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Impacts of Interconnecting the Wind Farm Projects within the Dogger Bank Zone

A Technical-Economical Evaluation of the Impact of Increased Wind Farm Connection Reliability

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Problem description

The problem for this thesis has been supplied by Statkraft, which is one of the firms that make up Forewind. Forewind has been awarded the Dogger Bank zone for wind farm development and the development is planned to be done in stages as a number of individual projects within the zone.

The aim of this master thesis is to study the potential benefit of interconnecting the individual projects in within Dogger Bank. Four projects have been selected to be studied and three potential layouts are compared. The benefit will be measured in increased profit from the wind farm.

The method that is used for studying the benefit of interconnecting the projects is a combination of a reliability analysis and an economic analysis. The reliability analysis will provide the amount of energy that is delivered to shore for each of the considered layouts, while the economic analysis will balance the increased energy output with the increased investment.

The layouts that are to be studied are the Base Case, in which each project is connected to shore through a single radial, Case Two, which superimposes a link between two and two projects onto the Base Case scenario, connecting the projects in pairs. And Case Three which superimposes a ring system between all four projects onto the Base Case layout.

Acknowledgements

I would like to thank my supervisors, sincerely for their aid and support during the work with this thesis. Kjetil Uhlen my primary supervisor at NTNU has been a great support in shaping the problem description and finalizing the thesis and its layout. Vijay Venu Vadlamudi's contribution in the field of reliability analyses has been priceless and his support in periods where progress was slow was most kind and encouraging. At Statkraft Leon Notkevich has been a great support and contributed with much useful information, internal documents and tips along the way. I would particularly like to thank Leon for so readily being available for discussions and obtaining additional information. I would also like to thank Jarle Eek at Statkraft who has been my official external supervisor and initiated the collaboration and provided the challenge of this thesis.

During the work with this thesis I have made several attempts at obtaining information on components that are used in the analyses. Though the results of my inquiries was largely negative I would like to offer my thanks to Carl Erik Hillesund at Statnett and Eiril Bjørnstad and Leif-Wilhelm Ramslie at ABB who all were ready to aid me in obtaining the necessary information.

Lastly a great thanks is owed to my friend Erika Berle for very useful help on the subject of economics, where my knowledge is superficial. Our discussion on the economic aspects of the project were absolutely of great importance in my work with developing the model for this.

Abstract

The Dogger Bank zone, which has been awarded to Forewind for development, is planned as the world's largest offshore wind farm with an agreed target of 9 GW installed capacity. Due to the size of the wind farm it will be developed as several individual projects (from here on referred to as projects) with a rated production of 1.2 GW. Each project is planned to be connected to shore via an HVDC link.

The aim of this master thesis is to investigate the possible benefits of including interconnections between the projects. Adding interconnections will be beneficial if the revenue from delivering more energy to the UK main grid is larger than the added investment cost over the life time of Dogger Bank.

In this thesis three connection schemes have been studied, in which four projects are included. These are:

> Base Case: Each project has an individual radial HVDC connection to shore. No links interconnect the projects.
>
> Case Two: Each project has an individual radial HVDC connection to shore. In addition two and two projects are connected in pairs by an HVDC connection with a rating of half of the rating to shore.
>
> Case Three: Each project has an individual radial HVDC connection to shore. In addition all four projects are interconnected by an HVDC ring system with a rating of half of the rating to shore.

In addition several analyses have been made on variations of these cases. Among these variations were varying reliability parameters, varying the ratings of cables, operating the system without HVDC circuit breakers and using HVAC technology for the project interconnections.

By performing reliability analyses and taking into account the actual production the amount of energy that is delivered to shore has been calculated for each of the three cases. The total costs of the different connection schemes has been studied by taking into account only the components that will have different investment costs and operation- and maintenance costs in the three cases. A simplified economic analysis was used. The analysis uses an imagined expense account and revenue account with the same interest rate, and the profit for each year is found as the difference between the revenue account and the expense account.

For the reliability analyses a tool was developed in Microsoft Excel which has the ability to take into account both overlapping faults and variable production for these particular cases. The method behind the Excel program, which is presented in this thesis, can be implemented in other platforms and be used to study alternative layouts and other systems.

The results yielded by the analyses show that Case Three is the best option among the three. An *Expected Situation* is defined, in which the layouts are as described above and the reliability variables and prices are as the expected level. The results in the *Expected Situation* show a profit increase of some £ 2 billion in Case Three compared to Base Case.

When varying the reliability variables it is found as would be expected that increasing the parameters (e.g. repair time and rate of failure) leads to a decrease in unavailability of the system and thereby a decrease in delivered energy and revenue. It is also found that as the availability of the system decreases the benefit of using the Case Two and Case Tree layouts increases.

Variations in cable price and interest rate, which are among the main influences in the economic analyses are found to have limited impact on the difference in profit between the three cases. High cable prices are found to, to some extent, reduce the benefit of added interconnections. Added interest rate tends to favour added interconnections.

Analyses of the project interconnections show that ratings of approximately 50 % of the project rating will be optimal. Congestion in the connections to shore makes the connections to shore the limiting factor for energy transmission in most situations. Some more energy is delivered when the interconnections are given higher rating, but the increase in revenue from this energy is not enough to cover the extra cost of higher rating.

Because HVDC circuit breakers are a brand new and costly technology analyses were performed to evaluate the impact of operating the system without such breakers. The analyses show that leaving out HVDC circuit breakers will have a positive impact on the Dogger Bank economy. Using HVAC instead of HVDC technology for the project interconnections was found to be beneficial because of the high cost of HVDC circuit breakers. Comparing the HVAC case with the HVDC case without HVDC circuit breakers leaves the two alternatives relatively equal in terms of profit and more thorough analyses are needed to decide which of the two offers the best solution.

Based on the analyses performed in this thesis it is fair to conclude that interconnection of the projects should not be disregarded in the development of the Dogger Bank zone.

Sammendrag

Dogger Bank området, som er tildelt Forewind for utvikling, er planlagt som verdens største offshore vindpark med et avtalt mål om 9 GW installert effekt. På grunn av parkens størrelse vil Dogger Bank utvikles som flere individuelle prosjekter (heretter omtalt som prosjekter) med nominell produksjon på 1.2 GW. Hvert av disse prosjektene er planlagt tilknyttet land gjennom en HVDC link.

Målet med denne masteroppgaven er å undersøke de potensielle fordelene av å inkludere sammenkoblinger mellom prosjektene. Slike sammenkoblinger vil være fordelaktige dersom de økte inntektene som følger av å levere mer energi til UKs sentralnett er større enn økningen i investeringskostnader over Dogger Banks levetid.

I denne oppgaven har tre tilknytningsalternativ som inkluderer fire prosjekter blitt studert. Disse er:

> Base Case: Hvert prosjekt har en individuell radiell HVDC tilknytning til land. Prosjektene er ikke knyttet sammen.
>
> Case To: Hvert prosjekt har en individuell radiell HVDC tilknytning til land. I tillegg er to og to prosjekter koblet sammen i par med en HVDC tilknytning med kapasitet lik halvparten av prosjekt effekten.
>
> Case Tre: Hvert prosjekt har en individuell radiell HVDC tilknytning til land. I tillegg er alle de fire prosjektene koblet sammen i et HVDC ring nett med kapasitet lik halvparten av prosjekt effekten.

I tillegg har flere analyser blitt gjennomført for å studere variasjoner i disse casene. Blant disse variasjonene var variasjoner i pålitelighetsparametre, variasjoner i kabel kapasitet, drift av systemene uten HVDC effektbrytere og bruk av HVAC teknologi for prosjektsammenkoblingene.

Ved å gjennomføre pålitelighetsanalyser og ta hensyn til produksjonsmønsteret til prosjektene ble det beregnet hvor mye energi som faktisk leveres til land i de tre tilfellene. De totale kostnadene av de ulike tilknyttningsalternativene er evaluert ved å kun hensynsta de komponentene som vil ha ulik investerings- og vedlikeholdskostnad i de tre alternativene. En forenklet økonomisk modell er benyttet for analysene. Modellen baserer seg på en tenkt utgiftskonto og en tenkt inntektskonto, begge med samme rente. Fortjenesten for hvert enkelt år finnes som forskjellen mellom inntekts- og utgiftskontoene.

Til pålitelighetsanalysene er det blitt utviklet et verktøy i Microsoft Excel som hensynstar både overlappende feil og varierende produksjon i de systemene som evalueres her. Metoden som er benyttet, og som er presentert i oppgaven, kan overføres til en annen plattform og da benyttes til å studere andre systemer også.

Resultatene fra analysene viser at Case Tre er det beste av de tre alternativene. En *Forventet Situasjon* har blitt definert og er en situasjon med layoutene som beskrevet over og alle priser og pålitelighetsvariabler som forventet. Resultatene fra den *Forventede Situasjonen* viser at fortjenesten i Case Tre er omtrent £ 2 milliarder høyere enn i Base Case.

Når pålitelighetsvariablene varieres viser analysene, som forventet, at når parametrene (f.eks reparasjonstid og feilrate) økes, synker påliteligheten til systemet og følgelig også mengden energi levert til land og inntektene. Analysene viser også at når påliteligheten til systemet synker øker fordelen av sammenkoblinger mellom prosjektene.

Variasjoner i kabelpris og renteverdi, som er blant hovedfaktorene i den økonomiske analysen vil ha relativt liten påvirkning på forskjellen mellom de ulike casene. Høye kabelpriser fører til en noe reduser fordel av sammenkoblingene. Økt rente tenderer til favorisering av økt sammenkobling.

Analyser av prosjektsammenkoblingene viser at kabler med kapasitet rundt 50 % av nominell produksjon per prosjekt er optimalt. På grunn av produksjonen fra nærmeste prosjekt vil kablene til land vil som regel være belastet nok til at disse er begrensende komponent i overføringen. Noe mer energi leveres til land når sammenkoblingene har høyere kapasitet, men inntektene fra dette er ikke nok til å dekke de økte investeringskostnadene.

Ettersom HVDC effektbrytere er en helt ny og dyr teknologi har analyser blitt gjennomført for å undersøke effekten av å drifte systemet uten slike brytere. Analysene viser at å utelate HVDC effektbrytere vil ha en positiv påvirkning på økonomien i Dogger Bank. Det ble også funnet at å benytte HVAC teknologi fremfor HVDC teknologi i sammenkoblingene mellom prosjektene gav positiv innvirkning på økonomien på grunn av den høye kostnaden av HVDC effektbrytere. En sammenlikning av systemet med HVAC teknologi og med HVDC teknologi men uten HVDC brytere viser at disse tilfellene gir relativt lik fortjeneste og grundigere analyser er nødvendige for å bestemme hvilket alternativ som er det beste.

Basert på analysene som er gjennomført i denne masteroppgaven er det rimelig å konkludere med at sammenkobling av prosjektene ikke bør forkastes i den videre utviklingen av Dogger Bank.

Preface

This thesis is the final report of a five year master degree in electrical power engineering at NTNU. The problem to be studied was provided by Statkraft and concerns the layout of the grid connection of the Dogger Bank wind farm.

The task of studying the potential benefits of interconnecting the Dogger Bank Projects has been both interesting and challenging. The master thesis follows a pre-master thesis project in which I studied control in multi-terminal HVDC systems. My interest for both wind power and HVDC technology has left me very interested in the results of the analyses.

Some of the challenges encountered in the work on this thesis have had a great influence on the final product. Most important among these were the choice of platform for the analyses and obtaining the input data for the analyses. A further explanation of the process of deciding on a platform and of the impact both challenges have had on my thesis is given below.

The main obstacle that has been encountered is the choice of platform for the analysis. As work was started on the thesis DigSilent Power Factory (from here on referred to as Power Factory) was chosen as the preferred platform. This choice was made both because both Kjetil Uhlen and myself were familiar with it after using it in one of his courses at the university, albeit for other types of analyses, and because Power Factory offered the possibility of combining reliability calculations and power flow analyses. After several failed attempts at using this software it was however discovered that large parts of the reliability analysis software did not function as intended, something which was confirmed by support. After discarding Power Factory as platform the choice fell on Microsoft Excel (from here on referred to as Excel). Based on my limited knowledge of reliability analyses the RelRad methodology appeared to be a suitable methodology and based on how the analysis is performed Excel seemed like a natural choice. It should be mentioned that at the time I regarded the reliability analyses as a relatively limited part of the scope, this changed gradually as the work progressed.

As will be described in the thesis RelRad methodology is not well suited in itself for analysing systems like those studied in here. This was quickly discovered and attempts at modifying the method for use on these systems were started. Vijay Venu Vadlamudi has throughout the work on the reliability analysis been very helpful and supportive and contributed with his knowledge on the subject. However we did not succeed at finding a method that could be applied to these systems which would give the output necessary for the analysis, and so the work on expanding the RelRad methodology was continued. Eventually a satisfactory solution was obtained.

Having established a methodology the next step was creating spread sheets in Excel that allowed studying the different layouts. This proved to be a rather more extensive job than anticipated and much time was spent on attempting to find good solutions for the calculations of one layout at the time. The calculations necessary for the analysis of Case Three is very much more extensive than for the others, combined with there being very many more situations that must be analysed. When the Excel sheet was extended to include this layout the amount of data became so large that Excel had problems operating. In addition there were found to be some limitations to Excels handling of circular references which made the calculations harder. Following this development I considered changing the platform again and this time turning to Matlab. For calculating the availability of the components and doing the analysis for the Base Case, Excel is still the preferred option, but the troubles that were encountered when the amount of data became larger would be solved much more easily by Matlab. After pondering the option of switching platform and discussing this with Vijay Venu Vadlamudi, who strongly advised against it, I decided not to switch as I felt sure that recreating the spread sheet as a program in Matlab would take too much time considering how much time was left of the work on the thesis. This has led to the method being less flexible than I could have hoped and though it is sufficient for the analyses performed here the Excel sheet should not be used in further studies. The methodology that has been developed and the procedure that is applied could however at a later stage be implemented into Matlab or similar and thereby increasing flexibility and allowing for more extensive studies.

Another challenge has been obtaining the input data to the analysis. Reliability data are available for most of the included components, though necessarily different sources use different data based on different studies. A more challenging spot has been obtaining prices. Because component prices are subject to competition these are kept secret. The prices that are used in this thesis are therefore prices that Statkraft has provided me with. The prices are however for a large part estimates and some are therefore subjected to sensitivity analyses as part of the thesis. At the beginning of the work with the thesis I wanted to include electric losses in the analyses. By including losses the amount of energy that is delivered through the system is lowered and though the percentage impact of the reliability analysis on lossless and actual systems is the same, the lowered amount of energy leads to less income and therefore less favourable analysis results for the more complex systems. Obtaining values of electric losses proved to be even more challenging than obtaining the prices, because the losses could not be calculated without more extensive studies by the suppliers, which they were, understandably, unwilling to do for free. In order for the inclusion of losses to make sense the component price would need to be related to that specific component, which as described was not possible.

Because of the trouble of getting good input data and the building of the reliability analysis being so much more time consuming than anticipated the resulting analysis has become less accurate, less flexible and less extensive than was my intention at the beginning of the master period. However I am glad to say, I have through the work on this thesis collected data, created a method for analysis and performed several analyses. The result of the analyses point a direction for which layouts should be studied further as was the target.

Contents

List of Terms

Dogger Bank	Refers to either the development zone awarded to Forewind in round 3 of UK's offshore wind farm leasing or the cluster of wind farm projects planned in the above development zone.
Project	Refers to one of the ten individual projects that Dogger Bank is split into.
Produced Power	Power delivered from wind turbines to the collection points
Node Power	Power delivered from collection points to the respective system's Node 4
Base Case Power Delivered to Shore	Power from the collection points of one project delivered to shore through the project's own HVDC link
Interconnection Point Power	Power delivered from a project's collection points to the project's Node 4 that cannot be transmitted through the project's connection to shore due to unavailability or lacking transmission capacity
Available Transmission Capacity	The transmission capacity that remains in a connection to shore after the respective project's Node Power has been given priority
Base Case	System layout in which each of the four projects has one single connection to shore
Case Two	System layout in which all four projects has individual connections to shore and the projects are connected in pair by one single link
Case Three	System layout in which all four projects has individual connections to shore and in addition all the four projects are connected through a ring system
Internal Grid	The grid structure that is upstream of Node 4
Collection grid	The radial connections that connect the WTGs to the collection points
Upstream Connection	The part of a project's connection to shore that is upstream of Node 4 and downstream of the collection points.
Transmission Grid	The grid that transmits the energy from Node 4 to shore
Connection to shore	Each project's HVDC link to shore
Project interconnection & inter-project link	Cable (with necessary equipment) connecting two projects to one another offshore.
Contract for Difference	In this case, a contract between wind power producer and the UK government that ensures the producer a certain energy price
Balanced Monopole	HVDC system layout consisting of two HVDC links and midpoint grounded converters
HVDC light	Siemens' VSC HVDC System
HVDC PLUS	ABB's VSC HVDC System
Expected Situation	The "base case" situation for all three layouts in terms of interconnection type, price data and reliability data.

List of Abbreviations

OFTO	Offshore Transmission Owner
WTG	Wind Turbine Generator
CAPEX	Capital Expenditure
OPEX	Operational Expenditure
MITS	Main Integrated Transmission Infrastructure
DC	Direct Current
AC	Alternating Current
HVDC	High Voltage Direct Current
HVAC	High Voltage Alternating Current
MT	Multi-terminal
MTHVDC	Multi-terminal HVDC
LCC	Line Commutated Converter
VSC	Voltage Source Converter
CSC	Current Source Converter
IGBT	Insulated Gate Bipolar Transistor
PWM	Pulse Width Modulation
MVSC	Multilevel VSC
ENS	Energy Not Served
END	Energy Not Delivered
CB	Circuit Breaker
DS	Disconnector Switch
LS	Load Switch
MTTR	Mean Time To Repair
MTTF	Mean Time To Failure
U	Unavailability
SAIFI	System Average Interruption Frequency Index
SAIDI	System Average Interruption Duration Index
CAIDI	Customer Average Interruption Duration Index
AENS	Average Energy Not Supplied
RelRad	Reliability in Radial systems
CfD	Contract for Difference
O&M	Operation and Maintenance
XLPE	Cross-Linked Poly-Ethylene
MI	Mass Impregnated (insulation/cable)
ROV	Remote Operated Vehicle

List of symbols

λ	Number of failures per year [1/yr]
MTTR	Mean time to repair [h]
U	Unavailability [h/yr]
P(…)	Probability of …
T_{px}	Transistor connecting phase x and node P in VSCs
T_{nx}	Transistor connecting phase x and node N in VSCs
V_{tri}	Triangular voltage signal used in PWM
$V_{control}$	Sinusoidal voltage signal used in PWM
P	Active power
V	Voltage magnitude
R	Electric resistance

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Introduction

The Dogger Bank zone, which has been awarded to Forewind for development, is planned as the world's largest offshore wind farm with an agreed target of 9 GW installed capacity. Due to the size of the wind farm it will be developed as several individual projects of 1.2 GW, each of which is planned to be connected to shore via an HVDC link. The aim of this master thesis is to investigate the possible benefits of including interconnections between the projects.

The benefit of using interconnections between the projects is that it would lead to an increase in reliability for the transmission system connecting the projects to shore, by adding to the number of available current paths. In the event of a fault on the primary route to shore the power can then be redirected through one of the alternatives.

The downsides of including interconnections is the added investment cost this will lead to and the increased complexity of the system. The added investment cost could be sufficiently high to remove all benefit that is achieved through delivering more energy to shore and it is the main purpose of this thesis to investigate whether this is the case.

The objective of this thesis is to study four projects in three different layouts, and based on this offer a recommendation of which layouts should be considered in the further development of the Dogger Bank zone. The recommendation will be made based on reliability analyses and economical analyses. The reliability analyses will yield the added amount of energy that can be transmitted due to the interconnections. The economical analyses will take into account the added revenue from the delivered energy and the increased investment costs of the interconnections and return the difference in profit between the layouts.

Part I. Background

Chapter 1. The Dogger Bank Zone

Chapter 1.1 Dogger Bank

In 2010 Forewind was awarded the rights to develop the Dogger Bank zone. This happened as part of the United Kingdom's third competitive leasing round for offshore wind, in which nine development zones with 25 GW of combined target generating capacity were awarded.

Forewind is a consortium of four companies who joined together for the Dogger Bank project. The companies in Forewind have special competence in different areas relevant for the project and together they have an economic strength and technological knowledge that enables them to face the challenges of such a large project.

The companies that constitute Forewind are RWE, SSE, Statkraft and Statoil. RWE is one of the UK's leading developers and operators of renewable energy plants. SSE is the largest non-nuclear electricity generator in the UK and is involved in wind, wave, tide and hydro power projects. Statkraft is Europe's largest generator of renewable energy, and the leading power generator in Norway. Statkraft produces and develops hydropower, wind power, gas power and district heating. Statoil is the largest Norwegian oil and gas company. The company also have some renewable power projects and is the developer of the world's first floating wind turbine. Statoil has 40 years of experience with offshore operation and the challenges that are specific to this environment.[2]

Dogger Bank is planned as the world's largest offshore wind farm with an agreed target installed production capacity of 9 GW. The Dogger Bank development area is located in the North Sea off the east coast of Yorkshire [3]. The zone is far offshore and stretches from a distance of 125 km offshore to 290 km offshore, covering a total area of 8 660 km^2.

Because Dogger Bank is such a huge zone, it will be developed sequentially in four stages, known as "tranches". Within each tranche there will be identified a number of projects areas, each with a capacity of up to 1.2 GW. Six such areas have already been defined, and 2 more are being considered. Development consent orders (applications) have already been submitted for the first two, and two more will follow shortly. From here on these smaller projects are referred to as projects, while Dogger Bank or the Dogger Bank Project is used to refer to the cluster of these projects.

The projects are planned to have individual export link to shore, connecting them to the National Grid integrated transmission system. The links will eventually be owned and operated by an Offshore Transmission Owner (OFTO). As a natural scope for wider optimisation of the zone, investigations are being made into the advantages of co-ordinating offshore networks in order to reap potential benefits of introducing alternative routes to market for the generation.

The fact that the projects are currently being developed individually means that in the development of each project is made no assumption of the other projects being realized, apart from that no decision should be made which causes problems for development of any of the remaining projects. At a later point in the planning it is natural to look for advantages of co-contracting projects that are ready for contracting, but assuming more projects will be implemented by a certain point in time leads to a larger uncertainty in the economic evaluations of the projects. During the planning phase the projects are therefore planned for having no interconnections[1] between them, causing the grid connection of each project to be a single HVDC link to shore.

Planning the projects as part of a whole could lead to a completely different connection scheme for the projects being chosen, possibly with interconnections between them and fewer links to shore. Planning Dogger Bank as one large project however leads to a great risk in terms of potential overinvestments if some of the projects are not realised and also a greater dependency on the order in which different parts of Dogger Bank are built.

This thesis aims at studying the effects of using interconnections in the primarily radial network structure and also evaluating the potential benefit of considering the first four projects as a whole, neglecting the risk of some projects not being built.

Only the first four projects are considered in order to reduce the scope of the analysis. These four projects are to be connected to shore at two different substations.

Chapter 1.2 Wind farm Layout

As described in Chapter 1.1 the Dogger Bank zone has been split into several individual projects areas. This split was performed after careful evaluation of the alternatives. Among the factors that were taken into account is what rating of equipment would provide the most cost effective solution. It was concluded that 1.2 GW installed capacity in each project was the best option. This led to potentially eight projects of equal rating. Due to the time limitations of the thesis only four projects will be studied here.

An analysis of only four out of eight projects is not sufficient to make any conclusions as to the final system layout, primarily because there are many more possible layouts for a total of eight projects. There is however a potential for drawing conclusions as to the effect of different schemes of interconnection, and evaluate whether increasing the level of complexity of the system appears to be economically beneficial.

The grid structure of the projects has for the purpose of this thesis been broken into two main parts, each with two sub parts in order to enable the description of and referring to these parts separately. These parts are:

[1] For the purpose of this thesis the term interconnection is used to describe links which connect one project to another. The links that connect the projects to the onshore grid are called connections to shore.

- Internal grid – The part of the grid which in all three layouts is used by a single project only
    - Collection grid – The radials that connect the WTGs to the collection points
    - Upstream connection – The grid connecting the collection points to the offshore converter station
- Transmission grid – The grid that is used to transmit the power from the offshore converters to shore
    - Connection to shore – Each project's HVDC link to shore
    - Project interconnection – The cables and relay system used to connect the projects to one another.

Chapter 1.2.1 Internal project layout

Extensive studies have been performed by Forewind to find the optimal number and placement of wind turbine generators, WTG, within each of the projects[2]. Although the individual wind farm's capacity and positioning of the WTGs, substation platforms and in-field cables will be finalised at a later stage in development, an indicative concept has been proposed by Forewind in order to inform the consenting process and to establish red line boundaries around the consented areas.

A conceptual base case wind farm was developed for the sake of cost of energy modelling in order to establish project- and wider zone economics. This base case was identified after detailed optioneering and cost modelling of the various options available for the entire wind farm design, taking due account of wind energy capture, wake losses, investment costs, operation and maintenance costs, availability, losses and economies of scale. The steps in this analysis are briefly described below.

First the optimal placement of the WTGs was found taking into account factors such as wake effect and cost. The results gave a wind farm with large well-spaced wind turbines. The spacing is larger than for most wind farms, an option which is available because the projects are so big and optimizing for efficient generation gives a better pay-off than for smaller projects. After the WTG location had been chosen a study was performed which showed that two collection points in each project would be the best option. An algorithm for optimising the position of these two collection points and the distribution of WTGs on radials was then used to decide the collection grid layout[3]. It was also found to be economically optimal to have one converter station for each project, placed midways the two collection points.

The collection grid of the individual projects is thus found to be optimal with one converter station which is connected to two collection points at which the transformers are situated. Each of these collection points is then connected to a varying number of radial cables to

[2] The location of the wind turbines is not final, but provides an assumption for use in the early planning phase. The final turbine location will be decided in the front-end engineering and building phase.
[3] Collection grid refers to the grid upstream of the collection points, or more specifically the radial connections than connect the WTGs to the collection points.

which a varying number of WTGs are connected. Because these layouts are confidential a mock collection grid layout is shown in Figure 1 as an illustration.

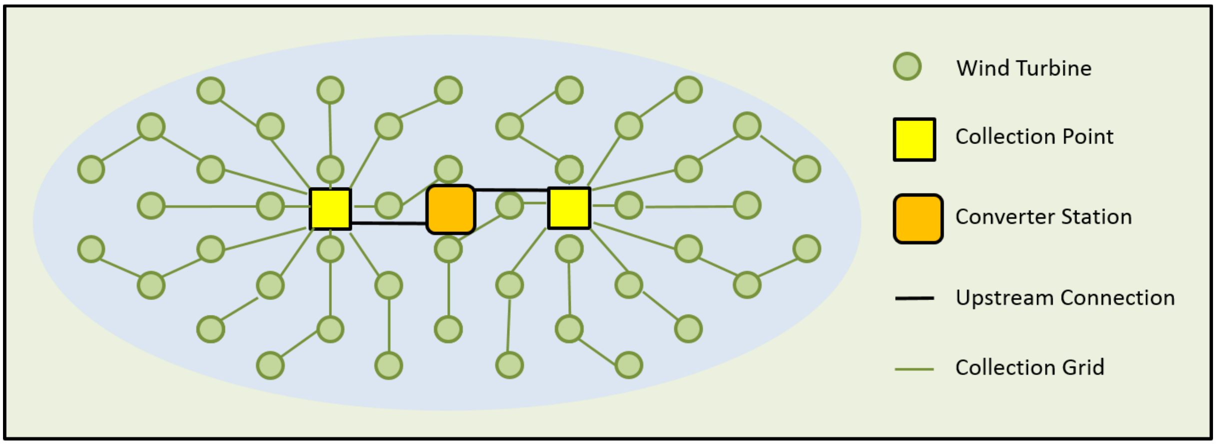


Figure 1: Example of project layout

This analysis further resulted in an indicative concept in which each project should comprise the following main components and systems:

- Installed wind farm capacity of up to 1200 MW
- WTGs with step-up transformers and switch gear
- In-field cables collecting the generation from the WTGs at either 33 kV or 66 kV, linking into:
  - Two to four AC offshore substation platforms, with step-up transformers and switch gear
  - AC subsea cable circuits connecting the AC offshore substation platforms to a single offshore converter platform
- One pair of HVDC cables linking the wind farm converter to:
  - An onshore converter located near the onshore main integrated transmission infrastructure (MITS)
  - One AC underground cable circuit at 400 kV linking the onshore converter to the MITS

The upstream connection is the furthest upstream part of the grid which is included in this thesis, hence its name, and can be designed in a number of ways, for this thesis one specific and likely layout has been selected and is visualized in Figure 2.

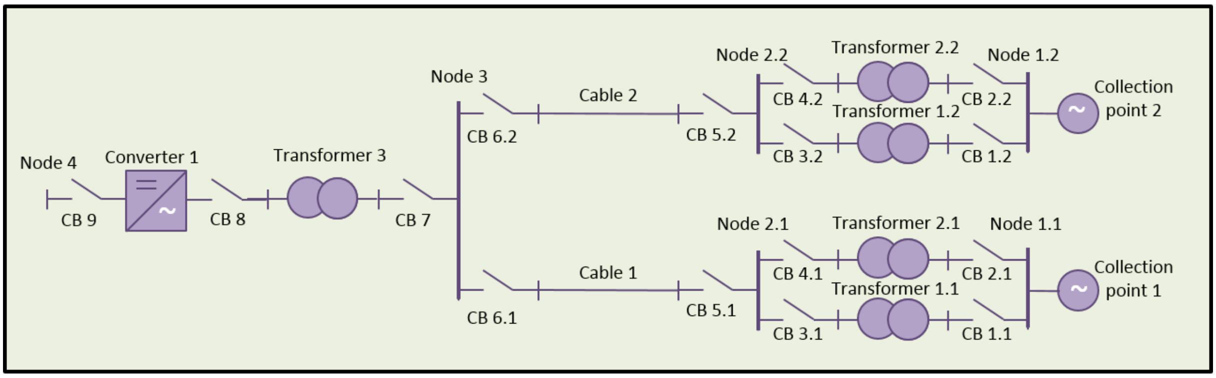


Figure 2: Upstream connection single line diagram

As can be seen from the figure the upstream connection consists of two radial connections from the offshore converter station to the respective collection points. These two radials are exactly equal as the rating of the two collection points are the same, and the converter station is located geographically midways between the collection points, ensuring that cables 1 and 2 are of equal length. These cables will however be of different length for the different projects, only within each project the two cables are identical. The transforming from collection grid voltage level (which will likely be 33 kV of 66 kV) to the upstream connection voltage level (which will likely be selected to be between 132 kV and 220 kV) is done by two transformers running in parallel[4]. The transformers are equipped with individual protection systems which implies that if one of the transformers should fail, power can still be transmitted through the other transformer. The rating of each of these transformers is 50 % of the project rating. If both transformers are available all produced power can be transmitted through the transformers, but should one of them fail, the transmission capacity would be reduced accordingly and some power may not be possible to transmit.

At the converter station a converter-transformer is used to transform the voltage level from the collection grid voltage level to the converter AC voltage level. The voltage level on the AC side of the converter must be higher than the HVDC voltage level, which is ± 300 kV. The main function of the transformer is to be a part of the control system for the converter.

The converter is a voltage source converter, which allows more flexibility in operation than its alternative, the line commutated converter.

Chapter 1.2.2 Base Case Layout, Single Radial to Shore

The Base Case scenario is a rather straight forward system layout. In the Base Case each of the projects is equipped with one radial connection to shore and there are no interconnections between any projects.

A purely radial system has the advantage of simplicity. By using only one link the power flow is easily controlled, there is much operational experience with such systems and the risk of unnecessary investments in components that will be used only upon connecting to another project, which turns out not to be realized for some reason or other, is removed.

The downside of using a purely radial system is that there is little or no redundancy. It would be possible to make the system more redundant but this would in most cases require a large investment. In order to create the HVDC link with N-1 standard it would be necessary to use twice as many of most components because the Base Case only contains one component with 100% rating. Installing for example two converter stations, each of 100% nominal rating

[4] The transformers will not in reality operate in parallel. The actual setup is more complex with half of the rated power being collected at a busbar and led through transformer 1 and the remaining half being collected at another busbar and led through transformer 2. In the event of a fault on one of the transformers this transformer will be de-energized and a switch between the busbars which is normally open will be closed, leading all the power through the energized transformer. For simplicity in the analysis of this thesis this step has been ignored, as it will be of little importance for the system reliability.

would be very costly. It should be noted that for a wind farm connection N-1 operation may not be the desired reliability level. Because win farms relatively rarely operate at nominal power, 100% rating of the connection during a fault in one component might not be necessary and it might be found that for example 50% rating during a fault may be sufficient to ensure that the wind farms reliability is at the desired level.

The system layout of the Base Case is shown in Figure 3.

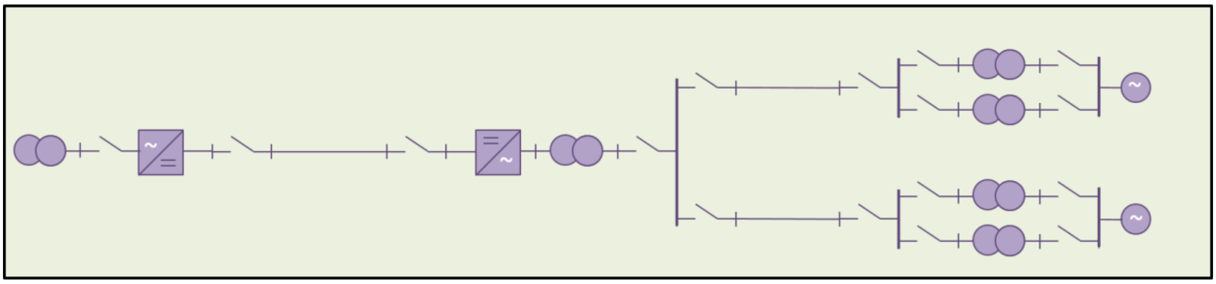


Figure 3: Base Case Single Line Diagram

Chapter 1.2.3 Case Two Layout, Two Project Interconnection

In the Case Two layout the projects are connected in pairs, so that for example Projects 1 and 2 and Projects 3 and 4, respectively, are connected by a link. This link can be either an HVDC link or an HVAC link. In the case of an HVAC link the link would be connected at Node 3. In the case of an HVDC link the link would be connected at Node 4, see Figure 4.

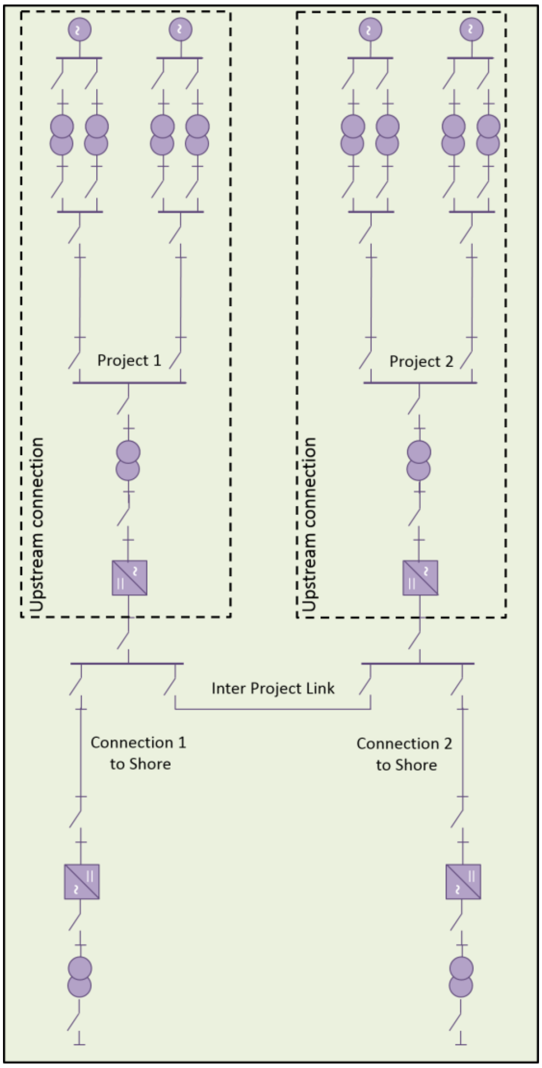


Figure 4: Case Two Single Line Diagram

In order to simplify the operation of the system the switchgear at either end of the link will likely be operated as normally open, and close only in the event of a fault on a connection to shore.

