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SYSTEMS WITH MULTIPLE DC INFEED

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SYSTEMS WITH MULTIPLE DC INFEED

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The convener would like to express his gratitude to Professor John Reeve who contributed greatly to the formative discussions before his untimely passing.

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EXECUTIVE SUMMARY

The characteristics of transmission systems with a single HVDC link or with multiple links electrically distant are fairly well known, with a wealth of experience obtained through studies and operations over the last half century. The increasing usage of electrical power, especially in developing countries, has led to configurations wherein multiple HVDC links are now appearing in electrically close proximity. An understanding of such systems must evolve from a series of independent single HVdc infeed ac system assessments, to one of how all HVdc links interact with one another and with the ac system as a whole.

In providing the framework for such an understanding, the intent of the guide is to provide a seamless transition between single and multiinfeed HVdc systems. To the extent possible, concepts applicable to single infeed HVdc systems have been extended to multiinfeed HVdc systems with a minimum of new terms to breach the differences between the two. Conversely, a multiinfeed HVdc system collapses into the conventional concepts of a single infeed HVdc system where electrical distances so warrant.

Aim of the Technical Brochure

The principal aim of the technical brochure is to provide planners of electrical transmission insight into the opportunities and challenges presented by the presence of multiple HVdc inverters in relatively close proximity. The benefits are not necessarily confined to planners. System operators, manufacturers, power generators, and regulators may also gain knowledge beneficial to their own requirements. The brochure does not replace the need for detailed technical studies but rather provides guidance and understanding to such studies.

The brochure goes beyond a theoretical development, by providing examples of multiinfeed planning that have occurred throughout the world.

A Basic Indicator

Critical to the planning process for a system involving HVdc is the real and reactive power interchange between the HVdc system and the ac system to which it is connected. Control systems associated with an HVdc link can provide a degree of optimization, but the inverter ac voltage waveform is paramount. Ideally, the ac voltage waveform should be distortionless and at or near unity in magnitude. An indicator based on the observed ac voltage change at one inverter ac bus for a small ac voltage change at another inverter bus provides a first level indication of the degree of interaction between two HVdc systems. This interaction factor is called the Multi Infeed Interaction Factor and is defined mathematically as:

$$\boldsymbol{MIIF_{e,n}} = \frac{\Delta \boldsymbol{V_e}}{\Delta \boldsymbol{V_n}} \qquad (1)$$

Where ΔVe is the observed voltage change at bus e for a small induced voltage change at bus n. Inverter ac busses electrically far apart will have MIIF values approaching zero, while MIIF values approaching unity indicate ac busses that are very close. MIIF values above about 0.15 indicate the possibility of some degree of interaction. For ac systems with many HVdc links, a matrix of MIIF values can be formed. MIIF values can be easily derived by using a transient stability program.

The approach above is sufficient if the HVdc links are of similar capacity. In situations where one HVdc link has much greater megawatt capacity than another, then MIIF values should be weighted by the HVdc power of the remote link and compared to the power of the inverter under investigation. If a remote HVdc system is relatively large in power, that system may have more influence over an ac bus than the inverter directly connected to it itself.

System Strength

Single infeed HVdc systems use a basic parameter called the Effective Short Circuit Ratio (ESCR) to assess whether or not the ac system into which the HVdc system is operating is sufficiently strong to support the operation of the HVdc system. For HVdc system i this is defined as:

$$\text{ESCRi} = (\text{SCCi} - \text{Qfi}) / \text{Pdci} \qquad (2)$$

Where SCCi is the short circuit level present at the inverter bus, Qfi is the shunt compensation present on the inverter bus, and Pdci is the rated power of the HVdc link. The stronger the ac system, as reflected in the short circuit level, generally the better is the HVdc performance. Most systems plan for an ESCR level above 2.0 at rated power.

In a multiinfeed context, equation 2 may produce optimistic results, for now the short circuit levels appearing at the respective inverter ac busses cannot be considered as dedicated to the associated HVdc link, but rather must be shared amongst HVdc links in proximity. Equation 2 can be extended to the multinfeed environment to be:

$$\boldsymbol{MIESCR_i} = \frac{(\boldsymbol{SCC_i} - \boldsymbol{Qf_i})}{\boldsymbol{Pdc_i} + \sum_{\boldsymbol{j}} (\boldsymbol{MIIF_{j,i}} \times \boldsymbol{Pdc_j})} \qquad (3)$$

Where MIESCR is the multiinfeed definition of ESCR and the subscript j refers to all other HVdc links in electrical proximity.

By this definition, an HVdc link may be embedded in a relatively weak MIESCR system, say around two, whereas a conventional calculation as per equation 2 might indicate that the system is relatively strong at say four or five.

Armed with some basic definitions, it is then possible to extend specific technical phenomena to systems with multiinfeed HVdc.

The Four Interaction Phenomena

The four technical interaction phenomena of greatest interest in a multiinfeed network are:

- Transient Over Voltage (TOV)
- Commutation Failure including Fault Recovery
- Harmonic Interaction
- Power Voltage Instability and Control Interaction

These interaction phenomena are considered for overhead systems and also for cable systems. For each of these phenomena, study methods are described as are mitigation strategies for problem situations. Much of the investigative work was performed with a modified version of the CIGRE HVdc benchmark model.

Transient Over Voltage (TOV) - The worst case TOV would be if all HVdc links blocked simultaneously. While possible in some systems and so can be considered an outer bound, in most situations the worst case TOV would derive from the simultaneous commutation failures of multiple HVdc links. The following figure presents a graph of worst case TOV versus MIESCR with typical HVdc system parameters. It should also be noted the dependence of TOV on system angle.

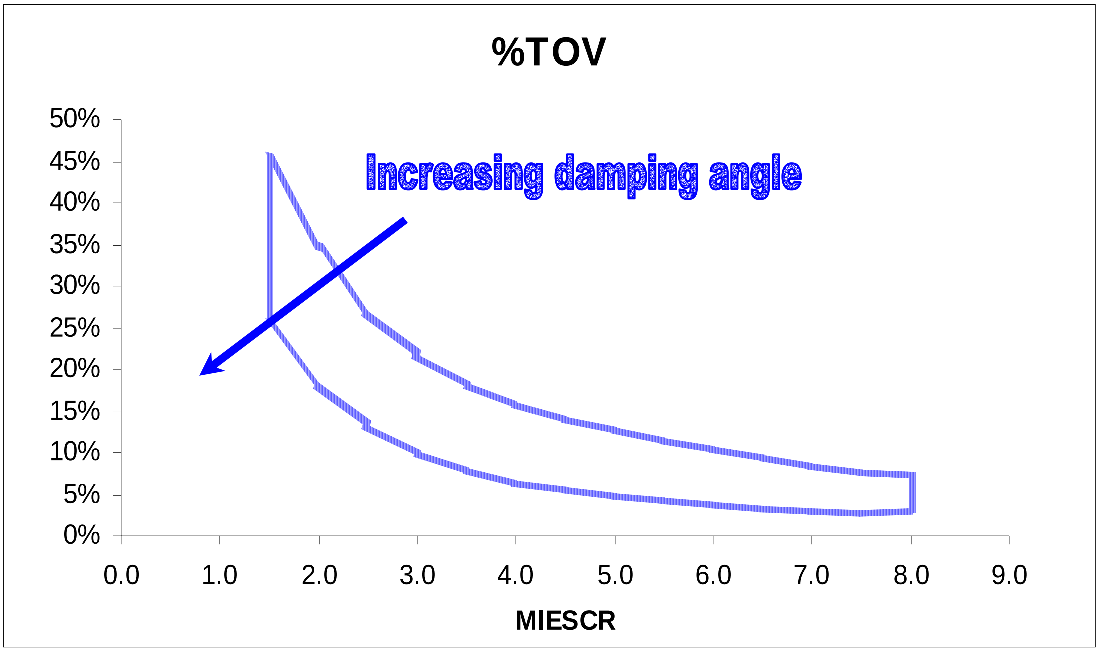

Figure 1: TOV versus MIESCR in a Multiinfeed Environment

Commutation Failure Including Fault Recovery - An HVdc system undergoing commutation failure will require additional MVAr to the point where other nearby HVdc systems may also suffer commutation failure, whereas the fault by itself would not do so. Systems more greatly interconnected, as evidenced by higher MIIFs, and systems with lower values of MIESCR are at greater risk. The guide attempts to quantify such risks. Of particular use is a contour map which links together busses where a fault produces the same voltage at the inverter bus in question and is expected to just induce commutation failure. Figure 2 is a contour map from the Manitoba Hydro system in Canada.

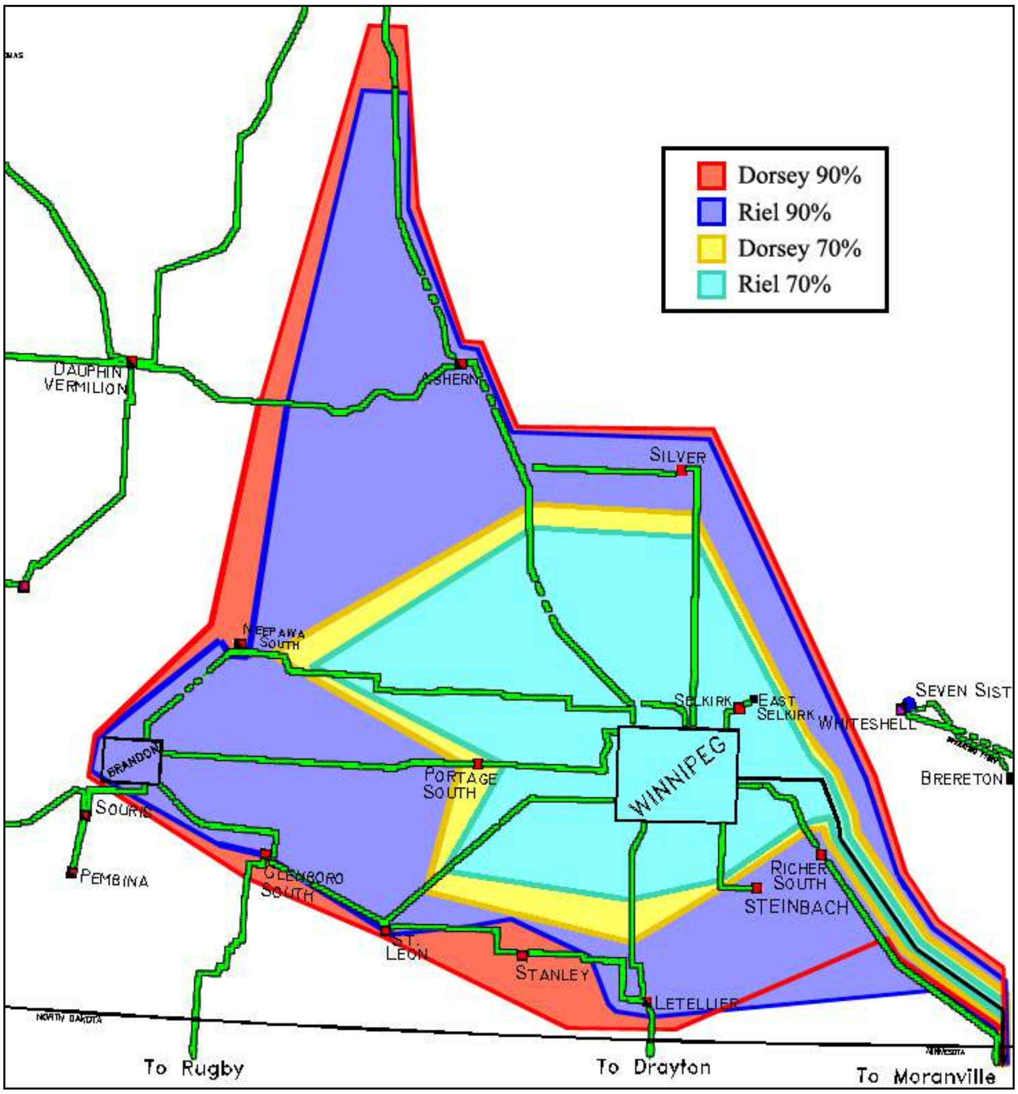

Figure 2: 230 kV Contour Map for the Dorsey and Riel Inverter Stations

Harmonic Interaction - Harmonic studies can be relatively complex requiring detailed study but it is reasonable to assume that inverters in closer proximity have a greater chance to interact harmonically. Inverters with linking MIIF values below 0.1 have virtually no chance of interacting harmonically.

Power Voltage Instability and Control Interaction - In single infeed HVdc systems, the chance of power voltage instability occurring is mostly related to the ESCR at the inverter; the actual ESCR being below the critical ESCR leading to voltage collapse. This concept can be extended to a multiinfeed system through the calculation of MIESCR. Since MIESCRs are often significantly lower than ESCRs, it is important to understand and avoid such very problematic conditions.

Conventional converter controls are not expected to adversely interact. Specialized auxiliary controls need to be coordinated according to the demands of the ac system.

Example Systems

Chapter 3 in the guide provides detailed examples of multiinfeed planning and operating situations in the world today. The examples chosen include Canada, Norway, China, and Denmark. All examples illustrate relatively tight coupling amongst converter stations which in turn precipitates relatively low MIESCR conditions, whereas a conventional calculation of ESCR would indicate otherwise.

The Future

Many of the guide concepts are either relatively new or reformulated in a different manner. Future work may want to expand further on the work done here. Additionally, the guide has intentionally limited itself to the analysis of line commutated inverters. Although some basic interaction truths can be inferred, further work would be desirable on interactions with voltage source converters, capacitively commutated converters, and line commutated rectifiers.

PREFACE

HVdc planning in the past has been dominated by considerations of individual HVdc link performance, specifically the performance of each link as it interfaces with its associated converter ac busses. With the proliferation of HVdc links within specific ac systems starting to occur, consideration must also be given to the influence each link has on other links in electrical proximity, ultimately determining the overall performance of the integrated ac/dc system.

In drawing upon the extensive research of the past, this guide provides a usable framework for system planning which encompasses HVdc multiinfeed systems. The guide provides a methodology for the understanding of multiinfeed HVdc performance within any particular ac system, by so doing pointing to the nature and the extent of necessary detailed studies. It is the intent of the guide to provide a framework that can be readily understood, especially by engineers that have had limited exposure to HVdc.

The challenge in this guide was in coming to a common understanding of what that framework should be. The commitment, perseverance, and abilities of the working group were instrumental to the final product and for that I am most grateful.

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April, 2008

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ACRONYMS

Please see text for a more detailed description.

HVdc - High Voltage direct current
CCC - Capacitor Commutated Converter
VSC - Voltage Source Converter
FACTS - Flexible AC Transmission Systems
SVC - Static Var Compensator
TSO - Transmission System Operator
CHP - Combined Heat and Power
GTO - Gate Turn Off Thyristor
IGBT - Insulated Gate Bipolar Transistor
PSCAD/EMTDC - a detailed time domain power system simulation tool
EMTP - a detailed time domain power system simulation tool

Pdc - HVdc power level
SCC - Short Circuit Capacity
MIIF - Multiinfeed Interaction Factor
SCR - Short Circuit Ratio
ESCR - Effective Short Circuit Ratio
MISCR - Multiinfeed Interactive Short Circuit Ratio
MIESCR - Multiinfeed Interactive Effective Short Circuit Ratio
CMIESCR - Critical Multiinfeed Interactive Effective Short Circuit Ratio
MSCR - Multiinfeed Short Circuit Ratio (alternate definition)
MESCR - Multiinfeed Effective Short Circuit Ratio (alternate definition)

TOV - Transient Over Voltage
CFII - Commutation Failure Immunity Index
PBR - Power Based Ratio
MPC - Maximum Power Curve
PV - Power Voltage
VQ - Voltage Var
Q_f - HVdc converter bus filters and capacitors
X_{avg} - Average system impedance seen from a converter bus

1. CHAPTER 1 - INTRODUCTION OF MULTIINFEED CONCEPTS

1.1. Introduction

The historical application of HVdc systems occurred in situations where significant technical and economic advantages accrued over comparable HVac systems. Often an HVac technical solution did not exist. HVdc systems were implemented for:

- Long distance overhead bulk power transmittal.
- Connecting systems of different nominal frequencies.
- Connecting asynchronous systems.
- Cable systems, especially undersea over longer distances.

Such situations were specialized and relatively sparse and as a consequence the interaction between adjacent HVdc systems was only rarely a consideration.

In recent years, a number of factors have contributed to an increasing consideration of HVdc applications. As a result, HVdc systems are being planned in closer proximity and their influence on each other, as it affects overall ac system performance, is a significant planning concern.

One important factor is the spread of deregulation into electrical markets around the world. Utilities are no longer monolithic generation, transmission, and distribution entities making decisions within that limited sphere, but rather separate units taking a larger view and making decisions which benefit their own particular commerce. In such a realm, HVdc is a valuable tool in connecting diverse areas for the economic advantage of all.

A second factor is the maturing of line commutated HVdc technology, with attendant gains in cost and reliability. HVdc is being considered as a connection alternative in more types of applications. Furthering that consideration are new forms of HVdc, such as CCC (capacitor commutated converter) and VSC (voltage sourced converter) which bring technological benefits in certain systems.

Finally, with the factors as mentioned above, the rapidly growing electrification of developing countries has resulted in the implementation or planning of new HVdc systems. Countries such as China and India, with high population densities in certain areas are starting to implement multiple HVdc links terminating in close electrical proximity.

This guide will give the planning engineer important technical direction for the implementation of multiinfeed HVdc systems. The guide will concentrate on the use of line commutated converters. Also, the implications of the different characteristics of cables compared with overhead lines will be addressed. The guide focuses on system aspects and does not delve into other issues such as interaction between electrodes or lines operating in the same corridor.

The guide can provide basic insight into the interaction process as a guide to planning, but naturally cannot provide specific details of the wide range of potential system configurations.

This guide will concentrate on the interaction between inverters, being typically more problematic. It is expected that other interactive effects between rectifiers or a combination of rectifiers and inverters may be inferred from this guide while not being specifically addressed. Each inverter is assumed to be self-compensated.

Chapter 3 of the guide will be devoted to completed planning studies and operational experience related to multiinfeed situations. Its focus will be to illustrate how the predicted effects, as described in previous chapters, have occurred in practice.

It is important to note that technically there is no inherent maximum number of HVdc links that may co-exist in a relatively congested electrical space. However, as the density of HVdc links increases, the sharing of system short circuit level by all affected inverters may lower to the point where further HVdc development is difficult. Based on detailed technical studies and with the aid of concepts contained within this guide, it will be the judgment of individual utilities as to whether or not any such limitation has been reached.

1.2. A Historical Perspective

An interesting place to begin is with the first paper listed in the bibliography that accompanies this report. Titled ***Aspects of Multiple Infeed of HVDC Inverter Stations Into a Common AC System,*** it was written by Peter Lips and presented at the IEEE Power Engineering Society Summer Meeting in 1972 [1]. The paper investigates power frequency and harmonic issues when multiple inverters are added into a distribution system, as in a dense urban area. Quoting from the Abstract, "for multiple infeed, each station can be dealt with separately with regard to its rating and that increasing the number of inverter stations connected to the same system does not increase the danger of harmonic instability."

A very perceptive comment is presented later in the Introduction: "The question is, what is the amount of inverter infeed an ac system can take for satisfactory performance, if the converter stations are closely neighbored and their ac busbars interconnected by links of low impedance. This is of special interest for the supply of crowded city areas by means of distributed inverter stations, which is seriously studied in several cases. In this paper, the parameters influencing the permissible converter rating will be discussed on a general basis."

The paper also elaborates on the influence of ac system short circuit capacity for inverter stations. And so, even though the study is directed toward urban infeeds, it identifies the critical issues of the short circuit ratio at and the impedance between converter stations that are attended to in this report.

It is also of interest to note that in the published discussions of the paper, the question is raised of commutation failures at nearby inverter stations triggered by voltage distortion from a commutation failure in one inverter station. This important issue also receives considerable attention in this report.

A second significant bibliography entry is ***DC Multi-Infeed Study*** [2]. This study was performed by CEPEL Laboratories in Rio de Janeiro, Brazil and the University of Wisconsin-Madison, United States, and the report was published in 1995 by EPRI. The genesis of this study arose from an increase in the number of dc converters that were electrically adjacent. This included the Scandinavia/Baltic regions, the Nelson River (Canada) and Itaipu (Brazil) double bipole systems, and the Los Angeles area fed by both the Pacific HVdc Intertie and the Intermountain Power Project. Quoting from the Abstract, "Power system studies have been performed using several digital (Load-Flow, Transient Stability, Eigenvalue, and EMTP programs) and analog (dc Simulator) tools in a complementary basis to investigate both low and high frequency interaction phenomena." The study was based on a realistic multiinfeed dc system with a detailed parallel ac network. Commutation failures following fault recovery received significant attention.

The third bibliography entry of note is number 23, ***Coordination of Controls of Multiple FACTS/HVDC Links in the Same System.*** This report was prepared by CIGRÉ Working Group 14.29 and published in 1999 [3]. The network studied was similar to that from the study of reference 2, above. Control interactions that were investigated included:

- Steady-state voltage/power stability
- Commutation failure interaction
- Electromechanical stability interactions
- Control mode stability interactions
- Electromagnetic stability and nonlinear interactions

A notable comment from the paper is the following: "The end result of any undesired interaction between dc links will be limits placed on the transfer capability of the transmission system, a condition not to be tolerated in a day and age when so much effort is being applied to utilize existing transmission systems to their fullest extent."

A fourth bibliography entry of note is number 31, ***On Voltage and Power Stability in AC/DC Systems.*** This report was prepared by CIGRÉ Working Group 14.05 and published in 2003 [4] and provides the most recent thorough summary of multiinfeed system analysis in the area of voltage and power stability.

The report that follows expands on the key elements mentioned above. The earlier authors recognized the need for a multi-dimensional measure of interaction potential, somewhat analogous to the concept of short circuit ratio (SCR) but applied to multiple inverters. That development is included in this report, the Multi Infeed Interaction Factor (MIIF) and the related calculation Multi Infeed Effective Short Circuit Ratio (MIESCR). It is a major contribution to our understanding of the performance of nearby inverters. Additionally, there is significant work presented on regions of possible commutation failure problems. So this report builds well upon the earlier work mentioned above.

1.3. The Test System

A common test system provides a basis for comparison of different technologies. It is intended to reveal significant interaction phenomena without undue complexity.

The parametric quantities important for study on the test system are:

- Short circuit levels on the converter buses.
- Electrical proximity of the converter buses.
- Relative converter power ratings.
- Reactive compensation at the converter buses.
- HVdc control strategies.
- HVdc line type, overhead or cable.

In evaluating these parametric variations, the following phenomena will be of interest:

- ac fault recovery.
- dc fault recovery.
- Small signal interactions.
- Harmonic interactions.

- Commutation failure performance.
- Power/voltage instability.

The test system of this guide, as shown in figure 1-1, is very similar to that used in CIGRÉ Report 14.29 on control interactions. Each HVdc system uses a standard control strategy of constant current control at the rectifier and constant extinction angle control at the inverter end respectively. The cable systems have modified controls which are discussed in the respective sections.

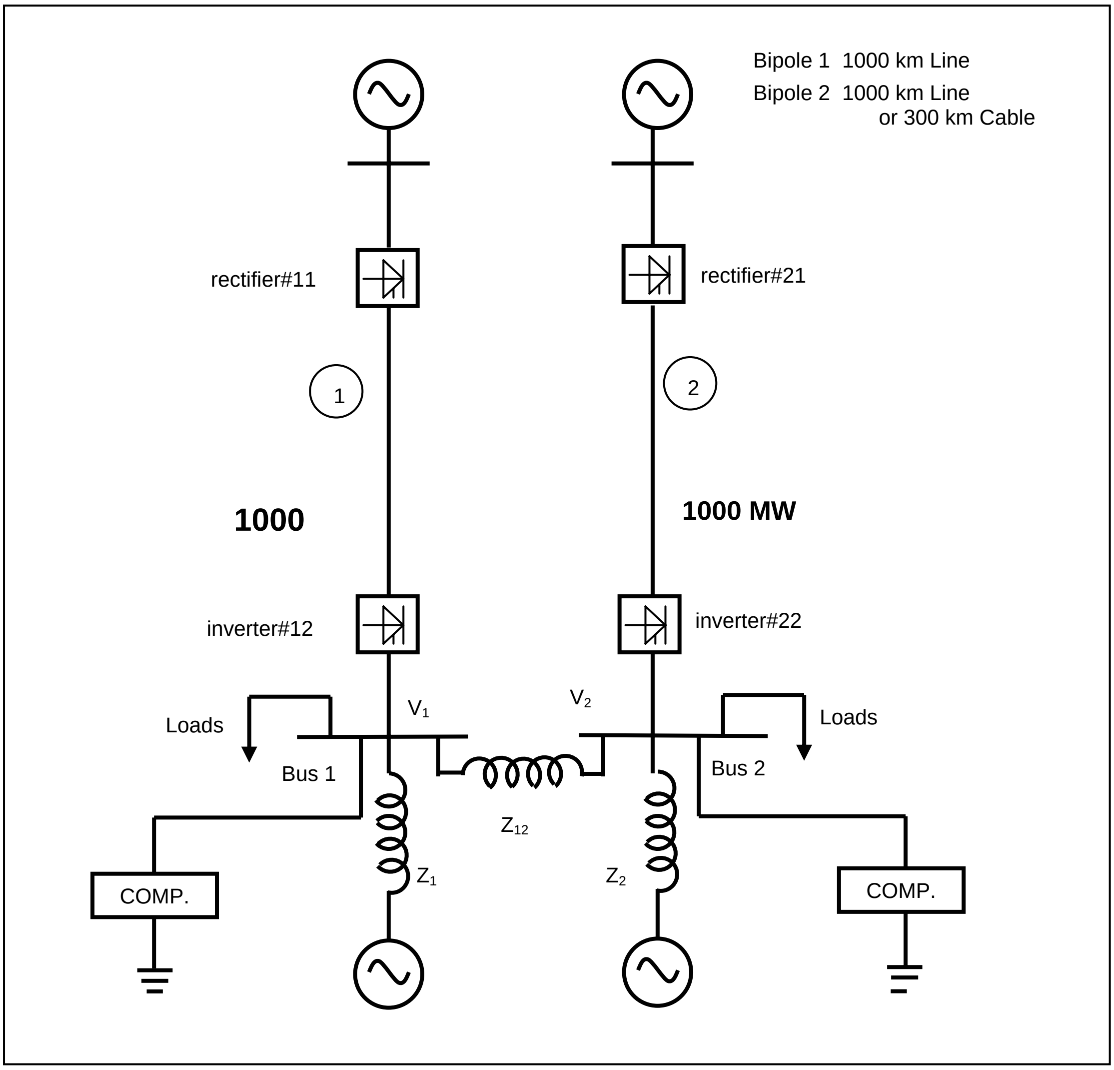


Figure 1-1 The Test System.

HVdc link 1 is considered to be an existing HVdc link within a given ac system and the plan is to incorporate link 2. Links 1 and 2 are supplied through rectifiers from ac systems which are asynchronous from the remote ac system and from each other. This will ensure no obscuring ac interactions between rectifiers or between rectifiers and inverters. Also, the short circuit levels at the rectifier ac buses are relatively high so that the phenomena observed are essentially due to the parameters of the inverters. For cable studies, both links 1 and 2 are replaced by a cable model with the associated controls. The overhead transmission line length is 1000 km, which is representative of a wide variety of existing or planned HVdc systems. The cable length is 300 km which reflects typical cable systems, for example the many cables crossing the Baltic.

It should be noted that while back-to-back HVdc links are not modeled explicitly in this guide, the interaction phenomena of HVdc links using dc lines are similar. However, certain issues specific to back-to-back schemes, such as cross-modulation of harmonics, will not be addressed.

The basic receiving ac system is sufficient to demonstrate the effect of parametric variations. Each inverter ac bus is directly connected to a separate infinite ac bus through finite impedance. The ac network interconnecting the two inverter buses is reduced to single impedance, Z_{12}. The complexity of the specific ac networks may preclude the derivation of such a reduced network equivalent with precision. However the methodology and approach to system studies described in the guide do not depend on such a reduced network. It is only used for the purposes of demonstrating and establishing the preliminary interaction concerns.

1.3.1. SCR and ESCR Calculations

An important tool to the HVdc planning engineer has been the SCR and ESCR calculation. [5]. Although not indicative of all effects, its simplicity has continued to make it a useful indicator of the level of performance expected from an HVdc link. The calculation and interpretation of SCR/ESCR is straightforward when HVdc links are either widely separated or terminating on the same ac bus. But the interpretation is more problematic when considering some finite electrical distance between inverter ac buses. The intention here is to retain the SCR/ESCR concept to include the mutual contribution between inverter ac buses.

For the ac bus location to which the new HVdc link is to be applied, the calculated short circuit level should include the compensation of any other HVdc links in the vicinity (i.e. the other inverter in the test system) as well as the entire common ac system under consideration. A division of the short circuit level by the rated power of the new link will provide the nominal SCR. When the compensation of the new link is included, whether it be filters, capacitors, a FACTS device, or synchronous compensators, the nominal ESCR can then be calculated.

This calculation may also be performed for any existing link considered to be in the sphere of influence of the new HVdc link. Later in this chapter a multiinfeed definition of ESCR is introduced, but first a new parameter for the analysis of multiinfeed systems, the multinfeed interaction factor (MIIF) must be explained.

1.3.2. Multi Infeed Interaction Factor (MIIF)

To complete the basic knowledge of interaction potential, a new factor called the Multi Infeed Interaction Factor (MIIF) is introduced. The ac system parameter most reflective of the interaction of a particular inverter with the ac system is the inverter ac bus voltage. The MIIF relates interaction between any two inverter ac voltages.

At the new HVdc infeed ac bus and with the new link injecting rated power, induce an approximate 1% step voltage (deltaVn) through the artificial switched connection of a shunt reactive element. Observe the percent change in ac voltage at other inverter ac buses of concern. The ratio of these numbers is the MIIF between the two buses.

$$MIIF_{e,n} = \frac{\Delta V_e}{\Delta V_n} \qquad \textbf{1-1}$$

where ΔV_e is the observed voltage change at another existing inverter ac bus.

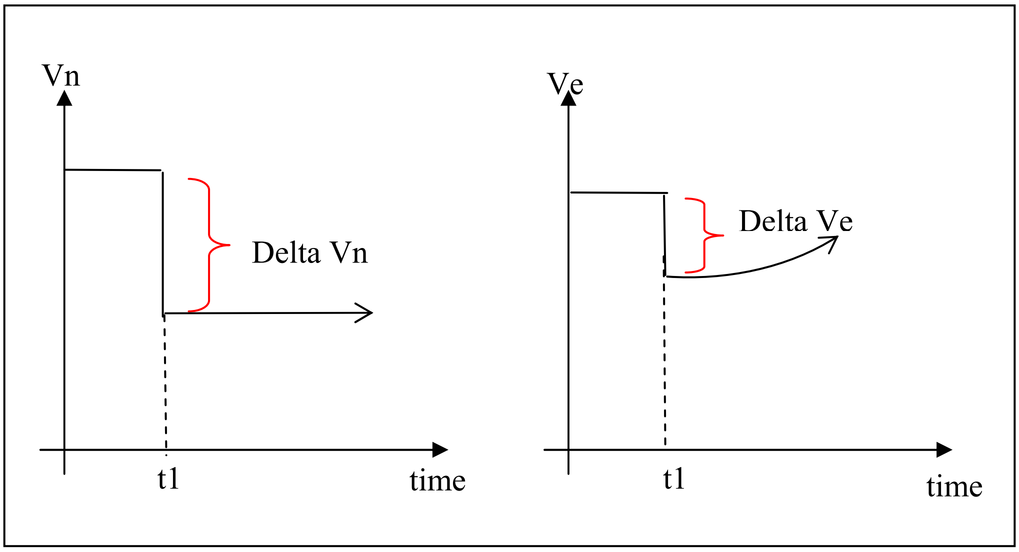
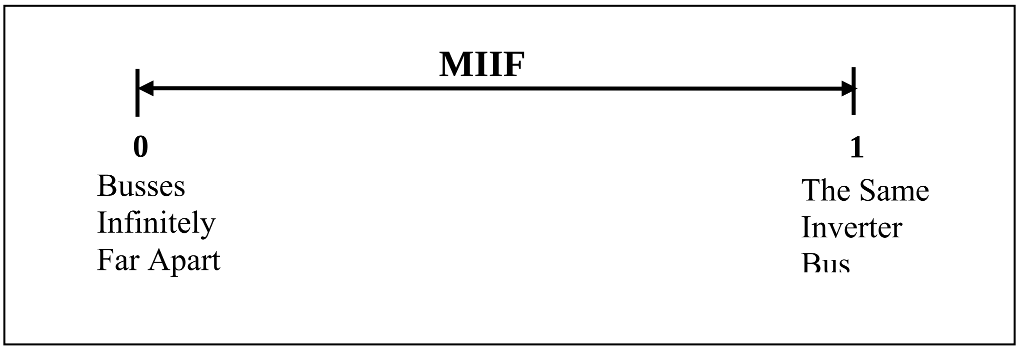


Figure 1-2 Determining the MIIF between an existing and new inverter bus.



For systems with several HVdc links in close proximity, there will be multiple MIIFs calculated forming a matrix. The MIIFs from the existing buses to the new bus may also be relevant. MIIF values range from zero to one with zero implying infinite electrical separation and one implying the same bus. Generally the MIIF matrix will be asymmetric, for the MIIF values between two inverter busses depend not only on the intervening impedance but also on the shunt impedance at each inverter bus. Diagonal elements of the MIIF matrix are unity.

Table 1-1 Typical MIIF Matrix

MIIF Table		Relative Inverter ac Voltage Change		
		Inverter1	**Inverter 2**	**Inverter3**
Bus at which fixed reduction is applied	**Inv. 1**	$MIIF_{1,1} = \frac{\Delta V_1}{\Delta V_1}$	$MIIF_{2,1} = \frac{\Delta V_2}{\Delta V_1}$	$MIIF_{3,1} = \frac{\Delta V_3}{\Delta V_1}$
	Inv. 2	$MIIF_{1,2} = \frac{\Delta V_1}{\Delta V_2}$	$MIIF_{2,2} = \frac{\Delta V_2}{\Delta V_2}$	$MIIF_{3,2} = \frac{\Delta V_3}{\Delta V_2}$
	Inv. 3	$MIIF_{1,3} = \frac{\Delta V_1}{\Delta V_3}$	$MIIF_{2,3} = \frac{\Delta V_2}{\Delta V_3}$	$MIIF_{3,3} = \frac{\Delta V_3}{\Delta V_3}$

In the test system, the receiving system reactances influence both the ESCR calculations and the MIIF value, as do the form and amount of compensation at the inverter ac bus. A test system exhibiting a one-to-one relationship between elements of the test system and analytical quantities is not feasible. Indeed, this is no different than any practical ac system.

