Preferred offshore power grids for wind energy

Master thesis report

Reinout Getreuer
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Thesis committee:
Prof.ir. M. A. M. M. van der Meijden (responsible professor)
Dr. A. Rodrigo Mor
Dr.ing. J. L. Rueda Torres
B. W. Tuinema Msc

Delft university of Technology
Faculty of Electrical Engineering, Mathematics and Computer Science

Department: Electrical sustainable energy
Group: Intelligent Electrical Power Grids
Executive summary

This thesis report is aimed to present a comprehensive approach for the selection of the most preferred grid topology for offshore wind transmission grids (<100 km). Unlike most planning studies of offshore power grids, this approach accounts for reliability enhancement considerations, together with meshed connections, wind-production-price-correlation and dynamic temperature overloading are included. It is tried to combine all these factors into want model.

The general approach in this thesis is based on two merits of offshore power grids. Firstly, at least in the Dutch case study, the design of the offshore power grid starts from a blank sheet paper, enabling the use a bottom up method of reliably analysis. Secondly, unlike onshore grids, the proffered amount of offshore power grid redundancy can be translated to a net present value (NPV) calculation of the lost energy and extra investments (at least, as long as the capacity of individual offshore power grid components are relatively small compared to the onshore installed instant back up power). These two grid properties enable the bottom up approach. The starting point is the radial connections where step-by-step extra redundancy options are added. Firstly the low costs shorter connections that connect two radial connections, then longer connections that connect two times two radial connections and so on and so forth.

The main result that followed form this bottom up approach in this specific case is that the Dutch preferred offshore grid contains only a small number of redundancy improvements. These improvements are located at the beginning of the transmission grid (i.e. close to the wind turbine) at medium voltage because of two reasons. Firstly redundancy improvements at this point have an effect on the biggest part of the transmission grid and secondly because medium voltage gear needs lower investments than high voltage gear. Fully meshed offshore power grids are not beneficial, nor desirable because after initial upgrades the added effect of extra redundancy is unprofitable. It was also found that dynamic temperature overloading does not have a significant effect on the amount of lost energy due to failures in the grid. Finally price correlation can have a profound effect on the preferred offshore grid configuration, but this heavily depends on the type of correlation (i.e. linear, exponential, ect.).
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# List of abbreviations and definitions

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<th>Definition</th>
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<tr>
<td>PV</td>
<td>Present value</td>
</tr>
<tr>
<td>NPV</td>
<td>Net present value</td>
</tr>
<tr>
<td>Coupler</td>
<td>A connection between two points</td>
</tr>
<tr>
<td>Branch</td>
<td>A single radial connection (350 MW in this thesis)</td>
</tr>
<tr>
<td>Branch coupler</td>
<td>Connection between two branches</td>
</tr>
<tr>
<td>Hub</td>
<td>An offshore platform with two branches (700 MW in this thesis)</td>
</tr>
<tr>
<td>Hub coupler</td>
<td>Connection between two hubs</td>
</tr>
<tr>
<td>Designated area</td>
<td>An area designated by government for wind farms (1400 MW in this thesis, unless pointed to be otherwise)</td>
</tr>
<tr>
<td>Designated area coupler</td>
<td>Connection between two designated areas</td>
</tr>
<tr>
<td>MTTR</td>
<td>Mean time to repair [h]</td>
</tr>
</tbody>
</table>
1 Introduction
The number of offshore wind farms that is operational, under construction or planned in northwestern Europa is rapidly increasing. The overwhelming majority of these offshore wind farms are connected with purely radial connections to the onshore grid. Due to, among others, a lack of research into offshore expansion planning, it is unclear if using purely radial connections is the preferred connection type. In this research, the objective is to examine the effect of different offshore grid options to come to a preferred offshore grid configuration. This preferred offshore grid is mainly based on the reliability of the grid and the resulting loss of income. The current Dutch offshore wind plans are used as the study case in this research.

1.1 Current offshore wind plan
Based on the directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the energy use from renewable sources, it has been decided that the Netherlands are obligated to have a renewable electrical energy supply of at least 14% by 2020 [1]. This target set by the European Community (now the European Union) and the European Parliament had the form of a directive. This has two implications. Firstly, unlike official so-called European recommendations and opinions, directives are binding and individual countries are required to comply with its contents. Secondly, unlike European regulations, of which the entirety is directly binding across Europe, a directive “sets out a goal that all EU countries must achieve. However, it is up to the individual countries to decide how” [2]. In the Netherlands, this European directive was worked out in 2013 for the specific Dutch situation with the use of a Dutch agreement called the Energy Agreement [3]. In this agreement, over 40 organizations, ranging from Greenpeace to metal industry employer’s organizations, together set a number of targets. Specifically for the Dutch offshore wind, it was agreed that there would be governmental subsidy for 3450 MW of offshore wind turbines, while the industry would realize a 40% cost reduction for the realization of the offshore wind goals. The targets in the Energy Agreement subsequently, were (and are) largely adopted in legislation by the government Rutte II, which is currently taken through Parliament in different bills and policy papers [4]. In these bills, a number of things have been determined such as the periodization and the location of the wind farms. The tender process for the 3450 MW of offshore wind energy will take place between 2015 and 2019, where these wind farms are expected to be operational starting between 2019 and 2023. In Figure 1, an overview of the designated wind farm areas as proposed by the Dutch government are shown. It can be seen that the Dutch coast is intensively used. The black dots represent oil and gas platforms and the darker blue areas include heavily traffic by ships. Finally, the orange line represents the 12 nautical mile (23 km) distance to shore. Building offshore wind within this area is controversial because of the public resistance against visual pollution. This leaves a relative small part of the Dutch North Sea suitable for (near) offshore wind. The designated areas that have passed all the tests are shown in (light and dark) orange and their individual names have also been indicated. In the first phase (the period between 2019 and 2023), 3450 MW of offshore wind farms will be built. Firstly, 1.4 GW is planned in Borssele and secondly, also 1.4 GW in Zuid Holland. The third and final 700 MW will be built in the Noord Holland area.
The 40% cost reduction of offshore wind is expected to be the result of cost reductions over the whole range of the offshore project. Topconsortium Kennis en Innovatie Wind op Zee (TKI Wind op Zee) has made a calculation [6] of the different reduction posts of which the results are graphically shown in Figure 2. The main cost reductions of 17 and 14 percentage point come from respectively wind turbine cost reduction and policy optimization. The offshore grid and onshore grid connection, where this thesis focuses on, only account for two-percentage point of the total cost reduction. These two-percentage points nevertheless represent (and require) a total cost reduction of € 3 Billion for the total 3450 MW offshore wind connection to the onshore grid. Based on a study by The Crown Estate [7] (2011), which was also used by TKI Wind op Zee, the total offshore grid and onshore grid connection for 3450 MW in the traditional manner will cost about € 18 Billion. This means that enabling € 3 Billion of cost reduction is only possible if the total costs of the transmission grid are lowered by 20%. TenneT has been appointed as the offshore grid operator because it is assumed that this improves the chances of making a € 3 Billion cost reduction.
Now the current Dutch offshore wind plans have been defined, the next step is to determine what defines a preferred offshore power grid. To do this, it is firstly necessary to determine which actors play a role in the definition of the preferred grid, and what their interests are. This will be examined in this section.

1.2 Offshore wind actors

The choice for an offshore grid configuration affects a number of actors. These different actors are graphically summarized in Figure 3. In this figure, on the left side the wind farm owners are depicted, who mainly want to maximize their profit, and on the right hand side are the energy consumers (both private and commercial who are shown as circles with crosses), who want the lowest possible energy costs while maintaining the highest possible security of supply. Between these two parties sits the TSO, who is obligated to connect the former and the latter and is allowed to charge both parties for doing so and to cover the system costs. The TSO owns the transmission grid. This was already the case for the Dutch onshore grid but in the near future also for the Dutch offshore grid. Next to these direct actors there is also the more general social economic interest, which should normatively be represented by the national parliament and carried out by the government. Other actors like non-governmental organizations, different forms of media or the public opinion could be investigated individually but are here seen in line with the parliament and government. Whereas the interests of the wind farm owner and energy consumer are quite clear and straightforward, this is much less the case for the political social-economic preference of the offshore grid. From this perspective, politicians should strive for high energy profits, cheap energy and high security of supply, but also strive for national goals that are less appealing, relevant or beneficial to the individual wind farm owner or energy consumer. Important national goals could be the lowering greenhouse gas emissions, stimulating new technologies, improving the national outlook or reducing national anxiety.
1.2.2 Interests

Now the main actors have been defined, their precise preferences and mutual cohesion will be explained. Building a wind farm is very costly and the wind farm owner wants to earn back this money. For that reason, the wind farm owner should be seen as an investor who wants to maximize his economical return. Other drives could be pointed out like the improvement of the public opinion of the investing company or pension fund. An example could be the participation of Royal Dutch Shell in several offshore wind projects [10]. While the latter drive might be a very real one, it is hard to integrate into a model. For that reason, the wind farm owner(s) preferred grid configuration is assumed to be based on maximizing profit. If a wind farm owner would pay for its own connection to shore, this would result in a healthy tradeoff between higher availability and lower costs of the connection. The problem is complicated though, because the connection to shore (i.e. the offshore grid) will in the current plans not be built and paid for directly by the wind farm owner but by the TSO who subsequently charges all grid users for the total (on- and offshore) grid cost. For this reason, the wind farm owner is not overly concerned about the grid costs because the grid costs are split over millions of transmission grid users. The wind farm owner thus prefers the highest possible availability (i.e. he would urge for overinvestment).

As has been pointed out, the energy consumer has two interests, cheap energy and high security of supply. The preference for the as inexpensive as possible energy is fulfilled when the TSO makes the right tradeoff between unavailability and investments. The comparison of these interests is simply a financial calculation. The integration of the security of supply is not so straightforward, since it is complicated to quantify. Because there are (at least for now) no consumers in the offshore grid, failures of the offshore grid will only affect the wind farm operators. Due to the relatively small power level of the maximum
component size (a maximum of 350 MW for a single component in the current plans), with about 3 GW of instant backup power in the European power system, offshore failures are not likely to cause a significant risk for the onshore power supply. Tuinena [11] (2015) also points out another argument to back this assumption. He states that all kinds of power imbalance in the onshore grid (like load prediction, wind prediction and generation adequacy) have a much more profound effect on the security of supply. In comparison with these imbalances, the unavailability of the offshore grid is insignificant.

Next to the direct preferences for the offshore grid, there are also indirect preferences that influence the social economic preferred offshore grid choice. Like mentioned before, these could be things like lowering greenhouse gas emissions, stimulating new technologies, improving the national outlook, reducing national anxiety or decreasing the national foreign dependence. To include these factors into the calculation of the social economic preferred offshore grid, it is necessary to quantify them. To do this, the value of electricity generated by wind power is increased (or the value of other generation types is decreased), thus favoring the production of wind energy. The society (consumers and/or government) basically set a bonus on the market price. In economic theory, this extra on-top-of-the-market price for wind energy could be added by the free market itself. An example of this could be the willingness of consumers to pay more for their electricity if it is wind energy [12]. In practice, governments increase this market price bonus even further. This is mainly done in two different ways. It could be a subsidy (paid to for example the wind farm owner or the TSO) but also a quota or fine on for example carbon emissions. The government can imply these incentives and disincentive on a whole range of manners and places. For this research, it is of importance to recalculate them to an increase of wind energy price.

The governmental incentives to lower greenhouse gas emissions are already in place in the form of NOx and CO2 emission allowances. These allowances have increased the price of conventional generation types. A future increase in the price of greenhouse gas emissions, which is expected by experts, would increase the generation cost of fossil fuels. As wind energy can be seen as zero added marginal costs production type, or as low as 5 to 20 eurocent per MWh [13], it is expected to take a wholesale price at the marginal generation costs of conventional electricity generation. In that sense, future expected increases in the greenhouse gas emission allowance prices could be added to the market energy prices. In this way, greenhouse gas emission allowances have a direct positive effect on the profitability of wind turbines. Governmental subsidies that for example guarantee the MWh price at a fixed high level increase the profitability even more directly.

In Table 1, the different possible preferences for different actors have been summarized. For every preference, a level of assumed effect can be defined. Effects with a high priority are for example the maximization of profit for the wind farm owner(s), and cheap energy for the consumer. For the national social preferences, the reduction of greenhouse gasses has been indicated as high. The drive to stimulate new technologies and to reduce foreign energy dependence are also big motivators for stimulating renewable energy sources. While these arguments do allow the government to spend some public money as subsidies, relatively the amount will be much smaller than for the direct reduction of the emission of greenhouse gasses. There is off course interdependence between the different preferences. The subsidies to stimulate new technologies for example, could also be seen as subsidies for lowering greenhouse gas emissions or the foreign energy
dependence or even to increase the national outlook. These preferences have been split here though, to become aware of different initial targets.

<table>
<thead>
<tr>
<th>Actor</th>
<th>Interests</th>
<th>Assumed effect</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind farm owner</td>
<td>- Maximization of profit</td>
<td>High</td>
</tr>
<tr>
<td>Consumer</td>
<td>- Low energy prices</td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>- High security of supply</td>
<td>High</td>
</tr>
<tr>
<td>TSO</td>
<td>- Harmonization of different interests (all players are equal)</td>
<td>-</td>
</tr>
<tr>
<td>Parliament/government</td>
<td>- Maximization of profit</td>
<td>Medium</td>
</tr>
<tr>
<td></td>
<td>- Low energy prices</td>
<td>Medium</td>
</tr>
<tr>
<td></td>
<td>- High security of supply</td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>- Lower greenhouse emissions</td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>- Kick starting new technologies</td>
<td>Medium</td>
</tr>
<tr>
<td></td>
<td>- Improving national outlook</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>- Lowering (national) anxiety</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>- Lowering foreign dependence</td>
<td>Medium</td>
</tr>
</tbody>
</table>

Table 1, table with actors, interests and their relevancy

Based on the assumptions in Table 1, it can be seen that there are four main priorities regarding offshore wind energy, namely maximization of profit, low energy prices, high security of supply and lowering greenhouse emissions. It has been explained before that the unavailability of the offshore power grid of wind energy forms no real threat for the security of supply of the onshore grid. This leaves a problem definition where maximization of profit, low energy prices and the lowering of greenhouse emissions are the main criteria to come to the social-economic preferred offshore grid. The three criteria have been shown graphically in Figure 4. In this research, it is assumed that the TSO strives to build this social-economic preferred offshore grid.

Figure 4, the main parameters defining the preferred offshore grid configuration.

1.3 Thesis objective
Based on the current Dutch offshore wind plan and the offshore wind actors it is possible to define the main research question. This question is: “What is the social-
economic preferred offshore transmission grid for wind energy”. The different parts of thesis question should be interpreted as follows:

1. The “offshore transmission grid for wind energy” refers to transmission grids for wind energy in general and specifically to the Dutch situation as was explained in 1.1 Current offshore wind plan.

2. The use of “preferred” in this research has two reasons. Firstly, the here proposed grid is the best of the options given, but since there are an infinite number of grid possibilities, and this thesis does not use an optimization process, the final grid cannot be called the optimized offshore grid. The second reason for preferred is to take a broader range of parameters into account. Not just hard economic values will be taken into account but also social-political preferences like the lowering of carbon emissions.

3. The social-economic part should be seen as the best grid for the society as a whole instead of just a limited number of actors.

The three different parts (maximization of profit, cheap energy and low carbon emissions) of the multicriteria analysis pointed out in Figure 4 are integrated with the use of a net present value (NPV) calculation for the different offshore transmission grid configurations.

1.4 Outline of this thesis

The outline of this thesis is as follows. In chapter 2 (Literature study), the current state of the art research concerning offshore (meshed) power grids and related topics are examined. In chapter 3 (Offshore grid configuration), the general topology of offshore power grids is taken apart and it is tried to thoroughly define the possible options and upgrades. In chapter 4 (Data collection), the component parameters ranging from failure statistics and capacities to thermal time constants and component costs are defined and also other economic parameters, like the energy price are assessed. In chapter 5 (Socio-economic reliability model), the complete thesis methodology is split up into different blocks, which are individually explained. In chapter 6 (Modeling), the reliability analysis model is put together and explained. The chapter 3 to 6 will finally lead to chapter 7 (Results), where the results of the proposed configurations from chapter 3 are discussed. Chapter 8 (Conclusions) then presents the conclusion of this research, after which chapter 9 (Recommendations & future work) goes into the interesting topics and relevant future work based on the research and conclusions in this thesis.
2 Literature study

2.1 Introduction
Offshore wind energy is a very hot topic in northwest Europe, both from an industrial as from an academic point of view. This is not very surprising when one takes a look at the long list of offshore wind farms that are either already built, under construction or planned. The main growth areas are Denmark, Great Britain and Germany, but also The Netherlands is part of this transition. This interest has led to a tsunami of papers on seemingly all aspects of offshore wind energy production, though the meshed grids seem to be an exception to this rule. The literature study first goes into the Energy production of wind farms. Secondly, the energy losses in the offshore networks that are handed by the literature are examined. Thirdly, the possible offshore configurations are discussed. The final two parts of the literature study are going into the overload capability of components and the possible correlation between energy prices and wind energy.

2.2 Energy production of wind farms
The maximum wind energy potential that could be produced at a certain location is mainly the result of the wind turbine type and the wind speed spectrum at the location of installation. This theoretical maximum is lower due the limited availability of the wind turbines and the wake effect. Since it is not the core of this thesis to calculate the offshore wind farm energy production, only a few of the many useful papers on wind farm energy production will be presented here.

Ali (2012) [14] presents a complete overview to come to the annual energy production of a wind farm. The starting point is the energy that wind consists of. The potential energy that can be harvested by a wind turbine can be calculated as:

\[ P_{wt} = 0.5 c_p A \rho v^3 \] (1)

Where
- \( P_{wt} \): power produced by the wind turbine [Watt]
- \( c_p \): overall efficiency of the wind turbine
- \( A \): swept area of the rotor [Meter²]
- \( \rho \): air density [Gram/meter³]
- \( v \): wind speed [Meter/second]

In Formula 1, the overall efficiency \( c_p \) and the swept area \( A \) are fixed parameters for a specific wind turbine. The air density \( \rho \) can vary by around 20% but is otherwise relatively easy to measure. The wind speed on the other hand is much less constant. In Figure 5, the wind speed variation over a 330 second plot is shown and in Figure 6, the speed variation is shown over an 8760 hour plot (one year).
Figure 5, varying wind speed in meters per second over a 300 second period [15]

Figure 6, varying wind speed in meters per second over a 8760 year period [16]

It can be seen from Figure 5 and Figure 6 that the wind speed does vary strongly over both short and long periods of time. This strongly varying wind speed is problematic because it makes it very hard to define an average wind speed that can be used to calculate the available wind power. When the varying wind speeds are shown as a spectral density the result is much clearer though. This has been done in Figure 7 where the spectral density, which is approximated by the Weibull curve, is represented in blue. It can be seen that this curve is now smooth and predictable. In red, the same figure gives the power production of a specific 2 MW wind turbine at different winds speeds. A wind turbine is only operational above the cut-in speed and below the cut-out speed, usually between approximately 3 m/s and 25 m/s. In Figure 7, the power output of a single wind turbine is shown. Below the cut-in speed the wind energy potential is too low to produce any energy. Above a certain wind speed (usually somewhere between 10 and 15 m/s), the wind turbine is put in a sub-optimal position due to the limited power rating of the generator. Between these two points, the produced wind energy is equal to $P_{wt}$. Above this wind speed, the energy output is constant and maximal. When the cut-out wind speed is reached, the windmill is switched off entirely for safety and protection. From the combination of the probability density function of the wind speed and the power curve in steady wind in Figure 7, it is clear that the total amount of lost energy from above the cut-off frequency is not very significant.
The red power curve shown in Figure 7 is the perfectly clean power output of a single wind turbine as a result of a certain wind speed. Ackermann (2012) [18] explains that when single wind turbines are put together in a wind farm, the individual turbines experience a drop in wind speed that could be formulated as a function of the individual spacing between the wind turbines. Barthelmie (2007) [19] Ali (2009) [20], Schallenberg-Rodriguez (2013) [21] and Samorani (2014) [22], among others, have made extensive analyses of the wake effect and put them in accurate models where they include all sorts of parameters like exact position of turbines, wind direction, turbulence coefficients, and more.

On the left hand side in Figure 8, the general effect of spacing on the efficiency ($\eta_{arr}$) of wind farms is shown. It can be seen that placing wind turbines closer together has a negative effect on the efficiency of the wind farm. The reason for this drop in efficiency is explained with the use of the wind roses of individual wind turbines in a wind farm on the right hand side of Figure 8. The wind speeds in Figure 8 are 10 m/s from every direction but due to the wake effect, the wind speed is not experienced as 10 m/s for every wind turbine from every direction. This leads to a distortion of the power output curve as was shown in Figure 7. In Figure 9, the comparison of the
power output of a single turbine (black) and a wind farm (red) is shown. The main result of the wake effect is that the rated power of the wind farm is now not reached at 15 m/s but at a higher wind speed. Also the cut-out wind speed is now not a clear point but a range from 20 m/s to 30 m/s, which is the result of different turbines experiencing different wind speeds and thus reaching their critical cut-out speed at different general wind speeds.

