

Medium Voltage Direct Current (MVDC) Converter for Pebble Bed Modular Reactor (PBMR)

HD Pretorius

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Supervisor: Prof Jan A de Kock

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Abstract

Nuclear and renewable energy systems will probably be used more and more extensively in future due to high environmental demands regarding pollution and exhaustion of the world's gas and coal reserves. Because most types of renewable energy systems do not supply electric power at line frequency and voltage a converter is used to connect these sources to the existing power system.

The Pebble Bed Modular Reactor (PBMR) is a nuclear power plant currently using a 50 Hz synchronous generator. A high-speed generator is now being investigated as an alternative to the conventional 3000 rpm synchronous generator. This option is considered, because the turbines in the thermo hydraulic system will run more efficiently at high speed and can be smaller in diameter. It also implies a smaller generator and possible reduction in the number of turbine shafts.

By using a 150 Hz generator implies that the generated electrical power frequency is also not that of the grid. This situation is similar to that of some renewable energy systems like wind farms. Although the frequency of wind farm generated power is in most cases lower than 50 Hz (nominal grid frequency in South Africa), the same technique of converting the generated power to direct current (DC) can be used. Direct current converters are also used to connect asynchronous networks, oil platforms, limiting flicker mitigation and $16\frac{2}{3}$ Hz railway systems to national grids.

These applications are therefore used in this thesis as a starting point for discussing the reason why a Medium Voltage Direct Current (MVDC) converter was chosen over a High Voltage Direct Current (HVDC) for the PBMR system. MVDC converters can be used to start-up the PBMR without the Start-up Blower System and Static Frequency converter. The converter can also control the active and reactive power flow and the frequency control allows a standard PBMR design for 50 Hz and 60 Hz systems.

A high-speed induction generator was found to be a good combination for use in co-operation with the converter. The construction of a 180 MW high-speed generator is however currently not possible. MVDC and especially IGBT technology are new technologies and are therefore expensive at this stage.

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Glossary of Symbols and Abbreviations

Symbols:

C	Capacitance	F
D	duty cycle	
f	frequency	Hz
f_c	cut-off frequency	Hz
h	harmonic order	
k	constant	
L	Inductance	H
m_a	Modulation amplitude	
m_f	modulation frequency	Hz
N	turns	
P	Active power	W
Q	Reactive power	var
R	Resistance	Ohm
S	Apparent power	VA
s	slip	
t	time	s
ω	angular velocity	rad/s
ω_c	cut-off frequency	rad/s
Φ	Flux	Vs
	Absolute value	
α	firing angel	rad

Abbreviations:

AC	Alternating current
BJT	Bipolar junction transistors
DC	Direct current
emf	Electro magnetic field
EMI	Electromagnetic induction
GTO	Gate turn-off thyristor
Hz	Hertz
HPT	High pressure turbine
HVDC	High voltage direct current
IGBT	Insulated gate bipolar transistor
IGCT	Insulated gate commutated thyristor
LPT	Low pressure turbine
mmf	Magneto motive force
MPS	Main power system
MVDC	Medium voltage direct current
MOSFET	Metal-oxide-semiconductor field effect transistor
NEMA	National electrical manufacturers association
PBMR	Pebble bed modular reactor
PTG	Power turbine generator
PWM	Pulse width modulation
rpm	revolutions per minute
rms	root mean square
SCR	Silicon controlled rectifier
SBS	Start-up blower system
SFC	Static frequency converter
SVC	Static var compensators
SGCT	Symmetric gate commutated thyristor
THD	Total harmonic distortion
VSC	Voltage source converter

Chapter 1

Introduction

1.1 Background

Nuclear and renewable energy systems will probably be used more and more extensively in future due to high environmental demands regarding pollution and exhaustion of the world's gas and coal reserves. Because most types of renewable energy systems do not supply electric power at line frequency and voltage a converter is used to connect these sources to the existing power system.

Wind farms can deliver a constant frequency power in two different ways. Firstly the generator rotational speed can be kept constant at synchronous speed by means of pitch control on the wind turbine. This ensures that the generator is rotated at a constant speed and electrical power is delivered to the network with a frequency equal to that of the network [3].

Secondly the pitch of the wind turbine can be kept constant. The generator will now generate power at a frequency proportional to that of the wind speed. The output is rectified and inverted to the appropriate network voltage and frequency. By using this method the rotational speed of the generator can be controlled externally to ensure a maximum power coefficient at all wind speeds [3].

The Pebble Bed Modular Reactor (PBMR) is also investigating the use of a generator with power output at a frequency different from the network frequency. This is the reason why technology used in variable speed wind farms, asynchronous networks, oil platforms, limiting flicker mitigation and railways are of particular interest in this investigation.

1.2 Pebble Bed Modular Reactor (PBMR) background

The PBMR is a nuclear power plant. This implies that controlled nuclear fission reaction is used to generate the heat required for the generation of electrical power. Uranium particles covered in graphite are used to create a nuclear fuel sphere of 60 mm in diameter. Helium is used as the coolant and energy transfer medium to a closed

cycle gas turbine. The turbine drives a 180 MW generator, which generates the electric power [5].

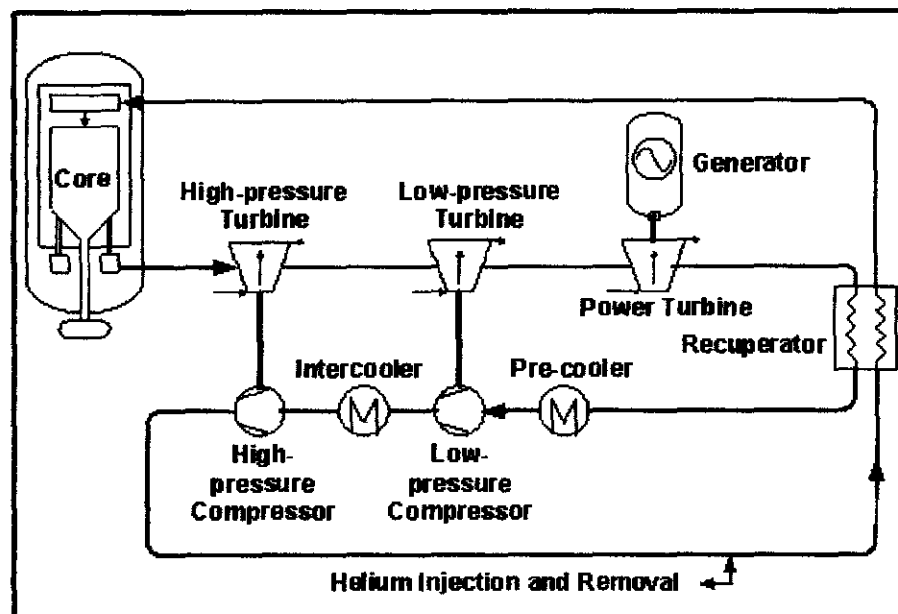


Figure 1-1 - A schematic diagram of the Brayton cycle PBMR gas circuit [5]

The PBMR uses a Brayton cycle gas circuit (described in section 5.2) to generate electrical power as shown in figure 1.1. There are three different turbines. The first one is the high-pressure turbine followed by the low-pressure turbine and finally the power turbine that drives a synchronous generator. The synchronous generator implies that the power turbine needs to drive the generator at a specific rotational speed (3000 rpm) in order to generate 50 Hz power. This tri-axial system is difficult to control and can lead to power system and process instability.

To start-up the system, electrical power from the grid is necessary. The synchronous generator needs an auxiliary motor or a frequency converter to enable it to start-up. When the system needs to shutdown quickly during a fault a braking resistor is needed to absorb the power and ensure a safe shutdown.

The PBMR company is currently investigating the possibility of using a high speed, 150 Hz induction generator. This was done because the turbines are more efficient and smaller at higher speeds. The 150 Hz induction generator will also be much smaller than the currently used 50 Hz generator. This will reduce the construction costs dramatically due to savings in expensive material used in the closed gas cycle.

1.3 Proposed Basic configuration

The use of a 150 Hz generator by the PBMR implies that the generated electrical power frequency is also not that of the grid. This situation is similar to that of some renewable energy systems like wind farms. Although the frequency of wind farm generated power is in most cases lower than 50 Hz, the same technique of converting the generated power to direct current (DC) and then back to alternating current (AC) can be used. The basic concept is shown in Figure 1-2

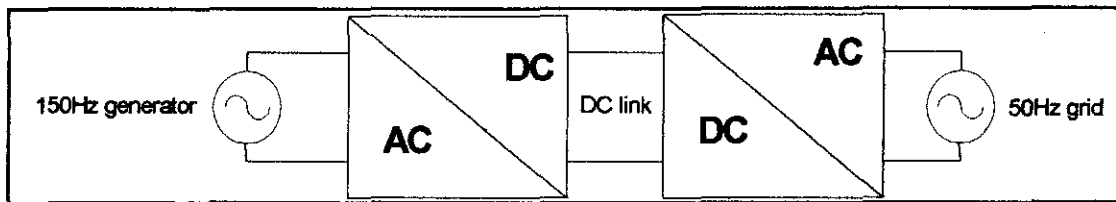


Figure 1-2 - Back-to-back AC/DC converter topology

This topology is also used in connecting asynchronous networks, oil platforms, limiting flicker mitigation and $16\frac{2}{3}$ Hz railway systems to national grids [6]. There are two different configurations of this topology. The so-called back-to-back configuration is a system where the DC link is very short and physically connected without a DC cable. The other possibility is to connect two islanded grids with a DC cable. The cable configuration is also used in countries where licenses for overhead lines are difficult to obtain, because of the environmental impact of overhead lines.

The DC link also allows the use of direct current sources like fuel cells and batteries as energy storage devices. These sources can serve as a temporary backup should a sudden increase in electrical power demand occur. This can give the PBMR system enough time to respond to the higher demand. The DC link can also be used as a connection point for wind farms, asynchronous networks or even other PBMR systems.

Up to now two major technologies were used. The technologies are known as High Voltage Direct Current (HVDC) and Medium Voltage Direct Current (MVDC). MVDC is also called HVDC Light (trademark of ABB) [1] or HVDC Plus (trademark of Siemens) [4].

HVDC is an older technology using thyristors as switching elements. Thyristors are not fully controllable, because they can be switched on at any instant, but negative line current is necessary to switch them off. This is why these converters are known as line commutated converters. It will soon become clear that HVDC technology does not offer all the advantages of MVDC. The only reason why HVDC dominates the market is because of the power limitations of MVDC converters.

MVDC is a new state-of-the-art technology based on IGBTs as switching elements. IGBTs are fully controllable and can be switched on and off at any instant in time. MVDC converters are currently used at small generation plants (e.g. wind farms), connecting medium sized power networks, connecting asynchronous networks, oil platforms, limiting flicker mitigation [1], and $16\frac{2}{3}$ Hz railway systems to national grids [6].

The MVDC converter will be able to convert the 150 Hz-generated power to 50 Hz or 60 Hz. By using a MVDC converter, the generator is in effect isolated from the electrical network and therefore traditional generator instability cannot occur with this generation configuration. The possibility of using a DC transmission cable increases the flexibility of the system.

The main difference between HVDC (High Voltage Direct Current) and MVDC lies in the switching elements used. HVDC uses thyristors instead of fully controllable switching elements like IGBTs, IGCTs and SGCTs. IGBTs high switching frequency allows the use of Pulse Width Modulation (PWM) to control the active and reactive power independently. The use of PWM also produces fewer harmonics in the system and results in savings on harmonic filters [2].

Up to now large power converters used HVDC, because of the power limitations of IGBTs and thus MVDC converters. The PBMR found that HVDC converters were too large and expensive with limited control advantages.

In recent years IGBT technology has developed at an incredible rate. This has opened the door for MVDC converters to be used in high power applications. Currently the largest HVDC Light converter of ABB is rated at 300 MVA with a DC voltage of +/- 150 kV [2].

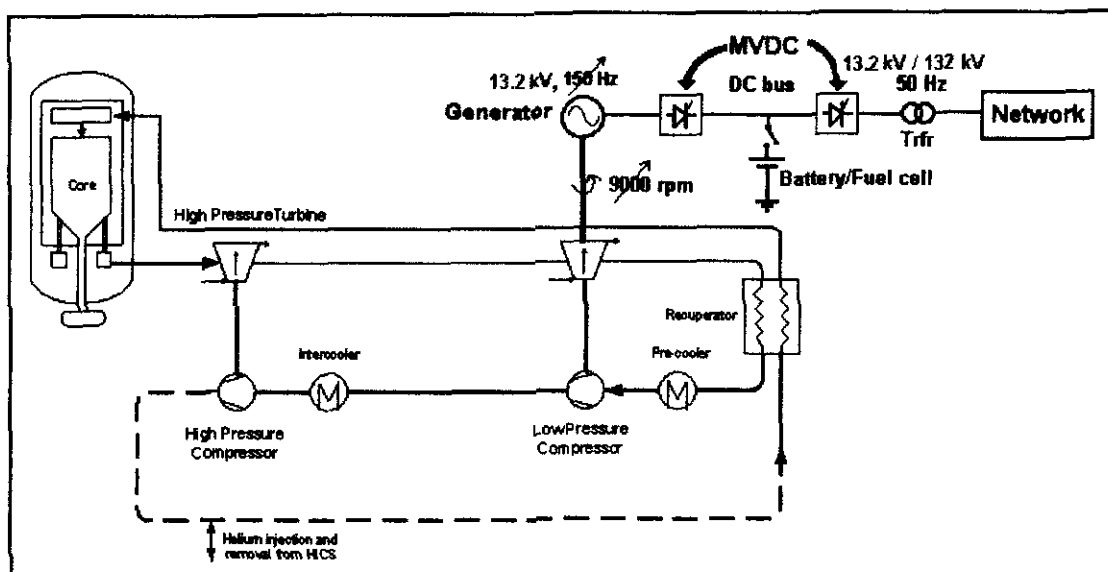


Figure 1-3 – Proposed system configuration

The proposed PBMR system configuration is shown in figure 1.3. In figure 1.3 there are only two turbine shafts instead of the three used in figure 1.1. This is possible, because the generator is driven at 9000 rpm and thus the low-pressure turbine can be used as a prime mover. This not only saves a turbine, but also some valuable space. The 150 Hz electrical power is converted to 50 Hz or 60 Hz by the MVDC converter. The output frequency of the MVDC converters can easily be changed from 50 Hz to 60 Hz. This is a major advantage, because currently the gas cycle of PBMR has to be redesigned if a 60 Hz output is needed.

1.4 Advantages of new system

The new system will have many advantages. These advantages will later be compared to the disadvantages (mainly a cost increase).

- Independent active and reactive power control.

The use of PWM allows the output to be of any amplitude and phase angle. Active and reactive power can therefore be altered almost immediately [9].

- Easy start-up from grid or storage element.

The proposed MVDC converter is a four-quadrant converter, power can be extracted from the grid or even a storage device. This power can be used to start-up the PBMR system without additional frequency converters or motors.

- Smaller generator and turbines.

The higher the rotational speed of the turbines and generator, the physically smaller they need to be to deliver the same power as a turbine or generator driven at a lower rotational speed. This can save valuable space and construction material.

- Increase in turbine efficiency.

Turbines are more efficient when driven at a higher rotational speed. The overall efficiency of the PBMR system can thus be improved.

- Turbine speed not critical and easier to control.

The MVDC converter controls the output frequency and therefore the generator doesn't need to be driven at any predetermined or specific rotational speed. Because the rotational speed is not that critical it implies simpler control of the system.

- Possible reduction in the number of turbine shafts.

The higher rotational speed of the 150 Hz generator will make it possible to combine the power turbine with the low-pressure turbine because they are now running at comparable rotational speeds. This can make it possible to use only two turbine shafts instead of the three currently used.

- No transformer tap changer needed.

The MVDC converter can control the amplitude of the output voltage and a tap changer is not necessary.

- Standard design for 50 Hz or 60 Hz PBMR.

The PBMR system is unaffected by the change in nominal or instantaneous grid frequency, because the MVDC converter controls the output frequency.

- Battery/Fuel cell backup (optional).

The DC bus allows the use of storage devices like batteries and fuel cells. These devices are still fairly expensive, but in future they may become affordable and their use could add even more flexibility and reliability to the system.

- Smaller footprint than HVDC.

IGBTs enable fast switching and therefore the use of PWM. Only small filters are therefore required to achieve the desired output waveform. PWM also allows the control of active and reactive power. Fewer components are therefore necessary and allow MVDC converters to take up only 20% of the space required by a HVDC converter of the same power rating [8].

- Only small series reactor needed for filtering.

No static var compensators are necessary, because the MVDC converter controls the active and reactive power. A small series reactor is however needed to filter out the high frequency harmonics created by the converter due to its high switching frequency.

- Improved local power quality.

Power quality is measured by the amount of harmonics, flicker and voltage fluctuations in the power system. MVDC converters improve the power quality by controlling the output voltage amplitude, frequency and phase angle.

- Low contribution to the fault current is possible.

According to Y. Jiang-Häfner [7] the contribution of an MVDC converter to fault current is dependant on the selected control strategy. If reactive power is controlled, the fault current contribution will be limited.

1.5 Purpose of this research

The main purpose of this research is to determine the feasibility of an MVDC converter should a 150 Hz generator be used by the PBMR.

Generation of 150 Hz power implies the use of a frequency converter. Up to now large power converters used HVDC technology, because of the power limitations of IGBTs and thus MVDC converters. HVDC converters were found to be too large and expensive with limited control advantages. Research is necessary to determine if MVDC would be a better solution. The advantages, disadvantages and cost implications must be examined.

1.6 Issues to be addressed

HVDC is a fairly well known technology and used extensively. The PBMR found the technology rather expensive and the footprint too large. MVDC's fast development over the past few years opened the door for new applications up to 300 MVA.

The potential of MVDC needs to be examined and compared to conventional HVDC. The advantages, disadvantages and cost implications must be determined.

The main issues concerning this project are the following:

- Gaining an understanding of the PBMR system and their goals.

It is necessary to understand the PBMR system, because the MVDC converter must be fully compatible with the PBMR. This will keep the research focused so that relevant conclusions can be drawn.

- Research existing frequency converters, especially HVDC and MVDC converters.

The history and development of converters are investigated to recognize all the possibilities of older and new technologies. This will also help to determine future trends and why development is taking that specific path. Interesting enough, the first transmission systems at about 1900 were DC systems.

- Determine the topology of the MVDC converter

An MVDC converter can be used in quite a few ways, each with some advantages and of course some disadvantages. The trade-off between these advantages and disadvantages are in most cases dependent on the specific application. It is therefore necessary to determine the optimum converter configuration for the PBMR.

- Determine parameters of a 180 MVA MVDC converter.

The parameters of the converter need to be determined to conduct an accurate simulation. These parameters will also have an effect on the cost of the converter.

- Evaluate advantages and disadvantages.

The PBMR is a profit driven company and therefore the advantages of a MVDC must compensate for the additional cost of the converter. These advantages must consequently result in some savings on other equipment and lower operating and transmission costs.

- Formulate the findings and recommendations.

Some recommendations will be provided for the PBMR. These findings will help them make an informed decision on whether to use high-speed generators with MVDC converters or not.

1.7 Outline

The thesis will be structured in the following manner:

Chapter 1 - Gives an introduction on the motivation behind the research as well as some background on the PBMR and MVDC converters. The advantages of MVDC converters are listed, but a complete discussion is only given in the appropriate chapters later on. The issues that will be addressed by this thesis are briefly discussed in the last part of this chapter.

Chapter 2 - Conventional HVDC systems are discussed in this chapter. The working and current applications of HVDC converters are examined in the first part of this chapter. The capabilities of these converters are outlined to determine their compatibility with the PBMR system.

Chapter 3 - MVDC systems are discussed in this chapter. The first part of this chapter is spent on the development of this new technology over the past few years. The differences between MVDC and HVDC are explained. The advantages of MVDC over HVDC and why they exist are discussed. MVDC's advantages for the PBMR are highlighted in the last part of the chapter.

Chapter 4 – In this chapter different configurations with the main difference in the power generator are evaluated. The DC, synchronous and the induction machine are the three machines that are compared in the investigation.

Chapter 5 – The different components necessary for the MVDC converter in the PBMR configuration are discussed. A basic design of a MVDC converter is also done in this chapter.

Chapter 6 - Based on the results of the previous chapters a conclusion is drawn and recommendations made to the management of the PBMR. Recommendations for further studies are also given.

Chapter 2

High Voltage Direct Current (HVDC) Converter

HVDC converters are used to convert direct current into alternating current and vice-versa. As an introduction the history of HVDC development and the current applications of these converters are discussed. The conversion process is discussed, using a six-pulse converter as viewpoint. To illustrate the advantages of HVDC converters, a comparison between AC and DC is made in the remainder of the chapter.

2.1 HVDC development history

The first commercial electricity generated (by Thomas A Edison) was DC electrical power. The transmission systems in the early 1880's were therefore also direct current systems [12]. Converter technology was non-existent. That limited DC transmission to low voltage applications.

There are three main reasons why AC gradually replaced DC transmission systems. Firstly there was the development of the robust constructed induction machine together with the availability of synchronous generators. The induction machine provided power to rotational drives. Secondly was the availability of transformers. Transformers could not only be used to step up AC voltages to minimize transmission losses, but also step down the voltage again to ensure safe usage. Low voltage AC could also be rectified to DC when necessary.

The mercury vapour rectifier was developed in 1901, but it only begun to be a real prospect for HVDC transmission in 1928 with the introduction of grid control to the rectifier. This gave the device the ability to control the rectification and inversion process [12].

Probably the most considerable contribution to HVDC came in 1954 when the Gotland 1 Scheme was commissioned in Sweden. This was the world's first commercial HVDC transmission system. The system was capable of transmitting 20 MW at a voltage of 100 kV using a single 96 km cable with sea return [12].

At about 1960 control electrodes were added to silicon diodes. These diodes were named silicon controlled rectifiers (SCRs) or Thyristors. This enabled the converters to

control the electrical power flow by delaying the fire angle (angle of switching after zero crossing of sine wave).

In 1961 a cross channel link between England and France was completed. Two single conductor submarine cables of 64 km at ± 100 kV linked the two 80 MW bridges. The mid-point of only one converter was grounded. This was done to ensure that no ground current flow under the sea, which effects the navigation of ships using compasses. Although both countries used a 50 Hz nominal frequency, they were not synchronized.

The first back-to-back converter was put into operation in 1965. The Sakuma Frequency Changer connected the 50 Hz and 60 Hz systems of Japan. The system is capable of transmitting 300 MW at a voltage of 250 kV in both directions.

The Eel River scheme in Canada, commissioned in 1972, was the first converter station using only thyristors as switching elements. The back-to-back converter exchanged 320 MW at 80 kV between two 60 Hz systems.

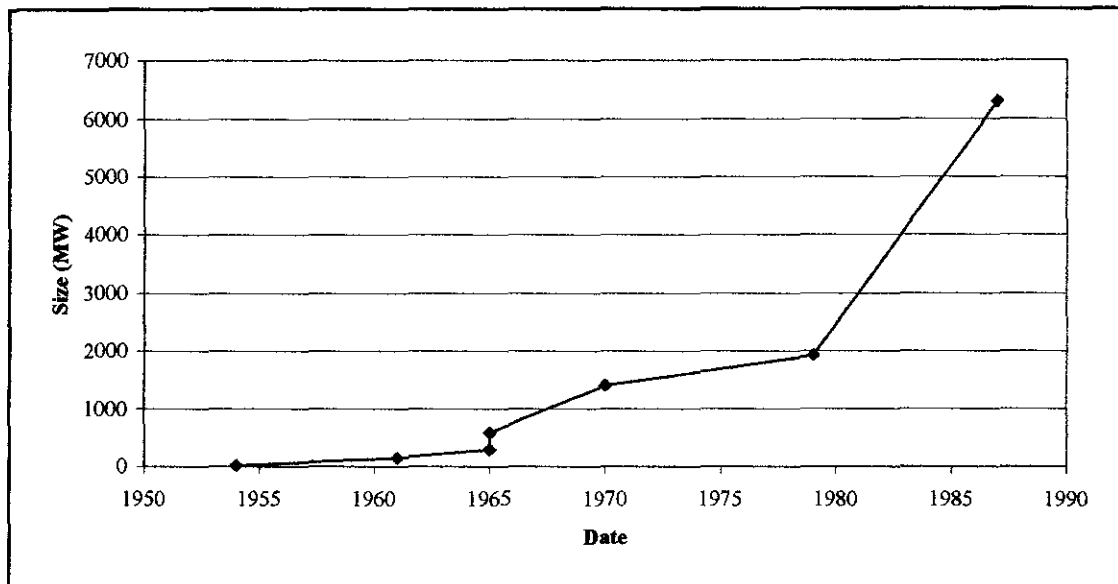
The important milestones in the development of DC transmission are given in Table 2-1.

Table 2-1 – Milestones in the development of HVDC technology [11]

Date	Development
1901	The appearance of Hewitt's mercury-vapour rectifier.
1940	Experiments with thyratrons in America and mercury arc valves in Europe.
1954	First commercial HVDC transmission, Gotland 1 - Sweden. (20 MW; 100 kV)
1960	Birth of the silicon controlled rectifier (SCR) or Thyristor.
1970	First solid-state semiconductor valves.
1979	First microcomputer based control equipment for HVDC.
1984	Highest DC transmission voltage (+/- 600 kV) in Itaipú, Brazil.
1994	First active DC filters for outstanding filtering performance.
1998	First Capacitor Commutated Converter (CCC) in Argentina-Brazil interconnection. (1100 (2 x 550) MW; ± 70 kV)
1999	First Voltage Source Converter for transmission in Gotland, Sweden. (50MW; ± 80 kV)

ABB is currently one of the largest suppliers of HVDC converters in the world. They supplied 40 000 MW of some 70 000 MW currently installed in the world [2]. This was done with 47 projects since 1954. The development, in size, of their converters is shown in the Graph 2.1. The graph shows the largest built HVDC projects in the last 50 years. The largest HVDC project was completed in 1987 at Itaipu, Brazil. The power rating of the whole project was over 6000 MW.

This shows the maturity of this technology. The largest completed project after that was a mere 2000 MW. The size of the converters is thus not determined by the capability of the technology, but by the application.



Graph 2.1 – HVDC's development in size

2.2 Typical HVDC applications

HVDC is currently used in various types of applications. HVDC is mainly used in connecting asynchronous networks, long distance transmission and where the constraints of right-of-way are a problem. HVDC is not used in connecting generated power to weak systems, because HVDC is dependant on the system for commutation. Synchronous condensers could be installed to overcome this problem with weak power systems. Table 2-1 indicates the HVDC projects completed in the past few years. The main reason why HVDC was chosen is also indicated.

Table 2-2 – Some HVDC projects since 1990 [2]

Year commissioned	Project	Size of instalment	Type of application	Description
2002 (2 nd phase)	Garabi 2, Brazil	1100 (2 x 550) MW ± 70 kV	Back-to-back (CCC)	Completes the 2200 MVA Asynchronous link between a 50 Hz and a 60 Hz system.
2001	Italy-Greece	500 MW 400 kV	Submarine link (163 km)	Monopolar link with additional 43 km land cable and 110 km line.
2000	Swepol (Sweden-Poland)	600 MW 450 kV	Submarine link (245 km)	First monopolar system with ground return
1999 (1 st phase)	Garabi 1, Brazil	1100 (2 x 550) MW ± 70 kV	Back-to-back (CCC)	1100 MVA Asynchronous link between a 50 Hz and a 60 Hz system.
1998	Chandrapur – Padghe, India	1500 MW ± 500 kV	752 km	Installed because of severe right-of way constrains.
1997	Leyte – Luzon, Philippines	440 MW 350 kV	23 km cable 433 km line	Built to increase system stability and avoid coal and oil imports to Luzon area.
1995	Kontek, Denmark - Germany	600 MW 400 kV	152 km cable	
1994	Baltic Cable, Sweden - Germany	600 MW 450 kV	249 km cable 12 km line	This converter was built because of postponed erections of power stations and to create an emergency power supply as well as increased system reliability.
1993	Skagerrak 3, Norway - Denmark	440 MW 350 kV	250 km	
1991/2	New Zealand DC Hybrid Link (Pole 2)	560 MW - 350 kV	42 km cable 575 km line	The system was implemented because of the long distance and sea crossing.
1990/2	Quebec – New England, Canada - USA	2000 MW ± 450 kV	1480 km line	HVDC mainly chosen because it connects two asynchronous networks.
1990	Rihand – Delhi, India	1500 MW ± 500 kV	814 km line	HVDC proofed to be more economical overall due to halved right-of-way requirements, lower transmission losses and better stability and control.

2.3 Six pulse HVDC converter operation

A converter is used to convert AC into DC and back to AC again. The side where power flows from the AC-side to the DC-side is known as the rectifier and the other side where power flows from the DC to the AC-side is called the inverter side. Figure 2-2 shows a six-pulse converter configuration.

HVDC utilizes thyristors as switching elements. Thyristors will only conduct current when forward biased and fired (triggered on the gate). Thyristors can therefore only conduct current in one direction, like a diode. A thyristor will only turn off once it is reversed biased and the current has decreased to zero. This happens when the line voltage becomes negative and the current drops to zero. The process is known as line commutation.

It is important to notice that a very rapid increase in a forward biased voltage just after switch-off may turn the thyristor on again. The converter must be designed in such a way that this situation cannot occur.

2.3.1 Components involving HVDC transmission

Except for the converters, HVDC transmission requires some auxiliary components to function properly. A typical DC transmission line consists of the DC line inductors (smoothing reactors), valves (stacked thyristors), DC-side harmonic filters, AC-side harmonic filters, converter transformers, a reactive power source, communication link and ground electrodes.

These components are shown in Figure 2-2. Figure 2-2 shows only the one side of the converter, but the other side is exactly the same. The filters and the reactive power source on the AC-side are also only shown on the one phase. The same filters and reactive source is connected to the other phases and then connected in a star configuration or grounded separately.

Smoothing reactors

The smoothing reactor plays an important role in a DC system. Reactors of 0,4 H to 1 H are normally connected in series on both sides of the line. These reactors are installed to:

- Prevent commutation failures in the inverter. The reactor limits the rate of change in direct current when a sudden decrease in the direct voltage occurs.
- Lower the occurrence of commutation failures in the inverter during dips in the AC voltage.
- Ensure an almost ripple free continuous direct current.
- Reduce the harmonic content of the direct current and voltage.
- Ensure that the current does not increase too rapidly during a fault. This allows the thyristor valves to gain control before the current becomes too large to handle electronically.

Thyristor valves

Semiconductors can be classified into three main groups according to their controllability. The on and off states of the first group (Diodes) is purely determined by the power circuit. Thyristors (2nd group) can be switched on by a control signal, but can only be turned off by the power circuit. The 3rd group is known as controllable switches and as the name suggests can be turned on and off by a control signal. Various types like IGBTs, IGCTs, SGCT, MOSFETs, GTOs and BJTs have been developed over the past years. IGBTs are currently used in most MVDC (HVDC Light / HVDC Plus) converters and will be discussed in chapter 4.

In Figure 2-1 the symbol of a thyristor is shown at the left side while the i-v characteristics is illustrated on the right hand side. In the off state the thyristor can block a forward voltage until the forward breakdown voltage is reached. Should a higher voltage be applied, the thyristor will be forced to its on state. The same is true for reverse voltages applied to the thyristor. The thyristor can only prevent current from flowing until the reverse breakdown voltage is reached. These conditions should be avoided.

Assuming the thyristor is used within its limits it can only be turned on by applying a positive gate current pulse while the thyristor is forward biased. Once the device is on, the gate current can be removed. The thyristor will now only turn off when the current goes negative under the influence of the power circuit.

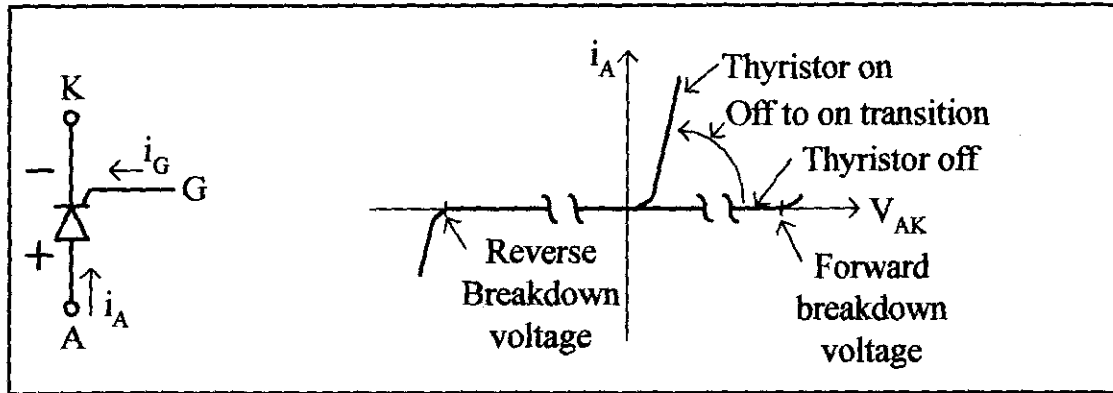


Figure 2-1 – Thyristor symbol and characteristics

Thyristors are connected together in various different ways to suit the application. In most cases a twelve-pulse group is used as can be seen in Figure 2-17. The twelve-pulse configuration eliminates the large 5th and 7th order harmonics created by six-pulse converters. Each of the twelve-pulse groups consists of a number of series connected thyristors. The voltage level of the converter and the capability of each thyristor determine the number of series connected thyristors.

Auxiliary circuits including heat sinks cooled by air, water or glycol, snubber circuits and the firing electronics accompany these valves. The communication between the control gear and the thyristors are done with a fibre optic link. The valves are interchangeable to enable fast maintenance. Thyristors are now triggered optically. Previously isolation transformers were used resulting in large and complex systems.

Harmonic filters

Both the rectifier and the inverter produce voltage harmonics on the DC line. This give rise to 6th and 12th order current harmonics on the DC transmission line. If these harmonics are not filtered out, they will cause noise interference in the neighbouring telephone lines and parallel communication channels. The magnitude of these harmonics is dependant on the firing angle (α), AC-side inductance (L_S) and the DC current (I_D).

The filtering is done with a series smoothing reactor and a shunt filter. The shunt filter consists of a series LC circuit. When a six-pulse converter is used, two of these filters are used at each side of the DC line. The one is tuned to filter the 6th order and the other one the 12th order current harmonics. Tuning implies that the LC combination is designed to have a low impedance at a certain frequency, e.g. 300 Hz ($6 \cdot 50$ Hz),

allowing the 6th order harmonic current of a 50 Hz system to flow from the DC line to ground.

Six and twelve-pulse converters also produce harmonics on the AC network. The order of the harmonics is given by $h = 6 \cdot k \pm 1$ and $h = 12 \cdot k \pm 1$ independently (where k is an integer). These harmonics may also cause interference with telephone lines and parallel communication channels. In addition, AC harmonics increase the power losses in the AC network.

To get rid of the large lower order harmonics, a filter is again designed to filter out a specific frequency harmonic. In the case of a six-pulse converter this is done for the 5th, 7th, 11th and 13th current harmonics, while only the 11th and 13th current harmonics is filtered separately in the case of a twelve-pulse converter. A high-pass filter is used to eliminate the higher order harmonics.

It is important to notice that the filter design is dependant on the AC system impedance. Not only does the system impedance influence the filtering properties of the filter at the harmonic frequency, but may also cause some resonance. In turn the system impedance is dependant on the connected loads, generation pattern and the transmission lines connected. These system properties may change in time and the filter design must anticipate these changes.

In addition, the filters supply a large part of reactive power needed by the converter. The reason for this is the dominance of the capacitive impedance over the series connected inductive elements at 50 Hz or 60 Hz. It is important to note that the reactive power demand of the converter decrease with a decrease in the power transfer. The filter capacitors must therefore be small enough so that the reactive power supplied by them never exceeds the reactive power demand of the converter at the minimum operational power level. If this criterion is not met, system overvoltage is likely to occur.

Converter transformers

Transformers are necessary to supply the converters with a AC voltage within its rating. Should the DC be transmitted over long distances, several converters can be connected in series to increase the DC output voltage to minimize line losses. The

Apollo Cahora Bassa Scheme for instance, utilizes four bridges per pole rated 133 kV to obtain the 533 kV DC transmission voltage. The voltage will be lower should only one, two or three of the bridges be in service at any stage.

The DC voltage is always kept constant by the converter, independent of the load. In order to reduce the reactive power consumed by the converter, the firing angle should be kept as small as possible. This implies that the ratio between the AC and DC voltage should be fixed. The AC voltage however varies throughout the day depending on the load.

To ensure a reasonably constant voltage at all times, a tap changer is normally used on both sides of the converter. The tap changer is controller so that if the fire angle (α) becomes smaller than 10° , it raises the DC voltage by raising the transformer ratio. On the other hand, should α become larger than 20° , the tap changer lowers the voltage by lowering the transformer ratio.

Reactive power supply

The reactive power that cannot be supplied by the AC-side filters needs to be supplied by another AC-side reactive source. Because the reactive power requirements vary throughout the day, the source must also be variable. Variable or fixed step static-, synchronous capacitors or generators are normally used to supply the reactive power. The reactive power needed by the converter will be discussed in section 3.3.4.

Communication link

The inverter on the other side needs the control settings on the rectifier. To maintain the current margin ΔI , the inverter must know what the rectifier current setting is. A fast and reliable communication link between the converters is therefore essential.

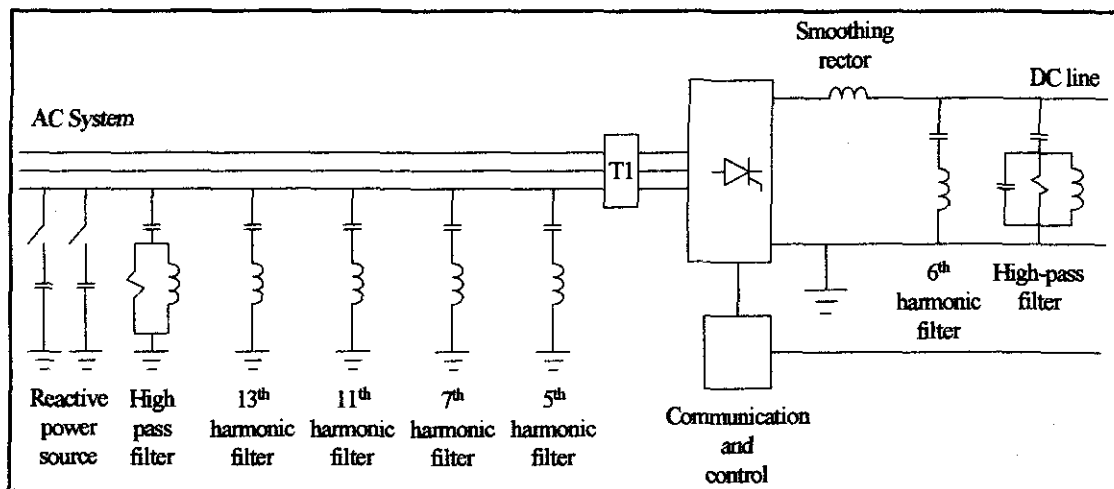


Figure 2-2 – Basic six-pulse converter components

2.3.2 Control angle

Thyristors can be triggered to conduct at any moment of an AC voltage cycle, if they are forward biased. This provides a way to control the voltage on the DC-side. The same can be done on the inverter side. The control operation will now be explained in more detail by using Figure 2-3.