Table 1-2 Typical Megawatt Weighted Relative Inverter ac Voltage Change matrix

MIIF Table		P_{DC}	Megawatt Weighted Relative Inverter ac Voltage Change		
			Inverter 1	**Inverter 2**	**Inverter 3**
Bus at which fixed reduction is applied	**Inv. 1**	P_{DC1}	P_{DC1}	$MIIF_{2,1} \times P_{DC2}$	$MIIF_{3,1} \times P_{DC3}$
	Inv. 2	P_{DC2}	$MIIF_{1,2} \times P_{DC1}$	P_{DC2}	$MIIF_{3,2} \times P_{DC3}$
	Inv. 3	P_{DC2}	$MIIF_{1,3} \times P_{DC1}$	$MIIF_{2,3} \times P_{DC2}$	P_{DC3}

The product MIIF X Pdc of other remote links (other off diagonal elements in each row of table 1-2) should be compared to the Pdc of the inverter, which is defining the diagonal term within that row. If any individual product is less than 15% of the inverters power then the chance for interaction is small. Product values between 15% and 40% indicate links with a moderate potential and product values above 40% indicate a high potential for inverter interaction. Given similarly sized links in a multiinfeed situation, this comparison can be simplified to a comparison of MIIF values. A large link may influence a smaller link even if it is not that close electrically from its sheer size, conversely a small link has little effect on a high power link even if electrically close. Theoretically, a large HVdc inverter at some electrical separation from another inverter bus may have more influence over the performance of that bus than a smaller inverter directly connected to that bus.

Regardless, if some interaction uncertainty remains after evaluation of the MIIF X Pdc products, and this is more likely to occur with high MIIF values, then such links can be included in any further technical analysis.

While the MIIF concept can be considered relatively new, more recent work has shown MIIF to be consistent to other developed approaches [6] [7] [8].

Example:

Inverter 1=2000 MW, Inverter 2=200 MW, $MIIF_{21}$=0.9, $MIIF_{12}$=0.7
The MIIF X Pdc product of the remote link for Inverter 2 is 0.9 X 2000 =1800 MW. Comparing 1800 MW to the Inverter 2 rating of 200 MW indicates that Inverter 1 has a strong potential to interact with Inverter 2. For Inverter 1 the remote link is Inverter 2 so the MIIF X Pdc product is 0.7 X 200 = 140 MW. The 140 MW value is 7% of the rating of Inverter 1, so the potential for Inverter 2 to influence the performance of Inverter 1 is small.

Table 1-3 MIIF matrix for the above example

MIIF Table		Relative Inverter ac Voltage Change	
		Inverter 1 P_{DC} **=2000MW**	**Inverter 2** P_{DC} **=200MW**
Bus at which fixed reduction is applied	**Inv. 1**	$MIIF_{1,1}$ = 1.0	$MIIF_{2,1}$ = 0.9
	Inv. 2	$MIIF_{1,2}$ = 0.7	$MIIF_{2,2}$ = 1.0

Table 1-4 MIIF x P_{DC} matrix for the above example

		Megawatt Weighted Relative Inverter ac Voltage Change	
	P_{DC}	**Inverter 1**	**Inverter 2**
Inv. 1	2000	***2000***	***0.9 x 200 = 180***
Inv. 2	200	***0.7x2000 = 1400***	***200***

1.3.3. Multiinfeed Interactive ESCR Definition (MIESCR)

The traditional definition of ESCR at a single infeed inverter bus is:

$$ESCR_i = \frac{(SCC_i - Qf_i)}{Pdc_i} \qquad 1\text{-}2$$

where SCC_i is the short circuit MVA available on the inverter bus, Qf_i is the bus filter and capacitor MVA and Pdc_i is the rated dc power of the link. Critical Effective

Short Circuit Ratio, ***CESCR*** is the critical value of ***ESCR*** for which the maximum available power on the HVdc link is its rated power.

If it can be considered that ESCR is a general indicator of performance, especially with respect to fault recovery and power voltage instability, then it would be logical to redefine the meaning of Pdc_i for a multiinfeed definition of ESCR. Therefore:

$$\boldsymbol{Pdc_i \quad \text{becomes} \qquad Pdc_i + \sum_j (MIIF_{j,i} \times Pdc_j)} \quad \textbf{1-3}$$

where ***j*** represents all links in electrical proximity so that now

$$\boldsymbol{MIESCR_i = \frac{(SCC_i - Qf_i)}{Pdc_i + \sum_j (MIIF_{j,i} \times Pdc_j)}} \qquad \textbf{1-4}$$

Table 1-5 MIESCRs of the example above

	P_{DC}	ESCR	Σ $MIIF_{j,i}$ x $P_{DC\,j}$	MIESCR
Inv. 1	*2000*	*3.0*	*2180*	*2.8*
Inv. 2	*200*	*20.0*	*1600*	*2.5*

It is interesting to observe in the above table 1-5 the dominating influence the large HVdc link is having on the smaller link resulting in a dramatically different value of MIESCR to its ESCR of 20. The system characteristics at the inverter 2 ac bus are mostly defined by the presence of link 1.

Although theoretically all links that influence the bus could be included in the calculation, it is likely that links with an MIIF of less than 0.15 and an MIIF X Pdc product below about 15% of the Pdc_i value, then their remoteness plus intervening control action within the ac network would make their inclusion in the calculation unduly pessimistic. This comparison can be simplified to a consideration of MIIF for similarly sized links.

Note that the definition of MIESCR collapses into the conventional definition of ESCR for single infeed systems.

1.3.4. A Comparison of Single and Multiinfeed Situations

Chapter 2 will explore this subject in depth, but the following table 1-6, illustrates the parallels between single and multiinfeed analysis. The extension from single infeed analysis is fairly straight forward. No single infeed link would ever be incorporated into an ac system without extensive detailed simulations and the same will be true for multiinfeed situations but the concepts contained in this report will help guide the more detailed studies in the same way that single infeed studies are guided today.

In single infeed calculations the ESCR and CESCR are often calculated having only the ac system short-circuit level as the ac system representation, whereas for multiinfeed calculations more network information is needed, a stability study program is needed to determine the MIIF values. The primary influence on the MIIF values is the impedances and short circuit contributing machines in the network. However, the loading and stress on the ac system influences the MIIF values and thus has a secondary influence on the MIESCR. The network loading influence results in MIESCR values that were found to be in the order of 5 to 15% lower than those produced in an unstressed network in one study.

Table 1-6 A Comparison of Single and Multiinfeed Methodologies.

	Single Infeed	**Multi Infeed**	**Comments**
Basic Indicators	1) ESCR	1) MIESCR 2) MIIF 3) ESCR	
Fault Recovery, including Commutation Failure Performance	1) ESCR 2) Detailed study 3) Contour map	1) MIESCR 2) Detailed study 3) Contour map 4) MIIF	The contour map is especially useful in multiinfeed situations to show common busses which result in c.f.
P/V Instability	1) CESCR 2) ESCR 3) Detailed studies	1) CMIESCR 2) MIESCR 3) Detailed studies	Whether in a single or multiinfeed situation, the applicable critical value may be similar.
TOV	1) ESCR 2) Detailed studies	1) MIESCR 2) Detailed studies	
Harmonics	1) ESCR 2) Detailed studies	1) MIESCR 2) Detailed studies 3) One amp injection	Detailed studies could be a harmonic and/or EMT program
Control Interaction	1)Detailed studies 2)ESCR	1) Detailed studies 2) MIESCR	
Operating Indicator	1) ESCR 2) Detailed studies	1) MIESCR 2) MIIF 3) Detailed studies	

1.4. Benefits of the Methodology

The methodology is a precursor of more detailed studies. The benefits derived from the methodology are:

1) **Overview** – The methodology gives the planner, with a few calculations, a general sense of the interactive effects of a proposed HVdc infeed. As result it a measure of the deterioration in the performance of the existing infeed(s) and a measure of the HVac system augmentation that may be required to restore the performance of those infeed(s).
2) **Location** – The inverter location may be sited so as to minimize the interactive impacts on existing links where feasible.
3) **Regulatory** – Most jurisdictions require proof that a new addition will not be detrimental to existing transmission. The methodology presents a relatively simple and intuitive interpretation of the situation and may not require

extensive technical expertise to understand complex detailed studies. It should be noted that the analysis is not limited to the planning of a new HVdc link, but could also be applied to situations where a new HVac line places existing HVdc links in closer proximity.

4) **Modeling** – A compact system equivalent model is amenable to detailed time domain simulation.
5) **Study Efficiency** – The methodology, especially in the calculation of MIIFs or the MIIF X Pdc product (in the case of dissimilar Pdc) can provide an alert to where more detailed studies would be prudent.
6) **HVdc Parameter Selection** – Certain parameters, such as compensation choice, have a direct effect on interaction. The methodology gives a general understanding on the effects of parameter modification without the need for detailed analysis.
7) **Operation** – Once the new dc link is operational, the concepts could be used to help map out safe and unsafe operating regions. This topic will be discussed further in Chapter 2.

1.5. Phenomena of Interest

The phenomena of concern for multiinfeed studies can be placed in one of four categories:

1. Transient Overvoltage Effects.
2. Commutation Failure Performance and AC Fault Recovery.
3. Harmonic Performance.
4. Control Performance Including Power/Voltage Instability.

Each of these phenomena will now be briefly described. Chapter 2 will provide a more extensive technical description for each of the phenomena.

1. Transient Overvoltage Effects (Chapter 2.1) - Conventional line commutated HVdc technology consumes significant MVArs, the ratio of MVArs to MWs at full load being around 50% for a modern scheme. Rejection of the MVArs with a bipole block will induce a transient overvoltage at the inverter bus. If another HVdc link is in close proximity, then blocking of that link will also induce an overvoltage at the given inverter bus. If both links block coincidentally, then the TOV experienced at the inverter bus will be higher than if any individual link had blocked.

2. Commutation Failure Performance and AC Fault Recovery (Chapter 2.2) - A commutation failure at one inverter may conceivably induce commutation failure on a nearby link. As with commutation failure, the ac fault recovery of a link in isolation is dictated in part by the ESCR of the inverter ac bus. With another link electrically nearby, the fault recovery is not only influenced by the strength of the bus, but also by the recovery characteristics of the other dc system.

3. Harmonic Interaction (Chapter 2.3) – Filtering and resonance considerations are an important element of an HVdc link design. Multiinfeed situations add a further degree of complexity for evaluation.

4. Control Performance Including Power/Voltage Instability (Chapter 2.4) - The power/voltage instability phenomenon, as it applies to a single HVdc link, is well documented. The collapse mechanism with the terminations of two or more links in close proximity is less clear due to the interaction and sharing of system short circuit level. Controllers which affect the performance of the ac system must be optimized according to the needs of the ac system. Any real control system can develop an instability and care must be exercised that any instability is not exacerbated by the presence of other links in close proximity.

1.5.1. Planning Procedure

This section will guide the planner in developing the basic indicators for an understanding of the multiinfeed interaction in a particular ac system. The example systems described in Chapter 3 will further aid in understanding.

1) Determine the rating of the new HVdc link and its injection bus within the ac system.

2) Calculate the basic Short Circuit Ratio (SCR) by dividing the short circuit level on the inverter bus by the rated HVdc power.

3) Set up a realistic power flow with the new link at or close to its full rating. Other HVdc links in proximity should be at high power levels. If the SCR is above 3.0, then the reactive compensation at the inverter bus can usually be supplied by shunt filter or capacitors. If lower than this number, then reactive compensation such as synchronous compensators may need to be considered depending on the function of the HVdc link in the system and the mode of the HVdc controls. Although usually not as critical, the SCR at the rectifier bus must also be considered. An ESCR can now be formed given the preliminary compensation assigned to the inverter bus.

4) Calculate an MIIF interaction matrix for all plausible inverters. Omit from further consideration all HVdc links whose MIIF is below 0.15 and the MIIF X Pdc product is below about 15% of the megawatt rating of the new link.

5) Calculate the multiinfeed ESCR, MIESCR, of the new link. If the MIESCR has been altered considerably by the presence of other nearby links, then the compensation determined previously may need to be reconsidered and the sequence repeated from the third step until a satisfactory system has been obtained. Decisions on compensation are usually not so trivial and may require more detailed studies, but the above methodology is an advantageous starting point. Compensation decisions guided by MIESCR for a new inverter bus may also affect the MIESCR values at existing inverter busses and so further influence the compensation choices made.

6) Perform further detailed studies with the guiding ideas as laid out in Chapter 2.

1.5.2. HVdc Penetration in a Large AC System

The question arises as to how much HVdc transmission input a particular ac system can accommodate. Can the concepts introduced in Chapter 1 provide a guide to the answer?

A general answer to that question might be that the amount of inverter capacity in an area is excessive if the amount of supporting ac system short circuit capacity that must be shared amongst the inverters is insufficient. In other words, if the MIESCR becomes too low, say below 2.5, then the system may be at the limit of HVdc transmission input depending on the reliance on HVdc system. The MIESCR is boosted with local generation, and can be artificially increased with synchronous compensators but with some negative consequences that will be discussed later.

Presently, only the Nelson River (Canada) [9] and Itaipu (Brazil) have employed synchronous compensators as an HVdc development strategy in a large integrated ac system. In the case of the Nelson River scheme the ESCR level has been kept above 2.5. Other examples of HVdc synchronous compensator application involve serving an isolated remote load where undersea cable transmission is required (e.g Cheju, Korea) or as maintaining throughput between two larger ac systems through undersea cable transmission (e.g. New Zealand). If the HVdc transmission scheme is small relative to the grid, then it may not require synchronous compensators (e.g. MacNeil, Canada) if the HVdc transmission system response can be tolerated within the contained ac system.

So, in some ways, there is no theoretical limit to the amount of HVdc that may exist within a particular system; synchronous compensators can continue to be added to the point where adequate power-voltage performance levels exist. But considering the cost, complexity, and maintenance associated with synchronous compensators continued HVdc development before further ac expansion may not be the best option. There is also the issue of system inertia where synchronous compensators typically add much less inertia to a system than a similar power level of ac generation. The lack of inertia could result in high frequency decay rates or high angular swings for some outages, which may be difficult to respond to with conventional protection practices.

A very approximate calculation can be made using the MIESCR formula in eqn 1-4:

$$\boldsymbol{MIESCR_i} = \frac{(\boldsymbol{SCC_i} - \boldsymbol{Qf_i})}{\boldsymbol{Pdc_i} + \sum_{\boldsymbol{j}} (\boldsymbol{MIIF_{j,i}} \times \boldsymbol{Pdc_j})}$$

With the conservative assumptions that an MIESCR below 2.5 is not desirable, all inverters are in close proximity (i.e. all MIIFs are unity), and that bus capacitance can be either ignored or balanced against the assumption that all MIIFs are unity, then

$$2.5 \le \frac{\boldsymbol{SCC_i}}{\sum \boldsymbol{Pdc}} \quad \textbf{1-5}$$

The short circuit level can be considered as the total area generation MVA divided by the average reactance through to an inverter bus, that is:

$$SCC_i = \frac{\sum MVA}{X_{avg}} \qquad \textbf{1-6}$$

The equation can now be rearranged so that:

$$\frac{\sum Pdc}{\sum MVA} \leq \frac{0.4}{X_{avg}} \qquad \textbf{1-7}$$

The proximity of the generation sources to the inverter busses will affect the outcome. Close in support, as reflected in a low X_{avg}, allows a greater penetration of HVdc relative to the ac generation. A low value of X_{avg}, say 0.25 pu, would indicate allowance of 160% of HVdc inverter power in relation to local generation capacity. A more conservative and realistic value of 0.50 pu for X_{avg} would indicate a value of 80%.

As a general conservative indicator it can be said that if the total inverter megawatt capacity starts to exceed about 50% of the generation MVA in the receiving ac network, then developmental choices between HVdc and HVac expansion must be carefully considered. This indicator is built on a number of assumptions and is neither an explicit decision tool nor a replacement for more detailed studies. It can help shape or confirm the outcome from such detailed studies.

The preceding derivation was governed by implications of real and reactive power flows; the ability of the ac system to support the operation of the HVdc. Angular and frequency stability is related to available inertia, generally the more the better. Most HVdc development does not include new inertia at the inverter and this will intensify in a multiinfeed environment. Even the use of inverter synchronous compensators, unless size overrated, does not establish the same level of inertia that a generator of equivalent inverter power would provide. In the absence of sufficient system inertia to receive large HVdc power levels, the stabilization of the voltage angles in the system can be challenging and may in fact place further restrictions [5].

Frequency control and system stability can be an issue related to the amount of energy lost by one or more HVdc links during a disturbance. Low inertia combined with energy lost by one or more HVdc links during a fault and in the post fault recovery period, may lead to angular instability. With a high percentage of HVdc input and an isolated ac receiving system, the rate of frequency decay may become an issue if all links permanently block near simultaneously. If the rate of decay of frequency is excessive, difficulty in implementing corrective action, such as a frequency based load shedding scheme, is likely.

1.6. References

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2. CHAPTER 2 - INTERACTION PHENOMENA

2.1. Introduction

Chapter 1 introduced some basic concepts which would be of assistance in understanding the multiinfeed nature of a particular system under study. Chapter 2 will use these basic concepts to delve into detail on the four basic phenomena of multiinfeed interaction. As stated in Chapter 1, these four phenomena are:

1) Transient Overvoltage Effects.
2) Commutation Failure Performance and AC Fault Recovery.
3) Harmonic Performance.
4) Control Performance Including Power/Voltage Instability.

Because Chapter 2 is of a more specific nature, the impact of cable systems is considered. Cable systems are found to mostly influence the results for commutation failure performance.

2.2. Transient Overvoltage

2.2.1. Transient Overvoltages (TOV) in a Multiinfeed Context

An important criterion in the design of an HVdc link is the permissible transient overvoltage at the ac terminals of the converter station. The overvoltage influences the ratings of the station equipment both on the ac and dc sides, and affects the ac network.

The overvoltages at the ac terminals of a converter station can occur due to disturbances on either the ac or the dc systems. The worst case overvoltages at most inverter buses are caused by a sudden complete loss of transmitted HVdc power, which is a bipole block. TOV is related to the elimination of reactive power consumption of the inverter terminal while having the compensation equipment, filters and other shunt capacitor banks still connected to the ac system.

In the case of multiinfeed HVdc schemes, the worst case transient overvoltage on the ac bus of a given HVdc converter station should result from a simultaneous block of all the HVdc schemes in electrical proximity. The worst case TOV at an inverter ac bus will therefore be the cumulative effect resulting from the full load rejection of the directly connected inverter as well as the interactive TOVs resulting from the simultaneous full load rejections of other HVdc schemes in proximity. In most practical situations, simultaneous blocking of all HVdc converters could be considered so unlikely as to not be defining for TOV design. TOV design levels as driven by fault driven simultaneous commutation failures may be more appropriate. Nevertheless, multiple simultaneous blocks can be considered an outside bound to the problem.

Weak ac/dc systems with low ESCRs present high TOV levels at the converter terminal of a single infeed dc scheme. Similarly, the worst case TOV levels are high for those inverters in a multiinfeed dc system terminating at weak ac bus bars with low MIESCRs (Multiinfeed Interactive Effective Short Circuit Ratio).

The tools and methods provided in this chapter will assist a planner in evaluating the approximate worst case TOV levels on the ac bus of a new inverter terminal in the proximity of other HVdc schemes. The impact of the new scheme on the TOV levels of the existing schemes can also be estimated without extensive studies. Therefore those systems that require extensive studies and possible mitigation can be readily identified.

2.2.2. Worst Case TOV vs MIESCR for an Inverter on the CIGRÉ Multiinfeed HVdc Test System

The worst case TOV on the ac bus of an inverter in a multiinfeed HVdc system is the t+ transient overvoltage at the inverter of consideration due to a full load rejection of all HVdc systems in proximity (proximity is defined by the MIIF or MIIFxPdc product as in section 1.3.2.). Control actions or saturation effects are not considered in the determination of the TOV levels discussed in this section. In some schemes, the TOV may be slightly higher a few cycles after t+ as a result of local machine dynamics such as from synchronous compensators (refer section 2.2.4.1).

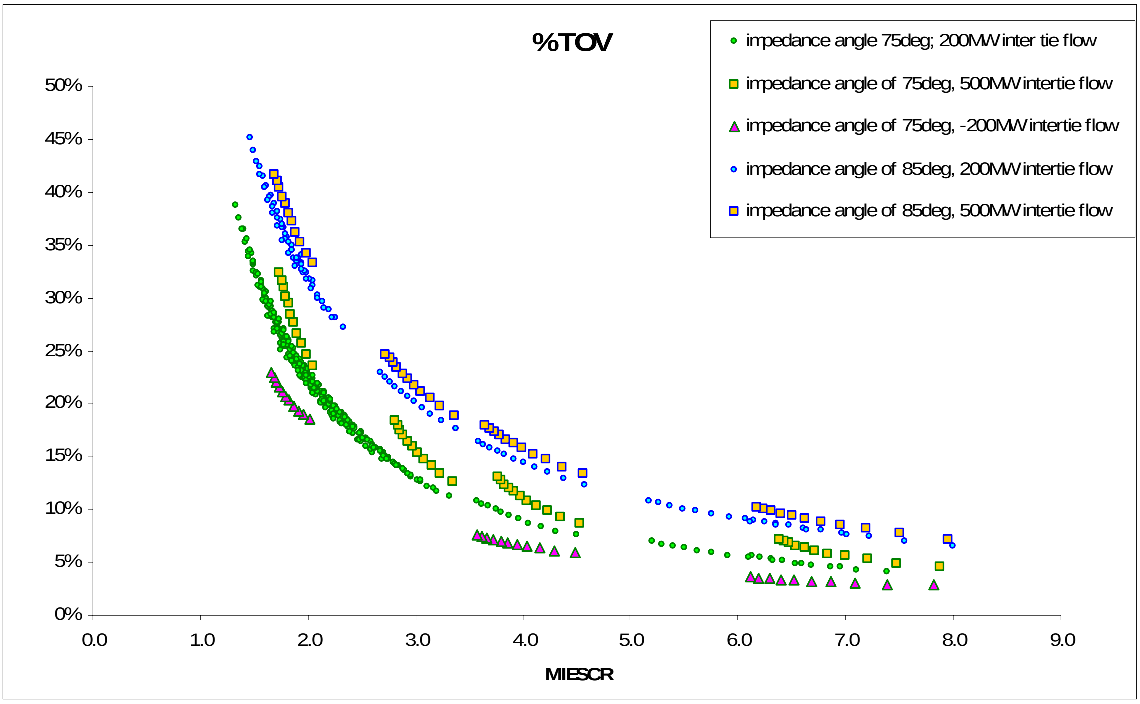

Figure 2-1 Percentage worst case TOV at an inverter of the CIGRÉ Multiinfeed HVdc Test System.

Figure 2-1 shows the spread of possible worst case TOV levels at one inverter of the CIGRÉ dual inverter multiinfeed HVdc test system for a block of both bipoles as a function of MIESCR of the inverter under consideration. The many different test system cases are achieved by systematically varying the individual inverter ac equivalents and the tie line length between the inverters. Weak inverters of below 2.5 MIESCR demonstrate over 15% transient overvoltages even with high damping in the ac system. As can be seen here the MIESCR at the inverter ac bus offers an effective measure of the true ac bus strength when the ac system is common to multiple HVdc schemes. It is representative of both the self HVdc block as well as the interactive effects that are prevalent via the ac system, due to the blocking of the second HVdc system in proximity. Worst case TOV therefore is a function of the MIESCR of the bus in multiinfeed HVdc schemes.

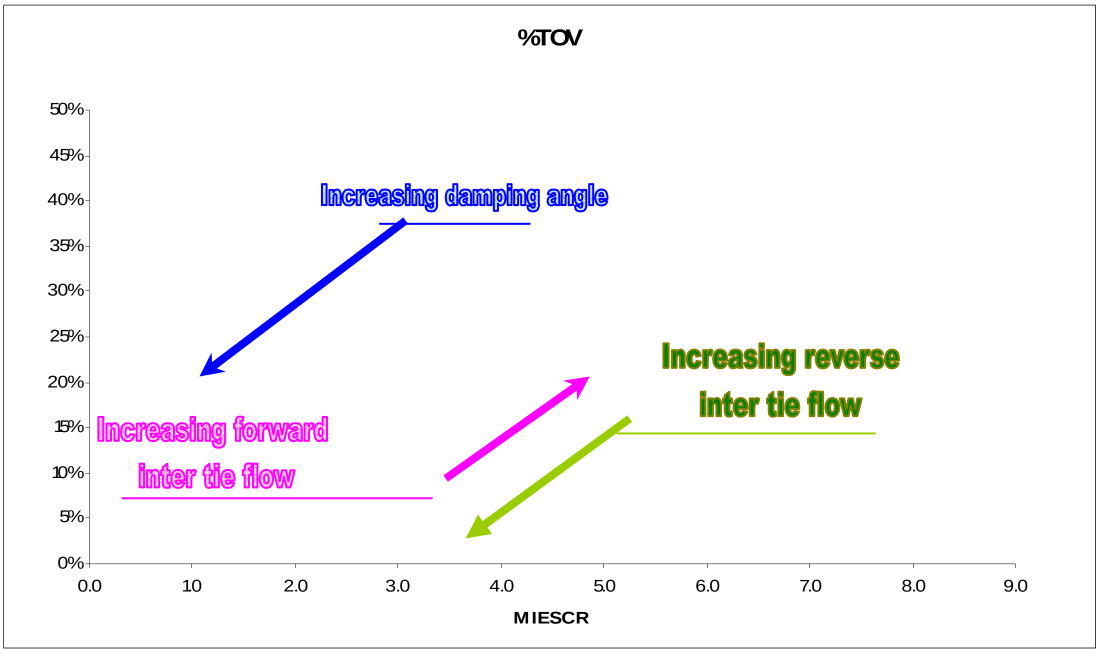

Figure 2-2 Worst case TOV range against the inverter MIESCR for the CIGRÉ Dual Inverter Multiinfeed HVdc Test System.

Figure 2-2 above shows the same graph marked with the range for TOV which can serve as a quick guide of the general pattern to the worst case TOV based on the inverter strength measured using the MIESCR parameter. As mentioned before, the worst case TOV is a cumulative effect of load rejection at its own HVdc bus as well as any HVdc bus in proximity. Note also that while the contribution from the self HVdc load rejection is based on the loading level of the HVdc system, the interactive TOV contribution is governed by both the loading level of other HVdc links in proximity. Thus it is important to note that the interactive TOV depends on the ***MIIF x*** $\boldsymbol{Pdc_{remote}}$ product. Only TOV due to HVdc load rejection is considered for this graph and simultaneous ac contingencies are not considered. However, since simultaneous ac disturbances should alter the SCR, thus the MIESCR at the inverter ac bus, it will not be surprising to see TOVs place well within the range shown in the graph. However it should be emphasized that such investigations were not carried out for verification.

Commutating reactance of an HVdc system governs the amount of reactive compensation required for the system and therefore is a parameter that affects the maximum TOV levels. The CIGRE benchmark was being utilized to derive the TOV boundaries shown in figure 2-2 where the individual HVdc systems are slightly over compensated in terms of the total MVARs provided by the ac filters, to a level equivalent to approximately 20% commutating reactance even though the commutating reactances are 18%. Based on the equation in [PV1], a multiinfeed system with individual HVdc systems at 15% commutating reactance would have

TOV levels reduced by a factor of about 0.87. For example, a 30% TOV would be reduced to 30% X 0.87 = 26.1%. The change of MIESCR for the system with 15% commutating reactance should also be noted. The dependence on commutating reactance is relatively small. Figure 2-3 below shows the TOV boundaries for systems of 20% and 15% commutating reactances.

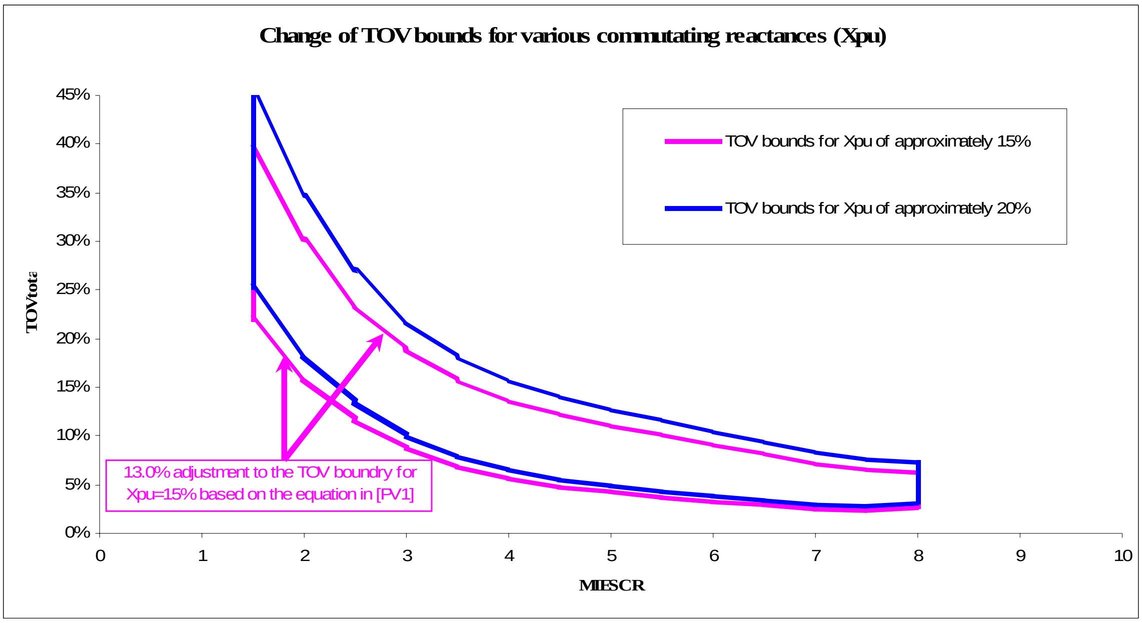

Figure 2-3 TOV boundaries for varied commutating reactance of the multiinfeed system.

If it is considered unduly pessimistic for all HVdc links to simultaneously block, then only those links which are considered relevant can be included in the MIESCR calculation for a TOV estimation. Such a scaled down computation of the MIESCR would have to always include the contribution from the HVdc link at the inverter of consideration. The single infeed TOV levels derived using the dual infeed test system shown in figure 2-4 are examples of such instances where the scaled down MIESCR reduces to the inverter bus ESCR. The TOV levels in the same examples therefore are the contributions due to blocking the HVdc on the inverter bus under analysis.

The trend of the worst case TOV dependence on the inverter bus MIESCR in a multiinfeed HVdc system is analogous to the TOV dependence on ESCR on single infeed HVdc schemes. Figure 2-4 shows the analogy of the TOV levels of a single infeed system [TOV1] to the worst case TOV on the dual inverter multiinfeed system.

In addition to the MIESCR there are other ac system characteristics that affect the worst case TOV at a multiinfeed inverter. As can be seen in figure 2-2, higher damping of the ac system impedance limits the overvoltages.

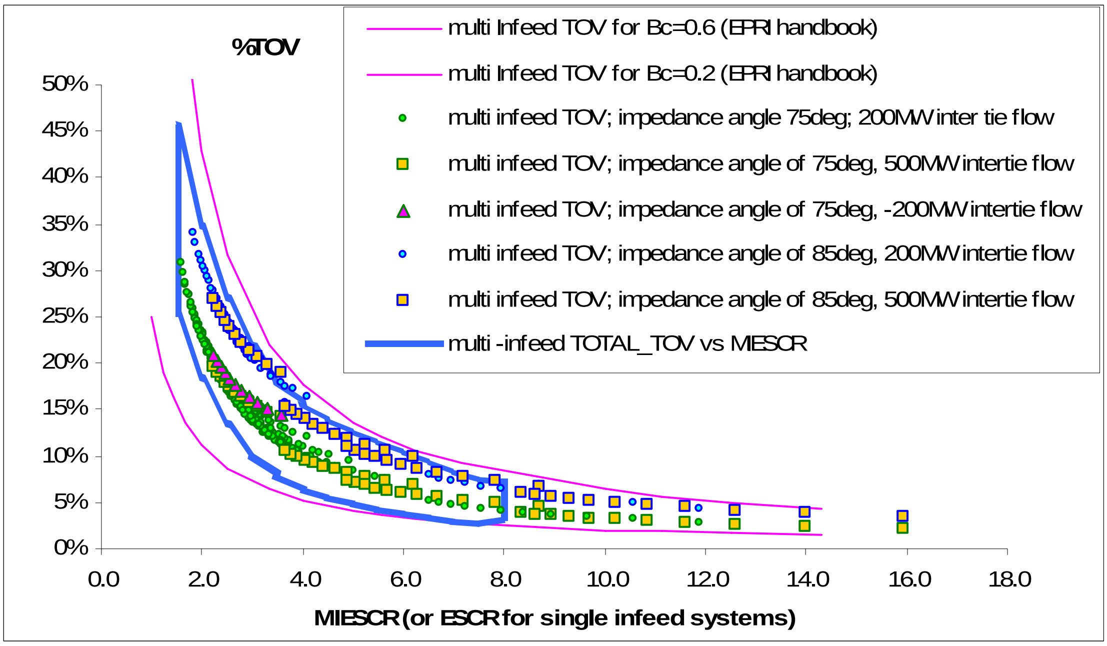

Figure 2-4 Comparison of worst case TOV-MIESCR relationship of a multiinfeed inverter to TOV-ESCR relationship of a single infeed inverter.

Another important phenomenon that can be observed in the test system is the TOV dependence on the power transfer between the two inverters. This occurs because of the sudden reduction in the tie line loading due to the block of the HVdc. The change in loading on the transmission line determines how much reactive power is released to the network when the HVdc inverter is suddenly blocked and thus results in a higher TOV for higher tie line power flows. In the test case, the power transfer between inverters is the power flow on the tie line connecting the two inverters and HVdc infeed contributes to all of it. However in most real systems the inverter buses are networked through many levels of voltage and the net power transfer cannot be determined readily. But the same phenomenon will occur and the TOV will depend on the change in network loading due to the blocking of the HVdc links. In power systems where the HVdc is a large contributor to the supplied power, the change in network loading due to the HVdc block will be significant and as a result will demonstrate generally higher levels of TOV on complete HVdc load rejection. It should also be noted that many other system details such as the voltage dependent load dynamics may not be well captured in the ac equivalent on the multiinfeed test system due to its simplicity. Therefore the TOV range in figure 2-2 derived using the multiinfeed test system is only representative of the worst case TOV trends on a representative multiinfeed HVdc system. As such the preliminary estimate of the TOVs of a given system should be obtained using transient stability models in conjunction with figure 2-2.

2.2.3. Study Tools and Methodology

The fundamental frequency overvoltage component at an inverter of a multiinfeed system, following a disturbance can be estimated using a transient stability program with good accuracy. The models for the purpose should be built with adequate details of the generators, loads and other dynamic devices which contribute to the instantaneous overvoltages and the system short circuit capacity. However, it will not represent any higher frequency effects such as harmonics or resonances. The effect of saturation in transformers or voltage limiting reactors would not normally be represented in stability studies so the resulting overvoltages would be pessimistic for systems with TOVs that are in the range of saturated levels.

It is worth noting that a transient stability type system model with basic HVdc representation would be required to determine the MIIF (MultiInfeed Interactive Factor) of the inverters where by the MIESCR of the inverters are computed on a multiinfeed HVdc system, as described in chapter 1. These same models are more than adequate for preliminary estimation of the worst case TOVs. Therefore it is recommended that the preliminary TOV levels be obtained using the transient stability system models under consideration rather than completely depending on the TOV graph of the test case in figure 2-2. For this purpose, the models should be set to have the worst case (highest possible) loading on the HVdc schemes and should be blocked simultaneously.