Based on the spectral density wind power shown in Figure 7 and the wind farm power curve shown in Figure 9, the total power output of an offshore wind farm can be estimated.

2.3 Energy losses in offshore networks

When wind energy is generated offshore, it has to be transmitted to the onshore grid. Figure 10, taken from Schoenmakers (2008) [25], gives an overview of the total energy flow from the wind turbine to the onshore grid. Firstly, the blue text is the input (energy production) and could be seen as the ideal case. Secondly, the green text is the amount of energy that is actually delivered to the onshore grid. Finally, the red text indicates the various loss mechanisms.

In Figure 10, as seen from the offshore substation, different loss mechanisms affect the total amount of energy delivered to shore. Firstly, a number of electric transmission losses could be pointed out. The biggest part of the losses is due to the cables, but also the transformers (both off- and onshore) and the compensation coils result in losses. These losses are the result of the resistance of the power cables and also copper and iron losses in the transformer. In a radial grid, the calculation of the cable losses is rather straightforward. As Ali explains, the computation of the collection grid losses is complicated by more complex connection topologies and even more by redundancy in the collection grid. The second loss mechanism is the result of failures. Every component in the transmission system has certain
unavailability. Depending on the grid configuration this leads to a particular amount of not-delivered energy to shore. Thirdly, and much in line with the unavailability due to failures, a certain amount of time is needed to maintenance the different components. This also leads to a certain amount of lost energy.

2.4 Offshore configurations

The core of this research is to come to the preferred social-economic offshore power grid. The starting point then is the different offshore grid configuration options. Matevosyan [27] shows that reinforcing the onshore transmission grid to match extreme combinations of offshore power production and onshore transport is not always the financially optimal option. Curtailment or temporarily overloading of network components could be financially beneficial. Ali (2009) [28] comes to a similar conclusion. Both papers start to calculate the amount of lost energy (in this case due to under-dimensioned transmission lines). Subsequently, they calculate the value of the lost (curtailed) energy and the costs of transmission grid reinforcement and then choose between the two options for the lowest (social) cost, using the net present value (NPV) of the grid reinforcements.

Studies with a binary conclusion, pro or con grid reinforcement, show that refraining from investments could lead to financial benefits. The next step is to come from binary options to a transmission grid analysis with numerous possibilities or even a full optimization. A number of papers have been written on this topic but most of the studies focus on High Voltage Direct Current (HVDC) technologies for the transmission grid, like for example Bresesti (2007) [29]. The general calculation of preferred HVDC and HVAC grids is generally the same. HVDC has a much longer range though, which is why a significant part of these HVDC papers focus on fully meshed North Sea grids as an option. An example of such a paper is Huertas-Hernando (2010) [30].

Wright (2002) [31], Schoenmakers (2008) [32], Stoutenburg (2010) [33] and González (2013) [34] do focus on HVAC and present methodologies for designing the transmission system for large offshore wind farms. In the master thesis of Schoenmakers a very broad overview of different relevant aspects is given, but component failure analysis are excluded accordingly due to a lack of data on failure rates and repair times. González uses a Monte Carlo optimization process, which integrates investment costs, risk and cost of losses neatly in to one calculation. All three studies are limited to radial connections though, leaving out the possibility of a meshed grid.

The studies by Kling (2004) [35], Tuinema (2010) [36], The Crown Estate (2011) [37] and Tuinema [38] (2015) all do include a meshed grid analysis. Kling approaches different technologies (AC and DC at different power and voltage levels) from three sides. Firstly the energy losses, secondly the investment costs and thirdly the effects of large-scale wind energy on the security of the onshore grid. Where Kling succeeds in analyzing the three different offshore power grid issues, he fails to integrate the perspectives into one conclusion. Tuinema (2010) does manage to integrate the first two perspectives pointed out by Kling (the lost energy and investment costs) by making a general cost assumption for the lost electricity. Though Tuinema focuses on the lowest community costs he does point out that “the choice for an offshore network (…) also [depends] on other factors like economic and environmental constraints”. In a more recent study, Tuinema (2015) presents a more complete offshore grid analysis. He defines a number of possible wind farm-to-shore connections (i.e. direct connections and different grid configurations with a hub-at-
and calculates the different least costs for this perspective. Tuinema also goes into the effects of the offshore grids for the onshore grid reliability where he shows that the occurrence of power imbalances caused by failures of the offshore grid is generally less severe than power imbalances caused by load and wind predictions and generation adequacy. Finally, the study by The Crown Estate that was published in 2011 can be seen as one of the more far-reaching and complete researches on offshore power grids. In the research, different future scenarios of the total amount of British offshore wind farms are taken into account and connected to the onshore grid with different connection strategies. Here, a distinction was made between radial, radial+ and coordinated offshore grids. These three different design strategies are graphically shown in Figure 11. In this figure, it can be seen that the coordinated design strategy refers to an offshore meshed grid where the reliability of the grid is taken into account. The conclusion by The Crown Estate was that coordinated offshore grids could indeed improve the total operation of the offshore grid in terms of the NPV of the grid choice.

![Diagram showing different design strategies](image)

Figure 11, different design strategies as where defined by The Crown Estate study [39].

Next to these specific case studies, Nedic (2011) [40] and Ergun (2012) [41] discuss methodologies and software tools to come to the optimization of meshed offshore power grids in terms of costs. Two main conclusions can be made about the current state of research concerning offshore grid configurations:

1. Firstly, there has not been much focus on the effect of meshed offshore power grids. This points out the necessity for further study.

2. Another conclusion from the literature is that it is rather difficult to study meshed offshore grids. For that reason, researchers mainly study radial network or simple meshed networks. Fully meshed offshore networks (i.e. networks that connect different countries) are difficult because one has to consider the markets of the connected countries, but also the social costs of the different countries. Moreover, if one studies failures of the meshed
offshore network, there are more possible effects such as price differences between countries.

2.5 Grid configuration technologies
To find the preferred offshore power grid in social-economic terms, the grid options are the starting point. As explained by for example Gonzalez (2013) [42], the choices for AC or DC, system voltage, component power capacities, cable technologies, redundancy and mesh options ultimately determine the cost of a certain configuration.

2.5.1 AC or DC
Unlike HVAC, HVDC does not have strongly increasing power losses with increasing cable lengths. HVDC systems are still much more expensive than HVAC systems and also less reliable [43]. This combination of higher costs and lower power losses result in a certain breakeven point between HVAC and HVDC when the length of the offshore power cables is increased enough. Kling (2004) [44] states that this breakeven point lays beyond 60 km whereas Alegría (2009) [45] and Barberis Negra (2006) [46] put it at 50 km and Fischer (2012) [47] at 120 km.

Among others, Fischer (2012), Ackermann (2012) [48] and Domínguez-García (2012) [49] pointed out that instead of having a binary choice between 50 Hz and 0 Hz (i.e. DC), it is also possible to operate at other frequencies. Fischer for example shows that running the transmission grid at 16.7 Hz instead of 50 Hz has a huge effect on the power transmission capacity. Were a fully compensated 50 Hz AC cable has a maximum range of about 120 km, 16.7 Hz fully compensated cables could be used up until 400 km with reasonable losses. Much like the choice between HVAC and HVDC the distances to shore in this study are significantly shorter than the critical offshore cable length of 50 Hz cables. Another advantage of lower frequencies is the reduced impact of the skin effect. The reduction of this effect leads to a lower (electrical) resistance, which either lowers energy losses in the cable or makes it possible to use less copper and thus have cheaper cables. Domínguez-García shows that the cable cost reduction due to lowering the operation frequency from for example 50 Hz to 15 Hz are significant and can be up to 20 to 25 percent.

The lower cable costs are totally annihilated by the increasing costs of other components though. This is partly the effect of non-standardized components. Apart from a few railway systems there is not much industrial standardization at lower operating frequencies (or strictly speaking, between 50 and 0 Hz). A second problem is the increased size of other components (like for example the transformers) when the frequency is lowered. Domínguez-García concludes that lower operating frequencies are not beneficial for offshore grids. He even states that higher operating frequencies (100 Hz for example) could actually be beneficial when there is very limited space on the offshore platform. But also for higher frequencies, the lack of standardization leads to high component prices. In conclusion, using lower frequencies in the offshore power grid is not beneficial in minimizing the overall social cost due to the curse of standardization.

2.5.2 Voltage level
As can be expected, different voltage levels can be used for the offshore power cables. The choice for certain voltage levels is mainly the result of power losses due to cable resistance and losses in other components, failure rates and repair times of the cables at certain voltage levels and the investment and operation costs of the
complete system at a certain voltage. Much like the choice for the AC frequency, it is indirectly again the industrial standardization that plays a key role. Voltages used by for example Kling (2004) and Tuinema (2015) are the 150 kV and 220 kV transmission voltages. Also the offshore 380 kV transmission standard is now available for a 3x single core offshore cable connection.

2.6 Overload capability of components

Next to the different grid configurations and voltage levels, also the overloading of components can improve the socio-economic performance of offshore power grids. A power grid always has to fulfill a number of constrains. The absolute voltage for example should always be between $V_{\text{min}} < |V(t)| < V_{\text{max}}$. In the same way there is a maximum temperature for every single component. Wadman (2012) [50] points out that at all times $T(t) < T_{\text{max}}$ should hold for all components, otherwise the aging process of these components is sped up greatly. In practice, this requirement is generally satisfied by constraining the maximum current to $|I(t)| < I_{\text{max}}$, were $I_{\text{max}}$ is the rated current of the component. This is a save and also easily implemented constraint, but as Wadman explains, it does lead to a certain over-demonetization of the system. This is the case because exposing a component to a current above the rated value will not directly result in a failure. When the $T_{\text{max}}$ is reached, only an increased failure rate occurs. Due to thermal inertia of components, the temperature level will always lag behind the current level. This time lag enables the overloading of components, which in turn could lower the needed level of redundancy or limit the size (in terms of power) of the components. To put it in other words, the constraints on the temperature are weaker than the constraints on the current.

The disadvantage of using the temperature constraint (and thus allowing overloading) is that new and possibly more complex safety regulations are needed. The maximum currents are based on extreme scenarios, peak temperatures in summer with peak usage of the component for an extended time. These temperatures are seldom reached and besides that components are not always used at their peak power. Due to these two factors, using temperature measurements can have a very profound effect on the transport capacity of components. This advantage does come at a cost though: it requires a complex system of temperature sensors. For that reason, it could be more practical to determine the cable temperature based on premeasured component properties and the (passed) current levels. The ambient temperature could be taken into account but also taking a maximum ambient temperature would suffice (this will off course limit the effect of overloading).

The Kema Prego report comes with the most straightforward solution for cables. It reasons that the usage of a general onshore power cable shows a daily pattern, a claim that is supported with the graph in Figure 12. The cable is only fully used for one or few hours a day (in the figure 4 at 9 o’clock) and thus has enough time to cool down during other parts of the day. Since the thermal parameters of the cable are often determinable, it is possible to increase the peak current by 22% for one hour. Since the relationship between current and power is linear, this also results in a 22% present increase in peak power.
2.7 Energy price correlation

The final effect that will be discussed in this literature study and that can have an effect on the social-economic preferred offshore grid is correlation between the wind speed and the energy price. Most studies addressed in the section This also leads to a certain amount of lost energy.

Offshore configurations use fixed energy prices. The goal of this research is to find the socio-economic preferred solution. The introduction of real-time fluctuating electricity prices could have a profound effect on the preferred grid choice. When the situation is simplified, it becomes much easier to predict the effect of a significant amount of wind energy in a power system.

As an example a node with a constant demand that is (relatively) isolated and heavily penetrated by wind energy, but otherwise completely supplied with the use of flexible fossil fuels is considered. This node has been shown in Figure 13. In this figure on the left hand the offshore wind farms are shown. On the right hand side (located on the island itself) the energy consumers are depicted as circles with crosses. With no wind, the energy is completely produced by the conventional (fossil) energy producers and presumably profitable. When the wind picks up, wind farms start to put up bids for electricity delivery. Since the conventional producers will try to maximize their profit, they keep trying to sell their energy up until the price reaches the marginal cost of the conventional producers. The wind farm owner has a marginal cost of almost zero and thus keeps placing lower bids. When the wind penetration reaches a hundred percent of the electricity demand, wind farm owners will keep lowering their biddings until the conventional producers finally stop their production. So, in the very special case of exactly hundred percent wind production, the energy prices are assumed to drop to the marginal cost of the cheapest conventional producer. This effect can actually be even stronger when it is costly or even impossible for the conventional producers to lower their energy production below a minimum production level, for example in the case of coal or nuclear power plants. This might actually lead to electricity prices below the marginal production cost of the cheapest conventional producer at hundred percent wind production. Even negative energy prices could occur in that case.
In reality, this simple principle of supply and demand economics is much less straightforward due to a number of reasons. Most importantly, nodes are not isolated, especially not in the Netherlands, which results in a large area with converging electricity prices. Munksgaard [51] (2008) turns cause and effect around. He states that as long as there is enough transmission capacity, the energy price in the isolated node will not have an increased energy price. So does the level of wind penetration have an (real-time) effect on the energy prices? The literature is not unambiguous on this topic, but the conclusion depends much on the perspective of the auteurs.

Writers like Bathurst [52] (2002), Matevosyan [53] (2006) and Pinson [54] (2007) approach the energy prices from the individual wind turbine or farm owner. In that perspective, they conclude that the energy producer does not have an effect on the (day ahead) electricity market prices. These prices are the result of supply and demand. The production of an individual owner is the result of a non-controllable entity (i.e. wind) that could be seen as a random input. The (day ahead spot) energy prices do have an effect on the owner’s earnings but as long as the energy prices are positive, it has no effect on the energy production of the wind turbine owner. This is strictly speaking certainly true but not of much relevance. Up until approximately 2010, there were not many areas with a high penetration of wind energy, which is why most early studies on this topic focus on a region with locally high wind penetration: the Nordic area. An early study by Morthorst [55] (2003) on a relatively isolated node with twenty percent wind energy of the total energy production suggests that there is some, but hardly significant correlation between the amount of wind energy and energy prices. His explanation is as follows: “Many partly exogenous factors influence the price determination at the spot market in the short term and therefore it is difficult to single out one factor as the most important one influencing the spot power price in the short run”. To put it in other words: so many factors are of influence on the spot price market that it is difficult to point out the most important one. Skytte [56] (1999) comes to a similar conclusion.

More recent studies by El-Fouly (2007) [57], Munksgaard (2008) [58], Jonsson (2010) [59], Morales (2011) [60] and Kakhki (2013) [61] Nazar (2013) [62] do show a stronger correlation between wind energy production and electricity prices. Munksgaard, based on the in Danish written work of Enevoldsen (2003) [63] states that the correlation between wind energy production and energy prices is truly significant, but only during the day. During the night, Munksgaard agrees with Morthorst’s conclusion. El-Fouly’s conclusion is more general. He states that the effect of wind energy production “is very small for the periods with low demands”, but
rather strong during high demand. The paper by Nazar shows a strong correlation between electricity spot prices and wind power. With the use of a simple linear regression he shows a negative correlation of 0.57 as can be seen in Figure 14.

![Figure 14, correlation between price and wind generation in DK-1 region [64].](image)

Beside a relatively strong correlation, Figure 14 also shows three other things. Firstly, the standard deviation is quite large. This is probably the result of what Morthorst depicted as "many factors are of influence". Secondly, this standard deviation seems to change for different wind power penetration levels. For low and high penetration, it is relatively small and between those two points the deviation is maximum. The third point that could be made is that the regression is not clearly linear. Jonsson also raises this issue. He enforces the conclusion that "wind power has a non-negligible impact on day-ahead electricity prices". Next to this, he also shows that the correlation is far from linear. Jonsson is able to extrapolate different price distributions for different penetration levels. Not just the mean energy prices, but also the standard deviation, skewness and kurtosis, depends on the percentage of wind energy. Jonssons results are shown in Figure 15.
Jonssons approach is very useable in this research. Different price distributions for different penetration levels of wind energy could be integrated in the calculation of the preferred offshore power grid. Jonssons results on their own are not useable though, because they are based on the Danish transmission system. The Dutch system is much less heavily penetrated by wind energy and is also more integrated with the surrounding transmission grids. Since no studies on the Dutch (future) correlation between wind penetration and real time electricity prices were found, it might be useful to make an assumption for the price distribution. This could be done based on different future scenarios with subsequently different assumed correlations.

A number of statements about wind energy price correlation can be made:

1. For a certain wind penetration, wind energy production price correlation can certainly be expected to occur.
2. This correlation can actually be quite strong.
3. Also, it does not have to be linear, but could for example be exponential.
4. The standard deviation of the correlation is very large though, which explains why early studies did not find a significant correlation.
5. Finally, the wind energy price correlation heavily depends on the total amount of wind power and the interconnection of the node or regional grid with surrounding areas.

In short, it can be said that wind energy price correlation is a parameter that should not be ignored in the design of offshore power grids. At the same time, it is hard to really integrate the correlation parameter in a realistic and accurate manner.

Figure 15, distribution of prices for different levels of forecasted wind power penetration.
3 Offshore grid configuration

3.1 Introduction
As was explained in chapter 1, the Dutch government has set a target to increase the total offshore wind power by 3.5 GW peak by the end of 2023. In Figure 16, current technologies and possible future options of placing and connecting offshore wind are shown. Currently, most offshore wind farms in the Netherlands are connected with the use of 150 kV HVAC radial connections between 10 to 25 km from the shore. Whereas the definition of nearshore wind energy depicts an distance of up to 10 to 15 km [65], also the 25 km to shore can been seen as relatively close to the onshore grid. In Figure 16, these wind farms are shown in blue. Other options of connecting the offshore wind farms are also shown in Figure 16, and are HVAC meshed grids and HVDC radial or meshed grids. In this chapter, the different options for the offshore grid connections for the 3.5 GW peak Dutch target will be examined. Ultimately, this chapter presents a list of possible configuration options.

3.2 Offshore grid concepts
The obvious primary function of the offshore grid is to transport the generated offshore wind power to the consumers, connected to the onshore grid. To achieve this goal, the electrical energy needs to be collected from the individual wind turbines and transmitted through the sea to the onshore grid. Before going into the different possible grid configurations, it is useful to clarify a few basic concepts. The concepts addressed here are the “collection grid”, “radial connections”, a “Branch”, “meshed grid”, a “Hub”, and “Designated areas”.

![Figure 16, different options for the Dutch offshore wind and grid connections](image)
3.2.1 Collection grid
Apart from a few very near-shore marine wind turbines that are individually connected to the onshore grid, the topology of an offshore wind transmission grid starts with a collection grid. This grid connects the individual wind turbines in the wind farm to a central connection point. In Figure 17, an aerial view of the Dutch offshore Princess Amalia wind farm is shown. If one looks closely, a white object can be seen between the fourth and the fifth row from the right. This is the central connection point where the strings connecting the individual wind turbines come together. A string is typically a medium voltage cable with ten up to twenty wind turbines that are directly connected to the cable. At the central point, the voltage is transformed from medium to high voltage after which one cable is used for the connection to the onshore grid. The advantages of the use of a central connection point are significant. Firstly, far less material (cable) is needed because the average length of an individual turbine connection is greatly reduced, for example from 15 km to the onshore grid to 1 km to the connection point. This has a direct positive effect on the overall costs of the network. A second advantage is that the connection point can be used as a transformer location where the voltage is increased. A collection grid could for example be made at 36 kV where the voltage after the central connection point is transformed up to 150 kV. This results in lower transmission losses and also enables the use of smaller, or fewer transmission cables because of the higher transport capacity of higher voltage cables. This again results in a financial advantage that usually far outweighs the higher costs of higher voltage gear.

Figure 17, aerial view of wind park Princess Amalia [66].

3.2.2 Radial connection
When the individual wind turbines are connected to the central connection point, the central connection point has to be connected to shore. The most straightforward way to connect the planned 3.5 GW of peak offshore wind power would be to create individual (radial) connections for every wind farm. In Figure 18, the schematic of a radial connection is shown. On the left side of the schematic, the individual wind turbines are shown which are connected to the transformer at the central connection point. This transformer is subsequently directly connected to the transformer that transforms the voltage to the 380 kV of the onshore grid on right of the scheme. A typical radial connection only consists of a single path. Currently, most offshore wind farms are realized in this way. Examples of these kinds of connections are the Princess Amalia [67] and the Eneco Luchterduinen [68] wind farms, off the Dutch coast. Both connections are HVAC at 150 kV and have installed capacities of respectively 120 and 129 MW.
3.2.3 Branch
Further on in this thesis, a “branch” will refer to a radial connection from the offshore central connection point to the onshore grid. In the current planning, every offshore platform will accommodate the offshore central connection point of two of those branches. This means that the offshore substations of the branches that are located on the same platform are separated by no more than 20 to 30 meters. The word branch is used because it is possible to couple two branches creating a non-radial configuration.

