Connection of offshore wind farms to the grid in Europe and Brittany

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Connection of offshore wind farms to the grid in Europe and Brittany

Master thesis

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**Glossary**

**ACER:** Agency for the Cooperation of Energy Regulators, it will be created in 2011 in order to encourage

**Ancillary services:** services provided by power plants that are necessary to the secure operation of the electric grid, such as voltage control, frequency control, etc.

**Call for tenders,** or tender process: method to allocate a project (for instance, the building of an offshore wind farm) by choosing the best of the applicants in competition.

**Capacity:** The maximal possible output of a power plant (in MW).

**Duration curve:** Curve which illustrates the distribution of a parameter, see chapter 3.3.3, last paragraph.

**Developer:** The company that plans the construction of a power plant, supervise the construction, and finally becomes the owner of the plant once it is built.

**Electricity consumption:** The amount of electricity that is used in a certain area. It can be either the instant consumption (in MW) or over a certain period (in MWh).

**ENTSOE:** European Network of Transmission System Operators for Electricity, including the TSOs of all European countries.

**ERGEG:** European Regulators' Group for Electricity and Gas.

**European network codes:** European rules written by the ENTSOE under the ACER’s supervision, dealing with the European electricity market, the access to the network and cross-border exchanges.

**Framework guidelines:** Documents to be published by the ACER as guides to the European “network codes”. See chapter 2.4.2.

**Load:** It has a similar meaning that “electricity consumption”. However, in this document, it will always refer to the instant consumption (in MW).

**Load factor:** The instant power output of a plan divided by its capacity, in %.

**Load flow calculation:** See chapter 3.1.4.

**Load management:** Temporary reduction of the load, usually undertaken by the TSO, especially during peak loads. It can take different forms: inform the households on the necessity to avoid electric heating during peak loads, contracts with industries, etc.

**Maximal / Minimal load:** The highest / lowest load within a year.

**N-1 criterion / N-1 assumption:** See chapter 3.1.6.
National Grid: The TSO of the UK.

OFTO: Offshore Transmission Operator, in UK, independent operator in charge of the construction and operation of the offshore transmission systems (see chapter 2.2.2.1).

Output curtailment: Reduction of the output of a power plant in order to maintain it under a certain limit.

RTE: Réseau de Transport d’Electricité, the French TSO.

TSO: Transmission System Operator, the authority in charge of the operation of the electric system (see chapter 3.1.1). Usually, there is one only TSO per country, but there are exceptions. In Germany, for instance, there are four TSOs (see chapter 2.3.1).

UK: United Kingdom.
1 Introduction

1.1 Presentation of RTE

RTE ("Réseau de Transport de l'Électricité") is responsible for transmitting electricity from generation plants to local electricity distribution operators. This company is the only Transmission System Operator (TSO) in France.

RTE was created in 2000 following the European law opening the European market up to competition, and became a subsidiary company of EDF ("Electricité de France") in 2005. RTE is one of the largest European Transmission System Operator (TSO) with more than 100,000 km of lines. This company employs around 8,400 people, and its turnover in 2008 was around 4,200 M€.

RTE's goals, defined through a public service contract between the State and the company, are controlled by the Commission of Energy Regulation (CRE).

RTE has a public service mission and must operate, maintain and develop the French electricity transport network at the best cost, while reducing its environmental impact. This company guarantees all users a fair and non-discriminating access to the grid, and preserves the freedom of all market actors. RTE aims to develop interconnection capacities, in cooperation with the other European TSOs.

It must secure the balance between generation and consumption at any time (from long to short terms and in real time), and assure the safety of the electric system operation.

The French grid is divided into seven areas, which are under the responsibility of regional units. SEO is the regional unit in charge of the western part of the grid. SDOP is the department in charge of the long term studies and the large operations of grid reinforcement.

1.2 Background

Offshore wind market has recently exploded in Europe and a lot of offshore wind projects are currently under progress. Installed capacity in Europe reaches 2 GW (from 1.5 GW in 2008) and may reach 3 GW at the end of 2010. There is no operational offshore wind farm in France yet, but many projects are under investigation, and the French government announces 6 GW by 2020. The French Transmission System Operator (TSO), RTE, is seriously investigating the issue to be well prepared to connect these large-scale farms to the grid.

As some countries have already gained much experience in connecting offshore wind farms to the grid, RTE may gain a benefit from being inspired by their rules and practices. Moreover, the grid management of RTE can be seen as quite conservative and perhaps too cautious, which, considering large scale wind farms, may easily lead to over-sized and costly reinforcements. It is therefore of great importance for RTE to gain knowledge from more experienced countries, as it might lead to smarter rules.
The French government has decided to organize a call for tenders for the building of offshore wind farms, quite similarly to what has been implemented in the UK and Denmark. The aim is 6 GW by 2020. Areas are to be selected by the local authorities before the beginning of the call for tenders, by the end of 2010. These areas are currently under discussion, and their location and size are already approximately known.

The French grid is divided into several areas. One of these areas, “the western area” may have to support an important part of the future French offshore generation. As the grid there is quite weak, reinforcement will be required. RTE usually studies projects one at a time to decide upon grid reinforcements, but this method may probably lead to non-optimal investment in the long run. Simulating the influence of the future offshore wind farms altogether is more appropriate, as all the locations of the future wind farms are almost decided.

1.3 Plan of the thesis

This document tackles these two different issues: first it describes the rules regarding connection to the grid in different countries, and then assesses the future impact of offshore wind power on the western French grid.

Part 2 gives a comprehensive view on legislation and practices regarding connection to the grid in the most advanced countries. These countries, whose selection methodology is described in a first chapter, are: United Kingdom, Germany, Denmark and France. In a second chapter, non-technical policies are described in each country: objectives, authorization procedures, distribution of the roles and responsibilities, financial issues, etc. In a third chapter, the most important technical requirements (related to the connection to the grid) are summarized, country by country, and then compared. Information is mostly extracted from legislation and grid codes. A fourth chapter describes the recent changes related to the transition from national electricity markets to a liberalized, deregulated, integrated European market, and the expected impacts on wind power. It stresses how the on-going process, which has recently led to a new set of rules called Third Energy Package, will have strong impacts on the connection rules in Europe in the long run, even though short term changes remain uncertain. Finally, a fifth chapter describes the current practices in Europe. A database of offshore transmission systems and offshore wind farms completes the information and comments on transmission technologies in use and on some wind farm characteristics.

Part 3 deals with theoretical aspects necessary to fully understand the report. Most information given here is related to part 4, but readers that are not familiar with power systems will still find useful information which helps understand part 2. The first chapter deals with the fundamentals of power system theory and major grid issues raised by large offshore wind farms. The second chapter deals with wind and power output assessment. It describes how it is usually performed. The third chapter describes the three pieces of software used to perform the part 4: mostly “Convergence” (load flow calculations), but also “Valoris” (costs/benefits assessment of grid reinforcement), and “R” (statistical analysis).

Part 4 describes the impact of the expected offshore wind farms on the western French grid. A first chapter describes the grid and the present context in France and more precisely in Brittany. A second chapter aims to provide an estimate of the distribution of the power factor over the time for the expected offshore wind farms in Brittany. The third chapter presents the results of the load flow calculations and considerations about possible grid reinforcement and costs.
2 European rules and practices regarding offshore wind power

In this part we give a comprehensive view on legislation and practices regarding connection to the grid of offshore wind farms in four countries: the United Kingdom (UK), Germany, Denmark and France. The reasons for the choice of these countries are given in the first chapter.

The analysis of the five countries is divided in three parts:

- First (chapter 2), non-technical policies, which include various features like objectives, financial issues, authorization procedures, etc.
- Secondly (chapter 3), technical rules and legislation, which correspond to a large degree to what can be found in grid codes.
- Thirdly (chapter 5), information about offshore transmission technologies and actual practices.

Chapter 4 describes the on-going changes at European level and the likely impacts on national rules and practices.

France has no operational offshore wind turbine yet. However, as around 6 GW are expected by 2020, there are still extensive rules regarding offshore wind power. One of the objectives of the part is to allow RTE to benchmark the French rules against the rules in other European countries.

2.1 Method of selection of the countries

The first criterion for the selection of the countries that were to be investigated is the number of offshore wind farms either operational or planned soon. The UK and Denmark have been selected as the two current leaders in wind offshore development (see figure 2-1). Germany has built only few offshore turbines for now, but has very ambitious development plans. France is also investigated as the key country of the study, as explained previously.
2.2 Non-technical policies

This part deals with national policies regarding offshore wind power, which are not related to technical issues.
It ranges from objectives of installed capacity, to financial issues, including authorization procedures etc. Some are not exclusively related to offshore wind power, and are not described in details. These policies are frequently modified. Hence this is only a snapshot of the policies in use in August 2010. There exists websites with frequent updates that can be used to track the recent changes [1], [2]. First a table shows an overview of the four countries, then most important features are discussed country by country and finally the payments given to wind farms owner are detailed.

2.2.1 Overview

Table 2-1 gives an overview of the main rules and practices in use in each country. Details, comments and maps are given country by country in chapter 2.2.2. The following list displays the references and explanations about each of the features described in the table:

- Operational capacity in January 2010: it is the capacity of offshore wind power that has been generating electricity since January 2010 [3].

- Planned capacity 2015: it is the capacity that is expected for 2015, according to the EWEA, which is the most important group of companies related to wind power in Europe [4].

- Objectives - Plans for 2020 – 2025: in all of the four countries under investigation, the authorities have objectives for 2020 or 2025, which are given here [5],[6], [7], [8].

- Authorization procedures: there are two methods to allocate permits for offshore wind farms, either by calls for tenders, or the “open door” procedure.
  - Call for tenders: Operators compete for the right to build wind farms, conforming to a schedule set by the government.
  - Open door: Projects can be submitted to the authority in charge at any moment, and are evaluated individually.

- Support mechanism: offshore wind farms are still too expensive to compete with conventional power plants. They are offered subsidies through various mechanisms, depending on the country. The principal mechanisms used in Europe are described below:
  - Feed-in tariffs: the electricity is sold at a constant price set in advance, usually for a limited period;
  - Certificates: Each kWh generated by a wind turbine gives a certificate which is sold to other electricity players through a dedicated market;
  - Premium payments: electricity from wind turbines is sold on the electricity market, but get an additional, constant payment in addition to the market price.
• Price (cEuros/kWh): it is an average price, as it is variable in all four countries: depending on the market prices in the UK, depending on the farm in the three other countries; the indication “Call for tenders” means that the price is set for each project individually, depending on candidates proposals. Further information is given in chapter 2.2.3.

• Obligation on market players to buy: it indicates if the kWh generated by offshore wind turbines are required to be bought be one or some other electricity player(s). If there is one only player in this case, he is mentioned in brackets [9].

• Incentives/penalties on wind plant owners for balancing/forecasting: depending on the country, wind plant owners can required to forecast the amount of kWh their plant will generate, and are charged in proportion to the unbalance, just like every other plant owner [9].

• Transmission costs charged to: Generation/Load (%): it indicates how transmission costs are shared between generators and consumers. On average, these transmission costs account for around 10 to 15 euros/Mwh, depending on the country [10].

• Location dependence of transmission charges: in some countries, transmission charges depend on the location of the power plant, or of the load, in the attempt to charge the players in proportion of their impact on the expenditure on the electricity network [10].

• Compensation in case of output curtailment: the output of the wind farms is sometimes required to be curtailed to not endanger the electric system. In such case, wind plant owners are often subsidised in compensation; but it is not always the case in all countries. “Yes, with exception” refers to countries such as France where curtailment without compensation is possible under certain conditions, specified in advance in the contract, and for a limited amount of hours per year.

• Who pays for the transmission line? it can be either the TSO, or the plant owner, or another operator. This refers only to shallow costs, i.e. local costs in opposition to deep costs which benefit several farms, as deep reinforcement is always paid by the TSO.

• Who is in charge of the design and the construction of the transmission line? It can be either the TSO, or the plant owner, or another operator. In most European countries, the connection lines of the first offshore wind farms were built by the plant owners. It this has changed a lot, and now the connection lines are designed by the TSO in most European countries, with the notable exception of the UK.

• Ownership of offshore assets: most offshore wind farms require an offshore platform housing many assets such as transformers, converter stations (DC) or reactive compensation devices. Usually, the offshore platform and every device located on it are all owned by the same player, with the possible exception of France.

• Priority connection: in some countries, renewable power plants, including wind farms, have priority on conventional power plants when several point are planned to be connected to the same station.
<table>
<thead>
<tr>
<th>Country</th>
<th>Operational capacity in January 2010 (MW)</th>
<th>Planned capacity 2015 (MW)</th>
<th>Objectives - Plans for 2020 - 2030 (MW)</th>
<th>Authorization procedures</th>
<th>Support mechanism</th>
<th>Price (€c/kWh)</th>
<th>Obligation on market players to buy</th>
<th>Incentives/penalties on wind plant owners for balancing/forecasting</th>
<th>Transmission costs charged to: Generation/Load (%)</th>
<th>Compensation in case of output curtailment</th>
<th>Who pays for the transmission line?</th>
<th>Who is in charge of the design and the construction of the transmission line?</th>
<th>Ownership of offshore assets</th>
<th>Priority connection</th>
<th>Explicit priority dispatch</th>
<th>Connection point / reactive requirements</th>
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<td>United Kingdom</td>
<td>880</td>
<td>8 800</td>
<td>33 000 (2025)</td>
<td>Call for tenders*</td>
<td>Certificates*</td>
<td>~12 (certificates) + ~5 (market price)*</td>
<td>No</td>
<td>Yes (TSO)*</td>
<td>27/73</td>
<td>Yes*</td>
<td>OFTO*</td>
<td>OFTO*</td>
<td>AC: Plant owner DC: Plant owner/TSO*</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
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<tr>
<td>Germany</td>
<td>42</td>
<td>10 100</td>
<td>20 000 – 25 000 (2025 – 2030)</td>
<td>Open door*</td>
<td>Feed-in tariff*</td>
<td>~15*</td>
<td>Yes*</td>
<td>Yes*</td>
<td>0/100</td>
<td>No</td>
<td>TSO*</td>
<td>TSO*</td>
<td></td>
<td>Yes</td>
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<td>Denmark</td>
<td>640*</td>
<td>1 300</td>
<td>4 600 (2025)</td>
<td>Call for tenders*</td>
<td>Feed-in tariff*</td>
<td>call for tenders* (last tender ~14)</td>
<td>Yes*</td>
<td>Yes*</td>
<td>2-5/95-98</td>
<td>No</td>
<td></td>
<td>TSO*</td>
<td></td>
<td>Yes</td>
<td>Yes</td>
<td>Offshore</td>
</tr>
<tr>
<td>France</td>
<td>0</td>
<td>1 100</td>
<td>6 000 (2020)</td>
<td>Call for tenders*</td>
<td>Feed-in tariff*</td>
<td>call for tenders*</td>
<td>Yes*</td>
<td>Yes (EDF)*</td>
<td>2/98</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
<td>Yes</td>
<td>No</td>
<td>Offshore</td>
</tr>
</tbody>
</table>

* means that further information is given in chapter 2.2.2 Country by country.

Table 2-1 Overview of the non-technical policies related to offshore wind power
• Explicit priority dispatch: many countries provide for explicit priority dispatch for all renewable generation. In all countries, wind power is dispatched first in normal conditions, as marginal generation costs are extremely low. Countries which provide for explicit priority dispatch guarantee it in official texts in addition. Still, in every country, wind farms can be curtailed if this is required for the security of the electric system.

• Connection point: this is the borderline between devices owned by different operators, often the TSO and the farm owner. Reactive power requirements usually apply at this point. It can be either at the offshore platform or at the onshore station. In the UK, there are two connection points: between the plant owner and the OFTO at the offshore platform, and between the OFTO and the TSO at the onshore station.

2.2.2 Country by country

2.2.2.1 United Kingdom

A call for tenders, divided into three successive rounds, aims to reach around 33 GW of offshore wind capacity by 2025. Most farms included in the first round (1 GW) are operational. The second round is under construction (7.2 GW) and should be entirely built by 2020. Wind operators in charge of building the farms included in the third round (around 25 GW) have been lately selected.

Rules dealing with offshore transmission lines have recently been amended. Independent operators, the Offshore Transmission Network Owners (OFTOs), selected through calls for tender, are in charge of the commissioning and the exploitation of the offshore grid. Financial arrangements between the TSO, the plant owner and the OFTO are not definitive yet, even though for the moment the OFTO finances the transmission line, or buys it from the plant owner in case the farm is already operational. The OFTO recovers its costs through payments from the TSO: 90% of this revenue is guaranteed, based on the cost of the offshore transmission assets, 10% is based on the availability of the transmission line. In early August 2010, a first call for tenders led to the selection of three OFTOs for seven wind farms.

As indicated in chapter 3.2.2, there are technical requirements both offshore, at the interface between the plant owner and the OFTO, and onshore, at the interface between the OFTO and the TSO. The OFTO keeps a free hand on the technical solutions, provided he respects the grid code [11]. Figure 2-2 locates the most important farms operational or planned by 2012 in the UK [11].

The Renewables Obligation is the main support and incentive scheme for renewable electricity projects in the UK. It is a system of green certificates given to wind farms owner in proportion to the amount of kWh generated, which can be sold on a dedicated market, in addition to the normal price the farm owner gets in selling his electricity on the electricity market. This scheme has come under criticism for lack of certainty with regard to ROC values, which is dependent on supply and demand in each year, the complexity of the scheme and its tendency to favour more established renewable technologies. It might be replaced with feed-in tariffs in the future [12] [13]. In the UK, the transmission charging on the generation side, which is variable depending on the location of the power plant and amount to around 27% of the total transmission charging, is much higher than in the three other countries. It might hinder a bit the development of offshore wind power in the areas with the highest transmission charges such as Scotland [14].
1. Barrow (90MW) - Operational
2. Robin Rigg East and West (180MW) - Operational
3. Gunfleet Sands 1 & 2 (164MW) - Operational
4. Sheringham Shoal (315MW) - Operational in April 2011
5. Ormonde (150MW) - Operational in March 2011
6. Greater Gabbard (504MW) - Operational in November 2010
7. Thanet (300MW) - Operational (2010)
8. Walney 1 (178MW) - Operational in October 2010
9. Walney 2 (183MW) - Should be operational in August 2011

2.2.2.2 Germany

State agencies have delimited five zones in the Baltic Sea and North Sea (1100 km²) where offshore wind farms have priority over other uses. Permits are allocated through an open door procedure. The first candidate to submit a satisfactory project is given priority in case of competing projects.