The disadvantage of choosing the Case Two layout is that the simplicity and individuality present in the Base Case are lost, or at least reduced. In the case of Projects 1 and 2 being interconnected and Project 1 being realized first, some additional investments are necessary when building Project 1 in order to allow for a later connection to Project 2.

The benefit of using the Case Two layout is that the redundancy of the connection to shore is increased. In the case where Project 1's connection to shore is unavailable and Project 2 is not delivering rated power, Project 1 can utilize the remaining transmission capacity of Project 2's connection to shore.

The increase in redundancy should increase the system reliability, but the extent of this is dependent on the relaying system that is used. In the case of an HVAC link normal HVAC circuit breakers can be applied and the reliability increase should be relatively high. In the case of an HVDC link the relaying system can be based on HVDC circuit breakers, or on HVAC circuit breakers, the choice between the two schemes could have a large impact on the reliability of the system. This point is further discussed in Chapter 3.

The system layout of Case Two is illustrated in Figure 4.

Chapter 1.2.4 Case Three Layout, Four Project Ring System

In Case Three all four projects that are considered in this thesis are connected in a ring. By using this layout the dependency on realization of all four projects in order to avoid unnecessary investments is increased further from Case Two. On the other hand the redundancy in the system is greatly increased and the amount of power delivered to shore should therefore be significantly increased.

As for Case Two there is a possibility of using either HVAC or HVDC cables to form the ring. The benefit of using HVDC interconnections is mainly that the cable costs will be much lower than in the HVAC case. The downside of HVDC interconnections is the need for expensive HVDC circuit breakers, or alternatively reduced availability due to the lack of such breakers.

The system layout for Case Three is illustrated in Figure 5.

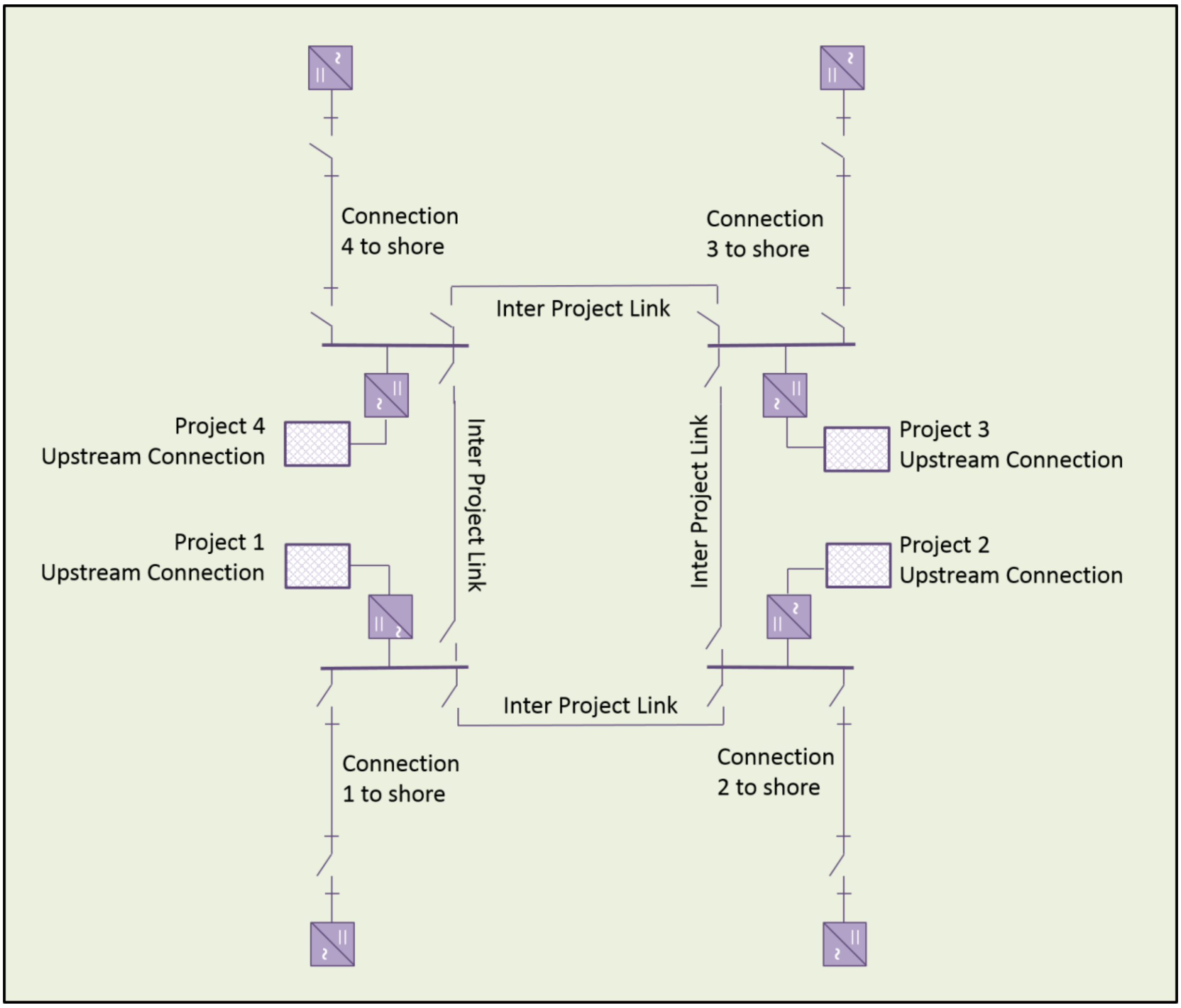


Figure 5: Case Three Single Line Diagram

Chapter 1.2.5 Rating of links and connections to shore

One option that has not so far been discussed is that the connections to shore do not have to be equal to the project rating. Because variations in the rating of the connections to shore are relevant for all of the above layouts this is not considered a separate case, but rather a point that should be analysed for all of the above cases.

In the Base Case there is clearly no benefit from increasing the rating of the connection to shore, as the additional capacity could never be utilized. For the Base Case the only reasonable option is therefore that the rating is equal to or lower than the project rating. The benefit of lowering the rating of the connection to shore is that this reduces the investment cost of the system. For a system with constant production at the rated level, this would not be beneficial, at least to the end that it would be better to reduce the rating of the entire system. For a wind farm system on the other hand, where the production is variable there could be economical benefits from reducing the rating of the connection to shore. This point is illustrated in Figure 6.

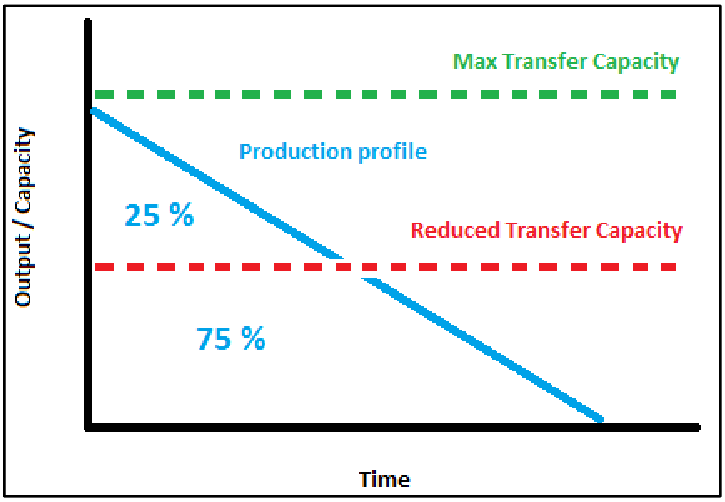


Figure 6: Illustration of how, for variable generation, reduced transmission capacity does not lead to equal reduction in transmitted power [Statkraft]

In Case Two there is an alternative path to shore for the produced power. In this layout there may be benefits of many different combinations of increased and decreased rating of the two connections to shore. Assuming for instance that the distance to shore is shorter for Project 1 than for Project 2, a possibility for the two connections to shore is that Project 1 has a higher than 100 % rating and Project 2 has a lower than 100 % rating. This could be a good solution because the unavailability of power cables is proportional with the length of the cable. The connection of Project 1 would in this case be available more often than the connection of Project 2, and hence, reducing the impact of a fault in Project 2's connection to shore could improve the availability of the system. Another possibility is to increase the rating of both connections to shore in order to reduce the impact of a fault in either one of the connections. The third option is to reduce the rating of both projects with the same argumentation as was used for the Base Case. When a link between the projects is added there is naturally also the possibility of setting the rating of this link to below rated project power. As for the Base Case, increasing the rating is an illogical option, but reducing it may improve the project economy.

Case Three provides a total of eight links and connections whose rating should be studied. Unlike in Case Two where the link should not be rated above 100 % of project rating, Case Three can benefit from links of rating up to 300 % of project rating. Similarly the rating of the connections to shore could be increased to as much as 400 % of project rating.

One of the possibilities when it comes to reducing the rating of a connection to shore is to reduce it to zero, leaving the system with one less connection to shore. This layout makes the project without the link 100 % dependent on another project also being realized.

Chapter 1.2.6 Meshed Systems

One last case that should be evaluated for the four projects is the implementation of a meshed system. The evaluation of this layout will not be a part of this thesis because extending the model in Excel to include this option would be too time consuming.

By implementing a meshed system there will be less dependency on the order in which other projects are realized compared to in a ring system. That is, there is still a dependency of other projects to be completed for the reliability to reach the desired level, however the dependency is shifted towards a dependency on any project to be completed rather than a specific one. Of course the interconnections cannot just be built at random between whichever projects are completed first, but a larger degree of freedom is possible.

As for the other layouts it is possible to implement this layout with HVAC or HVDC. Increasing the complexity of the system increases the potential problems with using the untested MTHVDC system, however the cost becomes more of a factor for systems with more interconnections and HVDC cables are significantly cheaper than HVAC cables.

Chapter 1.2.7 Final remarks

One trend that is seen through this list of possible layouts is that the price of redundancy falls as the number for interconnections[5] increases because the connections between the projects are very much shorter and therefore cheaper than making redundant connections to shore. Another trend is the reduced dependency on the order in which the other projects are completed. For the Base Case there is no dependency on the other projects, but for the others there is a reduced dependency from one specific project needing to be completed, to one of two others needing to be completed and further to any one of the other projects needing to be completed for the reliability to increase to a satisfying level.

Chapter 2. HVDC Systems

This chapter aims at giving an introduction to High Voltage Direct Current, HVDC, technology, its positive and negative attributes and the reason for using HVDC in the Dogger Bank projects.

The chapter is split into four sub chapters. The first of these describes the technology and explains how it differs from HVAC technology. The second sub chapter discusses the benefits and disadvantages of HVDC and described how the technology is used. The third sub chapter discusses the use of HVDC technology in grid systems, and the last sub chapter discusses the envisioned European Supergrid.

Chapter 2.1 HVDC Technology

HVDC point-to-point connections consist of two converter stations between which there is a DC link [4]. A more detailed description of the system layout is displayed in Figure 7.

[5] Note that redundancy and reliability are not linearly proportional

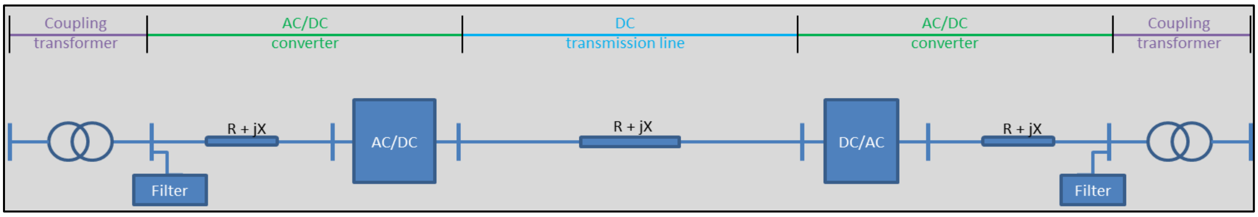


Figure 7: Single line diagram showing the layout of a DC point-to-point connection

The figure shows an HVDC link which interconnects two AC systems. The transmission line is an HVDC cable[6] or overhead line. The cable is modelled with both resistive and inductive elements. Under steady state operation only the resistive elements will affect the system, the inductive elements are included because of the transient periods that will occur when there are deviations from steady state operation of the DC system.

Connected at both ends of the cable are converter stations. The AC/DC converter will produce two types of losses; current dependent losses and current independent losses. The current dependent losses are modelled by resistive and inductive elements while the current independent losses cannot be modelled in circuit diagrams as simple as in Figure 7. The block which reads AC/DC represents the lossless converter.

Attached to the converter stations, on the AC side are filters and converter/coupling transformers. For the simpler types of converter the output AC current will contain a large amount of harmonics that needs to be removed by a filter before the power can be fed into the AC system. For more complex converter types the amount of harmonics can be significantly reduced and the filters can thus be made obsolete.

The transformers have a threefold task of transforming the voltage level between the AC system's level and the level of the HVDC connection, creating a galvanic separation and be part of the control system for the converters.

There are two main technologies that are used for HVAC/HVDC converters; namely Line Commutated Converters and Voltage Source Converters. The main difference between these two is the semiconductors they use for switching the current in order to change its wave shape. The converter technology will be further described in Part IV.Chapter 13.5.

Chapter 2.2 Use of HVDC technology

Low costs and low losses make HVDC an attractive technology for extra-long distance bulk power transmission. Until now large central generators have dominated most power systems. As renewables replace fossil fuel power generation, remote generation becomes more common. This leads to an increased need for extra-long distance bulk power transmission, and hence an increased focus on HVDC technology.

The low losses result from the absence of skin effect which in AC systems is a result of the frequency of the current. The result of the skin effect is to force current to have an uneven distribution across the conductor cross section. Current will mainly flow in the conductor's

[6] Often there are more than one cable, though this depends on the HVDC layout (balanced monopole, bipolar etc.) that is used.

outer circumference causing inefficient use of the conductor material as more current will flow in a smaller area, giving a higher over-all resistance.

The lower price of the HVDC systems result mainly from the use of cheaper and fewer cables. DC systems, needing only two conductors, one for positive voltage and one for negative[7], have a huge advantage over AC systems requiring three conductors, one for each phase. As mentioned the conductor utilisation is better in HVDC cables compared to HVAC cables due to the skin effect. Because DC transmission utilises the conductors better, the DC cables will need less conducting material and will hence be cheaper. The reason why HVDC is primarily used for long distance power transmission is that the AC/DC converter contributes strongly to both losses and cost of a connection. Long distance is therefore needed to make the benefit of the cables outweigh the negative impact of the converter.

An additional factor that makes HVDC transmission better suited than HVAC transmission over long distances is the impact of reactive power.

The cable inductance is proportional to the cable length, and consequently this parameter becomes high for long cables. In AC systems reactive power is generated by cables as a function of the cable inductance, and hence long cables generate much reactive power. Reactive power displaces active power in cables and therefore less active power can be transmitted through long AC cables. As there is no reactive power in DC cables this problem does not apply to HVDC cables and consequently their power carrying capacity is significantly higher for long distance cables. At a certain length the amount of reactive power will cause congestion in AC cables and they cannot carry any active power. It is possible to improve the power carting capacity of AC cables by installing reactive compensation, however this is an expensive option for submarine systems.

HVDC links are only cheaper for connections over large distances. This is because even if the cables or lines are cheaper for HVDC than for HVAC technology, they do require the added investment in AC/DC converters, which are expensive. There are a number of different estimates as to what is the break-even distance, meaning, the distance at which the two technologies cost the same. These estimates range from some 40 km, to about 500 km. This is likely a result of very varying input to the calculations, such as constantly varying prices of metal, unavailable component prices and variations in cable laying conditions, to mention a few. But if the break even distance is hard to estimate based on the literature, there is no doubt that as the distance increases the cost of HVDC transmission improves compared to HVAC transmission. There is also the added disadvantage of HVAC's power carrying capacity falling to zero as the reactive power in the cable becomes too large. This means that if HVAC transmission is to be used for extra-long distances reactive compensation is needed, further increasing the cost.

[7] For HVDC systems based on monopole with ground return only one cable is needed, most HVDC layouts however use two cables.

Chapter 2.3 Multi-Terminal HVDC

There appears to be no strict definition of HVDC grids. However there seems to be agreement on that HVDC grids are systems in which three or more HVDC terminals are connected in system in such a way that power can flow from one, via the next, to a third node without converting to AC along the transfer. Some make the distinction between multi-terminal HVDC (MTHVDC) systems and HVDC grids. In this case MTHVDC is a system as described above while an HVDC grid also requires redundancy of connections by forming a ring, or even a meshed layout. In this thesis the term MTHVDC is used and meshed or ring MTHVDC is used to specify the more complex grid structures.

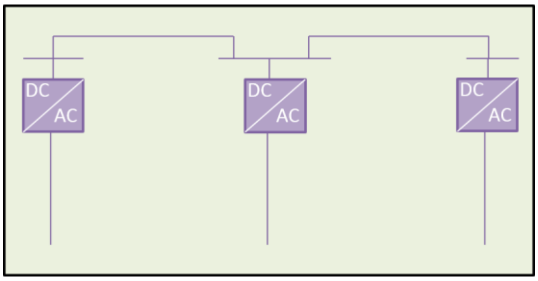


Figure 8: MTHVDC system layout

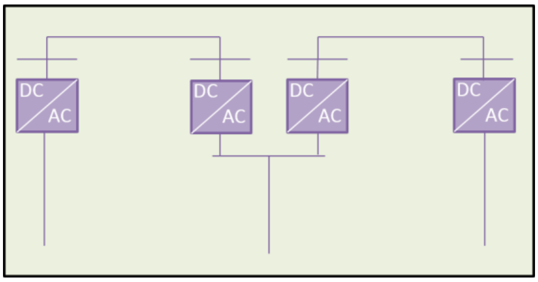


Figure 9: System of HVDC links

Figure 8 and Figure 9 illustrate the difference between an MTHVDC system and a system made up of individual links.

One of the more interesting properties of VSC HVDC (HVDC systems based on VSC converters) is that it can be used for multi-terminal HVDC (MTHVDC) systems. While there are two [5, 6] existing LCC based MTHVDC systems in operation these have very little flexibility compared to what is normally expected from grid type systems. Among others the need to shut down the entire system in order to change direction of power flow makes these systems very cumbersome compared to a VSC MTHVDC system which will have the ability to control the power flow based on much the same principle as is used in AC systems.

MTHVDC systems are technically challenging but provide some important benefits. There are two main situations in which MTHVDC would be considered, each of which provide different benefits.

If the system would otherwise be built as an AC system where the distances are very long then substituting the HVAC system for an HVDC system gives lower cost and lower losses.

If the system would otherwise be built as a system of many point-to-point HVDC connections then the switch to MTHVDC would significantly reduce investment costs, by needing fewer converters, and possibly reducing the electric losses, depending on how power flows in the system and which converter type would have been selected for use in the point-to-point option.

Chapter 2.4 The European Supergrid

Traditionally power systems have been built based on large scale power generation close to the load centres. This has led to power systems with relatively limited transmission capability between large load centres and instead many weakly interconnected areas that produce the power that is needed in that region.

The increased awareness of the problems associated with energy systems based on fossil fuels such as, global warming, limited resources and varying security of fuel supply[8], has led to more focus on using renewable energy sources. As renewable energy sources can only rarely be exploited in large scale near load centres (due to limited space and also taking into account other regards such as noise-pollution etc.) there is an on-going shift towards more remote large scale power production. At the same time there is a shift towards more small scale production which occurs both near the load centres (e.g. rooftop solar power production) and in more remote locations (e.g. small scale wind and hydro power production).

The connection of more small scale power production primarily calls for an upgrade of the grid, which is underway through the smart grid revolution. The shift towards large scale remote power production calls for an additional, extensive change of the power grid as new power lines need to be built to transmit the power from the remote generation plant to the load centres. Because the distances are typically long, HVDC connection is often considered. The number of new connections that will be necessary in the coming years if this trend continues is such that it has been suggested building a new grid of these, using a high voltage level and creating connection points to the existing power grid at strategic points. Such a grid could be made on a European level, interconnecting several countries and thereby tying the power markets closer together and at the same time increasing energy security.

Because this proposed grid will consist of many very long distance connections it has been considered to make the grid entirely or partly by using HVDC connections. Particularly in areas where cables are needed rather than overhead lines, such as subsea, HVDC would be the only possible solution. In a grid consisting at least partly of HVDC connections two main configurations are possible. The HVDC connections can be used as individual HVDC links in an HVDC system or they can form an HVDC grid.

The European Supergrid is envisioned by many although there are currently no concrete plans for building such a grid. It seems however that most of the visions of the European Supergrid have the North Sea Supergrid as a starting point.

[8] Fossil fuels provide higher security of supply than most renewable resources as most renewables power generation must be done instantaneously when the resource is available. However political issues may lead to sudden stops in delivery from certain areas, and many of the main countries in fossil fuel production are in politically unstable regions.

The North Sea Supergrid is pictured as the first stage of the European Supergrid, interconnecting the North Sea countries and allowing for connection of large scale, particularly far-offshore wind power production and also loads such as offshore oil and gas platforms. As this grid would have to be based on subsea cables only HVDC is a viable option.

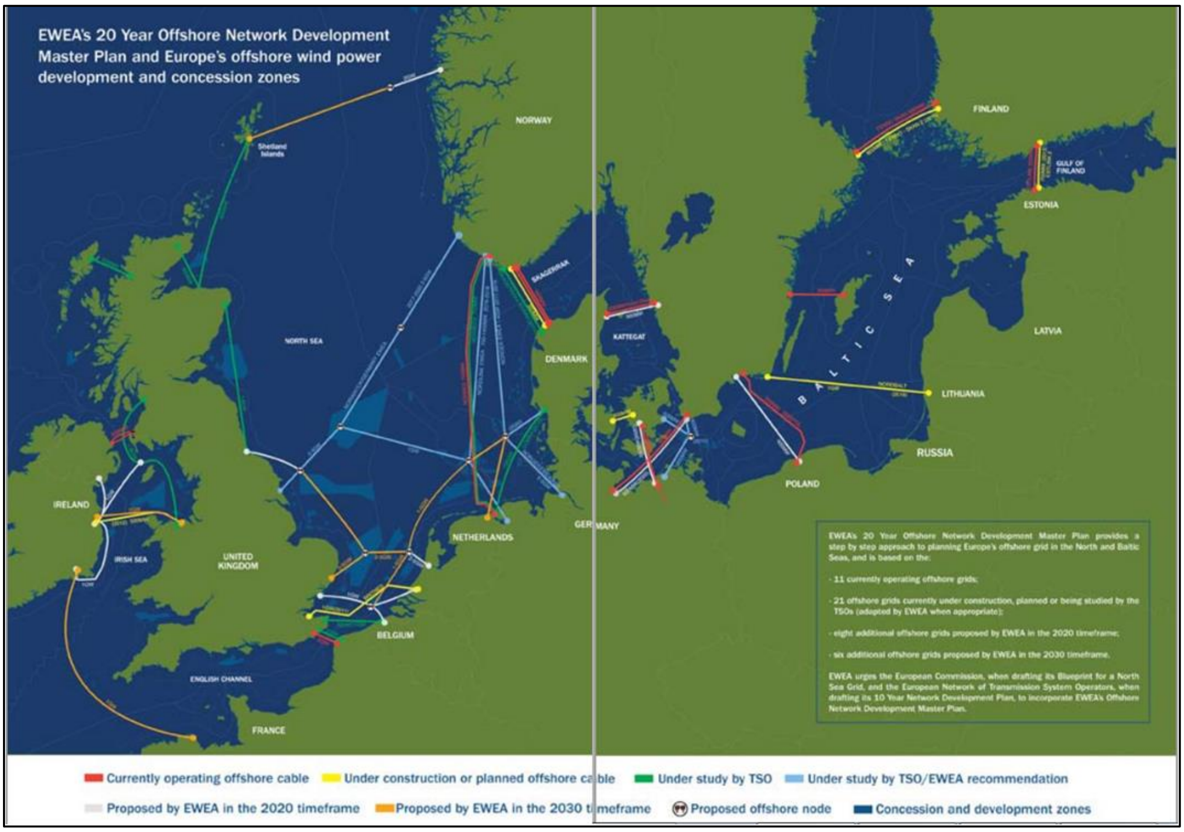


Figure 10: North Sea Supergrid layout proposed by EWEA

An interesting part of the plans for a North Sea Supergrid, from the perspective of this thesis, is that most scenarios use Dogger Bank as a natural node in the grid, see Figure 10. By including Dogger Bank in the North Sea Supergrid there is a possibility of selling the power at a higher price than would otherwise be possible because when continental Europe has high load and low production the prices will go up, and Forewind could choose to sell the power to Europe[9]. From the perspective of the grid developers the main benefit of including Dogger Bank might be the available transmission capacity to shore during periods with less than rated production at the wind farm. Should Dogger Bank be completed in its entirety Dogger Bank is expected to contribute approximately 10 % of the UK's electricity need in 2020[7]. This means that Dogger Bank will likely have a great influence on the electricity prices in the UK. It also means that if production suddenly drops, due to the wind conditions or faults, feeding electricity from another source into the same onshore connection points could be beneficial. Taking into account having a connection to another grid could lead to other result

[9] If Dogger Bank is receiving CfD pricing from the UK, it is unlikely that Forewind would be granted this advantage, though the UK government may want to utilize the possibility. CfD is described in Part III.Chapter 9.

of the cost benefit analyses that are performed in this thesis. For example higher rating of connections to shore, and increased interconnection number and rating would in all likelihood become increasingly beneficial, as the amount of energy delivered from the Dogger Bank node increases.

The main problem with the idea of including Dogger Bank in the European Supergrid is that Dogger Bank will be built before, probably long before, the Supergrid and hence it is not in the interest of Forewind to make investments in infrastructure that will only be used if the Supergrid is realized.

Chapter 3. Relaying systems

This chapter will provide a brief intro into relaying systems because they have a huge impact on the power system reliability.

Chapter 3.1 Definitions

[8] Describes relaying as "the branch of electric power engineering concerned with the principles of design and operation of equipment which detect abnormal power system conditions and initiate corrective action as quickly as possible in order to return the power system to its normal state." Relaying is then further divided into two separate requirements by stating that a reliable relaying system must be both dependable and secure. "Dependability is defined as the measure of certainty that the relays will operate correctly for all the faults for which they are designed to operate. Security is the measure of certainty that the relays will not operate incorrectly for any fault."[9]

The definitions given above provide an idea of the challenges of relaying. Although the definitions of dependability and security do not overlap, in reality they are somewhat contradictive. The contradiction arises from the want of a dependable system that will act on all faults, and the want of a secure system that never operates if it is not supposed to. In order to achieve any one of these two requirements one is almost guaranteed to interfere with the other. [9]

In [5] it is stated that general requirements of a relaying system is:

- Selectivity
  Detect and isolate the faulty item only
- Stability
  Leave all healthy circuits intact
- Sensitivity
  Detect even the smallest fault
- Speed
  Minimize damage to components, surroundings and personnel.
- Simple/inexpensive
  Minimize the risk of wrong settings due to complications
- Security

Dependable: Always trip when requested
Secure: Never trip when not supposed to

Isolating faults is necessary to prevent the fault current from a faulty device to cause faults in other equipment and also to de-energize the component to allow repair. In order to successfully isolate a fault the following has to happen:

- The relay system must realize that a fault has occurred
- The faulty component must be recognized
- The relevant circuit breakers must be triggered to open
- The circuit breakers must open

Methods for fault recognition and identification of the faulty component will not be discussed here and for the sake of the analyses performed as part of this thesis it is assumed that excellent methods for both challenges are applied.

In this thesis the relaying system is of great importance as the main focus is to determine the amount of energy that is supplied from Dogger Bank to shore, which is strongly dependent on the availability of the system. The relaying system plays an important part in determining the impact of a fault on the system. If the relaying system is not dependable then the impact of a fault will be increased. Similarly, by having an extensive relaying system the chances of a fault in one component inflicting a fault on another component is significantly reduced. Additionally the redundancy of relay components could be increased, this would lead to a higher dependability for the relaying system, even if each component's dependability is unchanged.

A relaying system consists of different kinds of switches and breakers as well as communication devices, measurement equipment etc. For the analyses performed here only the circuit breakers and disconnector switches are considered. For later, more extensive analyses more components should be included.

Chapter 3.2 HVAC Circuit Breakers

In AC grids a fault can be isolated by opening the circuit breakers (CB) at both (or all) connection points of the faulty component. The CB operates by mechanically separating the breaker contacts. As the contacts are moved apart an arc will ignite through which the current continues flowing. When the current reaches its natural zero crossing, due to being an AC current, the arc will extinguish. If the dielectric strength of the medium between the contacts is by now sufficiently high that it cannot be overcome by the voltages present, then the arc will not reignite and the CB is open. [9]

Circuit breakers are the only part of switchgear that can interrupt fault current and then close again on signal. Fuses can be used instead of CBs in, but these need to be replaced manually after an interruption. Fuses are not available for high voltage levels.

One of the situations that is of interest in this thesis is that more than one current path is available, one of which is prioritized. In this case the prioritized current path would be the only current path actually connected to the power source, the other paths would be connected through switchgear operated as normally open. Normally open would be used in order to avoid faults in other parts of the system from interfering with the power source and current path in question and also simplifies the power flow control. Should a fault occur that requires the connection to the rest of the system then the switchgear would close. A CB is now necessary to re-open the connection as result of a fault, while also Load Switches[10], LS, can be used in the case of disconnection during normal operation. From this it is clear that though DSs, LSs and CBs can be used for the operating mode, only CBs fulfil all requirements and is therefore the natural choice of switchgear for this situation.

In order to achieve selectivity in the protection system, that is, only de-energize the necessary parts of the system when a fault occurs it is important that any radial part of the system has sufficient switchgear to clear all, or nearly all, faults that occur in the radial. Because no CB is 10 % dependable there will always be a need for backup CBs to cover the cases when a fault occurs and the primary CB does not operate. If the fault is not contained to a single radial then larger parts of the system will be affected. If for example the component closest to a branching point experiences a fault and its protection system does not operate, then the CBs on all the other branches of the branching point must be tripped to ensure that the fault does not propagate further. This will also be the case when the busbar at the branching point experiences a fault. Naturally there will always be the possibility that even two lines of defence are insufficient, and the fault will propagate and trip a third line of defence.

Chapter 3.3 Disconnector Switches

If there is no current in the system one does not need to use circuit breakers to isolate a component. One can then choose to use a disconnector switch, DS. Unlike CBs DSs are incapable of interrupting a flowing current and can therefore not be used to isolate faults. A DS works by simply mechanically opening far enough so that the medium between the contacts will resist ignition of an arc when voltage is applied.

In protection systems DSs can be used as backup devises for CBs in order to maintain a large degree of selectivity. In such cases the DSs are not backups in terms of actually interrupting currents. In the event of a fault on a CB (during a fault on the component it protects) the next line of CBs can be used to interrupt the current. This leaves the relevant components de-energized in which case the DS can open. Once the DS is open the “next line of CBs” can re-close and only the faulty parts are de-energized.

[10] Load switches are switches that are capable of interrupting normal load currents but cannot interrupt fault currents.

Chapter 3.4 HVDC Circuit Breakers

For HVDC systems interrupting currents is less straight forward than for HVAC CBs. As the current does not oscillate around zero there will be no natural zero crossing, making the technology of AC CBs unfit for interrupting the current.

In November 2012 ABB reported to have successfully created an HVDC circuit breaker [10]. The HVDC CB was made as a combination of a power electronics and a mechanical switch. The Idea of the CB is that the power electronics are used to create an oscillating current, which the mechanical switch is then able to interrupt. The concept that is utilized in the breaker is one that has been attempted for a long while and that was described in [9], based on the article [4].

The most important difference between HVAC and HVDC systems when it comes to relaying in existing systems is that there has not been any circuit breakers available for HVDC use.

For point-to-point HVDC connections the problem of interrupting the current has been avoided by interrupting the current on the AC side of the converters. This is a cheap and practical solution as one would in any case need a CB in this position in order to isolate faults in the AC components, and it can easily and quickly interrupt the currents that arise from a fault within the system.

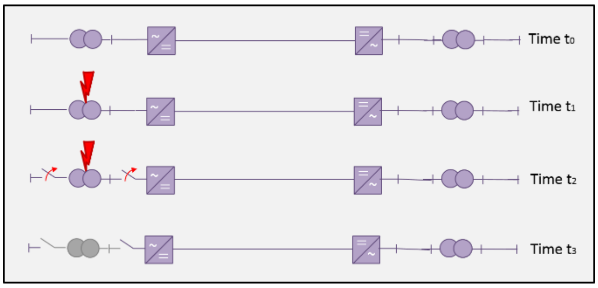


Figure 11: Isolating fault on HVAC side of point-to point HVDC connection

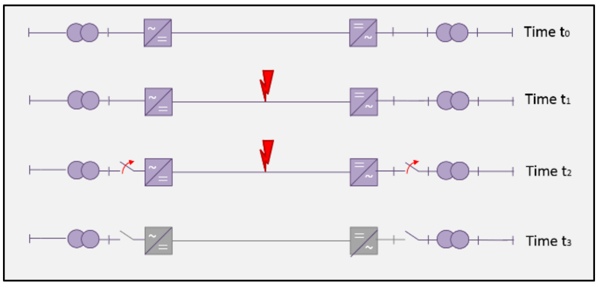


Figure 12: Isolating fault on HVDC point-to-point connection

The isolating procedure in point-to-point connections is illustrated by Figure 11 and Figure 12 for faults on the HVAC side and the HVDC side of the converters, respectively.

When implementing MTHVDC the solution of interrupting the current on the AC side becomes less practical. Although still feasible such a disconnection would mean a disconnection of all terminals in the system causing the entire grid to be out of function every time a fault occurs. Disconnector switches can be used in DC systems the same as in AC systems. This means the DSs could disconnect once the current in the system is removed, allowing the AC CBs to reclose and the non-faulty parts of the system would again be operational after a short interruption. However as stated in Chapter 3.1 one of the important aims of relays is to limit the negative impact that a faulty component will have on the rest of the system. Great efforts have therefore been put into developing efficient HVDC circuit breakers.

Because relay systems will never become 100 % dependable it is important to decide what will happen if a CB should not open on demand. The obvious answer is that the next line of CBs will open, this means that, for the case in Figure 12, one or both of the CBs between the converters and the transformers do not open. Consequently the protection system will trigger the CB(s) on the grid side of the transformer(s). In a case as simple as this the implication of the protection system not operating on demand is that the time it takes to isolate the fault will be double the ideal time. In more complex systems, with branches, the result of the protection system not operating on demand could be that a larger part than intended is isolated, because the next line of protection protects a connection point for the branches. In such cases it would be beneficial to open disconnector switches in order to further isolate the fault, and then close the circuit breakers, re-energizing the non-faulty parts of the system.

The fault recognition, location and CB tripping is different in HVDC systems than in HVAC systems. This is not further discussed here as the reliability of the protection system as a whole is considered out of scope for this thesis. Some methods that can be applied for these parts of the relay system are described in [9].

Part II. Power System Reliability

To evaluate the benefit of interconnecting the Dogger Bank projects, reliability analyses are performed for the different layout cases. Performing these analyses will yield the amount of energy that is transmitted from the wind farm collection points to the onshore grid.

This part of the thesis is dedicated to discussing reliability analyses and present the method that will be used as part of this thesis.

