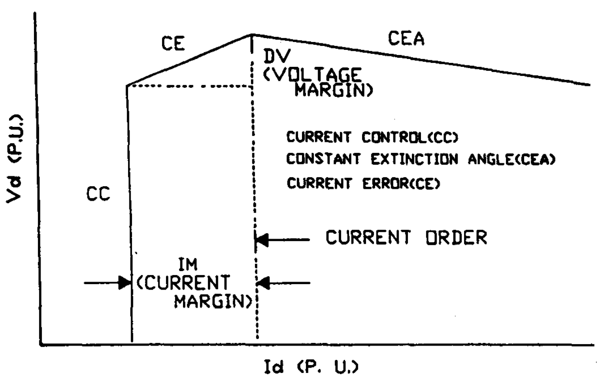


Fig. 2b: CEA, CC, CE characteristics

The block schematic of the paralleling controls is shown in Fig. 2a. The paralleling logic-block coordinates the closing of the high speed switches, and also assigns the correct current orders to the current (pole) controllers of the poles that are paralleled. The valve group control-block either passes on the pole controller's firing angle order, or selects another firing angle- based on whether there is need for other forms of control such as: constant extinction angle control or current error control. Fig. 2b shows a typical inverter characteristic outlining the meaning of CEA, CC and current error (CE) control. By changing the tap changer ratio, the inverter characteristics can be made to intersect the rectifier characteristic in any one of these three modes.

Fig. 3a shows two inverters and two rectifiers operating in parallel. As the rectifiers' uncontrolled characteristics are at a larger voltage than the inverters' characteristics (Fig 3b), the rectifiers are in constant current control, with $Id_1=Id_{ref1}$, $Id_2=Id_{ref2}$.

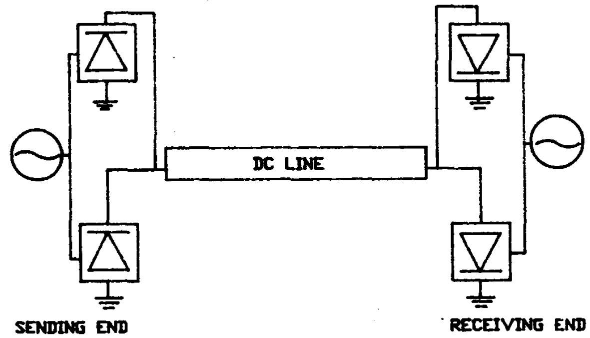


Fig. 3a: Two rectifiers and two inverters in parallel

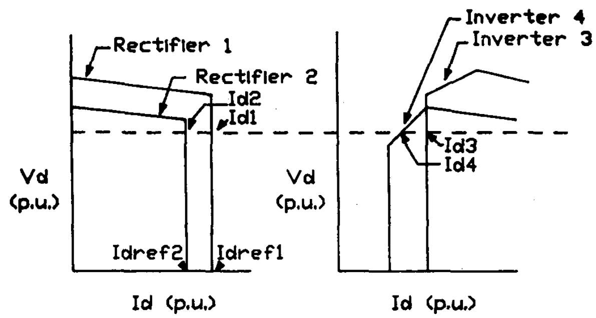


Fig. 3b: Multiterminal characteristics

The common voltage line (dotted) intersects one inverter in the CE characteristic, and the other on its constant current characteristic. (By Kirchoff's current law (KCL) $Id_1+Id_2=Id_3+Id_4$). Note that further dropping of the ac voltage (by tap changer control) on inverter 4 will result in its going into CEA operation. Note that exactly one of the four, say inverter 4, is in a voltage control mode (CEA) and absorbs the spill over current $Id_1+Id_2-Id_3$. During paralleling tests in 1985, it was observed that a mode of operation was possible with the rectifiers in stable, constant current operation, but with the inverters having a six hertz current oscillation . Fig. 4 shows field recordings of this phenomenon. The oscillation only occurred with the inverter of Bipole 2 in current error control and the inverter of Bipole 1 in CEA control. If the tap-changer-ratio of Bipole 2 were increased, so that it went into constant current operation , the oscillation would cease.

It was observed that the dc line current (sum of two rectifier currents) was constant without oscillations. Thus the rectifier did not seem to play a role in the phenomenon. Also, the ac side bus voltage on the inverter appeared to be sinusoidal and essentially free of low frequency oscillations. Thus there appeared to be no relationship between these oscillations and the ac side systems.

MODELLING

Choosing the minimum system

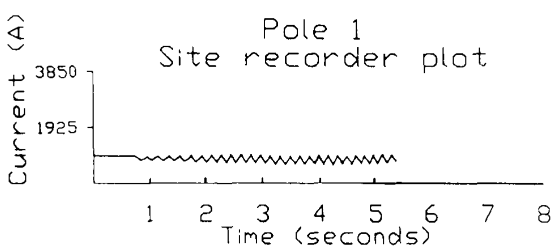
Although a highly detailed model of the dc system and some of the associated ac system has been developed using the EMTDC program, it is important to find a simpler system for study. Modeling a smaller system saves considerable computation time. The system must be simple, but should not be oversimplified to the point where the phenomenon to be looked at can no longer be represented.

