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GUIDE FOR PLANNING DC LINKS TERMINATING AT AC SYSTEMS LOCATIONS HAVING LOW SHORT-CIRCUIT CAPACITIES

PART I : AC/DC INTERACTION PHENOMENA

CIGRE Working Group 14.07 (AC/DC System Interaction)
IEEE Working Group 15.05.05 (HVDC Interaction with low SCR AC Systems)

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CIGRE-IEEE Joint Task Force (JTF)

CIGRE Working Group 14-07
AC/DC System Interaction

A Gavrilović, Convenor
Ph Adam
T Adielson
J D Ainsworth
G Andersson
J P Bowles
G D Breuer
P H Buxton
A E Hammad
R E Harrison
B Hansson
R Joetten
Y Kato
V V Khoudiakov
P C S Krishnayya
R H Lasseter
J Lemay
G Liss
W F Long
J McConnach
V V Mogirev
G Moraw
F Nozari
C A O Peixoto
D Povh
J Reeve
M Szechtman
H L Thanawala
C V Thio
P L Thomsen
T L Weaver
T Yacamini

IEEE Working Group 15.05.05
HVDC Interactions with Low SCR AC Systems

P C S Krishnayya, Chairman
M Baker
R B Biggs
J P Bowles
G Breuer
A Gavrilović
A E Hammad
R E Harrison
N G Hingorani
R Johnson
G Juette
R H Lasseter
T Lee
R L Lee
J Lemay
W F Long
D E Martin
D Melvold
J S McConnach
K Mortensen
S Nilsson
C A O Peixoto
R J Piwko
D Povh
A Rambabu
J Reeve
J P Stovall
R Thallam
C Thio
J Vithayathil
T L Weaver
C T Wu

The Principal Contributors to Part I of the Guide :

A Gavrilović, Co-Chairman JTF,
P C S Krishnayya, Co-Chairman JTF,
T L Weaver, Vice-chairman JTF,
R K Johnson, Secretary JTF
Ph Adam
T Adielson
J D Ainsworth
G Andersson
J P Bowles
G D Breuer
P H Buxton
A E Hammad
R Joetten
R H Lasseter
G Liss
W F Long
F Nozari
C A O Piexoto
D Povh
J Reeve
H L Thanawala
C V Thio
R Yacamini

FOREWORD

The purpose of this document is to give guidance on planning and design of dc links terminating at ac system locations having low short circuit capacities relative to the dc power infeed. The Guide is limited to those aspects of interactions between ac and dc systems which result from the fact that the ac system is 'weak' compared to the power of the dc link [i.e., ac system appears as a high impedance at the ac/dc interface bus]. Some more general aspects of the design and planning of high voltage dc transmission schemes are described only when this adds to the understanding of the interaction phenomena and for the sake of completeness of the guidelines.

The Guide is published in two parts:

Part I - AC/DC System Interaction Phenomena - classifies the strength of the ac/dc system, provides information about interactions between ac and dc systems and gives guidance on design and performance.

Part II - Planning Guidelines - considers the impact of the interactions and their mitigation on economics and overall system performance and discusses the studies which need to be performed.

The guide is the result of the work of the Joint Task Force [JTF] of the CIGRE Working Group 14.07 - AC/DC System Interactions and IEEE Working Group 15.05.05 - HVDC Interaction with Low SCR AC Systems which was set up in 1986 following the agreement between Mr. D.D Wilson, Chairman of the IEEE Transmission and Distribution Committee and Dr. T.E. Calverley, Chairman of the CIGRE Study Committee 14 - D.C. Links.

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Paris, France
3-5 rue de Metz-F-75010

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PART I: AC/DC INTERACTION PHENOMENA

CONTENTS

1. INTRODUCTION

1.1 General

The introduction over the last twenty years of thyristor valves based on large size thyristors has contributed to the improvement of the overall hvdc economy and reliability, making the application of high voltage dc transmission more widespread.

From earliest commercial applications of hvdc, planners found out that in a number of schemes the ac system at the point of the proposed dc power infeed was 'weak', that is, its impedance relative to the dc power was high and in some cases the inertia of the ac system was also low.

One of the important criteria in the design of dc links is the value of the permissible temporary overvoltage [TOV] at ac terminals of the convertor stations. In early schemes the problem of too high TOV was solved by the addition of synchronous compensators in the inverter stations, i.e. by the reduction of the ac system impedance as seen by the hvdc convertor. The application of metal-oxide arrestors has been made in some recent schemes to control TOV without the need for synchronous compensators. However, for a given dc power this resulted in the need to accept an ac system having higher impedance compared to previous schemes and several aspects of interactions between ac and dc systems became more evident.

The 'weaker' the ac system, that is, the lower the ratio of the ac system short circuit capacity to dc link power, the greater will be the ac/dc interactions. The ac/dc system strength, from the impedance point of view, is defined in the Guide. Based on that definition and on typical inverter characteristics [such as the value of the convertor transformer reactance] the following SCR values can be used to classify an ac/dc system:

A HIGH SCR AC/DC SYSTEM is categorized by an SCR value greater than 3.

A LOW SCR AC/DC SYSTEM is categorized by an SCR value between 2 and 3.

A VERY LOW SCR AC/DC SYSTEM is categorized by an SCR value lower than 2.

It should be emphasized that a scheme may be operating with High SCR for most of the time, but that it may appear as Low or Very Low SCR scheme during emergency, that is, at ac system outage conditions. In such cases the scheme must be designed to operate for those conditions, unless dc power reduction is acceptable.

Operation with Very Low SCR systems is possible only if very fast and continuous control of ac voltage is exercised because the inverter operation is in 'unstable' region of the ac voltage/ dc power characteristic. In modern ac system terms this mode of operation is similar to an ac system whose voltage stability is maintained by a fast static var compensator [SVC]. In such dc links at present in service, the required fast voltage control is executed by the hvdc convertor itself.

From the above, it can be seen that problems associated with Very Low SCR ac systems can be resolved either by strengthening the system by addition of synchronous compensators or by stabilizing the ac system voltage by fast control. On the other hand, synchronous compensators must be used to strengthen the system whenever there is a requirement to increase the inertia of the ac system. The system inertia constant referred to dc power, H_{dc}, should for example, be greater than 2s in order to maintain frequency deviation under fault conditions within 5 percent.

In addition to the system strength classification mentioned above, Part I of the Guide defines and discusses a number of ac/dc interaction phenomena and proposes methods of preventing associated potential problems.

Good preliminary judgement on the impact of most interactions on the design and performance of a dc transmission scheme can be based on SCR and inertia values quoted above, and on the discussions given in the document. However, the Guide stresses the need to carry out adequate studies at all stages of planning and design.

HVDC controls play an important role in most interaction phenomena and for that reason a detailed description of controls is included in the Guide.

AC/DC system interactions are concerned with voltage stability [voltage collapse phenomena], overvoltages, resonances and recovery from disturbances. Examples of their influence on the station design are the following:

Voltage stability conditions will determine the type of voltage control and the type of reactive power supply. The voltage stability - voltage collapse-interaction is similar to such phenomena in a purely ac system.

The level of temporary overvoltage [TOV] will influence station design, including thyristor valve and surge arrester ratings. The lower the value of SCR the higher the potential value of TOV.

Shunt capacitors are used in convertor stations for ac filters and for var supply. The larger the ratio of shunt capacitor Mvar to ac system short circuit MVA, the lower will be the resonant frequency.

Commutation failures and recovery from ac and dc faults represent an important aspect of dc operation. However, it should be noted that modern controls have a dominating influence on the recovery from faults and are less affected by ac system impedance compared to controls used in earlier schemes.

Part II of the Guide, which will be published as a separate document, will consider how the ac/dc interaction phenomena described in Part I should be taken into account in the planning and the preliminary design of ac/dc systems having Low or Very Low SCR values.

1.2 Scope

Part I of the Guide discusses the effects of various aspects of the ac/dc interactions on the design and performance of dc schemes where the ac system appears as a high impedance at the ac/dc interface bus, i.e., Low and Very Low Short Circuit [SCR] conditions. AC systems having zero or inadequate mechanical rotational inertia, such as island schemes with no or with limited local generation, are also considered.

The scope is confined to consideration of ac/dc interactions related to systems having Low or Very Low SCR and Inadequate or Zero Inertia. Environmental, siting, and construction issues are not addressed. General issues such as steady state reactive compensation, ac and dc filter requirements are not in the scope of the Guide, but would be included in a complete study for a particular dc scheme design.

In order to assist those not familiar with dc transmission and convertors, a brief description of basic rectifier and invertor operation is given in the APPENDIX.

1.3 Purpose

The purpose of Part I of the Guide is to address factors required to be considered in the design of dc transmission schemes in the context of system interactions resulting from dc links terminating at ac system locations having low short circuit capacities relative to dc power infeed and for cases where the inertia of the ac system is too low for satisfactory operation. The following ac/dc interactions are considered: power, voltage and frequency instabilities; harmonic resonances related instabilities; subsynchronous torsional interactions; temporary overvoltages and recoveries from ac and dc faults.

1.4 Definitions

Short circuit ratio [SCR]. The ratio of the ac system three phase short circuit MVA [expressing the ac system impedance] to dc power.

Weak or high impedance ac system. An ac/dc system having Low or Very Low SCR.

Maximum available power [MAP]. Maximum power which can be obtained by increasing dc current while not controlling the ac voltage.

Critical short circuit ratio [CSCR]. SCR corresponding to the operation at MAP; for typical inverter design CSCR=2. The following operational characteristics are associated with CSCR:

CSCR represents the border line between 'stable' and 'unstable' operating regions. For SCR values lower than CSCR, the operation is in the 'unstable' region of the ac voltage/dc power characteristic.

If the operation is at unity power factor for systems at CSCR [i.e., the operation is at MAP], then the fundamental component of the temporary overvoltage [TOV_{fc}] at full load rejection would be near 1.4pu.

A resonance near the second harmonic will occur for systems operating at CSCR.

Operation with minimum constant γ. Operation of an inverter at minimum commutation margin angle γ in order to ensure transmission at the maximum dc voltage [possible only at powers below MAP, i.e., in the 'stable' region of the ac voltage/dc power characteristic.

Operation with variable γ. Margin angle γ is varied around an average value in order to stabilize the ac voltage. This can be achieved either by a direct control of the ac voltage or indirectly by controlling the dc voltage. Another way of stabilizing the receiving system ac voltage is to arrange for the inverter, and not the rectifier, to be the current controlling station. These modes of control are normally used for operation beyond MAP, that is in the 'unstable' region of the ac voltage/dc power characteristic.

Inadequate inertia systems. AC systems having limited local generation, and therefore rotational inertia, so that the required voltage and frequency cannot be adequately maintained during transient ac or dc faults.

Zero inertia systems. Isolated ac systems having no local generation.

Effective dc inertia constant [H_{dc}]. Rotational ac system inertia constant H converted to the base of dc power.

In this guide rated values are assumed to be equal to nominal.

1.5 Acronyms

SCR	Short Circuit Ratio
ESCR	Effective Short Circuit Ratio
QESCR	Q [reactive] Effective Short Circuit Ratio
CSCR	Critical SCR
CESCR	Critical ESCR
CQESCR	Critical QESCR
OSCR	Operating SCR
MPC	Maximum Power Curve
MAP	Maximum Available Power

1.6 General References

The following general references present fundamentals of direct-current conversion technology.

1. IEEE Guide for Specification of High-Voltage Direct-Current Systems, Part I - Steady State Performance, ANSI/IEEE Std. 1030-1987.

2. IEC Report: Performance of high-voltage d.c. (HVDC) systems Part I: Steady-state conditions. IEC 919-1, First edition, 1988.

3. IEC Report: Performance of high-voltage d.c. (HVDC) systems Part 2: Steady-state conditions. IEC 919-2, First edition, 1991-01.

4. Guidelines for the application of metal oxide arresters without gaps for HVDC convertor stations, CIGRE Technical Brochure No. 34. Edited by SC 33/14 WG 05; Published 1989.

5. Compendium on HVDC schemes throughout the world, CIGRE Technical Brochure No. 3, Edited by SC 14 WG 04; Published 1987.

2. AC/DC SYSTEM STRENGTH

2.1 Introduction

AC system disturbances can affect the operation of any convertor, but mal-operation of a small convertor should have negligible effect on the ac system. However, it is not uncommon for a dc link to supply a large proportion of the ac system load so that the loss of its real power and the associated reactive power changes can have a profound effect on the system.

The interaction between ac and dc systems becomes more pronounced as the impedance of the ac system, as seen from the convertor ac terminals, is increased for a particular dc power. It follows that even a relatively small dc link connected to a point of the ac system having high impedance (low short circuit capacity) may have considerable effect on the local ac network, even if the latter may be part of a large ac system.

It is important that adequate system emf is available not only for normal operation, but also following a system fault. The rotational mechanical inertia of the ac system transiently provides the energy to maintain the system emf despite a temporary reduction in the supply of dc power through the inverter. The ac system generators and their turbines are the main source of the ac system rotational inertia.

If a system receives all or most of its power from a dc link, the inertia of the receiving system may be inadequate, so that upon the interruption of the dc infeed, due to any cause, the system emf and frequency may decrease to unacceptably low values. In such cases synchronous compensators are used to act as "transient generators" to maintain the system EMF and frequency.

An ac system can be defined as "Weak" from two aspects:

a) AC system impedance may be high relative to dc power at the point of connection.

b) AC system mechanical inertia may be inadequate relative to the dc power infeed.

2.2 High Impedance Systems

2.2.1 Short Circuit Ratios

2.2.1.1 Short Circuit Ratios (SCR)

The calculation of SCR is discussed in Section 2.2.5, which shows that it is really per unit admittance. However, for most practical cases this is not very different from that of pure inductance, and SCR is then often obtained from the following equation:

$$SCR = \frac{S}{P_{dI}} \qquad (2.1)$$

where S is the ac system three phase symmetrical short circuit level in MVA at the convertor terminal ac bus with 1.0 pu ac terminal voltage, and P_{dI} is the rated (considered in this guide to be equal to the nominal) dc terminal power in MW.

When considering the effects of short circuit currents on equipment only the maximum value need be calculated. In contrast, it is the minimum value of S at which the rated power P_{dI} will be transmitted which must be used when examining limiting operating conditions.

2.2.1.2 Effective Short Circuit Ratio (ESCR)

Shunt capacitors including ac filters connected at the ac terminal of a dc link can significantly increase the effective ac system impedance. To allow for this, the effective short circuit ratio (ESCR) is defined as follows:

$$ESCR = \frac{S - Q_C}{P_{dI}} \qquad (2.2)$$

where Q_c is the value of three phase fundamental Mvar in per unit of P_{dI} at per unit ac voltage of shunt capacitors connected to the convertor ac bars (ac filters and plain shunt banks).

2.2.1.3 Operating Short Circuit Ratio (OSCR)

The ratio S/P_{dI} will vary in practice due to changes in ac system configuration and due to different levels of dc power being transmitted. Therefore, it should be remembered that it is the operating SCR (OSCR) which is important, and which refers to actual power and corresponding actual S. Normally OSCR will be higher than the minimum specified SCR of the scheme, particularly at transmission below rated power. However, the lowest value of operating SCR may not necessarily coincide with rated power. For example, operation at a lower power level may coincide with a system arrangement having higher impedance value than the one specified for the rated value. It should be born in mind that at very low currents the satisfactory operation may be achieved only at a value of OSCR which has a higher value than the minimum SCR specified for operation at normal dc currents.

2.2.1.4 Effect of Convertor Reactive Power Consumption and QESCR

Short circuit ratios are sometimes used as a measure of expected performance of ac/dc systems, but as discussed later, this can give only approximate indication and the comparisons between systems by referring only to their respective short circuit ratios can be misleading.

One of the major reasons for different performance of DC systems having the same SCR or ESCR is due to the convertor reactive consumption which may differ considerably between the schemes under consideration. The reactive consumption of the convertor (Q_d) (see APPENDIX) can vary greatly depending on the operating α or γ and on the value of the commutating reactance (usually the convertor transformer leakage reactance). The value of Q_d can have a significant effect on the performance, in particular on the power transfer limits and on the temporary overvoltages. If the system short circuit MVA and Q_C are referred to the sum of P_d and Q_d rather than to P_d, a better, but still approximate, indication of performance can be obtained, as can be seen in Section 2.4.

Q effective short circuit ratio (QESCR) is defined as follows:

$$QESCR = \frac{S - Q_c}{P_d + Q_d} \qquad (2.3)$$

2.2.1.5 Synchronous and Static Var Compensators

Synchronous compensators (SC) contribute directly to the reduction of the ac system impedance and they are included in the calculation of short circuit ratios. SC's have been used to strengthen the ac system at the terminals of an inverter, this being a more economic solution compared to, for example, addition of a transmission line.

Operation of a dc link terminating at a point of high ac system impedance (i.e., of low short circuit capacity) can be enhanced by fast control of ac voltage. This can be done by using the convertors themselves to control the voltage or by employing a separate thyristor controlled reactor (TCR) or a saturated reactor (SR) at the ac terminals of the inverter. Fast control of the ac voltage does in effect "strengthen" the ac system.

If the ac system has a very high impedance, relative to the power being transmitted (a very low SCR System, see 2.2.4.3), the satisfactory operation can be achieved in two ways:

(a) By strengthening the ac system by, for example, addition of a synchronous compensator and in so doing, transform the system to a low SCR System (2.2.4.2).
(b) By applying very fast ac voltage control (2.2.7).

It is possible to express, approximately, the strengthening of the ac system by fast voltage control in terms of a reduction of the ac system impedance (2.2.7.1). However, it is recommended to ignore this effect when calculating the short circuit ratios. The ac voltage control and the dc power controls must be coordinated for each scheme; also, the convertor or TCR or SR are designed, due to economic considerations, to execute the voltage control within a predetermined ac voltage range. Later in this document it is emphasized that short circuit ratios describe the system only approximately and that operation with very low SCR assumes fast voltage control.

A static var compensator (SVC) normally consists of an element (TCR,SR) which provides continuously variable vars and one or more of the following elements:

i. fixed shunt filters, capacitors or reactors
ii. thyristor switched shunt capacitors
iii. mechanically switched shunt capacitors
iv. thyristor switched shunt reactors
v. mechanically switched shunt reactors

TCR and SR are excluded, as already stated, from the definition of short circuit ratios as their effects depend on their designed range, speed of response and coordination with other controls. The other elements, fixed or mechanically switched, would have to be included for calculating ESCR, because their presence adds directly to the ac system impedance.

Shunt reactors are usually disconnected for normal operating conditions, but would have to be considered if normally connected.

2.2.2 Power-Current Characteristics

2.2.2.1 Maximum Power Curve - MPC

For a given ac system impedance and other parameters of the ac/dc system shown on Figure 2.1 there will be a unique P_d/I_d characteristic, Figure 2.2, provided the starting conditions are defined and it is assumed that I_d changes almost instantaneously in response to the change of α of the rectifier; for example, due to a change in current order. All other quantities, ac system emf, γ (minimum) of the inverter, tap-changers, automatic voltage regulation (AVR) and the value of shunt capacitors and reactors are assumed not to have changed. When considering the inverter power capability, it is also assumed that the rectifier provides no limitation to the supply of dc current at rated dc voltage. Each subsequent point is calculated by steady state equations. These "quasi steady-state" characteristics give a good indication of dynamic performance.

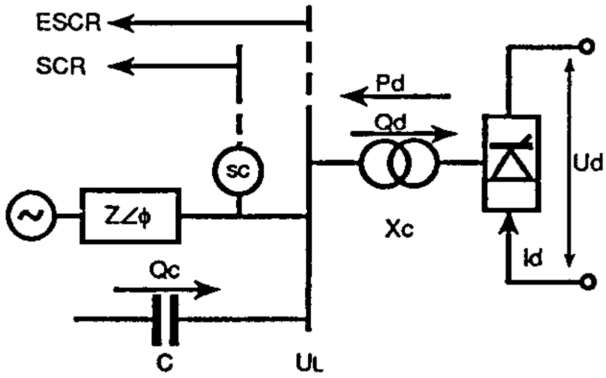


Figure 2.1
Simplified Representation of a DC Link Feeding an AC System with Shunt Capacitors (C) and Synchronous Compensators (SC) (if any) at Convertor Station Busbars

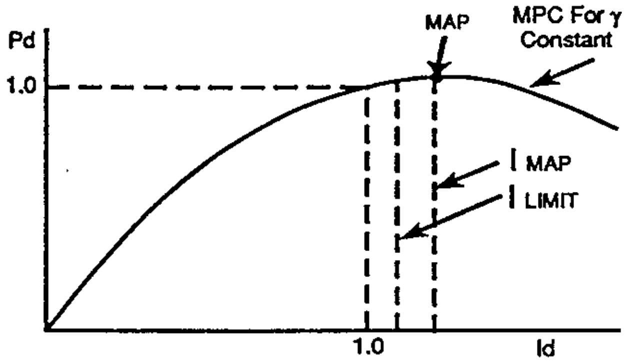


Figure 2.2
DC Power - DC Current Curve
For γ Minimum

The starting conditions are defined to be:

$P_d = 1.0$ pu, $U_d = 1.0$ pu, $U_L = 1.0$ pu and $I_d = 1.0$ pu.

(P_d = dc power, U_L = ac terminal i.e., convertor transformer line side voltage, U_d = dc voltage of the inverter and I_d = dc current.)

If the inverter is operated throughout at minimum constant γ the resulting characteristics will represent maximum obtainable power for the system parameters being considered. This curve is termed the Maximum Power Curve - MPC. Any power can be obtained below MPC by increasing α and γ, but power higher than MPC can be obtained only if one or more system parameters are changed, e.g., reduced system impedance, increased system emf, larger capacitor banks, etc.

A similar MPC curve can be obtained for the rectifier at minimum constant α.

2.2.2.2 Maximum Available Power - MAP

A maximum power curve (MPC) exhibits a maximum value termed Maximum Available Power (MAP) as can be seen on Figure 2.2. The increase of the current beyond MAP reduces the dc voltage to a greater extent than the corresponding dc current increase. This could be counteracted by changing the ac system conditions, e.g., by controlling the ac terminal voltage. It should be noted that dP_d/dI_d is positive for operation at dc currents smaller than I_{MAP}, the current corresponding to MAP; dP_d/dI_d is negative at dc currents larger than I_{MAP}.

2.2.3 Critical Short Circuit Ratios

Maximum power curves are plotted on Figure 2.3 for an inverter connected to ac systems having four different strengths. It can be seen that the rated (nominal) operating point A is located at different parts of MPC for different values of SCR.

For SCR = 4.5, the operating point A is well below MAP and the 1 pu current is considerably smaller than I_{MAP} = 1.8pu. For SCR = 3, A is nearer to MAP and I_{MAP} 1.4pu. In both of these cases dP_d/dI_d is positive.

For SCR = 1.5, the operating point A is "beyond" MAP, corresponding to I_{MAP} = 0.8 pu of rated dc current, I_{dN}. The value of dP_d/dI_d is negative. It may appear that there is another possible operating point for SCR = 1.5 at the left of MAP, Point B. However, inspection of Figure 2.3 will indicate that the voltage corresponding to point B for SCR = 1.5 is too high to be utilized, as indicated by point B':

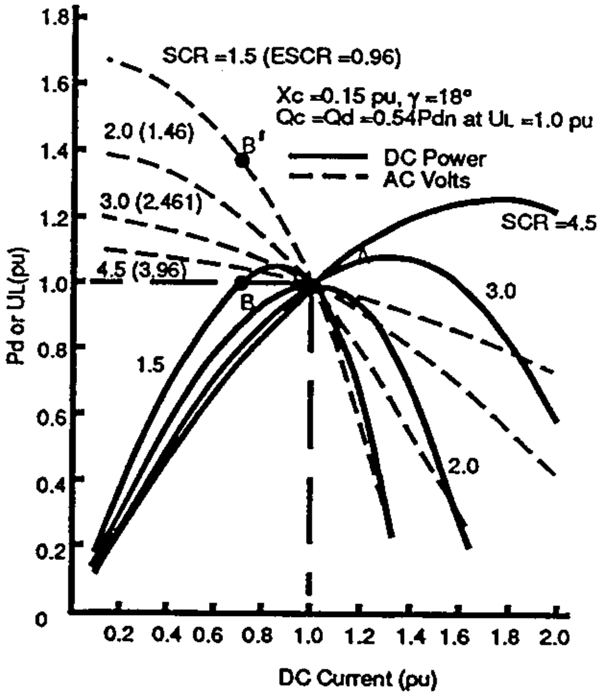


Figure 2.3
Variation of Inverter AC Terminal Voltage and Power with DC Current

When the rated values of P_d, I_d, U_d and U_L (all at 1.0 pu) correspond to the maximum point of P_d/I_d curve for operation with minimum γ, then the corresponding short circuit ratios are termed critical ratios (CSCR, CESCR, and CQESCR).

In this example, the critical short circuit ratio, CSCR is equal to 2, the operating point A coincides with the MAP of the curve for SCR = 2. However, as discussed in 2.4, the value of CSCR depends on the inverter reactive consumption, i.e., on the values of the commutating reactance X_c and on the commutation margin γ.

For calculation of Critical Short Circuit Ratios see 2.5

It is clear that the Critical Short Circuit Ratios represent a border line, when operating at γ constant, as the ratio dP_d/dI_d changes its sign. This is further discussed in Chapter 3.

2.2.4 Short Circuit Ratios as Indication of AC/DC System Strength

One can distinguish three typical cases by considering the transient conditions which would temporarily reduce the ac terminal voltage and/or increase the system impedance, e.g., due to the loss of an ac line. In such a case the power for a given current would reduce, i.e., the temporary system condition would result in a new power curve which has a lower maximum value.

2.2.4.1 High SCR System

Figure 2.4 shows an inverter connected to a system by two parallel ac lines. It is assumed that the original SCR of 4.5 is temporarily reduced to an SCR of 3 if one of the two lines has tripped.

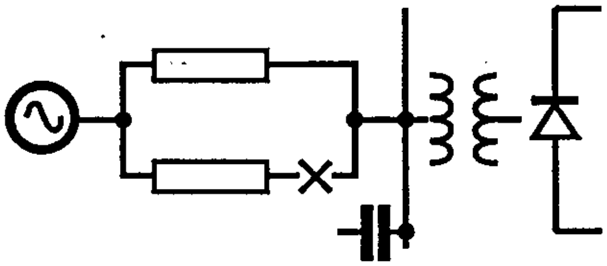


Figure 2.4
An Inverter Connected to a System
by Two Parallel AC Lines

In this case, power can be maintained at 1 pu value despite the reduction of MAP, as shown in Figure 2.5 by increasing dc current at the new operating point, B. Operation throughout is at dc currents having a lower value than the current corresponding to MAP ($I_d < I_{MAP}$). The assumed system disturbances have resulted in a reduction of MPC, but the new maximum, MAP-2, is still higher than the rated power. All operating conditions are at γ minimum constant and correspond to SCR > CSCR.

(It should be noted that a sufficiently severe system disturbance could always cause an excursion beyond MAP, but such rare events are not considered as part of the definition of system strength.)

2.2.4.2 Low SCR System

The normal operation is at $I_d < I_{MAP}$ but a system disturbance could reduce MAP below the rated power and operation would continue at a reduced power in current control at I_d which may be greater than I_{MAP} or in power control at a reduced power order. Normal operating conditions are at SCR > CSCR for operation at minimum γ, but temporary operation may be at SCR < CSCR at a power level lower than rated.

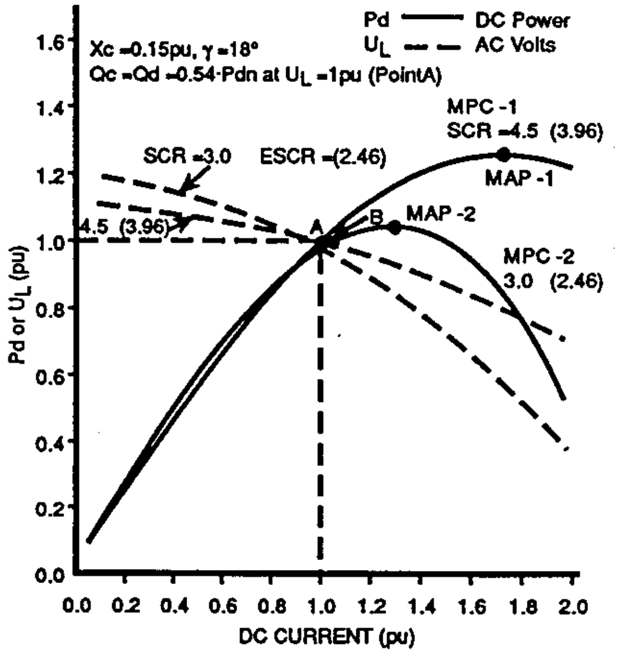


Figure 2.5
AC/DC System - High SCR Sudden Change
of SCR From 4.5 to 3.0

Power curves for this case are shown in Figure 2.6a. It has been assumed that an SCR of 3 reduces to a value of 2, as a consequence of the tripping of one line (Figure 2.4). The power at MAP-2 of the reduced MPC-2 is lower than the rated power at A. Any increase of current beyond 1.0pu would be counterproductive as the power would further reduce. It should be noted that the system impedance for curves SCR = 2 of Figures 2.3 and 2.6a are identical, but MAP-2 of Figure 2.6a has a lower value than MAP for SCR = 2 of Figure 2.3. The reason for this is that the initial ac terminal voltage, U_L, for all values of SCR's of Figure 2.3 was adjusted at 1 pu. In the case of Figure 2.6a U_L was adjusted to 1 pu for initial conditions at SCR = 3. After the line tripping ac terminal voltage had decreased, due to an increase of the system impedance, to a value of 0.93 pu of U_{LN} and power decreased to 0.92 pu of P_{dN} at 1.0 pu of I_d. These values represent the initial conditions for MPC-2.

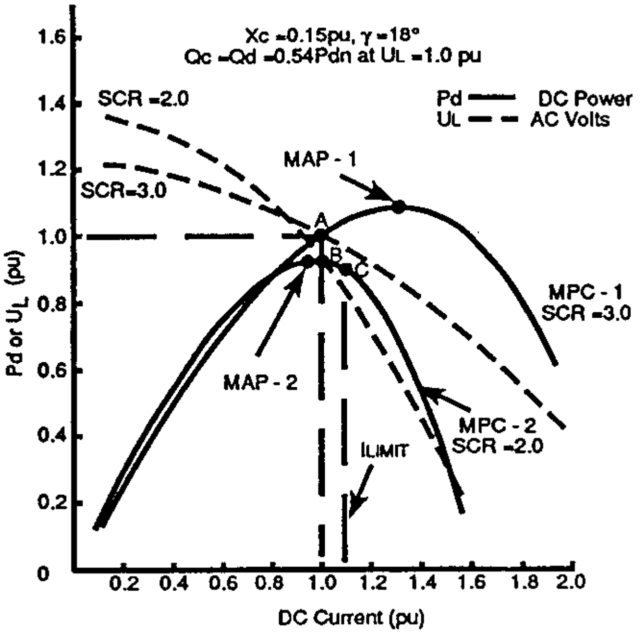


Figure 2.6a
AC/DC System - Low SCR Power and AC Voltage Curves Sudden Change of SCR from 3 to 2

2.2.4.3 Very Low SCR System

The normal operation is at a direct current equal to or larger than the current corresponding to MAP ($I_d > I_{MAP}$). Normal operating conditions are at SCR $\leq$ CSCR as indicated by point A on curve for SCR = 1.5 on Figure 2.3. In such cases a stable condition in power control is achieved by operation with variable γ. γ is normally kept at a value higher than the minimum so that the inverter itself can control the voltage. An alternative way of operating at SCR < CSCR can be achieved by the use of very fast static var compensators to control the ac voltage and hence the dc voltage.

The operation with very low SCR systems is discussed in Chapters 3 and 4.

2.2.4.4 Typical Values of SCR

In the initial stages of planning the utility may know only the short circuit MVA of the system and the required dc MW. The following are very approximate indications of the ac/dc system strength in terms of SCR.

For a high SCR system (approximately SCR > 3.0) as defined in 2.2.4.1 dc could normally be introduced without the need for any special steps. However, as can be seen from the ac voltage curves of Figure 2.3, the temporary overvoltage (TOV), the value of U_L at load rejection, ($I_d = 0$) - is becoming relatively high as SCR reduces and approaches the value of 3, and ac voltage control has been used for some schemes having SCR in that region (Cross Channel, Chateauguay).

The application of hvdc with a low SCR system as defined in 2.2.4.2 (approximately 3 > SCR > 2) may need some additional control features. (see Chapters 3 and 4) In addition, consideration should be given to ac voltage control and to the possibility of second/third harmonic resonance. These considerations may result in the need for some additional steps to be taken.

If SCR is lower than 2, the system may prove to be a very low SCR system as defined in 2.2.4.3 and the use of "variable γ control strategy" (see Chapters 3 and 4) may prove to be essential. Operation at constant γ could be possible provided very fast ac voltage control is used. Special steps would be needed to control ac overvoltages and low order harmonics.

When comparing the performance of a dc link based on the values of SCR, it should be appreciated that the value of CSCR, unlike SCR, depends on the value of Q_d, which in turn depends on the commutating reactance, X_c, and the value of γ. Two inverters rated for the same nominal power, but having different nominal Q_d, will have the same SCR, but the values of CSCR's will be different. It can be seen in 2.4 that for some typical examples CSCR may vary by more than 30 percent. In the examples considered in previous sections of this chapter, X_c = 15 percent and γ = 18° have been assumed, which may be considered to be in the middle of the range of practical values.

One system may have requirements which necessitate deeper study than another system. System damping, which in the simple model is represented by the impedance angle Φ, may differ greatly between two systems having the same value of SCR. This can be important for some interaction phenomena. All meaningful studies should use the available system data in sufficient detail to match the requirements of a particular study. However, it should be noted that the trends in convertor control design are making stability and recovery from faults less influenced by system damping, hence in the future the damping will principally affect the steady state harmonics and overvoltages due to major disturbances, such as total load rejection.

2.2.4.5 The Nature of AC System Disturbance

The definitions of the system strength given in 2.2.4 depend also on the operating conditions of a given system. For example, the disturbance described in 2.2.4.2 may be considered, by some utilities, to be an exceptional event, and that more "normal," relatively frequent disturbances may not result in the reduction of maximum available power (MAP-2) below the rated power.

The utilities usually specify the disturbance for which the power should be maintained at the rated value in terms of the ac terminal voltage reduction without specifying any associated change of the system impedance, i.e., as if the terminal voltage was reduced only by ac system emf reduction.

The effect on dc power will be different for the same amount of ac terminal voltage reduction, depending on whether the ac system impedance has changed or not.

In Figure 2.6b MPC-1 and MPC-2 are same as in Figure 2.6a: MPC-2 resulted from the ac system impedance increase by one-third, from SCR = 3 to SCR = 2; this resulted in ac terminal voltage drop from 1.0 pu [point A] to 0.93 pu [point B] at I_d = 1 pu; the power has reduced from 1 pu to 0.92 pu, which is very close to the value of MAP-2.

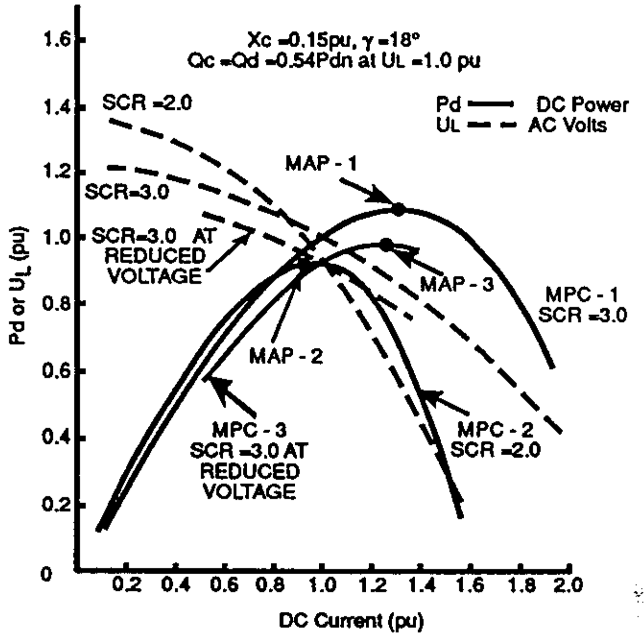


Figure 2.6b
AC/DC System - Low SCR Sudden AC Voltage Reduction without SCR Change (MAP-3)

MPC-3 in Figure 2.6b was obtained by assuming that ac terminal voltage has reduced to 0.93 pu without a change of the system impedance. DC power has reduced initially to a similar value as for MPC-2, but because MAP-3 has a greater value than MAP-2, the power can be increased to 0.98 pu [MAP-3] by increasing dc current to 1.25 pu.

This means that the power immediately available following the disturbances will differ by 6.5% for the two cases.

Relevant quantities for these two cases are tabulated in section 2.6.

2.2.4.6 Temporary Overvoltages (TOV)

When considering power transfer limits, MAP represents a clear change in the P_d/I_d characteristic. Moreover, for operation at currents higher than I_{MAP}, the control strategy based on constant γ operation cannot be used in power control mode.

When considering the values of TOV, there is no such definite "break point." In addition, depending on the location of the convertor station and on the utility practice, the acceptable value of TOV may vary from scheme to scheme.

Also, in highly meshed systems having generators which are electrically close to the convertor station, the effective short-circuit impedance corresponding to the SCR value calculated by sub-transient reactances will apply only to the first fundamental cycle and the subsequent TOV would be higher as transient reactances rather than subtransient values influence the voltages.

The fundamental components of TOV (TOV_{fc}) calculated from equation (8.1) in Section 8.5 have the following approximate values

High SCR systems (SCR>3)	TOV_{fc} Lower than 1.25 pu
Low SCR systems (3>SCR>2)	TOV_{fc} Higher than 1.25 but lower than 1.4 pu
Very low SCR systems (SCR<2)	TOV_{fc} Higher than 1.4 pu

(These are theoretical values, ignoring saturation of transformers; TOV_{fc} values will be lower in reality due to this (refer to Section 8.1).) However, the TOV peak values which includes harmonic components may not be reduced by saturation of convertor transformers.

It should be pointed out that the operation with Low SCR systems does not seem to cause particular difficulties from the point of view of transfer of power. Occasional temporary power reduction (see 2.2.4, 3.2.2 and 3.6.2) can be contained. However, the corresponding TOV is not always acceptable.

In Figure 2.7 P_d/I_d curve MPC-2 was plotted using data of the Cross Channel scheme. It can be seen that for SCR=3 (ACV-2) this would have resulted in TOV_{fc} of just over 1.3 pu, which was not acceptable to the utility. Static Var compensators were included in the installation to limit TOV_{fc} to 1.16pu. SCR = 3 is the minimum specified value; the operation normally is at an SCR value higher than 3.

It is interesting to compare MPC for the uncompensated Cross Channel scheme with the MPC for the "average" scheme data used in Figure 2.6 for the same SCR=3.

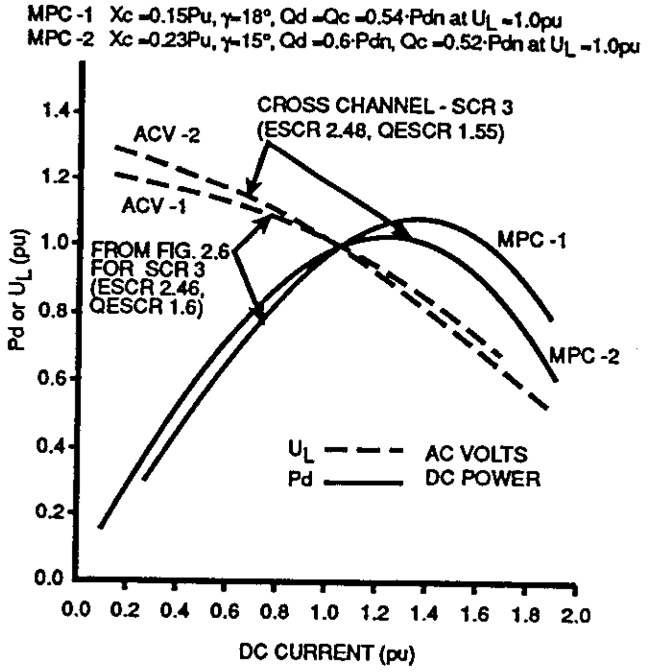


Figure 2.7
Power and AC Voltage Curves for SCR = 3
for two different convertor characteristics

For the "average" system TOV_{fc} is just over 1.2 pu, compared to the, uncompensated, Cross Channel scheme of just over 1.3 pu. This is due to the difference in the value of the commutating reactance and consequent higher var consumption. The difference in MAP values should also be noted.

2.2.5 Calculation Of Short Circuit Ratios

2.2.5.1 General

In many preliminary calculations it is convenient and customary to use a simplified representation of the ac system, as discussed in Section 2.2.5.2. To determine the system impedance and short circuit ratios, digital short-circuit programs from different origins can give different results for SCR for the same system, while giving the correct results for the normal purpose of these programs, which are usually used for studying ac systems alone. For example, a program may not represent the transmission lines' shunt capacitance, which would give unrealistically low system impedance, Z_s, and in consequence, a too high SCR. Some interaction phenomena are significantly influenced by the system resistive component (system damping) which is primarily provided by loads which may not be represented in some short circuit programs.

2.2.5.2 Simplified Representation of the AC/DC System

Referring to Figure 2.1, it is assumed that the ac system can be represented by a Thevenin equivalent emf at fundamental frequency, behind an impedance Z (or admittance Y = 1/Z).

Short Circuit Ratio (SCR) is defined as the value of Y at fundamental frequency, on a base of rated power (MW) of the convertor and rated ac system voltage, which is consistent with SCR defined in Section 2.2.1. Synchronous compensators, existing or supplied as part of the convertor station, are deemed to be connected as required for the operation considered; i.e., they form part of the SCR calculation.

Effective Short Circuit Ratio (ESCR) is defined as $(Y + Y_c)$ on the same base as for SCR, where Y_c is the admittance of all shunt filters and capacitor banks on the busbar which are connected for the operation under consideration. This definition is consistent with the definition in Section 2.2.1.

The following notes may be useful for defining a suitable system representation:

1. Representation of the ac system by an admittance defined by SCR is assumed to be relevant only to transients (e.g., ac faults) of a few hundred milliseconds. (For more detailed study of some particular characteristics a more detailed representation may be required.)

2. As a consequence of (1) the calculation of Y at fundamental frequency shall assume that synchronous machine field controls, transformer tap positions, and capacitor switching controls have no appreciable effect during the transient.

3. The reactance value of a synchronous machine is not constant, but effectively depends on the part of the transient being studied, and the method of supplying the field. The apparent value varies between subtransient and transient reactances (but not synchronous reactance). The effect of any errors in assumptions about this will normally be reduced by fixed ac system line and transformer reactances, hence calculation based on subtransient reactances (as commonly used in short circuit level calculation) will generally be sufficiently accurate. However, in this simple representation it would be safer to use the transient reactance for synchronous compensators connected in the station and for any nearby synchronous machines.

4. The system damping is important for most phenomena and therefore the impedance values corresponding to SCR and ESCR (and QESCR) should be expressed in polar form as magnitude and angle. Thus, for example, for a system with SCR = $3\angle{-80^\circ}$ the addition of 0.6 pu of capacitors plus filters gives ESCR of about $2.4\angle{-78^\circ}$. [Please note that because SCR and ESCR are defined as

admittances - see Section 2.2.5.2 - the angle should be negative as indicated.]

5. SCR (ESCR) values calculated at the ac terminals of the convertors may not be directly applicable in special cases such as where the convertor transformers have tertiaries connected to a synchronous compensator or compensators. In this case, the physical position of the tertiary usually is between line and valve windings such that there is a finite reactance between the filter bus and the tertiary terminals.

6. If the ac filters are connected to the tertiary winding of the convertor transformer and if this winding has a reactance value almost zero (the tertiary is placed physically between line and valve windings), then the tertiary becomes the commutating bus. This means that the equivalent ac system impedance is increased by the reactance of the line winding. Short circuit ratios must be calculated as if the line winding reactance forms part of the ac system.