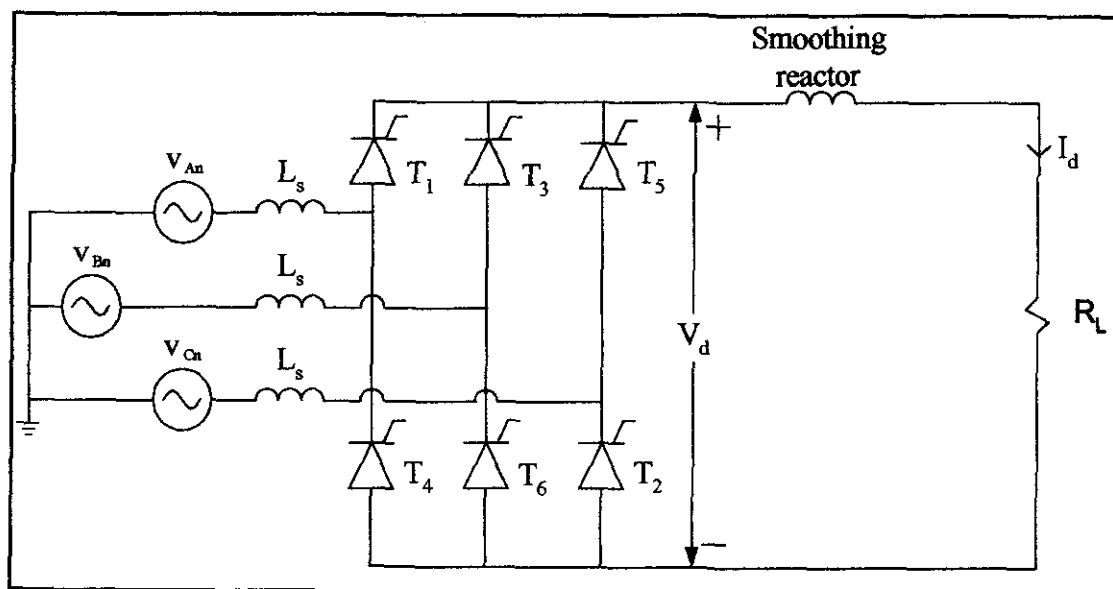


Figure 2-3 – Six-pulse bridge rectifier

As a start, assume the fire angle is zero and therefore the output is the equivalent of a plain diode bridge rectifier. In the top group (T_1 ; T_2 ; T_3), the diode with the highest potential at its anode will be fired to conduct while the other two are reversed biased.

In the bottom group (T2; T4; T6), the diode with the lowest potential at its cathode will conduct will the other two are also reversed biased.

It is clear that the output voltage will fluctuate between $1,225 V_{LL}$ and $\sqrt{2} V_{LL}$ as can be seen in Figure 2-5. The average of the DC output voltage will be $1,35 V_{LL}$, as will now be derived. This is also the maximum DC output voltage that the rectifier can provide. Due to the symmetry it is sufficient to obtain the average by evaluating only one 6th of a cycle, which is consequently a 60° ($\pi/3$ radians) interval as shown in Figure 2-4.

$$V_r = V_{cb} = \sqrt{2}V_{LL} \cos(wt) \quad -\frac{\pi}{6} < wt < \frac{\pi}{6} \quad (2.1)$$

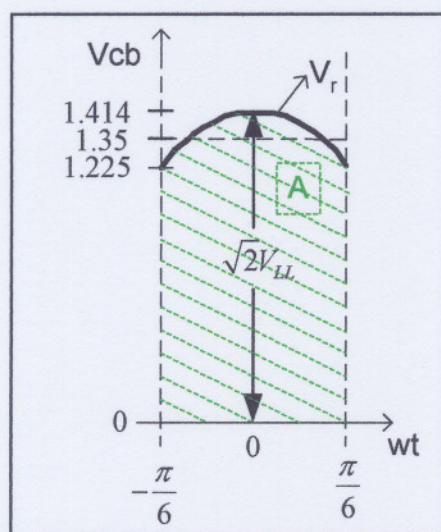


Figure 2-4 – A 60° ($\pi/3$ radians) cycle of V_{cb}

By integrating V_{cb} , the area (A) is obtained.

$$\begin{aligned} A &= \int_{-\pi/6}^{\pi/6} \sqrt{2}V_{LL} \cos(wt) d(wt) \\ &= \sqrt{2}V_{LL} [\sin(wt)]_{-\pi/6}^{\pi/6} \\ &= \sqrt{2}V_{LL} \end{aligned} \quad (2.2)$$

To obtain the average A must be divided by the interval, $\pi/3$.

$$V_d = \frac{A}{\pi/3} = \frac{3\sqrt{2}V_{LL}}{\pi} \approx 1,35V_{LL} \quad (2.3)$$

A complete cycle can be seen in Figure 2-5. The two thyristors that are conducting at any instant are also indicated at the bottom. The firing pulse and the thyristor it is switching on every 60° are also indicated.

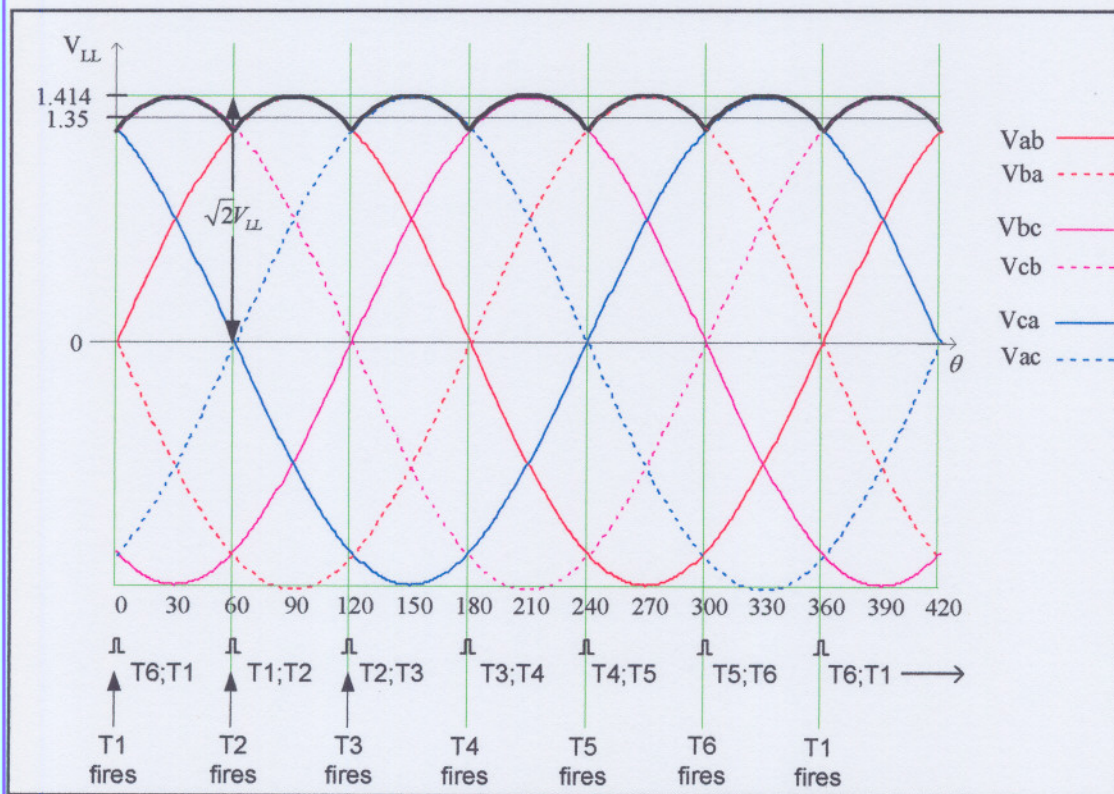


Figure 2-5 – Rectifier output with $\alpha = 0^\circ$

To illustrate the use of the firing angle, a delay of 45° is used, which means that $\alpha = 45^\circ$. Comparing Figure 2-5 & Figure 2-6, it can be seen that in Figure 2-6, thyristor T1 for example only starts conducting at $\theta = 45^\circ$ compared to 0° in Figure 2-5. The conduction period of the thyristors stay at 120° and the voltage segments at 60° . It is clear that the voltage has a much larger ripple, but the current will remain constant due to the large smoothing inductor.

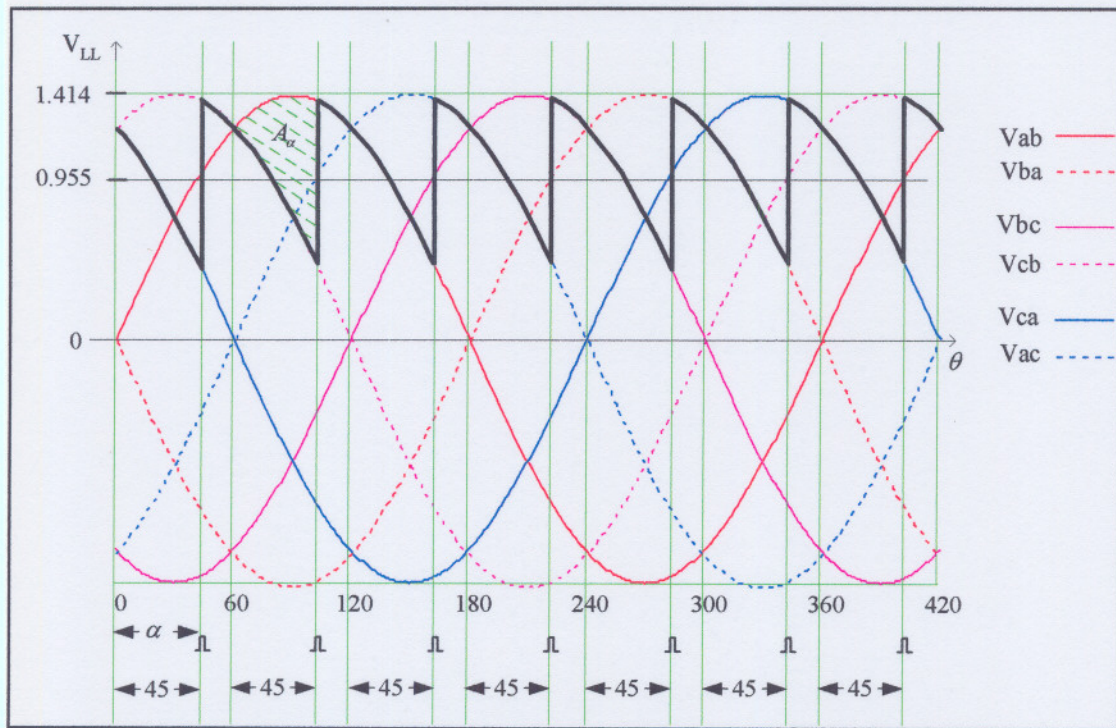


Figure 2-6 – Rectifier output with $\alpha = 45^\circ$

The reduction in the average voltage is equal to the volt-second area A_α , occurring every 60° ($\pi/3$ rad.), and therefore divided by $\pi/3$. The new reduced voltage, $V_{d\alpha}$, can be written as:

$$V_{d\alpha} = V_d - \frac{A_\alpha}{\pi/3} \quad (2.4)$$

The area A_α can be determined by the integral of $V_{ab} - V_{cb} = V_{ac}$. Choosing V_{ac} at the time origin in Figure 2-6, one can write:

$$V_{ac} = \sqrt{2}V_{LL} \sin(\omega t) \quad (2.5)$$

The area A_α can consequently be written as:

$$\begin{aligned} A_\alpha &= \int_0^\alpha \sqrt{2}V_{LL} \sin(\omega t) d(\omega t) \\ &= \sqrt{2}V_{LL} [-\cos(\omega t)]_0^\alpha \\ &= \sqrt{2}V_{LL} [1 - \cos(\alpha)] \end{aligned} \quad (2.6)$$

Substituting A_α gives:

$$\begin{aligned}
 V_{d\alpha} &= \frac{3\sqrt{2}V_{LL}}{\pi} - \frac{\sqrt{2}V_{LL}[1 - \cos(\alpha)]}{\pi/3} \\
 &= \frac{3\sqrt{2}V_{LL}}{\pi} \cos(\alpha) \\
 &= V_d \cos(\alpha)
 \end{aligned} \tag{2.7}$$

Should the firing angle be more than 90° , the output of the converter will become negative, as shown in Figure 2-9. The current however can't be negative, because thyristors can only conduct if current is flowing in a positive direction. In order for current to flow, a DC source with a voltage slightly higher than the negative voltage must be applied. The current now flows out of the positive terminal, delivering power to the AC system. The converter is now in inverter mode.

Figure 2-5, Figure 2-6 and Figure 2-7 illustrates the DC voltage output as a function of α . The triggering range of the thyristors is normally between 15° and 165° . The converter therefore acts like a rectifier between 15° and 90° and like an inverter between 90° and 165° . The maximum voltage is therefore generated at 15° and 165° , with zero at 90° . Because we assumed $L_s = 0$, the power angle (ϕ) will be the same as the delay angle (α). A phasor diagram is shown of the fundamental frequency component for the three different values of α at the right hand side of Figure 2-5, Figure 2-6 and Figure 2-7. The effect of L_s , the AC-side inductance, will be discussed in section 2.3.3 because L_s have a large influence on the commutation overlap.

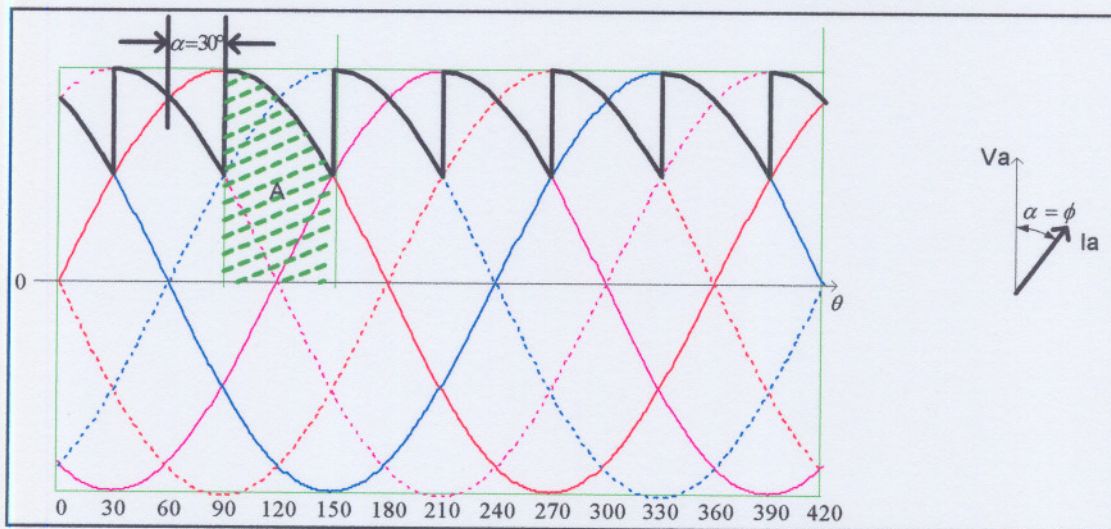


Figure 2-7 – Converter output voltage with $\alpha = 30^\circ$

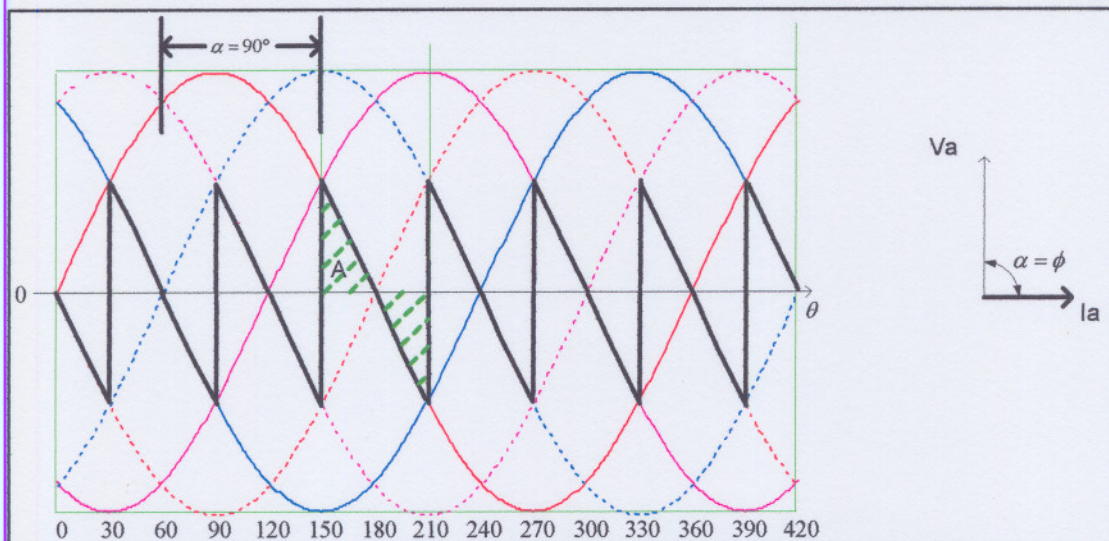


Figure 2-8 - Converter output voltage with $\alpha = 90^\circ$

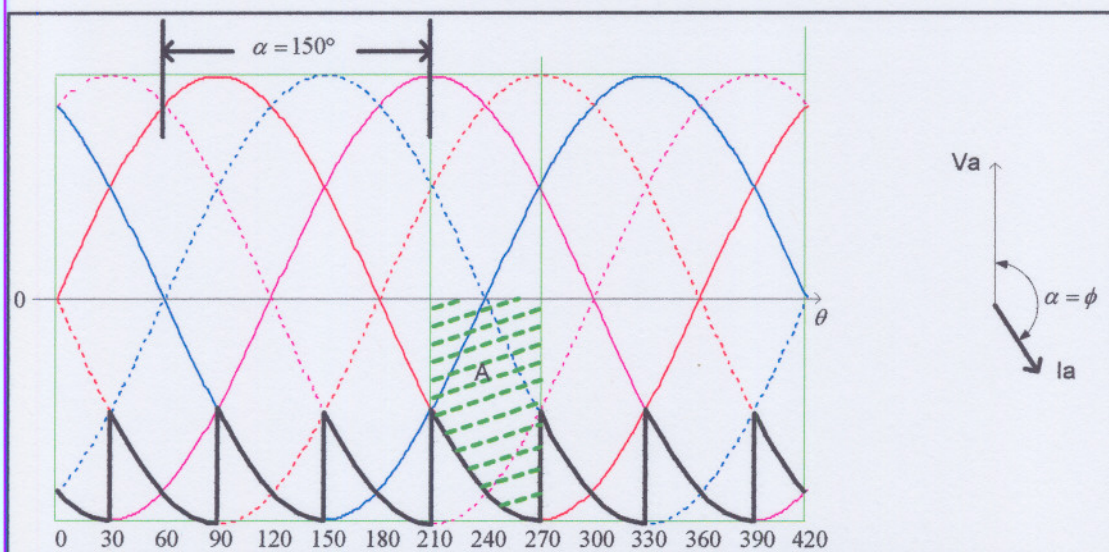


Figure 2-9 - Converter output voltage with $\alpha = 150^\circ$

2.3.3 Commutation angle

The current in a converter cannot switch instantaneous from one thyristor to another one. This transfer time of the current is called the commutation overlap period defined by the angle u . During this period the output voltage is determined by the average voltage of two simultaneous conducting thyristors. The overlap time is dependant on the direct current I_d . At full load the overlap can be as much as 30° decreasing to as small as 5° at light load [14]. This means that current flows in a thyristor for more than 120° , in fact $120^\circ + u$.

The commutation overlap not only results in a delay in the current built-up, but also delays the current cut-off by u . The effective firing angle is therefore somewhat larger than α , leading to a reduction in the power factor and average DC voltage.

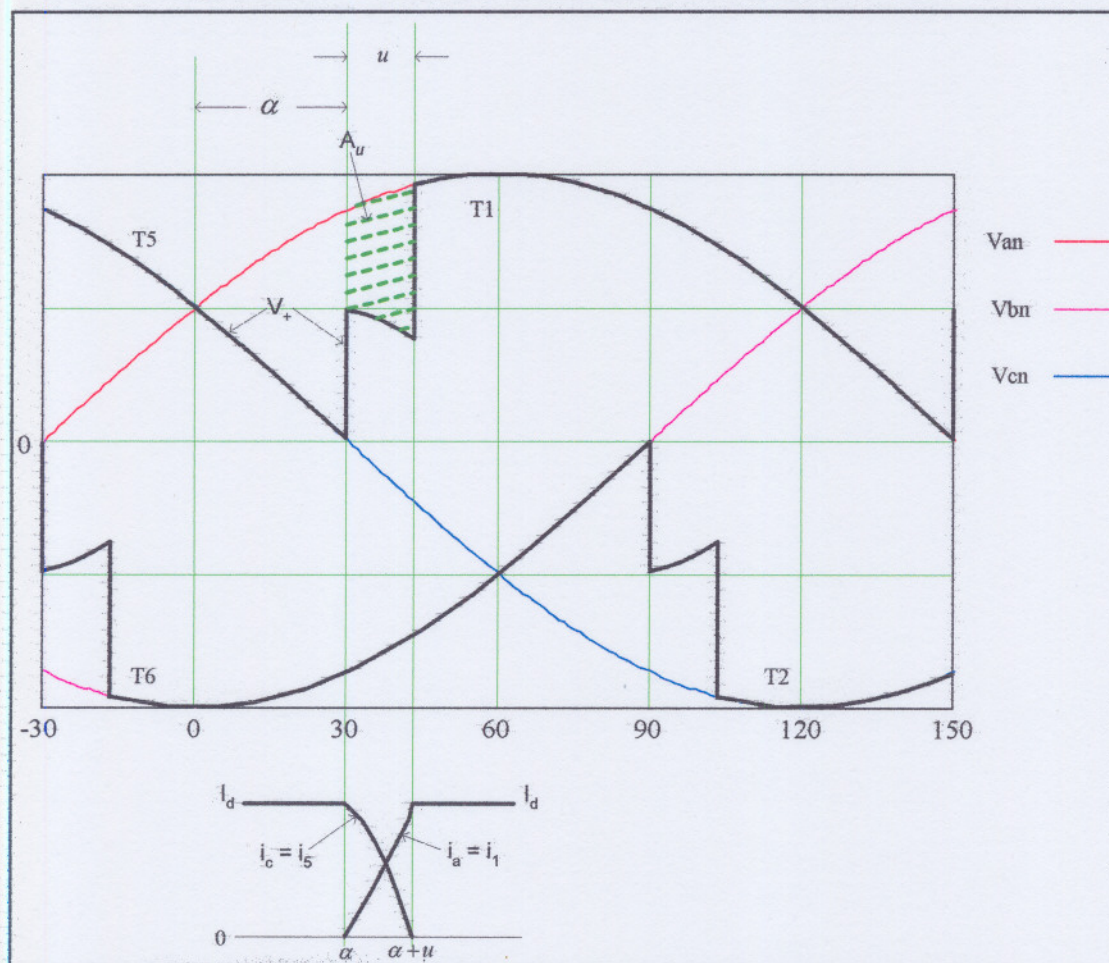


Figure 2-10 - The commutation process

The effect of the commutation process will now be described using Figure 2-10. T5 and T6 are conducting at $\theta = 0^\circ$ and during the commutation interval u , T1 takes over from T5. During the commutation interval T1 and T5 are both conducting short-circuiting V_{an} and V_{cn} through the AC-side inductance (L_s) of both phases. At the bottom of Figure 2-10 it can be seen that i_a increases from zero to I_d while i_c decreases from I_d to zero, completing the commutation period. The positive voltage during commutation (V_+), can be written as:

$$V_+ = V_{an} - V_{L_s} \quad \alpha < \omega t < \alpha + u \quad (2.8)$$

and V_{Ls} as:

$$V_{Ls} = L_s \frac{di_a}{dt} \quad (2.9)$$

The reduction in volt-second (A_u), is given by:

$$\begin{aligned} A_u &= \int_{\alpha}^{\alpha+u} (V_{an} - V_+) d(\omega t) \\ &= \int_{\alpha}^{\alpha+u} [V_{an} - (V_{an} - V_{Ls})] d(\omega t) \\ &= \int_{\alpha}^{\alpha+u} V_{Ls} d(\omega t) \end{aligned} \quad (2.10)$$

By substituting equation (2.9) into (2.10) and noting that i_a changes from zero to I_d in the same interval gives:

$$A_u = \omega L_s \int_0^{I_d} di_a = \omega L_s I_d \quad (2.11)$$

The reduction in the average voltage is equal to the volt-second area A_u , occurring every 60° ($\pi/3$ rad.), and therefore divided by $\pi/3$. The new reduced voltage, V_{du} , can be written as [15]:

$$\begin{aligned} V_{du} &= \frac{3\sqrt{2}V_{LL}}{\pi} \cos(\alpha) - \frac{\omega L_s I_d}{\pi/3} \\ &= \frac{3\sqrt{2}V_{LL}}{\pi} \cos(\alpha) - \frac{3\omega L_s I_d}{\pi} \end{aligned} \quad (2.12)$$

The harmonics are lower when commutation is taken into account. The commutation angle also increases when α decreases. This is another good reason to keep α as small as possible. Harmonics are therefore much less when the converter is operated near full load. Table 2-3 indicates the difference between typical and idealized harmonics.

Table 2-3 – Typical and Idealized harmonics [15]

	h	5	7	11	13	17	19	23	25
Typical	I_h/I_1	0.17	0.10	0.04	0.03	0.02	0.01	0.01	0.01
Idealized	I_h/I_1	0.20	0.14	0.09	0.07	0.06	0.05	0.04	0.04

2.3.4 Power angle

The converter consumes reactive power and therefore a power factor will be associated with it. On the other hand, the converter does not consume any active power, excluding losses. The DC power is therefore equal to the active power supplied from the AC bus. By equating these two powers, the power factor can be derived as follow:

$$V_d I_d = \sqrt{3} V_{LL} I \cos(\phi) \quad (2.13)$$

The power factor $\cos(\phi)$ can be written as:

$$\cos(\phi) = \frac{V_d I_d}{\sqrt{3} V_{LL} I} \quad (2.14)$$

According to Mohan et al [15], this can be rewritten as:

$$\cos(\phi) = \frac{1}{2} [\cos(\alpha) + \cos(\alpha + u)] \quad (2.15)$$

for the rectifier and as:

$$\cos(\phi) = \frac{1}{2} [\cos(\gamma) + \cos(\gamma + u)] \quad (2.16)$$

for the inverter. For a high power factor, α , γ should be as small as possible. At the rectifier it is easy to set α at 0° . The only exception is when multi-anode valves are used, in which case α should not be less than 5° in order to ensure equal current distribution between the different anodes.

At the inverter side this is more difficult. To prevent commutation failures from occurring, commutation should be completed before the commutating voltage reverses at $\gamma = 0^\circ$. This implies that γ must always be larger than zero. We therefore cannot control γ directly. The ignition advance angle $\beta = \gamma + u$ must rather be controlled. The overlap angle u can also only be estimated by the present direct current and commutating voltage. Because of these uncertainties, a safe way of operation would be to select a large β resulting in a lower power factor. A better way is using a constant extinction angle γ . This method will be described in section 2.3.6.

2.3.5 Voltage inversion

As mentioned earlier, thyristors cannot conduct negative current and inverting the voltage is the only way of power reversal. The voltage is inverted by letting α be larger than 90° . The maximum value for α is 180° .

2.3.6 Control characteristics

Fundamental control principles

Ohm's law gives the basic principle of control in the steady state. This means that the current in the DC line is equal to the difference in the terminal voltages divided by the resistance of the line. According to Kimbark [16] the equivalent circuit of DC transmission can be represented as illustrated in Figure 2-11.

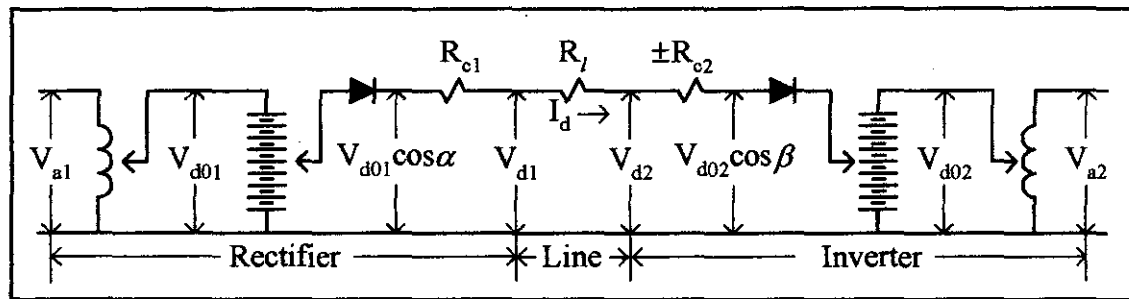


Figure 2-11 – Equivalent circuit of DC transmission [16]

The direct current I_d can therefore be written as:

$$I_d = \frac{V_{d01} \cos \alpha - V_{d02} \cos(\beta \text{ or } \gamma)}{R_{c1} + R_l \pm R_{c2}} \quad (2.17)$$

In equation (2.17) the value of the resistances are fixed and the current solely depend on the difference between the two internal voltages. Controlling the internal voltages controls the current and also the power.

The two internal voltages can be controlled by two methods. In the first instance changing the alternating voltage can control the voltage. The alternating voltage can be controlled by generator excitation, but in most cases are done by tap changing on the converter transformers. On the other hand by changing the ignition angle α on the rectifier the voltage can be altered. By delaying the ignition angle the internal voltage is reduced from the ideal no-load voltage V_{d01} by the factor $\cos \alpha$.

The changing of the ignition angle is fairly quick (1 – 10 ms) compared to the 5 sec to 6 sec per step required for tap changing. The ignition angle is therefore initially used for a fast reaction followed by tap changing to restore the ignition angle on the rectifier to its normal value.

Desired control properties

In order to implement proper control methods, one must first determine what and why certain entities must be controlled in order to ensure reliable power supply without unnecessary damage to equipment during normal operation and also transients. These features are:

- The limitation of the maximum continuous current below the rated current of the valves and other current carrying equipment.
- Operation at the highest possible power factor.

A higher power factor also reduces the stresses on the valves and damping circuits. The required current from the AC line is also at its minimum reducing I^2R (copper) losses over the line. The voltage drop at the AC terminals, due to load increase, is also minimized. The means of keeping the power factor as high as possible is discussed in section 2.3.4.

- The prevention of commutation failures of the inverter and arcbreak (only Mercury-Arc Valves) of the rectifier valves.
- Limit the fluctuations in the current due to disturbances on the alternating voltage.
- Keeping the sending voltage as constant as possible at its maximum rated voltage to minimize line losses.

HVDC converter control characteristics

To illustrate the characteristics of a converter, Figure 2-12 gives a graphical representation of the direct current (I_d) versus the direct voltage (V_d) as seen at a fixed point, in this case at the rectifier side of the DC line. The rectifier normally operates in the constant current mode and is therefore equipped with a current regulator. This results in the AB characteristic as shown in Figure 2-12.

The inverter normally operates in the so-called constant-extinction angle (CEA) control mode. This will be discussed in a short while. The inverter characteristic is then given by the equation:

$$V_d = V_{d02} \cos \gamma + (R_l - R_{c2})I_d \quad (2.18)$$

The commutation resistance R_{c2} is assumed to be larger than R_l resulting the line CD having a slightly negative slope.

At a specific point there can only be one voltage and one current and that is given by the intersection of the lines CD derived from the inverter characteristics and AB derived from the rectifier characteristics. This point is indicated as E in Figure 2-12.

The two lines can however be shifted. The rectifier line AB can be moved horizontally by altering the current setting on the current regulator. On the inverter side CD can be moved upwards or downwards by means of the tap changer, at the valve side, on the inverter station transformer. In this way it can be said that the rectifier controls the direct current and the inverter the direct voltage. The two controls influence each other very slightly, because AB is not perfectly upright and CD is also not exactly flat.

As an example, consider a reduction in the inverter side voltage. The inverter line is dropped down from CD to FG. The new intersection at point H now forms the operating point. The current stayed the same while the power delivered has dropped due to the lower DC voltage. Should this state continue, the tap changer would raise the direct voltage until the normal voltage is reached again.

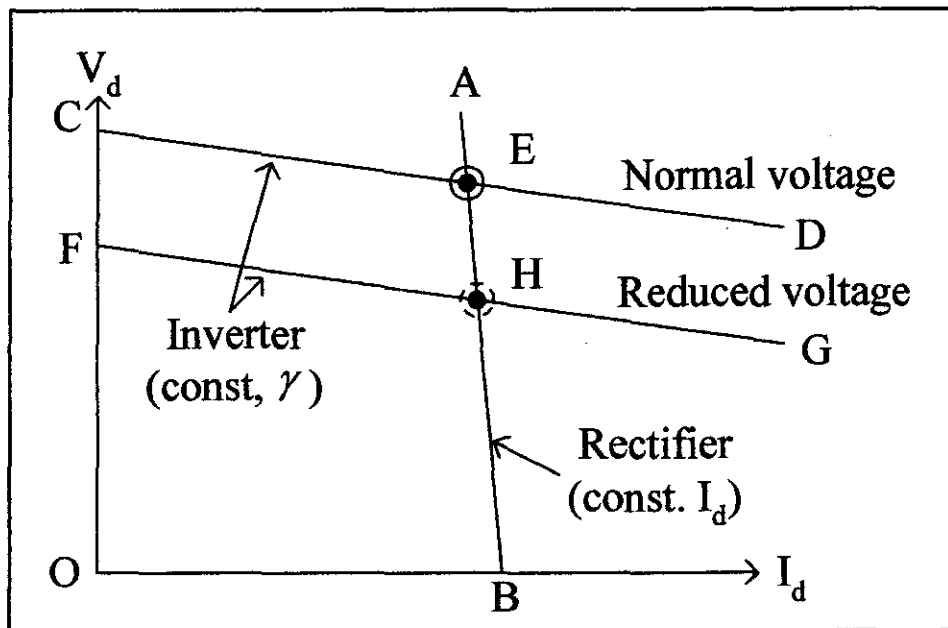


Figure 2-12 – Basic Converter control characteristics [16]

If the alternating voltage at the rectifier decreases, the current regulator would try to raise the direct voltage in order to maintain a constant current. Should the drop be quite significant, the minimum α will be reached before the voltage is restored. When this point is reached, the rectifier characteristic is changed to a horizontal line shown as AB in Figure 2-13. The line ABH in the same figure therefore gives the complete characteristic.

A large dip on the rectifier side will however shift the rectifier characteristics down to A'B'H, which does not intersect the inverter characteristics. The current will drop to zero after a short delay due to the series reactors. To prevent such a large change in current and power due to a moderate voltage dip, the inverter is also equipped with a current regulator. The current setting is set at a lower value than that of the rectifier altering the inverter characteristics to the line DFG shown in Figure 2-13. The new operating voltage is at the intersection marked L in Figure 2-13. This implies that the characteristics can be divided in two parts, one of CEA as before and another part of constant current control. Under these conditions, the inverter and rectifier have practically interchanged their functions as the rectifier is controlling the DC voltage and the inverter the current.

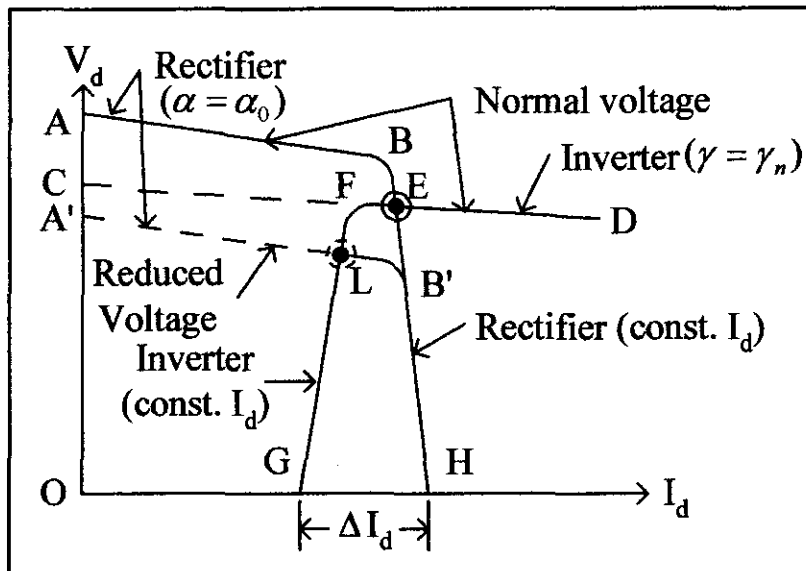


Figure 2-13 – Actual converter control characteristics [16]

The difference between the current setting on the rectifier and inverter is called the current margin indicated as ΔI_d . This is normally 15% of the rated current, although it can be smaller [16]. The setting must however be large enough to avoid the two steep constant current lines from crossing.

Converter characteristics for power reversal

In many cases the converter must be able to handle power flow in both directions over the DC line. This means that each converter must be able to act as a rectifier and an inverter. To quickly de-energize the DC line in some cases, both converters are used as inverters. These combined characteristics are illustrated in Figure 2-14. The control mode for each linear portion is also indicated as CIA (constant ignition angle), CC (constant current) and CEA (constant extinction angle) on the graphs.

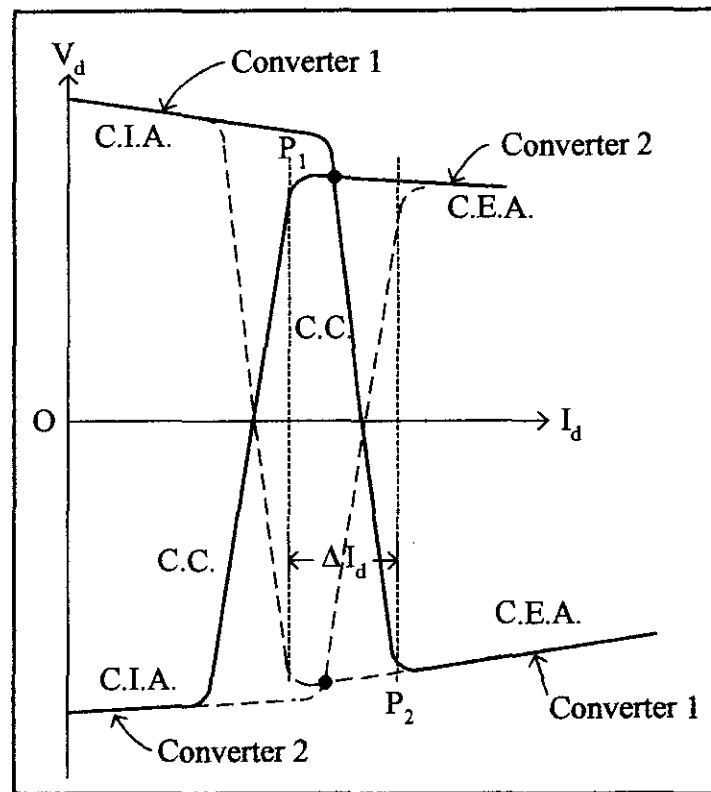


Figure 2-14 – Power reversal Converter characteristics

The characteristics shown by the solid lines represent a power flow from converter 1 to converter 2. It is noticeable that when the power flow is reversed as indicated by the dotted line, it is done by reversal of the direct voltage and not the current.

The reversal of power in such a system cannot be done instantly. The shunt capacitance of the line must first be discharged and then charged with the opposite polarity. During this process the current flowing at one end is larger than the other. To discharge the line more current is flowing out at the inverter side and when charging more current will be flowing in at the new rectifier side. The difference between the inflow and outflow of current may never exceed the current margin ΔI . The shortest time for power flow reversal is therefore:

$$T = C \frac{\Delta V_d}{\Delta I_d} \text{ sec} \quad (2.19)$$

where C is the line capacitance, ΔV_d the change in direct voltage and ΔI_d the current margin [16].

Constant minimum Ignition Angle (CIA) control

If the constant minimum ignition delay angle is allowed to be zero, $\alpha_0 = 0$, no special treatment is needed because inherently the minimum delay possible is zero. Where multi-anode valves are used, the minimum delay angle is in the order of 5° , and additional control is needed. One way of solving the problem is to measure the voltage across each valve and if it is less than a specific value CIA control is prevented from firing the valve.

Constant Current (CC) control

Constant current control is normally implemented at the rectifier side and is represented by the vertical lines in Figure 2-14. In order to implement CC control the direct current must be measured. This measured current (I_d) is then compared with the set current value (I_{ds}) and the difference is then amplified to result in the current error. The ignition angle α of the valves is then altered in order to reduce the error.