It was observed that the ac side voltage on the inverters was a nearly harmonic free 60Hz balanced waveform. It was thus decided to model the ac bus as a 230 kV infinite bus. The converter transformers were modelled in three phase detail to account for the non-zero commutating inductance.

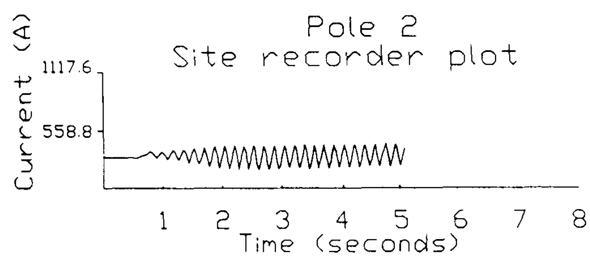
The inverters were modelled as six pulse valve groups. The higher harmonic behaviour was not being studied, and so the more accurate 12 pulse representation was deemed unnecessary. Also, the extra harmonics would not add harmonic voltages to the ac bus because it was modelled as an ideal voltage source. Similarly, although some 6th harmonic ripple current would now show up on the dc side, the important phenomenon being looked at here was the large low frequency oscillations of the dc current. We were, however, prepared to make the representation 12 pulse if the initial studies showed us that this was necessary. It was decided to model the two rectifiers in parallel as a single dc voltage source behind a Thevenin resistance. The voltage source was controlled by a complete set of dc controls (identical to those used for the full converter model) and included the $cos(\alpha)$ nonlinearity relating the dc voltage to the firing angle α. This simplified model was again chosen, as the harmonic behaviour was not important in this study.

The dc side filters and smoothing reactors were represented in full detail. The inductors and filters affect the transfer functions relating the dc currents and the converter voltages, and are therefore required in the model. Similarly the dc line was represented as a lumped inductance for this low frequency study.

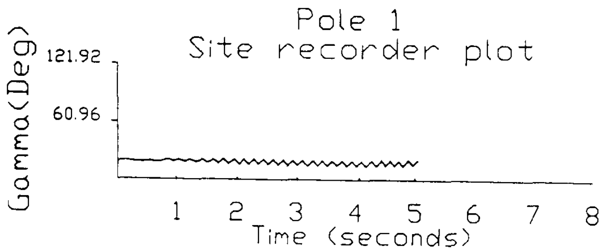
Finally, only a monopolar representation was chosen, because the other poles of the opposite polarity operated quite independently. Fig. 5 shows a schematic of the minimum system developed for this study. It is evident from Figure 5 that the sending end rectifiers of figure 3a have been clubbed together as a single, controlled voltage source, and the rectifier side smoothing inductors and the line side inductances are now represented by a single 1.72 H inductance. The 12th and high-pass filters of BP2 and the 6th, 12th and high-pass filters of Bp1 are properly represented on their respective buses. Note also, the 0.75H smoothing inductance of BP2, and the split 0.55H smoothing inductance of BP1.



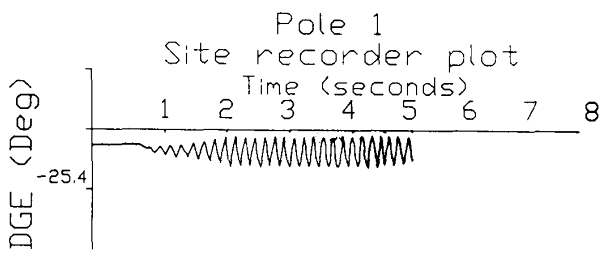
(a)



(b)



(c)



(d)

Fig. 4: Hathogram recordings of

(a) Pole 1 dc current

(b) Pole 2 dc current

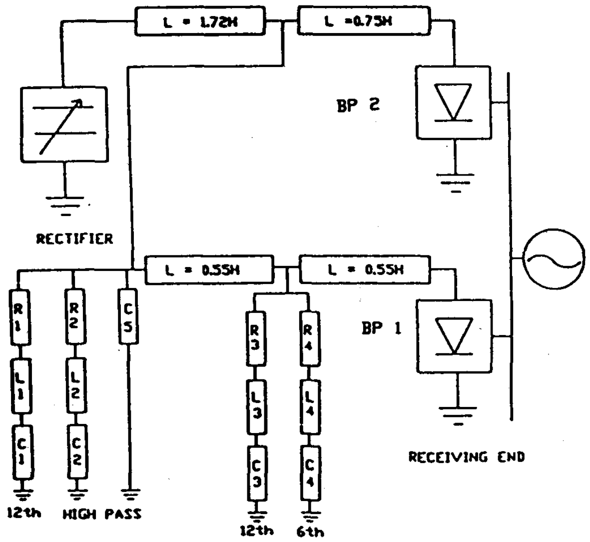
(c) Pole 1 extinction angle (gamma)