Chapter 4. Background

The core function of a power grid is to deliver electricity from the generators to the customers. Electricity has some properties that makes it harder to create a good system for its transportation compared to other forms of energy. These properties are most notably that electricity is produced and consumed momentarily, and that electricity cannot be stored[11]. The implication of these is that if there is no electric connection between generation and load, then the load will not be served and the energy that would have been converted to electricity by the generator, is lost. Because of this the availability of the power grid is essential and it is important to maintain a high availability of the grid.

Most reliability studies focus on the load points as the essential point of interest. This is natural as security of supply is considered the core task of a transmission- and/or distribution grid owner. A fault in the system results in a penalty cost[11] of undelivered energy in addition to loss of profit from not being able to transmit the energy and repair costs. Clearly, if the fault does not influence the amount of energy that is delivered to the customers, then the penalty cost and the loss of profit will be zero. This scheme provides the grid owners with an economic incentive for maintaining a high reliability in the system.

In the case of a connection grid for a wind farm the target is that all produced power should be delivered to someone who will pay for it. The associated penalty of a fault is in this case simply the loss of income from selling the energy and the repair costs.

The essential difference between say, a distribution grid and a wind farm connection grid is hence that in a distribution grid the penalty is a function of the demand of end users not being met, independent of where the energy is produced. Whereas for wind farm connections the penalty is function of the demand of the producer not being met, independent of where the energy is delivered to. This only holds true in cases where the restrictions in the grid to which the wind farm is connected do not restrict the supply of energy at any connection point.

[11] This is of course a partial truth. Energy cannot be stored as electricity, but the energy can be transferred to a lower value energy form, say potential energy as used in hydro power, kinetic energy as used in flywheels or chemical energy as used in batteries. However such transitions between energy levels lead to large losses and with the exception of pump-storage for hydro power the storage options tend to have low capacity.

For a distribution grid the reliability is often measured in terms of energy not served, ENS, for wind farm grids the corresponding reliability indice would be energy not delivered, END. As the purpose of the analyses performed in this thesis is to evaluate the cost vs. benefit of including inter project links the amount of energy that is actually delivered (delivered energy) is the parameter of interest.

Chapter 5. Challenges of overinvestment and unforeseeable faults

There are many different faults that may occur in a power system, and they can occur due to many possible sources of failure. Each of these has an individual probability of occurring and their impacts on the system vary. The level of investments made in order to strengthen the system and avoid these faults needs to be found based on a balance between the cost and the benefit of the investments. This chapter discusses how the level of investment should be decided and why a system should not be attempted made 100 % reliable.

It is impossible to prepare for all events that will lead to a fault in a power system. The majority of events could be prepared for by making the system very complex and contain multiple parallel components in order to always have a backup if a number of them should fail. Constructing a power system with many parallel components in this way would lead to a huge investment and the payoff would be small.

Chapter 5.1 Overlapping faults

If two electrically parallel power cables are buried in the same trench and one of them experiences an internal fault, then that cable will be de-energized and all of the power will flow in the second cable. If the rating of the second cable is sufficiently high to withstand this power flow without overheating, then the system can continue operation without interruption. If the rating of the cable is not sufficiently high the system operator must take action to reduce the power flow which will affect the customers. If, say, an excavator is digging close to the cable trench it is not unlikely that both cables will be damaged. Such an overlapping fault leads to both cables being de-energized and no energy will be delivered to the customers. One possible way of strengthening the system reliability is by laying a third cable in a trench a good distance away.

However even three cables are insufficient to prevent all faults. For example two excavators could be working in the areas of cables 1 and 2 and cable 3 respectively, or one of the cables could experience an internal fault while the others were damaged by the excavator, or any number of other combinations of faults could occur, some of these are illustrated in Figure 13 in which internal faults are represented by the red lightning bolts.

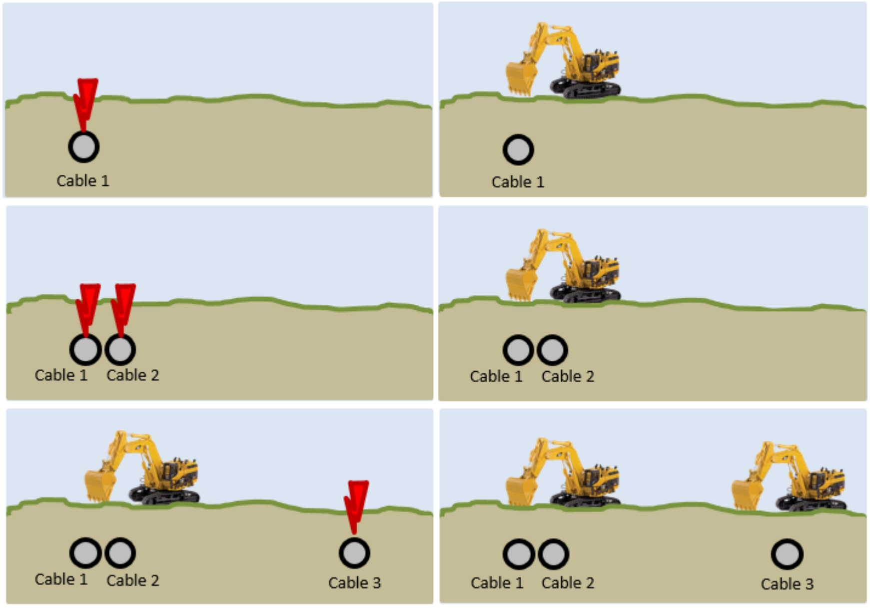


Figure 13: Possible situations which will lead to system unavailability in a system with one, two or three parallel cables. [12]

Because the repair time of cables tend to be long, the overlapping events do not necessarily have to occur at the same time. But the closer in time the events are the longer total outage time will be.

As larger investments are made to ensure system reliability, the less likely outages tend to become. In the example above the third cable significantly reduces the probability of an outage as several internal faults or several external forces are needed to take out the system. If attempts are made at ensuring against even more overlapping faults by adding components, then the reduction in hours of outage will become lower for each new component as the probability of all components failing will be very low. The investments will on the other hand be high.

Chapter 5.2 Unexpected faults

Most of the faults that have a relatively high probability of occurring are easy to foresee and therefore plan for. Less likely faults can be harder to predict because there is less experience with them and even though these faults can be few and far between, their impact on the power system can be significant. One example of such a fault is the Carrington Event [12, 13]:

In 1859 the earth experienced the first massive solar storm that there are any measurements for, known as the Carrington event. The storm was so massive that it led to northern lights being seen as far south as the Caribbean. At the time mankind was starting to really experiment with electricity and magnetism, most notably the telegraph system had

[12] The excavator picture was found on http://www.catmodels.com/products/55098-%252d-CAT-5110B-Excavator-with-Metal-Tracks.html (November 20th, 2013)

been developed and was becoming a very important part of the infrastructure. The Carrington event led to a massive geo-magnetic storm in the earth's atmosphere, causing great induced currents in the telegraph lines and thereby leading to many of the appliances catching fire. There was nothing to prepare the engineers of that time for the impact of the solar storm and the result was a massive unavailability of one of the time's most important parts of infrastructure.

In March 1989 six million people in Quebec, Canada lost their power supply due to a small (relatively to the Carrington event) solar flare. Large parts of the system remained de-energized for nine hours, some parts were de-energized for days. It was not immediately realized what had caused the outage, but eventually it was found to be a result of the solar flare.

After the 1989 event solar forecasts have become a standard forecast to provide to the affected industries and also to governments, unfortunately it is hard to obtain good forecasts and because of the speed at which the coronal mass ejections that result from the solar flares reach the earth, forecasts on upcoming events and a scale of its seriousness will be provided only three hours before the event occurs.

The best way of protecting the power system against the effects of massive coronal mass ejections is to allow the stress to even out over many components, which in terms of preparation means connecting every part of the power system. A system of many components over a small area may be able to reduce the stress of each component to a sustainable level, systems of fewer components will experience damage to equipment.

Before 1989 there was little focus on the impact of solar flares on the power system, because really large solar flares had not been experienced the last century, therefore the Canadian power system operators naturally did not take this into account. Today there is much more awareness of this potential threat, and protection schemes are planned in order to, not avoid, but reduce the impact of such a flare. It is estimated that the Carrington event is a once per two hundred years event, and being almost two hundred years since the last, one is expected to occur in foreseeable future.

As our knowledge increases there may be more fault cases that it is possible to prepare for and this makes it increasingly important to evaluate which investments are worthwhile. In order to evaluate what level of investment is reasonable, and thereby which faults should be prepared for a cost-benefit analysis is performed, based on a reliability analysis of the system.

Chapter 5.3 Evaluation of Fault Economy

A cost-benefit analysis is used to decide which faults should be attempted avoided.

Reliability analyses are performed, evaluating what the impact of a fault is in terms of how much energy will not be delivered to the customers. As previously described faults result in penalty costs, loss of profit and repair costs. The sum of these for each fault can therefore be considered the value of avoiding the fault. The cost of avoiding a fault is the sum of the marginal investment cost and the marginal operation and maintenance cost over the component's life span.

The faults are lined up by merit such that the faults with the highest cost of failure and lowest cost of avoiding failure are placed to the left and vice versa. A graph of the cost of failure and a graph of the cost of avoiding faults are drawn and the ideal level of investment is found by the crossing point of these graphs. All faults to the left of this point should be attempted avoided trough the appropriate additional investment.

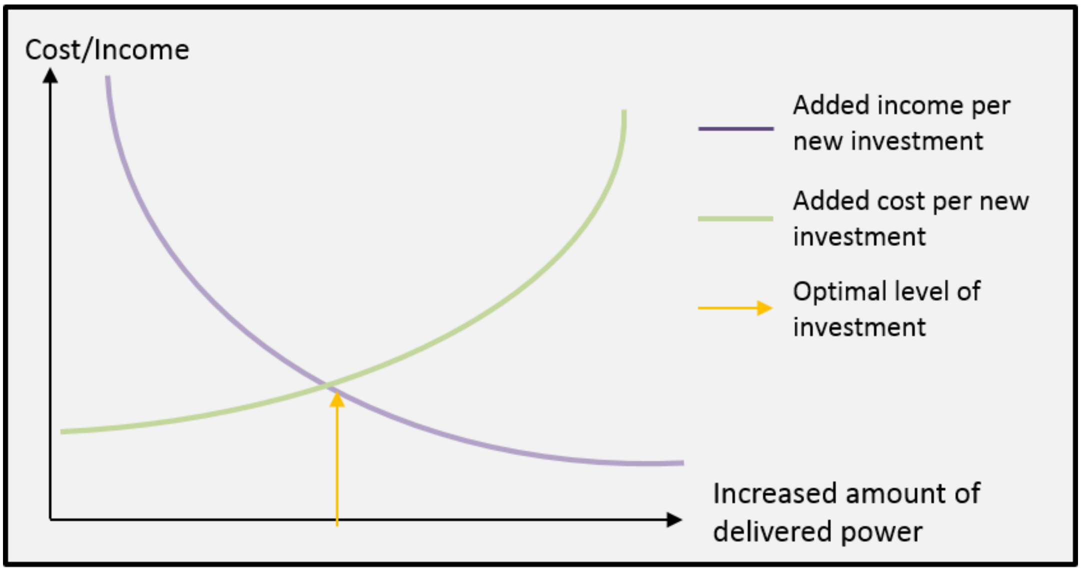


Figure 14: illustration of Cost-Benefit analysis showing the optimal level of investment

Such analyses should be performed regularly, and not only in the planning phase of the system. The justification for regular analysis of the investment level is that many parameters of the analysis change over time. The investments costs will vary as the costs of the individual components change. The marginal energy delivery will change with the power flow in the system and the amounts of loss in and the reliability of the components. Also both the energy price and the penalty cost of undelivered energy will vary with time.

In the beginning of this chapter it was stated that it is impossible to create a 100 % reliable system. This goes to the fact that in addition to the benefit of overinvestments being tiny, there are also potential sources of faults that we do not know of. There may evolve a bacteria that eats through power lines in a large scale, the plate tectonics of the earth may change, the earth may be hit by a meteor etc. There is no limit to what could possibly affect the power system, but the events do become less likely as the imagination is set free. There are of course also situations in which damage to the power system is of no consequence, if for example the earth is hit by a meteor and humans go extinct, there will be no-one to care if the power system works or not. These are the extreme cases, but they illustrate the point, no amount of overinvestment can ensure 100 % availability of the power system, and the overinvestment will become extreme if one attempts at it.

Chapter 6. Reliability analysis

Chapter 6.1 Reliability indices

Reliability analyses are performed to investigate the reliability of a system, but there is no one definition of what reliability is. The result of reliability analyses are therefore a number of so-called reliability indices, which act as indicators of a variety of system properties and which serve to give information on a specific aspect of the system reliability. Some of these reliability indices are: ([14])

Table 1: Some main reliability indices

Index type	Symbol	Explanation
Primary indices	λ	Number of failures per year [1/yr]
	MTTR	Mean time to repair [h]
	U	Unavailability [h/yr]
Customer-oriented indices	SAIFI	System average interruption frequency index [1/yr]
	SAIDI	System average interruption duration index [h]
	CAIDI	Customer average interruption duration index [h/yr]
Load/Energy-oriented indices	ENS	Energy not supplied [kWh]
	AENS	Average energy not supplied [kWh]

'The aim of the analysis is to obtain a more thorough knowledge of a system. Reliability analyses are based on probability theory and statistical data. This means that all reliability analyses are approximate and may contain large uncertainties. It is of course a target to reduce the uncertainty of all input data and to make the procedure as thorough as possible in order to increase the value of the output.

Chapter 6.2 RelRad methodology

The RelRad (RELiability in RADial systems) methodology has been developed for studying the reliability of radially operated distribution systems.

RELRAD is an analytical approach, based on the fault contribution from all network components and their consequences to the load points' outages. This differs from failure mode or minimum cut set analysis which assesses the individual load points' reliability directly by the minimum cut set. In short the minimum cut set analyses the individual load points, while the analytical simulation approach analyses the individual components.[15]

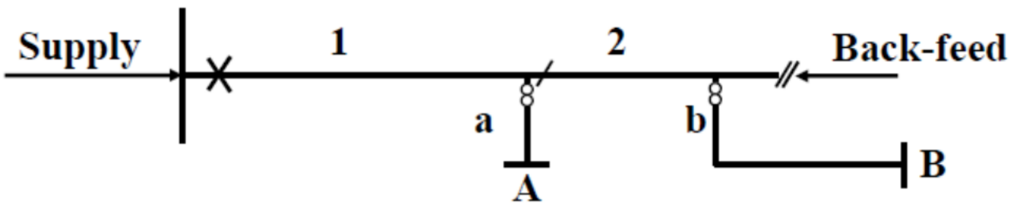
When applying the RelRad methodology the following is assumed [16]:

- The grid system is operated radially and any mesh-connections are considered reserve connections for use if the primary connection fails.
- Faults are isolated by the closest circuit breakers. If the circuit breakers fail the second closest circuit breakers will isolate the fault.

- All faults are considered statistically unrelated.
- Each fault is assumed repaired before the next fault occurs.
- Reserve connections are assumed available on demand.

The idea of the RelRad methodology is that each component is studied to decide its impact on all the different load points based on the position of the component and its frequency of failure and average repair time.

The impact a fault has on the different load points depends on the location of circuit breakers, disconnector switches and back-feed connections. An example from [14] is included.



Section	Load Point A			Load Point B		
	λ	r	U	λ	r	U
1	0.2	4.0	0.8	0.2	0.5	0.1
2	0.1	0.5	0.05	0.1	4.0	0.4
a	0.2	2.0	0.4			
b				0.6	2.0	1.2
Total	**0.5**	**2.5**	**1.25**	**0.9**	**1.89**	**1.7**

Figure 15: Example of RelRad methodology [14]

The example shows a simple distribution system with a supply line, two load points, one CB (marked by X), one DS (marked by /), two fuses (each marked by two small circles), a back-feed and four power cables that can experience faults (components 1, 2, a and b).

Row-wise each component is evaluated.

1. Component 1 has a frequency of outage λ=0.2, which means that on average it will experience a fault twice every decade. The rate of failure is independent of from where in the system one evaluates its impact, hence the same value is used for both load points.

2. When component 1 fails, then the CB will open and no power will be supplied to either load point. However, after some time the DS can open and allow the connection of the back-feed. The total time to open the DS and connect the back-feed is set to 0.5 hours. When the DS is open and the back-feed is connected load point A is still isolated, but load point B has restored power supply. This means that 0.5 hours is the repair time that is relevant for load point B. The repair time of component 1 is set to 4 hours. Therefore 4 hours is the relevant repair time for load point A. After this time the CB and the DS can be closed, and the back-feed disconnected and the system is back to normal.
3. When both the frequency of failure and the repair time are known the outage time per year of each load point that results from faults in component 1 can be calculated as the product of these. For load point A the average outage time is 0.8 hours per year, while it is 0.1 for load point B. This difference in outage time shows the advantage of the back-feed.

The above evaluation is done for all the four components. After the evaluation the overall impact on each of the load points of all the faults combined is calculated. The total outage time is found as the sum of the outage times of all individual components. The same goes for the frequencies of failure. The average repair time that is needed for a fault in the system is found as the total outage time divided by the total frequency of failure.

$$U_{System} = \sum_{1}^{N} U_{Component} \tag{1}$$

$$\lambda_{System} = \sum_{1}^{N} \lambda_{Component} \tag{2}$$

$$MTTR_{System} = \frac{U_{System}}{\lambda_{System}} \tag{3}$$

The example shows that faults are more likely to influence load point B as the frequency of failure for this load point is higher than for load point A. The total outage time is also higher for load point B. However the average repair time necessary to restore load point A is higher than for load point B.

In the above example the CB and DS are ideal components. This would not be the case in reality. The method for taking into account failures of operation in switchgear is different from the other components, because these components can only fail to operate when they are actually triggered to[13]. Therefore a probability of failure on demand must be found for CBs and DSs. The combination of a component failing and, for example, a CB also failing to operate can be evaluated as a separate component. For this "component" the frequency of

[13] In this thesis the switchgear is assumed 100 % secure.

failure would be the failure rate of the component multiplied by the probability of failure of the CB. When this approach is used it is important to also include the failure of the component without the CB failing to operate and the probability of this occurring is equal to the product of the failure rate of the component and (one minus the probability of the CB failing to operate). The formulae for including the protection system in the reliability analysis is:

$$\lambda_{protection\ system\ fails} = \lambda_{componnet} * P(\overline{protection}) \tag{4}$$

$$\lambda_{protection\ system\ works} = \lambda_{component} * (1 - P(\overline{protection})) \tag{5}$$

In which:

- Component refers to the component that is protected by the protection system in question.
- $\lambda_{protection\ system\ fails}$ is the number of failures of the component per year in which the protection system fails to operate.
- $P(\overline{protection})$ is the probability of failure to operate on demand of the protection system.

These two new failure rates substitute the single failure rate that would have been used if the protection system was assumed to be ideal.

In some cases the power system has two components operating in parallel. Parallel components are not necessarily considered parallel in the reliability sense, as this is a question of how they respond to faults.

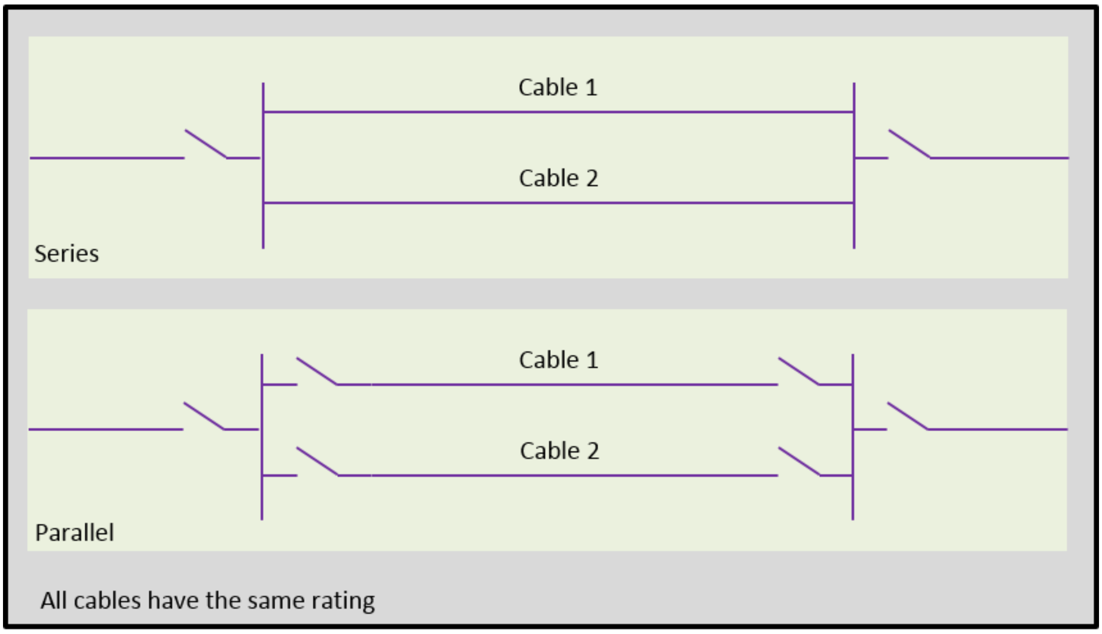


Figure 16: The difference between series and parallel components in the reliability network model

Figure 16 shows how the switchgear can separate series and parallel components when it comes to reliability analyses. In the figure all cables have equal rating, hence if a fault occurs on one of the two cables then the other cable can carry all of the power. The difference between the two layouts is however that in the upper scenario, if Cable 1 fails the only way to de-energize the cable is by opening the two CBs and thereby de-energizing both cables. In a system like this the components are said to be in series in the reliability sense, as a fault on either one component leads to unavailability of the entire link, like in a series connection. The two cables can therefore for the reliability analysis be studied as if they were series connected. The lower scenario has the possibility of de-energizing only the faulty cable. In this scenario the entire link will only be de-energized when both cables need experience a fault at the same time.

A third option that is not included in the figure is that the rating of the (electrically) parallel cables could be less than the rating of the cables at either side, and thereby lower than the link-rating. If the cables are then connected according to the lower scenario and a fault occurs in one of the cables, then the transmission capacity will be lower than under normal conditions. In this case the system operator needs information on the new transmission capacity in order to control the power flow to be below the rating and avoid overheating in the remaining component.

In the case of (reliability-wise) parallel components the frequency of failure and MTTR of the layout must be calculated before the RelRad analysis can be performed. The equations for calculating these indices are:

$$\lambda_{parallel} = \lambda_1 * \lambda_2 * \frac{(MTTR_1 + MTTR_2)}{8766} \qquad (6)$$

$$MTTR_{parallel} = \frac{MTTR_1 * MTTR_2}{MTTR_{\ 1} + MTTR_2} \qquad (7)$$

Where subscript parallel indicates that the indice holds for the combined system and subscript 1 and 2 refers to components 1 and 2 respectively. Similarly there are equations for systems of more parallel components. In the expression for λ the sum of MTTRs is divided by 8766, this is because the MTTR is given I hours, while the expression calls for the MTTR in amount of the year, this division is not included in the reference.

The main target of the analysis is to obtain the average outage time for each load point and this is done based on previously obtained average failure rates, repair times and probabilities of protection system not operating on demand.

The advantages of using this method is that it is fairly simple to keep track of and understand everything that happens and as such the analysis can easily be performed manually, even though this might be time consuming. Also the method is relatively easy to adjust, as will be described in the next chapter. In addition the input is based on experience and should hence be reasonably easily obtained, at least if one operates similar systems one self and can rely on experience from these.

One of the disadvantages of the RelRad method is that there is little certainty connected to the result. This would of course be true of any method that attempts at predicting the future. As the analysis is based on average values it will likely be accurate if a sufficiently long time period is evaluated, but this time period could be longer than the life span of the system components. There is also the added uncertainty connected to most components having non-uniform failure rates over the course of their life span. Many components are subject to quite a lot of failures during their first years of operation, following primarily from faults in the installations. The failure rate then normally falls to a lower level that lasts until the component begins to age. The last years of the life span of a component the failure rate rises again. The frequency of faults of a component can hence be said to follow the bath-tub model. Because "the edges of the bath tub" are relatively slim there are few years of experience with this and hence the data for these periods is limited. Mostly the average data do not take into account these changes in failure rates and consequently the use of the average numbers for time periods shorter than the components' life span results in higher inaccuracies in the results. Additional disadvantages of the RelRad method is that overlapping faults are not included, and also faults that lead to faults in other components are neglected.

Because the RelRad method was developed to evaluate radial distribution systems it is not in itself suited for use in this thesis. Some changes have therefore been made to it, which are discussed in the following chapters.

Chapter 7. Overlapping Faults

As previously described the RelRad method has some limitations that reduces its value as the systems become larger. One of the sources of error that increases with the size of the system is the fact that overlapping faults are not taken into account.

This chapter aims at describing the impact of overlapping faults in a system and provide a method for including this effect in a RelRad-based reliability analysis.

Chapter 7.1 Probability of overlapping faults

The probability of two components failing at the same time is found by multiplying the probabilities of a fault in each one of them.

$$P(\overline{component\ X}\ \cap \overline{component\ Y}) = P(\overline{component\ X}) * P(\overline{component\ Y}) \tag{8}$$

The probability of one component failing at the same time as any one other component in a systems of N components is given as the sum of the probabilities of each potential overlap. This could be expressed as:

$$P(\overline{component\ X}\ \cap \overline{other\ component}) = \sum_{\substack{Y=1 \\ Y\neq X}}^{Y=N} P(\overline{component\ X}\ \cap \overline{component\ Y}) \tag{9}$$

The probability that any two components should experience overlapping faults is the sum of the above expression for all components.

$$P(overlapping\ faults) = \sum_{X=1}^{X=N} P\left(\overline{component\ X}\ \cap \overline{other\ component}\right) \tag{10}$$

From this it follows that if two components have a low unavailability, meaning the probability of a failure is low, then the probability of them having overlapping failures is even lower. It is also clear from the above expressions that the number of components greatly influences the probability of overlapping failures. The relationships above show that as the unavailability of some or all components tends to 100% and/or the number of components in the system tends to infinity the probability of overlapping failures tends to 1.

It should be noted that the probability of overlapping faults that is given by the above equations is the probability of there being overlapping faults in the system at a given point in time, not the probability that overlapping faults will occur over a period. This is a result of using the component unavailability rather than the frequency of failure as the basis for probability of failure of a component.

One can for example imagine a system in which there is a component that fails every day, but is only unavailable for a few seconds, and another component that fails once every ten years and is then out for two days. Over a period of some decades one is guaranteed that overlapping failures will occur, but the impact will be very little as the total time during which the two components are both out may be less than one minute, the probability of overlapping failures over a period is therefore of less interest for the type of analysis which will be performed in this thesis, in which the system impact is the essential parameter to study.

Chapter 7.2 Effect of Overlapping Faults on System Availability

One thing is to evaluate the probability of several faults occurring at the same time, another is to evaluate whether the impact of this is significant. If two components fail at the same time then the overall system unavailability may be reduced if certain criteria are fulfilled. This idea is illustrated in Figure 17.

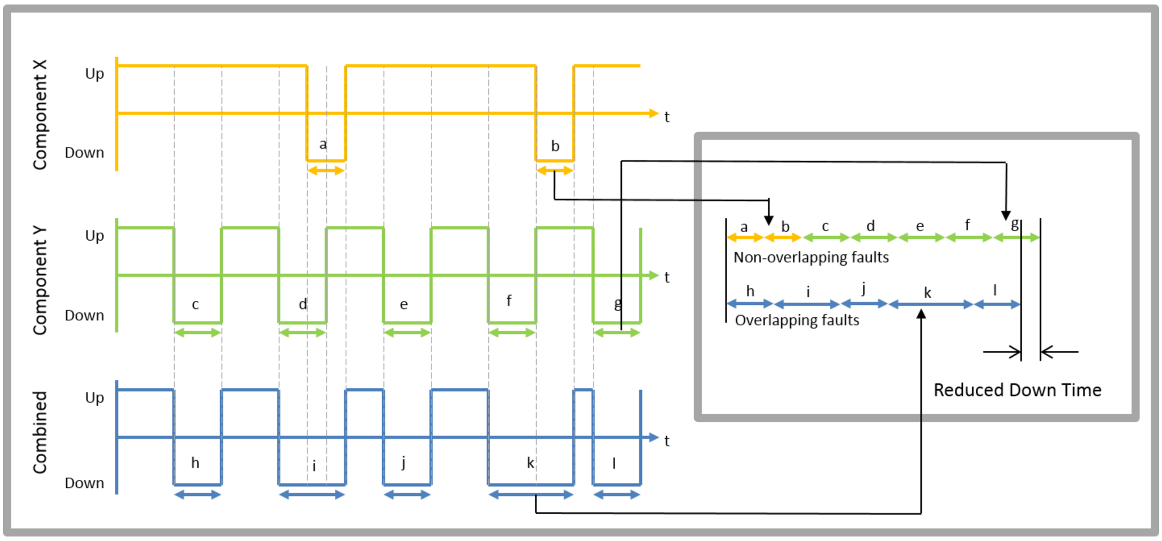


Figure 17: Effect of overlapping failures

The figure shows the status graph of two components X and Y. The two components are in this case connected in series, i.e. the system is down if either one of the components are down.

The top and middle status graphs show the individual MTTF (Mean Time To Failure) and MTTR for the two components. If overlapping faults are not considered the total down time of the system will be given by the sum of the two components' individual down times during the studied period as indicated by the uppermost line in the frame on the right.

The lowermost status graph shows the case in which overlapping failures are taken into account. In this graph the graph of component X is superimposed on the graph of component Y and a new, system status graph is made by using the above mentioned rule that when either one of the components are down, then the system is down. The result of including the possibility of overlapping faults is illustrated in the frame on the right, in which the blue arrows show the "graphical sum" of the down time over the studied period for this case. It is evident from the figure that the total down time of the system is reduced when overlapping faults are taken into account, compared to when they are not.

In the case when there are no overlapping failures, the system down time is simply the summation of individual down times of the components. When overlapping failures do occur then the system down time will always be less than the summation of the individual down times of the components.

From the figure the reduction in down time appears to be significant, but the input MTTRs and MTTFs are not realistic and have been chosen completely at random in order to illustrate the point, and hence this may not be the case. Also worth noticing is the fact that the down time of the system is not reduced by the entire down time of component X (which has the lowest down time of the two components). Rather some fraction of component X's down time is "removed" from the system down time. This results from the fact that the overlapping faults do not occur simultaneously, though part of their down times overlap.

In order for the effect of overlapping faults leading to reduced system unavailability certain criteria needs to be fulfilled;

- the components must be radially connected in a feeder
- the faults must be discovered when they occur
- the faults must be independently repaired

If the components are not radially connected the principle does not apply. If the components are connected in parallel[14] in a feeder, the unavailability of the system will only occur when both components are down and the system unavailability is therefore increased by including overlapping faults. If the components are placed in different feeders then the influence on the system becomes more complicated as there are more possibilities as to how the system is influenced by each of the faults.

When a fault occurs in a radial feeder it will normally be the case that no current is flowing in the feeder, When no current is flowing the probability of a second fault in the feeder is significantly reduced for most of the components. The exception from this is cables whose main source of faults is non-electricity related physical damage. The fact that the probability of a second fault is significantly reduced for other components than cables means that the influence of overlapping failures is reduced. But in the cases where a second fault does occur it is necessary to notice the fault immediately in order to achieve the above described reduced unavailability. If the fault is not noticed until the system is subjected to flowing current again, the advantage of using a time period in which the system is down in any case, to repair the component will be lost. There is a possibility that some advantage will be given by the repair crew already on-site in cases where a second fault is detected upon re-energizing the system, but this is hard to predict and will in any case contribute very little in the larger scheme of things.

By independent repair of faults it is meant that the restoring to working order of one component does not postpone the restoring of another. When components of different types fail at the same time different repair crews will likely be used to mend the components. In case for example two cables fail at the same time, which may in many cases be likely if the cables lie close together, the same repair crew could be used to mend the two faults. Using the same repair crew would result in reduced repair time as the requiring of a repair vessel and spare components will only need to be done once, but the actual repair would happen in sequence, rather than at the same time.

[14] Parallel components are, as previously described, considered to be series connected in the reliability sense unless they are equipped with individual protection systems.

Chapter 7.3 Reliability study including overlapping faults

In the cases where it is found to be necessary to include the possibility of overlapping faults it is necessary to find a way of tweaking the RelRad method in order to allow for overlapping faults. It is often stated that the RelRad method cannot be used for overlapping faults, but some of the methods that are included in RelRad, such as that of considering parallel operation of two components with 100% redundancy, take into account specific cases of overlapping faults in order not to overlook significant combinations.

The parallel-component method is a tool that can in principle be used to study the combined unavailability of any two components in a system, but the resulting impact on the system is less straight forward as it may not be a case of the system being up or down, but rather the system power carrying capacity may be reduced only some fraction due to the combined fault.

An alternative way of evaluating the system is to split it into several different modules and evaluating these individually. This is also done in normal RelRad, but the results may be used in a different way.

In order to simplify the system one would oftentimes need to sectionalize the system and study each section separately. This is in essence what is done when only a part of a system is studied, for example the system in one part of a town or inside one wind farm. Even though both of the mentioned systems would be connected to the main grid, one is only interested in one particular part. This part is then studied independently of the rest of the system and all of the relevant reliability indices are found for this particular section. This section can then be further divided into sub-sections in order to simplify calculations. When the reliability indices have been found for one of the sub-sections the entire sub-section can be replaced by one component whose reliability is given by these indices.

The procedure can be performed in two main ways. The section can be split into non overlapping sections, or into overlapping sections. By using non overlapping sub-sections each of the sub-sections are reduced to one component and when the calculations are finished for each of these then new calculations are performed for the remaining system, which now consists entirely or partly of reduced sub-sections. The number of calculations for a system of n sub-section will therefore be n+1. By using overlapping sub-sections the sub-sections are created such that one or more sub-sections lie within the next. This way the number of calculations is reduced to n for a system of n sub sections, but in this case the sequence in which the calculations are done matters, as the innermost sub-sections need to be computed first.

By using this method the sole target of the sub-sections is to simplify the system and hence the calculations.

An alternative is to use sections in a way that allows for overlapping failures. In this thesis the term modules are used for this method, as opposed to sections, this is done simply to separate the two methods from each other.

In this method the idea is that the system is split into modules which are allowed to have overlapping faults. The components within one module cannot fail at the same time, but all of the modules may experience a fault at the same time.

Considering the system in Figure 3 a possible sectioning of the system is to consider each component and its protection system as separate models. The two transformers that are operated in parallel would necessarily be considered as one module together, because the RelRad method already contains a method for studying this layout. The resulting modules would then be as illustrated by the colours in Figure 18. Because the two branches to the two collection points are exactly equal the modules of these branches can be considered as pairs. The two modules containing the parallel transformers are hence both called module 1.

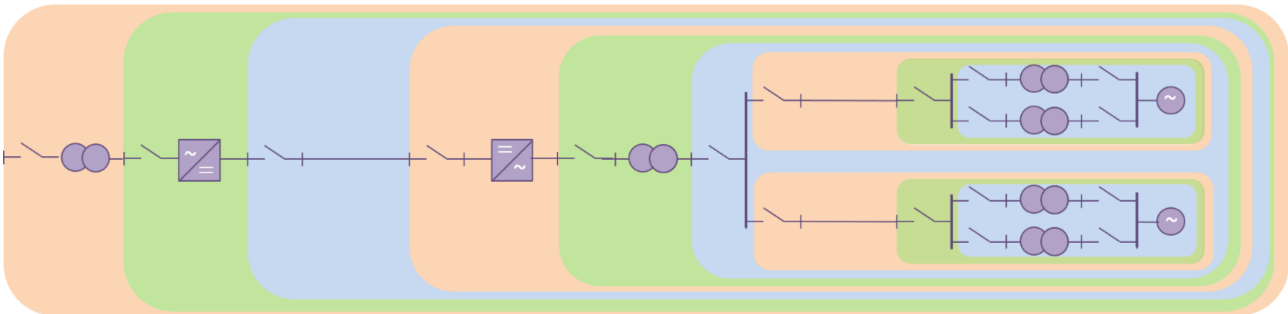


Figure 18: Example of module based analysis for Base Case

This approach requires starting at the generating point. A normal RelRad analysis is performed for the first (innermost) module. This involves finding the unavailability of the two transformers, with their protection system.