If the measured rectifier current is less than the set current, α must be decreased in order to increase the internal voltage of the rectifier. By raising the rectifier voltage the current will increase as indicated in equation. (2.17). Should the measured current be higher, exactly the opposite will happen.

On the inverter side, if the measured current is lower than the set current, the internal voltage must be decreased to result in a current rise. The voltage difference in equation (2.17) is again increased to raise the current.

Constant Extinction Angle control

Constant extinction angle control is used as an inverter control method as explained earlier. Using this method implies that the valve must be fired at such a time that an adequate time margin still exist for commutation to complete before the commutation voltage reverses. The voltage across the outgoing valve must also be negative for at least the time necessary to ensure complete de-ionisation of the arc path. The formula for the ignition time is explained by Kimbark [16]. A real-time analog computer is used to solve the ignition time necessary.

Tap changer control

The tap changer on the rectifier side is controlled in such a way that if α becomes less than 10° , it raises the direct voltage and lowers the voltage should α rise to more than 20° . The reason for this is found in a compromise between a high power factor and a large margin for quick increases of the rectifier voltage. At small values of α the power factor is high and secondly a margin for rapid increase of the rectifier voltage requires a large value of α .

The inverter tap changer is usually controlled in such a way that the voltage at the sending end is close to its rated value. It is however possible that the voltage is too low on a certain tap step and too high on the adjacent step. This will cause the control to oscillate the tap changer between these two steps resulting in unnecessary wear of the tap changer. To avoid this from happening, a dead band should be implemented depending on the step size of the transformer.

Power control

In many cases the DC line is required to deliver a predetermined value of power. The current control can meet these requirements if the direct voltage remains constant. More accurate power control can be implemented by letting the current compensate for the changes in voltage caused by changes in the line resistance, variation in the alternating voltage beyond the tap changer capability or even outages of valves.

The power control can be implemented by simply measuring the power, comparing it with the set demand and use the difference to alter the ignition of the valves. An improved method to measure the direct voltage and calculate the direct current needed is by the use of the set power demand:

$$I_d = \frac{P}{V_d} \quad (2.20)$$

This current command can now be used as an additional input signal to the current control supplementing it rather than overriding it, as was previously the case. The voltage at both ends will differ because of losses over the line and compensation is needed to ensure the same current command at both ends.

Current limits

The current can only operate in a certain safe operating area. It is therefore necessary to put several current limits on the current control system. A maximum current limit ensures that thermal damage due to overcurrent operation is avoided at all times. The minimum current limit of about 0.1 of the rated current is also necessary to avoid the possibility of arcbreak (only Mercury-Arc Valves) and discontinuous current.

The third not-so-obvious limit is the Voltage-Dependant Current limit. As shown in Figure 2-15, the same power can be delivered (at points A and B or C and D) by using either a high voltage and a low current or a low voltage together with a high current. Operating at low voltages and high currents not only leads to higher losses and a poor power factor, but also voltage instability. To avoid operation at these points a limit is presented as a straight line OE in Figure 2-15. The slope of the line must exceed the absolute value of the constant α lines.

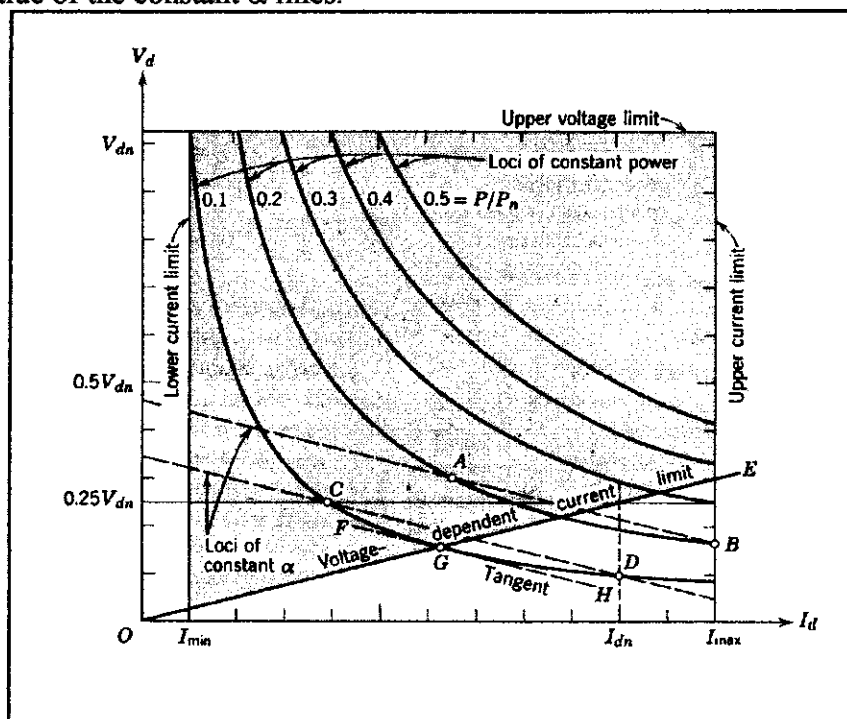


Figure 2-15 – Current and Voltage limits [16]

Frequency control

The frequency of an AC system is controlled by controlling the prime movers of the generators. If the frequency is too low the output of the generator is increased to increase its speed and also the frequency. Exactly the inverse happens when the frequency is too high.

When the power rating of the DC line is comparable or greater than that of the generators in the AC system it is connected to, the inverter or rectifier should share in the frequency regulation. This is done by the use of a frequency discriminator circuit, which determines the deviation of the frequency from its nominal value. This error is then used to increase or decrease the fire angles of the valves. On the inverter side a low frequency will advance the fire angle to increase the delivered power. A low frequency on the rectifier side must however delay the fire angle even more in order to decrease its sent power.

2.4 HVDC topology

A HVDC converter basically consists of a DC transmission line connecting two AC systems. One of the converters converts AC power into DC power while the other one reconverts the DC power into AC power. The one converter therefore acts like a rectifier and the other as an inverter.

Because of the high power levels associated with HVDC converters, it is important to limit the generation of harmonics. Figure 2-16 shows a six-pulse converter configuration. This converter configuration results in harmonics of the order $h = 6k \pm 1$, where k is an integer.

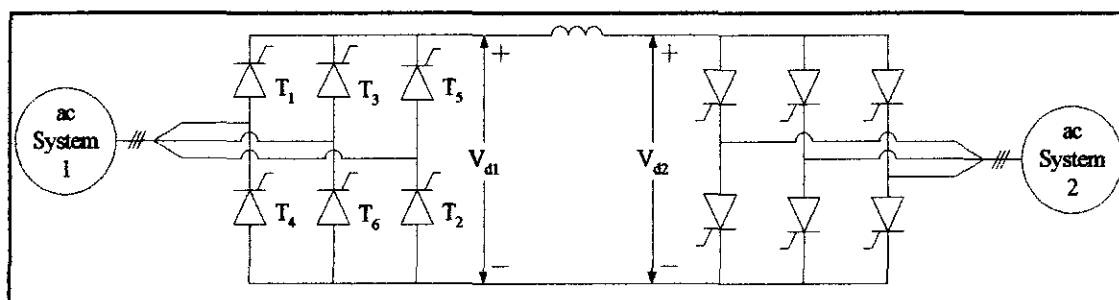


Figure 2-16 – Basic six-pulse HVDC configuration

In order to reduce harmonics, a 12-pulse converter can be used. These converters create harmonics of the order $h = 12k \pm 1$. A 12-pulse converter, as can be seen in Figure 2-17, however needs two transformers, the one connected as a Y-Y and the other as a Δ -Y. This creates a 12-pulse rectified voltage with less ripple and higher order harmonics. Less filtering and smaller smoothing reactors are therefore needed.

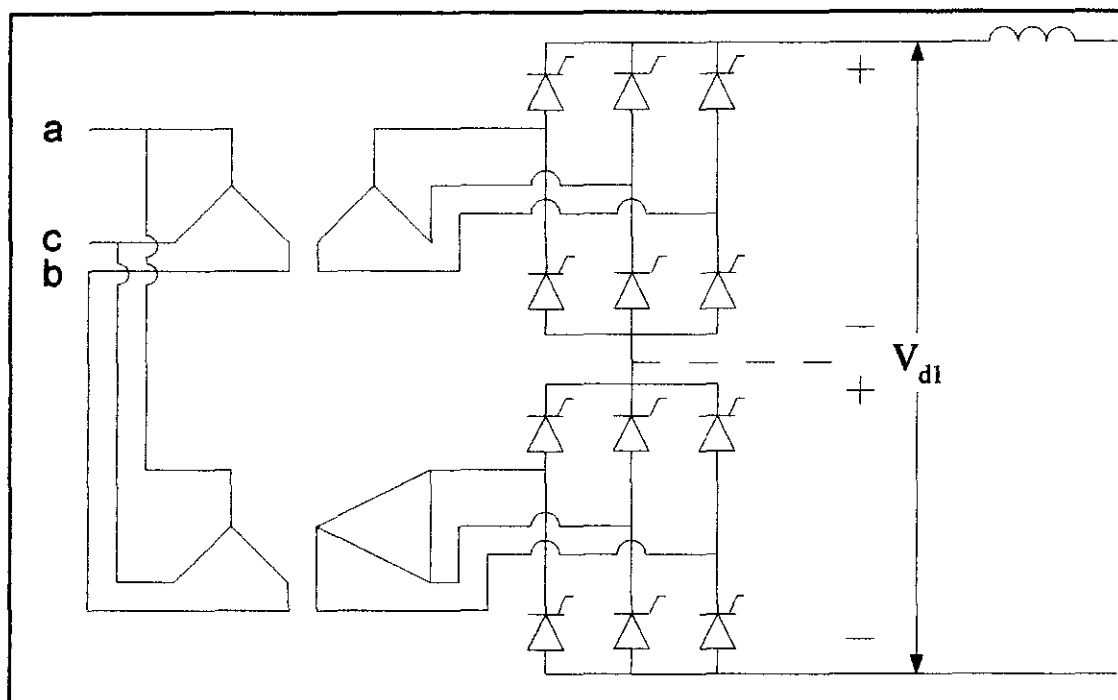


Figure 2-17 – Twelve-pulse converter configuration

The DC link connection between the two converter stations can be configured in three different ways. These connections are classified as monopolar, bipolar and homopolar links.

Monopolar links consists of a single conductor, using the ground as a return path. Because DC in the ground is much more corrosive than ac, proper grounding is necessary. The ground electrode is therefore situated several kilometres from the converter stations to ensure no local problems occur. Special grounding techniques are used to ensure minimum electrode resistance. The heat generated by the ground current may dry out the ground surrounding the electrode and is therefore generally situated near water.

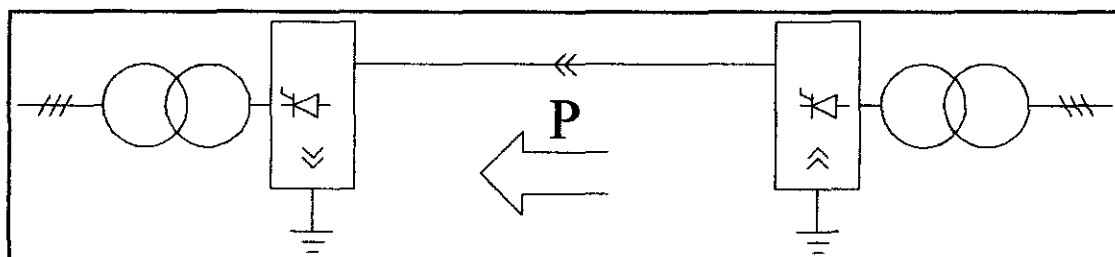


Figure 2-18 – Monopolar link

Most the HVDC converters are connected with bipolar links. This can be seen in Figure 2-19. The one line is normally positive and the other negative with a common ground at one or both ends. If both ends are grounded, the one line can still be used at half the normal power when the other one is interrupted. This increases the availability

of the system. The current in both lines are controlled to be equal, resulting only a small ground current under normal conditions. The corrosion of underground pipes and structures are therefore minimized.

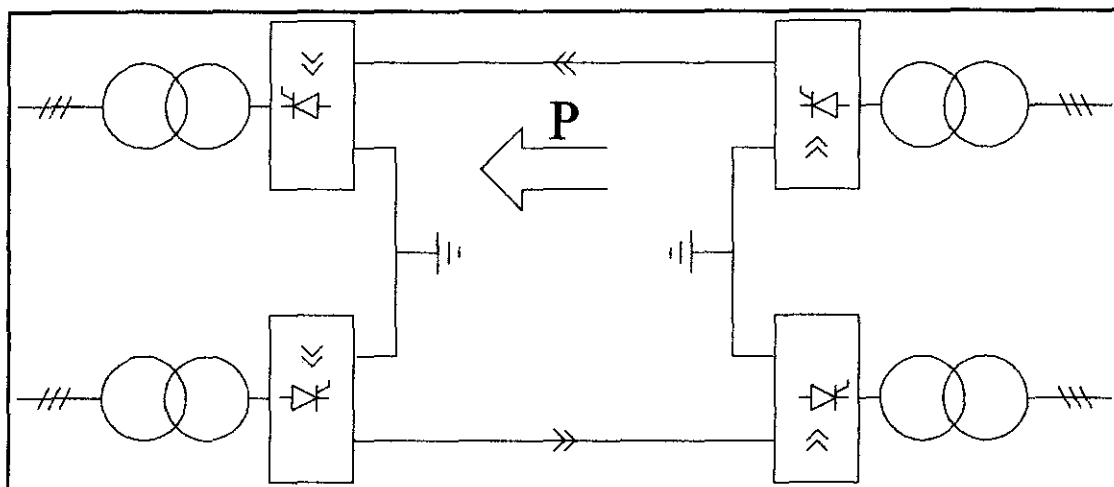


Figure 2-19 – Bipolar link

Homopolar links also uses two conductors, but with the same polarity. These links therefore also uses a ground return path. The link is illustrated in Figure 2-20.

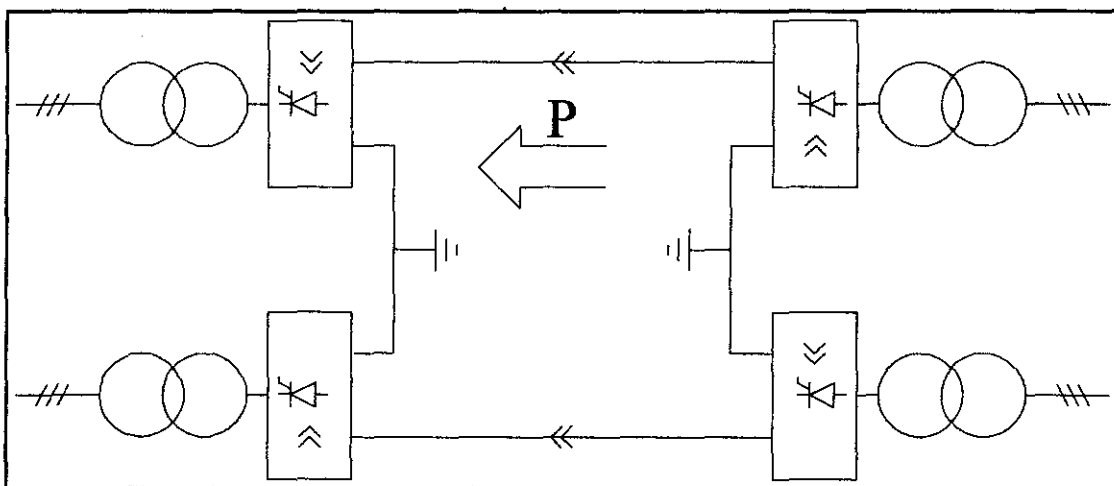


Figure 2-20 – Homopolar link

2.5 AC and DC transmission comparison

Alternating current is electric current that repeatedly changes polarity, causing current to flow in one direction for a moment and in the other direction the next moment. In power systems alternating current alternates in the form of a sine wave. Power systems usually use 50 Hz or 60 Hz sine waves implying that the current changes direction 50 or 60 times per second.

Nikola Tesla developed alternating current in 1882. Even though Thomas Edison already did direct current transmission, AC quickly gained ground due to the advantages mainly gained by the use of transformers.

Direct current however is the continuous flow of electricity in one direction, the high potential to the low potential. Direct current was originally used for electric power distribution after discovery by Thomas Edison, but quickly lost ground after the discovery of AC and its advantages at that stage. DC is however is gaining back some ground because of the developments in power electronics allowing HVDC and MVDC.

2.5.1 Advantages of DC transmission

Higher Power capability

The power transmission capabilities of DC links differ quite significant from that of AC transmission. One constrain of power transmission is the insulation level. The isolation determines the maximum peak voltage the transmission line can handle before spark over will occur. For the same isolation level the DC voltage V_{dc} is equal to the peak of the AC voltage V_{ac} [12].

$$V_{dc} = \sqrt{2}V_{ac} \quad (2.21)$$

If the skin effect of AC transmission is neglected, the same current can be transmitted with the same conductor size.

$$I_{dc} = I_{ac} \quad (2.22)$$

If two conductors are used for both applications, the power transmission capabilities can be written as:

$$\begin{aligned} P_{dc} &= V_{dc}I_{dc} \\ P_{ac} &= V_{ac}I_{ac} \cos \theta \end{aligned} \quad (2.23)$$

where $\cos \theta$ represents the power factor. The ratio of the two powers is now given to enlighten the greater DC power capability.

$$\begin{aligned}\frac{P_{dc}}{P_{ac}} &= \frac{\sqrt{2}}{\cos \theta} = 1.414 \quad \text{at unity power factor} \\ &= 1.768 \quad \text{at power factor of } 0.8\end{aligned}\quad (2.24)$$

AC power is normally transmitted using either single circuit or double circuit three phase lines. For single circuit applications the above ratio must be multiplied with $\frac{2}{3}$, and $\frac{4}{3}$ for the double circuit [16].

Another important aspect of power transmission is the efficiency. The efficiency of power transmission is determined by the amount of electrical power loss. This loss is dependant on the resistance of the line, which is dependent on the conductor cross-section area and electrical properties.

To be able to make a comparison we want to transmit a certain amount of power at a specific isolation level and at a particular efficiency. With these criteria we can determine the cross-sectional area ratio. Let the resistance of the conductors be R_{ac} and R_{dc} respectively. The current can be written as:

$$I_{dc} = \frac{P}{V_{dc}} \quad (2.25)$$

$$I_{ac} = \frac{P}{(V_{dc} / \sqrt{2}) \cos \theta} \quad (2.26)$$

For the same power loss follow:

$$\begin{aligned}P_L &= P_{dc} = P_{ac} \\ &= \left(\frac{P}{V_{dc}} \right)^2 R_{dc} = \left(\frac{\sqrt{2}P}{V_{dc} \cos \theta} \right)^2 R_{ac} \\ &= \left(\frac{P}{V_{dc}} \right)^2 \frac{\rho l}{A_{dc}} = \left(\frac{\sqrt{2}P}{V_{dc} \cos \theta} \right)^2 \frac{\rho l}{A_{ac}}\end{aligned}\quad (2.27)$$

The ratio area is:

$$\begin{aligned}\frac{A_{dc}}{A_{ac}} &= \frac{\cos^2 \theta}{2} = 0.5 \text{ at unity power factor} \\ &= 0.32 \text{ at a power factor of } 0.8\end{aligned}\quad (2.28)$$

This result shows that for the same power loss, and the AC system operating at unity power factor, half the amount of copper is needed for the same DC transmission line. Should the power factor of the AC system be reduced to 0.8, only a third of copper is needed.

Possible use of ground return

HVDC also allows the use of a ground return, which results in a monopolar DC link. The bipolar DC link is also more reliable than the corresponding AC system, because in case of a fault on the one conductor, the ground return may be used together with the other conductor at a reduced power level. For the same length transmission line, DC has a much lower ground resistance because, DC spreads over a much larger width and depth [12].

A ground return may however interfere with the navigation of ships using compasses. Dangerous step and touch potentials could also be created.

Smaller tower

Because a DC line has a higher power capability, DC lines will need a lower insulation level for the same power capabilities. DC transmission also uses only two conductors instead of the three or six for AC transmission. Both these characteristics suggest that DC transmission may use smaller towers.

Higher cable/overhead line capacity

AC cables needs a continuous charging current of about 6 A/km at 132 kV. This limits the maximum length of AC cable to about 80 km without series compensation. The absence of a charging current in DC transmission allows a higher active power transfer without any compensation and no length limitation.

Low fault current contribution

When an AC system is extended the fault level of the whole system is increased. This may cause the replacement of expensive circuit breakers and the redesign of the protection system. HVDC converters only contribute to the fault current up to its maximum current. HVDC is often used in parallel with AC systems in order to limit the fault current on expansion.

Skin effect

A time varying current generates a varying magnetic field, which induces a current (eddy currents) in the conductor. This current flows in the opposite direction and intends to shield the inside of the conductor from the applied current. As a result the current density is larger at the surface of the conductor. No skin effect is present in DC transmission and therefore the conductor metal cross sectional area is better utilized.

Less corona

When the electric field strength at the surface of a conductor exceeds the breakdown strength, current discharge occurs. This phenomenon is called corona and causes additional losses, communication interference, and audible noise interfering with nearby radio receivers and TV sets.

The forming of corona increases with frequency. For a specific conductor diameter and applied voltage much less corona will form with DC. The corona loss is therefore less and hence less interference. Bundling of conductors is commonly used in AC systems to reduce corona and as a bonus reduces the line inductance. Bundling in DC lines is however unnecessary and implies a substantial saving in line costs.

Improved stability

Stability of an AC system is its capability to operate with all synchronous machines in synchronism. With AC transmission, the sending and receiving end will have a phase difference, because of the inductance of the line. The difference should not exceed 30° at full load for transient stability [12]. This puts a limit on the maximum length of the line.

DC links is an asynchronous link and therefore the AC supply does not have to be synchronized with the link. The DC link in itself cannot have any stability problems even when connecting AC grids with different nominal frequencies. As a result of this the stability of the system is not dependant on the length of the DC line. The interruption of the DC line is seen as a loss of large load at the sending end and as loss of generation at the receiving end. The AC systems are however designed to be stable under these conditions of mild shock.

If however a single DC line must operate in parallel with one or more AC lines of comparable size, the interruption of the DC line may cause the loss of synchronism between the two AC systems. The use of a single DC line in parallel with AC lines is therefore not advisable. If two DC lines are used in parallel with the AC line and the one DC line can take over the load of the other one due to the loss of that line, stability won't be a problem. Bipolar line can also be seen as two separate lines.

Asynchronous interconnection

AC systems using different frequencies cannot be connected, because they can't be synchronized. Such systems can easily be connected via a HVDC converter. When AC systems of different frequencies need to be connected, HVDC is considered as the most economical solution.

Different power suppliers can even maintain different tolerances on their power systems. Energy can therefore easily be sold to other countries operating at 50 Hz or 60 Hz via a HVDC system. When HVDC is used as tie lines the power can be controlled very easily, unlike their AC counterparts. Even the reversal of power flow is trivial.

2.5.2 Problems with HVDC

Reactive power consumption

HVDC converters require large amounts of reactive power in both the rectifier and inverter modes. The reactive power consumption may be as much as 50% of the active power flowing in the DC line. This reactive power is supplied by adding large capacitors, which increase the overall system cost. The AC filters supply quite a lot of

the necessary reactive power. The calculation and optimal control in order to minimize reactive power consumption is discussed in section 2.3.4.

Costly converters

AC connections require only a transformer on both sides of the transmission line. HVDC need a converter station at each end of the DC line. These converters are much more expensive than the transformers. The cost distribution of a typical converter station can be seen in Figure 2-21. The DC lines is however less expensive and at a certain break-even-distance HVDC will always be the more economical solution. The economical comparison of AC and DC systems are however influenced by various factors and is discussed in more detail in section 2.5.3.

Harmonic generation

HVDC converters are a large source of harmonics. These harmonics are generated on both the AC and DC side. On the AC-side filters are used where smoothing reactors are used on the DC bus. These filters and reactors are expensive.

Circuit breaking

In DC circuits, the current is continuous without any zero crossings. Because the interrupting of the current cannot occur with a corresponding zero crossing as in AC systems, circuit breaking is very difficult.

Currently clearing of faults are done by making all the converters act as inverters to de-energize the line. Switching out the faulted line can now isolate the fault. This is done without any special HV DC breaker, because the line was de-energized first. The time needed to clear the fault and re-energize the line again is comparable to that of an AC line.

The problem arises when a complex DC network starts evolving. All the DC lines can't be de-energized until the fault is cleared. A circuit breaker capable of breaking fault currents and at a high voltage is therefore needed. At least the fault current won't be larger than the rated current, because it is limited by the converter control.

Low overload capacity

AC transmission lines can be overloaded for long periods because of the high overload capability of transformers. HVDC converters however have very little overload capacity. This is done in order to protect the equipment, especially the valves. If the overload current is allowed the possibility for the control system to lose control of the valves increases and can be disastrous. The voltage and current limits for the control system is shown in Figure 2-15. This control allows for no overload capacity. The advantage of control implies that the HVDC system cannot contribute to fault currents beyond that of the rated current.

2.5.3 Economic comparison

Cost structure

The exact cost of a HVDC system depends on various factors. The power capacity to be transmitted, type of transmission (line/cable), right-of-way, environment, safety and local power regulations are some of the most important variables. According to Rudervall et al [11] the typical cost structure for converter stations is:

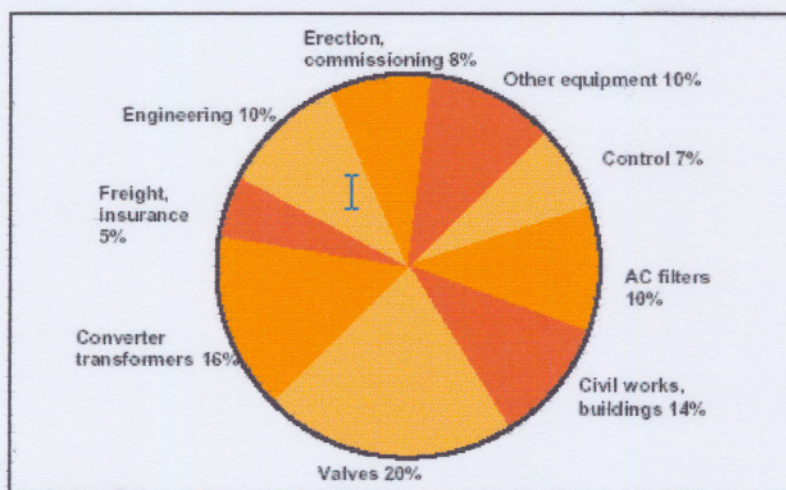


Figure 2-21 – Typical cost structure of a HVDC converter station [11]

Break-even distance

HVDC systems have a very high investment cost due to the two converter stations compared to the AC substations where transformers are the main expenditure. This makes the DC converter stations two to three times more expensive than the two AC transformer stations.

Over short distances, AC transmission is always the less expensive option and back-to-back converters are only used when other advantages are overwhelming. Connecting asynchronous networks is a good example.

The transmission medium however is less expensive because of lower right-of-way cost, lesser number of conductors and smaller tower size. This implies that a certain distance exists from where HVDC will be the most economical solution based purely on cost. Although the initial losses of a HVDC system are also higher over short distances (losses in the converter), the line losses do not increase as much over distance as for an AC system.

Figure 2-22 gives a graphical representation of the break-even point. The dotted green line represents the HVDC transmission system cost increasing as the distance increases. The DC line costs start high, because of the converter cost. The dotted purple line represents the AC transmission cost. The line starts fairly low because the AC transformer stations are much cheaper than the converter stations. The gradient of this line is much steeper since the higher transmission line cost. The break-even point is the point where these two lines cross. After this point HVDC is always the cheaper solution.

The two solid lines can be interpreted in exactly the same way. It is worth noting that the break-even distance is even shorter in this case.

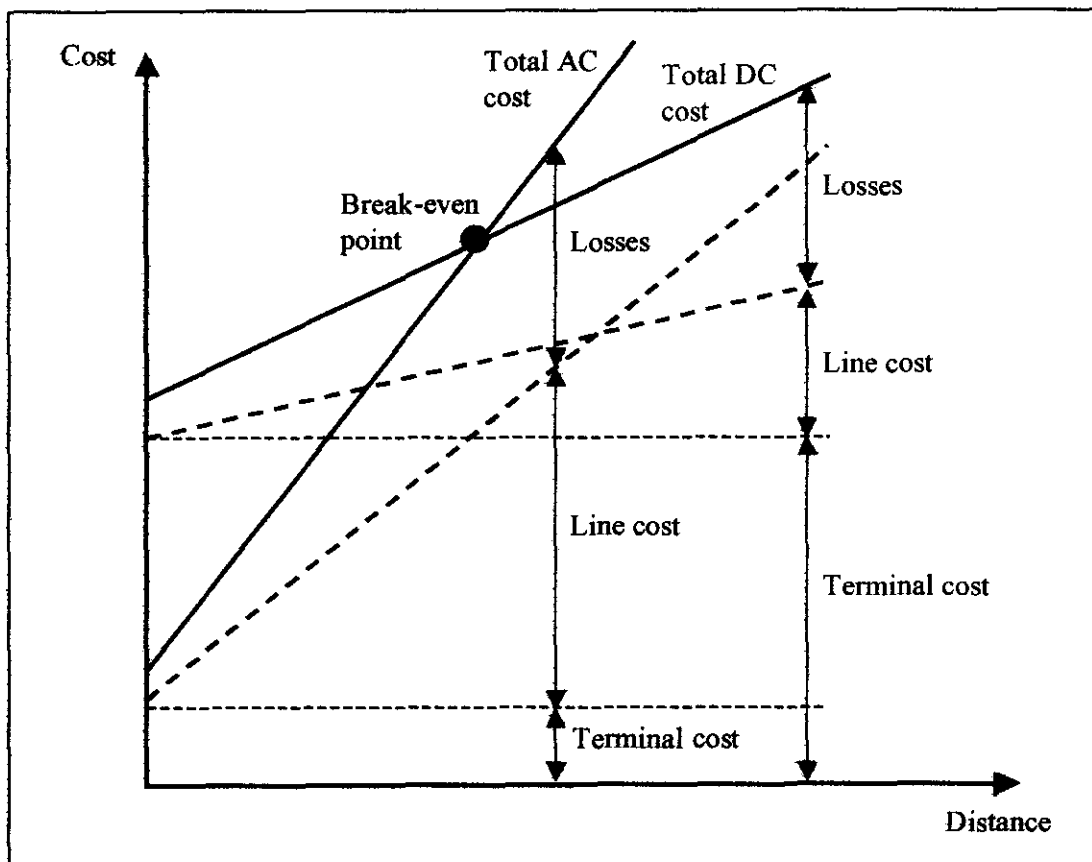


Figure 2-22 – AC and DC transmission break-even point [11]

The break-even distance for overhead lines is approximately 500 km depending on the factors mentioned earlier. This distance is much shorter when cables are used. For underground cables the distance is about 50 km and only about 25 km for submarine cables.

There are other decisive factors that can't be expressed in purely financial or economic values. Back-to-Back converters are therefore used in quite a few HVDC converter systems. The reason is mainly because HVDC is seen as the "better" solution as is the case in many asynchronous links, tie-line power control systems or environmental sensitive projects.

2.6 HVDC for PBMR

HVDC is a technology worth noting of when considering high power transmission systems. The technology is however not ideal for use in cooperation with the PBMR, because of a few reasons. In the first instance the PBMR is in need of a back-to-back converter and the long distance advantage of HVDC is therefore omitted. The required filtering equipment and reactive power compensators make the footprint of the overall

system to large. The technology is also fairly expensive for a relative small planned PBMR plant of 180 MW.

2.7 Conclusion

HVDC is a well-developed and proven technology. Over the past 20 years HVDC transmission technology has shown a tremendous growth. The electric power industry was previously only government owned, but in recent years more and more electrical power industries are privatised. HVDC transmission will therefore keep evolving to supply in the need of these private companies. In this deregulated market where electric power is traded between various companies, HVDC will play an important role in terms of stability, different power regulations of countries and the control of tie power flow.

In addition to the deregulation of the electric power industry, HVDC transmission is in some cases the obvious choice over AC transmission. For very long transmission links, beyond the break-even distance, HVDC transmission is the more economical choice. The connection of asynchronous links, for example a 50 Hz and 60 Hz systems, HVDC is the only solution. HVDC transmission has a lower transmission loss, because only active power is transferred. Over a distance of 500 km to 1000 km the losses of the HVDC system will be about 20% less than for an equivalent AC system [17].

There are also some other benefits that influence the choice in favour of HVDC over AC transmission. HVDC has a lower environmental impact, low fault current contribution, higher system controllability, improved stability, no skin effect and charging current.

Chapter 3

Medium Voltage Direct Current (MVDC) converters

MVDC converters are also used to convert direct current into alternating current and vice-versa. MVDC converters however utilize IGBTs as switching elements instead of thyristors used by HVDC converters. The main difference is that IGBTs are fully controllable and can therefore be turned on and off. Switching is also much faster, allowing the use of Pulse Width Modulation (PWM) as conversion technique. The implications of this will be discussed in more detail in this chapter.

As an introduction the development history and the current applications of MVDC converters is discussed. The advantages of MVDC converters are then described in some detail followed by an explanation of the conversion process, which implies the use of PWM.

3.1 MVDC development history

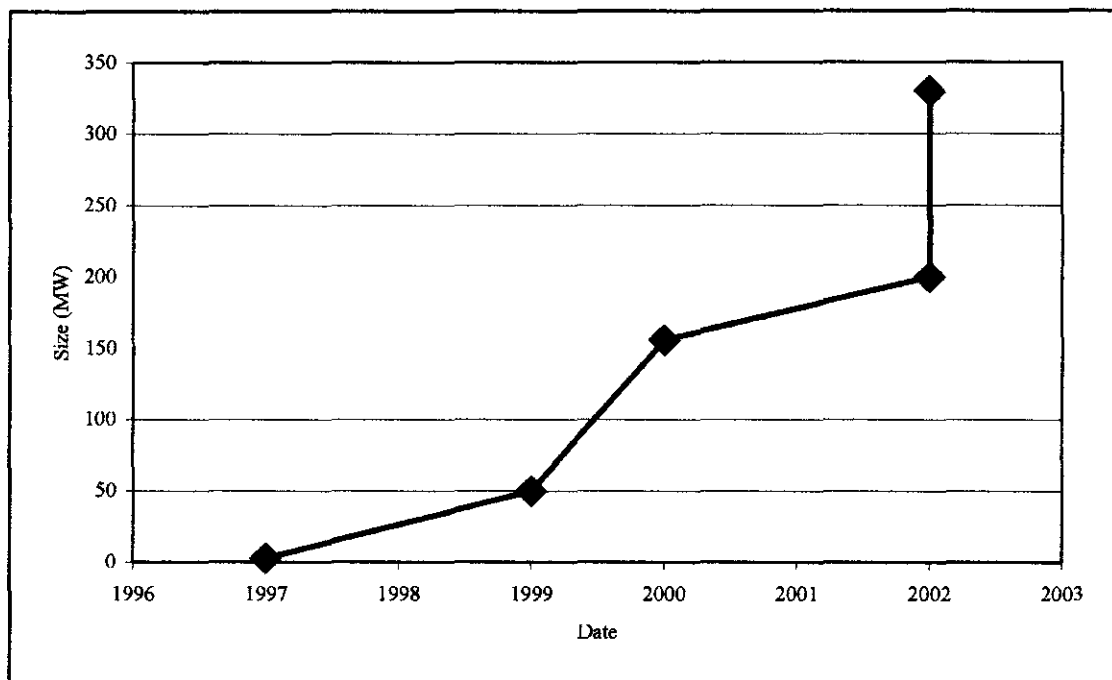
The use of power electronics in transmission and distribution of electricity dates back to 1954 when the first HVDC cable transmission system was built. Mercury arc valves were used as switching elements and it was only in 1970 that the first thyristor based HVDC transmission system was built. Both Mercury arc and thyristor valves are line commutated, which implies that they can only be turned off by the line current passing through zero.

Gate controlled turn off was only introduced in the late 1970's by means of Gate Turn-off Thyristors (GTOs). This made it possible to control the output frequency and was therefore used for variable motor drives. GTOs were however not used in transmission systems, because of higher losses and complicated units for supplying the high gate current needed. Snubber circuits were also necessary for protection of each individual device.

The search for a device with microelectronic characteristics, like MOSFETs, with a high power capability led to the development of Insulated Gate Bipolar Transistors (IGBTs). Much progress was made in the early 1980's in the lower voltage range

between 600 and 1200 V, but it was only realized in the early 1990's that IGBTs could be developed for the higher voltage ranges.

Due to these developments the world's first commercial MVDC (Called HVDC light by ABB) was commissioned in 1999. The two converter stations are rated at 50 MW with a DC voltage of ± 80 kV and are linked with two 70 km cables. Graph 3.1 shows development in size of MVDC converters. The system built in 1997 was a test transmission system and was rated at 3 MW and a DC voltage of ± 10 kV. Within 5 years MVDC evolved from that 3 MW system to a 330 MW, ± 150 kV system built as submarine connection between New Haven, Connecticut and Shoreham on Long Island in the USA.



Graph 3.1– MVDC's development in size

The steep upward curve is a clear indication of the giant steps made in MVDC technology. The curve is also far from stabilizing and this growth can still be expected over the next few years.

3.2 Typical MVDC applications

MVDC is currently used in various types of applications. MVDC is mainly used in connecting asynchronous networks, long distance transmissions, where the constraints of right-of-way is a problem, city centre power infeeds, offshore oil platforms, wind farms (both onshore and offshore), railway power supply and at arc furnaces for flicker

mitigation. Unlike HVDC, MVDC is also used in connecting generated power to weak systems, because MVDC is not dependent on the system for commutation.

When two power systems of different frequencies (asynchronous networks) need to be connected, HVDC or MVDC is the only solution. The choice between the two can be made considering the advantages of MVDC discussed in section 3.3. Normally HVDC will be used in very large connections above 250 MW and MVDC for smaller connections up to 250 MW.

When the two power systems are far from each other, MVDC or HVDC is also worth examining even if the two networks are of the same frequency. Over long distances the transmission losses in AC systems are higher than in DC transmission systems. AC systems can also become unstable due to voltage swing over a long distance. DC transmission lines and constructions are also cheaper and take up less space. All these reasons contribute to the use of HVDC and MVDC over long distances. The reasons for these advantages and the break-even distance were already discussed in sections 2.5.1 and 2.5.3 respectively.

The break-even distance is also influenced by the right-of-way costs, which can contribute significantly to the total cost of a transmission system especially in environmentally sensitive areas. HVDC and MVDC towers are smaller, requiring a smaller servitude and saving right-of-way costs. DC cable transmission is used if necessary. In some cases the DC cable is buried underneath an existing AC line and therefore requiring no additional right-of-way costs. More active power can also be transmitted in the same conductor size using DC instead of AC as discussed in section 2.5.1. It would therefore be possible to convert an existing AC line to a DC line with a higher power capability without additional construction or right-of-way cost, by using HVDC or MVDC transmission.

Right-of-way costs are high and difficult to obtain in developed, dense populated areas. MVDC can therefore be used as city centre power infeed mainly because the footprint is much smaller than HVDC and the converter station can fit into a building looking much more “natural” in the city than a traditional AC substation. Various MVDC converters can also be connected in parallel distributing power more evenly across the city.

Offshore oil platforms need electrical power and generating it locally takes up valuable space on the platform. Cables are the only way of transferring electricity from land underneath the sea to the platform. The platforms are situated quite far from the coast and as described in section 2.5.3, the break-even distance for DC submarine cable can be as short as 25 km. MVDC is preferred, because it takes up less space than HVDC. In some cases an oil platform can generate power that can be distributed to other surrounding oil platforms or even to land using parallel MVDC converters.