(d) Pole 1 current error

MODELLING THE CONTROLS

Many power system simulation programs include generic models for converter controls. For example, the generic current controller (or pole controller) from EMTDC [11] is shown in Fig. 6a(i). Many of the essential control channels are represented in such a generic block. For example in Fig. 6a(i), a proportional-integral (PI) controller adjusts the α order in response to the difference between measured and ordered current. A second path with the signal DGE at its output is used to change the extinction angle (γ) reference in the subsequent valve group controller in order to obtain the chamfered "current error control" characteristic.

A first attempt at modelling can be made by trying to fit the real controls with the generic block diagram. This usually leads to an improper representation, because there may be extra blocks and other signals in the real control systems, or there may be switches that change from one set of controls to another.



R1=7.94Ω R2=100.00Ω R3=5.50Ω R4=4.42Ω

L1=0.122*H* L2=0.02036*H* L3=0.122*H* L4=0.195*H*

C1=0.4μ*F* C2=0.6μ*F* C3=0.4μ*F* C4=1.0μ*F* C5=0.5μ*F*

Fig. 5: Minimum system configuration

For example, Fig. 6b shows a section of the actual control block diagram in which there are inputs proportional to the rate of dc current change. As the "Current Error Control" loop (dotted block A of figure 6b(i)) is critical in the study of these oscillations, it is important to model this loop accurately. Note that some of the control-blocks, such as the derivative block, 0.032s*IM, etc. are absent from the generic diagram of figure 6a(i). Similar details are missing in figure 6a(ii), and are included in figure 6b(ii). Considerable effort was spent with control diagrams even at the electronic circuit level in order to obtain a proper block diagram of the controls. Special efforts had to be made to ensure that all control circuit settings from the field were included. This is quite a drawn out process, since a number of control engineers needs to be consulted.

Figures 7 and 8 show the simulation results for the dc current of inverter 1 (Bipole 1) with the use of generic and detailed models respectively. As can be observed, the 6 Hz oscillations are evident in the detailed simulation. In this simulation, the inverters are each conducting approximately 1800A of current. The transformer taps have been adjusted to give the secondary voltage of the inverter 1 transformer a value of 4% above that of inverter 2, ensuring the operation of inverter 1 in current error (CE) control and that of inverter 2 in constant extinction angle (CEA) control.

Most control blocks on the Nelson River controls have response times much larger than the EMTDC time-step, which is used in the simulation. The smaller time-step is required for the simulation of the network elements (Converters, Filters, etc). Consequently, many of the controls can be simulated with a larger time step than the rest of the program (typically 1/12th of a cycle or so). This fact could be used to save computer time. It is important to select the "minimum system " for study by leaving out unnecessary details, however it is not essential to use a minimum control system," because the control simulation uses relatively less computer time.

STUDY OF THE OSCILLATIONS

Fig. 9 shows the result of a computer simulation, carried out on the system for which the site recored plots are given in Fig. 4.