The result from this analysis will be a graded status graph. The system will in this case not simply be either up or down, there is also a third option in which the system's transmission capacity is reduced to 50 %.

For the innermost module there are 5 possible fault states:

- Transformer 1.1 fails but the protection system operates
- Transformer 1.1 fails and its protection system does not operate
- Transformer 2.1 fails but the protection system operates
- Transformer 2.1 fails and its protection system does not operate
- Both transformers fail

From the figure it is clear that in the case of both transformers failing the protection system does not have any influence on the reliability of the system[15], because in any case no energy can be supplied.

These possible outcomes can also be written with probability syntax. T here refers to transformer and T_1 is hence transformer one, while p refers to protection system.

- $\overline{T1} + p1$
- $\overline{T1} + \overline{p1}$
- $\overline{T2} + p2$
- $\overline{T2} + \overline{p2}$
- $\overline{T1} + \overline{T2}$

In order to evaluate these outcomes some knowledge of the components is essential. First and foremost the failure rate of the transformers and their MTTR is necessary. The probability of the protection system not operating is also needed. In this thesis it is assumed that all circuit breakers are series connected with disconnector switches such that once the relevant part of the system is de-energized these switches can be opened to allow repairs of the circuit breakers and also provide extra security when repair is done on other components. Lastly it is essential to keep in mind that each of the transformers is only rated for half of the collection point's rated power. In order to supply maximum generated power both transformers need to be operational.

Following is an example of the method for evaluating this module:

Table 2: Input data to example of RelRad methodology expanded to include overlapping faults

Transformer			Circuit breaker	Disconnector Switch
MTTR [h]	763	**Probability of failure to operate %**	10	-
Failure frequency, λ [1/yr]	0.0308	**Manual operating time [h]**	-	1

The normal RelRad method does not take graded supply capacity into account, this can however be easily tweaked. The below table has two columns of MTTR and two columns of U. These columns contain the respective indices for when the system is unavailable (100 %) and when the transmission capacity is only reduced (50 %).

Table 3: Results of module 1 in example of expanded RelRad methodology

		MTTR		U	
	λ [1/yr]	50 %	100 %	50 %	100 %
$\overline{\mathbf{T1}} + \overline{\mathbf{T2}}$	0.0308*0.0308*(763+763)/8760 = 0.00017	-	381,5	-	0.063

[15] Naturally the operation of the protection system is also necessary to ensure other components are not damaged by the fault currents from the original fault. It is however assumed here that there are other protection equipment placed such that the fault will be cleared before permanent damage occurs. This means that if for example CB 3.1 fails to operate, CB 5.1, CB 4.1 and CB 1.1 will operate to isolate the fault.

$\overline{T1} + p1$	(0.0308-0.00017)*(1-0.1) = 0.02757	763	-	21.03	-
$\overline{T1} + \overline{p1}$	(0.0308-0.00017)*0.1 = 0.00306	762	1	2.33	0.00306
$\overline{T2} + p2$	(0.0308-0.00017)*(1-0.1) = 0.02757	763	-	21.03	-
$\overline{T2} + \overline{p2}$	(0.0308-0.00017)*0.1 = 0.00306	762	1	2.33	0.00306
Sum	**0.06143**	**760.54**	**1.14**	**46.72**	**0.07**

The steps that are used in this method are explained below.

Step 1: Find the parameters that can be used for overlapping faults of parallel components.

For parallel components RelRad has a method for calculating the probability of an outage of the system. In the RelRad method it is assumed that the system is down if and only if both components are down. This is also the case for the system that is studied here, the fact that the system is not running at full rating when one of the components are down does not influence the effect of both components being down. Λ and MTTR is in this case given by equations 6 and 7.

For the above case the values are found to be: λ = 0.0017 1/yr, MTTR = 381,5 h, as shown in the table.

Step 2: Evaluate the system impact of the outage of both transformers

During the time when both transformers are down zero energy will be supplied from collection point 1. Therefore the MTTR is placed in the 100 % column because 100 % of the energy is lost. The unavailability of the system due to this fault is found by multiplying the failure frequency with the MTTR. It is found that there are on average 0.063 hours per year in which the system is down due to this fault.

Step 3: Find the failure frequency of just one transformer failing

The failure frequency of the transformers is known, however this number includes the number of times that both the transformers fail and the number of times in which the protection system does not operate, a new number therefore needs to be found to evaluate the impact of *just* one transformer experiencing a fault. This is done by subtracting the number of faults in which both transformers fail and then multiplying with the probability of the protection system operating as it should (which equals one minus the probability of the protection system not operating on demand). The failure frequency for this particular case is found to be 0.02725 1/yr based on Equation 5. Because the two transformers are identical and the protection systems are identical this number is valid for both transformers.

Step 4: Evaluate the impact of one transformer failing

When one transformer fails and the protection system operates on demand the system remains energized, but only 50 % of the rated power can be supplied. The MTTR for the transformer is therefore placed in the 50 % column of the MTTR. This holds for both transformers.

Step 5: Find the failure frequency of one transformer and its protection system.

The failure frequency of both transformer and protection system is found by subtracting the number of failures of both transformers from the failure frequency of the transformer and multiplying the result by the probability of the protection system not operating on demand as in Equation 4. This comes out to 0.00306 1/yr, a number that is valid for both transformers.

Step 6: Evaluate the impact of one transformer and its protection system failing

When a transformer fails and the protection system fails to operate it is assumed that the next level of protection is activated and operates. Double protection system failures are not considered in this thesis.

When the protection system fails it is clear from the system layout that the entire module is de-energized and no power can be delivered from collection point 1. However, once the module is de-energized the disconnector switch in series with the faulty protection system can be opened and the open circuit breakers can now be closed, leaving the system in the same state as if the protection system had worked.

Since the manual operating time for the disconnector switch in this case is set to one hour this is the amount of time in which no energy can be delivered from collection point 1, one hour is set in the 100 % column of the MTTR. During the remaining 762 hour of the transformer's repair time only 50 % of the rated energy at collection point 1 cannot be delivered and 762 hours is therefore written in the 50 % column of the MTTR. The resulting unavailability shows that during on average 2.33 hours per year only 50 % of the rated energy can be delivered through this module due to this specific fault. Only for 0.003 hours per year no energy can be delivered through this module due to this fault. This holds for both transformers.

Step 7: Evaluate the reliability of the module

When all the components in the module have been evaluated the average yearly outage of the module can be found by summing all the outage durations in the 50 % column and all the outage durations in the 100 % column. These two sums can then be used to produce a graded status graph for the module.

The results show that for 46.72 hours per year the module only allows 50% of the rated energy to be delivered. This translates into 0.53 % of the time. The module allows no energy to be transmitted during 0.07 hours per year, which is 0.0008 %. The status graph for this system would be as indicated in Figure 19.Note that the size of the different levels is not proportional, as one would not be able to see the different states in that case.

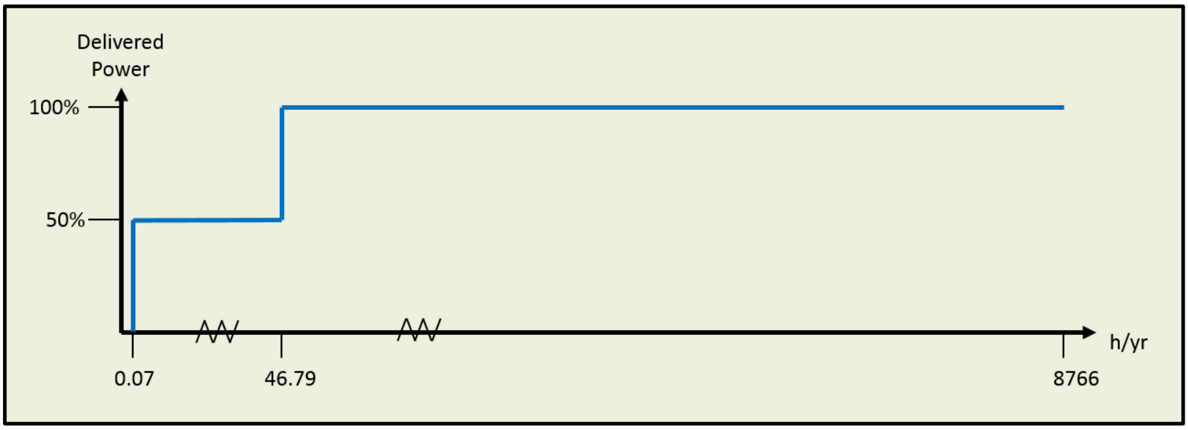


Figure 19: Status graph module 1

For the time being it is assumed that the power generation has no down time and also that rated power is delivered 100 % of the time. This is of course not probable for any generation source and completely impossible for a wind farm, but for simplicity this has been left out so far. Using this assumption leads to the module just discussed setting the limits on delivered power. This means that from now on the entire module can be replaced by the generator, though the generating pattern of the generator is now the pattern shown in Figure 19.

The next step in the analysis is to evaluate the second module, which contains Node 2.1 and its protection system. A RelRad analysis is performed to determine the unavailability of the module. A fault in this module results in unavailability of the entire feeder, and hence there are only two states for this module, up and down. The resulting hours of outage are found to be 6.6528 hours per year, or 0.076 %.

When the reliability data of module 2 has been calculated the effect of module 1 is included. At this stage it is useful to think of module 1 as a generator with the generating pattern shown in Figure 19. As the production from the “generator” is not constant, the effect of module 2 must be evaluated for each level of production. As can be seen from the figure there are three levels of production and it was found that module two has two possible states, this gives a total of 2*3=6 combinations. For each combination the probability of it occurring, and the amount of power that is delivered through module 2 when it occurs must be determined. This procedure is illustrated in Table 4.

Table 4: Overview of method for combining modules

Module 2	Probability	Module 1	Probability	Resulting State	Probability
Up	99.924%	100 % Up	99.4692 %	100 % Up	99.3936 %
		50 % Up	0.53 %	50 % Up	0.5296 %
		Down	0.0008 %	Down	0.0008 %
Down	0.076 %	100 % Up	99.4692 %	Down	0.0756 %
		50 % Up	0.53 %	Down	0.0004 %
		Down	0.0008 %	Down	0.0000 %

For each of the combinations the probability is found by multiplying the probabilities of the states of each module, while the delivered power is found as the lower value of the production and the capacity (If the production is less than the transmission capacity the production is the limiting factor, while if the transmission capacity is lower than the production the production must be reduced accordingly and the transmission capacity is the limiting factor).

When the analysis is finished it is evident from the above table that there are several combinations that give the same amount of delivered power, in the above case the four bottom combinations give zero delivered power. In order to limit the amount of combinations that needs to be evaluated for the following modules the combinations that leave the same amount of delivered power can be combined. This is done by summing the probabilities of the relevant combinations. For the current case this leaves three possible levels of delivered power which constitute the production pattern of the "generator" that replaces module 2. This procedure is then used for all radially connected modules.

In the above example a perfect generator at the collection point was assumed. In reality (in the system here considered) this generator is not perfect but has a production pattern similar to a wind turbine power curve, this means that the production varies non-linearly with wind speed. The power curve will be a relatively smooth curve, but needs to be discretized for the purpose of this analysis. The level of accuracy of the analysis is dependent on the number of levels that the power curve is split into.

The method for taking the power curve into account is essentially the same as for the combining module 1 and 2, with just one very important difference. Because all projects, and hence all collection points in Dogger Bank are subjected to approximately the same wind speed at any given moment the production levels need to be kept separate from each other. This is simple enough as it simply means that combinations of states, in which the collection point power is different, cannot be combined as was suggested above. In the case where the production is for instance 10 % then the production will be the limit for the module-combinations that give 50 % and 100 % transmission capacity, and the delivered power will in this case be 10 % with a probability of the sum of the two upper combinations in Table 4 multiplied by the probability of 10 % production. In the combinations that give 0 % transmission capacity this is clearly the limit and zero power will be delivered with a probability of the sum of the four bottom rows in Table 4 multiplied by the probability of 10 % production. The difference that needs to be taken into account when the production is part of a wind farm, is that even though the bottom four rows in the table will give zero delivered energy independently of the production level, these needs to be kept separate and cannot be summed for different levels of production. The reason for this becomes evident at module 4, where there are two "generators" present.

Table 5: Example of combination of variable production and module unavailability gives an example of the concept of how the calculation is performed for different levels of production. In this example produced power is combined with module 1. It has previously been described that module 1 should be calculated before the modules are combined in this way. In this example module 1 is not calculated beforehand, this is done in order to show which outcomes can be combined.

Table 5: Example of combination of variable production and module unavailability

Produced power	Probability	Module outage states	Probability	Delivered power	Probability	Resulting power	Probability
100 %	$P(100\%)$	Module Up	$P(up)$	100 %	$P(100\%) * P(up)$	100 %	$P(100\%) * P(up)$
		Transformer 1 Down	$P(\overline{T1})$	50 %	$P(100\%) * P(\overline{T1})$	50 %	$P(100\%) * P(\overline{T1})$
		Transformer 2 Down	$P(\overline{T2})$	50 %	$P(100\%) * P(\overline{T2})$		$+ P(100\%) * P(\overline{T2})$
		Both Transformers Down	$P(\overline{T1} \cup \overline{T2})$	0 %	$P(100\%) * P(\overline{T1} \cup \overline{T2})$	0 %	$P(100\%) * P(\overline{T1} \cup \overline{T2})$
75 %	$P(75\%)$	Module Up	$P(up)$	75 %	$P(75\%) * P(up)$	75 %	$P(75\%) * P(up)$
		Transformer 1 Down	$P(\overline{T1})$	50 %	$P(75\%) * P(\overline{T1})$	50 %	$P(75\%) * P(\overline{T1})$
		Transformer 2 Down	$P(\overline{T2})$	50 %	$P(75\%) * P(\overline{T2})$		$+ P(75\%) * P(\overline{T2})$
		Both Transformers Down	$P(\overline{T1} \cup \overline{T2})$	0 %	$P(75\%) * P(\overline{T1} \cup \overline{T2})$	0 %	$P(75\%) * P(\overline{T1} \cup \overline{T2})$
50 %	$P(50\%)$	Module Up	$P(up)$	50 %	$P(50\%) * P(up)$	50 %	$P(50\%) * P(up)$
		Transformer 1 Down	$P(\overline{T1})$	50 %	$P(50\%) * P(\overline{T1})$		$+ P(50\%) * P(\overline{T1})$
		Transformer 2 Down	$P(\overline{T2})$	50 %	$P(50\%) * P(\overline{T2})$		$+ P(50\%) * P(\overline{T2})$
		Both Transformers Down	$P(\overline{T1} \cup \overline{T2})$	0 %	$P(50\%) * P(\overline{T1} \cup \overline{T2})$	0 %	$P(50\%) * P(\overline{T1} \cup \overline{T2})$
25 %	$P(25\%)$	Module Up	$P(up)$	25 %	$P(25\%) * P(up)$	25 %	$P(25\%) * P(up)$
		Transformer 1 Down	$P(\overline{T1})$	25 %	$P(25\%) * P(\overline{T1})$		$+ P(25\%) * P(\overline{T1})$
		Transformer 2 Down	$P(\overline{T2})$	25 %	$P(25\%) * P(\overline{T2})$		$+ P(25\%) * P(\overline{T2})$
		Both Transformers Down	$P(\overline{T1} \cup \overline{T2})$	0 %	$P(25\%) * P(\overline{T1} \cup \overline{T2})$	0 %	$P(25\%) * P(\overline{T1} \cup \overline{T2})$
0 %	$P(0\%)$	Module Up	$P(up)$	0 %	$P(0\%) * P(up)$	0 %	$P(0\%) * P(up)$
		Transformer 1 Down	$P(\overline{T1})$	0 %	$P(0\%) * P(\overline{T1})$		$+ P(0\%) * P(\overline{T1})$
		Transformer 2 Down	$P(\overline{T2})$	0 %	$P(0\%) * P(\overline{T2})$		$+ P(0\%) * P(\overline{T2})$
		Both Transformers Down	$P(\overline{T1} \cup \overline{T2})$	0 %	$P(0\%) * P(\overline{T1} \cup \overline{T2})$		$+ P(1\%) * P(\overline{T1} \cup \overline{T2})$

The columns in the table are split in four groups, each of two columns. The first group presents the produced power delivered to the collection point. The first column gives the power level and the second the respective probability of occurrence.

The second group presents the module availability. After using the module based approach for evaluating the module one should have a list of percentage unavailabilities (giving the percentage amount of power that cannot be transmitted through the module due to various faults) and their respective probabilities of occurring. In the above table the actual faults are included in order to clarify the method. It should however be noted that in the example above protection system faults are ignored, though they should of course be included in the module based approach and through this being included in the step explained in the table. The two columns in this group contain the fault, which should be replaced by the percentage unavailability of the module. The second column contains the probability of the outage state occurring.

The third group contains the result of combining the two previous groups. The amount of power delivered through the module is given by the lower number of the produced power and the module's power carrying capacity. The probabilities of each of these are given by the product of the probabilities of the produced power and the available power carrying capacity.

The fourth group removes duplicates in the level of power delivered through the module. This is done by summing the probabilities of all equal power levels for each level of produced power. At this point it is important to note that duplicates cannot be removed from the column as such, but only for the different levels of production.

The table shows how each of the different levels of produced power lead to several levels of power delivered through the node. In the example above only five levels of production are included, whereas in the analysis that is performed in this thesis the level of detail is much higher, and hence the number of possible outcomes is increased proportionally.

When more than one "generator" is present in a module it is necessary to first simplify these into one. In module 4 there are two generators, in order to combine these into one all possible combinations of delivered power from the two generators must be evaluated. Because the collection points contain the produced power from wind turbines that are close to each other it is not a possible combination that collection point 1 produces 100 %, while collection point 2 produces 10 % of rated power. It is of course likely that the two are not subject to exactly the same wind speed, but the difference between them will be relatively small, and for simplicity it is therefore assumed that all collection points in Dogger Bank are subjected to the same wind speed. This means that for each of the production levels there are 2*2=4 combinations (for production below 50 % of rated production) or 3*3=9 combinations (for production above 50 % of rated production). When the "generators" are combined this is done by summing the amount of power delivered in from each of them, and multiplying the probabilities of the corresponding levels. When the two “generators” have been combined into one, module 4 can be calculated like any other module.

The modules do not necessarily have to comprise only one component and its protection system, but could include more components. It should however be noted that by using normal RelRad methodology within the module one will define a scenario in which only one fault can occur at the time, but any one fault in module x can overlap any fault in module y. By taking this into account one can see the benefit of using modules that comprise components connected in such a way that a fault on any one of them will lead to the other components being de energized. In the system in Figure 3 for example one can imagine a module that combines the two transformers and Node 2 of each of the radials. By combining these components in one module one effectively defines these as components that cannot have overlapping faults. This is a reasonable assumption because if one of the components fail the feeder will be de energized and hence the probability of a failure, or at least of a failure being noticed, on the other component is minimal.

By using modules containing more than one component one further improves the method by introducing a means of ignoring combinations of faults that will never occur, while those that may occur are taken into account.

Chapter 8. Method for studying the reliability of the projects

This thesis studies several possible layouts for the inter-project grid. The methodology for studying these are discussed in the following sub chapters.

Chapter 8.1 Terminology

At this point it is necessary to specify some terms in order to ensure a common understanding of the following procedure. First of all the power produced at the generators, which in reality is the power produced by a number of wind turbines, and delivered to the collection point, is referred to as the *produced power.* The power that is delivered to Node 4 is referred to as the *node power*. For each of the levels of produced power, there are multiple levels of node powers that are possible due to the outage of components in the links connecting the collection points with Node 4. The power that is delivered to shore from one project, via the project’s own link to shore is referred to as the *Base Case power delivered to shore*. This term is chosen as in the Base Case this is the only power that will be delivered to shore.

Chapter 8.2 Studying the upstream connection

The upstream connection is the term that in this thesis will be used to refer to the grid that connects each of the offshore converter stations to the project collection points. This connection is a two branched radial connection and contains only HVAC components, save the converter which could be considered to be an HVDC component and its downstream protection system which is an HVDC protection system.

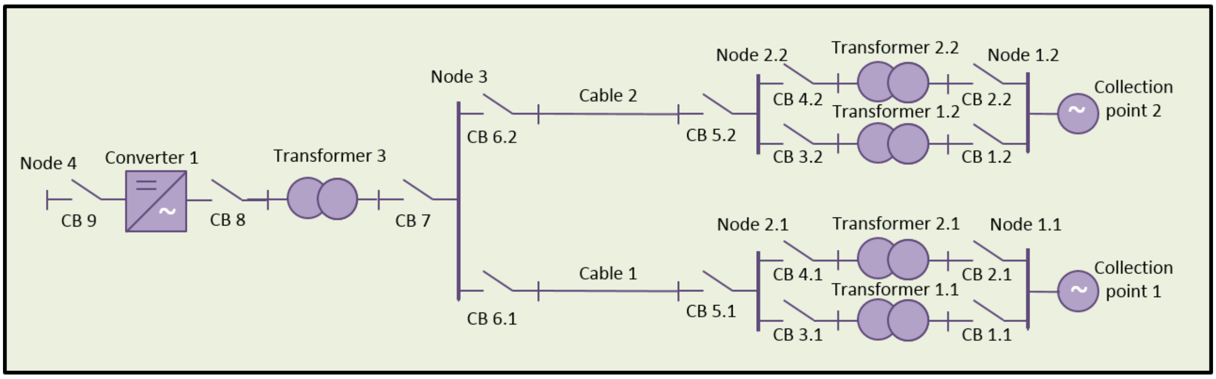


Figure 20: Upstream connection

When this system is studied the modular method described in Chapter 7.3 is utilized. It is assumed that all components may experience overlapping faults to the extent that all components in the system may experience a fault at the same time.

When variable power production is to be taken into account some simplifications need to be made. The first and most important simplification that must be made is the discretisation of the power curve of the wind turbines. This is done because the analysis algorithm does not allow for continuous data[16]. For this thesis Microsoft Excel has been chosen as the platform for the reliability study of the system. For more extensive analyses a program should be written in for example Matlab. One of the limitations of using Excel is that the program is not designed for using variable sizes of data, meaning matrices of variable sizes, and hence in order to do this complex formulae must be used and this will slow the computing and make the sheets less understandable and harder to debug. For this reason there are some limits to the extent to which the system can be evaluated, most notably in that the level of accuracy in the discretisation of the power curve cannot be changed at a later stage.

Based on the estimated wind conditions the production is calculated. The power curve used in this thesis has been discretized to integer values of wind speed. This leaves a curve along the lines of the curve in Figure 21.

[16] It would be possible to extend the algorithm to allow continuous data, but since the algorithm has been made with Excel as the platform, this is not possible in its current form. Excel limits the analysis to discrete data as it is not made for continuous data.

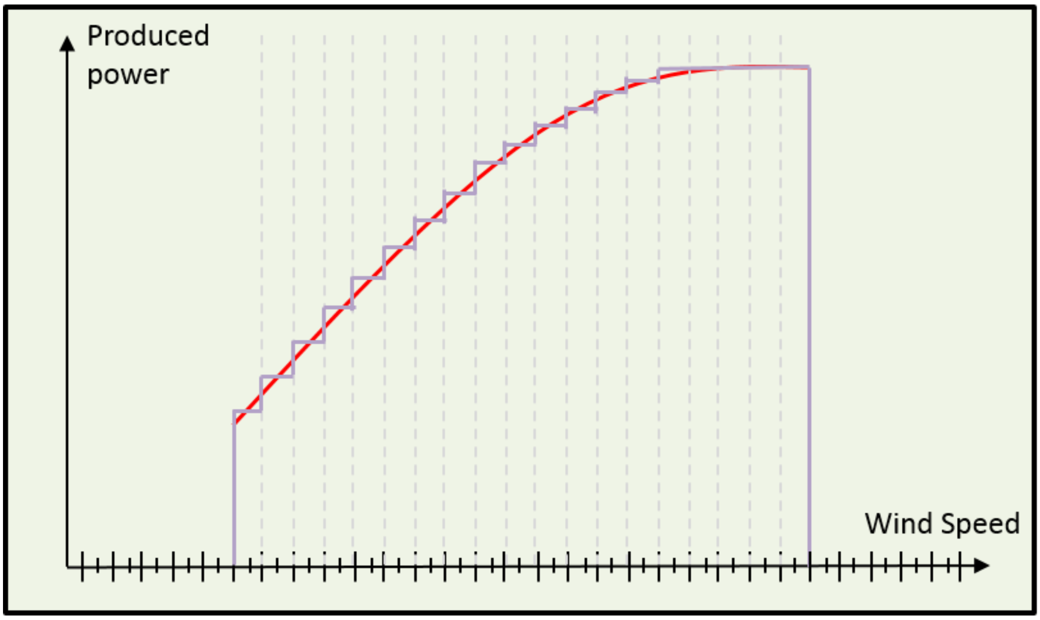


Figure 21: Example power curve for wind turbine or wind farm

Both coarser and finer discretisations could be applied, however this is the form of the data supplied by Statkraft and the level of accuracy is considered to be sufficient for this kind of analyses. The data has further been refined to take into account wake effects and electric losses in the internal grid of a project, leading up to the collection point. This leads to this data being usable directly as the production at each of the collection points.

For this upstream connection the module based analysis is used up to and including the offshore converter.

Chapter 8.3 Studying the connections to shore

Calculating the reliability of the connections to shore (which here refers to the part of the connection that is downstream of Node 4) of the different projects is very straight forward using the module based analysis. The only thing to be aware of at this point is that it might be interesting to evaluate the system with different levels of redundancy of the cable, which will be a significant contributor to the unavailability of the link. It might also be of interest to evaluate redundancies in the other components. No such redundancies have been considered in this thesis as it has been considered out of scope.

The module based analysis should include all components from the onshore transformer up to and including the cable. Because it is assumed that the UK National Grid is able to consume whatever power the link supplies to shore, the onshore transformer can be considered as connected to a stiff grid, which can be modelled as a perfect load. Should this not be the case and one wishes to include unavailability in the National Grid this load could be modelled as a variable load in much the same way as the variable production is considered at the other end, with the exception that the onshore connection points are not necessarily subject to the same availability in the grid.

Chapter 8.4 Obtaining the project node powers

As described in Chapter 8.4 there are several possible levels of power delivered to Node 4 for every given level of production. Below are some examples of the amount of power that may be delivered to Node 4 for some levels of produced power.

At the current stage in the method the availability of Node 4 is not considered. By this approach the result is valid for both the Base Case (in which there is no Node 4) and the HVDC interconnected layouts. Note also that at this point 100 % refers to the project rating, rather than the collection point rating as was the case in the previous chapter.

Table 6: Node power for 100 % of rated produced power

100 %	All components are up
75 %	One transformer is down
50 %	The link from one collection point to Node 4 is down Two non-parallel transformers are down
25 %	The link from one collection point to Node 4 is down in addition to a transformer in the other link Any three transformers are down
0 %	Both links from collection point to Node 4 are down

Table 7: Node power for 75 % of rated produced power

75 %	All components are up
62.5 %	One transformer is down
37.5 %	The link from one collection point to Node 4 is down Two non-parallel transformers are down
25 %	The link from one collection point to Node 4 is down in addition to a transformer in the other link Any three transformers are down
0 %	Both links from collection point to Node 4 are down

Table 8: Node power for 50 % of rated produced power

50 %	All components are up One transformer is down Two non-parallel transformers are down
25 %	The link from one collection point to Node 4 is down The link from one collection point to Node 4 is down in addition to a transformer in the other link Any three transformers are down
0 %	Both links from collection point to Node 4 are down

Table 9: Node power for 0 % of rated produced power

25 %	All components are up One transformer is down Two non-parallel transformers are down The link from one collection point to Node 4 is down The link from one collection point to Node 4 is down in addition to a transformer in the other link Any three transformers are down
0 %	Both links from collection point to Node 4 are down

These node powers illustrate the point that different amounts of power are delivered to Node 4 depending on both the production and which components are up and down at a given point in time.

By obtaining such tables, also containing the probability of each state, for all the considered levels of produced power the node power has been found, this is information that is of importance in the following procedure.

Chapter 8.5 Obtaining the power not supplied to shore and unutilized transmission capacity.

Once the node powers and their probabilities have been identified the next step is to identify the amount of power that is delivered to Node 4, but not supplied to shore. This energy is the energy that can be supplied to another project if there is sufficient transmission capacity for it. This power is here referred to as *interconnection point power*.

The interconnection point power is the power that is delivered to Node 4 but not to shore. Because the connection to shore only has two states of transmission[17] (up, if all components are up, down if any component is down) the interconnection point powers are of equal value as the node power, but the probability of each of the possible power levels differ in the two cases. The probability of each of the interconnection point power levels is equal to the probability of the corresponding node power level multiplied by the probability of the connection to shore being down and by the probability of Node 4 being up.

As for all wind farm projects the generation varies much and only for a relatively small part of the year the rated power is produced. Because the connection to shore is designed to transfer the rated power of the project there are large parts of the year when the connection is operated at a current, and hence a temperature, below the connection's rating. The amount of additional power that could be transferred through the connection to shore without overheating the components is of interest and needs to be calculated. This power will be referred to as *available transmission capacity* as it is a measure of how much additional power the connection is capable of transmitting without breaking its limits.

The available transmission capacity is found by subtracting the node power from the project rating. Hence each node power has a corresponding available transmission capacity. The probabilities of the available transmission capacity levels occurring is found by multiplying the probability of the corresponding node power by the probability of the connection to shore being up and by the probability of Node 4 being up.

[17] As described in Part II.Chapter 8.3 the analysis can be made to include more levels of transmission capacity by using different redundancy schemes, but this is not considered in this thesis.

After using this procedure on all four projects the result is, for each level of produced power, a set of some interconnection point powers and available transmission capacities and the probabilities of each of these occurring in each of the projects.

It should be noted that above the assumption is the Base Case scenario in which all projects are equipped with their own links of 100 % rating. In order to study cases where the rating of the connections are varied the equations need to be tweaked in order to allow this.

Chapter 8.6 Base Case

In the Base Case there are no interconnections between any systems and each project is connected to shore through a single radial connection. In this case the Interconnection point power and available transmission capacity are of no importance as there is no way of utilizing the two. The system availability is therefore, logically, evaluated based on the node power and the connection to shore. This is done by considering the connection to shore module as the last module in the system. Notice that for the Base Case there is no Node 4, therefore the probability of Node 4 being up should not be included.

The amount of energy that is delivered to shore in the Base Case is found as the sum of the product of each level of delivered power and its corresponding probability, multiplied 8766 h/yr. This gives the amount of energy delivered per year.

Chapter 8.7 Two Project Interconnection

One of the possible layouts of the four projects that are studied here is an interconnection of two and two projects. This means for example an interconnection of projects 1 and 2, and 3 and 4 respectively. The four projects may be combined through interconnections in three different combinations, and the most optimal of these should be found and studied. In the following an interconnection of projects 1 and 2 is used as an example.

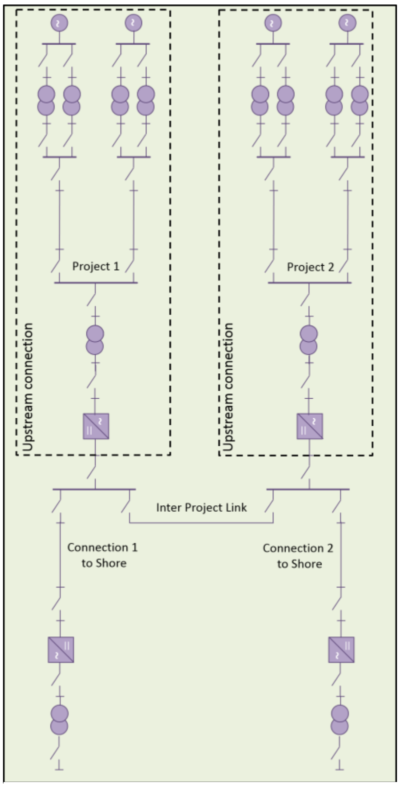


Figure 22: System layout for nterconnection between two projects

When studying the two project interconnection scheme the aim is to find out how much more energy can be delivered to shore by including the link. Before the evaluation is done some assumptions must be made. The most important assumption is that the electrically shortest route to shore is considered to be the project's own link to shore. This implies that if the project's link to shore is available, the system operator will always route the produced power through this current path. The other assumption is that HVDC CBs are available and can be used in the system. If HVDC CBs are not available the analysis must be made somewhat differently and an additional operation is necessary to obtain the result this will be explained towards the end of this sub-chapter.

From this point on particularly the procedure becomes more suited for a Matlab (or similar) program as the method becomes a little extensive in Excel.

The first point to consider is how much energy is delivered through the projects' own links. This is easily calculated by multiplying the Base Case energy by the probability of Node 4 being up. The second point is how much power is delivered from Project 1 through Connection 2 to shore. And the third point is how much power is delivered from Project 2 through Connection 1 to shore. The latter two points of interest are equal, but mirrored. Only the first of these will therefore be explained.

This method is more easily understood by considering the system to be of a form as shown in Figure 23. Note that in this figure the load and generator at each of the nodes will never be available at the same time (illustrated by different colours), as this condition has already been taken into account by the Base Case energy.

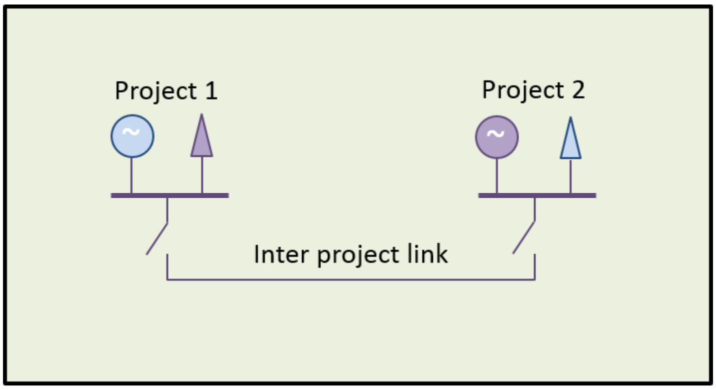


Figure 23: Simplified figure of the layout as seen from the two project's Node 4

The amount of power delivered from Project 1 to Node 4 of Project 2 is determined by the rating of the inter project link. This link will never be rated above 100 %, because more power than this cannot be supplied as there is no source for it. There may however be god reasons to choose a lower rating. The amount of power delivered is as before determined by the limiting factor which is the lower of the rating of the link and the interconnection point power.

The power that is actually delivered to shore is determined by the limiting factor of the power delivered through the inter project link and the available transmission capacity of Node 4, Project 2. At this point it is again necessary to make all possible combinations of delivered power and available transmission capacity for each level of produced power, and evaluate how much power is delivered to shore in each of the cases. The probability of each of these combinations are found by multiplying the probability of the relevant state at each of the two nodes and the probability of the link being available.

The amount of energy delivered to shore for this connection scheme is found by the same method as in the Base Case.