The worst case TOV graph in figure 2-2 used in conjunction with the transient stability programs are well suited for preliminary studies. Transient stability programs can also be adequate for some mitigation studies. Electromagnetic Transient Simulation programs with detailed models can be used for extensive TOV studies, especially if detailed mitigation is to be studied as well. It should be noted that the preliminary estimation of the transient overvoltages are based on a t+ (the immediate calculation after the disturbance) voltage measurement at the inverter under consideration due to a block on all the HVdc schemes in proximity. Thus the voltage control devices such as SVCs are left as fixed impedances for these measurements.

Refer to Chapter 3 for examples of real system TOV estimation studies and their comparability to the test system estimates.

2.2.4. Study Methods for Systems with Very High TOV Levels.

If the preliminary evaluation of TOVs on a given multiinfeed system suggests undesirable levels of worst case transient overvoltages, a detailed study will have to be executed to investigate the actual levels with more details in the models. The first round of studies are usually performed with transient stability study programs and do not require details of some voltage control devices. However, after qualifying for further studies the models have to be revised to include the additional voltage control devices on the system. If the systems require mitigation of the transient overvoltages after the second round of studies with transient stability programs, the models have to be built with sufficient detail for further study on electromagnetic transient simulation programs that will cover aspects of the system response beyond the fundamental frequency transients.

2.2.4.1. Mitigation Strategies

In the multiinfeed environment, the overvoltages could be due to disturbances of the ac system, the HVdc scheme or a neighboring HVdc scheme. If it is due to local events, the standard techniques of mitigation can be used at the inverter ac bus [TOV2]. In a situation where the overvoltage is a result of overvoltages at the neighboring bus bars, direct control at the source of the overvoltage would control those resulting effects as well. In the event that the direct control is not an option, the other standard techniques can be considered for voltage control at the inverter ac bus that is experiencing an unacceptable overvoltage. The mitigation strategies discussed below do not confine to the mitigation of the t+ overvoltages.

Converter controls: Firing angle of an inverter can be used to control the reactive power at the inverter ac terminal which in turn controls the voltage. Thus HVdc controls, if so designed, can be used as a mitigation measure for overvoltages, even in the multiinfeed environment. However, dc controls are not effective in the worst case scenario where all converters are blocked.

Switching Shunt Capacitors and AC Filters: Switching shunt capacitors and ac filters are a common and more economic mitigation measure in the case of single infeed HVdc systems. This can still be viewed as one method of controlling the voltage around the disturbed HVdc scheme and thus reducing the interactive effect on the neighboring schemes. However, when curtailing interactive overvoltages arising due to a disturbance on a neighboring HVdc scheme, switching filters may not be an option, as it may transfer unacceptable levels of harmonics into the ac system from the operating HVdc scheme.

Synchronous Compensators: Synchronous compensators are an expensive option, but may provide an adequate solution to the problem. In addition to the close-by internal voltage, the subtransient reactance of the machine and the transformer impedance dynamically help to strengthen the system while providing fast acting control of the available reactive power at the inverter busbar, which in turn limits the overvoltages. Synchronous compensators are typically applied when short circuit capacity or inertia is required along with voltage control. Even with a fast acting exciter, there may be a significant DOV (Dynamic Over Voltage) with a synchronous compensator. .

Static Var Compensators: This is an expensive option as well, but fast control times are an attractive feature in the multiinfeed environment where maintaining proper operating conditions for the inverter of interest is important.

Capacitor Commutated Converters (CCC): The capacitor commutated converter may be a solution in situations where a low DOV is required. The reactive power demand of the CCC converter is significantly lower than for a conventional HVdc converter due to the compensation of the converter transformer reactance by series capacitors. Since the CCC converter doesn’t require significant reactive power, high quality factor automatically tuned ac filters are used to lower the MVAr output of the filters. This results in a lower DOV in the CCC application.

Saturable Reactors: A saturable reactor can also act as a passive sink of excessive reactive power. Since a normal saturated reactor would inject an undesirable level of harmonic current, a specially designed and built saturated reactor named a “treble-tripler” has been used for such applications.

Surge Arresters: The approach here is to limit the overvoltage through dissipation of energy. It is a comparatively less costly method of overvoltage control.

2.2.5. Cable Systems

For systems with shorter cables, the tendency is to have the extinction angle controlled at the same value as in overhead line systems. Thus the reactive power rejected on a complete block of a cable HVdc schemes, which is the primary cause of the TOV levels under discussion, will be comparable to that of an overhead line HVdc scheme. Even if higher extinction angles at inverters exist, as may be required with longer cables, as long as the inverters are self compensated, it should be reflected in the MIESCR calculation of the inverter bus. Thus, the worst case TOV levels of cable systems should be well within the trends shown in figure 2-2.

2.3. Commutation Failure Performance and AC Fault Recovery

2.3.1. Introduction

Normal operation of an HVdc converter includes several switchings of thyristor valves within a three phase cycle. If one of the valves fails to switch off then two phases of the converter transformer will form a short circuit through the valve group, with no power being injected to the ac network. Commutation failure of an HVdc transmission system is often a significant disturbance in the operation of an ac system. Although the main reason for commutation failure is inverter ac voltage reduction due to faults in the inverter ac system, other events such as a sudden rise in the HVdc current, phase shift of ac voltage and rarely, malfunction of control circuits would cause failure as well.

If two or more HVdc transmission systems terminate in close electrical proximity (multiinfeed system), the commutation process becomes more complex due to interactions in response to common ac system disturbances. Due to the interactions, the commutation processes influence each other and the failure in one inverter can result in commutation failure in other converters.

Depending on the location of the fault which causes commutation failure in multiinfeed systems, the failure can be categorized as local or concurrent. The commutation failure is local when a fault on an ac bus causes the commutation failure of the converter independently of the dynamics introduced by other nearby inverter stations. For cases in which an ac fault on one bus results in commutation failure in one or more remote converters due in part to the system dynamic characteristics introduced by an inverter in local commutation failure, concurrent commutation failure has occurred.

In a multiinfeed environment, the situation of one inverter failing commutation from a fault may induce a nearby inverter to also fail commutation when the fault by itself should not have induced commutation failure (concurrent commutation failure). Phase shift, voltage dip and misfiring of the valves due to voltage distortion are some of the events causing commutation failure in the remote converter. The concept of the "local" commutation failure remains intact and unchanged.

Figure 2-5 shows the probability of commutation failure for the local and remote system. In this case, a balanced 3-phase reactor is switched on the ac bus of the local converter.

The size of the reactor is given as a per unit value of the short circuit level as seen from the ac bus of the local converter. As depicted in figure 2-5 switching a reactor larger than about 6% of the short circuit level causes commutation failure for the local inverter. However for the remote inverter to experience commutation failure, the reactor size should be at least 24% of the short circuit level.

There are two different aspects associated with commutation failure; one is the susceptibility of the HVdc converter to commutation failure and the second is the recovery time back to full power from commutation failure. There is a possibility that a system is more susceptible to failure in the commutation process compared to a similar dc scheme but at the same time, the ac system and/or control of the converter may be designed in such a way that it will recover from failure and return to normal operation faster than the one which is less likely to experience commutation failure. The tailoring of such characteristics is very dependant on the requirements of the ac system.

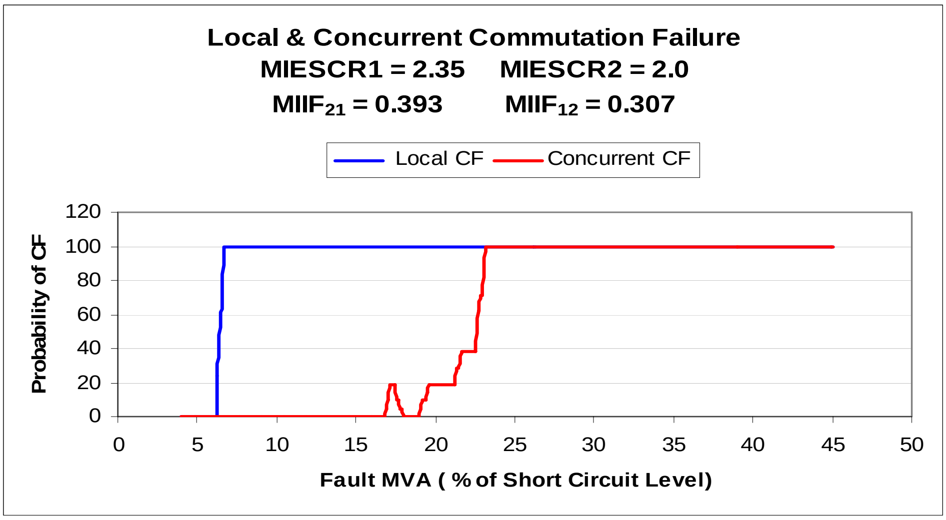

Figure 2-5 Local and Concurrent Commutation Failure in Multi-Infeed systems

2.3.2. Study Tools & Methodology

An initial high level assessment of commutation failure performance can be performed with stability study simulation software tools. But since commutation failure is affected by the transient behaviour of the system components, precise prediction of the occurrence of commutation failure after a disturbance requires a very detailed transient simulation of the ac network in proximity to the inverter ac bus using PSCAD/EMTDC or EMTP or any other tool which is suitable for electromagnetic transient simulation. The model should include the details of the ac and HVdc transmission lines, converter transformers, thyristor valves, generators and controls etc. Modelling all information about the system helps to predict the commutation failure performance precisely. However MIIF, MIESCR and other indices introduced in this report are very useful tools for assessing the immunity of a multiinfeed HVdc system to commutation failure.

2.3.3. Commutation Failure Immunity Assessment

The commutation failure is initiated through the application of an inductive fault at the converter bus as shown in figure 2-6. The studies were first carried out using an analytical method which includes only fundamental frequency ac behaviour and then with full transient simulation to validate the analytical results.

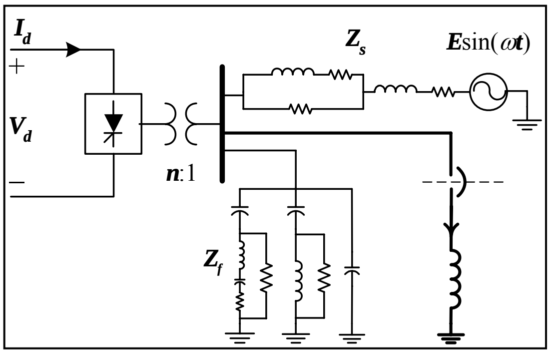

Figure 2-6 Application of a commutation failure in a single-infeed system

2.3.3.1. Steady State Analysis

A fundamental frequency (sinusoidal steady-state) representation of the ac network is assumed [CF2] and the reduction of ac voltage with fault application is calculated. In this steady-state analysis, the fault impedance is purely inductive. This assumption is equivalent to assuming that the fault is applied somewhere along an ac transmission line remote from the inverter. Later investigations will also show that in comparison with other impedance types, it is the worst case situation. With a fixed alpha, the voltage drop, (as per Eqn 2-1, causes the overlap angle (μ) to increase and consequently the extinction angle (γ) to decrease; thereby bringing the converter closer to commutation failure.

$$\cos(\alpha) - \cos(\alpha + \mu) = \frac{\sqrt{2}\boldsymbol{I_d} \times \boldsymbol{Xc}}{\boldsymbol{V_{ac}}} \qquad \textbf{\textit{2-1}}$$

$$\gamma = 180° - (\alpha + \mu)$$

In this analysis, an extinction angle (γ) of 15° (CIGRÉ benchmark) is assumed for unfaulted operation, and the size of the inductance that on application causes the calculated steady-state extinction angle to fall to a critical value of 7° is used to evaluate the critical fault level above which commutation failure occurs. Although an ideal valve will fail commutation at γ = 0°, the 7° value is often used for practical converters [CF1]. This method estimates the critical fault level that causes commutation failure. It ignores several transient effects such as transient phase shift or dc current changes which have a significant role in the commutation process. Consequently as will be shown in the next section, the results are optimistic.

2.3.3.2. Contour Map

A contour map is a helpful tool for assessing the susceptibility of a system to commutation failure, especially useful with the geographic information of the system incorporated. It is a powerful visualization tool in understanding the performance of any system.

A contour map example is discussed in detail in Chapter 3 sections 1.1.4 and 1.2.3. To create a contour map, a fault analysis should be conducted on the system to measure the amount of voltage dip at the inverter ac bus following the occurrence of a fault at various points in the system. All the busses on the transmission system for which a fault will cause the same voltage drop (for example 20%, which will most likely cause commutation failure) at a specific inverter bus, are connected together to create a contour.

In case of a change in the system, such as adding a new ac transmission line, the study will be repeated to create the new contour map. By comparing the two contours, the impact of the change of the system on commutation failure will be assessed.

In a multiinfeed environment, contours can be drawn for each of the inverters under question and an initial assessment of simultaneous local commutation failures can be made. Contour maps do not readily yield the presence of concurrent commutation failures.

2.3.3.3. Transient Simulation Method

Due to the aforementioned drawbacks with the steady state method, a more realistic study of the commutation process can be conducted with the use of electromagnetic transient (emt) simulation. Additionally, non symmetric faults such as single phase faults can be assessed for their commutation failure impact, which is difficult using only a steady state analysis.

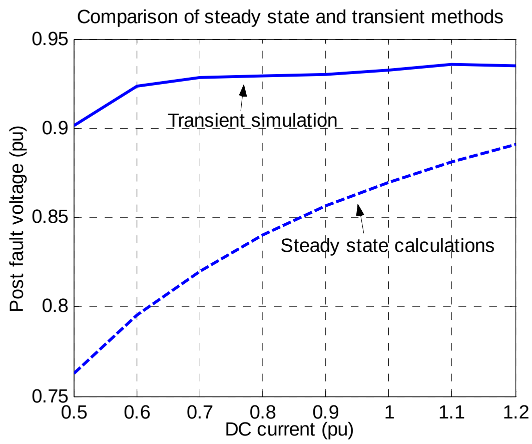

Figure 2-7 Calculated voltage drops which cause commutation failure using steady state and transient methods.

To compare the results of these two methods, the commutation failure phenomena are initially investigated using the single infeed CIGRÉ benchmark [CF3]. Later, the analysis is extended to multiinfeed systems. Figure 2-7 shows the voltage magnitude which results in commutation failure as a function of the dc current, computed using the steady state calculation and transient simulation methods. In the transient simulation, the undervoltage is created by applying a balanced three phase inductive fault on the inverter ac bus. The same figure shows that the steady state method is optimistic in that it predicts a much lower voltage at which commutation failure occurs. As the emt simulation based method is a full transient simulation, the results are more accurate than those computed with the simplified steady-state fundamental frequency model and is used in the discussion of commutation failures that follows.

2.3.4. Commutation Failure Immunity Index (CFII)

The analysis of commutation failure using transient method was conducted by applying a balanced 3-phase inductive fault on the ac bus [CF4]. The minimum size of an inductance which doesn't cause commutation failure is called Lmin and is used to define an index, namely commutation failure immunity index or CFII.

$$\boldsymbol{CFII} \quad = \quad \frac{\textbf{\textit{Worst Critical Fault MVA}}}{\boldsymbol{P_{dc}}} \times 100 \quad = \quad \frac{\boldsymbol{V_{ac}^2}}{\omega \times \boldsymbol{L}_{\min} \times \boldsymbol{P_{dc}}} \times 100 \quad \textbf{\textit{2-2}}$$

Local CFII is used for analysis of local commutation failure and concurrent CFII addresses the concurrent commutation failure phenomena in multiinfeed systems.

MIIF is defined in detail in Chapter 1. The study results show that there is a correlation between the value of MIIF and concurrent CFII. Figure 2-8 shows the value of $MIIF_{12}$ (as defined in Chapter 1) for as a function of the system strengths seen from local (ESCR1) and remote (ESCR2) buses.

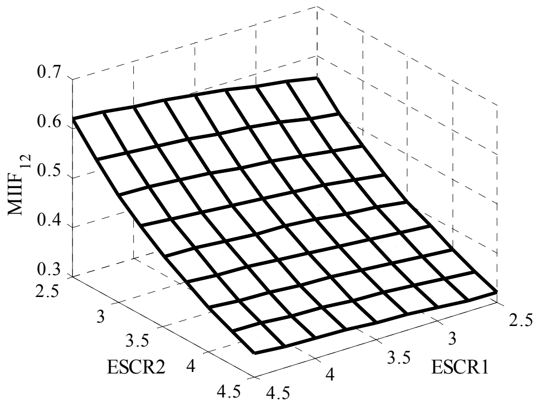

Figure 2-8 MIIF₁₂ as a function of AC System's Strengths

Figure 2-9 shows the value of concurrent Commutation Failure Immunity Index (CFII) as a function of the system strengths seen from local (ESCR1) and remote (ESCR2) bus.

Consolidating the information from figure 2-8 and figure 2-9 yields the concurrent CFII versus MIIF graph of figure 2-10 in which the points are closely clustered around a characteristic curve, indicating higher immunity with decreasing MIIF, as would be expected. Figure 2-10 thus quantifies the strong inverse correlation between the Concurrent CFII index and the MIIF and shows that MIIF is the critical parameter in estimating the propensity towards concurrent commutation failures.

Based on the graphs given in figure 2-10, it can be concluded that if MIIF is below 0.3 then concurrent commutation failure is rarely an issue.

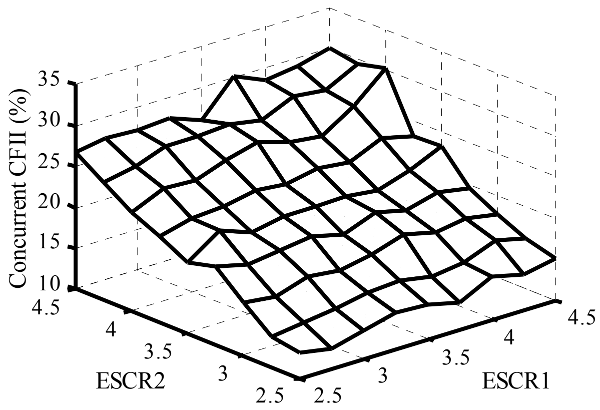

Figure 2-9 Concurrent CFII as a Function of Ac System Strengths

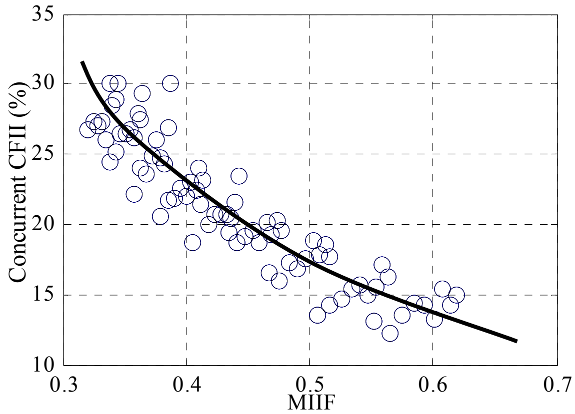

Figure 2-10 Concurrent CFII and MIIF are almost inversely proportional

In single infeed HVdc systems, the post fault recovery rate of the HVdc system to full power is mostly determined by the ESCR present on the inverter bus; the higher the ESCR the faster the recovery rate. This concept can be extended to multiinfeed systems, wherein the recovery rate can be related to the MIESCR appearing to each inverter. Some recovery rate tradeoffs amongst HVdc systems may be advantageous for the overall stability of the integrated system.

2.3.5. Mitigation Strategies

In the case of sustained commutation failure, some of the energy, as measured in MW-s, which would be injected into the receiving end ac network, will be interrupted. If the disturbance continues for a long time, it may cause instability of the ac system. Single commutation failure events are not likely to have a huge impact on the stability of the system; however it will decrease the "Power Quality" of both sending and receiving end. Considering the above factors, if commutation failure has a certain frequency of occurrence which is unacceptable to the ac system, some mitigation strategy should be employed to address the issue of commutation failure. Although a detailed study of the system and its parameters is required to design a specific countermeasure to address both local and concurrent commutation failure in multiinfeed HVdc schemes, the following mitigation strategies can be identified:

- ***Reduction of MIIF***

The study results show that systems with lower MIIFs are less susceptible to concurrent commutation failures and although susceptibility to commutation failure and recovery are two different concepts, in general a multiinfeed system with lower MIIFs, exhibits a better performance in regards to the effects of commutation failure.

- ***Using higher extinction angle (gamma) value***

The industry standard for selection of gamma is typically 17 degrees for 50 Hz, and 17 or 18 degrees for 60 Hz systems. Single infeed systems are showing acceptable performance using these extinction angle values, however in case of having concerns with commutation failure, one of the possibilities for avoidance is to use higher values of gamma. It is evident that there are some drawbacks in using larger gamma, such as higher MVAr consumption, higher valve stresses, higher converter transformer rating, and thus higher costs, but it will decrease the chances of commutation failure.

- ***Using other dc transmission technologies***

In this report, all the simulations and study are based on line commutated HVdc transmission. There are some other technologies available for dc transmission such as Voltage Sourced Converter (VSC) based dc transmission and the Capacitor Commutated Converter (CCC). The former is inherently immune to commutation failure and the latter has much less susceptibility to commutation failure.

- ***Using a larger smoothing reactor***

One of the factors which cause commutation failure is the rise of HVdc current following the ac voltage drop caused by a fault in the ac network. A larger smoothing reactor reduces the current rise and therefore reduces the chance of commutation failure. Although it is beneficial to have a larger smoothing reactor considering commutation failure, it also has an impact on other aspects of the HVdc transmission scheme such as cost and response time which should be thoroughly studied.

- ***Using a dc scheme with lower power ratings***

For all of the studies conducted for this report, two identical HVdc systems with equal power rating have been used. In other words the Power Base Ratio (PBR), which is the ratio of the ratings of the HVdc systems, was one (PBR = pdc1/pdc2 = 1). However the concepts are applicable to schemes of different ratings.

A preliminary analysis has been carried out on the impact of power base ratio and the conclusion is that if a new dc line is going to be added in proximity to an existing HVdc scheme, the smaller the relative rating of the new HVdc system, the lesser the impact on the commutation performance of the existing link.

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2.3.6. Cable Systems

2.3.6.1. Introduction

When considering an HVdc system incorporating a cable, a new level of complexity is added to the commutation failure problem. A fault on the ac system will cause a decrease in commutation voltage, which will transiently cause an increase in the HVdc current. Due to the stored energy in the cable, the HVdc current rise is greater than would be seen with an overhead line.

If the HVdc system is utilizing an overhead line, a rectifier in HVdc current control may be able to respond quick enough to minimize the resultant HVdc over-current and prevent a commutation failure. If the HVdc system is utilizing a cable, the capacitive effects of the cable maintain the HVdc voltage for a short period following the ac fault, which in effect increases the time before the rectifier current controller senses the fault and hence does not aid in the prevention of the commutation failure.

As a result of this, HVdc systems with longer cables can be simulated with dc voltage control at the inverter and with a higher gamma angle (~22 degrees). This enables the dc current controller at the rectifier time to act before the gamma angle reduces significantly, and gives similar results to HVdc systems with overhead lines.

2.3.6.2. Controls

If the HVdc cable is long and/or the ac system is weak, the preceding section dealing with overhead lines is not fully applicable due to control methods used in long distance cable schemes.

The longer the dc cable, the HVdc voltage as seen from the rectifier is maintained for a longer duration an ac fault. This in turn makes the current controller at the rectifier mostly ineffective for dealing with faults and even small changes in current at the inverter. Also, due to the rectifier dc voltage being maintained and the dc fault current being a function of the ac fault level and the discharge of the dc cable capacitance which further decreases the ac voltage, the normal cable control mode would lead to frequent commutation failures.

Because of this, control schemes used in long distance cable systems are slightly different from their overhead line counterparts. This could include:

- Controlling dc current at the inverter, and dc voltage at the rectifier
- Controlling dc voltage at the inverter, and dc current at the rectifier along with special control characteristics to mitigate transient current changes.
- Using the above control techniques in conjunction with a capacitor commutated converter (CCC).

In this report, the method of controlling the dc current at the inverter and the dc voltage at the rectifier is used [CF5]. The goal of the controls utilized for the control of an HVdc link with a long cable was to provide a stable model, without utilizing any special control functions that will vary from manufacturer to manufacturer. As such, the current control was moved to the inverter which does give a conservative representation. When looking at cable systems, only the transient simulation is used to evaluate commutation performance.

Systems with extremely long cables have a very significant capacitive discharge and are very difficult to minimize commutation failure, regardless of mitigative techniques employed.

2.3.6.3. HVdc and AC System Representation

Figure 2-11 shows the system simulated for the multiinfeed cable system test. The system is the same as before with the overhead line HVdc lines being replaced by 300 km length cables.

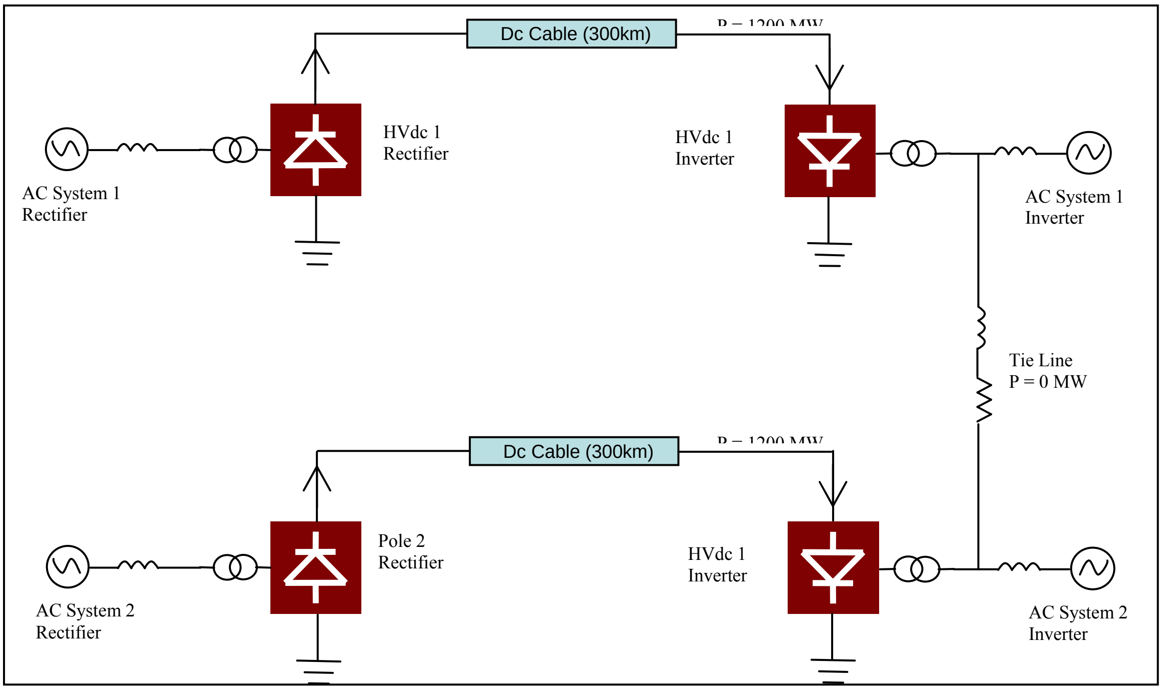

Figure 2-11 HVdc system utilizing an HVdc Cable

2.3.6.4. Transient Simulation Method

2.3.6.4.1. MIIF for Cable Systems

Using the techniques developed in Chapter 1, the interactions of the two systems were studied. MIIF values will not change from the overhead line test system as it is not dependent on HVdc line type.

2.3.6.4.2. Local CFII for a Cable System

In order to test the local CFII, the ESCR of system 1 was kept at 1.871 while the ESCR of system 2 was varied from 2 to 6. When this test was performed using a multiinfeed HVdc system utilizing an overhead HVdc line, the CFII was found to be 13.3%

Using the same ac system and test set-up, the HVdc link utilizing the HVdc cable was tested, and the CFII was found to be 22.8% as shown in figure 2-12.

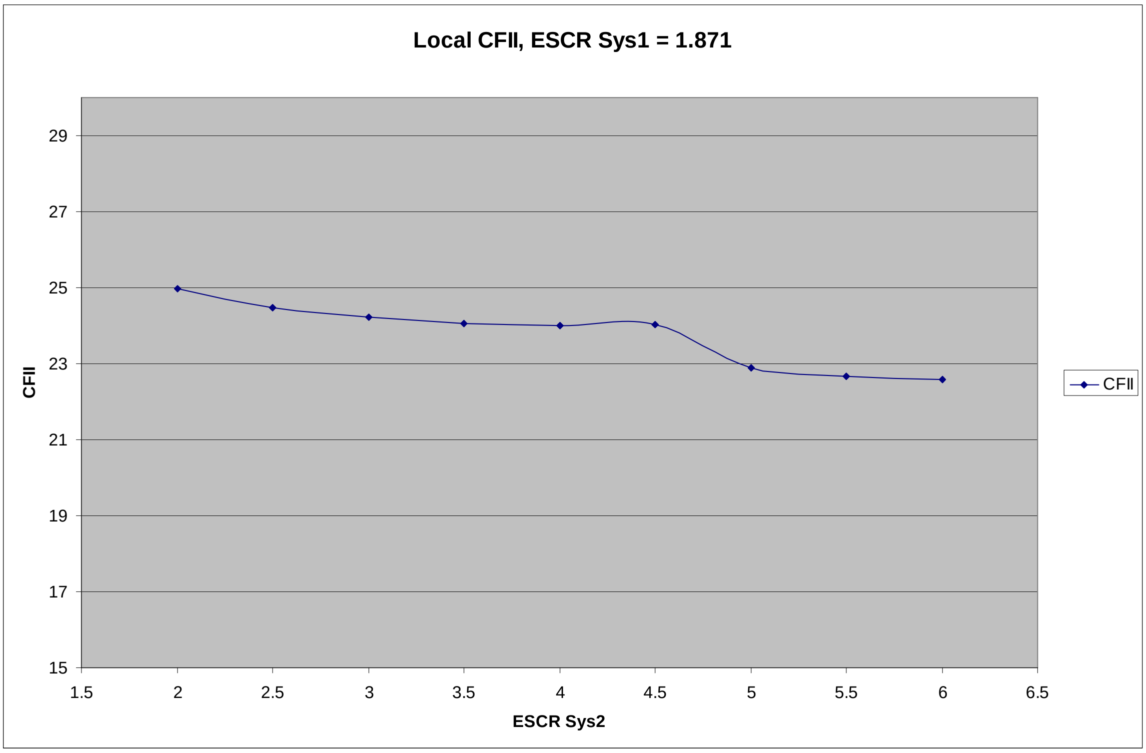

Figure 2-12 Local Commutation Failure Immunity Index-Cable System

As is evident in figure 2-12, the value of CFII stayed somewhat constant over the range of the test. This means that the local CFII is not as dependent on system strengths. A test was done replacing the HVdc cables in this model with an overhead line, and also another test done where the HVdc cable length halved. Both tests gave CFII values very close to values found for the 300 km test case.

2.3.6.5. Concurrent CFII for a Cable System

The same tests for calculating the concurrent commutation failure performed for the overhead line test system were also done for the cable system. When investigating the ac system, it was found that when system 2 had an ESCR under 3.5 there was instability which can be attributed to extremely weak systems leading to below critical MIESCR values.

The same general trend was found for the local commutation immunity index, as shown in figure 2-13, with the CFII being approximately 23%.

The graphs in figure 2-10 and figure 2-14 show that there is a correlation between concurrent CFII and MIIF. However in terms of absolute values, MIIF has lower values in cable systems compared to overhead lines but at the same time CFII values are higher in cable systems. It could be concluded that the cable system with the control method presented in this report (current control at inverter while assuming a higher gamma, and voltage control at rectifier), is more immune to commutation failure in general. In other words for the same range of fault levels, if MIIF is less than 0.3 it is very unlikely that interactions between HVdc cable systems to be an issue regarding commutation failure.

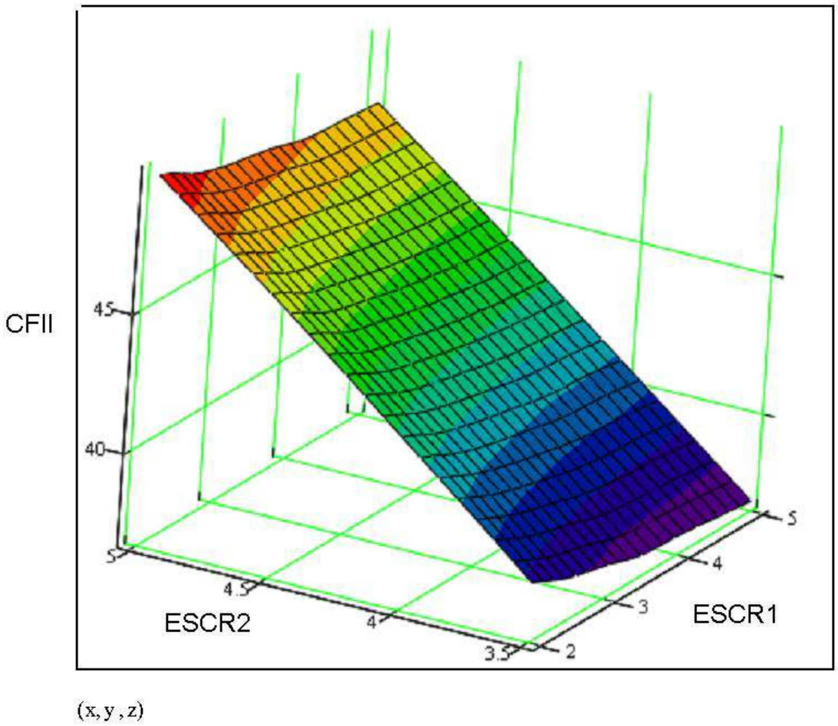

Figure 2-13   Concurrent Commutation Immunity Index -Cable System

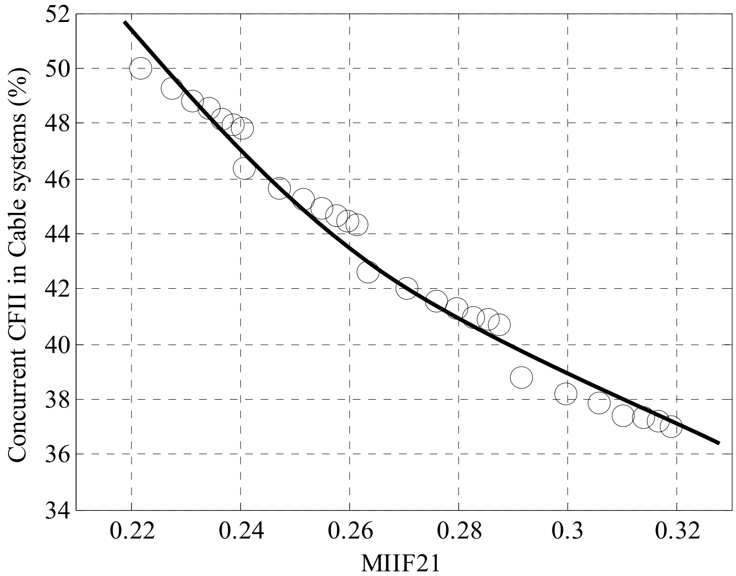

Figure 2-14   Correlation between Concurrent CFII and MIIF - Cable System

2.3.6.6. Conclusions

The main reasons for the higher immunity to commutation failures in the cable system are:

1. Higher steady-state Extinction Angle

   In a long distance cable system where the dc current is controlled at the inverter and extinction angle control tends to be less stable, the system is generally operated at a higher extinction angle of approximately 22 degrees, which gives a higher inherent immunity to commutation failures.