3.2.4 Meshed grid
As was just explained, the coupling of two branches creates a non-radial configuration, which is called a meshed grid. A meshed grid, by definition, has two or more parallel paths between (parts of) generation and load nodes, unlike a radial connection where there is only a single connection between the generation node and the rest of the network. The step from radial to meshed grids has a number of implications for the network. The first one is that the multiple paths between generation and load nodes create some level of redundancy. On the other hand, it makes the operation of the grid more complex.

3.2.5 Hub at sea concept
The offshore platforms that will allocate two branches are called hubs at sea, or just hubs. The hub concept has been proposed by TenneT to add to the governmental goal of reducing the costs of offshore power grids by 40 per cent. In principle, a hub is an offshore substation. The main difference between a central connection point, as was described before, and a substation is that the latter one is able to switch between different lines and connections. In a central connection point, it is only possible to connect or disconnect the entire connection. For this reason, the offshore substations (hubs) enable operation of meshed grids. The schematic of an offshore hub has been shown in Figure 19 where the branch couplers are represented as dotted lines.

The hub at sea concept can have a number of advantages:
1. Firstly, the standardization of the complete 3.5 GW Dutch offshore project should lead to considerable cost reductions.
2. Secondly, due to the hub concept, it is possible to couple the individual branches increasing the redundancy of the offshore grid.
3. Thirdly, due to connection of several wind farms to one offshore hub, fewer cables to shore are needed. Now only one offshore cable per 700 MW is needed instead of one cable per 120 MW in the case of for example the Princess Amalia farm. This reduces cable (laying) costs and also lowers the amount of needed material.
4. Fourthly, due to the lower number of cables also fewer dune crossings are needed.
5. The final advantage is that future wind farms that will be located even further offshore could use the current offshore hubs as platforms for compensation coils enabling the connection of distant offshore wind farms with the relatively cheap HVAC technology.

In short, the hub concept should decrease the offshore grid costs considerably by increased standardization and reducing the number of offshore connections to the onshore grid.

### 3.2.6 Designated area

The Dutch government has assigned three offshore locations for the 3.5 GW offshore wind energy. These areas were already pointed out in Figure 1. These locations are called designated areas. The three designated areas are called Borssele, Hollandse kust Zuid Holland and Hollandse kust Noord Holland. The first two of these designated areas will accommodate a total of 1.4 GW installed capacity each. To accommodate 1.4 GW, two hubs at sea with a total of four branches are needed. A schematic of the hubs in a designated area has been shown in Figure 20. The two hubs-at-sea within the same designated areas are about 5 to 10 km apart. Therefore, couplers between the offshore hubs are realistic and have been indicated with dotted lines.
3.3 Technologies

In terms of technology, two choices for the main transmission grid have to be made. These are a choice on the system frequency and a choice on the system voltage. Theoretically, the number of transmission technologies could be very large. Due to standardization, only a small number of technologies are actually economically viable. The frequency of the transmission grid has already been assessed in the literature study. Currently, there are only three dominant frequencies in the transmission network. These frequencies are 60 Hz, 50 Hz and 0 Hz, or DC. Frequencies in between these two levels, for example 16 Hz, could be beneficial as it combines the advantages of AC and DC. Due to the lack of standardization as explained in chapter two, this choice is not desirable for two main reasons:

1. Firstly, this is the case because of the higher costs due to the fact that these technologies are unconventional.
2. Secondly, there is also limited experience with the offshore behavior of such cables and other components, making the choice risky.

HVDC technologies on the other hand are applied at increasingly larger scale. Examples are the interceptions between oversea countries like NorNed and BritNed, but also a number of Geman offshore wind projects like DolWin1-3. As it was explained in chapter 2 though, HVAC is still a considerably lower priced solution for offshore connections of below approximately 80 km. For that reason, this research will focus on HVAC technologies. The final consideration point is the voltage level for the HVAC offshore grid connection. High voltage levels that are mostly used for offshore transmission grids in northwestern Europe are 134, 150 kV and 220 kV. TenneT has decisively chosen for the 220 kV technology. For that reason, this research is limited to 220 kV 50 Hz offshore transmission grids.

3.4 Relevant components

Wind energy that has been generated in an offshore wind turbine passes through a number of components before reaching the onshore grid. Figure 21 gives an overview of the most important components of which the transmission grid is composed. Starting on the left side from the wind turbine itself, the energy is first transmitted through a collection grid, which is most often shared with a number of other wind turbines, to the offshore hub. At this hub, there might be need of compensation coils after which the energy passes a disconnector that is connected to the busbar. This busbar combines all the different collection grids after which a second disconnector leads to the main offshore transformer where the voltage is transformed from 66 to 220 kV. The configuration of two disconnectors, a circuit breaker and the busbar could be realized in different ways. Extra components or other configurations could be implemented. The specific choice of the configuration is based on a tradeoff between a number of parameters:

1. Reducing the amount of components, and thereby the costs.
2. Ensuring sufficient protection of important components (mainly the offshore transformer).
3. Ensuring a sufficient reliability from mainly the different components

After the transformer, the energy passes through another disconnector and into the transmission cable. This main transmission cable can be assumed to be surrounded by compensation coils. At the onshore side of the transmission grid, the energy first
passes a disconnector after which it is transformed up to 380 kV, the onshore transmission voltage. The configuration around the final disconnector and circuit breaker configuration could again be realized in different ways, again having a positive effect on the reliability.

![Diagram showing offshore grid configuration](Figure 21)

The grid configuration shown in Figure 21 is generally simplified because only a number of components have a profound effect on the reliability of the offshore power grid. In the studies pointed out in chapter 2 by Kling (2004) [69], Tuinema (2010) [70] and The Crown Estate (2011) [71] suggest that it is mainly the unavailability of the offshore cable and the on- and offshore transformers that determine the reliability of the offshore grid. This leads to the simplified offshore grid configuration of a single branch as is shown in Figure 22. This configuration will hereafter be called the benchmark configuration or ‘0’ configuration.

![Diagram showing simplified offshore grid configuration](Figure 22)

### 3.5 Possible grid configurations

#### 3.5.1 Mesh (redundancy) options

Unlike the number of technologies, the number of meshed options for the offshore power grid of wind energy is very large. Different mesh options are possible at different levels. Firstly, couplers between branches itself are possible. Secondly, couplers between two hubs within a designated area could be made. Thirdly, couplers between the different designated areas are thinkable. Lastly, extra connections to shore are possible, for example connections to the UK, to Belgium or from the Borssele hubs to the onshore substations in Holland. These connections would need higher investments but could possibly be advantageous. Next to the different couplers, also a number of alternative upgrades will be examined. The effect of oversizing offshore power grid components is explained and also the option of
resizing the complete wind farm. The final option presented in this chapter is the effect of overloading components.

### 3.5.1.1 Branch couplers

Branch couplers are connections that connect the two branches that are located on an offshore hub, enabling meshed power flows through the two branches. These couplers are here referred to as the lowest level of meshed redundancy. In Figure 23, the system of two radial connections located on one hub is shown. The small gray circles represent possible extra connections. Couplers are possible at the offshore platform at 66 kV (the most left coupler) and 220 kV (the middle coupler) and at the onshore station at 220 kV (the most right coupler).

![Figure 23](image1.png)

Figure 23, possible couplers between branches, at 66 kv and 220 kv offshore and at 220 kV onshore

It is worth clarifying that the graphical representation of the branch couplers is simplified in Figure 23. In Figure 24, the 66 kV coupler is shown more closely. In this figure, it can be seen that the coupler is a cable or busbar to which one or both branches can be connected using a disconnector. More importantly, there is a single circuit breaker enabling the extinguishing of faults.

![Figure 24](image2.png)

Figure 24, more detailed configuration of a 66 kV branch coupler
3.5.1.2 Hub couplers

Hub couplers are couplers that connect the hubs within the same designated area. The first two designated areas have a planned installed capacity of 1.4 GW. For that reason, each of those designated areas will need two hubs of 700 MW to assure full power transmission capability. These two hubs are relatively close to one another, in the order of 5 to 10 kilometers. The hub couplers, just like branch couplers, can be made at 66 kV and 220 kV offshore and 220 kV onshore. A schematic overview of the configuration is shown in Figure 25. In this figure, the two offshore hubs are indicated and also the single onshore substation that is needed for this connection is shown. The 66 kV and 220 kV offshore couplers are indicated to have a length of between 5 and 10 km. The 220 kV onshore coupler is a coupler within a substation and for that reason, is assumed shorter than 50 meters. As can be seen in Figure 25, the hub coupler is connected at the branch coupler busbar. In this way, the hub coupler investment mainly consists of the cost price of the power cable connecting the two hubs and of the installation of this cable. Investments in compensation coils should not be necessary since the offshore cable is only between 5 and 10 km long. It is technically possible to construct the hub coupler without constructing the branch couplers. This choice would not be preferable though because of two reasons:

1. Firstly, four instead of one offshore 10 km hub coupler cables would be needed to connect the different branches.
2. Secondly, the disconnectors in the branch couplers, as where shown in Figure 24, could be used by the hub couplers. When the branch couplers are not installed, those disconnects are still needed though. Not investing in branch couplers would thus not decrease the total investment cost in disconnectors.

For these two reasons, it is assumed here that hub couplers are only a viable option when the investment in branch couplers is made.
It is good to notice that here again the graphical representation of the hubs couplers in Figure 25 is simplified. In Figure 26, the 66 kV branch and hub coupler are shown more closely. In this figure, it can be seen that in comparison with the branch coupler, an extra disconnector and circuit breaker are added. The circuit breaker is needed here to ensure the possibility of extinguishing faults from every possible branch. It is assumed here that the circuit breaker is only needed at one end of the hub coupler since it can interrupt faults form both directions.
3.5.1.3 **Designated area couplers**

The next topology level is a coupler between designated areas. Borssele and Zuid Holland are about 100 km apart and Zuid Holland and Noord Holland are about 40 km apart. Offshore cables at these distances are technically possible. Again, couplers at different voltage levels and places are possible. Offshore, these are the 66 kV and 220 kV connections. On the shore site, the onshore grid connections are now two separate substations. This leaves the option of making the designated area couplers at this point as an offshore cable and as an onshore line. The four different designated area coupler options are shown in Figure 27.
Figure 27, Designated area couplers
3.5.1.4 Grid connections to other locations

The fourth topology level is grid connections to other locations. Instead of connections between hubs in different designated areas, also different connections to the onshore grid are possible. Connections to for example the UK, Belgium or from one designated area to the onshore substation of another designated area are thinkable. In Figure 28 the distances between the offshore hubs and these other locations have been shown.

Due to the distance between the offshore hubs and the UK of over 150 km, these connections are not a readily option with HVAC technologies. The distance between the different Dutch and Belgium substations is only 40 up to 75 km. This makes cross grid connections a technologically viable option. The schematic representation of such configurations is shown in Figure 29. The connections to shore of offshore hub 1 and 2 in designated area 1 both have one connection to the onshore substation of designated area 1. The other two offshore cables are connected with the onshore substation of designated area 2. The main advantage of this configuration is the partial redundancy in the onshore grid connection. Because of the connection to two instead of one onshore substation the (100%) unavailability of the connection to the onshore grid can be expected to go down.
Figure 29, couplers to other locations

3.5.2 Oversizing components
Instead of physically adding extra components, the standard components, either cables or transformers, could also be scaled up. This does not lead to direct advantages, but only has effect in combination with certain proposed mesh options.

3.5.3 Resizing the wind farm
Instead of only increasing the investment in the offshore power system, it is also possible to under-dimension the system. The goal of intentional under-dimensioning the grid is to lower the investment cost while losing a relatively low amount of energy thereby resulting in a positive NPV. The oversizing of the wind park could be done in very small increments, for example the peak power of a single wind turbine.

It is good to notice here that this is called oversizing the wind farm and not under-sizing the power grid. This is so because increasing the power level of a power system by 1 percent leads to all kinds of non-linear effects on the cost of the power system because of standardization and maximum power level of components. Increasing the size of the wind farm power output by small increments on the other hand can be expected to be (almost) linear because adding a single wind turbine can do this.

In this thesis, the oversizing of wind farms will be examined in two ways. Firstly, it is assumed that the wind farm has full availability. The second is to find a realistic average unavailability for wind farms, which will be used to determine the preferred size of the offshore power system.
3.5.4 Overloading of components
The final option presented in this chapter is the effect of overloading components. It will be examined if the temporary overloading of offshore power grid components can have a positive effect on the operation of the offshore grid.

3.6 Summery of design options
In this chapter it was strived for to give a complete as possible overview of what offshore power grid possibilities there are. The effect of the different options is examined in chapter 7.

<table>
<thead>
<tr>
<th>Name</th>
<th>Options</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>Benchmark option: 220 kV radial</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Branch couplers</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>BC1 66 kV</td>
<td></td>
</tr>
<tr>
<td>BC2 220 kV offshore</td>
<td></td>
</tr>
<tr>
<td>BC3 220 kV onshore</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Hubs couplers</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>HC1 66 kV</td>
<td></td>
</tr>
<tr>
<td>HC2 220 kV offshore</td>
<td></td>
</tr>
<tr>
<td>HC3 220 kV onshore</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Designated area couplers</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>DC1 66 kV</td>
<td></td>
</tr>
<tr>
<td>DC2 220 kV offshore</td>
<td></td>
</tr>
<tr>
<td>DC3a 220 kV onshore over land</td>
<td></td>
</tr>
<tr>
<td>DC3b 220 kV onshore through sea</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Other locations couplers</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>LC1 220 kV cross coupler</td>
<td></td>
</tr>
<tr>
<td>LC2 220 kV Belgium coupler</td>
<td></td>
</tr>
<tr>
<td>LC3 220 kV UK coupler</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oversizing components:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>OT Transformers (off- and onshore)</td>
<td></td>
</tr>
<tr>
<td>OC Cables</td>
<td></td>
</tr>
<tr>
<td>RW Installed capacity of wind farm</td>
<td></td>
</tr>
<tr>
<td>OL Cables &amp; transformers</td>
<td></td>
</tr>
</tbody>
</table>

Table 2, summery of extra or higher power level options
4 Data collection

4.1 Introduction
In this chapter, the input data for the main model in this research will be presented and discussed. Firstly, the component data in the form of component failure statistics, component capacities and the component costs are analyzed. Furthermore, the load and generation profile will be given and finally, the economical parameters in the form of the energy price, investment time and return on investment are the subject of investigation.

4.2 Component failure statistics

4.2.1 Unavailability theory
One of the key factors in this thesis is the expected component unavailability. This unavailability is the multiplication of the failure rate and the mean time to repair (MTTR) of the component. Outages of power systems can be categorized in different types. In Risk Assessment of Power Systems [72], Wenyuan Li divides this into forced, semi-forced and planned outages. To use the words of Li: “A forced outage happens randomly and is totally out of one’s control. On the other hand, a planned outage is not caused by failure but is scheduled by personnel, such as a maintenance or replacement activity”. The third category, semi-forced outage, lies in the middle (it could also be called semi-planned) and includes cases that do not require a direct outage but need repair on a very short time notice. This research only takes into account the forced outages. The combination of all forced outages is reflected by the unavailability. As explained by Li, the unavailability can be calculated as:

\[ U^* = \frac{U}{8760} = \frac{\lambda}{\lambda + \mu} = \frac{MTTR}{MTTF + MTTR} = \frac{f \times MTTR}{8760} \]  

Where 
- \( U^* \) is the annualized unavailability of the component
- \( U \) is the unavailability of the component (hours/year)
- \( \lambda \) is the failure rate (failures/year)
- \( \mu \) is the repair rate (repairs/year)
- \( f \) is the average failure frequency (failures/year)
- \( MTTR \) is the mean time to repair (hours)
- \( MTTF \) is the mean time to failure (hours)

Forced repair failures could be subdivided into nonrepairable failures and repairable failures. A repairable failure only needs the replacement of a part of the component whereas the nonrepairable requires the replacement of the complete component. This distinction is not overly strict. A completely burned through transformer for example is clearly a nonrepairable failure, but a burned through cable, where only the replacement of a few meters is needed, should probably be considered as an repairable failure since the 25 km long component is still largely in tact. In this research, the repairable and non-repairable forced failures are put together in a single unavailability.
4.2.2 Component failure & MTTR statistics

Acquiring compartment failure and MTTR statics can be quite a struggle. In 2008, Schoenmaker wrote a thesis on offshore power collection systems. In his abstract, Schoenmaker stated the following: “Availability data and data about failure rates and mean repair times and costs have not been taken into account, because for the 220 kV HVAC and for the offshore HVDC VSC systems too little or no data was available at all” [73]. Since 2008, a number of studies have improved the situation somewhat. The investigations by FNN [74] 2008 and CIGRE [75] 2009 do go into different failure statistics of power system components. Yet, the basis for the data is still narrow and shallow (some numbers are based on as few as 6 failures). The failure statistics have been summarized in Table 3. The reports by FNN and CIGRE also shed light at the MTTRs of the different components of which an overview has been show in Table 4.

<table>
<thead>
<tr>
<th>Component type:</th>
<th>Failure-rate (f/y)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore transformers</td>
<td>0.06321</td>
</tr>
<tr>
<td>Onshore transformers</td>
<td>0.04507</td>
</tr>
<tr>
<td>Offshore cables 220 kV (100 km)</td>
<td>0.07380</td>
</tr>
<tr>
<td>Offshore cables 66 kV (100 km)</td>
<td>0.12770</td>
</tr>
<tr>
<td>Onshore cables 220 kV (100 km)</td>
<td>0.08800</td>
</tr>
</tbody>
</table>

Table 3, Failure rates for different components [76]

<table>
<thead>
<tr>
<th>Component type:</th>
<th>MTTR (h)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore transformers</td>
<td>480</td>
</tr>
<tr>
<td>Onshore transformers</td>
<td>480</td>
</tr>
<tr>
<td>Offshore cables 220 kV</td>
<td>1440</td>
</tr>
<tr>
<td>Offshore cables 66 kV</td>
<td>1440</td>
</tr>
<tr>
<td>Onshore cables 220 kV</td>
<td>600</td>
</tr>
</tbody>
</table>

Table 4, MTTRs for different components [77],[78]

4.3 Rated power of components

The power transmission capability of a power system component is obviously essential in determining the maximum load flow of a system. The maximum power, or rated power, of a power system component mainly depends on the rated voltage and rated current of the component and is a multiplication of the two. Since it is a three-phase system, the resulting number has to be multiplied with a factor of the root of three to reach the rated power as is explained in Power System Analysis by Grainger and Stevenson [79]. This calculation has been shown in the following formula:

\[ P_r = \sqrt{3} V_r I_r \] (3)

Where \( P_r \) is the rated power of the component [Watt]
\( V_r \) is the rated voltage of the component [Volt]
\( I_r \) is the rated current of the component [Ampere]

In this formula, the rated voltage of a certain component is based on the level of insulation of the component (i.e. the dielectric breakdown strength). The rated current mainly depends on the component losses, the maximum operation temperature and the heat dissipation of the component.
4.3.1 Cables

It is clear from formula 3 that the rated power of a cable is the result of the rated voltage and rated current of the cable. As was just mentioned, the rated voltage of the cable is determined based on the dielectric breakdown strength of the isolation of the cable. This breakdown strength is hardly influenced by the surroundings of the cable (apart from sharp conducting points breaching the insulation). For that reason, it can be seen as a fixed cable parameter.

The rated current of a cable is mainly constrained by the maximum operating temperature of the cable. Due to several types of losses in the cable, the temperature rises. Different kinds of cables have different maximum operating temperatures, but the effect is the same: when a cable gets to hot, it starts to deteriorate which results in a rapid loss of life or even an direct failure. Because the losses in a cable increase when the current increases, the maximum current, and thereby the power, are constrained. There are a number of parameters that determine the temperature rise and thus the rated current of a cable:

1. Firstly, the cross section of the cable.
2. Secondly, the conductor type.
3. Thirdly, the cable laying configuration.
4. Fourthly, the heat conductivity of the soil surrounding the cable.