An additional operation is needed to evaluate the energy delivered if the system is not equipped with HVDC CBs. When CBs are not present the entire system will have to shut down whenever a fault occurs in one of the HVDC components, that is, converters and HVDC cables. The total outage time due to such faults are calculated by summing the faults per year (λ) of each relevant component, and multiplying this by the switching time for the DSs. If say the system consists of three cables with outage rates of 0.1, 0.2 and 0.3 faults per year and the switching time is 1 hour then the outage time is (0.1+0.2+0.3)*1=0.6 hours per year. The impact of any other faults, and also the impact of the HVDC faults after they are isolated are calculated in the Excel sheet by setting the switching time to zero. As an example say this is 10 TWh. By multiplying this amount of energy by one minus the fraction of the year in which the system is shut down due to HVDC faults the total delivered energy is found. In this example this gives: 10 TWh * (1 – 0.6 h / 8766 h/year) = 9.9993 TWh.

Chapter 8.8 Four project ring system layout

Connecting all four projects in a ring system is another possible layout. The projects are not placed in a perfect square and as such there are large differences in the length of the links that make up the ring system. A rough example of the ring system layout is shown in Figure 24. The blue lines illustrate the ring system, while the orange lines illustrate the connections to shore.

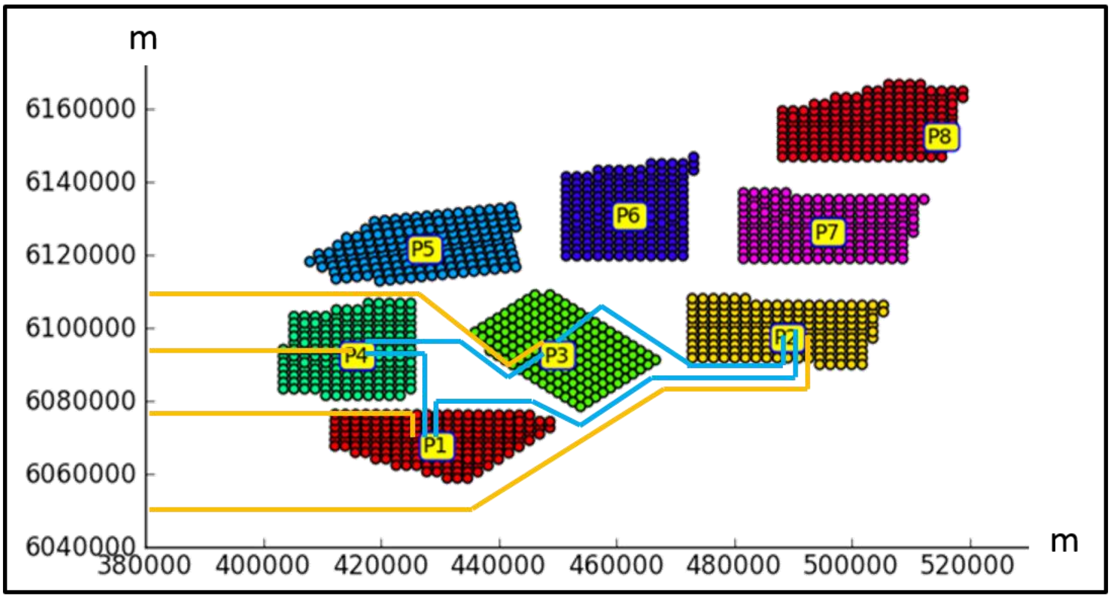


Figure 24: Illustration of ring system layout

When evaluating the effect of using a ring system the same starting point as was used for the two project layout is used. This is illustrated in Figure 25.

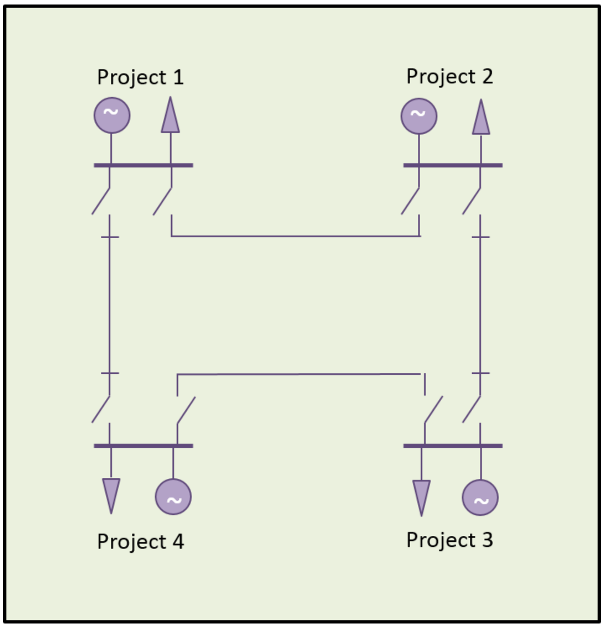


Figure 25: Simplified illustration of four project ring layout

The analysis of the ring system is a rather large and complex one. This results from there being several levels of produced power, for which there are several possible amounts of inter project power and available transmission capacity. There are four projects which can be combined in many ways and also the links that make up the ring may be unavailable, one or more at a time. In addition, as this is a ring system, an iterative loop is necessary to evaluate what power flows where in the ring.

The procedure will be equal for all levels of produced power and therefore the procedure is explained for only one of these. Assuming that there are three levels of inter project power and three corresponding levels of available transmission capacity. In addition there is a certain probability of the node being unavailable, which is of importance because if power is to be sent from for example project 4 to project 2 then this power will be sent through Node 4 in projects 4, 1 (or 3) and 2. Should one of these be unavailable there will therefore be no such transmission. This leaves seven states of each project. Because all possible combinations of these seven states in the four projects are possible, 7^4 = 2401 combinations are possible. In addition there are 4^2 = 16 possible layouts, resulting from the inter project links being up or down. In total there are therefore 38416 combinations that need to be studied for each level of produced power.

Consider first counter clockwise transmission. The amount of power that is delivered from project 1 to project 4 is given by the amount of power that is delivered from Project 2 to Project 1 and the amount of interconnection point power available at Project 1 and the rating of the link between projects 1 and 4. This amount is found through the following logic, here expressed by aid of pseudo code (note that X is used to express the amount of power that is transmitted through the interconnection links, while P refers to the interconnection point power of a project):

- Power is only delivered from project 1 to the ring system if the current state of project 1 has a power level above zero.

  If $P_1 > 0$
  $P_{1\_ring} = P_1$
  Else
  $P_{1\_ring} = 0$

  - In this case the power delivered from Node 4, Project 1 towards Node 4, Project 4 is the sum of the power from Project 1 and the power that is transmitted from Node 4, Project 2 to Node 4, Project 1.

    $X_{Node\_4,\ Project\_1} = P_{1\_ring} + X_{2\text{-}1}$

- If the power level of the current state is below zero in Project 1, then some of the power delivered from Node 4, Project 2 to Node 4, Project 1 will be delivered to shore via the link of Project 1.

  If $(P_1 < 0)$ AND $(X_{2\text{-}1} > 0)$
  $P_{1\_Shore} = \text{Minimum}(P_1\ ;\ X_{2\text{-}1})$

  This means that some of the available transmission capacity is no longer available

  $P_1 = P_1 - P_{1\_Shore}$ [18]

  - In this case the power delivered from Node 4, Project 1 towards Node 4, Project 4 is the remaining power delivered from Node 4, Project 2 to Node 4, Project 1

    $X_{Node\_4,\ Project\_1} = X_{2\text{-}1} - P_{1\_shiore}$

- The power that is actually delivered from Node 4, Project 1 to Node 4, Project 4 may be limited by the rating of the interconnection

  $X_{1\text{-}4} = \text{Minimum}(X_{Node\_4,\ Project\_1}\ ;\ L_{1.4\_rating})$

- Power can only be delivered in this link if both projects' Node 4 is available

  If (Node 4, Project 1 AND Node 4, Project 4) = UP

[18] For programming purposes it is important to notice that P_1 should always be updated based on the original value of P_1. That is $P_1 = P_{1\_original} - P_{1\_shore}$

$X_{1-4} = X_{1-4}$

Else

$X_{1-4} = 0$

When the amount of power transmitted to Node 4, Project 4 has been calculated then this same pattern is repeated throughout the circle. X_{1-4} works as a basis for calculating the amount of power that is sent to shore through the link of Project 4 and then to find how much power is transmitted to Node 4, Project 3 and so on until X_{2-1} is calculated and the circle is closed. At this point an iterative loop must be run to find the actual values of X_{2-1}. As a starting point for the iterative loop setting $X_{2-1} = 0$ would be a reasonable choice.

After the iterative loop is solved the power levels of the projects with positive power levels need to be updated. This is done as follows:

If for example projects 1, 2 and 3 have positive power statuses and project 4 has a negative power status then the amount of power delivered to shore in project 4 is the amount of power that has been “spent” from the other projects. Because Project 1 is electrically closer to Project 4 (out of the three) for power transmission in the counter clockwise direction, this project will have priority in delivering power through this link. This means that if the amount of power delivered to shore is say 400 MW and the status of Project 1 is 300 MW, then the updated status of Project 1 is zero, as all of this power would be delivered to shore. The remaining 100 MW must then originate from Project 2 or Project 3, and the same evaluation is performed for each of these. Should the case be that the power delivered to shore is 300 MW and the power status of Project 1 is 400 MW, then the updated power level of Project 1 is 100 MW.

When all power levels are updated the clockwise transmission can be evaluated in the same way as the counter clockwise. There is one important problem with this method, which is that the electric losses are only in a very small degree taken into account. As electric losses are not included in this analysis this does not make much of a difference here, but it means that the amount of energy that is supplied to shore will not necessarily be sent to shore through the same routes in reality. The total amount of energy (neglecting the electric losses), should however be correct.

Part III. Economy

This sub chapter provides an overview of the factors that contribute to the economy of Dogger Bank, but with a particular focus on the elements that are relevant for the economic analysis that will be performed as part of the simulations in order to evaluate which of the above mentioned grid layouts will turn out to be the most cost effective.

Chapter 9. Income

The revenue of Dogger Bank will be the product of the price of power and the amount of power delivered to the national grid. As a part of the UK's economic schemes for increasing the amount of renewable energy production in the country the government offers a Contract for Difference, CfD, for many renewable energy projects, among them offshore wind power.

The Financial Times defines CfD as follows [17]:
A contract for difference (CFD) is essentially a contract between an investor and an investment bank or a spread-betting firm. At the end of the contract, the parties exchange the difference between the opening and closing prices of a specified financial instrument, including shares or commodities.

CFDs do not carry votes like ordinary stock but enable investors to gain economic exposure to a listed company for a fraction of the cost of buying shares. They also escape stamp duty and can be bought in size without triggering obligations to disclose the holding. A form of synthetic dividend is normally also payable.

A CFD is simply an agreement between two parties – the investor and the CFD provider – to pay each other the change in the price of an underlying asset. Depending on which way the price moves, one party pays the other the difference from the time the contract was agreed to the point where it ends.

So like spread bets, CFDs involve the investor taking an opposing view to the insurer, speculating that an asset price will rise, by buying ('long' position), or fall, by selling ('short' position). Also like spread bets, CFDs incur no stamp duty as they do not involve buying an asset, only agreeing to receive or pay the movement in its price. And because you only have to put down a small deposit on trades, called 'margin', you can make large profits – or losses – on the money you commit, from small moves in the price. So CFDs give you the advantages of owning shares without many of the inconveniences. However, they differ from spread bets in their tax treatment.

For Dogger Bank this means that the owner enters a contract with the UK government ensuring a set strike price for all delivered energy. The crude idea is that the energy is sold in the power market. Should the momentary price of energy be below the strike price then the difference is reimbursed by the government to the wind farm owner. Should on the other hand the momentary price of energy be above the strike price then the difference is paid from the wind farm owner to the government.

The upside of this scheme for the wind farm owner is that the risk of volatile prices is removed and so the investment in the wind farm will be safer. The investment being safer might also lead to a lowered interest rate on any loans that are made for the investment, hence increasing the profit of the project. The downside of CfD from the wind farm owner's perspective is naturally that along with removing the risk connected to volatile prices, the potential benefit is also removed.

From the perspective of the government the benefit of the CfD is the reduced risk connected to investing in renewable energy. These new investments would serve to increase the amount of clean energy that can replace energy from fossil fuels, which would among other things help to achieve the EU's 20-20-20 goals. The disadvantage to the government of entering a CfD agreement is that all risk of volatile prices falls on them and the contract could prove to be rather costly.

One aspect of the CfD that reduces the benefit of the lowered risk is that the CfD strike price level is not set very far ahead. In 2013 the UK government released the prices that will be used for the coming years up to and including 2019 [18]. These prices are not definite, but are called draft strike prices and some adjustments must therefore be foreseen. However the problem for the investors would be that while the concession times for wind farms are approximately 20 years the CfD prices are only estimated for the first six of these and so the risk is only reduced for these years.

The prices for the CfD that are reported in [18] are:

Table 10: Draft strike prices for CfD for offshore wind power

Year	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Price [£/MWh]	155	155	150	140	135

The prices are given in 2012 values.

The strike prices under feed-in tariff in the CfD are set based on the cost of building wind farms, which was investigated in a Call for Evidence, CfE, started in October 2012.[19]

For the economic analysis performed as part of this thesis an assumption as to the CfD strike prices from year 2020 and onward had to be made. In conversation with Statkraft it was agreed that it would be reasonable to use the price 135 £/MWh for the remaining period as there is no other information available. It was also agreed that the first project should be assumed to be operational in 2014 and giving the price of 155 £/MWh for the first year of production.

Chapter 10. Expenses

The expenses connected to the projects are mainly the investment cost, CAPEX, but also cost of operation and maintenance (O&M), OPEX, are of importance. For the economic analysis performed here there will not be a large focus on the cost of O&M and simple assumptions will be made in order to, to some extent, include the added O&M cost connected to increasing the number of components.

The investment cost is of course dependent on which layout is chosen, but also on in what order, and in which year the different projects are built. The analysis of the cost is therefore made in such a way that the investment cost of each of the projects is added in the year the project is built. This means that for Case Two, the investment cost of the first project is included in the year of its building, the cost of the second project is not added until the second project is actually built, when also the cost of the inter-project link is included. Because more components, such as switchgear, are needed in Case Two than in the Base Case, to prepare for the interconnection of another project the cost of only one project is different in the two cases, reflecting the increased risk of waiting for another project. The delaying of the investment cost to the year when the investment is actually made is important as it is assumed that the project is financed by loan and the interest rate therefore increases the actual cost of the projects.

The O&M costs are assumed to be constant over the life time of the wind farms, although naturally dependent of what projects and inter-project links are in operation. As the cost is considered constant it must be adjusted for inflation. The life time of a wind farm is generally considered to be 20 years and the licensing will last for approximately this long, 20 years has therefore been chosen as the amount of time over which to study each of the projects. As not all projects are built simultaneously this means that the total time that is analysed is dependent on when the last project is built. The O&M costs of each project is no longer included after the life time of that particular project is passed.

Costs of removing the system components and restoring the area to normal are not included in the analysis.

Chapter 11. Risk, discounting, inflation and interest

The aim of the reliability analysis performed in this thesis, which is discussed in Part II, is to determine how much power will actually be delivered to shore from the projects when taking into account all possible faults. Because the potential faults and the risk of these occurring is already taken into account the amount of power delivered to shore can be considered risk free. This does not mean that the produced energy will actually be as calculated, but the risks connected with it has been taken into account and the output should therefore be a good estimate.

The purpose of the CfD scheme is to remove the risk of volatile energy prices and upon entering a CfD agreement the practical price of energy is therefore settled.

When there is no risk that needs to be taken into account for either production or price, the income is also risk free. As previously stated the O&M cost is considered to be constant, but inflation adjusted, no risk is included for this cost. The investment costs will in reality be subject to a level of risk, as the prices of metal in particular are highly volatile which will influence the cost of the project components. For the purpose of this thesis however this risk is disregarded.

Removing the risk in income, and neglecting the risk in costs leaves the projects risk free for the purpose of the analysis and there is no need to discount the resulting surplus to 2013 values, as the discounting rate will be set to zero and the 2013 value will be the same as the value in any other year.

The inflation rate that is used in this thesis is provided by Bank of England [6]. According to [6] the inflation target of the UK is 2 %, however for the coming years it is expected that the inflation level will be 2.5 %. Based on this information the inflation rate in this thesis is set to 2.5 % per year.

The interest rate that is of interest to this project is the interest rate a bank will give on a loan of the money for investment. For this thesis this interest rate has been assumed equal to 4 %, but a sensitivity analysis will be performed to evaluate the impact of this.

Chapter 12. Method for Economic Analysis

The economic analysis used in this thesis is a simple one. This is a result of some simplification such as constant interest rate, zero discounting rate, constant inflation, and constant O&M costs.

The input to the economic analysis is the cost of all components, the amount of each component in each project and each layout and the rating of the components. A spreadsheet in excel sums the cost of each individual component and returns the total investment cost of each project and each layout. From the reliability analyses the amount of energy delivered by each project in each of the layouts.

The spreadsheet for the economic calculation calculates the cost and income separately. In reality the investment will be made by a loan which will be repaid over the course of Dogger Bank's life time, this analysis is however simplified by assuming that the revenue is placed in an account with the same interest rate as the loan is subject to. In essence this is the same as repaying the loan when the money comes in, and only represents a simplification in the calculations.

The projects are not all built in the same year and therefore the investment costs do not appear in the analysis until the year of investment. This is also the first year in which the project produces energy and thereby income. Investment cost and income will not really come in the same year, as the actual building of the project will take time. The building time is however neglected in this analysis.

In the same year as the investment of a project is made the O&M cost is included. As this is a regular cost for all the years of a project's operation, this cost is included for 20 years following the investment cost, only adjusted for inflation.

The sum of the investment costs and O&M costs of each year is found and is added to the "loan account" for which there is an interest rate, causing the size of the loan to increase continually.

The revenue of Dogger Bank varies only with the CfD rate, as the production is assumed to be constant. The product of delivered energy and the CfD strike price of the relevant year makes up the year's revenue. This revenue is then added to the income account which is subject to the same interest rate as the loan account.

The difference between the revenue account and the loan account in the final year of the analysis, which is the 20th year of operation for the last-built project, gives the profit of the investment. Because only some of the investment costs are included in the analysis this profit does not equal the earnings of the project, but the profit can be used to compare the different layouts as the remaining investment cost is equal for all the layouts.

Part IV. Simulations

Chapter 13. System Components

In this part the components that are used in the system are described and their input values into the analysis are defined.

Chapter 13.1 Relay system

The relay system is as previously described of great importance to the reliability of the system. There are more than one possible way of operating the relay system, and the relevant ones will be discussed here.

Chapter 13.1.1 HVAC Circuit Breakers

HVAC CBs are a mature technology and there have been extensive studies of their reliability. These analyses provide information on both the failure rate and repair time of the breakers. As previously described the components in the relaying system are not considered separate components, meaning that faults in the CBs is only considered possible at the moment their operation is requested. This means that a failure rate of the CBs is less useful as this gives the number of faults per year, while the number of faults per year of a CB is necessarily dependent on how many times the CB operates per year. For this reason a different reliability indice is used for CBs, namely a probability of failure on demand.

Chapter 13.1.1.1 Unavailability

The literature gives a wide variety of reliability data for HVAC CBs:

[14] proposes a probability of failure to operate on demand of 10 %. This is significantly higher that all the other suggestions that have been found. It is worth mentioning that [14] does not provide any reference as to where the probability is found, nor does it make any attempt at justify the value. it is therefore not unreasonable to assume that this number is used as a mock number, used only to show the principle of how the method works and not as an example of an actual value.

[20] provides MTTR and λ for the CBs. These are set to different levels based on the voltage level of, and location of the CB. For 36 kV CBs λ is set to 0.024, while it is 0.0.32 for 150 kV CBs. This implies that the probability of a fault is increased with increasing voltage level. The MTTR of CBs on land is set to 4 hours, while it is set to 720 hours for offshore CBs on platforms, the even higher level of 2160 hours is used for wind turbine installed CBs. This shows that the repair time (or possibly replacement time, this is not stated, but the very short time of 4 hours suggests this is not a repair time unless only manual opening of the CB is necessary to reset it) is very short when travel does not need to be taken into account. When acquiring a vessel and travelling offshore is necessary the time required for the repair increases dramatically. For the wind turbine mounted CBs the weather conditions have been taken into account such that if the weather is bad the repair would have to wait. Like [14] this report does not provide any reference or justification of the reliability data used.

A third proposed set of reliability data for CBs is found in [21]. Here the data is based on experience through the study of approximately 16 000 CB*yeas. For a voltage level of 220 kV λ is found to be 1.99 [1/(100 CB*years)] or approximately 0.002 failures per year. This article does not discuss the repair time of the CBs.

The final article that has been studied to find reliability data for circuit breakers is [22]. This article bases its analysis on Cigré's collected data of failures in CBs from a total of approximately 9300 CBs of different types. The faults that occur are studied by source, which are divided into five categories and all of these are further studied for four types of CBs. The SF6 CB with hydraulic drive is clearly the most commonly used of the CBs therefore this type is used as a basis for this thesis[19]. The resulting reliability data when all sources are take into account are λ = 0.674 failures per year and MTTR = 93.64985 hours. Compared to the λ in [20, 21] this is very high, while as previously stated it is very low compared to [14]. Because the reliability data in this article appears to be highly reliable as it is based on Cigré data from a large number of CBs and because the article includes MTTR, which is necessary this article is chosen as the source of reliability data for HVAC CBs for this thesis.

The above mentioned failure rate and repair time is not mentioned in the article, because the failures of the CB are split into five sub categories. The average values for the CB as a whole is therefore calculated based on RelRad methodology with these sources of faults as individual components, and assuming that all five sources of error lead to failure of operation of the CB. When the average values were calculated the average unavailability of the CB was found to be 63.12 hours per year. Translating this to a probability of unavailability gives 0.72 %. The fact that the CB will be unable to operate 0.72 % of the time means that this is also the probability that the CB will not operate on demand. It is not made abundantly clear in the article that the data can be interpreted in this way, however this seems to be the logic conclusion to draw.

From the data in [22] it is clear the there is one source of error that has a much longer MTTR that all the others. This source of error thereby causes a potential problem of leading to longer repair times for the CB than for the faulty component that tripped the CB. As this is not taken into account in the analysis in its current state this would lead to an error in the output of the analysis. However the data from [20] suggests that it is possible to replace the CB very quickly, though this is not explicitly stated. For these cases it should therefore be considered if the CB can be replaced by a spare, which might be kept offshore. When the fault occurs the breaker could then be replaced by the spare, repaired and then used as a spare.

The reliability data that will be used for the AC CBs is:

[19] There have not been performed any analysis as to whether this is a reasonable choice and the decision is made purely on the bases of it being used more commonly in the studied systems. Based on the author's limited knowledge of these breakers however this appears to be a reasonable choice.

Table 11: Reliability analysis input for HVAC circuit breakers

Probability of failure to operate on demand	0.72 %

Chapter 13.1.1.2 Price

The price of HVAC switchgear used in this thesis has been offered by Statkraft as a reasonable assumption of the combined price of the HVAC switchgear and the platform on which it is placed. An approximate price of 10 million NOK was suggested by Statkraft and the price in GBP was set to £ 1 million based on an exchange rate of just above 10 NOK/GBP.

Chapter 13.1.2 Disconnector Switches

Chapter 13.1.2.1 Unavailability

For the purpose of this analysis faults in the DSs have not been included. As DSs are relatively cheap components it is assumed that if the unavailability of the DSs is considered significant their redundancy will be increased.

One thing that is included for the DSs is their switching time. To physically switch a DS on or off takes only about a second, however many DSs are operated manually, and hence their switching time is prolonged by the time it takes to get there. Because there will always be crew located offshore the switching time has been set to one hour as a starting point for the analysis. It is also possible to remotely operate the DSs, this would require an increased investment (this investment is not included in the analysis because the communication system is considered out of scope for the economic analysis) but would lower the switching time to only a few seconds. In the sensitivity analysis, the switching time of the DSs should therefore be varied from zero to a few hours.

The reliability data that will be used for both AC and DC DSs is:

Table 12: Reliability analysis input for disconnector switches

Switching time [h]	1

Chapter 13.1.2.2 Price

Because one DS is included for every circuit breaker, the DSs have not been evaluated with an individual price.

Chapter 13.1.3 HVDC Circuit Breakers

HVDC circuit breakers were announced to have been achieved in November 2012. Because they are such a new invention they are not yet at the market, and ABB are currently looking for pilot projects where the CBs can be installed and tested in a real system. In a conversation with Leif-Willhelm Ramslie who is involved with ABBs HVDC CB project he said a final price for the first commercial HVDC CBs has not yet been decided. In a report by Sweco, written for Forewind there is made mention of a price assumption provided by ABB.

This price assumption is that the price of HVDC CBs will add 10 - 20% to the price of a VSC station. Because there is made no references to where this information was obtained in the Sweco report, apart from that it comes from ABB, Leif-Willhelm Ramslie was asked to confirm that this estimate was reasonable. According to him the estimate seemed reasonable, though naturally this is no guarantee for the actual price.

Chapter 13.1.3.1 Unavailability

Because DC CBs are not yet on the market there is no knowledge as to the reliability of these breakers. For this reason the same data as for AC is used as a basis.

Due to generally being more complex than its AC counterpart and, among other things, containing IGBT components which, based on the converter data, fail relatively often it is reasonable to assume that the unavailability of the DC CBs will be higher than what is the case for AC CBs. Sensitivity analysis of the unavailability of these breakers is therefore necessary.

The starting point reliability data for the DC CBs for use in the analysis is:

Table 13: Reliability analysis input for HVDC circuit breakers

Probability of failure to operate on demand	0.72 %

Chapter 13.1.3.2 Price

The price of HVDC circuit breakers is not yet finalized by ABB s the CB is still some way away from commercialisation. An estimate of the price level has however been offered as is reported in a report by Sweco written for Forewind. In this report ABB is reported to have proposed that using HVDA CBs will increase the price of the converter station by 10 % – 20 %. Sweco appears to interpret this as follows:

In a point-to-point connection there is a need for eight HVDC CBs (bipolar layout, in a balanced monopolar layout four HVDC CBs are needed). The total cost of these eight CBs will be somewhere between 10 % and 20 % of the price of the converter stations. If eight CBs costs say 20 % of the cost of two converter stations, then one CB will cost 5 % of one of the converter stations.

A price of 5 % of the converter cost has been used in this thesis.

Chapter 13.2 Cables

Cables are the components that contribute most to the cost of the projects[20] in addition they have the longest repair time and are as such important contributors to the unavailability of

[20] The cables contribute most of the components that are included in this thesis, their contribution compared to the wind turbines is not investigated.

the transmission system from the collection points to shore. This chapter aims at describing different aspects of the cables.

Chapter 13.2.1 Cable system

For both AC and DC cables the insulation type used in Dogger Bank is likely to be cross-linked polyethylene, XLPE. This is the dominating insulation material for cables up to 300 kV [23] and [24] refers to lead sheath XLPE cables as commonly used cables for high voltage subsea use. XLPE is a relatively cheap isolation type but also a simple one which means there are fewer components in the cables that may fail and also that the repair of the cable in case of a fault is relatively simple. Another benefit of XLPE over Mass Impregnated, MI, insulation (the most likely alternative) is that it can be operated at higher temperatures. While the maximum continuous temperature of MI cables is 70°C XLPE cables can be operated at 90°C. The downside to using XLPE cables is that there is little experience with using it at voltage levels such as those relevant in this thesis, because cables of this sort were only realized in the last decade.

In the case of the AC connections these will be installed as three core cables. The DC cables will be installed in a balanced monopole setup, also known as symmetric monopole or midpoint grounded monopole.

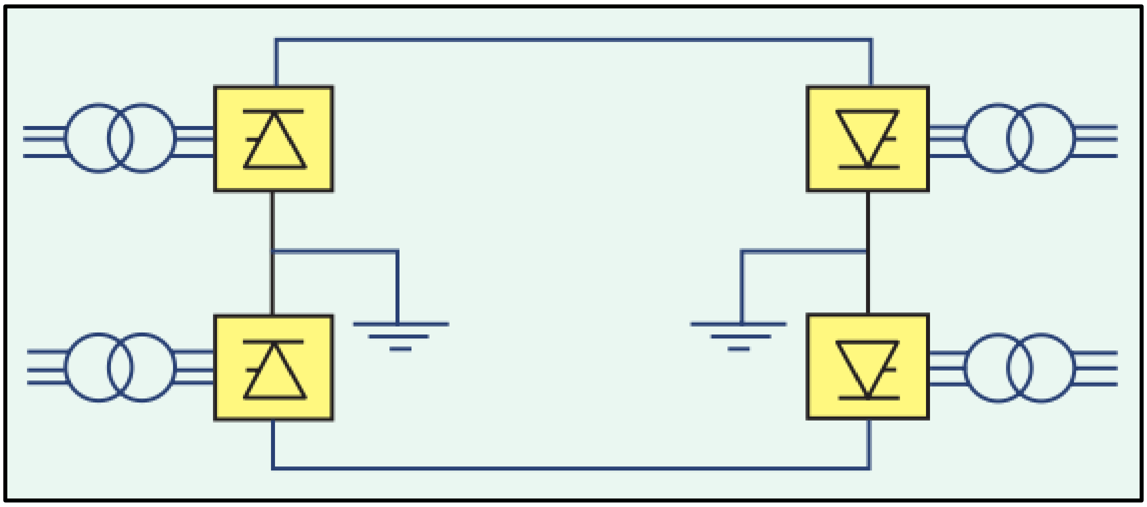


Figure 26: Balanced monopole setup [25]

This setup uses two cables, one of which is a return cable. By grounding the midpoint the return cable is set to be operated under negative voltage. This method is cheaper than bipolar setup, in which there are two converters at both ends which allows increased flexibility and control, but more expensive than the simple monopole setup which uses a ground return. One of the main downsides to simple monopolar setup is the impact on the nearby magnetic field. A single DC cable produces a constant magnetic field around it. Should this field not lie along the earth's magnetic field then a compass would be disturbed into recognizing north as whichever direction is the vector sum of the two fields. This effect is not only affecting humans (in the age of the GPS the impact to humans would be limited) but, as stated by [26] “Species with magneto- or electro sensory capabilities may detect and/or react to the fields generated by AC and DC cables.“

Chapter 13.2.2 Cable type

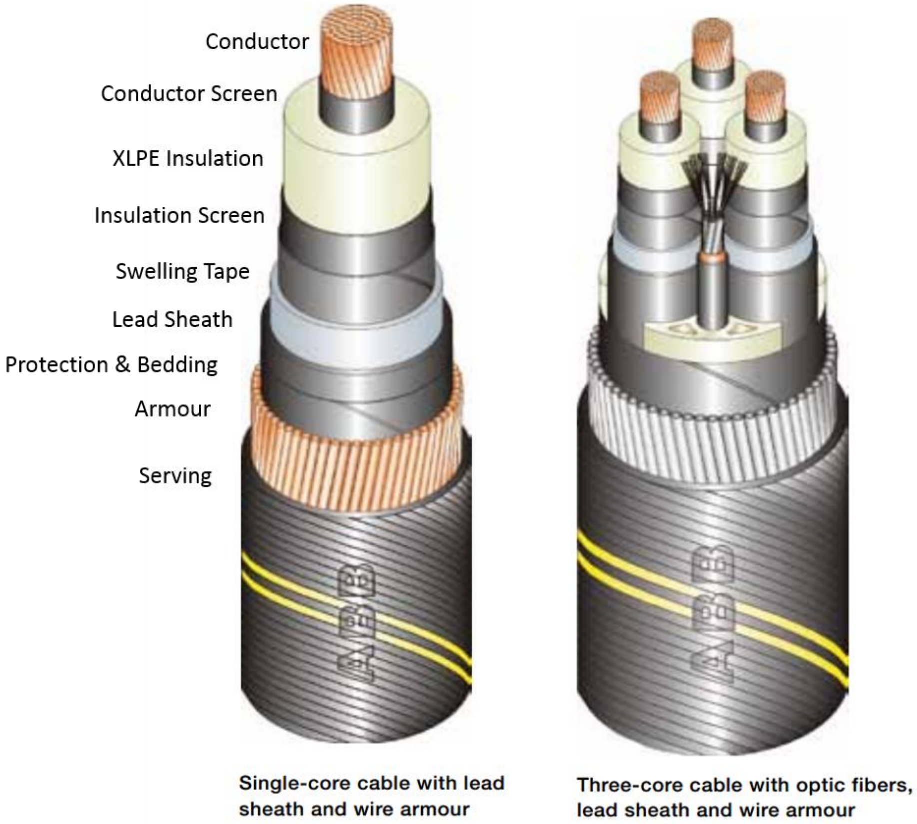


Figure 27: Single Core and Three Core XLPE cables from ABB, cable illustration from [27]

As the figure shows the components in single core and three core cables are the same, this also holds for HVDC cables. The cables in the figure are XLPE cables with copper conductors, lead sheaths and wired armour.

There are two materials that are commonly used for the conductor; aluminium and copper. Copper is superior to aluminium in terms of conductivity, but is also considerably more expensive. The figure shows stranded conductors which means that the conductor is made up of many conducting strands placed together in a circle shape and twisted along the cable length. There are many possible ways of making the conductor, including compact conductor, in which the conductor is one single rod of conductor material, and sector, in which the conductor consists of several pie shaped sectors. One of the main arguments for not using compact conductors is that compact conductors give stiffer cables and hence larger bend radiuses.

The conductor screen is used to even out the surface of the conductor as this needs to be completely smooth to avoid air gaps between the conductor and the insulation. Similarly the insulation screen is used to even out the surface of the insulation. An additional purpose of the conductor screen is the separation of the conductor and the insulation as copper act as a catalyst for the ageing mechanisms of the insulation. The insulation is a massive body of XLPE.

The main purpose of the lead sheath is protection against radial water ingress and against hydrocarbons, both of which speed up the aging process of the insulation.

The armouring is as the name suggests used for protection of the cable against external forces, most notably the length-wise gravitational forces the cable is subjected to during laying and lifting (for repair or removal).

Chapter 13.2.3 Cable laying

The laying of cables is a demanding and time consuming process, with an estimated laying seed of 1-2 km per day. The cable is laid by a cable laying vessel which holds the cable on a drum and leads it over a large wheel in order to avoid sharp angles and to allow control of the forces the vessel is subjected to. From the wheel the cable is lain at an angle to the sea floor. This angle is carefully monitored as deviations from the optimal angle could lead to damages. If the angle was to become too large, tending towards direct vertical laying then the vertical forces in the cable would be too strong and the cable could become compressed. In the case of attempting direct vertical laying there is also a possibility of the vessel being moved backwards rather than forwards due to weather conditions and this could lead to the angle being subjected to angular forced for which it is not designed. Should on the other hand the angle be too small then the length of the suspended cable would be longer than intended, leading to increased stress at the bearing point of the cable on the wheel and potentially damaging the cable by stretching it. Cable armour is designed for a certain laying angle to make sure it can withstand the longitudinal forces it will be subjected to. The cable is of course designed with some margin of error to allow some variation is angle. The angle also ensures a relatively long length of suspended cable, which reduces the impact of a level of movement caused by weather conditions.

When more than one cable is to lie in the same trench then bundling is used. The cables are then connected by steel straps or similar as they meter by meter leave the vessel. Bundling of cables allows two or more cables to be laid in one action.

The sea floor conditions are of huge importance to the cable laying process. Because the cable does not do well with sharp objects and because there is often a wish to bury the cable for further protection there are attempts to lay the cable in sand or gravel. The cost of cable makes it economical to attempt at straight line laying, which is also the simplest procedure for the cable laying crew. When areas with much rocks are encountered the cable must be attempted to be lain around these and in order to achieve this a submarine remote operated vessel, ROV, is utilized. The ROV can guide the cable into more optimal positioning than is possible for the cable laying vessel. After making a turn with a cable it should be attempted to allow a certain distance of straight cable to avoid turns pulling on each other. Laying the cable in free spans, meaning the cable is suspended in the sea, without support from the sea floor, must be avoided as this will cause significant wear on the cable. Ocean currents can at times be strong enough to cause significant wear of suspended cables and also the cables are more exposed to damage from for example anchors or fishing gear.