There are four TSOs in Germany (see 2.3.1). They are in charge of the commissioning, financing and exploitation of the offshore grid from the farm to the national grid, provided the farm is built before 2015. They are required to pay for the transmission line and to buy the wind electricity at a constant price (the feed-in tariff). They are also the balancing responsible players for this electricity. All the resulting charges for the TSOs are recovered through charges are directly paid by the consumers on their electricity bills. The costs are shared between the four TSOs in proportion to the number of consumers.

The feed-in tariff is 15 €c/kWh for 12 years, but can be extended under certain conditions regarding water depth and distance from the shore. This tariff will decrease for the farms built after 2015. The feed-in tariff is not applicable in protected areas of nature and landscape. As a principal rule, network operators are required to take on electricity generated from renewable energies prior to electricity generated from conventional energies. This rule can still be disregarded in some exceptional circumstances [15].

The only operational offshore wind farm above 50 MW in Germany is the experimental farm Alpha Ventus (60 MW), but many other farms should be operational soon, including the farm Nord E.ON 1 which is the first wind farm connected through a DC transmission system.
2.2.2.3 Denmark

Denmark is the country in the world with the longest experience in offshore wind power, the first farm being built in 1991. Calls for tender are organized from time to time. Five ones have been organised from 2002 to 2010, for the offshore wind farms written in bold lettering in table 2.2. State agencies are in charge of the selection of the areas to be built, which are then allocated through a call for tenders. The price per kWh is set depending on candidates offers and is the principal criterion to choose the successful applicant.

All the offshore wind farms above 50 MW have been built through this procedure for now. In parallel to these occasional calls for tenders, an “open door” procedure should be operational soon. The coexistence of these two procedures is likely a transitional process. In accordance with the deregulation process in the European energy sector, private players tend to replace state agencies as far as possible. However, at the same time, the Danish regulator do not want to abandon the former method before being certain of the effectiveness of the new one. Besides, call for tenders can help reach the national objectives if there are not enough “open door” projects.

Offshore wind farms are said to be given priority dispatch, but actually they can still be required to reduce their generation at any moment, with financial compensation. As every other market player, wind farms operators are required to forecast their generation on a day ahead market, and pay for imbalance. They are allocated a rebate of 2.3 øre/kWh (~0.3 €c/kWh) to cover a part of these costs. As for the electricity prices, they are usually set through the calls for tender and depend on the farm. The most recent price, for the Anholt wind farm, is 105,1 øre/kWh (~14 €c/kWh) for the first 20 TWh. Figure 2-3 and table 2-2 locate the wind farms in Denmark. [16]

![Figure 2-3 Map of the offshore wind farms in Denmark](image)
Operational offshore wind farms

<table>
<thead>
<tr>
<th>No.</th>
<th>Farm Name</th>
<th>Turbines</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.</td>
<td>Tunø Knob (1995)</td>
<td>10</td>
<td>5 MW</td>
</tr>
<tr>
<td>5.</td>
<td>Rønland (2003)</td>
<td>8</td>
<td>17 MW</td>
</tr>
<tr>
<td>8.</td>
<td>Frederikshavn (2003)</td>
<td>3</td>
<td>7 MW</td>
</tr>
<tr>
<td>10.</td>
<td>Avedøre Holme (2009/10)</td>
<td>3</td>
<td>10-13 MW</td>
</tr>
<tr>
<td>11.</td>
<td>Sprogø (2009)</td>
<td>7</td>
<td>21 MW</td>
</tr>
</tbody>
</table>

Planned offshore wind farms

<table>
<thead>
<tr>
<th>No.</th>
<th>Farm Name</th>
<th>Turbines</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>12.</td>
<td>Rødsand II (2010)</td>
<td>90</td>
<td>207 MW</td>
</tr>
</tbody>
</table>

Table 2-2 List of the offshore wind farms in Denmark

2.2.2.4 France

There is no operational offshore wind farm in France yet, and the objective corresponds to the call for tenders in preparation: around 6 GW by 2020. Just like in Denmark, state agencies are in charge of the selection of the areas to be built, which are then allocated through the call for tenders. Capacities allowed to be built in each area are determined before the start of the call for tender, which is certainly inappropriate in the French context, as explained in chapter 2.5.4. The price per kWh is also set depending on candidates offers, but the selection criteria should be more diversified than in Denmark. Indeed, the French authorities are afraid of the potential risk of project failure due to price underestimation in case the price criterion is over-weighted. The transmission assets are designed by the TSO but still paid by the plant owner, even if there will exist some mechanisms intended to reduce the financial risk, as explained in chapter 2.2.3.4.

At the connection of the farm, the TSO (RTE) may announce a certain number of hours of curtailment per year which are not subsidized. The wind farm owner has the possibility to finance grid reinforcements to avoid them. A subsidiary of EDF (the main electricity company in France) buys the electricity at the feed-in tariff, and is the balance responsible entity for every wind farm in France, with financial compensation. It means that this company is required to forecast how much wind energy will be generated in France every 30 min, as though all the French wind farms would constitute a conventional power plant owned by EDF.

In case of AC transmission lines, the plant owner owns the offshore platform and the transformers installed on it. However, in case of DC transmission lines, RTE will probably own the offshore platform that contains the converter station, although the plant owner still owns the transformers. This is still not clear if there will
be two or one unique offshore platform in case of DC. There is no reason to have two platforms, except that RTE is reluctant to install his own devices on a platform owned by a private company, or to house assets owned by a private company on its own platform.

2.2.3 Prices in detail

2.2.3.1 UK

The Renewables Obligation is the main support and incentive scheme for renewable electricity projects in the UK. It places an obligation on UK suppliers of electricity to source a proportion of their electricity from renewable sources (the figure is currently 10.4 per cent and is set to increase by 1 per cent annually for the next five years). Renewables Obligation Certificates (ROCs) are generated in respect of megawatt hours (MWh) of renewable energy generated: each kWh from offshore wind farms receives 2 ROCs. At the end of each one-year obligation period suppliers are required to present sufficient ROCs to meet their obligations under the Renewables Obligation. Where suppliers do not have sufficient ROCs to cover their obligation, they can buy ROCs on the market or a payment may be made into a buy-out fund (35,76 £/ROC in early 2009). The proceeds of the fund are then paid back to suppliers in proportion to how many ROCs they have presented. That explains why the actual price of the ROCs is always higher than the above payment. To give an idea, the average price achieved via on-line auctions was 49.24 £/ROC (~60 Euros/ROC, ~12 €c /kWh) on 25th March 2010. In addition, electricity is sold to the market at around 5 €c /kWh. Hence, in total, the offshore wind plant owners are paid around 17 €c /kWh in average for each kWh they generate. This price is slightly higher than in Denmark and in Germany, especially for there is no time limitation, but it is counterbalanced by the uncertainty on the prices which does not exist in any of the three other countries. Consequently, green certificates are often said to be less efficient than feed-in tariffs for being more costly [17], [13].

2.2.3.2 Germany

Both the level and the duration of the German feed-in tariff are variable. The level depend of the year the farm is built, as illustrated in figure 2-4: 15 €c /kWh for the farms built before 2016, 13 €c /kWh for the farms built in 2016, then it will decreases of 5% per year, to a minimum of 3.5 €c /kWh. The duration of the feed-in tariff depends on the distance to the coastline and on the water depth, as illustrated in figure 2-5: the minimal duration is 12 years, and is extended for the farms located at least twelve nautical miles seawards and in a water depth of at least 20 metres, by 0.5 months for each full nautical mile beyond 12 nautical miles and by 1.7 months for each additional full meter of water depth. After this period, wind plant owners can still sell their electricity at a guaranteed price of 3.5 €c /kWh, if it is higher than the market prices [18].
Comparison of multiple reimbursement rates for wind turbines going on line at different times

Figure 2-4 Level of the German feed-in tariffs for offshore wind farms [19]

Extension of the period of increased reimbursement rate conditioned to the distance to coast and water depth

*note: The period of 12 years for starting reimbursement will be extended according to distance from the coast and water depth. 0.5 months for every nautical mile over an initial coast distance from 12 nautical miles and 1.7 months for every meter over an initial water depth from 20 meters.

Division of the axis:
10 m additional water depth or 34 additional nautical miles extend the reimbursement rate by 17 months.

Figure 2-5 Duration of the German feed-in tariffs for offshore wind farms [19]
2.2.3.3 Denmark

Wind farms owners sell their electricity on the market just like other plant owners. In addition, they are allowed, for the lifetime of the wind farm, a premium (i.e. in addition to the market price) of 10 øre/kWh (~1.3 €/kWh) for 20 years, as well as a rebate of 2.3 øre/kWh (~0.3 €/kWh) for balancing costs and a compensation of up to 0.7 øre/kWh (~0.1 €/kWh) if the farm is subject to a network tariff. The sum of these payments cannot exceed 36 øre/kWh (~4.8 €/kWh).

However, the owners of the five offshore wind farms built through the calls for tenders get higher payments, according to the price set through the tendering process. Thus, the two offshore wind farms Horns Rev I and Nysted/Rødsand I got a feed-in tariff (i.e. instead of the market price) of 45.3 øre/kWh (~6 €/kWh) for 42,000 full-load hours, the Horns Rev II farm got 51.8 øre/kWh (~6.9 €/kWh) for 50,000 full-load hours, the Rødsand II farm got 62.9 øre/kWh (~8.4 €/kWh) for 50,000 full-load hours, and the Anholt farm got 105.1 øre/kWh (~14 €/kWh) for the first 20 TWh. The rebate of 2.3 øre/kWh (~0.3 €/kWh) for balancing costs and the compensation for the network tariff are paid in addition to the feed-in tariff. Once the full-load hours have been reached, the feed-in tariff is no longer paid and wind farms owners sell their electricity to the market price, but the rebate and the compensation are still paid [20], [16], [21].

2.2.3.4 France

As explained previously, the future offshore wind farms in France will be allowed to sell their electricity at a constant feed-in tariff over a certain amount of years to be determined in the future. The feed-in tariff will correspond to the price set through the tendering process, like in Denmark. There will still exist two mechanisms of financial risk reduction: both late changes in raw material prices and the difference between the initial estimate and the final cost of the connection assets (which are designed by the TSO and paid by the successful applicant) will be mitigated, leading to a slight modulation of this feed-in tariff.

2.2.4 Conclusion

First of all, it is noticeable that two countries, UK and Germany, should account for more than half of the capacity installed in Europe in few years, reaching around 30 GW each by 2025 while all other countries will remain below 10 MW. Hence, when the French government announces 6 GW by 2020 with the ambition to make France one of the leaders on the wind offshore market, it sounds quite inappropriate.

Methods to allocate permits and support mechanisms can both be considered to have important impacts on offshore wind power development. However, these are in no case decisive: UK and Germany do have very different policies, and though they are likely to be both successful in their offshore wind development program. The only factor that affects significantly the amount of capacity to be built is the area made available for offshore wind farms. In all countries, offshore wind power is subsidised through mechanisms that offer a better price than the normal market price. The prices amounts to around 15 €/kWh for the recent or short-term future offshore wind farms. For the moment, such prices are high enough to make sure that most areas made available for offshore wind farms will find quickly a developer
willing to build a farm. However, as the costs required to build a farm are highly depend on the location, the most unfavourable areas will not be built until either technical progress allows a reduction of these costs, or higher prices are offered, which is what will certainly happen in France as the price is set through a call for tenders.

The different policies described in this chapter are likely to have some impact on the overall efficiency of offshore wind programs, but the lack of experience makes comparisons difficult. There is still a consensus on the fact that the lesser the financial uncertainty for the private companies, the lesser the average costs, at the condition there still remain sufficient incentives for efficient operation. Hence, support mechanisms based on the market prices (the Renewable Obligation Certificates in the UK for instance) are often said to be less efficient than feed-in tariffs. The willingness to lessen the financial uncertainty for private players is particularly well illustrated, in the four countries investigated, by the institution of mechanisms for public financing of the connection to the grid, once financed by the plant owners.
2.3 Grid codes – technical rules

Grid codes contain most technical rules related to the connection of power plants to the grid. They are issued by the Transmission System Operators (TSOs). This chapter describes the most important rules of these grid codes, i.e. (1) dimensioning voltages and frequencies, (2) voltage control and reactive power output requirements, (3) frequency control, and (4) fault ride through capability.

Numerous other requirements are included in grid codes, dealing with power quality (flicker, harmonics, voltage unbalance), black start capabilities (usually it does not concern wind turbines [22]), island modes capabilities, protection devices, data exchanges, etc. These are not described here, for they usually correspond to international standards (often IEC and EN) and do not vary much over Europe. For instance, the standard IEC TR 61000-3-6 is a reference for harmonic currents and IEC TR 61000-3-7 for flicker.

The four major rules are described for each of the four countries under investigation. In Germany, there are four TSOs in Germany: Transpower (recently bought by the Dutch TSO Tennet), Amprion, EnBW TNG and 50 Hertz. Each TSO is in charge of its own area, as illustrated in figure 2-6 [23]. Almost every offshore wind farm is, or will be, located within Transpower territory. Therefore, only Transpower has a chapter dedicated to offshore Transmission in its grid code [24]. This will represent the German rules in the present chapter.

Many codes describe the rules in use in the UK electricity market: The Balancing and Settlement Code (BSC), the Connection and Use of System Code (CUSC), the System Operator-Transmission Owner Code (STC, or SO-TO Code), the Grid Code, the Distribution Code et le Distribution Connection Use of System Code (DCUSA), and the NETS Security and Quality of Supply Standard (NETS SQSS), and the Charging Statements. There are technical requirements both for the wind farm, offshore, at the interface wind farm / offshore transmission line, and for the OFTO (Offshore Transmission Owner, see chapter 2.2.2.2), onshore, at the interface offshore transmission line / national grid. Wind farms owners must comply with the CUSC, the BSC and the Grid Code, while the OFTOs must comply with the NETS SQSS, the STC and some parts of the
Grid Code, specified in the STC. The CUSC constitutes the contractual framework for connection to, and use of, National Grid’s high voltage transmission system. The BSC contains the rules and governance arrangements for electricity balancing and settlement. The Grid Code covers all material technical aspects relating to connections to and the operation and use of the transmission system. The STC defines the high-level relationship between the National Electricity Transmission System Operator (NETSO), i.e. National Grid, and the other Transmission Owners. The NETS SQSS sets out a coordinated set of criteria and methodologies that Transmission Licensees (both onshore and offshore) shall use in the planning and operation of the National Electricity Transmission System [25]. In the following, it is always specified whether the rules described apply offshore for the wind farm, or onshore for the OFTO.

New rules dealing with wind power have been released in late 2010 in Denmark [26]. These rules are certainly the most comprehensive ones that have been released for now, and make a distinction between farms depending on their capacity: either below 1,5 MW, or between 1,5 MW and 25 MW, or above 25 MW. Only the rules dealing with the farms above 25 MW are taken into consideration in the following. The French grid code [27], not available in English, is the only grid code where there is no dedicated chapter for wind turbines, even if there is sometimes some differences in the rules depending on the type of the power plant.

2.3.1 Dimensioning voltages and frequencies

In order to avoid a system failure in case of slight voltage or frequency changes, any automatic disconnection of a power plant from the grid is always prohibited within certain voltage and frequency ranges during a last a certain time period. This requirement exists in all countries for all power plants, but the ranges and the time periods vary depending on the countries, and sometimes depending on the power plant. In all European countries, the nominal frequency is 50 Hz, and power plants are required to cover a range approximately from 47 Hz to 52 Hz. There are many nominal voltage levels, usually three or four per country as only the high voltage grid is considered here. Therefore the voltage range is often given in the per unit system (p.u.).

**UK**

The dimensioning frequencies are:
- from 47.5 Hz to 52 Hz in continuous operation,
- from 47 Hz to 47.5 Hz for at least 20 s.

The dimensioning voltages are:
- from 0.95 to 1.05 p.u. in continuous operation,
- from 0.90 to 0.95 p.u. and from 1.05 to 1.1 p.u. for at least 15 mn.

**Germany**

Figure 2-7 defines the dimensioning voltages and frequencies in Germany. For instance, if the frequency falls between 46,5 and 47,5 Hz for less than 10s, wind turbines are prohibited to be disconnected. If the frequency goes above 53,5 Hz or below 46,5 Hz, then the wind turbines must remain connected 300 ms and are then required to be disconnected. When the voltage level fall below 0,9 p.u., the requirements are described in chapter 2.3.4 on fault ride through capabilities.

24
Denmark
Figure 2-8 defines the dimensioning voltages and frequencies in Denmark.
France

The dimensioning voltages are:

- for the 400 kV grid:
  - from 320 kV to 340 kV for at least 1h,
  - from 340 kV to 360 kV for at least 1h30,
  - from 360 kV to 380 kV for at least 5h,
  - from 380 kV to 420 kV in continuous operation,
  - from 420 kV to 424 kV for at least 20 min,
  - from 424 kV to 440 kV for at least 5 min.

The higher voltage corresponds to 1,1 p.u. and the lower voltage corresponds to 0,8 p.u.

- for the 220 kV grid:
  - from 180 kV to 190 kV for at least 1h,
  - from 190 kV to 200 kV for at least 1h30,
  - from 200 kV to 245 kV in continuous operation,
  - from 245 kV to 247.5 kV for at least 20 min,
  - from 247.5 kV to 250 kV for at least 5 min.

The higher voltage corresponds to around 1,14 p.u. and the lower voltage corresponds to 0,82 p.u.

The dimensioning frequencies are:

- from 47Hz to 47,5Hz for at least 1min,
- from 47,5Hz to 49Hz for at least 3mn,
- from 49Hz to 49,5Hz for at least 5h,
- from 49,5Hz to 50,5Hz in continuous operation,
- from 50,5Hz to 51Hz for at least 1h,
- from 51Hz to 52Hz for at least 15 min.

Comparison

The rules vary over the countries, and it is not possible to determine the most stringent rules, as the result would depend on the criteria. For instance, in the UK the frequency range where continuous operation is required is much larger than in the three other countries, while this is in Germany that the voltage range where continuous operation is required is the largest. Dimensioning frequencies and voltages that would fulfil all the requirement would range from 0,8 p.u. to 1,14 p.u. (from 0,9 p.u. to 1,1 p.u. in continuous operation) for the voltage and from 46,6 Hz to 52 Hz (from 47,5 Hz to 52 Hz in continuous operation).