The former two of these parameters determine the generated amount of heat in the cable due to electric resistance. The latter two determine the ability to dissipate the heat to the surrounding area. Increasing the conductor cross section thus increases the power level of the cable. This parameters is not endlessly scalable due to the skin effect [80]. The skin effect pushes AC current to the outside of the cable thereby reducing the effective conductor cross section of the cable and increasing the resistance. Therefore, increasing the cross-section of a cable above a certain point is not very effective from a current carrying perspective and very expensive due to the extra needed conductor costs. Doubling the cross section of a cable reduces the DC cable resistance by halve thereby enabling an increased cable capacity of a factor two. Due to the skin effect, this linear increase in power does not apply to AC cables. This effect can be seen in Figure 30, where the specifications of ABB 220 kV offshore cables are shown. Increasing the cross section from 120 mm\(^2\) (the first dot) to 240 mm\(^2\) (the third dot) only leads to an increased rated current of 40 %. Increasing the cable from 500 mm\(^2\) to a 1000 mm\(^2\) has an effect lower than 25 %.
Based on the formula in Equation 3 and the values given in Figure 30, the rated power levels of offshore 220 kV cables with different conductor cross sections can be calculated. The result of this calculation is shown in Figure 31. In this figure, it can be seen that the biggest offshore copper conductor offshore cross section of 1000 mm$^2$ does not even reach 350 MW.

The cable specifications of Prysmian [82], NKT [83], Nexans [84], Brugg [85] and Riyadh-cables [86] do shown that is possible to increase the cable cross section of three-core cables further, thereby reaching power levels of 350 MW or even higher. It can nevertheless be concluded that 350 to 430 MW is the power limit of three-core offshore cables due to the skin-effect. Using single-core cables that are installed in pairs of three with enough spacing to prevent mutual cable heating increases the maximum power level up to even 500 MW. Two conclusions can be drawn from the analysis above:
1. The first one is that despite the strongly varying rated currents for different conductor types and producers, power levels of over 350 MW are reachable.

2. The second conclusion is that incasing the power level significantly is complicated, mainly due to the skin-effect. Depending on the laying type capacities of 430 MW for three-core and even 500 MW for single core cable with considerable spacing is the maximum capacities of 220 kV power cables.

The skin effect also occurs in the conductors in power transformers. Due to the fact that power transformers are actively cooled, smaller conductor cross-sections can be used thereby reducing the skin effect. For that reason, increasing the power level of power transformers is much less constrained than it is for (offshore) power cables.

### 4.3.2 Thermal time constant

Overloading a component with a voltage leads to a very undesirable loss of life, but current overloading a component can be beneficial to reduce the lost energy. To determine the overloading capability of a component, the thermal time constant of the component is needed. The thermal-time constants of transformers and offshore cables are given in Table 5.

<table>
<thead>
<tr>
<th>Component</th>
<th>Thermal time constant (τ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer</td>
<td>1.7</td>
</tr>
<tr>
<td>Offshore cable</td>
<td>0.8</td>
</tr>
</tbody>
</table>

Table 5, thermal time constant [87], [88].

### 4.4 Component costs

The final component parameter is the transmission system price. Only when this price is known, it is possible to make a comparison between different configurations. Currently, the offshore transmission systems in for example Belgium and Denmark are part of the complete offshore wind project. For that reason, the costs of the transmission system are often not explicitly mentioned but added to the collection grid and the wind turbines. This makes it hard to get an idea about the transmission system costs. In the United Kingdom, the transmission grids are tendered and built separately from the offshore wind park. This makes the British offshore wind projects very useful to get an overview of the relative costs of the different transmission system components. For that reason, most of the data found on the complete power offshore power systems are based on British studies and offshore wind project cost assessments.

In Appendix A, Analysis of offshore transmission system costs”, an overview of the different total costs of offshore transmission systems is given. The data from this appendix is used to formulate the system costs in Table 6. In the table, the system costs for HVDC, 380 kV, 220 kV and 134/150 kV systems have been estimated based on existing data. When the total costs of the power systems are recalculated in system costs per MW, a first conclusion can be drawn. It is clear from Table 6 that the 220 kV systems are the cheapest solution to transport wind power from wind farms to the onshore grid. A remark has to be made that using HVDC for small wind farms is not possible because the low system cost per MW is only reached when the system is put in at full scale (i.e. 1 GW).

Another remark that can be made here on the € 135 million for a 350 MW 220 kV system is that it does not correspond with the governmental plans. In these plans,
the total cost for the transmission grid for 3500 MW of offshore wind power was estimated to be € 3 billion. Dividing this € 3 billion by ten 350 MW branches results in a cost of € 300 million per branch. That is a 220% higher number than the € 135 million calculated in Appendix A. A part of this difference could be contributed to the development costs of the system and to the cost of capital that were not taking into account in Appendix A. The difference between the estimate based on existing data and the number given by the governmental plans is large. This does not have consequences for the rest of the research because the main calculation is based on the added value of redundancy options, not on the overall NPV of the configuration. Only in the resizing the wind farm is the total estimated system cost used. These calculations thus have a large margin of uncertainty due to the unclear system costs.

<table>
<thead>
<tr>
<th>Complete system</th>
<th>Total estimated system cost (M€)</th>
<th>System costs per MW (M€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>134/150 kV system gear (250 MW)</td>
<td>135,00</td>
<td>0.54</td>
</tr>
<tr>
<td>220 kV system gear (350 MW)</td>
<td>135,00</td>
<td>0.39</td>
</tr>
<tr>
<td>380 kV system gear (700 MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HVDC system gear (1 GW)</td>
<td>500,00</td>
<td>0.50</td>
</tr>
</tbody>
</table>

Table 6, total estimated system costs for offshore power systems (see Appendix A.)

4.4.1 Coupler costs
Based on the data in Appendix A, the individual component costs of the different coupler options will be analyzed. These costs include both the investment cost and maintenance cost for the complete lifetime. Firstly, the costs of offshore cables per meter and disconnector costs are shown in Table 7.

<table>
<thead>
<tr>
<th>Component type:</th>
<th>Total cost (€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore cables 220 kV (€/m)</td>
<td>€1200</td>
</tr>
<tr>
<td></td>
<td>* Component cost 350 MW</td>
</tr>
<tr>
<td></td>
<td>* Installation cost</td>
</tr>
<tr>
<td>Offshore cables 66 kV (€/m)</td>
<td>€ 900</td>
</tr>
<tr>
<td></td>
<td>* Component cost</td>
</tr>
<tr>
<td></td>
<td>* Installation cost</td>
</tr>
<tr>
<td>Disconnector 66 kV</td>
<td>€ 1.3M</td>
</tr>
<tr>
<td>Disconnector 220 kV offshore</td>
<td>€ 7.4M</td>
</tr>
<tr>
<td>Disconnector 220 kV onshore</td>
<td>€ 1.8M</td>
</tr>
</tbody>
</table>

Table 7, the costs of different component (some split up to origins) [89], Appendix A

Based on these component costs, the costs of branch, hub and designated area couplers can be determined. The results are shown in Table 8, Table 9 and Table 10. It can be seen in Table 8 that the branch couplers costs are mainly based on the disconnector cost. The 66 kV branch coupler consists of two 175 MW connections. For that reason, the costs are € 2.6 million instead of € 1.3 million to connect every branch connector to both 66 kV fields. In both branches one of these fields is connected with one of the fields in the other branch.

<table>
<thead>
<tr>
<th>Branch couplers</th>
<th>Investment costs (M€)</th>
</tr>
</thead>
</table>

* Values for 380 kV could not be determined.
Table 8, approximate costs of a branch coupler, coupling 700 MW.

66 kV Offshore at 220 kV Onshore at 220 kV
2.6 7.4 1.8

Table 9, approximate costs of a hub coupler, coupling 1400 MW.

<table>
<thead>
<tr>
<th>Hub couplers</th>
<th>Investment costs (€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>66 kV (5 km) per 175 MW</td>
<td>6.8M</td>
</tr>
<tr>
<td>Cable</td>
<td>4.5M</td>
</tr>
<tr>
<td>Disconnector</td>
<td>1.3M</td>
</tr>
<tr>
<td>220 kV offshore (5 km) per 350 MW</td>
<td>13.4M</td>
</tr>
<tr>
<td>Cable</td>
<td>6.0M</td>
</tr>
<tr>
<td>Disconnector</td>
<td>7.4M</td>
</tr>
<tr>
<td>220 kV onshore per 350 MW</td>
<td>1.8M</td>
</tr>
<tr>
<td>Disconnector</td>
<td>1.8M</td>
</tr>
</tbody>
</table>

Table 10, approximate costs of a designated area coupler, coupling 2800 MW

<table>
<thead>
<tr>
<th>Designated area couplers</th>
<th>Investment costs (M€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>66 kV offshore (45 km) (without compensation coils)</td>
<td>40.50</td>
</tr>
<tr>
<td>220 kV offshore (45 km) (without compensation coils)</td>
<td>54.00</td>
</tr>
</tbody>
</table>

4.5 Load and generation profile
In this thesis, the wind energy production of the Scenario 2020, as provided by TenneT, is used as the generation profile. The wind energy production is assumed to be constant and equal within a single designated area over the course of an hour. The wind data has been scaled to match the peak power of 350 MW of one offshore branch.

4.6 Energy prices
To determine the NPV of certain grid configurations, it is essential to define the net worth of a certain amount of energy. This energy net worth, or energy price in this research is built up from four parameters:

1. The first parameter is the current market energy price.
2. Secondly, government fees like for example carbon emission fees could increase this market price.
3. Thirdly, governmental subsidies are granted to renewable energy producers in different ways, thereby increasing the net worth of an MWh of wind energy.
4. The final parameter that is included here is the possible correlation between wind energy production and the energy price.
These four parameters are further examined below.

4.6.1 The market price
With the Dutch market energy price, one could refer to the wholesale price, the spot price or even the consumer energy price (before excise duty and value added tax). In this research, the APX ENDEX exchange prices will be used to define the market energy price. According to the Authority for Consumers and Markets, the “transparency of prices on the exchanges APX (spot contracts) and ENDEX (futures contracts) in the Netherlands is generally regarded by market participants as sufficient.” [90].

![Figure 32, Electricity futures prices on APX ENDEX exchange (2009-2012) [91]](image)

In Figure 32, the month ahead, three-months ahead and year ahead energy prices per MWh are shown. From this figure it can be seen that the average market energy price lies around € 50 per MWh. This price will be used as the assumed energy price in this research.

4.6.2 Carbon
The first method a government can use to influence the energy market price is the installment of a production fee. The carbon emission allowance is an example of such a fee. When a utility (or any kind of industry for that matter) wants to emit carbon dioxide to produce energy (or other products), the utility is obligated to possess the allowance to emission that particularly amount of carbon. The amount of carbon emission allowances in the market is limited creating a sort of stock exchange for carbon emission allowances with supply and demand. Between 2008 and 2012, the average price of carbon emissions went down from around € 25 per ton CO2 down to below € 10 per ton CO2 [92]. This decrease is attributed to an oversupply of carbon emission allowances and expected to go up again in the future. As can be seen in Figure 33, the carbon emission price went to an all time low in 2013 of 3 €/tCO2 and from there has been steadily climbing. With 7 €/tCO2 it could be seen as still relatively low.
So what is the exact effect of these carbon emission allowances? Carbon emission allowances increase the price of energy production types that emit carbon as a by-product of the energy generation. Zero-carbon emitting generation types (like wind energy) are not directly influenced. Because of a possible change in the merit of order though, the average energy price, which wind farm operators generally have to take, the average energy price increases.

According to the EA World Energy Outlook 2011 [94], the Dutch generation mix results in a carbon emission of about 0.26 tCO2/MWh. Based on a carbon emission allowance price of €7.50 this leads to a current increased energy price of €2.00 per MWh, or a price increase of approximately four percent assuming a market energy price of 50 €/MWh. Most experts agree that the carbon emission fee price is going to continue to increase in the future. The IEA World Energy Outlook 2011 gives a high estimate of 31 €/tCO2, which results in a price increase of 8 €/MWh. This analysis results in two conclusions:

1. Firstly, because the earlier defined market energy price of 50 €/MWh already contained the effect of €2 per MWh, this has no extra effect on the market energy price.
2. The possible high estimate of 8 €/MWh would then increase this market energy price of 50 €/MWh by an additional six euros to 56 €/MWh.

Because the high estimate of 8 €/MWh is (obviously) an estimate, it will only be used in the sensitivity analysis in chapter 7. Otherwise, the 50 €/MWh is used as the energy price.

4.6.3 Subsidies
The market energy prices and the carbon emission fees do not complete the assumed wind energy value though. The Dutch government pays renewable energy subsidies, which effectively increase the net worth of wind energy. Different brochures released by the RVO [95], Bosch [96] (2011) and internetconsultatie [97] (2015) (which is managing wind energy subsidies) write about the height of the wind energy subsidies. Internetconsultatie states that the calculation of the maximum subsidies can be calculated as follows:
\[ Ms = (Tb - Be) \cdot P \cdot Vlu \cdot y \]  

Where

- \( Ms \) is the maximum subsidy per MWh [Euro/MWh]
- \( Tb \) is the tender bid of the wind farm operator [Euro]
- \( Be \) is the basis energy price [Euro]
- \( P \) is the amount of installed power [MW]
- \( Vlu \) is the maximum amount of full power subsidy hours [-]
- \( y \) is the number of years [Years]

As can be seen in formula 4, the government does not give a fixed amount of subsidy on top of a fluctuating energy price, but rather assures a fixed wind energy price. According to the RVO, Bosch and Internetconsultatie, this price lies around a €100 per MWh for a maximum of 15 years. After this period, the subsidy program is ended.

Three statements about the cash flow of a MWh of wind energy can be made:

1. Firstly, the exact amount of subsidy for wind energy heavily depends on a number of parameters, but the net cash flow (income) per MWh is practically fixed at €100.
2. Secondly, this income from wind energy for the wind farm operator is fixed for 15 years at 100 €/MWh (as long as the market energy price does not surpass the 100 €/MWh point).
3. Finally, after the 15-year period the subsidy scheme is ended and the market price again determines wind farm operators income.

To conclude, for the first 15 years after the start of the operation of the wind farm the income per MWh can be assumed to be €100 and for the period afterwards, the market energy price should be taken. In this research this market price is assumed to be €50 per MWh.

4.6.4 **Price correlation**

In chapter 2 “Energy price correlation”, it was explained that in power grids that are heavily penetrated by wind energy, it is likely that a certain level of wind energy price correlation will occur. In Figure 34, the effect of increased wind energy penetration in the grid has been shown graphically. With low demand (for example during the night), the effect of extra wind energy is not strong. The energy price was low and will remain low. During peak hours high-energy prices can be lowered substantially. Because most energy consumers have a fixed energy price, there is no intensive to lower energy consumption during peak load hours. This results in a very inelastic power demand and a steep demand curve.
Two main problems arise when the wind energy price correlation is taken into account.

1. Firstly, as was pointed out in chapter 2, it is hard to determine the height of the price correlation. Whereas it seems to be clear that there is some sort of correlation, the exact percentage cannot easily be determined.

2. Secondly, as was pointed out in chapter 2 and is also visible in Figure 34, the energy price correlation cannot be expected to be linear, since it is relatively weak for lower energy prices and strong at higher energy prices. Because of these two problems, it is chosen to only include the price correlation as a sensitivity parameter in chapter 7. This is done based on a linear price correlation to prevent to complicate matters too much. In the remainder of chapter 7, the price correlation is thus equal to 0 %.

4.7 Other economical parameters

Next to the components costs and the energy price, two other economical parameters need to be defined to come to a preferred offshore power grid in social economic terms based on the NPV of different options. These two parameters are the investment time and the rate of return on investments. The effect of the investment time is as follows: a longer investment time means that the investment has more time to pay itself back, most often resulting in a higher NPV. The investment time should not be chosen longer than the lifetime of the system because this would result in a too optimistic NPV calculation. Another issue that has to be resolved is that a positive cash flow of € 100 ten years away from now is not the same as a positive cash flow of € 100 next year. Income that has been generated earlier has a higher net worth because the value of this money is not lowered by ten years of inflation and can be reinvested earlier to generate extra income. For that reason, the cash flow per year is compensated by an expected rate of return. These
parameters are taken here to be respectively 5 % annually as the rate of return and 30 years for the investment period.
5 Socio-economic reliability model

5.1 Introduction

The objective of this thesis, as has been defined in the introduction, is to come to a social-economic preferred solution of the offshore grid configuration. This solution is interpreted, as is explained in chapter 1, as the grid topology with the lowest overall cost for society. In this chapter, the main approach to come to this least cost grid is explained. In Figure 35, the general study approach is shown graphically. On the left, different kinds of data are the inputs of the main model. This data is used to simulate and calculate the preferred configuration. The data used in this thesis includes market energy prices, energy fees and subsidies, hourly wind energy production, component capacities and failure rates, interest rates, investment time and of course the possible technical grid configurations. All these parameters are used in the simulation to come to the ultimate result. From this data, various output functions are calculated, such as the (correlated) energy price, the transmitted energy, the total investment costs, the maintenance costs, total earnings, total expenses and ultimately the overall cost of the particular topology.

![Figure 35, general thesis topology](image)

In Figure 36, a complete overview of the study approach is shown. On the left side (in light blue), the different input data are shown and on the right, lower corner, the solution of the study is given in black. In between, the processing of the data and the calculation of the results in different simulations and calculations are positioned. To get an understanding of the complete approach, Figure 36 is broken up into different parts that will be examined individually.
5.2 (Correlated) Energy price

We start with the calculation of the (correlated) energy price of which the schematic overview is shown in Figure 37. The average energy price is based on the market energy price and is subsequently compensated (either up or down) with energy fees and subsidies. Next to this average energy price, it is also possible to introduce correlation between the produced wind energy and the energy price. For this reason, the hourly wind energy production is also used as an input of the correlated energy price.
5.3 Transmitted energy
The next step is the calculation of the transmitted energy. The approach is given in Figure 38. The matlab model used for the simulation will be explained in detail in chapter 6, but an overview of the approach is given here. The first input is the hourly wind energy production. This dataset gives the amount of energy that should be transmitted over the offshore grid for every hour of the year. The last input, in the down left-hand corner is the technical configuration. This is a specific offshore grid configuration of which the performance will be examined. Between these two inputs, the failure rates and repair times of the components and other component characteristics are given. The component characteristics are, among others, the rated current, rated power and the thermal inertia of the specific components. The combination of these inputs enables the calculation of the total transmitted energy.

![Figure 38, topology of the calculation of the transmitted energy](image)

5.4 Total investment
The final primary calculation is the calculation of the total investment. The approach of this calculation is very straightforward but nevertheless given in Figure 39. Here, it is again the technical configuration that determines the outcome of this calculation.

![Figure 39, topology of the calculation of the total expenses](image)

5.5 Total yearly cash flow
The calculation of the earnings subsequently is much like a multiplication of the (correlated) energy price and the hourly-transmitted energy, of which the approach is given in Figure 40. The amount of transmitted energy (or the amount of lost energy) multiplied with the worth of that amount of energy results in a yearly cash flow (or lost cash flow).
5.6 Net present value of the configuration

From the total investment and the yearly (lost) cash flow, the NPV of the chosen configuration can be calculated. The topology overview of this calculation is given in Figure 41.

![Figure 41, topology of the calculation of the cost of the configuration]

To determine the profitability of a certain upgrade, the net present value (NPV) of this upgrade is calculated. According to the Collins English Dictionary, the NPV is defined as: "an assessment of the long-term profitability of a project made by adding together all the revenue it can be expected to achieve over its whole life and deducting all the costs involved, discounting both future costs and revenue at an appropriate rate" [99]. To put it in other words, the present value of an investment is based on the expenses and income, taking into account the rate of return on comparable investments and the duration of the investment. **Johnson** [100] (2010) gives the general discrete formula for the calculation of the NPV, which is formulated as:

\[ NPV(i) = R_0 + \sum_{t=0}^{N} \frac{R_t}{(1 + i)^t} \]  

(5)

Where  
- \( R_0 \) is the initial investment  
- \( N \) is the total investment time (in years)  
- \( R_t \) is the net cash flow in year \( t \)
i is the rate of return of investments with comparable risk

$t$ is the time in years

In Table 11, the calculation of the NPV is shown for a total investment time of 20 years. It can be seen that in year 0, the NPV is the negative initial investment because these are the expenses and there has not yet been any incoming cash flow. In the years 1 to 20, the NPV is calculated by subtracting benefits with cost (in this case the energy income subtracted with the needed maintenance) and correcting that for the rate of return. Adding all the yearly PV of the cash flow results in the NPV of that specific configuration.