Offshore windfarms also need to be connected to land with cables, but have the additional problem of complying with the strict power quality regulations of various power utilities. Thyristor converters generated unacceptable levels of harmonic distortion and large filters were needed to filter out the harmonics. MVDC converters using PWM only generate high order harmonic distortion that can be filtered out easily. When induction generators are used at the windfarms, they require large amounts of reactive power from the grid increasing line losses and making voltage control difficult. MVDC converters can however control the power factor at any angle. Frequency control can also be a problem especially when the windfarm is connected to a weak power system. Changes in wind speed or a sudden load change can cause the windfarm to trip because it cannot maintain the desired frequency. MVDC converters can however maintain the desired output frequency, even in islanded grids. The use of MVDC converters also allows the use of variable speed generation. This means that the generator does not have to run at a constant speed (synchronous speed), and the rotational speed can therefore be altered to optimise generation at various wind speeds. Figure 3-1 illustrates the gain in energy production against wind speed on an annual basis.

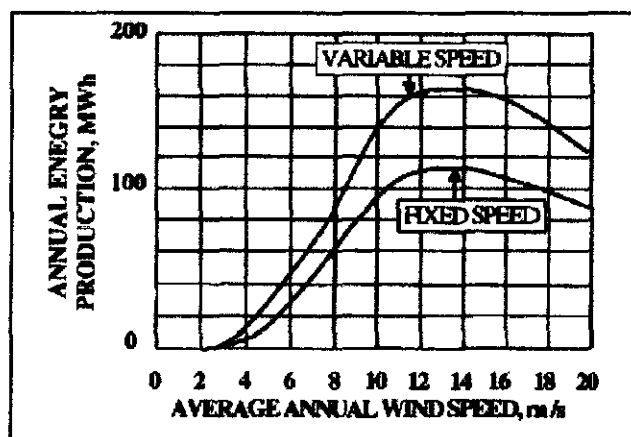


Figure 3-1 – Fixed speed vs. Variable speed generation systems [19]

Unlike windfarms where the generation is variable, at arc furnaces the load is very variable. Especially during the initial stage of scrap metal melting, short circuits regularly occur between the electrodes resulting in high reactive power bursts causing voltage drops in the transmission system. This low frequency voltage drops results in visible fluctuations in the light intensity from lamps even at other customers connected at the same point of supply. This low frequency disturbance is called flicker and its level is given as a value called P_{ST} . Measurements have shown that the P_{ST} level can be reduced by a factor of between 4 and 5 using a VSC (Voltage Source Converter), like MVDC converters, instead of Static var Compensators (SVCs) [20]. This is mainly because MVDC converters have a high switching frequency and reactive power control is faster using (SVCs) that utilizes thyristors. This is why MVDC converters can be implemented at arc furnaces where large changes in reactive power consumption are experienced during the melting process [20].

Due to the historical development of railways, their power supply normally has a lower frequency than that of the national grid or even DC. Cycloconverters are a common way of reducing the grid frequency to that of the railroad supply. These converters can however only supply integer parts of the grid frequency. The output frequency must also be at least one third or less than the grid frequency to ensure acceptable harmonic distortion levels. Other drawbacks are the high number of thyristors used in such converters and the complex control systems. MVDC converters are now used more often in railway applications especially because energy recovery during braking is easy and more effective.

Table 3-1– Some MVDC projects already commissioned

Year commissioned	Project	Size of instalment	Type of application	Description
2002	Murraylink-Australia	200 MW ± 150 kV	Underground link (177 km)	This is the longest extruded cable system using 150 kV. The system allows power trade between Victoria and South Australia with a low environmental impact.
2002	Cross Sound Cable - US	330 MW ± 150 kV	Submarine link (40 km)	It is the largest HVDC light transmission installation providing the much needed power to Long Island. The system reliability is also improved and promotes competition in the energy market.
2000	Eagle Pass - Texas and Mexico	36 MW ± 15.9 kV	Back-to-Back	The project allows the exchange of power between Mexico and the USA. It also serves as voltage support at both ends.
2000	Tjaereborg - Denmark	7.2 MW ± 9 kV	Submarine link (4.3 km)	The system was built to evaluate HVDC light as new technology for transmitting power from offshore wind farms.
2000	Directlink – Australia	180 MW ± 80 kV	59 km cable	The Directlink HVDC Light project links the regional electricity markets of New South Wales and Queensland to allow energy trade between the two for the first time.
1999	Gotland – Sweden	50 MW ± 80 kV	70 km cable	Gotland was the world's first commercial HVDC light transmission system. The reasons for using HVDC light are wind power voltage support and constrains in the right-of-way.
1997	Hällsjön - Sweden	3 MW ± 10 kV	0.2 km cable 10 km line	This was the world's first HVDC light test transmission system.

3.3 Advantages of MVDC

MVDC converters are voltage source converters (VSC) utilizing the latest in power semiconductor and control technology. IGBTs are the semiconductors used for fast switching at medium power levels and therefore the converters can be called Medium Voltage Direct Current (MVDC) converters. Siemens refers to their MVDC converters as HVDC PLUS converters and ABB is calling it HVDC Light. The use of these modern devices contribute to the following advantages:

3.3.1 Feeding into passive networks

Unlike HVDC, MVDC does not depend on the network for commutation of the valves. This allows MVDC converters to be connected to weak power systems and even passive systems with no generators on the inverter side. This also allows the variable power generated by windfarms to be connected to the national power grid.

3.3.2 Power quality control

MVDC converters have a switching frequency of about 2 kHz, which is 40 times that of conventional HVDC line commutated converters operating at 50 Hz or 60 Hz. This means that MVDC has a faster response time and steep voltage changes attained within 50 ms. Voltage transients and flicker is therefore limited by the fast response from the converter control. This is why MVDC converters are used at arc furnaces for flicker mitigation.

3.3.3 Factory pre-tested compact design

Most of the electrical components are assembled in enclosures and tested at the factory before they are shipped to the yard. The heaviest piece of equipment was a mass of about 20 tons and can therefore be transported by truck to the site [18]. These pre-assembled component enclosures also requires less civil work and reduce the delivery time.

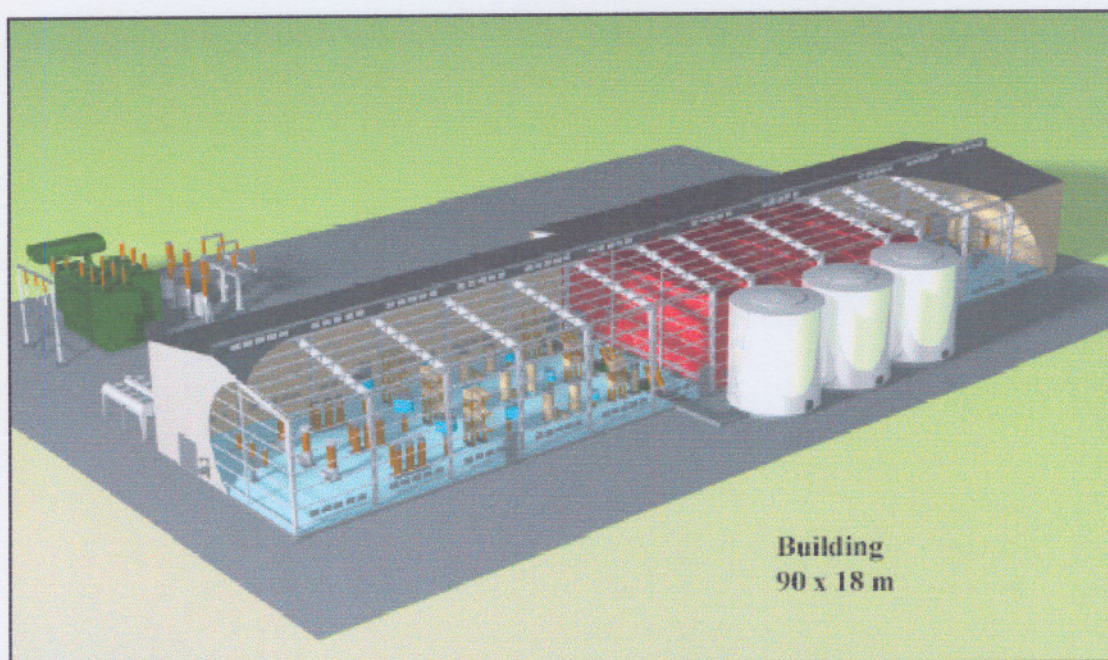


Figure 3-2– 330 MW HVDC LightTM building [18]

One of the key factors for a shorter delivery time is standardization. Many of the modules in different MVDC applications are the same, which shortens design and manufacturing time. According to Weimers [18] the total delivery time for a complete MVDC project is about 12 months. Weimers also predicts that this can be reduced to 6 months in the near future.

MVDC converters take up less space mainly because of the lower filtering requirements. The compact design is especially of high value when the system must be built in expensive urban areas or where space is limited like on oil platforms and offshore windfarms.

3.3.4 Multi-terminal parallel connections is possible

In conventional HVDC power stations operating in unidirectional mode, changing the polarity of the direct voltage reverses the power flow. Using MVDC, power reversal is accomplished by changing the direction of the current flow. This makes it possible for many voltage source converters, like MVDC converters, to be connected in parallel at the DC terminals without any mechanical reversing switches needed for the parallel operation of HVDC converters.

3.3.5 Independent control of active and reactive power

The use of PWM makes it possible for the control to create any phase angle or amplitude almost instantly. This implies that the active and reactive power can be controlled independently. It is important to notice that this is done without any reactive power compensation equipment. AC filtering is however necessary to filter out the high frequency harmonics caused by the fast switching of the IGBTs. The active power transmitted can therefore be kept constant, while the reactive power controller controls the voltage.

3.4 MVDC operation

3.4.1 Insulated Gate Bipolar Transistor (IGBTs)

The development of IGBTs was a major step in the search for the ideal power semiconductor. To verify this statement, one must first determine what characteristics are required from an ideal switching device. These characteristics are:

- A very small or ideally no current flowing through the device when it is in the off state.
- The on-state voltage should be low or zero ideally. This would minimize the on-state losses of the power semiconductor.
- The on-state resistance, which causes the on-state voltage drop, should have a positive temperature coefficient. This not only prevents the device from going into a self-destructing mode where under high current conditions the device heats up and starts conducting even more current, but also allows paralleling because the current will be shared equally.
- The device should be able to handle large continuous currents. This minimizes the need for paralleling several devices to obtain a large current capability. The problem with equal current sharing is also avoided.
- The device must have a very high, ideally infinite, forward- and reverse voltage blocking ability. This will imply that fewer devices in series would be necessary to handle a certain voltage. Each series connected device contributes

to the on-state voltage drop and therefore fewer devices also imply a lower on-state voltage loss.

- The control of the device must require very little power. This leads to a simple control circuit.
- To eliminate the use of snubber circuits, the device must be able to handle both rated current and rated voltage simultaneously.
- Short switching times will permit the device to be used at very high switching frequencies with low switching losses.
- To be able to fully capitalize on short switching times, the device must be able to handle large changes in voltage (dv/dt) and current (di/dt).

In the search for this ideal semiconductor device, researchers have decided to try and combine the characteristics of Bipolar Junction Transistors (BJTs) and MOSFETs. BJTs have very low on-state losses, but have longer switching times especially during turn-off. MOSFETs on the other hand have fast switching times, but their on-state losses are fairly high. This combination led to the development of the IGBT.

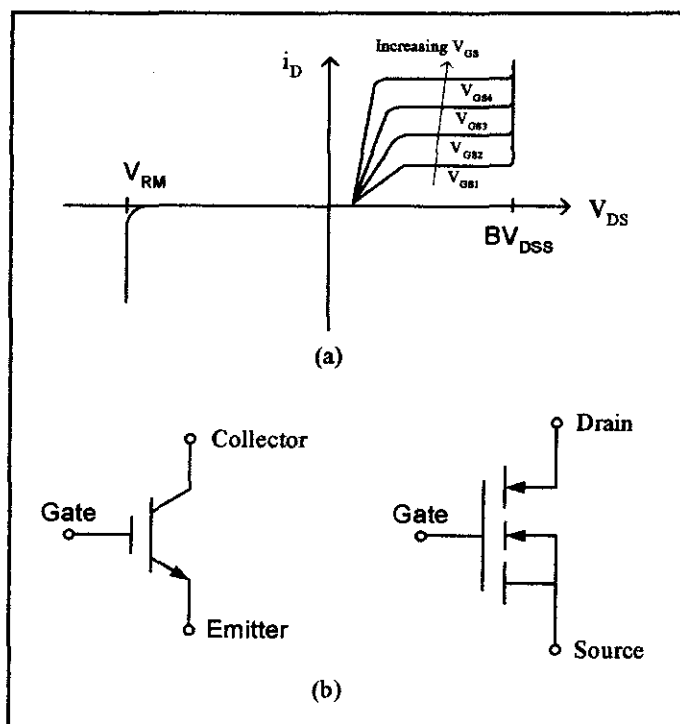


Figure 3-3 – The transfer a characteristic of the IGBT is shown in (a) and the two used symbols in (b)

Figure 3-3 (b) shows the two symbols used for the IGBT. The reason for the existence of the two symbols is led back to the two combined devices used to form the IGBT. Some prefer to consider the IGBT as a BJT with a MOSFET gate and therefore use the modified BJT symbol on the left. The more often used symbol is the one on the right of Figure 3-3 (b). The symbol is basically that of a MOSFET with an additional arrowhead in the drain, indicating the injection contact.

The i-v characteristic of the IGBT is shown in Figure 3-3 (a). For positive V_{DS} the graph is quite similar to that of a BJT. The main difference is that the control signal is an input voltage on the gate (V_{GS}) and not a current as is the case with a BJT. The reverse breakdown voltage is indicated as V_{RM} Figure 3-3 (a).

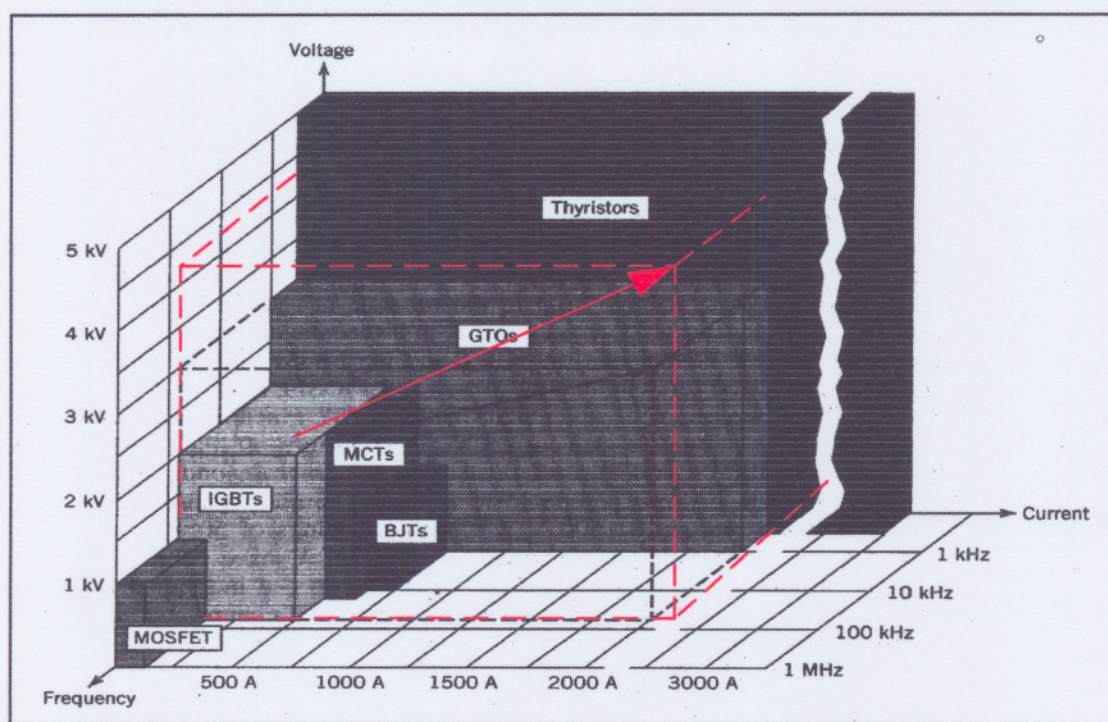


Figure 3-4 – Graphical comparison of power semiconductor device capabilities [15]

In Figure 3-4 the different power semiconductor device power and switching frequency are compared. From this graph the advantages of the IGBT as a switching element can easily be seen. The switching frequency is lower than that of the MOSFET but is higher than that of the BJT. The IGBT can also handle a much higher voltage than both the MOSFET and BJT and the current capability is only slightly

lower than that of the BJT. IGBTs are also still in the development stage and a rapid expansion of its capabilities can be expected.

Mohan et al [15] was printed in 1995 and since then IGBTs have developed rapidly. The dotted red lines indicate the new capabilities of IGBTs (see Figure 3-4). Fuji Electric has developed a 2 kA, 4,5 kV IGBT and Mitsubishi a 900 A, 4,5 kV IGBT in 2000. In 2002 Powerex marketed a 2,4 kA, 1,7 kV IGBT.

The improvement of power capability is not the only improvement in IGBT technology, but also the reduction in losses. Figure 3-5 illustrates the reduction in losses of a 55 kW inverter with respect to the IGBTs generation. The 1st through till the 3rd generation IGBTs used epitaxial wafers while the 4th and “new” generation used floating zone wafers. Each of the wafers was improved and led to a reduction in losses. One important feature that improved quite a lot is the energy lost by switching off the IGBT due to a long current tail during switch-off. This is one of the main drawbacks of IGBTs compared to the fast switching off of MOSTETs.

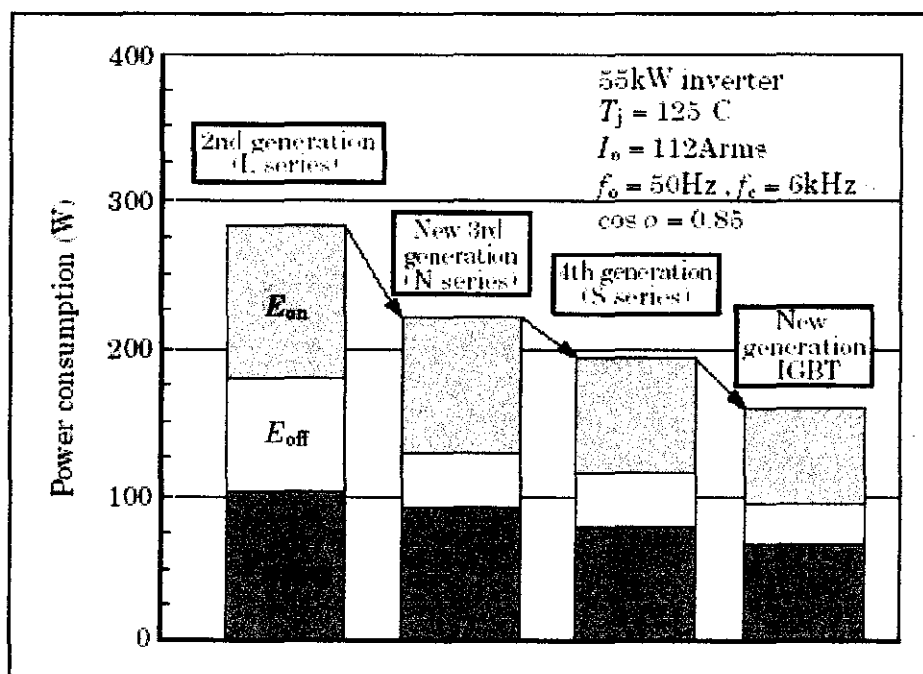


Figure 3-5 – The influence of the IGBTs generation on losses based on a 55 kW inverter [19]

GTOs are also discarded because the pulse width modulation (PWM) requires a high switching frequency. Currently MVDC converters operate at a frequency of 2 kHz.

Other emerging semiconductor devices are IGCTs (Integrated gate-commutated thyristor) and SGCTs (Symmetrical Gate-Commutated Thyristor). The IGCT combines

the high-switching frequency and low switching losses of IGBTs with the high voltage capability and lower on-state losses of GTOs. IGCTs are a much more proven technology than SGCTs, a 100 MVA SGCT based converter was already built in 1996 to supply a 16,67 Hz German railway.

SGCTs are also a modified version of a GTO similar to an IGCT. Powerex introduced SGCTs in 2000 and is therefore a technology still undergoing testing and further developments. Already the devices have advantages like small snubber requirements, fewer semiconductors with a higher switching frequency. SGCT AC drives are used in large AC drives, like motor drives, up to 3 MVA. Comparing the different properties of IGBTs, IGCTs, SGCTs and GTOs in Figure 3-6, SGCTs seems to be one of the devices of the future. The switching frequency compares with that of IGBTs combined with lower conduction- and switching losses.

	MV SGCT	MV GTO	MV IGBT	MV IGCT	LV IGBT
Conduction losses	Low	Low	High	Low	Medium
Switching losses	Low	Low	Medium	Low	Low
Switching frequency	High	Low	High	High	High
PIV Rating (Volts)	6500	6500	3300	6500	1700
Gate Drive	Integral	Separate	Synchronized with IGBT	Integral	Synchronized with IGBT
Failure rate	Low	Low	High	Low	Low
Failure mode	No-rupture, no-arc	No-rupture, no-arc	Rupture, arc	No-rupture, no-arc	Rupture, arc
Cooling	Double sided	Double sided	Single sided	Double sided	Single sided
Thermal stress	Low	Low	High	Low	High
Parts count	Low	Medium	Medium-High	Medium-High	Very High

Figure 3-6 – IGBT, SGCT, GTO and IGCT comparison [34]

3.5 Pulse width modulation (PWM)

Pulse width modulation can be implemented in various ways. This includes PWM for DC voltage or AC voltage control. The AC voltage control is done with various schemes like bipolar voltage switching and unipolar voltage switching. The basic principals of PWM will be discussed using DC voltage control as illustration. The AC voltage control will be discussed in more detail because it is applicable to MVDC converters.

3.5.1 DC voltage control

The purpose of a DC-DC converter is to maintain a constant DC voltage output supplying a load. This constant output must be maintained even when the input voltage

and load is fluctuating. The average output voltage is controlled varying the duty cycle. The duty cycle (D) is the ratio of the on time (t_{on}) to the switching period (T_s) as can be seen in Figure 3-7 and equation (3.1).

$$D = \frac{t_{on}}{T_s} = \frac{V_{control}}{V_s} \quad (3.1)$$

Another control method is to vary both the duty cycle and the switching frequency. This method is however seldom used in DC-DC converters.

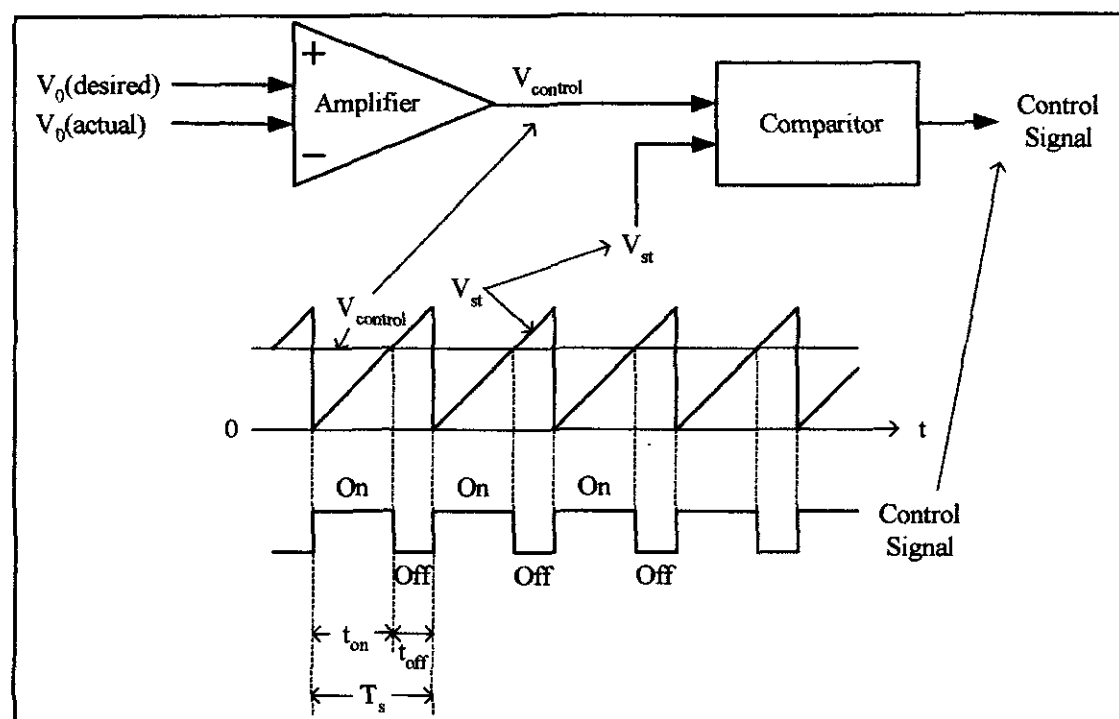


Figure 3-7 – DC control PWM block diagram and waveforms

Figure 3-7 illustrates PWM using a constant switching frequency. The first input is the desired voltage level ($V_{o\text{desired}}$). The second input is the actual output voltage level ($V_{o\text{actual}}$) that is subtracted from the desired voltage and then amplified using an amplifier. This error/control signal is then compared with the sawtooth waveform to result in the signal controlling the switch and therefore determining its duty cycle. The switch will be turned on whenever V_{control} is larger than V_s and is turned off when V_{control} is smaller than V_s . The switching frequency is determined by the frequency of the sawtooth signal set at a constant frequency of between a few kilohertz and few hundred kilohertz.

3.5.2 Sinusoidal PWM control

Switch-mode DC-to-AC inverters are used in AC motor drives, uninterruptible AC power supplies and other applications where a pure, magnitude and frequency controllable sinusoidal AC output is required. Figure 3-8 shows the basic converter configuration of a single-phase inverter. Since inverters normally supply inductive loads like motors the output of the inverter can be expected to look like the waveforms shown in Figure 3-9. The output current will lag the output voltage and this implies that the converter must be able to operate in all four quadrants as indicated on the right hand side of Figure 3-9. During interval 1, both the current and voltage are positive and the converter is therefore operating in the first quadrant. During interval 2, the current is positive while the voltage is negative resulting operation in the second quadrant. At interval 3 both the current and the voltage are negative giving operation in the third quadrant, while during the fourth period only the current is negative, corresponding to operation in the fourth quadrant.

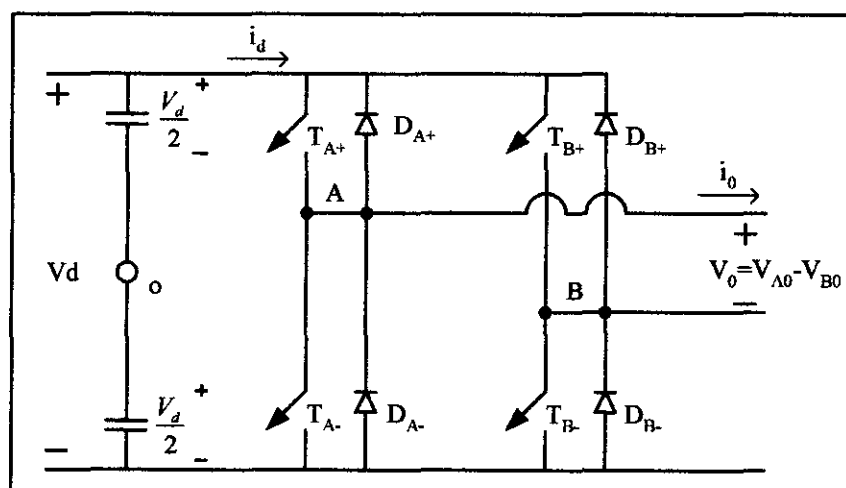


Figure 3-8 – Single phase PWM inverter

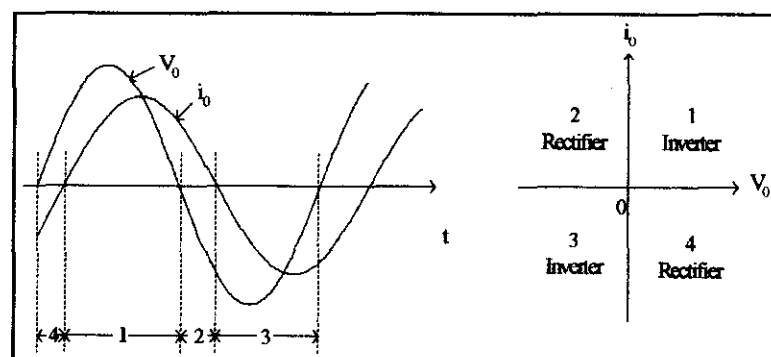


Figure 3-9 – Sinusoidal PWM converter output

Basic PWM switching scheme

During the DC voltage control, the control signal (V_{control}) was constant or changing very slowly compared to the high frequency triangular waveform, which determined the switching speed. The duty cycle determined the output voltage level.

A sinusoidal PWM converter must be capable of generating a sinusoidal output with controllable magnitude and frequency. It would therefore make sense to use a sinusoidal control signal with a frequency equalling that of the desired output. The frequency and magnitude of the triangular waveform is again kept constant and results in a constant switching frequency. The frequency of the triangular waveform is often called the carrier frequency because it determines the switching frequency (f_s).

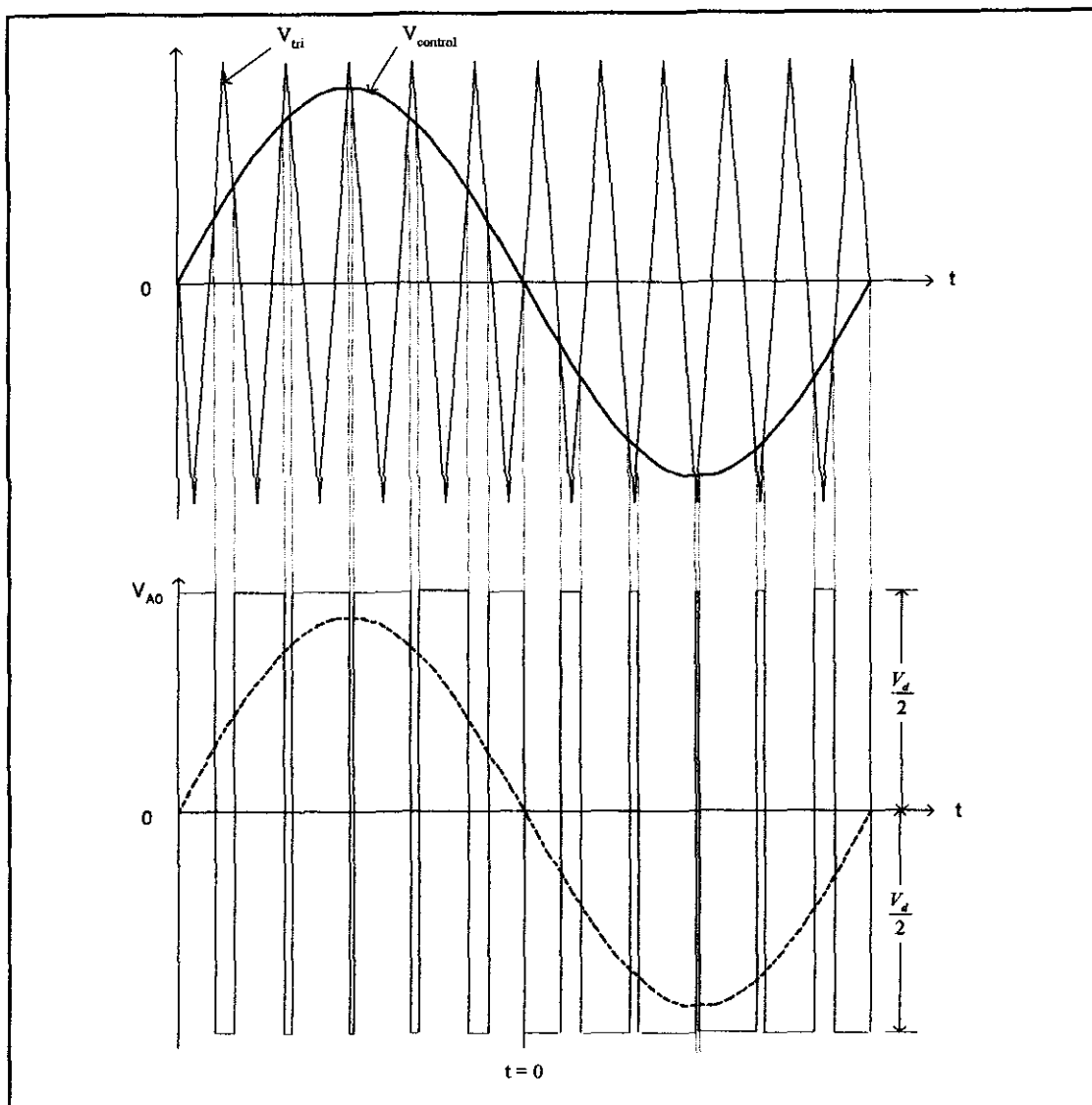


Figure 3-10 – Illustration of PWM generated sinusoidal output

The generation of a sinusoidal output will now be discussed using Figure 3-10. The frequency of the control signal determines the frequency of the generated output voltage f_1 , called the modulation frequency. The amplitude modulation ratio (m_a) is defined as:

$$m_a = \frac{\hat{V}_{control}}{\hat{V}_{tri}} \quad (3.2)$$

where the circumflex indicates the peak values of the indicated signals. The frequency modulation ratio, m_f is indicated as:

$$m_f = \frac{f_s}{f_1} \quad (3.3)$$

Comparing $V_{control}$ and V_{tri} controls the switches T_{A+} and T_{A-} of Figure 3-8. When $V_{control}$ is larger than V_{tri} , T_{A+} is on giving an output $V_{A0} = V_d/2$ and when $V_{control}$ is smaller than V_{tri} , T_{A-} is on and the resulting output is $V_{A0} = -V_d/2$. It is important to note that the output is independent of the current.

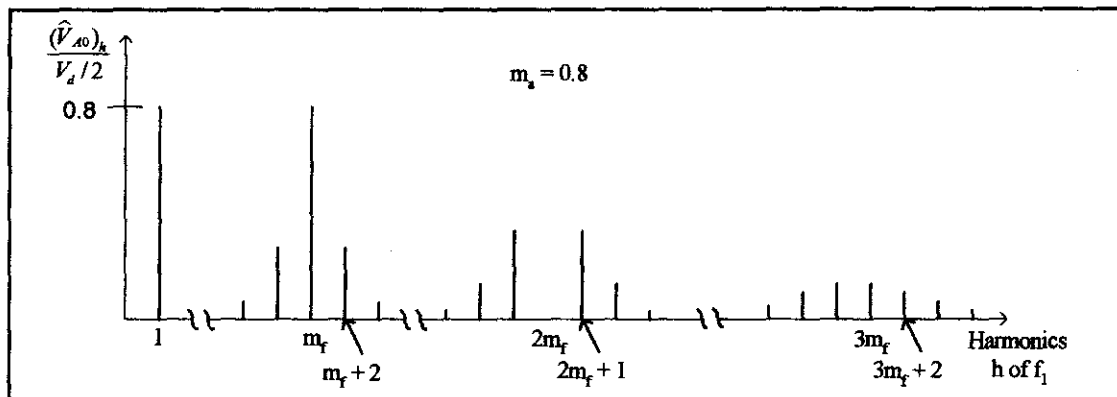


Figure 3-11 – Harmonical content of the output voltage [15]

Figure 3-11 shows the normalized harmonical voltages $(\hat{V}_{A0})_h / \frac{1}{2}V_d$ with $m_a = 0.8$.

There are three important conclusions one can derive by the investigation of Figure 3-11.

- The peak amplitude of the fundamental frequency component is m_a times the peak of $V_{A0} = 0.5 \cdot V_d$. This can be said because $V_{control}$ can be considered

constant during one switching period, assuming m_f is large. The instantaneous average during each switching period can be written as:

$$V_{A0} = \frac{V_{control}}{\hat{V}_{tri}} \frac{V_d}{2} \quad (3.4)$$

A higher switching frequency results in the smaller variations in $V_{control}$ and therefore also V_{A0} from one switching period to another. This means that the output is following the sinusoidal $V_{control}$ more closely, resulting in fewer harmonics.

- The harmonics appear as sidebands around the switching frequency and its multiples. For $m_f \geq 9$ and $m_a \leq 1$, the harmonic amplitudes is almost independent of m_f [15]. Table 3-2 shows the harmonics as a function of m_a . It is easy to see that a modulation amplitude, m_a , plays an important role in the harmonical content of the output voltage. The closer m_a can be kept to one, the lower the harmonics generated. It would therefore be better to operate the converter near its full load capacity.

Table 3-2 – Harmonics of V_{A0} for $m_f \geq 9$ [15]

$m_a \backslash h$	0.2	0.4	0.6	0.8	1
1 - fundamental	0.2	0.4	0.6	0.8	1
m_f	1.242	0.15	1.006	0.818	0.601
$m_f \pm 2$	0.016	0.061	0.131	0.220	0.318
$m_f \pm 4$					0.018
$2m_f \pm 1$	0.190	0.326	0.370	0.314	0.181
$2m_f \pm 3$		0.024	0.071	0.139	0.212
$2m_f \pm 5$				0.013	0.033
$3m_f$	0.335	0.123	0.083	0.171	0.113
$3m_f \pm 2$	0.044	0.139	0.203	0.176	0.062
$3m_f \pm 4$		0.012	0.047	0.104	0.157
$3m_f \pm 6$				0.016	0.044
$4m_f \pm 1$	0.163	0.157	0.008	0.105	0.068
$4m_f \pm 3$	0.012	0.070	0.132	0.115	0.009
$4m_f \pm 5$			0.034	0.084	0.119
$4m_f \pm 7$				0.017	0.050

- The frequency modulation ratio should be an odd integer. This results in odd symmetry causing the cosine terms in the Fourier analysis to be zero and half wave symmetry ensures that only odd harmonics are present. This symmetry can be seen in Figure 3-10 with the time origin $t = 0$ as indicated.

The selection of m_f

From a harmonic point of view m_f should be selected as high as possible. This will result in a large difference between the modulating frequency (f_1) and the switching frequency making it easier to filter out the harmonics situated at multiples of the switching frequency. However, the higher the switching frequency, the higher the switching losses are. In most applications the switching frequency is selected lower than 6 kHz, but is sometimes even selected above 20 kHz to be above the audible range.

A value of $m_f \leq 21$ is considered to be small. When a small value of m_f is selected, the triangular signal and the control signal should be synchronized. This also implies that m_f must be an integer and preferable odd as mentioned earlier. If the two signals were not synchronized, it would lead to the forming of undesirable subharmonics.

Whenever m_f is large, > 21 , the synchronization is not that important because the amplitudes of the subharmonics will be very small. For this asynchronous PWM it is possible to even vary the frequency of the control signal as long as m_f is still large.

Overmodulation

Overmodulation is when m_a is no longer smaller or equal to one, but larger than one. This implies that the amplitude of the output no longer varies linearly with m_a as shown in Figure 3-12. Although the output voltage is very nearly sinusoidal when m_a is smaller than one, the maximum amplitude of the output voltage is not very high due to the notches seen in Figure 3-10. To increase the amplitude of the fundamental frequency component of the output, m_a is selected larger than one. This however results in many more lower order harmonics. It is therefore recommended that synchronous PWM be used at all times, even when $m_f \geq 21$.