7. Any capacitor banks associated with static var compensators (SVCs) should be lumped with other capacitors on the busbar. If switched capacitor banks are used then the maximum value of capacitors which may be connected during the operation to give lowest value of ESCR (or OESCR) for a particular system configuration should be used. The representation of continuously responding SVCs requires careful consideration, as discussed in Section 2.2.1.5.

8. Short circuit ratios defined in this Section are not applicable for studies involving mechanical shaft resonances of machines; such studies should use relevant system representation. The same applies in general to all studies of slow phenomena associated with machines; e.g., inter-machine and inter-system swinging, field controls and governors.

9. For some other studies, e.g., overvoltages and recovery from faults, it is important to represent the convertor transformer saturation properties and nearby loads accurately. This may also apply to other large transformers close to the convertor stations.

Although SCR (ESCR) calculated as above would give a numerical definition of the ac system admittance (and impedance) represented by the Thevenin equivalent circuit, when comparing the results all relevant convertor quantities must also be stated: commutating reactance X_c, delay angle α or commutation margin (γ) and the control strategy. As discussed in 2.2.1.4, QESCR takes most of these into account.

It was noted in Section 2.2.5.1 that different computer programs may give different values of system impedance which may lead to small errors. The more direct method to obtain an equivalent system impedance value is to make all system emfs zero, to inject a current at the terminal of the convertor and measure the resulting voltage. This is in effect what a network reduction program does. It should always be remembered that it is necessary to obtain the value of the system impedance as accurately as possible; the short circuit MVA has no direct relevance in the study of DC operation, although it is a convenient quantity to use in discussion.

2.2.5.3 Load Representation

It was pointed out in 2.2.5.1 and in Note 4 above that load representation is important. For example, induction motors add to the emf of the system, but they do collapse at low ac voltage. A large number of induction motors in the vicinity of the inverter may have considerable effect on the performance. It is recommended that users of both in-house and externally sourced computer programs scrutinize how loads are represented in assessing the validity of SCR calculations. Loads should be represented using the best knowledge available. In the absence of load data, it is suggested that load characteristics should be estimated rather than completely omitted. The ac/dc system behaviour is influenced by load characteristics and the omission of load representation may give misleading and possibly overly pessimistic results. For example, loads may contribute substantial damping to transient disturbances, and possibly be the source of additional short circuit MVA.

2.2.6 Application Of Synchronous Compensators

Synchronous compensators have been used to strengthen the ac system at the inverter end in a number of DC schemes. The cost and maintenance requirements of synchronous compensators may restrict their application to special situations.

In addition to the reduction of the system impedance both at fundamental and harmonic frequencies, the synchronous compensators have the following beneficial characteristics:

a) They can supply both positive and negative continuously variable reactive power, which in most cases eliminates the need for frequent shunt capacitor switching.

b) They tend to increase the natural resonant frequency between the filters and the ac system.

c) They are able to provide an increase of reactive power on reduction of ac busbar voltage, in contrast with var reduction when supplied by shunt capacitors.

The application of synchronous compensators at schemes

▼

like Nelson River (Manitoba, Canada) and Itaipu (Brazil) has changed the system from being very low SCR to a low SCR system as defined in Section 2.2.4.

A requirement for dimensioning the synchronous compensator in these schemes was the need to limit the fundamental component of the temporary overvoltages to values lower than 1.4 pu. From the second table in 2.4, it can be seen that the operation at the critical short circuit ratio (CSCR) corresponds to TOV_{fc} of 1.4 pu. (See also 3.1). It should be noted that the reduction of the system impedance, by addition of synchronous compensators, to reduce TOV has at the same time resulted in bringing the operating point and therefore the operating direct current to a smaller value than I_{MAP}.

2.2.7 Control of AC Voltage by Variable Static Equipment

The consequence of ac/dc interaction, when the ac system impedance is high, is evidenced by large ac voltage variations. Very fast and continuous ac voltage control would effectively strengthen the system.

The application of metal oxide (MO) gapless surge arresters has contributed to the possibility of limiting TOV to required values without the need to use synchronous compensators.

2.2.7.1 The Application of TCR and SR Static Var Compensators

A fast TCR (thyristor controlled reactor) or SR (saturated reactor) static var compensator can be used to keep the terminal ac voltage constant within the required range. The compensator var absorption must be continuously variable within its prescribed range.

In practice the size (var range) of the TCR or SR has to be limited on economic grounds. These compensators lose control at very low ac voltage and may have limited overload range. The operating range is usually increased by the use of thyristor switched capacitors (TSC) and/or mechanically switched capacitors to keep the TCR or SR within its designed range.

Usually a voltage/current or voltage/var characteristic of the TCR or SR is designed with a slope to suit the ac system, usually 3 to 5% on the SVC rating. The equivalent system impedance is determined by the addition of this slope reactance in parallel with the ac system impedance. However, as discussed in Section 2.2.1.5, the effect of a TCR or SR is not included in the definition of SCR but has to be considered for each separate scheme.

2.2.7.2 The Application of the Inverter with Variable γ

The reactive power consumption of the inverter can be varied by operation with different values of the commutation margin angle γ (See APPENDIX).

Highgate and Virginia Smith (Sidney) convertors in the United States and McNeill in Alberta, Canada, are examples of schemes which are designed to operate with very low SCR systems, and TOV is controlled by a combination of MO arresters, convertor control action and subsequent mechanical switching of capacitors/ filters. In the case of the McNeill station the effective system impedance is increased by the line winding of the convertor transformer (see Note 6 in Section 2.2.5.2).

If γ is varied in response to ac voltage variation, the inverter can be designed to act as a TCR in a limited range of conditions. As the dc transmission voltage depends on the value of γ, during steady-state conditions the convertor transformer tapchanger and mechanically or thyristor switched capacitors are used to keep γ near its nominal value. These matters are further discussed in Chapters 3 and 4.

2.2.8 Multi-Convertor Systems

General guidelines have to be considered with caution while studying a system, because a particular system has to be studied in detail commensurate with its complexity.

Practical experience with and the background investigations of multi-convertor systems are not as widespread as that for more conventional two-terminal schemes. For this reason the comments in this section are kept in very general terms.

2.2.8.1 Multi-Infeed Systems

Multi-infeed inverters connected to the same busbar or being electrically close can be divided into two categories:

a) All inverters are controlled by one master controller which shares the duty evenly among the separate inverters. In this case the ac system impedance should be referred to the total dc power. The short circuit ratios should be calculated as if this were one large inverter. However, it should be noted that even when only one master controller is used, the recovery of individual inverters can be staggered with the effect being as if each inverter is recovering against a stronger system.

b) Two (or more) inverters are operated separately. As an example, suppose inverter A is at constant power and inverter B is at constant power but with power modulation. In most respects the various phenomena would be as if the system consisted of one large inverter. However, the demand for power increase from the inverter B will respond as if short circuit ratios are referred only to its own power, but Q_c in the formula must include all capacitors used with both inverters.

2.2.8.2 Rectifier-Inverter System

Consider the case where convertors of two or more different dc schemes of comparable ratings are located electrically close to each other. If one convertor is operating as an inverter while a neighbouring convertor acts as a rectifier, it can be viewed that the power infeed from the inverter of one dc scheme is totally or partially taken away by the rectifier of another dc scheme as shown in Figure 2.8. The situation is not dissimilar from multi-infeed systems (2.2.8.1). To the first approximation the reactive power consumption of the rectifier and the inverter are similar. Therefore, for most phenomena the short circuit ratios should be calculated by reference to the total power P of rectifier plus inverter.

If the common ac system voltage suddenly reduces with or without ac system impedance increase the rectifier will consume more reactive power and both dc currents will increase to maintain dc power which would further increase reactive power consumption.

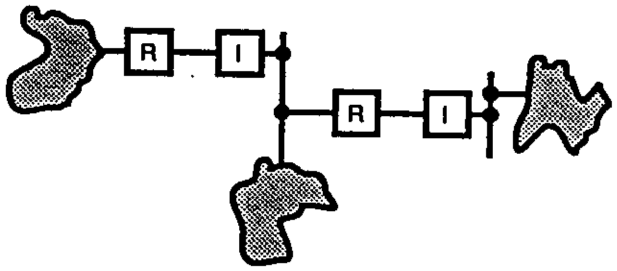


Figure 2.8
A rectifier and inverter connected
at the same location

For the remote inverter, regarding any effects due to its ac system changes or power changes, its short circuit ratio should be referred only to its own power.

2.2.8.3 Multiterminal Schemes

Each inverter SCR should be calculated only with reference to its own power for all phenomena except when considering recovery from faults. The dc peak current due to faults and commutation failures will depend on the combined rating of the rectifiers. This fact will lead to a risk of consequential commutation failures, because the recovery will be carried out at this higher dc overcurrent compared to what would be expected based on the inverter rating.

2.2.8.4 Two Independent DC Schemes Operating in the Same AC System

Two independent convertors may be connected to two different parts of the same ac system. To make two inverters independent of each other the ac impedance between them should have a high value. If two inverters are interconnected by a high impedance ac line they will be more independent of each other than if they are further away from each other geographically but connected by strong ac lines. A low impedance ac interconnection may lead to more interactions between the two inverters than if they were interconnected by a "weak" ac link. An ac system fault anywhere on the "strong" ac system will affect more or less similarly the inverters connected to it and will approach conditions described in 2.2.8.1.

2.2.9 DC Link in Parallel with an AC Line

The effect of an arrangement such as illustrated on Figure 2.9 is not immediately obvious and it is advisable to carry out studies with full representation rather than rely on short circuit ratios. The following comments may serve as general guidelines.

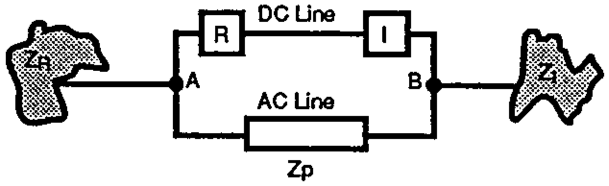


Figure 2.9
AC and DC operating in Parallel

2.2.9.1 Power Transfer Limits

In Section 3 it is stated that values of MAP can be calculated for point to point schemes initially for the receiving terminal under the assumption that the sending terminal will not impose a limitation, particularly as the rectifier station can be designed, if that is desirable, not to impose a power limitation. However, for the system shown on Figure 2.9, the following cases will indicate the position:

a) High SCR rectifier-end ac system (low Z_R) and high impedance parallel ac path (high Z_P).

   In this case the rectifier loading will have negligible effect on the ac voltage at A and the rectifier will not impose a limitation as for normal point to point transmission. Furthermore, the inverter-end ac system will benefit from the ac parallel line and the impedance to calculate the SCR at B would be equal to Z_I in parallel with $Z_P + Z_R$.

b) Low and very low SCR ac system at rectifier end (high Z_R) and low impedance parallel path (low Z_P).

   In this case the rectifier loading will influence the voltage at A, and due to the low Z_p the voltage at B will be affected by both inverter and rectifier loading. Thus the two convertors will behave in a manner approaching the case of being connected to the same ac busbars. The use of SCR is not recommended in this case and full representation is preferred.

c) Low and very low SCR ac system at rectifier end (high Z_R) and high impedance parallel ac path (high Z_P).

In this case the rectifier loading may be limited by the low SCR sending end system. The high Z_P will tend to decouple the two ac systems but again the use of SCR is not recommended and full representation is preferred.

d) For the fourth combination of High SCR rectifier end system (low Z_R) and low impedance parallel ac path (low Z_P), the inverter end system is unlikely to have Low or Very Low SCR.

2.2.9.2 Temporary Overvoltages

DC load rejection affects both the rectifier and the inverter, therefore similar arguments apply as in 2.2.9.1.

2.2.9.3 Recovery from Faults

The inverter recovers against a system impedance and therefore it will always benefit from a reduced impedance.

2.2.9.4 Resonances

This case is similar to 2.2.9.3.

2.2.10 General Comments

It has been pointed out that the use of short circuit ratios for estimating scheme performance should be made with caution. This is true in particular if the system departs from the standard point-to-point scheme. The more complex the scheme, the greater need for full representation of the system.

When studying or designing a scheme, the ac system representation has to be as accurate and comprehensive as required by a particular study. It must be stressed that it is often required to assume the possibility of a particular ac/dc interaction in order to set up the simulator correctly or use a digital program. For example, in a number of schemes no studies were carried out during planning or design stages which would have looked for second harmonic or subsynchronous interactions and instabilities or resonances, and yet these effects were experienced in service. One purpose of this Guide is to draw attention to possible ac/dc interactions so that correct studies could be carried out at appropriate times.

The effects of dc operation and maloperation at fundamental frequency with a balanced ac system can be simulated accurately using load flow, transient stability and other digital programs. The operating conditions with distorted and/or unbalanced ac systems are studied by the use of dc simulators and Electro-Magnetic Transients Program (EMTP)-type programs.

2.3 Inadequate and Zero Mechanical Inertia

2.3.1 Inertia Constants

Turbine generators in an ac system represent a large rotating mass. Their inertia ensures that an ac system does not collapse due to system faults. During a fault, a balance of power between the load consumption and generation is not maintained. The mechanical inertia of turbine generator set ensures that its speed, and therefore the frequency of the system (except for some oscillation) has not changed substantially.

A typical steam turbine generator set may have an inertia constant H of 5 seconds based on the generator MVA rating. Assume that a generator operates at 0.9 power factor so that the inertia constant H_p based on its MW rating is

$$H_p = \frac{5}{0.9} = 5.55 \textit{ seconds}$$

Assume that 2/3 of the power of an ac system is supplied by dc, then the inertia of the system referred to dc power would correspond to

$$H_{DC} = \frac{5.55}{2} = 2.77 \textit{ seconds based on dc infeed}$$

As is shown in the next section, an H_{DC} of 2.77 is usually adequate for satisfactory operation. It follows that the dc infeed must represent a very large proportion of the system power supply before steps need to be taken to increase the inertia by addition of a synchronous compensator.

2.3.2 Infeed into a System without any Generation

2.3.2.1 Calculation of Frequency Change

If all the power is brought into a system by dc, i.e., there is no local generator, then that system will have no mechanical inertia (apart from the inertia of motor loads which can initially be neglected). The inverters at present used in DC are line commutated; i.e., they rely for their operation on the ac system providing adequate sinusoidal voltage to achieve the commutation process. Therefore, a dc inverter supplying an "island system" must be provided with a synchronous compensator having adequate inertia to maintain the frequency and voltage to an acceptable level during system faults.

The relationship between change of machine frequency (df), mechanical power input (P_m) and electrical power output (P_e) for small changes of frequency can be represented by

$$df = \frac{(P_m - P_e) \cdot f_o \cdot dt}{2H} \qquad (2.4)$$

Where f_o is the system nominal frequency and H is the conventional inertia constant of the machine expressed in MW-s/MVA of machine capacity, and P_m and P_e are in per unit of machine MVA rating.

The inertia constant can be converted to the base of dc power to give an effective inertia constant, H_{dc}.

$$H_{dc} = H \cdot \frac{MVA\ rating\ of\ the\ machine}{MW\ rating\ of\ the\ dc\ system} \qquad (2.5)$$

giving from (2.4)

$$df = \frac{p \cdot dt \cdot f_o}{2H_{dc}} \qquad (2.6)$$

where p is the per unit machine accelerating power (P_m - P_e) to the base of rated dc power.

It can therefore be seen that H_{dc} gives a measure of the inertia weakness of the system by relating the change of machine speed to the temporary energy imbalance (p.dt) imposed by any given disturbance.

Temporary reduction of the power infeed by dc may be caused by the following typical events:

- a commutation failure lasting some 100 ms.
- a fault in the sending ac system or in the receiving system which may last up to some 8 cycles depending on the back-up breaker setting.
- a dc line fault which may be cleared by dc controls in 100 to 200 ms.

From equation (2.6)

$$H_{dc} = \frac{p \cdot dt \cdot f_o}{2df} \qquad (2.7)$$

For a loss of power for, say, 200 ms to allow for the breaker clearance time and for the fact that the dc power would not instantly recover to its rated level, it can be calculated from equation (2.7) that H_{dc} to limit the frequency reduction to, for example, 5%, will be equal to 2s. It should be stressed that these values give only an approximate indication of the requirements.

Zero inertia systems are further discussed in Chapter 9.

2.3.2.2 Forced Commutation

Feeding into a system without any generation of its own and without synchronous compensators is not possible with conventional, line commutated inverters, but "forced commutation" is required and convertor circuits have been proposed. However, such schemes have not as yet been considered for actual projects.

2.3.2.3 Gate Turn-Off Thyristor (GTO)

Inverters using GTOs, or similar devices, supplying power into a "dead load" have been used in industrial applications. However, so far the application of these devices to dc transmission has not proved economical, but the promise is there.

2.4 Numerical Examples of Critical Short Circuit Ratios and TOV_{fc} Values

Critical short circuit ratios and the fundamental component of the temporary overvoltage for an assumed impedance angle of $\Phi = 80°$ have been calculated for six cases of inverter operation with different equipment characteristics (Table I). For cases A, B, C and D it is assumed that $Q_c = Q_d$. For cases E and F shunt capacitors are sized to provide some net vars to the ac system at the rated condition.

The maximum difference between the cases are (see also Figure 2.11):

CSCR	CESCR	CQSCR	TOV
32.0%	17%	10%	1.8%

TABLE I

Case	Commutating reactance X_c % (i)	Commutation Margin γ (minimum)	Q_d	Q_c
A	12%	18°	0.5 P	0.5 P
B	15%	18°	0.54P	0.54 P
C	20%	18°	0.6 P	0.6 P
D	20%	20°	0.63P	0.63 P
E	12.6%	17°	0.5 P	0.875P
F	20%	18°	0.6 P	0.875P

Case	CSCR (ii)		CESCR (iii)		CQESCR (iv)	TOV_{fc} (v)
A	1.87	-80°	1.37	-76.4°	0.91	1.43
B	2.01	-80°	1.47	-76.4°	0.95	1.42
C	2.2	-80°	1.6	-76.3°	1.0	1.40
D	2.25	-80°	1.62	-76.1°	0.99	1.41
E	2.24	-80°	1.37	-73.7°	0.91	1.39
F	2.47	-80°	1.60	-74.5°	1.0	1.39

(i) For these examples commutating reactance = convertor transformer leakage reactance.
(ii) Calculated from CESCR by adding the corresponding value of Q_c in pu of P_d.
(iii) Calculated by the formulae given in Section 2.5.
(iv) Calculated from CESCR and formula 2.11.
(v) Calculated by formula (8.1) in Section 8.5 which gives a theoretical value as it does not include the transformer saturation effect.

It is clear that the value of MAP depends on the system impedance, shunt capacitor Mvar Q_c and the reactive consumption of the inverter Q_d. For this reason the variation in CSCR is the largest. CESCR takes into account the influence of Q_c and the difference in CESCR's are greatly reduced. CQESCR takes into account both the value of Q_c and of Q_d. If QESCR is between 0.9 and 1.0 the operation is at or near MAP.

It is also interesting to note that the value calculated for TOV for all cases is around 1.4 pu. It can be shown that if the operation at MAP (i.e., at CSCR) is at unity power factor then TOV_{fc} (for complete load rejection) is $k \cdot 2^{1/2}$ of the terminal ac voltage at MAP. The factor k has a value close to unity for typical ac system data (see also Section 3.1 of chapter 3).Even if the normal operation is at a γ larger than minimum, CSCR should be calculated for γ minimum as that would represent the maximum obtainable power (MPC). However, TOV should be calculated using the normal (operating) γ as the rated Q_d (not the one corresponding to minimum γ) will be rejected by the convertor in case of a fault.

CSCR, CESCR and CQESCR are plotted on Figure 2.11 against the commutating reactance X_c for values of γ = 15° and 20°, Φ=70° and 90° and for Q_c/Q_d = 1.0 and 1.5.

2.5 Calculation of Critical Short Circuit Ratios

If the starting conditions ($P_d = 1.0$, $U_L = 1.0$, $I_d = 1.0$) coincide with the MAP of MPC, e.g., Figure 2.3 for SCR = 2, the corresponding short circuit ratio is termed "critical."

For a simplified system representation (Figure 2.1), the critical ac system impedance can be calculated from the following equation:

$$CESCR = \frac{1}{U_L^2}\ [\ \sin\phi P_d \tan(\gamma+u) - Q_d$$

$$+\sqrt{\left[\frac{P_d}{\cos(\gamma+u)}\right]^2 - \cos^2\phi\,(P_d \tan(\gamma+u) - Q_d)^2} \qquad (2.8)$$

It should be noted that shunt capacitors must be assumed to be connected.

The value of CESCR is little affected by the system damping in the range of 70° to 90° and if system damping is neglected (Φ = 90°) the following equation is obtained:

$$CESCR = \frac{1}{U^2}\left[-Q_d + P_d \cot \tfrac{1}{2}\,(90^\circ-\gamma-u)\right] \qquad (2.9)$$

CSCR can be calculated by adding Q_c to the above equation.

U_L = Convertor bus ac voltage per unit

Q_d = Reactive power consumed by the inverter (per unit) (calculated from one of the equations A7, A11, or A13 in the APPENDIX)

P_d = Active power supplied by the inverter to the ac system (per unit)

γ = Extinction angle of the inverter (commutation margin)

u = Overlap angle of the inverter (calculated from Eq. (A.9)) in the Appendix

Φ = Angle of ac system impedance

CESCR can also be calculated by considering the effect on the ac voltage of small var changes at the convertor ac busbars. The magnitude of this effect can be judged by the voltage stability factor [B3].

The voltage stability factor (VSF) is defined as the incremental ac voltage variation, dU_L, due to a small reactive power (dQ) injected into the commutation busbar for a given power level, i.e.,

$$VSF = \frac{dU_L}{dQ} \qquad (2.10)$$

This index can be used for calculating the critical ratios for large systems using digital computer programs. VSF is a more general factor than CSCR and CESCR, and is also used in the study of ac systems. VSF also permits an approximate evaluation of the system dynamic behaviour under small perturbations from a voltage oscillation point of view. VSF is plotted against ESCR in Figure 2.10 [B10]. This figure assumes operation in the constant γ mode. A positive VSF indicates that the DC would operate in constant γ mode at currents smaller than I_{MAP}. A negative VSF indicates that the system would operate, in constant γ mode, at a dc current greater than I_{MAP}. The transition point of VSF as dc current changes gives the same criterion as the MAP concept and equation (2.1) applies identically to both. It should be noted that a negative VSF indicates that the constant power control mode with constant γ would be unstable. However, in constant current control with constant γ VSF has a positive value.

Critical short circuit ratios can be calculated with adequate accuracy for planning considerations using the following simple equations, derived from equation (2.3):

$$CESCR = CQESCR\,(1 + Q_d) \qquad (2.11)$$

and

$$CSCR = CQESCR\,(1 + Q_d) + Q_c \qquad (2.12)$$

where Q_d and Q_c are in per unit of P_d.

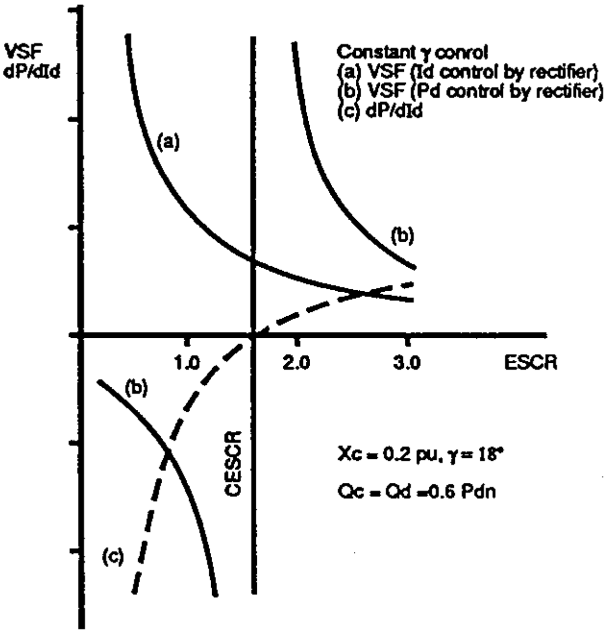


Figure 2.10
VSF and dP/dId as a Function of the Effective Short Circuit Ratio (ESCR) at Nominal Operating Conditions and Unity Power Factor

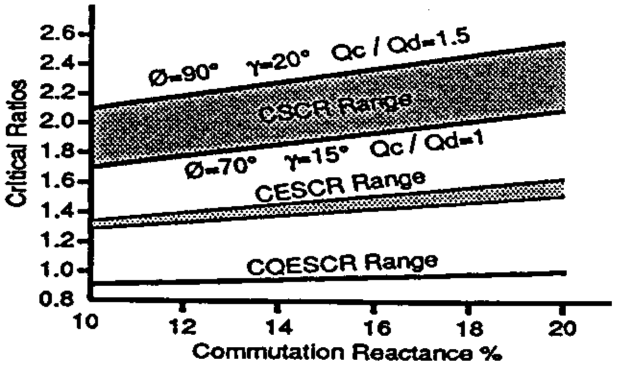


Figure 2.11
Sensitivity of critical short circuit ratios

From Figure 2.12, approximate values of CQESCR and Q_d can be obtained, and Q_c selected according to the desired reactive compensation.

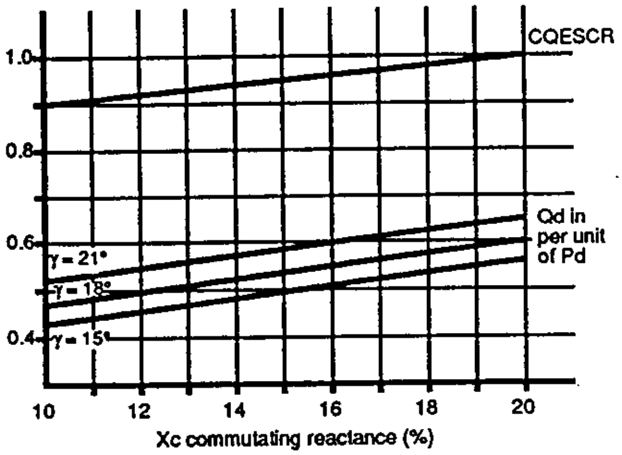


Figure 2.12
CQESCR & Qd
as a function of Xc

Example 1 for average value of the commutating reactance x_c = 15%, from Figure 2.12, CQESCR = 0.95 and for $\gamma=15°$ Q_d = 0.54, and for $Q_c = Q_d$ the following value for CSCR is obtained from equation (3):

CSCR = 0.95 (1 + 0.54) + 0.54 = 2.0

Using the correct formula (1) for $x_c=15\%$, $\gamma=18°$, $Q_c=Q_d$, $\Phi=80°$, CSCR=2.0

Using the correct formula (1) for $x_c=15\%$, $\gamma=20°$, $Q_c=Q_d$, $\Phi=70°$,CSCR=2.04] Using equation (12) and Figure 2.12, we also get CSCR = 2.4

Example 2 for $x_c=20\%$, from figure 2.12 CQSCR=1.0 and for $\gamma=20°$ $Q_d=0.64$, for $Q_c=1.5Q_d$

CSCR = 1.0 (1 + 0.64) + 0.96 = 2.6

Using the correct formula for $x_c=20\%$, $\gamma=20°$, $\Phi=70°$, $Q_c=1.5Q_d$, CSCR=2.56

Using the correct formula for $x_c=20\%$, $\gamma=15°$, $\Phi=70°$, $Q_c=1.5Q_d$, CSCR=2.4. Using equation (12) and Figure 2.12, we also get CSCR = 2.4

2.6 Numerical Examples of Power Reduction Due to AC System Impedance Increase and AC Voltage Reduction

As discussed in section 2.2.4.5, power reduction due to a reduction of the terminal voltage is greater if the system impedance (Z_s) is increased at the same time.

Consider the two cases represented in Figures 2.6a and b.

Initial conditions at SCR = 3.

System emf	I_d	U_L	U_d	P_d	γ	SCR
0.998	1.0	1.0	1.0	1.0	18°	3
(a) Condition after the line trip, Z_s increases by 1/3.						
0.998	1.0	0.93	0.92	0.92	18°	2
0.998	1.1	0.84	0.81	0.90	18°	2
0.998	0.96	0.97	0.96	0.93(MAP)	18°	2
(b) Condition after system emf reduces to give U_L = 0.93 at SCR = 3.						
0.947	1.0	0.93	0.92	0.92	18°	3
0.947	1.1	0.89	0.87	0.96	18°	3
0.947	1.25	0.82	0.78	0.98(MAP)	18°	3

It can be seen that conditions immediately after system change and before dc current changes, i.e., at I_d = 1.0, are identical for the two cases, but in the case (a) I_{MAP} is at 0.96 pu and in the case (b) it is at 1.25 pu of I_d. Operation at a current limit of, say 1.1 pu, would result in a power of 0.9 in case (a) and 0.96 in case (b).

A demand to maintain rated power (without, say, capacitor switching) at a specified minimum SCR for a sudden system change may not justify the increase in the extra cost of the convertor equipment and of losses. This is especially true if the particular system change is an uncommon event.

2.7 AC/DC System Strength - Summary Tables

2.7.1 Power Transfer and TOV(1)

	P_{MAP}(2)	TOV_{fc} (theoretical)
High SCR Systems SCR > 3, ESCR > 2.5	$P_{MAP} > 1.1$	$1.25 > TOV_{fc}$
Low SCR Systems 3>SCR>2, 2.5>ESCR>1.5	$1.0 < P_{MAP} \leq 1.1$	$1.25 < TOV_{fc} < 1.4$
Very Low SCR Systems 2 > SCR, 1.5 > ESCR	(3)	$TOV_{fc} > 1.4$

2.7.2 Critical Short Circuit Ratios

CSCR = 2   CESCR = 1.47   CQESCR = 0.95

Notes for 2.7.1 and 2.7.2

Note 1: The above figures are based on assumed typical values of X_c (15%), γ_{min} (18°), and $Q_d = Q_c = 0.54 \cdot P_{dN}$.

If X_c and γ_{min} have higher values resulting in larger Q_d, then the theoretical division between high and low SCR systems would be at an SCR value higher than 3 and the division between Low SCR and Very Low SCR systems would be at an SCR value higher than 2.

Similarly, values of ESCR, CSCR, or CESCR would have correspondingly higher values.

CQESCR would still have a value near unity, see Figure 2.12.

Note 2: P_{MAP} represents the maximum power immediately available starting from nominal (rated) conditions (P_d, U_L, I_d all at 1 pu and γ_{min} = const), without the use of fast ac voltage control.

Note 3: The additional power available immediately, starting from nominal rated conditions, depends on the equipment design, i.e. the value of γ or on the available range of TCR and SR.

2.7.3 Inadequate Inertia Systems

To avoid frequency reduction by more than 5% (i.e. 2.5Hz for 50Hz systems or 3Hz for 60 Hz systems) due to a system fault, the effective dc inertia constant, H_{dc}, should be greater than 2s.

3. DC POWER TRANSFER LIMITS

3.1 Description of Phenomena

Considering the fundamental components of ac currents and voltages, a power system may exhibit two major types of instabilities: (i) phase angle instability and (ii) voltage instability.

The first of these is characterized by the fact that after a disturbance a generator or a group of generators loses synchronism with the rest of the system and line trips are executed by out-of-step relays or some other protections. The reason for the system to separate could either be that no new operating point exists (steady state instability), or that the system cannot settle down to the new equilibrium point due to the kinetic energy injected into the rotors of the generators as a consequence of the fault (transient instability). The system could also become unstable due to inadequate damping. The time scale for this instability is typically in the region of a few to ten seconds. These matters are discussed further in Chapter 7.

The voltage instability is characterized by the fact that the voltage at a certain bus or in a certain region of the network progressively decreases. (Usually it collapses and this type of instability is often called voltage collapse). The generator pole angles do not necessarily change significantly. (This is at least true during the initial stages of the breakdown. The voltage instability may cause protection to act, which could cause the system to become phase angle unstable). The time scale for this instability may vary substantially depending on different characteristics of the system. If tapchangers are involved the process can extend over several minutes. The instability could develop much faster if for example tripping of a line or of a shunt capacitor bank results in sudden lack of voltage support, or some fast controllable devices play decisive roles in the dynamics of the system.

Extensive work is going on at present concerning the voltage collapse phenomenon as a consequence of a number of large breakdowns and disturbances which occurred in recent years and are believed to have been caused by voltage instabilities. No generally accepted method of analysis or description of the phenomenon exists for a generic system but some general characteristics could be described by the following simple model.

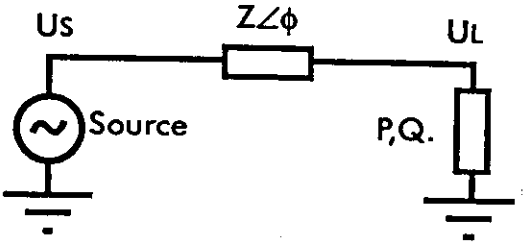


Figure 3.1
Simplified AC System Representation

Consider a load supplied by a strong network via a transmission line, Figure 3.1. For a given load there exist in steady state two possible modes of operation: one with "high" voltage and "low" current, and one with "low" voltage and "high" current. Normally the first of these two solutions is the desired one since it gives lower losses and exhibits other properties that are attractive. If the voltage at the sending end is kept constant curves as shown in Figure 3.2a are obtained for different power factors of the load. From these curves the following important observations can be made:

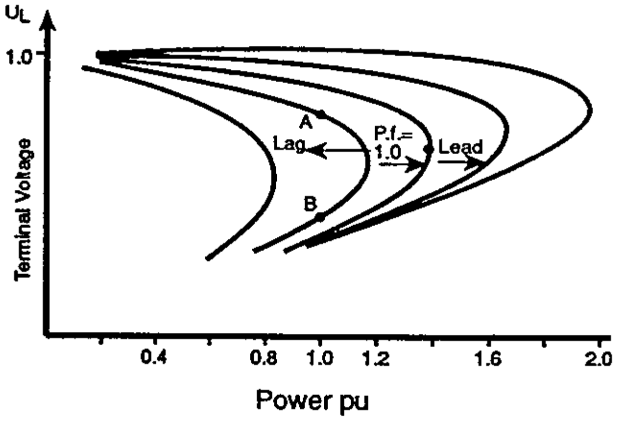


Figure 3.2a
Terminal voltage vs Power for Different Load Power Factors

- There is a maximum possible load which can be supplied at a given power factor.

- For a given load smaller than the maximum, two different operating points exist corresponding to different voltage levels (e.g points A and B on Figure 3.2a).

Furthermore, a simple analysis shows that:

- For operating points on the upper branch of the curve, $dU/dQ > 0$, and on the lower branch $dU/dQ < 0$.

- If U_s is the voltage at the sending end it can be shown that $dU/dU_s > 0$ for points on the upper branch, whereas $dU/dU_s < 0$ on the lower branch.

The two last observations together with the standard ways of controlling voltage in ac systems, lead to the fact that points on the upper branch are called stable and those on the lower branch are called unstable. The point corresponding to the maximum load is mathematically called a static bifurcation point. If a power larger than this maximum is demanded by a load device the system cannot converge to any of the solutions that are given in Figure 3.2a. To predict the behaviour of the system for such a case the dynamic properties of the system are needed, such as load characteristics, tap changer control and generator/motor dynamics.

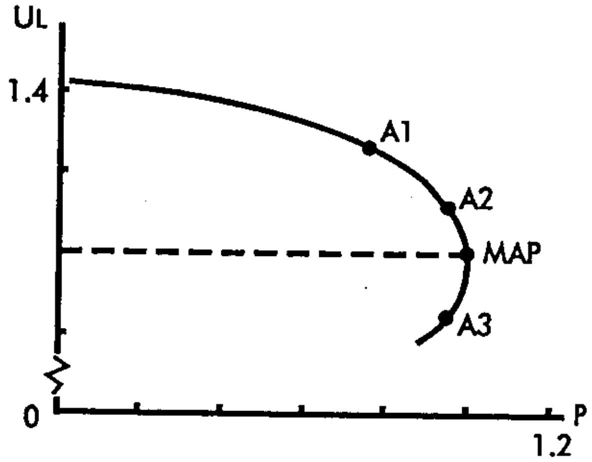


Figure 3.2b
AC Voltage/Power Curve
(Unity Load Power Factor)

Consider the curve for unity power factor of Figure 3.2b for the case when the small resistance of the ac line is neglected. It can be shown that for such a case the terminal voltage, U_L, corresponding to the maximum power point (MAP), is related to the sending end voltage by the following equation:

$$U_L = \frac{U_s}{\sqrt{2}} \qquad (3.1)$$

For curves in Chapter 2 dc power and ac terminal voltages are plotted as a function of dc current. From these curves it is seen that the ac terminal voltage is a monotonic decreasing function of dc current, and consequently there is a unique relationship between the dc current and the ac terminal voltage. Therefore, it is possible to plot the dc power as function of the ac terminal voltage. Furthermore, if in such a plot the ac terminal voltage is on the y-axis and the dc power on the x-axis the well known ac voltage/power curve used in ac system analysis is obtained. Some of the curves shown as dc power versus dc current will be discussed as ac voltage versus dc power below.

The ac system impedance for Figure 3.2b was chosen to be equivalent to the system impedance of the inverter operation curve for SCR = 2 (ESCR = 1.46) of Figure 2.3. The ac voltage/power curve corresponding to the Figure 2.3 for SCR = 2, is almost identical to that of Figure 3.2b. The reason for this is that in Figure 2.3 the power factor at P_{dN} = 1.O pu is unity, same as in Figure 3.2b.

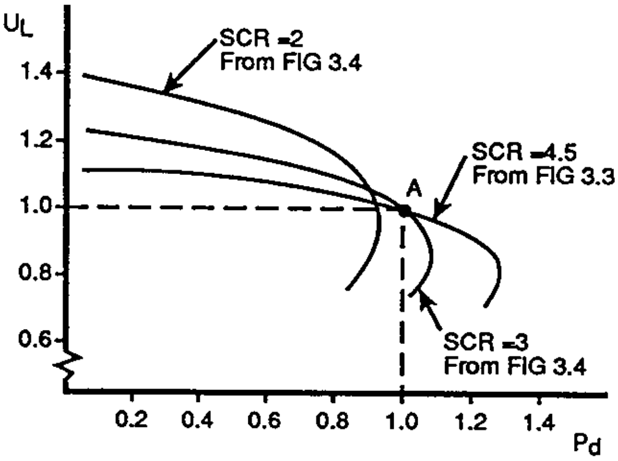


Figure 3.2c
AC Voltage - DC Power Curves

AC voltage and power from Figure 3.3 for SCR = 4.5 and from Figure 3.4 for SCR = 3 are plotted on figure 3.2c. The main difference between curves of Figures 3.2c and 3.2a is that the former are calculated to give 1 pu ac voltage at 1 pu dc power and the latter are calculated to give 1 pu ac voltage at zero power; also, there are differences in system impedances in the former curves. However, curves corresponding to the operation of a dc convertor are the same as those of an ac load having the same P and Q characteristics.

The third curve on Figure 3.2c corresponds to the curve for SCR = 2 of Figure 3.4. This curve is obtained by tripping one of the two parallel ac lines to which the inverter was connected (Figure 2.4) when operating at the point A of the curve for SCR = 3, as discussed in 2.2.4.2 and 3.2.2. It can be seen that the maximum power (MAP) of the curve, corresponding to the new condition, is lower than the power before the disturbance at point A. The attempt of the convertor to draw an increasing current, in order to maintain the original power, would result in voltage collapse as already discussed.

An important factor, that differs in the dc case as compared with the pure ac configuration, is the controllability of the dc convertor. As will be shown in the subsequent sections of this chapter, unlike the general ac case, the convertors can be controlled in such a way that voltage instability does not occur and that, moreover, the dc controls can further enhance the performance of the ac system. For these reasons, it is convenient to plot power against dc current, the controlled quantity, rather than against the voltage, but the phenomena considered are the same.

3.2 Power Limits of an Inverter

3.2.1 Power Limits of an Inverter Connected to a High SCR AC System - With γ Constant

The operating point of an inverter connected to an ac system having a high short circuit ratio, will be well below MAP; in Figure 3.3 an SCR = 4.5 has been assumed. In such cases, it is most economic to design the system so that the operating point is on the Maximum Power Curve - MPC for γ minimum. The operation at MPC is achieved while operating the inverter at a constant commutation margin having minimum value γ of, say, 15° (50 Hz), 18° (60 Hz). The dc voltage is maintained close to its rated value by the inverter transformer tapchanger.

Operation at MPC (minimum γ) gives minimum cost due to the following factors:

1. Minimum reactive power consumption,
2. Minimum ratings of valves, transformers, shunt capacitors,
3. Minimum generation of harmonic currents,
4. Minimum Losses.

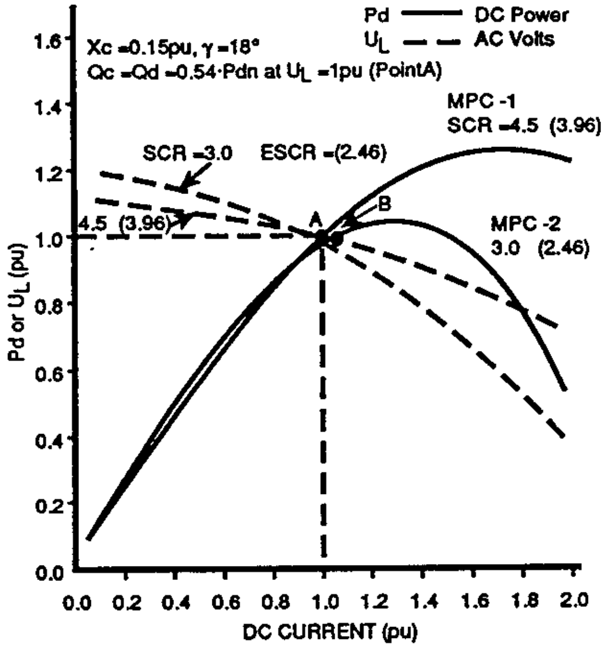


Figure 3.3
AC/DC System - High SCR, sudden change of SCR from 4.5 to 3.0

MPC can be suddenly reduced by a combination of the increase of the ac system impedance and of the reduction of terminal ac bus voltage, possibly due to a line trip in the ac system. Such a reduction of MPC is shown on Figure 3.3.

The pre-disturbance operation is with a system having SCR = 4.5. The operating point A corresponds to P_d, U_L, U_d, and I_d having the rated values of 1.0 pu. The commutating reactance is 15 percent, the inverter reactive consumption $Q_{dN} = 0.54 \cdot P_{dN}$. Shunt capacitors (including filters) nominal rating Q_{cN} is fixed and at $U_L = 1$ pu is equal to Q_{dN}. Operation is at minimum constant γ.

If, following an ac line trip, as discussed in 2.2.4.1, while operating at point A, the system impedance is increased by one third corresponding to the sudden reduction of SCR from 4.5 to 3, the operation will be according to MPC-2 of Figure 3.3.

MPC-2 is also a quasi-steady-state curve, but for the new ac system conditions.

Assuming constant - γ control at the inverter, a decrease in the inverter ac voltage causes an immediate decrease in dc voltage. Assuming for the present that the HVDC master control at the rectifier is for constant power (which is not always the case) then it will increase dc current to maintain power at the set value, unless the current limit setting of the rectifier is reached. It is still assumed that AVR's, circuit breakers controlling shunt capacitors etc. and OLTC's have not operated, as they are slow compared to dc current controls. MAP-2 in this case is higher than the rated power P_{dN} and the power has been maintained at its predisturbance level, at the new operating point B.

For details of numerical values see 3.9.

3.2.2 Power Limits of an Inverter Connected to a Low SCR AC System with γ Constant.

There are a number of schemes in service with SCR having approximate value of 3 or lower, but higher than SCR = 2, with normal operating point at MPC with constant γ at rated currents smaller than I_{MAP} (see Section 3.6.2). However, the operation is sufficiently near MAP-1 that a sudden, but relatively moderate, change in the ac system voltage may result in a MAP-2 being lower than the rated power. This event is illustrated in Figure 3.4. A similar event as shown in Figure 3.3, has been assumed, except that the system impedance prior to the line trip corresponds to SCR = 3 and after the line trip to SCR = 2. The required power cannot be maintained but the current limit imposed by the rectifier prevents the collapse of the system despite the demand for higher power from the master controller.