<table>
<thead>
<tr>
<th>Year</th>
<th>Benefits</th>
<th>Cost</th>
<th>Benefits-cost</th>
<th>Net present value</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>-</td>
<td>Initial investment (Ii)</td>
<td>0-Ii</td>
<td>- Initial investment</td>
</tr>
<tr>
<td>1</td>
<td>Energy income (Ei)</td>
<td>Maintenance (M)</td>
<td>Ei-M</td>
<td>(Ei-M)/(1+i)^1</td>
</tr>
<tr>
<td>2</td>
<td>Ei</td>
<td>M</td>
<td>Ei-M</td>
<td>(Ei-M)/(1+i)^2</td>
</tr>
<tr>
<td>3</td>
<td>Ei</td>
<td>M</td>
<td>Ei-M</td>
<td>(Ei-M)/(1+i)^3</td>
</tr>
<tr>
<td>4</td>
<td>Ei</td>
<td>M</td>
<td>Ei-M</td>
<td>(Ei-M)/(1+i)^4</td>
</tr>
<tr>
<td>5</td>
<td>Ei</td>
<td>M</td>
<td>Ei-M</td>
<td>(Ei-M)/(1+i)^5</td>
</tr>
<tr>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
</tr>
<tr>
<td>20</td>
<td>Ei</td>
<td>M</td>
<td>Ei-M</td>
<td>(Ei-M)/(1+i)^20</td>
</tr>
</tbody>
</table>

Table 11, calculation of net present value

**5.7 Preferred configuration selection**

The final step in this research is the selection of the preferred configuration and is shown in Figure 42. As was explained before, only a small amount of binary options already leads to a very large number of possible grid configurations. For that reason, in this research an iterative configuration selection method is used, rather than one based on sheer calculation power.

The starting point is the lowest level topology grid improvement. At this topology level, the most beneficial options are selected and taken to the next topology level. This process is repeated until all options are assessed and a final ranking of most beneficial grid configurations remains. An overview of the different topology levels is given in Table 12.

<table>
<thead>
<tr>
<th>Topology level:</th>
<th>Option type</th>
<th>Number of options</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Branch couplers</td>
<td>3</td>
</tr>
<tr>
<td>2.</td>
<td>Hub couplers</td>
<td>3</td>
</tr>
<tr>
<td>3.</td>
<td>Designated area couplers</td>
<td>4</td>
</tr>
<tr>
<td>4.</td>
<td>Grid connections to other locations</td>
<td>1</td>
</tr>
<tr>
<td>5.</td>
<td>Oversizing components</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Resizing the wind farm</td>
<td>Many</td>
</tr>
<tr>
<td>---</td>
<td>------------------------</td>
<td>------</td>
</tr>
<tr>
<td>7.</td>
<td>Overloading of components</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 12, list of different topology levels taken into account
6 Modeling

6.1 Introduction

In this chapter, the reliability model will be explained. The goal of this thesis is to define the preferred offshore grid configuration. The calculations for this grid choice are performed in Matlab. Figure 43 gives an overview of the complete simulation model. The main model, which performs the simulation itself, is either a Monte Carlo simulation or a state enumeration. The state enumeration is the faster and more accurate model, but the Monte Carlo has a broader application because it calculates in a chronological order. Because of this chronological simulation, it becomes possible to include real time system behavior, like for example real time component temperatures. The Scenario 2020 supplies the model with hourly wind energy production during a complete year. The “Contingency lists” give the parameters of the components such as failure rates, repair times, thermal time constants, rated powers, and maximum rated temperatures. The main model gets the needed data from the Scenario 2020 and from the “Contingency lists”. The main model uses this input data and calls the load flow function for every simulated hour. The load flow-function then returns a maximum grid power flow for a specific hour. From this hourly load flow, the main model subsequently calculates the amount of lost energy. The methodology to come to the amount of lost energy is completely different for the Monte Carlo and the state enumeration. The results of both methodologies nevertheless are the same (apart from the accuracy and error margin). Also the data input and the load flows are identical for the methodologies.

In this chapter, first the main model will be discussed with extra attention for the accuracy of the model. Secondly, the load flow functions are covered and the chapter is concluded with the explanation of the working and function of the price correlation model and thermal model add-ons.

Figure 43, overview of the Monte Carlo/state enumeration model
One could define different levels of power system evaluation. The first question is whether the power system is capable in every load scenario to transmit all power from the generation nodes to the load nodes in normal operation. If this is the case, it could be said that the network is N-0 redundant (always sufficient when there are zero failures). Due to randomly occurring component failures, a real power grid has to operate with a reduced amount of components for a certain percentage of time. This leads to operation states with first- or higher-order failures. When the power system for example is always sufficient with one failure, it is N-1 redundant. Like mentioned before, in the offshore grid it is not so much the N-x level that is of interest. What is much more relevant is the amount of lost power due to certain failures that are present in a certain load-generation scenario. The state of a power grid with one or multiple failures is called a contingency state. The possible number of contingency states in a power grid is generally very large. If every component can take two states (either working or failed), the number of contingency states can be calculated as:

$$N_C = 2^m - 1$$  \hspace{1cm} (6)

Where $N_C$ is the total possible number of contingency states and $m$ is the total number of components in the power grid.

This means that even for a small network of for example 21 components, there are over two million (2097151) different contingency states.

There is another factor that worsens the running time of the reliability analysis. To get a real gasp of the performance of a power grid, every contingency state needs to be evaluated for different load scenarios. For a simulation representing a year this would minimally be the typical load-generation-distribution for different seasons or different months (i.e. four to twelve load scenarios). In a real power grid, the number of load-generation-distribution scenarios that occur during a year is very large. For that reason, many more load scenarios are needed to get a more realistic representation of the power grid performance. The contingency state load flow calculation might be repeated for every day of the year, every hour of the year or even in smaller increments.

The final main component that plays a role in the computation time of a power grid analysis is the time to run the load flow of a contingency state. Obviously, this duration depends heavily on both the computation power of the processor and the extensiveness of the tested network. To calculate every contingency state for every generation-load-distribution scenario, the calculation time is as follows:

$$t_t = t_{lf} L_S (2^m - 1)$$  \hspace{1cm} (7)

Where $t_t$ is the total computation time, $t_{lf}$ is the computation time of a single load flow calculation, $L_S$ is the number of different load-generation-distribution scenarios and $m$ is the total number of components in the system.

To get a gasp of the fastness of calculating every scenario for every contingency state it is good to use an example. A system with 21 components is taken. When a single load flow calculation takes 0.2 ms (which is an reasonable assumption) and all the contingency states of a 21 component system are included for every hour of the
year, the total computation time is: \(2097151 \times 8760 \times 0.0002 = 3.67 \times 10^6\) seconds or over 42 days. So even for this small network of 21 components, the complete calculation will take weeks to finish. When 10 different possible configurations have been formulated, the total commutation time of these configurations will take over a year.

Since time is obviously limited for practical reasons, it is essential to reduce the total simulation time while maintaining a reasonable accurate result (or at least knowing the accuracy). Making a careful selection of important contingency states can do this. Next to the fastness of the contingency, also the determination of the relative weight of the different results is an issue. This leads to a two-folded purpose of the main model. Firstly, it has to choose the contingency states that are to be assessed, leaving out (relatively) irrelevant states. Secondly, it has to give every contingency state the right weight in comparison with the other contingency states.

### 6.2 Main model

Beshir [101] (1996), Li [102] (2002) and Rei [103] (2006) write about two simulation methods, namely state enumeration and Monte Carlo simulation. As is pointed out by Beshir, the advantages of the state enumeration are the straightforward contingency state selection method and the simply defined accuracy. Rei adds an additional point that could both be seen as an advance or disadvantage: a state enumeration has a fixed running time. The Monte Carlo simulation on the other hand has a certain randomized (exponentially in this research) contingency state selection method, a less simply defined accuracy with confidence intervals and can be run for every preferred duration of time. The running time depends on the desired accuracy though. These points, in itself are not intrinsic advantageous. What is an advantage of the Monte Carlo simulation though, is that it can be run chronological which makes it possible to include effects that are time dependent.

#### 6.2.1 State enumeration

The contingency state selection method of a state enumeration is based on the chance that a certain contingency state is present at a certain moment. Higher-order contingencies (for example three simultaneous failures or more) can be expected to have a more profound effect on the grid. One congested highway has much less effect on all the commuters in an area then for example ten congested highways in the same area. Nevertheless, since the likelihood of a higher-order contingency state is the multiplication of the individual component failure rates, their relative weight is usually low. So higher-order contingency states can be seen as rather disastrous, but generally at the same time have little weight in the total calculation because they occur less often. In other words, they are high-impact low-probability failures. This leaves two options (apart from including these very time consuming calculations). Firstly, these higher-order failures states could be neglected and thus have “no-impact”. Secondly, these higher-order failure states could be considered as total error states. These two options lead to a lower and upper estimate of the result. In this thesis, the latter option is chosen, thus resulting in a lower limit estimate: higher-order contingencies are taken to have a max load flow of zero (or in other words are taken out of the calculation). As is explained by Rei, this saves a lot of calculation time and leads to the lower boundary result, because including higher-order failures in the calculation can never result in higher losses. It is possible though, or even likely, that
in some combinations of contingency states and load-generation-distribution scenarios still a part of the energy can be transported. The relative error that is the result of this not included energy is nevertheless far from significant and can therefore be omitted.

**6.2.2 Simulation process**

In Figure 44, the simulation topology of a state enumeration is shown graphically. Every enclosing operation can be seen as a for-loop that runs for a number of iterations. Every enclosed operation is subsequently run for that number of iterations.

The outer operator runs through a number of different load-generation-distribution scenarios, 8760 for this thesis to be exact. These 8760 scenarios represent an hourly wind power production during a complete year. The inner operator runs through the selected contingency states. This selection is made based on an order restriction. To put it in other words, the state enumeration can be chosen to include for example only third-order and lower contingency states. Dependent failures (i.e. multiple failures with a common cause) are not included in this research due to a lack of statistics on this matter. One thing that is good to notice here is that the order of the load scenarios and the state enumeration could be revised to speed up the calculation. During every contingency state, two main operations are performed. The first step is the calculation of the maximum load flow through the power grid based on the specific combination of the load-generation-distribution scenario and contingency state. From the transported power, the lost power can be calculated. The second step is the determination of the weight of the individual contingency states. As is explained before, the weight of a contingency state depends on the likeliness to occur, which in turn depends on the likeliness of the failure of an individual component states. The likeliness of a certain contingency state to occur can be calculated as:

$$
C = \prod_{i=1}^{n} (f_r(i) \cdot r_t(i)) \cdot \prod_{j=1}^{m} (1 - f_r(j) \cdot r_t(i))
$$

(8)
\[
= \prod_{i=1}^{n} (U^*) \cdot \prod_{j=1}^{m} (1 - U^*)
\]

Where

\begin{align*}
C & \text{ probability of a specific contingency state to occur} \\
n & \text{is the total number of failed components in the system} \\
m & \text{is the total number of components in operation} \\
f_r(x) & \text{is the failure rate of component } x \text{ [failures/year]} \\
r_r(x) & \text{is the repair time of component } x \text{ [years]} \\
U & \text{is the annualized unavailability of component } x \\
i,j & \text{are positive integers}
\end{align*}

With this calculation of the individual weight of a contingency state and a certain amount of lost energy for a load-generation-distribution scenario, the total lost energy for that combination can be determined. The combination of all contingency state and load-generation-distribution scenarios is then calculated as:

\[
P_{\text{lost}}(t) = \left( P_{\text{pro}}(t) - P_{\text{flow}}(t) \right) \left( \prod_{l=1}^{n} \left( 1 - U^*(l) \right) \right) \\
+ \sum_{i=1}^{n} \left( P_{\text{pro}}(t) - P_{\text{flow}}(t, i) \right) \left( U^*(i) \prod_{l=i}^{n} \left( 1 - U^*(l) \right) \right) \\
+ \sum_{i=1}^{n-1} \sum_{j=i}^{n} \left( P_{\text{pro}}(t) - P_{\text{flow}}(t, i, j) \right) \left( U^*(i) \cdot U^*(j) \prod_{l=i,j}^{n} \left( 1 - U^*(l) \right) \right) \\
+ \sum_{i=1}^{n-2} \sum_{j=i}^{n-1} \sum_{k=j}^{n} \left( P_{\text{pro}}(t) - P_{\text{flow}}(t, i, j, k) \right) \left( U^*(i) \cdot U^*(j) \cdot U^*(k) \prod_{l=i,j,k}^{n} \left( 1 - U^*(l) \right) \right)
\]

Where

\begin{align*}
P_{\text{lost}}(t) & \text{is the lost power at time } t \text{ (in MW)} \\
P_{\text{pro}}(t) & \text{is the produced power at time } t \text{ (in MW)} \\
P_{\text{flow}}(t) & \text{is the maximum power flow through the grid at time } t \text{ as a result of the component states (in MW)} \\
n & \text{is the total number of components in the system} \\
i,j,k,l & \text{are positive integers}
\end{align*}

In this formula, every line represents the calculation of a certain order of contingency states. The first line calculates the load flow in case of no failures and multiplies this with the probability of no failures. The fourth line calculates the load flow of all possible combinations of three simultaneous failures in the grid and weights them to their relative likelihood of occurrence. Every extra order in the calculation leads to an
extra product-operation and thus increases the duration of the complete simulation by a factor \( n \) that can be approximated by:

\[
\text{Factor} = n - \text{order}
\]  

(10)

Where \( n \) is the total number of components in the system and \( \text{order} \) is extra order that will be calculated.

The final step in the calculation is the introduction of the complete list of load scenarios. As is said before, in this thesis the wind power production during 8760 different hours of a year are taken as these scenarios. This results in the following calculation of the expected average power loss as a result of a certain grid configuration with given component failure rates:

\[
P_{\text{average lost}} = \frac{1}{8760} \sum_{t=1}^{8760} p_{\text{lost}}(t)
\]  

(11)

6.2.1 Monte Carlo

In comparison with the state enumeration calculation that uses strict algebraic equations to calculate the expected value, the Monte Carlo simulation is analytically much less structured. In a state enumeration the selection of the included contingency states is very clear and the subsequent calculation very orderly. This cannot be said about the Monte Carlo simulation, where the selection methodology is based on randomness. This means that where the state enumeration leads to a lower bound calculation the Monte Carlo simulation results in the, to use the words of Rei, “estimates of the real performance of the system.”

In this study, the times to failure are sampled using the exponential distribution. Letting components fail exponentially random weighed by their individual component failure rate does this. This is unlike the state enumeration where the calculation is weighed by the likelihood of a contingency state. This randomness is needed to create ongoing changing contingency states, thus realistically simulating the grid operation. The exponentially random time until the components fails as was explained by Li in Risk Assessment of Power Systems [104] is calculated as:

\[
t_{\text{fail}}(x) = -\frac{8760 \cdot \ln(x)}{f_r}
\]  

(12)

Where \( t_{\text{fail}} \) is the randomly determined time in hours until a failure, \( x \) is an evenly distributed random number between 0 and 1, and \( f_r \) is the yearly failure rate of the component.

The characteristic shape of the \( t_{\text{fail}}(x) \) function for a failure rate of 1.0 (one expected failure per year) is plotted in Figure 45. As can be seen in this figure, some components, despite being expected to last for one year, fail practically directly, while a small percentage keeps working for over 40000 hours. Actually, 50% of the sampled components fail within 6072 hours, while the expected duration was 8760 hours (one year). The longevity of some components compensates the quick failures of others. It is good to observe that the average failure time is still once per year. It is
important to notice that this exponentially randomization is not necessarily a realistic representation of reality but much more a usable and easy to compose modeling topology.

![Exponentially randomized component failures](image)

**Figure 45, the exponentially randomized component failure**

Now the exponentially random failure time has been explained we can go into the complete simulation process. This process has been graphically shown in Figure 46. Before the Monte Carlo simulation starts, the contingency list is initialized. This means that all the components are weighted randomly chosen to be either working or failed. Subsequently, every component gets an exponentially random time of failure based on the individual failure rates or, if already failed, a random time to repair. After the initialization, the Monte Carlo simulation starts to run at time \( t=0 \) for a certain step size until the total simulation time \( t_s \) is reached. This is comparable with the load-generation-distribution scenarios step in the state enumeration. During every Monte Carlo step, the contingency list is updated. Components that reach their failure time are taken out of the configuration for a predefined repair time. Unlike the component failure, the repair time is not an exponentially random sample. A fixed amount of time, reasonable and possibly different for every component, is taken to simulate the real repair time. Components that reach the repair time are put into the configuration again. When the grid configuration has been determined, the load flow calculation is performed, which results in a certain average energy loss. In this thesis, the step size is chosen to be constant and set at one hour. It is possible though, to change the step size. Larger steps, for example could be used during periods with no failures and smaller steps when there are one or more failures thereby lowering the running time of the model with the los of accuracy.
In the state enumeration, every load scenario is calculated once for every included contingency state. In the Monte Carlo simulation, a load scenario can be run multiple times for some contingency states, while leaving out others completely. Since the contingency state selection method in the Monte Carlo simulation is random, the running time has to be increased drastically to reach a comparable amount of accuracy. Depending on (among others) the number of components, the failure rates and the needed accuracy the simulation runs for a million, a billion or even more iterations where the state enumeration only needs to assess 8760 load scenarios. Yet, the Monte Carlo simulation will likely omit a number of contingency state load scenario combinations where the state enumeration will assess all the most likely combinations.

6.3 Model Accuracy
The average expected power loss has now been determined for both the state enumeration and the Monte Carlo simulation. In the next section, the accuracy of the different configurations will be assessed.

6.3.1 State enumeration
In a state enumeration, most of the contingency states (for example of an order higher than three) are omitted from the calculation. In this research, the power flow during the omitted contingency states is assumed to be zero and thus neglected. Since this is not necessarily the case, a certain error in the final result of the state enumeration is present. For a state enumeration that includes failures up until the third order, this error can be calculated as:

\[
\text{Error} = 1 - \prod_{i=1}^{n} (1 - U(i)) - \sum_{i=1}^{n} U(i) \cdot \prod_{l=1, l \neq i}^{n} (1 - U(l))
\]

(13)
This error represents the total probability of the contingency states that are omitted and have an unknown effect. Choosing a higher order will result in a smaller error but greatly increase the running time of the model.

### 6.3.1 Monte Carlo

In the state enumeration the error is clearly defined and the boundaries of the uncertainty are rock solid. This is not the case for the Monte Carlo simulation. In this research, the standard deviation is used to determine the accuracy of the model. The Monte Carlo simulation starts to run at time \( t = 0 \) and then runs until time \( t_r \), the total running time, is reached. During this time, the (moving) average lost energy per time unit is constantly recalculated. As shown in the lower part of Figure 47, new averages are calculated during the Monte Carlo simulation to show the progress of the simulation. Using these (moving) averages to derive the standard deviation of the final result does not work, since the (moving) average is heavily depended on the past averages. Due to this autocorrelation the moving average cannot be used to calculate the standard deviation.

The solution to this problem is straightforward: instead of using the moving average, the averages of independent time intervals must be used. This is the same as rerunning the simulation for the number of time intervals, as shown in the upper part of Figure 47. For this reason, a single Monte Carlo simulation runs \( n \) times for the total running time \( t_r \) to get \( n \) results, which will be called samples.

The accuracy of the simulation result is given as a lower (L) and upper (U) limit, with a certain confidence level. For example, the average of a simulation could be 10 GWh with a confidence interval of 9 to 11 and a confidence level of 95%. This means, though the true value is probably not exactly 10, it is very likely that it lies...
somewhere between 9 and 11. Since the samples result in a normal distribution, it can be said that even in the unlikely case that the true value does not lie between 9 and 11 (which has a probability of 5%) the value can still be expected to be close to either 9 or 11. The lower and upper limit are calculated as [105]:

\[ L = \bar{x} - t_c \frac{S_x}{\sqrt{n-1}} \]  
(14)

\[ U = \bar{x} - t_c \frac{S_x}{\sqrt{n-1}} \]  
(15)

Where
- \( L \) is the lower limit
- \( U \) is the upper limit
- \( n \) is the number of samples
- \( \bar{x} \) is the mean of the \( n \) samples
- \( S_x \) is the standard deviation of the sample
- \( t_c \) is the confidence coefficient

Here the calculation of \( \bar{x} \), the mean of the samples is defined as [106]:

\[ \bar{x} = \frac{1}{n} \sum_{i=1}^{n} x_i = \frac{1}{n} \sum_{i=1}^{n} (x_1 + x_2 + \cdots + x_i) \]  
(16)

Where
- \( n \) is the number of samples
- \( x_i \) is the average of the \( i \)th sample

The standard deviation, \( S_x \), of the sample is calculated as:

\[ S_x = \sqrt{\frac{1}{n-1} \sum_{i=1}^{n} (x_i - \bar{x})^2} = \sqrt{\frac{1}{n-1} [(x_1 - \bar{x})^2 + (x_2 - \bar{x})^2 + \cdots + (x_n - \bar{x})^2]} \]  
(17)

Finally, the value for the confidence coefficient \( t_c \) can be acquired from Table 13. As can be seen, the coefficient depends on two parameters. Firstly (horizontally), it depends on the desired confidence level. The higher this level, and thus the smaller the chance that the true value lies outside of the calculated confidence interval, the bigger \( t_c \) becomes. Since the calculated confidence interval is multiplied with \( t_c \), the size of this interval is increased proportionally. The second parameter (vertically) is the number of samples. More samples lead to a higher confidence level.