2. Current Control at the Inverter

   In order to adequately control the current against the large transient emf source created by the HVdc cable, dc current control is enabled at the inverter while the rectifier is responsible for controlling dc voltage.

These methods are not used as a standard control method for overhead lines because commutation failures are less likely and do not justify the costs associated with the higher losses, harmonics generation and reactive power requirements.

HVdc cable systems of very long length are not as robust in their immunity to commutation failures as compared to shorter cable systems or overhead lines. For cable systems of more modest length, MIIF values below 0.3 would indicate a much diminished interaction concern.

2.4. Harmonic Performance

2.4.1. Introduction

Line commutated HVdc converters are major harmonic sources in power system. They generate harmonics on both the ac and dc sides of their valve groups. Harmonic effects are not confined to a converter station and can propagate over great distances within the network. The voltage and current harmonic levels in the network can be amplified by system series and parallel resonances. The harmonics in an HVdc system reduce the efficiency of power generation and transmission. They may also lower the efficiency of power utilization and damage the insulation of system components if not properly addressed. In addition, a plant mal-function can occur if the system has high harmonic contents. The harmonics entering the ac network and the HVdc line may result in the overheating of capacitors and generators, instability of the system controls, and interference with communication circuits. In order to have efficient and high quality power, it is necessary to define the level of wave distortion that can be permitted in the power system.

The ac filters associated with line commutated HVdc converters are also sinks of harmonics from the network and this must be considered in harmonic interaction studies.

Harmonics in the ac current of an HVdc converter are divided into characteristic and non-characteristic harmonics:

2.4.1.1. Characteristic Harmonics

The characteristic harmonics are the harmonics which are present under idealized circumstances, with balanced non-distorted ac voltages equidistant firing pulses, matching converter transformer impedances between phases and groups, and no harmonic interaction between the ac and dc sides. The orders of the ac and dc harmonics are respectively 6n ± 1 and 6n for a 6-pulse converter; and 12n ± 1 and 12n for a 12-pulse converter.

2.4.1.2. Non-Characteristic Harmonics

Non-characteristic harmonics result from unbalances in ac waveforms including harmonic distortion, variation from ideal firing angle instant among valves, differences in reactance among converter transformer phases and wye and delta groups, and harmonic interaction between the ac and dc sides. They can be problematic because typically individual harmonic filters are not provided for these harmonics. Instead, filtering for non-characteristic harmonics is typically factored into the design of the filter banks principally intended for major characteristic harmonics. Also, given the right circumstances, they can excite harmonic resonances, such as the second harmonic resonance phenomenon. Equidistant firing of the converter valves is key in the minimization of non-characteristic harmonics. The commonly used phase-locked loop based firing systems has greatly reduced the problems associated with most non-characteristic harmonics. Typical specifications require the valves to be fired within 0.1° of their intended firing angle order. However, the amount of second harmonic on the dc side and positive sequence third harmonic on the ac side is a direct function of the amount of negative sequence at fundamental frequency in the converter ac bus voltage.

Problems related to non-characteristic harmonics and harmonic resonance can often be mitigated through the firing controls by incorporating a modulation signal in the firing angle order. In some circumstances the addition of non-characteristic harmonic filters on the converter bus is required.

Considering non-characteristic harmonics, typically only the third harmonic is likely to be of sufficient magnitude to be worth considering in the interaction studies. As a general rule, for negative sequence voltage unbalance less than 1%, the third harmonic is not likely to be a problem.

2.4.2. Harmonic Interactions in Multiinfeed HVdc Systems

Since there are two or more harmonic sources in multiinfeed systems, there is a possibility that they will interact with one another. Such situations need to be studied in detail to check for possible harmonic interactions. While this document is focused on multiinfeed inverter interactions, the concepts discussed here would also apply to harmonic interactions between rectifiers or mixed situations. Experience has shown that in systems with an MIIF less than about 0.1, harmonic interactions are not a concern. There are systems in service with two bipoles on one bus (MIIF=1.0) and filter coordination has been reasonably straightforward and successful in this case. For systems with an MIIF between 0.1 and 1.0 it is possible to have some level of harmonic interaction through the network, where the higher the MIIF the higher the possibility of severe interaction. It is expected that as the MIIF becomes lower, the inherent damping of the network and the diversity of transmission paths will lessen the severity of interactions.

Severe harmonic interactions are not expected to occur when effective filters are in service at the converter stations in question. However at harmonics where filters are not in-service, during filter outages, or in the case of severe filter de-tuning, it is possible for harmonics from one converter to have a significant impact on another.

2.4.3. Basics of Filter Design

Designing a harmonic filter for the harmonic currents generated by a converter and preventing their propagation to the rest of the network is a multi-variable optimization task which should consider technical and cost related issues. Figure 2-15 shows how the harmonic current (I_{hc}) is distributed between the filter (I_{hf}) and the ac network (I_{hN}):

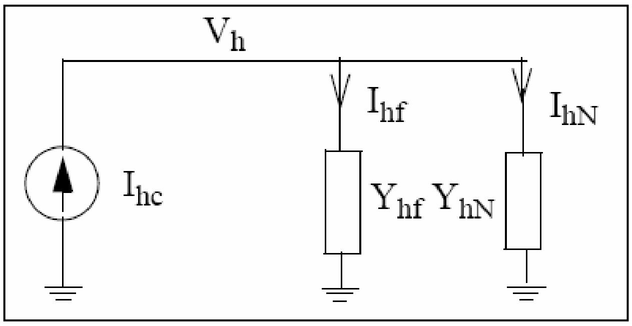

Figure 2-15 Harmonic Current is divided between filter and ac network

The main goal in filter design is to reduce the magnitude of V_h. There are some standards that set a maximum limit on the magnitude of V_h (or harmonic voltage distortion). On some systems, this is typically around 1% of the fundamental frequency voltage. On other systems it may be a function of harmonic number with maximum permitted distortion reducing at higher order harmonics.

One of the critical parameters in the filter design process is the impedance of the network. Unfortunately it is not straightforward to predict the network impedance at harmonic frequency as it is a nonlinear function of time and system configuration. Typically a region defined by two lines and an angle in which network impedance varies is assumed, based on detailed frequency scans of the system:

More recent filter studies have used impedance sectors or polygons for individual harmonics or harmonic ranges to reduce the cost and complexity of the filters [HI3]

In most traditional optimum filter design procedures the angle ϕm is used as a design parameter, which is basically a limit on the R/X ratio of the network impedance in harmonic frequencies, typically to the 50th. The absolute value of the system impedance is considered to vary in a very wide range and the filter is designed for the impedance which causes the highest value of Vh.

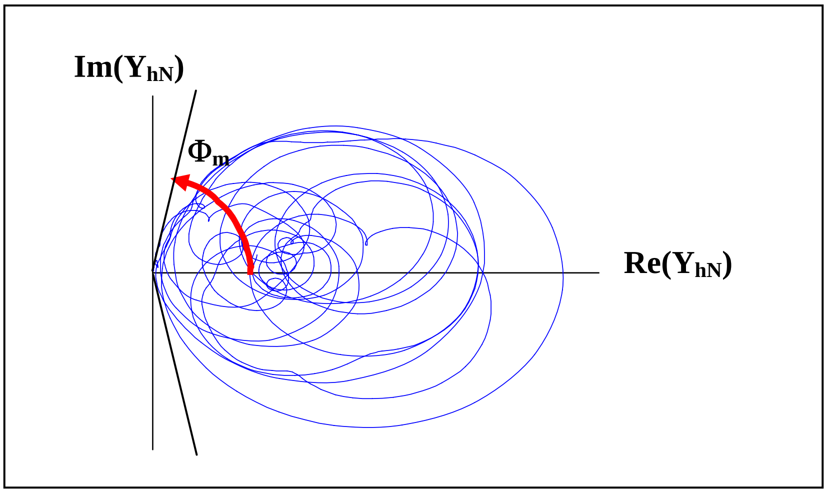

Figure 2-16 Typical Network Impedance at Harmonic Frequencies

As in the case of single infeed, the extent of the network model for a multiinfeed study should include all busses where the impedance value for a given harmonic is influenced by the inclusion of a detailed model of the bus. Further from that bus, the network is often represented by an equivalent impedance.

2.4.4. Study Tools & Methodology

The study of harmonics includes both steady state and fast transient phenomena and at each stage different methodologies are used. At the planning stage, where details of the system design are not generally finalized, a steady state analysis is often used to give insight to the harmonic levels and possible problems associated with those harmonic levels. However in later stages of studies, especially if non-characteristic harmonics are of concern then, electromagnetic transient simulation programs or software packages designed specifically for the study of harmonics are used.

2.4.4.1. Steady State Analysis

For characteristic harmonics in multiinfeed systems, since the system impedance would be somewhat based on speculation and thus have a safety margin included, the addition of another converter station and some additional transmission lines may not change the system impedance at harmonic frequencies to a great extent. The impact of additional converter stations is in the possible change of system impedance and also in that each additional converter station will inject harmonics. However in filter design there is a range of values assumed for system impedance, so as long as the design parameters remain the same, the presence of additional converters may not have an impact on the existing or new converter filter design.

Even with different design parameters for the converters, possibly because of the trend towards higher power quality standards, the new system may have a lower acceptable value for harmonic voltage (V_h). Since the existing system may have higher harmonic content, the filter design process for the new converter should take this into account, and also consider that it is desirable to have no changes to the filters for existing converters.

Under some circumstances higher harmonic content could be allowed for the new converter. In this case, a detailed study is required to ensure that the filters installed at the existing converter bus are sufficient and if not the filters will need to be redesigned.

As mentioned in the introduction, experience shows that if MIIF values between two converters are less than 0.1 then the interaction level between converters will be so low that harmonic interaction is very unlikely to be an issue.

2.4.4.2. Transient Simulation Method

For non-characteristic harmonics a detailed transient simulation study of the system is generally required for the design of the filters to account for unbalances in ac waveforms including harmonic distortion, variation from ideal firing angle instant among valves, differences in reactance among converter transformer phases and wye and delta groups, and harmonic interaction between the ac and dc sides.

2.4.4.3. Harmonic Current Injection Method

A harmonic current injection simulation can be used as an effective technique to determine the existence of potentially problematic resonance conditions in multiinfeed systems.

The influence of the current harmonics of one converter on another is determined by injecting 1 Ampere of harmonic current at one converter bus and by monitoring voltages at all converter buses. The ratio of the converter harmonic bus voltages can provide an indication of a problem resonance situation. For example if the harmonic voltage at the third harmonic is five times higher at the remote converter bus than at the injected converter bus, then there is likely a resonance situation that may require mitigation.

This method could be used to look at non-characteristic as well as zero-sequence harmonics. Care has to be exercised when looking at low order harmonics (2^{nd} & 3^{rd}) where there can be ac/dc interaction effects in which case the transferred dc-side impedance may have to be taken into account.

2.4.5. Low Order Resonances

Low order resonances between the filters and network occur in HVdc systems and may lead to problems under some system conditions especially in weak ac systems. The following formula provides an estimate of the resonance frequency at an inverter bus, and if it is close to the second harmonic (value of SCR should be low which occurs in weak systems) then a resonance condition may be present. [PV1]

$$\frac{\omega_0}{\omega_N} = \sqrt{\frac{\boldsymbol{SCR}}{\boldsymbol{k}}} \qquad \textbf{\textit{2-3}}$$

$$\boldsymbol{k_i} = \frac{\boldsymbol{Q_d}}{\boldsymbol{P_d}};\ \omega_N = \textbf{\textit{system frequency}};\ \omega_0 = \textbf{\textit{resonance frequency of inverter bus}}$$

As an extension of the equation used for single infeed systems, the proposed multiinfeed benchmark system was used to check the usefulness of the equation and it was determined that it could reasonably predict the existence of resonances near the second harmonic but was not accurate for predicting third harmonic resonance or higher. It is also noted that a resonance near the second harmonic does not occur for strong inverter buses as the filters and local capacitors would have to be unreasonably large and therefore the use of the equation in a multiinfeed context is limited.

$$\frac{\omega_{0i}}{\omega_N} = \sqrt{\frac{SCR_i}{k_i}} \qquad \textbf{\textit{2-4}}$$

$$k_i = \frac{Q_{di}}{P_{di}};\ \ \omega_N = \textit{system frequency};\ \omega_{0i} = \textit{resonance frequency of } i^{th} \textit{ inverter bus}$$

Note that SCR_i at the inverter bus i of interest here is as defined in the multiinfeed context as the short circuit capacity at the inverter bus due to the entire ac network with multiple HVdc infeed, divided by the HVdc rating of the considered inverter.

If MIIF is below 0.1, then the impedance between converter busses is quite high and similar to single infeed systems, the SCR used in Equation 2-5 is mostly a function of the local ac system impedance. Therefore in multiinfeed systems with low values of MIIF (less than 0.1), interaction between HVdc systems will not affect the low order harmonic resonance phenomena.

2.4.6. Mitigation Strategies

Reduction of MIIF
For very low values of MIIF, less than 0.1, filter design is the same as for single-infeed systems. Thus if there is a cost effective way of lowering the MIIF, it could simplify the filter design.

Revising the existing filter design
If the design parameters of the new HVdc system are different from the existing HVdc system, for example if V_h is higher, then the existing filter design should be re-evaluated.

Using other HVdc transmission technologies
In other HVdc transmission technologies like VSC based HVdc, there is often a high pass filter that needs to be considered in analysis. If V_h is the same for all converter stations, then again no specific precautions are required.

2.4.7. Conclusions

- With the same harmonic standard for new and existing HVdc converters, no specific precaution is required for characteristic harmonics.
- A more limiting harmonic standard for new HVdc system will affect the filter design of only the new system.
- A less limiting harmonic standard for the new system, though unlikely, could require a re-evalution of the design for existing filters, if the new installation is significantly larger than the existing converter or if both converters are in very

close proximity (high MIIF values). If the new installation is smaller in capacity than the existing facilities, it may be more economic to design filters for the new facility to a more limiting distortion than that required by the standard.

- For non-characteristic harmonics, if the negative sequence voltage is less than 1% of the positive sequence, then it is unlikely that non-characteristic harmonics will be an issue. If a filter is required for the non-characteristic third harmonic then it will likely be relatively costly due to the large reactors, high damping, and the need to withstand transient third harmonic during single phase faults. If filters for non-characteristic harmonics are deemed necessary, a detailed analysis of the system is required to design filters both for existing and new systems.

- For negative sequence voltage unbalance less than 1%, the third harmonic is not likely to be a problem. For systems with higher negative sequence voltage, a detailed study is required for filter design to make sure non-characteristic harmonics are not an issue, and if they are, then special filtering might be required.

- If the MIIF is less than 0.1, interaction between HVdc systems is unlikely to cause any issue regarding both characteristic and non-characteristic harmonics.

- With design parameters such as V_h remaining the same, the converter power ratings are not a factor in the filter design.

2.4.8. Cable Systems

Cable systems have no special requirements in harmonic considerations in comparison to overhead lines.

2.5. Control Interactions and Power/Voltage Instability

2.5.1. Control Interactions and PV Instability in a Multiinfeed Context

A comprehensive overview of the static and dynamic approaches to evaluating the power-voltage stability at an inverter of a multiinfeed HVdc system has been provided in [PV2]. It reports the major work done in this area prior to the year 2002.

This guide is based on the same framework of static and dynamic approaches of PV stability analysis shown in figure 2-17. The basic addition to the available tools in this guide is the parameter MIESCR defined in chapter 1. It is emphasized as the first level planning tool that can be used to determine PV stability at an inverter of a multiinfeed HVdc systems. It is also fundamentally analogous to the ESCR- PV stability relationship of an inverter in a single infeed HVdc system.

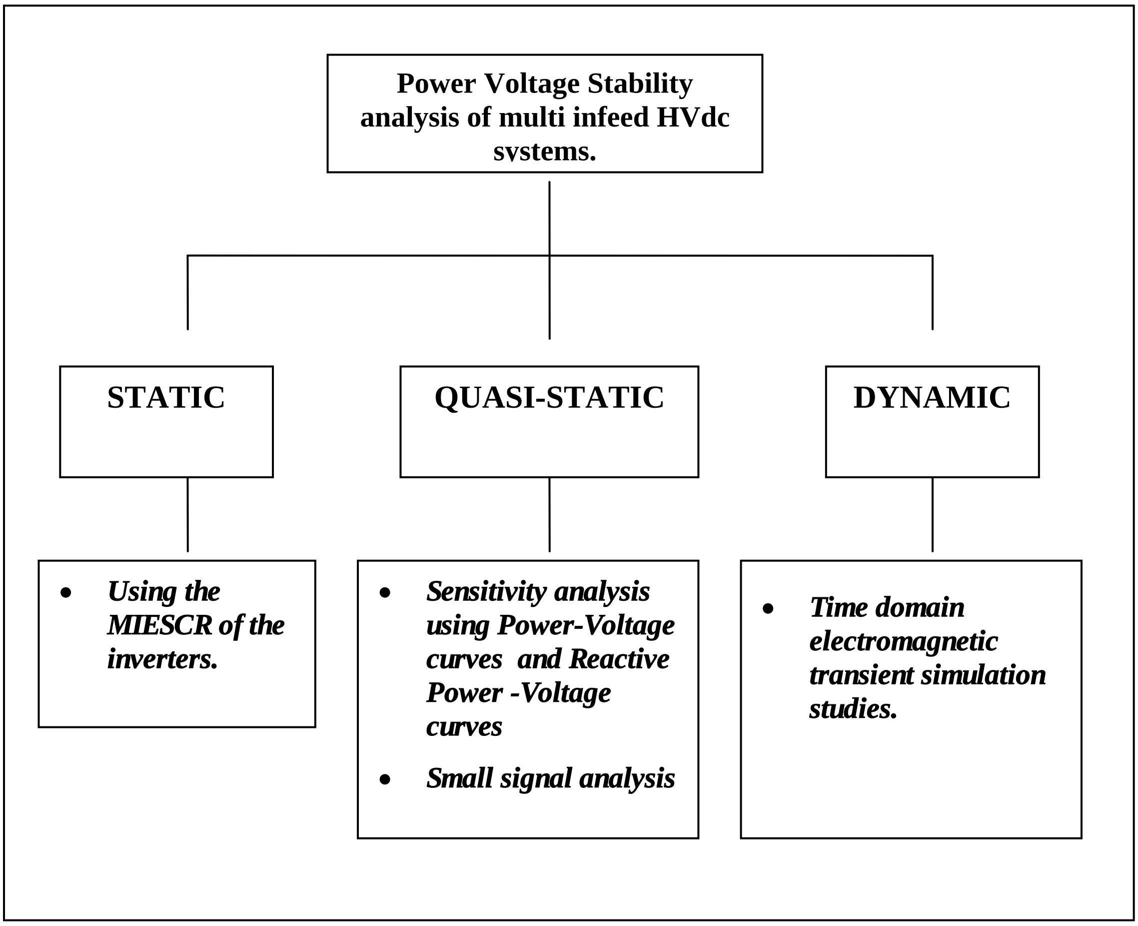

Figure 2-17 Framework for Power Voltage stability analysis of multiinfeed HVdc Systems.

The static tools are intended for initial analysis in the initial planning stages of multiinfeed systems. They can also be useful, as discussed later, in evaluating the general mitigation strategies and in making HVdc development or expansion decisions.

Quasi-static approaches are secondary tools that can be used to verify and refine system PV stability boundaries in the presence of additional system details (typically transient stability type models)

Dynamic tools are time domain analysis with the most detailed models of controls and other dynamics of the system. These should be utilized to fine tune the performance of the multiinfeed systems by investigating the design details such as controls, compensation, filters etc.

The greatest planning insight into a particular multiinfeed system arises from the static approach and will be described within this guide. Further refinements through quasi-static and dynamic approaches are described very briefly in section 2.5.2.2, and in more detail in references [PV3], [PV4],[PV5], [PV6].

In order to verify the suitability of the MIESCR indices for a particular system, field measurements, dynamic simulations and mathematical analysis could also be done.

2.5.1.1. Control Interactions

Expansion of existing HVdc systems and construction of new dc links will naturally result in an increase in the number of instances of multiinfeed systems in future. Multiinfeed systems provide promising features for improving the stability of interconnected networks in case of large disturbances and also increase the controllability of the overall network; however, they also tend to increase the potential for unfavorable interactions between the constituent HVdc schemes, and between the HVdc and ac systems. This mainly arises from fast control actions available through the HVdc system controls and also the harmonic interactions present in the network. Presence of fast and highly-controllable equipment in close proximity is a leading cause of adverse control interactions in multiinfeed systems. Moreover, unlike conventional HVdc systems, where converters operate in isolation, multiinfeed systems tend to be (significantly) affected by each other.

The existence of control interactions is in part affected by the topology and characteristics of the network in which HVdc converters are embedded. Experience with multiinfeed systems indicates that multiinfeed converters that observe a large transference impedance between their commutation terminals are less likely to face interactions. In such cases the two (or more) systems operate essentially independently. However, when the systems terminate in the same electrical area, strong interactions can be observed depending on the short-circuit ratio (SCR) seen by individual converter stations. Control interactions are practically absent in systems with a high SCR.

Current literature and accumulated experience with existing systems does not show adverse interaction between conventional controllers in the individual control systems. Interactions are mostly initiated by higher-level controls such as the VDCOL and stability-improvement control add-ons.

2.5.1.2. PV Instability

In single infeed HVdc systems the ESCR at the inverter bus is the basic static indicator of the PV stability at the inverter ac bus. A single infeed HVdc system with typical HVdc parameters and controls can deliver rated power without causing power voltage instability at the inverter ac busbar if the ESCR is 1.5 or more. Thus the

Critical ESCR (CESCR) for PV stability of a single infeed inverter with typical parameters is about 1.5. With a margin to instability, systems with ESCR values less than 2.5 are recognized as weak buses and are usually designed with appropriate mitigation strategies for PV stability, especially in systems where the dependence on HVdc power delivery is high.

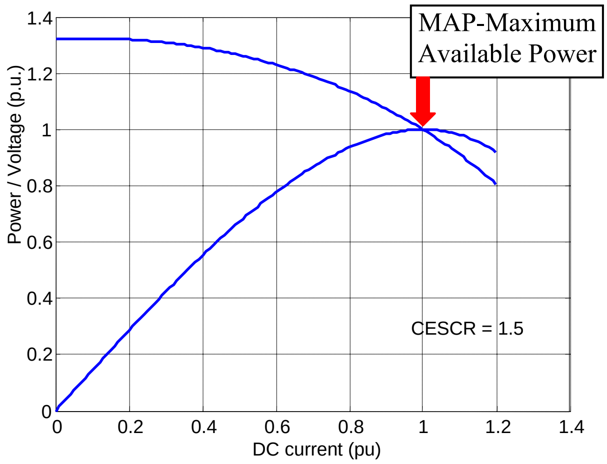

Figure 2-18 Maximum Available Power of a Single Infeed Inverter (CESCR).

In the case of multiple HVdc schemes in electrical proximity, a conventional calculation of inverter ESCR for each scheme fails to provide a proper measure of the PV instability of the inverter ac bus, due to an inability to capture the effect of HVdc systems sharing ac system strength.

The ***MultiInfeed Interactive Effective Short Circuit Ratio*** (MIESCR) parameter defined in chapter 1 that estimates the strength of a given inverter busbar with respect to all the HVdc systems shared by the common ac system provides an effective measure of the PV stability in a multiinfeed context. The work reported in ref [PV9] shows that MIESCR at an inverter bus bar generally defined for all multiinfeed HVdc systems, simplifies to the inverter ESCR at the extreme cases where the electrical distances between the inverters are very large (i.e. single infeed or low MIIFs) and very small (multiple inverters on the same ac busbar or high MIIFs). The following section reports the analysis carried out using the dual inverter multiinfeed test system that confirms MIESCR as an effective static indicator of PV instability at a multiinfeed inverter ac bus. It also establishes the Critial MIESCR (CMIESCR) to be approximately 1.5 for systems with typical HVdc parameters and controls. With a margin to allow for contingencies and a possible heavily loaded ac system, multiinfeed inverters with MIESCR of 2.5 or greater will thus be typically PV stable.

MIESCRs computed at the inverters of a multiinfeed HVdc system can therefore be the fundamental set of indicators for PV stability. It should be noted that every inverter on the multiinfeed system should be PV stable for successful operation of the system. The weakest inverter or the inverter with the lowest MIESCR (closest to its CMIESCR) will determine the point of instability for the entire system, as the voltage instability on an ac system is a phenomena that would be wide spread across the shared ac system.

It should also be noted that the definition of MIESCR in chapter 1 is based on the ratings of the individual HVdc systems and therefore would determine the ability of individual inverters to deliver rated power on their respective HVdc links, while others in the vicinity are delivering their rated HVdc power as well. However, if on a given multiinfeed system the simultaneous delivery of rated power on all HVdc links is not planned, then the MIESCR should be computed for the worst case simultaneous HVdc power delivery of the multiple HVdc schemes. It should be noted that the decision to include an HVdc link in the MIESCR calculation, as described in Chapter 1, is appropriate for the PV phenomenon as well.

2.5.1.3. Test System - Dual Inverter Multiinfeed HVdc System

The analysis of the test system is presented for three different scenarios. In all three scenarios one HVdc system is maintained at critical stability. The maximum available power curves evaluated for both inverters are utilized to determine the state of stability for individual inverter at rated power delivery.

Scenario 1: Figure 2-19 shows the MAP curves of the two HVdc systems where the test system is set up such that the first HVdc scheme is critically stable and scheme 2 unstable, with both at rated power levels.

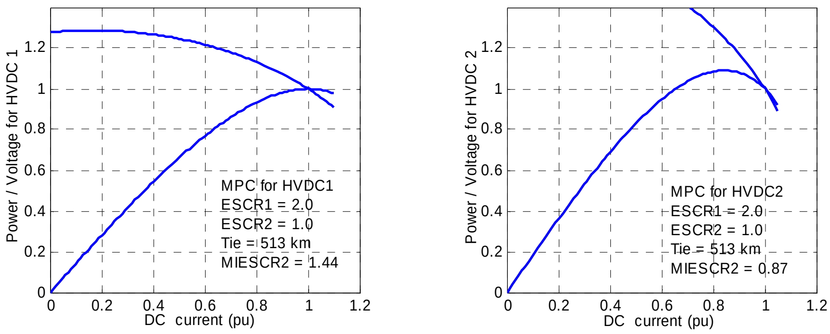

Figure 2-19 MAP curves of the HVdc schemes for a test case where HVdc system 1 is critically stable and the other is unstable at their ratings.

The MIESCRs calculated for the inverter buses have values of 1.44 and 0.87 respectively at inverters 1 and 2. Here, only the inverter bus strength of scheme 1 is adequate to deliver the rated power in constant power control mode of operation and has a CMIESCR value of 1.44.

Scenario 2: The test system is then set up such that both HVdc schemes are critically stable at their rated power as shown in the MAP curves of figure 2-20. It is worth noting that the CMIESCR of both inverters are evaluated to be 1.43.

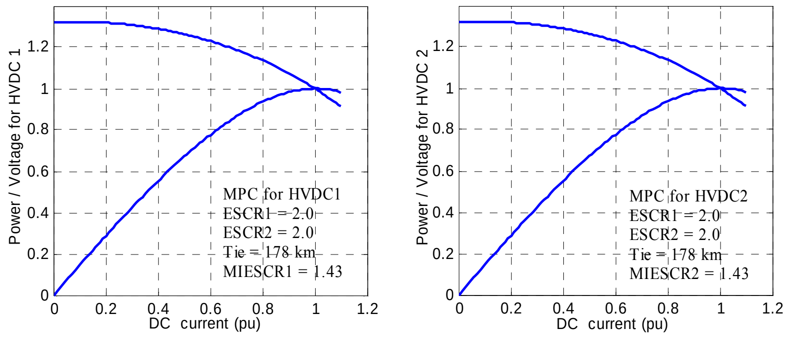

Figure 2-20 MAP curves of the two HVdc schemes of the test system where both are critically stable at their ratings.

<u>Scenario 3:</u> In this scenario one HVdc scheme is critically stable at rated power while the other is stable at its rated power level. figure 2-21 shows the MAP curves of the two HVdc schemes and has respective MIESCR values of 1.43 and 2.13.

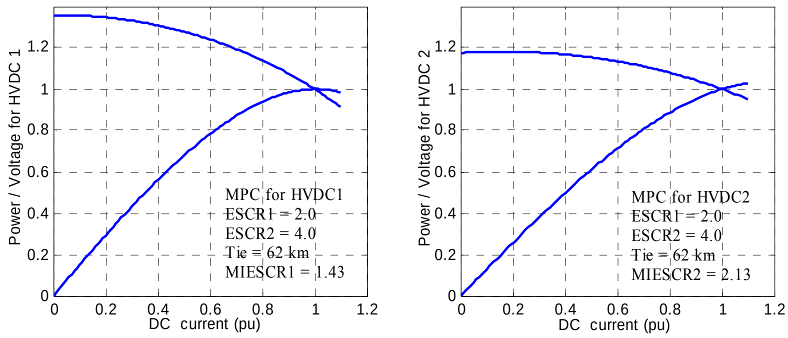

Figure 2-21 MAP curves of the HVdc schemes of a test case where HVdc system 1 is critically stable and the other is stable at rated power.

The MIESCR values for many different such test systems are reported in table 2-1 where the first HVdc scheme is in critical PV stability. The tie line length of the test system in these cases is set such that the $HVDC_1$ is in critical PV stability at its rated power for the chosen values of $ESCR_1$ and $ESCR_2$. All the test scenarios demonstrate $CMIESCR_1$ value falling in the range of 1.43~1.52. Also note that the ESCR for multiinfeed systems is based on the entire ac system strength, as of the definition in chapter 1.

The results of these dual inverter test cases show that those systems with MIESCRs less than approximately 1.5 to be PV unstable and those systems with MIESCRs greater than about 1.5 to be PV stable at the inverter. The point emphasized here is that when $HVDC_1$ is made to maintain its critical stability, the $MIESCR_1$ at its inverter always is near a value of 1.5 (numbers shown in bold). It should also be noted that in cases where $MIESCR_2$ is below 1.5 the MAP curve of $HVDC_2$ demonstrates P-V instability and when greater than 1.5 it demonstrates stability. Therefore a CMIESCR (Critical Multiinfeed Interactive Effective Short Circuit Ratio) of approximately 1.5 would be reasonable based on the above dual inverter test system MAP curves.

Table 2-1 Parameters of the dual inverter test systems with $HVDC_1$ in critical stability.

$ESCR_1$	$ESCR_2$	Tie line length (km)	$MIIF_{21}$	$MIIF_{12}$	$MIESCR_1$	$MIESCR_2$
2.0	1.00	513	0.392	0.151	**1.44**	0.87
2.0	1.50	266	0.400	0.278	**1.43**	1.17
2.0	2.00	178	0.395	0.395	**1.43**	1.43
2.0	2.50	128	0.398	0.518	**1.43**	1.65
2.0	3.00	97	0.401	0.641	**1.43**	1.83
2.0	3.50	77	0.401	0.757	**1.43**	1.99
2.0	4.00	62	0.402	0.875	**1.43**	2.13
2.0	4.50	52	0.398	0.980	**1.43**	2.27
2.0	5.00	43	0.400	1.093	**1.43**	2.39
2.5	1.00	251	0.720	0.219	**1.45**	0.82
2.5	1.50	126	0.708	0.383	**1.46**	1.08
2.5	2.00	74	0.711	0.551	**1.46**	1.29
2.5	2.50	46	0.715	0.715	**1.46**	1.46
2.5	3.00	29	0.717	0.873	**1.46**	1.60
3.0	1.0	166	0.978	0.249	**1.52**	0.80
3.0	1.5	72	0.978	0.442	**1.52**	1.04
3.0	2.0	34	0.984	0.633	**1.51**	1.23
3.0	2.5	14	0.986	0.814	**1.51**	1.38
3.0	3.0	2	0.983	0.983	**1.51**	1.51

2.5.1.4. Test System with a Very Long Tie Line

Now consider a special test case configuration where the tie line length is very long. The MAP curves for the two HVdc schemes (identical due to the symmetry) are shown in figure 2-22. The inverter ESCRs are set at 1.5.

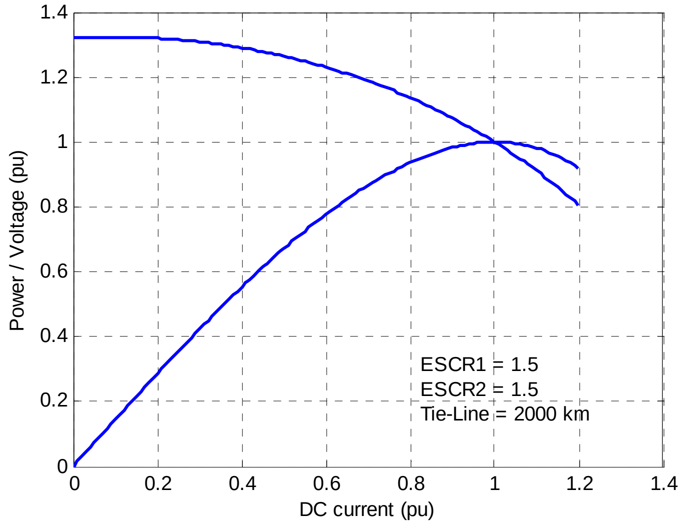

Figure 2-22 MAP curves for remote HVdc schemes.

Since the tie line is long, the $MIIF_{1,2}$ and $MIIF_{2,1}$ are both near zero. The MIESCR values therefore are equal to the ESCR values and are given by the following equations.

$$MIESCR_1 = \frac{SCC_{MVA_1} - Q_{filter_1}}{P_{dc1}} = ESCR_1 \quad and$$
$$MIESCR_2 = \frac{SCC_{MVA_1} - Q_{filter_2}}{P_{dc2}} = ESCR_2 \qquad \textbf{2-6}$$

Having both HVdc schemes in their critical stability limit further confirms the CMIESCR of 1.5 for this special test case where they are effectively two single infeed systems.

2.5.1.5. Test System with a Very Short Tie Line

The second special case test system considered here has a very short tie line and therefore can be considered to have a common inverter bus. Here again the MAP curves for the two HVdc schemes are identical due to the symmetry and are shown in figure 2-23. The inverter ESCRs are set at 3.0.