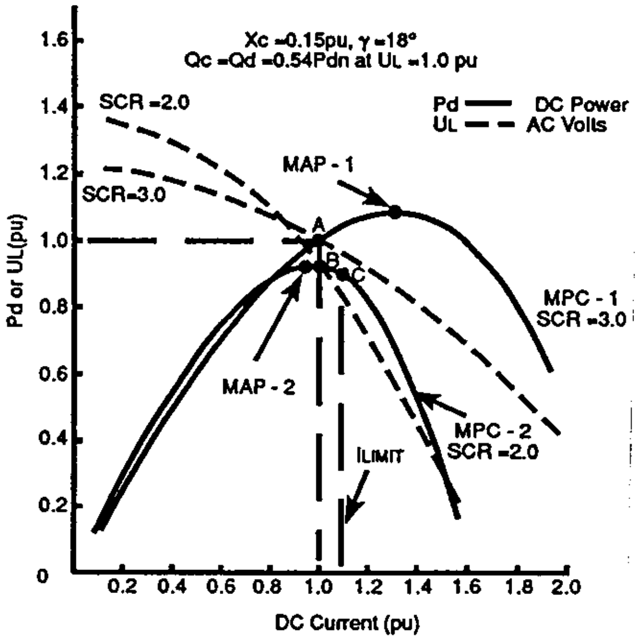


Figure 3.4
AC/DC System - Low SCR Power and AC Voltage Curves Sudden Change of SCR from 3 to 2

The operating point B on MPC-2 will be in the region where dP_d/dI_d is negative and stable operation would not be achieved in power control mode, but stable operation continues in constant current control mode.

If the dc system is used to control ac frequency or to provide system damping, operation in the constant current mode would not be acceptable except for a very brief period of time; e.g., while the fault is being cleared. Also, for these changes in ac system conditions the power level may drop quickly to a lower value (determined by current limit) and also jump back to the original value if ac system conditions are suddenly restored. For possible steps to be taken to enhance performance in such cases see Section 3.6.

For details of numerical values see 3.9.

3.2.3 Power Limit of an Inverter Connected to a Very Low SCR AC System with Variable γ Control

The operation at currents higher than I_{MAP} corresponds to operation at a point on the lower branch of a curve shown in Figure 3.2 which in ac transmission is considered the unstable part of the characteristics. In principle, it can be argued that it is the nature of the load which determines the stability. Assume that the load in Figure 3.1 is a static impedance load. If the impedance of the ac supply line is high and if the inductive component of the load is high, the maximum power on Figure 3.2 would be relatively low and the operating point may be at the lower "unstable" part of the curve. An inverter connected to a high impedance ac line operating at constant γ in the region where dP_d/dI_d is negative will be unstable if its controls demand an increasing current to keep the power constant. But if the controls are arranged to keep the current constant, stability can be achieved. However, any variation of ac voltage would directly cause variation of power which would not be acceptable for most applications.

An alternative control strategy, used in a number of schemes, is to control the dc voltage through inverter action by varying γ. The rectifier performs the same duty as in the previous case of controlling the dc current in order to achieve the desired power. An increase of γ increases var consumption and a decrease of γ reduces the var consumption. Therefore, in order to be able to increase ac voltage, as well as to reduce it, the inverter must be normally operating at a higher γ than the minimum.

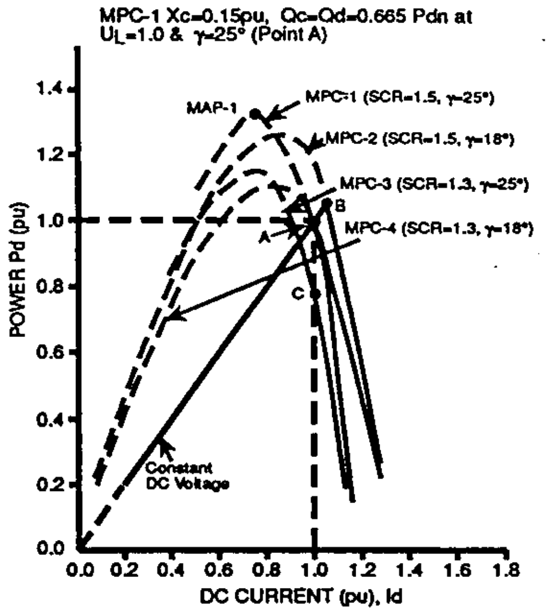


Figure 3.5
AC/DC System - Very Low SCR, Sudden Change of SCR from 1.5 to 1.3

Consider the four power curves on Figure 3.5. Normal operation is at point A with γ = 25°, curve MPC-1. Commutating reactance X_c is 15 percent as in the previous cases. The value of shunt capacitors is made equal to Q_d at γ = 25° at U_L = 1.0 p.u. It should be noted that normal operation at currents smaller than 1.0 are not practical due to the high voltage as explained in Section 2.2.3 and by Figure 2.3. For example MAP-1 occurs at I_{MAP} = 0.75 pu, U_L = 1.4 pu and U_d = 1.5 pu. Therefore, for normal operation with ac systems having Very Low SCR at dc currents higher than I_{MAP}, the power transfer limit is lower than the power corresponding to MAP. In the example on Figure 3.5 the maximum transmittable power, before ac system conditions are changed, is obtained by reducing γ to its minimum value. In this example at the minimum

γ = 18°, the point B is reached on MPC-2 which represent the maximum power which can be achieved from normal operating conditions by increasing current. The straight line O-A-B is the line of constant dc voltage. It should be noted that control of dc voltage, for operation with ac systems having very low short circuit ratios, is not necessarily the only control strategy for operation at $I_d > I_{MAP}$. Controlling other quantities, such as ac voltage, reactive component of the inverter current etc. could also be considered.

Curve MPC-3 is obtained by assuming that an ac line has tripped, causing an increase in the system impedance by 13 percent. At $I_d = 1.0$, before a change of γ value, this would result in reductions of U_L to 0.81 pu, U_d to 0.8 pu and P_d to 0.8 pu, point C on MPC-3. However, γ would instantly respond by reducing its value. In this example this would result in restoring the power to 1 pu, with $U_L = 0.95$, $P_d = 1.0$, and $I_d = 1.0$, at minimum γ = 18°, i.e., point A on MPC-4.

γ is maintained at its normal value, in the example considered at 25° by the inverter tap changer and by shunt capacitor switching. For example, if the condition of MPC-4 persisted, additional shunt capacitors would be switched-in in order to increase the ac voltage and allow γ to return to a value near 25°. It must be stressed that, as in the previous cases, the controls must be stable, during the period before capacitor switching in, for operation at γ minimum in the current control mode (at $dP_d/dI_d < 0$).

The cost of the inverter designed for continuous operation at larger values of γ will be higher compared to the inverter designed for operation at minimum γ for the following reasons:

1. Reactive power consumption will be greater,

2. Valves, transformers, and shunt capacitors will have higher ratings,

3. Generation of ac and dc harmonics will be higher,

4. Convertor terminal losses will be higher.

The benefit of operating with variable γ is the ability to operate stably in the power control mode, for the design range of ac system variations, at dc currents larger than I_{MAP}, with ac systems having very low short circuit ratios.

A further benefit is that due to normal operation at γ larger than minimum, the probability of commutation failures would be reduced.

For details of numerical values see 3.9.

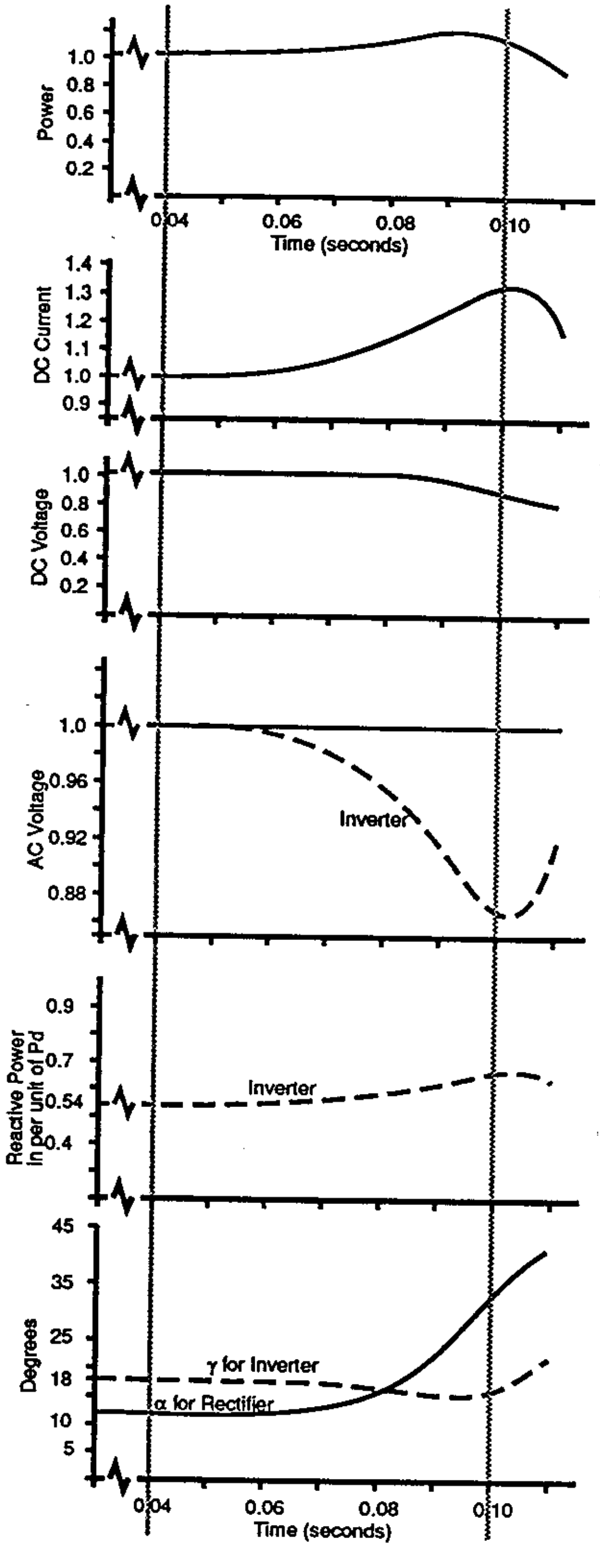


Figure 3.6
Results of Transient Stability Program for a 10% Increase of Power Order, Applies at 0.04 Seconds
X=0.15%, Qc=Qd=0.54.Pd, & γ=18° at U_L=1.0

3.2.4 Results from a Transient Stability Program

As discussed in the previous sections, to determine the power limits of an inverter (or of a rectifier) "quasi-steady-state" power curves are used, i.e., each point is calculated by steady state equations. These calculations are conveniently done by hand or, as in most cases of curves in this Guide, by digital load-flow programs having adequate dc link representation. The statement that these quasi-steady state curves give a good indication of dynamic performances was verified by using a transient stability program. The conditions of an inverter having data as used in the case of the power curve in Figure 3.4 for SCR = 3 has been used. The SCR of the rectifier was set to a very high value in order not to represent a limitation to the inverter performance. Results are shown in Figures 3.6. It should be noted that the particular controls used with this program allowed normal γ to reduce from 18° to an absolute minimum of 15°. Temporary reduction of γ allows a higher (short time) overload or maintenance of required power for a slightly greater voltage depression, at a risk of higher commutation failure probability. The power order was increased by 10 percent at time = 0.04s. The current limit was set to a value just over 1.3 pu in order to show the power increase to MAP and its subsequent reduction, despite the current increase. Soon after 0.1 seconds the current is reduced in response to ac voltage reduction and so reduces the inverter var consumption. This is one of the methods used in practice to avoid ac voltage collapse. The analysis of the values of I_d, U_d, P_d and γ indicate that these quantities are consistent with values achieved for Figure 3.4 for SCR = 3.

3.3 Power Limits of a DC Link

3.3.1 Introduction

In the preceding sections the limits which an inverter may impose on the value of power transmitted were considered under the assumption that the rectifier operation will not be responsible for a lower limit. However, the rectifier is subject to the same limitations as the inverter; at increasing dc current the voltage will be reducing and the amount of control in hand depends on the value of α in normal operation. In this section an example is given which takes into account both ends of the dc link. It has been assumed that the scheme is bi-directional and that the two ac systems have different values of short circuit ratios. Either end may function as an inverter, but with differing operating strategies. Operation normally at γ = 19° (with absolute limit at γ = 15°) was assumed for the ac system having a low short circuit ratio value (System X) and a variable γ strategy was assumed to control dc voltage for the other end which has a very low SCR value (System Y). The effect of a 5 percent ac voltage reduction on power transfer was calculated.

3.3.2 Example Data

	System X	System Y
ESCR	2.75	1.0

(Φ was assumed to be 90° as the resistive component has only a small effect on power calculation)

X_C	15%	14%

Table 1 gives initial conditions. Power is assumed positive for System X to System Y direction and it is assumed negative, marked with a minus sign, for the opposite direction.

3.3.3 Application of the Disturbance

Voltage changes are specified as "changes of 5 percent of the nominal bus voltage." It is therefore assumed here that the observed voltage change at the disturbed busbar is 5 percent, whatever the prime cause (e.g., a remote fault or loss of a line with negligible change in the value of the system impedance).

Table 2 summarizes the cases studied.

3.3.4 Calculated Solutions

Table 3 gives the calculated solutions. These are for the conditions after the convertor controls have settled (i.e., after about 100 ms) but before tapchangers or capacitors have switched. The "remote busbar" is the convertor busbar not subjected to the initial voltage depression.

TABLE 1 - INITIAL CONDITIONS

Case	U_{dc} pu	I_d pu	α (rectifier)	γ (inverter)	SYSTEM EMF	
					X	Y
A	1	1	12°	25°	1.047	1.169
*B	-1	1	12°	19°	1.047	1.101

* Power from Y to X

TABLE 2 - SUMMARY OF CASES STUDIED

Case Ref.	Power Flow	System Voltage Depressed 5% at
A_1	X - Y	X
A_2	X - Y	Y
B_1	Y - X	X
B_2	Y - X	Y

TABLE 3 - CALCULATED SOLUTIONS AFTER VOLTAGE DEPRESSION

Case	Power pu	AC Voltage on the Remote Busbar	U_{dc}	I_d	α rectifier	γ inverter
A_1	.970	.990	.970	1	3°	26.7°
A_2	1	1	1	1	12°	18.4°
*B_1	.969	.969	-.962	1.039	10.5°	15°
*B_2	.972	.997	-.972	1	3°	21.9°

*Power from Y to X

3.3.5 Comments on Individual Cases

For cases A_1 and B_2 the rectifier α reaches its minimum of 3° and the inverter takes over control of current (and power) by increasing its γ which increases its reactive power consumption hence reduces its ac busbar voltage.

For case B_1 a combination of the reduction of γ to 15° and the increase of dc current to 1.039 pu successfully restores power to 1.0 pu.

Power is reduced by up to 3 percent for cases A_1 and B_2, otherwise power control is maintained (except for a brief dip until the master control takes effect). This is because the master power control output (current order) reaches the sliding current limit (refer to Section 3.6.2.1) which, for a power order of 1 pu, limits dc current to 1.05 pu, if the rectifier is still in control, or 1 pu if the inverter is in control.

The ac voltage on the "remote" busbar is only slightly depressed in all cases, with a maximum of 3.1 percent (case B_1).

The results in Table 3 are to some extent a compromise, because they depend on the values used for the current limits (1.05 and 1.0 as described above). For example, an increase in current limit by .05 pu for case A_1 would cause the power to be maintained at 1 pu (instead of 0.97 pu) but with a larger reduction of remote ac voltage, by 3.2 percent instead of 1 percent. In other cases an increase in current limit would actually reduce power, with a further voltage depression, hence would be pointless.

In practice the capacitor switching and tap changer control would restore the desired conditions.

3.3.6 Rectifier Connected to a Very Low SCR AC System

The main consideration in this Guide is given to the conditions at the inverter of a dc link terminating at locations having low short circuit capacity. However, particular attention must be given to the case when the rectifier ac/dc system has a very low SCR.

In ac/dc systems having very low SCR it is essential to have fast control of the voltage. If the dc link itself is used to provide this fast control, the inverter is the voltage controlling convertor. One common method is to control for constant dc voltage, which indirectly exerts a control on the ac voltage. In back-to-back systems, if the ac voltage at either end rises to a predetermined value, an ac voltage loop takes over to control ac voltage directly, operating through the inverter control system.

If there is a dc line between the rectifier and the inverter and the rectifier ac/dc system has a high SCR value and the inverter a low or very low SCR value, the system will operate well, as the inverter controls dc and ac voltages local to the very low ac/dc system. However, if the rectifier ac/dc system has a very low SCR value, the inverter will not be very effective in quickly controlling the dc voltage at the rectifier end, and therefore its ac voltage (due to the inductance and the capacitance of the dc line) even if the telecommunication were to be very fast. There are examples of back-to-back schemes where both ac systems have low or very low SCRs. On the other hand, it is difficult to visualize a practical case where power would be supplied from a very low SCR ac/dc system over a transmission line. However, the application of a fast compensator at the rectifier ac system would enable operation even in such a case. Of course, there would be always the option of strengthening the ac system (2.2.6).

Using only the inverter to provide fast voltage control in back-to-back schemes where both ac/dc systems have very low SCR values may have some limitations. If both ac systems exhibit frequent and fast ac voltage variations, inverter voltage control, coupled with automatic capacitor and inductor switching at the two ac bus-bars, may not always provide acceptable performance. In such cases, consideration should be given to improving the conditions of one of the two ac systems. This can be done by providing fast ac voltage control by an independent compensator (2.2.7.1) or by strengthening one of the ac systems (2.2.6).

3.4 Principal Parameters

For ac/dc systems having low and very low short circuit ratios, the ac voltage stability at the terminals of the convertor station has to be fully analyzed and studied. Such a phenomenon can be responsible for the ac voltage excursions during steady state as well as dynamic operation of the dc scheme. Fault recovery performance, temporary overvoltages and overall ac/dc system transients and dynamic stabilities are also closely tied to the ac voltage stability phenomenon.

The solution(s) adopted to alleviate such a problem stem from the following parameters which directly influence the severity of such a phenomenon:

a) ac system impedance (fundamental frequency)
b) rated dc power
c) rated reactive power (which depends on commutating reactance and on α and γ)
d) range of acceptable ac voltage regulation
e) level of var compensation
f) dc control strategy

For a given system impedance and other system parameters shown in Figure 2.1, there will be a unique P_d/I_d characteristic for operation at γ minimum (constant) which will represent the maximum power curve.

3.5 Trends and Sensitivities of System Parameters

3.5.1 AC System Impedance

The closer that the system impedance approaches that corresponding to the critical short circuit ratio (CSCR), the greater the probability that the operation may take place at currents larger the I_{MAP}.

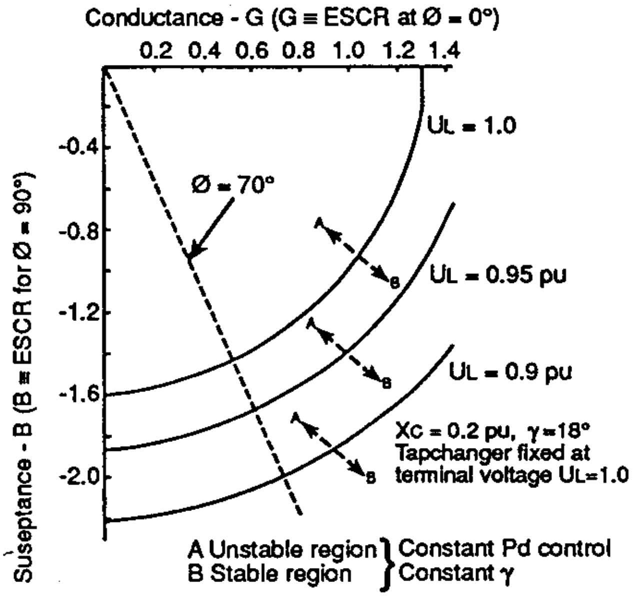


Figure 3.7

Curves for Constant MAP for Different AC Systems Admittance
G (Effective Conductance) and
B (Effective Susceptance) in Per Unit of Pd

The curves of constant MAP have been drawn on Figure 3.7 [B1] for different values of system admittances, for three different values of ac terminal voltage. ESCR for a system impedance having the angle $\Phi = 90°$ has the value of the susceptance B and for system impedance angle $\Phi = 0°$ ESCR has the numerical value of the conductance G. It can be seen that the value of MAP and therefore of CSCR does not vary much for system impedance angles in the practical range of, say, $\Phi = 70°$ to $\Phi = 85°$ which means that the simpler formula (9) given in Chapter 2.5, can be normally used.

The variation of the terminal ac voltage was achieved by varying the emf behind the ac system impedance without varying the value of impedance, in order to indicate the effect of ac voltage on MAP. In practice, a disturbance, such as an ac line trip, would result in a change of both impedance and terminal voltage values.

3.5.2 Convertor Reactive Power Consumption

It has been shown in Chapter 2 that QESCR gives a better indication of the ac/dc system operation because it takes into account the convertor reactive power consumption

(Q_d). The values of CSCR and CESCR will be higher for higher values of Q_d. This means that the higher Q_d, the lower the value of MAP and hence of power transfer, for the same values of SCR and ESCR. A value of QESCR equal to about .95 indicates that the operation is near MAP. (See Section 2.4).

3.6 Possible Improvements

3.6.1 Reducing the AC System Impedance

The desired performance can always be achieved by increasing SCR, i.e., by reducing the ac system impedance. This can be done by finding a more suitable connecting point in the receiving ac system or by adding an ac line. The former may not be possible to achieve and the latter may be uneconomical.

Another method employed in practice has been to use a synchronous compensator at the inverter station as discussed in Section 2.2.6.

3.6.2 Control Improvements for Normal Operation with $I_d < I_{MAP}$

In Sections 2.2.4.2 and 3.2.2 it has been pointed out that due to ac system changes like line outages, the resultant MAP value may be smaller than the required power and stable operation can continue only in a constant current control mode at reduced power levels.

The following control action can be taken to minimize these disadvantages.

3.6.2.1 Sliding Current Limit

The use of a sliding current limit set at say 0.05 pu above the per-unit power order prevents large uncontrolled changes in power due to sudden ac voltage changes, as could be found in the case of a fixed 1.1 pu current limit used in many schemes. The use of a sliding current limit is of particular importance for operation at lower values of power. On Figure 3.8 it was assumed that the operation is at 0.5 pu of power at $I_d = 0.5$ pu at an increased ac system impedance, but having a value of SCR (i.e., OSCR), equivalent to the SCR = 3 of Figure 3.4. In this case a sudden increase of system impedance, due for example to a line trip, would result in a reduction of MAP below the required 0.5 pu. A current limit of 1.1 or 1.05 pu could cause the collapse of the voltage and hence power transmission. However, a sliding current limit set at 0.05 pu of power order, in the example of Figure 3.8 $I_{Limit} = 0.55$ pu, would allow transmission to continue at only a slightly lower power level until ac voltage is corrected by, for example, capacitor switching.

3.6.2.2 Temporary Reduction of Power Order

The power order can be automatically reduced for ac voltage reductions below a preset limit, so that the actual power is always some percentage smaller than MAP. In that way the power will continue to be controlled in coordination with ordered current changes.

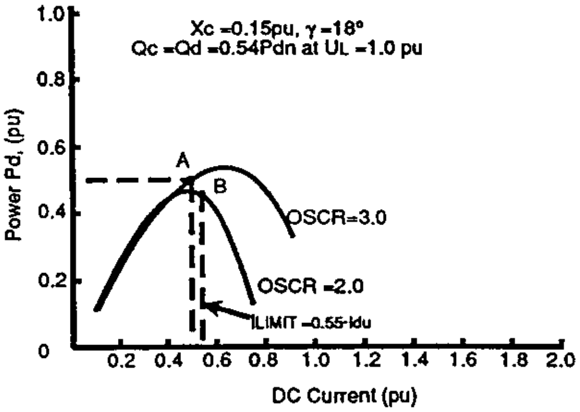


Figure 3.8
Operation at reduced load
sliding current limit

The time during which the power level is lower than required can be minimized by having available shunt capacitor banks which can be automatically switched to restore the ac voltage. This will be effective, as the voltage stability factor, VSF, is positive in current control.

There are a number of schemes where the operating point is sufficiently near the MAP, so that a relatively moderate, sudden ac voltage reduction may result in MAP-2 being lower than the power being transmitted.

The Itaipu scheme is designed to operate at CESCR of approximately 1.5; so far the minimum OESCR in service was 1.8 (The worst case studied was for ESCR = 1.55, $X_c = 18$ percent, $\gamma = 17°$, and $Q_c = 0.6P$). The power control system has a slow voltage feedback. The time constant is chosen to match the speed of response of the synchronous compensator voltage control systems (500 ms). For large voltage decreases a changeover to constant current control for a preset time takes place. A moderate voltage reduction in the inverter ac network may lead to a commutation failure which will activate the constant current mode. The recovery will, as in most other schemes, take place in constant current control mode.

In the Nelson River scheme (minimum ESCR = 2.51, $\phi = -75°$, $\gamma = 18°$, $X_c = 20$ percent, $Q_c = 0.6P$) for reduced ac voltage to 0.95 pu, operation is changed from purely constant power by replacing measured voltage, in the master control circuit, by a fixed dc voltage in order to prevent increasing current order with reduced voltage. It is released at 1.0 pu ac voltage. A damping capability, required by the ac system from the dc, is maintained, as is the important function of dc power reduction for tie-line trips.

3.6.2.3 Operation with an Increased γ

If the normal operation is very near MAP, so that excursions beyond MAP may be unacceptably frequent, it may be economical to design the inverter for normal operation at a γ slightly larger than the minimum, in order to provide some margin to deal with frequent ac voltage changes.

3.6.3 Normal Operation with $I_{dc} > I_{MAP}$ - Application of TCR or SR with Constant γ.

If sufficiently fast control of the inverter ac busbar voltage is provided by a saturated reactor (SR) or thyristor controlled reactor (TCR), the power control mode of operation required for system stabilization and frequency control would be stable because ac voltage could be controlled faster than the voltage feedback which determines I_{order}. Static compensators are already used in service at the inverter terminals to control overvoltages, (e.g., Cross Channel, Chateauguay).

Additional shunt capacitors would be required to compensate for SVC reactive consumption in normal operation and there would be a requirement for switching additional capacitor banks to keep the SVC in range.

The application of an SVC in this way should be considered for existing schemes where due to ac system changes the operation at $I_d > I_{MAP}$ may result and the existing dc equipment is not rated for operation at larger γ. For new schemes it is likely to be more economical to design the equipment for operation at variable γ.

A synchronous compensator could be used in the same way as described above for SVC, provided the control of ac busbar voltage is faster than the required power control speed, i.e., the voltage feedback which determines I_{order}. However, it should be noted that in all schemes which are in-service where a synchronous compensator is used, the ac system was sufficiently strengthened so that the normal operating point is on the left side of MAP ($I_d < I_{map}$).

3.7 Influence of DC Controls

As indicated in previous sections the control mode employed is very important. The quality of the controls cannot be overstated. Controls are discussed in Section 4.

3.8 Methods of Study

3.8.1 Hand Calculation

For preliminary consideration the values of CSCR, MAP, power reduction due to ac voltage reductions etc., can be calculated by hand (or simple digital programs) using steady state equations. This can be done initially by taking just the inverter into consideration. Similar calculations can be carried out taking into consideration the combined operation of the rectifier and the inverter.

3.8.2 Digital System Programs

Good load flow and transient stability programs will provide correct results.

3.8.3 DC Simulator

A DC simulator is normally used for more detailed studies required for design and stability criteria of control circuits. Additional information on the use of dc simulator is provided in Chapters 8 and 10 of the Guide.

3.9 Discussion of Power Curves

3.9.1 AC/DC System Having High Short Circuit Ratio - Figure 3.3

Initial Conditions Point A on MPC-1

I_d	U_L	U_d	P_d	X_c	γ	SCR
1.0	1.0	1.0	1.0	15%	18°	4.5

Possible immediate overload at MAP-1

1.74	0.83	0.73	1.28	15%	18°	4.5

Conditions following a line trip before current increase - new initial conditions, Point B on MPC-2

1.0	0.984	0.983	0.983	15%	18°	3.0

Restored conditions

1.04	0.98	0.929	1.0	15%	18°	3.0

Possible immediate overload at MAP-2

1.3	0.85	0.814	1.06	15%	18°	3.0

Higher power values from those indicated above could be obtained only if the ac voltage applied to the inverter is increased.

3.9.2 AC/DC System Having Low Short Circuit Ratio -Figure 3.4

The conditions for example in Figure 3.4 are as follows:

Initial Conditions, Point A at MPC-1

1.0	1.0	1.0	1.0	18°	15%	3

Possible immediate overload to MAP-1

1.32	0.87	0.83	1.08	18°	15%	3

Conditions following a line trip before current increase - new initial conditions, Point B on MPC-2

I_d	U_L	U_d	P_d	γ	X_c	SCR
1.0	0.93	0.92	0.92	18°	15%	2

However, the current would immediately increase up to the current limit, Point C on MPC-2

1.1	0.84	0.81	0.9	18°	15%	2

Conditions at MAP-2

0.96	0.96	0.96	0.93	18°	15%	2

Higher power values can be obtained only if the ac voltage applied to the inverter is increased.

3.9.3 AC/DC System Having Very Low Short Circuit Ratio - Figure 3.5

Initial Conditions, Point A at MPC-1

I_d	U_L	U_d	P_d	γ	X_c	SCR
1.0	1.0	1.0	1.0	25°	15%	1.5

Possible immediate overload, Point B on MAP-2

1.07	0.96	1.0	1.07	18°	15%	1.5

Conditions following a line trip before reduction of γ, Point C on MPC-3

1.0	0.81	0.8	0.8	25°	15%	1.3

However, γ would immediately reduce to its minimum, Point A on MPC-4

1.0	0.95	1.0	1.0	18°	15%	1.3

Higher values can be obtained only if the ac voltage applied to the inverter is increased.

3.9.4 Discussion of Results

It should be noted that the above results are obtained for the specified inverter and ac system data and apply just to this example. Also, it should be remembered that only the inverter characteristics were considered; i.e., any restrictions which a practical rectifier may impose on power transmitted were ignored. However, the examples do serve to indicate the possible performance with ac/dc systems of different SCR values.

High and low SCR systems will allow an immediate overload up to the value of MAP, i.e., even without ac voltage control provided that there are no other limitations, such as inadequate output from the rectifier or by equipment rating. The higher the SCR of the system, the higher the value of the immediate overload. The low SCR system cannot maintain the power at the level being transmitted, following the assumed ac system disturbance; a current limit would allow the transmission to continue at a reduced power level.

The amount of immediate overload when operating with very low SCR systems depends on the design rating corresponding to the nominal value of γ. In the particular example of Figure 3.5 the normal operation at $\gamma = 25°$ allows an immediate overload of 1.07 pu and just permits a system disturbance which increases the ac system impedance by 15 percent to continue transmission without temporary power reduction.

Satisfactory operation with very low SCR systems depends on good ac voltage control to maintain γ normally near its nominal value and to keep ac voltage within prescribed limits despite steep voltage changes, due to dc current variation.

It should be also noted that the large sudden system changes assumed in these examples may cause, in practice, a commutation failure which is discussed in Chapter 10.

4. CONTROL AND PROTECTION FOR DC TRANSMISSION

4.1 Introduction

Controls are involved to a larger or smaller extent in most phenomena of interactions between ac and dc systems. The control system is of immediate importance for stability and performance during disturbances. Special control functions can be added to improve, in many cases, the behaviour of the total transmission system.

If the convertor stations are connected to a high SCR system, i.e., an ac system having a low impedance, the control system design is straightforward and a high speed of response can be achieved in most cases. The exception to this would be the schemes having long dc cables or very long transmission lines. With low and very low SCR ac systems, on the other hand, stabilization of the dc controls require more care and it may be necessary to accept that recoveries from ac system faults are slower than if the ac networks were strong.

4.2 Hierarchical Division of the DC Control System

4.2.1 Introduction

Several control levels can be found in a dc scheme since an ac/dc system itself can be considered as divided into different hierarchical levels. Power dispatch, system frequency, ac voltage, machine signals, etc., constitute the constraints of the "ac world" which should be correctly treated in a coordinated manner by the relevant control levels, in order to provide a stable ac/dc relationship.

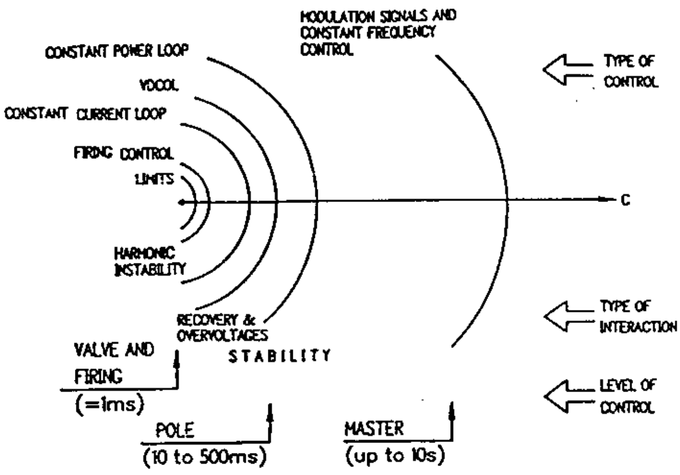


Figure 4.1
Hierarchical Levels of HVDC Controls
with Typical Time Constant

The magnitude of time constants is different for each control level. The shortest time constant is related to valve electronics. Time constants increase in value (and frequencies of concern become lower) as the controls move closer to the ac system. Figure 4.1 indicates the various levels and typical time constants associated with each control level.

4.2.2 Thyristor and Valve Control Level

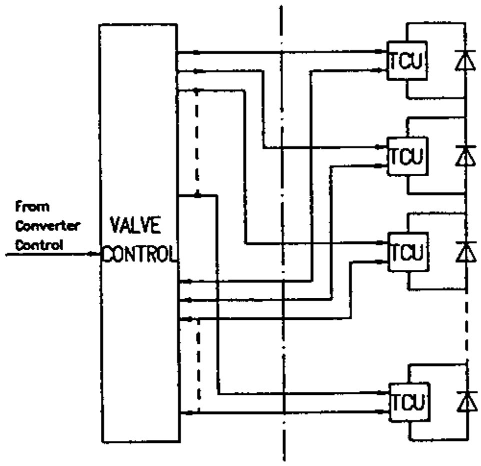


Figure 4.2
The Thyristor and Valve Control Levels
in the Control Hierarchy

The lowest hierarchical level in the control system is the valve and thyristor control equipment. This covers the electronic equipment used for transmission of control pulses to the valve for the firing of the individual thyristors, and for supervision and monitoring of valve status. A simplified block diagram is given in Figure 4.2. The thyristor control units (TCU) communicate with the valve control system and convert received firing pulses, normally light pulses transmitted by fibre optic light guides, into current pulses applied to the thyristor gates. Return channels from the TCUs to the valve control system are often used for thyristor supervision.

4.2.3 Convertor and Basic Control Level

The convertor control level consists of the convertor firing control. This subsystem determines the firing instants for all valves of the convertor. The firing control system can operate in one of several modes. The principal modes are:

1. Minimum alpha control and minimum commutation margin control, which define limits of convertor control and must always be able to override other modes of control,
2. Direct current control.
3. Direct voltage control.

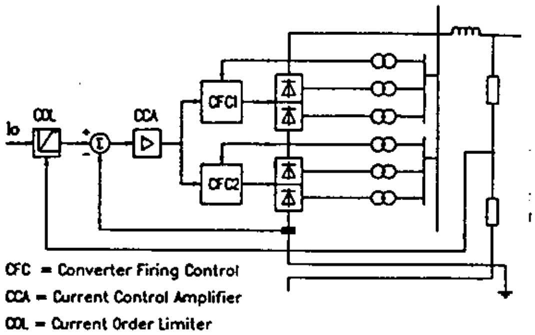
Direct current and direct voltage modes of control are used to execute the requirements of higher level control loops which control system quantities such as transmission power and reactive power consumption.

In current control, which is the normal rectifier mode of operation, the delay angle alpha is determined by a control signal from a current controller which is used to control the current in the dc circuit.

4.2.4 Pole Control Level

The current control amplifier (CCA) is found in the pole control level which is next in the hierarchy (Figure 4.3). When two or more convertor groups are connected in series in the same pole they must carry the same direct current and therefore must be served by a common control amplifier. Most dc systems operate under the current margin method, which will be discussed later. One of the principles involved in this method is that both rectifier and inverter are provided with a current controller but the controller in only one of the stations is active. The controller in the inverter station is normally made "inactive" by making its current order smaller than the order in the rectifier station. However, the status of the two controllers can be dynamically changed during and after disturbances. The convertor and the basic pole control levels are illustrated in Figure 4.3 in which CFC1 and CFC2 indicate convertor firing control systems for two 12-pulse convertors in the pole. CCA is the current control amplifier and COL is the current order limiter (see Section 4.6).

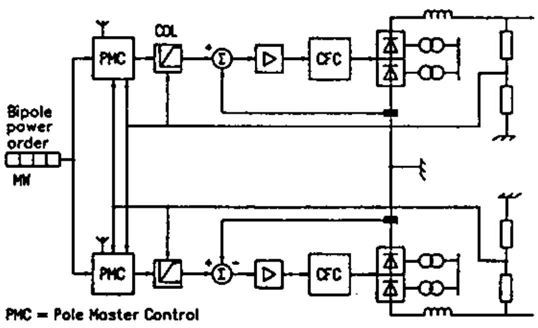
The control functions considered so far represent the basic control system needed to operate a dc system. This part of the control system is normally not designed for a specific project but parameter values and some special functions are changed to suit a particular system.



CFC = Converter Firing Control
CCA = Current Control Amplifier
COL = Current Order Limiter

Figure 4.3
Convertor and Basic Control Levels
in the Control Hierarchy

4.2.5 Pole Master Control Level



PMC = Pole Master Control

Figure 4.4
Pole Master Control in a Bipolar Transmission

The next level in the hierarchy is the pole master control level shown in Figure 4.4. Master control functions can be found also on the bipole level but it is often considered sound design philosophy to refer many of the master control functions to the pole level, which is advantageous from the availability point of view. The pole master control equipment (PMC) normally includes such functions as power control which determines the current order, current order transmission between stations, and current order limitation for overload control. Also, power order ramping and power modulation for ac network stabilization may be performed by the pole master controller.

4.2.6 Bipole Control Level

Control functions at the bipole level should be avoided as far as possible. However, some functions related to total transmission power must be situated in the bipole level control. The integrating frequency controller intended for constant frequency control of a receiving island network is usually common to the two poles of a bipolar transmission scheme. Also a reactive power controller, which switches shunt banks and filters and which generates orders to change control angles, is preferably a bipolar control function.

In addition to control functions, as discussed above, protective and sequence control functions are also found on each of the hierarchical levels with segregation to lowest possible level. For example, protection functions at the bipole level, e.g., protection which can trip the whole bipole, should be avoided for availability reasons.

4.3 Types of Interaction between Controls and the AC System

4.3.1 Introduction

The control systems for a dc transmission must be stable with adequate stability margins over the whole range of operation.

It is easier to achieve control system stability and fast response when the ac network has a large SCR value than when it has a low or very low SCR. For instance, it may be impossible to achieve a fast power control system if the receiving ac network has a very low SCR. This problem can sometimes be solved by slowing down the direct voltage signal fed back to the power controller to allow the ac system voltage control to act before the current order is significantly changed. This can reduce the influence of the ac voltage variations.

With line commutated convertors, which are used for dc systems, the commutation process depends on the ac voltage waveform and therefore the commutating voltage is the main interface parameter between ac and dc systems.

4.3.2 Firing of Thyristors

4.3.2.1 Thyristor Firing Voltage and the Availability of Gating Pulses

Two conditions are required simultaneously for the thyristor to start conducting: (i) a positive voltage applied across the thyristor must be larger than a given minimum and (ii) a positive current must be injected to the thyristor gate. Sufficient voltage is made available by limiting the minimum alpha to value of say 2° to 5°. The firing signal transmitted from ground potential is used to release the firing pulses, which are generated at the individual thyristor levels.

The energy for the firing pulses is derived from capacitors at the thyristor levels, charged by the ac voltage applied across the valve. It is important to be able to adequately charge these capacitors even if ac voltage has a low value for a prolonged period of time. It is particularly important for systems where dc represents a large proportion of power infeed to be able to recover quickly from an ac or dc system fault, in order to prevent the collapse of the ac system. It may also be important to transmit as much power as possible during system faults when ac voltage may be low. This can be done only if the ability to provide energy for the firing pulses is not lost during the disturbance. In practice other factors may impose a minimum ac voltage for convertor operation.

4.3.2.2 Thyristor Re-firing

A valve should be able to refire during the conduction interval defined by the firing control system, after a current extinction, due to, for example, a brief ac voltage reduction to zero as a consequence of an ac system fault. This requirement is not as obvious as it may seem because modern valve control systems are based on the principle of firing the valve by transmitting one or a small number of short pulses to the valve at the beginning of the conduction interval. Thus, the requirement of refiring at current extinction means that the valve control system must be designed to generate and transmit new firing pulses when the voltage builds up across the valve during the conduction interval, e.g., during the period that a valve would normally conduct. This matter can also be handled by the thyristor control unit if start and stop pulses are received from the valve control system.

If the valves are able to refire after current extinction the dc system can operate with very low currents, below the limit for continuous current operation, and can be used to form a very low load to a generator station in radial operation with the dc link during the startup of the generators. This property of the dc system is also important when the transmission system is used for the infeed of power to an island network if the dc transmission is used for acceleration of the synchronous compensator from a low frequency to rated frequency as is the case in the Gotland transmission (see Chapter 9).

4.3.3 Interactions with the Firing Controls

4.3.3.1 Individual Phase Firing Control

The individual phase control system applies a method of firing pulse generation directly synchronized to the ac voltage waveform. This method creates an unintentional feedback loop from the voltage waveform via delay angle determination, phase current variation, ac voltage fluctuation and thence back to the voltage waveform.

This is illustrated in Figure 4.5, in which the quantities involved in the feedback loop are denoted as superimposed disturbances; i.e., $\Delta\alpha$ (for variations in delay angle), ΔI_{ph} (phase current) ΔU_{ac} (phase voltage) and ΔU_{cf} (control function). Here U_{cf} is a control function derived from the ac bus voltage and used for direct determination of the phase position for firing, i.e., the delay angle. It should be noted that even if the direct current, I_d in the figure, is ideally smoothed, a disturbance in α will cause disturbances in phase currents. The most important parameters for the loop gain are the equivalent network impedance Z_n and the value of the direct current. A higher Zn (i.e., a weaker ac network), and a higher direct current result in a higher loop gain and a higher risk for instability.

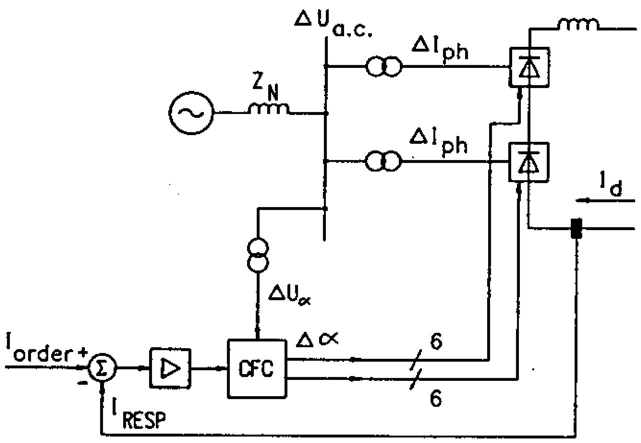
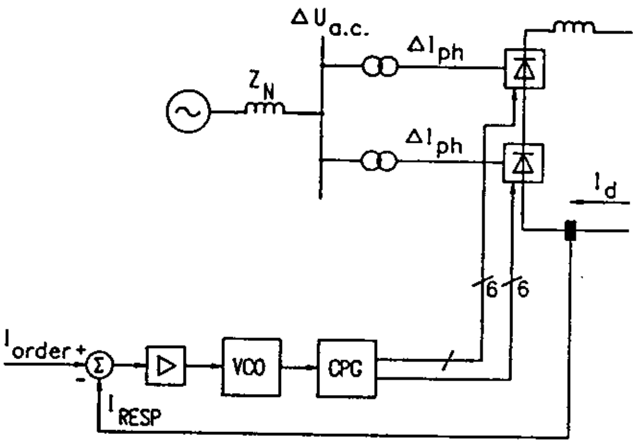


Figure 4.5
Current Control with Individual Phase Firing
Control System

4.3.3.2 Equidistant - Phase-locked Oscillator - Firing Control Systems

The harmonic instability phenomenon was one of the main reasons for developing the equidistant firing control system or, using another name, the phase-locked oscillator control system, used in all modern dc schemes. It should be noted that an equidistant firing control system does not give equal distances between firings in all situations, not even in steady-state operation. Exact equidistant firing is obtained only in steady state operation with completely balanced commutation voltages. The name "equidistant firing control" refers to the fact that each firing is substantially fixed in time with reference to the previous firing and not to the previous zero crossing of the commutation voltage, which is the case in the individual phase control system. The equidistant type of firing control system does not rely on a control function derived from the ac voltage but is only indirectly synchronized to the ac voltage by the current feedback, and accordingly the unintentional feedback loop discussed in 4.3.3.1 is broken (B11).