<table>
<thead>
<tr>
<th></th>
<th>90%</th>
<th>95%</th>
<th>97.5%</th>
<th>99.5%</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>3.08</td>
<td>6.31</td>
<td>12.71</td>
<td>63.66</td>
</tr>
<tr>
<td>2</td>
<td>1.89</td>
<td>2.92</td>
<td>4.30</td>
<td>9.93</td>
</tr>
<tr>
<td>3</td>
<td>1.64</td>
<td>2.35</td>
<td>3.18</td>
<td>5.84</td>
</tr>
<tr>
<td>4</td>
<td>1.53</td>
<td>2.13</td>
<td>2.78</td>
<td>4.60</td>
</tr>
</tbody>
</table>
As can be seen in Table 13, samples larger than 30 hardly lower the confidence coefficient. The number of samples affect the confidence interval in another way though, namely as a division of the root of the number of samples, as can be seen in the equation below:

\[
(L, U) = x \pm t_c \frac{S_x}{\sqrt{n - 1}}
\]  

This formula for calculating the confidence interval leads to two options for a higher accuracy. Firstly, increasing the number of samples (i.e. increasing the number of complete simulations) decreases the size of the confidence level by approximately the root of the number of samples. In other words, more samples lead to a more accurate result. The second method to decrease the distance between the lower and the upper limit (and thus increasing the accuracy) is lowering the standard deviation \(S_x\). Increasing the simulation time of the Monte Carlo simulation can do this. It will result in an average over a longer time with a lower standard deviation \(S_x\). Figure 48 shows this graphically with the same simulation plotted for different time frames. The left figure is plotted between 0 and 500 000 hours. The figure on the right is plotted for a 50 times longer time frame. The plot on the left shows very significant changes with time, whereas the plot on the right becomes more and more stable with increasing simulation time. It can be seen on the right of Figure 48 that after approximately 0.5 x 10^7 hours, the calculated average starts to change less abruptly. This does not take away the fact that the average can change up and down significantly, but according to the law of large numbers \([107]\), the result will move toward the true value with increased simulation time. This means that a longer simulation time results in a smaller standard deviation between different samples. To conclude, both increasing the simulation time \(t\) and the number of samples \(n\) lead to a higher accuracy and a smaller confidence window.
The introduction of the sample method results in the simulation overview as is shown in Figure 49. The determination of the accuracy is simply an iteration of the complete simulation.

**Accuracy determination iterations**

- Contingency list initialization
- Monte carlo simulation
- Contingency list update
- Load flow

Figure 49, improved simulation process of the Monte Carlo reliability simulation

### 6.4 Load flow function

A load flow calculation of a true radial connection is very straightforward. Three characteristics are the key to those calculations. Firstly, the connection is made up of different components that are connected purely in series. Secondly, the maximum power flow through the connection is limited to the component with the lowest rated
power and thirdly, when one component fails the maximum power flow of the whole connection is reduced to zero. These three characteristics have the effect that different load flow functions lead to generally the same result. This is because there is for example no effect on the preferred path due to different impedances because there is only one path. Most studies on offshore power transportation focus on radial connections. The power flow in a meshed grid cannot just be seen as a more complex radial power flow. Firstly, the connection is now made up of components that are both in series and parallel. Due to the presence of parallel components, the maximum power flow is not restricted to the rated power of the smallest component in the network. This also applies for the failure of a component since the power flow could be reallocated to parallel paths. A more profound method is needed to determine the maximum power flow because of two reasons. Firstly, the number of possible paths increases rapidly with an increase of nodes resulting in very extensive calculations. Secondly, an optimal usage of component power is not even assured because the impedances of the components now determine the power flow. Three main different load-flow calculations can be defined. These methods, which are shown in Table 14 and are explained by Kirtley [108] and Hertem [109], are the graph load flow, the DC load flow and the AC load flow.

<table>
<thead>
<tr>
<th>Name:</th>
<th>Based on:</th>
<th>Calculation by:</th>
<th>Parameters:</th>
<th>Solution is:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Graph flow</td>
<td>Power levels</td>
<td>Assessing all possible paths</td>
<td>P</td>
<td>The ideal case</td>
</tr>
<tr>
<td>DC load flow</td>
<td>Power levels &amp; impedances</td>
<td>Set of linear equations</td>
<td>V, δ, P, Q</td>
<td>Approximation</td>
</tr>
<tr>
<td>AC load flow</td>
<td>Power levels &amp; impedances</td>
<td>Set of non-linear equations</td>
<td>V, δ, P, Q</td>
<td>Accurate</td>
</tr>
</tbody>
</table>

Table 14, aspects of different load flow calculations

As is explained by Grainger and Stevenson in Power System Analysis [110], a number of assumptions apply for all three the calculation types:
1. The system is represented as a one-line-diagram
2. The system is in steady state (i.e. there are no transients)
3. The system frequency is constant
4. A balanced loading of the three phases

The AC load flow is more complex than the DC load flow due to the non-linearity of the equations. The running time of the DC load flow and Graph load flow mainly depends on the extensiveness of the configuration. The DC load flow needs the impedance of components to run. Because these impedances were not acquired, the DC load flow cannot be accurately used. Nevertheless, the graph flow simulation can be expected to be accurate in this case because of a number of reasons. Firstly, the studied network is more or less symmetrical. Secondly, the power flow is unidirectional from the generation node to the load (onshore grid) node. Thirdly, it is assumed that the power flows can be directed quite accurately due to the ability of switching wind turbine (strings) from one radial branch to another. This makes it possible to distribute the load in increments of at the highest 10 per cent, with 10 strings of wind turbines and full wind power production. In the case of more strings and lower wind power production, the increment become even smaller.
6.4.1 Graph flow

A graph flow is the most simplified method of analyzing power systems. This kind of load flow analysis assumes that all connections are (and can be) loaded to the rated capacity. This is only possible if the distribution of the power can be directed appropriately from a power grid operation point of view. In the method, components are reduced to a single parameter: the rated power level. Subsequently, every possible path from the generation nodes to the load nodes has to be defined individually to come to the complete solution. When all paths have been defined, the simulation for a certain load distribution can be simulated. One of two things can happen during the simulation. Either at some point all the energy has been moved from the generation nodes to the load nodes, or every possible path has been tried and a certain amount of energy cannot be transported. In the first case, the graph load flow returns the conclusion of zero lost energy and in the second case, it returns the amount of energy that cannot be transported.

In an onshore power grid, the graph load flow is very problematic for a number of reasons. In small networks, the graph load flow is easy to compose and also has a short running time. Due to its exponential increased complexity, both the simulation time and the composing time increase drastically with only small increases in network size. Since onshore networks are heavily interconnected, the number of paths is extremely large. Another problem is that load and generation nodes can vary, move and interchange over time increasing the number of possible paths even further. It is mathematically possible, but will take too long to compose and to run. The Dutch offshore power grid as studied in this research on the other hand provides a perfect case since the generation and load nodes are clear and fixed at certain places.

6.5 Price Correlation

The model that has been explained above can use different methods (Monte Carlo/state enumeration and graph flow/DC load flow) but has the same output: an amount of lost energy. The choice of configuration is based on the investment costs of that specific configuration in comparison with the PV of the added cash flow of the configuration. For that reason, the amount of lost energy should be multiplied by the applicable energy price. As has been pointed out before, this energy price could be correlated with the amount of produced wind energy. For this reason, a simple operator is built into the code to analyze the effect of different correlation levels. The energy price can be determined for every load scenario based on the following formula:

\[ C_{\text{now}} = C_{\text{average}} \left(1 + 0.5 \rho_{\text{wind}} - \rho_{\text{wind}} \frac{P_{\text{now}}}{P_{\text{rated}}} \right) \]  

(19)

Where

- \( C_{\text{now}} \) is the current energy price [Euro]
- \( C_{\text{average}} \) is the selected average energy price [Euro]
- \( \rho_{\text{wind}} \) is the selected wind-price correlation
- \( P_{\text{now}} \) is the current wind power production [Watt]
- \( P_{\text{rated}} \) is the rated power of the wind farm [Watt]
6.6 Overloading

The cables and transformers in the power grid have certain rated powers, which can be seen as the standard maximum power. It is possible though, to overload a component for a certain amount of time. As has been described in the literature study, this can have different effects. As long as the cable temperature remains below the maximum operation (rated) temperature, the effect of overloading on the lifetime of the component is very limited. Further on, this type of overloading will be referred to as ‘current overloading’. When the rated temperature is exceeded, the aging process of the component is accelerated, which increases the failure rate. This type of overloading will further be referred to as ‘temperature overloading’.

So, what is the effect of current overloading of certain components without exceeding the maximum temperature, and when would it be beneficial? Speaking in quantitative terms, temporary current overloading will increase the power transporting capability of the grid and will increase the (temporary) power capacity of bottlenecks. This can be beneficial in different situations. A first advantage is that by temporarily current overloading, energy losses due to component failures can be lowered. A second possible advantage of overloading components is that it could compensate an under-dimensioning of the grid itself, or in other words, partly preventing curtailment. Since the grid is only fully used for a limited amount of time, it could be beneficial to under-dimension the grid and compensate wind farm owners for their lost income. Allowing overloading of the system components could lower the amount of curtailed energy and thus lower the amount of energy the TSO has to compensate.

6.6.1 The model

Hunt [111], Karahan [112], Wadman, the IEEE Guide [113] and the Siemens product description [114] all formulate a general thermal model that predicts the component temperature as a result of the (past) current, along with a number of fixed parameters. The general transient temperature first-order differential equation of a component is given as:

\[
\tau \frac{d\theta(t)}{dt} + \theta(t) = \frac{|I_{meas}(t)|^2}{I_{meas}^2}
\]  

(20)

Where \( \tau \) is the thermal time constant for heating of the component, \( \Theta \) is the relative temperature of the component, \( I_{meas} \) is the measured current, and \( I_{max} \) is the rated current of the component.

In the formula \( \Theta \) is defined as:

\[
\theta(t) = \frac{T(t) - T_0}{T_{max} - T_0}
\]  

(21)

Where \( T \) is the temperature of the components, \( T_0 \) is the ambient temperature, and \( T_{max} \) is the maximum operation temperature of the component.

The direct solution of this differential equation is:
This formula can be simplified when the current through the component is (assumed) constant over time (i.e. \( I(t) \equiv I \)) to:

\[
T(t) = T_0 + \frac{T_{\text{max}} - T_0}{R_{\text{max}}^2} \int_0^t |I(s)|^2 e^{(s-t)/\tau} \, ds
\]

(22)

This final equation thus gives the temperature of a component at time \( t \) as a result of the measured current through the component, the rated current, the ambient temperature, the maximal operation temperature and the thermal time constant for heating of the component. When the \( I_{\text{max}}, T_{\text{max}}, \) and \( \tau \) of a component are known, the temperature increase of the component can be determined when the current through the component is known (and assumed constant for some time).

The same general model can be used in this thesis, but a few adaptations are made. Firstly, the ambient temperature will not be used. Instead, the maximum temperature is always adjusted for the maximum ambient temperature. This is achieved by lowering the maximum operating temperature by the maximal assumed ambient temperature. For example, when the maximum assumed ambient temperature is 20 °C and the maximum operating temperature of the component is 100 °C, the maximum component temperature is set at 100-20 = 80 °C. The second adjustment in the model is the addition of a starting temperature. When a component has already been used on a certain power level for a certain time, the temperature will have been elevated. For that reason, the final temperature of the last sample is added in the model in the form of \( T_{\text{start}} \). Finally, to make the model directly usable for load-flow calculations, it will not be based on current but on power. The relation between current and power is linear. For this reason, it is sufficient to replace the instantaneous current with instantaneous power and the rated current with the rated power. The adaptations result in the following model:

\[
T(t) = T_{\text{start}} + \left( \frac{|P_{\text{meas}}|^2}{P_{\text{max}}^2} T_{\text{max}} - T_{\text{start}} \right) (1 - e^{-t/\tau})
\]

(23)

Where \( P_{\text{meas}} \) is the measured power

\( P_{\text{max}} \) is the rated power of the component

\( T_{\text{start}} \) is the temperature of the component at \( t = 0 \)

In Figure 50, the result of a number of temporary overloads is shown. The component has a \( P_{\text{max}} \) of 350 MW and the component is overloaded by over 14 percent resulting in a \( P_{\text{meas}} \) of 400 MW. The time constant \( \tau \) is taken to be 1.7 hours. The maximum operating temperature is 150 °C and the maximum ambient temperature is taken to be 30 °C. This results in a \( T_{\text{max}} \) of 120 °C. For the starting temperature \( T_{\text{start}} \), different temperatures have been taken, namely 0, 45, 90, 135 and 180 °C. The different starting temperatures lead to different possible overloading times. With a completely cooled down component (i.e. a component at ambient temperature), an overload of approximately 2.5 hours is permitted, while a component that starts at a temperature of 90 °C reaches the critical temperature of 120 °C in 1 hour. It is obvious that when the component is already above the 120 °C...
limit, it will not operate below the critical temperature. Furthermore, it is good to note that the component that starts at a temperature of 180 °C actually cools down during the overloading period. The model thus calculates the heating or cooling of the component. This makes it possible to calculate the continuous component temperature in increments of hourly component temperatures.

![Figure 50, dynamic temperature development of a component during overloading for five starting temperatures.](image)

Equation (24 is built into a function, which can be called by the main model. In Figure 51, the relative power level and the relative temperature of a transformer are shown for a random 500-hour period. As can be seen, the component only reaches the maximum temperature after an extended time of maximum loading. The thermal inertia results in a temperature that lags behind the power level of the component. Since cooling goes faster at higher temperature differences, the relative temperature is almost always below the relative power level.
Figure 51, percentage of the maximum component temperature as a result of the current and past power levels in the component

6.7 Conclusions
In Figure 52 the updated version of the overview of the Matlab model is shown. As can be seen, the price correlation function is simply called by the main model (either Monte Carlo or state enumeration) to determine the current energy price. As is explained by Wadman [115], to enable overloading of components, the simulation needs to be in time domain. For that reason the component temperature function only works with the Monte Carlo simulation.
7 Simulation results

7.1 Introduction
In this chapter, the component data and economical parameters from chapter 4 and the models presented in chapter 5 and 6 will be used to assess the effect of the different configuration options as defined in chapter 3. In the first part of this chapter, the worst-case reference scenario, in the form of the radial connections, will be analyzed. In the second part, all the different configuration options will be examined. The third part of this chapter is composed of sensitivity analyses of the different parameters used in the research. This will lead to the two final parts of this chapter, where the preferred grid for the current situation is selected and subsequently, a more general result is derived that could be used for other offshore wind projects.

7.1.1 Unavailability
With the component unavailability as defined in chapter 4 and the simulation models presented in chapter 6, it is possible to assess the reliability of different offshore grid configurations. The radial 220 kV configuration forms a logical starting point for three reasons:

1. Firstly, the radial configuration can be seen as the worst-case scenario in terms of reliability for the 220 kV options because there is no redundancy in that configuration.
2. Secondly, the radial configuration is the lowest cost 220 kV connection option due to the absence of redundancy investments.
3. Thirdly, the reliability analysis of radial connections is very straightforward, making it easy to calculate, analyze and compare.

Because of these three reasons, the radial 220 kV configuration is taken as the benchmark or configuration 0. As was just mentioned, the calculation of both the reliability and the lost energy is simple for the radial case. This is because a radial transmission grid can only transmit power when all components are working, such that a radial connection is either available or unavailable. Unavailability is thus equal to one minus the probability that all components are operational. For the 220 kV radial configurations, this results in 1.08 % of unavailability due to forced outages, which is just over 94 hours per year. Based on the 2020 wind energy scenario presented in chapter 4, the total yearly average collected wind energy for a 350 MW wind farm is 1.39 TWh. Of this 1.39 TWh, 1.08 % cannot be transported to the onshore grid due to unavailability of the offshore grid. This results in 14.95 GWh of lost energy.
In Figure 53, the origins of the unavailability of the radial offshore grid are shown. As can be seen, the unavailability of the grid counts for over 99.5 % to first-order failures, where offshore cable failures account for approximately 45 %. With the use of the present value (PV) model presented in chapter 5 and the economical parameters given in chapter 4, it can be calculated that the PV of the lost energy is € 18.3 million per 350 MW branch connection. This € 18.3 million is the PV of the lost cash flow from wind energy over the total investment period of the grid. This cash flow thus is the PV of the lost income from wind energy over the total investment period.

### 7.2 Options for improvement

In this part, the different proposed grid improvements from chapter 3 will be assessed and compared. The here calculated PVs are based on the component parameters and energy prices as defined in chapter 4, subsequently using the socio-economic reliability model from chapter 5 and calculating the lost energy with the load flow models described in chapter 6. With this approach, it is possible to come to an overall analysis of different grid configurations in the form of the PVs of the extra-generated cash flow of the different redundancy options. Figure 54 from chapter 3 is shown here again as a reminder to the different acronyms of branch and hub couplers.
The starting point of the grid analysis is the lowest level redundancy option, the branch couplers. As mentioned before, this can be done at three different points, namely 66 kV offshore, 220 kV offshore and 220 kV onshore. With these three options, the total amount of grid configurations is $3^2=9$. The result of the reliability analysis of these eight configurations is shown in Figure 55. In the figure, the amount of lost energy due to the unavailability of the grid is presented in ‘orange vertical stripes’. The amount of saved energy due to the added branch coupler(s) is given in ‘green diagonal stripes’. The amount of energy is presented as GWh per year for a single branch (350 MW connection).
Three main observations can be made in Figure 55:

1. Firstly, the benchmark configuration (0) with “no branch couplers” leads to an amount of lost power of just under 15 GWh per year. This number, resulting from the reliability calculation, is indeed the same number as was calculated in 7.1.1 for the radial configuration.

2. Secondly, like predicted in chapter 3, of the three single branch coupler configurations (‘Offshore at 66 kV’, ‘Offshore at 220 kV’ and ‘Onshore at 220 kV’), the effect on the amount of saved energy becomes weaker when the redundancy option is located closer to the onshore grid. The ‘Offshore 66 kV’ coupler saves close to 5.6 GWh per year whereas the ‘Off- and onshore at 220 kV’ only save 3.8 and 1.3 GWh per year respectively.

3. Finally, the redundancy effect of configurations with more than one branch coupler is roughly as effective as the most effective single branch coupler of that configuration. For example, adding the ‘Offshore at 220 kV’ coupler to the ‘66 kV coupler’ only saves an extra 0.04 GWh per year.

In conclusion, it can be said that adding more than one branch coupler has no significant effect on the amount of lost energy and the 66 kV branch coupler has the biggest impact on the amount of saved energy because it has a redundancy effect on a larger number of components.

The configurations in Figure 55 are all based on coupler capacities of 350 MW. In Figure 56, the effect of different coupler capacities is assessed. From the figure, it is clear that the effect of an increased branch coupler capacity has a positive effect on the extra saved energy until a power level of approximately 175 MW.

Two important observations can be made based on Figure 56:

1. Firstly, the effect on the energy that can be saved with increasing coupler capacities approaches a horizontal asymptote. At first, the effect is strong.
Closer to the 175 MW point, the effect slows down and after the 175 MW point, there is no added effect.

2. Secondly, in an offshore grid fitted exactly to the size of the wind farm, the branch coupler capacities should not be higher than 50 percent of the peak power of that branch. The extra capacity above the 50 percent will not be used in practice. This point has been indicated in Figure 56 with the vertical gray dotted line at the 175 MW point.

The effect in Figure 56 can easily be explained. At 50 % of the peak wind power, a 350 MW transformer has to process 175 MW from its own branch. In this case, the transformer could thus take up to 175 MW from another branch. At higher wind powers, the transformer can take less power from the other branch because it has to process more power from its own branch and at lower wind speeds, there is simply no need for a branch coupler capacity of more than 175 MW. The conclusion that can be made here is thus that in a configuration with only branch couplers, a branch coupler capacity of over 175 MW is over-dimensioned. It is good to notice here that this effect might be different for more meshed offshore grids.

Based on the amount of saved energy shown in Figure 55 with ‘green diagonal stripes’, and the PV model described in chapter 5, it is possible to come to a PV for the extra-generated cash flow for the different branch coupler configurations. The result of these calculations is shown in Figure 57 in ‘blue diagonal stripes’. In the figure, also the investment costs of the configurations are added in ‘red horizontal stripes’. Subtracting the investment costs from the PV of the cash flow results in a net present value (NPV) of the configuration, which is shown in blue. The calculation here is done per designated area of 1400 MW, which accounts for 4 branch couplers (or 8 branch couplers at 66 kV).

Two main conclusions on branch couplers can be drawn from Figure 57:
1. Firstly, the ‘66 kV branch coupler’ clearly has the highest NPV. This is due to the combination of the low investment costs and the relatively strong effect on the amount of lost energy.

2. Secondly, investing in multiple couplers within a single branch always has strong a negative effect on the NPV of the configuration. This is the result of a not significant increase in the PV of the cash flow on one hand and a strong increase in the investment costs on the other hand.