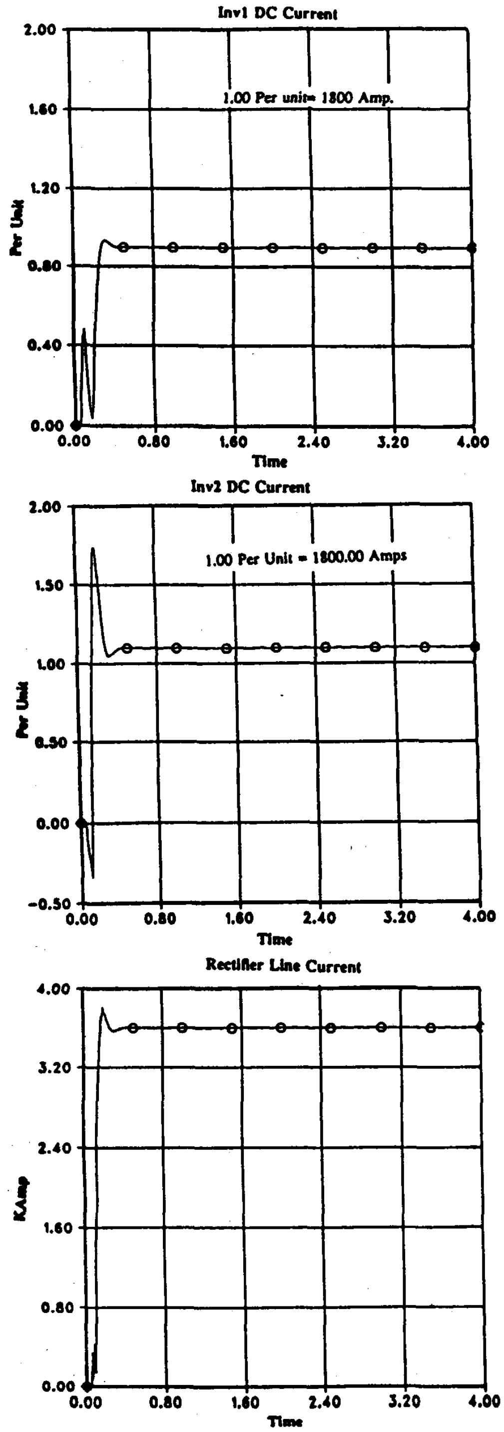


Fig. 7: Simulation results obtained with generic controller

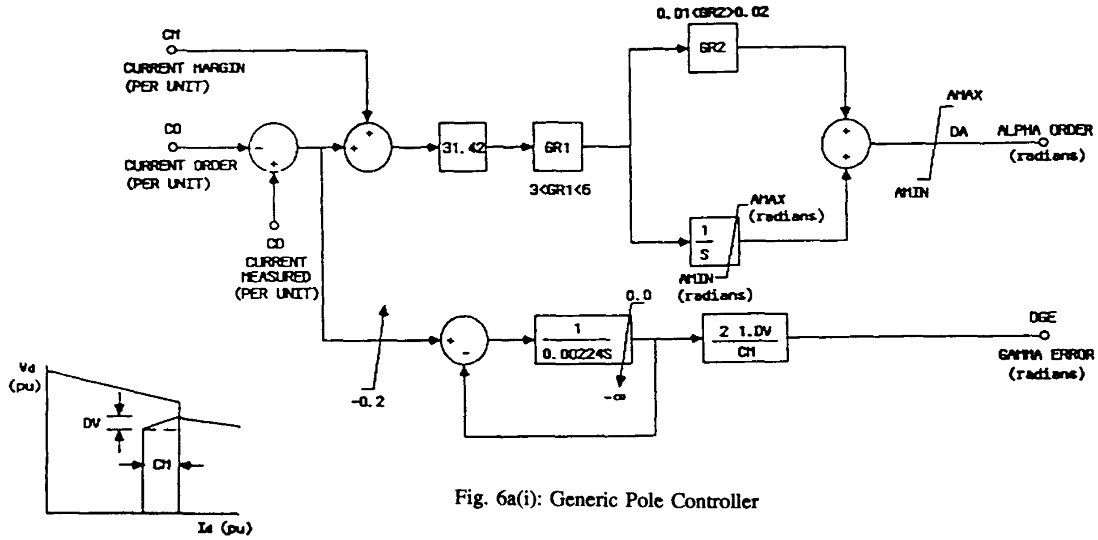


Fig. 6a(i): Generic Pole Controller

As can be observed, the oscillations on poles 2 and 4 (of Bipole 1 and 2 respectively) are mutually opposite in phase, as they must be, because the dc line current put out by the rectifier is essentially oscillation free. In our case, the simulated dc rectifier current does have a very small amount of oscillation, and this shows some lack of exact agreement between field and simulated results. The oscillations in the converter's extinction angle were also quite clearly visible. (This trace is not shown in the paper.) The magnitude of the oscillations are somewhat more in the simulation, but the frequency is quite accurate. It is difficult to get exact agreement on the magnitude of the oscillations, because the magnitude is only limited by inherent nonlinearities in the system and controls, which are not easy to estimate and model. We have modelled these with the best information that was available.

Similar simulations were carried out for different system conditions (a smoothing reactor out of service, different loading and tap changer ratios), and yielded acceptable comparisons between field test results and simulation. It was thought that the di/dt signal from the dc current to the pole controller (Fig. 6b(i)) would play an important role in limiting these oscillations in the current , because derivative control responds quickly to changes. Several simulations with different di/dt gains were attempted, but had marginal effect on the oscillations. It was then observed that