2.3.2 Fault ride through capabilities

In chapter 2.3.2, it is explained how the wind turbines are prohibited to be disconnected from the grid in case of slight changes in frequency or voltage level, in order to reinforce the grid stability. For the same reason, in all the four grid codes, there exists also a requirement prohibiting the wind turbines to be disconnected in case of an important voltage drop, as long this voltage drop is short enough. The capability of the wind turbine to not be disconnected in case of such a voltage drop is called “fault ride through
The minimal fault ride through capabilities required are a bit different in the four grid codes, but they are defined by similar figures: a chart with the voltage level of the connection point (in % of the nominal voltage) on the y-axis and the time (in ms) on the x-axis.

**Germany**

The minimal fault ride through capability required in Germany is defined by figure 2-9. Exceptionally, there are two lines. The limit line 2 is the one to be normally taken into consideration. The limit line 1, which is less stringent, can be used instead of the line 2 in exceptional circumstances provided there is a special agreement with the TSO. For instance, if the line 2 is taken into consideration, this means that the wind turbine is authorised to be disconnected only if the voltage drops down to 0 kV more than 150 ms, or down to 15 % of the nominal voltage more than approximately 350 ms, etc.

![Figure 2-9 Fault ride through capability in Germany](image)

**UK**

In the UK there are different requirements for the offshore wind farm (at the interface point between the farm and the connection line) and for the OFTO (at the interface between the connection line and a station of the onshore grid). Figure 2-10 defines the minimal fault ride through capability required for the wind farm, while figure 2-11 defines the minimal fault ride through capability for the OFTO. It is remarkable that the requirements for the OFTO are more stringent, as the OFTOs are required to withstand faults that last longer.
$V/V_N$ is the ratio of the voltage at the LV side of the Offshore Platform to the nominal voltage of the LV side of the Offshore Platform.

Figure 2-10 Fault ride through capability required for an offshore wind farm in the UK

Figure 2-11 Fault ride through capability required for the OFTO in the UK
**Denmark**
The minimal fault ride through capability required in Germany is defined by figure 2-12.

![Figure 2-12 Fault ride through capability in Denmark](image)

**France**
The minimal fault ride through capability required in France is defined by figure 2-13.

![Figure 2-13 Fault ride through capability in France](image)
Comparison
The minimal fault ride through capabilities required in the four different countries are not much different. The requirements in Germany are still a bit more stringent than in the three other countries, and only France and Germany require that the wind farm is capable of withstanding a voltage level of 0 kV without disconnecting (for 150 ms in the two countries).

2.3.3 Voltage control and reactive power requirements

All grid codes state that wind turbines are required to participate in voltage control, except in the UK, where there is such a requirement onshore, for the OFTO, but not offshore, for the wind farm. The wind farm is only required to maintain its reactive power output between 0,05 Pmax and −0,05 Pmax, except if otherwise stated in the contract: voltage control is possible in exchange for payment from the OFTO.

There are two types of reactive power requirements: static requirements define a minimal range of reactive power output that the wind farm must be capable of covering, while dynamic requirements deal with the reactive power response in case of a voltage drop. Such dynamic requirements are not dealt with precisely in the French grid code.

Germany
The static reactive power requirements are described by figure 2-14.
The dynamic requirements are described with the help of figure 2-15. It indicates the amount of reactive current that is required to be injected into the grid in function of the voltage drop. Even if there is no such precise information on the time-response than in the UK, where it is required that “90% of the full reactive capability shall be generated within 1s”, the indication that the “rise time” is required to be inferior to 20 ms shows that the reactive response must be extremely quick.

![Figure 2-15 Dynamic reactive power requirements in Germany](image)

**UK**
As indicated above, there is no requirement offshore, for the wind farm. However, there are ones onshore, for the OFTO. Indeed, the OFTO is required to participate in voltage control, and the static reactive requirements are described by figure 2-16. Point A is equivalent in MVAR to 0.95 leading power factor at the maximum active power output Pmax, which means QA = -0.33 Pmax. Point B is equivalent to 0.95 lagging power factor, which means QB = 0.33 Pmax. Point C is equivalent to -5% of the maximum active power output. Point D is equivalent to +5% of the maximum active power output. Point E is equivalent to -12% of the maximum active power output.
The dynamic requirements are not as comprehensive as in Germany or Denmark. Only the time-delay of the reactive response is given in the UK grid code, considering that the reactive power output corresponds to the maximum as defined for the static requirements, i.e. $Q=0.33\ P_{\text{max}}$ as long as the active power output is above $0.2\ P_{\text{max}}$. This time-delay is illustrated in figure 2-17 [28]. The reactive power output response shall commence within 200 ms, and 90% of the full reactive capability shall be generated within 1s. Moreover, any oscillation shall be less than 5% of the new reactive power output within 2s. This is a bit less quick than in Germany and Denmark, but still requires advanced technology.
Denmark
The static reactive power requirements are described by figure 2-18.

The dynamic requirements are described by figure 2-19. These are very similar to the requirements in Germany, but the time delay is given more precisely and is less stringent: there is a tolerance of +/- 20 % after 100 ms. The area B means that a reduction in the active power output is acceptable and area C means that the wind turbine is authorized to be disconnected (see chapter 2.3.4).
France
The static reactive power requirements are:

When the active power output (P) is (strictly) positive:
- When \( U = U_{\text{dim}} \) (where \( U_{\text{dim}} \) is determined project by project – usually 405 kV and 235 kV for the very high voltage (400 kV and 225 kV)), then the reactive (Q) capability of the plant is required to range from \( Q = -0.28 \ P_{\text{max}} \) to \( Q = +0.30 \ P_{\text{max}} \)
- When \( U = 0.9 \ U_{\text{dim}} \), the reactive (Q) capability of the plant is required to reach \( Q = +0.30 \ P_{\text{max}} \)

The dynamic requirements are much less stringent than in the three other countries: Following a change, the new reactive power output is required be reached within 10s.

Comparison
In the four countries, the static power output requirements, i.e. the range of reactive power the wind turbine is required to be capable of covering, range approximately from \( Q = -0.33 \ P_{\text{max}} \) (equivalent to 0.95 leading power factor when \( P = P_{\text{max}} \)) to \( Q = +0.33 \ P_{\text{max}} \) (equivalent to 0.95 lagging power factor when \( P = P_{\text{max}} \)). The requirements in France are a bit less stringent, while in Germany these requirements are also less stringent for leading power factor, but are more stringent for lagging power factor. In Germany, Denmark and in the UK, the static reactive requirements are progressive as the wind turbine starts generating active power, and are to be fully fulfilled only when the active power output is at least equal to 20% of the rated capacity. France is the only country where the static reactive requirements are to be fulfilled as soon as the wind turbine starts generating active power. However, France has not much experience with large wind farms yet, and this requirement is likely to be modified in the future. Indeed, such a requirement does not sound appropriate for wind turbines, as their reactive capability are not at their maximum when the active power output is low, and can only be fulfilled with the help of additional reactive compensation devices (see chapter 2.5.2).

There is a huge difference in the dynamic power output requirements between France and the three other countries: while the required time-delay of the reactive response in case of a voltage drop is below 200 ms in Germany (20 ms) Denmark (100 ms) and in the UK (200 ms), this time-delay is 10s in France. Again, it is likely that France will change this rule in the future. Such a low time-response is not a problem at low levels of wind penetration in a power system, which is the case in France, where wind power accounts for around 1% or 2% of the electricity generated. However the wind penetration level is likely to increase greatly in France is the future, and then such a low time-response would sound inappropriate, for it would endanger the power system unnecessarily, considering wind turbines can have the capability of providing quick reactive responses if required. The examples of the three other countries show that in the most advanced countries, this has been considered as important enough to be systematically required, and not negotiated for each project individually, as it can be the case in France.

### 2.3.4 Frequency control

There is no proper frequency control required in France, Germany and in the UK. However, the wind farms are required to decrease their output in case of high frequencies. For instance, in France the active power output is required to be decrease by 25% when frequency reaches 50.5 Hz, then 25% more for each 0.5 Hz in addition. Hence, the active power output is equal to zero at 52 Hz. The rules in Germany are similar, and the active power output is required to respect the formula displayed in figure 2-20: the active power output is required to be...
output is required to start being reduced when the frequency reaches 50.2 Hz, until the turbine stop generating when the frequency reaches 52.7 Hz.

\[
\Delta p = 20P_M \frac{50.2 \text{Hz} - f_{\text{grid}}}{50 \text{Hz}}
\]

when \(50.2 \text{ Hz} \leq f_{\text{grid}} \leq 52.7 \text{ Hz}\)

\(P_M\): currently available power

\(\Delta p\): Power reduction

\(f_{\text{grid}}\): Grid frequency

In the range \(47.5 \text{ Hz} \leq f_{\text{grid}} \leq 50.2 \text{ Hz}\) no restriction

Figure 2-20 Active power output decrease in case of high frequency in Germany

**Denmark**

In Denmark, wind turbines must be capable of providing frequency control when required by the TSO. Their active power output is required to follow the curve plotted in figure 2-21. All the parameters of the curve can be modified by the TSO at any moment and have to be taken into consideration within 10s.

Figure 2-21 Frequency control in Denmark
This means that the output of the wind turbines is constantly curtailed (and therefore some “free” power from the wind is “wasted”), even under normal grid operation, in order to keep a reserve to be capable of supporting the frequency in case the frequency falls below a certain level. This rule has been added very recently (October 2010) in the Danish grid code, and is quite unique in Europe, with the notable exception of Ireland, where similar rules were included in the grid code few years ago. However, it is not possible to know the magnitude of the change yet as it will depend on the level of \( P_{\text{delta}} \): for instance, if \( P_{\text{delta}} \) is maintained at around 98% of \( P_{\text{available}} \), this would not be a significant change. The fact that a country with an important amount of wind power implements such a rule might still be the beginning of a small revolution in Europe, in case the other countries would decide to do the same: the idea of wind turbines participating in supporting the frequency in case of frequency fall was hardly imaginable a few years ago. However, as written previously, the fact that some “free” power has to be “wasted” is an important drawback, and this rule does not sound very useful as long as wind power penetration does not reach very high levels, which is not the case for the moment in Europe. Hence, this sounds more like a test for the future than like an essential measure for the security of the electric system in Denmark.

### 2.3.5 Conclusion

There used to be few requirements for wind turbines. However, with the increasing penetration of wind power in the electric systems, requirements as stringent as the ones in use for conventional plants become necessary for the secure operation of the grid. Requirements on dimensioning voltages and frequencies and on fault ride through capability, which prohibit wind farm from disconnecting from the grid under certain conditions, are quite similar in the four countries under investigation. There are more differences in the requirements on voltage control. In particular, rules in France are very different from the rules in the three other countries for two reasons: first the time delay of the reactive response of the wind farm required in case of voltage drop is much larger in France, and secondly the France require that wind turbines generate reactive power as soon as they start generating active power, while in the three other countries this is progressive and the full reactive requirements are to be respected only when the active power output reach 20% of the rated capacity. These two major differences are likely to be explained by the lesser penetration of wind power in the electric system for the first one, by the lack of experience for the second, and are certainly worth being investigated further. Besides, in the UK, there is a somehow surprising rule requiring that the operator of the connection line provides voltage control with stringent dynamic requirements, while the operator of the offshore wind farm has no voltage control requirement at all. This could be a poor use of the capabilities of the wind turbines in case the two players do not come to an agreement for the furnishing of reactive power in exchange of payments.

Wind turbines are not usually required to provide proper frequency control, even if in all countries the active power output has to be decreased when the frequency is too high. However, a new regulation in Denmark in late 2010, similar to the rules implemented a few years ago in Ireland, requires that wind farms participate in frequency control, even in case of low frequency. This means that the active power output of the wind farm is lowered intentionally under normal conditions, and hence can be increased in case the frequency falls. The important drawback of such requirement is that a part of the power “freely available” in the wind is “wasted”, even under normal conditions. Hence, frequency control from conventional plants is much less costly, and such a rule is not likely to be implemented all over Europe as long as wind power penetration remains quite low.
2.4 Third energy package

European energy structures are currently experiencing deep changes. The transition from national energy markets to a deregulated, liberalized integrated European market, intended to handle concerns like environmental issues, secure and independent energy supply and financial efficiency, requires the implementation of a complex regulation at European level. Started in the 1990s, the process recently led to the Third Energy Package, adopted in April 2009 by the European Parliament.

As explained below, the Third Energy Package is expected to lead to many changes in European electricity rules. Many features are still under discussion, and the short term outcomes cannot be predicted yet, but it is worth studying it to stress the likely impact on wind power regulation within Europe.

Chapters 2.4.1 and 2.4.2 deal with the history of energy markets in Europe and the content of the “Third Energy Package”, while chapter 2.4.3 focuses on the current developments of the on-going process and describes and comments two important documents which have been recently published. The major stakeholders, who decide or influence the electricity rules at European level, are described, as well as their views on the future changes.

2.4.1 History of the integrated European energy market:

In the second half of the last century, energy issues were controlled by national agencies almost everywhere, but the emergence of neoliberal ideas in the 1980s paved the way for major changes. The first electricity and gas directives were adopted in the late 1990s, with the objective of opening up the electricity and gas markets by gradually introducing competition. The Commission has consistently argued that liberalization increases the efficiency of the energy sector and the competitiveness of the European economy as a whole. However, a number of stakeholders and member states, notably France and Germany, vehemently disagree with this assessment. While most member states had implemented the electricity and gas directives by September 2000, a 2001 Commission inquiry concluded that further measures were necessary in order to complete the internal energy market and to reap its benefits.

The second gas and electricity directives, adopted in June 2003, include “unbundling”, whereby energy transmission networks have to be run independently from the generation and supply side. According to the directives, markets for all non-household gas and electricity customers are to be liberalised by July 2004. For private households, the deadline is July 2007. After these dates, businesses and private customers would theoretically have been able to choose their power and gas suppliers freely in a competitive marketplace.

However, a competition enquiry in the electricity sector, published in January 2007, revealed some "serious malfunctions" in the market for industrial consumers. For example, market concentration still reflects the "old" market structure, characterised by national or regional monopolies - usually dominated by vertically integrated companies - which control electricity prices in the wholesale market and block new entrants to the market. Corrective action was promised by the EU executive, which tabled a further package of proposals in September 2007 (“Third Energy Package”). After long negotiations, the Parliament and the Czech Presidency struck a compromise deal on the legislative package on 23 March 2009 [29].
2.4.2 Presentation of the Third Energy Package

This Third Energy Package consists of five regulations of the European Parliament dealing with electricity and gas markets in Europe [30]. It promotes a more deregulated and integrated European market through two mechanisms:

- The full separation of generation and transmission assets (“unbundling”)
- The creation of three European agencies: the ACER (Agency for the Cooperation of Energy Regulators) [31], the ENTSOE (European Network of Transmission System Operators for Electricity) [32] and the ENTSOG (European Network of Transmission System Operators for Gas), in charge of supervising the national regulators and TSOs.

The ACER will not replace the national regulators, but will encourage their cooperation and coordinate their functioning at the European level. It will be officially created in March 2011 and will replace the existing ERGEG (European Regulators’ Group for Electricity and Gas). But, unlike the ERGEG, the ACER has effective power to implement rules at the European level. In parallel, the powers and duties of national regulators are harmonized and strengthened so that they are able to issue binding decisions on companies and impose penalties on those that fail to comply.

The ENTSOE, has the same role than the ACER, but with the national Transmission System Operators (TSOs). It was created in 2009 from several existing networks of TSOs.

In order to get an idea of the likely impacts of these changes on the national grid codes, it is interesting to read several extracts of the regulation of the European Parliament which deals with the creation of the ENTSOE and the conditions for access to the network and for cross-border exchanges in electricity in Europe [32]. As indicated in the quotes 2-1, 2-2 and 2-3, this regulation introduces twelve “network codes” within the European electricity market, covering as many topics. These “network codes”, which are the main tools for implementing changes in national legislations, are listed in quote 2-1. They will be written by the ENTSOE within a few years, based on “framework guidelines” to be published by the ACER. The aim of these “framework guidelines” is to give clear guidance about what should be the “network codes”, leaving the technical details to the ENTSOE.

These quotes give some preliminary indications on the extend of the future changes. Every network code may have an impact on wind power rules within Europe, but what exactly is included in the terms “cross-border network issues and market integration issues”, and therefore will be modified (see quote 2-2), is still not clear. At this time (mid-2010), only technical issues, related to the second “network code”: “(b) network connection rules” (see quote 2-1, in bold type), have been further discussed, as explained in the next chapter.
“Article 8.6 - The network codes referred to in paragraphs 1 and 2 shall cover the following areas, taking into account, if appropriate, regional specificities:

(a) network security and reliability rules including rules for technical transmission reserve capacity for operational network security;

(b) network connection rules;

(c) third-party access rules;

(d) data exchange and settlement rules;

(e) interoperability rules;

(f) operational procedures in an emergency;

(g) capacity-allocation and congestion-management rules;

(h) rules for trading related to technical and operational provision of network access services and system balancing;

(i) transparency rules;

(j) balancing rules including network-related reserve power rules;

(k) rules regarding harmonised transmission tariff structures including locational signals and inter-transmission system operator compensation rules; and

(l) energy efficiency regarding electricity networks.”

Quote 2-1 REGULATION (EC) No 714/2009 OF THE EUROPEAN PARLIAMENT [32]

“Article 8.7 -

The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States’ right to establish national network codes which do not affect cross-border trade.”


“Article 21 - Right of Member States to provide for more detailed measures

This Regulation shall be without prejudice to the rights of Member States to maintain or introduce measures that contain more detailed provisions than those set out herein or in the Guidelines referred to in Article 18.”

2.4.3  Network code on connection rules

As stated above, the ACER is to be created next year (2011). European regulators, within the ERGEG, decided to use the interim period (before the creation of the ACER) for initiating the publication in advance of one of the twelve network codes, in order to test the implementation process. The code that has been selected as pilot project is the second one “(b) network connection rules”. This code is dedicated to technical rules (and wind power is particularly concerned, as explained below). An “impact assessment draft” [33] has been published by the ERGEG in March 2010, as a preparatory document for the pilot “framework guidelines”.

The ENTSOE is also involved in this pilot project, as it is in charge of writing the final “network codes” from the directions given by the framework guidelines. It has published in early 2010 a working draft: “Requirements for Grid Connection Applicable to all Generators”. [34]

These two documents, which have been recently published and prepare the network code on connection rules, are described below. They certainly give valuable information on what could be the future changes, but many things remain uncertain. The positions and expectations of the most important stakeholders involved in the process, both on this specific network code and on the whole energy package, are also described.

2.4.3.1  Pilot code development milestones

The Pilot Code Development Milestones for 2010

![Diagram of Pilot Code Development Milestones](image)

FWGL means Framework Guidelines.