Based on the results in Figure 57 and the two conclusions given above, a ranking of the top branch configuration options can be made. This ranking is given in Table 15.

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Branch coupler option</th>
<th>NPV (M€) (see Figure 57)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>66 kV (BC1) 350 MW</td>
<td>22.20</td>
</tr>
<tr>
<td>2</td>
<td>Offshore at 220 kV (BC2) 350 MW</td>
<td>3.94</td>
</tr>
<tr>
<td>3</td>
<td>Onshore at 220 kV (BC3) 350 MW</td>
<td>2.78</td>
</tr>
</tbody>
</table>

Table 15, ranking of the top branch coupler configurations (NPV per 1400 MW connection)

### 7.2.2 Hub couplers

The next redundancy option level is the hub coupler. The hub couplers can be installed at three different locations bringing the total configuration options at $2^3=64$. This total amount of configurations can be narrowed down in two ways though. Firstly, as explained in chapter 3, a hub coupler can only be constructed when the branch coupler is already in place. Secondly, based on Figure 55 and Figure 57, multiple couplers at the same topology level do not result in an added effect. The combination of these two constraints lowers the total amount of configurations to no more than three: the ‘66 kV branch & hub coupler’, the ‘Offshore at 220 kV branch & hub coupler’ and the ‘Onshore at 220 kV branch & hub coupler’.

The result of the reliability analysis of these three configurations is shown in Figure 58. In the figure, the amount of saved energy due to hub couplers is represented in ‘dark green squares’. The amount of lost energy is presented as GWh per year for a single branch (i.e. 350 MW).
Two main observations can be made based on Figure 58:

1. Firstly, also for the hub couplers the effect on the amount of saved energy becomes weaker when the redundancy is located closer to the onshore grid.
2. Secondly, for all the three configurations the amount of extra saved energy due to the hub couplers is considerably lower than the amount of extra saved energy due to the branch coupler. In all three cases, the effect of the hub coupler is about 55% of the branch coupler.

As was the case for the branch couplers in Figure 55, also the configurations in Figure 58 are all based on coupler capacities of 350 MW. In Figure 59, the effect of different branch and hub coupler capacities is assessed with the use of a 3D plot.

In Figure 59 three main observations can be made:

1. Firstly, on the right hand axis (where the hub coupler power level is 0) the same 66 kV branch coupler shape as in Figure 55 can be seen. Here again, the maximum effect of an increased branch coupler power level lies at about 175 MW.
2. Secondly, for increased hub coupler capacities (i.e. higher than 0), the maximum branch coupler power level with an effect on the saved energy increases up to 250 MW. This is because the hub coupler enables extra spreading of the otherwise lost power over the remaining components.
3. Thirdly, it can be seen that the saved energy due to the hub couplers increases until a power level of 175 MW.

It can thus be concluded that there is no need to increase the branch and hub coupler capacities beyond respectively 250 and 175 MW. It is good to notice again that these values might be different for more meshed power systems.
Based on the amounts of saved energy shown in ‘dark green squares’ in Figure 58, and the PV model described in chapter 5, it is possible to come to a PV for the cash flow of the different hub coupler configurations. The result of these calculations is shown in Figure 60 in ‘blue diagonal stripes’. In the figure, also the investment costs of the configurations are added in ‘red horizontal stripes’ and the NPV with a ‘blue horizontal line’. The calculation is done per designated area of 1400 MW consisting of 4 branch couplers.

Two main conclusions can be drawn from Figure 60:

1. Firstly, just like the branch level, it is again the ‘66 kV coupler’ that has the highest NPV, followed by the ‘Offshore at 220 kV’ and finally the ‘onshore at 220 kV’.
2. Secondly, both the ‘66 kV coupler’ (HC1) and the ‘Offshore at 220 kV’ (HC2) have a positive NPV of roughly the same amount. The amount of saved energy for the HC1 configuration is substantially larger than for the HC2 configuration but this is partly compensated by the lower investment costs of HC2 in respect to HC1.

Based on the results from Figure 60 and the branch coupler ranking given in Table 15, a ranking of the configuration options for branch and hub couplers can be made. This ranking is given in Table 16.

<table>
<thead>
<tr>
<th>#</th>
<th>Top coupler configurations options</th>
<th>Branch coupler NPV (M€) (see Table 15)</th>
<th>Hub coupler NPV (M€) (see Figure 60)</th>
<th>Total NPV (M€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>BC1 (350 MW) &amp; HC1 (175 MW)</td>
<td>22,20</td>
<td>5,24</td>
<td>27,44</td>
</tr>
</tbody>
</table>
### 7.2.3 Designated area couplers

The next redundancy level is the designated area coupler. The designated area couplers can be made at four different locations bringing the amount of coupler options from 6 to 10 and the total amount of configuration options at $2^{10}=1024$. There are two separate reasons to invest in designated area couplers.

1. The first reason is to increase the NPV of the grid by saving extra energy that would otherwise be lost due to unavailability of the offshore grid.
2. The second reason is to increase the reliability of the connection to the onshore grid. This has an effect for both the use of the offshore grid and for the onshore grid itself.

Due to the size of grid configurations with designated area couplers, it is not possible to assess the load flow simulation of these configurations using a graph flow. It is nevertheless possible to make statements on the profitability of the designated area couplers. When it is assumed that all the energy that is lost in a power system with 66 kV branch and hub couplers can be saved using designated area couplers (9.6 GWh/year), the PV of this cash flow for eight 350 MW connections to the onshore grid is € 33.9 million. The investment costs of the shortest designated area coupler, which is 40 km, is expected to be at least € 45.0 million. On top of this, in the expected investment costs, the costs of compensation reactors are not included. To conclude, even in a highly over-estimated scenario, the NPV of the lowest cost designated area coupler is still strongly negative.

The second advantage of designated area couplers is that they reinforce the onshore grid. A simplified representation of the onshore grid is shown in Figure 61. The connections in this grid are all 380 kV connections and have a capacity of 2635 MVA. The 150 kV grid has been left out of this configuration since most 150 kV connections have a capacity of about 484 MVA and therefore, the 150 kV network hardly creates redundancy for the 380 kV grid.

<p>| | | | | | |</p>
<table>
<thead>
<tr>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>BC1 (350 MW)</td>
<td>22,20</td>
<td>-</td>
<td>22,20</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>BC2 (350 MW)</td>
<td>3,94</td>
<td>-</td>
<td>3,94</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>BC3 (350 MW) &amp; HC3 (350 MW)</td>
<td>2,78</td>
<td>0,99</td>
<td>3,77</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>BC3 (350 MW)</td>
<td>2,78</td>
<td>-</td>
<td>2,78</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>BC2 (350 MW) &amp; HC2 (350 MW)</td>
<td>3,94</td>
<td>-5,08</td>
<td>-1,14</td>
<td></td>
</tr>
</tbody>
</table>

Table 16, ranking of the top branch & hub coupler configurations (NPV per 1400 MW offshore grid)
Based on the simplified grid in Figure 61, a number of statements about the off- and onshore grid configuration can be made:

1. Firstly, the onshore grid between the designated area connection points is already very strong with up to 4x 380 kV connections. Extra redundancy upgrades in this area will thus have little added effect on the overall reliability of the grid. Also, the 350 MW capacity of the offshore power grid is relatively small in comparison to the 2635 MVA 380 kV lines.

2. Secondly, as shown in Figure 61, the designated area couplers enable large loop flows through the offshore grid based on the specific impedance of the different paths. These flows can form a serious issue for the operation of the grid.

Apart from these two observations, the onshore grid in general is more reliable than the offshore grid. For that reason, onshore reinforcements have more effect than offshore reinforcements. On top of that, onshore reinforcements will also have far lower investment costs. In conclusion, designated area couplers will not have a positive NPV based on the amount of saved energy and neither have a significant effect on availability of the onshore grid.

7.2.4 Grid connections to other locations
Next to designated area couplers, it is also possible to connect the offshore hubs with other onshore locations. In chapter 3, the most feasible options have been discussed and pointed out. Just like the designated area couplers, grid connections to other locations could have an effect on the amount of lost energy and on the reliability of
the onshore grid. The effect on the amount of lost energy due to the unavailability of the offshore grid is purely negative. This is mainly the result of two factors:

1. Firstly, changing (one or more) connections from the standard onshore substation to another onshore substation on itself does not lead to increased internal redundancy in the offshore grid and will thus not lower the amount of lost energy in that way.

2. Secondly, the amount of lost energy will actually increase. Due to the grid connections to other locations, the average length of offshore cables will increase from 30-40 km up to 90 km. When it is assumed that the new cable length is 80 km, the unavailability of the radial connection goes up from 1.08 % to 1.56 % which subsequently leads to 21.7 GWh instead of 14.95 GWh of yearly-lost energy.

What is the effect of the grid connection to other locations on the availability of the connection to the onshore grid? This availability is increased since the designated areas now have more than one connection to the shore. When one of the onshore substations experiences a blackout, there is still the connection with the other substation. The overall effect is very limited though due to the following reason:

3. As was shown in Figure 61, the Dutch onshore grid is very strong and the expected unavailability of the onshore substations will be very low.

Next to the arguments given above, there are some other problems to consider:

4. Due to the increased cable length, the total cost of the offshore grid can be expected to increase considerably.

5. The different substations are planned to be installed with time gaps of about 2 to 3 years. For that reason, making connections to other substations will lead to logistical problems, since one cannot make a grid connection to a substation that does not (yet) exist.

6. Finally, the argument about loops flow as is shown in Figure 61 will also worsen the operation of the offshore grid when connection to other locations are implemented.

To conclude, the effect of making grid connections at different locations is possible but does not have a positive effect on the off- and onshore grid operation and also leads to a whole range of problems. For that reason, it is deemed here as feasible but not beneficial.

7.2.5 Oversizing of components

Next the effect of oversizing components will be assessed. In regard with oversizing components, three things should be considered:

1. Firstly, oversizing a radial connection does not have an effect on an offshore power grid fitted to the wind farm power size, as long as the reliability of the components remains the same. The connection is either fully available or fully unavailable.

2. Secondly, the increased capacity of components only has effect when there are couplers present in the grid, because only then the extra power could be brought in from another branch.

3. Thirdly, it should be noted that oversizing components is seen here as a result of standardization and not an investment on itself. Therefore, the investment costs of oversized components are not taken into account.
In Figure 62, the effect of increased component sizes for different branch couplers is shown. On the left, the amount of saved energy due to the coupler itself is shown. On the right, the effect of oversizing the complete power grid is shown. The results in between show cases where one or two components have an increased capacity.

In Figure 62, two observations can be made:
1. Firstly, increasing the capacity of the complete offshore grid from 350 MW to 400 MW, which has been done on the right hand side of the graph, leads to an increased amount of saved energy between 25 and 33%, depending on the grid configuration.
2. Secondly, oversizing components only has an effect when the complete path from the coupler to the onshore grid is increased in size. This means that for the 66 kV offshore branch coupler, the complete offshore grid needs to be oversized.

In Figure 63, the same graph as in Figure 62 is shown but for configurations with both branch and hub couplers. It can be seen that the effect of oversizing different components is roughly the same as for the branch coupler case. The only difference is that the amount of saved energy is increased by 40 to 45 %, depending on the configuration.
The conclusion that can be drawn about oversizing components is that it only has effect when the complete path from a coupler to the onshore grid has an increased capacity. This has different implications for different couplers.

1. For the branch and hub couplers at 220 kV onshore, only the onshore transformers need to be oversized, which results in a 42% increase in saved energy.
2. For the branch and hub couplers at 220 kV offshore, also the offshore cable has to be oversized. Unlike a standardized transformer that could very well be cheaper at an oversized capacity, a cable is not likely to be oversized as a result of standardization.
3. For the branch and hub couplers at 66 kV, oversizing components only has an effect if the complete connection is oversized. This option will be assessed in the next part “Resizing the wind farm”.

So, the effect of oversizing components as a result of standardization can only have a positive effect on the ‘Onshore at 220 kV’ (BC3) and the ‘Onshore at 220 kV branch & hub couplers’ (BC3 & HC3) configurations.

### 7.2.6 Resizing the wind farm

The next option that is assessed here is the effect of resizing of the wind farm with respect to the offshore transmission grid. In Figure 64, the effect on the NPV of resizing the wind farm capacity relative to the offshore grid capacity is shown in a graph for the radial, or benchmark configuration (0). The relative size of the wind

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**Figure 63**, Effect of increased component size on the amount of saved energy (for branch and hub couplers)
farm is varied between 91% to 110 % of the transmission capacity of the grid. The 100 % point in the middle of this graph is the standard situation that has been used in the calculations above. On this point, there is no effect on the NPV.

In Figure 64, three main observations can be made:

1. Firstly, it can be seen that both increasing and decreasing the relative size of the wind farm in increments of 1 % has a negative effect on the NPV of the power system.

2. Secondly, the negative NPVs on the left side of the graph are the result of a relatively more expensive offshore grid (a smaller wind farm, which uses the same offshore grid, thus increasing the relative grid costs). This does also decrease the amount of power losses, but the NPV of the saved power losses does not weight the relatively more expensive offshore grid.

3. Thirdly, on the right hand side the same increments have an even stronger effect on the NPV. This lowering is the result of an increasing part of the generated wind energy that cannot be transmitted to the onshore grid. This lost energy should in part be compensated by the fact that the offshore grid is now relatively cheaper, because there is a larger wind farm with the same offshore grid. Evidently, the relative reductions in the investments in the offshore grid costs do not offset the NPV of the extra-lost energy.

The graph in Figure 64 seems to suggest that the optimum relative size between the wind farm and the offshore grid is 100 %. If we zoom in on this 100 % point, this turns out to be incorrect. In the graph in Figure 65, the scale has been adjusted from 99.91 % to 100.10 %.
Figure 65, the effect on the NPV of resizing the wind farm relative to the power system size (€ 135 M grid)

The graph in Figure 65 proves two things:
1. The first one is that oversizing the wind farm does in fact lead to a higher NPV and thereby to a more optimal situation.
2. The second point is that the optimum wind farm size lies somewhere between 0.03 and 0.04 % above the size of the power system.

How should this 0.03 to 0.04 % be interpreted? Assuming that the power output of the wind turbines is relatively low, let’s say 2.5 MW peak. This would mean that a total of 140 wind turbines would be connected per offshore branch of 350 MW. Adding one wind turbine and increasing the total amount to 141 would mean an increase of 0.71 % in peak output power. Increments in the order of 0.03-0.04 % are thus 20 times smaller than the effect of one wind turbine and might actually be problematic to achieve. Also gaining € 30 000 on a € 135 million offshore grid, or 0.022 %, is not a huge achievement. Yet to be sure, adding 1/20 of a wind turbine, if this would be possible, will lead to an overall higher expected NPV of the complete power system. The conclusion here then is two sided: oversizing the wind farm can improve the NPV of a radial grid connection, but the added value is far from significant.

In the graph of Figure 65, all parameters, apart from the relative wind farm size, where kept constant. In Figure 66, the wind farm investment costs, the price correlation and the level of redundancy are varied. It is clear from this figure that it is mainly the ratio between the energy price per MWh and the total investment costs of the offshore grid that determine the optimal wind farm size. With relatively low offshore grid costs in comparison with the energy price, the oversizing of a wind farm leads to relatively high amount of lost cash flow that is not compensated by the lowered investment costs.
A number of things can be noted in Figure 66:

1. Firstly, an increased wind energy production price correlation increases the NPV of oversized wind farms.
2. Secondly, both higher power system costs and lowered energy prices increase the NPV of oversized wind farms.
3. Thirdly, an extra meshed power systems does not have much effect on the NPV of the configurations.

There is a fifth factor that could play a roll here though. The world wide average availability of an offshore wind turbine lies between 0.95 and 0.98 [118] Bussel (2001) [119]. For that reason it might be interesting to undersize the capacity of the power grid to match the average availability of the wind farm. A more final conclusion about the resizing of wind farms cannot be made here because of two reasons:

1. Firstly, as was mentioned in chapter 4, the data on the total offshore power grid costs used in this thesis was not clear or coherent.
2. Secondly, the real-time unavailability of wind turbines cannot be expected to be fixed on the average unavailability. There could be an auto correlation on the real time unavailability of wind turbines (for example due to storms) or another unforeseen mechanism that has an effect on the preferred offshore power grid size.

It can nevertheless be concluded that an overdimensioned wind farm (and thus a underdimensioned offshore power grid) can be desirable in certain situations. It can be expected that this overdimensioned of the wind farm is up to 10 percent of the total wind farm capacity. Up to 5 percent point is due to the unavailability of the wind turbines, the other 5 percent point could be the result of an extreme combination of total offshore power grid cost and energy price.

7.2.7 Effect of overloading
The overloading of one or more components means that these components are used above their rated power for a certain period of time. This is usually done in the order
of magnitude of tens of minutes or hours. Because the MTTR of (offshore) power system components is usually in the order of weeks, the direct effect of overloading based on the MTTR cannot expected to be very high. During the first 2 hours of a forced maintenance, the lost power might be reduced considerably, but after these 2 hours, it would still take 597 hours for the component to be replaced.

What could have a positive effect is that wind farms do not have a constant power output. For that reason, components can cool down and be overloaded for a number of cycles during the MTTR of the component. This could increase the effect of overloading from 2 hours of overloading during 600 hours unavailability to for example 2 hours of overloading during the same unavailability period. This would be an increase form 0.5% to 50%.

So, do the simulations results agree about the effect of overloading? Because the dynamic temperature of a component is a chronological parameter, a state enumeration cannot be used to calculate the effect of overloading of components. A Monte Carlo simulation can be run chronological and was therefore used to calculate this effect. The state enumeration for the BC1 configuration with no overloading resulted in an average yearly lost energy of 9.36 GWh. The results of the Monte Carlo simulation of the BC1 configuration with a 95% confidence interval are shown in Figure 67.

![Figure 67](image)

**Effect of overloading on the amount of lost energy**

<table>
<thead>
<tr>
<th>Yearly lost energy (GWh/year)</th>
<th>Upper limit</th>
<th>Average</th>
<th>Lower limit</th>
</tr>
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<tbody>
<tr>
<td>1 hour run</td>
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<td></td>
<td></td>
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<tr>
<td>3 hour run</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>9 hour run</td>
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</tbody>
</table>

Figure 67, the difference between overloading and no overloading for the BC1 configuration (95% confidence interval)

Two conclusions can be made based on the results in Figure 67:
1. Overloading does not have a significant effect on the amount of lost energy. The 95% confidence interval for overloading overlaps with the result of the state enumeration with no overloading.
2. Looking at the results of the run with the highest accuracy (the 9 hour run), it can be said with 95% confidence that the effect of overloading lies between 0.3 higher losses and 1.4% lower losses. Since there is no reason for the overloading to result in higher losses, the real 95% confidence interval lies between 0% and 1.4% lower losses.

The explanation of this insignificant effect of the overloading of components can be found in the wind power production pattern. The autocorrelation of the wind power production (as was delivered by the 2020 data set) shows a high auto-correlation. In
Figure 68, the autocorrelation of the produced amount of wind energy is shown. It can be seen that the produced amount of wind energy shows a correlation of above 60% for at least 10 hours. Even after these first 10 hours, the autocorrelation remains high for an extended period of time. In time series analysis a 5 % auto correlation is usually seen as significant [120]. It can be seen in Figure 68 that the hourly wind energy production with an autocorrelation of about 20 % for over 120 hours is located well above the 5 % significant level. In other words there is a very strong basis wind pattern.

This is unlike for example a load profile in a neighborhood where the 24-hour correlation (the correlation between periods 24 hours apart) is quite high, but the correlation over several hours can be quite weak. Daily load peaks in a neighborhood have a duration between 20 min to 120 min whereas these wind patterns show wind cycles that can take over 100 hours.

The conclusion that can be made about the overloading of components based on Figure 67 and Figure 68 is the then following: due to the length of the basic wind pattern and the relative short period of overloading the effect of component overloading is hardly significant on the amount of lost power in an offshore wind farm.

![Wind pattern autocorrelation](image)

In Figure 69 the same calculation as in Figure 67 is shown but now for a 4 % oversized wind farm. It can be seen that the total amount of lost energy increased from around 9.4 GWh/year to around 25 GWh/year. This increase in lost energy is obviously the result of the 4 % oversized wind farm. It is the question though, if the amount of lost energy is considerably lower than would have been expected. In other words, is the effect of overloading improved due to the resizing of the wind farm, or the other way around, is the effect of resizing the wind farm improved due to the overloading of components?
Two conclusions can be made based on the results in Figure 69:

1. Firstly, again there is not a clear significance of overloading on the amount of lost energy. Except for the 9 hour run, the 95% confidence interval for overloading overlaps with the result of the state enumeration with no overloading. Looking at the results of the run with the highest accuracy (the 9 hour run), it can be said with 95% confidence that the effect of overloading leads to between 0.1 and 1.5% lower losses.