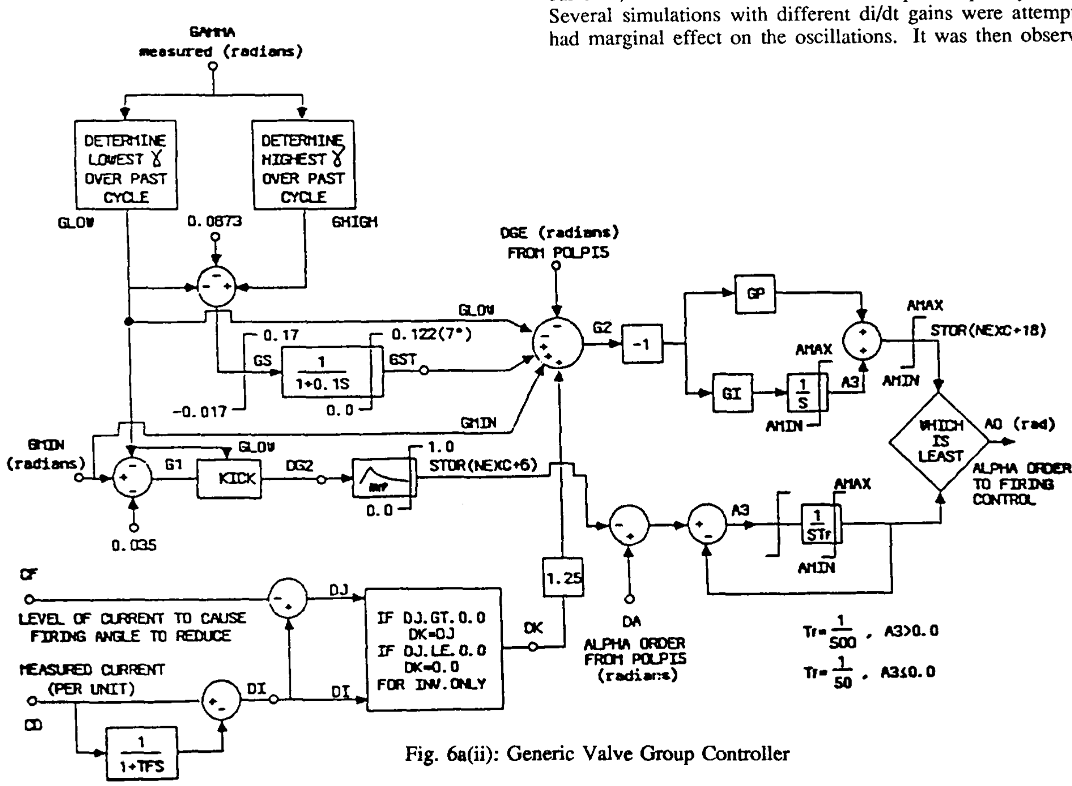


Fig. 6a(ii): Generic Valve Group Controller

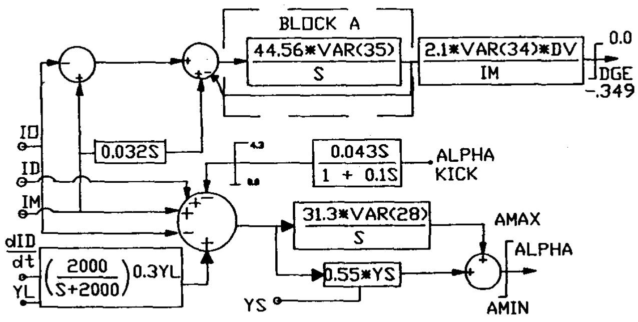
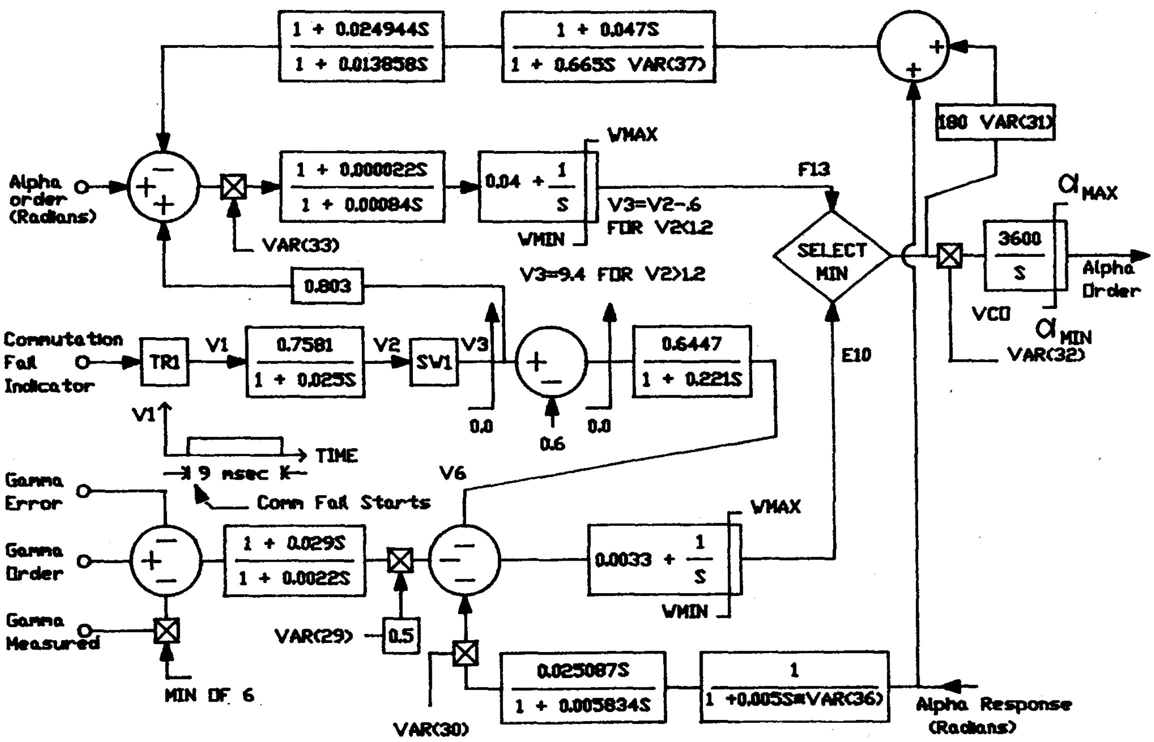