Figure 2-22 Pilot code development Milestones [35]
Only a working draft on “Requirements common to all Generators” (by the ENTSOE) and an “impact assessment draft” (by the ERGEG) have been published for now (July 2010). Neither the working draft on the requirements dedicated on wind power (by the ENTSOE) nor the Draft Framework Guidelines (by the ERGEG) has been published for now, though these two documents were planned earlier in the year.

2.4.3.2 Pilot Framework Guideline, Impact Assessment Draft, ERGEG

This chapter describes the only document published by the ERGEG for now on the pilot network code on connection rules: the impact assessment draft [33]. It is a preparatory document to the pilot framework guideline document and evaluates different policy options, from the status quo (no action at the EU level) to the implementation of rules established and agreed at EU level.

It concludes that legislation at EU level is the best solution, justifying the Third Energy Package. It gives indications on what should be included in the final network code on connection rules. Nevertheless, the future impact on the national technical legislations is still uncertain, as key questions remain.

As stated above (chapter 2.4.2), the regulation from the European Parliament which describes the process of the implementation of the network codes [32] stipulates:

“The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States’ right to establish national network codes which do not affect cross-border trade.”

The impact assessment draft gives some indications on what exactly does “affect cross-border trade”, (and therefore is likely to be amended by the future EU legislation). It states that “this should include defining common frequency and voltage ranges for transmission and distribution networks, requirements for reactive power, load-frequency control and fault ride through capability. Where necessary, the framework guideline should also request the establishment of minimum requirements and procedures for connection to the grid.”

However, nothing is definitive, and it is still not known how restrictive the rules will be. Such sentences as “The grid connection regime should establish an appropriate minimum degree of standardisation” indicate that there is no plan to impose important changes in national technical rules.

Some important points are not mentioned: in particular, the possible differences in the rules depending on the type of technology, the size of the plant, the voltage level, etc; the possible need for specific rules for renewable energy; the possible retroactivity of the rules; the applicability of the rules to distribution users. Moreover, it is still not clear whether some issues, for instance dealing with grid access, connection costs, demand response, exchange of information, should be included in the network code on connection rules or in other ones (which will be written later, as explained in chapters 2.4.2 and 2.4.3). The quote 2-4 shows the most important extracts of the Pilot Framework Guideline.
Recent experiences have (...) indicated that the existing rules are not sufficiently harmonised in terms of compatibility and coherence between TSOs in a synchronous area. p.11

Additionally, the need to comply with a diversity of connection requirements throughout Europe may lead to higher production costs for manufacturers of generation facilities, because of less standardisation of units, resulting in higher investment costs for operators. p.12

The grid connection regime should establish an appropriate minimum degree of standardisation necessary to ensure equitable treatment in the connection of power plants generators and consumers to the extent that these rules may impact on crossborder system security and trade. Therefore, a grid connection regime should clearly identify and explain those areas where further harmonisation of rules in different Member States is necessary. Where variation may be required for different technologies or to reflect specific regional technical needs, this should also be identified and explained. At least the existing standards of security and quality of supply should be maintained. p.18

Recent experience and results of studies indicate that standardised requirements for e.g. voltage and frequency variations of generation and consumption units connected within a synchronous area would benefit European grid users. p.18

The operational objectives of the framework guideline are to establish and define the basic key aspects of European rules on electricity grid connection that need to be harmonised in order to provide system security in synchronous areas. Specifically, this should include defining common frequency and voltage ranges for transmission and distribution networks, requirements for reactive power, load-frequency control and fault ride through capability. Where necessary, the framework guideline should also request the establishment of minimum requirements and procedures for connection to the grid. p.19

The network codes prepared by the ENTSO for Electricity are not intended to replace the necessary national network codes for non-cross-border issues. p.26

The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States’ right to establish national network codes which do not affect cross-border trade. p.26

Quote 2-4 Pilot Framework Guideline [33]
This chapter describes the document published by the ENTSOE on the pilot network code on connection rules: Requirements for grid connection applicable to all generators [34]. This working draft is a preparatory document to the definitive network code, and illustrates quite well what would be the network code if the ENTSOE was in charge of the whole writing process, as it has been written without consideration to the ERGEG’s view.

As it appears in this working draft, the ENTSOE has a more clear cut position that the ERGEG on what should be the network code on network connection rules. Indeed, the working draft insists in particular on the necessity for (1) dedicated sections for the different types of generation, (2) a focus on technical requirements for connection, while issues about Grid access and Connection costs are dealt with in future network codes, (3) a serious attention to distribution level, as more and more power plants - mostly wind farms and solar plants - are connected at this level.

The document described in this chapter was published in early 2010 by the ENTSOE, as a first work in the writing of the network code. It could look like the final network code, even if it is still incomplete (some chapters are missing, etc.). And many changes are likely to occur, as the definitive code is required to conform with the framework guidelines, not published yet.

This working draft describes a common basis applicable to all types of generators. Dedicated sections for the different types of generation will follow. In particular, a section for wind power should be published soon. The document has the shape of a technical grid code, and describes harmonized requirements. Detailed parameters are often left up to the TSO, and most sections would not lead to major changes in national rules, as most rules described here already exist in the current national grid codes. Still, this document proposes (1) harmonizing the “dimensioning voltages and frequencies”, i.e. the range of voltage and frequency a power plant should be capable of generating within, within synchronous areas, (2) harmonizing, at a lesser extent, the rules on frequency control and voltage control, and (3) imposing several basic rules, such as having stringent requirement for power plants connected to the lower-level distribution network, or inertia requirements for every plant, etc.

Thus this document proposes a common blueprint for national codes. Only few changes are imposed, as all the issues mentioned here are more or less already dealt with in the national codes. Still, this could help harmonizing the form of the grid codes and facilitate comparisons, if the TSOs do reorganize their respective grid code to fit to the model, which they will probably be reluctant to, as it will require much work. And besides, more accurate requirements could be given in the dedicated sections for the different types of power plants, in the future. The quote 2-5 shows the most important extracts of this document.

Unfortunately, not much can be said about wind power at this time, as the dedicated document, that was expected earlier in the year, has not be published yet.
The purpose of this Network Code is to set out clear and objective requirements for generators for grid (Network) connection and access in order to contribute to non-discrimination, effective competition and the efficient functioning of the internal electricity market. p.3-4

The scope of application of this Network Code includes all new and Modified Power Generating Facilities. Existing Power Generating Facilities are not covered unless changed or modified. p.4

Network Operators are entitled to impose additional requirements covering aspects not specified in this Network Code on the Power Generating Facilities when needed for secure system operation due to local/regional specifics. p.4

Network Operators are not entitled to change or modify requirements specified in this Network Code by own codes or bilateral contracts with Power Generation Facility Operators unless authorized by derogation. p.4

Requirements in this Network Code define common principles and parameters or ranges of parameters. Network Operators can select coverage for their Network (by explicit choice of disabling requirements which is not required in their context and by selection of threshold or parameters). p.4

The necessary degree of a common level of requirements can be determined by the extent of the system-wide impact of a requirement. For the most important mandatory requirements with relevance to transmission system security a common level of methods and principles is necessary and a common agreement on specific parameters and settings is endeavoured. p.6

For requirements with lower impacts a mutual agreement on methods and principles provides sufficient standardisation. At least it is ensured that the same issues are covered by each Network Operator within an interconnected Network. Individual methods/principles and parameters/settings to achieve the same target are acceptable. p.6

it is of crucial importance that these requirements are shared as well by Generating Units connected to the transmission Networks as to the lower-level distribution Networks. p. 7

Quote 2-5 Requirements for Grid Connection Applicable to all Generators, Working Draft, ENTSOE
2.4.3.4 Points of view of other stakeholders

Many stakeholders have been consulted on this network code on connection rules. Their points of view are interesting, as pressure groups may still influence the outcome. Everyone welcome the publication of European network codes, especially for it should clarify the rules on cross-border trading. On the specific network code on connection rules, the views differ. The positions of the most influent groups are summarized below:

- Ralph Pfeiffer, from Amprion, one of the four German TSOs: He states that current national regulations are coinciding to a large extent throughout Europe, even though specific approaches and parameters (threshold values, etc.) vary. He also states that the requirements to distribution system users are often much less stringent than to transmission system users, and that TSOs lack of sufficient information from the distribution system. He makes a distinction between requirements relevant for system security (to be harmonized to the largest possible extent: common parameters, thresholds, etc) and the ones for which common methods and principles could be sufficient. He also insists on the necessity of more stringent rules for distribution networks users.

- Eurelectric, Union of the Electricity Industry (many companies of the electricity industry, including TSOs): They think that the code should define the technical requirements, but not technical, engineering and design solutions, which are left up to the plant owners. For them, there should be a transitory period before the new rules apply, and only the new plants should be impacted. A system of financial incentives should be set up to encourage old plants to respect the new rules. They think that a queuing system, i.e. an “Open door” procedure based on the “First come first served” approach, is not appropriate. They also advocate the equality of treatment for RES and non-RES regarding administrative procedures and connection costs, the obligation for consumers as well to conform to grid code requirements, the remuneration of any investment that contributes to the system stability/security, and market solutions for the ancillary services.

- EWEA, European Wind Energy Association (wind turbines manufacturers, wind farms developers, various companies supporting the wind energy): they strongly support the publication of strong European technical standards, but that should still leave room for local differences in some extent, just as they support a more integrated European market. They have even published a generic grid code format for wind power plants as an example of possible harmonized grid code [36] This is understandable, as large wind power penetration in Europe requires high levels of cross border exchanges. And such high levels of exchanges require harmonized rules throughout Europe. Moreover, they assure that standardized solutions would significantly reduce costs for wind turbine manufacturers and wind plant operators. They also insist on the necessity of rules dedicated to wind power, and on the stability of these rules, i.e. a reasonable minimum period between changes.

- IFIEC Europe (large electricity consumers): they welcome the initiative because it should provide for a better protection for the grid users and an improved visibility. They recommend, among other things, high power quality standards and the generalization of the possibility for consumers to provide remunerated grid services just like generators, such as load shedding.
The stakeholders point out very different priorities to be dealt with, depending on the interest of the companies they represent. These are not really conflicting, apart from the difference about the level of harmonization required in the respective views of the EWEA and the TSOs. Indeed, the EWEA thinks that a strong harmonization of the technical connection rules throughout the European countries would significantly simplify the work of wind power companies and therefore reduce the cost of wind power; on the opposite, the TSOs tend to think that there are only few rules that require some harmonization throughout the European countries (in particular, the dimensioning frequencies), and that strong harmonization is not necessary, as the potential advantages are not worth the large amount of work at the charge of the TSOs that would be required.

At this stage, it can be said from the publications and points of view of the European Parliament, the ERGEG and the ENTSOE, in charge of the network codes, that (1) the network code will probably conform to the TSOs’ opinion regarding the level of harmonization, and (2) none of the expectations of Eurelectric, the EWEA or the IFIEC is likely to be included in the network code on connection rules, nor in the future network codes, as there is a strong will to not impose rules at the European level if they are not really necessary. However this cannot be taken for granted, for the different pressure groups still have some influence on the decision-makers.

2.4.4 Conclusion

It is likely that the European electricity market will become fully integrated in the long run, with common rules and standards regarding connection to the grid. The transition process might still take a long time. In the short term, the recent Third Energy Package is certainly an important step forward. Some stakeholders, and especially the wind power industry, would like to see in this package a good opportunity to speed up consequently the harmonization process of the technical connection rules throughout the European countries. However, they probably will not be able to convince the decision makers on this point, and the impact on this Third Energy Package on the technical connection rules on wind power in Europe should be minor. This package illustrates quite well the progressive improvement of the international cooperation between TSOs. And this harmonization of the technical connection rules on wind power, which is not likely to be imposed by the European institutions, might be set up progressively as the talks between TSOs go further. However, except for some very few rules such as the dimensioning frequencies of the turbines, in any case it is very unlikely that such harmonization takes places in the very next years.
2.5 Practices in use – transmission technologies

Grid codes describe technical rules and requirements, but do not give much information on technical, engineering and design solutions. This chapter presents the practices in use in Europe. It includes a database of offshore wind farms, with focus on the transmission systems which connect the farms to the grid. It also gives information and comments on offshore transmission technologies in use and on some wind farm characteristics. The database (appendix 1) gathers every operational wind farm above 100 MW, and some other future farms whose characteristics are available.

Information and comments below give an overview of the technologies in use for the connection of offshore wind farms, and includes cost estimates. The issue of capacity per km², which has been included in the database (although few reliable data is available), is described and it is explained why this is an important issue in such countries like France. Additional information about redundancy, water depth, foundations and distance to the shore is also given. Typical designs of a transmission system for an offshore wind farm can be found in [37] or in [38].

2.5.1 Cables

There exist many types of cables. For example, AC cables vs DC cables, 3-core vs single core (for AC cables only), copper vs aluminium, underground cables vs overhead lines, ... There is a wide range of diameters, suitable for different voltage levels and capable of carrying different amounts of power.

- Cable type: Many features are the same throughout Europe. For example, almost every AC offshore cable is a 3-core copper underground cable, while almost every onshore cable is a single core aluminium underground cable.

- Diameter: As a general rule, the larger the cable, the cheaper the cost per (MVA.km): one big cable is very often preferred to two smaller ones [39]. Even though availability, or delivery time, is also to be taking into consideration. Still, depending on the countries, there are differences in the choice of the diameter. For instance, in France, according to the current rules, cables are designed to carry 100 % of the maximum power output, even when the voltage level is slightly lower than usual: “90% of Udim”, where Udim is determined project by project – usually 405 kV and 235 kV for the very high voltage (400 kV and 225 kV). In addition, there are additional requirements about reactive power carriage. In the UK, recent publications from the TSO inform that the optimal rating for offshore cables is somewhere between 90% and 95% of the wind farm capacity. As a consequence, one 3-core 1000 mm² Cu 220 kV cable is supposed to be suitable for more than 300 MW in UK, as compared to 250 MW in France, assuming short cable length.

- Voltage level: Inter-array cabling is always AC power at 33 kV for big farms. AC connection lines, from the farm to the onshore grid, are often at the same voltage level than the part of the grid they are connected to. This is because a high voltage level reduces both the losses and the number and/or the diameter of cables. But, at the same time, it is expensive to unnecessarily step up or down the voltage level. Some wind farms are still connected through 33kV transmission lines to the national grid (see Burbo Bank in UK (Appendix 1)). This is likely explained by the willingness to avoid
installing a transformer offshore, the farm being small and close to the grid, which lessens the advantages of a high voltage connection line. DC* cables are either at 150 kV or 300 kV.

- The choice between AC and DC is less “established” than the above issues. AC systems are definitively more suitable for short distances and low capacities, and DC systems for long distances and high capacities. Nevertheless, it is difficult to determine which solution is better for many projects characterized by “mid-capacity” (approximately between 300 MW and 700 MW) and “mid-distance” (approximately between 40 km and 120 km). More details are given in chapter 2.5.3. As most operational farms are located near the coastline and have low capacity, there is only one DC transmission line for the moment (Bard/NordE.ON).

AC cables have the disadvantage of generating reactive power. The longer the cable, the more reactive power is generated, and the less active power can be carried, as illustrated in figure 2-23, and additionally the more reactive compensation devices must be installed. DC cables do not generate reactive power. Moreover, the converter stations AC/DC have good reactive power capacities and are therefore of great help for voltage control [40].

Hence the choice between AC and DC is not simple and depends on local parameters: national rules and practices, robustness of the local grid, … For instance, a 600 MW farm located approximately 50 km from the onshore station is more likely to be connected through AC transmission system in UK - 2 cables could be sufficient (see the above paragraph “Diameter”) than in France - 3 cables are needed. Reactive compensation strategies are also of importance, as DC should be more easily preferred in countries that have a stringent regulation regarding the time delay of reactive furniture: in UK for instance, Statcoms are systematically required for AC connection systems (unless cables are very short), which increases the costs of AC systems.

* There exist two DC technologies: either based on Voltage-Source Converter (VSC), or Current Source Converter (CSC) (also known as Line-Commutated Converter (LCC)). Only DC VSC is suitable for the offshore wind farms that are currently planned. DC CSC is suitable for much higher distances (beyond 200-300 km). Hence « DC » actually means « DC VSC » here.
For the moment, there is no operational DC VSC system whose rating exceed 500 MW. However, on the contrary to RTE which is reluctant to use technology that has not been previously installed elsewhere, National Grid (the TSO of the UK) considers that there is no reason to not use in very future connection lines the DC VSC converter stations and the 300 kV DC XLPE subsea cables up to 1300 MW already available in the catalogue of some manufacturers - the limiting factor is actually the rating of the cables [39]. This cautiousness in France could be quite costly, for the installation of one 1300 MW DC connection lines is much cheaper (around 40%) than the equivalent installation of three 450 MW DC connection lines (see chapter 2.5.3).

The awareness of such a difference of costs would have certainly changed the way the areas have been selected for the call for tenders: in particular, some very large areas have been divided into several small ones of 500 MW each, because these 500 MW correspond either to the maximum rating of a single DC line or to two times the maximum rating of a single AC line, according to the French criteria.

2.5.2 Reactive power compensation

AC cables generate much reactive power: around 3 Mvar per km for 300 MVA cables at 220 kV (see chapter 3.1). If not compensated, this reactive power raises the voltage level nearby. It might be a problem especially in summer, when load is low and voltage levels tend to be high. Even though many countries require that wind farms participate in absorbing reactive power, one has to take into consideration the situation where the cable is switched on, and thus generates reactive power, while the farm is not generating, and thus does not absorb reactive power.

There exist several types of reactive compensation devices. The most elementary ones are reactors (also called inductors) and capacitors (also called condensers) that, respectively, absorb and generate reactive power. They are simple and cheap, but it is not possible to switch them quickly enough to handle dynamic issues. Moreover their reactive power output is proportional to the square of the voltage level, which is detrimental for system stability in case of voltage drop [41].

Statcoms and SVCs are more elaborate. They can either generate or absorb reactive power on demand, and their quick responses make them adequate for dynamic issues. A Statcom (sometimes named SVC +) has better characteristics than a SVC. First, its response is quicker. Moreover, the maximal available reactive power from a STATCOM is proportional to the voltage, and consequently the available maximal reactive power decreases more slowly for STATCOMs than SVCs, when the voltage decreases: in contrast the maximal available reactive power from a SVC is proportional to the square of the voltage level, just like reactors and capacitors. [42]

First of all, many farms do not have reactive power compensation devices. This often corresponds to farms located close to the coast, as their cables are short enough to not generate much reactive power. As for more distant farms, practices vary depending on the countries:

- in France (in the future): Reactors are to be installed in onshore stations (reactors on offshore platforms are prohibited for the moment because the TSO owns reactors, but not the platform). They will be connected independently to the busbar rather than connected directly to the offshore cable (to be able to switch them on/off independently). Neither SVC nor STATCOM are planned;
Figure 2.24 Estimated connection costs in €/(MW.km) All farms included
• in UK (currently): Small reactors are put on the offshore platforms near the wind farm. Statcoms are systematically installed in onshore stations (except for small farms located close to the coastline), in addition to extra reactors. The need for Statcoms is explained by the stringent dynamic reactive requirement and by the fact that the independent operators of the transmission lines (OFTOs) are required to provide voltage control, while the offshore wind farms are not required to (see chapter 2.3.3);

• in Denmark: Only reactors are installed for the moment, but not only in the onshore station: also midway between the farm and the onshore station (Horns Rev 2), or potentially offshore.