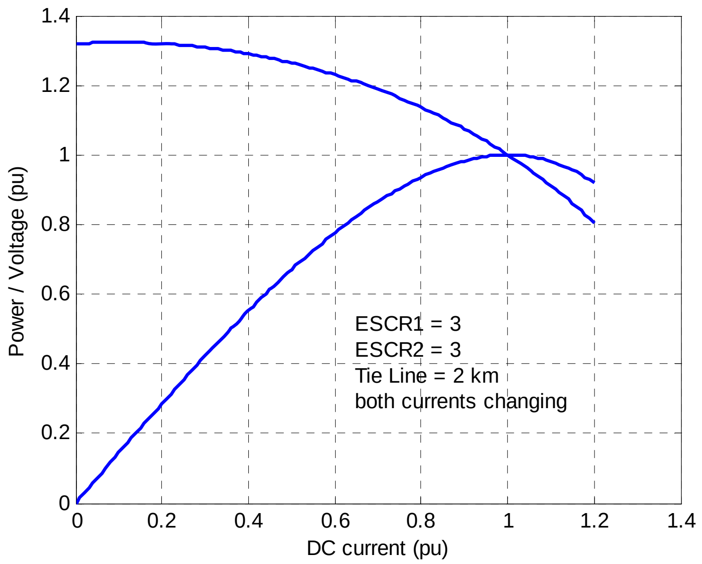

Figure 2-23 MAP curves for the HVdc schemes on a common inverter bus.

Since the tie line is very short the $MIIF_{1,2}$ and $MIIF_{2,1}$ are both nearly unity. The MIESCR values are therefore given by the following equation which is equal to half the ESCR values.

$$MIESCR_1 = \frac{SCC_{MVA_1} - Q_{filter_1}}{P_{dc_1} + P_{dc_2}} = \frac{ESCR_1}{2} = 1.5 \quad and$$
$$MIESCR_2 = \frac{SCC_{MVA_2} - Q_{filter_2}}{P_{dc_2} + P_{dc_1}} = \frac{ESCR_2}{2} = 1.5 \qquad \textbf{2-7}$$

Both HVdc schemes are in critical stability limit confirming the CMIESCR of 1.5 for this special test case of the common inverter.

2.5.1.6. Test System - Three Inverter Multiinfeed HVdc System

The investigation is extended to a three inverter multiinfeed HVdc test system. The results are shown in table 2-2 and again $HVDC_1$ in critical stability has its $MIESCR_1$ value near 1.4 for all the different system configurations, which is close to 1.5 as obtained for the single and dual infeed systems.

Table 2-2 Parameters of the Three inverter Multiinfeed HVdc test system with $HVDC_1$ in critical stability for various system ESCR values.

	$SYSTEM_1$	$SYSTEM_2$	$SYSTEM_3$	$SYSTEM_4$
ZS_1 (Ω)	40	35	30	25
ZS_2	16	19	23	31
ZS_3	20	20	20	20
Tie_{12} (km)	70	70	70	70
Tie_{13}	100	100	100	100
Tie_{23}	70	70	70	70
$ESCR_1$	2.60	2.69	2.84	3.03
$ESCR_2$	4.23	3.78	3.53	2.90
$ESCR_3$	3.64	3.58	3.39	3.45
$MIESCR_1$	**1.38**	**1.38**	**1.40**	**1.41**
$MIESCR_2$	1.80	1.65	1.52	1.35
$MIESCR_3$	1.69	1.64	1.59	1.52

2.5.1.7. Test System - Dual Inverter Multiinfeed HVdc System with Unequal Converter Ratings

MAP curves are obtained for the same three scenarios covered in section I sub-section D above with different power ratings for the two HVdc schemes.

<u>Scenario 1:</u> MAP curves of the two HVdc systems where the test system is set up such that the first HVdc scheme is critically stable and the second is unstable at its rated power level, where the rated power levels are unequal. The critical MIESCR for system 1 is near 1.5 even for these unequally rated systems.

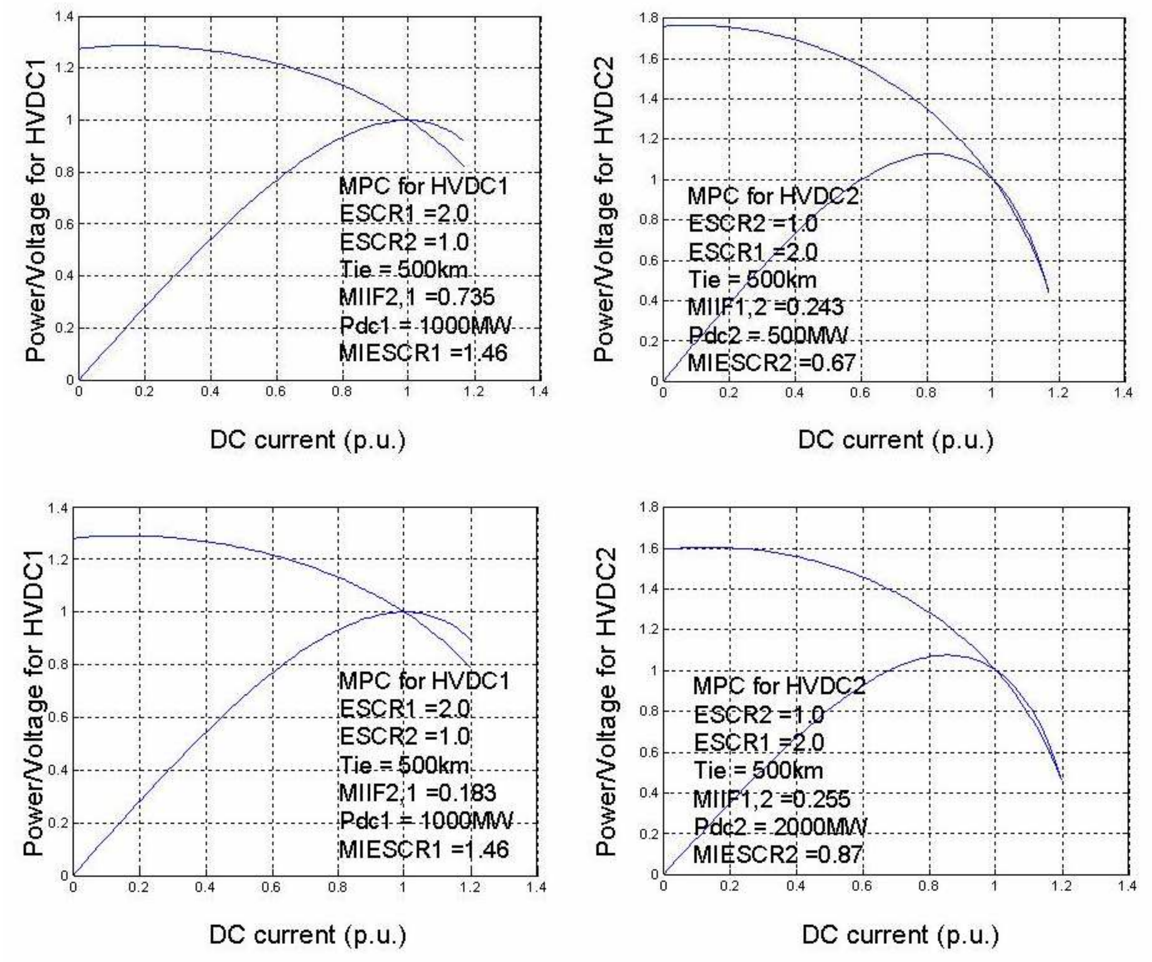

Figure 2-24 MAP curves of two examples of unequally rated HVdc schemes where one HVdc system is critically stable and the other is unstable at their ratings.

<u>Scenario 2:</u> The test system is then set up such that both HVdc schemes are critically stable at their rated power and the critical MIESCR of both inverters are evaluated to be close to 1.5, even for differently rated systems.

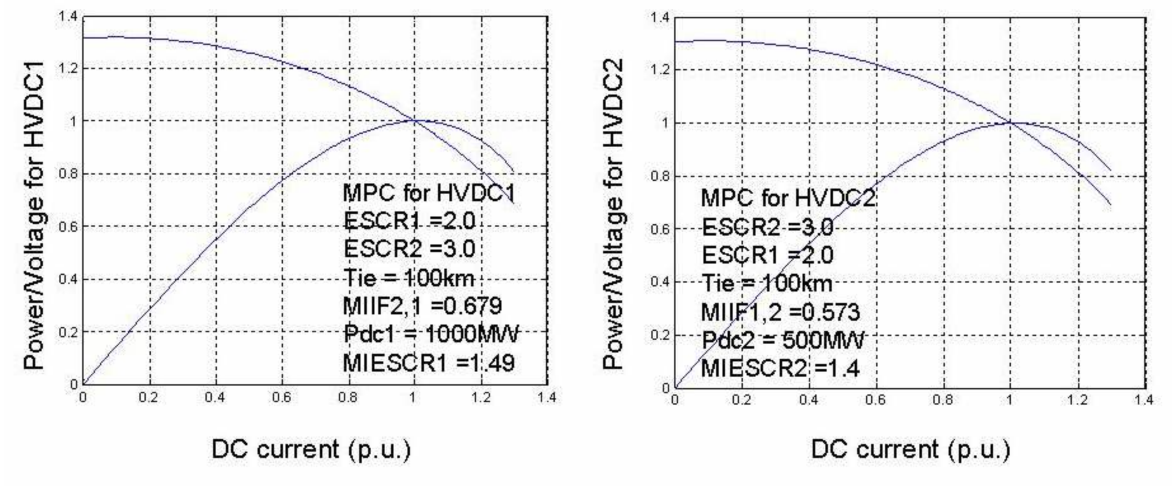

Figure 2-25 MAP curves of two unequally rated HVdc schemes where both of them are critically stable at their ratings

Scenario 3: In this scenario one HVdc scheme is critically stable while the other is stable at their rated power levels. The inverter close to critical stability still maintains an MIESCR close to 1.5

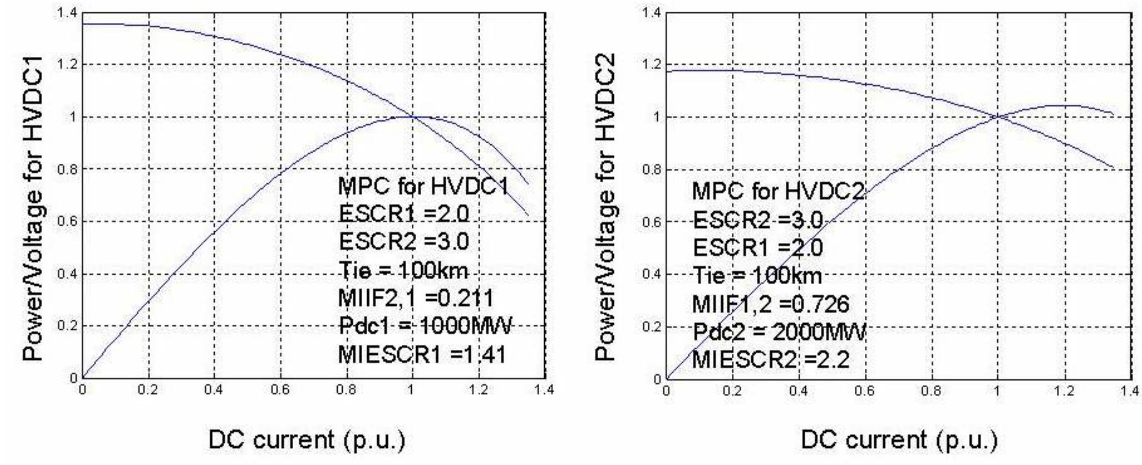

Figure 2-26 ***MAP curves of two unequally rated HVdc schemes where one HVdc system is critically stable and the other is stable at their ratings.***

The above results strongly support MIESCR to be a good indicator of potential inverter PV instability in multiinfeed HVdc schemes. The results also characterize those HVdc schemes in critical PV stability with a CMIESCR value close to 1.5, results that agree with the single infeed CESCR with similar HVdc parameters. It should be noted that the CMIESCR of 1.5 is based on the HVdc parameters set in the benchmark test case with a commutating reactance of 18%, a 15^{o} extinction angle, and near unity reactive power compensation. Variations of the HVdc parameters will affect the critical value of MIESCR (similar to that of single infeed HVdc). As mentioned before, instability will be initiated at the bus with the lowest MIESCR, but all HVdc inverter busses will become unstable with the collapsing ac voltage.

A similar parameter ***Multiinfeed Effective Short Circuit Ratio*** - MESCR reported in ref [PV1] also has been used to determine the inverter PV-stability of multiinfeed test systems. There again a critical point of PV instability has been characterized by an MESCR value of 1.5 for the three different configurations covered in the reference. The methods presented with MIESCR are empirical and can readily be applied on large power systems with available study tools. Reference [PV1] presents an analytical method which requires specialized study tools at the present time.

It is worth mentioning that, although the MIESCR parameter is basically perceived as a static quantity for the system, there are some dynamics that are accounted for through the evaluation of the MIIFs that enters into the computation of MIESCR. Even in a system where a majority of generators are equipped with fast acting exciters, there can still be some influence on the PV stability of the HVdc system as explained in [PV8], which may not be completely captured in the MIESCR parameter. Here, the excitation dynamics introduced for MIESCR consideration are no different to that experienced for a single infeed ESCR evaluation. As such the suitability of the MIESCR indices for a particular system should be verified by field measurements, dynamic simulations and mathematical analysis where possible.

2.5.2. Study Tools and Methodology

2.5.2.1. Control Interactions

Study of control interactions in multiinfeed HVdc systems calls for different tools and techniques depending on the nature and goal of the study. A detailed assessment of control interactions and their impact on subsequent dynamic behavior of the systems is possible through detailed simulations using electromagnetic transient simulation tools (e.g., EMTP-typle programs or transient network analyzers).

Highly-detailed models of the system components, including control systems at various levels and respective limits, can be developed and interconnected to obtain an accurate representation of the actual system. Control interactions can be simulated in great detail by considering various scenarios that could lead to such interactions. While this approach has been used extensively in both single and multiinfeed systems, it does not provide a convenient means for identifying root causes of adverse control interactions. Neither does it provide an adequate insight and a universal methodology for design of controllers to eliminate adverse interactions.

The formal methodology for the study of control interactions is to use small-signal modeling and analysis techniques. Here models of network equipment and controls are developed and assembled to form the overall network model. To allow formal analyses such as eigenvalue assessment, the models need to be linearized around the operating point of interest. Note that small-signal models typically are not as detailed as transient simulation models and often do not include high-order dynamics of the system. In other words, small-signal models are best suited to represent low-frequency dynamics of the system. A particular challenge in developing small-signal models for HVdc converters has been the line commutation of thyristors. This poses significant challenge as opposed to other switches such as GTOs or IGBTs where controlled turn-off exists.

There has been research work on the development of small-signal models for HVdc converters. However, further research seems to be necessary to develop commercially available tools that could model (i) both ac and dc sides, (ii) converter dynamics, and (iii) associated control modules and various control modes.

2.5.2.2. PV Instability

As MIESCR provides the preliminary evaluation of the PV stability of an inverter, discussion of some aspects of computing the MIESCR is deemed necessary for better understanding.

The MIESCR is similar to the MESCR as proposed in reference [PV1]. However it does not directly incorporate the system impedance matrix elements in the computation. It arrives at a similar relationship via the computation of the MIIF. The MultiInfeed Interaction Factor is derived using transient stability type models of the multiinfeed HVdc sytem under consideration for the operating point under investigation. It is a direct measure of the voltage coupling between the two inverters in question, which translates into a function of the elements of the effective system impedance matrix that is discussed in reference [PV1]. Since MIIF is a ratio, it should not be sensitive to the accuracy of maintaining the 1% at the $\boldsymbol{i}^{th}$ busbar. The intent here is to maintain a relatively small disturbance that would not operate any voltage controlling devices resulting in topological alterations on the system that would effectively change the system impedance matrix. Also, the voltage dip should be large enough to be significant within the numerical accuracies of the transient stability type software.

Another important point is the method by which the filter capacitors at the inverters are accounted for in the MIESCR computation. The filter capacitors at the inverter bus of consideration are incorporated into the MIESCR equation directly as in the case of a single infeed system. The filters at the remote inverter are indirectly accounted for through the SCC at the inverter bus. As emphasized in Chapter 1, the SCC of the inverter bus of consideration is determined using the entire shared ac system with the filters on the remote inverter buses. However, it should be noted that some error may be introduced to the MIESCR computation due to the remote filters. The error is a minimum when the inverters under consideration are electrically far apart. The error increases as they come electrically close together. The error introduced is a maximum when the inverters share a common ac bus due to the filters of the j^{th} HVdc scheme having no contribution to the inverter bus SCC. Therefore in the extreme case where the inverters are on a common ac bus, it is suggested that, all filters be used in $Q_{filteri}$ when computing the MIESCR of the bus. Also incorporating any other shunt capacitors in the close proximity to the inverter bus under consideration would minimize the error.

As much as MIESCR is a static tool it can also be utilized to evaluated the weakening of the inverter buses under ac system contingencies. The post contingency values of MIESCR computed for the individual inverters should have the corresponding post contingency SCC and MIIF numbers.

As mentioned at the beginning of section 2.5.1, in addition to the static techniques there are the quasi-static and dynamic ways of analyzing the PV stability at an inverter of a multiinfeed HVdc system.

2.5.2.3. Quasi-Static Methods of PV Stability Analysis

The reference [TOV2] has provided a discussion on the many quasi-static techniques and the various references that describe the theoretical background to these different methods of PV stability analysis at an inverter of a multiinfeed HVdc system.

This guide focuses on the tools and methods that can be readily applicable to large power systems with commercially available software. Some insights on the deficiencies of the analysis tools may be pointed out wherever applicable.

2.5.2.4. Sensitivity Analysis using the Power-Voltage and Reactive Power-Voltage Curves

PV and QV analysis on ac systems is a widely used method and the approach normally is to load the system in various directions of power transfer until the system exhibits instability. The eigenanalysis performed on the reduced system Jacobian matrix as the transfer increases reveals the weak buses that cause the voltage collapse of the system. The theoretical basis to this is covered in the references [PV4], [PV5]. This same technique can be utilized to determine the PV instability at an inverter. Here the loading directions considered would be the loading of HVdc systems of the multiinfeed HVdc system. Increasing the transfer on one HVdc scheme at a time with the others in their maximum possible loading conditions would give better insights to the PV instability at individual inverters of the multiinfeed system. The analysis is then repeated for various ac system contingencies to analyze the PV stability performance at the inverters under contingent situations.

Close to the point of voltage instability those weaker buses should demonstrate very high voltage sensitivities to changes in reactive power. That is $\partial \boldsymbol{V} / \partial \boldsymbol{Q} \rightarrow \infty$. QV analysis of the buses in question can be used to verify the inverters that are reaching PV instability at the power transfer increases on the HVdc system(s). With the preliminary evaluation of the inverter MIESCRs, quasi static type of studies can be focused on the weaker inverters of the multiinfeed HVdc systems for further verification. Most voltage stability software do not allow for a solution very near the nose point, or the instability point due to singularities of the power flow Jacobian. Therefore the systems will be indicating PV instability at transfer levels a little short of what is used for computing MIESCRs of the inverters.

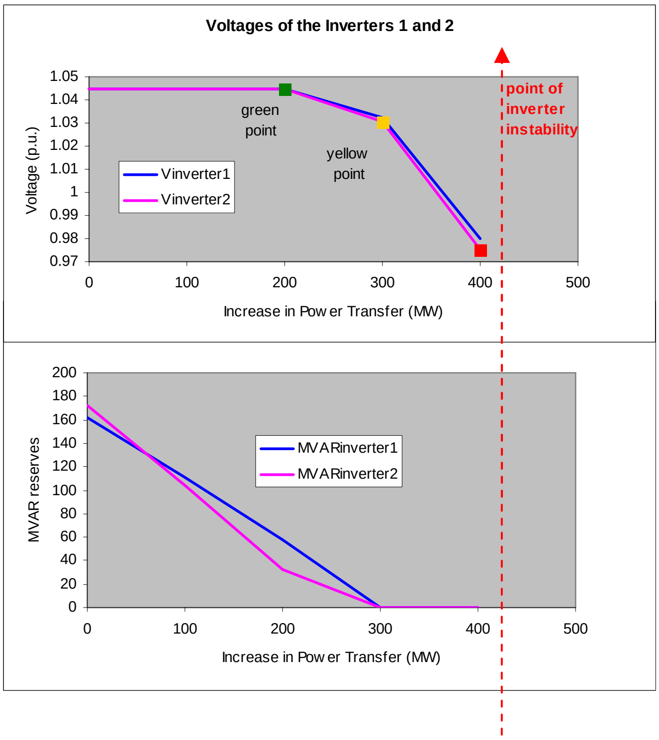

Figure 2-27 Reactive reserves at an inverter approaching loss of voltage control instability.

Available reactive power reserves at the inverter buses are another indicator that can be utilized to determine the PV instability the inverters reach. Usually, inverters that are heavily compensated with active devices such as synchronous compensators experience "***loss of voltage control instability***", a form of instability that arises from a change in effective impedance due to fixed excitation control, prior to "***clogging voltage instability***" at the inverter. (Clogging voltage instability is due to the I^2X losses in the ac network and the eventual reduction in shunt capacitor reactive power supply at the inverter [PV7]). Such inverters would demonstrate zero reactive reserves of the synchronous machines at the bus itself or the reactive reserve basin (in the neighborhood of the inverter bus) well before the nose point or the point of instability. A typical example is shown in figure 2-27 where the reactive power reserves of the synchronous condensers are depleted completely, well before the stability limit. Note that the inverter voltage deterioration is much more rapid after the reactive power reserves have depleted.

Reference [PV8] provides a more complete description of the dependency of the machine dynamics on stability limits.

One of the major difficulties utilizing voltage stability software for analysis of PV instability at inverters arises from their inability to study inverters alone within a vast ac system. Therefore although instability of the system is indicated, it is unclear if it is due to the PV instability at an inverter of the multiinfeed system. It may be due to the weakening of some ac bus on the large system. One way to verify PV instability at the inverter under investigation is by introduction of a fictitious reactive resource at the inverter. If the artificially increased reactive resources warrant an increase in the maximum power transfer then the inverter can be concluded as the weakest prior to the introduction of the fictitious reactive resource.

2.5.2.5. Small Signal Eigen Value Analysis

It has been demonstrated in ref [PV6] that small signal analysis on a multiinfeed HVdc system can be used to dertermine the PV stability at the inverters. Near 0Hz eigenanalysis of the multiinfeed HVdc system that is linearized at an operating point with worst case HVdc power transfer is indicative of the PV instability.

Unlike in the case of small signal analysis of other frequencies, the difficulty here is that systems in PV instability do not have a convergent load flow solution. Therefore, the linearized system can only be close to PV instability and therefore eigenanalysis will not result in unstable eigenvalues, but only those close to instability.

2.5.2.6. Dynamic Methods of PV Analysis

Time domain analysis is used to fine tune specific instability and mitigation issues. A prior understanding of the PV stability limits and details of a system are required to carry out a meaningful time domain analysis. Detailed models of the HVdc systems, controls and a reasonable representation of the shared ac system would be needed for such studies. Time domain analysis targeting optimization of control strategies and mitigation issues can be made manageable by selectively focusing on weak system configurations.

2.5.3. Study Methods

2.5.3.1. Control Interactions

As stated in 2.5.2.1, small-signal analysis of multiinfeed systems is the formal method for analysis of control interactions. Using small-signal models, a detailed analysis can be performed of the locations of system poles and zeros (which provides a clear picture of the stability of the system), and through use of standard indicators such as participation factors identify root causes of instabilities and design controllers that can alleviate such issues.

Existing literature and experience with multiinfeed systems however, suggests that specific recommendations should be sought for individual multiinfeed systems. This is because the structure of the ac and HVdc systems, modes of operation of neighboring converters and also strength of the terminating ac system all make contributions to control interactions, thus limiting the opportunity for drawing universal conclusions. It is therefore recommended that multiinfeed systems be studied on a case-by-case basis for specific measures.

2.5.3.2. PV Instability

There are two approaches to improving PV stability of a single infeed inverter: one approach is to curtail the HVdc transmission by means of controls to suit the ac system strength offered at the inverter; the other is to strengthen the ac systems by means of additional devices such as synchronous compensators. These approaches essentially affect the operating value of ESCR at the inverter.

In multiinfeed inverters, in addition to the above two approaches, there is the third approach to improving PV stability. That is by curtailing the power delivered by the remote HVdc systems that influence the MIESCR at the inverter of concern. An MIESCR figure that properly reflects any such mitigation strategy should indicate PV stability at the inverter. As such MIESCR can be utilized as a strong indicator in the preliminary mitigation planning as well. Here again, re-iterating through quasi-static and dynamic study techniques will offer more insights to what is revealed by the MIESCR computations.

2.5.4. Mitigation Strategies

2.5.4.1. Control Interactions

The existing literature on the multiinfeed HVdc systems has shown that the dynamic behavior of the system partially depends on the mode of operation of the converters terminating into the common ac system and also the topology of the system at the remote end.

The root cause of control interactions is the presence of fast acting controls (through the dc converters) in close proximity. Rapid operation of controls may lead to undesirable interaction in response to a given disturbance. Specific measures to reduce or eliminate adverse interactions in a multiinfeed system should be based on studies on the system using the methods previously mentioned.

Overall it is suggested that coordination of controls be carried out to ensure cooperative rather than competitive operation. It is observed that problems in a given dc system can be alleviated through proper use of control actions in other systems. It is also highly recommended that the controls be optimized. This should include various levels of controls as well as parameters of the voltage-dependent current order limiter (VDCOL).

Choice of the optimization approach depends on the platform used for studies. The recently developed optimization-enabled transient simulation (OE-EMTS) that uses nonlinear optimization to conduct guided transient simulations of the network (implemented in the PSCAD/EMTDC program) is one such tool.

2.5.4.2. PV Instability

Power/voltage instability involving an HVdc link is a very serious concern and especially so in a multiinfeed system where more than one link may participate in the collapse. It will be important to either prevent a system from entering into a voltage collapse state or to stop the collapse from progressing. In comparison with voltage collapse in an ac system, voltage collapse involving one or more HVdc links can progress quickly. Possible mitigating strategies include:

Control Modifications: An HVdc link in power control will order a larger current with a deteriorating ac voltage, since the magnitude of the dc voltage is related to the ac voltage magnitude. A greater dc line current will consume more MVAr at the inverter terminals and therefore contribute to the deteriorating ac voltage. Since maintaining voltage stability will be more important than maintaining constant dc power flow, many schemes incorporate special logic that inhibits the power controller from ordering large dc currents under conditions of low ac voltage [Chapter 3 - Canada]. This strategy would also be applicable to multiinfeed situations.

Limiting HVdc Power Levels: PV instability, as applied to HVdc systems, is a situation in which excessive power is being injected by one or more HVdc links relative to the amount of power that the ac system can accept. In single HVdc infeed systems, the ac/dc configuration may be simple enough that a deterministic rule set can be developed relating configuration to maximum allowable HVdc power level [PV10]. Alternatively, the impending voltage collapse can be sensed and power limited [Chapter 3 - Canada]. In more complex multiinfeed situations, a derivation of the MIESCR at each of the inverter busses may be possible, especially with the more sophisticated data acquisition tools available, and compared to the critical ESCR. HVdc power levels can be lowered so that MIESCR values are no longer in violation. A feedback sensing system may also be possible and desirable but must be carefully considered so that remedial action is initiated at the most advantageous location.

2.5.4.2.1. A Note on Machine Self-Excitation

Machine self-excitation can, in some ways, be considered the inverse of PV instability. Rather than a deficiency of vars leading to a voltage collapse, a surplus of capacitive vars may exist which can self excite one or more machines. Because a large number of filters and capacitors may exist at a converter station, the potential exists for self-excitation of nearby machines upon HVdc blocking and this has been considered in the protection and design of single infeed systems. This concern should be extended to multiinfeed systems wherein filters and capacitors from a number of links have the potential to self-excite machines within a contained area.

2.5.5. Cable Systems

2.5.5.1. Control Interactions

Control interactions in cable systems could be different from conventional multiinfeed systems as the mode of operation of converters may be affected by the requirements of the cable links. However, since control interactions are best studied on a case-by-case basis, it seems that cable systems will not substantially change this scheme. As long as the study tool permits proper modeling of cable systems and modifications to the controls to represent those used in cable systems, the procedures, methodologies and study methods should remain identical to those presented earlier.

2.5.5.2. PV Instability

Most cable systems operate the inverter in current control for performance reasons and thus would be less susceptible to PV instabilities. However, should there be an overriding power control or if the link is forced into gamma control, the mechanism of PV instability and its analysis should be no different than that of a conventional over head system.

2.6. Operating Systems

The intent of this document is primarily to assist planners in the integration of a new HVdc link into a complex multiinfeed HVdc environment. Nonetheless, the principles within this guide could have some benefit in the day to day operation of systems which contain more than one HVdc link.

With the sophisticated data acquisition and computational tools available today, the calculation of MIIF, ESCR, and MIESCR quantities for operational situations can be readily accomplished. The calculated quantities can then be compared to threshold levels to identify undesirable operating states.

In consideration of the four basic interactive effects described earlier in this chapter, both transient overvoltage and harmonic effects are, in most schemes, design issues and are usually not an operating concern as long as the system is operated as designed.

For commutation failure purposes, the commutation failure contour map is a powerful visualization tool for ascertaining common susceptibility to ac bus faults. The derivation of the map can be computationally intensive to the point where MIIF values may be a reasonable indicator of common mode commutation failures. Only more detailed studies can pre-determine limits for operational situations where such common mode susceptibilities become a general problem to the system.

Power/voltage instability of an HVdc link is often an important operational consideration. In single infeed situations the problem is more contained within the elements connected to an inverter bus in relation to the HVdc power level. As described above, power/voltage instability in a multiinfeed sense is more complex and could be best understood operationally through an estimation of the MIESCR, with appropriate remedial action being taken as a critical value is approached.

In terms of general stability, ongoing operational evaluations of MIIF and MIESCR values may give some indication of appropriate damping controller gains which could be adjusted accordingly.

Mitigation operating strategies could include setting limits on the amount of power flowing on a particular HVdc link and switching in or out of certain key elements within the combined ac/dc system.

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3. CHAPTER 3 - SYSTEM APPLICATIONS

Following the principles laid out in Chapters 1 and 2, this chapter will discuss specific multiinfeed situations.

3.1. Canada

Currently the Manitoba Hydro system has two bipoles terminating at a common inverter bus called Dorsey near the city of Winnipeg. The combined rating of these two bipoles is 3854 MW although maximum available generation would limit this power to just over 3500 MW. Manitoba Hydro is considering adding a third bipole, also near the city of Winnipeg, but terminating on the opposite side of the city. The rating of this bipole would be 2000 MW. Two other HVdc links are located in the northern United States and need to be evaluated for possible inclusion in studies. Figure 3-1 provides a geographical overview of the system under consideration. For the purposes of this study, Bipoles I and II will be considered as one link.

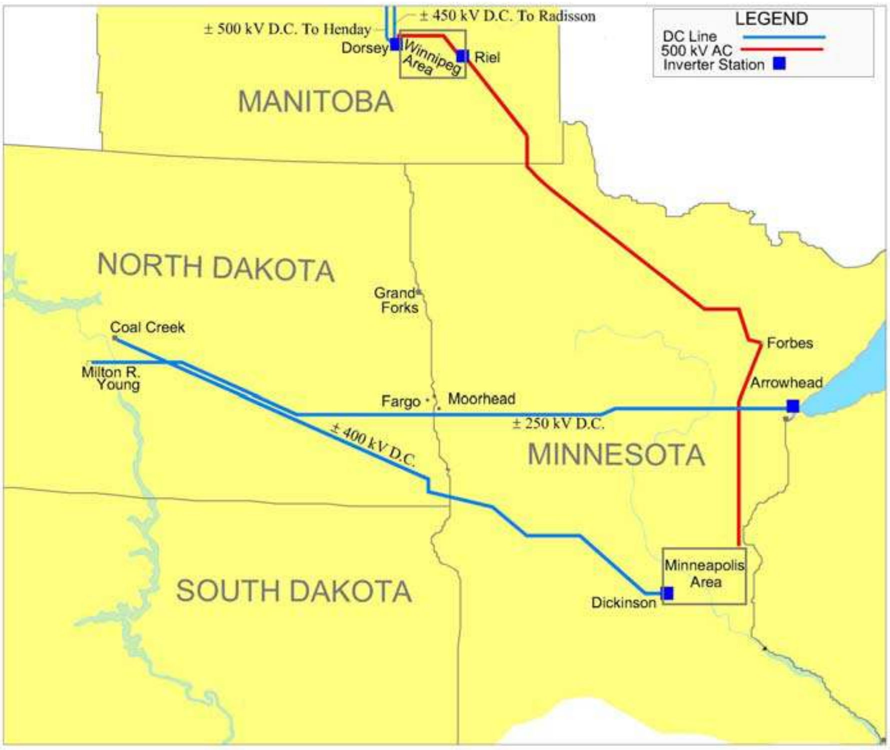

Figure 3-1 Geographical Overview

3.1.1. MIIF

Using a standard transient stability program to apply a 1% step voltage at various inverter busses, the following MIIF table can be derived for the system illustrated in figure 3-1.

Table 3-1 MIIF Table for the Manitoba Hydro System.

	Bipole I Dorsey	Bipole II Dorsey	Bipole III Riel	CU Dickinson	Square Butte ArrowHead
BP I Dorsey ***(Existing)***	1.0000	1.0000	0.9521	0.0403	0.0414
BP II Dorsey ***(Exisiting)***	1.0000	1.0000	0.9521	0.0403	0.0414
BP III/Riel ***(Proposed)***	0.6528	0.6528	1.0000	0.0487	0.0518
CU/Dickinson ***(Existing)***	0.0464	0.0464	0.0414	1.0000	0.0665
SB/ArrowHead ***(Existing)***	0.0990	0.0990	0.0888	0.1120	1.0000

Both the Square Butte and CU HVdc lines are of somewhat lower rating than either the Bipole I or II lines or the Bipole III line. Therefore, given the very low MIIF values between the U.S. and Canadian links, it can be concluded that multiinfeed considerations should be considered only between the Dorsey and Riel inverter buses. Further, as Bipoles I and II supply the same inverter bus at Dorsey and have similar characteristics, they can be treated as one entity. Table 3-1 can now be reduced to:

Table 3-2 Reduced MIIF Table for the Manitoba Hydro System.

	Bp I & II/ Dorsey	BPIII/ Riel
BP I & II/Dorsey ***(Existing)***	1.0000	0.9521
BP III/Riel ***(Proposed)***	0.6528	1.0000

The very high MIIF values between Dorsey and Riel indicate a very strong interactive effect between these two busses. Note that, given realistic power flows on all three HVdc lines, the MIIF X Pdc product of Bipoles I and II as seen at Riel will in most cases be greater than the actual power on Bipole III. This means that Bipoles I and II connected at Dorsey will, for many phenomena, have more influence over the operation of the Riel bus than the directly connected Bipole III inverter.

3.1.2. MIESCR at the Inverters.

Dorsey has always been considered as connected to a weak system and existing compensation consists of nine synchronous compensators and shunt filters. Although the absolute worst case ESCR for Dorsey today is 2.5, in most realistic situations the actual ESCR is greater than 3.0. Many compensation options have been considered for the studied new Riel inverter station. Table 3-3 shows the MIESCR at the inverters for the most probable compensation option, the addition of 4 250 MVAr synchronous compensators. A conventional calculation of ESCR at either the Dorsey or Riel bus with shunt filters would indicate sufficient strength without the need for synchronous compensators at Riel, but the MIESCR calculation shows enough weakness that synchronous compensators are warranted. Further, maintaining the MIESCR at Dorsey at a value similar to the ESCR value before Riel implies similar TOV numbers for simultaneous blocking of all bipoles and also a similar margin to the critical MIESCR point for power/ voltage instability.