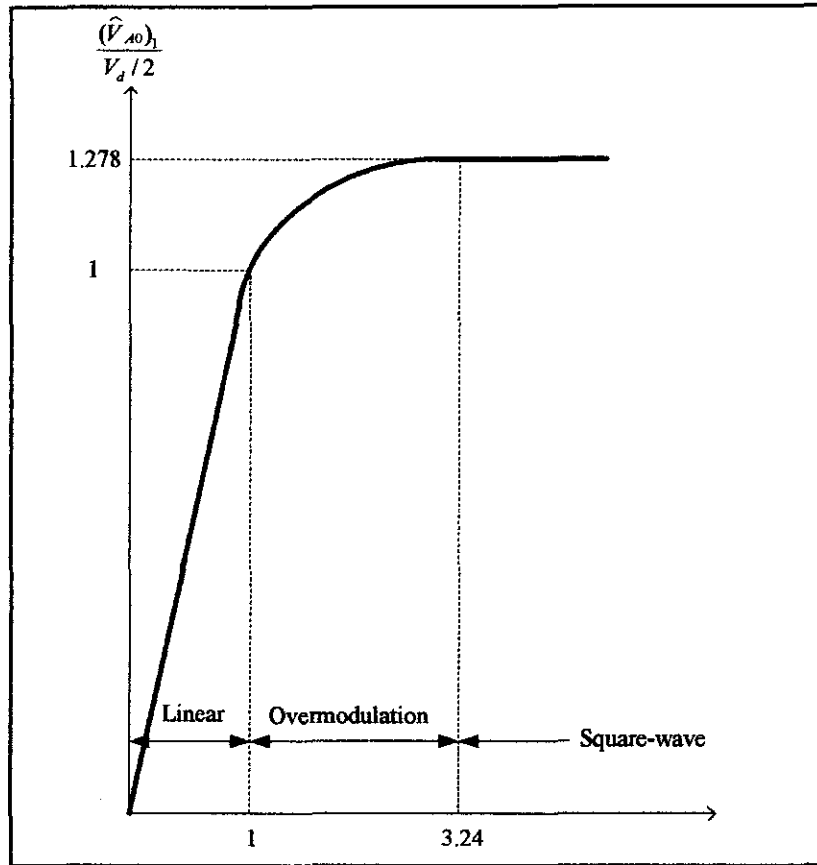


Figure 3-12 – The influence of m_a on the output voltage

Another reason for using a large value of m_a is that switching losses are lower because V_{control} will be larger than V_{tri} for many cycles of V_{tri} and the switch will therefore stay on until V_{control} is again lower than V_{tri} . This is why overmodulation is often used in high power application where harmonics is not the main concern.

Bipolar PWM voltage control

Bipolar PWM voltage switching utilizes the switching of two switches together. T_{A+} and T_{B-} are switched simultaneously while T_{A-} and T_{B+} forms the other switching pair. The output waveform is determined in the exact same way as previously mentioned and illustrated in Figure 3-10. The only difference is that the output of leg B is the negative of the output on leg A. This means that the output has the waveform as in Figure 3-10 but with amplitude twice as high. The peak amplitude of the output is therefore given by:

$$\hat{V}_{o1} = m_a V_d \quad (3.5)$$

Unipolar PWM voltage control

With unipolar switching leg A and B in Figure 3-10 are controlled separately by comparing V_{tri} with $V_{control}$ and $-V_{control}$, respectively. The logic of each leg A, where $V_{control}$ is compared with V_{tri} , can be given as:

$$\begin{aligned} V_{control} > V_{tri} &\Rightarrow T_{A+} \rightarrow on \text{ and } V_{AN} = V_d \\ V_{control} < V_{tri} &\Rightarrow T_{A-} \rightarrow on \text{ and } V_{AN} = 0 \end{aligned} \quad (3.6)$$

The logic of each leg B, where $V_{control}$ is compared with V_{tri} , can be given as:

$$\begin{aligned} -V_{control} > V_{tri} &\Rightarrow T_{B+} \rightarrow on \text{ and } V_{AN} = V_d \\ -V_{control} < V_{tri} &\Rightarrow T_{B-} \rightarrow on \text{ and } V_{AN} = 0 \end{aligned} \quad (3.7)$$

By applying these logics, the output can be determined as shown in Figure 3-13. The status of the switches on leg A can be determined by comparing the $V_{control}$ (red) signal with the triangular wave. The result can be seen as V_{AN} in Figure 3-13. By using the $-V_{control}$ (blue) signal the status of the switches on leg B can be determined. This results in V_{BN} as shown in Figure 3-13. The output voltage is the simple sum of $V_{AN} - V_{BN}$ as shown at the bottom of Figure 3-13. The green sinusoidal waveform is the fundamental frequency component of the output voltage.

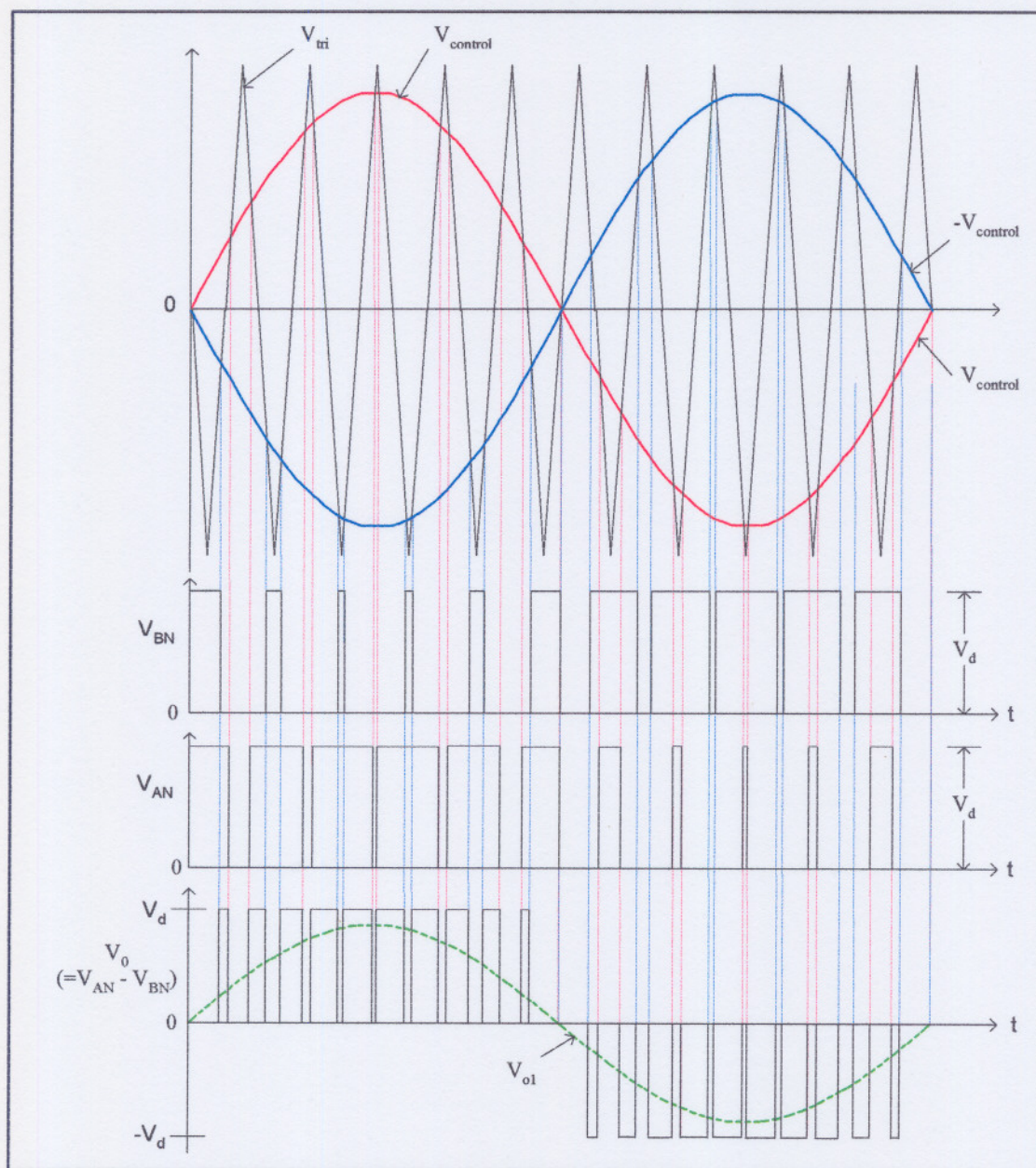


Figure 3-13 – Unipolar PWM switching waveforms

The advantage of unipolar switching is that the frequency of the output voltage is in effect doubled and the harmonics are therefore situated at sidebands around $2m_f$ as shown in Figure 3-14. Another advantage is that the change in output voltage is only V_d at each switch, compared to $2V_d$ when bipolar switching is used.

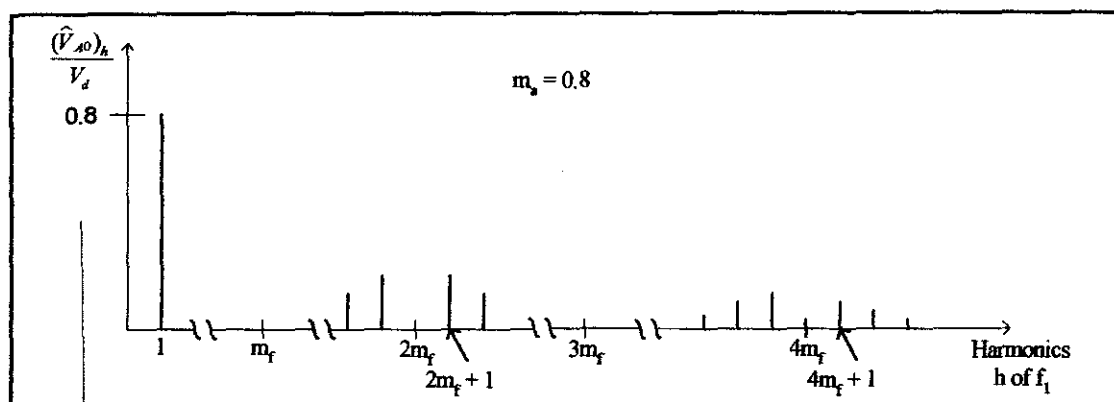


Figure 3-14 – Unipolar PWM output voltage harmonics

3.5.3 Conclusion

The best suitable PWM switching scheme for the PBMR MVDC converter would be the unipolar PWM voltage-switching scheme. The scheme is selected because of the following reasons:

- The voltage rating of the switches must only be capable of handling V_d instead of $2 \cdot V_d$ in the bipolar scheme.
- The frequency of the output is double the switching frequency and the harmonics are therefore situated in sidebands of $2 \cdot m_f$ instead of m_f as with the bipolar scheme. This would require smaller and higher order filters.

On the rectifier side overmodulation can be used to reduce the switching losses. The rectifier side will be acting more or less like a diode bridge with some control.

Chapter 4

Proposed system configuration

In this chapter the current PBMR system is evaluated and a new system using a 150 Hz induction generator with an MVDC converter is suggested. This was the result after various systems and configurations were investigated and reviewed. The other configurations mainly differed in the machine that was used as generator. The different types of generators are therefore also thoroughly investigated, because they are responsible for most of the suggested configurations' properties.

4.1 Proposed PBMR system configuration

4.1.1 Overall PMBR configuration

In order to make suggestions to alter the PBMR current configuration, one first needs to investigate the current system. The basic current configuration of the PBMR is shown in Figure 4-1 and a more detailed electrical configuration is shown in Figure 4-2

To obtain a better understanding of the whole PBMR plant let us firstly consider only Figure 4-1 where the whole thermodynamic Brayton (gas turbine) cycle is shown. The PBMR is based on the Brayton cycle and can be described as followed [23]:

The gas used in the Brayton cycle is Helium. Helium enters the reactor (top orange line) at a temperature of 500 °C and at a pressure of 8,4 MPa and moves downward between the hot fuel spheres or pebbles. The heat is generated by a nuclear reaction inside the spheres and the heat is transferred to the Helium gas passing through the pebbles. The helium is heated to a temperature of 900 °C before it leaves the reactor at the indicated red line.

The hot high-pressure helium now drives the first turbine, called the high-pressure turbine. The high-pressure turbine is called so because the gas is now at its highest pressure level and drives the High-Pressure Compressor. The helium then flows through to the low-pressure turbine as indicated by the lighter red line. The gas pressure is now lower, because of the loss at the high-pressure turbine and the low-pressure turbine drives the low-pressure compressor.

The helium gas now passes into the power turbine. The power turbine drives the generator at a speed of 3000 rpm to generate a 50 Hz power output. At this point the helium is still at a high temperature. It then flows through the primary side of the recuperator where it transfers heat to the low temperature gas returning to the reactor. This is done to cool down the gas, because this increases the density of the Helium gas. The higher the density of the gas, the better the efficiency of the compressors.

To cool down the gas even more (blue line) it is sent through a pre-cooler after passing through the primary side of the recuperator. This again increases the density of the helium and improves the efficiency of the compressor. The low-pressure compressor then compresses the helium for the first time.

The same process is then basically repeated when the helium is again cooled down in the inter-cooler and then sent to the High-pressure compressor. The High-pressure Compressor then compresses the helium to 8,5 MPa. The cold, high-pressure helium gas then flows through the recuperator's secondary side where it is pre-heated before it returns to the reactor as again indicated by the top orange line.

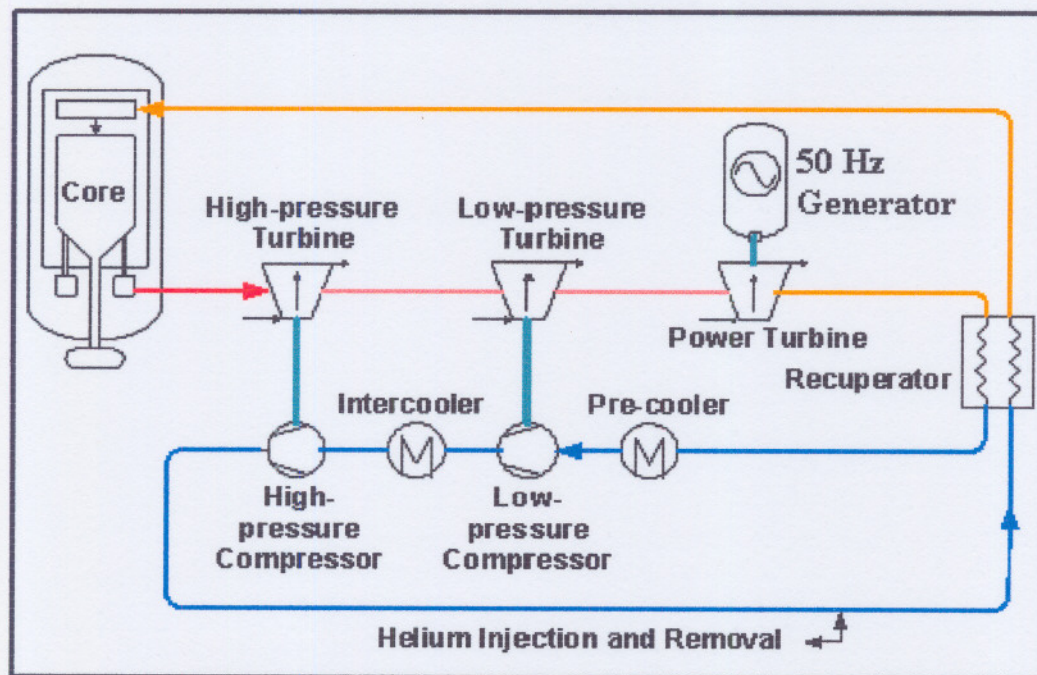


Figure 4-1 – Current PBMR power conversion unit [23]

4.1.2 Current PBMR electrical configuration

The PBMR currently uses a 180 MW synchronous generator as indicated in Figure 4-2. The synchronous generator must be driven at exactly 3000 rpm in order to

generate 50 Hz power for the South-African grid. The PBMR is also an export product and therefore quite a lot of changes will be necessary to implement the same system in the USA for instance, where the national grid frequency is 60 Hz.

The generator is connected to the national grid by means of a 13,2 kV/132 kV transformer. The transformer will also be equipped with an on-load tap-changer for voltage control between the generator and the grid. The tap-changer is used for better voltage regulation. When the load current increases the voltage drop over the transformer's internal impedance increases, causing a drop in the secondary voltage. The tap-changer corrects this drop by selecting another tap position.

The system is also equipped with a 5,3 MW Static frequency converter (SFC) as shown in Figure 4-2. The SFC is necessary to start-up the synchronous generator from the grid. The synchronous generator must be running at synchronous speed to be able to synchronize it and connect it to the grid. This SFC was not included in the previous PBMR configuration, but was introduced later when the difficulty of starting up the system using the synchronous machine became evident. The 5,3 MW SFC is an additional piece of equipment used only during start-up. In power plants this does not happen very often and the SFC won't be used for very long periods of time resulting in low returns on the SFC investment.

To be able to get the whole Brayton cycle started, gas flow is needed. Therefore the system needs additional power from the grid. This power is fed through a 13,2 kV/11,5 kV transformer. This 11,5 kV is again stepped down to 1 kV and then used to drive the two 500 kW SBS (Start-up Blower System) motors driving both the high-pressure and low-pressure turbines. The remaining 3,2 MW is used to power all the auxiliary equipment, eg the cooling system. To get the PBMR started, a total of 9,5 MW is needed from the grid. This consists of the 5,3 MW needed by the synchronous generator and an additional 4,2 MW for the SBS and auxiliaries.

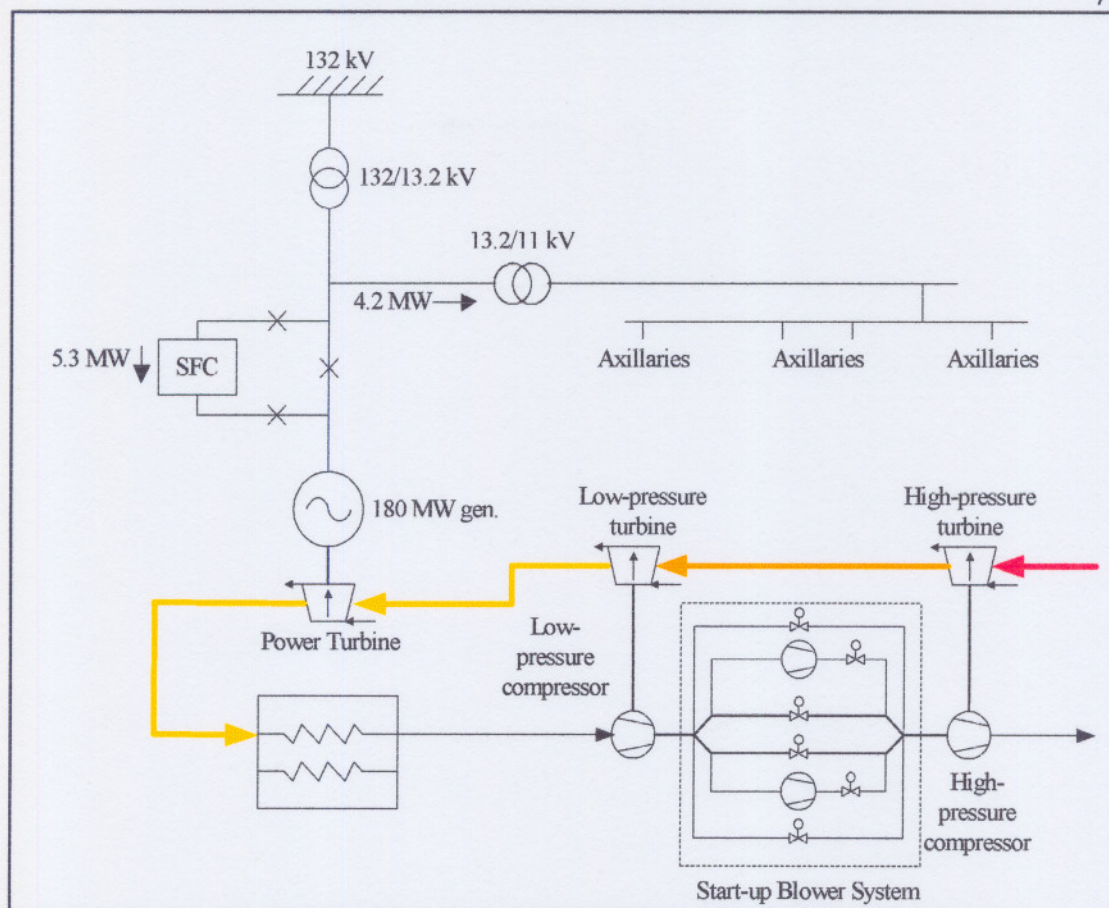


Figure 4-2 – Current PBMR electrical configuration

4.1.3 Possible other configurations

Some other possible configurations for the PBMR will now be discussed and explained. In the first place the possible use of a DC generator in combination with an MVDC inverter is investigated. The second possibility discussed is the use of a high-speed induction generator in combination with an MVDC converter. The use of a high-speed synchronous superconductor and conventional generator with an MVDC converter is also discussed. The possibility of a powerformer generator is also briefly evaluated.

4.1.3.1 Direct current (DC) Generator with MVDC inverter

DC machines are very versatile and extensively used in the industry. A wide range of volt-ampere or torque-speed characteristics can be obtained by using various connections of the field winding [23]. The different excitation methods were investigated in section 4.2 and the shunt-excited machine was found to be the best for further investigation into a possible PBMR configuration.

The DC machines can easily operate as generators or motors, but are presently mostly used as motors, because of the widespread use of AC power. These motors are extensively used in the industry, because of the relative ease of speed control over a wide range. DC motors are therefore used in machine tools, mills, pumps, cranes, hoists and fans. DC motors are still the dominant motor used as traction motors in locomotives and cars.

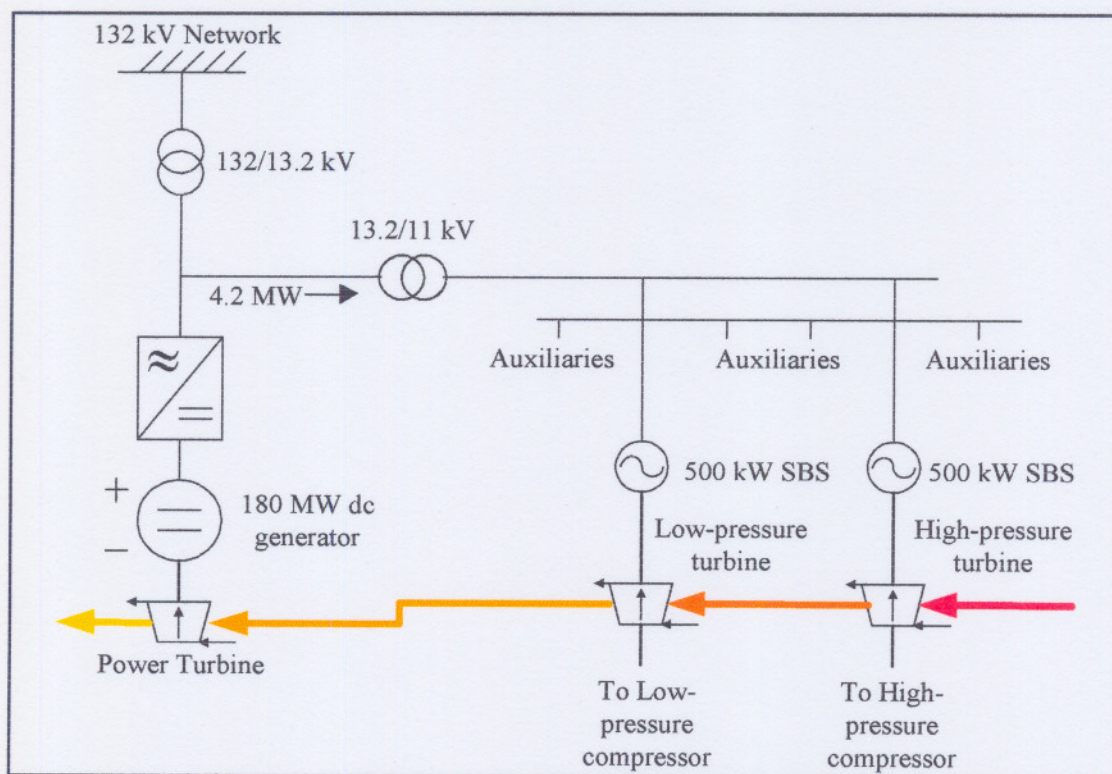


Figure 4-3 – Possible PBMR configuration using a DC generator

Figure 4-3 shows how the DC generator will fit into the PBMR system. A 180 MW MVDC inverter is however necessary to invert the DC into a 13,2 kV AC voltage. The DC voltage ripple of large generators is very small and will be less than 5% [14]. The capacitor used for the ripple limitation on the DC bus can therefore be small.

This configuration will have the same control advantages as seen from the converter's prospective than a full back-to-back converter and an induction generator. An additional advantage for the DC system is the fact that the inverter will cost almost half of a back-to-back converter, because a back-to-back converter basically consists of two inverters. The one is used as a rectifier to convert the AC generator voltage into DC and the other one as an inverter to convert the DC voltage into a 50 Hz AC output.

The DC machine is however not without drawbacks. The DC field is applied to the stator and the rotor generates the power. The total power is therefore fed through the commutator. The commutator will therefore be very large and the rotor diameter will therefore be larger than that of induction machines. This will result in higher stresses on the rotor making high-speed applications even more difficult. The commutator also needs regular cleaning from the carbon dust formed by the brushes. The brushes will also need regular replacement.

The regular maintenance will require the power station to shutdown and the downtime losses will be very high. The PBMR nuclear station environment is also not an area where one would want to do regular maintenance.

Although DC machines are easy to start-up, the efficiency of these machines is fairly low. The half bridge will have more or less half the power losses of the full bridges used in AC machines' configurations. The MVDC converter is expected to have an efficiency of 99% or more. This means that the half bridge converter would have an efficiency of approximately 99.5%. If the DC machine were therefore more than 0.5% less efficient than the AC machines, the overall DC system would still be less efficient than the AC systems.

4.1.3.2 High-speed induction generator with MVDC converter

Induction machines are very robust machines, especially squirrel-cage induction machines. The compact and strong construction of these machines opens the possibility for high-speed power generation. The construction has a higher yield strength making it possible to operate at higher rotational speeds.

High-speed power generation is beneficial, because the turbines have a higher efficiency at higher rotational speeds. The induction machine can also be made smaller, because of the higher frequency according to equation (4.8). Because the generator can operate at 9000 rpm, the power turbine and the low-pressure turbine can be combined. This reduces the three-shaft system to a two-shaft system, which will not only be less expensive and more efficient but also easier to control. By combining the power turbine and the low-pressure turbine, the power turbine is connected to a compressor. This will enable the generator to start the system by starting the gas cycle by means of the low-pressure compressor. The SBS can therefore be eliminated, which

is also another control advantage. The 150 Hz needs to be converted to 50 Hz or 60 Hz with an MVDC converter.

The converter is very expensive, but fortunately has some additional advantages. The advantages of MVDC converters were discussed in section 3.3. These advantages hold several advantages for the PBMR. The advantages include:

- A smaller turbine and generator set can be cheaper and save space.
- The three-shaft system is reduced to a two-shaft system.
- Independent active and reactive power control.
- MVDC converter controls output frequency. This implies one PBMR design for both 50 Hz and 60 Hz applications.
- Stable variable speed power generation.
- No additional start-up equipment like the SFC will be required.
- No contribution to short-circuit current after the converter.
- Because the generator can operate at a variable frequency, the generator control can be slower and less sophisticated. The PBMR system will be more stable, because of the speed can vary in a larger range.
- Both SBS motors and compressors can be eliminated, because the gas flow can be started with the generator operating as a motor controlled by the MVDC converter.

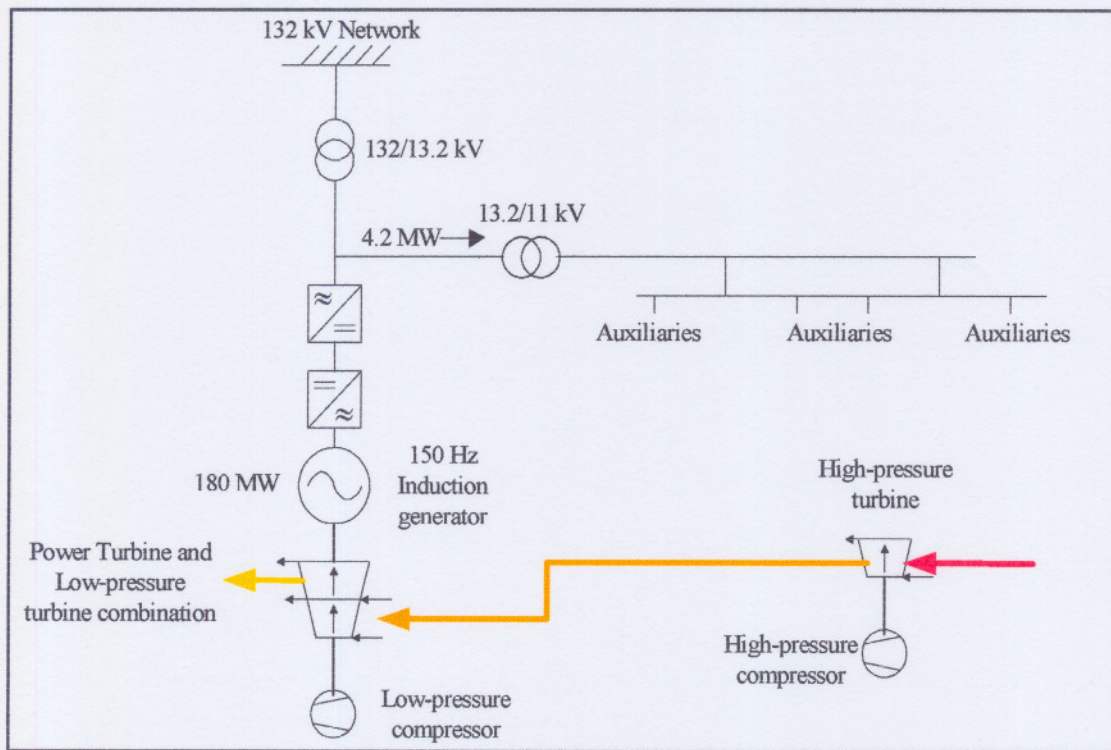


Figure 4-4 – High-speed induction generator and MVDC converter PBMR configuration

4.1.3.3 Conventional High-speed Synchronous generator

Using a high-speed synchronous generator will also imply the use of an MVDC converter to convert the 150 Hz power to 50 Hz or 60 Hz. The same advantages as with the high-speed squirrel-cage induction generator are possible. This includes the size reduction and MVDC advantages.

The one difference between the squirrel-cage induction machine and conventional synchronous machines lies in the rotor construction. The squirrel cage rotor is more robust in comparison with the wound rotor of the synchronous machine. The wound conductors of the synchronous machine need retaining rings at the ends of the rotor where they create an overhang. The yield strength of the material currently used is not high enough to keep the wound rotor construction together while rotating at 9000 rpm. This led to the investigation of super-conductor synchronous machines. The use of superconductors would reduce the physical size of a 180 MW rotor and it could be possible to use this smaller rotor at 9000 rpm.

4.1.3.4 High-speed Synchronous generator using superconductors

As mentioned in the previous section the main reason why superconductors need to be used is because the centrifugal force at 9000 rpm will cause conventional synchronous generators to disintegrate. The use of superconductors will allow the machine to be much smaller (about 50%) and the smaller rotor will therefore have lower tip-speed resulting in a lower centrifugal force at the tip. The yield strength of the material will then be capable to keep the construction together.

In a recent study done by Lamont [26] it was found that even the use of superconductors would not currently be feasible. Running a 180 MW machine at 9000 rpm would indeed be possible, but superconductor generators are still in the development phase and would probably only become commercially available between 2010 and 2015. Using these machines shows great potential and will be approximately 1% more efficient (99.5%) than traditional generators.

4.1.3.5 180 MW MVDC converter with powerformer generator

The use of a powerformer as generator can eliminate the use of a step-up transformer and therefore increase the overall efficiency by approximately 1% [28]. In power generation applications the voltage of normal synchronous, asynchronous and DC machines will be fed through a step-up transformer. The reason is simply to minimize losses.

The powerformer is a permanent magnet synchronous machine using high-voltage cables. The use of these cables allows the generator to generate a high output voltage and therefore eliminates the use of a step-up transformer. Because high-voltage cables are used in the stator, the construction of these machines is very large and heavy. A 3 MW prototype developed for wind power applications weighed about 150 tonnes [28]. This is a tremendous disadvantage for the PBMR system and won't be investigated any further.

4.2 DC generators

Generators are used to convert mechanical energy into electrical energy. Generators consist of a number of conducting coils and a magnetic field. Relative motion between the coils and the field induce a voltage in the coils. There are three main types of generators namely DC, Synchronous and induction generators. Each one of these has

its own unique characteristics making each one most suitable for different applications. The characteristics of all three these generator will be investigated to determine the one most suitable for the PBMR. The electrical properties of the machines will be investigated, because Lamont [26] did investigate the physical limitations regarding the yield strengths.

Some general definitions for DC machine include: the stator of a machine is the part of the machine that does not move and is normally the outer frame. The rotor on the other hand is the part that is free to move and is normally the inner part of the machine.

The conductors placed in the slots of the stator or rotor is interconnected to form windings. The winding in which voltage is induced is called the armature winding. The winding through which a current sent in order to provide the primary flux in the machine is called the field winding.

In the DC machine the field winding is placed on the stator and the armature winding on the rotor. DC current is fed through the field winding to produce a flux in the machine. The voltage in the armature windings is alternating, but is rectified by the commutator and brushes.

DC machines have various different characteristics depending on the type of field excitation. There are basically four ways of connecting the field excitation circuit namely separately, series, shunt/parallel and compound. These different schemes will be discussed in more detail later.

Despite the differences in excitation, the fundamental characteristics of DC machines are the same. The armature voltage developed and also the torque developed can be expressed with the same equations for all four schemes. According to Sen [24] these quantities can be expressed as:

$$E_a = K_a \Phi \omega_m \quad (4.1)$$

where E_a is the average terminal voltage of the armature

Φ is the flux per pole

ω_m is the rotational speed in radians per second

and K_a is the armature constant given by:

$$K_a = \frac{Np}{\pi a} \quad (4.2)$$

where N is the total number of turns in the armature winding
 p is the number of poles
 and a is the number of parallel paths

The induced voltage is proportional to the product of the flux and the rotational speed. It is therefore more meaningful to draw a magnetizing curve in terms of the induced voltage at a particular speed. This is experimentally done by measuring the no-load voltage as a function of the field current at a constant speed. Figure 4-5 shows the resulting curve done at 1000 rpm. The curves at other rotational speeds can be obtained by direct proportion.

It can be seen that the curve does not start at zero when no field current is applied. This is due to the residual magnetism causing a small emf without any field current. The curve is linear over a wide range of field current. For high values of field current the curve flattens fast due to the saturation of the iron core.

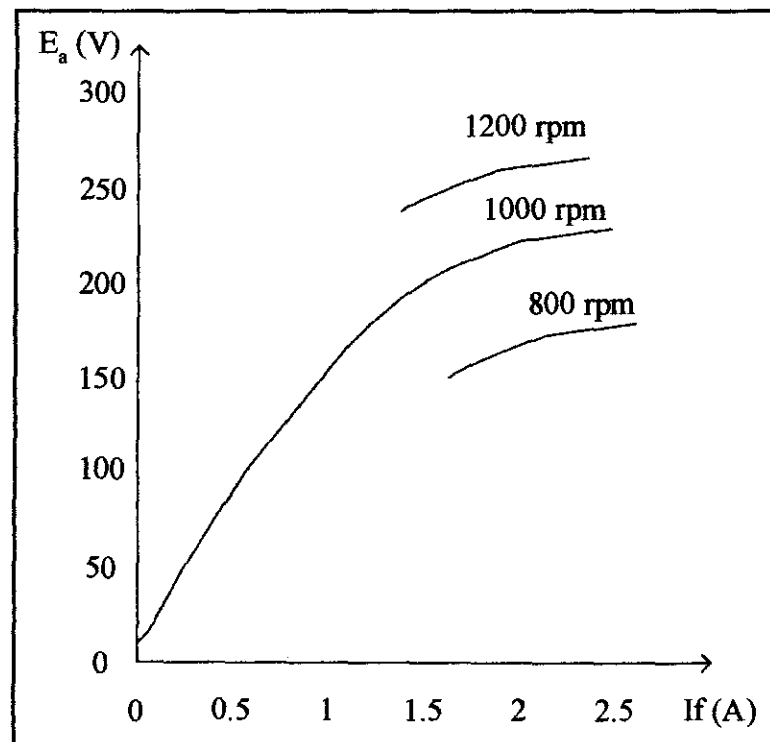


Figure 4-5 – Typical DC machine magnetization curve [25]

The developed torque can be written as:

$$T = \frac{N\Phi p}{\pi a} I_a = K_a \Phi I_a \quad (4.3)$$

where I_a is the armature terminal current.

The different excitation methods have different properties and different advantages and disadvantages. They are summarized in Table 4-1 in order to choose one best suited for the PBMR application. This will be discussed in more detail.

Table 4-1 – Comparison of different DC motor excitation methods

Separate		Shunt		Series	
<i>Advantage</i>	<i>Disadvantage</i>	<i>Advantage</i>	<i>Disadvantage</i>	<i>Advantage</i>	<i>Disadvantage</i>
Total I_a independent control	Additional excitation source needed	No additional source needed	Output depends on load current	No additional source needed	Output depends on load current
Nearly constant output voltage over whole load range		Inherent safe during terminal short circuit		High starting torque	Load must be connected
Only small excitation current needed because of many field turns		Only small excitation current needed because of many field turns			Large excitation current with fewer turns
Control done on small field current		Control done on small field current			Control done on whole armature current

The best excitation method for the PBMR application will be the shunt excited DC machine. All the methods were evaluated and the results are given in Table 4-1. The different excitation method's advantages and disadvantages were evaluated from PBMR perspective and the choice can be explained as followed.

In the PBMR configuration all the excitation methods needs the MVDC inverter to invert the direct current into 50 Hz or 60 Hz alternating current depending on the network frequency. The independent control of the separately excited DC generator is therefore not necessary, because the MVDC converter can control the output voltage. The additional power source will therefore be an unnecessary expenditure.

The series excitation has many disadvantages, but the fact that the whole armature current must be controlled and the load that must be connected to ensure operation eliminates this method. The high starting torque of this machine won't be necessary to start-up the PBMR system, because only a fraction of the power is needed to start-up the PBMR system.

Compound machines are also not considered, because they are more complex than the other DC generator options and their advantages could also be gained with the existing MVDC inverter. These machines will be more expensive without any additional advantages added to the overall system.

The shunt excitation is most suited for the PBMR system. Although the output is dependant on the load current, the system's output voltage could be kept constant by the MVDC inverter. This method doesn't need an additional DC power source and the inherent safety is a huge advantage in the nuclear environment. The shunt excitation will now be discussed in a bit more detail.

4.2.1 Shunt excited DC generator

A shunt or self-excited generator is a DC machine whose field winding is connected in parallel with the armature terminals. The main gain of this way of excitation is that no external source of excitation is needed and from there the name of self-excited generator. Again the separate shunt winding has a large number of turns and therefore takes only a small current of less than 5% of the rated armature current.

The output voltage of a shunt-excited generator is controlled by means of the rheostat R_{fc} shown in Figure 4-6. The rheostat controls the current flowing in the shunt field and therefore the flux determining the armature voltage as shown in equation (4.5). A rheostat is however not practical for large machines, like the PBMR, because of the losses and a small PWM converter can be used.