Fig. 6b(i): Actual Pole Controller

there was a particular K/(1+sT) type delay block (see dotted block A in figure 6b(i)), in the controls, in series with the DGE signal. Decreasing the time constant T from 22ms to 3 ms cured the oscillations in the simulation, as can be evidenced from Fig. 10, which is a resimulation of the case shown in Fig. 8, but with the control modification introduced. A capacitor in the Bipole 1 controls was replaced to give the real system the same time constant as in the simulation. This resolved the oscillation problem on the real system.

If figure 6b(i) is drawn without the di/dt signal and the "[0.032s]" block, (which showed little impact on the oscillations), its structure is very similar to the generic block in figure 6a(i). Thus in retrospect, the oscillations could have been demonstrated using the generic pole controller model. However, the pole controller output signals (ALPHA ORDER and DGE) are inputs to the valve group controller, the structure of which differs markedly from the generic block (see for example the feedback loop from the *Select Min* Block to the Alpha Order summing junction, the Alpha Response signal, etc.). Thus the two controller cascade is very different from that obtained by cascading the two generic controller blocks and hence the oscillations could not be simulated by using only the generic models. Presumably, we could have modeled the valve group controller leaving the generic model for the pole controller, but there was no a priori way of knowing that the di/dt signal would not be important.



Note:- In fig. 6b(i), 6b(ii),

Fig. 6b(ii): Actual Valve Group Controller

VAk(n) represents gain that can be changed

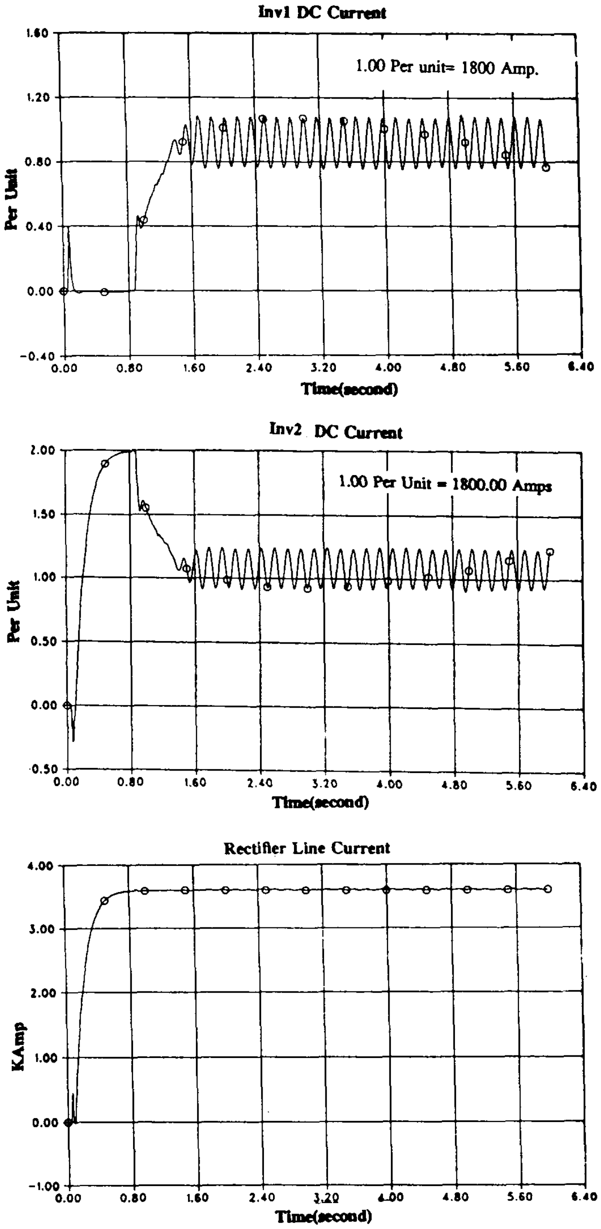


Fig. 8: Simulaton results obtained with actual controller