As shown in Figure 4.6, the basic element in an equidistant firing control system operating in current control mode is a voltage controlled oscillator (VCO), the output pulse signal of which in steady state ($I_{order} = I_{resp}$) has a frequency equal to the pulse number for the convertor multiplied by the ac system frequency. The control pulse generator separates the pulse signal into one signal per valve. As soon as a deviation occurs between current order and current response the frequency of the VCO will change temporarily. Steady state operation will be restored, with a new or the predisturbance value at the delay angle α, following a transient delay. Using this type of firing control allows stable operation with a weak rectifier ac network.



VCO = Voltage Controlled Oscillator
CPG = Control Pulse Generator

Figure 4.6
Current Control with Equidistant Firing
Control System

4.3.3.3 Commutation Margin Angle Control for Inverters

The inverter must always be provided with a firing control function which, as far as possible, guarantees that firing does not take place later than at the instant which would result in a minimum commutation margin.

Two techniques have often been utilized for the inverter firing control: γ predictive and γ feedback. In the γ predictive approach, the firing pulses are ordered according to a calculation of predicted voltage-time area for commutation and extinction. The other approach executes the firing pulses according to the difference between a γ order and a measured value of γ. Predictive inverter firing is, by nature, individual per valve or phase, but can be provided with a balancing circuit to attain equidistant firing and stable operation when feeding a weak ac network.

4.4 Current Control

The design of the direct current control system is determined by main circuit parameters; e.g., the inductance of the dc reactor, the characteristics of the dc line and the impedances of the ac networks and of the convertor transformer. The impedance of the receiving ac system is the most important parameter. Thus, the characteristic of the inverter considered as a load to the rectifier is dependent on characteristics of the inverter ac network.

Typical natural frequencies of the current controller for cable and long overhead line schemes are in the range of 5 to 30 Hz. Whether this frequency would interact with the network (thermal machines, for instance) or not should be investigated for each application.

The normal way of illustrating the cooperation between a rectifier and an inverter is by reference to the well-known U_d/I_d diagram. In the traditional way of controlling dc transmission, the rectifier controls the current and the inverter operates with constant margin of commutation giving the point of operation indicated by A in Figure 4.7. As the inverter is given a current order lower than the rectifier by the value of current margin, it is forced into minimum commutation margin control. The strategy is called the constant current margin control, which gives the maximum dc voltage for a given ac voltage applied to the inverter.

The slope of the nearly horizontal line of the inverter characteristic is such that an increase in current results in a decrease in voltage; i.e., the rectifier current control system experiences the inverter as a negative resistance load for small and low frequency current variations. This is easily handled by correct tuning of the current controller as long as the magnitude of the negative resistance is moderate.

The slope of the nearby horizontal part of the inverter characteristic can be obtained from the equation for the inverter direct voltage for constant γ operation neglecting resistive voltage drops. (See also APPENDIX)

$$U_d = U_{dio}\cos\gamma - d_x \frac{I_d}{I_{dN}} U_{dioN} \qquad (4.1)$$

Normally such characteristics as those shown in Figure 4.7 are drawn for steady state conditions assuming constant applied ac voltage. According to the equation (4.1), for these conditions, the slope of the inverter characteristic is only determined by the convertor transformer impedance, i.e., d_x. However, U_{dio} follows the ac bus voltage dynamic variations and thus increased current means decreased U_{dio} which is restored to its nominal value, at a longer timescale, by the convertor tapchanger and by the ac voltage control by, for example, capacitor switching.

Thus in practice, for dynamic current variations, the negative resistance of the inverter as seen from the rectifier is also highly dependent on the network impedance. It is normally possible to attain stable operation by adjusting the control parameters in both rectifier and inverter basic control systems. If the dynamic slope of the inverter characteristic is large, as shown in Figure 4.8, instability may result.

The modification shown in Figure 4.9 is obtained by increasing the margin of commutation, by increasing γ in proportion to the decrease in current below a set reference value. The result of this measure is that the negative slope is replaced by a positive slope in the region of decreasing current. With a current oscillation superimposed on the average current value, the average resistance will then be less negative or even positive. This simplifies the conditions for the rectifier current control system considerably. It should be noted that the operating point A should move only vertically and not in a horizontal direction for inverter ac network voltage variations. The characteristic of Figure 4.9 is also useful for avoiding this so called 3-point crossover instability indicated in Figure 4.8, i.e avoiding the characteristic where there may be three possible operating points, A, B or C.

The operating point A of Figure 4.9 corresponds to operation at minimum commutation margin as normally implemented to minimize the cost of the convertor station.

An alternative solution is presented in Figure 4.10a in which the characteristics are so arranged that the normal point of operation is moved down along the part of the characteristic with positive slope. Now the inverter is able to increase the voltage at increased direct current. This method has been found to be very effective when the inverter is connected to a weak ac network. The normal operating point A corresponds to a value of γ larger than the minimum.

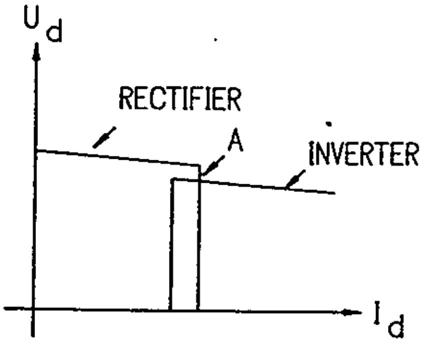


Figure 4.7
Ud/Id Characteristics for an HVDC Transmission System, Simple Version (Udio Constant)

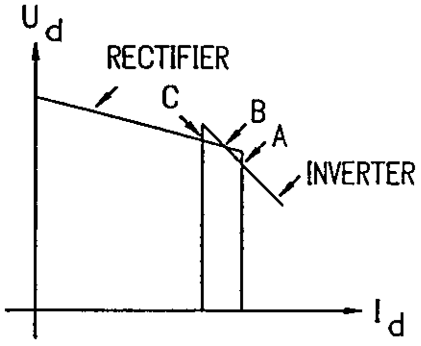


Figure 4.8
Ud/Id Characteristics for Weak Inverter AC System (Udio Not Kept Constant)

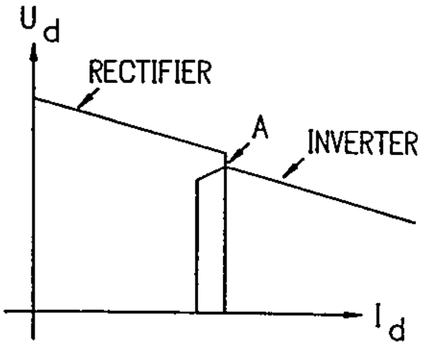


Figure 4.9
Modified Inverter Ud/Id Characteristic

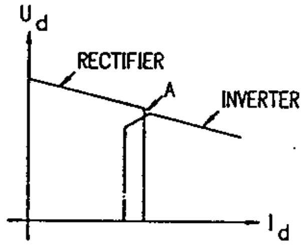


Figure 4.10a
Modified Inverter Characteristic with Normal Operation with Higher than Minimum

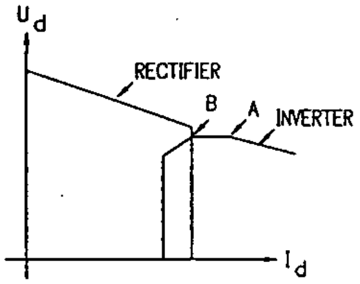


Figure 4.10b
Alternative Inverter Characteristic with Normal Operation with γ Higher than Minimum

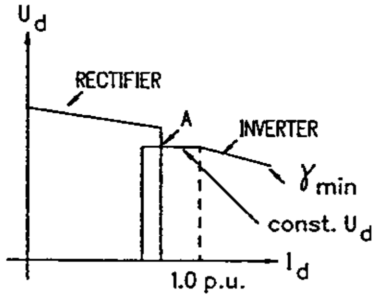


Figure 4.10c
Inverter Characteristic for Constant Power Factor Control with Normal Operation with γ Higher than Minimum

Another modification, shown in Figure 4.10b, is similar to Figure 4.10a, but with a horizontal characteristic near A, i.e., with constant dc voltage control. This characteristic is often used to achieve stability in the "constant power" control mode when operating with weak ac systems. Also in this case the normal value of γ is larger than the minimum. (See also Section 3.6.2.3).

Constant power factor control has been used in some cases for securing stable operation of an inverter. Basically, this control system employs constant dc voltage control with a minimum γ limit as shown in Figure 4.10c, combined with the convertor transformer tap control to keep the voltage of the transformer valve winding constant. The margin angle is kept minimum in full load operation and is effectively increased in partial load operation.

Current control stability with a weak inverter ac network can also be improved by designing the system for current control function being executed by the inverter as shown in Figure 4.11.

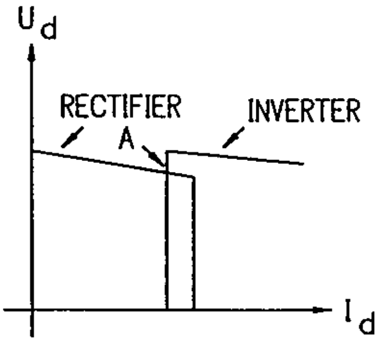


Figure 4.11
Ud/Id/Characteristics for Current Control Performed by the Inverter

This alternative suffers, however, from increased station cost in the same way as the solution presented in Figure 4.10a and b. Normal operation with γ higher than the minimum value for a given dc line voltage, implies that the valves must be designed for higher damping circuit losses and higher ac voltage, and the resultant higher reactive power consumption of the inverter must be compensated. However, it may be justified to operate with a high value of γ in the steady state as an alternative to the use of fast static var compensators for ac voltage stabilization.

4.5 Power Control (see also Chapter 3)

From a steady-state point of view, power control of the rectifier with constant γ control of the inverter is not in itself stable if the strength of the inverter ac network is below a certain value (operation to the right of the Maximum Available Power (MAP) point in Figure 4.12, with γ constant). If the power order is increased, the increase in direct current will cause a decrease of the voltage by such a magnitude that the net effect would be a decrease in power infeed to the ac network. The voltage decrease will generate a still higher current and the power will further reduce until the current limit is reached. For operation with a low SCR ac system three methods were used in practice to improve the operating conditions as discussed in Section 3.6.2.

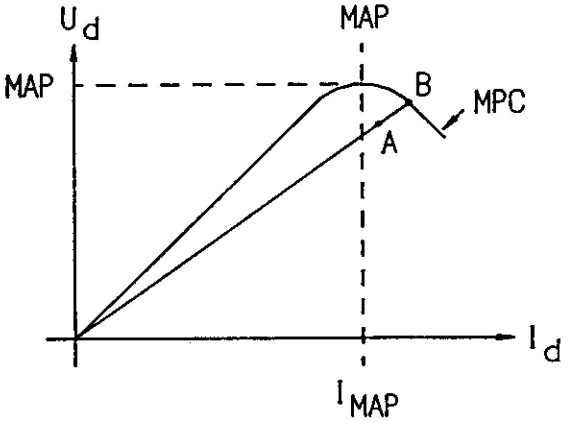


Figure 4.12
Characteristic of HVDC Transmission in Power Control with Inverter Operating at an Increased γ

However, for operation with very low SCR ac systems, when the operating point may normally correspond to dc currents higher than I_{MAP}, one possibility is to establish a sufficiently fast control of the ac voltage to avoid normal operation with a value of dP/dI being negative. For example, this can be done by very fast static var compensators as discussed in Section 3.6.3 or by varying the value of γ to control voltage, i.e., arrange for the inverter to behave as a static compensator. In this case the normal operating point will be at A of Figures 4.11 and 4.12. The range of this type of behaviour is determined by the allowed range of variation of γ (distance between points A and B) and sooner or later minimum γ will be reached at Point B. When minimum γ is reached, the inverter will operate in constant γ control, and operation will try to jump to the current limit as before. The effect of this can sometimes be much improved by sliding limits; i.e., current limits tied to a power order which limits current to just above the normal value for the power order. See also Section 3.6.2.1.

4.6 Reduction of the Direct Current at Low Voltage

To avoid feeding a high current into a disturbed ac network, and to get a controlled recovery from the disturbance it is normal to reduce the current order when the direct voltage is reduced. The break points D and E in Figure 4.13 are typically between 70 percent and 30 percent of dc voltage, and in special cases even higher depending on ac system requirements. The higher voltage is applied when the receiving ac network is sensitive to disturbances which could cause large voltage fluctuations as in the Itaipu scheme.

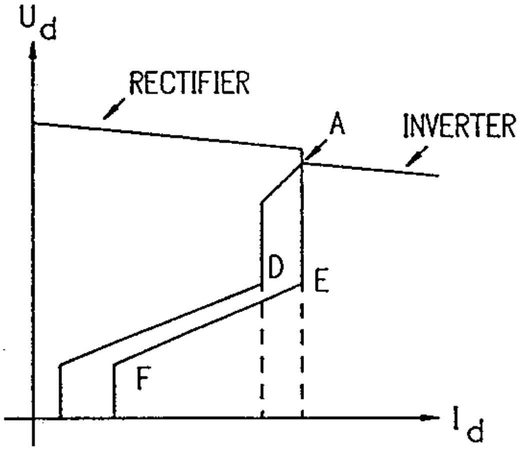


Figure 4.13
Ud x Id Characteristics with Current Order Reduction at Low Voltage, Alternative 1

The main difference in the alternative arrangement of Figure 4.13 is that the part E-F of the rectifier characteristic is kept horizontal.

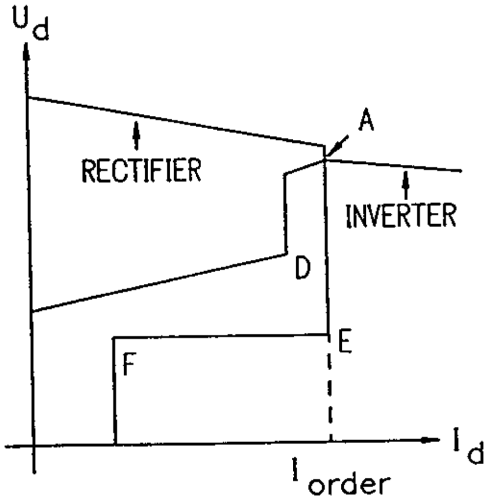


Figure 4.14
Ud/Id Characteristics with Current Order Reduction at Low Voltage, Alternative 2

The terms VDCOL (Voltage Dependent Current Order Limit) and LVCL (Low Voltage Current Limit) have been used for the function which reduces the current when the voltage decreases.

4.7 AC system Instabilities

The following instabilities are examples where the convertors can help the ac system.

(a) Low-frequency instability, at frequencies from about 0.1 Hz to 2 Hz. This is the region of inter-machine and inter-area electro-mechanical oscillations. The dc link can contribute to the damping at these frequencies by the addition of special control loops from a measured ac quantity such as frequency or phase angle of the ac system. The feedback signal is generally "ac-coupled," so that steady state operation is not affected.

(b) Very low frequency instability, below about 0.1 Hz. This is the system frequency control region, relevant to machine speed control by turbine governors. Comments are as for (a). In addition, control of absolute frequency is sometimes used, either with an integral (flat) power/frequency characteristic or with a power/frequency droop as for generators.

(c) The ability of a dc link to change power relatively quickly (power run-back) can be useful as an over ride feature. For example, if a substantial reduction of ac voltage occurs (perhaps for a reason not connected with the presence of a dc link), the dc link can be ordered to reduce power quickly, and hence the reactive power consumption, so as to restore ac voltage sufficiently to prevent ac system collapse. Another example of runback application is the case when an ac line connecting the convertor station to the ac network is lost.

As mentioned above, dc schemes can be used to counteract inter-machine or inter-area power oscillations by the utilization of external-area signals, such as frequency or voltage deviations, phase angle changes, or power changes in an ac parallel line.

Originally, the dc controls were designed to improve damping to real power oscillations by modulating the dc power P_d. No concern was taken to the reactive power changes delta Q_d resulting from the modulation P_d. However, as the ac network becomes weaker, variations in reactive power will cause voltage variations, which can be detrimental for overall system stability. More recently, several techniques of modulation have been proposed with good results:

- modulation of γ as a function of ac voltage variations,

- direct voltage control by inverter γ,

- a coordinated modulation of transmitted active power and reactive power consumed by one of the convertor stations.

4.8 Influence on the Control of Resonances in the AC Network

Chapter 5 discusses harmonic and resonance influences on control design.

4.9 Summary of Convertor Control instability Phenomena

In principle a combination of one or more dc links including their filters, dc lines and the ac systems with their machines, lines, and loads is mathematically a single entity. It is usually convenient to subdivide instabilities into several types, distinguished by their frequency referred to the dc side, as follows:

(a) Super-synchronous instability, at frequencies above fundamental. This is sometimes loosely called "harmonic instability," though in general it is at a non-integer frequency.

As mentioned earlier harmonic instability was a problem in some earlier dc systems, but modern control principles should eliminate this problem.

(b) Core-saturation instability, at fundamental frequency referred to the dc side (2nd harmonic plus dc referred to the ac side) with convertor transformer cores saturated.

This can occur with a low or very low SCR ac system with certain resonance conditions as discussed in Chapter 5. It is cured by the proper choice of control constants or by the addition of special control loops.

(c) Sub-synchronous instability, at frequencies from about 5 Hz to 40 Hz. This can occur either at a frequency unrelated to any natural frequency of the ac system, or in conjunction with machine torsional mechanical resonances. This is cured by the use of suitable control types and control constants, again sometimes with extra control loops (See Chapter 6).

(d) Power control instability. With ac systems represented by fixed Thevenin equivalents this is a "runaway" condition (in practice prevented by current limit), mathematically at zero frequency, which occurs in restricted conditions with an ac system having a very low SCR. This is discussed in Chapter 3 and Section 4.5.

It should be stressed that the controls must be stable for operation in current control mode with the inverter operating at constant γ even when dP/dI is negative. In all control modes, constant power at constant γ, variable γ, or constant γ with static var compensators, during a temporary low ac voltage, operation will take place in current mode with the inverter at constant γ.

4.10 System Parameters of Principal Interest to the Controls

The response time of the dc controls is short compared to other time constants of the network. The speed that can be applied to the dc controls will be dependent on the capacity of the network to support variations of real and reactive power of the convertors. For instance, it should be noted that a very rapid recovery after an ac system disturbance may lead to a commutation failure if the inverter ac network has a high impedance.

In designing the controls for a given power scheme, one should consider the following aspects:

(a) The network impedance as a function of frequency should be known (preferably to above the 3rd harmonic), in magnitude and phase. This parameter is important for identifying possibilities of parallel resonance in the ac network or ac/dc/ac coupling via dc line harmonic magnification, which should be damped by the controls.

(b) The speed of the dc link recovery after faults should be such that it satisfies the conditions of both networks, at the rectifier and at the inverter side, if they are isolated. If there are other interconnections or a parallel ac line, the problem of adjusting the controls is quite different, because the performance of one station can greatly influence the other station. Studies should be carried out to identify the receiving and sending end ac network needs, in terms of stability, overvoltage levels, etc., and the controls designed accordingly.

(c) The presence of other fast voltage control devices, such as static compensators in the vicinity of the convertor station may influence the dc controls design.

4.11 AC Voltage Variations

4.11.1 Load Rejection Overvoltages
(See also Chapter 8)

If the ac networks have high system impedance (low and very low SCR ac systems), high ac overvoltages will occur at the loss of transmitted power. The reason is that the reactive power consumption is reduced or eliminated when transmitted active power is lost while the compensation equipment, filters and shunt banks, are still connected.

Loss of full load is of course the worst case and can be the consequence of a permanent fault in the dc system or a loss of commutation voltage in one of the ac networks.

A dc scheme should be so designed as to make the tripping of a bipole an extremely rare event. In the case of monopolar transmission the loss of the whole transmission is of course more probable.

The overvoltage problem can be minimized by combining the convertor blocking controls with an interstation control sequence which trips filters and shunt banks as required.

Some form of back up to the interstation sequence control system must be available for the case when the telecommunication system is out of order. Such a back-up can be obtained by including protection which trips filters and shunt banks at high ac overvoltage. The action from this protection must be delayed and coordinated with ac network line protection in order not to trip the reactive elements at load rejections caused by temporary ground faults in one of the ac networks.

For a fault in the inverter ac network, the rectifier continues to feed current into the dc circuit with a rectifier delay angle α close to 90°. This means that the rectifier consumes a sufficient amount of reactive power to limit ac voltage rise. If the same type of fault occurs in the rectifier ac network it would be theoretically possible to let the inverter feed current into the dc line at a large control angle. However, an inverter must be prevented from feeding a current through a ground fault on the dc line and for this reason it is normally provided with an α minimum limitation at, say, 100°. It is possible to discriminate between ac and dc faults, by transmitting an indication from the rectifier to the inverter informing the latter that the fault is in the ac network (i.e., not on the dc line). However, point-to-point dc schemes should also operate without the telecommunication system. Overvoltages in the absence of telecommunications must be taken into account when considering the insulation coordination.

4.11.2 Temporary Overvoltage at Recovery after an AC System Fault

When the ac voltage recovers following an earth fault, the convertor transformers are energized and harmonic inrush current is generated. Recovery after a close 3-phase fault is the most critical case. If the ac side impedance - the parallel combination of the ac network and the filter and shunt banks - is high for the inrush current harmonics the temporary overvoltage on the ac bus may be high until the current starts to flow in the dc circuit.

To minimize these overvoltages it is important to ensure that dc current starts to flow at low dc voltage as ac voltage recovers. Some control systems are designed to allow dc current to flow at a reduced value during the fault so as to avoid the delay on ac voltage recovery.

4.11.3 Reduction of AC Network Voltage Variations by DC Controls

4.11.3.1 Voltage Change on Reactive Switching

When a shunt reactive bank is switched at a dc terminal, the system voltage changes in the vicinity of the terminal. At buses that directly serve consumers, the voltage change could cause the consumers' lights to blink. If the voltage change were to occur frequently, the result might be annoying flickering of lights.

Generally, weak systems exhibit a high sensitivity of voltage change on reactive switchings. Consequently, the required limit on voltage change for reactive switching would often establish the size of reactive banks, i.e., filters, capacitors and reactors. Parameters, besides the bank size, that influence the voltage change on reactive switching are:

- the ac system impedance,
- the amount of shunt compensation already connected to the bus,
- the amount of power being transferred by the dc convertor,
- the natural action of the dc convertor and its controls following the switching event.

These key parameters must be considered in establishing an appropriate voltage change criterion for a convertor terminal and in determining the appropriate size of capacitor, filter, and reactor banks for the purpose of limiting flicker.

The appropriate criterion for limiting the voltage change caused by reactive switching must also be based on the following considerations:

- the degree of consumer dissatisfaction caused by flicker resulting from the voltage change,
- the relative frequency of switching events that cause the voltage change,
- the relationship of voltage change at the convertor commutation bus to the voltage change at lower voltage buses serving consumers. The higher the impedance between the convertor commutation bus and low voltage buses to which consumers are connected, the lower the voltage change on the lower voltage system.

The permissible flicker limits discussed in the publications quoted in the Bibliography [B27, B28] provide some guidance in this area. Considering a typical frequency of reactive switchings in dc installations (about two per hour to two per minute), it appears that 2 to 3 % is a reasonable upper limit on voltage change to avoid customer dissatisfaction due to voltage flicker.

Moreover, a suitable criterion for voltage change on reactive switching should permit a slightly higher limit on voltage change at low power transfer levels than it would at rated power transfer levels, because dc systems will seldom operate near minimum power transfer levels and because shunt banks are not frequently switched in such situations.

4.11.3.2 Application of DC Controls

The consumption of reactive power by a dc convertor is, among other parameters, dependent on the control angles α or γ. A control function can be used to limit variations of ac voltage by varying the control angle of the convertor. This type of control is suitably applied in the convertor station which determines the direct voltage. However, it should be noted that varying the angle and by this the consumption of reactive power in one convertor station, also results in a corresponding variation in control angle and reactive consumption in the other station. It must be determined that this is acceptable before a decision is made to use this type of control.

To be able to both decrease and increase the ac voltage, the inverter must operate in the steady-state with a γ higher than the minimum value. This means higher equipment costs for valves, convertors, transformers and reactive compensation equipment, and also higher losses, but this may still be the cheapest solution.

In cases where it is sufficient to limit only the overvoltages, normal operation can be at γ minimum, avoiding the extra cost of the equipment.

To reduce the variations in ac voltage caused by shunt bank switching, a step change of suitable magnitude in γ can be coordinated with the bank switching. When switching in a capacitor bank, γ is increased as simultaneously as possible. To switch off a bank γ is first slowly increased, and when the bank is switched off γ is simultaneously decreased in a step back to the normal value.

4.11.4 Tapchanger Control

The convertor transformers are normally provided with on-load tapchangers which are integrated into the control system to influence given dc quantities.

With an inverter in constant commutation margin control, the tapchanger is often used to keep the direct voltage in steady-state close to the nominal value. In the case of the rectifier, which normally controls the dc current, the tapchanger is normally used to control α to near the nominal value. Other variations are sometimes used such as to control γ in an inverter operating in closed loop I_d or U_d control.

In all cases the objective is to increase or decrease the voltage of the valve side of the convertor transformer by increasing or decreasing the turns ratio. However, this change in transformer turns ratio also changes the reactive consumption of the convertor and this may counteract the tapchanger operation. Thus, a decrease in the turns ratio, with the intent of increasing the valve side voltage, may increase the reactive consumption of the convertor to such a degree that with a low or very low SCR ac network the effective change in the valve-side voltage will be very small. In such a situation, many tapchanger steps will be needed to attain the necessary variation of the valve-side voltage with the consequence that the effective tapchanger range will be low and the tapchanger will operate very frequently.

With a low or very low SCR ac network (SCR below about 2.0 and depending on the system impedance angle) the net effect in voltage variation when stepping the tap-changer may be even negative, i.e., the valve-side voltage will decrease when the transformer network side turns ratio is decreased and vice versa. This phenomenon is discussed in Bibliography B16.

4.12 AC Network Frequency and Stabilization Control

4.12.1 Introduction

The inherent controllability of the power transmitted by a dc system is unique in electrical power transmission, i.e., the power transmitted by the dc line is easily controlled with a high speed of response. Furthermore, the interconnection of two or more ac systems or of two or more buses in one ac system by a dc link is asynchronous and the transmission stability is not affected by a phase angle difference.

Thus, the dc transmission can be used for stabilization of an ac system by modulating the power transmitted in accordance with the variations in some ac system quantity, such as frequency or phase change. The link can also be used to directly control the frequency of an ac network connected to one of the substations.

These applications will be discussed below with reference to some typical cases.

4.12.2 Constant Frequency Control

A dc system can be used for transmitting power to an isolated area network without local generation, and with a synchronous compensator as the dominating rotating inertia. The frequency of this network must be controlled by varying the power transmitted over the dc line to attain balance between the load of the network and the infeed of dc power. To do this, the deviation from the nominal frequency in the island network is measured by a frequency discriminator and fed to a control amplifier. The output from the latter is used as a current order or forms a contribution for an operator-set current or power order of the master control hierarchical level.

By incorporating such a control system, the frequency can be kept very close to the nominal value as long as the dc transmission is in operation. The largest frequency deviation is, however, obtained during serious faults in the ac network to which the rectifier is connected and this deviation is in the worst case determined only by the load, the inertia of the synchronous compensator, the duration of fault and the speed of recovery of the dc link. The guidelines for the decision about the size of the synchronous compensator to be installed are discussed in Chapters 2 and 9.

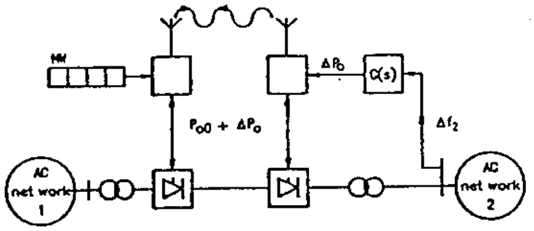


Figure 4.15
Constant Frequency Control of an Island AC Network

Figure 4.15 illustrates constant frequency control.

4.12.3 Power/Frequency Control

DC transmission can be used to assist the existing power generation station in controlling the frequency of the network by modulating the transmitted power in proportion to the frequency deviation. It is often stated in such cases that a dead-band for the frequency deviation shall exist. The gain of the regulator as well as the dead-band are normally variable.

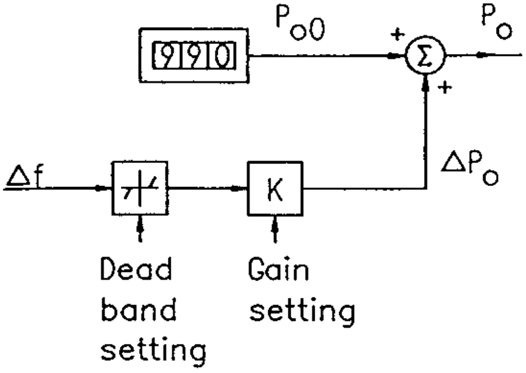


Figure 4.16
Power/Frequency Controller

Figure 4.16 shows an example of a controller arrangement in which the power/frequency control unit generates an additional power order ΔP_0 to a manually set order P_O.

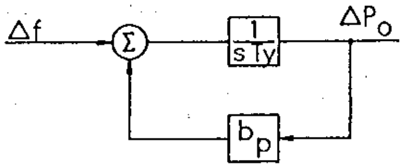


Figure 4.17
Turbine Governor Power/Frequency Control

If required, the regulator can be so designed that its characteristic is similar to a turbine governor as illustrated in Figure 4.17. The control function has a variable static feedback (speed droop) giving a resulting transfer function.

$$\frac{P_o(s)}{f(s)} = \frac{1}{b_p} \cdot \frac{1}{1+s(\frac{T_y}{b_p})} \qquad (4.2)$$

with T_y = response time of the pilot servomotor

b_p = permanent feedback (speed droop)

When b_p is set to zero the constant frequency control according to the preceding paragraph is obtained.

$$\frac{P_o(s)}{f(s)} = \frac{1}{sT_y} \qquad (4.3)$$

4.12.4 Stabilization of an AC Interconnection by a Parallel DC Link

When two ac systems are interconnected by parallel ac and dc links the latter can be used to stabilize the interconnection to a degree which is not possible with ac systems alone.

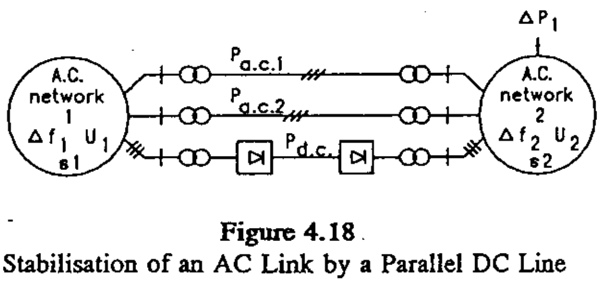


Figure 4.18
Stabilisation of an AC Link by a Parallel DC Line

In Figure 4.18 two ac networks are interconnected by two ac lines and one parallel dc line.

Here it is important that the phase angle difference between the two ac networks does not exceed a critical limit for the interconnection to be stable. The critical limit may be reached when the load in one of the networks is suddenly changed or when one of the two ac links is lost. If ΔP_L corresponds to a load increase in the receiving ac network 2, this network decelerates. If one ac link is lost, ac network 1 accelerates and ac network 2 decelerates.

$$\Delta\delta = \delta_1 - \delta_2 \qquad (4.4)$$

If in this case the power order for the dc line is partly determined by a regulator which derives a power order from suitable ac system quantities in the two ac networks or the two ac lines via a control amplifier with suitable dynamic properties, the interconnection may be stabilized.

The most probable quantities to be measured are the frequency deviations Δf_1 and Δf_2. The regulator derives the power order from the difference between these two frequency deviation signals; i.e.,

$$P_O = G(s) \,.\, \Delta F(s) = G(s) \,.\, [f_1(s) - f_2(s)] \qquad (4.5)$$

where G(s) is the transfer function of the regulator.

A possible alternative to the frequency may be the measurement of the power transmitted over the ac line as this power is determined by the phase angle difference between the interconnected networks according to

$$P = \frac{U_1 U_2}{X} \sin(\delta_1 - \delta_2) \qquad (4.6)$$

In special cases one of the two networks may be so large that its frequency is negligibly affected by variations in the power transmitted over the dc line. The situation is accordingly simplified and the power of the dc line can be modulated with regard only to the frequency of the smaller network.

The stabilization regulator is normally active only during transients; i.e., the static gain of the regulator is zero. Further, to optimize the stabilization ability of the dc link, the gain of the regulator is made as high as possible for the important frequency region in which the oscillation frequencies are found. Digital computer simulations, using power system stability programs, are normally performed for the determination of an appropriate transfer function.

This technique for stabilizing a parallel ac line by dc has been applied in the Pacific dc Intertie. Here oscillations in the parallel ac intertie are detected by measuring the power transmitted in the ac line; this ac power variation is, after some filtering, used to modulate the dc power, which is obtained by modulating the current order of the rectifier. The maximum amplitude of the current modulation is kept within 3% of rated current, which guarantees that there will be enough current margin even when the current is reduced.

4.12.5 Stabilization of Isolated AC System by a DC Link Supplied From an Isolated System

Where the dc link is supplied from an isolated ac system, network 3 on Figure 4.19 (e.g., a generating station) and feeds a complex ac receiving system, the dc link can be used to provide damping over much of the receiving system. For example, if the local receiving system has weak ac tie line to a neighbouring system, the two systems (networks 1 and 2 in Figure 4.19) can exhibit relative swings due to transients at a frequency often well below 1 Hz, at which machine damper windings give poor damping.

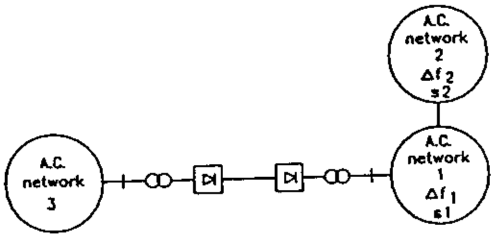


Figure 4.19
Stabilisation of a Weak Interconnection Within One of the AC Networks

This is the case in the Manitoba system in Canada, where the natural swing frequency relative to the Saskatchewan system is about 0.3Hz, and the systems can actually exhibit negative damping (continuous oscillation) in some conditions. This was substantially improved by modulation of the Nelson River dc link power; this provides strong damping. The method is based on a measurement of the change of absolute phase angle of the local busbar voltage at the inverter station. The advantage of this method is that it requires no telecommunication for its derivation, and yet can detect and damp prospective swings in many parts of the ac system.

In a more general case there might be complex ac systems at both ends of a dc link; damping can be provided to both if damping signals are taken from each ac busbar. Of course it must be accepted that any dc modulation will affect the power in the ac systems at each end of the dc link; however, the effect is usually small and in most cases the control constants can be chosen so that both systems are adequately damped.

4.12.6 Telecommunication Requirements

For higher level control, the capacity and speed of response of the telecommunication link are of importance.

Both of these properties depend on the bandwidth of the telecommunication link and the terminal interface equipment. As an indication of the requirements, assume that the current order is to be transmitted alone on one telecommunication channel. A modern remote control terminal equipment together with a 2400 baud channel can handle a message with 11 information carrying bits and a reasonable number of administration bits, with a delay of about 20 ms. The delay is in this case highly dependent on the number of security bits included. Eleven bits can be used to represent a current order with a theoretical resolution of 0.05 percent. Such a telecommunication link normally represents enough capacity for damping control as the expected oscillation frequency for a disturbed ac network is normally below 2 Hz. Sometimes different types of information are combined in one message with the consequence that the telecommunication delay is increased.

For constant frequency control and power/frequency control the capacity requirement of the telecommunication system is more moderate, as such control can be made rather slow.

To avoid unnecessary telecommunication delay, the leading master control equipment, i.e., that part of the master control system where the current order is calculated, should be located in the dc substation nearest to the controlled quantity. Or, if quantities in the two ac networks are controlled, it should be nearer to the more sensitive ac network.

4.12.7 Power System Damping and Frequency Control without Telecommunication

Temporary breaks of telecommunication must not be allowed to impair modulation control functions. One solution is to force the station in which the controlled quantity is measured to take over current control when the telecommunication system fails, unless it is already in control. This situation occurs if the ac network connected to the inverter is to be stabilized by damping control and the direct current is controlled by the rectifier. In this case, the inverter is forced to take over current control and dc power is then determined by the station connected to the ac network which has to be stabilized by frequency control. The current order in the other station is determined by the measured current response and a margin which is added with suitable sign. Figure 4.20 illustrates this case.

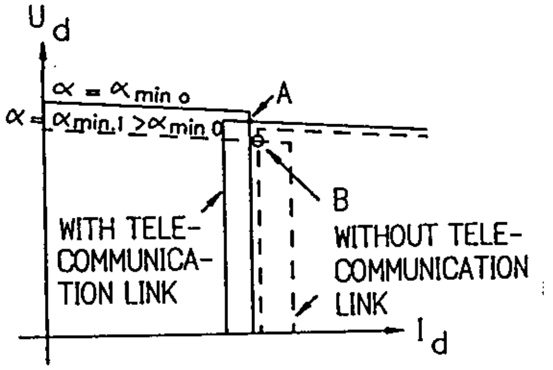


Figure 4.20
Back-up Control Without Telecommunication

A simpler method, which does not rely on the derivation of the current order from the current response, is to lock the control orders from the master control system in both substations when the telecommunication link fails and then add the additional modulating order only in the station in which the controlled quantity is measured. The order in the other station would be continuously kept locked. In this case, the modulating order contribution must be limited to, say, 0.5 of the current margin. The current margin can be increased to allow for a larger modulation signal.

4.12.8 Emergency Power Control

The term Emergency Power Control is used for a type of stabilization control applied with success in a number of dc schemes including the Konti-Skan, Skagerrak, and Fenno-Skan transmission systems. The transmitted power is changed by a preset amount of megawatts with a preset rate of change, as a result of a significant change in an ac system quantity, usually the system frequency. Such a significant change is interpreted as an indication that a large disturbance has occurred in the power system.

Several reference levels for the change in the system quantity can be used - in Skagerrak there are six levels - and the action from the emergency controller can increase or decrease the transmitted power and also the power flow direction can be reversed.

4.12.9 Influence on Both AC Networks of DC Power Modulation

It should be noted that modulation of the dc link power, in order to control an ac system quantity, affects both the sending and receiving ac networks. This means, for example, that when oscillations in one ac network are damped by the dc link the other network must accept the same degree of power modulation.

4.13 Control and Protection Considerations for Back-to-Back Schemes

With only a few exceptions, all the principles of control and protection for point to point transmission also apply to back-to-back schemes.

With no dc line there is no requirement for dc filters. Communication requirements for interstation convertor control are greatly simplified with back-to-back schemes. There is no need for an interstation telecommunication system and associated back-up when all convertor controls are located in the same building as in the case of the back-to-back schemes.

Load rejection overvoltages in the undisturbed ac network following a serious fault in the other ac network can be more readily controlled in a back-to-back scheme, as there is no dc transmission line and accordingly no need for a minimum limitation of α to 100° as discussed in 4.11.1 above. In the back-to-back configuration, the convertor connected to the faulted ac, (rectifier or inverter) system, upon sensing a severe ac voltage drop, can automatically block during the ac fault, form a bypass valve pair and carry current fed from the unfaulted side convertor. The convertor on the other side connected to the "healthy" ac system can automatically be operated as a rectifier with valve commutation in the normal manner with a firing angle α close to 90° (in a TCR mode). With limited direct current (less than 0.5 pu), it can absorb a relatively high amount of reactive power. By absorbing reactive power from the ac system, the convertor limits the ac overvoltage during the fault. Point-to-point dc configurations would require fast telecommunications to limit overvoltages in the way described if the fault occurs in the rectifier ac network. This could theoretically be done but it is not advisable to rely on telecommunication for limiting ac overvoltages to safe values.

Overvoltages can also appear on the ac systems when there is not an ac system fault, for example due to a sudden power reduction by the dc link, or due to changes within the ac system. Such overvoltages can be limited rapidly by a TCR mode control loop which overrides normal controls; this must act on the inverter irrespective in which ac system the overvoltage has occurred, with the rectifier continuing to control dc current.

The overvoltage, due to load rejection, can be controlled more reliably in the back-to-back schemes than in geographically separated stations, because, the ac filters connected to both ac networks can immediately be tripped.

In summary, it can be stated that most of the control functions are easier to realize for a back-to-back scheme than for point-to-point transmission. This can result in better performance if the basic conditions are equal in all other aspects.

4.14 Control and Protection Considerations for Multiterminal Schemes

It was demonstrated in 1963 [B19] that the conventional current margin control principle can be applied to systems with more than two terminals connected in parallel. The main difference between the control systems for two terminal and multiterminal schemes is mainly found at the master control level. Control principles for multiterminal applications with other control characteristics have also been proposed.

The load flow in a multiterminal system is not as simple as in the two terminal system and consequently a number of control functions must be included in the master control, either for automatic action or for assistance to the operator. Examples of additional tasks in the master control of a multiterminal system are:

- Balancing of the power orders for the different convertor stations.
- Coordination of power order ramping.
- Balancing and distribution of current orders to the convertor stations.
- Coordination of power modulation.
- Controlling the direct voltage at one of the stations.
- Determining temporary load flow for fast recovery after contingencies.
- Assisting the operator in determining the load flow and dc system configuration after a loss of components.

Specific requirements of individual schemes may call for other control functions to be implemented.

The protection features which relate to the individual main circuit components are basically the same for multiterminal and for two terminal systems. Care must be taken for protection which involves actions which affects the whole system. An example of this is the dc line protection which must be designed to operate satisfactorily even when no telecommunication is available.

In some cases, especially for meshed dc network schemes, it may be necessary to include in the protection system a function which, by current change measurement in the dc system nodes, can identify a faulty dc line section for fast disconnection. As mentioned, this is of special interest for meshed network schemes because in this case the power can reach all stations even if a line section is lost and fast automatic line section tripping can be applied by using dc breakers.

The discussion above refers mainly to multiterminal systems with convertors connected in parallel to the dc line. In the special case when tapping stations have very low rating compared to the main transmission, probably less than 5 percent of the main transmission rating, it may be useful to connect them in series with the main station. In this case the direct current is the same through all convertors and the tapped power must be controlled by a basic voltage control system which controls the voltage across the convertor bridge. The amount of power which can be taken from such a tapping convertor is dependent on the current in the transmission and is low when the current is low.

4.15 Higher Level Controller Characteristics for DC Schemes in Operation

In this section some examples of structures of regulators for higher level control functions are presented. Most dc transmission systems are provided with such control functions used for ac system stabilization by modulation of the transmitted active power or the reactive power consumed by the convertor or for steady state or transient control of ac system frequency by varying the transmitted power.

4.15.1 The CU Project

In the CU dc system, a bipolar transmission with a rating of 2 x 500 MW, power is transmitted from a coal fired turbine generator station in Coal Creek, North Dakota to Dickinson close to Minneapolis, Minnesota. The two convertor stations are interconnected by a meshed ac network.