2.5.3 Costs

The database (appendix 1) gathers the characteristics of many connection lines of offshore wind farms. The costs given include only the devices related to the direct connection to the grid: at a maximum, cables, reactive compensation devices, platforms, transformers and converter stations in case of DC (what is exactly included depends on the farm). Inter array cabling and deep grid reinforcement are not included. The costs that correspond to operational projects in UK include platforms, offshore transformers, sometimes many reactive compensation devices (Statcoms, reactors), while the costs corresponding to most other farms do not.

Many prices for the various components are given in [39]. For instance, according to this document and considering an exchange rate of 1 Pound = 1,15 Euro (average rate from august to October 2010), the approximate cost of a single DV VSC converter station of 450 MW is 65 €M, 110 €M for a 1000 MW station, 135 €M for a 1300 MW station ; 1 €M per km of 300 kV, 450 MW DC offshore cables; 0,9 €M per km onshore, 2,3 €M per km of 300 kV, 1300 MW DC offshore cables, 1,7 €M per km onshore; 1,6 €M per km of 220 KV, 300 MVA AC offshore cables; 5 €M a 500 MVA transformer; 3,5€M an inductor 220 kV 200 MVar; 5,5 €M a capacitor 220 kV 200 MVar; 17 €M a SVC 200 MVar; 23 €M a Statcom 200 MVar. As it can be noticed from these prices, the cost of a DC system is far from proportional to its capacity, and much money can be saved by building farms of 1300 MW or so, which is the maximal capacity per converter station today. It can be estimated that three 450 MW DC connection lines cost about 40% more than one 1300 MW DC connection line. The same result is found using the prices available in RTE database. That is why some farms planned in UK (round 3) have costs about average in €M/MW, although they are located far from the coast. Corresponding costs in €k/(MW.km) are then very low (See Dogger Bank for instance).

It is difficult to compare the connection costs of the different wind farms, as they rarely include the same elements, and it has been sometimes not possible to find out about the elements included in the price. Moreover, the interest of such a comparison is not obvious, for the cost of the various components being the same and the installation costs being not that different over Europe, there is no reason to find differences in the connection costs of similar wind farms located in different countries. It could have been interesting to investigate the evolution of these costs over the years, but there is not enough old data to get satisfying results. Figures 2-22, 2-23 and 2-24, derived from the data of the database (appendix 1), give an idea of the large degree of variability of these costs depending on the components taken into consideration. They represent the distribution of the costs in function of capacity and distance to the grid. Two types of cost are indicated: in kEuros/(MW.km) in M€Euro/MW, as they are both needed to give a
Figure 2-25 Estimated connection costs in €k/(MW.km), the most expensive farms being removed
satisfying overview: figure 2-24 gives the costs in “k Euros/(MW.km)”, all farms included (when the costs are available), figure 2-25 gives the costs in “k Euros/(MW.km)”, but the most expensive connection systems have been removed to have a better view of the other ones, figure 2-26 gives the costs in “MEUro/MW”, all farms included. In these figures, the cost are proportional to the diameters of the circles. The precise connection costs can be found in appendix 1.

Costs in €/(MW.km) range from 2.5 €/(MW.km), which correspond to the very large farms planned in the round 3 in UK connected through 1300 MW DC connection lines, to 25 €/(MW.km) for the farms being currently built in the UK, whose price includes more components than usual. Costs in €M/MW range from 0.16 €M/MW, which correspond to a project that has been cancelled in western France and does not include the offshore platform and the transformers, to 1 €M/MW for the first DC connection line built for an offshore wind farm at NordE.ON 1 in Germany.

2.5.4 Capacity per km²

The question of the capacity of offshore wind power that can be built per km² is not that important in countries like UK where the limiting factor is the grid itself, as there are many offshore areas available. However capacity per km² can be a crucial point in countries characterized by lack of offshore areas, as explained below for the specific case of France.

Unfortunately, reliable information on the area covered by a specific wind farm is difficult to find, and is usually not available before the farm is operational. That explains why only few capacities per km² are given in the database (Appendix 1). Three existing wind farms in the UK are very close to 9 MW/km² [43]. And the future offshore wind farm of Ormonde is expected to reach 15 MW/km² [44]. It is frequent to find much lower values - 1 MW per km² or so - in various documents, especially for farms that are not built yet, but such low values are always calculated using much larger areas than the ones actually built.

Many factors may impact the capacity per km²:
- the capacity of a single turbine;
- the average wind speed;
- the variability of the wind direction;
- the size and shape of the farm: for instance, the larger the farm, the more turbines perturb the incoming wind, the lower the power output of the last turbines, unless they are built farther;
- the strategy of the developer: either a higher capacity (more turbines within the same area) or a better load factor (less turbines in order to lower the wake effect);
- fishing issues;
- maritime traffic.

For the moment, there is no operational offshore wind farm where fishing issues and maritime traffic did have an impact on the capacity per km². However, as explained below, the will to let large ships navigate within the wind farm could be a major reason to impose a large distance between the wind turbines in France.
Figure 2-26 Estimated connection costs in €M/MW
The following describes the situation in France where this question of capacity per km² is central, as an assumption of 5 MW/km² has been made that could lead to a bad use of the few available areas. In many countries, like the UK, there are plenty of areas to build offshore wind farms and the most limiting factor to offshore wind power is the capacity of the electricity network to withstand a large amount of infeed power. The situation in France is very different, as there is a severe lack of offshore areas available for wind power in the French seas, for (1) there are many protected areas for environmental issue, many fishing area, many forbidden areas for other reasons: military issues, radars, emblematic patrimony, etc; (2) the French government decided to keep the wind farms away from the coastline to facilitate local acceptance (10-15km minimum), (3) the ocean floors fall steeply, and building offshore wind farms beyond 30m of water depth is very expensive and will face further delay as few adequate ships are available, (4) there are low wind speeds in the southern French seas.

The French government has an objective of 6 GW of offshore wind power by 2020, which is not likely to change. He decided to use an assumption of 5 MW/km² for the selection of the areas where the offshore wind farms will be built. Thus, several areas for a total of 1200km² - this is calculated from the objective of 6 GW and the assumption of 5 MW/km² - will be attributed through a future call for tenders to the developers. The process of selection of the areas, under the supervision of local state agencies, is about to come to its end, and most areas have already been selected. A certain capacity is attributed to each area, based on the assumption of 5 MW/km², and it is said that this capacity is definitive and will not be modified in the future. If it is actually the case, it sounds quite inappropriate. Indeed, the areas would not be built at their full potential, as the assumption of 5 MW/km² is very low compared to the 9 MW/km² of the existing farms mentioned above. In the context of a lack of available areas, some areas that are located near popular spots or highly frequented fishing areas had to be included in the call for tender to reach the objective of 6 GW, and raise severe problems of local acceptance. If the areas were built at their full potential, either the most sensible areas could have been abandoned for a better acceptance of the overall process, and the farthest areas for a reduction of the connection costs, or, depending on the priorities, national objectives could have been higher, as the French grid is already capable of withstanding much more than 6 GW without large reinforcement.

The reason advanced to justify the need to determine at the very beginning of the call for tenders the definitive amount of MW per area is that the building of the connection line, under the supervision of the TSO, requires to be planned long time in advance. However, there are no actual justification for the low assumption of 5 MW/km². Navigation issues had once been advanced to justify the need for a large distance between turbines, but no further explanation is given, and the affirmation that “the larger the distance between the wind turbines, the lesser the risk of collision with ships” is very uncertain.

Thus, the method which is very likely to be used for the French call for tenders, which is actually very similar to the one used in the other European countries, is certainly inappropriate in the French context, i.e. a severe lack of available areas. At least, the seriousness of the consequences should have incited the decision makers to investigate further the issue.
2.5.5 Redundancy

The question is still under reflection in many countries. It depends a lot on the actual availability of various components. Reasonable decisions are difficult to take for the moment, as there is still an evident lack of experience. UK has led many studies on the topic and implemented several rules. For example, a planned outage or a fault outage of a single transformer circuit should not result in the loss of more than 50% of the offshore wind farm capacity or 1000MW, whichever is the smaller [45].

2.5.6 Distance to the shore, water depth and foundations

At the moment, all offshore wind turbines are installed on foundations, except for some floating prototypes. As a consequence, wind farms are limited to shallow waters. As illustrated in figures 2-27 and 2-28, most farms are built at less than 40 km from the shore, and less than 30 m of water depth.

![Figure 2-27 Distance to the shore of offshore wind farms [46]](image)

![Figure 2-28 Water depths for offshore wind farms [46]](image)
Until recently, there was no real need for deep foundations, as the areas near the coasts have been naturally built first. However, some projects are now planned in deep water, and monopile foundations, which have been widely used up to now, as indicated in figure 2-29, will no longer be suitable. There are many technologies suitable for deep waters, as shown in table 2-5, which sum up the different foundation types. Nevertheless, theses have not been widely used so far and remain very expensive. As this is an important area of research, costs might still be reduced quickly. Therefore, with the likely reduction in the cost of the foundations, more and more offshore wind farms will be built far away from the shore in the future years and TSOs will have to prepare for very long transmission lines of several hundreds of kilometers.

![Figure 2-29 Share of the different types of foundation in offshore wind farms](image.png)

2.5.7 Conclusion

Practices vary to a certain extent depending on the country, and rules described in the previous chapters have actual impacts on the practices: for instance, Statcoms in UK, installed because of stringent dynamic reactive requirements for the operator of the cable while there is no voltage control requirement at the wind farm side, or reactors in France, prohibited on offshore platforms because of ownership issues. However, technologies in use are much similar in the different countries, which can be easily explained by few amount of manufacturers in the offshore market.

The investigation of the practices in Europe, and especially in the UK whose experience on offshore wind power is unique in the world, shows that three major issues are probably worth being further investigated by the French authorities. The first one is the method to be used for the call for tenders in France and the assumption of 5 MW/km², which sound inappropriate for the French context, as it would certainly lead to a very poor use of the few convenient areas available. The second issue concerns the availability of DC connection lines of 1300 MW, whose denial in France, because it has not been installed anywhere yet, leads probably to an imperfect division of some large areas selected for the call for tender. The third issue
<table>
<thead>
<tr>
<th>Type of substructure</th>
<th>Brief physical description</th>
<th>Suitable water depths</th>
<th>Advantages</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monopile steel</td>
<td>One supporting pillar</td>
<td>10 - 30 m</td>
<td>Easy to manufacture, experience gained on previous projects</td>
<td>Piling noise, and competitiveness depending on seabed conditions and turbine weight</td>
</tr>
<tr>
<td>Monopile concrete, installed by drilling</td>
<td>One supporting pillar</td>
<td>10 - 30 m</td>
<td>Combination of proven methods, cost effective, less environmental impact (noise), industrialisation possible</td>
<td>Heavy to transport</td>
</tr>
<tr>
<td>Gravity base</td>
<td>Concrete structure, used at Thornton bank</td>
<td>Up to 40 m and more</td>
<td>No piling noise, inexpensive</td>
<td>Transportation can be problematic for heavy turbines; it requires a preparation of the seabed; Need heavy equipment to remove it</td>
</tr>
<tr>
<td>Suction bucket</td>
<td>Steel cylinder with sealed top pressed into the ocean floor</td>
<td>n.a.</td>
<td>No piling, relatively easy to install, easy to remove</td>
<td>Very sensitive to seabed conditions</td>
</tr>
<tr>
<td>Tripod / quadropod</td>
<td>3 / 4 –legged structure</td>
<td>Up to 30 m and more</td>
<td>High strength; adequate for heavy large-scale turbines</td>
<td>Complex to manufacture, heavy to transport</td>
</tr>
<tr>
<td>Jacket</td>
<td>Lattice structure</td>
<td>&gt;40m</td>
<td>Less noise; adequate for heavy large-scale turbines</td>
<td>Expensive so far; subject to wave loading and fatigue failure; Large offshore installation period (first piles, later on placing of structure and grouting), therefore sensitive to weather impact</td>
</tr>
<tr>
<td>Floating</td>
<td>No contact with seabed</td>
<td>&gt;50m</td>
<td>Suitable for deep waters, allowing large energy potentials to be harnessed</td>
<td>Weight and cost, stability, low track record for offshore wind</td>
</tr>
<tr>
<td>Spar buoy Hywind being tested</td>
<td>Floating steel cylinder attached to seabed</td>
<td>120 – 700m</td>
<td>Very deep water, less steel</td>
<td>Expensive at this stage</td>
</tr>
<tr>
<td>Semi submersible</td>
<td>Floating steel cylinder attached to seabed</td>
<td>Blue H prototype being tested in 113m</td>
<td>Deep water, less steel</td>
<td>Expensive at this stage</td>
</tr>
</tbody>
</table>

Table 2-3 Overview of the different types of foundations [47]
It is difficult to give an estimate of the cost of a connection line, for it depends heavily on the location of the farm, the type of connection, the reactive compensation devices needed, the choice to include or not certain components in the price, etc. However, it is likely that the price of any connection line to be built in the next years would range from \( 2.5 \, \text{€/k(MW.km)} \) to \( 25 \, \text{€/k(MW.km)} \), and from \( 0.16 \, \text{€/M/MW} \) to \( 1 \, \text{€/M/MW} \), which are the extreme costs found within a large panel of several dozens of farms.

### 2.6 Conclusion of the part

Part 2 provides a comprehensive overview of the current rules and practices regarding the connection to the grid of offshore wind farms in the most advanced European countries. One of the aims of the part was to compare the situation in France, where a 6 GW call for tender is about to start, with other countries. A first chapter, dedicated to non-technical rules, such as future objectives, methods of attributing the areas to be built or support mechanisms, concludes that the policies are quite diverse. Some policies are still frequent, such as call for tenders (except in Germany) or feed-in tariffs (except in the UK). The lack of experience makes it difficult to determine the most efficient policies, even though feed-in tariff is often claimed as the best support mechanism. It is certain though that the main determinant of offshore wind growth is the area made available by the authorities. In all countries there are mechanisms that reduce financial risks for offshore wind developers, such as feed-in tariff or financing of the connection line through network fees, as it is usually taken for granted that lessening the financial risks leads to the reduction of the overall costs. The non-technical rules in use in France are coherent compared to the other countries. However, the method used for the call for tenders is certainly inappropriate in the French context and will certainly lead to a poor use of the few convenient areas available, with consequences on the overall costs and on the acceptability of the farms.

The investigation of the technical rules showed fewer differences between the countries. Four rules, dealing with dimensioning frequencies and voltages, fault ride through capability, voltage control and frequency control, can have an important impact on the design and operation of the wind turbines. They are never exactly the same in the different countries investigated, but are still quite similar, with four exceptions. The first one is the time-delay required for the reactive response of the wind farm in case of voltage drop, which is much longer in France than in the other countries. It is certainly not a problem today considering the low amount of wind power in France, but this could endanger unnecessarily the power system in the future in case wind penetration increases a lot. The second exception is the reactive requirements when the wind turbine active power output is low. France is the only country which requires that the reactive requirements apply as soon the turbine start generating, while full reactive requirements typically apply when the active output reach 20% of the rated capacity in the other countries. The French rule is not appropriate to the wind turbines actual capabilities and would certainly deserve further investigation. The third exception is the quite surprising rule in the UK requiring that the operator of the connection line provides voltage control with stringent dynamic requirements, while the operator of the offshore wind farm. The fourth exception is related to frequency control, which is usually not properly
required except in case of very high frequency. However, Denmark has recently implemented a new legislation which makes possible for the TSO to require that wind farms participate in frequency control even in case of low frequency, by curtailing continuously their output in normal conditions.

The current process of integration of the European electricity market was raising the question of its impact on European rules on wind power. Even though this question cannot be answered with any certainty, the network codes to be written soon at the European level are likely to not impose many changes in the national rules dealing with wind power, except for perhaps dimensioning voltages and frequencies. Some pressure groups, including in particular wind industry, try to convince the decision-makers of the necessity for an extensive harmonization of the rules throughout Europe, but this is not likely to happen before long.

The investigation of the current and expected practices related to the connection of offshore wind farms in Europe shows in particular some interesting differences between France and the UK, which is certainly the most experienced country on offshore wind power. A first difference is the very cautiousness of the French TSO, RTE, when it comes to new technologies. The reluctance of RTE to even investigate the possibility to build large HVDC connection lines (up to 1300 MW) contrasts sharply with the willingness, in the UK, to use extensively this technology, which could lead to major reductions in the connection costs, for the very future offshore wind farms. A second difference is related to the rules in use for the design of the AC cables. For instance, the cables used to connect 300 MW in the UK could not connect farms above 250 MW in France. A third difference is the surprising reluctance of RTE to put reactors offshore, while this is a common practice in the UK. The last major difference is the extensive use of Statcoms in the UK. All these issues would deserve further investigation, especially the first one because of its important impact on the choice of the areas selected for the call for tender.
3 Theory

This part helps understand the two other parts by explaining the theories and complex concepts they refer to. Most of the content of part 2, which describes the European practices, can be understood without these theoretical explanations. This is however not the case for part 4, which relies deeply on power system theory.

It is much beyond the scope of this part to deal with in-depth power system theory, and only the most basic principles are given. Some considerations related to the management of electricity networks, wind power assessment and power system components are also discussed. The software that are used to investigate the impact of the wind farms are also described.

3.1 Power system theory and key components

The purpose of this chapter is not to provide in-depth knowledge in power system theory, but only the very basics. Further scientific and technical literature should be read for a better understanding, see for instance [48] or [49]. Chapters 3.1.1, 3.1.2 and 3.1.3 are heavily inspired by this later book.

3.1.1 Structure of an electric power system

Modern electric power systems consist of three subsystems: the generation subsystem, the transmission subsystem, and the distribution subsystem. In the generation subsystem, the power plants produce the electricity. The transmission subsystem, or transmission network, consists of the high voltage power lines (usually above 40 kV or so) and transmits the electricity over large distances. The distribution subsystem, or distribution network, consists of the power lines at lesser voltage levels (usually below 40 kV) and transmit the electricity from the transmission system to the consumers.