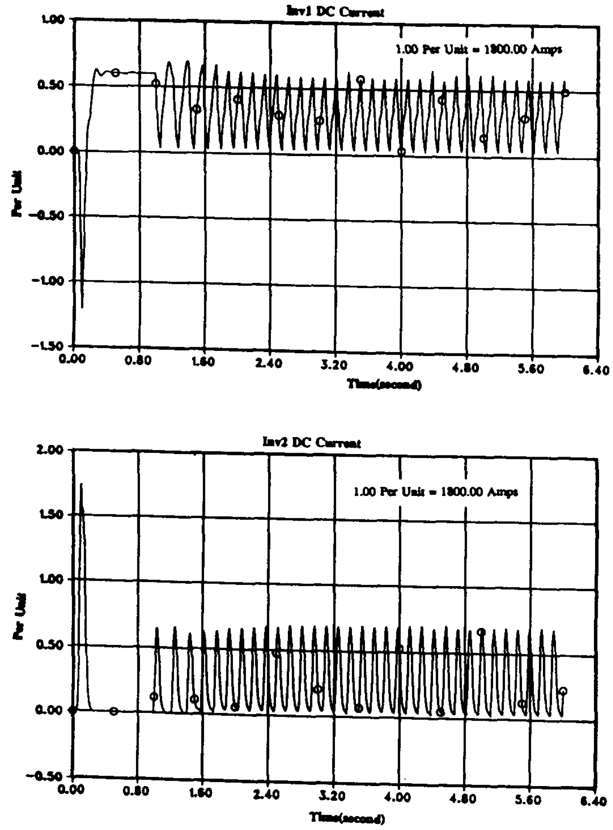


Fig. 9: Simulation results obtained with parameter obtained from field

The oscillations in the field traces of figure 4 were initiated by a tap changer ratio-change from a configuration of stable operation. Our aim here is to simulate the oscillations and then find ways of eliminating them, and so the traces of figure 9 are obtained with the system started up with the tap changer ratios already set. Hence, the dynamics of the growth of the oscillations that is seen in figure 4 is not the same as seen in figure 9.

CONCLUDING REMARKS

The paper shows that careful modelling of an operating dc system on a digital simulation program can result in an useful facility for studying control modifications of the real system. In particular, the paper demonstrates one such use, where the proposed control modification, for eliminating the observed low frequency oscillations on paralleled bipoles of the Nelson River transmission system, was investigated.

The paper describes how the choice of the level of modelling-details was made for the study. The need for the detailed modelling of the controls and the accurate determination of parameters from the field should be stressed.

ACKNOWLEDGEMENTS

The financial support provided by the Manitoba Hydro Research Committee and by NSERC Canada is gratefully appreciated.

The authors acknowledge the assistance provided by Dennis Woodford of the Manitoba HVDC Research Centre and by Tony Weekes and Dr. M.M. Rashwan of Manitoba Hydro.

REFERENCES

1. K. G. Fehrle and R. H. Lasseter, "Simulation of Control Systems and Application to HVDC Converters," *IEEE Tutorial Course on Digital Simulation of Electrical Transient Phenomena* , Chapter vi, pp 47-54, Course text 81EH0173-5-PWR, 1981.