The dc link is used to stabilize the ac network and the modulation power order is derived from frequency deviation measured at both rectifier and inverter commutation buses:

The modulating power order is

$$\Delta P_m = \Delta P_{mR} - \Delta P_{mI} = H_R(s) \cdot \Delta f_R - H_I(s) \cdot \Delta f_I \tag{4.7}$$

where subscript R and I refer to rectifier and inverter respectively. Here,

$$H_R(s) = \frac{5000s}{(1 + 1.59\ s)\ (1 + 0.159\ s)} \tag{4.8}$$

$$H_I(s) = \frac{9000s}{(1 + 0.531\ s)\ (1 + 0.531\ s)} \tag{4.9}$$

ΔP_{mI} value is sent by telecommunication from the inverter to the rectifier.

The power modulation control for the CU project was originally based on the frequency in the sending end network but it was later found that consideration must be taken also of the receiving network frequency.

4.15.2 Itaipu

The Itaipu dc transmission project consists of two bipoles with two 12-pulse convertors connected in series in each pole and with a pole voltage of 600 kV. It transmits 6300 MW from nine 700 MW, 50 Hz generators in the Itaipu hydroelectric plant to the 60 Hz Brazilian ac network with the inverters located in the Sao Paulo area. Paraguay 50Hz network presents a small local load at the Itaipu end of the transmission.

The Itaipu project is provided with three types of modulating controls. A control for reactive modulation of the inverter acts on the γ reference. It has a transfer function from ac network voltage to γ modulation equal to:

$$H(s) = \frac{49.3\ s^2}{(1+0.482s)(1+0.318s)(1+0.08s)(1+0.053s)} \quad \text{degree/pu voltage} \qquad (4.10)$$

This controller is not always in operation because it is not always needed. In fact it was found in practice that the network did not need voltage stabilization and the γ modulation regulator has been disconnected.

The active power is modulated by frequency controllers for both sending and receiving ac networks.

The dc bipoles are the only loads of importance for the 50 Hz Itaipu generators and the transmission links must assist in controlling their frequency.

For the receiving 60 Hz system the dc transmission is provided with a power/frequency control function with adjustable gain (similar to droop setting in a generator station). For a significant control action from the sending end 50Hz controller, the 60Hz regulator is put in hold position.

The structures of these controllers are presented in Figure 4.21. The block diagram refers to one bipole (1 pu = 3150 MW).

4.15.3 The Intermountain Power Project (IPP)

The IPP dc system transmits power from a generating station in Utah to the Los Angeles area in the United States. The dc link which is rated 800 MW per pole (500kV and 1600 A) can be in a radial configuration with the generators but also an ac load in the form of outgoing lines can be connected. Thus, a frequency control function is used at the sending end side.

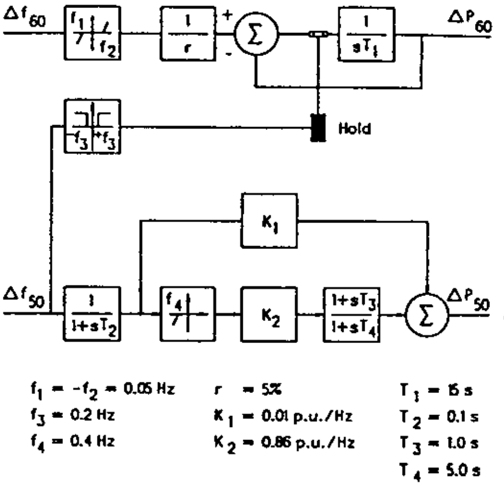


Figure 4.21
Itaipu Frequency Controllers for
50Hz and 60Hz Networks

The frequency controller configuration is different for radial operation and operation with an ac system connected. Figure 4.22a is the one used in radial operation with an integral part included. As indicated the integral part is located on the bipole hierarchical control level with a proportional part in each pole.

When the ac network is connected a proportional controller with dead-band according to Figure 4.22b per pole is used.

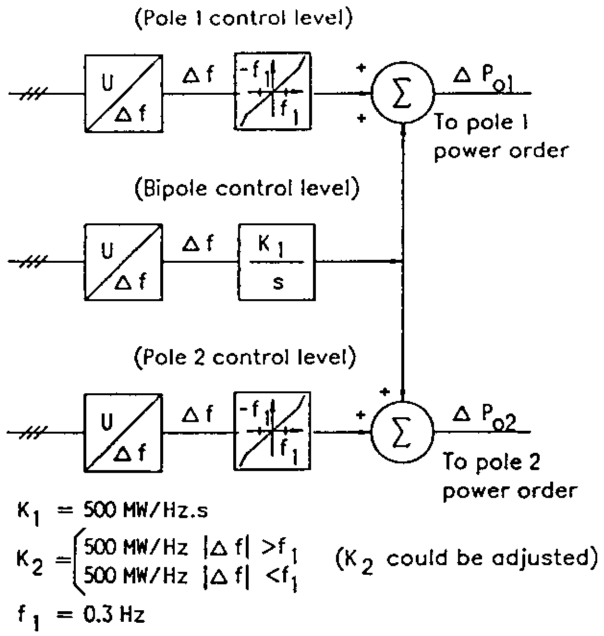
4.15.4 The Gotland Transmission

The Gotland transmission system was extended during 1987 to a bipolar transmission with a total rated capacity of 260MW feeding the island of Gotland. The maximum service power at present is limited to 165 MW. The island normally has no power generation of its own but synchronous compensators with a total capacity of 196 MVA are connected close to the convertor. The H factors for those compensators are 1.7 (70 MVA), 2.5 (77 MVA), 1.7 (30 MVA) and 0.8 (19 MVA) which according to Section 2.3 gives H_{dc} = 2.3 (see Chapters 2 and 9).

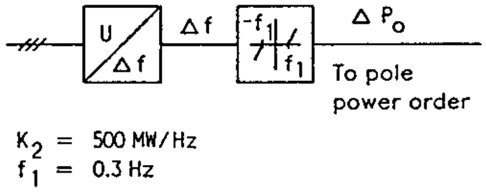
A frequency controller of PID type is included in the dc control system. It has the following transfer function:

$$G(s) = \frac{\Delta P}{\Delta f} = K_1 + \frac{K_2}{s} + K_3 s \qquad (4.11)$$

K_1 = 30 MW/Hz
K_2 = 27 MW/(Hz . s)
K_3 = 20 (MW . s)/Hz



a. Sending end generators in radial connection



b. A.C. Network connected

Figure 4.22a and b
IPP Frequency Controllers for
Sending End AC Network

At the start of the transmission with the deenergized ac network a diesel engine accelerates the 30 MVA synchronous compensator, disconnected from the ac network and from the other compensators, up to 30 Hz. Then the dc link is deblocked and takes over and increases the speed to 50Hz. During this interval only the proportional part of the frequency regulator is in operation. However, the transmitted power is limited to around 3 MW during acceleration and the link acts as a constant power source until the frequency is close to 50 Hz. The other compensators are electrically started after that 50 Hz has been reached and some load has been connected.

4.15.5 Other Projects

In Bibliography entry B24. the control system for the following North American projects are presented:

- David A Hamil DC Tie (the Stegal back-to-back tie)
- Pacific DC Intertie
- Square Butte DC System
- Nelson River Bipoles 1 and 2
- Vancouver Island DC System
- Eel River Back-to-Back DC System
- CU DC System (original version)

The Cabora Bassa dc transmission between Mozambique and South Africa is discussed in Bibliography entry B25.

4.16 Protection

There are only a few protection aspects of interest with reference to ac/dc interaction. For instance, for the setting of parameters such as delay times, operation times and detection levels for the dc protection, there is often a need for coordination with the ac side protection. For the case of the detection (delay) time for a persistent commutation failure, the convertor tripping must be set with consideration of the settings of the ac side line protection. A serious ac system fault must not be interpreted as a permanent valve fault which produces commutation failures. Thus the delay time to convertor blocking from such a protection must be longer than the time during which a fault in the ac system can exist until the faulty part is disconnected by ac protection. The same applies to a possible simple dc side undervoltage protection which is designed as a back-up for the dc line protection to detect a ground fault on the dc side. The delay time to blocking from this type of protection must also overlap the delay time of ac line protection, as the serious faults in the ac system also cause low voltage on the dc side of the dc convertor.

In a few cases, the ac network impedance has some importance for the functioning of the dc protection. One such case is the commutation failure protection and its need to make a fast detection of a faulty valve. A permanent valve fault is a very rare event and can, from the practical point of view, affect only one six-pulse bridge at a time. If the ac network to which the convertor is connected has a high SCR, disturbances generated by the faulty bridge will not cause a commutation failure in other bridges. A fast identification of the faulty bridge by the commutation failure protection is possible. On the other hand, if the ac network has a low SCR, the original valve fault may cause commutation failures in the other bridges. Accordingly the commutation failure protection delay time must be long enough to let the ac side protection disconnect a supposedly faulty ac branch, a permanent valve fault cannot be identified until this possible fault in the ac network has been disconnected.

Another aspect to consider here is the influence of the dc transmission on ac line protection close to the dc convertor station. This protection is designed to measure sinusoidal voltage waveforms and can be disturbed by a high content of harmonics. As long as the ac network has a high SCR the amount of harmonics in the voltage waveform is normally not critical for the ac line protection.

However, when the network impedance is high the harmonic current generated by the convertor at unsymmetrical ac system faults will disturb the ac voltage considerably. This may cause incorrect operation of the ac line protection. The short circuit level and fault current distribution of the ac network, possible harmonic resonance etc., are important factors in this case. The choice of the type of protection to be used should be considered and sometimes additional filtering of the input signals should be applied.

5. RESONANCES, INSTABILITIES, AND HARMONIC TRANSFER

5.1 Introduction
5.2 Basic Concepts
5.3 Harmonic Resonance-Related Instabilities and Solutions
5.4 Factors Influencing Harmonic Problems
5.5 Trends and Sensitivities of System Parameters
5.6 Methods of Study
5.7 Different Types of Schemes and Harmonic Problems
5.8 Comments

5.1 Introduction

All practical electrical circuits and networks have natural frequencies of oscillation or resonances, and dc schemes are no exception. It is also true that in active circuits involving control systems, these resonances may contribute to potential instabilities in any system.

Another feature of many electrical devices, for example, synchronous machines, is that a certain frequency appearing at the terminals of a device will be transferred through the device and may appear as side-bands or transferred harmonics in some other part of the system. In machines, this feature contributes to subsynchronous torsional interactions. This feature of harmonic transfer also occurs on dc schemes, with the convertors acting as modulators. Frequencies which are present on the ac side of a convertor will be transferred through as side-bands to the dc side and vice-versa.

It is clear, therefore, that what might appear to be separate phenomena of resonance, instability and harmonic transfer are in fact interdependent and have thus been included under this one section heading.

5.2 Basic Concepts

In an examination of resonances and related problems there are several basic concepts which must be defined and explained. This is particularly so when control loops are involved in the phenomena. A brief explanation of these concepts is, therefore, given here. A more detailed understanding will be found in Bibliography entries B32-B40.

5.2.1 Loop Instability

This type of instability is the classical type of instability which is described in standard control texts. This will in general "grow from nothing" and can occur at any frequency either integer or non-integer both on the ac and dc sides (non-integer will of course be more common). This can happen even in a perfectly balanced system with no extraneous injection.

In dc schemes which are connected to ac power supplies of a fixed frequency it is useful to consider instabilities at frequencies both higher and lower than the ac system fundamental frequency, the so-called subsynchronous and super-synchronous frequencies.

At sub-synchronous frequencies typically in the range from 5 Hz to 40 Hz one may encounter a conventional control instability which can be cured by suitable choice of control loop gain and other parameters. The behaviour in this frequency region also influences mutual effects, including possible instabilities, with shaft torsional resonances in nearby machines.

An instability which occurs at a super-synchronous frequency has been loosely described as a "harmonic instability". In general, it starts from a non-integer frequency, nearly always close to a resonance; however, it can lock into the nearest harmonic frequency as instability amplitude grows. This has been generally cured by use of the phase-locked oscillator (equidistant firing) type of control system. [B11, B12]

5.2.2 Harmonic Magnification

It can be shown that, viewed from the ac terminals, a dc convertor appears substantially as a source of harmonic current. This is true for both characteristic harmonics; i.e., those of order $n = kp \pm 1$ where k is an integer and p the pulse number, and also for non-characteristic harmonics. The effective impedance in which this current flows is that of the complete system comprising the ac system, capacitors, cables, filters, machines, loads, reactive compensators, etc. Because the system is current-fed, the worst case will be when the impedance is a maximum. This will be characterized by a maximum in the impedance versus frequency curve.

For ac systems with SCR lower than 3, the principal (i.e., lowest) resonance frequency approaches the 2nd harmonic. For SCR=2 the resonance may even be below the second harmonic.

The exact resonant frequency will of course be a function predominately of the ac system Thevenin equivalent impedance (inductive) and the ac filters which are capacitive at all frequencies below their lowest resonant frequency.

It should be noted that not only the magnitude but also the phase angle of the impedance will be significant at any given frequency.

All long distance dc transmission schemes have dc lines or cables which, with dc reactors, exhibit various resonances. Because a convertor can be considered (approximately) as a voltage source at its dc terminals, it is the minimum impedance on the impedance versus frequency curve for the dc system which is significant, as this will lead to a high harmonic current. Again, any calculations must consider both characteristic and non-characteristic harmonics; in this case, the characteristic voltage harmonics are of order $n = pk$. The impedance phase angle should again be considered in any calculations at a given frequency. The existence of the "remote" dc station will have little effect at 12th harmonic and upwards for a long line or cable scheme, but for lower frequencies; e.g., fundamental or 2nd harmonic it can have a strong effect. The concept of "resonance" for the dc system in isolation is then not valid, and studies must always include both dc stations.

In addition to the generation of characteristic harmonics convertors may, under some circumstances, generate all other harmonics. Amongst the reasons for this are the following:

- unbalanced firing pulses due to control system errors,
- unbalanced impedances, e.g., ac system, filters, transformers and untransposed lines,
- harmonics from other sources both on the ac and the dc sides, such as other convertors, machines, static compensators and loads,
- saturation of convertor transformers or other nearby transformers.

Since harmonic resonances can exist on either side of the convertor, it follows that each of the prime sources as above may be subject to magnification on either the ac or dc side of the convertor.

The distinction from instability is that effect is here proportional to the cause, and if the cause (e.g., an extraneous emf in an ac system) vanishes, then so does the effect.

5.2.3 Harmonic Transfer Through Convertors

A dc convertor acts as a modulator to harmonics. If a harmonic exists on the ac side of a convertor it will transfer this harmonic through the convertor, giving side-band harmonics on the dc side. For example, a second harmonic voltage on the ac side will give fundamental and third harmonic currents on the dc side. Similarly, a dc side harmonic will transfer through to the ac side as side-bands. As an example, fundamental frequency on the dc side will give dc and a second harmonic on the ac side (valve windings). This modulation is also true for non-integer harmonics in both directions.

It follows, therefore, that the ac and dc systems are effectively coupled at both integer and non-integer frequencies; this coupling must be accounted for in all calculations. The substantial coupling which can occur through the dc system, as in back-to-back schemes, or in long line schemes at low frequencies (below 3rd harmonic), effectively extends all the way from one ac system to the other, via the dc link.

5.3 Harmonic Resonance-Related Instabilities and Solutions

In the introduction it was suggested that any problem associated with resonances and instabilities might be influenced by several factors. These can include ac or dc side resonances, harmonic amplification, transfer of harmonics through convertors, the generation of harmonics by other plant and non-theoretical harmonic generation. In addition, any problems encountered may also be affected by such parameters as control loop transfer functions and the saturation of convertor transformers or other local transformers. It is therefore often difficult to define exactly which parameters are dominating the effects seen in practice; this makes groupings and classifications difficult.

The following groupings are made with this in mind. The changes which were made to controls and plant to alleviate these problems are also described.

5.3.1 Core Saturation Instability

Chronologically the first harmonic instability to be described which was not a simple loop instability was the so called "core saturation instability". This particular problem involved the mild saturation of the convertor transformers by a small amount of direct current on their secondary sides [B13]. Problems have since been experienced on other schemes which have also involved the saturation of the convertor transformer. The mechanism of the instability is different in each case but they are grouped together here because of the common element of core saturation. To date this type of problem has been experienced on four systems; namely, the Kingsnorth, Nelson River, New England, and Chateauguay schemes. A more detailed explanation of each problem is given below with the attempted solutions. Another feature of this type of instability is that there may be "complementary resonances" on the ac and dc side of the convertors. In some schemes this has proved to be the major driving force. These schemes have, therefore, been grouped together under the next grouping of complementary resonances also.

If a dc system is resonant at an integer harmonic frequency then it may possibly be susceptible to core saturation instability. The system does not in fact have to be exactly on resonance at an integer harmonic. Depending upon the Q factor of the system a "near resonance" will also give the type of problems discussed here. In this type of phenomena, which can occur with a single sided resonance or with complementary resonances (the latter being potentially more vulnerable), the source of the harmonic excitation is a saturated convertor transformer which supplies all integer harmonics to the system.

There are two ways in which this type of instability can be excited. The first, which is a true instability in that it will start from an infinitesimally small excitation, occurs when a dc scheme which has a second harmonic ac resonance is excited by a 2nd harmonic of very small amplitude. One of the possible results of such a magnification, as described previously, is that fundamental ac will exist on the dc side of the convertor. This fundamental on the dc side will in turn produce dc and second harmonic on the valve winding side of the convertor transformer. The dc component will saturate the transformer, producing among other frequencies the second harmonic which will further contribute to magnification and thus force the system into instability. The original small excitation then becomes irrelevant and the instability is now driven by the new source of excitation, namely the saturated transformer. This type of instability is characterized by a slow build-up of harmonics taking perhaps seconds or even minutes. The slow build-up is a function of the manner in which dc builds up in the transformer secondary winding and the ac system. Examples of this type of instability have been reported on at least four schemes to date.

The second type of core saturation instability is similar but cannot start spontaneously; i.e., it is stable in the steady state until the transformers are suddenly excited by a transient. The system will then jump relatively suddenly to the steady unstable mode. This requires a large transient in the ac system such that the convertor transformers can become saturated. Three examples of this type of excitation are (1) energization of the convertor transformer producing inrush current, (2) blocking of part of a multipolar scheme producing an overvoltage and hence transformer saturation and (3) commutation failure producing transformer saturation. When the transformer is saturated in this way there is always the danger of harmonic resonances causing harmonic amplification of temporary overvoltages (this is discussed in section 4). A second consequence might be the induction of core saturation instability as described. The saturated transformer can excite resonances with the ac and dc systems leading to a build-up of harmonics on both sides of the convertors. This type of instability has been reported on at least two schemes.

In principle core saturation instability can be cured by a suitable choice of control system and its associated frequency response. However, this can lead to control parameters which are unsuitable at other frequencies, e.g., subsynchronous. Hence, for minimizing core saturation instability while avoiding subsynchronous difficulties an auxiliary loop can be placed in parallel with the main control.

Two versions of auxiliary control have been used. The first was used in the Kingsnorth and Nelson River schemes. These schemes both exhibited fundamental frequency resonance on the dc side. In these schemes 2nd harmonic components of primary magnetizing current are measured, demodulated to dc, passed via control integrators and then remodulated to ac by multiplying variable fundamental frequency waveforms (from valve winding currents) to inject back into the main control. The second method was used in the 2 x 500 MW back to back link between Hydro-Quebec and New York Power Authority system at Chateauguay which has a second harmonic resonance on the New York ac side. The solution adopted was to process the measured fundamental component on the dc side to obtain a modulation signal which when applied to the rectifier controls counteracted the dc fundamental component. This sufficiently reduced the dc component in the inverter transformer secondaries to eliminate second harmonic build up in the inverter ac system. The inverter control was left running on equidistance pulse spacing.

5.3.2 Complementary Resonances

If a resonance exists or the impedance is high on the ac side at, say, the second harmonic and at the same time a resonance (or low impedance) exists on the dc side at fundamental frequency there is the possibility that this could lead to a harmonic problem.

Suppose that a small amount of 2nd harmonic exists on the ac side. This will transfer through as fundamental and the 3rd harmonic on the dc side. The fundamental dc side voltage feeds the low dc side impedance, giving a current on the dc side including a fundamental frequency component. This fundamental component will, in turn, cause a second harmonic and a dc component to be generated on the ac side. This now sees a high impedance because of the ac side resonance, giving a higher component of second harmonic on the ac side. This will add to the second harmonic which was already there - this is the classical feature for a harmonic build-up. In a more general form, if the dc resonance is low impedance near a frequency f and an ac system high impedance resonance is near ($\pm f \pm f_o$) where f_o is ac system frequency, then the resonances are complimentary. This type of build up has been reported on at least three schemes.

To date, two schemes have been reported as having experienced complementary resonances which were of an integer nature.

One case of non-integer complementary resonance has been reported from the Nelson River scheme where the ac system natural frequency was 153 Hz. Following deblocking a sustained 93 Hz oscillation was measured on the dc side. This was studied and found to be associated with a ground mode resonance on the dc side of 93 Hz. This was solved by a simple control which introduced damping at the appropriate frequency.

5.3.3 Harmonic Coupling Between AC Systems Joined by DC Links

DC schemes are in general asynchronous ties, either joining systems of the same nominal frequency or systems of different frequencies (the exception being systems with parallel ac line). The dc interconnection is either a long overhead line, or a dc cable, or of zero length (a back-to-back scheme). On the dc side of the convertor a range of harmonic voltages are generated in addition to the desired dc voltage; the principal components are generated in addition to the desired dc voltage; the principle components are of order 12K where k = 1, 2, 3... for a normal 12 pulse dc scheme. These voltages will cause currents of a low amplitude to flow on the dc side and hence to the convertor at the other end. This convertor will transfer the harmonics through as side-band frequencies. These side-band frequencies are non-integer if the two systems are asynchronous. The resulting currents thus injected into the ac systems are of very low value and will in the majority of cases be insignificant and virtually undetectable.

In order to give guidance on the problem, typical figures have been extracted from Bibliography entry B32. Let the two system frequencies be f_1 and f_2. Then, assuming 12-pulse convertors, the frequencies of cross-modulation torques in each system are at frequencies of $12k\ (f_1 - f_2)$ where k = 1, 2, 3,...

Consider a typical example. If a dc link connects two systems which are at the same nominal frequency and if the system frequencies differ by up to 0.75 Hz then torsional oscillations will be generated on the shaft of both connected ac systems at frequencies of 9, 18, 27 Hz, etc. These are in the frequency range where turbo alternator shafts could be put at risk.

Back-to-back schemes are probably most at risk from this problem because of the close intercoupling of the terminals. With long dc transmission lines and cable systems the cross-modulation should be reduced by the line capacitances and inductances.

The two exceptions to this conclusion are where there are resonances with a high Q factor in the ac system. These could take two forms, either electrical or mechanical. If an electrical resonance exists at one of the corresponding real frequencies a harmonic magnification will take place. The Q-factor of an electrical resonance is unlikely to be very high, hence this effect will not usually be important.

The second form of resonance, a mechanical resonance, may be more significant. Such a resonance with a very high Q factor exists in alternators in thermal sets and to a lesser extent in hydro-generators. This is the torsional shaft resonance caused by the large masses on a turbo-alternator shaft and the extremely low associated damping.

A modulation frequency generated by dc cross-modulation could coincide with one of the shaft torsional natural frequencies when transferred through the electrical generator, (again as modulation side-bands). Then a build-up of torsional oscillations could occur in the turbo-alternator shaft, perhaps leading to shaft fatigue problems and damage. This phenomena is similar to the torsional oscillation described in Section 6. The mechanism of build-up is, however, different. To date, no reports have been received of cross-modulation causing shaft damage. The implications of such a problem, however, are large, and it is recommended that turbo-alternators which may be at risk should be monitored.

In considering this problem it should be emphasized that the amplitudes of injection harmonics are very low. However, it has been reported [B33] that an excitation of only 350 kW at a low frequency caused a 720 MW alternator to be put at risk in one scheme involving a slip energy recovery system in a power station. A slip energy recovery system under these conditions is electrically identical to an asynchronous dc scheme.

It has been suggested [B32, B34] that a level of 0.1 percent of cross modulated injection might be possible, which is about twice that of the example above.

5.3.4 Harmonics and Static Var Compensators

Static var compensators (SVCs) both of the saturated reactor (SR) type and the thyristor controlled reactor (TCR) type can be considered as sources of harmonics on an ac system.

All of the previous arguments about the excitation of harmonic resonances and the production of non-characteristic harmonics under unbalanced systems will apply. Any harmonic studies which are carried out on a simulator or computer program should include the effect of SVCs.

On the Chateauguay scheme when the problem on the dc system had been controlled by modulating the rectifier it was found that operating restrictions could not be removed completely because a similar problem occurred with the controls of the static var compensator located on the same inverter bus.

The manufacturer of the SVC will also be implementing a control solution to the problem.

In the meantime, Hydro-Quebec wanted to increase its export capacity to the full capacity of the single 765-kV line to New York. Load-flow studies of the New York system indicated that in order to achieve this, an additional 270 Mvar of reactive power compensation would be required at Chateauguay. It was decided to install this in the form of two 135 Mvar damped second harmonic filters.

Although not strictly required to resolve the control problems, these filters were seen to have the advantage of essentially eliminating second harmonic transient overvoltages and therefore reducing arrester stresses. At the same time, these second harmonic filters will permit the existing operating restrictions to be removed for the critical winter peak load periods. When the SVC control solution is implemented, tested and accepted it is expected that there would be no need for the existing operating restrictions even without the second harmonic filters.

5.3.5 Parallel AC/DC Transmission Lines

If a dc line runs in parallel with an ac line in the same right-of-way or if an existing ac line is converted to dc, then fundamental voltage will be induced on the dc side.

It might be thought that control action could also be used to eliminate the problem. This is not necessarily the case. The fundamental frequency emf induced on the dc line will cause a fundamental frequency component in the dc line, if control actions are disregarded. This will produce transferred harmonics on the ac side which will include dc and 2nd harmonic. This dc component will saturate the convertor transformer and reinforce the already generated 2nd harmonic. To complete the steady-state higher harmonics, the sidebands of the theoretical harmonics will also be present.

It is possible, by control means, to reduce or eliminate the fundamental frequency component on the dc side by modulating the convertor firing angle using the type of feedback circuits used on Chateauguay to cure core saturation instability.

However, in practice this is not an ideal solution because the modulation of α in a fundamental frequency pattern gives both dc saturation of the convertor transformers and high amounts of harmonics on the ac side. Thus, nothing is gained by using controls in this particular case and measures such as the provision of filters on the main circuit must be taken.

5.4 Factors Influencing Harmonic Problems

The factors which will affect the harmonic magnification and harmonic instabilities described previously include the following:

- high impedance resonances on the ac side
- low impedance resonances on the dc side
- complementary resonances
- ac system voltage unbalance (negative sequence)
- ac system impedance unbalance
- extraneous frequencies from the ac system
- extraneous frequencies from the dc system (normally originating in the remote ac system)
- coupling from an ac line to a dc line
- convertor control system unbalance errors
- transformer saturation
- control feedback

5.5 Trends and Sensitivities of System Parameters

The parameters which will have the biggest influence on harmonic resonances on the ac side are the strength (impedance) of the ac system, its impedance angle, and the size of the harmonic filter. On the dc side, the size of the dc reactor, the presence of dc filters and the inductance and capacitance of the line will dominate.

As a guide, the lowest parallel resonance frequency on the ac side can be found approximately from:

$$f_{(res)} = f_1\sqrt{S/Q_c} \qquad (5.1)$$

where

f_1 = fundamental frequency
S = short circuit capacity of the ac system in MVA
Q_c = size of the filter and shunt capacitor bank in Mvar

provided the resulting value of $f_{(res)}$ is well below the lowest tuned filter frequency.

In a typical dc scheme Q_c is normally dimensioned to compensate fully for convertor var consumption Q_d. Q_d has normally a value between 0.5 and 0.6 of dc power, P_d. For $Q_c=Q_d=0.5P_d$, the above equation can be expressed in terms of SCR as follows:

$$f_{(res)}=f_1\sqrt{S/0.5Pd}=f_1\sqrt{2\cdot SCR} \qquad (5.2)$$

For the conditions assume the resonant frequency will be equal to the second harmonic for SCR=2.

Once the system impedances have been decided, the trends and sensitivities will be dominated by the controller as described previously.

5.6 Methods of Study

There are at present basically three methods of carrying out the type of study needed to solve the problems described.

The first is using the HVDC simulators (physical models). These are suitable for the study of large amplitude disturbances.

Time domain studies by computer which form the second group come in three forms, namely, the specially designed package, the general power systems package such as

EMTP or EMTDC or the now widely available proprietary software like SPICE or SILVER LISCO.

The third method of analysis is using frequency domain methods.

The type of study carried out will vary depending partly on the problem to be solved and partly on the availability of study tools.

5.7 Different Types of Schemes and Harmonic Problems

For types of schemes other than point-to-point transmissions the underlying mechanisms and physics are the same. In the following sections only those aspects that are specific or of special importance for the other types of schemes are discussed.

5.7.1 Back-to-Back Schemes

These have a relatively restricted dc system, usually comprising only a dc reactor. The effective dc system loop impedance is that of the dc reactor plus summed commutation reactances plus transferred ac system impedance effects. In some cases no dc reactor is used; the remaining effects ensure that effective loop impedance is still substantial.

At subsynchronous frequencies the effective dc loop impedance is low, which is a substantial advantage for stability at such frequencies. For avoidance of core saturation instability, the absence of fundamental frequency resonance on the dc side is an advantage, though back-to-back schemes have still exhibited core-saturation instability due to near-2nd-harmonic resonance on the ac side. At low-order harmonics the usual harmonic effects are generally not much different from long-line schemes. However, there is a substantially greater harmonic transfer effect from one ac system to the other, so that, for example, a negative-sequence fundamental component in one ac system goes through a double transformation to contribute small amount of negative sequence fundamental and 3rd harmonic to the other ac system.

5.7.2 Multi-Infeed Schemes

For multi-infeed schemes the harmonic interaction not only takes place through the convertors, but also through the ac network. The complexity of the situation is thus enhanced. In order to analyze the risks for adverse interaction all dc schemes that are electrically close must be considered. It is possible that the performance when each scheme alone is in operation is acceptable; however, operation with two or more dc systems gives unacceptable performance if no corrective measures, in the control or by equipment, are taken.

5.7.3 Multi-Terminal Schemes

The considerations concerning harmonic resonances for multi-terminal schemes are basically the same as for point-to-point transmission and multi-infeed schemes if ac coupling exists between the terminals. But, due to the complexity of the dc side system in multi-terminal schemes there may be more harmonic resonances on the dc side. A careful design of dc filters is necessary also with regard to the choice of their location and the smoothing reactor values so as to meet filter performance requirements.

It is also obvious that a number of operating configurations exist, and a careful analysis of all these are necessary.

5.7.4 Low and Zero Inertia Systems

For a dc infeed into a low or zero inertia ac system a synchronous compensator is used on the inverter side. Besides providing the necessary commutation voltage or enhancement of the existing ac system strength the synchronous compensator partly compensates for the reactive power consumed by the dc convertor. This is generally similar to more conventional schemes, except that the ac system impedance viewed from the convertor is dominated by the synchronous compensator(s).

5.8 Comments

In several of the schemes built to date there have been harmonic problems at some stage of the development. In most cases these problems have been overcome by additions to the controllers. The additional control circuits are relatively inexpensive, especially if considered early in the design stage of a project. Thus, careful consideration should be given to the possible need of such circuits.

6. SUBSYNCHRONOUS TORSIONAL INTERACTIONS BETWEEN DC CONVERTORS AND NEARBY TURBINE-GENERATORS

6.1 Introduction

The potential for subsynchronous torsional interactions between a dc transmission system and nearby turbine-generators was first experienced during field tests at the Square Butte DC System in North Dakota. This dc system employs a supplementary Frequency Sensitive Power Controller (FSPC) to damp out low frequency electromechanical oscillations between the sending end and the receiving end systems. Prior to the test, it was suspected that the FSPC had enough residual gain to stimulate torsional oscillations in one of the generators at the sending end.

The test confirmed that the FSPC did interact and destabilize the first torsional mode of one of the units (11.5 Hz). To the surprise of everyone, however, it was also found that the dc current control acting without the FSPC was enough to destabilize the first torsional mode upon loss of one of the ac transmission lines. Thus, it was observed that dc control systems can interact with a turbine-generator rotor and exert a destabilizing influence on a torsional mode of oscillation, even in the normal mode of control without supplementary damping signals.

Field modifications were initially made which allowed stable operation under limited conditions. These were immediately followed by an analysis of the interaction which led to control system modifications that allowed stable operation under all but extreme system contingencies.

Following this development, the Electric Power Research Institute initiated a research project (RP1425-1) to investigate this phenomenon and to develop generic solutions. In the project, it was found that negative damping to turbine-generator torsional modes of oscillation is inherent to the objective of controlling current in a dc transmission system. Some degree of negative damping will exist within the bandwidth of this current control and torsional vibrations at frequencies higher than the bandwidth of the current control will experience positive damping. This was the case with the CU dc system in North Dakota which was extensively tested in the summer of 1979. The CU dc system is located adjacent to a power plant, for which the turbine-generator units have a first torsional mode frequency of 19 Hz, considerably higher than the 11.5 Hz of the unit near Square Butte. Nineteen Hz was just beyond the range of negative damping caused by the current control.

The outcome of the EPRI research project has also shown that the interaction is sensitive to many system parameters, most significantly ac system strength, dc power, and the control mode of the dc system. Maximum interaction occurs with the weakest ac transmission system, especially in the limiting case of an isolated turbine-generator whose only load is a dc convertor. It has also been shown that special dc power modulation control for damping electromechanical modes of system oscillation can cause significant subsynchronous torsional interaction and may require appropriate control filtering to limit the interaction at critical torsional frequencies.

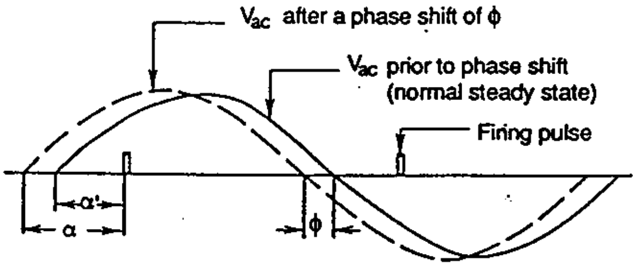
One method to mitigate the torsional interaction is by varying the frequency range and magnitude of the negative damping associated with the rectifier current control loop. This can be achieved, within a fairly limited range, by modifying the characteristics of the current control loop. Otherwise, a supplementary damping control device may be required to assure torsional stability of all units in the area.

The methodology for designing a supplementary Subsynchronous Damping Control (SSDC) was developed under the EPRI project, and its performance and robustness have been demonstrated by both digital computer programs and dc simulators. Such a controller would ensure net positive damping contributions to torsional modes of oscillations for all turbine-generators in the vicinity of the dc system. The project also developed practical guidelines in determining the need for an SSDC in dc systems.

In this section, the considerations involved in deciding whether to add subsynchronous damping control are discussed, along with considerations for turbine-generator protection against torsional vibrations. Inasmuch as the solution to the torsional interaction consists of a control modification, adopting such a solution has only a minor impact on overall system costs and should have no influence on decisions with respect to location and ratings of major equipments.

6.2 Description of the Phenomenon

Turbine-generator rotor motion causes variations in both magnitude and phase angle of the ac voltage supplying the convertor. The effect on convertor firing angle caused by an angular shift in the voltage waveform is illustrated in Figure 6.1. For the equidistant firing angle control, utilized in modern dc systems, a shift in voltage phase, ϕ, causes an equal shift in the apparent firing angle, α, away from the steady-state pre-shift firing angle, α'. The apparent change in firing angle, as well as variations in the voltage magnitude will result in changes in direct voltage and current, thereby dc power transfer. Meanwhile at the terminal, a closed loop control on direct current, direct voltage, or firing angle would respond to correct for these changes, thereby impacting the magnitude and phase of variations in dc power transfer. The ultimate effect of the change in dc power is a change in the generator electrical torque. If the accumulated phase lags between the change in the generator shaft speed and the ultimate resulting change in electrical torque on the generator rotor exceed 90°, the torsional oscillations may become unstable.



α = Actual firing angle following shift in V_{ac}
α' = Steady-state firing angle before shift in V_{ac}
α' = $\alpha' + \phi$

Figure 6.1
Effect of Alternating Voltage Phase Shift on
Firing Angle with Equidistant Firing Control

6.3 Principal Parameters

The ability of a dc system to impact torsional oscillations of a nearby generator unit is, of course, dependent upon the relative size of the dc system compared to the unit, as well as the electrical distance from the convertor to the unit. DC transmission from a remote, somewhat isolated power plant would likely interact with the generator torsional modes, while a dc interconnection of relatively large networks may not be prone to this condition.

Based on the results of the EPRI research project, the influence of dc control on torsional damping of a particular generator can be quantified by Unit Interaction Factor (UIF) as:

$$UIF_g = \frac{MW_{dc}}{MVA_g} \left[1 - \frac{SC_g}{SC_{tot}}\right]^2 \qquad (6.1)$$

where: UIFg = Unit Interaction Factor of the generator,
MW_{dc} = Rating of the DC system,
MVA_g = Rating of the generator,
SC_{tot} = Short Circuit Capacity at the DC commutating bus <u>including</u> the generator, and
SC_g = Short Circuit Capacity at the DC commutating bus <u>excluding</u> the generator.

For unit interaction factors less than about 0.1, there is very little interaction between the dc controls and the turbine-generator torsional oscillations. Hence, an SSDC would not be required to solve a potential destabilization problem, nor would an SSDC significantly enhance the torsional fatigue loss-of-life of the generator.

It is noteworthy that the subsynchronous torsional interaction phenomenon is particular to steam turbine-generators. Hydraulic turbine-generators do not experience the same kind of problem. It has also been found that only units near a rectifier terminal are vulnerable to torsional interactions. The units near an inverter terminal do not experience much destabilization. This is due to the fact that inverters react differently to phase angle variations than rectifiers do. In addition, it would be unlikely to have network situations with units weakly connected to the ac system at the inverter end of a dc transmission link. If there were turbine-generators near the inverter terminal, one would normally expect that there is sufficient load in the area to provide damping for subsynchronous oscillations.

It should also be noted that another possibility for adverse torsional oscillations in nearby units has been mentioned in the literature [B55]. This possibility has been surmised from a design consideration in the field of variable speed drive systems, in which care must be taken to avoid excitation of various oscillatory modes in associated mechanical systems by harmonics generated by the electrical conversion systems. In dc system applications, the transfer of harmonics from one end of the dc link to the other may possibly result in steady-state oscillations that could excite torsional modes of nearby turbine-generators. Such a phenomenon has not been observed to-date, nevertheless, its possibility is fully discussed in Section 5.3.3 of this guide.

6.4 Trends and Sensitivities of System Parameters

During the field tests at the Square Butte facility, it was found that the instability of the torsional mode of oscillation depended on the power level of the dc line and upon the number of ac transmission lines in service. Either reducing the dc power level or closing in another transmission line was found to eliminate the instability. This was confirmed by analytical results which matched measured test conditions. Figures 6.2 and 6.3 show families of curves where ac system strength and dc power level, respectively, are varied for the simple parallel ac/dc system of Figure 6.4.

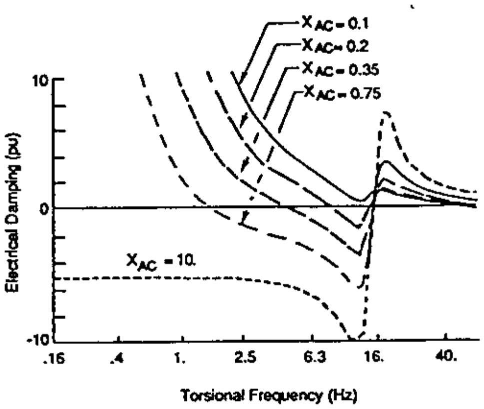


Figure 6.2
Plot of Electrical Damping versus Torsional Frequency for Several Levels of AC System Strength,
$X_{ac} \cdot P_{dc} = 1.0$ pu

The destabilizing effect of the dc system increases as the parallel ac system weakens, since as the ac system becomes weaker, the inherent positive damping of the ac system diminishes and the coupling between the dc line and the turbine-generator increases. Hence, the worst case in terms of torsional interaction with dc systems is the maximum dc power with the weakest conceivable ac system. As a point of reference, the turbine-generator located near the Square Butte terminal became torsionally unstable when the negative damping contribution exceeded 2 pu at the torsional frequency of 11.5 Hz. It can be seen from Figure 6.2 that for rated dc power transfer in a nearby radial configuration (X_{ac} = 10 pu), the negative damping contribution is in the neighbourhood of 10 pu at 11.5 Hz, thereby creating an unstable condition.

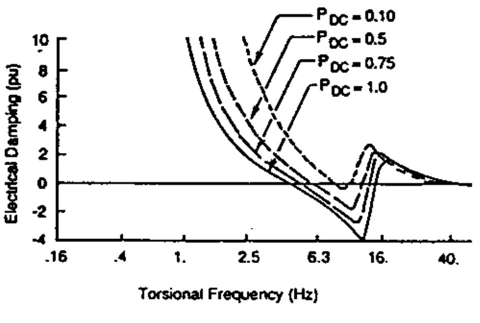


Figure 6.3
Plot of Electrical Damping versus Torsional Frequency for Several HVDC Power Levels,
$P_{dc} \cdot X_{ac} = 0.35$pu

Figure 6.4
Simplified System Representation for Sensitivity Studies
$X_{ac}/R = 7$

The nominal firing angle at which the rectifier operates also has a substantial influence on the damping effect of the convertor. Operation at relatively large nominal firing angles would tend to increase the destabilizing impact of the convertor. This is an important consideration for dc links that are required to operate at a reduced direct voltage where both the rectifier firing angle and the inverter extinction angle are increased above their nominal steady-state values. Such operating modes may thus drastically increase the negative damping effect of the convertors at torsional frequencies.

Other factors impacting the torsional interaction are the gain and time constant of the exciter and the power system stabilizer, if any, on nearby generators [B15]. It has been observed on the Cross-Channel Link that a very small time constant of generator speed measurement would result in a reduced electrical damping at critical torsional frequencies. Increasing the measurement time constant, to effectively reduce the speed loop gain at torsional frequencies, would solve the reduced electrical damping problem.

6.5 Influence of DC Controls

The interaction observed at the Square Butte project occurred through two different control paths: the Frequency Sensitive Power Control (FSPC), and the current control. In the case of the FSPC, the interaction was due to high gain and large phase lag in the lower range of the subsynchronous torsional frequency region [B47]. Only one of the units near the rectifier terminal had a torsional frequency low enough to interact with the FSPC. The first torsional mode frequency of the other unit was high enough so that a negative damping interaction did not occur. Thus, for this situation, notch filtering of the FSPC at 11.5 Hz was an effective and appropriate method of eliminating interaction through that control path. A double notch filter with frequencies staggered about the torsional frequency of 11.5 Hz was installed. Tests showed safe operation of the FSPC for all system conditions.

Solution of the torsional instability through the current control path was not quite as easy. In fact, analysis showed that negative electrical damping to turbine-generators near rectifier terminals was inherent to the objective of controlling dc current, resulting in a degree of negative electrical damping over some frequency range. The analysis also showed that torsional oscillations at frequencies higher than the bandwidth of the current control will experience positive damping. This was the case with the CU dc system for which the nearby turbine-generator units have a first torsional mode frequency of 19 Hz, considerably higher than the 11.5 Hz of the unit near the Square Butte dc tie.

Although it may not be possible to totally eliminate the negative electrical damping, it is possible to minimize the magnitude of the interaction at the frequencies at which the negative damping occurs. This approach was taken at Square Butte, for which analysis showed that the dc current regulator could be adjusted to maintain torsional stability for all anticipated system operating conditions without degrading the response of the dc system. The control system was modified accordingly, and subsequent field tests showed that the changes resulted in stable operation.

6.5.1 Subsynchronous Damping Control (SSDC)

The SSDC concept developed under EPRI RP1425-1 consists of a wide bandwidth controller sensitive to generator speed if available, or to the frequency of an ac signal synthesized from voltage and current measured at the dc convertor terminal. With such a design, the SSDC can be made to provide a positive damping contribution over the entire range of subsynchronous torsional frequency, as indicated in Figure 6.5. This figure represents the damping influence of an isolated turbine-generator whose only load is a dc convertor. For this particular system, negative damping exists up through 30 Hz without an SSDC, but with the SSDC the damping characteristic changed to positive damping for frequencies above 5 Hz.