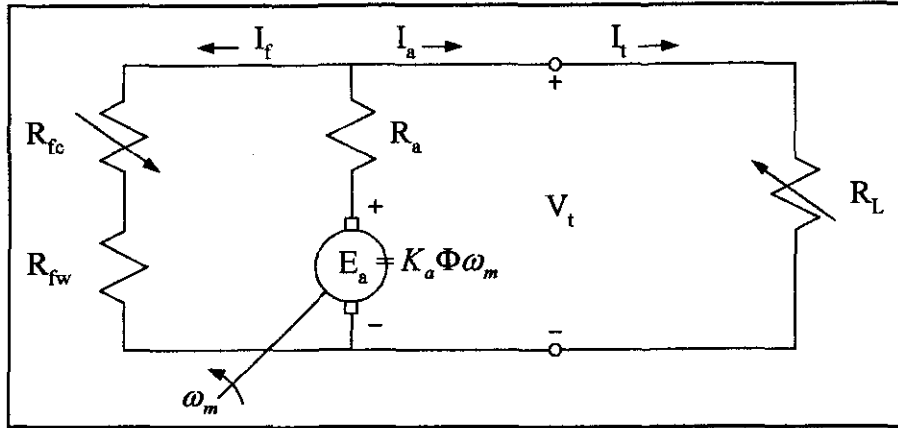


Figure 4-6 – Shunt excited DC generator model

The steady state model of the shunt-excited DC generator is shown in Figure 4-6. The equations describing the steady state operation on the load are:

$$E_a = V_t + I_a R_a \quad (4.4)$$

$$E_a = K_a \Phi \omega_m \quad (4.5)$$

where Φ is a function of I_f

$$V_t = I_f R_f = I_f (R_{fw} + R_{fc}) \quad (4.6)$$

$$V_t = I_L R_L \quad (4.7)$$

It is worth noting that when the machine terminals are short-circuited, it implies that R_L is zero and the field current will reduce to zero. This means that the machine is inherently safe although the armature current can still be large enough to cause damage before R_L is reduced to zero.

4.3 Induction generators

Induction motors are the motors used most frequently in the industry. They are very simple, robust, low priced and easy to maintain. The induction motor is seldom used as

a generator, because the output frequency is dependant on the slip of the machine and is therefore difficult to connect to the grid complying with all power regulations. The simple and rugged construction of especially the squirrel-cage rotor and the greater possibility of using such a machine at a higher rotational speed as required by the PBMR, is the main motivation why the induction generator - MVDC converter combination is also investigated in the thesis.

4.3.1 Basic construction and operational principals

As with DC machines the induction machine consists of two main parts namely a stationary stator and revolving rotor. Their rotor can either be a squirrel-cage or a wound rotor. A squirrel-cage rotor consists of bare copper bars pushed into the slots and welded together to two copper end-rings. The advantage of this rotor is that it is nearly solid with no overhang and retaining rings. Another advantage of this rotor is that it does not contain a commutator as the DC machine or slip rings as synchronous machines. Wound rotor machines have windings similar to that on the stator and the windings are also connected to external resistors via slip rings and brushes. The resistors are usually only used during start-up for higher start-up torque. The two different rotors can be seen in Figure 4-7.

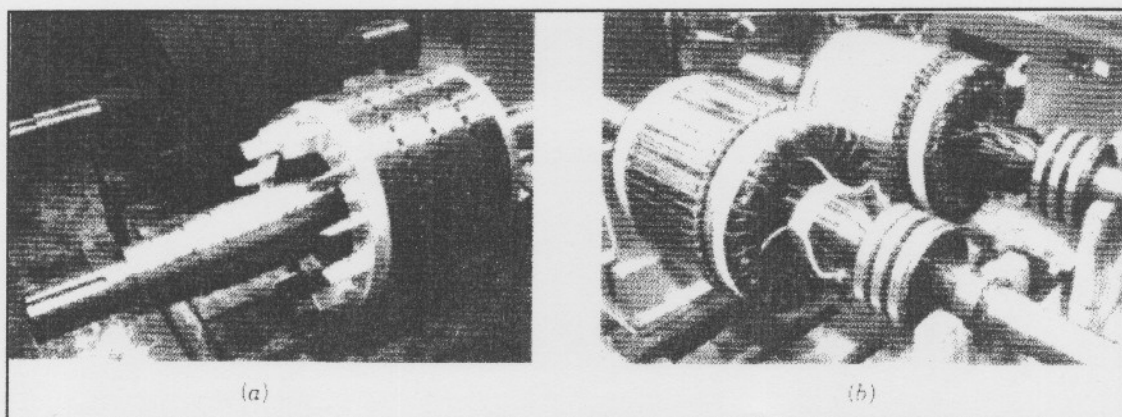


Figure 4-7 – Induction machine rotors - a) Squirrel-cage and b) Wound rotor [24]

In induction machines the stator windings serve as both the armature windings and the field winding. When the stator windings are connected to an AC supply, flux is produced in the air gap and rotates at a fixed speed, known as the synchronous speed. The rotating flux induces a voltage in the stator windings and the rotor windings. The rotor windings are short circuited by means of the end rings allowing current to flow. These currents also produce a flux that reacts with the rotating flux producing a torque. The steady state speed of the rotor is very close to the synchronous speed.

4.3.2 Induced armature voltage

The stator of a three phase induction machines produces a rotating flux. The rms value of the induced voltage is given by [24]:

$$E_{rms} = 4.44 f N \Phi_p \quad (4.8)$$

where f is the frequency in Hertz

N is the number of turns

and Φ is the flux per pole

This equation is also used for transformers, but has some limitation for machines. The winding is distributed over several slots and the induced voltage will be less. To compensate for this a factor K_w , called the winding factor is multiplied with the original formula. K_w is smaller than unity and normally is between 0.85 and 0.95 [24]. The rms voltage can therefore be rewritten as:

$$E_{rms} = 4.44 f N \Phi_p K_w \quad (4.9)$$

In this equation the number of turns, the winding factor and the frequency is constant for a given machine. When a converter, like an MVDC converter, is used the frequency no longer needs to be seen as a constant. The frequency can be used as method of control within the flux and insulation limitations of the design.

4.3.3 Modes of operation

The induction machine can operate in three different modes namely motoring, generating and plugging. Although in the PBMR system the machine will be operated as a generator for most of the time, it will be necessary to operate as a motor during start-up to get the Brayton cycle going. The three modes can be defined in terms of the slip and the torque as shown in Figure 4-8.

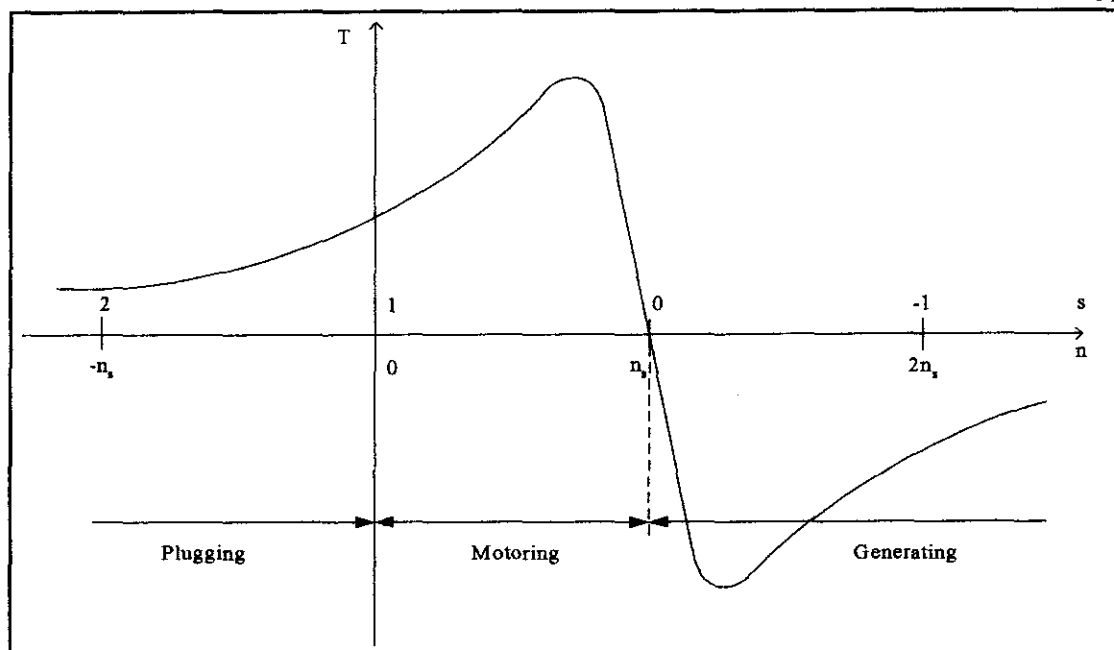


Figure 4-8 – Three modes of induction machine operation

4.3.3.1 Motoring

In this state the rotor will rotate in the direction of the stator's rotating field. The speed of rotation is less than the synchronous speed n_s as shown in Figure 4-8. The slip during motoring will vary between 0 and 1.

The induction machine will only be used as a motor during the start-up of the PBMR system and it is therefore important to look at the start-up characteristics of the machine. When the induction machine is directly connected to the supply it will draw a current of between 500% and 800% of the rated current of the machine. In the case of the 180 MW induction machine this would imply a line current of between 39 kA and 63 kA, which would lead to a huge and unacceptable drop in the system supply voltage.

One method is to use a star-delta starting which in fact reduces the starting voltage to 58% of its nominal value. An autotransformer can also be used to reduce the voltage and hence the current during start-up.

The modern way is to use a solid-state voltage controller that also reduces the start-up voltage over a wide range. The controller can therefore be used to provide a smooth starting. The controller can also be used for speed control of the motor.

The reduction in voltage at start-up leads to a reduction in the starting torque. In the case of the PBMR the load at start-up will be a turbine and the required torque will rise

as the speed increase. This is an advantage, because as the speed increases the voltage can also be increased without necessarily increasing the current.

Should the system be equipped with an MVDC converter none of the above auxiliary equipment would be necessary, because the converter is able to supply a reduced voltage to the induction machine during start-up. These converters have very little overload capacities and the current will have to be limited to the nominal load current.

4.3.3.2 Generating

When the speed of the rotor exceeds that of the rotating stator field or synchronous speed the machine will start producing a torque in the opposite direction of the rotating field. This will happen when the motor is connected to a train running downhill or when a turbine at a super-synchronous speed. Electrical power will now be delivered to the power network. The slip during this operation mode is negative.

The synchronous speed of the machine is determined by the network frequency it is connected to. When an MVDC converter is used the frequency of generator side and the network side can be allowed to differ. The induction machine can therefore be manipulated to still act as a generator by lowering the frequency of the converter at the generator side. This will allow the machine to generate power in a much wider range of speed and the control of the generator system will have the luxury of not having to control the turbine speed at exactly synchronous speed.

4.3.4 Performance properties

The most important performance characteristics are the efficiency, power factor, starting torque and maximum torque.

The developed mechanical torque per phase can be written as [24]:

$$T_{mech} = \frac{I_2^2 R_2}{s\omega_s} \quad (4.10)$$

The torque against slip characteristics can be seen in Figure 4-8. In the case of wound rotor induction machines, the resistance R_2 is increased externally through the slip rings to create a larger start-up torque.

The power factor is given by:

$$P_f = \cos \theta_1 \quad (4.11)$$

where θ_1 is the phase angle of the stator current I_1 . The typical variation of the power factor against speed is shown in Figure 4-9 b). This indicates that the best operating point would be just below synchronous speed. At lower speeds the reactive power consumption can even be more than half (50%) of the rated power.

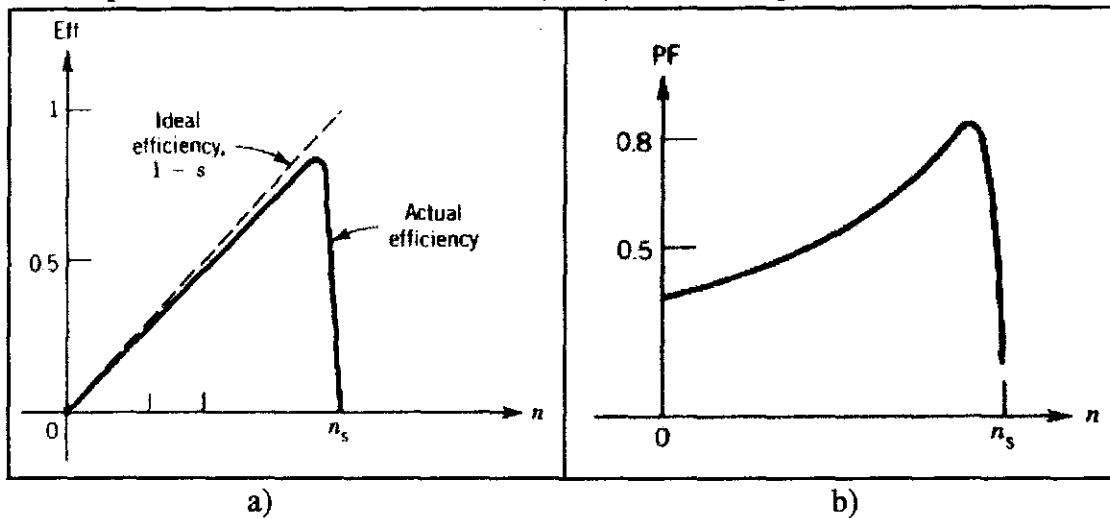


Figure 4-9 – Induction machine efficiency (a) and power factor (b) as functions of speed [24]

The efficiency of any machine is the most important feature from an economical perspective. The efficiency is basically the machine's capability of converting as much as possible electrical energy into mechanical energy and vice versa. The efficiency can be mathematically represented as:

$$\eta = \frac{P_{out}}{P_{in}} \quad (4.12)$$

where P_{out} is measured at the shaft and P_{in} is the input electrical power in the case of a motor. The difference between the two is caused by the stator core and copper losses, the rotor core and copper losses plus the friction and windage losses. The efficiency of the machine is very dependant on the slip as shown in Figure 4-9 (a). Large induction motors have efficiencies of as high as 98% for a 20 MW machine [14 p270]. It would therefore be possible for a 180 MW high-speed induction machine to have an efficiency of more than 99%. This is possible, because larger machines have better efficiencies than smaller ones. The induction machine will also show an efficiency

improvement at higher rotational speeds like 9000 rpm. This due to the fact that the high-speed induction machines will be smaller than conventional machines and this will lead to smaller rotational losses (friction and windage losses).

4.3.5 Speed control methods

4.3.5.1 Line voltage control

The torque developed by an induction machine is proportional to the square of the terminal voltage. When the motor is therefore operated at a voltage lower than the rated voltage, at say 0.707 pu, the drop in the torque curve will be significant as shown in Figure 4-10. This will result in a new operating point at a reduced speed as indicated by the new intersection point of the torque and load curves.

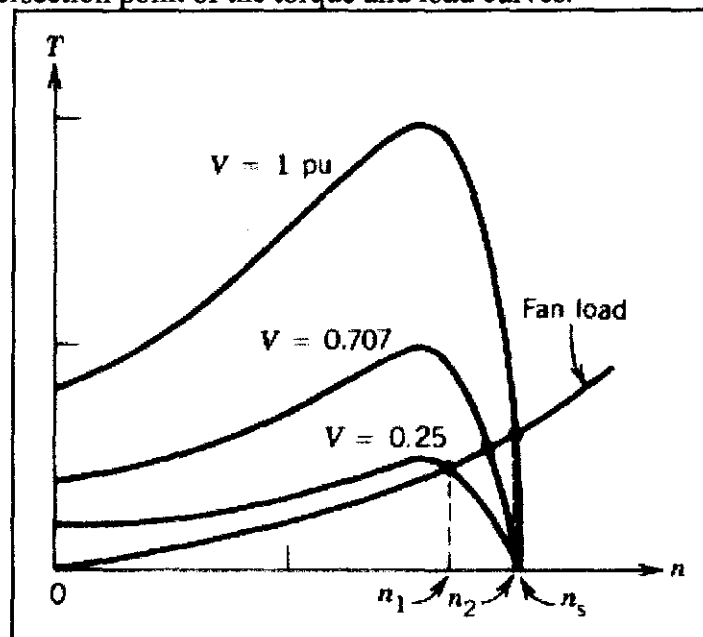


Figure 4-10 – Torque and speed characteristics at various terminal voltages [24]

Using an autotransformer can vary the terminal voltage. The autotransformer will supply a sinusoidal voltage at the terminals altering the torque curve and therefore indirectly the speed.

A solid-state voltage controller can also control the voltage. This results in the new operating point of the machine. These converters create large harmonic currents and are therefore only used for smaller machines, because expensive filters are needed for larger machines.

Although this method can control the speed over a wider range the method does not suit the PBMR system. The PBMR is a large system and wants to generate electrical energy as efficient as possible. In Figure 4-10 it can be seen that the slip is dramatically increased at lower speeds. The efficiency is virtually direct proportional to the slip, especially for high values of slip, as indicated by the ideal efficiency line (1-s).

4.3.5.2 Line frequency control

Changing the frequency of the AC supply can vary the synchronous speed of an induction machine as seen in equation (4.9). This will however require a frequency converter. From equation (4.9) one can see that if the voltage drop over R_1 and X_1 (stator winding resistance and leakage reactance) is small in comparison with V_1 , the terminal voltage V_1 is direct proportional to the line frequency.

$$V_1 \propto \Phi_p f \quad (4.13)$$

To avoid the saturation of the core, the frequency cannot be changed freely, because maintaining the same terminal voltage while operating at higher frequency would saturate the magnetic core as can be seen in equation (4.13). The control must rather maintain constant flux (volts per Hertz) to avoid any saturation of the core. At very low frequencies the voltage drop over R_1 and X_1 are not neglectable any more and the volts per hertz ratio is increased to solve the problem.

The advantage of this type of control can be seen in the torque characteristics at the different frequencies as illustrated in Figure 4-11. At frequencies below the base frequency the torque curve has the same maximum torque due to the constant flux that is maintained. At higher values the voltage cannot be increased any more as less torque is available, because of the decrease in flux. The main advantage of this control method is the fact that the slip for all the curves are very low and therefore a high efficiency is maintained over the whole frequency range. The power factor is also at its highest at low slip.

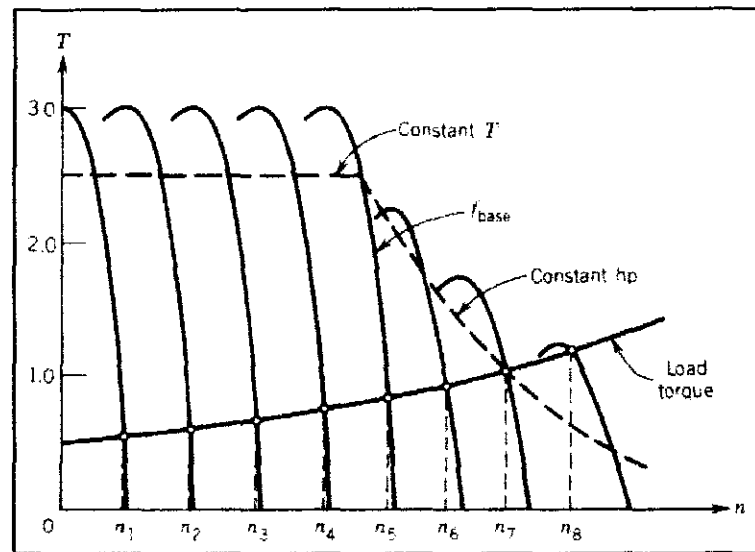


Figure 4-11 – Torque curve of induction motor at different line frequencies [24]

4.3.5.3 Pole changing

The synchronous speed of an induction machine is direct proportional to the number of poles and can therefore be used for speed regulation. This will work because the operating speed of the machine is close to the synchronous speed. This requires the coil connections to be changed in the stator. This complex stator will then only allow two discrete synchronous speeds normally in a ratio of 2:1.

The two synchronous speeds won't be a benefit for the PBMR, because this won't simplify the control system. Although no additional converters are necessary there is no additional power flow or increased stability added to the system.

4.4 Synchronous generators

In these machines the rotor is carrying the field winding while the armature winding is situated on the stator. The field winding is excited with direct current producing a flux in the air-gap. When the rotor rotates, voltage is induced in the armature winding situated in the stator. The armature current will therefore produce a rotating flux in the air-gap with the same rotational speed of the rotor and from there the name synchronous machine.

An important characteristic of synchronous machines is that they can draw either lagging or leading reactive current from the AC system. In the case of induction machines, the flux is solely provided by the stator and the therefore always operated with a lagging power factor. In the synchronous machines both the DC rotor current

and AC stator current provide excitation. The DC rotor excitation can be set to provide just the necessary excitation for the stator to draw no reactive current. If the DC excitation is decreased (machine is underexcited) the machine will draw lagging reactive current and if the excitation is increased (machine is overexcited), leading reactive current will be drawn from the AC system.

4.4.1 Basic operation

Although the induction and synchronous machines are two different machines they have many properties in common. The excitation voltage E_f is induced by the rotation of the rotor and has the same rms voltage as the induction machine given by:

$$E_f = 4.44 f N \Phi_f K_w \quad (4.14)$$

where Φ_f is the flux per pole due to I_f and the other abbreviations has the same meaning as before

The synchronous speed is also given by:

$$n = \frac{120 f}{p} \quad (4.15)$$

The difference here is that when the terminals are connected to a load, the current I_a will start to flow at the exact same frequency as the excitation voltage E_f . There is no slip and the air gap flux is a combination of the field flux Φ_f and the armature reaction flux Φ_a .

4.4.2 Starting the synchronous motor

The synchronous motor is not a self-starting motor like the DC and induction motors. The reason for this is explained using Figure 4-12. At start-up the rotor is in a stationary position with poles as indicated. When the stator is connected to the supply it starts producing a field rotating at synchronous speed. At instant $t = 0$ the field produces a torque in the clockwise direction on the rotor. Half a period later the rotor experiences a counter clockwise-directed torque, because it is still in the same position due to its large inertia. The resultant torque experienced by the rotor is therefore zero after every cycle and will only vibrate. A few options are however available to start-up the synchronous machine.

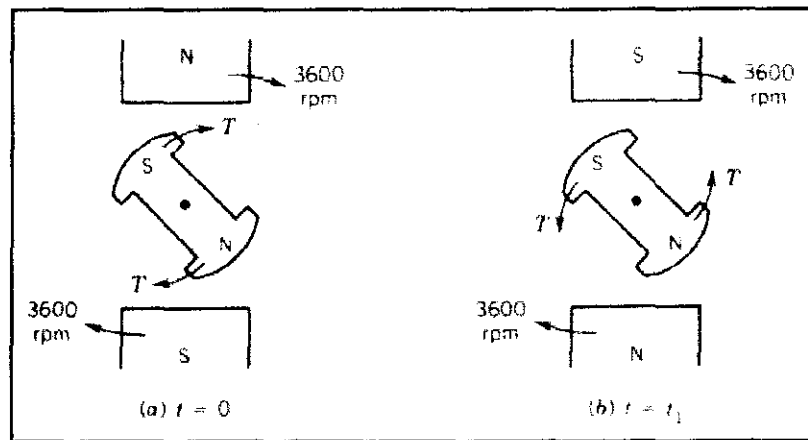


Figure 4-12 – Synchronous machine rotor torque at start –up

4.4.2.1 Start-up as an induction motor

One possibility to enable the synchronous machine to start-up on its own, i.e. to start it as an induction machine. To be able to do this the machine will need an additional winding mounted on the rotor similar to the squirrel-cage of the induction machine, i.e. the damper winding.

To start the machine the field is left unexcited while the stator is connected to the AC supply. The induced current in the damper windings will produce a torque similar to the induction machine and speed it up to near synchronous speed. The rotor poles are then excited from the DC source and because the stator and rotor poles are close to each other will then lock and the machine will run at synchronous speed.

If the machine is running at synchronous speed no current will be induced in the damper windings. When the rotor speed is reduced or increased due to a load change, current will be induced in the damper windings producing torque that will help restoring the synchronous speed. Synchronous machine normally have damper windings to damp transients.

4.4.2.2 Start-up using a variable frequency supply

A frequency converter can be used to reduce the supply frequency to enable the rotor to follow the now slow rotating field. The frequency is gradually increased to bring the machine up to synchronous speed. These converters are however very expensive, but can be used to operate the machine at variable speeds.

4.4.2.3 Start-up using a pony motor

Another possibility is to use an additional smaller (pony) motor to bring the synchronous machine up to synchronous speed. When synchronous speed is reached the field of the synchronous machine can be connected and the pony motor disconnected. This method would not be ideal for the PBMR, because the pony motor is only used during start-up and in power stations this happens very seldom and the pony won't be used for very long times.

4.4.3 Performance properties

The synchronous machine has one major advantage over the other generators. The machine is capable of controlling the power factor by controlling the field current. The power transfer for a three-phase machine can be written as:

$$P = 3V_t I_a \cos \phi = 3 \frac{V_t E_f}{X_s} \sin \delta \quad (4.16)$$

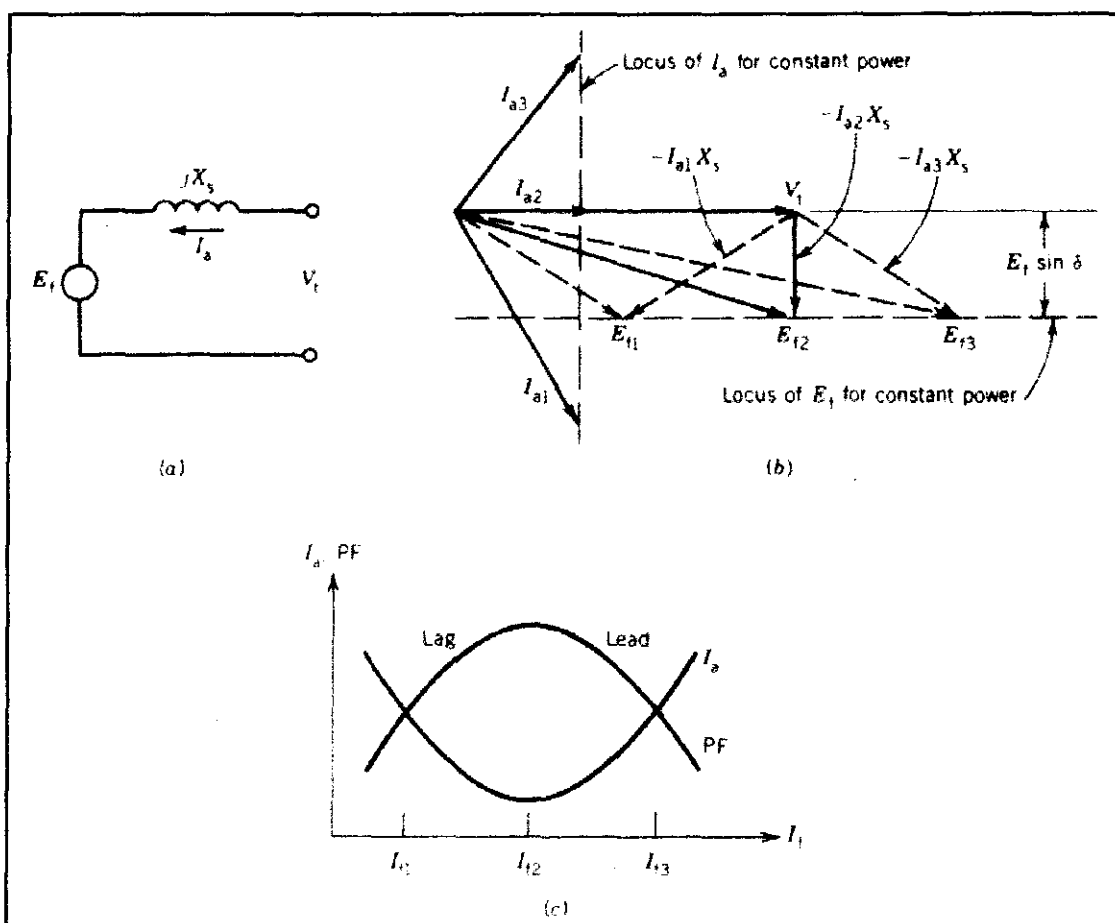


Figure 4-13 – Illustration of power factor variation during a constant power operation

When the synchronous machine is connected to the grid V_t is kept constant. For a constant power operation the in-phase component of the stator current $|I_a \cos \phi|$ is also constant as shown by the I_a locus in Figure 4-13 b). The term $|E_f \sin \delta|$ must also be constant for a constant power operation as indicated by the horizontal locus of $E_f \sin \delta$.

The excitation voltage E_f changes linearly with the field current I_f and therefore E_f will change along the locus of E_f and I_a along the locus of I_a as the field current is changed. As I_a changes along its locus it results in huge changes in the power factor angle ϕ of the stator current. Figure 4-13 (c) shows that the power factor can be altered from leading to lagging and even unity power factor by changing I_f .

4.5 Machine choice

In order to make a choice between the three different generators discussed, there are two more general topics to be discussed. The power density and the application range of the machines are compared before a choice is made.

4.5.1 AC and DC motor power density summary

Despite the electrical properties of AC and DC machines discussed in the previous sections, the construction and physical size can also be a determining factor. This can be measured as power or torque density (power or torque per frame size) of the machine.

In Figure 4-14 the rated power of a standard AC and DC machine for a specific NEMA frame diameter are shown. In (a) the machines are open, self-ventilated machines while these in (b) are force ventilated and in (c) the machines are totally enclosed machines. The totally enclosed machines show virtually no difference between the AC and DC machines' power densities.

The force ventilated machines are the more likely machine type to be used and in Figure 4-14 (b) the DC machine shows a distinct advantage. At the 400-diameter mark the DC machine has an output power of nearly 300 kW while the AC machine only has a rated power of just over 75 kW. The difference is nearly four times and this would undoubtedly swing the favour in the DC machine as choice for the PBMR where size plays an important role.

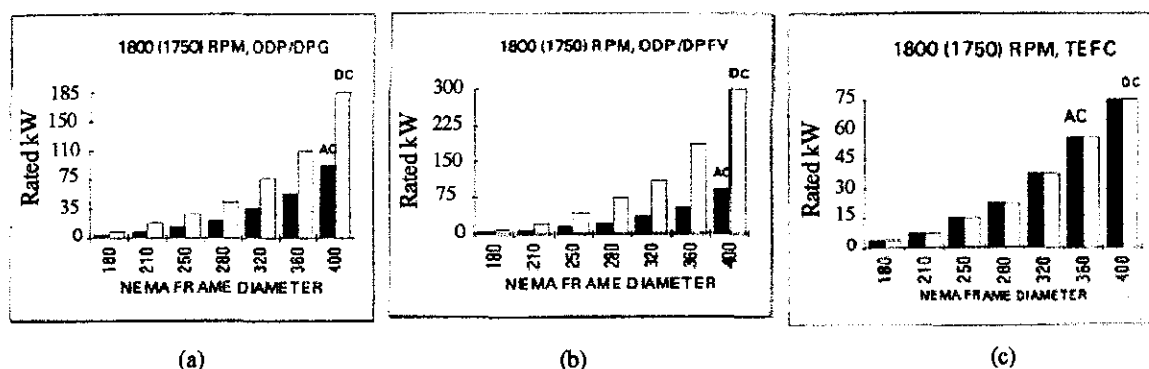


Figure 4-14 – AC and DC motor power density using standard machines available [27]

The difference between the power densities of Figure 4-14 (b) and (c) are however of such proportions one can't just accept them. All the comparisons were done based on typical AC and DC machines of one company. How big differences can the historical considerations and standardization (NEMA standards) really make on the physics of AC and DC machines?

In order to make a more “apples with apples” comparison, Reliance Electric [27] compared the power densities of AC and DC machines with new designs created without any constraints like historical development or standardization. Various frame sizes and power ratings were used and all followed the same pattern.

The results of these tests were quite different of the previous comparisons. Because the PBMR will require a newly designed machine one can make the assumption that the results in Figure 4-15 are more applicable. These test shows that the AC induction machine has a large advantage in power density. This advantage can be expected to increase when higher rotational speeds (like 9000 rpm) are used. The advantage is probably due to the fact that the DC machine has some non-torque producing equipment like the commutator and brushes. Another important feature especially in power generation are the efficiency or losses of the machines. The AC machine now shows a clear advantage.

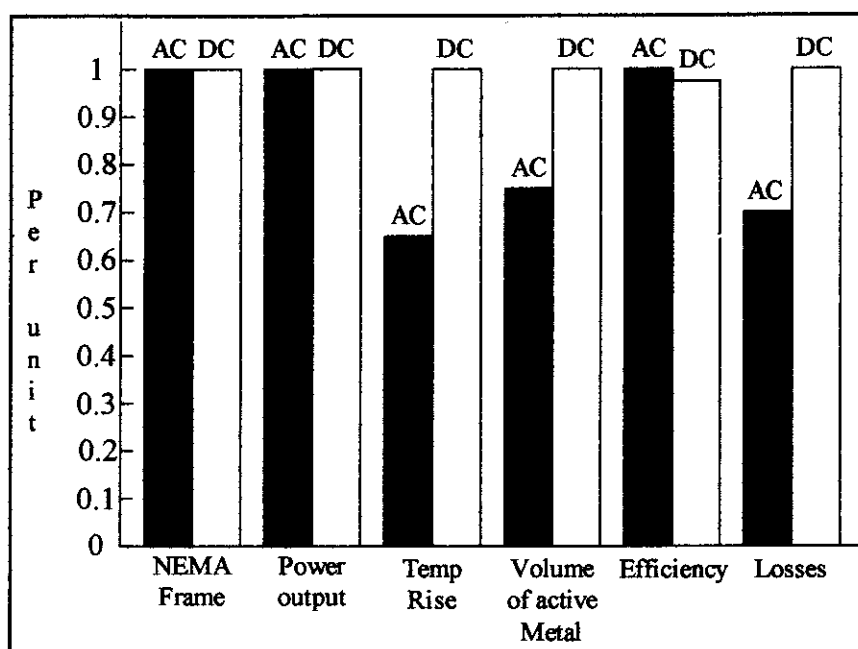


Figure 4-15 - Unconstrained AC and DC machine power density comparison [27]

4.5.2 Machine applications

The primary use of synchronous machines is as AC generators currently supplying almost all of the electrical power used world wide. The main reason is the high efficiency and reactive power control capabilities. The motors also have very high efficiencies (up to 99% [14 p338]), but they are only used in constant speed applications where continuous operation is required. This is because of the difficulties starting synchronous motors.

The disadvantage of synchronous machines is the DC current required for excitation. The problems with the slip rings and brushes can be overcome with the use of a small exciter mounted on the rotor shaft.

Synchronous machines have a higher initial cost when compared to induction machines and are therefore not suitable at high speeds and for smaller applications below 40 kW in the medium speed range. They are however used in low speed applications, because at these speeds induction machines require a large amount of iron to establish a high air-gap flux density, increasing their size and cost. The typical application range of induction and synchronous machines are shown in Figure 4-16.

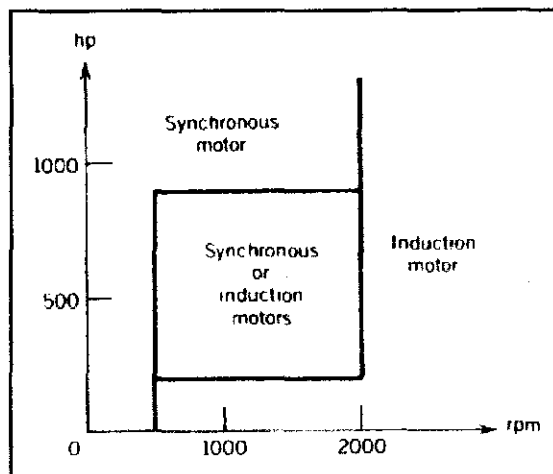


Figure 4-16 – Application range of induction and synchronous machines [24]

4.5.3 Conclusion of generator choice

All the generator set-ups discussed had their advantages and disadvantages. The best combination for the PBMR is the high-speed induction generator with the full MVDC converter. Although the combination is not the cheapest solution it provides some important advantages.

The advantages and disadvantages of the different machines are summarized in Table 4-2 to Table 4-4. These advantages include the machine properties discussed in section 4.2 to 4.3 as well as the PBMR implications discussed in section 4.1.

4.5.3.1 Direct current machine

The advantages are not in particular necessary for the PBMR. A power generation plant is not started regularly and the easy motor operation is not that important as the capability to start-up the system. The high starting torque is also nice to have, but the PBMR is started with blowers starting the Brayton cycle and won't need a high starting torque.

The DC machine system does not offer real advantages in the PBMR system. The disadvantages are influencing the PBMR system negatively in quite a few ways and the system is therefore not the ideal system for this particular application.

Table 4-2 – Direct current machine advantages and disadvantages

Advantages	Disadvantages
Easy to control via the field	Large expensive machine (Lower power density - see Figure 4-15)
No rectifier (1/2 – bridge)	High maintenance on brushes
Easy to operate as motor	Sparking at brushes may be unacceptable
High starting torque	Rotor and stator are wound
	Total power must flow through inverter
	Rotor carries all the delivered current
	Lower efficiency (see Figure 4-15)

4.5.3.2 Synchronous machine

The use of a high-speed synchronous generator would have the advantage of size reduction and increased efficiency of the turbines but would then also need an MVDC converter. The advantage of power factor control by the generator will be wasted because the converter will do it in any case. Conventional design 9000 rpm synchronous generators are currently not possible and Lamont [26] estimated that 180 MW superconductor generators would only be available in about 6 to 11 years.

Table 4-3 – Synchronous machine advantages and disadvantages

Advantages	Disadvantages
Easy to control	DC current source necessary
Reactive power control (high power factor)	Slip rings and brushes need maintenance
Smaller than DC machines	Difficult to start-up
High efficiency (± 0.99) for large machines	High-speed superconductor machine only possible between 2010 and 2015
	Fast control at constant speed needed
	Wound stator and rotor

4.5.3.3 High-speed squirrel-cage induction machine

Except for the high investment cost of the MVDC converter the use of the high-speed squirrel-cage induction machine is by far the most promising option for the PBMR. When one takes in consideration the fact that the PBMR is a nuclear power station, the possibility of constructing these plants close to densely populated areas is quite high.

The plant can even be constructed in “nuclear friendly” countries that has no environmental and other issues surrounding nuclear power stations. The power can then be transmitted to neighbouring countries using DC transmission. In such cases the break-even distance can come into play and this initially more expensive solution may even prove to be the economical solution.

Table 4-4 – Squirrel-cage induction machine advantages and disadvantages

Advantages	Disadvantages
Low cost, rigid machine Very low maintenance (no brushes and slip rings) Smaller than all the other machines (Highest power density) High efficiency (± 0.98)[14 p270] See section 4.1.3.2 for PBMR MVDC advantages See section 4.3 for MVDC's advantages over HVDC Only stator is wound	Full bridge is necessary Complex control system Poor lagging power factor (± 0.9) MVDC converter very expensive

4.6 Summary

The current PBMR system was evaluated and three different configurations were investigated. The key difference between the configurations was the machine choice.

The high-speed induction generator with an MVDC converter was found to be the best choice because of the many advantages of the system. The most important advantages include the increase in turbine efficiency, smaller turbines and generator, two-shaft system with less sophisticated control and a standard design for 50 Hz and 60 Hz systems.

The core disadvantages of the proposed system are the induction machine's poor power factor and the additional cost of the MVDC converter. These factors cannot be overlooked, but the advantages were found to be more significant considering the system as a whole including possible foreign installation.

Chapter 5

Basic MVDC converter design

In the previous chapter a new system configuration using a high-speed induction generator and MVDC converter was suggested. In this chapter the MVDC converter and the necessary components are discussed. These components include the DC bus capacitor, filtering equipment and the transformer.

5.1 Components of an MVDC converter

All MVDC converters consist of the same basic building blocks as shown in Figure 5-1 [22]. On the AC sides a harmonic filter is normally installed to filter out the harmonic caused by the switching of the power electronics. The filters are therefore tuned to filter out harmonics around the switching frequency. The AC-side is connected to the DC-side by the power electronic switches, which are IGBTs in most MVDC applications at this stage.

On the DC-side a DC capacitor, C_{dc} , is connected to ensure the voltage is almost ripple free and constant for at least one switching period. The DC-side is equipped with high frequency filters, L_{fdc} and C_{fdc} , filtering out frequencies of 100 kHz and above [22]. This is done to ensure no interference of radio broadcasts and other high frequency equipment near the DC cable. The two converter sides, the rectifier side and inverter side, can either be directly connected resulting in a so-called back-to-back converter configuration or the two sides can be connected using DC cable/line over some distance.