Table 3-3 MIESR for Manitoba Hydro System with 4x250 MVAr synchronous compensators or shunt filterscapacitors at Riel.

Inverter	Pdc	With shunt filters only at Riel				With sync compensation at Riel			
		MIIF		ESCR	MIESCR	MIIF		ESCR	MIESCR
		Bp I & II/ Dorsey	BPIII/ Riel			Bp I & II/ Dorsey	BPIII/ Riel		
BP I & II/Dorsey	3854	1.0000	0.9521	**3.79**	**2.54**	1.0000	0.8113	**4.34**	**3.05**
BP III/Riel	2000	0.6528	1.0000	**4.50**	**1.99**	0.6600	1.0000	**6.23**	**2.74**

3.1.3. Transient Over Voltage Considerations.

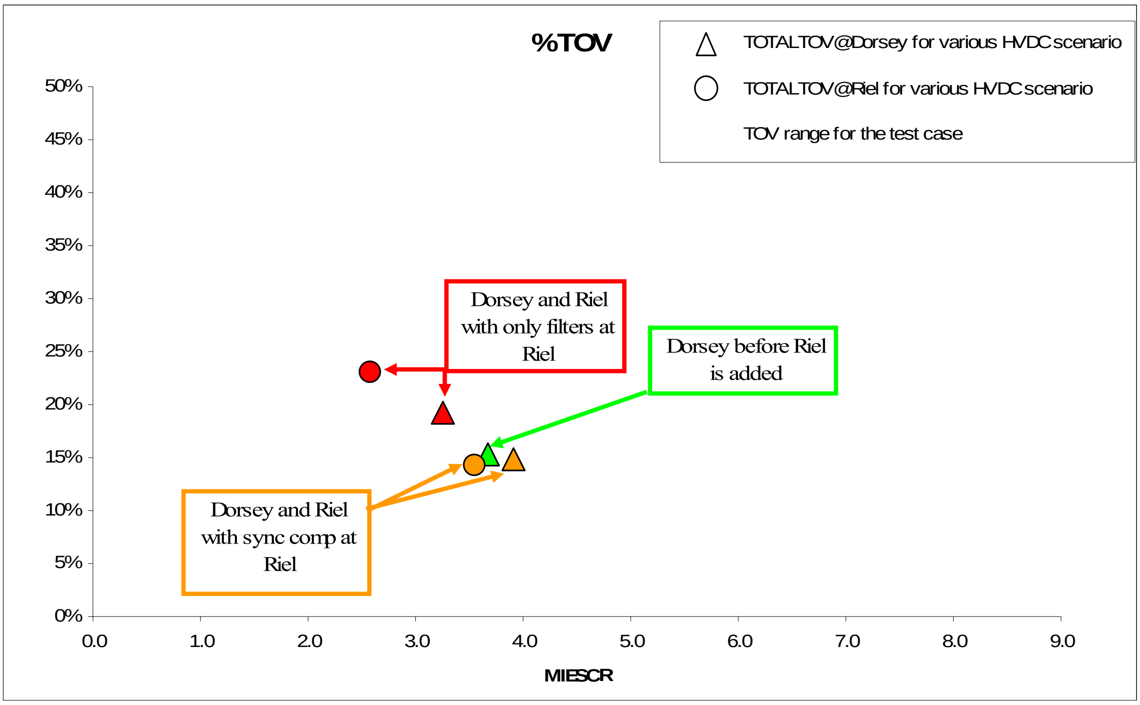

Figure 3-2 Simultaneous block of all Manitoba Hydro inverters; transient over voltage performance compared to the multi infeed test system worst case TOV patterns.

The relationship of an inverter MIESCR to the worst case transient over voltage due to a block of both HVdc links on the test system was established in Chapter 2. Here the TOV on the buses of Riel and Dorsey stations of the Manitoba Hydro system are evaluated using transient stability software and placed on the same graph. A simultaneous block of all three bipoles is considered a credible disturbance considering that all three links are supplied from the same small rectifier ac system.

It should be noted here that the bipoles at Dorsey are having a significant influence on the Riel inverter station due to their electrical proximity as well as nearly double the size of the HVdc system at Dorsey. Figure 3-2 shows the worst case TOV levels at both Dorsey and Riel stations in the absence of synchronous compensation at the proposed Riel inverter bus. The improvement of the MIESCR as a result of the synchronous compensation at Riel station improves the worst case TOV to an acceptable level at the proposed Riel inverter station. It also restores the worst case TOV at the Dorsey station to the current level and therefore a redesign of the existing inverter station can be avoided.

A TOV level based only on the ESCR for the inverter stations would seem inconsistent with the normally observed levels of TOV for single infeed systems of comparable ESCR.

Table 3-4 Simultaneous three bipole block TOV for Manitoba Hydro inverter buses with either 4x250 MVAr synchronous compensators or shunt filters/capacitors at Riel.

Inverter	Operating Pdc	With shunt filters only at Riel					With sync compensation at Riel				
		MIIF		operating ESCR	operating MIESCR	TOV	MIIF		operating ESCR	operating MIESCR	TOV
		Bp I & II/ Dorsey	BPIII/ Riel				Bp I & II/ Dorsey	BPIII/ Riel			
BP I & II/Dorsey (E)	3050	1.0000	0.9521	**4.79**	**3.26**	**19.3%**	1.0000	0.8113	**5.48**	**3.92**	**14.9%**
BP III/Riel (P)	1500	0.6528	1.0000	**6.00**	**2.58**	**23.0%**	0.6600	1.0000	**8.30**	**3.13**	**14.2%**

3.1.4. Commutation Failure and Fault Recovery.

Owing to the very high MIIF factors between the Dorsey and Riel inverter busses, it would be expected that there could be many ac busses wherein a solid ac fault at that ac bus would induce commutation failure on all three bipoles. The decision to add synchronous compensators at the Riel inverter bus does provide some immunity against common ac faults, but the greatest gain in using synchronous compensators is in providing a similar dc power recovery rate to the two bipole system so that the stability of the interconnected ac system is less likely to be affected. Figure 3-3 is a contour map of the southern Manitoba system, showing the large number of 230 kV ac busses that can affect both bipoles. Contour maps can be developed at other voltage levels and show similar dual vulnerability. The 90% contours are busses which first induce commutation failure. The 70% contours are for busses which induce more persistent commutation failures.

The contour map of figure 3-3, showing the great number of ac busses which can lead to commutation failures on all Manitoba HVdc links, provides further support to the decision that the MIESCR at both inverter locations should be no worse than in the initial system. The MIESCR is related to post fault HVdc recovery rate.

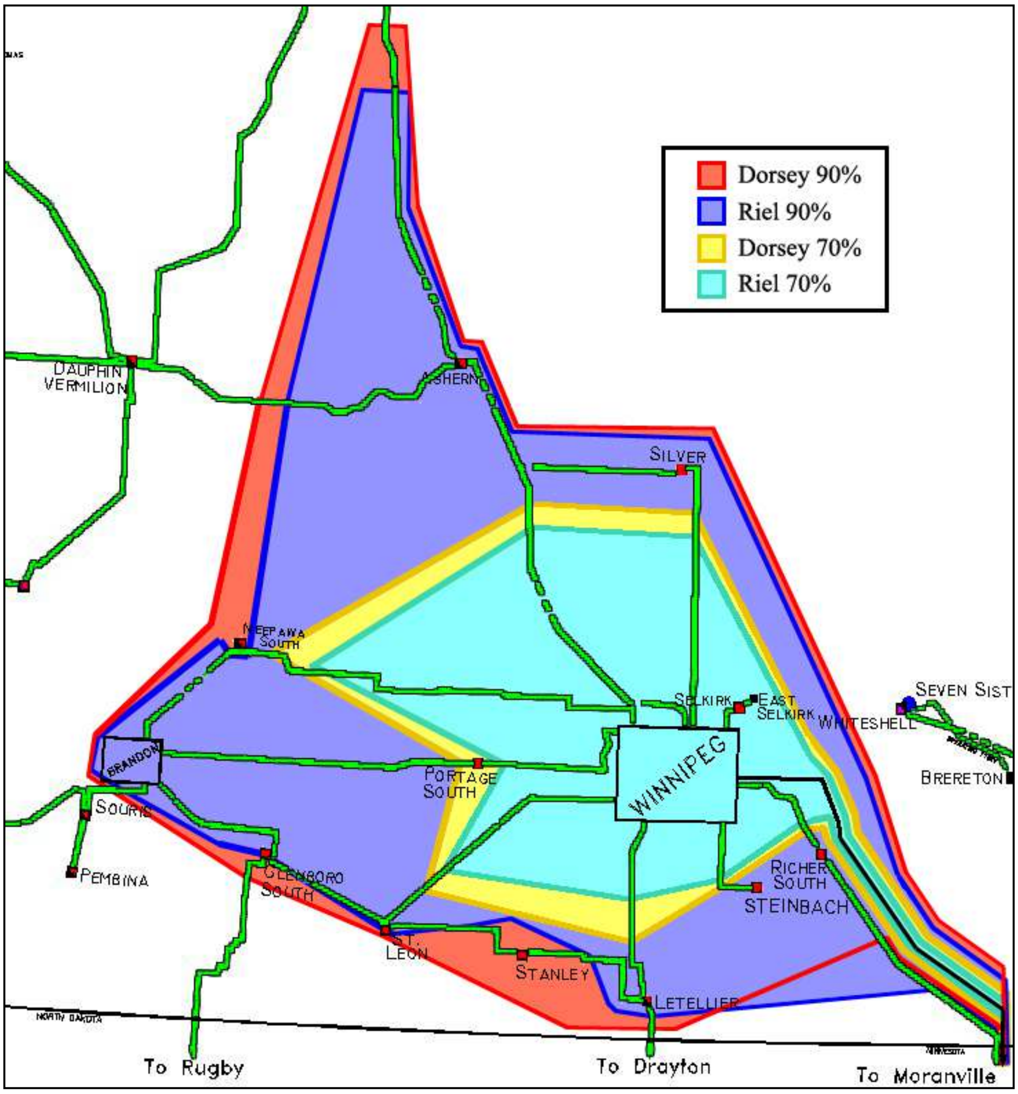

Figure 3-3 230 kV Contour Map for Commutation Failure Susceptibility

3.1.5. Harmonics

Studies have not been done to evaluate possible harmonic interactions between Dorsey Station and future Riel Station. However, the collector system for Bipole I&II as shown in figure 3-4 is a multiinfeed situation which has been evaluated extensively over its many years of operation and is indicative of the type of interaction that could occur between Dorsey and Riel.

The collector system provides an example of a harmonic interaction at the 5th harmonic. The collector system was modeled in a harmonic simulation program to demonstrate the 5th harmonic interaction. The plots in figure 3-5 are a simulation of a case in the Nelson River Collector System where there is a 5th harmonic (300 Hz) series resonance seen from Radisson (Bipole I) looking down the lines to Henday which would result in Bipole I harmonics flowing to Henday. There are no 5th&7th harmonic filters at Henday. The second plot shows that there is parallel resonance at the 5th harmonic as seen from Henday (Bipole II).

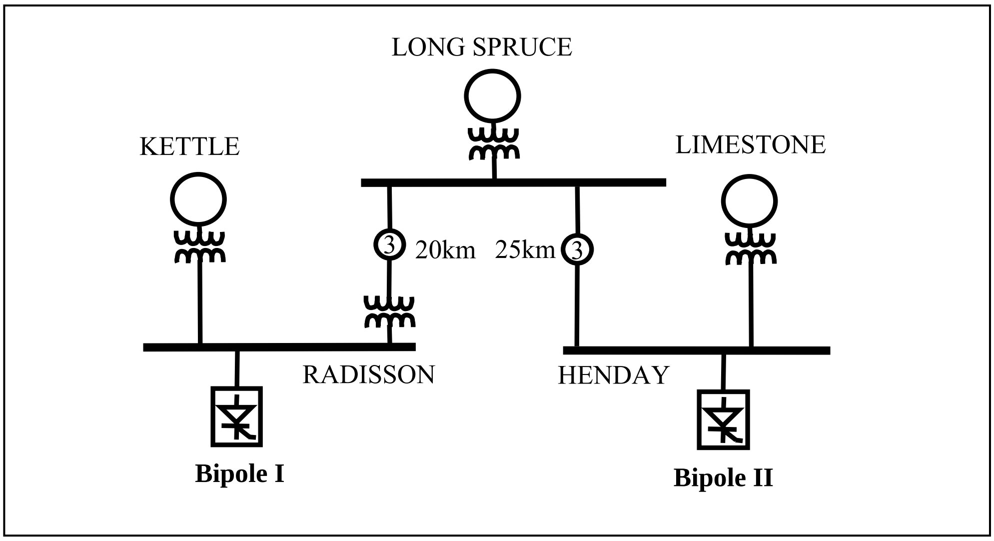

Figure 3-4 Manitoba Hydro Collector System for Bipole I&II.

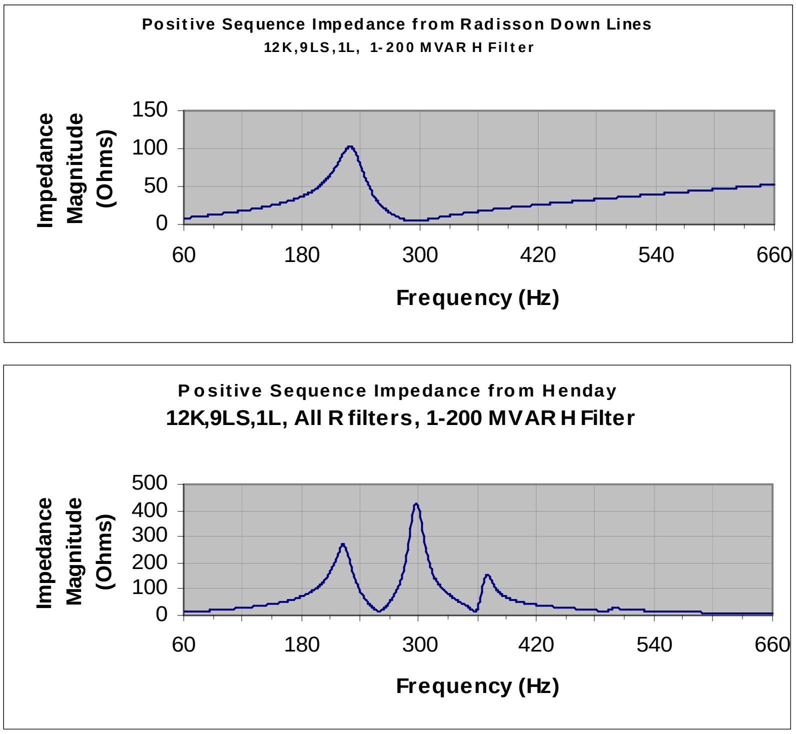

Figure 3-5 Harmonic Impedance Plots for the Collector System, a) Looking down the lines from Radisson to Henday, b) Looking down the lines from Henday to Radisson.

To simulate the situation of Radisson converters producing 5^{th} harmonic, 1 Ampere of harmonic current is injected at Radisson and the voltages monitored at Radisson and Henday. A ratio of the Henday voltage to Radisson voltage is shown in figure 3-6. This plot clearly shows that there will be significant distortion at Henday at the 5^{th} harmonic as a result of these resonances, since the distortion at Henday is about 9 times of that at Radisson.

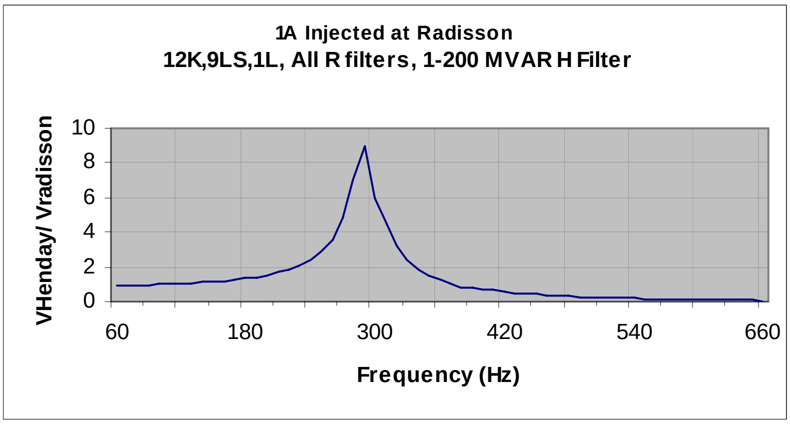

Figure 3-6 Ratio of Henday Voltage to Radisson Voltage With One Ampere Injected at Radisson.

The plot in figure 3-7 shows that with 1 Ampere injected at Henday there will be no effect at Radisson at the 5th harmonic. This is because the parallel resonance blocks the 5th harmonic from flowing to Radisson and there are 5th harmonic filters at Radisson to limit the distortion at that bus.

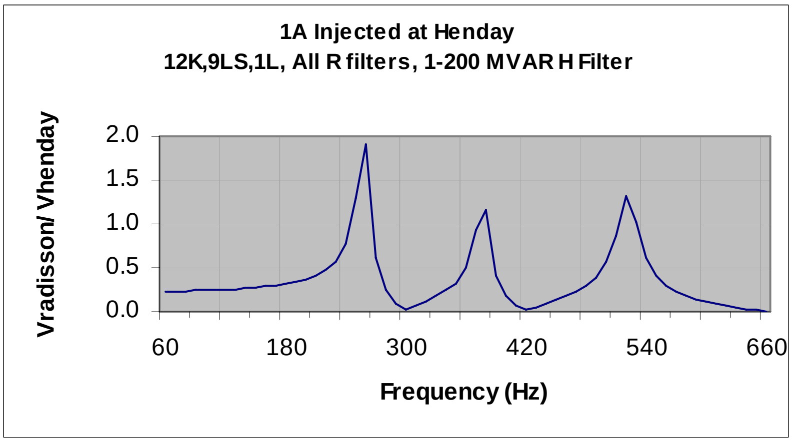

Figure 3-7 Ratio of Henday Voltage to Radisson Voltage With One Ampere Injected at Henday.

This method could be used to look at non characteristic harmonics as well as at zero-sequence. Care has to be taken when looking at low order harmonics (2nd & 3rd) where there can be ac/dc interaction effects and the transferred dc impedance may have to be accounted for.

Usually it is expected that a situation like this 5th harmonic interaction should not occur since there are harmonic filters in place at the harmonic in question. However, the Bipole I&II Collector System is unusual in the sense that there are no significant loads other than the HVdc converters, and transmission distances are short, so there is very little damping of resonances. Also, there is direct transmission between the two converter stations with no other path for the harmonics other than the generators. In the southern system with a possible future Riel Station there would be significant damping from loads and longer transmission lines, and there would be many other transmission paths other than those between the converter stations that would affect resonances and harmonic flows. This would be the case in most multiinfeed systems. However harmonic interactions in the southern system will have to be studied in detail.

3.1.6. Control Interactions and Power/Voltage Instability.

The existing Manitoba Hydro system experienced power/voltage instability on a number of occasions in the early 1980's at the Dorsey inverter bus. The nature of the experience was very consistent. An event occurred in the system whereby the synchronous compensators became limited in the overexcited region, changing the effective impedance from near X"d to Xd, and hence triggering a voltage collapse. The critical ESCR (CESCR) was calculated for the Dorsey bus at about 2.1, so considering that much of the system strength seen by the inverters connected to the Dorsey bus is derived from the synchronous compensators, it is important to keep the synchronous compensators in full AVR control.

The mitigating measures taken at that time included "freezing" the P/U circuit so that high currents would not be ordered as the ac voltage dips, plus a small power order reduction which frees sufficient MVArs to place the synchronous condensers back into conventional AVR control. A Dorsey voltage collapse has not been experienced since these measures were instituted.

With a new inverter in place at Riel, and in consideration of the close proximity of the two inverter busses as evidenced by the high MIIF values, the management of this complex situation must be carefully considered and proven through detailed studies. Nonetheless certain truths about this situation are evident:

1. The future bipole at Riel will have a lower commutating reactance to that of the existing bipoles but other parameters will be similar, so that the expected CESCR should be somewhat lower.

2. Maintaining the MIESCR at either Dorsey or Riel above that of the respective CESCR values will be an important consideration.

3. The two inverter busses are electrically close enough that an impending voltage collapse at one inverter bus will be counteracted to a degree by the synchronous compensator reactive control and P/U action at the other inverter bus.

4. If a voltage collapse is starting to occur on a particular inverter bus, then the most effective mitigation of that collapse would be associated with equipment and controls directly connected to that bus. Nonetheless, it would be advantageous if the actions taken at the other inverter bus provide a back-up to the actions on the bus where the instability is occurring.

5. It would be logical to conclude that the types of counteractive measures occurring on each inverter bus would be essentially identical, so that the bus where the instability is originating is likely to counteract first.

Regarding multiinfeed control considerations, both Dorsey and Riel will be observing similar ac system modes and should be able to assist in the damping of such modes. This is a general ac damping problem in which damping power introduced at the

Dorsey and Riel inverter busses plays a role and is not a specialized control consideration specific to multiinfeed systems.

However, the existing ac damping control is susceptible to a control related instability which has been observed in the field and in studies [CAN1]. The instability is influenced by controller gains and time constants, the ESCR at the inverter bus, and power levels on the Bipole I and II HVdc links (figure 3-8). The frequency associated with this instability is 8 Hz. If a similar type control is introduced on Bipole III with similar gains and time constants, it is quite possible that the 8 Hz oscillation may reappear. The instability will be influenced by the electrical closeness, essentially MIIF, between inverters and by the ability of the inverter to influence the damping parameter of the inverter bus. It would be expected then that the instability would be related to MIESCR in this multiinfeed environment.

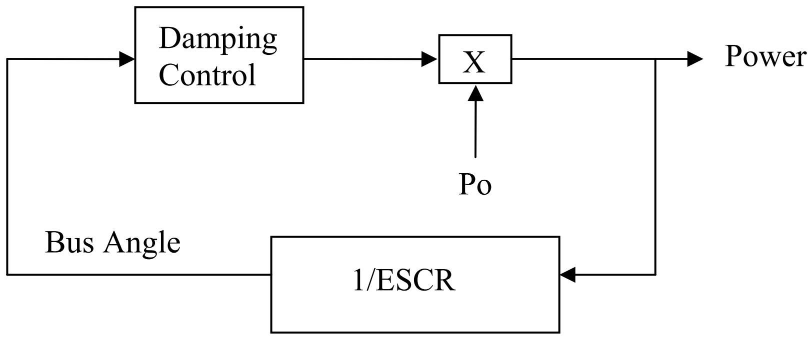

Figure 3-8

3.1.7. Conclusions

Multiinfeed considerations will be integral to the planning process for the future inverter to be located at the Riel site. An important calculated parameter is the MIESCR. In this multiinfeed situation, the MIESCR at Dorsey should not be too different than the ESCR value that exists today. Also, because of the electrical closeness between Dorsey and Riel, as exhibited by the high MIIF numbers, the MIESCR at Riel should be similar to that of Dorsey for fault recovery, TOV, and power/voltage instability considerations.

3.2. Norway

Norway is a part of the synchronously operated Nordel system. In the north and east there is one 110 kV ac connection to Russia and one 220 kV connection to Finland. Along the border to Sweden there are several ac connections. In the southern part of Norway, there are three HVdc links to Denmark (Skagerrak pole 1, 2 and 3), and one HVdc link to the Netherlands is being commissioned. Statnett SF, the Norwegian TSO, operates the Norwegian grid.

Figure 3-9 The Nordel Area and Neighbouring Systems.

The Norwegian production system is dominated by hydropower generation with a capacity of 28 GW and with an average annual energy production of 121 TWh. Hydropower represents more than 97 % of the total generation. This hydropower dominance makes the Norwegian system strongly dependent on precipitation and inflow to the reservoirs. Referred to a statistically normal year, a dry year may require an annual import of up to 35 TWh, while a wet year may allow for an export of up to 25 TWh. To manage hydrological variations of up to 60 TWh, transmission capacity to systems with thermal generation are vital. Both the Skagerrak HVdc links and the Norned HVdc link ensure transmission capacity directly to thermal systems.

Table 3-5 HVdc link data

HVdc	**AC filters/compensation**		**Length, voltage**
Skagerrak pole 1, 2 and 3 1040 MW (270 + 270 + 500)	11 + 13 HP24 SVC SC	2 x 83 MVAr 2 x 90 MVAr +/- 200 MVAr +140/-90 MVAr	3 x 240 km (127 km cable). Pole 1 and 2: 250 kV Pole 3: 350 kV
Norned 700 MW	11 + 13 + HP24 3 Shunt capacitors	2 x 100 MVAr 1 x 95 MVAr 2 x 95 MVAr	2 x 580 km, +/- 450 kV

Norned has two very long submarine cables and a standard cable control strategy: Current regulation at the rectifier, voltage regulation at the inverter and a gamma angle of 22 degrees.

When importing power to Norway, the generation level within Norway is reduced. Increased HVdc capacity will lead to increased import and even lower generation levels. A combination of increased HVdc import and weakened system voltage support is challenging.

In addition to the existing Skagerrak and Norned HVdc links, Skagerrak pole 4 (600 MW) to Denmark and a new HVdc connection to Germany (700 – 1400 MW) is under evaluation. MIESCR calculations will be an important parameter in these evaluations.

3.2.1. MIIF and MIESCR at the inverters

These evaluations are based on a severe combination of low load level, low generation level and maximum HVdc import. Normally the generation level will be higher. However, this severe situation is considered as a worst case for MIESCR for planning purposes.

The Norned HVdc link will be in operation from the beginning of 2008. Statnett has received permission to construct a new 400 kV ac line from Holen to the converter location at Kristiansand. This line is under construction and is expected to be in operation in the autumn of 2009.

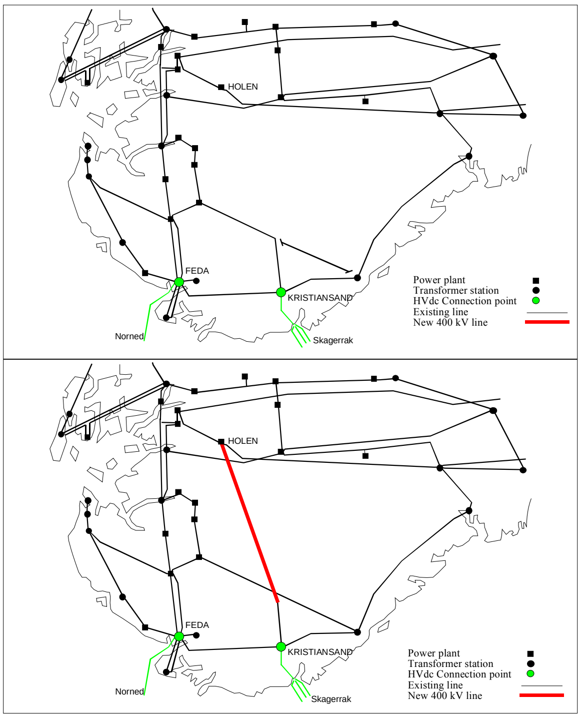

Figure 3-10 Existing (Intermediate) grid and reinforced grid with new 400kV line.

The calculations below include both the intermediate and final states, before and after the commissioning of the new ac line. Voltage variations are simulated in a standard transient stability program, short circuit power calculations are based on the subtransient reactance. All simulations represent the post fault situations after the line outage, which represents a worst case for planning purposes. Skagerrak poles 1, 2 and 3 are connected to the same 300 kV bus and are treated as one link.

Table 3-6 MIIF Tables for the Norwegian System, intermediate and final state.

	Intermediate	
	Skagerrak	Norned
Skagerrak	1.0000	0.8039
Norned	0.8225	1.0000

	With new 400kV line	
	Skagerrak	Norned
Skagerrak	1.0000	0.7206
Norned	0.7535	1.0000

The electric coupling between Norned and Skagerrak is strong and the MIIF tables confirm a high level of interaction. During the intermediate state the MIIF is above 0.8, falling to a level of 0.75 after finishing the grid reinforcements.

Table 3-7 MIESCR for the Norwegian System, intermediate and final state

Inverter	Pdc	Intermediate periode				With new 400 kV line			
		MIIF		ESCR	MIESCR	MIIF		ESCR	MIESCR
		Skagerrak	Norned			Skagerrak	Norned		
Skagerrak	1040	1.0000	0.8039	3.16	2.06	1.0000	0.7206	3.51	2.37
Norned	700	0.8225	1.0000	4.55	2.04	0.7535	1.0000	5.3	2.49
One equivalent link	1740	-	-	1.62	-	-	-	1.88	-

The distance between Norned (Feda station) and Skagerrak (Kristiansand station) is only 63 km. Considering the low level of local generation, an alternative methodology is to treat the two links as one equivalent large link, since they have to share the same source of voltage support. This conservative procedure results in an ESCR of 1.6 during the intermediate state, increasing to 1.9 in the final state. The corresponding MIESCR values are 2.0 and 2.4, representing values between the traditional ESCR values and the conservative "one equivalent" HVdc link approach. MIESCR values of 2.0 to 2.4 indicate challenging operational conditions.

3.2.2. Transient Over Voltage Considerations

In accordance with the recommendations in chapter 2, both HVdc links, Skagerrak and Norned, are blocked. The TOV are evaluated using standard transient stability software – saturation is not represented. The 'weakened grid' values below correspond to the scenarios in table 3-6.

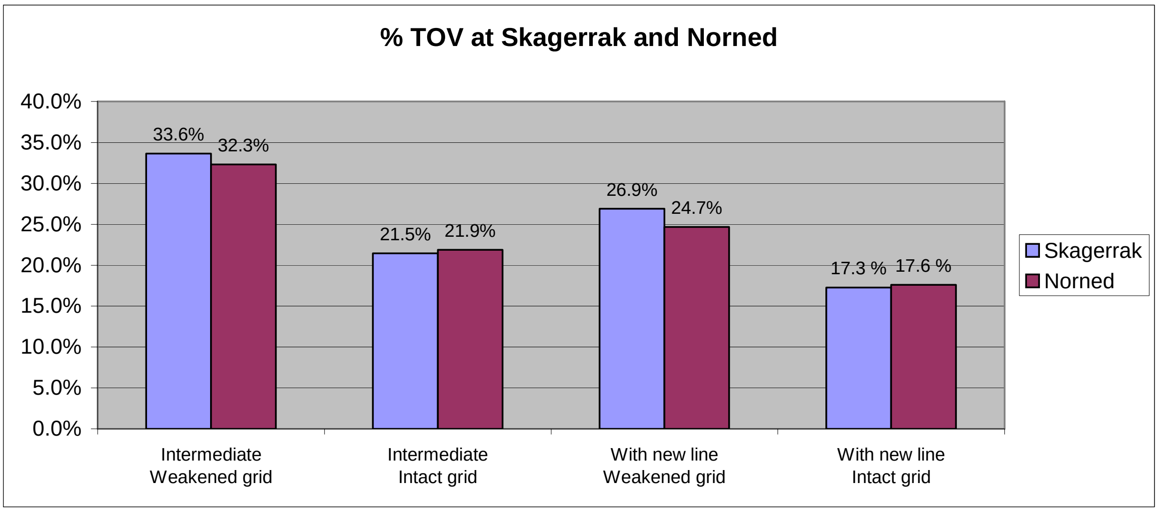

Figure 3-11 TOV results for Skagerrak and Norned.

The TOV results show near identical TOV levels at both HVdc stations and confirm the strong interaction between the links.

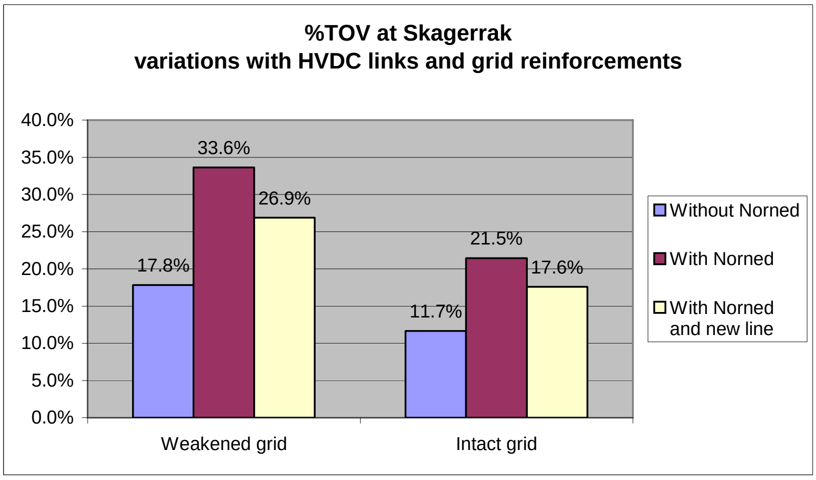

Figure 3-12 TOV results for Skagerrak, without/with Norned and grid reinforcements.

Looking at the TOV at Skagerrak without Norned, with Norned during intermediate state and finally with Norned and the new line, illustrates that increased HVdc capacity increases the level of TOV. However, these TOV levels are not critical.

The chosen mitigation strategy is limiting the over voltages by use of surge arresters.

3.2.3. Commutation Failure and Fault Recovery.

High MIIF values and nearly identical TOV conditions at Skagerrak and Norned indicates that solid ac bus faults will induce commutation failure on both links while in import mode. Contour maps for the Norwegian 300 and 400 kV system show identical conditions at Feda and Kristiansand. Solid bus faults are expected to cause commutation failure at both HVdc links while in import mode.

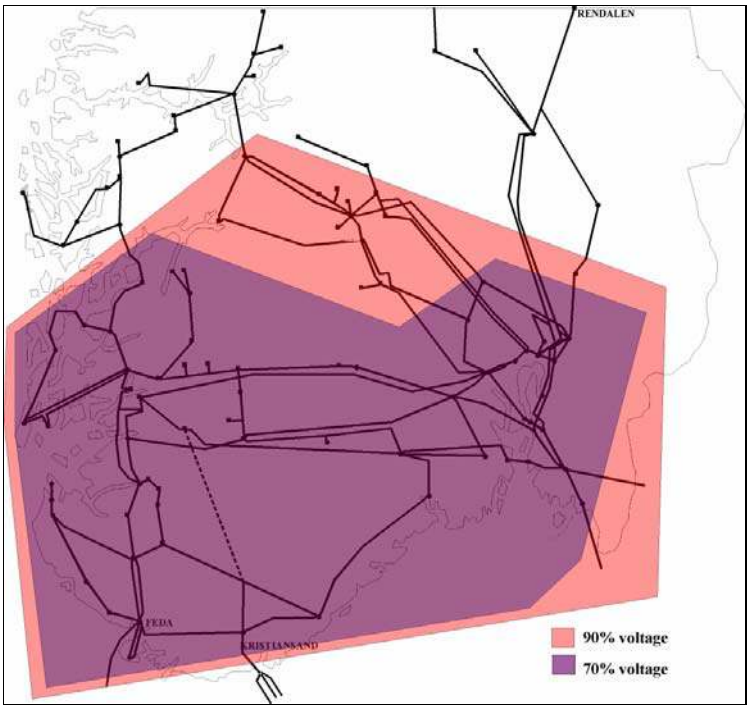

Figure 3-13 300/400 kV Contour Map for Commutation Failure Susceptibility.