2. Secondly, with a 4% reduction in the offshore power grid costs the total amount of lost energy is increased by over 165%. This makes it clear that the overloading of components does not readily enable the oversizing of wind farms.

So, also for oversized wind farms the effect of temporarily component overloading is relatively small. With a 95% confidence the effect of overloading of an oversized wind farm (0.1 - 1.5% lower losses) lies in the same range as a right sized wind farm (0.0 - 1.4% lower losses). An added effect of overloading for oversized wind farms is thus not found.

### 7.3 Sensitivity analysis

In this section, the effect of different parameter values on different grid configurations are assessed. In Table 17, an overview of the different parameter values have been shown. The parameter boxes in grey are the assumed values. In most cases a higher and lower value have been chosen. For the CO2 emission allowance price and the price correlation this was not done because lowering the value had no effect or was not possible.
7.3.1 Market energy and Greenhouse gas emission allowance price sensitivity

In Figure 70, the sensitivity of the market energy price and greenhouse gas emission allowance price on the NPV of different configurations is assessed.

In Figure 70 three main observations can be made:
1. Firstly, the effect of an increased energy price has a positive effect on the NPV of different configurations.
2. Secondly, due to the relative size of the CO2 emission allowance price, the effect of even an 800% increased price is negligible.
3. Thirdly, the market energy price does have a significant effect on the NPV of different configurations.

7.3.2 Interest rate and investment period sensitivity

In Figure 71, the sensitivity of the interest rate and investment time on the NPV of different configurations is assessed.
In Figure 71 three main observations can be made:
1. Firstly, the effect of an increased interest rate has a negative effect on the NPV whereas an increased investment time has a positive effect on the NPV.
2. Secondly, both parameters have a non-linear effect on the NPV of the different configurations.
3. Finally, and most importantly, an increased interest rate to 10% does lead to a change in the preferred grid selection ranking.

### Repair time sensitivity

In Figure 72, the sensitivity of the repair time and offshore cable length on the NPV of different configurations is assessed.

In Figure 72 three main observations can be made:
1. Firstly, both the effect of the increased repair time and the increased offshore cable length lead to generally higher NPV of the different configurations.
2. Secondly, the insensitivity of the BC3 and BC3 & HC3 configuration for the offshore cable length is due to the fact that these configurations have very little effect on the reliability of the offshore part of the offshore grid.
3. Finally, and most importantly, the effect of an increased value for both parameters can lead to a change in the preferred ranking.
7.3.4 Price correlation sensitivity

The effect of price correlation sensitivity on the NPV of different configurations is shown in Figure 73 on the left-hand side. On the right hand side, the graph is zoomed in on the BC1 and BC1 & HC1 configurations to get a better picture of the effect of price correlation.

![Figure 73, investment period sensitivity at different scales (per 700 MW connection)](image)

In Figure 73 two main observations can be made:
1. Firstly, as can be seen in the left hand side figure, the effect of wind energy production price correlation of up to 25 % on the NPV of the different configurations is not significant.
2. Secondly, as can be seen in the right hand side figure, the effect of the wind power price correlation is not the same for different configurations. In less meshed configurations, the price correlation appears to have a positive effect, whereas in more meshed configurations the effect is negative.

The explanation of these effects can be found in the model that is used to simulate the price correlation. This model was presented in chapter 6. The effect of price correlation should not lower the average energy price since that would be another principle. This means that a lower energy price during high wind speed also requires a higher energy price during low wind speeds to keep the average energy price at the same amount. The effect of price correlation on the NPV of the configuration thus depends on at which power level the most energy is saved. The insensitivity of the NPV of the configurations proves that the average energy price of the saved energy of the configurations lies around the average energy price. For the BC1 configuration, the average energy price is increased slightly as a result of energy price correlation. The opposite happens for the BC1 & HC1 configuration.

In conclusion, the effect of wind energy price correlation is very small. This is the result of price correlation working in both directions and leads to an either slightly higher or lower NPV depending on the configuration.

7.3.5 Relative sensitivity

In Figure 74 and Figure 75, the relative sensitivity for different parameters is shown for the BC1 and the BC1 & HC1 configuration.
In Figure 74 and Figure 75, four things can be noted:

1. Firstly, for both configurations, it is clearly the repair time that has the relatively strongest effect on the NPV of the different configurations.

2. Secondly, both for the cable length and for the repair time, a high value results in a higher NPV. This is due to the increased amount of lost energy, which thereby generates more cash flow for the different configurations, while the investment costs stay the same.

3. Thirdly, the effect pointed out under ‘2.’ is much stronger for the BC1 & BC2 than for the BC1. This is the result of the higher redundancy of the BC1 & BC2 that can profit more from the higher losses due to unavailability, or losses relative more cash flow as a result of the lower losses.

4. Finally, the relative sensitivity of the CO2 emission allowance price is almost zero, and also the market energy price and investment time sensitivity are well below 5 %, while the relative interest rate sensitive is above 7.5%.

The different sensitivities pointed out under point ‘4.’ can be explained with the graph in Figure 76. This graph shows the yearly cash flow of the 66 kV branch coupler, as was calculated by the PV model presented in chapter 5. The graph mainly shows two things:
1. Firstly, the PV of the yearly cash flow is lowered every year due to the interest rate of 5%. This makes the PV of the expected cash flow in year one about twice as high as the PV of the expected cash flow in year 15.

2. The second effect is more significant though. The difference in PV of the expected cash flow between the 15th and 16th year more than 50%.

This effect is the result of the governmentally guaranteed € 100 per MWh for the first 15 years and the € 50 per MWh assumed market price that is taken from year 16 to 30. Due to this fixed governmental subsidy, the effect of a change in marked energy price, CO2 emission allowance price or investment period is very small. The interest rate on the other hand affects the complete investment period and therefore has a higher relative sensitivity.

![Yearly cashflow of the 66 kV branch coupler](image)

**Figure 76**, the yearly cash flow for the 66 kV branch coupler

### 7.4 Preferred grid selection

The preferred grid selection from the obtained results is then very straightforward. In Table 18, the configuration ranking has been shown again and it is clear that only two configuration options show a truly positive NPV. The difference in NPV between the configuration with 66 kV branch and hub couplers (BC1 & HC1) and the configuration with only 66 kV branch couplers (BC1) is very small. In the sensitivity analysis, it has been shown that an increase in interest rate could create a cross over and change the ranking order of the two most profitable options.

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Top coupler configurations options</th>
<th>Total NPV (M€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>66 kV branch &amp; hub couplers (BC1 &amp; HC1)</td>
<td>€ 27,44</td>
</tr>
<tr>
<td>2</td>
<td>66 kV branch coupler (BC1)</td>
<td>€ 22,20</td>
</tr>
<tr>
<td>3</td>
<td>Offshore at 220 kV (BC2)</td>
<td>€ 3,94</td>
</tr>
<tr>
<td>4</td>
<td>Onshore at 220 kV branch &amp; hub couplers (BC3 &amp; HC3)</td>
<td>€ 3,77</td>
</tr>
<tr>
<td>5</td>
<td>Onshore at 220 kV (BC3)</td>
<td>€ 2,78</td>
</tr>
<tr>
<td>6</td>
<td>Offshore at 220 kV branch &amp; hub couplers (BC2 &amp; HC2)</td>
<td>€ -1,14</td>
</tr>
</tbody>
</table>

Table 18, ranking of the top branch & hub coupler configurations (NPV per 1400 MW offshore grid)
Based on Table 18 and section 0 Two conclusions can be made based on the results in Figure 69:

3. Firstly, again there is not a clear significance of overloading on the amount of lost energy. Except for the 9 hour run, the 95 % confidence interval for overloading overlaps with the result of the state enumeration with no overloading. Looking at the results of the run with the highest accuracy (the 9 hour run), it can be said with 95 % confidence that the effect of overloading leads to between 0.1 and 1.5 % lower losses.

4. Secondly, with a 4 % reduction in the offshore power grid costs the total mount of lost energy is increased by over 165 %. This makes it clear that the overloading of components does not readily enable the oversizing of wind farms.

So, also for oversized wind farms the effect of temporarily component overloading is relatively small. With a 95 % confidence the effect of overloading of an oversized wind farm (0.1 - 1.5 % lower losses) lies in the same range as a right sized wind farm (0.0 - 1.4% lower losses). An added effect of overloading for oversized wind farms is thus not found.

Sensitivity analysis, two conclusions can be drawn:

1. Firstly, based on the assumptions made here, only the 66 kV branch & hub couplers (BC1 & HC1) and the 66 kV (BC1) configuration show a distinctive positive NPV. The other configurations are either a marginal increase or decrease.

2. Secondly, as was seen in the sensitivity analysis, different values for the repair time, the length of the offshore cable or the rate of return could change the order of the two most profitable configurations.

So it is the 66 kV branch & hub couplers (BC1 & HC1) configuration that has the highest NPV, but the 66 kV branch coupler (BC1) could have a higher NPV depending on the true value of the repair time, the length of the offshore cable or the rate of return.

7.5 Effect of different energy price & offshore cable length

From the three sensitive parameters, the repair time and interest rate can be seen as fixed parameters that should be based on statistical data and the current market. The cable length for a certain wind farm (i.e. the distance to the onshore grid) is a wind farm specific parameter. The amount of subsidy that is granted by the government in a country can in the same way be seen as a value that depends from location to location. For that reason, in Figure 77 the NPV of the BC1 and BC1 & HC1 configurations have been plotted against different energy prices and distances to the onshore grid. The distance to the onshore grid is a very straightforward parameter, which is easily defined for a specific wind farm. The energy price that is used here is the energy price for the first 15 year. The energy price of the 16th to 30th year is halved. This is done to keep the general energy price characteristic that was used in this thesis.
Figure 77, NPV of different configurations as a function of the energy price and the offshore cable length

The two different planes in Figure 77 are both plotted in Figure 78. This makes it possible to differentiate between the two configurations for different wind farms with different governmental subsidies and market energy prices. The planes in Figure 78 are shown from above in Figure 79, giving a clear overview of the different preferences for given parameters.

Figure 78, NPV comparison of the BC1 and BC1 & HC1 configuration as a function of energy price and offshore cable length as seen from the side
Figure 79, NPV comparison of the BC1 and BC1 & HC1 configuration as a function of energy price and offshore cable length as seen from above.
8 Conclusion

The main conclusion that can be made based on this research is that for offshore power grids with individual components of relatively low capacity, reliability is much less critical than in the onshore grid. For that reason, TSOs need a completely different approach for offshore grids in comparison with onshore grids. This is mainly the result of the absence of power consumers in the offshore grid, the very strong Dutch transmission grid, and the amount of offshore wind capacity compared to the installed onshore conventional generation and transmission capacity. The analyses shows that in the specific Dutch offshore case, investments in redundancy has limited impact. This is presumably the reason for the domination of radial offshore grids. It can nevertheless be said that some level of investments in offshore power grid redundancy can have a positive effect on the NPV of the complete offshore transmission system. These investments can have a positive NPV and are able to reduce the expected amount of lost energy due to forced outages from 1.08 % to almost 0.50 %.

Of all the proposed configuration options, it is the 66 kV branch coupler that has the most distinct positive NPV. Of the hub couplers, the 66 kV coupler was the only distinctive profitable options. It has been shown that adding multiple couplers on the same level (i.e. multiple branch or hub couplers) do not have a significant effect on the amount of saved energy, but will increase the needed investment. The designated area couplers and grid connections to other locations are simply too expensive and have a limited effect on the amount of lost energy. Oversizing components only has a positive effect on the 66 kV couplers when the complete grid is oversized and is therefore deemed as not desirable. Finally, the effect of overloading was also too small to be significant. The ultimate decision options based on energy price and offshore cable length is shown in Figure 79.

It has been shown that resizing the offshore grid can have a positive effect on the total NPV of the configuration depending on five parameters: the offshore grid costs, the amount of redundancy in the configuration, the level of wind price correlation, the energy price and finally the unavailability of offshore wind turbines. As was mentioned no final conclusions about the preferred relative wind farm size can be made. It can be said though that in situations with very low energy prices or very high transmission grids costs (due to for example the use of HVDC technology or far offshore located wind farms), oversizing the wind farm could very well have a positive effect on the NPV of the system as a whole.

The overall conclusion on offshore meshed power grids is the following: in overly meshed offshore power grids, different redundancy options cancel out each other’s profitability. The first upgrade generally has the most effect (it was chosen first for that reason), after which the effect of every further upgrade is lowered. Unless there are offshore power consumers or the amount of offshore wind capacity compared to the installed onshore conventional generation capacity is significantly large, offshore power grids can be expected to remain relatively radial. Creating a fully meshed offshore grid might be very beneficial in terms of offshore power grid reliability, but certainly is not economical profitable based on a reduction of the unavailability of the grid.
9 Recommendations & future work

In this research, graph flow theory was used for the load flow analysis of the offshore power systems. This graph flows could be seen as the optimum power flow because it is assumed that all the energy can be directed through every path. In reality, it might be so that in certain situations, the predicted amount of saved energy is actually lower because of the limited directing options of the power. For that reason, the use of a DC load flow simulation instead of a graph flow could lead to a more accurate result.

The focus in this thesis lies on 220 kV offshore power systems for two reasons. Firstly, this was the technology that was chosen by TenneT to realize the Dutch offshore power grid. Secondly, based on the data that was collected for this research, the 220 kV options show the lowest cost per MW. It would nevertheless be good for future research to also include lower voltage levels like 134 and 150 kV and higher voltage levels like 380 kV.

The proposed grid connections here are based on forced maintenance. Including planned maintenance is likely to improve the NPV of configurations with more redundancy, because of the increased amount of lost energy. One could define two extremes regarding the effect of planned maintenance:

1. Firstly, when this maintenance could be planned in such a way that it occurs at zero wind speed or during the (planned) maintenance of the wind farm, the analysis in this research can be considered as complete and accurate.
2. The second extreme is where the planned maintenance should be regarded as random in respect to the power production. In that case, the random down time of the power system is increased greatly also increasing the profitability of possible redundancy options.

The true effect of planned maintenance can be expected to lie somewhere in-between these extremes. Determining where exactly would be of added value in the choice of the preferred offshore power grid.

Another topic that needs additional research is the effect of resizing the wind farm. In this thesis, it is shown that based on different parameters, an undersized offshore power grid or oversized offshore wind farm can be beneficial. The total offshore grid costs, the redundancy of the configuration, the level of wind energy price correlations and the energy price all have an effect on the preferred size of the wind farm. Additional research on the internal relations of these parameters and the overall effect on the preferred wind farm size is needed though.

The final topic of recommended future work that is proposed here is the future extension of the offshore hubs. One of the advantages of offshore hubs is that they enable other hubs, father away from shore to use AC technology. These intermediate hubs can than serve as compensation coil platforms that enable offshore AC connections of over 80 km. This configuration also enables more meshed offshore grids and leads to the question whether it is possible and desirable to increase the redundancy of the offshore power grid when the number of components, nodes and the total power is increased.
### Appendix A. Analysis of offshore transmission system costs

<table>
<thead>
<tr>
<th>134/150 kV system gear</th>
<th>London array (315 MW)</th>
<th>Greater Gabbard (250 MW)</th>
<th>Sheringham Shoal (157 MW)</th>
<th>Schoenmaker (250 MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Reference)</td>
<td>[121]</td>
<td>[122]</td>
<td>[123]</td>
<td>[124]</td>
</tr>
<tr>
<td>Offshore total</td>
<td>197,6</td>
<td>190,0</td>
<td>175,0</td>
<td>57,8</td>
</tr>
<tr>
<td>Platform &amp; installation</td>
<td>70,0</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Converter</td>
<td>80,0</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>AC components</td>
<td>47,6</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cables total (100 km)</td>
<td>107,5</td>
<td>110,0</td>
<td>110,0</td>
<td>52,0</td>
</tr>
<tr>
<td>Cables (£/m) or (€/m)</td>
<td>1075</td>
<td>1100</td>
<td>1100</td>
<td></td>
</tr>
<tr>
<td>Onshore substation</td>
<td>96,0</td>
<td>115,0</td>
<td>110,0</td>
<td>9,8</td>
</tr>
<tr>
<td>Development costs</td>
<td>(54,5)</td>
<td>-</td>
<td>-</td>
<td>9,8</td>
</tr>
<tr>
<td>IDC</td>
<td>(17,5)</td>
<td>-</td>
<td>-</td>
<td>0,0</td>
</tr>
<tr>
<td><strong>Total:</strong></td>
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<td><strong>£ 415,0</strong></td>
<td><strong>£ 395,0</strong></td>
<td><strong>€ 119,6</strong></td>
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Table 19, cost assessments of different 150 kV (and 132 kV) offshore transmission system
### 220 kV system gear

<table>
<thead>
<tr>
<th></th>
<th>Renewable (500 MW)</th>
<th>TCE (500 MW)</th>
<th>TCE (300 MW)</th>
<th>Schoenmaker (350 MW)</th>
<th>NSCOGI (500 MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Reference)</td>
<td>[125]</td>
<td>[126]</td>
<td>[127]</td>
<td>[128]</td>
<td>[129]</td>
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<tr>
<td>Offshore total</td>
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<td>190,0</td>
<td>175,0</td>
<td>57,8</td>
<td>107,5</td>
</tr>
<tr>
<td>Platform &amp; installation</td>
<td>70,0</td>
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<tr>
<td>Converter</td>
<td>80,0</td>
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<td>-</td>
<td>-</td>
</tr>
<tr>
<td>AC components</td>
<td>47,6</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cables total (100 km)</td>
<td>107,5</td>
<td>110,0</td>
<td>110,0</td>
<td>52,0</td>
<td>52,0</td>
</tr>
<tr>
<td>Cables (£/m) or (€/m)</td>
<td>1075</td>
<td>1100</td>
<td>1100</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Onshore substation</td>
<td>96,0</td>
<td>115,0</td>
<td>110,0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Development costs</td>
<td>(54,5)</td>
<td>-</td>
<td>-</td>
<td>9,8</td>
<td>15,0</td>
</tr>
<tr>
<td>IDC</td>
<td>(17,5)</td>
<td>-</td>
<td>-</td>
<td>0,0</td>
<td>0,0</td>
</tr>
<tr>
<td>Total:</td>
<td>£ 401,1</td>
<td>£ 415,0</td>
<td>£ 395,0</td>
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<td>€ 0,0</td>
</tr>
</tbody>
</table>

Table 20, cost assessments of different 220 kV offshore transmission systems

### HVDC kV system gear

<table>
<thead>
<tr>
<th></th>
<th>Renewable (500 MW)</th>
<th>TCE 1 GW (500 kV)</th>
<th>TCE 1 GW (300 kV)</th>
<th>Schoenmaker 1 GW (300 kV)</th>
<th>NSCOGI 1 GW (VSC 500 kV)</th>
<th>NSCOGI 1 GW CSC (400 kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore total</td>
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<td>£190</td>
<td>£175</td>
<td>£220</td>
<td>€ 341</td>
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<tr>
<td>Converter</td>
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<td>AC components</td>
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<td>Included</td>
<td>Included</td>
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<tr>
<td>Cables total (100 km)</td>
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<td>£110</td>
<td>£110</td>
<td>£70</td>
<td>£130</td>
<td>£130</td>
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<td>Offshore cables (£/m)</td>
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<td>£1.100</td>
<td>£1.100</td>
<td>£700</td>
<td>£1.300</td>
<td>£1.300</td>
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<tr>
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<td>£96</td>
<td>£115</td>
<td>£110</td>
<td>£85</td>
<td>€ 121</td>
<td>€ 92</td>
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<tr>
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<td>-</td>
<td>-</td>
<td>-</td>
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<td>-</td>
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<tr>
<td>IDC</td>
<td>£17</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total:</td>
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<td>£415</td>
<td>£395</td>
<td>£375</td>
<td>£592</td>
<td>£535</td>
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</table>

Table 21, cost assessments of different HVDC offshore transmission systems
## Appendix B. Configuration options and costs

<table>
<thead>
<tr>
<th>Name</th>
<th>Options</th>
<th>Total capacity (MW)</th>
<th>Cost (M€)</th>
<th>Cost 1.4 GW (M€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Benchmark options</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0</td>
<td>150 kV radial (7x)</td>
<td>200</td>
<td>108</td>
<td>756</td>
</tr>
<tr>
<td>B2</td>
<td>220 kV radial (4x)</td>
<td>350</td>
<td>56</td>
<td>624</td>
</tr>
<tr>
<td>B3</td>
<td>380 kV radial (2x)</td>
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<td>?</td>
<td>?</td>
</tr>
<tr>
<td>B4</td>
<td>HVDC radial (1.5x)</td>
<td>1000</td>
<td>480</td>
<td>720</td>
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</tbody>
</table>

Table 22, estimated costs of different technology configurations based on the analysis in Appendix