One of the main functions of the transmission system is to make it possible to optimize the generation within the country and also support trading with electricity with neighbouring countries. It must be capable of withstand different disturbances such as disconnection of transmission lines, lightning storms, outage of power plants as well as unexpected growth in power demand without reducing the quality of the electricity services. Transmission systems are usually meshed, i.e. there are a number of closed loops, in order to withstand the loss of any line without serious damage.

Transmission and distribution networks are owned and operated respectively by Transmission System Operators (TSO) and Distribution System Operators (DSO). TSOs are often state utilities and are monopolistic “by definition”. There is usually one TSO by country, but not always: for instance, there are four TSOs in Germany, each one in charge of its own area, as described in chapter 2.3. The situation of DSOs in the different countries are much more diverse.

The end users (either generators or consumers) can be connected to every voltage level. Generally, the higher power need the end user has, the higher voltage level the user is connected to. Except for some few components, all power systems are operated in Alternative Current (AC) (usually 50 or 60 Hz). It is preferred to Direct Current (DC) mainly because it is quite easy and cheap to change the voltage level of AC power, with transformers. DC lines are still useful to connect different power systems that are not
synchronised, or to carry power over long distances, as both losses and reactive problems are reduced in DC lines. AC systems are always symmetrical three-phase systems.

3.1.2 Alternating current, active and reactive power

First the fundamentals are given for a single phase AC system, then three-phases systems are described.

3.1.2.1 Single phase alternating system:

When a source of alternating voltage

\[ u(t) = V_m \cos(\omega t) = Re(\sqrt{2}Ve^{j\omega t}) \]  

feeds an impedance \( Z \), as illustrated in figure 3-1, an alternating current

\[ i(t) = I_m \cos(\omega t - \theta) = Re(\sqrt{2}Ie^{j\omega t}) \]  

is given rise, where

\[ V_m = \text{peak value of the voltage} \]
\[ I_m = \text{peak value of the current} \]
\[ V = \frac{V_m}{\sqrt{2}} = \text{RMS (Root Mean Square) value of the voltage} \]
\[ I = \frac{I_m}{\sqrt{2}} = \text{RMS value of the current} \]
\[ \bar{V} = Ve^{j0} = \text{Complex single phase voltage} \]
\[ \bar{I} = Ie^{-j\theta} = \text{Complex single phase current} \]
\[ Z = \frac{\bar{V}}{\bar{I}} = R + jX = \text{Complex impedance} \]
\[ \omega = 2\pi f \text{ where } f \text{ is the frequency} \]
\[ \theta = \text{arctan}\left(\frac{X}{R}\right) = \text{phase angle between voltage and current} \]

As the voltage and the current are alternating, this is called an Alternative Current (AC) system.
The power consumed in the impedance $\tilde{Z}$ in figure 3-1 is:

\[
p(t) = u(t) \cdot i(t) = V_m I_m \cos(\omega t) \cos(\omega t - \theta) \]
\[
= V_m I_m \cos(\omega t) [\cos(\theta) \cos(\omega t) + \sin(\omega t) \sin(\theta)]
\]
\[
= \frac{V_m I_m}{\sqrt{2} \sqrt{2}} [(1 + \cos(2\omega t)) \cos(\theta) + \sin(2\omega t) \sin(\theta)]
\]
\[
= P(1 + \cos(2\omega t)) + Q\sin(2\omega t)
\]

(3.3)

Where

\[
P = \frac{V_m I_m}{\sqrt{2} \sqrt{2}} \cos(\theta) = UI \cos(\theta) = \text{active power} \tag{3.4}
\]
\[
Q = \frac{V_m I_m}{\sqrt{2} \sqrt{2}} \sin(\theta) = UI \sin(\theta) = \text{reactive power} \tag{3.5}
\]

Thus the power can be divided into two parts. One part with the mean value $P$ which pulsates with the double frequency and one part with the amplitude $Q$ which also pulsates with double frequency.

The complex power $\tilde{S}$ is defined by $\tilde{S} = P + jQ$.

Then,

\[
\tilde{S} = P + jQ = UI(\cos(\theta) + j \sin(\theta)) = UIe^{j\theta} = VI^* \tag{3.6}
\]

### 3.1.2.2 Symmetrical three-phase system

All AC lines consist of three parallel lines, whose alternating voltages $u_a(t) = V_m \cos(\omega t)$, $u_b(t)$, and $u_c(t)$ have (ideally) the same peak value compared with ground and a phase shift of 120° between them, i.e.

\[
u_b(t) = V_m \cos(\omega t - 120°) \tag{3.7}
\]
\[
u_c(t) = V_m \cos(\omega t + 120°) \tag{3.8}
\]

This is called a symmetrical three-phase system.

The voltage between two phases is often used and is called phase-to-phase voltage. The voltage $u_{ab}$ between phases $a$ and $b$ is equal to:

\[
u_{ab}(t) = u_a(t) - u_b(t) = V_m \cos(\omega t) - V_m \cos(\omega t - 120°) = \sqrt{3} V_m \cos(\omega t + 30°) \tag{3.9}
\]

The phase-to-phase voltage has an amplitude and a RMS value which is $\sqrt{3}$ times larger than the amplitude of the phase voltage. When a voltage is mentioned in a three-phase system, it is usually the RMS value of the phase-to-phase voltage. For example, a 400 kV line has a peak value of the phase to ground voltage $V_{m_{400kV}}$ equal to:

\[
V_{m_{400kV}} = \sqrt{\frac{2}{3}} \ast 400 = 326,6 \text{ kV} \tag{3.10}
\]

The total three-phase power flowing through the three-phase line is
where $U$ is the RMS value of the phase-to-phase voltage.

Under the assumption of symmetry, the three-phased system can be studied as there were three different single phase systems.

### 3.1.3 Models of line, power flow

The so-called $\pi$-equivalent model, as shown in figure 3-2 is often used to model power lines.

![Figure 3-2 π-equivalent model of a line](image)

Where

\[ \bar{Z}_L = R_L + jX_L \quad (3.12) \]
\[ \bar{Y}_L = jB_L \quad (3.13) \]

$B_L$ is the shunt susceptance of the line (which is the capacitance multiplied by the pulsation $\omega$), divided into two equals part, one at each end of the line.

The admittance $\bar{Y}_L$ is the inverse of the reactance, i.e. $\bar{Y}_L = \frac{1}{\bar{X}}$ \quad (3.14)

The power flowing from the sending end $P_{SR}$ et $Q_{SR}$ is:

\[ \bar{S}_{SR} = \sqrt{3} \bar{U}_S \bar{I}_S = P_{SR} + jQ_{SR} \quad (3.15) \]
\[ P_{SR} = \sqrt{3} \left[ \frac{U_S^2}{2} R + \frac{U_S U_R}{2} (X \sin(\theta_{SR}) - R \cos(\theta_{SR})) \right] \quad (3.16) \]
\[ Q_{SR} = \sqrt{3} \left[ -\frac{B_L}{2} U_S^2 + \frac{U_S^2}{2} X + \frac{U_S U_R}{2} (R \sin(\theta_{SR}) + X \cos(\theta_{SR})) \right] \quad (3.17) \]

Where

$U_S$ and $U_R$ are RMS values of phase-to-phase voltages

\[ \bar{U}_S = U_S e^{j\theta_S} \quad (3.18) \]
\[ \bar{U}_R = U_R e^{j\theta_R} \quad (3.19) \]
\[ \theta_{SR} = \theta_S - \theta_R \quad (3.20) \]

This means the power flow can be calculated directly from voltage levels and phase angles.

For very high voltage lines, $R_L \ll X_L$, \[ \bar{Z}_L = jX_L \quad (3.21) \]

and $\theta_{SR}$ is low.
Then

\[ P_{SR} \approx \frac{u_s u_R}{x} \sin(\theta_{SR}) \]  
\[ Q_{SR} \approx -\frac{b_L}{2} u_s^2 + \frac{u_s (u_S - u_R)}{x} \]  

(3.22)  
(3.23)

Hence, the active power flows from the bus with the higher voltage angle toward the bus with the lower voltage angle, while the reactive power tends to flow from the bus with the higher voltage level towards the bus with the lower voltage level. Power lines tend to generate reactive power because of the shunt admittances. As cables have a much higher susceptance \( B_L \) than overhead lines, they generate much reactive power, which tends to raise the voltage level if not compensated by reactors (see chapter 3.1.5).

Lines are limited in the amount of power they are capable of carrying. The first limit is the consequence of (3.22):

\[ P_{SR} \approx \frac{u_s u_R}{x} \sin(\theta_{SR}) \leq \frac{u_s u_R}{x} \]  

(3.24)

It is still possible to increase this limit by adding series capacitors, which reduces the reactance of the line \( X \).

The second limit is decided line per line by the TSO. Its purpose is to avoid intensity levels which are too high. Indeed, the temperature of the lines increases with intensity, and lines get longer when the temperature increases, which lowers their height. To avoid short-circuits with a tree or with the ground, intensity must remain below certain limits, which usually depend on the season: lines get warm quicker in summer than in winter, and the limit to the intensity level is therefore lower in summer. In most countries, there are several limits depending on how much time the line is overloaded.

In France, there are three progressive limits, that cannot be exceeded for more than, respectively, 20 min (the lower one), 10 min, and 1 min (the upper one). If one of these limits is exceeded for more time than the time limit, the line is disconnected. Moreover, the year is divided into four periods, and each period has different limits. Recently, and this is important for the results of the simulation, the method that RTE uses for calculating these limits has been modified and simulate more accurately the wind cooling of the lines. As a consequence, the limits currently in use will change soon, even though the exact planning is uncertain. The results of the simulation are based by default on the limits currently in use, but the impact of the new method is always specified.

Even if these limits have no impact on the power flows, they do have one on the rate of load/overload of the lines. In the following, the loadings of the lines are given in percentage of the “20 min limit”. It is always specified when the “1 min limit” is exceeded. Indeed, it is acceptable to exceed the “20 min limit” (or even the “10 min limit”) from time to time, because in 10 min adequate measures can easily be taken, such as curtailment orders or local power cuts. However, exceeding the “1 min limit” usually leads to the line disconnection. Therefore it is important to not reach it.

Tables in appendix 2 give these limits for the lines that are of concern, for the two periods corresponding to the two situations under investigation: Maximal load, in winter, and minimal load, in summer.
3.1.4 Load flow calculation

The technique of determining all bus voltages in a network is usually called load flow calculation. When knowing the voltage magnitude and voltage angle at all buses, the system state is completely determined, as indicated in chapter 3.1.3.

It can be shown that the unknown voltage quantities, i.e. the magnitude and the angle at each bus, can be solved with the help of the equations above and the basic balance equations for active and reactive power (at a bus, \( \sum_i P_i = 0 \) and \( \sum_i Q_i = 0 \)), as long as, at each bus:

- either the voltage magnitude and the voltage angle are known: the bus is then called “slack bus”,
- or the active power generated and consumed at the bus, plus the voltage magnitude are known: the bus is then called PU-bus,
- or the active power generated and consumed at the bus, plus the reactive power generated and consumed at the bus, are known: the bus is then called PQ-bus.

This system is not linear, and required numerical methods to be solved. The iterative Newton-Raphson method is the best known method to solve such systems, and is widely used for load flow calculations. It will not be described in this report, but it is abundantly documented, for instance in [49].

3.1.5 Some key components of a power system

Transformers are key components of power systems. They are used to switch from a voltage level to another one. This is very important because high voltage levels are indispensable to transport large amounts of electricity (few losses, and smaller line diameter), while generation and final use require low voltage levels.

One very special type of transformer is the phase-shifting transformer. Its purpose is no more to change the voltage level, but, by changing the phase angle, to force the active power flow in one direction (see the impact of the phase angle on the active power flow in chapter 3.1.3). It is very can be very useful to redirect the power flow (as there are always several paths in meshed grid) in order to avoid overloads, but it increases the losses. Indeed, the natural flow minimizes always the losses, and in addition there are some internal losses.

Reactors \((Z = j\omega L)\), capacitors \((Z = \frac{1}{j\omega C})\) and other reactive compensation devices are also of great importance, for they help control the voltage level.

From (3.25), we deduce that for shunt reactors \((Z = j\omega L)\), \(Q\) is positive: shunt reactors absorb reactive power. On the contrary, for shunt capacitors \((Z = \frac{1}{j\omega C})\), \(Q\) is negative: shunt capacitor generate reactive power.

\[
\mathbf{S} = \mathbf{U}^* \mathbf{I}^* = \frac{\mathbf{V}^2}{\mathbf{Z}^*} = P + jQ \quad (3.25)
\]
The generation of reactive power at a node increases the flow from this node to the nodes nearby. In consequence, from (3.23) the voltage level raises. Thus shunt capacitors generate reactive power and raise the voltage level, while shunt reactors absorb reactive power and lower the voltage level. For more information about more advanced reactive compensation devices, see chapter 2.5.2.

3.1.6 “N-1 criterion” and “N-1 assumption”

The components of a power system are not infallible, and faults occur regularly. Major collapses are however very rare. Indeed, the operation of the transmission network usually respects the so-called “N-1 criterion”. It means that the system must be capable of withstanding any fault, in all circumstances, as long as there is only one fault in the surroundings. It is the responsibility of the TSO to make sure this criterion is continuously satisfied [50].

TSOs conduct long term grid studies in order to detect the future problems on the grid as soon as possible. Such studies determine in advance what grid reinforcement is needed in such a way the “N-1 criterion” will be satisfied. Thus every possible fault has to be simulated, to make sure the system can withstand it. In practice, only the most serious faults (that are normally known by grid operators) are simulated. Moreover, power systems are usually divided into several parts that are studied more or less independently to each other.

Later in the report, the “N-1 assumption” will refer to the assumption that the most serious fault has happened. Running a simulation, or a load flow calculation, “under the N-1 assumption” means simulating the system assuming the most serious fault has happened, or, when there are several possible serious fault, it means running several simulations, one for each serious fault.
3.2 Offshore wind resource assessment - Power output of wind farms

In order to study the impact of wind farms on the grid, it is necessary to know what will be their power output. The output of wind farms, just like solar power plants and some hydro plants, depends entirely on natural, uncontrollable events. They are just completely different from nuclear plants, for instance, which are expected to be generating at full capacity during the whole year, except for some weeks of maintenance.

This chapter explains how the power output of a wind farm can be estimated, provided wind speed data is available. This method has been used in part 4 to estimate the output of the expected farms in France.

3.2.1 Wind resource assessment

The best way to get access to reliable data of wind speed is of course on-site measurements, but such measurements are very rare offshore. There are also satellites measurements, such like Seawinds for instance [51]. Raw data is not complete as satellites do not cover the whole surface of the earth, but there exist so-called “gridded products” that have been corrected and completed [52]. Unfortunately these products have often a very low temporal resolution (daily or weekly), which is not sufficient for a good assessment of the farm output.

In such cases, when the temporal resolution is too low, it is possible to use some typical distributions, which indicate the probability of each wind speed, drawn from one or several parameters, such as the average wind speed. The Weibull distribution and the Rayleigh distribution are often used for this purpose.

Datasets of wind speed are taken at different heights, often below 60 m. And the wind speed required to calculate the output of a wind turbine should be at the hub height (around 90 m for offshore turbines). Thus it is necessary to calculate the right wind speed, using the formula:

\[
\nu(Z) = \frac{\nu(Z_{ref}) \ln(\frac{Z}{Z_0})}{\ln(\frac{Z_{ref}}{Z_0})}
\]

where

\(\nu(Z)\) = wind speed at height \(Z\) above ground level,

\(\nu(Z_{ref})\) = reference speed, i.e. a wind speed that is already know at height \(Z_{ref}\),

\(Z\) = height above ground level for the desired velocity \(\nu(Z)\),

\(Z_0\) = roughness length in the current wind direction (0.0002 for water surfaces),

\(Z_{ref}\) = reference height, i.e. the height where the exact wind speed \(\nu(Z_{ref})\) is known.

3.2.2 Power output of wind farms

The best way to estimate the power output of a wind farm from wind speed data is to use the power curve of the expected turbines. Usually available on the manufacturers websites, they give, for each wind speed, the corresponding output. As power curves are not linear at all, it is very useful to have datasets of wind
speed with high temporal resolution, or to use some typical wind speed distribution (Weibull for instance) in order to simulate such a high temporal resolution.

Then, to get the right output of the farm, it is necessary to estimate the losses, which are mainly the wake losses (the turbines facing the wind perturb it, which reduces the output of the following turbines) and various electrical losses that are not already taken into account in the load curve. The total losses are difficult to estimate because of the lack of available data and the lack of experience for offshore wind farms. It can still be estimated between 10% and 20% [53], [54]. The non-availability of the turbines, for technical reasons or because of grid issues, should also be taken into account. It is sometimes claimed that the availability of offshore wind turbines is higher than 95%, but some actual examples show this claim might be very optimistic [43].
3.3 Software

Three pieces of software are used in part 4. The most important one, “Convergence”, has been developed by RTE to study grid issues. Most of the results of part 4 come from this software. A second software, “Valoris” also specific to RTE, and mostly dedicated to financial issues, has been used to a much lesser degree. A software dedicated to statistics, “R”, has also been used, mostly to process raw data of wind speeds and power outputs. The following gives short overviews of these pieces of software, to facilitate the understanding of part 4. The part dealing with Convergence is much more detailed than the two other ones, given their respective importance in part 4.

3.3.1 Convergence

Convergence has been recently developed at RTE to replace the former software dedicated to grid studies. The main reason for this change is that there were two different pieces of software in RTE for long term grid studies, and for day-ahead and real-time grid management. Convergence is now common to these two activities, and facilitates the cooperation. It is basically a simulator of the French transmission network, from 63 kV to 400 kV. Based on the Newton-Raphson method, it calculates load flows from any situation the user generates, and provides a wide range of results: power flow in each line, risks of overload if a fault occurs, losses, etc. The software is divided into three windows.

The first one is basically a files explorer. All the different files are available and this is the place where you can create new studies, and import or export files, mainly from the software which were previously used at RTE. The other windows are accessible from this one.