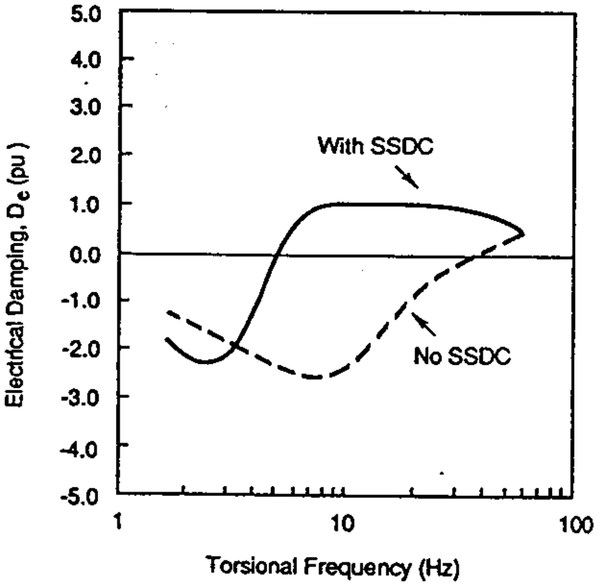


Figure 6.5
Impact of Practical SSDC on Electrical Damping

Such a control was tested on a dc simulator. The configuration consisted of a turbine-generator unit connected solely to a dc transmission system. The turbine-generator unit had two torsional modes at 13.5 and 22 Hz. Significant test results demonstrated that an SSDC can be built to provide positive damping to torsional vibrations over a wide frequency range. Very little modulation of the system is required.

Another method to damp torsional oscillations is to modulate the firing instant with a suitable phase and amplitude with regard to the generator oscillations. The input signal for this modulation can be derived either from the speed of the generator or from the bus frequency. In the case of using the generator speed as the input signal, the only required signal processing is to pass the signal through a bandpass filter to eliminate the low intermachine oscillation frequencies and the high frequency noise. Considerable positive damping contributions may be achieved in the subsynchronous torsional frequency range with such a damping method. However, in some applications, it may not be possible to use such a wide bandwidth damping controller. In these situations, it might be possible to focus on one torsional mode at a time by using bandpass filtering techniques. Bibliography entry B49 indicates that in case of the bus frequency as input, in order to overcome the inherent delay associated with the frequency measurement, the signal is passed through a narrow bandpass filter tuned to one torsional frequency. Therefore, positive damping may only be provided for that particular torsional frequency.

The first consideration in applying an SSDC is whether it is needed to solve a potential problem associated with dc destabilization or whether it can significantly reduce fatigue damage per event on adjacent turbine-generator units. The research results have indicated that units near an inverter terminal are not likely to suffer destabilization; indeed, for some combinations of torsional frequencies and dc control characteristics, the inverter control action actually improves the damping somewhat as compared to a pure ac transmission system. Thus, only units near a rectifier station need to be considered.

6.5.2 Impact on Planning for Systems with DC Transmission

Planning for the location and size of major transmission and generation facilities should not be influenced by concerns over the existence of the dc torsional interaction phenomenon. Major equipment items can be chosen and cited for optimum economics while considering advantages of dc power control in steady-state and transient stability characteristics of the transmission system. The only influence of torsional interaction control is a potential side benefit by reducing fatigue duty on the turbine-generator shaft. This is a contrast to the problems associated with series-compensated ac transmission systems, where the SSR interaction can limit the amount of power transfer through an ac line or require additional pieces of major equipment to allow higher levels of compensation. The torsional interaction with dc systems can be mitigated relatively simply by including appropriate controls with a negligible impact on the overall cost of the system.

After the major equipment has been chosen, studies should be initiated to determine the need for an SSDC. Preliminary screening studies involving Unit Interaction Factor (UIF) calculations should be conducted for all conceivable system contingencies. Results of this screening study are often sufficient to determine whether an SSDC should be included in the equipment specification. Since the interaction is dependent upon the exact characteristics of the controls, detailed studies should await vendor selection.

6.5.3 Turbine-Generator Protection

Protective relays are available to protect against turbine generator instabilities caused by the transmission network. For example, relays have been applied to each of the Coal Creek turbine generators, near the CU HVDC system, as a backup in case of control system failure which could cause torsional instability. These relays use generator speed as an input to detect torsional oscillations and trip the associated unit when oscillations become excessive.

It should be noted that SSDC is not a protection device. It is simply a control device which allows stable operation in situations where, because of torsional interactions, it was not possible to operate. Thus, it is prudent to provide protective torsional relays to any nearby unit which may adversely interact with the convertor.

6.6 Methods of Study

The combined ac/dc system can be visualized in a block diagram form shown in Figure 6.6. It is instructive to open the loop shown in the figure at the electrical torque feedback point and to calculate the transfer function from generator rotor speed, $\Delta \underline{w}_G$, to electrical torque, ΔT_e, which consists of effective damping and synchronizing coefficients as:

$$\frac{\Delta T_e}{\Delta w_G}(jw) = D_e(w) - j\,\frac{w_b}{w}\,K_e(w) \qquad (6.2)$$

where D_e = effective damping factor due to electrical system
K_e = effective synchronizing factor due to electrical system
$\underline{w}$ = frequency of oscillations
$\underline{w}_b$ = system base frequency.

The electrical system will be producing positive damping if the real part of the above transfer function, D_e, is positive. In other words, the electrical damping will be positive if, for a positive (or negative) change in the generator shaft speed, the resulting change in the generator electrical torque will also be positive (or negative), so that it will oppose the change in the shaft speed.

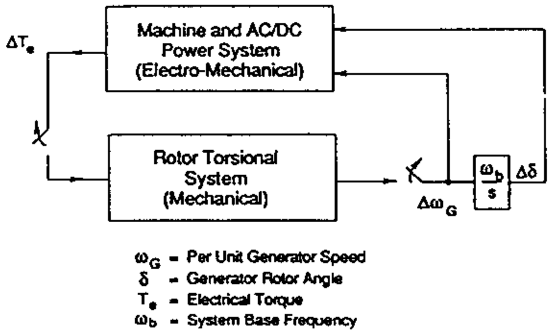


Figure 6.6
Conceptual System Diagram

It should be noted that without the electrical damping contribution, a torsional system has inherent positive damping due to steam flow, friction, windage, and losses due to shaft twisting, which can be lumped together and termed mechanical damping. A torsional mode will become unstable when the electrical damping contribution is negative and exceeds the mechanical damping contribution. Therefore, comparison of the D_e versus frequency curve, for a specific machine, with estimated values of mechanical damping is an indication of relative stability of torsional oscillation modes. An example is shown in Figure 6.7. Such a D_e versus frequency plotting approach is very informative when utilized in sensitivity studies, since it readily provides an indication of damping on other modes of oscillation which may exist in the system. Furthermore, the results can be related to modifications in the frequency response characteristics of the control systems.

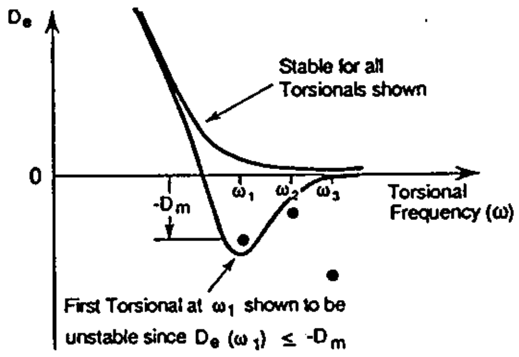


Figure 6.7
Curves of Electrical Damping, D_e, versus Torsional Frequency, ω, showing Stable and Unstable Modes of Oscillation

Another method for investigating the damping effect from the convertor on the nearby generators is to incorporate an electronic model of the turbine-generators in the dc simulator setup of the system. It would then be possible to modulate the shaft speed of the machine and measure the momentary amplitude and phase of the dc power, i.e., the electrical power on the rotor when the convertor is the only load for the generator (isolated operation). Comparison of the dc power with the momentary speed of the rotor would yield the complex transfer function from rotor motion to dc power. The real part of the transfer function, for each frequency, would then be a measure of the damping contribution from the convertor on a torsional oscillation at that frequency.

There is yet another method suggested in the literature for interaction analysts. This method is based on modelling the convertor and its control as an equivalent admittance, valid for a particular combination of network configuration, torsional frequency, and level of series compensation. The convertor equivalent admittance is then combined with those of other system elements to arrive at the net impedance of the system viewed from a given generator, which subsequently can be used for torsional interaction analysis.

7. TRANSIENT, STEADY-STATE, LOW FREQUENCY AND POWER FREQUENCY STABILITIES

7.1 Introduction

A number of phenomena occurring in ac systems fall under the general classification of stability. The particular areas that will be considered hereunder include power system steady-state and low frequency stability, power system transient stability and power frequency stability. There are other types of instabilities that are particularly connected with dc convertors, such as harmonic instability and core saturation instability. Subsynchronous instability and voltage instability can also occur in ac and dc systems. These types of instabilities are discussed in other sections of this guide.

7.2 Definitions and Descriptions

The following definitions [B58] apply to electrical systems in general and are applicable to systems that include dc links.

1. Transient Stability of a Power System: A power system is transiently stable for an aperiodic steady-state operating condition and for a particular disturbance, if, following that disturbance, it reaches an acceptable steady-state operating condition. This is generally taken to mean that, for example, for loss of a line, no generator or load has to be disconnected.

2. Steady-State Stability of a Power System: A power system is steady-state stable for a particular steady-state operating condition if following small disturbances, it reaches a steady-state operating condition which is identical or close to the pre-disturbance operating condition. This is also known as Small Disturbance Stability of a Power System.

Transient stability is a characteristic of an ac system and is concerned with the electromechanical stability of machines subsequent to a disturbance.

For transient stability there are indirect effects caused by the interaction between a dc link and machine behaviour. An ac fault near a dc inverter will cause a collapse of inverter operation during the fault, hence loss of power infeed for this time. Machine will swing as for any ac system but the "megawatt second" shock can exacerbate machine behaviour. After the fault is removed, the dc power will not recover instantly; the recovery time depends on the dc line, the characteristics of the ac networks and the control system design. It is usually essential to minimize convertor recovery time to prevent the undue increase of the MW-sec shock, and hence possible transient instability between ac system machines. Recovery time is usually longer when the ac system has a low or very low SCR relative to convertor rating.

Steady-state stability is the response to small disturbances. With constant demand and generation a system could be said to be in a "steady-state" but in practice the system is continually subjected to small disturbances arising from changing demand, generation output and voltage conditions. These small disturbances require the system to move continually from one steady-state condition to another. Like all dynamic systems the movement from one steady-state condition to another involves some oscillation prior to settling to the new condition. In an ac system, these oscillations are damped by machine damper windings and loads. Damping of such oscillations can be improved by using power stabilizer signals on machine voltage regulators, and by the use of supplementary damping controls on dc links.

However, inter-area swings involving weak tie-lines may be at such low frequencies, such as 0.15 Hz, at which damper windings have little effect. Negative damping from various causes has then been known to produce continuous oscillations (low frequency or dynamic instability). As in the case of transient stability, a dc link with basic controls does not directly affect this type of instability, due to its much higher natural frequency, but with proper action by supplementary controls system damping and stabilization can be achieved.

When studying the different types of instabilities of an ac/dc system, it is very important to first consider the stability of the convertor with basic controls (refer also to Chapters 3 and 4); this is particularly relevant in the case of very low SCR systems.

Power frequency stability refers to the frequency conditions of the ac system as a whole. Power frequency stability can be described in terms of steady-state and transient stability, but in this case it is applicable to generator groups within a system. A steady-state or oscillatory instability can occur leading to variations in system frequency in the case of governor hunting. This is relevant, for example, where an isolated generating station feeds only a dc link. To assist speed control of the generator the dc control would require a characteristic responsive to system frequency such that the dc system load on the generator has a response like that of an ac system. Some form of frequency feedback should be employed to achieve this characteristic.

The transient form of power frequency instability can occur when a receiving system relies relatively heavily on infeed via dc. If system frequency and voltage fall too low, for example, during a transient disturbance, then the system may collapse if the dc input power cannot supply the load power under relevant conditions.

Generator governors will operate to control overspeeds, but fast DC link control action in the form of DC power increase or generator tripping may also be required if the overspeed presents a problem.

7.3 Main Parameters and Effects

The main parameters influencing the stability of interconnected systems and their effects are as follows:

7.3.1 Transient Stability

- Type and location of fault and method and time of fault clearance and change in system configuration due to fault clearance: these affect the angle to which synchronous machines swing during the fault and consequently the synchronizing power required to restore synchronism.

- Pre-fault power flow in ac lines.

- System inertia: this also affects the angle to which synchronous machines swing.

- SCR: this affects the ability of the dc link to recover after fault clearance. There is no direct relationship between SCR and machine swing as a low SCR system may have a high inertia and vice versa. AC machine recovery is a function of fault infeed from the machine terminals. Recovery is thus a function of the ac system impedance rather than ac/dc interaction.

- Machine angle swings that occur subsequent to fault clearance: the consequent voltage swings (to a relatively low magnitude) may cause inverter commutation failures several cycles after an apparent successful recovery. This condition is accentuated in cases of low SCR.

- Var compensation system: both synchronous and static compensation affect system voltage and recovery subsequent to faults.

- Rate of power recovery: after relatively long ac system faults, fast recovery may cause voltage instability at the inverter bus of a low or very low SCR system due to the temporarily depressed ac system voltage seen by the inverter. In this case a slower rate of recovery may be desirable.

- DC recovery from faults is dependent on a number of additional factors including protection and control sequences such as voltage-dependent current order-limits (VDCOL), temporary blocking, ac voltage waveform distortion due to transformer saturation (magnetizing inrush current) harmonic impedance, and settings of dc current recovery ramp rates.

7.3.2 Steady-State and Low Frequency Stability

- Network and generation configuration: the problem of poor damping will normally occur between plant/demand groups that are electrically far apart, particularly when there is a heavy exchange of power between the two groups.

- SCR: this affects the stability of the ac voltage during normal operation. Stability is improved by higher values of SCR.

- Amount and type of reactive compensation: both synchronous and static compensation may interact with link controls. Link and associated equipment (e.g., SVC) controls which in themselves are stable, may in combination provide unstable or oscillatory operating modes. Also, constant power control contributes to poor damping where the dc link represents a large part of the ac load. This may lead to machine governor hunting unless an extra frequency damping control loop is added.
- Type of load: loads generally exhibit variations of real and reactive power as a function of voltage and frequency. These characteristics can affect system damping modes.

7.3.3 Power Frequency Stability

The same factors that influence transient and steady-state stability also influence frequency stability. An additional factor is the output of machines lost after a fault as a proportion of total system demand. The higher the proportion, the more likely the occurrence of power frequency instability.

7.4 Trends and Sensitivities of System Parameters

The most important parameters that influence both steady-state and transient stability of synchronous machines are generally applicable to ac systems and not confined to dc links. These include system inertia, fault clearance times, and automatic voltage regulator and governor controls, and are therefore not discussed here.

System fault level affects machine stability and link recovery. In particular, low SCR systems will require longer recovery times to ensure that ac voltages are maintained at satisfactory levels.

A synchronous compensator (or compensators) increases the inertia of the system and its SCR, assisting in voltage control. If the link terminal is electrically remote from the rest of the ac system, it can in principle have transient instability problems of its own. Under disturbed conditions a synchronous compensator can introduce new oscillation modes. This has to be considered when studying low frequency stability but is of course no different from that of adding a new generator in a purely ac system. Consideration also has to be given to the modulation of the ac voltage resulting from these oscillations. Where a dc link supplies an isolated load without local generation, but supported by a synchronous compensator, its inertia and ratio of compensator rating to link rating are important to its stability (see Chapter 9). The synchronous compensator should be appropriately sized (reactances and time constants) to mitigate the voltage modulation problem when it is used to support a weak ac system.

In cases assessing the effect of machine swinging on the modulation of ac busbar voltage, the synchronous compensator can oscillate with combined dominant and hunting modes which are a function of the inertias and impedances.

Static compensation does not increase the ESCR but assists in voltage control subsequent to fault clearance by controlling the overvoltages.

DC control strategy affects system recovery. One strategy is to try to recover power as fast as possible. However, the corresponding reactive consumption tends to reduce the ac voltage. Recovery may not be achieved for a system having a very low SCR unless some temporary limitation is put in the dc current magnitude by the control strategy. Another strategy involves temporary blocking of the inverter if the fault voltage falls below a certain level. After fault clearing the convertors are deblocked and the current ramped up according to a set rate. This strategy generally may enable smooth restoration but will extend the recovery time.

For a low SCR system, the utilization of modulation of real and/or reactive power can be a valuable asset for enhancing system performance. The criterion for aiding system performance in some configurations may consist of the transfer of real power of the proper magnitude and timing, while in other cases reactive power control is more critical to overall performance. The tailoring of the dc system behaviour to achieve the most favourable overall ac/dc performance is an attainable system design objective.

7.5 AC and DC Parallel Operation

In the context of weak systems, addition of an ac line increases the strength of the ac system but the dc link may improve performance of interconnected system through modulation.

7.6 Influence of DC Control

7.6.1 Transient Stability

Where system contingencies, such as faults, result in the reduction of transmission capability, a generation source will usually accelerate. Remote sources may decelerate as load exceeds generation as a result of the fault which decreases power into that area. Upon clearing the fault, the generation and the remaining transmission experience a transient swing and may approach instability. Very long fault clearance times can cause a loss of synchronism prior to clearance.

If this loss of synchronism does not occur, in an ac/ dc system where a dc link is connected to the generation and a system load point, it has been found advantageous to increase the sending end dc link power in the post-fault period in response to the increase of generator speed. This action will remove energy from the generator, reduce its speed, and thus reduce the angular displacement between the generator and the ac receiving system. The magnitude of the modulation applied for this purpose has been in the range of 20 to 40% of the dc link rating. Systems have been designed with temporary overload limits as high as 65%. In other cases higher limits have been utilized for modulation consistent with the following provisions. The level of modulation is a function of ac system power transfer need, ac voltage support (var) capability and dc system design. Similarly, for receiving end phase angle or speed changes, dc link power can be controlled to correct this condition within the limits imposed by the controllability of the receiving end phase angle, the dc link capability, and the energy that may be taken from the generation source.

7.6.2 Steady-State Stability

Conditions have existed where heavily loaded ac systems oscillate at a period of seconds and with insufficient damping to prevent buildup of the oscillations. If an existing dc link is connected to one or both buses of the system experiencing a substantial angular swing, suitable control of the dc link can modulate the dc power flow in such a manner that damping is introduced to cause a decay in the system oscillations. The magnitude of the modulation to achieve sufficient damping has been found to be of the order of a few percent of the dc link rating and is considered a small-signal modulation.

7.6.3 Power Frequency Stability

A generator or group of generators representing a small proportion of the total system capacity connected to an ac system has its frequency controlled by the system. Where generation is not connected to the system by ac lines, as in the case of generation connected through dc links only, or in cases of system breakup where generation and load exist in islands, the governors are too slow and hence not effective in controlling system frequency. By suitable control, the dc link response can hold the generation frequency within close limits without reliance on the governors for this purpose.

7.7 Methods and Tools for Study

The complexity of calculations required makes it necessary to use computer programs. The method is to include an appropriate dc link model within a standard ac transient stability or small-signal stability program.

7.7.1 Transient Stability

a) In the standard ac transient stability program, representation of real and reactive powers at the high-voltage busbar as a function of busbar voltage. This can represent normal and abnormal operation (i.e., commutation failure), and the effect of changes in real and reactive power demand/infeed on ac system machines can be addressed in the transient stability program. The dc is represented by a quasi-steady state model. This represents the convertors by steady-state equations allowing dc quantities to vary with time. These equations relate the rms ac quantities on one side with the average dc quantities on the other. The control schemes can be represented by a V_d/I_d characteristic or a series of transfer functions.

b) Time domain analysis. The solution is achieved by comparing instantaneous ac and dc values on a three phase basis using EMTP-type programs. The ac and dc network solutions are carried out separately and compared periodically to ensure agreement on interface quantities. The time steps required for the dc solution are far shorter than those that would be used for the normal transient stability solution and therefore during this calculation a Thevenin equivalent ac network is used. The interface point should be chosen such that ideally the ac quantities are sinusoidal.

c) Simulators can be used but the accuracy of results is very dependent on the complexity and number of machine models used.

7.7.2 Small Signal Stability

a) An analysis of steady-state oscillations can be made assuming that the response of the system is linear for small disturbances around a particular operating condition. This assumption enables a simplified linear mathematical representation and provides an understanding of the capability of the system to dampen such steady-state oscillations. The calculation of eigenvalues provides the oscillation frequency and degree of damping for each instability mode.

b) Simulators can be a powerful tool in assessing control and ac system interactions, particularly the fast varieties.

7.8 Different Types of Schemes

The previous discussion of transient stability was concerned with point-to-point dc transmission. Aspects of transient stability relevant to back-to-back and multi-terminal dc schemes are discussed here.

A dc terminal interacts with the transient stability response of the ac system through:

a) Its ability to recover from disturbances (e.g., an ac fault) and to permit the ac system to re-establish synchronizing power.

b) Fast changes of power followed by power modulation to improve ac system transient stability and damping. Modulation of reactive power can be coordinated with the real power or the special requirements of the system.

In general terms, the same considerations apply to back-to-back schemes and multi-terminal schemes. The following are more specific considerations.

7.8.1 Back-to-Back Schemes

Changes in power order do not require communication between terminals. A fast change in power to assist the ac system can be implemented in minimum time irrespective of which side of the station is controlling current (or power). Also, small and large signal modulation can be applied without communication with full local knowledge of both ac systems. Any coordinated modulation of real and reactive power is performed with locally derived data from each ac system. The extent to which the faster response will be of benefit depends on the ac stability margins. Should one of the ac systems have both low inertia (a faster transient swing) and high impedance, a shorter time will be available for the dc system to provide effective assistance. Fast dc power order changes can only be implemented once the convertors have recovered their operating capability.

7.8.2 Multi-Terminal Schemes

Two factors will make greater demands on the multi-terminal performance.

(a) The recovery of a terminal from ac disturbances can be expected to be more complicated because of the possibility of transiently diverted dc current from unfaulted terminals. Interaction with the ac system parameters together with the control response capabilities will determine whether a multi-terminal case for transient ac swings will be more onerous than for an equivalent terminal rating in a back-to-back scheme.

(b) Power modulation and changes in power order, unless within overall margins, are implemented through coordination of all terminals, (different operating control characteristics leave room for this problem to be minimized).

Should two or more of the multi-terminal stations terminate in the same system, power changes, modulation and ac transient swings will be coupled by the common ac system. Thus, interaction with the ac system is extended to ac interaction between terminals. This gives rise to common mode disturbances for which the recovery of more than one terminal is a consideration. Power order changes and modulation can be proportionally assigned to the terminals to provide the best performance.

A disturbance which causes a power interruption by dc voltage collapse in one inverter station when other stations are connected to isolated ac systems will also interrupt power flow elsewhere. The nature of the local interaction will determine the recovery performance after the disturbance is cleared at the remote station. In this situation, the common mode coupling is via the dc system.

8. TEMPORARY OVERVOLTAGES

8.1 Description of the Phenomena
8.2 Main Parameters Affecting the Phenomena
8.3 Trends and Sensitivities of the System Parameters
8.4 Influence of DC Control
8.5 Methods and Tools for Study
8.6 Measures for the Limitation of Temporary Overvoltages
8.7 Different Types of Schemes

8.1 Description of the Phenomena

Changes in the reactive power balance of the ac network initiated by switching, faults, or power flow variation (in either ac or dc networks) produce changes in the operating voltage. Surplus reactive power also can lead to voltage increases. Larger disturbances result in temporary overvoltages. The term temporary overvoltage refers to the complete waveform which consists of the fundamental component and the possible superimposed oscillatory component.

On the busbars with close generator infeed, temporary overvoltages are reduced within a time constant which is in the range of 200 to 600 ms by the generator excitation system. In such networks, the possibility of self-excitation of generators after load rejection must be taken into account.

If generators are electrically distant from the convertor terminal, temporary overvoltages can be sustained for seconds; they can only be reduced by switching network elements, use of static var compensators (SVCs), or special metal oxide (MO) arresters.

The dc station always consumes reactive power in the range of 0.5 to 0.6 pu of transmitted power. The amount consumed depends on the commutation reactance and operating α and γ but is influenced only marginally by the power flow direction (rectifier or inverter). If the short circuit capacity of the ac network is low relative to the dc power, a sudden change in the active power, and therefore also in the reactive power, or the blocking of the dc due to a fault, will lead to high temporary overvoltages. These overvoltages influence the design and the costs of dc stations.

For equivalent ac network strengths, temporary overvoltages in the rectifier mode are normally more severe than in the inverter mode, as the voltage drop of the active power on the ac network impedance produces an additional increase of overvoltage.

Usually the loss of convertor real and reactive power occurs almost simultaneously in both dc terminals, and temporary overvoltages occur in both stations. Only in the case where the temporary bypass operation mode is used by the convertor control can the overvoltage be avoided in the non-faulted ac network.

Temporary overvoltage can lead to saturation of the convertor transformer or transformers near the dc station. Normally the saturation effect reduces the amplitude of the fundamental frequency component of the overvoltage. However, if resonance conditions in the ac network are close to one of the lower order harmonics, the overvoltage can be amplified. This is often the case when dc power is large compared to the short circuit capacity of ac network, as the resonance frequency of such networks is low. Shunt capacitors connected to the convertor bus for ac filtering and reactive power compensation make conditions worse by further reducing the resonance frequency.

In the case of a fault in the ac network and subsequent blocking of the convertors, even higher overvoltages can occur than at load rejection. At the recovery of the system, the voltage component, according to the resonance frequency of the network, is superimposed on the load rejection overvoltage.

When switching transformers, high inrush current can occur. If the harmonic components of this current meet resonance conditions in the network, high harmonic voltages are superimposed on the operating voltage. This leads to temporary overvoltages which can last for several seconds.

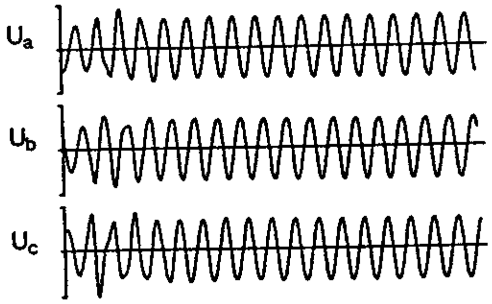


Figure 8.1
Temporary Overvoltage at Blocking of DC Transmission (SCR = 2.4)

Figure 8.1 shows an example of temporary overvoltage at load rejection initiated by blocking the dc convertor. Figure 8.2 shows a temporary overvoltage at fault clearing in the ac network when the dc remains blocked. The ESCR of the studied system was 1.8 pu. A temporary overvoltage caused by transformer energization is shown in Figure 8.3.

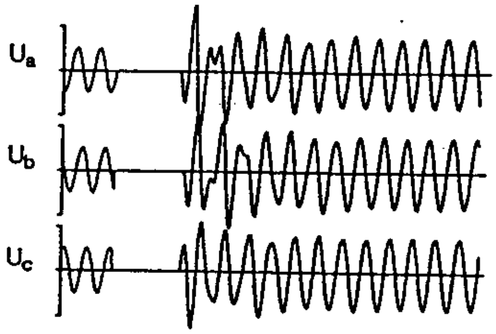


Figure 8.2
Temporary overvoltage at fault clearing without restart of dc transmission (SCR = 2.4)

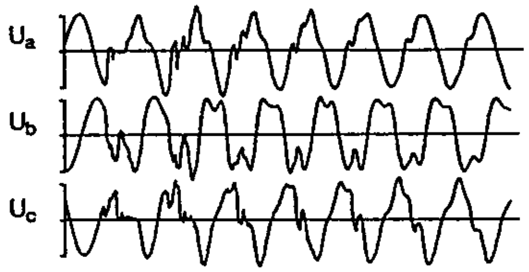


Figure 8.3
Temporary Overvoltage at Convertor Transformer Energisation (SCR = 2.4)

Temporary overvoltages on the ac side primarily influence the design of arresters on the busbar and through that, the insulation level on the ac side of the dc substation. The stress on the valve side arresters in the station is relatively low, as the voltage across the valves is reduced by a factor of approximately square root of three when the convertors are blocked.

However, if the temporary bypass mode is used for faults in the ac network close to the convertor station, the valve arresters can be stressed by the full value of the temporary overvoltage after fault clearing.

At partial load rejection, such as load rejection in one pole of a bipolar dc transmission, temporary overvoltages are lower than at full load rejection. But it should be noted that in this case the valves remaining in operation are stressed by the full overvoltage, unlike the blocked valves. This type of overvoltage may be critical for an economic valve design. However, overvoltages can be reduced via control action increasing active and reactive power of the sound pole.

8.2 Main Parameters Affecting the Phenomena

The main parameters influencing the temporary overvoltages are:

- Strength of the ac network (system impedance) related to the rating of the dc scheme. In addition to the network impedance at the fundamental frequency, the knowledge of the impedance and angle at lower harmonic frequencies for positive and zero sequence system is of importance. However, the value and angle of the ac system equivalent impedance at the fundamental frequency can be used for rough estimation of temporary overvoltages.

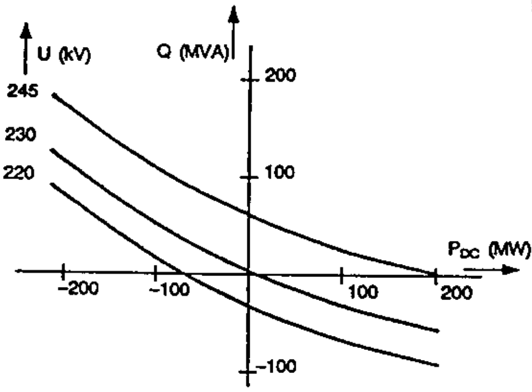


Figure 8.4
Reactive Power Requirements of Low and Very Low SCR System Depending on the Active Powr Loading (Example)

- Reactive power consumption of the network, depending on the active power infeed into the network as shown in Figure 8.4. This parameter influences the overvoltage component produced by the change in active power.
- Reactive power of the dc station defined by the commutating reactance, firing angles, and the operating conditions.
- Saturation characteristic of the convertor transformer and the network transformers close to the dc station (to calculate harmonic currents at saturation).
- Reactive power compensation equipment connected to the busbar of the dc station at the given operating conditions. Information is needed on size and conditions for switching compensation units.
- Configuration of the dc scheme and of the ac network in order to analyze the possible faults and switching operations leading to temporary overvoltages and to determine the most severe realistic case.

- In the case where the generators are electrically close to the dc station, the data of turbo-generators are important (primarily those related to the excitation and speed control systems).
- Information on the use of additional measures for reducing temporary overvoltages, e.g., static var compensators, fast switching of capacitor banks and ac filters, MO arresters.

8.3 Trends and Sensitivities of the System Parameters

The most important parameter is the value and phase angle of the impedance of the ac network related to the rating of the dc transmission. Regarding the temporary overvoltages, the network can be assumed to be weak if the fundamental frequency component of overvoltage at full blocking of convertor station lies between values of 1.25 to 1.4 pu. This is the case at SCR = 2.0 to 3.0. At higher overvoltages (with weaker networks), additional measures for reduction should be considered to keep costs of the dc stations within limits and not to endanger the voltage sensitive equipment in the ac network.

A further important parameter is the resonance frequency of the ac network seen from the ac busbar of the dc station. If the resonance is close to the 2nd or 3rd harmonic, the overvoltage can be amplified by the saturation phenomena.

The damping in the network plays an important role as it influences the amplitude of overvoltages and length of their duration. The amplitude of the fundamental frequency component of temporary overvoltage at an impedance angle of 90° is the same for the rectifier and the inverter. For lower angles in the range of expected values for ac network, the overvoltages reduce at the inverter and increase at the rectifier.

A reduction of the amplitude of temporary overvoltages produced by saturation can also be obtained by the use of ac filters which provide damping at low frequencies of the order of 2nd to 5th harmonics. In this case, filters bypass the harmonics produced by saturation which would flow into the network and produce overvoltages.

8.4 Influence of DC Control

The reactive power of a dc convertor station can be controlled by increasing the firing angle and influencing the consumption of reactive power. However, in this case the dc station must be designed for reactive power and voltage control.

After a fault occurs in the ac network, with the resultant temporary blocking of the dc transmission, overvoltages can be limited if the dc restarts immediately. An increasing reactive power demand of the convertor at restarting reduces the overvoltage. Nevertheless, for the design of equipment the most severe case must be taken into account; i.e., when the dc fails to deblock, and the full overvoltage occurs.

The use of the temporary bypass operation mode for an ac system fault enables operation at reduced current and increased firing angle in the station connected to the unfaulted ac network. The reactive power demand of this station remains nearly unchanged, and overvoltages can be avoided.

If a fault occurs in only one dc pole of a bipolar dc scheme, control can be arranged to increase active and reactive power of the unfaulted dc pole to counteract the overvoltage.

8.5 Methods and Tools for Study

The estimation of the fundamental frequency component of temporary overvoltage at blocking and also at fault clearing without dc restart can be done by simplified calculation. It can be conducted separately for each station as the influence of one terminal on the other can be neglected.

Assuming the total ac system seen by the convertor is represented by a Thevenin equivalent and fixed voltage infeed behind the impedance $Z/\underline{\Phi}_E$, the overvoltage factor of the fundamental component of TOV, k_{TOV}, based on the initial steady-state voltage U_{LO} on the convertor bus is:

$$k_{TOV} = \frac{U_{LTOV}}{U_{LO}} = [1 + 2\frac{Z}{U_{LO}^2}(P\cos\Phi_E + Q\sin\Phi_E) + \frac{Z^2}{U_{LO}^4}(P^2 + Q^2)]^{1/2} \qquad (8.1)$$

where

$Z/\underline{\Phi}_E$ = total effective ac impedance, usually defined by ESCR = $(1/Z)\,/\underline{-\Phi}_E$

U_{LO} = initial steady state voltage

U_{LTOV} = fundamental frequency component of the temporary overvoltage after convertor blocking

P & Q = real and reactive power drawn by the convertor

P = positive for rectifier, negative for inverter

Q = positive for rectifier or inverter

Quantities (P, Q, ac impedance) are per unit values; the base is usually the rated ac voltage and rated convertor real power.

The equation 8.1 applies exactly only if the solution is less than the saturation voltage of transformers on the busbar, typically about 1.2 per unit of rated voltage. For higher values, the actual fundamental frequency voltage component of temporary overvoltage will be lower than given by the equation, accompanied, however, by harmonic distortion components.

The reciprocal value of $Z\underline{/\Phi_E}$ given in pu represents ESCR and includes filters and capacitor banks on the busbar. To find this value from the system impedance $Z_s\underline{/\Phi_s}$ with its reciprocal value representing SCR, the following equation is valid:

$$\frac{1}{Z\,\underline{/\Phi_E}} = \frac{1}{Z_s\,\underline{/\Phi_s}} + jQ_F \qquad (8.2)$$

where

$\frac{1}{Z_s\,\underline{/\Phi_s}}$ = admittance of ac system alone, excluding filters and capacitors

Q_F = Total capacitive admittance of filters and capacitors

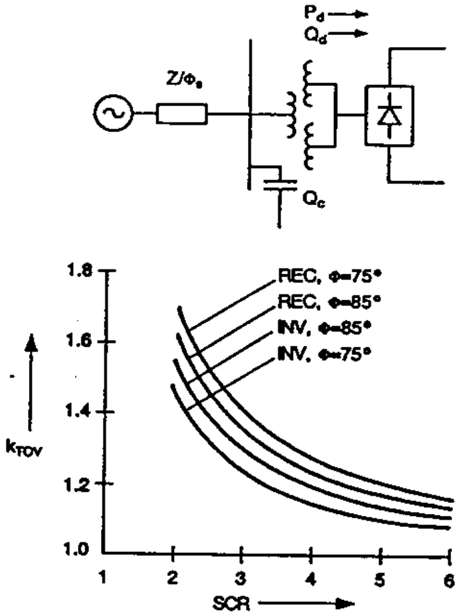


Figure 8.5
System Configuration and Results of Simplified Calculation for Overvoltage factor K_{TOV} at Blocking of DC Over SCR Assumptions :

P_d = ± 1pu
Q_d = 0.6pu
Q_c = 0.6pu
U_{LO} = 1.0pu

For the calculation, the fundamental frequency network impedance and angle and the reactive power compensation at the busbar of the dc station are used. The active and reactive power loading of the dc is dropped to zero and the corresponding overvoltage is calculated assuming the constant voltage behind the network impedance. Figure 8.5 shows the system configuration for the calculation and the results of overvoltage factors for rectifier and inverter operation plotted against SCR, with the impedance angle of the network as a parameter. The calculation gives the fundamental frequency overvoltage component only. The estimation can, however, be used in the planning stages of dc projects.

It is possible to more accurately calculate the fundamental frequency component of the temporary overvoltage following fault clearing without restarting the dc system. The ac network must be simulated in detail, at least in the neighborhood of the dc station. The calculation can be done using a transient stability program, representing a positive sequence system. The dc infeed can be represented by the active and reactive power loading which can be removed when calculating an overvoltage at load rejection or at fault clearing. An example of such a study where the network was simulated in detail and the generators were represented including their complete excitation systems is given in Figure 8.6.

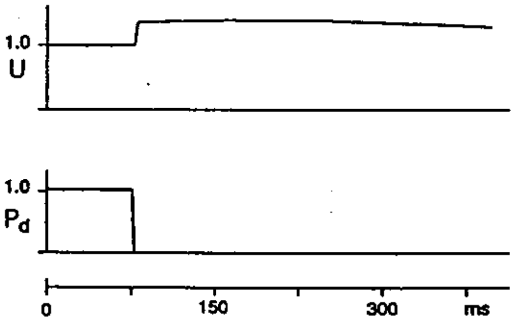


Figure 8.6
Overvoltage Following DC Load Rejection Calculated by Stability Program. The AC Network was Represented in Detail including Excitation Systems of Generators (SCR = 4)

However, this calculation doesn't take into account the transient component of the phenomena and the possible resonance conditions due to saturation. The results of such a study can be used for the design of most equipment if critical resonance conditions are not expected in the ac network. They are, however, not suitable for the detailed study of the arrester stresses for insulation coordination or the determination of transient voltage required for design of other equipment.

For a detailed study, as necessary for the design of surge arresters, a three-phase representation of the ac network, using the corresponding network impedance at least up to the 4th harmonic, is needed. Depending on the use of a control function for limiting temporary overvoltages, the dc should be simulated by either simplified or by detailed control representation. The saturation of the transformers should be also properly simulated in this case. The study can be done by digital computers or using an analog simulator. An example of such a detailed study made on simulator is given in Figure 8.7. The dc is blocked at the fault on the ac busbar of the convertor station and remains blocked after fault clearing. The bus voltages, arrester currents in phases a and b and the dc power are shown in the figure.

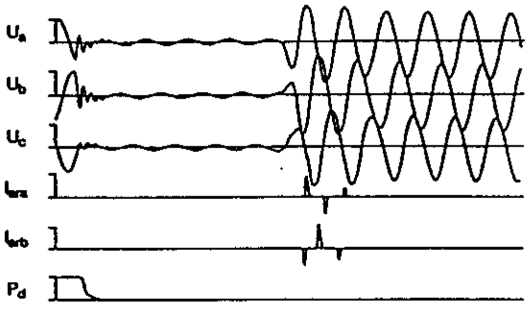


Figure 8.7
Fault Clearing with DC Remaining Blocked.
Study of Energy Stress in the AC Bus Arrester.
(SCR = 2.2)

This detailed network representation must be also used when studying overvoltages and arrester stresses at transformer energization. The example in Figure 8.3 shows the result of such a study.

8.6 Measures for the Limitation of Temporary Overvoltages

In weak networks temporary overvoltages caused by load rejection in dc systems can reach very high values. This has an impact on the design and costs of the dc equipment and can also endanger other equipment in the network. Temporary overvoltages can be reduced, apart from convertor control, by such different means as the use of synchronous compensator (SC), static var compensators (SVCs), metal oxide arresters, and the switching of shunt capacitors and ac filters connected to the busbar of the dc station.

8.6.1 Synchronous Compensator

Synchronous compensators connected to the busbar of the dc station increase the short circuit ratio of the network. The increase depends on the rating of the synchronous compensators and the sum of the subtransient reactance of the machine and the reactance of the step-up transformer. The temporary overvoltages are then reduced according to the increased short circuit ratio of the network.

The use of synchronous compensators solely for the limitation of temporary overvoltages would, however, be a very expensive solution owing to high investment costs and high operating losses. Because of longer maintenance times and higher outage probability of synchronous compensators, one unit should be assumed to be out of operation when calculating the maximum temporary overvoltage.

Synchronous compensators should therefore be used only where reinforcement of the network is also needed because insufficient short circuit capacity produces problems with other interactions and in low inertia systems.

Sometimes synchronous compensators are connected to the tertiary of convertor transformers. However, in such a case the possible configurations for load rejection must be studied. If, for example, the entire dc station is disconnected due to a fault, the ac network experiences temporary overvoltages without the synchronous compensators becoming effective.

8.6.2 Static Var Compensators (SVCs)

The static var compensator connected to the busbar of the dc station can contribute to the limitation of temporary overvoltages by shifting the operating point by fast control into the inductive range. The inductive impedance of the compensator connected in parallel to the network impedance reduces the total effective impedance of the network and through that limits temporary overvoltages.

Because of the time constant of the SVC control, the reduction of the temporary overvoltage is effective about 2 cycles after the occurrence of the TOV.

The SVC, as a measure solely for the reduction of TOV, is an expensive item. However, if the SVC is needed for ac voltage control during normal operation, it can be a competitive solution. The solution is especially suitable if voltage control of the ac network and TOV limitation are also needed when the dc system is out of operation and overvoltages can be limited by control action.

To reduce investment costs and losses when the SVC is used for TOV limitation, it can be built for low rated power during normal operation, but with a high overload capability for the short time of TOV.

The other possibility for limiting TOV by an SVC is by employing a saturable reactor connected to the busbar of the dc station. The advantages of this solution are a large short-time overload capability of the equipment and a response corresponding directly to the voltage increase. However, in many cases additional elements must be provided in this type of SVC to adjust the saturable reactor to the operating voltage and to flatten the slope of the impedance in the saturation area. Problems may also arise from the additional production of harmonics, especially during unsymmetrical fault conditions.

8.6.3 Metal Oxide (MO) Arresters

The MO arrester offers an alternative solution to limit temporary overvoltages and can act alone or in conjunction with convertor control and the switching of shunt capacitors and ac filters.

The basic idea behind the use of MO arresters to limit temporary overvoltages at the convertor station is to exploit the high energy absorption capability offered by the MO equipment. Various solutions are possible. Two basic approaches adopted in recent dc projects are discussed below:

- Arresters with an extremely low protective level limiting the temporary overvoltages (TOV) to values of typically 1.4 pu and permanently connected to the ac busbar. To achieve this low protective level and because of the given MO material characteristic, significant currents flow through the arrester at normal operating voltages. The arrester, therefore, needs special cooling to avoid overheating during continuous operation.

  The use of such permanently connected MO arresters is recommended where the initial two or three peaks of the overvoltage are higher than the acceptable value and cannot be limited by other arresters installed in the station.

- Special MO arresters which are switched in by circuit breakers in the case of high temporary overvoltages. When the overvoltage has been reduced either by restarting the dc system or by switching out the shunt capacitors and ac filters, the arrester is disconnected from the network to prevent overloading caused by normal operating voltage. This arrester can limit the temporary overvoltage to values as low as 1.25 pu. However, the closing time of the breaker must be considered with the result that the overvoltage is not limited until a few cycles after its occurrence.

In both solutions the possible fault contingencies must be studied carefully to determine the maximum energy stress of the arrester. Lower protective levels require higher energy capability of the MO equipment and consequently lead to higher costs. Experience shows that the optimum overall design could be in the range of 1.25 to 1.4 pu.