Dynamic simulations confirm concurrent commutation failures. To ensure proper post fault performance, special control strategies are implemented. After a commutation failure, a normal recovery rate is used up to 90% of pre fault power level, then the recovery from 90 to 100% of pre fault load level is slowed down to reduce the reactive power consumption and give a smoother recovery. This control strategy is implemented at Norned and Skagerrak pole 1 and 2.

3.2.4. Harmonics

At Feda, the short circuit power may be low. In the MIIF calculations the corresponding short circuit power (SCP) at Feda is 3700 MVA. The filters and shunt capacitors at Feda have a rating of 485 MVAr.

The corresponding low order resonance frequency between the filters and the network is 2.8, indicating a possible 3rd harmonic resonance.

$$\boldsymbol{n} = \sqrt{\frac{\boldsymbol{SCP}}{\boldsymbol{Q}_{\boldsymbol{filters}}}} = \sqrt{\frac{3700}{485}} = 2.76$$

As a part of the Norned ac filter design, studies were carried out to investigate the possible harmonic interaction between Feda (Norned) and Kristiansand (Skagerrak).

The 300 kV transmission line connecting Feda and Kristiansand was modeled in detail, while the rest of the ac system was represented by a worst-case impedance sector.

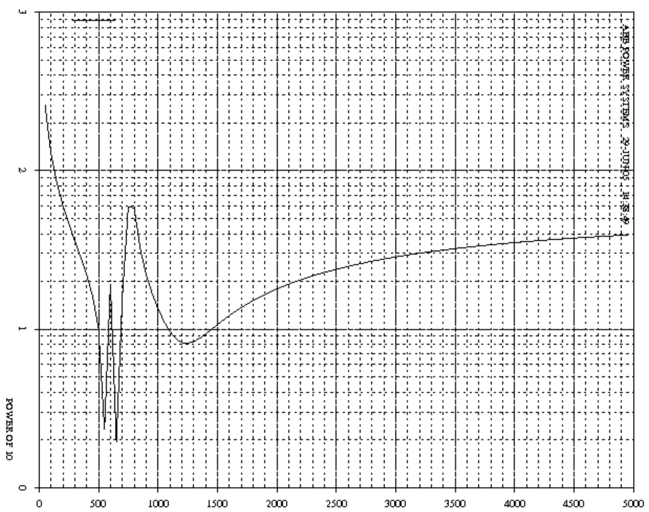

Figure 3-14 Impedance of all Kristiansand filters connected, seen from Kristiansand [no line connected, |Z| in ohm versus frequency (Hz)].

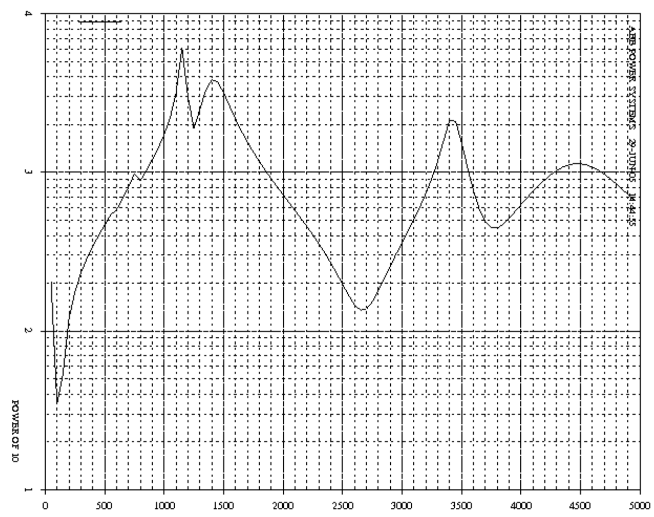

Figure 3-15 Impedance of all Kristiansand filters connected, seen from Feda [|Z| in ohm versus frequency (Hz)].

In figure 3-15, the impedance of the same filters at Kristiansand, but now seen from Feda through the transmission line, is plotted. Clearly, the total impedance is very high, the impedance of the line dominates, and no filtering effect can be seen from Feda at the characteristic harmonics. Worth noting, however, is the low impedance at around 100-150 Hz, caused by the series resonance of the line inductance with the capacitance of the Kristiansand filters.

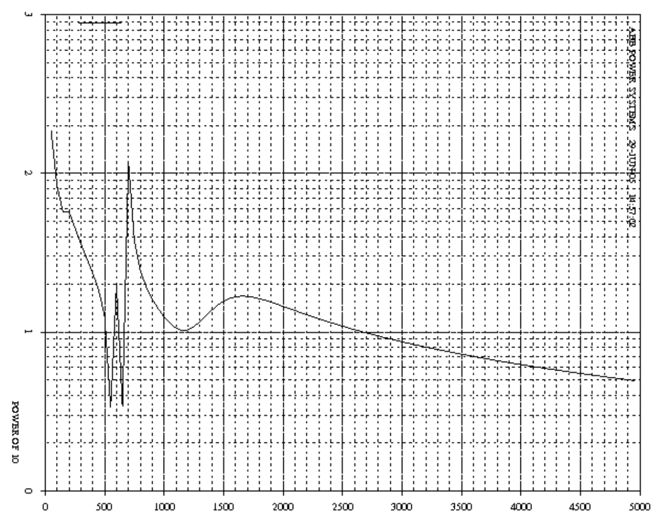

Figure 3-16 Impedance of all Feda filters connected, seen from Feda [no line connected; |Z| in ohm versus frequency (Hz)].

In figure 3-16, the local impedance of the filters at Feda (all connected, no external line or network) is shown. Comparing figure 3-15 and figure 3-16, it can be seen that the impedance of the local filters at Feda is many times less (around 100 times at h11 and 13) than the impedance seen looking into the line towards Kristiansand. It can therefore be expected that the Kristiansand filters will have an insignificant impact on the harmonic performance and rating at Feda. The only possible exception is in respect of the low order harmonics, particularly the 3rd harmonic.

Based on further investigations, it can be concluded that the harmonic interaction with Kristiansand, due to harmonic generation at Feda:

- has a negligible effect on all harmonic distortion at Feda except the 3^{rd}
- reduces 3^{rd} harmonic distortion at Feda
- causes an increase in 3^{rd} and 5^{th} harmonic distortion at Kristiansand, but at levels which are acceptable for performance and have a negligible impact on filter rating

and the reverse applies due to harmonic generation at Kristiansand.

Historically Statnett has experienced 3^{rd} harmonic resonance at the existing Kristiansand Station under certain operation conditions. To avoid any possible 3^{rd} harmonic interaction between Kristiansand and the new Feda Station, one of the shunt capacitor banks at Feda was designed and constructed as a 3^{rd} harmonic filter.

3.2.5. Mitigation Strategies

The main challenge of the Norwegian system is the possible low level of local generation and low short circuit power. To ensure proper system performance, online measurement of the local short circuit power level is established and is now available on the control center. Low short circuit power levels may trigger startup of local generation.

At present the possibility of using local hydropower plants as synchronous compensators is being evaluated. This strategy requires modification of the turbines, because the turbines must be drained before the plant can operate as a synchronous compensator. Consequently, this strategy is limited to new plants or as a part of the renewal of old plants.

Commutation failure and fault recovery are improved by special control strategies.

At Kristiansand there is a 200 MVAr SVC that did not improve the fault recovery during import conditions. Now the SVC control strategy during Skagerrak power import to Norway has been changed. The control of the SVC in Kristiansand will be frozen at the detection of commutation failure and will be released during the HVdc link recovery or after 800 ms at the latest.

3.3. China

China case - Case example where the receiving end is relatively strong but heavily loaded.

3.3.1. General

The China Case was conducted with two planned configurations for the China Southern Power Grid (CSG system). Configuration 1 includes four HVdc transmission links operating in a common ac network: Gui-Guang II (GUG2), Gui-Guang I (GUG1), Tian-Guang (TSQ) and 3Gorges-Guang (3GG) HVdc links.

Configuration 2 includes five HVdc transmission links. Besides the above referred four HVdc links an additional link has been added, and that is the Yunnan-Guang (YUG) HVdc link. All these HVdc transmission links will supply 15800MW of electrical power into a load center. In this configuration, there are another four double circuit ac transmission lines supplying 6700MW to the same load area.

The load center has about 34% of its load supplied by importing electrical power from the west area through these long HVdc and HVac transmission lines.

The purpose of the study is to investigate if the system under peak load condition would withstand some critical contingencies, identify the possible stability problems and determine countermeasures to those stability problems that would be identified.

It should be noted that not all possible operating conditions have been studied for the two planned configurations, as these would considerably increase the scope of the study. Therefore, the results obtained in this study are considered as indicative of the expected system performance.

The scope of this study does not cover harmonic interaction amongst the inverters as a preliminary investigation made by the operator of the China Southern Power Grid indicated that no harmonic increasing effect were found between converter stations.

3.3.2. Configuration 1 with Four HVdc Links

The primary goal of the study was to confirm the acceptable performance of different HVdc transmission links during recovery of system faults and analyze the sensitivity for commutation failure between different converters.

In order to study the dynamic performance of China Southern hybrid HVac/dc power system using PSCAD/EMTDC, an equivalent system was obtained by reducing the original system using a dynamic equivalency method. The configuration of the equivalent system is shown in figure 3-17. The equivalent system contains 4 bipolar HVdc links, 26 equivalent generators, 15 coupling transformers, 180 ac lines, and 91 ac bus-bars. The basic information of the 4 HVdc links is listed in table 3-8.

Table 3-8 Basic information of the four HVdc links

HVdc Links	Rated dc Current (A)	Rated dc Voltage (kV)	Rated dc Power (MW)	Rated ac Voltage at Inverter Side (kV)	Short circuit capacities at Inverter ac Busbar (MVA)
GUG2	3000	± 500 kV	3000	525	33965.5
GUG1	3000	± 500 kV	3000	525	22015
3GG	3000	± 500 kV	3000	525	15345
TSQ	1800	± 500 kV	1800	230	13523.4

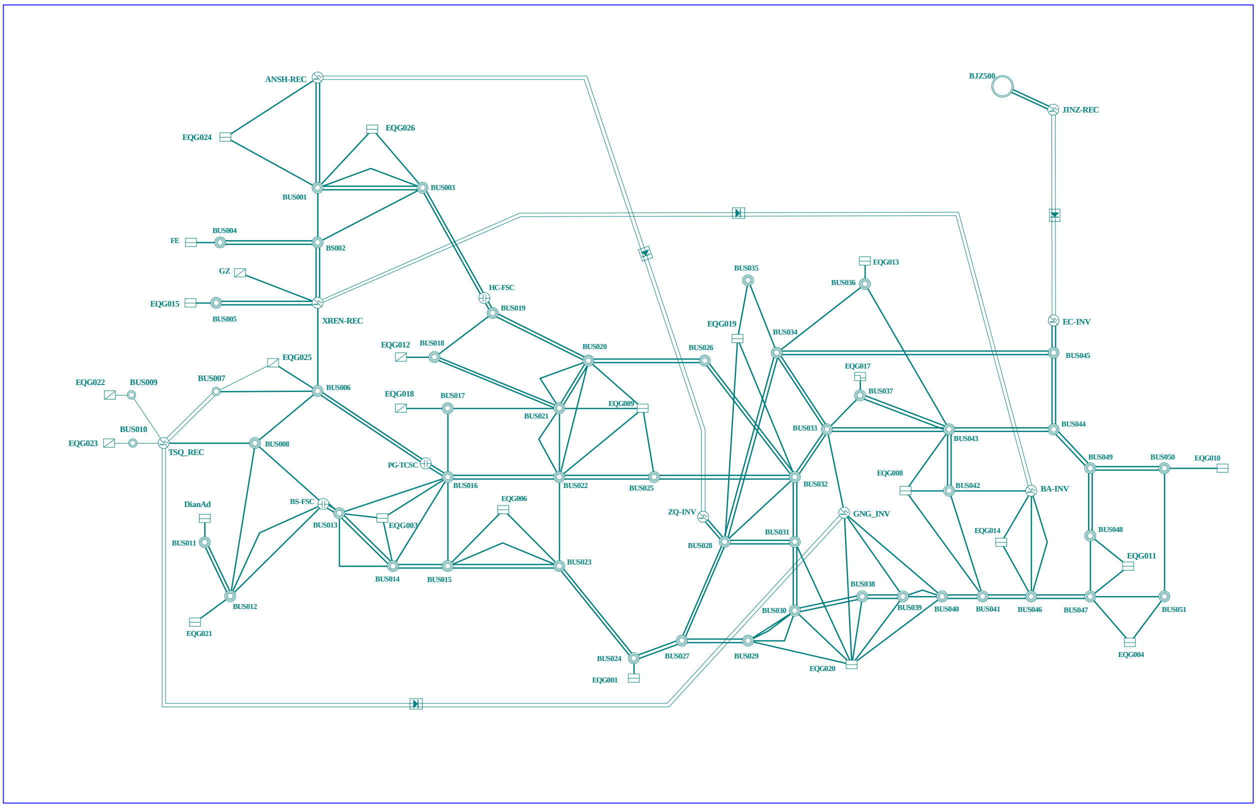

Figure 3-17: The configuration of the equivalent system for the study

3.3.2.1. MIIF and MIESCR of the equivalent system

The MIIF was calculated by running in PSCAD/EMTDC the available equivalent model (with all the four HVdc links operating at rated power). Following the procedure to calculate the MIIF described in Chapter 1, an approximate 1% step voltage was induced through the artificial switched connection of a shunt reactive element at one HVdc inverter ac bus bar, and the percent change in ac voltage was recorded at the other three inverter ac buses. The ratios of these numbers are the elements of the MIIF matrix. This procedure of calculation was repeated by inducing the step voltage at the next HVdc inverter ac bus bars, one by one and all the MIIF matrix elements were then obtained, as shown in table 3-9.

With the basic information for all four HVdc bipolar links and the MIIF matrix, the elements included in table 3-10 and table 3-11 were calculated.

Table 3-9 Multi-Infeed Interaction Factor – MIIF Matrix

		Relative Inverter ac Voltage Change			
		GUG2 Inverter	GUG1 Inverter	3GG Inverter	TSQ Inverter
Bus at which fixed reduction is applied	GUG2 Inverter	1.000	0.182	0.471	0.212
	GUG1 Inverter	0.226	1.000	0.424	0.286
	3GG Inverter	0.200	0.192	1.000	0.182
	TSQ Inverter	0.217	0.182	0.261	1.000

Table 3-10 Pdc × MIIF Matrix [values being presented in MW]

		Megawatt Weighted Relative Inverter ac Voltage Change			
		GUG2 Inverter	GUG1 Inverter	3GG Inverter	TSQ Inverter
Bus at which fixed reduction is applied	GUG2 Inverter	3000	546	1413	381
	GUG1 Inverter	678	3000	1272	514
	3GG Inverter	600	576	3000	327
	TSQ Inverter	391	328	4670	1800

Table 3-11 Short Circuit Ratio and Effective Short Circuit Ratio calculated for the studied configuration

Inverter Bus	Rating	Individual SCR	Multi-Infeed MISCR	Individual ESCR	Multi-Infeed MIESCR
HVdc 4: GUG II	3000 MW (± 500 kV)	11.32	7.28	10.64	6.84
HVdc 3: GUG I	3000 MW (± 500 kV)	7.34	4.95	6.73	4.54
HVdc 1: 3GG	3000 MW (± 500 kV)	5.12	2.49	4.62	2.25
HVdc 2: TSQ	1800 MW (± 500 kV)	7.51	3.52	6.9	3.24

Note: $$\boldsymbol{MISCR_i} = \frac{\boldsymbol{SCR_i} \times \boldsymbol{Pdc_i}}{\boldsymbol{Pdc_i} + \sum_j (\boldsymbol{MIIF_{j,i}} \times \boldsymbol{Pdc_j})}$$

3.3.2.2. Dynamic Performance Study Using PSCAD/EMTDC Simulation

One objective of the study was to confirm that all four HVdc links can operate with their inverters operating in a common ac system with minimum negative influence of one HVdc link on the other. Since the ac system is quite strongly coupled for all inverters, it is likely that any ac fault close to one inverter station would also disturb the other three inverters significantly. The criteria for acceptable behavior is not necessarily based on whether one or more inverters suffer commutations failures upon the actual fault initiation but on the assurance that when commutation failures occur that recovery of each inverter is fast and is without subsequent commutation failures. It is also important that no commutation failures are caused in other inverter stations for induced commutation failures/misfires at one inverter (sympathetic commutations failures).

For the case having single phase-to-ground faults in the inverter ac system with successful single phase re-close, the recovery performance after fault clearance is satisfactory (all the HVdc links will recover to 90% pre-fault power within 120 ms).

For the case having a single phase-to-ground fault in the inverter ac system with failed single phase re-close and then resulting in tripping of the faulty ac line, the fault is effectively applied twice in the ac system. Upon clearing the fault by tripping of the faulty line the power recovery of all HVdc links is stable and the response time is satisfactory.

The HVdc links showed good performance during the recovery of ac faults, even in those cases where all four HVdc links suffer commutation failure due to a major disturbance in the ac voltage.

Commutation failure sensitivity analysis indicates that, commutation failure of one HVdc link caused by loss of firing pulse does not spread to other links (sympathetic commutation failures).

3.3.3. Configuration 2 with Five HVdc Links

3.3.3.1. General overview of the studied system

<u>Recall the basic definitions</u>

Lets recall some of the basic definitions made in chapter 1, which will support the description of the system that will be studied.

Two basic relations, SCR and ESCR, are defined using the traditional formulas as (see chapter 1, section 1.3.3)

$$\boldsymbol{SCR_i} = \frac{\boldsymbol{SCC_i}}{\boldsymbol{Pdc_i}} \quad \text{and}$$

$$\boldsymbol{ESCR_i} = \frac{\boldsymbol{SCC_i} - \boldsymbol{Qf_i}}{\boldsymbol{Pdc_i}}$$

where, $\boldsymbol{SCC_i}$, $\boldsymbol{Qf_i}$ and $\boldsymbol{Pdc_i}$ are the short circuit MVA available on the inverter bus, the bus filter and capacitor MVA and rated power of the $\boldsymbol{i^{th}}$ link, respectively.

These expressions can be generalized by a complex form, by using the impedances $\boldsymbol{Z_{Li}}$ or $\boldsymbol{Z_{Ei}}$, which are the Thevenin impedance and effective Thevinin impedance, respectively, of the converter bus expressed in per unit of the rated power of the HVdc converter station. This will take the phase angle impedance into account. Then, they are defined as

$$\boldsymbol{SCR_i} = \frac{1}{\boldsymbol{Z_{L\,i}}}$$

and

$$\boldsymbol{SCR_i} = \frac{1}{\boldsymbol{Z_{E\,i}}}$$

However, these two different approaches of defining SCR and ESCR give approximately similar amplitude values.

Extending these definitions to a multiinfeed system, a proposal presented in [CHN2] defines the Multi-Infeed Short Circuit Ratio (MSCR) and Multi-Infeed Effective Short Circuit Ratio (MESCR) where the impact of the other converters included in the system are taken into consideration in the calculation. They are given by

$$\boldsymbol{MSCR_i} = \frac{1}{\sum_{\boldsymbol{m}=1}^{\boldsymbol{k}} \boldsymbol{Pdc_i} \times \boldsymbol{z_{i\,,m}}} \qquad \textbf{\textit{3-1}}$$

where,

$\boldsymbol{i}$ is the converter bus under consideration

$\boldsymbol{k}$ corresponds to the number of HVdc terminal stations

$\boldsymbol{m}$ varies from converter #1 up to converter #k

$\boldsymbol{z_{i\,,m}}$ is the $\boldsymbol{i^{th}}$, $\boldsymbol{m^{th}}$ element in the $\boldsymbol{Z_{BUS}}$ matrix in p.u.

If the matrix $\boldsymbol{Z_{BUS}}$ includes the shunt compensation element needed by the converter then the formula express the Multi-Infeed Effective Short Circuit Ratio (MESCR).

It should be noted that the above formulas, which makes use of elements that are extracted from $\boldsymbol{Z_{BUS}}$, are equivalent to equation (1-4) that is defined in chapter 1. In equation (1-4) it does not use elements included in the $\boldsymbol{Z_{BUS}}$ matrix, but instead, makes use of the Multi Infeed Interaction Factors (MIIF) which are calculated for every converter in order to consider the influence of remote converters.

It should also be noted that in the definition proposed in [CHN2] it is assumed that all sources are operating at nominal voltage and zero phase angle (which means that it does not take into consideration the initial operating conditions). However, the definitions described in equations (1-4) of chapter 1, takes in to consideration the actual operating conditions in the calculations. This means that it small deviations between the two calculation procedures are to be expected.

In [CHN2] also defines the term Participation Index, as

$$\boldsymbol{P_{i\,i} = Pdc_i \times z_{i\,,\,i}} \quad \textbf{\textit{3-2}}$$

which is the participation index of the own converter, and

$$\boldsymbol{P_{i\,m} = Pdc_m \times z_{i\,,\,m} \quad m \neq i} \quad \textbf{\textit{3-3}}$$

which is the participation index of the remote converter that is electrically connected to the converter bus under consideration.

It should also be noted the Participation Indicies have similar significance to the product $\boldsymbol{MIIF_{j\,,\,i} \times Pdc_j}$ defined in equation (1-3) of chapter 1. However, observe that the Participation Index $\boldsymbol{P_{i,m} = Pdc_m \times z_{i,m}}$ will be given in per unit while the product $\boldsymbol{MIIF_{j\,,\,i} \times Pdc_j}$ is normally given in MW.

<u>General description of the system</u>

The China South Grid (CSG) system includes several provinces. A large amount of electrical power is transmitted to a heavily loaded area in Guangdong from the west areas mainly by HVdc/HVac parallel transmission lines. The distance between the east and the west areas is in the range of 1000~1500km. In the middle area are the transmission corridors. Figure 3-18 below shows a geographic diagram of China Southern Power Grid for the studied configuration, emphasizing the five HVdc transmission lines and the 500kV ac transmission corridors.

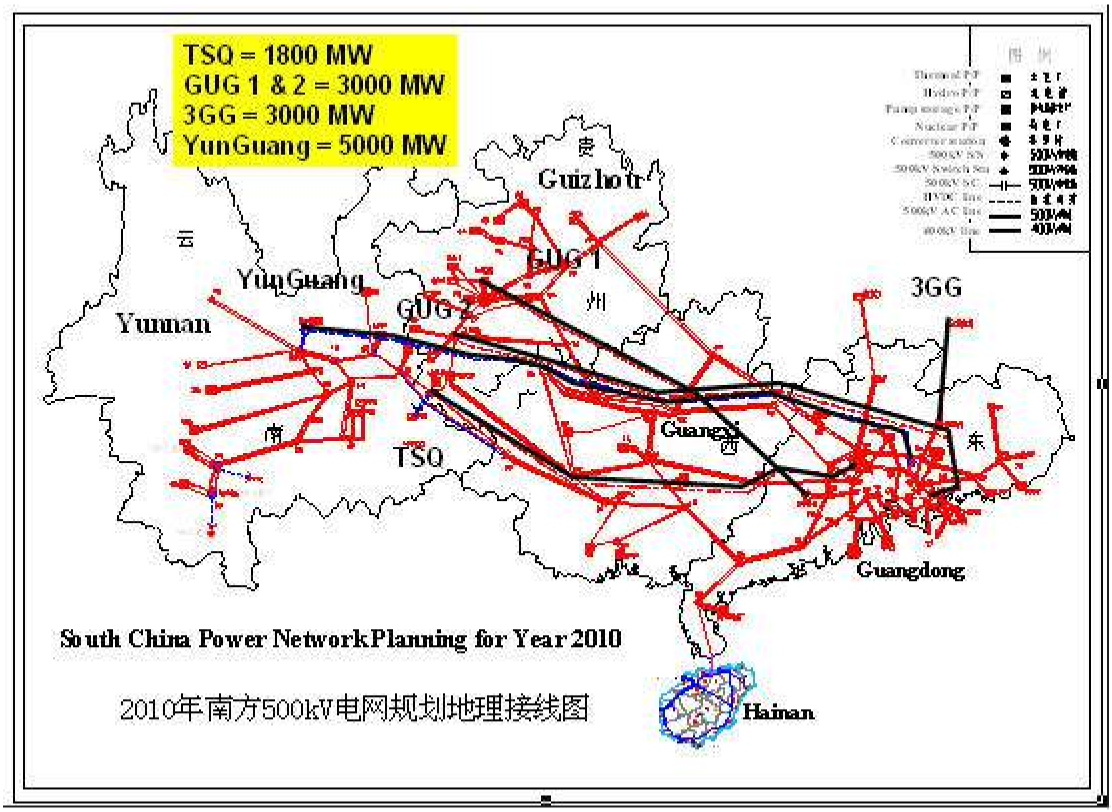

Figure 3-18 Geographic diagram of network configuration for the China Southern Power Grid

All of the HVdc inverter stations are positioned in a rather strong system. If considering the individual inverter stations, table 3-12 presents the results of calculated Short Circuit Ratios (SCR) and Effective Short Circuit Ratios (ESCR). The 3GG inverter station has the lowest short circuit ratio; the calculation shows an SCR value greater than 5. Regarding the inverter stations for the TSQ and GUG II, the calculations show SCR values around 10. When considering the influence of local reactive power compensation, the corresponding ESCR for these inverter stations are about 5 and 9 respectively.

Now, taking into consideration the influence of all links in electrical proximity by calculating the MSCR and MESCR (using the definition according to [CHN2]) at each inverter station, the results are also shown in table 3-12. It should be noted that only the amplitude values of MSCR and MESCR are presented in the table and that these values are similar to those produced by the definition in chapter 1.

By comparing the SCR values with the corresponding MSCR for each of the inverter stations, it can be concluded that all HVdc links are electrically close connected. For example, the 3GG inverter has an ***SCR*** = 5.51 which is reduced to ***MSCR*** = 2.97 with the influence from the other inverter stations. The reduction for the TSQ inverter station is even more ‘dramatic’: from ***SCR*** = 9.33 it is reduced to ***MSCR*** = 3.99.

One explaination as to why TSQ is more influenced by the interaction with the neighborhood inverter stations is that its nominal rating is lower as compared to the other converter stations; TSQ is rated 1800 MW while the others are 3000 MW, with the exception of YUG with an even higher rating of 5000 MW.

The inverter station of the GUG II HVdc link is located in the strongest part of the network and also is least affected by the inverters from the other HVdc links (the short circuit ratio is reduced from ***SCR*** = 9.90 to ***MSCR*** = 5.86 when considering the impact from the other links). Hence, it can be expected that the dynamic performance for this link would not be much influenced by the other links during dynamic operation of the system.

Similar analysis and conclusions can be drawn by observing the ESCR and its corresponding MESCR calculated for each of the converter stations.

Table 3-12 Short Circuit Ratio and Effective Short Circuit Ratio calculated for the studied configuration

Inverter Bus	Rating	Individual SCR	Multi-Infeed MSCR	Individual ESCR	Multi-Infeed MESCR
HVdc 1: 3GG	3000 MW (± 500 kV)	5.51	2.97	4.83	2.49
HVdc 2: TSQ	1800 MW (± 500 kV)	9.33	3.99	8.64	3.4
HVdc 3: GUG I	3000 MW (± 500 kV)	7.45	3.98	6.83	3.44
HVdc 4: GUG II	3000 MW (± 500 kV)	9.9	5.86	9.4	5.26
HVdc 5: YUG	5000 MW (± 800 kV)	7.22	3.84	6.48	3.31

With the Participation Index it is possible to evaluate the intensity of interaction between HVdc converter stations. Results of this calculation are presented in table 3-13.

The calculation of the Participation Index shown in the table 3-13 considers that all reactive power compensation is included in the system, including the reactive power compensation for the operation of the converters.

From the results the following can be observed:

- The HVdc converter station YUG, interacts the most with the other converter stations.

- The reasons for this are that the nominal rating of this converter station (5000 MW) is higher than any other HVdc station and that the YUG converter station is sitting electrically close to all the other converter station, except to GUG II.

- As YUG interacts more with 3GG as compared with the other converter stations, this means that disturbances related to YUG, like commutation failures, will affect more the operation of 3GG and will affect less the operation of the other converter stations.

- YUG also receives influence from 3GG. The Participation Index received from 3GG is significantly higher as compared with the others. The table 3-13 shows participation index with 3GG of 0.0657 pu, while with the others not higher than 0.038.

- GUG II is the converter station that receives the least influence from the other converter stations.

- Regarding the TSQ HVdc link, the nominal rating of the converter station is only 1800 MW. Considering this and also the fact that the short circuit capacity as measured at the converter bus is high, makes its own Participation Index to be only 0.1155 pu. Because of this, the contribution from the relatively high Participation Indexes, produces the 'dramatic' reduction of short circuit ratio, from $\boldsymbol{SCR} = 9.33$ to $\boldsymbol{MSCR} = 3.99$.

- It can also be noted that, for the TSQ converter station, the sum of different Participation Indexes of remote converters exceeds the Participation Index of its own converter.

Table 3-13 Participation Index (absolute values)

	3GG	TSQ	GUG I	GUG II	YUG	$\sum P_{i,m}$	$MESCR \approx \frac{1}{\sum P_{i,m}}$
3GG	***0.2071***	***0.0255***	***0.0397***	***0.0237***	***0.1094***	***0.4054***	***2.47***
TSQ	***0.0425***	***0.1155***	***0.0465***	***0.0189***	***0.07***	***0.2933***	***3.41***
GUG I	***0.0397***	***0.0296***	***0.1468***	***0.0173***	***0.0634***	***0.2968***	***3.37***
GUG II	***0.0237***	***0.0113***	***0.0173***	***0.1064***	***0.037***	***0.1957***	***5.11***
YUG	***0.0657***	***0.0252***	***0.038***	***0.0222***	***0.154***	***0.3051***	***3.28***

<u>The MIIF matrix</u>

Chapter 1 defines an empirical method to calculate the so called Multi Infeed Interactive Effective Short Circuit Ratio (MIESCR) based on the calculation of Multi Infeed Interaction Factor (MIIF). Chapter 1 also describes the procedure to calculate these ratios, by means of ordinary load flow and transient stability analysis program. It is expected that the results from these calculations will give approximately the same information to that previously obtained from MESCR and Participation Indices.

Table 3-14 below presents the MIIF matrix calculated for the CSG system. Table 3-15 is an extension of table 3-14 where the results of the product $\boldsymbol{MIIF_{j,i}} \times \boldsymbol{Pdc_j}$ are included. It should be noted that values included in table 3-15 have similar interpretation to those values given in table 3-13 where Participation Indexes are given.

Table 3-14 Multi-Infeed Interaction Factor – MIIF Matrix

		Relative inverter ac Voltage change				
		3GG	**TSQ**	**GUG I**	**GUG II**	**YUG**
Bus at which fixed reduction is applied	**3GG**	1.0000	0.2546	0.2298	0.1573	0.3620
	TSQ	0.2534	1.0000	0.2749	0.1385	0.2529
	GUG I	0.3304	0.3985	1.0000	0.1753	0.3218
	GUG II	0.2868	0.2541	0.2210	1.0000	0.2756
	YUG	0.7316	0.5107	0.4538	0.3048	1.0000

Table 3-15 Pdc x MIIF Matrix [values are presented in MW]

		Relative inverter ac Voltage Change				
		3GG	**TSQ**	**GUG I**	**GUG II**	**YUG**
Bus at which fixed reduction is applied	**3GG**	3000	458	689	472	1810
	TSQ	760	1800	825	416	1265
	GUG I	991	717	3000	526	1609
	GUG II	860	457	663	3000	1378
	YUG	2195	919	1361	914	5000

3.3.3.2. Quasi-static analysis of the system

Quasi Static Modal Analysis methodology has been used to qualify and quantify the Voltage Stability and Power Stability conditions of the CSG system. Weak elements or areas in the electrical system can be identified by using the Q-V modal analysis. It is based on a calculation of the eigenvalues, participation factors and V-Q sensitivities. Maximum Power Curve (or MPC curve) also indicates the stability margin for the individual HVdc link.

<u>Maximum Power Curves</u>

The study of Maximum Power Curve, or MPC, is a static approach for the stability analysis of an HVdc transmission system, which was introduced by J.D. Ainsworth in the earlier 1980’s and used for a single infeed topology of an HVdc converter, where the power sensitivity to small changes in the dc current was studied and power stability limits verified. This study has been extended to a multiple infeed topology, where different HVdc links are connected to different buses [CHN1].

The Maximum Power Curve and V-I curve of different HVdc links were calculated assuming that the dc current in one HVdc link was increased while dc currents in the other four HVdc links were unchanged. It was also assumed that all HVdc links were operating in Constant Power Control with a slow response time.

A conservative assumption in this study is that all loads in the system have a constant load characteristic. This means that the load remains unchanged when the voltage is changed at the connection point.

A sample of the results from the calculation is presented in figure 3-19. As can be observed from the curves, the HVdc links nr. 1 (3GG) is operating very close to the Maximum Available Power (MAP) condition. For this link the critical MESCR is 2.49.

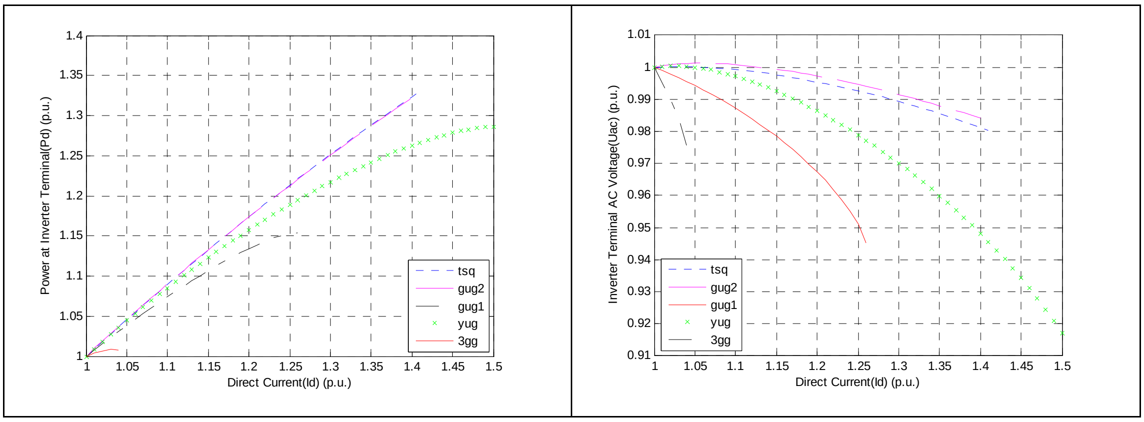

Figure 3-19: Maximum Power Curves and V-I Curves for the five HVdc links

The low stability conditions observed in the results can be explained as follows.

The system is quite sensitive to reactive power balance in the load area, in particular close to the inverter from the HVdc nr. 1 (3GG).

Figure 3-20 shows the measured power angle in some critical areas of the network. It can be seen that the angle difference between some provinces in the west side (generation area) and provinces in the east side, close to the load center, exceeds 70 electrical degrees. This indicates that the ac lines connecting these areas are heavily loaded.

It should be noted that a conservative assumption regarding load representation has been considered, as constant load. A different representation of the load, having voltage dependence, would improve the results.