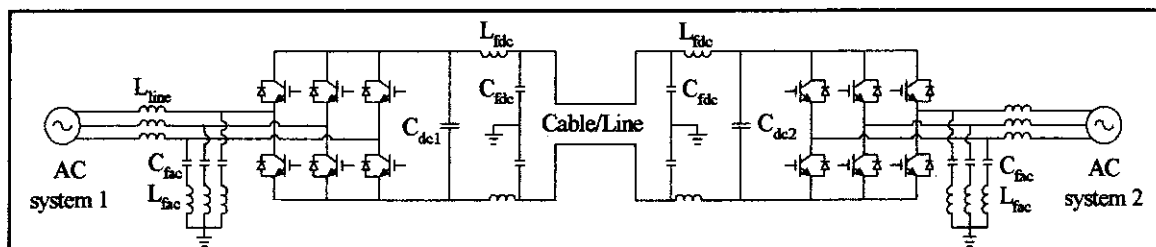


Figure 5-1 – Typical Components of an MVDC converter [22]

In the case of the selected high-speed asynchronous generator in the PBMR configuration a step-up transformer will be necessary. The generator cannot generate high enough voltages to allow a direct connection to the distribution network. This choice is driven by the fact that I^2R losses will be much lower at the higher voltages. The rating,

positioning and necessity of a tap-changer will be discussed in more detail later on in section 5.1.3. With the proposed PBMR configuration the necessary components are shown in Figure 5-2.

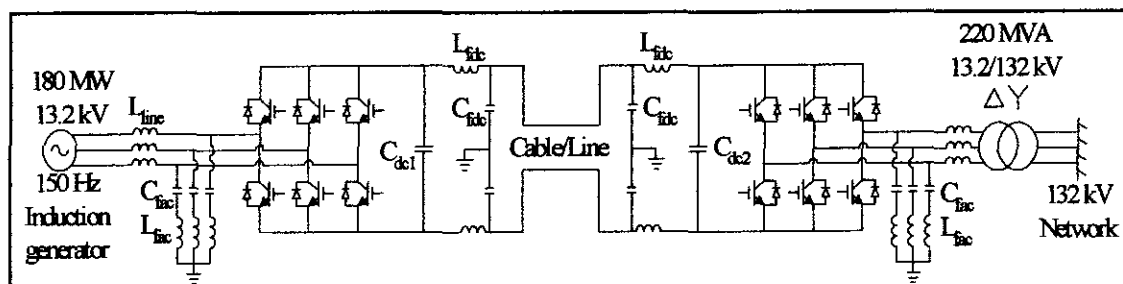


Figure 5-2 – MVDC components in PBMR configuration

5.1.1 Suggested switching frequency of the MVDC converter

The MVDC converters in the range of the PBMR's 180 MW use IGBTs with a switching frequency capability of about 2 kHz. Higher switching frequencies are not used for such large applications, because the switching losses increase linearly with increase in switching frequency. At lower switching frequencies the harmonics created by the converter are larger and at lower frequencies. There is therefore a trade-off between a high switching frequency with higher losses, but fewer harmonics and a lower switching frequency with lower losses, but more harmonics.

The carrier frequency or switching frequency, f_s are set at 1950 Hz for 50 Hz power system connections. The reason for this can be explained as follows: the frequency modulation ratio, m_f is 39 in this case and is considered large (> 21) [15]. Under these conditions the switching frequency and modulation frequency are normally not synchronized (resulting in an integer m_f), because the gain in harmonic reduction by doing so is not that much. It is however recommended in the case of the PBMR, because 180 MW is quite a large MVDC converter and the reduction in harmonics will be noticeable. The reason for choosing 1950 Hz and not 2000 Hz is because the frequency modulation ratio should be an odd integer. Choosing an odd integer will result in the elimination of even harmonics. In power system applications where the line-to-line harmonics are of importance, choosing a frequency modulation ratio that is a multiple of 3, like 39, eliminates the most dominant harmonics [15].

5.1.2 Converter Properties

The converter on the generator side will operate as a rectifier for most of the time as power is delivered from the generator to the grid. To enable the start-up of the generator the converter must be able to act as an inverter. This implies that a four-quadrant converter is necessary. Because both the generator side converter and the sending end converter must be capable of four-quadrant operation, they will be carbon copies of each other connected back-to-back.

The switching elements suggested for the MVDC converter are IGBTs. The IGBT was discussed in section 3.4.1 and are recommended because of the following reasons:

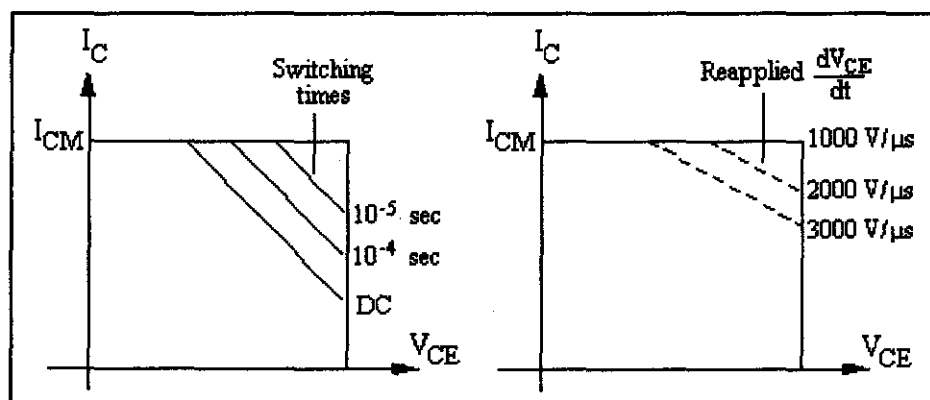
- Low base power required.
- High enough switching frequency required for PWM.
- Low switching losses.
- Relative low on state losses.
- Easy to parallel.
- Advanced but proven technology.

Other promising technologies are SGCTs and IGCTs. They are new technologies promising even greater advantages than IGBTs as can be seen in Figure 3-6, but were not chosen because of a lack of maturity of the technologies.

To obtain the rated current and voltage of the MVDC converter, several IGBTs are needed. The power ratings of one of the largest currently available IGBTs are shown in Table 5-1 while Figure 5-1 shows the safe operating area (SOA) of IGBTs. With this information and the power rating of the MVDC converter the total number of IGBTs needed, can be determined.

Table 5-1 – Selected IGBTs ratings [30]

Parameter	Symbol	Rating	Unit
Collector-emitter voltage	V_{CES}	4 500	V
Gate-emitter voltage	V_{GES}	+20	V
DC collector current	I_C	2 000	A
	$-I_C$	2 000	A
Pulse collector current	I_C (pulse)	4 000	A
	$-I_C$ (pulse)	4 000	A
Max collector power dissipation	P_C	10 000	W
Junction temperature	T_j	-40 - 125	°C
Mounting force	-	55 - 70	kN

**Figure 5-3 – Safe operating areas (SOA) of an IGBT (left – forward biased; right – reverse biased)**

The step-up transformer is located at the generator side of the MVDC converter. The reason for this is discussed in section 5.1.3.1. This implies that the converter is subjected to a higher voltage and lower current leading to more IGBTs in series and less IGBTs in parallel.

For the 180 MW converter the DC current will therefore be 1 364 A using 132 kV. This means that the 2 000 A IGBT shown in Table 5-1 will be capable of handling the current without additional IGBTs in parallel. It will also be unnecessary to use an additional parallel IGBT to increase the safety margin, because the current is well below the maximum continuous current rating of the IGBTs. Another important property of the IGBTs is the fact that they become a short circuit whenever they blow. This means that operation can continue when a single IGBT becomes faulty. This also implies that additional parallel IGBTs are not necessary. Should the IGBTs become

open circuited when they blow, additional parallel IGBTs would be necessary to continue operation when a single IGBT has become faulty.

The IGBTs are however not capable of handling the voltage individually and a series combination will be necessary. The IGBT shown in Table 5-1 can handle a voltage of 4 500 V. For the 132 kV, 30 IGBTs would be necessary. For a safety margin of 20%, it is suggested that at least 36 IGBTs be used in series for each valve. This will also allow continuous operation even when no more than two IGBTs in series become faulty.

5.1.3 Transformer

The main transformer of the PBMR is currently rated 210 MVA @ 13,2 kV/132 kV equipped with an on-load tap changer. A transformer rated 10 MVA @ 13,2 kV/11,5 kV, equipped with an off-circuit tap changer, is used to reduce the fault current level at its secondary terminals while feeding the auxiliary equipment. The voltage of 13,2 kV is brought down to 11,5 kV to enable to use standard switchgear normally rated @ 11 kV. The extra 0,5 kV ensures better voltage regulation.

Converters are normally connected to the AC system by means of transformers for the following reasons:

- To provide a reactance between the converter and the AC system. If this is the only reason, a reactor can be used.
- Ensuring a voltage suitable for transmission
- Connecting of two 6-pulse converters to form a twelve-pulse converter.
- To connect two different converters with different DC voltages to the same network.

In the case of the PBMR a transformer will be necessary to step-up the voltage to 132 kV, because it is the voltage used for transmission at Koeberg. A direct connection would only have been possible if a powerformer was used, but was eliminated as discussed in section 5.1.3. The second reason is therefore important in this case.

5.1.3.1 Transformer position

The best possible position for the step-up transformer will be on the generator side of the MVDC converter. This position ensures the minimum converter losses and the physical smallest transformer. The only disadvantage of the position is the fact that the auxiliary transformer is connected to the high voltage side and will need higher isolation levels.

The step-up transformer can be positioned at two different positions each with its own advantages. The one possibility is to insert the transformer on the network side of the converter and the other possibility is between the generator and the converter.

Positioning the transformer at the network side of the MVDC converter implies that the transformer will be subjected to a constant 50 Hz or 60 Hz frequency power. This simplifies the transformer's specification and design. This position will also allow the auxiliary transformer to be connected to a lower primary voltage.

Should the transformer however be located between the generator and the MVDC converter, the losses of the MVDC converter will be reduced. The reason for this reduction in losses is due to the properties of the switching elements.

The total losses of the IGBTs consists of two types of losses namely the switching losses and the conduction losses. The switching losses can be written as:

$$P_{switch} = (E_{on} + E_{off})f \quad (4.17)$$

The turn-on energy (E_{on}) and the turn off energy (E_{off}) are direct proportional to the current and the voltage. The position of the transformer will therefore not influence the losses of the IGBTs during switching.

The conduction losses of the IGBTs can be written as:

$$P_{cond} = I_c V_{ce} \quad (4.18)$$

Examining equation (4.18) it might appear that the conduction losses are also directly proportional to the current and the voltage, but V_{ce} is also dependant on I_c and can be written as:

$$V_{ce} = V_{TO} + R_{ce} I_c \quad (4.19)$$

In equation (4.19) V_{TO} and R_{ce} are output characteristics of the IGBT. By substituting V_{ce} of equation (4.19) into equation (4.18), the conduction losses can be written as:

$$\begin{aligned} P_{cond} &= I_c(V_{TO} + I_c R_c) \\ &= I_c V_{TO} + I_c^2 R_c \end{aligned} \quad (4.20)$$

Equation (4.20) shows that the conduction losses depends more on the current than the voltage and it would therefore be advisable to use a higher voltage rather than a higher current. This implies that one would rather use more IGBTs in series than in parallel to obtain a desired power capability.

Another advantage of this position is the fact that the DC voltage will be much higher and therefore reducing the bulk DC capacitor's size. The capacitor volume is approximately proportional to the voltage rating, but the energy storage capacity is proportional to the square of the voltage rating. The capacitor will therefore be physically smaller and consequently less expensive.

This transformer position between the generator and the MVDC converter subjects the transformer to the variable frequency of the generator. The disadvantage of this is the fact that if the transformer is designed for 150 Hz operation it won't be capable of handling the full power at a lower frequency, because the core will saturate. In the case of the PBMR such an operating point won't occur. The induction generator has exactly the same property. The PBMR will operate between 40% and 100% of its rated power and in that power range the MVDC converter will operate in constant flux control as described in section 5.2.1.6. This implies that the transformer can be designed for 150 Hz without degrading it for possible lower frequency operation. A 150 Hz transformer will also be much smaller than the 50 Hz or 60 Hz transformer needed on the network side.

The only disadvantage of this position is that the auxiliary transformer has to be connected to the 132 kV transmission voltage. The low voltage side will be a variable 150 Hz voltage, which is not suitable for the auxiliary equipment. The higher isolation needed will increase the cost of this transformer slightly. The main transformer will however be less expensive, because it is smaller and this saving will be more than the cost increase of the relatively much smaller auxiliary transformer.

The reasons for installing the transformer on the generator side of the transformer can therefore be summarised as followed:

- Increased MVDC converter efficiency.
- Physically smaller and less expensive transformer.
- Same transformer design for 50 Hz and 60 Hz systems.
- Present MVDC systems use voltages between 80 kV and 150 kV.
- The bulk DC capacitor will be less expensive.

5.1.3.2 Transformer configuration

The transformer can either be connected as a star-star, delta-delta, star-delta or a delta-star connection. Each of these connections has different advantages and the application determines the choice. To be able to make a choice all four connection types will be discussed shortly.

▪ Star-star connection

The star-star connection is shown in Figure 5-4. It can be seen that the line current will be equal to the current in each coil while the voltage across the coil is only $1/\sqrt{3}$ of the line-to-line voltage. This connection type will have the following advantages:

- The conductors' cross sectional area is large, because it conducts the whole line current, while the number of turns is at its minimum because the voltage across the coil is only the phase voltage. The coil's isolation requirement is therefore at its minimum resulting in a high winding space factor.
- Ideal for low current, high voltage applications.
- Both neutrals are available for grounding.
- Graded insulation can be used on the primary winding
- If one phase becomes faulted, the other two phases can still supply load at $1/\sqrt{3}$ of the nominal 3 phase rating.

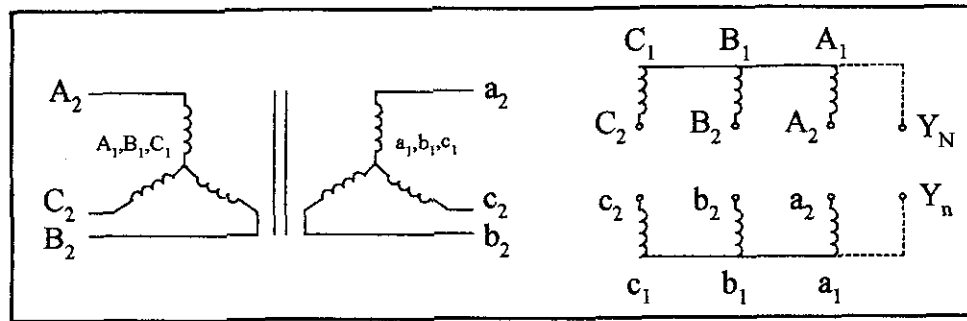


Figure 5-4 – Star-star transformer connection

▪ **Delta-delta connection**

The delta-delta connection is shown in Figure 5-5. In this case the voltage across the coil is the line-to-line voltage, but the current is only $1/\sqrt{3}$ of the line current. This type of connection will have the following advantages:

- If one phase becomes faulty, the two remaining phases can be operated in open delta at $1/\sqrt{3}$ of the nominal three phase power output [29].
- Ideal connection for high current, low voltage applications.
- Third harmonic voltages are eliminated, because the third harmonic currents circulate in the delta.

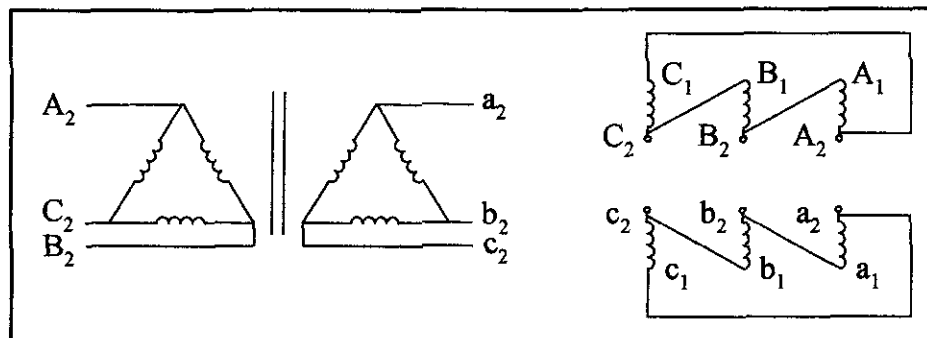


Figure 5-5 – Delta-delta transformer connection

These transformers are very seldom used. The advantage of operation at a reduced rating seems to be overseen, because utilities prefer to immediately replace faulty units. The fact that no neutral is available unless additional equipment is used is also a great drawback.

▪ Star-delta connection

In this case the primary is connected as a star while the secondary is connected in delta. The primary will therefore have the same properties as mentioned in the previously discussed star-star connection and the secondary as the delta-delta connection. This combination has the following advantages:

- Third harmonic voltages are eliminated, because the third harmonic current circulates in the secondary delta [29].
- The primary side has a neutral available to ground.
- Graded insulation can be used on the primary winding.
- Ideal connection for step-down applications.

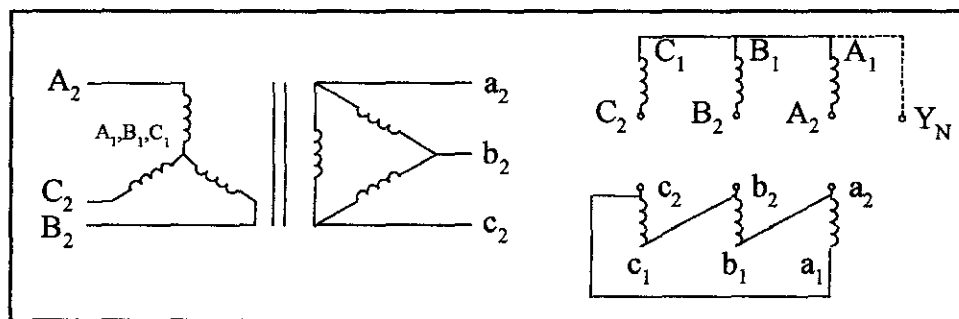


Figure 5-6 – Star-delta transformer connection

These transformers are normally used as step-down transformers and generator transformers.

▪ Delta-star connection

The primary side is now connected in delta while the secondary side is connected in star. The primary will therefore have the same properties as mentioned in the previously discussed delta-delta connection and the secondary as the star-star connection. This combination has the following advantages:

- Again the third harmonic voltages are eliminated, because the third harmonic current is circulating in the primary delta.
- The secondary may be grounded.

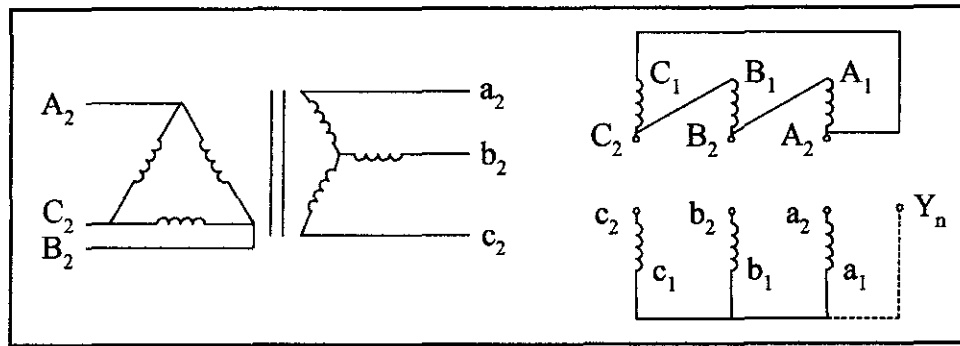


Figure 5-7 – Delta-star transformer connection

This connection type is used for stepping up voltages for high voltage distribution as the third harmonic voltages are eliminated and the high voltage side can be grounded.

5.1.3.3 Harmonics and the K-factor

In the modern power system environment more and more switch-mode power supplies are used. The converter size has increased dramatically due to the fast growth in the power capabilities of power electronics, e.g. IGBTs, IGCTs and SGCTs. The continuous switching of these elements is causing more harmonic distortion in the current.

These large harmonic currents may cause transformers supplying these types of loads to overheat even when used at 50% of its nameplate rating. It is therefore evident that something has to be done when non-linear loads are to be supplied by a transformer. One way of dealing with the problem is to increase the nominal rating with 20% to 50% when these loads are to be connected. The modern way however is the introduction of transformers designed with a so-called K-factor [31].

The K-factor is an indication of the transformer's designed capability to handle harmonic currents. These transformers are designed to supply 100% of its rated fundamental frequency load plus the harmonic loads indicated in Table 5-2 without exceeding its rated temperature rise. A transformer with a K-4 factor can therefore carry its rated load with an additional 50% non-linear load without overheating.

Table 5-2 – Standard K-factor values and their harmonic capability [31]

K Factor	Non Linear/Harmonic Loads
K-1	Generally no Harmonic/ non-linear loads
K-4	50% Non-Linear Load 16.7% of the rated current at the 3 rd Harmonic 10.0% of the rated current at the 5 th Harmonic 7.1% of the rated current at the 7 th Harmonic 5.6% of the rated current at the 9 th Harmonic For harmonics larger than the 9 th but smaller than the 25 th harmonic, the percentage of the fundamental current shall be the reciprocal of the odd harmonic number times 0.5.
K-13	100% Non-Linear Load 33.3% of the rated current at the 3 rd harmonic 20.0% of the rated current at the 5 th harmonic 14.3% of the rated current at the 7 th harmonic 11.1% of the rated current at the 9 th harmonic For harmonics larger than the 9 th but smaller than the 25 th harmonic, the percentage of the fundamental current shall be the reciprocal of the odd harmonic number times 1.
K-20	125% Non-Linear Load 41.7% of the rated current at the 3 rd harmonic 25.0% of the rated current at the 5 th harmonic 17.9% of the rated current at the 7 th harmonic 13.9% of the rated current at the 9 th harmonic For harmonics larger than the 9 th but smaller than the 25 th harmonic, the percentage of the fundamental current shall be the reciprocal of the odd harmonic number times 1.25.
K-30	150% Non-Linear Load 50.0% of the rated current at the 3 rd harmonic 30.0% of the rated current at the 5 th harmonic 21.4% of the rated current at the 7 th harmonic 16.7% of the rated current at the 9 th harmonic For harmonics larger than the 9 th but smaller than the 25 th harmonic, the percentage of the fundamental current shall be the reciprocal of the odd harmonic number times 1.5.

The MVDC converter has a switching frequency of 1950 Hz, which is 39 times the fundamental frequency. Harmonics generated by the converter will therefore appear at sidebands of the switching frequency. Using the unipolar PWM switching scheme the harmonics generated by the converter will only appear at two times the modulation frequency. These high order harmonics can easily be filtered out using a high-pass filter. For these high order harmonics one would therefore rather filter them out than using a transformer designed with a K-factor.

This transformer is also located at the beginning of the distribution network, in fact just after the power generator, and using a K-factor designed transformer would imply that

all the harmonics are sent through the entire system and all the equipment down the network must therefore be capable of handling these harmonics.

5.1.3.4 Transformer efficiency

Transformers are very efficient pieces of equipment. The efficiency of transformers is however dependant on the power factor of the load. The best efficiency occurs at a power factor of one and become worse as the power factor drops as illustrated in Figure 5-8. The load current also influences the power factor and the efficiency is not at its best at full load current. The best efficiency is obtained if the transformer is operated at a load current such that the copper loss equals the core losses [24].

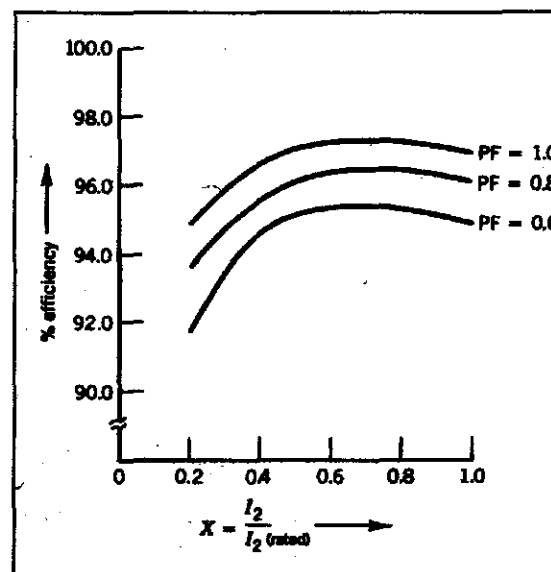


Figure 5-8 – Transformer efficiency at three different power factors [24]

Figure 5-8 shows that the influence of the load current is not much as long as the load is kept above about 40% of its nominal current rating. The efficiency shows a significant difference of about 1% for a power factor difference of 20%. One percent might look small, but for a 180 MW transformer equals 1.8 MW of lost power. At a cost of R35 / MWh contributes to a total of R500 000 lost in only one year.

The MVDC converter can deliver unity power, but the asynchronous generator will need reactive power from the grid. To enable the converter to deliver power at a unity power factor, reactive power must be supplied to the generator using additional capacitor banks, which may be the filter capacitors.

5.1.3.5 Grounding

The grounding of transformers has three main goals namely the protection of the power system equipment, safety to humans and cost. In the power system the high-voltage side grounding will focus on power system protection and cost while the low-voltage side focuses on human safety. In this case the star-point is on the high-voltage side and grounding of this point will have an influence on the cost and protection of the system.

It is suggested that the high-voltage star connection is grounded, because of the following reasons:

- Continuous arcing to ground is avoided and earth faults become a short-circuit. This eliminates high-voltage oscillation, which occurs frequently in systems having an isolated neutral [29].
- Grounding of the neutral point ensures maximum effectiveness of automatic protective gear when an earth fault occurs on the system.
- Grounding of the neutral point also ensures that the voltage of any live conductor cannot exceed the line-to-neutral voltage. The neutral point will be at zero potential, making it possible to reduce the insulation to earth, which results in a large cost saving. This is not only applicable to overhead lines and cables, but also to transformers.

If the neutral point is isolated and an earth fault should occur on one of the lines, the voltage of the two lines will rise to the line-to-line voltage above earth. The isolation of the system must therefore be designed for this possibility, increasing the system cost.

Even under normal conditions the voltage of an ungrounded system may rise to levels above the breakdown voltage of the insulation. These conditions appear by means of electrostatic induction on overhead lines subjected to dust, fog, rain and changes in the altitude of the lines [29].

5.1.3.6 Tap changer

Tap changers are used to vary the voltage of a power system ensuring a good voltage regulation throughout the system. In older systems the generators were used to increase or decrease the system voltage when changes in the load takes place. In the modern era

the generators operate as constant voltage machines and transformers equipped with on-load tap changers ensure good voltage regulation throughout the extensive power system. There are two types of tap-changing i.e. off-circuit and on-load tap changing.

Off-circuit tap changing is the simpler and the cheaper of the two methods. The transformer tapings are terminated inside the tank and the cover of the tank must be removed in order to change the tap setting. Models are available where the taps can be manually changed from outside the tank. The drawback of both these configurations is that the transformer must be completely disconnected from the grid before the taps can be changed. This type will therefore not be suitable for the PBMR where the transformer is the main grid connection and the system can't be shut down just to change a tap.

On-load tap changers on the other hand can change tap positions while power is delivered to a load. This is why this type of tap changing will be more suited for power generation purposes. The tap will be on the high-voltage side to minimize the current that needs to be switched. On-load tap-changers are therefore very useful in applications where the load is constantly changing and voltage regulation is required.

The PBMR is a nuclear power plant that will be used in cooperation with many other fossil-fuel generator units. Although nuclear power plants are more expensive to build, their operating cost is much lower than that of fossil-fuel plants, because their nuclear fuel is less expensive. The PBMR plant will therefore normally operate at its rated power output while the fossil-fuel plants will react on load changes. The PBMR is however designed to operate between 40% and 100% of its rated power.

Should these variances in the load occur:

- The MVDC converter can handle the voltage regulation.
- The MVDC converter can quickly react to changes in the reactive power demand caused by voltage dips.

The MVDC converter is therefore capable of handling all the tasks a tap changer would normally be intended to. A tap changer is therefore not necessary.

5.1.3.7 Recommendation

The delta-star configuration without any tap changer and a grounded neutral is considered the best transformer choice for the PBMR. The PBMR transformer is a large step-up transformer used for power generation and following from the previous sections the main reasons for the choice are therefore:

- The primary delta ensures third harmonic voltages from the generator are not fed into MVDC converter and the power system.
- The high voltage side is connected in star and the low voltage side in delta resulting in the most economical connection. This is because on the high-voltage side the number of turns per phase is at its minimum, because the phase voltage is $1/\sqrt{3}$ of the line voltage and the isolation required is therefore at its minimum. The insulation can also be graded thus saving cost.

On the low-voltage side where the current is high the winding cross sectional area only needs to be large enough to carry $1/\sqrt{3}$ of the line current. This can also be seen in Table 5-3.

Table 5-3 – Economic comparison of transformer connections

High-voltage star	58%	58%	100%
Low-voltage delta	100%	100%	58%
Low-voltage star	58%	58%	100%
High-voltage delta	100%	100%	58%

- Grounding of the neutral point ensures that the voltage of any line conductor cannot exceed the line to neutral voltage, making it possible to reduce the isolation to earth, which results in a large cost saving. The grounding also ensures maximum effectiveness of automatic protective gear when an earth fault occurs on the system.
- To ensure maximum efficiency of the transformer the power factor must be as close as possible to unity implying reactive power compensation for the induction generator.

- No tap changer is needed, because the MVDC converter will be capable of controlling the voltage within the voltage regulation requirements.

5.1.4 AC shunt filter

5.1.4.1 Purpose

The AC line filter has two main purposes. The filter is in the first place designed to filter out harmonics caused by the switching of the power electronics. The filter is therefore designed to filter out frequencies equal to- and larger than the switching frequency. As can be seen in Figure 3-11 the harmonics appear as sidebands around the switching frequency and its multiples. The higher the switching frequency, the higher the frequency of the harmonics and therefore the smaller the filter required.

5.1.4.2 Network side filter

There are two possible options when selecting the AC network side filter. One possibility is to implement a low-pass filter that is designed to filter out all frequencies above a certain cut-off frequency. An example of a low-pass filter and its ideal frequency response is shown in Figure 5-9.

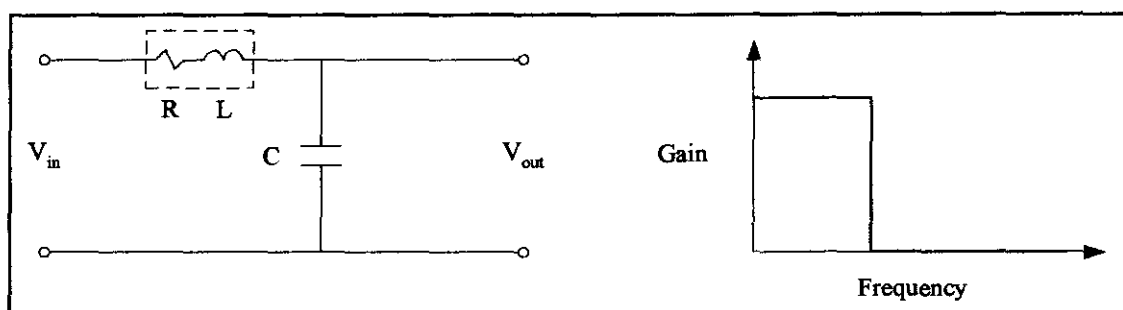


Figure 5-9 – Example of a low-pass filter

The other possibility is to design several notch/band-reject filters, each one tuned to filter out a specific harmonic. The configuration and resulting frequency response are illustrated in Figure 5-10.

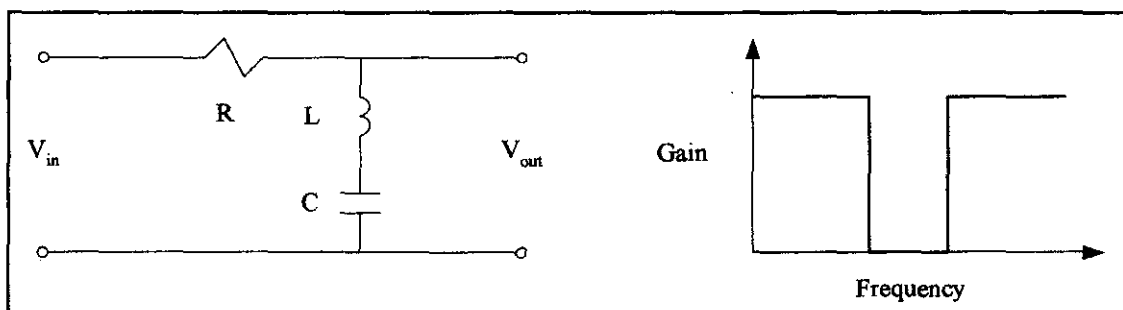


Figure 5-10 – Example of a notch/band-reject filter

The MVDC converter will generate harmonics at multiples of its switching frequency. The switching frequency was selected as 1950 Hz in section 5.1.1. For a 50 Hz power system the lowest harmonics will therefore be of the 39th order.

Notch filters are normally used in power systems when large lower order harmonics like 5th, 7th, 11th and 13th order harmonics are expected. Another drawback of notch filters is the fact that the inductance and capacitance of the filter inductor and capacitor changes over years. It could therefore happen that the notch shifts outside the designed frequency and the filter will become less and less effective.

The high order of the MVDC converter's harmonics requires smaller filters and consequently allows the use a single filter. A sole low-pass filter can therefore be used to filter out all the higher order harmonics. Low-pass filters are also less complex and therefore easier to design. A low-pass filter is therefore suggested for the MVDC converter and it will be designed in the next few paragraphs.

The transfer function of the low-pass filter shown in Figure 5-9 can be written as:

$$H(s) = \frac{1}{s^2 LC + sRC + 1} \quad (4.21)$$

To be able to select appropriate values for L, C and R, the transfer function is separated into a magnitude and angle functions. From equation (4.21) it is evident that H(s) has complex poles. In order to simplify it, R can be omitted, because it only represents the resistance of the inductor. This means that R will not only be small with little influence, but also uncontrollable because it is a fixed property of the inductor. The simplified magnitude of the transfer function can therefore be written as:

$$|H(jw)| = \frac{\left| \frac{1}{LC} \right|}{\left| \frac{1}{\sqrt{LC}} - w \right| \left| \frac{1}{\sqrt{LC}} + w \right|} \quad (4.22)$$

To ensure that the harmonics are properly filtered out, the corner frequency of the low-pass filter must be selected much lower than the switching frequency of the converter. The corner frequency is situated at the poles of equation (4.22) and the corner frequency can therefore be written as:

$$\omega_c = \frac{1}{\sqrt{LC}} \quad (4.23)$$

By selecting a low corner frequency of 200 Hz, the L and C can be determined. If the corner frequency were set to low, the filter would filter out lower order harmonics caused by other loads. This could overload the filter. A cut-off frequency of one decade below the switching frequency will ensure an attenuation of -40 dB at the switching frequency for this second order filter.

The capacitor should be chosen as large as possible to minimize the losses. The maximum size of the capacitor is determined by the maximum reactive power that will be needed. The reactive power needed is dependant on the system properties at the point of common coupling. A good approximation of common load and line power factors are 0.85. The expected reactive power demand will therefore be:

$$\begin{aligned} Q &= S \sin \theta \\ &= 180 \sin(31.788^\circ) \\ &= 94.8 \text{ MVar} \end{aligned} \quad (4.24)$$

The total reactive power needed for each phase will therefore be:

$$\begin{aligned} Q_{\text{total phase}} &= \frac{Q}{3} \\ &= \frac{94.8 \times 10^6}{3} \\ &= 32 \text{ MVar} \end{aligned} \quad (4.25)$$

The phase voltage will be $132 \text{ kV}/\sqrt{3}$, and the capacitive current per phase will be:

$$\begin{aligned} I_c &= \frac{Q}{V} \\ &= \frac{32 \times 10^6}{132 \times 10^3 / \sqrt{3}} \\ &= 420 \text{ A} \end{aligned} \quad (4.26)$$

The capacitive reactance per phase therefore is:

$$\begin{aligned}
 X_c &= \frac{V}{I} \\
 &= \frac{132 \times 10^3 / \sqrt{3}}{420} \\
 &= 181 \Omega
 \end{aligned} \tag{4.27}$$

The capacitance that is needed per phase is therefore:

$$\begin{aligned}
 C &= \frac{1}{2\pi f X_c} \\
 &= \frac{1}{2\pi \times 50 \times 181} \\
 &= 17.59 \mu F
 \end{aligned} \tag{4.28}$$

Using equation (4.23) for the corner frequency can now complete the filter design. The frequency range on the generator side of the transformer will vary between 110 Hz and 150 Hz during the normal power operation. To filter out the 1950 Hz switching harmonics, the corner frequency can be selected as:

$$\begin{aligned}
 \omega_c &= \frac{1}{\sqrt{LC}} \\
 \therefore L &= \frac{1}{C\omega_c^2} \\
 &= \frac{1}{17.59 \times 10^{-6} \times (2\pi 1950)^2} \\
 &= 3.79 \text{ mH}
 \end{aligned} \tag{4.29}$$

To verify the calculations, the amplitude and phase response of the transfer function with the designed values was plotted using Matlab as illustrated in Figure 5-11. A cut-off frequency of 200 Hz corresponds to a cut-off frequency of 1256.6 rad/s and this corresponds to the corner frequency shown in Figure 5-11.

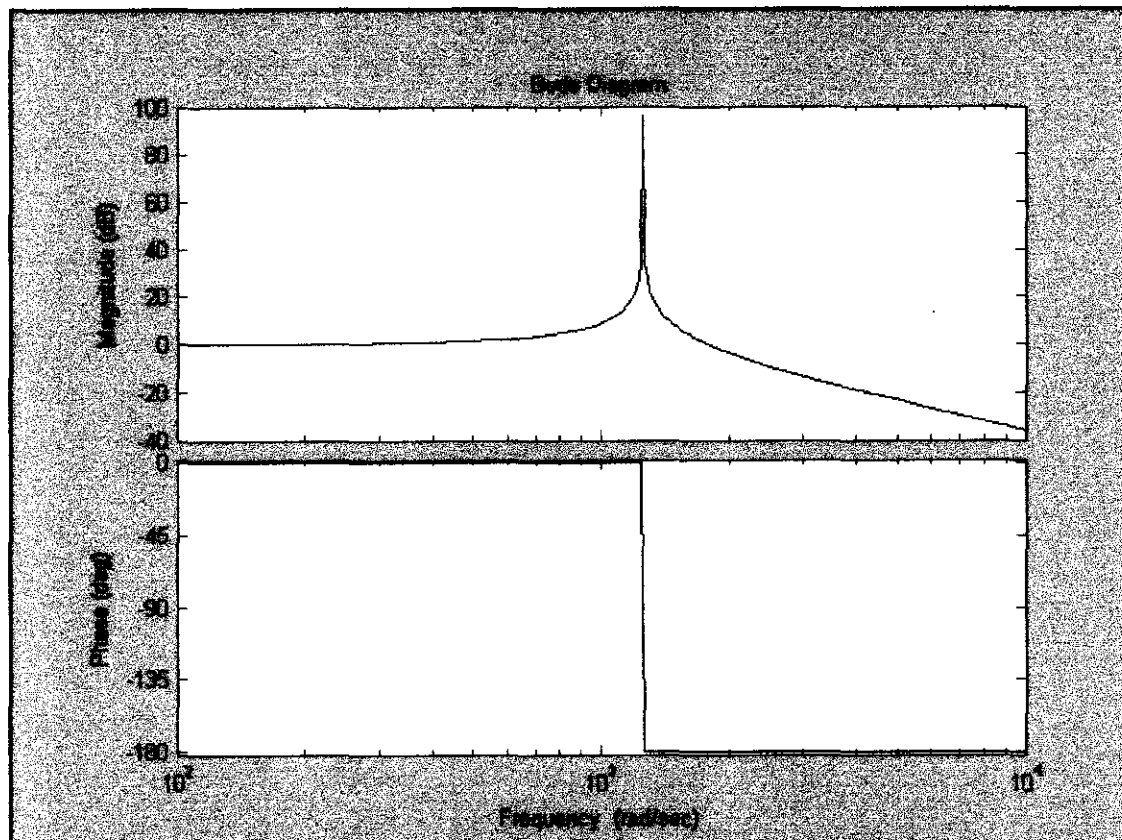


Figure 5-11 – Amplitude and phase response of the designed low-pass filter

To avoid the high gain at the corner frequency, a resistor must be inserted in series with the capacitor. A common ratio used to determine the value of the resistor is given by:

$$\begin{aligned}
 \frac{X_c}{R} &= 15 \\
 \therefore R &= \frac{X_c}{15} \\
 &= \frac{1/(2\pi 50 * 5.86 * 10^{-6})}{15} \\
 &= 36 \quad \Omega
 \end{aligned} \tag{4.30}$$

In the Hellsjon MVDC installation a filter kvar rating of 10% of the nominal power rating of the MVDC converter was found to be adequate to keep the THD well below the 5% recommended for voltages below 69 kV in the IEEE Std 519-92. In this case the voltage is 132 kV and the IEEE Std 519-92 recommends a THD of less than 2.5%. The filter should therefore be larger, in the order of 20% of the nominal power rating. This will also meet the South African NRS048-2:1996 standard, which recommends a THD of less than 3% for high voltage systems. High voltage systems are systems using a voltage above 44 kV.