8.6.4 Switching of Shunt Capacitors and AC Filters

Shunt capacitors and ac filters used for reactive power compensation in the dc stations decrease the SCR on the busbar, which is the main parameter influencing the amplitude of temporary overvoltages following load rejection. TOV can, therefore, be reduced if capacitor banks and ac filters are disconnected. However, in this case the circuit breakers for this equipment must be designed to switch off at maximum TOV. This means that breakers usually are one voltage level higher than in normal cases. When applying this measure for the limitation of TOV, the corresponding opening time of breaker and a suitable strategy for back-up protection (e.g., a second breaker to disconnect the whole station) must be taken into account.

This solution leads to considerably higher costs for the ac switchyard. However, the switching of capacitor banks and ac filters can support other measures for the limitation of TOV and, in case of MO-arresters, is an essential part of the operating strategy.

8.7 Different Types of Schemes

The fundamental and general characteristics concerning temporary overvoltages are covered in the sections above. In this section only the aspects that are specific or of special importance for other types of schemes, other than point-to-point transmission, are discussed.

8.7.1 Back-to-Back Schemes

The fact that the rectifier and the inverter are in the same station is of importance. A properly designed control and protection system can in principle eliminate temporary overvoltages on the dc side, both regarding magnitude and duration. The formation of by-pass pairs on the faulty side enables dc current to circulate, and the consumption of reactive power on the undisturbed side is maintained, resulting in voltage control.

In a back-to-back scheme the two ac systems are more closely coupled to each other, especially concerning harmonics, than in a line or cable transmission. The total impedance in the dc circuit is just the sum of the leakage reactances of the convertor transformers and the smoothing reactor. As a consequence, harmonics in the ac voltage appearing on one ac side can more easily be transferred to harmonic currents on the other ac side via the convertors. Large negative sequence voltages which occur, e.g., as a consequence of single line to ground faults, will give rise to third harmonic currents appearing on the other side. If no low harmonic filters are provided, the transferred harmonic currents might cause high temporary overvoltages of that frequency if the system is of high impedance.

If low order harmonic filters are installed, the third harmonic current can lead to high stresses in these filters. The possibility of transferring harmonics from one ac system to the other must therefore be considered when designing the smoothing reactor and when rating the components in the filters.

8.7.2 Multi-infeed Schemes

For a single-infeed scheme in a low or very low SCR system, the highest temporary overvoltages are most often caused by a disturbance in the dc system. These can include the convertor ac buses, as well as dc line faults and ac faults in the rectifier or inverter. As soon as the convertors resume normal operation, the overvoltages are damped to values that will not impose any stresses on the equipment. However, if multiple dc schemes are connected electrically close to each other, the situation is more complex. Disturbances in one of the systems, such as a load rejection, will cause high temporary overvoltages, even though the other scheme(s) is (are) running properly. This must be considered when designing the equipment. Particularly, the valves must be designed to commutate during the overvoltages that might occur due to disturbances in other schemes. Different control actions, such as increased firing angles and filter tripping, can be used to limit these overvoltages, as discussed in Section 8.6.

Not only are the equipment stresses of importance when discussing temporary overvoltages in multi-infeed systems, the distortion of the commutating voltage as a consequence of a disturbance in one dc system might give rise to a malfunction in another dc system. As an example, a commutation failure in system 1 distorts the wave-form of the voltage so badly that system 2 also suffers a commutation failure, and so on. This process can, for unfavorable network configurations, jeopardize both the performance of the different dc transmissions, and the equipment might also be overstressed.

8.7.3 Multiterminal Schemes

Multiterminal schemes which include dc lines or cables have basically the same temporary overvoltage characteristics as point-to-point transmission and multi-infeed systems, depending on the coupling via the ac system between the terminals. A few points might be added, more as remarks rather than as specific characteristics for these systems.

The dc side system is usually more complex than for a point-to-point transmission. Also, the number of conceivable operating configurations is often very large. These facts make a study of temporary overvoltages on different locations on the dc side very comprehensive. The probability that a fundamental frequency or second harmonic resonance will occur is increased in some of these operating configurations. The existence of this resonance is of great significance for the magnitude of temporary overvoltages in the system.

It is easier to locally determine a proper action to limit the magnitude or duration of a temporary overvoltage in point-to-point schemes than it is in a multiterminal system. For a multiterminal system one has to consider the impact on the other station for a specific action. Such an evaluation takes time and increases the duration of the temporary overvoltages. This fact has to be considered when designing the equipment.

8.7.4 Low and Zero Inertia Schemes

In a zero, and very often also low, inertia system, a synchronous compensator has to be installed in order to achieve acceptable system performance. The synchronous compensator might then be installed at the inverter bus, and this system configuration can for certain contingencies give rise to very high temporary overvoltages.

The most severe case is if the last outgoing line from the inverter ac bus is tripped. The active power from the dc convertor will then very rapidly accelerate the synchronous compensator. Furthermore, there is a very high risk that the synchronous compensator will be self-excited because of the capacitive load of the connected ac filters. In unfavorable cases the voltage will rise to high values in just a few cycles and might jeopardize the equipment.

This fault scenario must be analyzed in detail for the pertinent schemes, and protections that prevent self-excitation of the synchronous compensator must be installed.

9. ZERO AND LOW INERTIA SYSTEMS

9.1 Introduction
9.2 Zero Inertia Systems - Island of Gotland
9.3 Low Inertia System - Island of Corsica

9.1 Introduction

A feature of an island electrical system, which is not connected to other networks by ac transmission lines, is that its mechanical inertia is due solely to local rotational plant. The effect on frequency due to the permanent loss of one generator unit will depend on the size of that unit relative to the total load and on the amount of spinning reserve in service. In cases where there is no local generation, the system inertia has to be provided by synchronous compensators as discussed in Chapter 2.

The network of Gotland Island can be described as a zero inertia system because it operates without any local generation. The frequency is maintained in steady and transient states by the dc link and the synchronous compensators. For normal system conditions the Gotland network can be considered as a high short circuit ratio system, SCR = 4.7 (based on X''_d, and OSCR = 3 based on X'_d. With the largest synchronous compensator out of service OSCR is just under 3. Both values of SCR are referred to 160 MW, which is normally the maximum operating power, although the installed dc equipment is rated for 260 MW.

Most of the power in the Corsican system is supplied by local diesel generator units. As Corsica is an isolated system, it depends for its inertia entirely on local diesel sets. At a system load of 60 MW, a permanent loss of a 20-MW diesel unit could cause a considerable frequency drop. In these circumstances, the Corsican system can be considered as having inadequate inertia. The dc station at Lucciana, tapped from the 200/300 MW Sardinia-Italian Mainland DC Link, is rated for 50 MW. It can import or export power, but in all circumstances it provides a 20-MW "spinning reserve" for the Corsican system. The dc power is modulated in order to control the island frequency.

The Corsican system falls between high and low short circuit ratio systems if operated at the maximum power. For nominal system conditions SCR=3 for 50 MW of dc power; normally operation is at dc power lower than 50MW. For exceptional system conditions corresponding to short circuit level of 120 MVA, OSCR = 4 because the dc power would be limited to 30 MW.

9.2 Zero Inertia Systems - Island of Gotland

9.2.1 Description of the System

The electrical load on the island of Gotland is normally supplied by bipolar dc cable transmission from the mainland of Sweden as there is no local generation. The present island peak load is 160 MW; the rating of each dc convertor is 130 MW, with a continuous overload capability of 30MW per pole. Four synchronous compensators provide the voltage and frequency on the island. Their total rating is 196 MVA, and their resulting inertia constant is 1.9 seconds. [$H = (1.7 \times 70 + 2.5 \times 77 + 1.7 \times 30 + 0.8 \times 19)/196 = 1.92$ and $H_{dc} = 2.3$]. They provide a short circuit capacity of about 750 MVA. The frequency on the island is controlled by modulating the power of the dc link by means of a regulator, which provides the current order to the dc convertors. The ac voltage is controlled by automatic voltage regulators of the synchronous compensators. The reactive power is supplied mainly by shunt capacitors on the feeders and the ac filters: 52 MVAr at the dc inverter (busbars). The synchronous compensators are lightly loaded, in order to provide sufficient margins at disturbances.

Problems related to low short circuit capacity have not been experienced, e.g., large temporary overvoltages or voltage instability. Therefore, problems related to the low inertia are discussed below.

9.2.2 Frequency Deviation

9.2.2.1 Faults on the Mainland

Because of the small inertia constants of the synchronous compensators (SC) the frequency deviations at load rejections can be relatively large. The principal relationship between the power from the SC, the inertia constant and the duration of the load rejection is given by equation (2.4) in Chapter 2. The event which causes the largest frequency deviation is a solid 3-phase fault at the rectifier on the Swedish Mainland. This affects both dc poles, as their ac buses are connected for operational reasons. The power to the island becomes zero and the load is supplied by the kinetic energy of the SCs. The duration of the power interruption is determined by the fault detection and clearing time, which is 5 cycles and by the charging time of the cable, which is about 2 cycles. Hence, the cable charging time adds significantly to the load rejection time. The frequency deviation is also affected by the power response of the dc link after fault clearing, as determined by the dc control and the frequency regulator. The full power is restored over some 150ms, which is equivalent to a total power loss for a further 75 ms. Therefore, the power is lost for a total equivalent time of some 0.215 s (0.1 + 0.04 + 0.075). From equation (2.6) in Section 2.3.2.1, the drop in frequency is calculated to be 2.3 Hz. This compares to 2.2 Hz obtained by full modelling of the system. No load shedding will be performed.

With the largest synchronous compensator out of operation, the frequency deviation becomes about 4 Hz. In this case, parts of the load will be shed to ensure that the SCs stay in operation.

9.2.2.2 Faults on the Island

The inverters supply the power to a 70-kV ac network to which 10-kV distribution networks are connected through 70/10-kV transformers. The load reactive power is supplied mainly by shunt capacitors in the distribution networks. The reactive power of the inverters is supplied mainly by the harmonic filters and partly by the synchronous compensators, with ample regulating margins for disturbances. The ac-busbars of the dc-convertors of both poles are interconnected. Therefore, events in the ac-network of the island affect both poles of the convertors. Reduced ac voltage will reduce the load as well. In addition, the inverters will experience commutation failures for faults in the 10-kV distribution networks. The commutation failures will temporarily interrupt the supply of power and the consumption of reactive power by the inverters and will discharge the dc cable, in fact, to a negative voltage. Because of the charging time of the cable, it takes a longer time than normal for the inverters to regain commutation. Hence, a commutation failure represents a somewhat more serious event than what is normally the case for dc transmission by overhead line. Even so, the frequency deviations are smaller than for faults on the mainland. No load shedding will be performed. An actual commutation failure event is described in the Section 9.2.3.

9.2.2.3 DC Link Equipment Faults

Most faults of the dc link are limited to one pole. For the outage of one pole the power is increased on the remaining pole employing a 25% overload capability, which limits the frequency deviations to values which will normally not result in any load shedding. Bipolar faults seldom occur, as the two poles are completely separated, to the degree of the overhead line sections being installed on separate towers. Temporary bipolar faults are comparable in their severity to faults on the mainland. For permanent bipolar faults a black-out on the island cannot be avoided.

9.2.3 Commutation Failure

9.2.3.1 Description of the Event

A 3-phase short circuit in a distribution network close to the dc station on Gotland, causes a commutation failure. An oscillogram from the fault recorder in one pole is shown in Figure 9.1. Starting from the top, it shows the ac voltages, the ac currents of the two 6-pulse groups, the dc voltage, the dc current and the comutation angle γ of

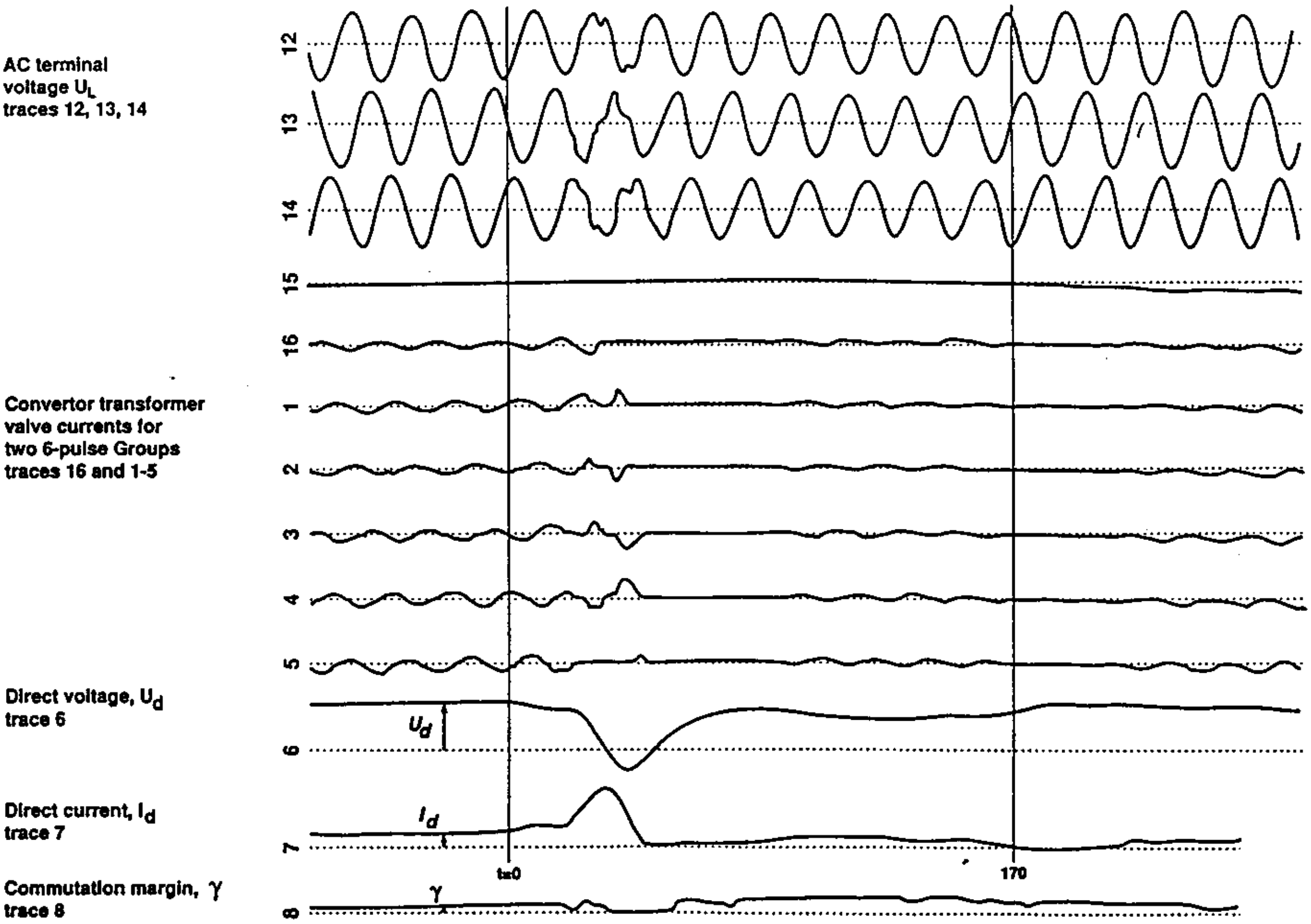


Figure 9.1 - Gotland Inverter - Commutation Failure and Recovery

the dc pole. Before the disturbance, the power was 108 MW, about 43% of the rated power, the dc voltage was 150kV, and the commutation margin, γ, was 19°. (Initially the value of γ was set to 17°, and relatively numerous commutation failures were experienced, caused by faults in the distribution network.)

After the short circuit (t = 0) the commutation voltage of the inverters decreased 10 to 20% and became somewhat distorted. It was obviously sufficient to create a commutation failure in one 6-pulse group 21 ms after the short circuit. It can clearly be seen on the ac phase currents, traces 3 and 4, just prior to t = 21 ms, that a normal commutation started and that the dc current commutated back again. Then two valves connected to the same phase conducted the dc current, thus short-circuiting the dc-side of the 6-pulse group. As a consequence, a fast increase of the current was obtained, trace 7. The ac voltage became more distorted and a commutation failure was created in the other group 7 ms later. Then the dc side of the pole became short circuited. Similar events took place in the other dc pole. Hence, the 3-phase short circuit in the distribution network created commutation failures in all four 6-pulse groups of the dc inverter.

9.2.3.2 System Performance

The bypass of the inverter started an oscillation between the inductance of the dc reactor and the capacitance of the dc cable, which discharged the cable to a negative voltage and forced the dc current in the inverter to zero at t = 48ms. The cable was then charged by the rectifier; the transient state was determined mainly by the current controller and the capacitance of the cable. At t = 80 ms the dc voltage approached the "back emf" voltage of the inverter; transmission could be resumed at 60 to 70% dc voltage. The fault was cleared and the ac voltage was restored at t = 170ms. The sudden increase of the voltage of the inverter forced the current to zero, after which the dc transmission resumed and the prefault power was achieved.

The principal consequence for the system was an interruption of power transmission with a duration of about 3 cycles of the power frequency, but the dc link restarted and transmitted a reduced power during the fault. The unbalance between the load and the power from the dc link was supplied from the kinetic energy of the synchronous compensators. It did not cause any load shedding, and the frequency was controlled to its normal value by means of the frequency controller of the dc transmission.

9.2.3.3 Conclusions

(1) Relatively minor disturbances of the commutation voltage of a dc inverter, even operating with an extinction angle of 19° which is higher than normally used, can create commutation failures in all of the 6-pulse groups of the dc station.

(2) An interruption of power transmission of short duration is caused by commutation failures.

(3) For cable transmission, the duration of the power interruption is increased due to its capacitance, (compared with overhead line transmission); the cable is discharged to a negative voltage and the charging time is increased.

(4) The short interruption of power transmission had no serious effect on the supply of the loads of the Gotland network.

9.3 Low Inertia System - Island of Corsica

9.3.1 Short Circuit Ratios

The 50-MW Lucciana convertor station is connected to the Corsican 90 kV ac system at a point where the minimum short-circuit level specified for operation at full load is 180 MVA. In this case the system load is about 60 MW and OSCR = 3.6. Given the large amount of capacitor banks installed at the convertor bus (5 x 10 Mvar), the minimum OESCR is 2.6. In exceptional conditions the short-circuit level can be 120 MVA, but in that case the maximum power available from the convertors is limited to 30 MW, OSCR = 4. In this case, the OESCR is (120-30)/30 = 3.

9.3.2 Frequency Deviation

As the Corsican System is an isolated network with no ac interconnection with other systems, the frequency is very sensitive to the loss of a local generator (their maximum size is 20 MW for a total installation of 330 MW). When in the "spinning reserve control mode", the convertor station power level is limited to 30 MW so that in the event of the loss of a generation unit, the convertors can inject up to 20 MW into the ac system to compensate this loss. Then the "frequency control mode", which is the basic control mode of the convertor station, adjusts the power level of the inverter to maintain the system frequency at its specified value (50 Hz).

The operator of the convertor station can select in advance two steps of power (12 or 20 MW) for the "spinning reserve control mode", according to the rating of generators in operation on the system.

During the commissioning of the convertor station, a maximum variation of 4 Hz was recorded after the intentional trip of a 20-MW diesel unit, thus confirming simulator results. As shown in Figure 9.2, the convertor was exporting 5 MW from the island when the generator was tripped. The power direction was automatically reversed and the dc link settled to import 15 MW and

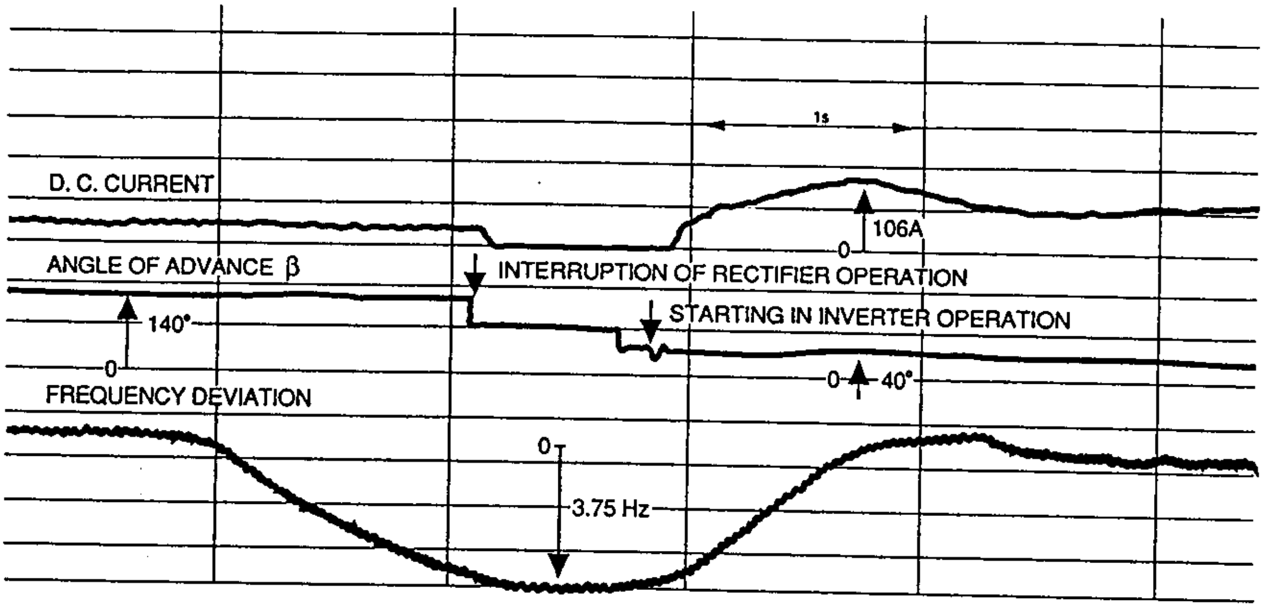


Figure 9.2

Automatic Reversal of Power Flow of the Corsican Station for Controlling the Network Frequency After Tripping One 20MW Generator. The Station previously exporting 5MW reverses power and injects 15MW.

hence restore the balance of power.

9.3.3 Commutation Failures

Because of local climatic and geographic conditions, ac system faults are frequent. After a survey it was established that 80% of the system faults which would affect the future convertor ac bus caused voltage reductions of less than 20% at that bus. The convertor was designed to operate at $\gamma = 40°$ at rated ac voltage while in current control. This choice of γ has resulted from extensive ac system fault simulations and probability calculations.

The Corsican dc convertor station is a parallel tap on the SCR dc link interconnecting the island of Sardinia and the Italian Mainland. This means that a commutation failure in Corsica will also temporarily affect power transmission in Sardinia and Italy. A probability of one commutation failure in Corsica for a period of 5 days was found acceptable by both Italian and French utilities. Voltage reductions by less than 20% have proved to cause no commutation failures regardless of the operating conditions.

9.3.4 DC Controls

The convertors operate in dc current control with constant power factor ($\tan \phi = 1$).

The station has two loops to regulate the system frequency: the fast loop modulates the power as for a rotating machine, with a transfer function between modulated power and frequency variation in pu of $H_f(s) = 1/(0.02 + 0.045s)$; the slow loop modulates the power order in a pure integral way with a transfer function between modulated power and frequency modulation

$$H_s(s) = (k_i/s)\ (1/fn) \qquad (9.1)$$

with $k_i = 100$ MW/s and $f_n = 50$ Hz

Both loops have their output signals limited in amplitude.

10. RECOVERY OF DC SYSTEMS FROM AC AND DC SYSTEM FAULTS

10.1 Introduction

10.1.1 AC System Faults

AC system faults in the electrical proximity of the inverter station causing inverter ac busbar voltage reductions in any or all phases may cause commutation failures in some or all of the connected valve groups. During the period of commutation failures, usually the fault duration, the associated valve groups cannot deliver any power into the ac network.

The energy loss to the ac system during the fault is unavoidable. After fault clearing, the dc would normally be required to recover as quickly as possible to minimize the energy loss and prevent transient instability of the synchronous machines in the ac system. The importance of commutation failures during system faults, and therefore also the importance of commutation failure probability for remote faults in low and very low SCR systems, depends on the sensitivity of the receiving ac system to the energy deficit during the failure and the convertor behaviour during the subsequent recovery period. If the recovery period is not smoothly controlled, the effects on the ac system can be aggravated.

10.1.2 DC System Faults

Notwithstanding the potential for large power and energy loss to the ac system, from the point of view of the behaviour and response of the actual convertors, the operation resulting from dc side faults is generally not so complex or parametrically sensitive as for ac side faults.

DC side faults within the station result in the blocking of the affected valve groups or pole and a corresponding permanent loss of the groups or poles and thus a permanent loss of the associated dc transmission capacity. DC side faults will be either station ground faults, station equipment faults or insulation breakdown, dc line or cable faults, or ground electrode line faults. With the exception of a temporary dc line fault, these dc-side faults result in a shutdown of the faulted zone, which could be a convertor group, pole, or bipole.

Bipole shutdowns should be very rare. They can be caused by multiple contingencies or sequential events, an overall bipole control failure, a line tower failure, or auxiliary service failure common to both poles. A permanent fault on the electrode line or the common neutral connection of the poles can also cause or require a bipole shutdown. If the neutral fault is a ground short-circuit it may not always be necessary to immediately and automatically block the bipole, since this can be done by operator action. These ground faults may be difficult to detect. However, a fault resulting in an electrode line or neutral open circuit can result in high dc voltages on the low voltage side of the pole station equipment if the bipole is not blocked immediately.

DC station faults, either in the valve group or pole zones, lead to group blocking and usually shutdown of the pole. Restoration of the pole is normally done by operator action following fault investigation and correction. Alternatively, if the fault is a permanent fault in a valve group zone, in some schemes the group can be isolated and bypassed by switches or breakers and the remaining healthy groups in the pole can be restored to full power. In this case, it is possible to employ an automatic sequence which detects the fault zone, blocks, bypasses, and isolates the faulty group and automatically restores power in the remaining healthy groups in the pole. For most dc applications in low and very low SCR ac systems, however, these sequence times are likely to be long enough, and the energy loss large enough, such that they are not likely to meet the required constraints for transient stability. As a result, most present schemes employ only manual pole restoration.

It follows from the above that, in the context of dc recovery within a low and very low SCR ac system, only temporary dc line faults are relevant and therefore only these will be discussed further in this Section as a category of dc side faults.

10.2 Parametric Behaviour of the Phenomena

10.2.1 Effect of Commutation Margin Angle γ

Where inverters are operated at γ of 18° (on 60 Hz) it is likely that an ac voltage reduction to less than about 85 to 90% at the inverter may frequently cause commutation failures. However, with γ about 20° or larger it is not likely that commutation failures would occur for such or even greater voltage reduction. The effect of various γs is also discussed further in Section 10.4 on actual system examples. (For an explanation of the commutation fialure phenomena see Section A1.2 in the APPENDIX).

In dealing with the fundamental principle of the margin angle, special mention should be made of the effect of single phase-to-ground faults in the ac network. The commutation voltages on the convertor valves correspond to the phase-to-phase voltages on the ac side of the system. It can be easily demonstrated vectorially that a single phase fault results not only in a voltage drop in the phase-to-phase voltages but also in a phase shift, and where the relative shift of one voltage is leading and the other lagging. The phase shift in the leading direction effectively infringes on the commutation margin angle and, combined with the voltage drop, increases the probability of commutation failure.

If single-phase tripping and reclosing are applied in the vicinity of the inverter station, special actions must usually be taken. If the system is weak and the single-phase tripping and reclosing occur on a line that has large significance for the operation, the dc power has to be reduced during the time between tripping and reclosing to avoid disturbances in the ac system. Such a scheme has been implemented for the Highgate convertor station. [B84]

For remote faults the voltage drop and phase shift may be small but the phase shift can reach a value of 30° for a fault close to the busbar of the convertor station. These phase shifts can only be recognized by the dc controls if firing synchronizing voltages are developed out of the ac phase-to-phase voltages. An appropriate strategy could then theoretically reduce the probability of commutation failures.

γ controllers often utilize the minimum γ history occurring over the last power frequency cycle (out of 12 commutations for a 12-pulse group) to possibly avoid successive commutation failures with a distorted waveform.

10.2.2 Effect of AC System Strength on Commutation Failures

Generally, it can be expected that the weaker the ac system at the inverter the more likely an ac fault remote from the inverter will cause commutation failures since it is more likely to result in a larger voltage reduction (or manifested as a voltage phase shift for single phase faults) at the inverter.

An apparent anomaly can arise in some situations where the system strength is seemingly increased but the inverter's exposure to system faults and hence incidence of commutation failures is also increased. This does not imply that the inverter's performance is worse with the stronger system. One has to be careful in evaluating the relative causes and effects. An extreme example of this would be if an entirely separate system was connected to an inverter or it was already connected to an ac system by a new tie line. This new system would effectively increase the total system strength and actually improve the inverter performance for remote faults in the previously connected system. However, the inverter is now exposed to all the faults in the new system and this has to be considered as well. A less obvious example could be when a new line is added in an existing system. The new line may increase the equivalent system strength and generally improve inverter performance but it may also increase the inverter's effective exposure to faults in a network at the end of that line or, of course, on the line itself.

Another scenario could be postulated where a new system addition may increase the system strength but move the system, as seen at the inverter, closer to a harmonic resonance. Under certain faults or switching actions this could inadvertently increase voltage distortions, increase incidence of commutation failures, and deteriorate the inverter performance.

10.2.3 Quality of Recovery from Commutation Failures

Recovery after faults is usually easier with a high SCR system and takes longer with a low and very low SCR system. Normally, however, it is the weak inverter ac system which is more in need of fast recovery to preserve stability. On the other hand, post-fault system swings and voltage instability at the inverter bus of certain weak systems may cause subsequent commutation failures. In these cases, slower rates of dc recovery may be desirable and must be optimized.

Very low SCR ac systems may have difficulty providing sufficient reactive power at the rate required for fast dc system recovery. Also, such systems may exhibit high temporary overvoltages with severe ac voltage distortion due to harmonic current injection caused by magnetizing inrush currents at re-energization of the convertor transformers upon fault clearing. DC convertor controls have difficulty in operating correctly against such highly distorted ac voltages. This can result in commutation failures and delayed recovery of the dc system.

Commutation failures from unbalanced ac system faults can excite dc side low order harmonic resonances which may then interact with harmonic resonances on the ac side leading to failure to recover, or at best, delayed recovery.

For low and very low SCR ac systems with high mechanical inertia where fast injection of real power to maintain frequency is not necessary and fast dc power response could result in unsuccessful recovery, it may be prudent to extend (or delay) the dc recovery time. Control strategies to accomplish this are discussed in a following section.

The strength of the ac system is of course relative to the dc power or power rating of the connected dc convertors. For a particular ac system, recovery from faults becomes more critical and difficult with increasing dc power injection. This is just another way of expressing that it is the short-circuit-ratio (SCR) which is relevant. It is especially important to note here the special case of multi-infeed dc, that is, where more than one dc link or group of convertors are connected to a system. Even if they are not connected to the same point in the system but are within electrical proximity, it is the total dc power of all convertors may be relevant to the recovery phenomena (see Section 2.2.8). It may be particularly onerous if all convertors are required to recover at the same rate and in the same fashion. In some cases of low and very low SCR systems, therefore, it may be advantageous to have a staggered recovery of convertors for multi-infeed situations. This has the same effect as artificially increasing the SCR for this situation.

In general, the time for a dc system to recover to 90% of its pre-fault power following ac fault clearing is typically in the range of 100 ms to 300 ms. In some cases where delayed or ramped recovery is adopted, which may be necessary with low and very low SCR ac systems, the recovery time may be longer, say 500 ms. The recovery time depends on the characteristics of the dc and ac systems and the control strategy used.

10.2.4 Effect of AC and DC System Characteristics and DC Controls on Recovery from AC Faults

The important characteristics of the dc system which influence the recovery time include dc line inductance, dc line capacitance (particularly if it is a cable system), dc line reactor inductance, resonances of the dc main circuit at harmonic frequencies, convertor transformer reactance, saturation characteristics and magnetizing inrush current characteristics, types of ac harmonic filters provided (particularly their damping effect at the low harmonic frequencies) and type of reactive power compensation provided. The important ac system characteristics include its equivalent impedance at the fundamental frequency, its impedance at low order harmonics (2nd to 4th), the damping effect of nearby loads, system mechanical inertia, ac fault clearing times, and the method of control of voltage at the interface bus.

The ac system impedance is of importance in two frequency regions. One is at the two sideband frequencies of $f_o \pm f_m$, where f_o is the system frequency and f_m is the modulation frequency in the range 10 Hz to 30 Hz. This frequency region is relevant to convertor stability and machine shaft resonances and, in transient form, covers the main part of convertor recovery after faults. Usually, the ac system impedance (or the SCR) is sufficiently defined at the mean of the sideband frequencies, that is, at f_o.

The second important region is at the harmonic frequencies from about 2nd to 4th harmonics. This is relevant because, with a low and very low SCR ac system, the resonant frequency of the ac system impedance with capacitor and filter banks will be in this region (see Section 5.5). This is excited by both the shock of restoring ac voltage and by magnetizing inrush current after a fault, and causes ac voltage distortion. Above about the 4th or 5th harmonic ac system impedance is of little importance for convertor stability and recovery, because ac filters act as a barrier to such frequencies. For simulator studies this gives the useful result that the representation of ac lines can be by relatively long lumped sections. It should be noted that harmonic impedances are of less importance where damping exists due to nearby loads, or is provided by low-order damped ac filters.

Satisfactory recovery of a dc system from ac system faults is possible only when the desired operating point in the steady-state is stable. Stable operation here refers to the dc system response to small or medium perturbations of the ac system reference conditions such as the commutation voltage. For small perturbations (e.g., oscillations with frequencies of the order of 3 Hz - 10 Hz) the dc system response is determined by the parameters of the main circuit (such as mentioned earlier), the convertor control system (i.e., type, gain, phase advance settings, etc.), possible static compensator controls and possibly the master controls and telecommunications. Below 3 Hz, stability depends also on damping controls, and ac system machines and their controls.

For medium perturbations such as slow changes of ac voltages within ± 10% the dc system response is governed by the convertor current-voltage characteristics and can manifest itself as "crossover instability" with weak ac systems. A possible remedy in such cases is to modify the voltage-current characteristics of the convertor in the so-called "current margin error region" to obtain stable operating points in the whole range. (See Section 4.4.)

Most present-day dc control systems are capable of resynchronizing and commencing correct operation of the dc system within two cycles of clearing of a severe ac fault, such as a three-phase to ground fault. Also the gains and time constraints of the control systems are such that they do not limit or increase the recovery time set by the main system characteristics, and there is no significant delay in changeover between different control modes at the same convertor, for instance from constant γ to constant-current.

With modern thyristor valves there need not be any delay in the recovery due to waiting for recharging of the valve firing supply following ac fault clearing for fault durations (up to a specified maximum) (see Section 4.3.2). Control strategies, designed to obtain the desired optimum response of an integrated ac-dc system, may not always require fast recovery of the dc system from ac faults.

To obtain good dc system recovery, that is, no post-clearing commutation failures, control strategy alternatives can include delay or slow ramp recovery, reduced current level and reduced power level at recovery (especially when part of the receiving or sending end system is disconnected due to some fault). Another method that has been found to be helpful in improving recovery is to switch the dc system control mode (master control level) from constant power control to constant current control. There are several ways of doing this - some explicit, some implicit:

- action taken by the master control to revert to current control on detection of ac voltage depression (explicit).
- placing an upper limit on the current order (at a reduced level or at the prefault level) by the master control; this explicitly states that whenever the power control function orders a current order higher than this fixed limit, the control mode will revert to current control.
- the implicit methods involve filtering, limiting or clamping the dc voltage feedback signal.
- sometimes the time response of the power control function is made very long such that the purpose of power control is to ensure that the operator requested power order is delivered on average (in the steady state) but that for all practical purposes, during transients the control mode can be considered to be constant current. For this purpose, the power controller function has a response time of several seconds.

A voltage dependent current order limit (VDCOL) function is normally provided in dc control systems. (See Section 4.6.) This function can have an important role in determining the dc system recovery from faults, particularly from faults in a weak receiving-end ac system. The action of this function is to limit the current order as a function of the reduction in dc line voltage. There are many variations of the implementation of this function, including:

- differing delays on imposing limits
- ramped or exponential limit application
- stepped or proportional current order reduction
- hysteresis between decreasing and increasing voltage thresholds
- different delays and ramps for release of limits
- different characteristics at different terminals.

The voltage feedback signal used is sometimes actually derived from the rectifier and inverter ac system voltages, rather than the dc line voltage. This is particularly true for back-to-back dc systems.

If the VDCOL function is activated during an inverter ac system fault, the result will be to decrease the dc current and hence the inverter reactive power consumption, thus helping to support the ac system voltage. In the case of severe single line to ground faults, the VDCOL may also help to recover normal commutation and thus some power transfer can resume during the fault. Following fault clearing, the removal of the VDCOL function current limit may be delayed and ramped so as to maximize the recovery rate while avoiding subsequent commutation failures.

One variation is to have VDCOL action at only the rectifier with a high minimum α at the inverter (e.g., 115°). Approximately 40 percent (cos 115°) line voltage must be established by the rectifier before current flows, thus minimizing reactive power consumption. Therefore, the minimum α inverter characteristic relative to the VDCOL characteristic is important. The VDCOL here is applied and released with different time constants.

If single-phase tripping and reclosing are applied in the vicinity of the inverter station, special actions must usually be taken. If the system has a low and very low SCR and the single-phase tripping and reclosing occur on a line that has a large significance for system operation, the dc power has to be reduced during the time between tripping and reclosing to avoid communication failures and other disturbances in the ac system. Such a remedial scheme has been implemented for the Highgate convertor station. For ac lines not in the immediate electrical vicinity of the inverter, single-phase tripping and reclosing would enable a continued dc power transfer [B84].

It should also be noted that following a commutation failure due to an ac fault, the inverter current may not need to be reduced by VDCOL action even for schemes with low SCR. If the disturbance is of short duration (100-200ms), rated current may be held in the dc circuit during the fault, which could subsequently speed up the normal restoration of prefault conditions since no ramping-up process would be necessary. Each scheme would have to be studied in detail to determine the possible advantages of this strategy.

10.2.5 Parameters Affecting Recovery From DC Line Faults

It was previously established that for faults on the dc side, only temporary dc line faults are relevant for dc recovery within a weak ac system.

DC line faults can be caused by flashovers due to lightning overvoltages, insulator contamination flash-overs, flashovers due to overvoltages arising from faults or control malfunctions, insulation flashover caused by airborne pollutants and ionization from such things as forest fires, conductor-tree contact, and tower failures.

Most faults caused by insulation flashovers are temporary in that they can usually be cleared by a short-duration controlled de-energization of the affected pole.

In contrast to ac system faults, where the ac voltage and system behaviour are interactive with the dc behaviour, dc line faults are mainly a matter of the total energy loss for the receiving ac system. However, it is possible to draw down the rectifier ac voltage during the controlled de-energization if the rectifier system is weak. This results from the sudden and large reactive demand during large convertor firing angle changes. This is not likely to be of much significance unless the voltage reduction is very severe and if special problems exist in the rectifier system.

The most common causes of line faults usually result in a single pole fault with the other healthy pole remaining unaffected in terms of power. In some cases where the dc is operating below full load, the healthy pole can quickly increase its power to help compensate for the temporary interruption of power flow on the faulted pole.

Single pole faults in a bipolar system can cause two side effects with respect to electrical operation on the dc side. There will be a surge of neutral or electrode current, equal in magnitude to the healthy pole current, until the faulted pole recovers. Also, the healthy pole can experience a transient overvoltage in the order of 1.7 pu as a result of induction from the sudden voltage collapse on the faulted pole.

In some cases where faults are caused by insulator failures or pollution, recovery to full voltage may not be successful and the fault may simply re-establish itself. Following an unsuccessful recovery attempt, some schemes employ a recovery attempt at reduced voltage in order to recover as much energy as soon as possible. Reduced voltage operation requires the use of higher firing angles, valve group blocking, or a combination of both.

The energy lost to the ac system is ultimately dependent on the total control sequence used to clear the fault. This sequence is basically composed of the fault detection, de-energization control action (rectifier firing angle force-retard), a waiting period or deionization time, and a restart control where the voltage recovers at some predefined set rate.

Faults can be detected by rate of change of voltage sensing at the line ends, by voltage level sensing, by line end current differential, or by some combination of these. The subsequent control action normally retards the rectifier firing angle even into the inverter operating region to quickly absorb all energy from the dc line and deionize the fault.

Since the detection and control action is relatively very fast, the most significant factors affecting the energy loss are the deionization time, the number of restart attempts that may be required to clear a particular fault, and the recovery rate.

Typically, all actions including detection, force retard, and controlled restart to 90% power, but excluding the deionization time, can require less than 50 ms. Depending on many factors including flashover mechanism and air conditions, the deionization time required may be of the order of from 100 to 500 ms to ensure a high restart success rate.

10.2.6 Effect of Compensation Type on Recovery from Faults

During a fault, synchronous compensators reduce the net effective impedance by the shunting effect of their transient reactance. Their effect on stability and recovery from faults depends on speed and optimization of their excitation system.

Static compensators act differently than synchronous compensators in that they neither increase the inertia or necessarily reduce the effective impedance of the ac system. Their effect on the impedance depends on the compensator type and their mode of operation at any particular time. Certain compensator types, if so designed, can react quickly to limit undervoltages and overvoltages during and following faults and also stabilize the voltage. Static compensators cannot directly influence the sensitivity of ac system frequency to fluctuations in power caused by a fault. However, they can be applied to reduce power fluctuations by improving recovery times and stability.

10.3 Different Types of Schemes

Discussion and consideration for recovery from faults for other transmission schemes are generally similar to those described for normal point-to-point transmission. Fundamental differences for various types of schemes which may have to be considered are discussed below.

10.3.1 Back-to-Back Schemes

The fact that a back-to-back transmission system has no dc line and that both the rectifier and the inverter are located in the same building results in some differences, as compared to point-to-point transmission, in the pre-condition for recovery performance.

The control equipment for the rectifier and the inverter are normally so close to each other that it is as easy to interconnect them as to interconnect control subsystems in one convertor station. Thus, control actions can be taken at the same time in both the rectifier and the inverter for ac and dc system faults. This can be used to improve the recovery performance as the rectifier and the inverter can be easily coordinated at recovery.

A consequence of this is the better possibility, when compared to line transmission, of avoiding commutation failures in the inverter connected to a weak ac network, after ac system faults. Another consequence is that the recovery after a fault can be more easily controlled, this being especially important when the receiving ac network has a low or very low SCR. In this case a smooth recovery may be required to prevent the voltage in the network from being so disturbed that subsequent commutation failures occur. For these reasons it is likely that a back-to-back transmission system can be operated with a weaker inverter ac network than is possible for point-to-point transmission.

The delay in recovery after an ac system fault caused by the necessary charging of the line in a point-to-point transmission is, of course, of no consequence in a back-to-back scheme.

A back-to-back transmission link is more easily subjected to harmonic disturbance interactions between the two connected ac networks than a dc system with a long overhead line or cable. Harmonic disturbances in the rectifier ac network may, for that reason, cause distortions in the inverter if the ac network connected to this station has a very low SCR value. A case which must be considered is the recovery after a zero impedance 3-phase fault in the rectifier, especially if the rectifier ac network has a low or very low SCR. When the ac voltage recovers, the inrush current to the convertor transformers causes distortion in the rectifier commutation voltage and the corresponding harmonics are transferred to the inverter ac network via the dc circuit. If the ac system, with the ac filters and shunt banks, at the rectifier is in parallel resonance at, or close, to the second harmonic the distortion will be considerable. This phenomenon must be studied, for instance on a dc simulator, for a specific back-to-back project with weak ac networks to investigate the risk of commutation failures.

10.3.2 Multi-Terminal Schemes

In a multi-terminal dc system with a moderate number of nearly equal rated convertor stations, with none of the connected ac networks having a very low SCR, a recovery performance similar to that for point-to-point transmission can be obtained for ac system faults.

However, if there is a station in the dc system with a significantly lower rating than the average, and especially if its connected ac network has a very low SCR, special precautions may be needed to attain optimal recovery performance for the whole dc system. To judge the significance of the ac network in this case, its short circuit ratio should be related not only to its own convertor capacity but also to the total transmission capacity of the dc system.