The second window displays a tree whose nodes correspond to different states of the French electric network. At this stage, the states are not fully described, i.e. some parameters are missing, such as the voltage levels, the load flows, .... The main function of Convergence is to determine the missing parameters with the help of some successive calculations, including a load-flow calculation based on the Newton-Raphson method. These calculations are launched from the third windows, which is accessible from any node of the tree. The nodes are successively built by modifying some of the parameters of their “father”, starting from an initial situation which represents the French transmission network sometimes in the recent past. One can, for instance, add new stations, new lines, new plants, new reactive compensation devices, change the characteristics of any component, change the consumption level, changes the season in order to have the correct intensity limits for the lines, open circuit breakers, etc. Figure 3-5 shows a simplified example of such a tree, where the nodes, in black, derive from their “father” by applying a set of modifications, in red.

The third window is accessible from any node of the tree. It displays a map representing the grid as defined in the node in question, as illustrated by the screen capture in figure 3-4. As explained in the previous paragraph, It is also from this window that calculations of missing parameters are started and results displayed. From the states of the grid as defined in the nodes of the tree, two preliminary calculations must be completed before the proper load flow calculation is started. The first calculation determines the active power output of every power plant, except the plants whose output has been previously imposed, which are usually the plants to be studied. Convergence selects by default the plants that have the lesser marginal costs, until generation matches consumption. The user can also select any plant to manually start it or shut
it down. Once this is done, the second calculation determines the reactive power output of the plants and reactive compensation devices, in such a way that correct voltage levels will come out of the load flow calculation. This is more complex than the previous step, and additional inputs are required, such as indications of what should be the voltage at each node, for instance. Several methods are possible. They will not be described here, but they are based on the same principles than a proper load flow calculation, but with more degrees of liberty. Convergence performs automatically the calculation based on the method selected, provided the parameters of the grid are coherent enough to make the algorithm converge. Once reactive and active power outputs are known at each node (active and reactive consumption levels are parameters that are described in the nodes of the tree), the proper load flow calculation is started, as all the nodes are then either PQ or slack bus. As explained in chapter 3.1.4, this calculation determines all missing parameters of the grid (voltages, phase angles, active and reactive power flows, losses...). All the parameters can then be displayed either on the map, or in tables. Once this is done, the impact of a fault on any component of the system can be evaluated. The study of the system under the “N-1 assumption”, as defined in chapter 3.1.6, is facilitated by the possibility to analyse automatically a list a faults, for a system whose parameters have been previously calculated assuming no fault. For each fault, a list of overloaded lines and unacceptable voltages level is displayed.

Figure 3-4 shows the very high voltage grid, i.e. 400 kV and 225 kV, in northern Brittany, where two offshore wind farms are expected. The numbers next to the lines indicate the active power flows (in MW). Red and green represent, respectively, the 400 kV and 225 kV devices. The boxes represent the stations.

Figure 3-4 Screenshot of the third window in Convergence
Initial situation
*Grid as in January 2010*

Add new lines, new power plants (but not the offshore wind farms, as the goal is to study their impact), etc.

*Expected grid in 2015*

*June, minimal load*

- *ETC ...*

*December, maximal load*

- *ETC ...*

- *Add the offshore wind farms, variant 1 (200 MW at station A, 400 MW at station B)*

- *Add the offshore wind farms, variant 2 (100 MW at A, 200 MW at B)*

- *No modification*

- *Reference situation for maximal load*

Maximal load, variant 1

- Access to the third windows to start the calculations of the missing parameters (voltage level, load flows, ...)

Maximal load, variant 2

- Access to the third windows to start the calculations of the missing parameters (voltage level, load flows, ...)

ETC ...

- Access to the third windows to start the calculations of the missing parameters (voltage level, load flows, ...)

Figure 3-5 Schema representing a typical tree in Convergence
3.3.2 Valoris

This software is above all a database gathering the characteristics, costs, etc, of many components, such as lines and cables. It gathers also various pieces of information such like load curves. It has been used in some rare occasions in the simulation, especially when it comes to financial issues.

3.3.3 R

R [55] is a language and environment dedicated to statistics. It is widely used among statisticians as it is both open source and very powerful. Compared to products dedicated to general mathematics such as Matlab, it is possible to make more or less the same operations when it comes to statistics, but R is more appropriate as the very structure of Matlab is not designed especially for statistics. Some would say that R is a product for Statisticians which has mathematical functions, while MatLab is a software for Mathematicians which has Statistical models built in it.

R can be easily extended via packages, and most basic functions can be found ready-to-use. It has been used to analyse some wind speed data and power output data that have been used in the simulation. These operations were very basic, and only simple code has been written. In the following, the functionalities that have been used in the present study are shortly described:

- import files at various formats;
- select datasets based on certain criteria in order to eliminate the ones that seem biased;
- modify datasets, perform various operations, such as multiplication by a certain coefficient
- combine datasets together, for instance in order to obtain a new dataset which is the average of some other ones
- calculate statistical parameters, such as the average or the variance
- Display curves and figures
4 Grid study

As it has been explained previously, several offshore wind farms are expected off the coasts of Brittany in the context of the call for tenders to be launched in France. The fact that the grid in Brittany is considered as quite weak makes it important to conduct extensive studies on the future impacts of these farms.

This part describes situation of offshore wind power in Brittany and presents the results of the investigation that has been conducted as a part of the master thesis. This investigation is mainly based on many grid studies undertaken with the help of Convergence (see 3.3.1). Considerations about electric grids, wind speed and wind farms output and costs complete the part.

4.1 Context

This first chapter describes the context in France, and more specifically Brittany, where three large offshore wind farms are expected by 2015-2020. It gives an overview of the present electric system in Brittany, describes the expected changes and explains why the issue of offshore wind power is particularly important there.

4.1.1 The French transmission network

French transmission network is based on a hierarchical structure depending on voltage levels and is divided into two types of network: the transmission grid and the sub-transmission grid. The transmission grid, characterized by a Very High Voltage level (400kV), is used for long distance transportation of electricity generated by the main power plants, throughout the country and abroad. It is a highly meshed network which is connected to the transmission grid of the neighbouring countries. The second type of network, the sub-transmission grid, aims at delivering electricity from the transmission grid to the distribution network or the largest industrial consumers. This regional network is organized into three voltage levels: VHV (225kV), HV(90kV and 63kV). Figure 4-1 displays a map of France representing the 400 kV grid, in red, the 225 kV, in green, and the interconnections with the neighbour countries. The French transmission network is divided into seven areas, to facilitate the management. The area that is of concern here is the “western area”, described in the next chapter, and circled on figure 4-1.

4.1.2 The western area and the grid in Brittany

The “western area” of the French transmission network correspond to the four areas in grey, circled in black, in figure 4-2. In this area, there are many nuclear plants, whose names are in red on figure 4-2, several thermal plants, in grey and in brown, and some renewable plants: mostly onshore wind power, around 1 GW and hydro power, 240 MW in “La Rance”.

In this area, just like in France, electricity consumption is highly dependent on the season, because of the massive use of electric heating. In winter, during cold days, electric heating usually represents around 40% of the total electricity consumption. That is why there is a big difference between the minimal load, 4800 MW, during summer nights, and the maximal load, 17500 MW, during winter evenings. These numbers correspond to the consumption of the “western area”. They are based on what have been observed these last 3 years.
Brittany is the grey area to the west on figure 4-2, circled in red. It is the “critical” area of the western grid. It is a large electricity importer, as around 90% of the electricity consumed in Brittany is generated elsewhere. This consumption amounts to around 21 TWh in 2009, while the maximal load reaches 4500 MW. This is considered to be a serious problem as the consumption increases quite rapidly over the years, and new plants, especially thermal plants, tend to be systematically refused by local people. In Brittany, the system is operated quite close to its limits in extreme conditions, especially in winter, with low voltage levels and lines nearly overloaded. RTE warns regularly against the risk of power cuts in Brittany, and many plans of grid reinforcement and new plants are under investigation. Load management is another potential solution, but even if a pilot project called “EcoWatt” has been recently tested, RTE does not consider this is sufficient to solve the problem of electricity supply in Brittany.

In Brittany, in addition to around 300 MW of onshore wind farms and several very small domestic plants, there are one hydro plant of 240 MW in “La Rance”, two thermal plants in “Dirinon” (160 MW) and “Brennilis” (285 MW). There are also 2500 MW of thermal power plants in “Cordemais”, just beyond the south-eastern border of Brittany. Figure 4-3 shows the very high voltage grid (225 kV, in green, and 400 kV, in red) in Brittany, which is circled in black on the map, and the three main power plants, in the boxes.
Figure 4-2 "Western area" and principal power plants [56]

Figure 4-3 Very High Voltage Grid and main power plants in Brittany [56]
4.1.3 Expected farms and grid connections

The legislation in France has been described in details in part 2. It has been explained that the French government is about to organize a call for tenders for the allocation of several offshore areas to be built with wind farms, with the objective of 6 GW of offshore wind power by 2020. Within the context of this call for tenders, three offshore wind farms are expected to be connected to the western grid. Two farms of 350 MW and 200 MW are planned in northern Brittany, connected between “Plaine Haute” and “La Rance”. One another farm of 1000 MW is planned to the South West of Brittany, connected around “Cordemais”. Figure 4-4 shows the two areas that have been selected for the call for tender in northern Brittany: 200 MW (zone 7) and 350 MW (zone 6). The choice of the connection lines is not definitive yet. The zone 6 is expected to be connected through two 3-core AC cables to “Rance” (225 kV), the zone 7 through one 3-core AC cable to “Trégueux” (225 kV). However, there are two other scenarios that are also quite probable: either 200 MW in “Doberie” instead of 200 MW in “Trégueux”, or 175 MW in “Doberie” and 175 MW in “La Rance” instead of 350 MW in “La Rance”. This choice depends mainly on the feasibility of the different possible layouts for the subsea cables, as there are many protected areas for environmental reasons in the surroundings where any installation of cables could be prohibited. The boxes and the stars in red, green and yellow in the background represent old projects of offshore wind farms once studied by various developers under the “open door” policy in use years ago. These projects are now obsolete with the new policy based on calls for tenders.

Figure 4-5 shows the area of 1000 MW (zone 8) to the South West of Brittany, near Cordemais. This area is expected to be connected through two DC connection lines of 500 MW each either to “Cordemais” (400 kV) or to a new 400 kV station to the north. The zone 9 had once been selected for the call for tender, but is very likely to be abandoned because of the strong opposition of an influential politician who lives in the surroundings (!).

The capacities are not definitive either. Therefore, the grid study does not focus on one only scenario, but on several probable ones, and at the same time determine critical cases (for instance, the maximal capacity...
the grid can handle, according to the station that houses the connection, etc). These probable scenarios are, as explained above:

- scenario 1: 200 MW in “Trégueux”, 350 MW in “La Rance” and 1000 MW in “Cordemais” (or to the north of Cordemais, but as this has very few impact on the power flows, this possible variant will not be taken into consideration);
- scenario 2: 200 MW in “Doberie”, 350 MW in “La Rance” and 1000 MW in “Cordemais”;
- scenario 3: 200 MW in “Trégueux”, 175 MW in “Doberie”, 175 MW in “La Rance” and 1000 MW in “Cordemais”.

Figure 4-5 Expected offshore wind farm near Cordemais [56]

4.1.4 Expected grid reinforcement in Brittany

As explained above, the electric system in Brittany is quite weak, is sometimes operated close to its limits and faces a quick increase in the maximal load over the years. Actions intended to reinforce the grid are frequent all over France, as they are necessary for the grid to withstand the continuous increase in the electricity consumption. In Brittany, such actions will be particularly numerous in the very next years. They have to be taken into consideration in the simulations as explained in chapter 4.3.1 and 4.3.2. Most actions will have minor impact, and they will not be described here. They are included in the in Convergence (see chapter 3.3.1). The installation of a phase-shifting transformer, also known as a quadrature booster (see 3.1.5 for a short explanation), between “La Rance” and “Launay” is worth mentioning though, as it has strong impacts on the study. The construction of a new 225 kV line between “Plaine-Haute” and “Poteau-Rouge” is under consideration. However it is still quite uncertain, and thus it will be only studied as a variant, referred to as the “potential 225 kV reinforcement” in the following chapters. It is represented in blue in figure 4-3. There are also some new thermal plants under consideration, but they are not likely to be operational soon, for they face very strong local oppositions.
4.2 Wind speed and load factor

As explained in chapter 4.3.2, in order to estimate properly the impacts of the wind farms on the grid, it is necessary to know the distribution of the power factor. This chapter describes how such a distribution has been estimated. As few data were available, the estimate is not intended to be very accurate, but only to give an idea. In order to make this estimate, the choice has been made to use datasets of wind speed and the power curve of a certain offshore wind turbine, the Vestas V112 offshore, according to the method described in chapter 3.2. The choice of the Vestas V112 has been made considering that Vestas is the most important manufacturer on the offshore wind market (42.6% of the market share), the Vestas turbines being therefore the most likely to be built [57].

There is no on-site offshore wind measures available in France and data from satellites such as [58] have been considered not as suitable as the data from Netherlands below, for their time resolution is often too low, as explained in chapter 3.2.1. The choice has been made to use datasets measured off the coasts of Netherlands, for (1) the wind speeds in Netherlands and in France are likely to be quite similar, as the two countries are not very distant, and in addition the average wind speed is nearly equal in the two countries, as illustrated in figure 4-6; (2) many datasets measured at different offshore spots were available, which makes them more reliable; (3) there were at least 20 years of measurements for each dataset, and the temporal resolution was 10 minutes, which is sufficient to get robust conclusions; (4) together with these offshore datasets of wind speed, many onshore datasets were also available, which could be interesting in the future, as a work of analysis of onshore wind speeds and actual wind farms power output in France is currently in progress: if a strong correlation can be found between offshore and onshore wind speed in Netherlands, perhaps some extrapolation can be made with the onshore data in France.

These datasets have been processed with R (see 3.3.3) in order to display the curves in figure 4-7, that represent the distribution of the wind speed, averaged on the different measurement spots. It was clear from the datasets that the wind speeds were sensibly higher during four winter months: November, December, January and February. Therefore, the distribution that corresponds to winter months only has been plotted in addition to the one that correspond to the entire year. RTE usually uses its own type of curves to represent the distribution of wind speeds or load factor. They represent the function f(x) for x from 0% to 100%, where f(x) is the highest wind speed that is exceeded x(%) of the time; for example f(50%) = 8.9 m/s means that half of the time, the wind speed is above 8.9 m/s. This looks like duration curves and is equivalent to more conventional curves like the probability density function. The most important steps of the processing of the datasets, which leads to the curves, are: (1) some lists had several consecutive years of 0 m/s measurements, probably because of malfunctions of measurement device: they had to be eliminated to not distort the results; (2) wind speeds were measured at different heights in the different datasets: they have been multiplied by different factors in order to all correspond to the estimated wind speed at 100 m, according to the formula in 3.2.1; the 100 m corresponds to the height of the wind turbine Vestas V112 Offshore, whose power curve has been used; (3) a new dataset containing the average wind speed over the different locations, at 100 m, has been built; (4) the curves described above have been plotted from this new dataset.
Figure 4-6 Average wind speed throughout Europe [59]

Figure 4-7 Distribution of wind speed
Hence, from figure 4-7, we can say in particular, considering the winter months only, that:
- half of the time, the wind speed is above 8,9 m/s
- 60% of the time, the wind speed is above 7,8 m/s
- 70% of the time, the wind speed is above 6,8 m/s
- 80% of the time, the wind speed is above 5,7 m/s
- 90% of the time, the wind speed is above 4,3 m/s

This figure shows also that the average wind speed in winter is around 1 m/s higher than the average wind speed for the entire year. This phenomenon is not surprising and characterises also the onshore wind speeds in France.

The distribution of the wind speeds being estimated, the next step consist of combining this distribution of wind speeds with the power curve of the wind turbine in order to obtain an estimate of the distribution of the load factor of the turbine, which is displayed in table 4-1. Because of this difference between summer and winter, the two seasons have been analysed separately. The following illustrates the winter months only: November, December, January, February. The same operations have been done for the summer months (June, July, August). The results for summer are displayed later in the report, in table 4-6.

<table>
<thead>
<tr>
<th>Percent of the time (%)</th>
<th>100</th>
<th>95</th>
<th>90</th>
<th>85</th>
<th>80</th>
<th>75</th>
<th>70</th>
<th>65</th>
<th>60</th>
<th>55</th>
<th>50</th>
<th>40</th>
<th>30</th>
<th>25</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind speed (m/s) (winter only)</td>
<td>0</td>
<td>3,4</td>
<td>4,3</td>
<td>5</td>
<td>5,7</td>
<td>6,3</td>
<td>6,8</td>
<td>7,3</td>
<td>7,8</td>
<td>8,3</td>
<td>8,9</td>
<td>10,1</td>
<td>11,3</td>
<td>12</td>
</tr>
<tr>
<td>Corresponding load factor (%) (Vestas V112)</td>
<td>0</td>
<td>3,5</td>
<td>8</td>
<td>12</td>
<td>16</td>
<td>21</td>
<td>27</td>
<td>35</td>
<td>44</td>
<td>53</td>
<td>63</td>
<td>85</td>
<td>95</td>
<td>100</td>
</tr>
</tbody>
</table>

Average load factor: 58%

Table 4-1 Distribution of wind speed and load factor

However, this load factor based on the power curve of one turbine is not equal to the actual load factor of the farms, as some losses are not included in the power curve of the turbine. These losses are due to the wake effect within the farm and to various electrical losses and amount to around 10% of the power output. The unavailability of the farm is also to be taken into consideration; it has been estimated to 5%. The estimate of the final distribution curve of the load factor, which takes into consideration the extra losses and the unavailability of the farm, is displayed in figure 4-8, for the winter months only. From figure 4-8, it can be said, for example, that wind farms are expected to have 88% of the time a load factor above 5%, and 81% a load factor above 10%, etc.
This chapter gathers the results of many load flow calculations that have been made with Convergence, which are intended to investigate the impact of the future offshore wind turbines on the grid in Brittany. Different approaches have been used, depending on the simulation. It could be, for instance to investigate the lines which become overloaded for a given scenario, or to determine how high can be the output of the offshore wind farms before a line is overloaded. As explained in chapter 3.1.6, the operation of the grid usually respects the so-called “N-1 criterion”, i.e. the system is capable of withstanding any fault, in all circumstances, as long as there is only one fault in the surroundings. And grid studies are based on the “N-1 assumption”, i.e. the simulation is run on a system that has experienced a fault. The problems that are expected to occur are very different in summer (June, July, August) and in winter (November, December, January, February). The two seasons are therefore studied separately.