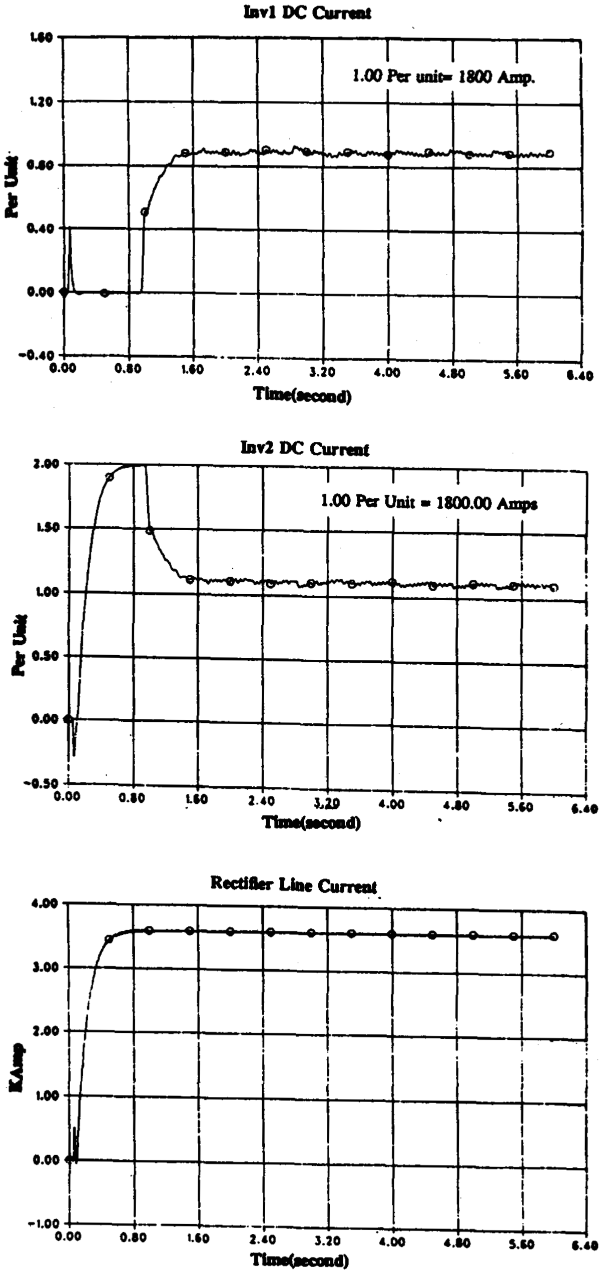


Fig. 10: Simulation results showing

elimination of oscillation with control change

2. J. Reeve and S. P. Chen , "Digital Simulation of Multiterminal HVDC Transmission Systems," *IEEE Transactions on Power Apparatus and Systems* , vol PAS-103, No. 12, pp 3634-3644, Dec 1984.

3. D. A. Woodford, A. M. Gole, and R. W. Menzies, "Digital Simulation of DC Links and AC Machines," *IEEE Transactions on Power Apparatus and Systems* , vol PAS-102, No. 6, pp 1616-1623, June 1983.

4. M. D. Hefferman, K. S. Turner, J. Arrilaga, and C. P. Arnold, 1981, "Computation of AC-DC System Disturbances, Parts I, II and III," *IEEE Transactions on Power Apparatus and systems* , vol PAS-100, No. 11, pp 4341-4363, Nov. 1981.

5. S. Nyati, S.R. Atmuri, V. Koschik, R.M. Mathur and D. Flueckiger, "Comparison of Voltage Control Devices at HVDC Converter Stations Connected to weak AC systems," IEEE PAS winter meeting, New Orleans, 1987, Paper No. 87WM 159-7.

6. Hilmi M. Turanli, Robert W. Menzies and Dennis A. Woodford. "Feasibility of DC Transmission with Forced Commutation to Remote Loads," (83SM 466-0); *IEEE Trans. PAS* , pp 1256-1263. June 84.

7. S. Arabi and M. Z. Tarnawacky, "A Diode Rectifier Series Tap on an HVDC Lines" *IEEE Trans. PAS* , Volume PAS-104, No. 9, pp 2540-2546. Sept-85.

8. D. A. Woodford, "Validation of Digital Simulation of DC links," *IEEE Trans. PAS* , Volume PAS-104, No. 9, pp 2588-2594, Sept-85.

9. T. Ino, R. M. Mathur, M. R. Iravani, and S. Sasaki, 1985, "Validation of Digital Simulation of DC Links - Part II," *IEEE Trans. PAS* , Volume PAS-104, No. 9, pp 2596, 2602, Sept-85.

10. D. Brandt, I.H. Mckay, M.M. Rashwan, S.T. Ranade, "Paralleling and Deparallelling tests on Nelson River HVDC Bipole 1 & 2" *IEEE Trans. PAS* , Vol PAS-1103, No 4, April 1984.

11. EMTDC User's Manual, Version 1.0, Manitoba HVDC Research Centre, 1986, pp 762-76.

BIOGRAPHIES

T. Shome (S'88) was born in Calcutta, India in 1959. He has a B.Tech. Hons.(EE) degree from IIT, Kharagpur and a Nuclear Engineering diploma from BARC, Trombay, Bombay, India. He is currently a graduate student in the Department of Electrical engineering, University of Manitoba. His research interests include Power System Simulation, HVDC, VLSI, Digital Image Processing, Nonlinear Control, Digital Signal Processing , Systems Software and Parallel Processing Architecture.

Ani Gole (S'77,M'82) was born in Jamshedpur, India in 1955. He has a B.Tech(EE) degree from IIT, Bombay, and a Ph.D.(EE) degree from the University of Manitoba, where he is currently an Associate Professor in the Department of Electrical Engineering. His research interests include power system simulation, HVDC, VLSI for power system applications and the use of optimisation techniques. Ani is a registered Professional Engineer in the Province of Manitoba, and a member of the IEEE PES.

R.J. Hamlin was born in Winnipeg, Canada in 1942. He graduated from the University of Manitoba in 1964. He has worked for Manitoba Hydro on various aspects of the Nelson River HVDC system including planning, design and commissioning. He has special interest in harmonics analysis and measurement of HVDC systems. He is currently the manager of the Telecontrol Department. He is a Registered Professional Engineer and a member of IEEE PES.

D. P. Brandt (M'82) was born in Morris, Manitoba, in 1952 and graduated with a B.Sc. in Electrical Engineering from the University of Manitoba in 1975. Since 1975 he has been employed with Manitoba Hydro. From 1976 to 1978 he was a HVDC commissioning Engineer at Dorsey Station. Since 1979 he has worked in the HVDC field as a HVDC Controls Design Engineer. From 1986 to 1987 he took leave from Manitoba Hydro and was employed with Brown Boveri Switzerland in the HVDC Systems Engineering Department. He is presently Senior HVDC Controls Engineer with Manitoba Hydro HVDC Department.