This situation may require some precautions for the recovery after a ground fault in any of the connected ac networks. The small convertor, when in inverter operation with its low or very low SCR ac system, may not be able to manage a fast recovery without the risk of an ac voltage collapse which affects the recovery of the whole dc system. On the other hand, fast recovery may be required for the other larger stations. This contradiction may be solved by letting the small convertor recover its dc voltage as quickly as possible in conjunction with all connected convertors but delaying the increase of current through it, enabling the other convertors to have a fast power recovery. In some cases, it may be necessary to block the small convertor to allow other convertors to recover.

A multi-terminal dc scheme can exist in a variety of configurations, especially if it includes four or more convertors. Optimal recovery performance for each configuration requires various recovery control parameters and strategies.

For faults on the dc side in multi-terminal schemes, special considerations can exist for the various configurations. All dc-side faults will, at least temporarily, affect all convertors connected to the faulty pole in all the separate stations of the scheme. In some cases, a permanent fault may involve action sequences to switch and isolate a dc line and/or a convertor. These may involve parallel or radial dc lines and parallel or series convertors. If the isolating switches are full dc breakers, they would be capable of interrupting dc current and withstanding the recovery voltages, and also could provide load breaking capability. Without dc breakers, the action sequence must ensure that the dc currents are reduced to zero and this may require significant station-to-station control coordination, signalling, and delay times. In some configurations, switches may only require a capability to commutate dc current to a parallel path which would be much less duty than full load breaking. Example applications of this would be switches on parallel dc lines or a metallic-return transfer breaker, where dc current is diverted from a ground return to a line conductor current return in a pole.

10.3.3 Multi-Infeed DC Schemes

A special case may be made for situations where more than one dc transmission scheme is feeding into the same ac system, that is, multi-infeed dc. Mention was already made in Section 10.2.3 that it may be advantageous to have staggered recovery of convertors from ac system faults for this situation.

A short circuit ratio defined as the quotient between the network short circuit capacity and the totally installed dc power may be very low in this type of configuration. For that reason, a fast recovery of all dc transmission at the same time after an inverter ac network fault may not be possible. Thus, either such a joint recovery must be made slowly or other measures must be taken to avoid causing a collapse of the ac network voltage at recovery.

For example, two separate inverters may be connected to the same ac bus, or inverters may be connected to different buses in the system. If both inverters have, in principle, identical recovery strategies, then an ac fault may require that the ac system must support the recovery of both inverters or the recovery of total dc power.

Alternatively, it may sometimes be possible to help a particularly weak system by delaying the recovery of one inverter until the first inverter has recovered to normal. It may also have to be determined whether a commutation failure in one inverter could cause sympathetic commutation failures in other inverters by means of ac transferred distortions. Thus, it is important that commutation failures do not also occur in the inverter following recovery after a fault in the rectifier ac network. A rectifier can drive current so fast that inverter γ is reduced to the commutation failure point. A weak inverter ac system can aggravate this effect through a collapsing ac voltage inducing a faster and higher dc line current rise.

10.3.4 Low Inertia Systems

The case of infeed of dc power to an isolated network with low inertia is a special case of the more general one with infeed to a weak network.

An interruption of power transmission in this case causes a decrease in frequency and the control system for the inverter must be designed for operation with a low network frequency. The frequency decrease following a temporary interruption depends on the duration of the fault, the load in the island network during the fault, the speed of recovery of the dc link and the inertia of any synchronous compensators which may be installed to make inverter operation possible. (See Section 9.2.3 and Figure 9.1).

From an economic point of view, it is normally desirable to choose a synchronous compensator which is as small as possible. However, a small machine means both a low inertia, which gives large frequency fluctuations at disturbances, and a low short-circuit power with associated large voltage fluctuations. Studies need to be performed to investigate the necessary size of the synchronous compensator(s).

Since the losses in the network are of great importance for the dynamic performance of dc transmission connected to a low or very low SCR ac network, the loads in the island network should be taken into consideration. An isolated ac network with low inertia is often of small geographic extent and the loads are found electrically close to the inverter bus. This is important for the behaviour of the dc system.

10.4 System Experience and Examples

10.4.1 AC System Faults

The following are some examples of control strategies used to obtain good dc system recoveries and some examples of fault responses from actual systems.

For the Itaipu dc system a 320-ms restart time was found to be better than a 160-ms restart time for a three-phase fault at the inverter. The dc voltage measurement time constant was increased from 50 ms to 500 ms. A current control mode of operation with a prefault value of current order was adopted at the inverter for ac system faults at both Itaipu and Highgate.

Both at Miles City and at Sidney, for a 5-cycle three-phase fault at the inverter, the restart delay after fault clearing is 2 cycles and the recovery current is 0.3 pu. For Miles City, (SCR = 2.0), the recovery rate is 2 pu/s giving a recovery time of 450 ms. At Sidney where the SCR is about 3.5 to 6.0 the recovery rate is 10 pu/s giving a recovery time of 90 ms. For loss of the Sidney-Stegall line the east to west power flow is limited to 125 MW and from west to east it is in the range of 75 MW to 100 MW. This type of power reduction for loss of a critical line is implemented for Highgate also. In the Cross Channel scheme (minimum ESCR 2.5) the recovery to 80 percent of the power varies from 100 ms to 150 ms, depending on the fault.

On the Des Cantons - Comerford dc link between Hydro-Quebec and New England, maximum power order limits are imposed for the loss of certain key ac lines. At Des Cantons, a power order limit is imposed to avoid ac system voltage instability whenever the single 735-kV ac line feeding the substation is disconnected. The limit imposed is a function of both the local load level on the 230-kV network as well as the direction of power exchange over the dc link. The power reduction limits imposed at Comerford are to avoid serious overloads of ac transmission lines or ac voltage stability problems. The limits depend on which ac line is lost and on the direction of power transfer. The limit is imposed instantaneously when the problem associated with a particular outage is related to ac voltage stability. When the problem is related to thermal overload, the power order is ramped to its limit over a period of a minute or more.

On the Nelson River system, bipole 1 maintains valve firing during the fault and advances γ in an attempt to recover commutation. This strategy attempts to recover power as fast as possible. However, the corresponding reactive consumption tends to reduce the ac voltage further and recovery may be critical for certain weak system situations. On bipole 2, a protection sequence is used if the commutating voltage falls below 0.5 pu. The rectifier is then force-retarded by an α-ramp to a 120° limit and the inverter is put into bypass pair operation followed by pulse blocking. When the ac voltage recovers to above 0.85 pu the pulses are deblocked and the current is allowed to recover. Bipole 2 recovers within about 170 ms after fault clearing. The different mechanism and rate of recovery between bipoles 1 and 2 is deemed in some cases to be beneficial for total dc recovery against the low SCR inverter ac system (minimum ESCR = 2.5).

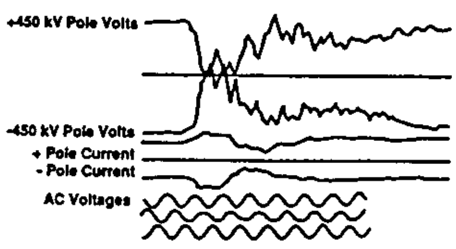


Figure 10.1
Nelson River Bipole 1
Response for AC System Fault

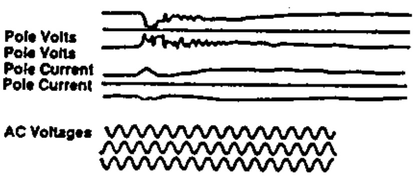


Figure 10.2
Nelson River Bipole 2
Response for AC System Fault

Figures 10.1 and 10.2 show typical commutation failures and responses of Nelson River bipoles 1 and 2 respectively for ac faults remote from the inverters.

Figure 10.3 shows a typical commutation failure at Sellindge terminal of the 2000 MW Cross Channel Link where 60 MW-s was lost during the commutation failure with about another 50 MW-s being lost during the recovery [B83]. In the case of a system having a high SCR value, this would not be noticed except in this case a commutation failure occurred. It was almost certainly due to a phase shift on the 400-kV system which triggered an acceleration-sensitive device on a large generator which consequently unloaded. γ at Sellindge is 15° on 50 Hz, and the fault level is generally in excess of 12 GVA.

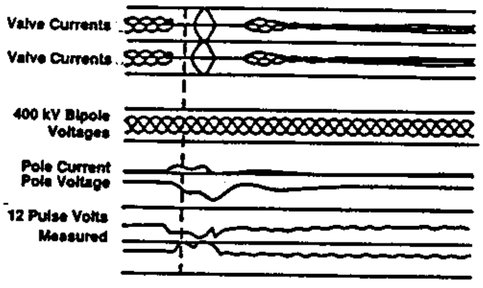


Figure 10.3
Sellindge (Cross Channel) Commutation Failure
Due to Lightning Strike on Remote Circuit

Figure 10.4 illustrates a more unusual event, and gives a rather better illustration of the capabilities of a modern convertor [B83]. Following severe storms in October 1987 in Southern England and Northern France there was significant insulation pollution, resulting in many ac system faults in both countries. One event in particular led to a persistent high impedance line fault which reduced the voltage on one phase of the CEGB 400-kV system to 0.8 pu for about 0.5 s. As Figure 10.4 illustrates, the initial voltage reduction resulted in a commutation failure of the UK inverter, but the dc link was able to resume operation within a few cycles of the beginning of the incident, continuing to transmit almost the ordered power throughout the 0.5 second voltage reduction. The conditions during this event were remarkably stable in that the direct voltage, although somewhat was able to resume operation within a few cycles of the beginning of the incident, continuing to transmit almost the ordered power throughout the 0.5 second voltage reduction. The conditions during this event were remarkably stable in that the direct voltage, although somewhat reduced, was well smoothed by the comparatively large cable capacitance, and the inverter proved capable of continuing to operate with no further commutation failure in the face of severely unbalanced ac network voltages. There has been some occasional discussion on the efficacy of commutation failure prediction circuits. Opinion is divided on whether their advantages outweigh their disadvantages. It is interesting to note that this performance was obtained from a convertor whose normal steady state γ is 15° (on 50° Hz), incorporating no commutation failure prediction circuits.

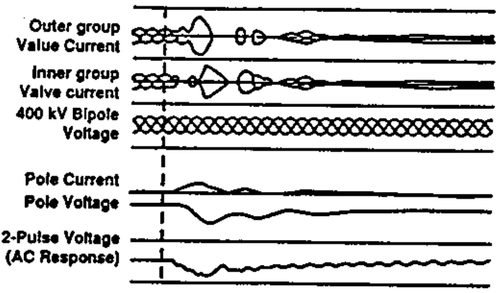
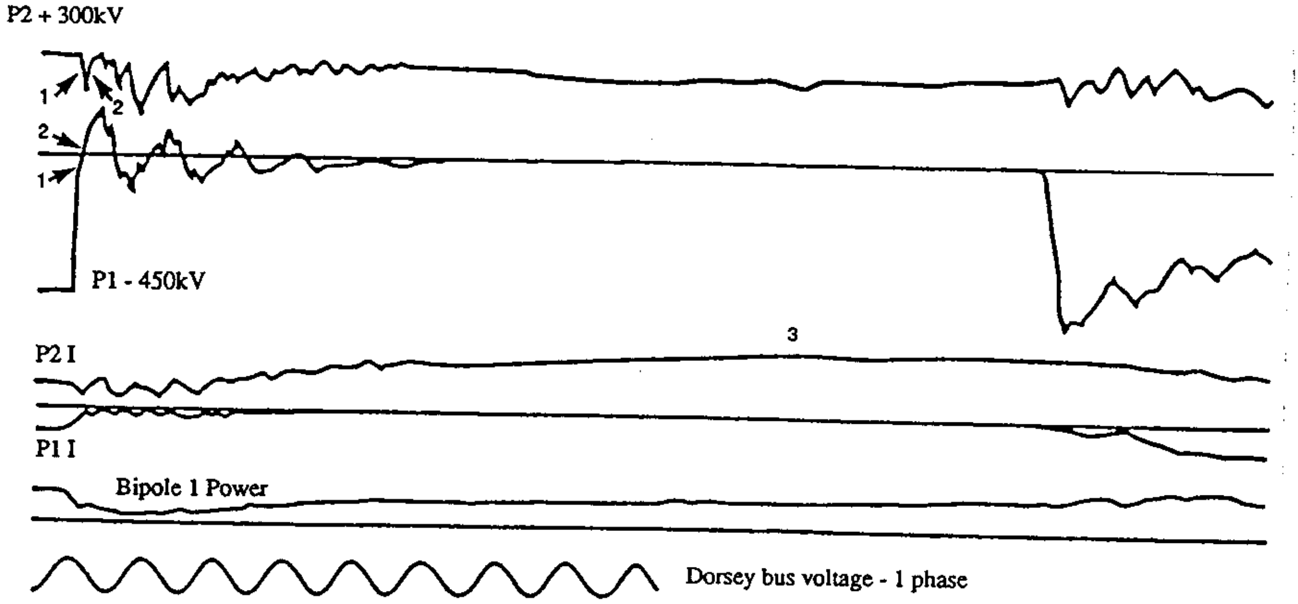


Figure 10.4
Sellindge (Cross Channel) Commutation Recovery
Following Prolonged AC Line - Ground Fault

10.4.2 DC System Faults

On the Nelson River system line fault tests have been conducted in an attempt to determine an acceptable minimum deionization time required to clear a temporary pole to ground fault and allow successful restarts. These tests indicated that 100 ms should be sufficient and this has been implemented. However, there has not been long term experience with natural line faults using this deionization time since, until recently, automatic restarts were not allowed due to power surge constraints imposed by the receiving end ac system.

Figure 10.5 shows the dc response and recovery from a dc line fault. This particular restart used a 200 ms deionization time. These traces also show the fault side effects of induction into the healthy pole, and the healthy pole voltage reduction due to rectifier ac voltage



(1) +ve sequence (metallic mode) wave - opposite polarity induction in healthy pole.
(2) -ve sequence (ground mode) wave - same polarity induction in healthy pole.
(3) The current in Pole 2 increases to compensate for voltage reduction.
Healthy pole voltage reduction is due to rectifier end ac voltage depression, which in turn is due to increased var consumption when forced retard is applied.
Line Travel Time = 3.2 msec

Figure 10.5
DC Line Fault on Nelson River BP-1 Near Rectifier
With Successful Restart (Inverter Traces)

depression with increased reactive consumption during firing angle force-retard.

10.5 Methods and Tools for Studies

Various study tools, ranging from standard load flow and stability programs to full dc simulators can be used to study important aspects of dc recovery from faults.

To study the performance and optimization of the dc side, considerable modelling detail of the dc system and controls is required as well as three-phase representation of the ac network, effect of harmonics, unbalances and non-linearities, etc. For recovery from normal faults up to about 300 ms, however, an ac system can be represented relatively simply as a Thevenin equivalent of fixed emf behind a linear impedance. Machine controls do not have time to change appreciably in this time, and any phase change due to finite inertia is irrelevant to convertors.

DC side studies therefore require the use of dc simulators or their near equivalent digital programs such as electromagnetic transient programs. Studies can include the sensitivity of dc recovery to such things as voltage distortions due to saturation non-linearities, control constants and strategies, and dc current ramp rates.

At an early stage of the dc system design, the dc side studies indicated above may be used to determine the approximate dc response and power transfer for various faults and the possible dc recovery times. This information can then be used to study the corresponding effect of faults on the ac system. An interactive optimization must then take place.

For the fully integrated ac/dc studies, the system stability performance generally depends on the dc power recovery, which in turn depends not only on the dc current recovery rate but also on the ac voltage recovery. In addition, the dynamic stability following faults can be positively influenced by proper dc modulation control to provide damping.

Proper stability studies therefore require some detailed dc system modelling to give at least equivalent responses. The representation should include correct functional simulation of the effects from dc current and γ controllers, master power controls, modulation or damping controls, telecommunication time delays and special dc logic or protection sequences including group blocking, current or voltage ramps and VDCOL.

In general, the models must not be overdetailed in order for events to take place which are consistent with the dc solution time step. For stability purposes, approximations are useful as long as the overall real and reactive power responses are reasonably correct.

A. APPENDIX :
BASICS OF CONVERTOR OPERATION

A1. The DC Conversion Process

A1.1 Steady State Operation

A1.1.1 The Basic DC Convertor

The basic dc convertor is a valve group consisting of six unidirectional valves acting as switches in six-pulse operation, Figure A1. The ac voltage is fed to the convertor through a convertor transformer. In modern convertors the active elements in the valves consist of thyristors, and they are timed to switch in such a way that the voltage between the dc terminals is fixed to the desired value. This is done by the control system, which from different input signals determines when each individual valve should be fired to obtain the appropriate performance. The simplest dc-system consists of two six-pulse bridges connected together by a dc line which carries the direct current. Figure A2 shows such a simple system and how the current flows in the system at a certain instant. Active power is injected into the dc line by a convertor operating as rectifier and is injected into the ac system connected to the other convertor which is operating as inverter. Usually in practical applications two six-pulse bridges are connected in series to obtain twelve-pulse operation which will be explained below.

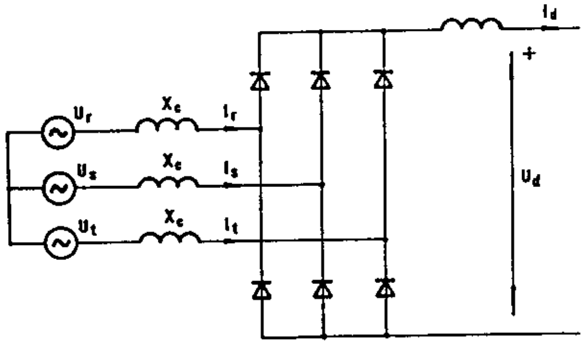


Figure A1
The Basic Six-Pulse Convertor Bridge

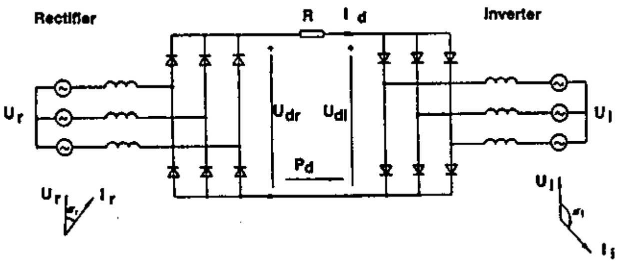


Figure A2
Basic Circuit of an HVDC Link

A1.1.2 Operation of the Basic Six-Pulse Convertor

To explain the operation of a six-pulse convertor it is assumed that a constant, smooth direct current I_d flows through the convertor, Figure A3. The convertor transformer reactance reflected to the dc side, the dc reactors and reactance of the dc line will smooth the current, which justifies this assumption. The voltage between the dc terminals of the convertor consists of the different parts of the phase-to-phase voltages at the dc side of the convertor transformer determined by the switching of the valves. In steady state the firing of the valves is done in such a way that each valve is fired with a fixed delay with reference to the zero-crossing of the voltage across that valve. This delay is measured in electrical degrees and is called delay angle or firing angle and is denoted α. Because of the reactance of the convertor transformers the direct current cannot commutate from one phase to another instantaneously and the dc current is consequently shared between the two phases during the commutation process. A detailed analysis of this process is out of the scope of this appendix and the reader is referred to Bibliography entries [B85] and [B86] for a comprehensive treatment.

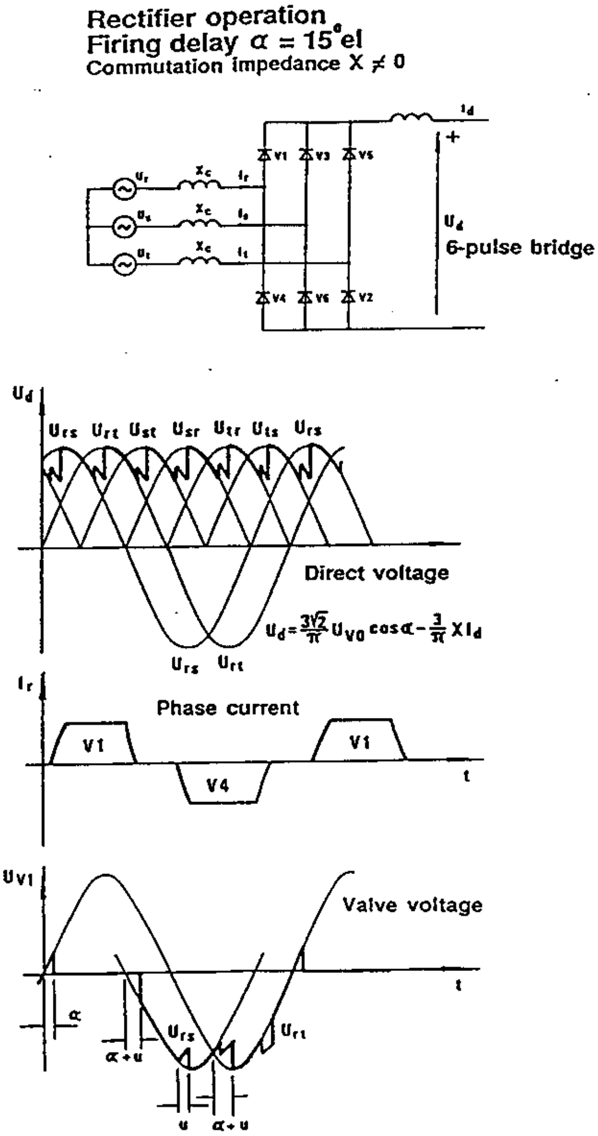


Figure A3
Direct Voltage, Phase Currents and Valve Voltages
of a Six-Pulse Convertor Bridge in Rectifier Operation

A1.1.3 Direct Voltage of Six-pulse Convertor

The resulting voltage shape of a six-pulse convertor is shown in Figure A3 for a convertor operating with α = 15° (rectifier operation). In this figure the phase current and the valve voltage are also shown. The phasors of the ac voltage and the fundamental component of the phase current are depicted in Figure A2. It can be shown that the value of the dc content of the voltage between the convertor terminals is given by (neglecting resistive losses in the convertor and assuming overlap angle u less than 60°, i.e., no double commutation)

$$U_d = \frac{3\sqrt{2}}{\pi} \cos\alpha \; U_{vo} - \frac{3}{\pi} X_c I_d \quad \textit{(rectifier)} \tag{A1}$$

where

U_{vo} is the phase-to-phase rms of the ac voltage at the dc side of the convertor transformer,

X_c is the commutation reactance referred to the valve side of the convertor transformer per phase in ohms,

α is the firing angle.

The commutation reactance should include the leakage reactance of the convertor transformer and other reactances in the commutation circuit that may influence the commutation process. By defining the quantities U_{dio} and d_x through

$$U_{dio} = \frac{3\sqrt{2}}{\pi} U_{vo} \tag{A2}$$

and

$$d_x = \frac{3}{\pi} X_c \frac{I_{dN}}{U_{dioN}} \tag{A3}$$

equation (A1) can be written as

$$U_d = U_{dio} \cos\alpha - d_x \frac{I_d}{I_{dN}} U_{dioN} \tag{A4}$$

(An index N indicates the nominal value of the quantity which usually equals the rated value). The equations (A1) and (A4) are, of course, equivalent and both notations are used in the literature. If the commutation reactance is expressed in pu based on the convertor transformer ac quantities and with the transformer rating equal to $U_{dioN} \cdot I_{dN} \cdot \pi/3$ the quantities d_x and X_c (pu) are related through

$$d_x = \frac{1}{2} X_c(pu) \tag{A5}$$

For small values of α the voltage U_d is positive and the convertor feeds power into the dc system given by $U_d I_d$. If α increases U_d decreases and for an α value approximately equal to 90° U_d vanishes. For still greater values the dc voltage becomes negative which means that power is fed into from the dc side via the convertor into the ac system, inverter operation.

Instead of using the delay angle for specifying the inverter operation, the angle between the current extinction of the valve and the positive going zero crossing of the valve voltage is normally used. This angle is called the extinction angle or commutation margin and is denoted by γ. The voltage across the convertor bridge is given by

$$U_d = \frac{3\sqrt{2}}{\pi} U_{VO} \cos\gamma - \frac{3}{\pi} X_c I_d \quad \textit{(inverter)} \tag{A6}$$

or

$$U_d = U_{dio} \cos\gamma - d_x \frac{I_d}{I_{dN}} U_{dioN} \tag{A6'}$$

with U_d defined as positive in opposite direction from I_d as shown in Fig. A.2 for the inventer. Figure A4 illustrates the dc voltage and phase currents for an inverter. Additional diagrams as for the rectifier are also given in this figure.

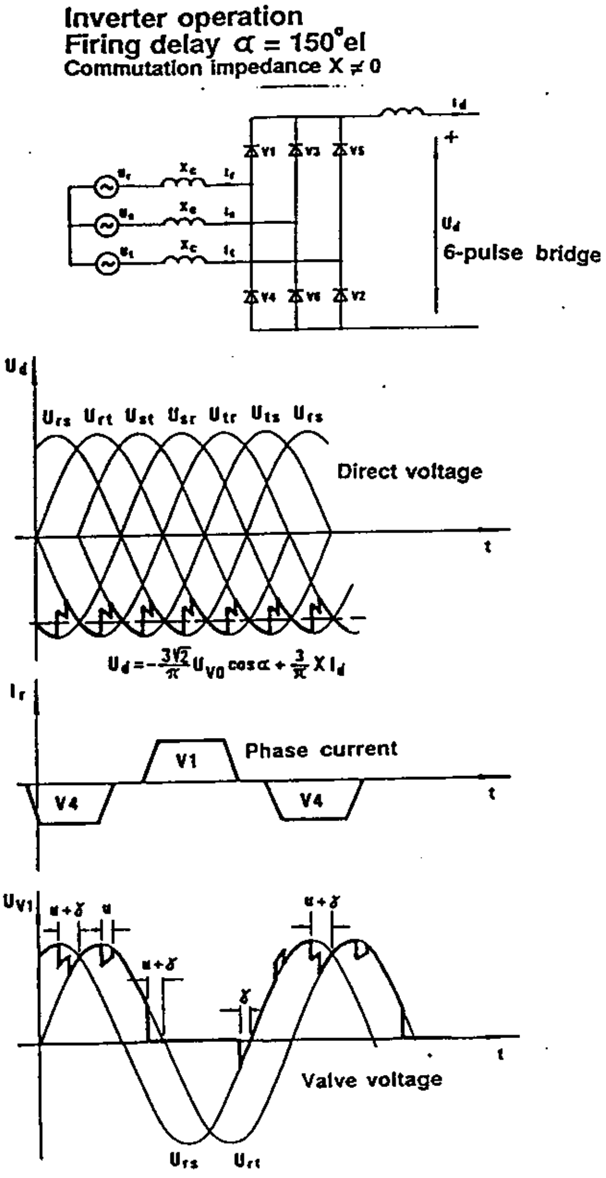


Figure A4
Direct Voltage, Phase Currents and Valve Voltages of a Six-Pulse Convertor Bridge in Inverter Operation

A1.1.4 Reactive Power Consumption

An important observation from figures A2, A3 and A4 is that the phase currents lag the phase voltages both for a rectifier and for an inverter. This means that a convertor always consumes reactive power whether it operates as a rectifier or as an inverter. This is a generic characteristic of a line-commutated convertor. It can be shown that the reactive power consumption of a convertor is given by

$$Q_d = \frac{3\sqrt{2}}{\pi} K_q \, I_d \, U_{vo} \tag{A7}$$

or equivalently

$$Q_d = K_q \, I_d \, U_{dio} \tag{A7'}$$

with

$$K_q = \frac{1}{4} \, \frac{2u + \sin 2\alpha - \sin(2\alpha + 2u)}{\cos\alpha - \cos(\alpha + u)} \tag{A8}$$

and u is the overlap angle (radians) determined from

$$\cos\alpha - \cos(\alpha + u) = \sqrt{2} \, X_c \, \frac{I_d}{U_{vo}} \tag{A9}$$

or

$$\cos\alpha - \cos(\alpha + u) = 2 \, d_x \, \frac{I_d}{I_{dN}} \, \frac{U_{dioN}}{U_{dio}} \tag{A9'}$$

The relationship between the angles α, u and γ is

$$\alpha + u + \gamma = 180^\circ \quad (\pi \text{ radians}) \tag{A10}$$

An alternative formula for the reactive power is given by

$$Q_d = U_d \, I_d \tan\Phi = P_d \tan\Phi \tag{A11}$$

with

$$\tan\Phi = \frac{2u + \sin 2\alpha - \sin(2\alpha + 2u)}{\cos 2\alpha - \cos(2\alpha + 2u)} \tag{A12}$$

with u in radians or approximately

$$\cos\Phi = \frac{1}{2}\left[\cos\alpha + \cos(\alpha + u)\right]$$

The angle Φ can thus be regarded as an equivalent load angle for the convertor.

Equations (A7) - (A12) apply to both rectifier and inverter operations. However, for inverter operation due consideration must be taken to the signs of P_d and I_d. Inverter operation equations (A7) - (A12) can also be used if α is replaced by γ, which is the normal way of expressing reactive power consumption for an inverter.

Figures A5a and b show the relation between Q_d and P_d for typical values of d_x, x_c and α(γ). The dc voltage is assumed to be held at the nominal value.

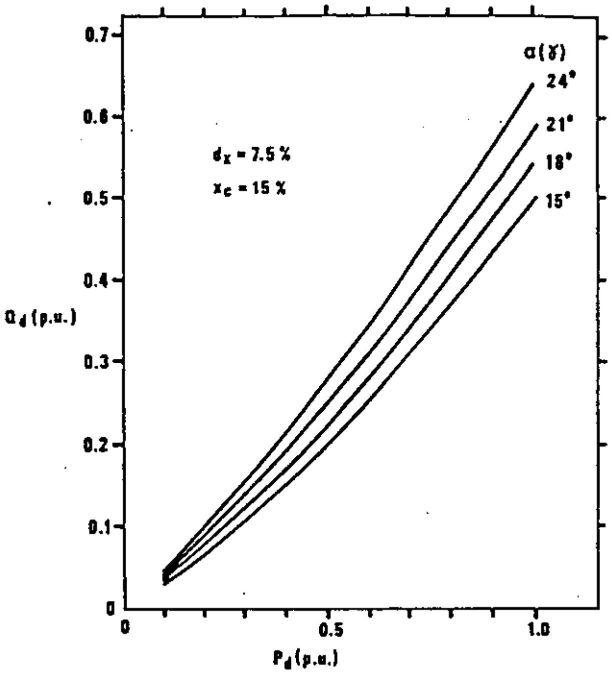


Figure A5a
Reactive Power Consumption of an HVDC Convertor as Function of the Active Power for Different Values of the Delay Angle (α or γ)

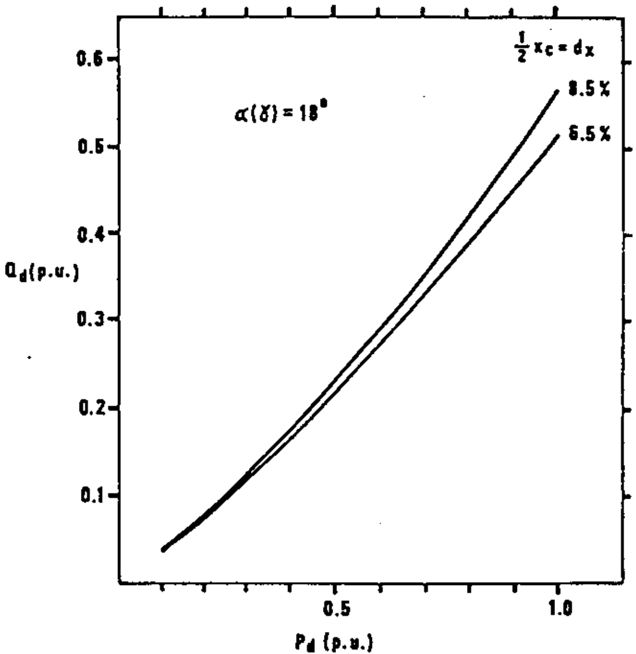


Figure A5b
Reactive Power Consumption of an HVDC Convertor as Function of the Active Power for Different Values of the Commutating Reactance

The above exact formula can be cumbersome to use for hand calculations. For most applications the following approximate formulae give satisfactory results:

$$Q_d \approx P_d \left[\left(\frac{3\sqrt{2}}{\pi} \, \frac{U_{vo}}{U_d} \right)^2 - 1 \right]^{1/2} \tag{A13}$$

or

$$Q_d = P_d \tan \left\{ \cos^{-1} (\cos \alpha - K d_x) \right\} \; where \; K = I_d / I_{dN} \tag{A13'}$$

$$Q_d \approx P_d \left[\left(\frac{U_{dio}}{U_d} \right)^2 - 1 \right]^{1/2} \tag{A13"}$$

(These formulae yield a value of the reactive power that is too high, but the error is at maximum a few percent for typical system parameters.)

The reactive power consumption of the convertors is of significance for the discussion in Chapters 2 and 3 and therefore the formulae above will be discussed and illustrated here. It is obvious that an increase in active power causes increased reactive power consumption if the firing angles are kept constant. A simple analysis shows also that an increase in d_x (x_c) or firing angle (extinction angle) also causes a larger reactive power consumption. A convertor with $d_x = 7.5\%$ ($x_c = 15\%$) and $\alpha(\gamma) = 18°$ consumes 0.54 pu reactive power at 1 pu active power. If the nominal $\alpha(\gamma)$ is increased to 19° the reactive power goes up to 0.56 pu. By increasing d_x to 8.5% (x_c to 17%), and keeping $\alpha(\gamma)$ at 18°, the reactive power rated load increases to 0.57 pu. These figures apply to steady state at rated conditions. If any variable quantity changes it value, e.g, I_d or $\alpha(\gamma)$, the effect on the reactive power depends on the control mode of the convertor, which is discussed in Chapters 2 and 3.

A1.1.5 Harmonic Generation

As seen from Figures A3 and A4 the phase currents and dc voltages contain harmonics, and a Fourier expansion of these shows that the current on the ac side contains harmonics of order

$$n_I = 6\,k \pm 1, \; k = 1, 2, \ldots \tag{A14}$$

and the dc voltage contains harmonics of order

$$n_u = 6k, \; k = 1, 2, \ldots \tag{A15}$$

The amplitudes of the harmonic currents and voltages are approximately proportional to the inverse of the order of the harmonic.

A1.1.6 Twelve-Pulse Operation

Normally two six-pulse convertors are connected in series to obtain twelve-pulse operation. This is obtained by introducing a 30° phase shift between the convertor transformers of the two six-pulse convertors, e.g., by using one Y/Y and one Y/Δ connected transformer. By doing this, a smoother dc voltage is obtained and the total phase current becomes more sinusoidal, see Figure A6. Ideally, harmonics of order

$$n_u = 12k, \; k = 1, 2, \ldots \tag{A16}$$

are present in the dc voltage and harmonics of order

$$n_I = 12k \pm 1, \; k = 1, 2, \ldots \tag{A17}$$

in the phase currents. Harmonics of the orders given by equations (A14) - (A15) and (A16) - (A17) are called characteristic six-pulse and twelve-pulse harmonics, respectively. Due to imperfections and unbalances in the system, harmonics of other orders occur. Also, a more detailed modelling of the components in the DC-system would show that harmonics other than the characteristic ones are created. The characteristic harmonics are usually dominating, but consideration must be taken to the non-characteristic harmonics. Filters are normally installed to filter the principal harmonics.

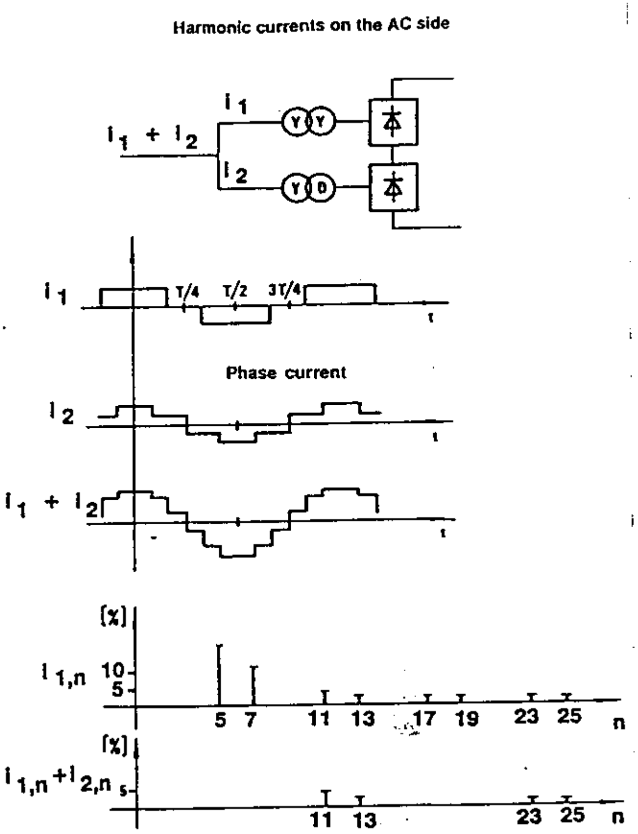


Figure A6
Phase Currents and Harmonic Content of Phase Currents of Six-Pulse and Twelve-Pulse Convertors

A1.1.7 DC System Operation

A very brief description of how a DC system, including its control system, normally is operated will be given below. A two terminal system consists basically of a rectifier, a dc line, an inverter and a control system, see Figure A7. The dc current I_d, is determined by the voltage difference between the rectifier and the dc line resistance

$$I_d = \frac{U_{dR} - U_{dI}}{R_d} \tag{A18}$$

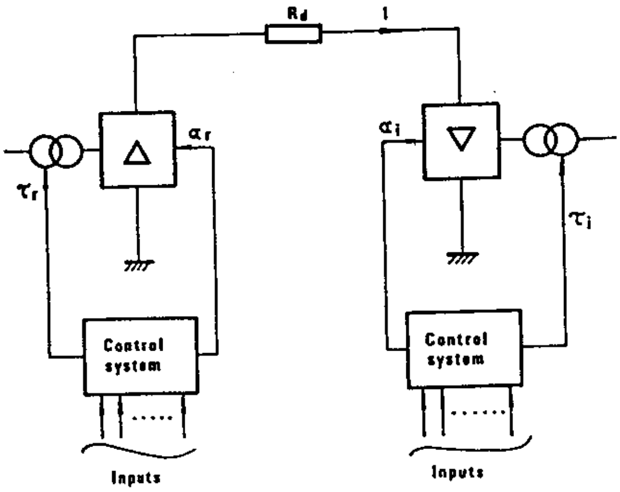


Figure A7
Schematic and Simplified Description of an HVDC System

The voltages U_{dR} and U_{dI} are given by equations (A1) and (A6), respectively, and can consequently be controlled by the firing angles of the convertors. Normally, the inverter is operated in such a way that γ is at the minimum permissible value, γ_{min} (see A1. 2), which is in the range 15° - 18°. In real time (i.e., microseconds), a minimum extinction angle, γ_{min}, of 15° for a 50 Hz system is equivalent to 18° for a 60 Hz system (833µs). By doing this, the reactive power consumption of the inverter is minimized and the cost of the valves is minimized. The desired value of the dc current is now obtained by adjusting the firing angle in the rectifier. To minimize the losses of the dc line, the dc voltage should be as high as possible. Since γ is at the minimum value, the voltage is controlled by changing the turns ratio of the inverter convertor transformers by the tap changers. The tap changers are also used in the rectifier in such a way that the firing angle is typically around 15°, so that for small ac voltage variations the rectifier can maintain the required current without waiting for tap changer action.

The current order to the current controller is either obtained directly as an input, e.g., from the dispatcher, or from a power controller. The power controller determines the current order through

$$I_{do} = \frac{P_{do}}{U_d\ meas} \tag{A19}$$

with obvious notation. Usually some filtering is included in the measurement of U_d to avoid action due to fast transients.

A1.2 Commutation Failures

From the ac system point of view it is important that the behaviour of the DC system during transients and disturbances in the system is such that the stability and performance of the overall system is maintained. To avoid this, special consideration must be taken. A phenomenon that plays an important role in this context is the commutation failure which will be briefly discussed here.

To establish a forward blocking capability of a valve the stored charges in the thyristors established during the conduction interval must be removed. Therefore, the valve requires a certain negative voltage-time area, before it can exhibit a forward blocking capability. This imposes no problem for a rectifier but could cause difficulties during inverter operation. As discussed above it is desirable to keep γ as small as possible and if for some reason, e.g., a sudden reduction of the ac voltage in the inverter, the forward blocking capability is not established before the zero-crossing of the valve voltage, a commutation failure will occur as explained below.

Consider a commutation from valve V1 to valve V3 in Figure A8. Assume that after the firing of valve V3 some disturbance in the voltage occurs which reduces the remaining voltage-time area for valve V1 in such a way that no forward blocking capability is obtained for valve V1. Consequently, the current through valve V1 starts to increase while the current through valve V3 reduces to zero again. The next commutation that will take place is from valve V2 to valve V4, and if this commutation is successful that means that both valves V1 and V4 are conducting current at the same time and the six-pulse bridge is short-circuited on the dc side.

The dc current will now increase and the dc line will be discharged through the by-pass pair. The dc voltage across the six-pulse group will remain zero until the current is commutated from valve V4 to V6. At this time the dc voltage starts to increase and the following commutations take place in a normal way and normal operation is resumed. Since the dc voltage is zero during a period of time following the commutation failure, no active power will be transmitted during this time. This might impose a substantial disturbance on the ac system. If the system is weak this loss of power could cause such severe disturbances on the ac system that it results in consequential commutation failures. It is therefore of great importance that the system is designed in such a way that commutation failures are avoided for frequent disturbances in the ac system.

The minimum permissible commutation margin, γ_{min}, is determined from the negative voltage-time area required for thyristors to exhibit forward blocking capacity. When determining γ_{min} consideration must be taken of the asymmetries in the voltage distribution of series connected thyristors, security margins, variation in component values, etc.

Commutation failure

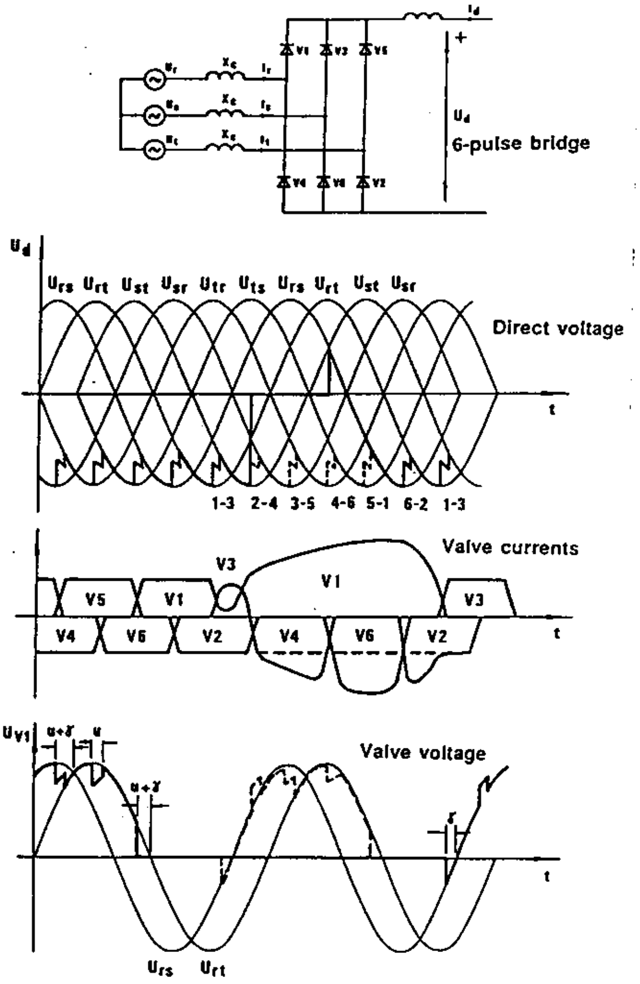


Figure A8
Direct Voltage, Valve Currents and Valve Voltages
During a Commutation Failure in a Convertor Bridge

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21, rue d'Artois
FR-75 008 PARIS
Tél. : +33 1 53 89 12 90
Fax : +33 1 53 89 12 99

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