Chapter 13.2.4 Cable Damage

Most faults in subsea cables are caused by external impacts, mainly due to fishing. Trawling is a fishing technique in which a fishing net is pulled through the sea, connected to the boat at the top and to a steel “door” at the sea floor, which is dragged after the boat. According to [28] trawls are not, during normal conditions, expected to disturb the sea floor to depths beyond 0.5 m. As it is rather common to bury cables at a 1 m depth this means that cables should not be damaged by this. However, though the cable is buried at 1 m depth the sea floor is not stable and so the cable may not remain buried at this depth and impacts may occur. The weight of the steel door is sufficient to seriously damage the cable upon impact at the speed of the trawl, but the largest hazard for the cable is the attempted retrieval of stuck fishing gear by the crew. [28] Anchoring is the second most important source of externally caused faults. Heavy anchors connected to large boats, with a huge momentum are lowered onto the cables and cause damage by impact or they are dragged along the sea floor and catches the cable, dragging it out of position and damaging it.

The cable laying process also contributes with many faults. These faults include errors made by the installation crew on the boat as well as the cable being placed in unbeneficial locations like for example in areas where there are stones that can damage the cable, or even the cable being laid in suspense between rocks, cliffs etc. These faults do not necessarily lead to damage right away, but can cause deterioration over a period.

Faulty equipment is another source of faults. If the cable, the cable joints or any other equipment connected to it is not correctly manufactured then faults are likely to arise. If oxygen is present in the cable the insulation and the conductor can be damaged by its presence through oxidation. As mentioned the copper in the conductor can work as a catalyst for the deterioration of the insulation which makes the conductor screen very important. Any voids in the insulation are likely to be subject to partial discharges which leads to further damage in the insulation. Impurities in the cable can lead to “routes” of less dielectric strength through which so-called electric trees can grow. Electric tree growth leads to weakening of the insulation in the specific area and will eventually lead to total break-through. If humidity is present in AC cables water trees will start to grow. Water trees are paths of humidity through the insulation and when they reach all the way through a current path through the insulation has been made. [23]

Faults may of course also be caused by harmful operation of the system. If for example the cable is subjected to too much current over too long a time the insulation will overheat and start to deteriorate.

Chapter 13.2.5 Cable repair

Cable repair is a very demanding part of subsea cable engineering and consists of varying tasks. The first problem encountered when a cable experiences a fault is that the exact location of the fault must be located. There are a number of different proposed methods for doing this which are based on the sending of electric impulses into the cable and analysing the reflected impulse. This thesis will not go into detail in these methods. These methods of locating the fault are only so accurate, and there will normally be a need of divers or submarine vehicles to determine the exact position of the fault. Because, as stated in the previous sub chapter, most faults in subsea cables are caused by external impacts the faulty area can often be located by looking at the cable. In cases where the fault is caused by insulation deterioration or other non-visible causes the fine-localizing will prove more challenging and particularly if the cable is buried and therefore not as easily available.

Once the fault has been located the cable can be cut in two near the damaged area and the first of the cable ends is brought to the surface. In cases of shallow waters this can be done relatively easily, while for deep waters submarine remote operated vehicles, ROV, are used for this task. After the one end of the cut cable has been brought to the surface any additional damaged length of cable is removed and a new length of cable is jointed to the cable end. The cable is them lowered back into the sea, such that the joint rests on the sea floor and the second end of the cut cable is brought to the surface. The same procedure of cutting away any damaged cable and then jointing the new piece of cable to the old one is performed. The cable is lowered onto the sea floor and the amount of extra cable that results from the repair cable being much longer than the cut away part must be placed in a suitable way. [28]

Attempts have been made at subsea repair. Two such attempts are mentioned in [28], however it is stated that neither has been followed up and that in most cases it is necessary to bring the cable ends to the surface for repair.

As can be told by the method for repairing cables it is necessary that a spare cable is jointed in at the location of the fault and it is evident by the procedure that the length of this cable is significantly longer than the cut away bit. According to [28] the length of such repair cables must be twice the water depth plus the amount needed to run through the aboard equipment plus the cut away length. It is also stated the in the case of a fault occurring during the repair, such as damage by the anchor of the cable laying vessel or faults occurring when jointing, it is generally a good idea to bring extra cable along, rather than finding one self in need of it when at the location. Because submarine cables are not off the shelf orderings, extra lengths of cable are included in the original order. These extra lengths are stored for the times they are needed as repair cables. By having repair cables ready the repair time is significantly reduced.

Chapter 13.2.6 Unavailability

Chapter 13.2.6.1 HVDC Cables

In 2009 Cigré published a review of the availability of cable projects [29]. The report describes the results of a survey that was sent to owners of high voltage cable projects both onshore and offshore worldwide. The survey asked for information on the numbers of failures that occurred in the period between 1990 and 2005[21] and their origin.

In the period between 1990 and 2005 there were HVDC projects using the cable types XLPE (cross-linked poly ethylene), SCOF (self-contained oil filled) and MI (mass impregnated). As explained above XLPE is the natural choice of cable technology for the Dogger Bank projects, however there is little experience with its use in HVDC projects. The world's first submarine XLPE cable was delivered by Nexans [30] to be used in ABB's HVDC light system [31] for the connection of Horns Rev wind farm to Denmark mainland. This project was installed in 2002 and used a voltage level of 170 kV. The next record was set in 2005 when Nexans [30] delivered a 420 kV XLPE cable to the connection of the platform Ormen Lange to mainland Norway, which also used ABB's HVDC light [32]. These facts clearly show that the Cigré survey could not receive any information on XLPE projects of voltage levels relevant for Dogger Bank. For this reason the data for MI cables, which are closer to XLPE in reliability, are used as a basis for the cable reliability data in this thesis. XLPE cables are likely to be somewhat more reliable when it comes to internal faults, but because almost all cable failures happen due to external forces, they are likely to be almost identical in overall reliability.

From the Cigré report it is possible to draw some conclusions as to the reliability of MI cables. HVDC MI cables are particularly well represented in the survey with 2687 km of installed cable out of the total 7000 km of subsea cables, both HVDC and HVAC. Out of these 2687 km, 532 km are installed in a relevant voltage level. For the HVDC MI cables there are reported 18 faults, 11 of which are external and a total of 7 being caused by trawling. The seven faults that are not caused by external forces are caused mainly by thermal exposure or protection wear.

The survey also takes into account the age of the cables, to determine if there is significant changes in frequencies of faults over the life span. For MI cables if is found that there are some more failures during the first five years of operation, apart from this the failure frequency appears to be relatively constant.

For MI cables in the voltage range of 220 kV – 500 kV the failure frequency is found to be 0.0998 faults per 100 km per year.

The MTTR is also evaluated for the cables. There is no information on what faults lead to what outage times, nor on at what times of year the failures occur and hence to which

[21] These dates were used for the subsea cables, not for the onshore cables.

extent weather conditions is a major factor. An estimate of MTTR based on this information is therefore very uncertain. 11 out of the total of 18 faults are reported with a known repair time, the remaining seven have unknown repair times, further devaluing the MTTR that can be estimated. By using the provided repair times, it can be calculated an average value of 2.3 months, which equals 3367.2 hours. Because there are an entirety of seven (almost 40 %) faults with unknown repair time this average time does not have much credit. In order to increase the credibility an average value is calculated based on all faults of known duration, for this case ten out of 49 (approximately 20 %) of the faults have unknown durations and the credibility of this estimate is much higher. The overall fault duration is found to be approximately 1.9 months or 1368 hours. As this is a lower estimate than for MI cables alone, and the XLPE cables can be expected to have lower than average repair times due to less complex structure than the oil filled cables, this estimate will be used in the reliability analyses.

Using balanced monopolar HVDC layout leads to the cables being lain in pairs and buried together. When two cables are buried together it is reasonable to assume that any external source of failure will damage both cables, and because a failure does not become twice as likely when there are two cables in a trench this means that the failure rate per length is lowered in this case. This leads to the conclusion that the failure rate of external failures will not be proportional to the length of cable, but rather to the length of the cable trench, or half the cable length. The Internal failures will naturally be proportional to the length of cable, as the system is not allowed to operate in unbalanced HVDC mode. In taking into account the HVDC layout leads to the failure rate being given by:

$$\lambda = \lambda_1 * (external\ failure\ rate * 0.5 + internal\ failure\ rate) \tag{11}$$

$$\lambda = 0.0998 * \left(\frac{11}{18} * 0.5 + \frac{7}{18}\right) = 0.094 \tag{12}$$

The data that will be used in the analysis are therefore:

Table 14: Reliability analysis input for HVDC cables

Failure rate [1/(100km*yr)]	0.094
MTTR [h]	1368

Chapter 13.2.6.2 HVAC Cables

Assuming that XLPE cables are also used in the AC parts of the system the availability is given by the Cigré report [29]. The report does not include any studies of AC XLPE cables in the voltage range 220 kV to 500 kV which would be the relevant range. However there is included surveys of AC XLPE cables in the voltage range 110 kV – 219 kV, this voltage level is not however studied as an individual level for determining failure rates. The report shows that none of the AC cable systems suffered from "internal faults" and all faults were consequently results of external forces, insufficient protection or related to the landfall troughs. Because of this it seems reasonable to expect that the failure rate of the AC cables should be relatively equal for the 200 kV – 500 kV case, as for the 60-219 kV case, at least if there are other numbers to support this. For the XLPE systems in the 60 kV – 219 kV the failure rate is reported to be 0.0705 failures per 100 km per year. Comparing this to the 220 kV – 500 kV which has a failure rate of 0.0738 faults per 100 km per year a good concurrence is found and hence the estimate of 0.0705 faults per 100 km per year is used also for the higher voltage level.

When it comes to the MTTR is likely that the repair time of oil filled cables will be significantly higher than for extruded cables. For this reason it is assumed that the average MTTR of lower voltage HVAC XLPE cables is valid also for somewhat higher voltage levels. As such the MTTR is calculated to be one month on average, which equals 720 hours. This repair time appears to be unreasonably much shorter than what is the case for the MI cables considered for the DC cables. It would be reasonable to expect that the repair time of the AC and the DC cables were approximately equal, particularly if water depth is not taken into account. As the Cigré report only reports four failures for the AC XLPE cables it is therefore assumed that the data basis is insufficient and that the repair time is equal to that of the DC cables.

The data that will be used in the analysis are therefore:

Table 15: Reliability analysis input for HVAC cables

Failure rate [1/(100km*yr)]	0.0705
MTTR [h]	1368

Chapter 13.2.7 Price

Chapter 13.2.7.1 HVDC Cables

HVDC cable prices used in this thesis are based on estimates by Statkraft. Prices for 1000 MW cables and 1320 MW cables have been offered by Statkraft and by interpolation the price for 1200 MW cables was found to be £ 1 456 220 per km of two cables, including laying costs. By extrapolation a price of some £ 980 000 was found for the cables of 600 MW rating. Statkraft estimates say £ 1 000 000 per km is a reasonable estimate and the rounded of value is used as extrapolation will have certain weaknesses. Both prices include laying costs and two cables per km.

Chapter 13.2.7.2 HVAC Cables

HVAC cable prices were based on Statkraft estimates and set to £ 1 600 000 per km three phase cable.

Chapter 13.3 Nodes

The busbars of the nodes in the system have been included only in the reliability analyses. Little information has been found on the reliability of busbars and the failure rate used in the analyses of this thesis is based on [20]. However the repair time given in [20] was found to be unrealistically high compared to other components. The repair time of circuit breakers given in [22] was therefore used as a basis for the busbar repair time.

Failure rate [1/yr)]	0.02
MTTR [h]	100

Chapter 13.4 Transformers

There are two types of transformers that are present in the system; power transformers and converter transformers. The power transformers are used by the collection points to transform the voltage to the collection grid voltage level. The converter transformers are in reality power transformers with tap changers that contribute to the control of the HVDC power flow.

Chapter 13.4.1 Price

Chapter 13.4.1.1 Power transformer

Because the part of the layout where the power transformers are located is equal for all the studied layouts it is not necessary to include the price of these transformers in the investment cost used in the economic analysis.

Chapter 13.4.1.2 Converter transformer

The price of the converter transformer is included in the converter price.

Chapter 13.4.2 Unavailability

The two transformer types are in this thesis assumed to have equal failure rate. [33] has included an overview of failure rates and repair times for transformers used in wind power projects divided into categories of severity and availability of a spare transformer. These values are based on Cigré studies and are considered reliable.

The total failure rate, including both severe and less severe faults is found to be 0.0308 failures per year. The repair time of the transformers is given by the following table:

Table 16: Transformer MTTR by position of spare unit [33]

Position of spare unit transformer	Station Manning		MTTR [h]
Onsite	24	h/day	16
Onsite	24	h/day (on call)	17
Onsite	8	h/weekdays	48
Offsite - spare is available at the opposite HVDC station	24	h/day	103
Offsite - spare at factory facilities, same country	24	h/day	121
Offsite - spare at factory facilities, overseas	24	h/day	817
Worst case scenario	-		2160

For the transformers it is clearly a good idea to evaluate the impact of having spare transformers available. As there is planned a storage offshore and one onshore it would be possible to have transformers available at these storages, hence it is worth considering the second row. However one would wish to limit the storage capacity offshore, as space is very costly offshore. This means that the third row might be more relevant for all of the offshore transformers, by storing the transformers onshore. The third likely situation is that there is a spare available from an overseas factory, this is considered the most likely scenario and is used as the *Expected Situation*. The worst case scenario may of course occur, but is not likely to be the general rule and for this reason this case is not considered.

The reliability data that will be used for the analysis of the transformers are:

Table 17: Reliability analysis input for power transformers and converter transformers

Failure rate [1/yr]	0.0308
MTTR1 [h]	17
MTTR2 [h]	103
MTTR3 [h]	817

Chapter 13.5 Converters

For HVDC systems there are two main technologies that can be utilized for the AC/DC conversion. LCC and VSC converters. Of these only VSC converters are possible to use in wind farm systems and therefore these have been selected for use in the Dogger Bank project.

Chapter 13.5.1 Choice of converter technology

There are two main technologies for HVDC transmission, LCC HVDC and VSC HVDC, distinguished by the converter technology. LCC HVDC is often referred to as HVDC Classic and is the older and the more mature of the two. It is based on line commutated or current source converters, which uses thyristors as switching components. VSC HVDC has relatively recently surfaced as a competing transmission technology. Voltage source converter HVDC uses transistors as switching devices. There are presently two manufacturers of VSC HVDC with installed systems, ABB and Siemens with their HVDC Light and HVDC Plus technologies respectively. There are quite a few differences between HVDC classic and VSC HVDC, and only some of these will be covered here.

Being the more mature technology LCC has both lower cost and lower losses than VSC technology. It also supports higher ratings and is therefore better suited for extra-long distance extra high power transmission than VSC. Having been used longer and more extensively, the operation experience is well documented and so is the reliability of HVDC classic links and its components.

What is considered the main benefit of using VSC technology varies depending on who you ask, although most commonly it is stated to be one of the following:

- The ability to independently control the active and reactive power on the converter AC side.
- The ability to change the direction of the power flow by changing the direction of the current through the converter.

The individual control of active and reactive power is a great advantage over LCC technology which consumes reactive power and therefore needs a reactive compensator on the AC side. As VSCs can be set to produce reactive power they can be used as a reactive compensator device, improving the power flow in the AC system.

The current through an LCC converter is constant and the power flow is changed by adjusting the voltage at the converter terminal. In order to change the direction of power flow through an LCC converter the voltage polarity needs to be changed and hence the system needs to be shut down for this to happen. In VSC converters the voltage at the converter terminal is constant and in order to change the power flow the current is adjusted. This results in a more flexible power flow control. This power control method also allows for some further advantages. Extruded XLPE cables can only be used in VSC HVDC systems. As these are cheaper than the mass impregnated cables and the oil-filled cables that are used for LCC systems and also much simpler and more environmentally friendly than the oil filled cables this offers a real advantage.

Some other advantages of using VSC compared to LCC HVDC is that VSC converters are capable of black start, which means that they can be connected to a weak AC system. LCC, which does not have this possibility, would not be suited for this kind of use. LCC HVDC produces much harmonics and therefore needs large filters to be fitted. Particularly for offshore use these filters become expensive because of the added cost of the platforms on which they are placed. Multi-layer VSC HVDC produces much less harmonics and can be tuned to remove problematic harmonics. This makes the filters obsolete and helps reduce the system cost.

By examining the pros and cons of the two competing technologies it appears that LCC technology provides cheaper transmission in many cases, while the strength of VSC is that it is technically superior, allowing for more control and larger degrees of freedom of choice after installation.

Chapter 13.5.2 Introduction to VSC converters

Voltage Source Converters, VSC, is a relatively new technology for use in high voltage systems. Line Commutated Converters, LCC, are often referred to as HVDC classic as this has been the only available option for high voltage AC/DC conversion over several decades.

VSC converter technology has been successfully implemented by ABB and Siemens, who name their technologic solutions HVDC light and HVDC PLUS, respectively. ABB was first to create a VSC based HVDC system and their first commercial project was the connection of Gotland to the Swedish mainland in 1997. After about a decade of improvement of the technology while ABB was the sole provider of VSC technology, Siemens installed their first VSC link in 2010 in the Trans bay cable project between Pittsburg in the East Bay and Potrero Hill in the centre of San Francisco.

The main difference between VSC and LCC converters is the different switching devices used. LCC employs thyristors, which are semi-controllable switches, while VSC employs transistors, which are fully controllable switches.

The decades of use of LCC technology has made it a mature technology, a conclusion that is drawn based on the very limited improvements that are made in reducing losses and cost of the converters. The same is not true of VSC technology in which there are made much more significant improvements, and which saw the new concept of HVDC PLUS emerge recently from Siemens. The constant improvements in price and electric losses are predicted to make VSC and LCC relatively equal in these two aspects within some years or decades and in the event of this then VSC would likely replace LCC technology all together for new installations. The prices of the converters are dependent both on the component cost itself and the space the converter takes up. Particularly offshore space is an important cost factor as the components must be placed on expensive platforms.

Among the main benefits of using VSC technology is that it allows for increased control of the power flow, and subsequently is better suited for use in multi-terminal systems than its counterpart. Another important benefit is that VSC converters, unlike LCC converters, can be used for black-start operation. This allows the link to connect both strong and weak grid systems and is particularly interesting for wind farm projects which require the black start capability for the cases where a fault in the system forces it to shut down.

Chapter 13.5.3 VSC converter technology

This sub-chapter is an excerpt from the pre-master project of the author [9] to provide an overview of the converter technology.

A voltage source converter is shown in Figure 28. The figure displays a three phase full bridge converter. Voltage source converters can also be single phase, but as they are most commonly used for three phases the term VSC is commonly accepted to refer to three phase VSCs. VSCs are bidirectional AC/DC converters and can thus be used both as inverters and

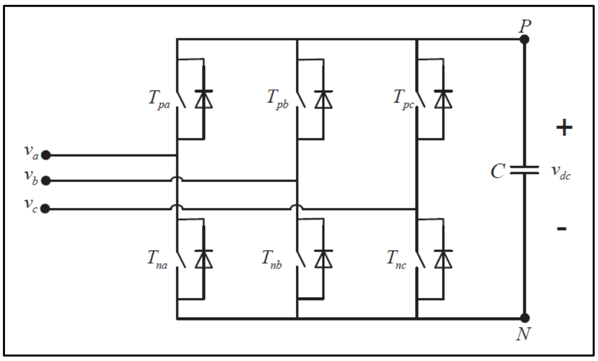


Figure 28: Voltage Source Converter [1]

rectifiers.

Insulated gate bipolar transistors (IGBT) are used as switching devices in VSCs. Transistors are fully controllable semi conductive devices and hence allow controlled switching on and off of each conductive path on the bridge.

The operation of VSCs is based on switching on and off of the transistors at different times in order to produce a certain output. In rectifier mode the current is led from the AC side and through the transistor bridge. Depending on the instantaneous direction of the voltage in each phase the current will pass through either transistor px or nx (see Figure 28), where x

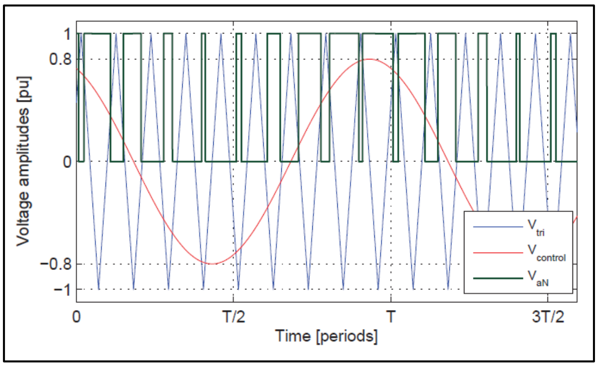


Figure 29: Output voltage from VSC in inverter mode [1]

refers to the name of the phase (a, b or c). The current will then return via the other phases' opposing transistors. For example when phase a has positive voltage the current will flow through T_{pa} and return via T_{nb} and T_{nc}. A thorough description of the switching will not be provided here, interested readers are referred to [34].

The switching scheme most commonly used is pulse width modulation (PWM). In PWM switching, see Figure 29, the output signal for each phase is a function of a two signals, one triangular, V_{tri}, and one sinusoidal control signal, $V_{control}$. Whenever the control signal has a higher instantaneous value than the triangular signal the output voltage will be 1 pu, at all other times the output voltage will be zero. The output voltage signal will therefore be a series of square waves of different period as indicated by the green signal in Figure 29.

It is clear that the output signal in Figure 29 needs filtering before it can be transmitted into an AC system. In Figure 7 such a filter is included in the DC system. By using a more complex version of the VSC a signal without the need for filtering can be obtained. The layout needed for this result is a multilevel converter (MVSC). In MVSCs stacks of transistors replace each transistor in Figure 28, this idea is portrayed in Figure 31.

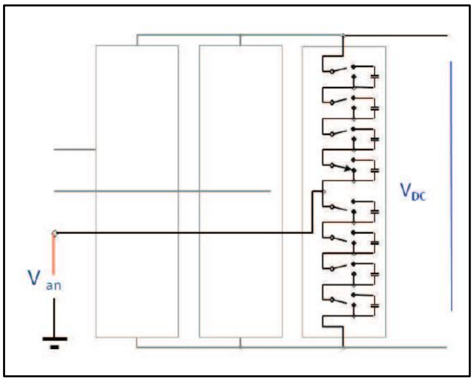


Figure 31: Concept for multilevel converter

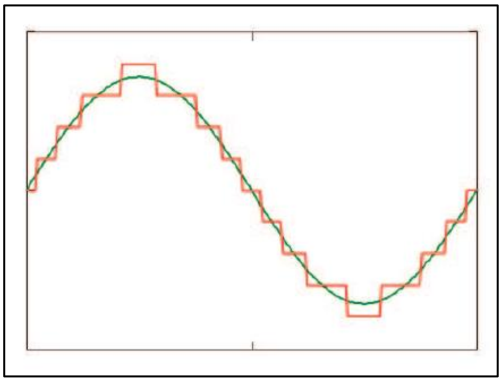


Figure 30: Single phase output voltage from an MVSC

By using this configuration the output voltage is no longer a 1 bit (on or off) signal but an n bit signal, where 2^n is the number of stacked transistor elements. By increasing the number of bits in the signal the signal can be approximated better to a sine wave. Figure 30 displays a three bit sinusoidal approximation (orange line) which would be the output of an MVSC with eight stacked elements as in Figure 31.

The improved output voltage of the converter means removing many low frequency harmonics. This means that the size of the filters can be reduced and in some cases filters can be made obsolete by using multilevel converters.

In addition to improving the output voltage the MVSC also provides redundancy of transistor elements. If an element should be damaged it can be easily bypassed and the converter will still be operational. This significantly reduces the down-time of the converters as the converter will only be turned off for the period of time it takes to repair or replace the element. The main drawback of multilevel converters is the price. By increasing the number of IGBTs the price will be much higher.

Power control in VSCs is more flexible than power control in LCCs. The direction of the power flow through the VSC is dependent on the direction of the current through the converter rather than the voltage across it, as is the case for LCCs. This is necessary in a meshed grid in order to avoid switching In and point-to-point connections a change in power direction at one node necessarily means the other node should also change and such a way of changing power direction is less problematic. For simple grids it is possible to run the system in such a way that power direction through the nodes will never change, the impact of switching in the system will not be very large due to the size of the system. In large meshed systems however the impact of switching the system will be significant as many systems are connected to it.

In rectifier mode the VSC allows voltage control, meaning the voltage can be set to a value. In inverter mode the controllable parameters are voltage level and voltage angle. By allowing control of these two parameters the active and reactive power on the AC side of the converter can be controlled independently.

The size of VSCs is reduced compared to LCCs. This is mainly due to the reduction in circuit elements. Reduction in size is particularly important in offshore locations where space is expensive due to the need for platforms.

Chapter 13.5.4 Price

The converter price used in the analysis is based on a report Siemens has written for Forewind, investigating some potential layouts for the Dogger Bank projects. The prices Siemens use are:

Table 18: Price estimate for converter stations

Converter station rating	900 MW	1100 MW	1400 MW	1700 MW
Converter station price [£M]	334	365	439	541

These prices also include the cost of the converter transformer.

Chapter 13.5.5 Unavailability

There are large uncertainties connected to the unavailability of VSC converters. These uncertainties result both from there being so little operational experience with the converters and from their rapid development, which might leave whatever operational experience there is, inapplicable. An unfortunate fact is that there is no publicly available recording of faults and repair times, nor does there appear to be any significant ongoing survey of this.

Many propose that the unavailability of VSC converters would not be very different from that of HVDC classic converters. In addition there are some more specific suggestions as to the reliability of VSC converters, most notably by Cigré and DNV. DNV splits the failure of converters into five potential sources of error, whose proposed impact on reliability is given in the table below.

Table 19: DNV internal reliability indices for VSC converters [35]

	MTTF [yr]	MTBF [yr]	λ [1/yr]	MTTR [h]	U [h]
DC filter	6	6.00	0.17	24	4.00
IGBT system	2	2.00	0.50	24	11.98
Converter reactor	7	7.00	0.14	24	3.43
AC filter	24	24.00	0.04	24	1.00
Control system	1	1.00	1.00	9	8.99
Overall			1.85	15.90	29.40
Overall, excluding filters			1.64	14.87	24.40
Percentage deviation			11 %	6 %	17 %

The table shows that the control system is the component that is likely to fail most often, but that the largest impact on availability is made by the IGBT valves. By using multi-level converters the filters can be made obsolete and for this reason the overall impact of the converter when excluding the filters is calculated. As the table shows there is a large impact of not including the filters. [35] does not provide any basis on which these numbers have been selected or calculated and as such they represent a large uncertainty.

In [36] Cigré base their suggested values on fault studies of two individual projects. A total of four converters hardly makes for a strong statistic, and as the study only covers a few years, during which there is a dramatic reduction of faults the values have little credibility. The reported outages in the two projects are:

Table 20: Outage rates for two specific VSC HVDC schemes [36]

	Halvarsson Converter	Tomson Converter	Total
Period	IGBT Failures	IGBT Failures	IGBT Failures
July 2003 – June 2004	16	18	34
July 2004 – June 2005	11	10	21
July 2005 – June 2006	14	8	22
July 2006 – June 2007	2	4	6
July 2007 – June 2008	2	4	6
July 2008 – June 2009	5	4	9
July 2009 – Nov 2009	2	5	7

Unfortunately there is no reporting of the outage times connected to these outages.

In a different report by Cigré [37] reliability is studied based on operation of projects in two specific years. The survey includes 34 monopolar and bipolar HVDC schemes.

Table 21: Outage rates and outage durations for VSC converters during two specific years [37]

Category	Average outage rate [1/yr]		Average outage duration [h]	
	2005	2006	2005	2006
Valves	1.4	1.5	3.7*	2.3
Control and protection	1.7	2.1	2.0	3.9
DC equipment	1.1	0.7	5.9	6.9
Average total	4.3		4.1	
Average total per converter	1.4			

*Excluding one exceptionally long outage duration of 1743 h.

Comparing the results in the three above tables show large variations in both outage frequencies and outage durations. Because of the very limited input into the analysis in Table 20 and the large variations within the data this survey is disregarded in this thesis. Table 19 Table 21 show some variation in failure rates, but the most notable difference is the repair time. In both cases the repair time is given for onshore converters, offshore converters will normally have a much higher repair time due to the time it takes to acquire a vessel and to travel to the site. In the case of Dogger Bank there will be crew placed offshore and as converters tend to experience easily mended faults more often than other components it is natural to assume that spare parts will be kept in storage offshore in order to keep the repair time low. Using this assumption is can further be assumed that the repair time will be equal to that of an onshore converter.

Because the DNV data uses the same repair time for all components this appears to be a pure assumption, albeit probably a skilled assumption. However the Cigré data, which is experience based offers significantly lower repair times. From this basis it is reasonable to conclude that experience will give the more accurate estimate and therefore the Cigré repair time will be used in this thesis. With the same logic the Cigré failure frequency is also used.

Table 22: Reliability analysis input for VSC converters

Failure rate [1/yr]	1.4
MTTR [h]	4.1

Chapter 14. Simulations

Chapter 14.1 Assumptions and Simplifications

This sub chapter is dedicated to provide an overview of the main assumptions that have been made and to briefly discuss the impact of making these assumptions.

The aim of the thesis is to study three possible layouts for the connections to shore of four projects in the Dogger Bank zone and present which of these layouts appears to be the most economically beneficial.

One of the main simplifications that is made in the analyses is that electric losses are neglected. By neglecting electric losses the amount of energy delivered to shore is increased compared to the real life value and hence the revenue of sale of the electricity is enlarged. This simplification thereby serves to increase the benefit of layouts that deliver more energy than others. This is particularly true as the electric length of alternative connections will reasonably always be greater than the electric length of the primary path to shore of a project. The result of this simplification is therefore that more complex layouts are favoured unjustly.

The onshore national grid is modelled as a stiff grid in this thesis. This implies that the national grid will be able to receive all energy delivered from Dogger Bank. The EU directive on promotion of the use of renewables states that energy from renewable sources should always have priority in the grid. This means that the assumption is not far from the truth, though outages in the national grid will likely restrict the power flow at times.

Another important simplification that is made is that maintenance periods for the system components are left out. When maintenance work is done, components generally have to be de-energized, which for many components means that the entire system is left de-energized (particularly in the Base Case where so many components are connected radially without alternative current paths). During periods when the system is left de-energized there will naturally be no production and the energy that would otherwise be produced is "lost". In order to reduce the impact of the maintenance work this is therefore often attempted scheduled to periods with low wind speeds and therefore low production as the amount of "lost" energy can then be kept at a low level. In order to keep the time necessary for the maintenance as short as possible and thereby reducing the amount of "lost" energy, the maintenance work is attempted scheduled for time periods with agreeable weather. Rough weather may increase the difficulty of the job or may even prohibit the maintenance crew from entering the component platforms or from using the maintenance vessels. In such cases the system remains de-energized over longer time periods than are theoretically necessary. Over a year the summer is the time period with the lowest wind speeds and the most agreeable weather. Maintenance work will therefore to as large an extent as possible be performed during the summer months. In order to take into account the energy that is "lost" due to maintenance work some knowledge of the wind speed distribution over the year is necessary. In the work with this thesis such knowledge has not been available and extending the model to take into account maintenance work was therefore not considered. One observation is however made. Because the more complex layouts provide alternative current paths during the time when a connection to shore is undergoing maintenance, the impact of including maintenance work in the analysis will increase the resulting benefit of using the complex cases.

While repair times are accounted for in the analysis, the cost of the repair is not. If components need replacement as a result of a fault this cost is absolutely worth noting. As the difference between the cases is only cables and switchgear the cost of repair or replacement of these are the only repair costs that would influence the final result. Clearly the cost of repair of these components will only influence the cases in which the components are present, and therefore the more complex layouts are favoured by leaving out these costs. The cost of removing the components after the end of Dogger Banks concession time is also neglected.

In the analysis of Case Two and Case Three the added cost of extra HVDC CBs has been added as to the investment cost of each project, which means that the investment in the switchgear is made at least a year or more before the switchgear is actually used. One thing that is not taken into account is the need to de-energize parts of the system during work on the interconnections. This added down time would however likely be scheduled during periods with low wind speeds and loss of revenue that results from this would probably be small. As the number of interconnections increases the impact will naturally grow and hence the simplification of leaving out this loss of revenue favours the complex layouts over the simpler ones.

An assumption is also made as to the building of the four projects. It is assumed that the projects are built in the order indicated by their name, and that one project is built each year. Project 1 is assumed built in 2014 and it is assumed that the investments are made in the same year as the project starts producing power. These last assumptions are clear and simply wrong, however the impact of the assumptions should be limited. The assumption of the four projects being fulfilled in four consecutive years is unlikely to be true. Because there will likely be more time between the building of the projects, the amount of time during which for example all four projects are in operation is reduced and the benefit of choosing the more complex layouts will be reduced. If the connections to shore are not removed at the end of a concession period (this is not studied in this thesis) then these will still serve as alternative current paths to shore for the remainder of the life time of Dogger Bank. Depending on how much energy is delivered through this/these remaining connection(s) to shore, during the remainder of Dogger Bank's life time, the impact of extending the time between the building of the projects could potentially be a strengthening of the Dogger Bank economy.

Overlapping faults have been included in the reliability analyses of this thesis to the extent that all components may experience faults at the same time. In reality this is improbable as when a fault occurs in one component, other components will need to be de-energized and these (with the exception of cables) will not be likely to develop a fault. The error that is imposed by considering these overlapping faults is however very small. For the components that may experience overlapping faults, for example components in the upstream connection and in the connection to shore (not in Base Case) the probability of the overlaps is higher as there are more possible combinations of possible than of impossible overlaps, hence the overall impact of including overlapping faults is of a corrective nature.

Very significant assumptions have been made for the input data to the analyses which are presented in Chapter 13 and Chapter 14.2. The reliability data have been found in a number of different articles and reports and have been selected based on the credibility of the sources and based on which can be confirmed by other sources. The economic data have for the most part been offered by Statkraft, but are only estimates and can therefore hold large uncertainties. Because of the uncertainty of these data sensitivity analyses are performed for the most important of them in order to see the impact of potential variations in the values. For the cable price there is added uncertainty as the cable laying price will likely not be equal for all areas.

A simplification of which components are included in both the reliability analyses and the economic analyses has also been made, with the assumption that all other costs are equal between the cases and that failures in the remaining components will have insignificant impacts on the reliability of the system. In the economic analyses the included components are: Cables to shore, inter-project cables, HVDC CBs, converter stations, and additional HVAC CBs needed in the case of AC interconnections. The most significant components that have been left out from the analyses are additional protection system devices, communication devices and regulating system components.

It has been assumed that control system of Dogger Bank works perfectly and that no start-up time is required after a change in the power flow or a fault. Individual remote control of the WTGs is assumed in order to be able to lower the production when the transmission system is only able to transmit some of the produced power. The relay system of Dogger Bank is assumed to be almost perfect in the sense that if a CB fails to operate on demand then the next line of CBs will always operate without fault. It is also assumed that the CBs are 100 % secure and therefore will never operate out of turn. All DSs are considered ideal (though manually operated) components. The DSs are also assumed to be free of charge, which is definitely wrong, though the price is considered to be comparatively small.

No analyses have been made for the case where only three projects are operating and all of these are connected together. In Case Three such a layout would be relevant in the year before the fourth project is built and in the first year after Project 1 is decommissioned (assuming the connections to shore are removed once the project is decommissioned). Because having three projects interconnected would lead to more energy being delivered to shore than if only two projects are interconnected, this simplification leads to less delivered energy in two of the operating years and hence makes Case Three appear less beneficial than in reality.

Chapter 14.2 Input

This chapter is included to collect all the input data in one chapter.

Chapter 14.2.1 System parameters

Some of the characteristics of the system are important in order to evaluate the reliability and cost of the system. The input values that represent the *Expected Situation* are included in the table below.