All HVdc transmission systems are operating assuming a slow Power Flow Controller. A fast Power Order Controller would also improve the stability condition.

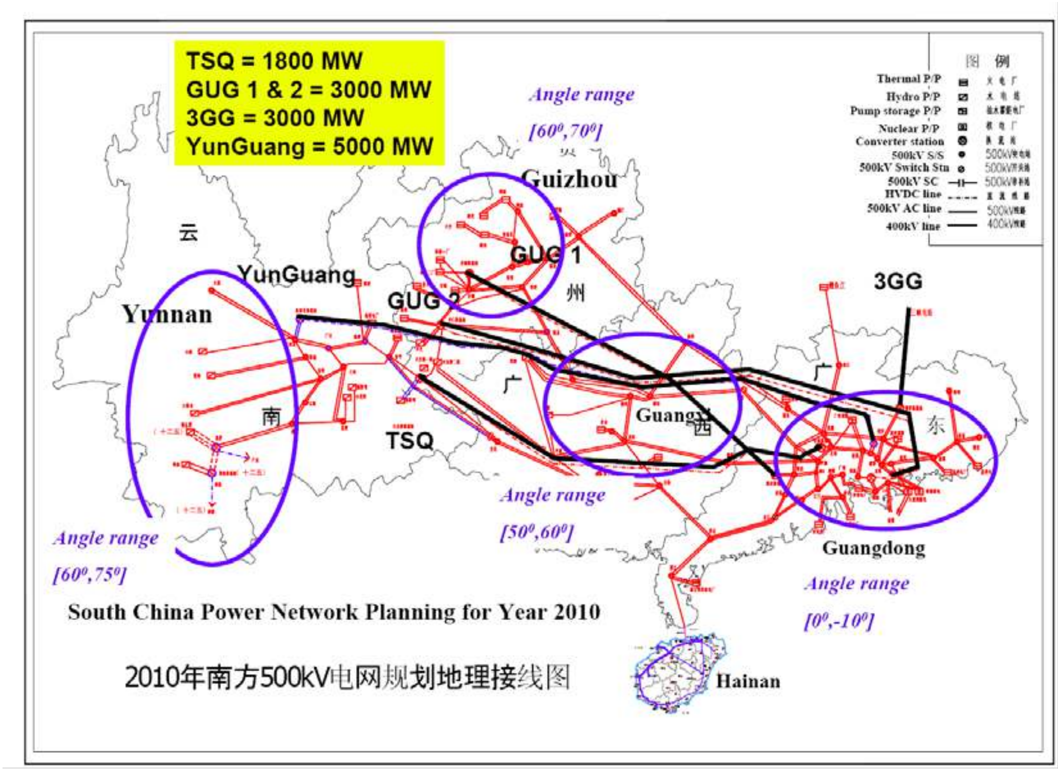

Figure 3-20 Power angle in critical areas of the CSG system

V-Q sensitivity analysis

From V-Q sensitivity analysis it is possible to evaluate the voltage stability related information from a system wide perspective, providing information regarding the mechanism of instability, evaluate the security of the transmission grid by quantifying the stability margins and power transfer limits. It is also possible to identify weak points in the system and areas of voltage instability, as well as identification of possible remedial measures to be taken to improve the system stability in those identified weak points.

From this sensitivity analysis made on different busses in the system it has been identified that the busses located in the "interface area" where the four main transmission corridors and some HVdc links terminate, are the most sensitive busses. Figure 3-21 shows the critical area.

It was also identified that most of the long transmission lines, belonging to the four main transmission corridors and transferring a large quantity of power from the western generation area to the eastern load area, have high participation relative to those busses that have high V-Q sensitivity. The V-Q sensitivity of these busses, which is related to the voltage stability margin conditions, is significantly degraded if some of these branches are tripped.

Another observation from this analysis was that most of the generators located in a load area, or are connected to main transmission lines feeding this area, are important for maintaining system stability.

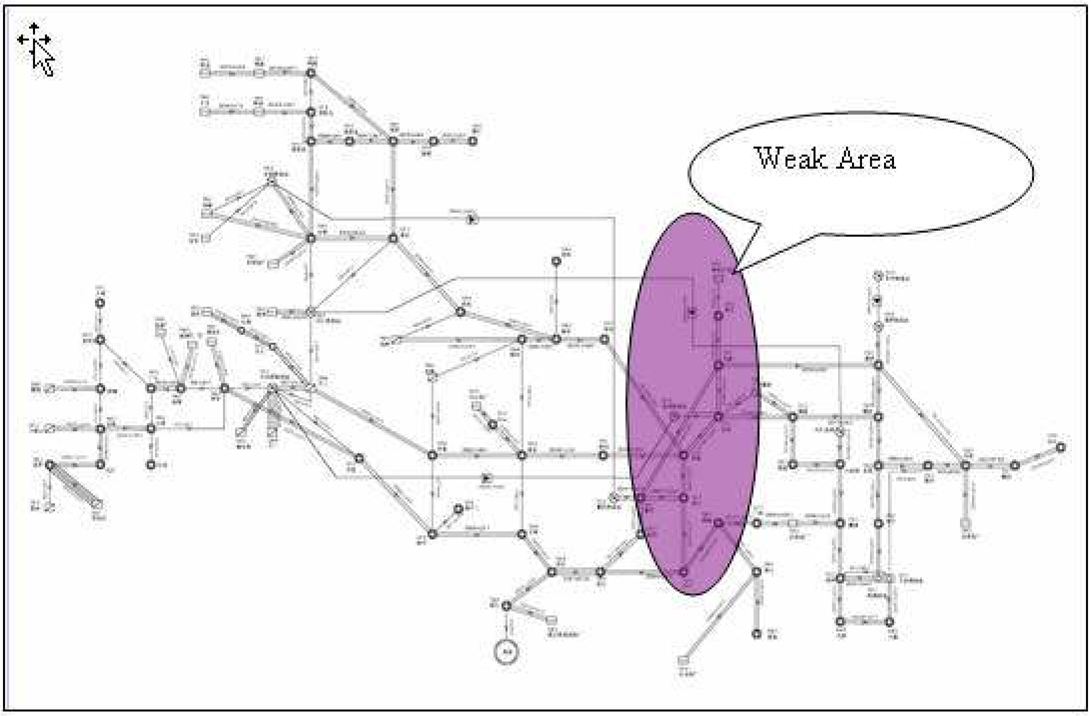

Figure 3-21 Identification of 'critical area' inside the main load area in Guangdong electrical system

<u>P-V curves</u>

P-V curves relate bus voltage to load within the region, which give an approximate indication of voltage collapse due to excess of load level in a given area. P-V curves of five ac buses close to the HVdc inverters in the main load area were drawn as shown in figure 3-22 below.

From the figure 3-22 it is possible to observe that the operation point of the ac system is close to the "nose" part of the curves, which indicates that the ac system is heavily loaded and its operating point is close to the system stability limit.

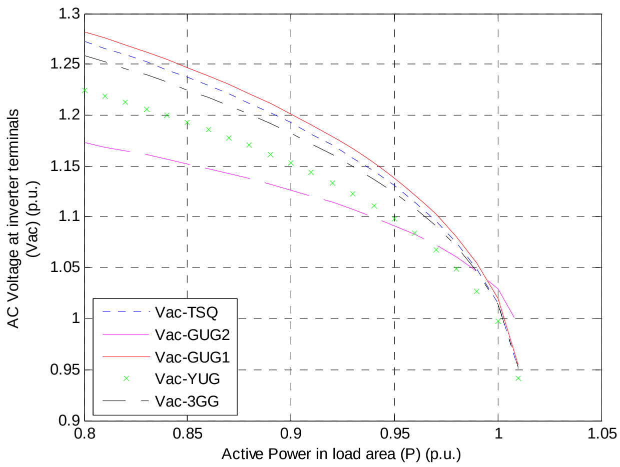

Figure 3-22 P-V curves for the different ac inverter busses

Applying remedial measures

It has been verified that the 'interface area' is the critical area in the CSG system. In order to improve the system performance, a remedial measure would be to add reactive power support devices on some of the busses in that area. This means that these devices would support the most critical area of the system.

Two important considerations should be pointed out. First, it is advisable that those devices should have fast response to changes in the system. This means that an SVC or STATCOM or fast switching shunt devices like capacitor banks and shunt reactors should be used. Second, considering that this 'interface area' is a rather big area, it is convenient to consider several reactive power support devices located on different busses, since a single unit cannot cover the whole area.

Conclusions

From the Load Flow Analysis we have identified that most of the high voltage transmission lines are operating under a heavily loaded condition.

Load flow results show that the power angle difference between the generation area in the western region of CSG system and the load area in the eastern region exceeds 70 electrical degrees. This is already an indication of potential difficulties in operating the system, especially during contingencies which results in outages of some key connection lines between these two regions.

From the Sensitivity Analysis it was observed that the load area is very sensitive to both reactive and active power variation. The area is operating quite close to the voltage stability limit. A particular critical area in the main load area of the CSG system is the 'interface area' where the main transmission corridors and some HVdc links are terminated.

The study has shown that the introduction of some reactive power support in this critical area, such as an SVC or fast switchable capacitors, would significantly improve the voltage stability condition of the entire CSG system. This corrective measure was studied in more detail in the electromechanical transient studies, as discussed in the following section.

3.3.3.3. Fundamental frequency stability study

General

An initial investigation of the system regarding the fundamental frequency transient stability conditions of the studied configuration for the CSG system was performed without considering the effect of any control actions.

The studies reveal that some of the contingencies resulted in instability. The harmful contingencies were reinvestigated considering various control actions.

This section summarizes the findings of all investigations. A number of control measures have been investigated to manage harmful contingencies. The general problem with the network is the impaired power transfer capability to the main load area in the event of a contingency. Amongst the solutions discussed, the best option was found to be a combination of series and shunt compensation.

Series compensation of 30% on three ac transmission corridors connecting the generation area in the west to the main load area in the east and shunt compensation comprising of 3x100 MVAr switched shunt capacitors in parallel with 100 MVAr

SVC at three locations in the so called ‘interface area’ in the load area was felt adequate in managing the harmful contingencies. To manage a bipole trip of HVdc nr. 5 (YUG), it is necessary to shed some generation. However, if the amount of series compensation is increased or series compensation is introduced on more lines, it might be possible to manage a bipole trip of the HVdc transmission link without any generation shedding. Either the amount of series compensation on the existing lines should be increased or series compensation added to more lines.

The results were quite encouraging and all harmful contingencies with a fault-on period of 100 ms were managed with this arrangement.

The cases that have been studied are based on the list of contingencies that includes:

- Single pole and bipole trip of converters
- Three phase fault on ac lines inside the load area close to inverter bus and subsequent trip of single/double circuit lines after 100 ms.
- Three phase fault on ac line feeders to the load area close to inverter bus and subsequent trip of single/double circuits ac line feeders after 100 ms.
- Three phase fault at some of the generator terminals and subsequent trip of the generator after 100 ms.
- Three phase fault at rectifier terminal with a fault clearing time of 100 ms.

<u>Screening harmful contingencies</u>

Trip of converters

The following contingencies were harmful as the system was unstable following one of these contingencies.

Single pole and bipole trip of HVdc nr 5 (YUG)

Bipole trip of HVdc nr 3 GUG I

Bipole trip of HVdc nr 4 GUG II

Three Phase Fault near inverter bus

The following cases were not successful:

Double circuit trip of some ac lines in the load area after a 100 ms 3 phase fault close to the load area

Three-Phase Fault at ac line Feeder to load area

The following cases were not successful:

None of the line trips with fault-on period

Single/double circuit trip of some ac feeders to the load area for fault-on period of 100 ms

Three Phase Fault at rectifier terminal

All three phase fault at all rectifier terminals of 100 ms were successful.

Three Phase Fault at generator terminal

All contingencies with a fault-on period of 100 ms were successful.

250 ms Fault Period

Contingencies with 250 ms were considered to be outside the scope of this work.

Overview of control measures

Intuitively the problem is the impaired ability of the network to deliver power to the load area in Guangdong when a harmful contingency occurs. The qualitative solution is the series compensation or the shunt compensation or both. To manage the set of harmful contingencies, a combination of the following control measures were explored:

- Power frequency control (PFC)
- Load/generation shedding
- Static VAR compensator (SVC) of different capacities at the so called 'interface area' in the load area in Guangdong
- Fixed capacitors at 'interface area' in the load area
- Switched shunt capacitors at 'interface area' in the load area
- Series compensation on three different ac corridor lines

Power frequency control was employed on all the links and it was used in combination with other control measures also in the studies. The Power Frequency Controller is a higher level controller to the HVdc transmission link which basically adds a contribution to the set power order based on measured frequency deviation seen at the converter bus. It includes a proportional gain (which is typically in the order of 150 000 MW/pu of frequency deviation) and a lead/lag filter to provide a derivative action to the controller.

Conclusions

A number of control actions were employed and their effect on the post disturbance network was investigated. Studies reveal that series compensation along with shunt compensation might be a better option to reinforce the network.

A 3x100 MVAr capacitor switched in parallel with 100 MVAr SVC at three different locations in the 'interface area' in Guangdong was employed to provide shunt compensation. The network would need series compensation of about 30% on three different ac line feeders to the load area in Guangdong. In addition, power frequency control was also employed. This arrangement worked fine for all contingencies without any generation/load shedding except bipole trip of HVdc nr. 5 (YUG). Bipole trip of this HVdc link needed 2435 MW of generation to be shed.

The studies revealed that emergency power control along with four different lines to reinforce power corridors did help in the case of a bipole trip of HVdc nr 5 (YUG) but generation of 1400 MW needed to be shed. Emergency power control involves exchange of data between various links and calls for higher reliability and might not find favour with network owners.

There is a need for further reinforcement of the network so that a bipole trip of HVdc nr. 5 (YUG) can be managed without any generation shedding.

A Fast Power Flow Controller (response time of 50 ms) has shown to be beneficial to the system as compared with a typical implementation of the controller which is characterized by a slow response time (response time of 1 second).

3.3.3.4. Dynamic Performance Study

The main objective of the dynamic performance study (DPS) is to study the interaction between the HVdc inverters connected in the Guangdong area. The focus is on the commutation failure sensitivity of different inverters and the recovery performance of different links after major disturbances under normal and contingency system operating conditions. The purpose of the study is to verify if, due to these phenomena of concern, it might be needed to develop coordinated recovery control strategy to achieve acceptable performance of multiple HVdc links.

<u>System Setup</u>

The simulation setup was prepared based on PSCAD version 4.1.1.

An equivalent of the China Southern Grid has been prepared where the major 500 kV buses in the load area in Guangdong are retained and the major 500 kV ac connections between the west and east parts of the CSG network are also retained. Figure 3-23 illustrates a schematic representation of the equivalent.

This equivalent network consists of 135 nodes, 274 branches and 22 aggregated dynamic generators. The system steady state and dynamic performance has been verified in comparison with the results from the full network simulation.

Further investigation has shown that it is fairly accurate to only model 9 aggregated generators as dynamic machines in the developed CSG equivalent.

Another investigation that is presently in progress is to verify that similar study results and conclusions could be obtained by using a more simplified equivalent, considerable smaller than the one that has been built. Having obtained such experience, this would simplify future work if a more complex system having increased number of HVdc transmission links would be studied.

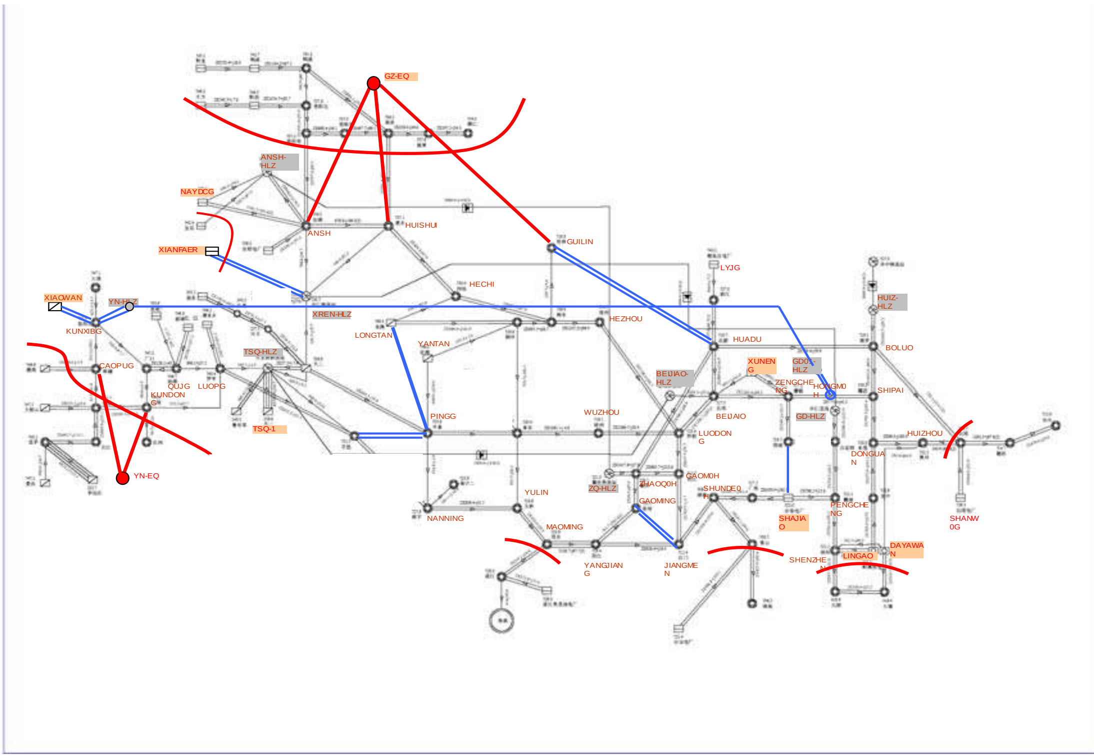

Figure 3-23 CSG equivalent represented in EMTDC/PSCAD

<ins>Conclusions</ins>

The overall results of this DPS study indicate that satisfactory performance of all HVdc transmission links can be expected for the studied configuration. The interaction between the five HVdc transmission links is minor mainly because of the strength of the ac network.

The main findings of this DPS study can be summarized as follows:

Commutation failure sensitivity analysis indicates that, except for the HVdc link nr. 5 (YUG), commutation failure of one HVdc link caused by an impedance fault or induced by removal of firing pulse does not spread to the healthy links. However, commutation failure of the HVdc link nr. 5 (YUG) may induce commutation failures in the other healthy links.

For severe ac faults in the load area of Guangdong, the five HVdc transmission links all suffer from commutation failure. However, the overall recovery performance of multiple HVdc links is satisfactory. In the few problematic cases, acceptable performance could be achieved with proper control parameter settings for different HVdc links.

There exists a risk of prolonged recovery involving HVdc nr 1 (3GG) and nr. 5 (YUG) if some generation included in the load area is not in service, which results in reduced dynamic reactive power support to the inverter converters from these HVdc links.

3.4. Denmark

The transmission system in Denmark is owned and operated by Energinet.dk, the Danish TSO. The Energinet.dk system is divided into two electrical separated systems, the Eastern system and the Western system.

The Western system is synchronous with the European system UCTE via 400 kV and 220 kV AC transmission overhead lines.

The Eastern system is synchronous with the Nordic system NORDEL via 400 kV and 132 kV AC submarine cables.

The Western system has two HVdc links to Sweden, Konti-Skan pole 1 (380 MW) and pole 2 (360 MW), and three HVdc links to Norway, Skagerrak pole 1 (250 MW), pole 2 (250 MW) and pole 3 (440 MW).

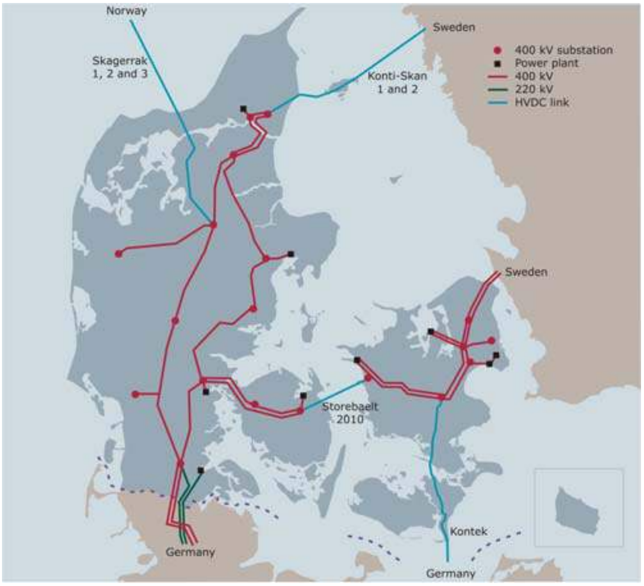

Figure 3-24 Goegraphycal Overview of the Danish Power System.

The Danish power system is characterised by a high penetration of distributed power sources, ie wind power and CHP (combined heat and power) plants. In the Western system, wind power penetration is 200%, which is calculated as maximum wind power production divided by minimum consumer loading, while in the Eastern system wind power penetration is 85%. Where CHP is concerned, penetration is 136% in the Western system and 74% in the Eastern system.

The installed production capacities are shown in the table 3-16 below.

Table 3-16 Installed Production Capacities

Synchronous area	**Western Denmark UCTE**	**Eastern Denmark Nordel**
Central power stations	3400 MW	3800 MW
Local CHP plants	1700 MW	650 MW
Wind power plants	2400 MW	750 MW
Wind power penetration	65-200%	30-85%
Combined heat and power penetration	46-136%	25-74%

CHP and wind power production is determined by the weather conditions, with CHP production being high in cold weather when the need for domestic heating is high, and wind power production being high at high wind velocities. Wind power has priority access and can only be stopped by the TSO if power system security is in jeopardy. In this case the wind turbine owner must be compensated.

In order to provide sufficient short-circuit capacity and inertia in the power system, at least three central power stations must be in operation at any time in the Western and the Eastern systems, respectively.

The design values for the existing HVdc links in the Western system are as follows:

Table 3-17 Design Values for the Existing HVdc links in the Western System.

HVDC	**AC filters/compensation**		**Minimum SCC design**
Konti-Skan 1, 380 MW (commissioned 2005) 400 kV Vester Hassing	Combined Filter: 3rd/27th double damped 11th/13th double tuned Damped filter (12th)	1 x 60 Mvar 2 x 60 Mvar	2,000 MVA
Konti-Skan 2, 300 MW (360 MW)* 400 kV Vester Hassing	2 x HP12 Shunt capacitor HP24 Synchronous condenser	2 x 55 Mvar 1 x 55 Mvar 1 x 20 Mvar 100 MVA	1,200 MVA
Skagerrak 1+2, 2 x 250 MW (2 x 275 MW)*	2 x AF11/13 Shunt capacitor Synchronous condensers	2 x 40 Mvar 1 x 80 Mvar 160 MVA	3,000 MVA
Skagerrak 3 400 kV Tjele 440 MW (500 MW)	4 x HP11/24	4 x 65 Mvar	1,700 MVA

The design values for the existing HVdc link in the Eastern system are as follows:

Table 3-18 DesignValues for the Existing HVdc links in the Eastern System.

HVDC	AC filters/compensation		Minimum SCC design
Kontek, 600 MW (commissioned 1995) 400 kV Bjæverskov	HP 12/24 double tuned	2 x 113 Mvar	3000 MVA
	Shunt capacitor bank	1 x 100 Mvar	

Currently, the Eastern and Western systems are not interconnected, but contracts have been signed for the construction of a new 600 MW monopole HVdc link (Storebaelt) connecting the Western and the Eastern systems. The new HVdc link will be ready for commercial operation in April 2010. In addition, a 600 MW HVdc pole to Norway (Skagerrak pole 4) is being planned for commissioning in 2012 or later.

The design values for the Storebaelt HVdc link between the Western and the Eastern system are as follows:

Table 3-19 Design Values for the Storebaelt HVdc Link.

HVDC, West	AC filters/compensation		Minimum SCC design
Storebaelt, 600 MW (planned commissioning 2010) 400 kV Fraugde	HP 12/24 double tuned	4 x 85 Mvar	3500 MVA

HVDC, East	AC filters/compensation		Minimum SCC design
Storebaelt, 600 MW (planned commissioning 2010) 400 kV Herslev	HP 12/24 double tuned	4 x 85 Mvar	2800 MVA

Also, the HVdc links in the Eastern system are located in fairly close vicinity to the Baltic Cable HVdc link in Southern Sweden; however this link has been disregarded in the MIIF and ESCR calculations below.

3.4.1. MIIF and ESCR

As the Danish power system is characterised by high wind power penetration, at least two scenarios must be considered:

1. A maximum scenario with high electric power supply from central power stations and without power supply from distributed generation and consequently a high short-circuit level in the system.
2. A minimum scenario with high production from wind power and CHP plants and a minimum number of central power stations in operation and consequently a low short-circuit level in the system.

Table 3-20 MIIF and ESCR for the Western System.

Maximum scenario	Konti-Skan 1+2 Vester Hassing	Skagerrak 1+2 Tjele	Skagerrak 3 Tjele	Storebaelt 1 Fraugde	ESCR MVA/MW
Konti-Skan 1+2	1.0000	0.5286	0.6785	0.2375	9.2
Skagerrak 1+2	0.4356	1.0000	0.5020	0.1253	11.5
Skagerrak 3	0.6874	0.6200	1.0000	0.2506	12.9
Storebaelt 1	0.3184	0.2766	0.3027	1.0000	11.6

Minimum scenario	Konti-Skan 1+2 Vester Hassing	Skagerrak 1+2 Tjele	Skagerrak 3 Tjele	Storebaelt 1 Fraugde	ESCR MVA/Mvar
Konti-Skan 1+2	1.0000	0.7124	0.8954	0.6608	4.8
Skagerrak 1+2	0.6958	1.0000	0.8126	0.5903	7.2
Skagerrak 3	0.7851	0.7006	1.0000	0.6257	7.7
Storebaelt 1	0.4182	0.3641	0.4510	1.0000	7.4

The Western system is strong with the ESCR being higher than 9 in the maximum scenario and higher than 4 in the minimum scenario. However, the MIIF also indicated a moderate (maximum scenario) to high risk (minimum scenario) of interaction between the new Storebaelt HVdc inverters and the existing HVdc inverters in West. The Storebaelt HVdc inverter has less coupling with the Skagerrak and the Konti-Skan inverters than the coupling between the inverters in Skagerrak and in Konti-Skan.

Table 3-21 MIIF for the Eastern System.

Maximum scenario	Kontek 1 Bjæverskov	Storebaelt 1 Herslev	**ESCR** MVA/MW
Kontek 1	1.0000	0.8755	17.0
Storebaelt 1	0.6538	1.0000	12.0

Minimum scenario	Kontek 1 Bjæverskov	Storebaelt 1 Herslev	**ESCR** MVA/MW
Kontek 1	1.0000	0.9818	3.4
Storebaelt 1	0.7298	1.0000	3.0

The Eastern system is strong with an ESCR of approx. 17 in the maximum scenario and approx. 3 in the minimum scenario. In both scenarios, the MIIF indicates a high risk of interaction between the existing Kontek HVdc inverter and the new Storebaelt HVdc inverter.

3.4.2. MIESCR for the Eastern and Western Systems

The MIESCR for the HVdc links in the Western system is listed in the tables below.

Table 3-22 MIESCR for the HVDC Links in the Western System.

Maximum Scenario Western system	**SCC_{max} MVA**	**Q_c Mvar**	**Σ P_{dc} x MIIF**	**MIESCR= (SCC - Qc)/ $\Sigma(P_{dc}$ x MIIF)**
Konti-Skan 1 + 2	7143	317	1513	4.5
Skagerrak 1 + 2	5911	166	1168	4.9
Skagerrak 3	7231	254	1509	4.6
Storebaelt 1	7270	246	1137	6.1

Minimum Scenario Western system	**SCC_{max} MVA**	**Q_c Mvar**	**Σ Pdc x MIIF**	**MIESCR= (SCC - Qc)/ $\Sigma(P_{dc}$ x MIIF)**
Konti-skan 1 + 2	3882	317	1976	1.8
Skagerrak 1 + 2	3762	166	1808	2.0
Skagerrak 3	4401	254	1847	2.2
Storebaelt 1	4795	246	1335	3.3

In the minimum scenario, the MIESCR for the existing HVdc links is low (without the new Storebaelt link the MIESCRs are approx. 0.5 higher). The MIESCR is 3.3 for the new Storebaelt link, which is somewhat better than the MIESCR for the existing links.

The MIESCR for the Eastern system is shown in the table below.

Table 3-23 MIESCR for the HVdc Links in the Eastern System.

Maximum Scenario Eastern system	**SCC_{max} MVA**	**Q_c Mvar**	**Σ Pdc x MIIF**	**MIESCR= (SCC - Qc)/ $\Sigma(P_{dc}$ x MIIF)**
Kontek 1	10231	240.8	1125	6.7
Storebaelt 1	8500	246	992	9.2

Minimum Scenario Eastern system	**SCC_{max} MVA**	**Q_c Mvar**	**Σ Pdc x MIIF**	**MIESCR= (SCC - Qc)/ $\Sigma(P_{dc}$ x MIIF)**
Kontek 1	2200	317	1189	3.4
Storebaelt 1	2500	246	1038	3.0

The MIESCR for the Eastern system is better than the corresponding value for the Western system; however, the Baltic Cable HVdc inverter has been disregarded in the calculation. For an adequate estimation of the MIESCR, the Baltic Cable must also be taken into account.

3.4.2.1. Operational Experiences

In general, no serious operational problems have been experienced with the existing HVdc links. However, due to the high penetration of distributed renewable generation - wind power and CHP plants - one of the planner's concerns has been to assess whether additional remedies are required in order to provide sufficient short-circuit power for the operation of existing HVdc links and, eventually, the future HVdc links.

The calculated ESCR indicates that in the minimum scenario the short-circuit power is sufficient for ensuring proper operation of the existing HVdc links and the new Storebaelt HVdc link.

Harmonics and power/voltage stability have not caused operational problems insofar, whereas fault recovery after sympatric commutation failures has been dealt with by appropriately tuning the HVdc controls and coordinating dc recovery times.

3.4.2.2. The Western Power System.

Operational experiences in the Western power system indicate that commutation failure in one of the HVdc station will cause a concurrent commutation failure in the other HVdc stations. This is in line with the calculated MIIF, which shows a high degree of mutual coupling and interaction between the HVdc stations in Vester Hassing and Tjele, both in the minimum and maximum scenarios, with the trend being even more pronounced in the minimum scenario, however.

With respect to the new Storebaelt HVdc link, in the maximum scenario the MIIF for the Western system shows moderate mutual coupling and a subsequent moderate risk of interaction with the existing HVdc link. In the minimum scenario, the MIIF indicates a high risk of interaction; however, the risk is lower than between the existing HVdc links.

Studies of disturbances have been conducted with a transient stability program for the existing HVdc links in the Western system and under various load conditions, different fault locations and post-fault system outages. The studies show that the Western system is stable at peak load (maximum scenario). At low load with large distributed generation (minimum scenario) the Western system is more oscillatory and fault recovery is slower. For post-fault stability, special control strategies and dc power runback are required.

3.4.2.3. The Eastern Power System

The Kontek HVdc link from Zealand to Germany is the only HVdc link in the Eastern power system. The Eastern power system is connected to Sweden with 132 kV and 400 kV AC submarine cables, and the Kontek HVdc link may therefore interact with Swepol and the Baltic Cable HVdc links in Sweden. However, due to an insufficient grid model and HVdc models, the Swedish HVdc Links have been disregarded in the calculation of the MIIF for the Eastern power system.

The ESCR for the Eastern system is sufficient even in the minimum scenario. The MIIF for the Kontek Link and the new Storebaelt HVdc link is high in both scenarios. The risk of concurrent commutation failure on the Kontek and the Storebaelt HVdc inverters is therefore high and very probable. In addition, it must also be expected that there is a mutual coupling with Swepol and Baltic Cable which may cause concurrent commutation failures on all four HVdc links.

3.4.3. MIIF Approximation using Short-Circuit Calculation

The interaction between multiple HVdc inverters in a power system is mainly due to impedances between busses in an AC grid. The mutual coupling between busses, say bus A and bus B, is the off-diagonal elements Z_{AB} and Z_{BA} in the $\underline{Z}$ (= 1/$\underline{Y}$) impedance matrix for the grid. By way of initially estimating the MIIF between busses in a grid, a load-flow calculation followed by short-circuit calculations can be used without dynamic simulation models being required. If the initial estimation of the MIIF indicates a potential risk of interaction, then a supplementary new MIFF calculation in accordance with the definition may be required.

The estimation of the MIIF based on short-circuit calculations does not take account of any dynamic interaction, only impedances in the grid are used in the estimation.

As an example, the MIIF between the Kontek and the new Storebaelt HVdc inverters is determined by using short-circuit calculations. For each of the two scenarios load-flow calculations followed by short-circuit calculations are performed.

First, a three-phase short circuit is applied to the Kontek inverter AC bus. The bus voltage at the Kontek inverter before and after the short circuit is applied is observed as follows: The bus voltage at the Kontek inverter is V_{e0} = 413.3 kV before the short circuit is applied, and afterwards the bus voltage is V_{e0+} = 0 kV, which means that the relative voltage change at the Kontek inverter bus is (V_{e0} - V_{e0+})/ V_{e0}, which is (413.3 - 0) / 413.3 = 1 pu. Similarly, if the bus voltage at the Storebaelt HVdc inverter before the short circuit is applied is V_{n0} = 408.3 kV, and after the short circuit is applied, the bus voltage is V_{n0+} = 13.75 kV, then the relative voltage change is (408.3 - 13.8) / 408.3 = 0.97, which is equal to the estimated MIIF (= 0.97/1) for the minimum scenario.

Secondly, a short circuit is applied to the Storebaelt HVdc inverter AC bus, and the bus voltages before and after the short circuit are applied is observed and the relative voltage changes calculated.

The results are summarised in the table below.

Table 3-24 Short Circuit Calculation based MIIF

Maximum Scenario	**V_0 = initial voltage**	**V_{0+} = voltage after application of short circuit**		**MIIF based on short-circuit calculations**	
		Kontek	Storebaelt	Kontek	Storebaelt
Kontek	410.99 kV	0.00 kV	37.12 kV	1.00	0.91 (0.88)
Storebaelt	412.28 kV	140.20 kV	0.00 kV	0.66 (0.65)	1.00

Minimum scenario	**V_0 = initial voltage**	**V_{0+} = voltage after application of short circuit**		**MIIF based on short-circuit calculations**	
		Kontek	Storebaelt	Kontek	Storebaelt
Kontek	408.30 kV	0.00 kV	13.75 kV	1.00	0.97 (0.98)
Storebaelt	413.30 kV	89.52 kV	0.00 kV	0.78 (0.73)	1.00

V_0 is calculated using a load-flow calculation.

The MIIF values in parenthesis in the table above are based on calculations performed by a dynamic stability program (Digsilent: Power Factory) with models of the Kontek and the new Storebaelt HVdc inverters and in accordance with the definition in Chapter 1. The load-flow and short-circuit calculations are performed using the same program package. It can be seen from the table 3-24 that the estimated MIIF and the MIIF in the parenthesis are in good agreement with each other.

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