5.1.4.3 Generator side filter

On the generator side a similar low-pass filter can be installed. Installing a filter on the input side will improve the power factor and reduce the EMI. The reduction of EMI is of special importance when operation is in the close proximity of any broadcasting facilities.

In order to avoid oscillation, damping is usually necessary. The resonant frequency of the input filter should be a decade lower than that of the DC filter to avoid any interaction between the two [15]. The capacitor should also be chosen as large as possible to minimize the losses. The maximum size of the capacitor is determined by the maximum reactive power that will be needed by the induction generator and the transformer. Because the frequency will vary while the load changes from its minimum to its maximum, the maximum reactive power that will be needed won't be necessarily during maximum power command. This point must therefore be determined and the maximum reactive power command at that point can then be used to calculate the capacitor's size.

The reactive power needed respectively by the generator and the transformer can be written as:

$$\begin{aligned} Q_{gen} &= \sqrt{S^2 - P^2} \\ Q_t &= I^2 X_t \end{aligned} \quad (4.31)$$

The reactive power that can be supplied by the capacitor on the hand are given by:

$$Q_c = \frac{V^2}{X_c} \quad (4.32)$$

With the assumption that the power factor of the induction generator remains constant over the 40% to 100% power range, the reactive power needed by the generator will be direct proportional to the real power demand. The relation can therefore be written as:

$$Q_c \propto P \quad (4.33)$$

The reactive power consumption of the transformer is direct proportional to the product of the square of the current and the frequency. This can be derived by substituting X_t with $1/2\pi fC$ in equation (4.31). The relationship between the reactive power

consumption of the transformer in terms of the current and frequency can therefore be written as:

$$Q_t \propto f^2 \quad (4.34)$$

The same can be done for the capacitor. Substituting X_c in equation (4.32) with $1/2\pi fC$ the relationship of the reactive power in terms of the frequency and voltage can be written as:

$$Q_c \propto E^2 f \quad (4.35)$$

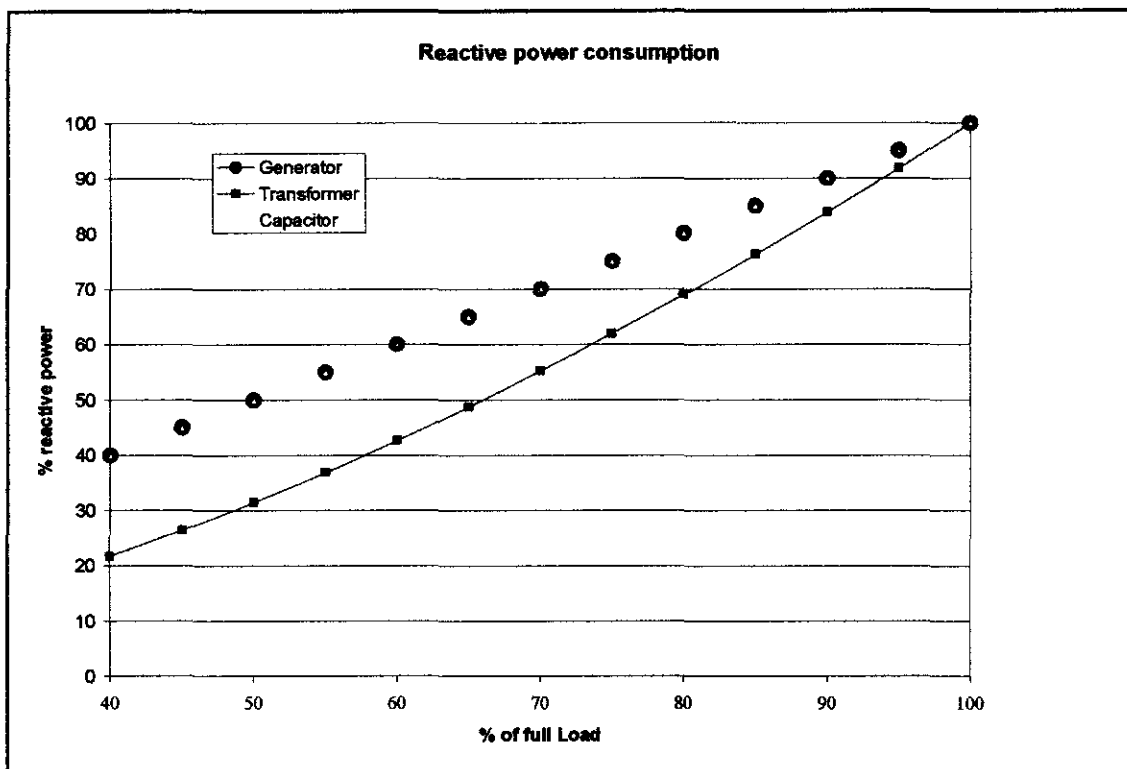


Figure 5-12 - The percentage reactive power of the generator, transformer and capacitor over the operating range.

The relationships in equations (4.33) – (4.35) were used to compile the graph shown in Figure 5-12. The graph shows the percentage of reactive power needed by the generator and the transformer as well as the percentage of reactive power that can be delivered by the capacitor. The percentages are each in terms of the respective reactive power capabilities at full load. It can be seen that all the reactive power capabilities are lowering as the load decreases. The important result from this graph is that it can be seen that the capacitor's reactive power capability never decreases beneath both the generator and the transformer's reactive power curves. This implies that designing the

capacitor at full load, the capacitor will be able to deliver the necessary reactive power over the complete 40% to 100% power range.

The total reactive power demand of the generator at full load, assuming a power factor of 0.92 can be calculated as followed:

$$\begin{aligned} P &= S \cos \theta \\ &= 180 \times 10^6 \times 0.92 \\ &= 165.5 \text{ MW} \end{aligned} \quad (4.36)$$

$$\begin{aligned} \therefore Q &= \sqrt{S^2 - P^2} \\ &= \sqrt{(180 \times 10^6)^2 - (165.5 \times 10^6)^2} \\ &= 70.55 \text{ Mvar} \end{aligned} \quad (4.37)$$

The reactive power needed by the transformer assuming an inductive reactance of 12% and a total power rating of 210 MVA will now be determined. According to equation (4.31) the reactive power needed by the transformer is given by:

$$Q_t = I^2 X_t \quad (4.38)$$

The current is the full load current of 180 MVA system and X_t is the reactance of the 210 MVA transformer. The following calculations will therefore be done in the per-unit system using the following single-phase base values on the high voltage side of the transformer [33]:

$$\begin{aligned} S_b &= 180 \times 10^6 / 3 = 60 \text{ MVA} \\ V_b &= 132 \times 10^6 / \sqrt{3} = 76.21 \text{ kV} \\ Z_b &= \frac{V_b^2}{S_b} = \frac{(76.21 \times 10^3)^2}{60 \times 10^6} = 96.8 \Omega \\ I_b &= \frac{S_b}{V_b} = \frac{60 \times 10^6}{76.21 \times 10^3} = 787.3 \text{ A} \end{aligned} \quad (4.39)$$

Because the transformer has a different power rating than the selected base value, the 0.12 per-unit reactance must be changed accordingly.

$$\begin{aligned}
Z_{p.u.new} &= Z_{p.u.old} \left(\frac{V_{base,old}}{V_{base,new}} \right)^2 \left(\frac{S_{base,new}}{S_{base,old}} \right) \\
&= 0.12 \left(\frac{76.21 \times 10^3}{76.21 \times 10^3} \right)^2 \left(\frac{180 \times 10^6}{210 \times 10^6} \right) \\
&= 0.103
\end{aligned} \tag{4.40}$$

The reactive power consumption of the transformer can now be calculated using equation (4.38) and the new base values:

$$\begin{aligned}
Q_{r\phi} &= I^2 X_t \\
&= I^2 Z_{p.u} \times Z_b \\
&= 918^2 \times 0.103 \times 96.8 \\
&= 8.4 \text{ Mvar}
\end{aligned} \tag{4.41}$$

The calculations was only for a single phase and the total reactive power needed will be three times more:

$$Q_t = 3 \times 8.4 \times 10^6 = 25.2 \text{ Mvar} \tag{4.42}$$

The needed capacitance can now be calculated. The capacitors will each be connected to ground and therefore the calculations will again be done per phase in order to determine the size of each capacitor. The total reactive power needed for each phase will therefore be:

$$\begin{aligned}
Q_{total, phase} &= \frac{Q_{gen} + Q_t}{3} \\
&= \frac{70.55 \times 10^6 + 25.2 \times 10^6}{3} \\
&= 32 \text{ Mvar}
\end{aligned} \tag{4.43}$$

The phase voltage will be $132 \text{ kV}/\sqrt{3}$, and the capacitive current per phase will be:

$$\begin{aligned}
I_c &= \frac{Q}{V} \\
&= \frac{32 \times 10^6}{132 \times 10^3 / \sqrt{3}} \\
&= 420 \text{ A}
\end{aligned} \tag{4.44}$$

The capacitive reactance per phase therefore is:

$$\begin{aligned}
 X_c &= \frac{V}{I} \\
 &= \frac{132 \times 10^3 / \sqrt{3}}{420} \\
 &= 181 \Omega
 \end{aligned} \tag{4.45}$$

The capacitance that is needed per phase is therefore:

$$\begin{aligned}
 C &= \frac{1}{2\pi f X_c} \\
 &= \frac{1}{2\pi \times 150 \times 181} \\
 &= 5.86 \mu F
 \end{aligned} \tag{4.46}$$

Using equation (4.23) for the corner frequency can now complete the filter design. The frequency range on the generator side of the transformer will vary between 110 Hz and 150 Hz during the normal power operation. To filter out the switching frequency harmonics, the corner frequency can be selected as

$$\begin{aligned}
 \omega_c &= \frac{1}{\sqrt{LC}} \\
 \therefore L &= \frac{1}{C\omega_c^2} \\
 &= \frac{1}{5.86 \times 10^{-6} \times (2\pi 1980)^2} \\
 &= 1.103 \text{ mH}
 \end{aligned} \tag{4.47}$$

5.1.5 DC link

The DC link normally consists of a DC capacitor, D_{dc} , and an inductor, L_{fde} as shown in Figure 5-1. The combination acts as a low-pass filter that reduces the ripple in the DC voltage. To limit the initial inrush current into the capacitor a resistor or inductor is connected in series during the charging period. A DC cable or overhead line is also used if the DC current needs to be transmitted. In the case of the PBMR the two converters are connected back-to-back and no DC transmission medium is therefore necessary.

5.1.5.1 DC capacitor

The DC capacitor, $C_{dc1,2}$, is one of the most important components in a Voltage source converter (VSC) like the MVDC converter shown in Figure 5-1. The fast control of power by MVDC converters allows the capacitor to maintain a constant DC voltage. This allows the DC capacitor to be smaller without affecting the converter performance. The capacitor is however still necessary to keep the voltage ripple at acceptable levels. It is important for accurate control that the DC voltage is constant for at least one switching period.

Fluctuations in the load also need to be absorbed in some way. One way of dealing with this problem is to simply transfer the fluctuations to the main power grid, but this will result in the generation of current harmonics the converter was supposed to eliminate in the first place. In motor drive applications where the motor speed is not that critical, the load itself can be used to absorb the fluctuation [22]. In transmission applications, the DC capacitor must be able to handle these fluctuations. The DC capacitor is therefore designed for ripple limitation and voltage deviations due to load changes.

The DC capacitor also provides a hold-up time during which the regulated supply keeps on supplying a regulated voltage in the absence of an AC input voltage. The capacitor value can be calculated as a function of the hold-up time [15]:

$$C_d = 2 \times \frac{\text{Rated power output} \times \text{hold-up time}}{(V_{d,nominal}^2 - V_{d,min}^2) \times \eta} \quad (4.48)$$

$V_{d,min}$ is normally chosen in the range of 60 – 75% of the nominal input voltage $V_{d,nominal}$ [15] and η is the efficiency of the converter. Choosing a minimum DC voltage of 70% of the nominal voltage together with an expected efficiency of 0.99 and a hold-up time of 0.5 seconds. The hold-up time provided by the capacitor is the time during which the converter can supply a regulated output in the absence of the AC supply caused by a momentary power outage. The zone 2 distance protection is normally set at about 0.5 seconds and is therefore also used as the hold-up time. The capacitor's needed capacitance can now be calculated:

$$\begin{aligned} C_d &= \frac{2 \times 180 \times 10^6 \times 0.5}{[(132 \times 10^3)^2 - (0.7 \times 132 \times 10^3)^2 \times 0.99]} \\ &= 0.02F \end{aligned} \quad (4.49)$$

To protect the DC link against overvoltages, e.g. during failure of the control system, the link is also equipped with a voltage-limiting device. This is normally done with a brake chopper. This chopper will have a peak power rating larger than the converter rating, however this is much smaller than the ones used with conventional converters. The chopper should also be independent of the control system and can be operated from the DC link voltage.

5.1.5.2 DC inductor

The DC inductor is connected in series with the DC line and should therefore have a current rating of equal or greater than the maximum converter output current. In the case of the PBMR using a 180 MW converter with a DC voltage of 132 kV it relates to a current rating of larger than 1364 A.

The inductance of the inductor has a negative influence on the dynamic behaviour of the system and also contributes to the converter losses. The inductance however lowers the fault level and inrush current when the inverter starts the first time. The inductor/capacitor combination is a low pass filter and the corner frequency is given by equation (4.29). According to Mohan [15], the corner frequency should be selected much smaller than the switching frequency. Selecting a corner frequency of 200 Hz, the inductance needed is:

$$\begin{aligned}
 \omega_c &= \frac{1}{\sqrt{LC}} \\
 \therefore L &= \frac{1}{C\omega_c^2} \\
 &= \frac{1}{0.02 \times (2\pi 200)^2} \\
 &= 32 \mu H
 \end{aligned} \tag{4.50}$$

5.2 Control strategy

The PBMR goes through various stages from a complete shutdown until the normal power operation mode is entered. During these run-up phases different control modes for the MVDC converter will be necessary to ensure the system starts up smoothly within its limits.

5.2.1 Present Modes of operation

In order to implement an MVDC converter into the system an understanding of the current system is needed. The MVDC converter must be controlled in a specific sequence to keep all parameters involved within their limits. Only the primary start-up sequence will be investigated as indicated by the green path in Figure 5-13.

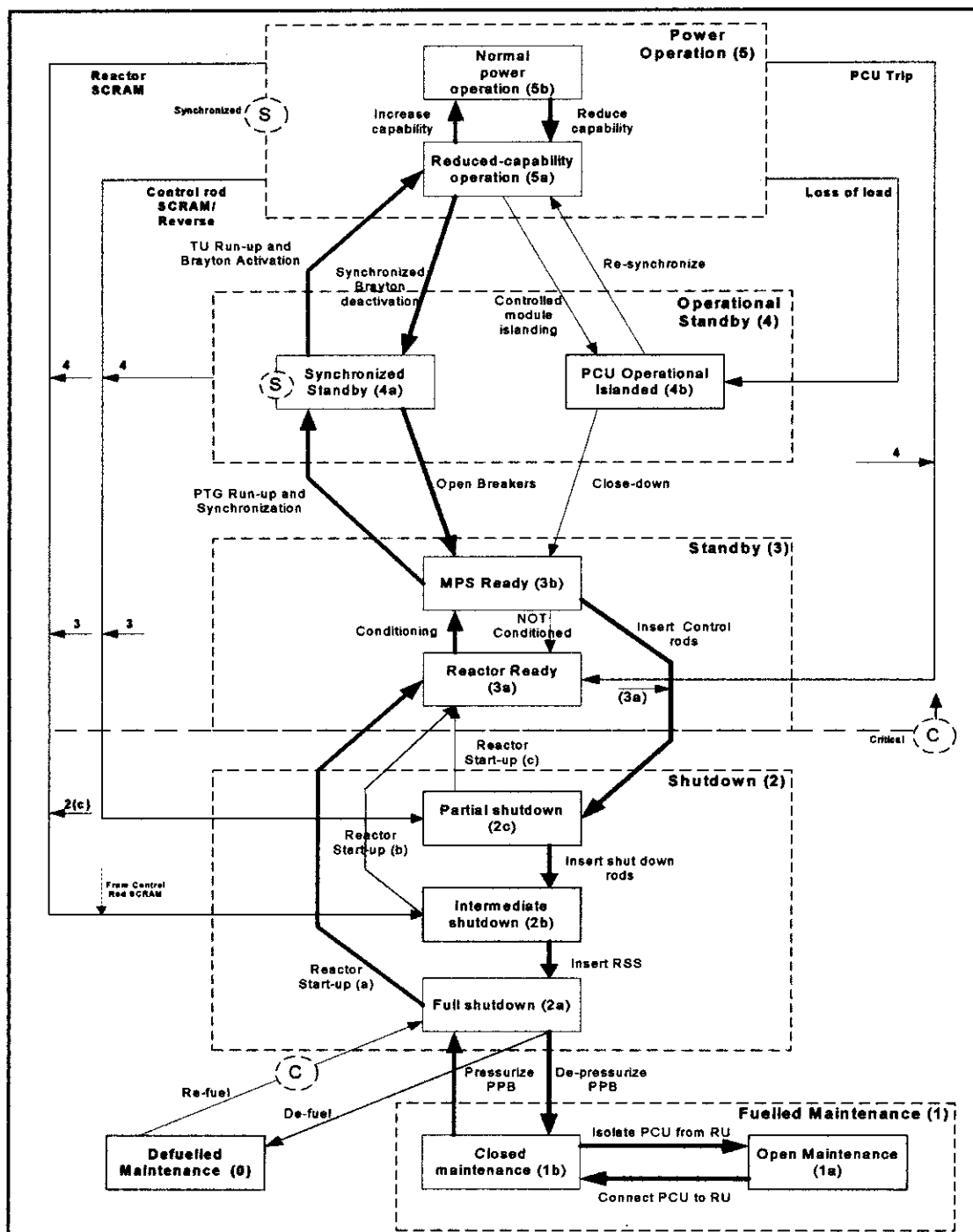


Figure 5-13 – Present PBMR modes of operation [32]

Investigating the indicated green path will reveal that not all the modes/states are relevant or are influenced by the MVDC converter or the Main Power System. These states are therefore excluded.

5.2.1.1 Closed maintenance to Full shutdown transition

The first state of interest is the transition from the closed maintenance (1b) mode to the full shutdown state. The SBS (Start-up Blower System) system is started during this transition to start the gas flow. Because the SBS system is not present any longer and the function of starting the gas cycle needs to be fulfilled by the high-speed induction generator driving the power- and low pressure turbine combination as well as the low pressure compressor. This implies that converter A in Figure 5-14 is acting as an inverter while converter B is rectifying the AC current from the grid.

During the depressurise Primary Pressure Boundary state the SBS is also active for cooling purposes. This state may take up to two days, implying that the converter must be capable of running in this mode continuously.

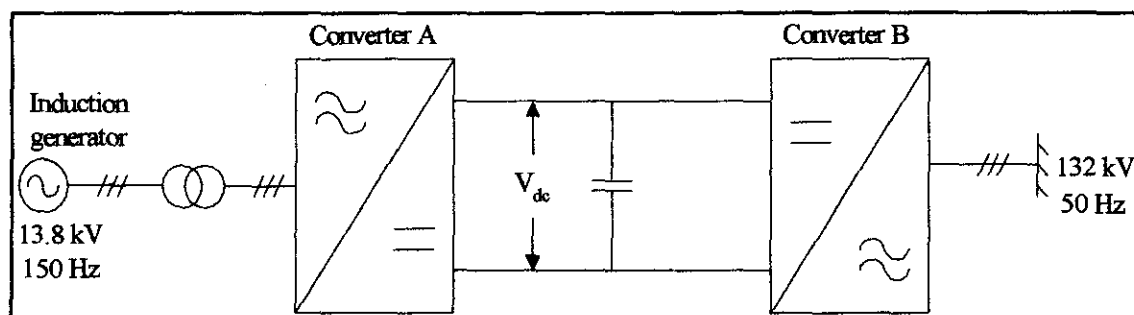


Figure 5-14 – Simplified converter configuration

5.2.1.2 Reactor start-up (a)

During the Reactor Start-up (a) state the SBS is responsible for temperature control until the Reactor Outlet Temperature has stabilized. This implies that the converter must be able to control the induction generator's speed during this period of time.

5.2.1.3 Conditioning

The aim of the conditioning period is to get the Main Power System (MPS) within its specified start-up parameters before start-up. These parameters consist of MPS temperatures, turbo machine speed and valve positions. The SBS is again used to control the reactor fluidic heat by means of adjusting the mass flow. The MVDC converter to fulfil this function must again control the induction generator.

5.2.1.4 Power Turbine Generator run-up and synchronization

The Power Turbine Generator (PTG) run-up and synchronization is the transition from the MPS ready (3b) to the Synchronized Standby (4a). During this stage the SFC is used to run-up the synchronous generator to 50 Hz. The Brayton cycle is however not activated yet and as soon as the generator is synchronized it is driven from the power grid. The PTG is accelerated at a speed of 5% of the nominal speed per minute. This is fast enough to take the PTG safely through its critical speed ranges.

In the case of the suggested system the MVDC converter will be used to accelerate the PTG through its critical speed ranges. Synchronization is not necessary, because the MVDC converter will deliver 50 Hz power to the grid as soon as the Brayton cycle starts driving the induction machine.

5.2.1.5 Turbo unit run-up and Brayton cycle activation

During this transition the Brayton cycle is activated. The High Pressure Turbine (HPT) and the Low Pressure Turbine (LPT) are accelerated from their initial speeds of less than 20% of their nominal speed at a rate of 5% of their nominal speed by means of valve controlling. The SBS system is still active during the initial stages of this transition, but is switched off as soon as the Brayton cycle becomes self-sustained. This means that in the new system the generator will continue to fulfil the purpose of the SBS and would be able to start generating power as soon as a pressure drop occurs over the LPC, which implies that the Brayton cycle is activated.

5.2.1.6 Power operation

The power operation mode consists of two sub modes namely the Reduced-capability operation (5a) and Normal power operation (5b). In both these modes the Brayton cycle is self-sustaining and therefore both the SBS and SFC are inactive. The remote grid operator, subjected to the local boundaries like minimum, maximum and ramp rate of power, sets the target power delivery.

During normal power operation the power delivered to the grid will be between 40% and 100% of the maximum continuous rating. This is important for the MVDC converter control, because this limits the frequency range the converter must be able to operate in during this mode. The relationship between speed (ω) and output power (P) are given by:

$$P \propto \omega^3 \quad (4.51)$$

The frequency is direct proportional to the speed and the upper limit of the frequency is 150 Hz when 100% power will be delivered at that point. The power is only allowed to drop to 40% of the maximum continuous rating and the lower limit of the frequency can therefore be set at:

$$\begin{aligned} 100\% \text{ Power} &\propto 150^3 \text{ Hz}^3 \\ \therefore 40\% \text{ Power} &\propto 0.4 \times 150^3 \text{ Hz}^3 \\ \therefore 40\% \text{ Power} &\propto 110.52 \text{ Hz} \end{aligned} \quad (4.52)$$

At 110 Hz the voltage supplied to the generator must also be lowered in order not to saturate the core. During this mode the generator will therefore be operated with a constant flux implying a constant relationship between the voltage and frequency given by:

$$\frac{E}{f} = k \quad (4.53)$$

When the system is delivering rated power, the voltage will be at its maximum. At the lower set point of 110 Hz the voltage must be lowered according to equation (4.53). The lower voltage set point is therefore:

$$\begin{aligned} \frac{E}{f} &= \frac{E_{\max}}{150} = \frac{E_{\min}}{110} \\ \therefore E_{\min} &= 73.3\% \text{ of } E_{\max} \end{aligned} \quad (4.54)$$

5.2.2 Power flow

The different modes and state of the PBMR start-up was discussed in the previous section, while the power required or delivered by the PBMR in each mode or state of operation is discussed in this section. The power and frequency of the power turbine during each mode are also illustrated in Figure 5-15.

The first mode where the MVDC converter will come into play is during the Pressurize transition. During this transition the SBS is started to start the gas flow cycle. The SBS is driven by two 500 kW motors while the auxiliaries needs approximately 9.5 MW. The 9.5 MW however includes 5.3 MW for the SFC and 4.2 MW for the other

auxiliaries. These other auxiliaries will be fed through a transformer connected to the 132 kV network and not the MVDC converter. The expected total power required from the converter is therefore expected to be 2×500 kW plus the 5.3 MW of the SFC, because the generator is used to start the gas cycle. In total at least 6.3 MW will therefore be required to start the gas flow.

The rotational speed of the generator will therefore increase from zero to less than 20% of the maximum speed, which is 30 Hz. This is done to ensure that the turbine does not run at its critical speed for long periods of time.

During the reactor start-up (a) the SBS introduces gas flow to run both the turbines at speeds of less than 20% of its rated speeds. Controlling valves does this. In this case the Low-pressure turbine is connected to the generator and the generator speed must still be limited to 20% of its rated speed while valves can still control the speed of the high-pressure turbine below 20% of its rated speed. The same power requirements are therefore expected as for the pressurize transition, with the only difference is that the generator are running at a constant speed.

During the conditioning period the reactor adjusting the mass-flow rate through the reactor controls fluidic heat. The generator speed will therefore be varying during this period but will remain below the critical speed of 30 Hz. The speed control during this period will therefore be determined by a temperature reading.

The Power turbine and Turbo unit run-up cannot be separated any more because the Low-pressure turbine is connected to the power generator. The power generator does not need to be synchronized to the power grid due to the MVDC converter. The generator and turbine run-up will therefore happen simultaneously resulting in the Brayton cycle activation during this stage. This run-up acceleration should still be done at a rate of at least 5% of the maximum speed to ensure a rapid transverse through the critical speeds of both the generator and turbines.

Should the Brayton cycle be activated before the power turbine has reached a speed of 73.3%, the power can be used to accelerate the generator, but power delivery cannot be started. Power delivery can only start when the rotational speed exceeds 73.3% or 110 Hz, because the MVDC converter and transformer set-up can only supply the rated 132 kV to the network with a generator voltage at more than 73.3% of the rated voltage.

The whole PBMR is also only designed to deliver power between 40% and 100% of its rated power, which correlates to 73.3% of the rated speed and voltage

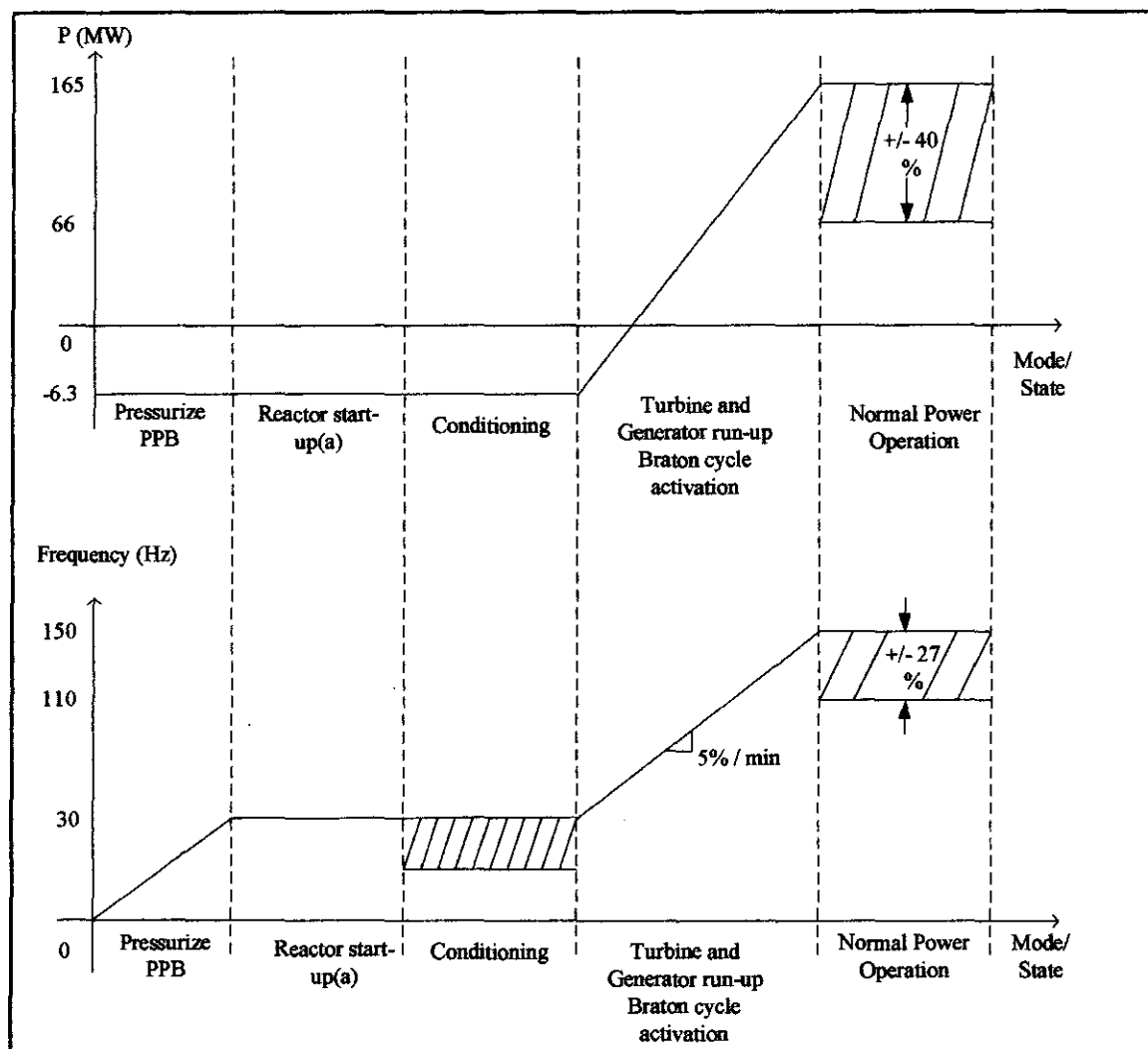


Figure 5-15 – Expected Power and Frequency during PBMR run-up Modes

Chapter 6

Conclusion and Recommendations

6.1 Introduction

The PBMR company is currently investigating the possibility of using a high-speed generator for their new power plant. The reason for this is twofold. Firstly the power turbines are more efficient at higher rotational speeds and they are looking at 9000 rpm as alternative to the currently used 3000 rpm generators. Should this be possible, it will imply that the power turbine can be combined with the LPT simplifying the three-shaft system to a two-shaft system.

The use of such a 150 Hz (9000 rpm) generator by the PBMR implies that the generated electrical power frequency is not compatible with the 50 Hz of the South-African national grid. This situation is similar to that of some renewable energy systems like wind farms. Although the frequency of wind farm generated power is in most cases lower than 50 Hz, the same technique of converting the generated power to direct current (DC) and then back to alternating current (AC) can be used.

The aim of this investigation is to determine the feasibility of using a converter for converting the generated 150 Hz power to usable 50 Hz power. For this purpose HVDC transmission and MVDC converters were investigated. Combinations of a MVDC converter and different generator types were also investigated. These types include DC generators, high-speed induction generators, conventional synchronous generators and superconductor synchronous generators.

6.2 Findings

6.2.1 HVDC transmission

HVDC is a well-developed and proven technology. Over the past 20 years HVDC transmission technology has shown a tremendous growth. The electric power industry was previously only government owned, but in recent years more and more electrical power industries are privatised. HVDC transmission will therefore keep evolving to supply in the need of these private companies. In this deregulated market where electric power is traded between various companies, HVDC will play an important role in

terms of stability, different power regulations of countries and the control of tie power flow.

In addition to the deregulation of the electric power industry, HVDC transmission is in some cases the obvious choice over AC transmission. For very long transmission links, beyond the break-even distance, HVDC transmission is the more economical choice. The connection of asynchronous links, for example a 50 Hz and 60 Hz systems, HVDC is the only solution. HVDC transmission has a lower transmission loss because only active power is transferred. Over a distance of 500 km to 1000 km the losses of the HVDC system will be about 20% less than for an equivalent AC system [17].

There are also some other benefits that influence the choice in favour of HVDC over AC transmission. HVDC has a lower environmental impact, low fault current contribution, higher system controllability, improved stability, no skin effect and charging current.

HVDC is therefore a technology worth noting of when considering high power transmission systems. The technology is however not ideal for use in cooperation with the PBMR, because of a few reasons. In the first instance the PBMR is in need of a back-to-back converter and the long distance advantage of HVDC is therefore omitted. The required filtering equipment and reactive power compensators make the footprint of the overall system too large. The technology is also fairly expensive for a relative small planned PBMR plant of 180 MW.

6.2.2 The MVDC converter

MVDC converters are voltage source converters (VSC) utilizing the latest in power semiconductor and control technology. IGBTs are the semiconductors used for fast switching at medium power levels and therefore the converters can be called Medium Voltage Direct Current (MVDC) converters.

In the search for this ideal semiconductor device, researchers have decided to try and combine the characteristics of Bipolar Junction Transistors (BJTs) and MOSFETs. BJTs. This combination led to the development of the IGBT.

This resulted in IGBTs having a switching frequency lower than that of the MOSFET but is higher than that of the BJT. The IGBT can also handle a much higher voltage

than both the MOSFET and BJT and the current capability is only slightly lower than that of the BJT.

IGBTs are also still in the development stage and a rapid expansion of its capabilities can still be expected. Mohan et al [15] was printed in 1995 and since then IGBTs have developed rapidly. In 1995 IGBTs had a maximum current rating of 500 A and a voltage capability of 2 kV. Fuji Electric has developed a 2 kA, 4.5 kV IGBT and Mitsubishi a 900 A, 4.5 kV IGBT in 2000. In 2002 Powerex marketed a 2.4 kA, 1700 V IGBT. From these figures one can expect IGBTs to keep evolving into a real high power device in the near future.

The use of IGBTs as switching devices allows the use of PWM switching schemes. The best suitable PWM switching scheme for the PBMR MVDC converter would be the unipolar PWM voltage-switching scheme. The scheme was selected because of several advantages as discussed in section 3.5.2.

MVDC converters have a few advantages over HVDC converters. They are discussed in section 3.3. For the PBMR the important advantages are the smaller footprint and independent active and reactive power control. Unlike HVDC systems MVDC converters can feed passive or islanded networks. An MVDC converter can therefore be used to start-up the PBMR.

It is also important to notice that MVDC transmission will have the same advantages of HVDC transmission mentioned in section 2.5.1.

6.2.3 Proposed PBMR system configuration

The current PBMR system was evaluated and three different configurations were investigated. The key difference between the configurations was the machine choice. The 9000 rpm induction generator was found to be an excellent choice for the PBMR.

The high-speed induction generator with an MVDC converter was the superior choice, because of the many advantages of the system. The most important advantages include the increase in turbine efficiency, smaller turbines and generator, two-shaft system with less sophisticated control and a standard design for 50 Hz and 60 Hz systems.

The core disadvantages of the proposed system are the induction machine's poor power factor and the additional cost of the MVDC converter. These factors cannot be

overlooked, but the advantages were found to be more significant considering the system as a whole including possible foreign installation.

6.2.4 Basic MVDC converter design

The MVDC converter system will basically consist of a step-up transformer, AC filtering equipment, the two IGBT driven converters and DC filtering equipment. The generator side was found to be the best position for the step-up transformer. The main reason for this was the lower switching losses of the MVDC converter at higher voltages.

A delta-star configuration without a tap changer and an earthed neutral is considered the best transformer choice for the PBMR. The harmonics are filtered and therefore a K-factor designed transformer won't be necessary as described in section 5.1.3.3.

The switching frequency was selected as 1950 Hz. This is well within the IGBTs' capabilities and the reasons for the specific frequency is described in section 5.1.1. The specific IGBT selected is capable of handling the current, but 36 IGBTs in series will be necessary in each valve to handle the voltage as calculated in section 3.4.1.

The low-pass filter was selected as the best option on the generator side. The filter was also designed to supply in the reactive power command of the induction generator. In section 5.1.4.3 the per phase values of the filter was calculated as a 32 MVA filter with a capacitance of 5.86 μF and an inductance of 108 mH. On the DC bus the capacitor should have a capacitance of 0.02 F.

The PBMR goes through various stages from a complete shutdown until the normal power operation mode is entered. The MVDC converter will be capable of handling these transitions without the use of the SBS and the SFC. The complete start-up power flow and frequency requirements are shown in Figure 5-15.

6.3 Recommendations

The study showed that the best possible option for the PBMR would be a 180 MVA high-speed induction generator with a MVDC converter. As shown by Lamont [26], the technology to build such a generator is currently not available. He however expect superconductor technology to evolve in such a way that 180 MW high-speed generators could be built as early as 2010. The MVDC and IGBT technology is also still

developing and therefore expensive. By the year 2010 it can be expected to have matured and newer technologies to force IGBT technology to more affordable levels.

It is therefore recommended that the development of other switching elements be followed closely. In Figure 3-6 it was shown that SGCTs already shows several advantages over IGBTs although the technology was only developed in 2000.

6.4 Conclusion

HVDC and MVDC converters were investigated during this study. HVDC technology was found not suited for the PBMR system. It can mainly be ascribed to the large footprint and the fact that HVDC cannot feed passive networks and would therefore not be capable of starting the PBMR system from the grid. Currently starting the PBMR seems to be difficult and is therefore a major disadvantage compared to MVDC.

MVDC on the other hand hold many advantages for the PBMR. An MVDC converter will be capable of starting the PBMR without the use of the currently used SBS system and the SFC. The MVDC converter can control active and reactive power flow and relieve some of the control from the generator making the overall PBMR system easier to control. The PBMRs are also devolved for export to foreign countries and the use of the converter would imply a standard design of the PBMR for both 50 Hz and 60 Hz networks.

When a high-speed generator is used in cooperation with the MVDC converter even more advantages are gained. The best generator suited for this combination was found to be an induction generator. With a high-speed generation the turbines more efficient than at lower speeds, improving the overall efficiency. The high-speed generator also allows the LPT and power turbine to be combined, reducing the three-shaft system to a two-shaft system. This would not only result in a cost saving but also a further relieve on the control system.

The use of an MVDC converter also opens the possibility for DC transmission. The current system is developed for Koeberg near Cape Town and only a back-to-back converter will be used. When the system reaches for developed countries where right-of-way are very expensive or cables are used for large city center infeeds, the break-even point of DC transmission may easily be reached, making it the more economical option.

For the current system building a 180 MW induction generator is not possible and the MVDC technology are very expensive. The use of a MVDC converter with the current 3000 rpm system will loose the advantage of reducing the three-shaft system to a two-shaft system together with the increase in effectiveness of the power turbine. The MVDC converter would therefore be too expensive and the addition losses of the converter can't be regained without the use of a high-speed turbine.

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