Table 23: Overview of system parameters for the analyses

Cable lengths	
Cable	**Length [km]**
Connection 1 to shore	213
Connection 2 to shore	261
Connection 3 to shore	223
Connection 4 to shore	215
Project 1 intra project cables	9.5
Project 2 intra project cables	8
Project 3 intra project cables	6
Project 4 intra project cables	5
Inter project cable 1-2	72.9
Inter project cable 1-3	28.2
Inter project cable 1-4	30.6
Inter project cable 2-3	41.2
Inter project cable 2-4	95.3
Inter project cable 3-4	35.3
Power and energy	
Rated power per project	1 153.7856 MW
Lossless energy potential per project	5 909 150.559 MWh
Total lossless energy potential	23 636 602.236 MWh
Discrete power curve	Confidential

Chapter 14.2.2 Reliability analysis

The reliability indices that are used in the reliability analyses are repeated in the table below.

Table 24: Overview of all input values for the reliability analysis

Component	Reliability indice	Value
HVAC CB	Probability of failure to operate on demand	0.72 %
DS	Switching time [h]	1
HVDC CB	Probability of failure to operate on demand	0.72 %
HVDC Cable	Failure rate [1/(100km*yr)]	0.094
	MTTR [h]	1368
HVAC Cable	Failure rate [1/(100km*yr)]	0.0705
	MTTR [h]	1368
Transformer	Failure rate [1/yr]	0.0308
	MTTR [h]	817
Converter	Failure rate [1/yr]	1.4
	MTTR [h]	4.1
Node	Failure rate [1/yr]	0.02
	MTTR [h]	100

Table 25: Overview of all input values for the economic analysis

Investment cost		
Component	**Rating**	**Price**
HVDC Cable	Appx 1000 MW	£ $518\,720 + 781.25 * [MW]$ 1/km
HVDC Cable	600 MW	£ 1 000 000
HVAC Cable	600 MW	£ 1 600 000
Converter	2x 900 MW	£ 334 000 000
Converter	2x 1 100 MW	£ 365 000 000
Converter	2x 1 400 MW	£ 439 000 000
Converter	2x 1 700 MW	£ 541 000 000
HVDC Circuit Breaker	900 MW	£ 8 350 000 - £ 16 700 000
HVDC Circuit Breaker	1 100 MW	£ 9 125 000 - £ 18 250 000
HVDC Circuit Breaker	1 400 MW	£ 10 975 000 - £ 21 950 000
HVDC Circuit Breaker	1 700 MW	£ 13 525 000 - £ 27 050 000
O&M cost		
Component	**Rating**	**Price**
HVDC Cable		£ 2 700 [1/(km*yr)]
Converter	2x 1 000 MW	£ 1 480 000 [1/yr]
Converter	2x 1 320 MW	£ 1 628 000 [1/yr]
Economic parameters		
Interest rate		4 %
Inflation rate		2 %
Discounting rate		0 %
CfD strike price	See Table 10	

Chapter 15. Results

This chapter conveys the results obtained in the analyses. As the analyses are sensitivity analyses with regards to individual parameters the results are presented to show the impact of each variation individually.

The results are presented graphically along with a table of the results of each case in each state. The axes of the graphical representations only stretch over the span relevant to view the differences between the cases and states. This is done because the differences are relatively small, order of magnitude a few percent of the total value. For this reason the axes are not the same in each figure, and the different simulations cannot be compared at a glance.

In the result graphs that display the economic results of the simulations the term profit is used on the Y-axis. This is not the profit of the project, but rather, as previously described, the surplus found when subtracting the investment cost and O&M cost that are included in this thesis from the revenue. The profit of the Dogger Bank projects will hence be considerably lower than what is presented here as very large costs have been left out. The values on the Y-axis hence serve to show the difference between the cases only.

All of the analyses spring out from the case in which the input values are as given in Chapter 14.2. Because the word Base Case is in this thesis used to describe the different layouts the term Expected Situation will be used to refer to the mentioned input values. In the Expected Situation all connections to shore have 100 % rating (equal to project rating) and all interconnections are made with HVDC cables connected in an MTHVDC system with HVDC CBs available at all points of interconnection.

Many of the graphs include the Produced Energy as a series. This is done to illustrate the amount of losses that result from the grid. The Produced Energy is the total amount of energy that is delivered from the wind turbines to the collection points.

As described in Part I.Chapter 1.2.3 there are three different ways of interconnecting the Projects in Case Two, these are illustrated in **Feil! Fant ikke referansekilden.**.

In the analyses it was found that which one of these is the best option is dependent on the input data. However, none of the analyses proved Option three as the better option reliability wise, hence this layout will never (in the analyses performed here) deliver more power than the alternatives. Also the cables needed here are longer than in the other Options which means that this Option will always be the more expensive. The conclusion can therefore be drawn that Option three will never be the best one and hence it has been left out of the following results.

Options one and two vary as to which is the better layout and hence both are included below. They are referred to as Case Two (1) and Case Two (2) respectively.

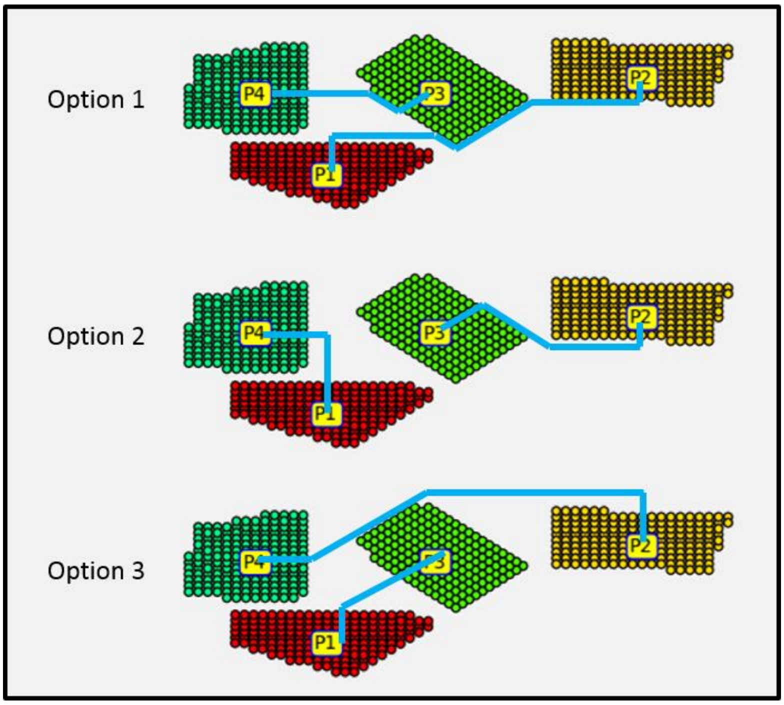


Figure 32: Three possible layouts of Case Two

Chapter 15.1 Expected Situation

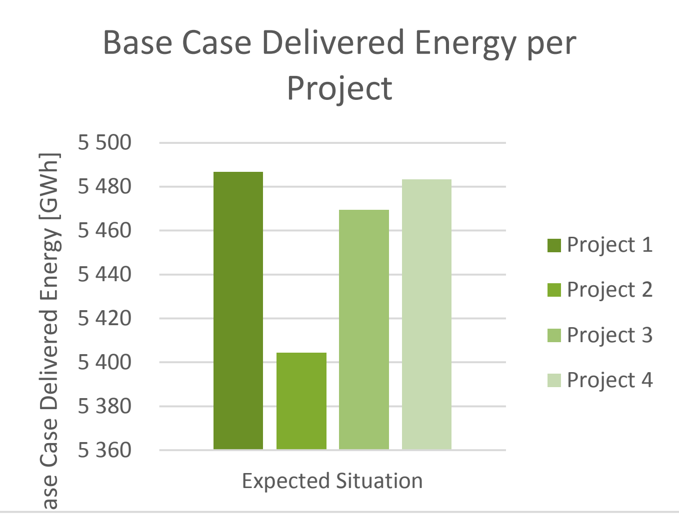


Chart 1: Base Case Delivered Energy to Shore for Each Project in the Expected Situation

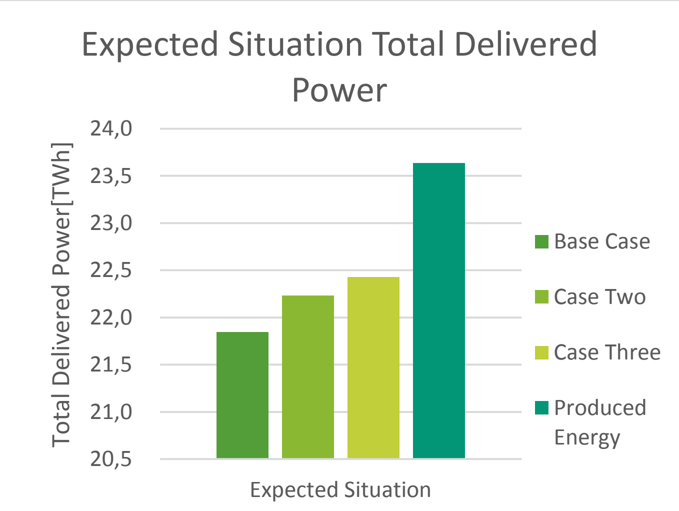


Chart 2: Total Delivered Energy to Shore for the Different Layouts in the Expected Situation

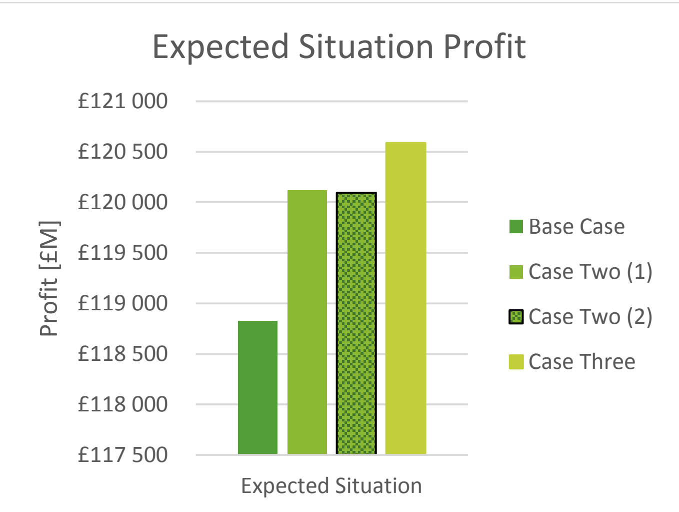
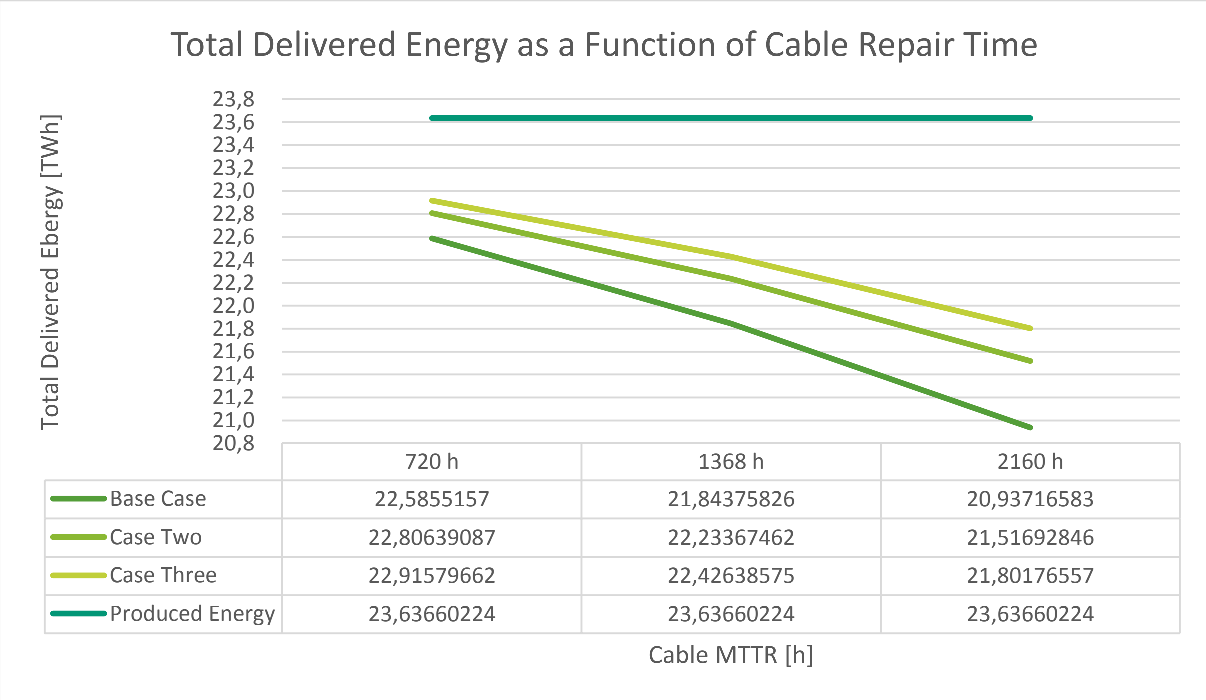


Chart 3: Profit of the Different Layouts in the Expected Situation

The Base Case Delivered Energy clearly varies a great deal between the Projects. This is a natural consequence of the differences in the lengths of the connections to shore. Also the differences in cable length within the Project, namely the cables from the collection points to the converter, contribute to the differences. The magnitudes of difference in cable length within Projects are very much lower than the magnitude of difference in cable length in the connections to shore. This leads to the variations in delivered power being very close to proportional to the length of the connection to shore.

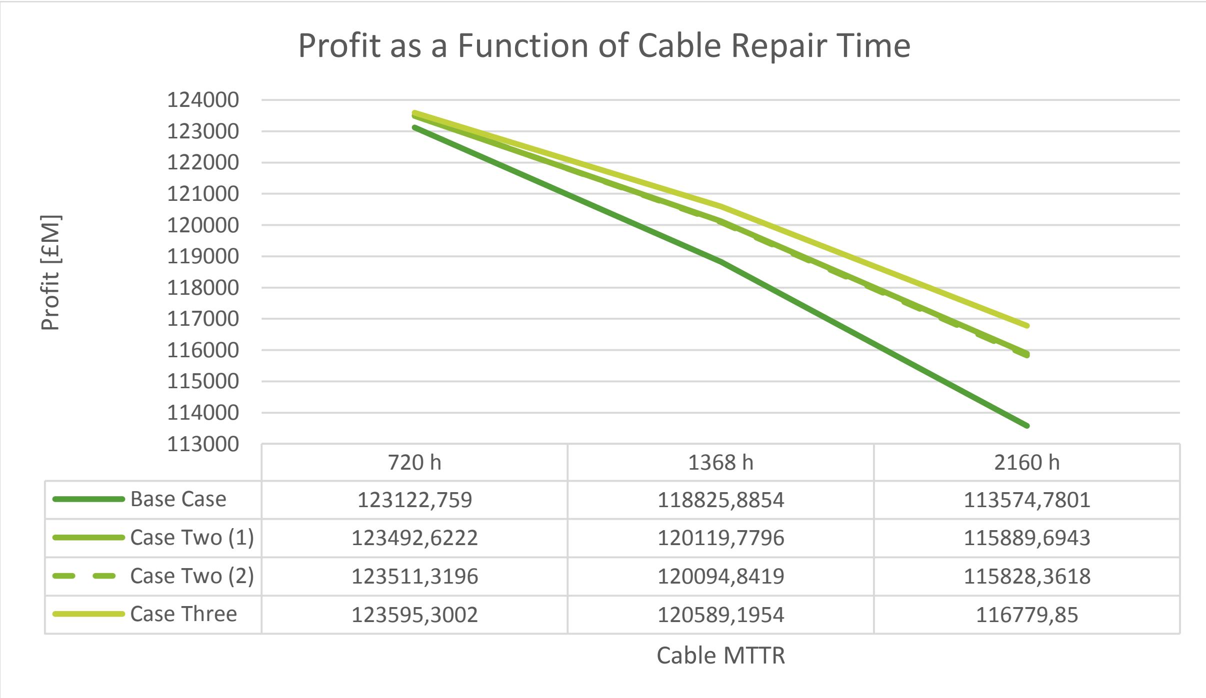
The column chart showing total delivered energy shows that the amount of energy delivered does increase as the complexity of the system is increased, however the increase is non-linear and the increase in delivered power from the Base Case to Case Two is larger than the corresponding increase between Case Two and Case Three. Case Two is here illustrated by Option 2.

The profit chart shows that the profit also increases with increased complexity of the system. The increase in profit follows to a large extent the tendency of the produced energy in that the increase in profit is larger from Base Case to Case Two than from Case Two to Case Three.



	720 h	1368 h	2160 h
Base Case	22,5855157	21,84375826	20,93716583
Case Two	22,80639087	22,23367462	21,51692846
Case Three	22,91579662	22,42638575	21,80176557
Produced Energy	23,63660224	23,63660224	23,63660224

Chart 4: Total Delivered Energy as a Function of Cable Repair Time

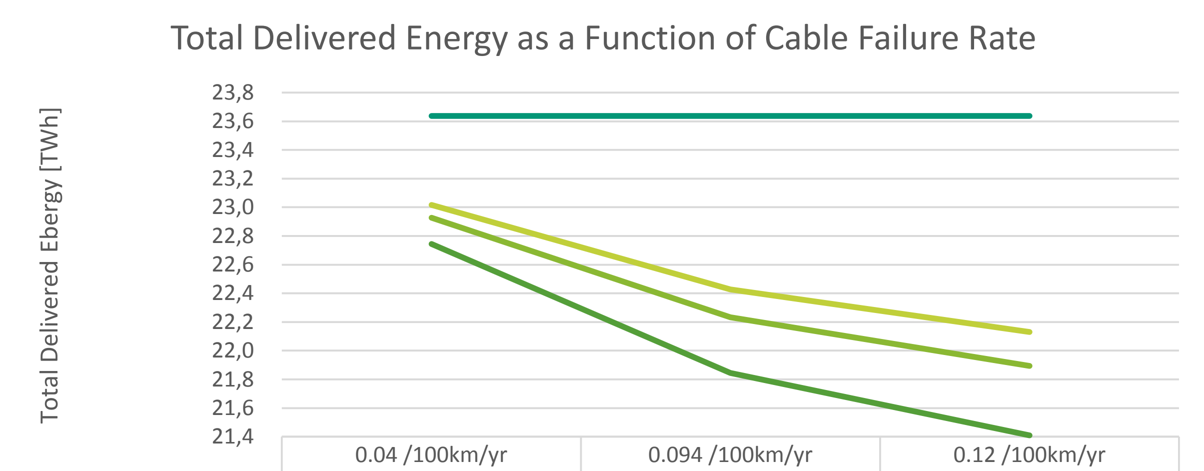


	720 h	1368 h	2160 h
Base Case	123122,759	118825,8854	113574,7801
Case Two (1)	123492,6222	120119,7796	115889,6943
Case Two (2)	123511,3196	120094,8419	115828,3618
Case Three	123595,3002	120589,1954	116779,85

Chart 5: Profit as a Function of Cable Repair Time

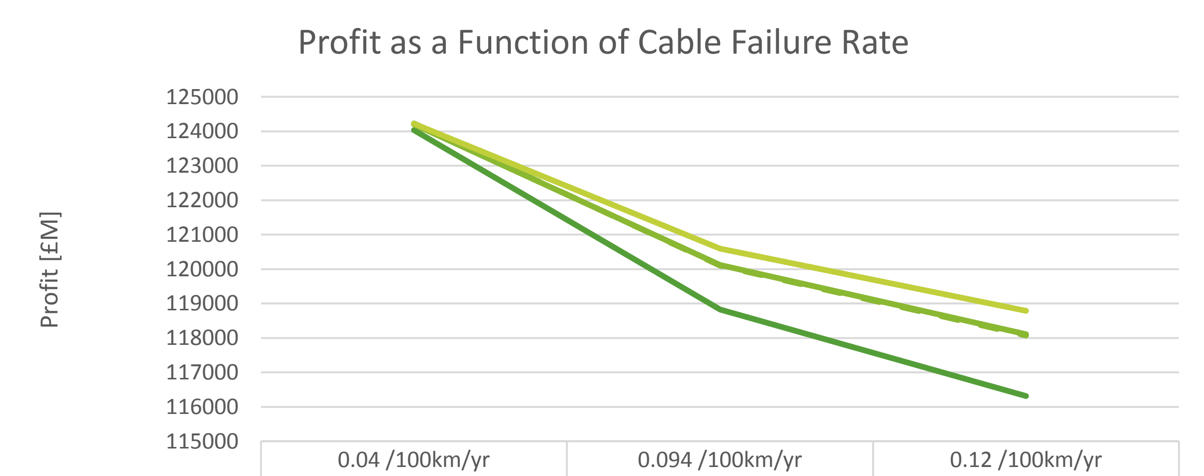
The above two graphs show a few trends that are of interest. First and foremost the graphs show that as the cable repair time increases the delivered power, and hence the profit is reduced. Secondly the graph shows that the benefit of using a more complex system increases with increased repair time. Thirdly the trend of the difference between Base Case and Case Two is larger than the difference between Case Two and Case Three, as was observed for the expeced case. The repair times that are used are one, two and three months, and the repair time applies to all cables in the sytem. As the cables are an important contributor to the system unavailability in any case because such long distances are used, it is reasonable to expect a large impact of varying the repair time.

Chapter 15.3 Cable Failure Rate



	0.04 /100km/yr	0.094 /100km/yr	0.12 /100km/yr
Base Case	22,74333643	21,84375826	21,41062803
Case Two	22,92645205	22,23367462	21,89364168
Case Three	23,01737653	22,42638575	22,13156362
Produced Energy	23,63660224	23,63660224	23,63660224

Chart 6: Total Delivered Energy as a Function of Cable Failure Rate

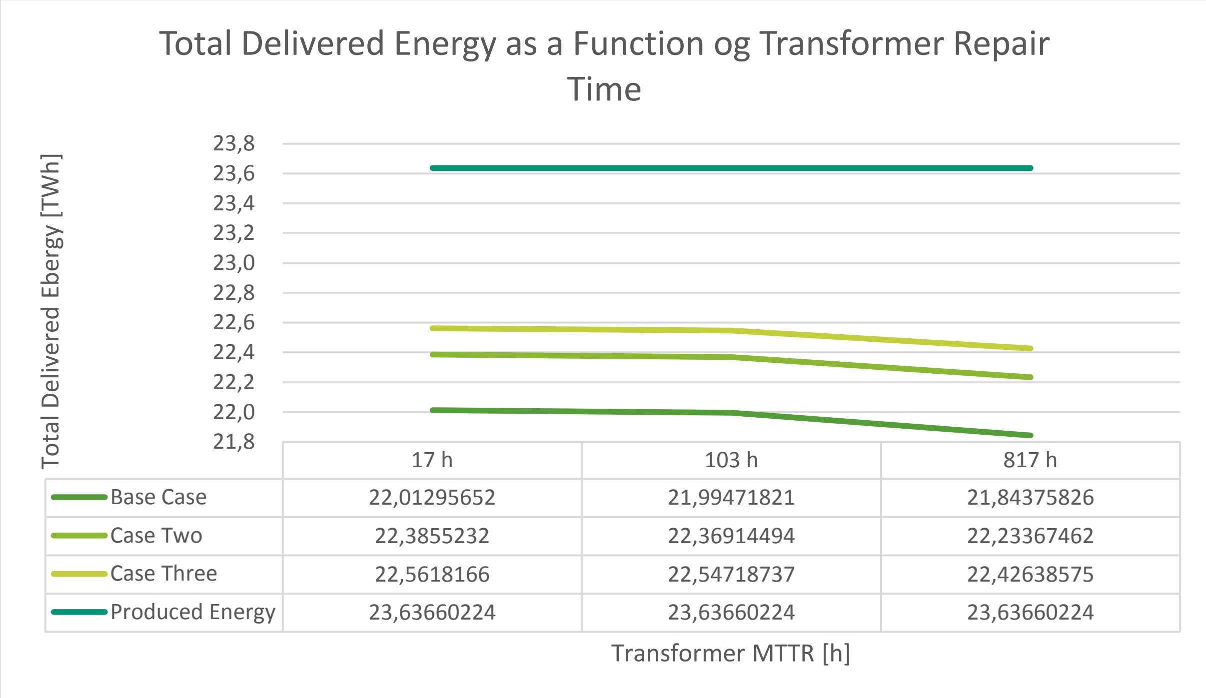


	0.04 /100km/yr	0.094 /100km/yr	0.12 /100km/yr
Base Case	124036,3631	118825,8854	116317,1368
Case Two (1)	124199,1669	120119,7796	118113,5451
Case Two (2)	124228,8321	120094,8419	118068,9655
Case Three	124221,1768	120589,1954	118787,7156

Chart 7: Profit as a Function of Cable Failure Rate

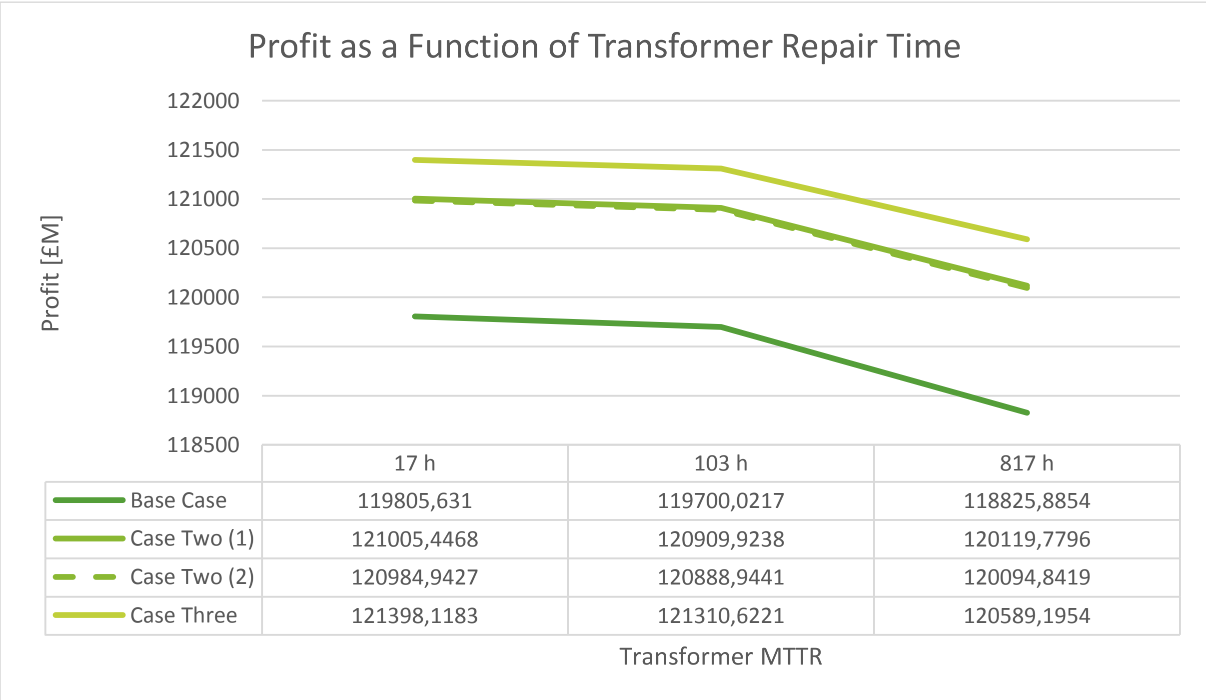
The impact of variations in cable failures rate are found to be similar to the impact of varying repair times. Because the failure rates and repair times were not presented along with a probability of these occuring it is hard to say that the three sets of values that are evaluated correspond. Assuming that they do however it is found that the impact of a high failure rate is lower than the impact of a high repair time.

Chapter 15.4 Transformer Repair Time



	17 h	103 h	817 h
Base Case	22,01295652	21,99471821	21,84375826
Case Two	22,3855232	22,36914494	22,23367462
Case Three	22,5618166	22,54718737	22,42638575
Produced Energy	23,63660224	23,63660224	23,63660224

Chart 8: Total Delivered Energy as a Function of Transformer Repair Time

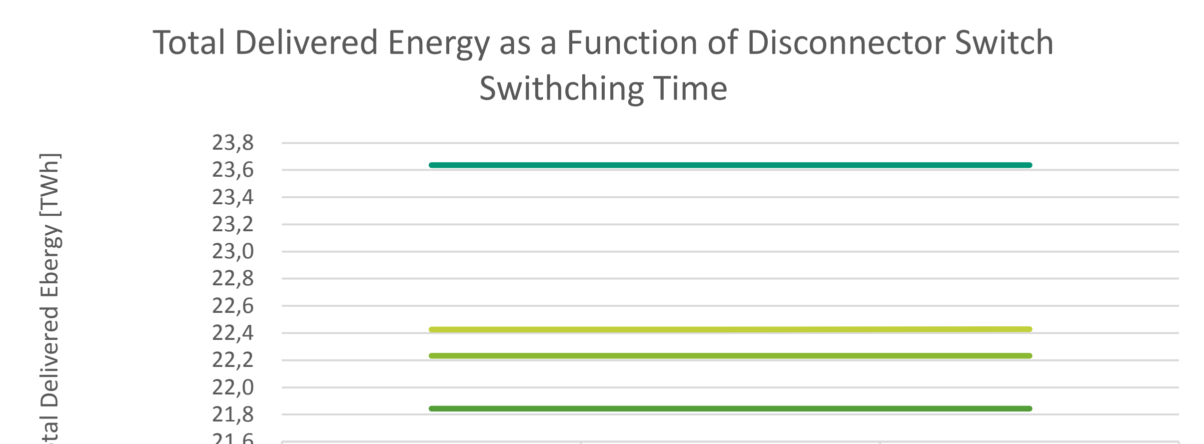


	17 h	103 h	817 h
Base Case	119805,631	119700,0217	118825,8854
Case Two (1)	121005,4468	120909,9238	120119,7796
Case Two (2)	120984,9427	120888,9441	120094,8419
Case Three	121398,1183	121310,6221	120589,1954

Chart 9: Profit as a Function of Transformer Repair Time

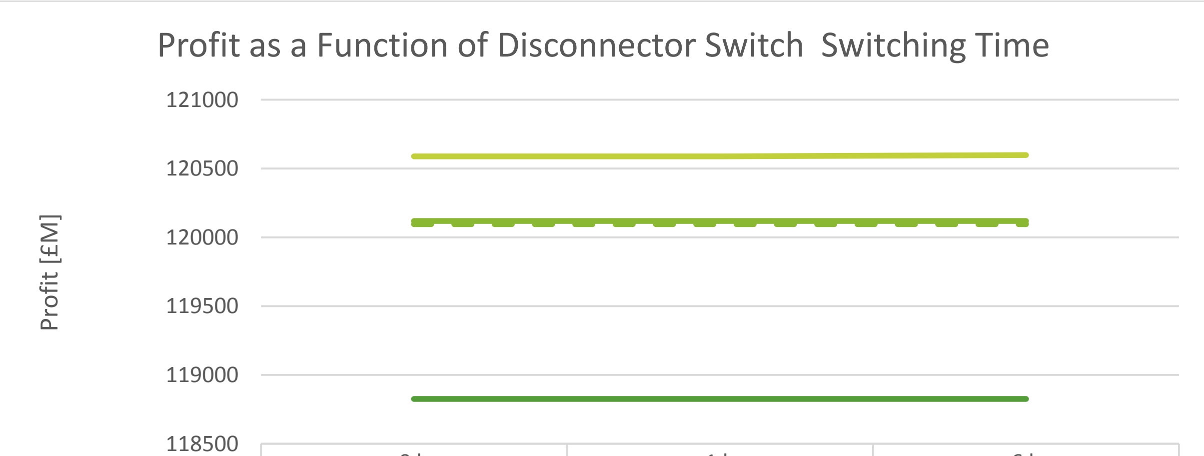
The above graphs show the impact of the location of spare transformers. As previously explained the repair time of the transformer is mainly dependent on the time it takes to bring the transformer to the site. If the transformer is available on site the repair time is as low as 17 h, whereas if the transformer is locaed on shore or overseas, the aquiring time and hence the repair time increases rapidly. Again it is evident that the benefit of Case Two compared to Base Case is higher than for Case Three compared to Case Two.

Chapter 15.5 Switching Time



	0 h	1 h	6 h
Base Case	21,84375931	21,84375826	21,84375227
Case Two	22,23367564	22,23367462	22,23366882
Case Three	22,42638671	22,42638575	22,42813318
Produced Energy	23,63660224	23,63660224	23,63660224

Chart 10: Total Delivered Energy as a Function of Disconnector Switch Switching Time



	0 h	1 h	6 h
Base Case	118825,8915	118825,8854	118825,8507
Case Two (1)	120119,7856	120119,7796	120119,7458
Case Two (2)	120094,8478	120094,8419	120094,8081
Case Three	120589,201	120589,1954	120597,7221

Chart 11: Profit as a Function of Disconnector Switch Switching Time

The impact of varying the switching time is very low. Of course the variations in switching time presented in the graphs are very small and a large impact was not to be expected, but these values are plausible ones as there are crew offshore, and the travel time to manually switch is low.

Chapter 15.6 AC vs. DC Interconnections

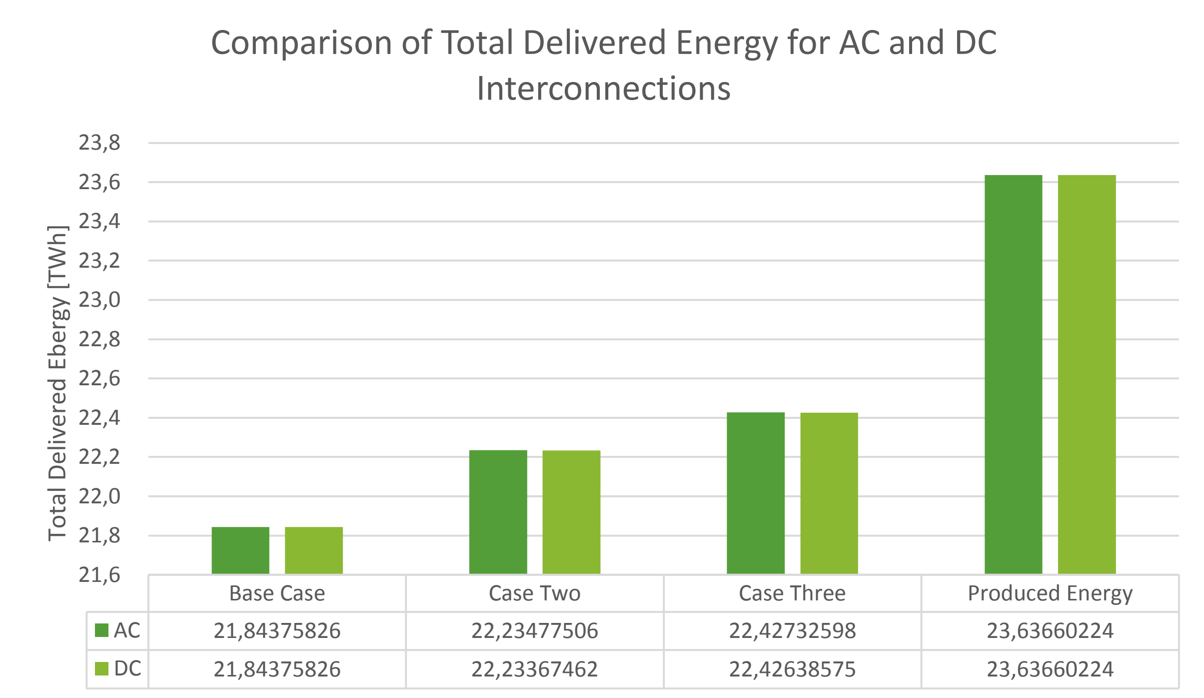


Chart 12: Comparison of Total Delivered energy for AC and DC Interconnections

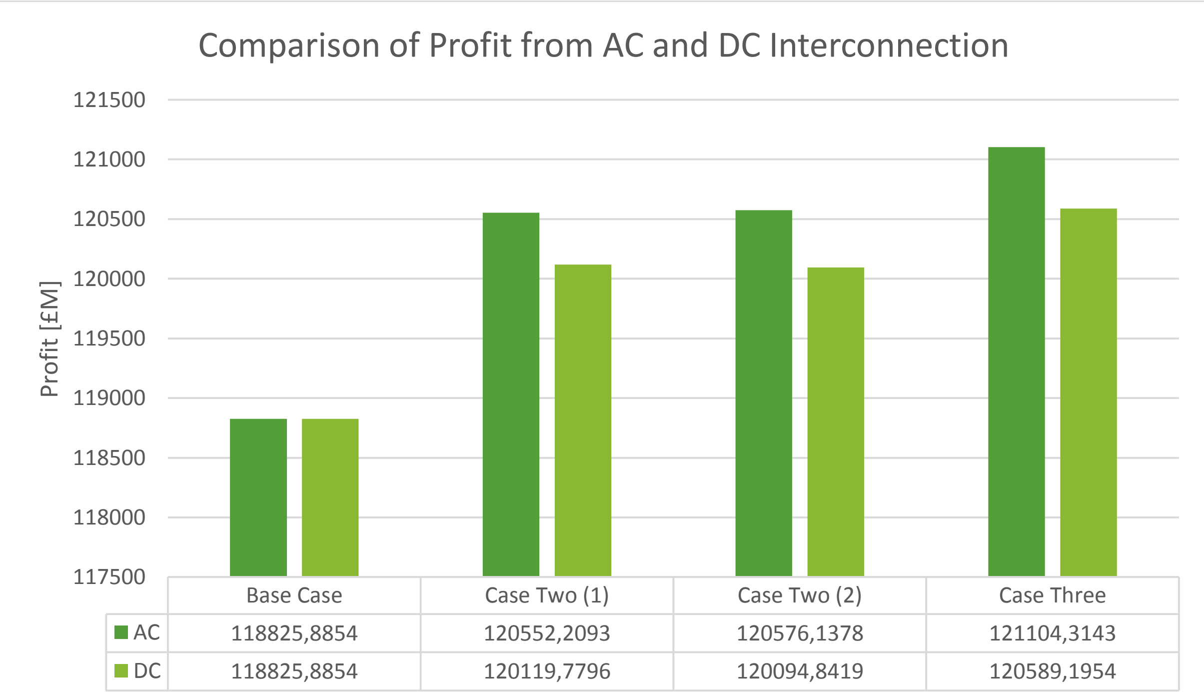
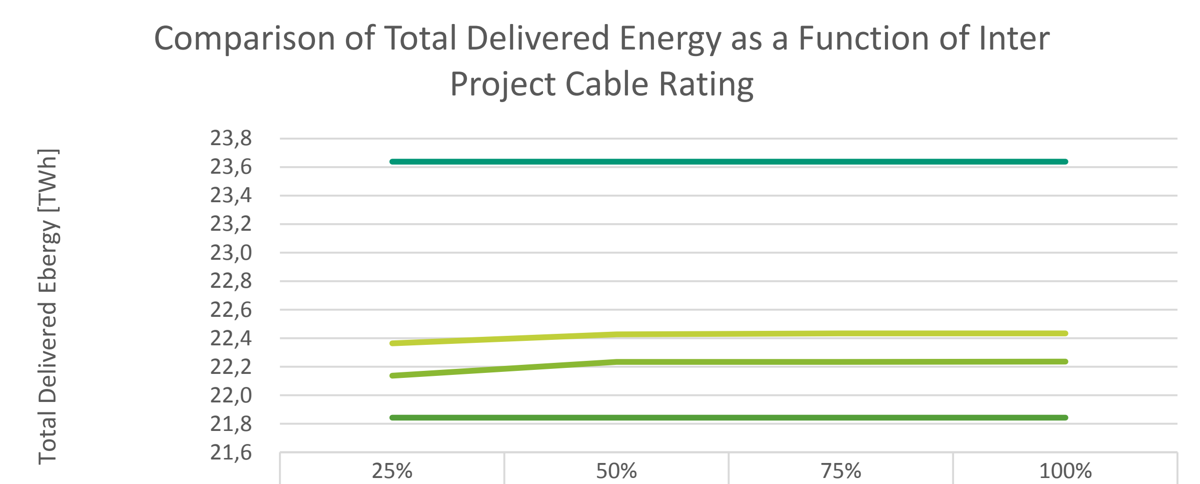


Chart 13: Comparison of Profit from AC and DC Interconnections

The comparison on AC and DC inerconnections is not very thouroughly done. The main source of error in the AC case is that, due to the limits of Excel, it was not possible to evaluate the AC cable as connected on the AC side. Hence the converter unavailability influences the AC interconnection to appear worse than it really is. In addition only the case in which HVDC CBs are used in the MTHVDC system is studied, whereas a system without this would give a very different answer. The results here show that there are only very small difference in the availability of the AC and DC connection schemes, but due to the cost of HVDC CBs the investment cost is higher in the DC case and HVAC therefore turns out to be the best option.

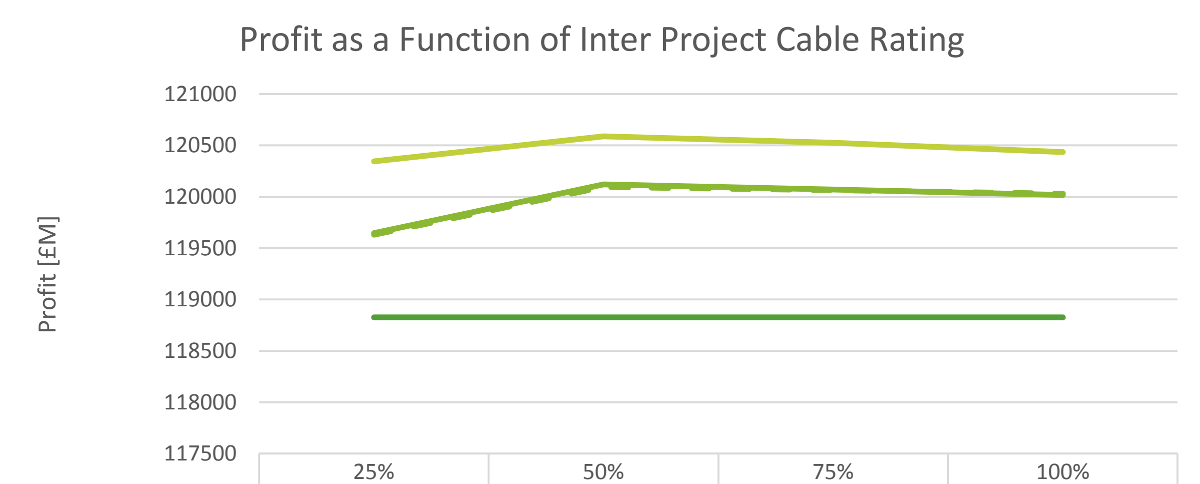
Chapter 15.7 Inter-Project Cable Rating



	25%	50%	75%	100%
Base Case	21,84375826	21,84375826	21,84375826	21,84375814
Case Two	22,13709735	22,23367462	22,23492007	22,23579955
Case Three	22,36383106	22,42638575	22,43285211	22,43351617
Produced Energy	23,63660224	23,63660224	23,63660224	23,63660224

Interconnection rating [% of Project Rating]

Chart 14: Comparison of Total Delivered Energy as a Function of Inter Project Cable Rating



	25%	50%	75%	100%
Base Case	118825,8854	118825,8854	118825,8854	118825,8846
Case Two (1)	119647,4948	120119,7796	120069,4958	120017,2058
Case Two (2)	119630,8758	120094,8419	120063,8365	120030,9308
Case Three	120344,3177	120589,1954	120526,6247	120435,594

Interconnection Rating[% of Project Rating]

Chart 15: Profit as a Function of Inter Project Cable Rating

When comparing the delivered energy and profit of the different cases for varying ratings of the inter project connections it is found that the amount of delivered energy grows continously as the cable rating increases, but the profit falls slightly for ratings above 50 %.

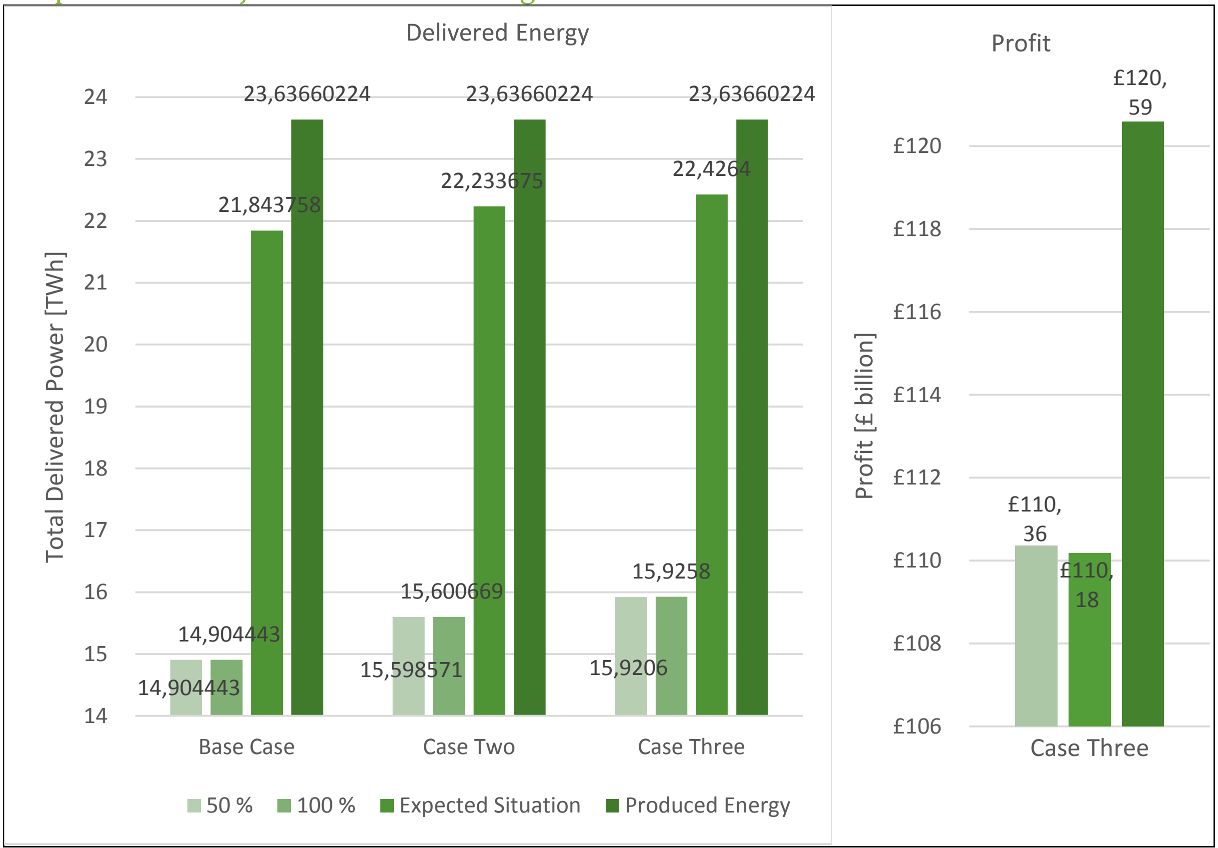
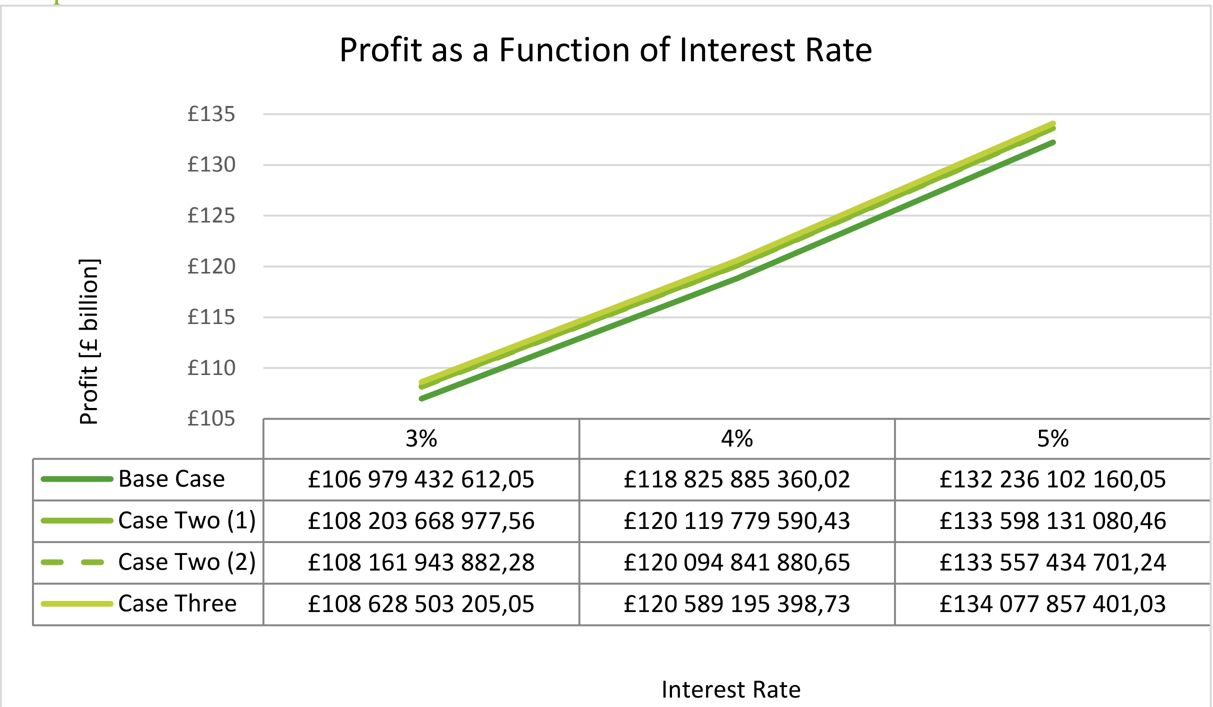


Chart 16: Comparison of the case where Project 2 has a connection to shore of 50 % rating and the inter-project links are 50 % or 100 % rated and the expected situation in terms of delivered energy to shore and profit

For Case Three a possible version of the layout is to reduce the rating of one of the connections to shore. Because Project 2 has the longest connection to shore, this is the most expensive connection and is also the connection most prone to faults. This makes Project 2's connection to shore the best suited connection for lowered rating. The chart above shows the impact of using such a layout. The two leftmost bars show the outcome for the described layout with a rating of the inter-project links of 50 % and 100 % respectively. Calculations show that the decrease in Investment cost is £ 171 573 420 and £ 89 453 820 respectively for the two cases. It is however evident from the chart that this saving is nowhere near enough to make up for the decrease in delivered energy.

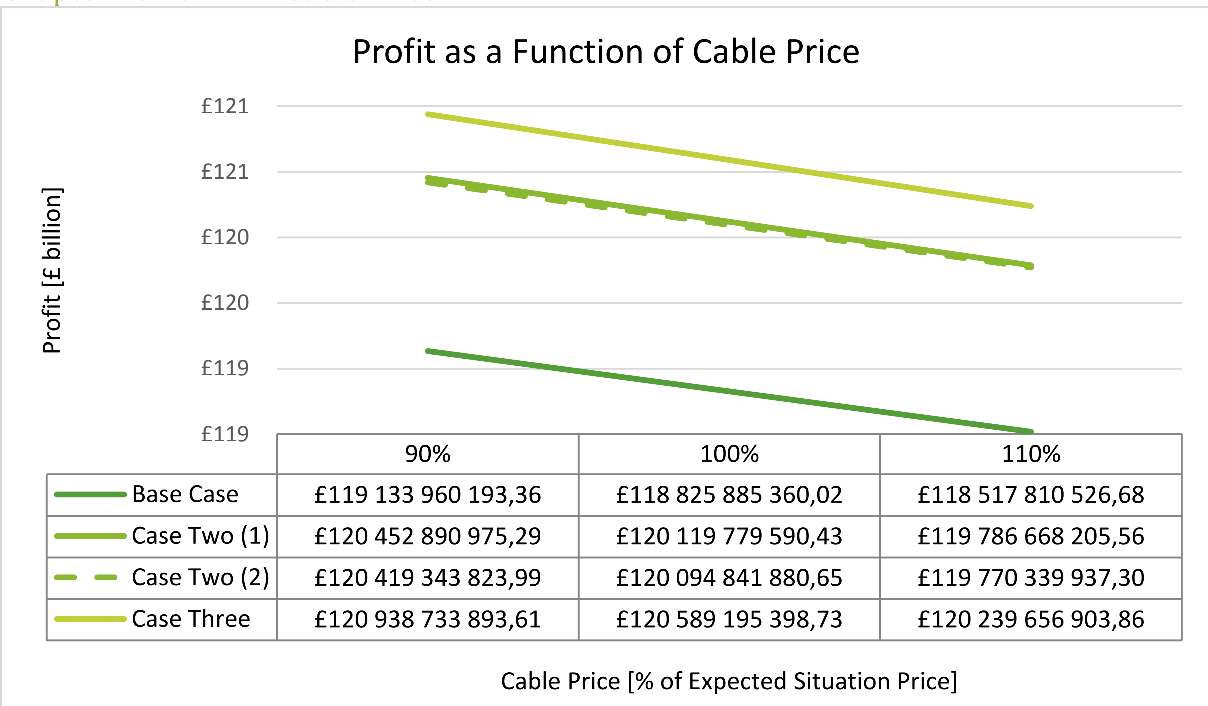
Chapter 15.9 Interest Rate



	3%	4%	5%
Base Case	£106 979 432 612,05	£118 825 885 360,02	£132 236 102 160,05
Case Two (1)	£108 203 668 977,56	£120 119 779 590,43	£133 598 131 080,46
Case Two (2)	£108 161 943 882,28	£120 094 841 880,65	£133 557 434 701,24
Case Three	£108 628 503 205,05	£120 589 195 398,73	£134 077 857 401,03

Chart 17: Profit as a Function of Interest Rate

Chapter 15.10 Cable Price



	90%	100%	110%
Base Case	£119 133 960 193,36	£118 825 885 360,02	£118 517 810 526,68
Case Two (1)	£120 452 890 975,29	£120 119 779 590,43	£119 786 668 205,56
Case Two (2)	£120 419 343 823,99	£120 094 841 880,65	£119 770 339 937,30
Case Three	£120 938 733 893,61	£120 589 195 398,73	£120 239 656 903,86

Chart 18: Profit as a Function of Cable Price

The above two chart shows the cases as very nearly parallel as the interest rate and the cable price changes. This implies that the impact of these parameters on the benefit of using Case Three over Base Case is limited.

Chapter 16. Discussion and Conclusion

The previous chapter presented the results of the main analyses performed in the work on this thesis. The results show with great consistency that the most optimal layout is the Case Three layout in which all four projects are connected in a ring system. The *Expected Situation* results show an increase of approximately £ 2.1 billion in the profit if the ring layout is selected instead of the Base Case layout. The increased profit from implementing the Case Two layout, in which the projects are connected in pairs is calculated to approximately £ 1.5 billion.

Though the results of the analyses consistently show Case Three as the optimal layout the chapter on assumptions and simplifications indicates that the results may not be as clear as they appear here because almost all of the simplifications made serve to favour the use of interconnections. Because of this favouring of Case Two and Case Three, the results obtained in the analyses will show these two cases as better than they actually are. Depending on the magnitude of the impact of these simplifications the gap in profit between the three cases will likely decrease. If the magnitude of the impact from the simplifications is large, then the gap in profit may even be reversed and Case Three may not be the more optimal of the three layouts after all.

The results presented in Chart 3 shows that the marginal increase in profit is less between Case Two and Case Three than Between Base Case and Case Two. The inverse of this relationship will in all likelihood be found in the impact of the simplifications that have been made for this thesis, meaning the marginal benefit (or favouring) resulting from the simplifications is larger for Case Three than for Case Two.

It is evident that the different layouts will give different developments of the economy over the operating years of the wind farms as a result of variations in investment cost and delivered energy. Chart 19 shows how the economy of the different layouts develop relative to the Base Case economy.

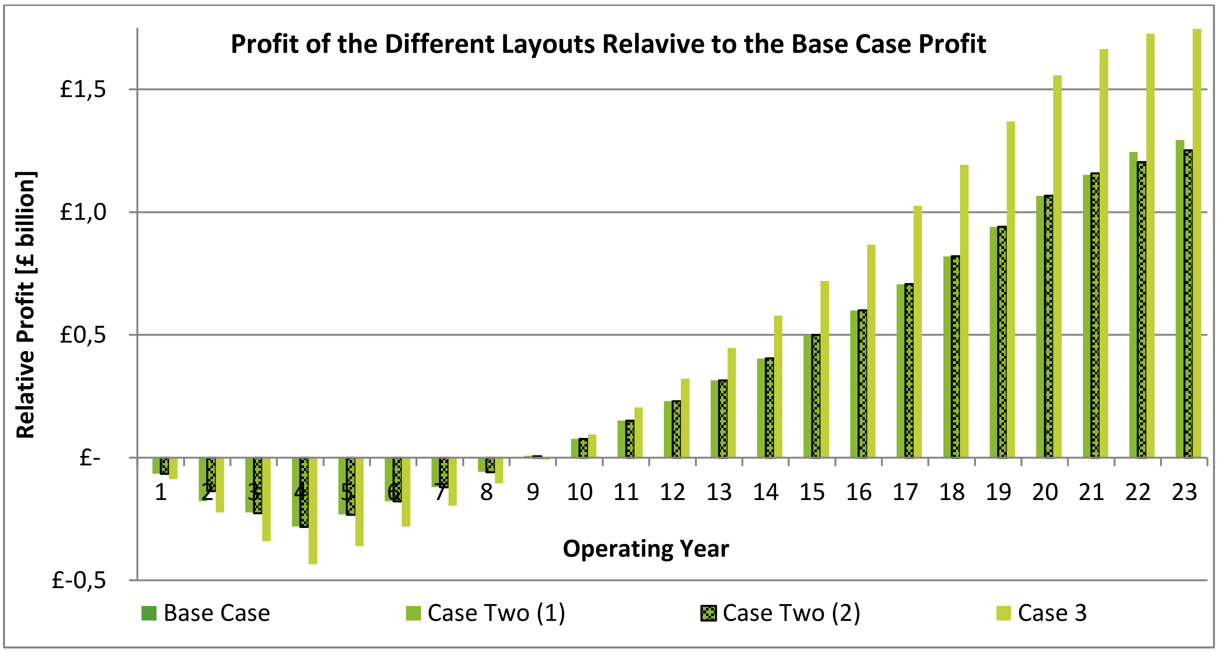


Chart 19: Relative development in profit of the different layouts

The chart shows that as time goes, the more complex grid structures, which deliver more energy to shore, start to benefit from the added investment that was made in the first four years. The development of the chart in the first four years shows the impact of the added investments being made as more projects are built. Because the chart shows relative development of the economy the Base Case economy is always zero in the above chart, though naturally it increases a great deal over the years of operation.

By looking more closely at the profit in each year it is found that the break even operating time, meaning the year in which the profit of Base Case is equal to Case Two and Case Three respectively, is some time in year 9 for Case Two and some time in year 10 for Case Three. This implies that only after this amount of time can the added investment be justified. Some wind farm projects experience problems with the wind turbines and have trouble operating the wind farm through the entire licence period. There are also discussions online in wind power fora as to what is the real life time of a wind turbine, some claim it is significantly lower than 20 years. Should this be the case for Dogger Bank and the operation is stopped due to wind turbine problems the benefit of choosing a more complex grid structure would be much reduced. It is however unlikely that such a stop in operation should happen as early as in year nine, which means that there should be some benefit to choosing Case Two or Case Three over Base Case. If Forewind should want to continue operation of Dogger Bank after the first concession runs out, and they are granted a new licence much of the grid system can be kept as is and the new turbines can be connected to it. In this case the benefit of choosing a more complex grid structure will become very beneficial as the increase in delivered power will persist longer, without much added investments.

Neither the differences in delivered energy nor the differences in profit are very large when comparing the differences cases, this is evident when looking at the Y-axes used in the result graphs above. To demonstrate the relative insignificance of these differences the column diagrams for the expected situation are repeated below along with the same diagram with Y-axes that start at zero.

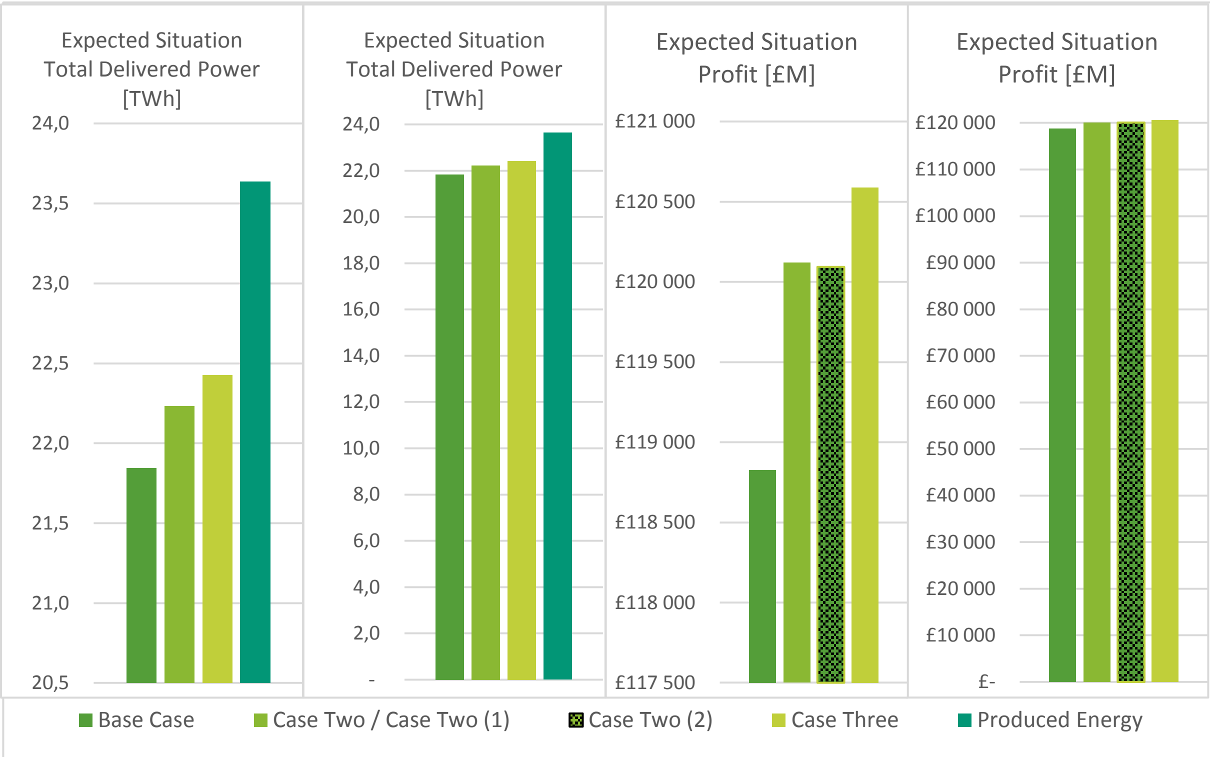


Chart 20: Relative Significance of Changing Layout

The charts show that though the differences in delivered energy are significant, most of the energy is delivered through the project's own connection to shore. This point can also be deducted when looking at the results of the sensitivity analyses of interconnection power rating in the expected situation and in the case where Project 2 has a reduced capacity to shore. The first of these analyses (Chart 14 and Chart 15) shows that the amount of power delivered to shore is hardly changing when the inter-project links' rating increase. This implies that it is not the inter-project links that is the limiting factor, but rather the connections to shore themselves. This further implies that the concurrency of the wind farms has a negative effect for the wind farm owner as well as, for the power system[22]. The second analysis (whose economic part was performed only for Case Three) confirms this by showing (Chart 16) that some more energy is transmitted via the inter-project links, but the total amount of energy delivered to shore is significantly reduced. The fact that much less energy is delivered to shore in this case is a confirmation of the congestion of the links to shore, while the increase in energy transmitted via the inter-project links is a confirmation of

[22] For the power system concurrancy in wind power production is problematic as it leads to very uneven power curves. For wind farms spread over a large area (e.g. globaly) the wind will tend to be spread in a way so that the total production will be more or less constant. The level of concurrancy experienced by Dogger Bank will lead to more volatile power levels delivered to the system.

these links not being congested. These results originate from the fact that for large parts of the time Project 2 will deliver energy to the ring system as its own connection to shore is congested. When for example the production at Project 2 is say 90 % then 40 % will be delivered to the ring system, if all four wind farms deliver the same amount of power from the upstream connection and all connections to shore are available then each of the other projects can transmit 10 % extra and only 10 % of the energy is lost.

Analyses were also performed to investigate the benefit of the HVDC circuit breakers. A sensitivity analyses of the switching time was performed for this situation. In the expected situation with HVDC CBs a 1 hour switching time was assumed and this was also used as a starting point for this analysis. It was found that with a switching time of 1 hour the increase in profit compared to having HVDC CBs installed was £ 450 594 483.00. Operating the system without HVDC CBs therefore appears to be a god solution because the revenue is increased and the risk is reduced by decreasing the investment. When 6 hour switching time was used it was found however that the impact on the economy of Dogger Bank was negative. A loss of £ 1 316 262 573.88 was calculated. The break even switching time, meaning the switching time that leaves the situations with and without HVDC CBs equal, was found to be approximately 2.24 hours. 2.24 hours or roughly 2 hours and 15 minutes is a fairly wide opening in time, so long as there are no overlapping faults, overlapping faults could lead to the need for switching DSs that are far between and the travel time may become a significant factor. Even though two hours should be sufficient to switch the DSs there is always a possibility of some delays particularly due to weather. Should the weather be such that the switching must be delayed regularly the benefit of not using HVDC CBs is lost. Remote operated DSs are also available, and at a lower price than CBs. By using remote operated DSs the switching time can fall to almost zero. A down side to remote operated switchgear is of course that the dependability of the switchgear is reduced.

Because the economic risk is reduced by lowering the investment it seems that not using HVDC CBs leaves the system more economically sound, particularly if the switches can be remotely operated at a low cost. The gain of having zero switching time, which is approximately what remote switching would give, is calculated to £ 814 486 819.64 (neglecting the price of the switches) compared to the case which uses HVDC CB.

An analysis was done to evaluate the benefit of interconnecting the Projects through HVAC connections. This analysis shows that HVAC connections would be beneficial compared to HVDC connections. The impact of choosing AC over DC for the interconnections is found to be approximately equal to the impact of choosing Case Three over Case Two, to the end that Case Two with AC interconnections yields a loss of only £ 37 million compared to Case Three with DC interconnections. When comparing the HVAC case with the HVDC case without HVDC CBs the difference in profit is found to be limited and further studies should be made to evaluate which of these offers the best solution.

In the analysis of AC interconnections an error was deliberately made as the Excel sheet could not handle the added complexity of correcting the error. The error that was imposed is that in the reliability analysis the AC interconnection is connected on the DC side of the offshore converter. The implication of this error is that while in reality the link would be dependent on the availability of the converter station at the receiving end of the interconnection, it is in this case dependent on the availability of the converter station at the sending end. Because this is the case for both (Case Two) or all four (Case Three) interconnections, the total impact of this should be zero.

Even though AC interconnections appears to be more beneficial than HVDC interconnections with HVDC CBs there are some large uncertainties that have not been taken into account for this thesis and that may change the result. First and foremost reactive compensation has not been considered. As the cables are relatively long, the interconnection of Project 1 and Project 2 is 73 km long, there may well be need for compensation which will increase the investment cost and reduce the benefit that is obtained by using HVAC CBs rather than HVDC CBs. A second, potentially significant uncertainty is the electric losses of the system. For short distances HVDC connections usually has higher losses than HVAC connections, because of the added losses in the converters. Because the interconnections in this case are used to feed power into HVDC links the converter electric losses are already taken into account and HVDC inter-project links would be left with much lower electric losses than their AC counterpart. The difference in electric losses leads to the total delivered energy being reduced in the AC case compared to the DC case. Taking into account these two main uncertainties leaves the HVAC solution with higher investment and lower increase in total delivered power compared to what is reflected in the above results, this of course may lead to the HVDC solution yielding the greater profit, or it may serve only to close the gap between the solutions somewhat.

The reliability analyses performed in this thesis do not attempt at evaluating the availability of the system, but rather the delivered energy. As the source of the energy is wind turbines the produced power in each project is normally below rated power. Because the connections to shore are dimensioned for the projects' rated power the system will normally have available transmission capacity to shore, meaning more energy can be transported through the connections to shore without causing overheating in any component. This available transmission capacity could be utilized by other actors in the market, most notably if Dogger Bank is made a node in the envisioned European Supergrid. It has not been considered within the scope of this thesis to evaluate the potential value of such a connection, nor to evaluate the economic impact such a connection would have on the investment cost of the projects in the building phase or in any other phase of the development. However the amount of available transmission capacity has been calculated with the intention of being used as an input to later analyses of such connection schemes.

By subtracting the actual amounts of energy delivered to shore, from the total amount of energy that can be carried through the connections to shore (taking unavailability into account) it is found that approximately 15.77 TWh can be delivered through the connections to shore in the Base Case, 15.38 TWh in Case Two and 15.19 TWh in Case Three. This energy can only be transmitted in periods of sub rated WTG production and is therefore not very flexible. The unutilized transmission capacity over the year is found to be just below 40 % in all three cases which is an interesting point to recognize as the congestion of the connections to shore has previously been discussed. It is clear that most of this available transmission capacity stems from periods with little or no wind, or even with winds above cut–off speed. Because this available transmission capacity is limited in time to mainly periods where Dogger Bank has little or no production it can be assumed that there are price incentives to transmit energy to the UK national grid in these periods and hence a connection via Dogger Bank could have a positive impact. The availability of "available transmission capacity" that can be utilized by a third part will not be sufficiently high to suffice as the only current path for an inter-country cable like for example the proposed cable between Norway and UK.

Analyses were also made to study the impact of the main economic influences, namely the cable price and the interest rate. A ± 10 % change in cable price and a ± 1 % (the interest rate is given in percent) interest rate were studied. The results of these analyses appears at first glance to show no impact of these changes. However there are some differences, though the impact of these changes are insignificant compared to that found in some of the other sensitivity analyses. The impact on the total economy is naturally non-negligible, but the impact on the marginal differences between the layouts is negligible.

For the cable repair time, the cable failure rate and the transformer repair time the same trend is found in the results. All of these show that as the parameter is increased the unavailability of the system increases and the amount of energy that is delivered to shore is reduced. A more interesting observation for this thesis is that as the parameter is increased the difference between the three cases is increased, though the ratio between them remain roughly the same. The implication of this is that Case Three becomes increasingly more beneficial as the reliability of the components is reduced. If the connections to shore were 100 % reliable then all of the produced energy would be transported this way and the inter project links would be obsolete. In this case the total delivered energy would be equal in all three cases. The relative profit of the three cases would however be inversed as unnecessary investments would be made in Case Two and Case Three.

Based on the analyses performed in this thesis it is fair to conclude that interconnection of the projects should not be disregarded in the development of the Dogger Bank zone.

Further work

In the work on this thesis many simplifications have been made, most importantly in terms of electric losses, energy prices and neglecting planned outages. The impact of the simplifications need to be examined in order to evaluate the real value of added interconnections.

The results presented in this thesis show a trend of increasing profit when more projects are connected together although the marginal increase in profit declines. As more projects are planned in the Dogger Bank zone further studies should be made which take into consideration these other projects. Possible layouts that should be considered are for example a ring or meshed system of all Dogger Bank projects. Another possible layout is for example two ring systems.

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