4.3.1 Summer

In summer, consumption is always low, as electric heating is not used. At the same time, the lines are more easily overloaded as limits are lowered because of the high temperature (see 3.1.3) The main risk is that the lines that transfer electricity from a power plant are overloaded. Then RTE has to curtail the power plant, which is considered acceptable if it is exceptional, but not if it occurs often. The probability that this happens is obviously higher when the local consumption, located near the plant, is low.
In northern Brittany, there is such a risk because of the two farms of 350 MW and 200 MW that are expected, especially when the hydro plant in “La Rance”, whose output is not really controllable, is generating at full output. On the contrary, the 1000 MW farm connected near “Cordemais” is not a problem, considering the thermal plants in “Cordemais”, fully controllable are not generating at full output. Therefore, this chapter will focus on northern Brittany.

It is also usually in summer that the grid encounters problems of high voltage levels and this issue is also investigated. It is important to keep in mind that the problems of overload described in this chapter can only occur during the three months of summer (June, July, August), when the limits to the level of intensity in the lines are at their lowest point (see 3.1.3).

### 4.3.1.1 Goals of the chapter

This chapter pursues 4 goals, that all concern northern Brittany exclusively, and not the area near Cordemais, except for the last one:

1. Determine what lines are overloaded (under the “N-1 assumption”) and how much they are overloaded, under the most probable scenarios. With this information, it is possible to estimate the cost of the replacement of these lines by new lines with sufficient capacity/rating to respect the “N-1 criterion”.
2. Assuming no grid reinforcement, estimate how much hours per year overloads will occur under the most probable scenarios.
3. Estimate how much power can be generated without grid reinforcement, and without breaking the “N-1 criterion”.
4. Determine the effects of the farms on the voltage level.

### 4.3.1.2 Assumptions

Here are described in details the main assumptions that are constant throughout this chapter 4.3.1, unless indicated otherwise. In regard to consumption and generation, rules at RTE usually require that unfavourable, but still realistic assumptions are used, which in summer means maximal generation and minimal load in the area.

These assumptions are:
- the load in western France at its minimal level: 4800 MW;
- every onshore wind farm is generating at full output, which corresponds to 1000 MW of onshore wind power throughout the western grid;
- the hydro plant in “La Rance” is generating at full output: 240 MW;
- the offshore wind farm near “Cordemais” is generating at full output: 1000 MW;
- the thermal plants in “Cordemais” are not generating: 0 MW (this assumption is not the most unfavourable as, even if it is rare, these thermal plants are sometimes generating in summer, but it is certain that they will be shut down if the offshore wind farm connected to “Cordemais” is generating at full output);
- the thermal plants in “Brennilis” and “Dirinon” never generate in summer: 0 MW;
- the angle of the phase shifting transformer is 3,5°: it forces a bit the power flow from “La Rance” to “Launay”
The outputs of the two offshore wind farms in northern Brittany vary throughout the chapter. The “potential 225 kV reinforcement” and the new limits for the lines (see chapters 4.1.4 and 3.1.1) are not taken into consideration by default, but their impact is still analysed for each case.

4.3.1.3 Goal 1: overloaded lines

The goal here is to determine which lines are overloaded under the “N-1 assumption” and how much they are overloaded, for each of the three most probable scenarios (see chapter 4.1.3).

Method:
The outputs of the two offshore wind farms is determined by the scenario. For each scenario, a load flow calculation is run, and gives the loadings under the “N-1 assumption”. The “20 min limits” (see 3.1.3) noted \( I_{\text{max}20} \) are taken to calculate the loadings \( \frac{l}{I_{\text{max}20}} \), which correspond to the actual intensity within the line divided by the intensity limit of the line. The new “20 min limits” noted \( I'_{\text{max}20} \) are also given in the tables, with the loadings \( \frac{l}{I'_{\text{max}20}} \). The impacts of “potential 225 kV reinforcement” are described at the end of each section. The signs to the right of the tables indicate what happens to the intensity of the overloaded line when the angle of the phase shifting transformer is increased:
- “\( \rightarrow \)" means that the intensity of the line does not change
- “\( \Rightarrow \)" means that the intensity increases
- “\( \Rightarrow \)" means that the intensity decreases

Results:

a) Scenario 1 : 200 MW in “Trégueux”, 350 MW in “La Rance”

<table>
<thead>
<tr>
<th>Fault on the line</th>
<th>Overloaded Line</th>
<th>Intensity ( l )</th>
<th>Current “20 min limit” ( l_{\text{max}20} )</th>
<th>Loading ( \frac{l}{l_{\text{max}20}} )</th>
<th>Future “20 min limit” ( l'_{\text{max}20} )</th>
<th>Future Loading ( \frac{l'}{l'_{\text{max}20}} )</th>
<th>Power P</th>
</tr>
</thead>
<tbody>
<tr>
<td>«LAUNAY» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>840 A</td>
<td>715 A</td>
<td>117%</td>
<td>795 A</td>
<td>106 %</td>
<td>355,2 MW</td>
</tr>
<tr>
<td>«DOMLOUP» - «PLAINE HAUTE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>708,4 A</td>
<td>715 A</td>
<td>99,10%</td>
<td>795 A</td>
<td>89 %</td>
<td>297,8 MW</td>
</tr>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>766,1 A</td>
<td>760 A</td>
<td>100,80%</td>
<td>901 A</td>
<td>85 %</td>
<td>312,7 MW</td>
</tr>
</tbody>
</table>

Table 4-2 overloaded lines under scenario 1

Under this scenario, the “potential 225 kV reinforcement” solves all the overloads. The “1 min limit” is never exceeded.
b) Scenario 2: 200 MW in “Doberie”, 350 MW in “La Rance”

<table>
<thead>
<tr>
<th>Fault on the line</th>
<th>Overloaded Line</th>
<th>Intensity $I$</th>
<th>Current “20 min limit” $I_{max20}$</th>
<th>Future “20 min limit” $I'_{max20}$</th>
<th>Power $P$</th>
</tr>
</thead>
<tbody>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«LAUNAY» - «LA RANCE»</td>
<td>813,2 A</td>
<td>760 A</td>
<td>107%</td>
<td>901 A</td>
</tr>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«DOBERIE» - «TREGUEUX»</td>
<td>910 A</td>
<td>940 A</td>
<td>97%</td>
<td>1217 A</td>
</tr>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>895 A</td>
<td>715 A</td>
<td>125%</td>
<td>795 A</td>
</tr>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>914,2 A</td>
<td>715 A</td>
<td>128%</td>
<td>795 A</td>
</tr>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>756 A</td>
<td>760 A</td>
<td>99%</td>
<td>901 A</td>
</tr>
<tr>
<td>«DOMLOUP» - «PLAINE HAUTE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>734,4 A</td>
<td>715 A</td>
<td>103%</td>
<td>795 A</td>
</tr>
</tbody>
</table>

Table 4-3 overloaded lines under scenario 2

The “1 min limit” is never exceeded here. By increasing a bit the angle of the phase shifting transformer, the overload that is underlined in the table (115 %) can be decreased down to 113 %, without increasing the load of the line “LAUNAY” – “LA RANCE” too much. Under this scenario, the “potential 225 kV reinforcement” solves all the overloads, except for a fault on the line “DOBERIE” - “TREGUEUX” with the current limits: the overloading on the line “BELLE EPINE” – “LA RANCE” is not solved, but still decreases from 128% to 126%. With the “potential 225 kV reinforcement” plus the future limits, it is possible to solve all the overloads by adjusting the angle of the phase shifting transformer (from 3,5° to 10°).

c) Scenario 3: 200 MW in “Trégueux”, 175 MW in “Doberie”, 175 MW in “La Rance”

<table>
<thead>
<tr>
<th>Fault on the line</th>
<th>Overloaded Line</th>
<th>Intensity $I$</th>
<th>Current “20 min limit” $I_{max20}$</th>
<th>Future “20 min limit” $I'_{max20}$</th>
<th>Power $P$</th>
</tr>
</thead>
<tbody>
<tr>
<td>«LAUNAY» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>771,6 A</td>
<td>715 A</td>
<td>108%</td>
<td>795 A</td>
</tr>
</tbody>
</table>

Table 4-4 overloaded lines under scenario 3

Under this scenario, the “potential 225 kV reinforcement” solves all the overloads. The “1 min limit” is never exceeded.

Costs:
Table 4-5 displays the estimated costs of replacement of the current lines by new lines with sufficient capacity/rating to respect the “N-1 criterion”. These cost are found with the help of the software “Valoris”, which contains a database of power lines.
4.3.1.4  **Goal 2: occurrence of overloads in summer**

Assuming no grid reinforcement, the goal here is to estimate how much hours per year overloads will occur under the most probable scenarios.

The tables in chapter 4.3.1.3 give the overloads assuming that a fault occur when the offshore wind farms are generating at full output AND when the load is at its lowest level. In reality, the probability that it happens is extremely low. All the faults that lead potentially to one or several overload(s) are indicated in the tables above (in summer only). For each potential overload, the probability that it actually happens is estimated. The method is described in details for the first case: scenario 1, fault on the line: “BELLE EPINE” - “LA RANCE”, overloaded line: “LAUNAY” - “LA RANCE”, current “20 min limits”, no “potential 225 kV reinforcement”. Only the results are given for the other cases.

**Method in detail.** based on the scenario 1, with a fault on the line: “BELLE EPINE” - “LA RANCE” and an overload on the line: “LAUNAY” - “LA RANCE”:

The fact that the line is overloaded or not depends on many probabilistic parameters: fault on the line: “BELLE EPINE” - “LA RANCE”, load factors on the two offshore wind farms, load factors of the onshore wind farms, output of the power plants nearby (especially the hydro power plant in “La Rance”), consumption level in the area... The best way to estimate the probability of overload is to use probabilistic tools, such as the Monte Carlo method. No such tools are used here. The approach is based on the results of a report, that concludes that in such a situation with many probabilistic parameters, if some parameters are much more impacting than others (and this is the case here) it is reasonable to keep constant the minor parameters at average levels. This is actually very intuitive.

Here, only three parameters have a strong impact of the probability of overload: the fault on the line “BELLE EPINE” - “LA RANCE”, the load factors on the two offshore wind farms, and the output of the hydro power plant in “La Rance”. The load in the western part of France could have an impact, but only if it exceed 9 GW, which is very unlikely in summer and is not taken into consideration. The line “BELLE EPINE” - “LA RANCE”, is either operational or down. It is assumed to be down about 1% of the time. The load factors of the two offshore farms are assumed to be equal, as they are quite close to each other (around 30 km). Based on the data available for onshore wind farms, this assumption is reasonable as, the difference between the outputs of two wind farms located at such a low distance is about one or two per cent in average. Table 4-6 shows an estimate of the distribution of the load factor in summer, which takes into consideration all the losses, including the unavailability of the farm. This table is the equivalent for the summer months of figure 4-8, which is for the winter months.
The power output of the hydro power plant in “La Rance” is assumed to follow the distribution described in table 4-7:

Table 4-7 Distribution of the power output of the hydro power plant in “La Rance”

The load in the northern part of the France is assumed to be at its average level in summer (6,5 GW). The power factor of onshore wind farms is assumed equal to its average level 25 %.

For this specific fault and this specific overload, some load flow calculations allowed to complete table 4-8. This table indicates (either Yes (Y) or No (N)) if the fault on the line “BELLE EPINE” - “LA RANCE” leads actually to the overload of the line “LAUNAY” - “LA RANCE”, for different combinations of the load factor of the offshore wind farms and the output of the hydro plant. If it is a Yes, a probability is given in brackets, which is the probability that the load factor and the output are both in the given ranges, calculated with the help of tables 4-6 and 4-7.

For example, table 4-6 indicates that the probability that the load factor of the offshore wind farms is between 98 % and 100 % is 10 %. Table 4-7 indicates that the probability that the output of the hydro plant is higher than 120 MW (approximately 38 %) minus the probability that the power output is higher than 150 MW (approximately 29 %). As the load factor of the wind farms and the power output of the hydro plant are assumed independent from each other, the probability that “the load factor of the offshore wind farms is between 98 % and 100 % AND the output of the hydro plant is between 120 MW and 150 MW” is 0,9 % (which is equal to 10 % multiplied by 9 %).

Table 4-8 Overloading of the line “LAUNAY” - “LA RANCE” in case of a fault “BELLE EPINE” - “LA RANCE” according on load factor and power output
The probability that a fault on the line “BELLE EPINE” – “LA RANCE” leads actually to the overload of the line “LAUNAY” – “LA RANCE” is equal to the probability that the combination of the load factor and the output corresponds to a “Y” in table 4-8. As the different combinations are exclusive events, this probability is equal to the sum of all the probabilities given in bracket. Then a fault on the line “BELLE EPINE” – “LA RANCE” leads actually to the overload of the line “LAUNAY” – “LA RANCE” around 6.9% of the time, in summer, where 6.9% is the sum of the percentages in the brackets. Thus, the line “LAUNAY” – “LA RANCE” is expected to be overloaded around 0.069% (= 6.9%*1% (probability that the line “BELLE EPINE” – “LA RANCE” is down)) of the time, in summer, if only the fault “BELLE EPINE” – “LA RANCE” is taken into consideration. Then, for each scenario, it is possible to estimate the probability that at least one line is overloaded, by summing the probabilities of overload of the different lines for the different faults (it is assumed that the faults occur one at a time).

### Results:

**a) Scenario 1: 200 MW in “Trégueux”, 350 MW in “La Rance”**

<table>
<thead>
<tr>
<th>Fault on the line</th>
<th>Overloaded Line</th>
<th>Probability (%) (Current limits)</th>
<th>Hours per summer in average (Current limits)</th>
<th>Probability (%) (Future limits)</th>
<th>Hours per summer in average (Future limits)</th>
</tr>
</thead>
<tbody>
<tr>
<td>«LAUNAY» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>0.069%</td>
<td>1.5 hours</td>
<td>0.016%</td>
<td>0.35 hours</td>
</tr>
<tr>
<td>«DOMLOUP» - «PLAINE HAUTE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>0%</td>
<td>0 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«LAUNAY» - «LA RANCE»</td>
<td>0.002%</td>
<td>0.05 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>0.07%</strong></td>
<td><strong>1.55 hours</strong></td>
<td><strong>0.016%</strong></td>
<td><strong>0.35 hours</strong></td>
</tr>
</tbody>
</table>

Table 4-9 Estimated probability of overload in summer for scenario 1

**b) Scenario 2: 200 MW in “Doberie”, 350 MW in “La Rance”**

<table>
<thead>
<tr>
<th>Fault on the line</th>
<th>Overloaded Line</th>
<th>Probability (%) (Current limits)</th>
<th>Hours per summer in average (Current limits)</th>
<th>Probability (%) (Future limits)</th>
<th>Hours per summer in average (Future limits)</th>
</tr>
</thead>
<tbody>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«LAUNAY» - «LA RANCE»</td>
<td>0.019%</td>
<td>0.4 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
<tr>
<td>«DOBRIE» - «TREGUEUX»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>0%</td>
<td>0 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
<tr>
<td>«LAUNAY» - «LA RANCE»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>0.125%</td>
<td>2.8 hours</td>
<td>0.05%</td>
<td>1.1 hours</td>
</tr>
<tr>
<td>«DOBRIE» - «TREGUEUX»</td>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>0.055%</td>
<td>1.2 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
<tr>
<td>«DOMLOUP» - «PLAINE HAUTE»</td>
<td>«LAUNAY» - «LA RANCE»</td>
<td>0%</td>
<td>0 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>0.27%</strong></td>
<td><strong>5.9 hours</strong></td>
<td><strong>0.05%</strong></td>
<td><strong>1.1 hours</strong></td>
</tr>
</tbody>
</table>

Table 4-10 Estimated probability of overload in summer for scenario 2
c) Scenario 3: Scenario 3: 200 MW in “Trégueux”, 175 MW in “Doberie”, 175 MW in “La Rance”

<table>
<thead>
<tr>
<th>Fault on the line</th>
<th>Overloaded Line</th>
<th>Probability (%) (Current limits)</th>
<th>Hours per summer in average (Current limits)</th>
<th>Probability (%) (Future limits)</th>
<th>Hours per summer in average (Future limits)</th>
</tr>
</thead>
<tbody>
<tr>
<td>«BELLE EPINE» - «LA RANCE»</td>
<td>«LAUNAY» - «LA RANCE»</td>
<td>0,027%</td>
<td>0,6 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>0,027%</td>
<td>0,6 hours</td>
<td>0%</td>
<td>0 hours</td>
</tr>
</tbody>
</table>

Table 4-11 Estimated probability of overload in summer for scenario 3

For such low amounts of hours of overload, curtailment measures are far cheaper than the other possible measure that consist of replace the current lines by new lines with sufficient rating to respect the “N-1 criterion”. Indeed, 6 hours of power curtailment means some 200 MWh maximum being curtailed (as only a few dozens of MW are to be curtailed in average). Assuming these 200 MWh are to paid at the feed-in tariff to the offshore wind farm owner, i.e. around 150 €/MWh (this is a very much unfavourable assumption, as a the cost of a curtailed MWh is usually a few dozens of euros maximum), the cost of the curtailment measures is about 30000 € per year for the scenario 2 and the current intensity limits, to be compared with the 20 €M necessary to replace the current lines by new ones.

4.3.1.5 Goal 3: Maximal power output without breaking the “N-1 criterion”

The goal here is to estimate how much power can be generated without breaking the “N-1 criterion”, and without grid reinforcement (with the exception of measures of grid reinforcement that are already planned; moreover, the “potential 225 kV reinforcement” is investigated as a variant).

This chapter indicates the maximal offshore wind power output it is possible to have in northern Brittany without any line overload (without any grid reinforcement), under different scenarios of connection. Though it does not correspond to any actual limitation, as these values can be increased by grid reinforcement, this approach, compared to the precedent ones, facilitate the comparison of numerous different scenarios of connection to the different nearby stations.

**Method:**

First the stations of connection of the wind farms are chosen. The two farms are either connected to one of the three nearby 225 kV stations (“Trégueux”, “La Rance”, “Doberie”), or to several of them: the 200 MW farm is connected to either “Trégueux” or “Doberie”, and the 350 MW farm is either connected to one of the three 225 kV stations (“Trégueux”, “La Rance”, “Doberie”) or connected half to “Doberie” and half to “La Rance”. The possibility of a connection line to “Plaine Haute”, a 400 kV station located around 20 km to the South of “Trégueux”, is also investigated. This 400 kV station is not envisaged in the context of the current call for tender, because of the extra costs induced by the farther distance, but it could still be an interesting solution if the capacity to be connected in the area were to be increased.

Then the capacities of the farms are progressively increased (or decreased) until the load flow calculation detects that it both respects the “N-1 criterion” and cannot be increased anymore. If the total capacity of the two farms is lower than 450 MW, the scenario of connection is not indicated.
Results:

a) Current limits and no “potential 225 kV reinforcement”

<table>
<thead>
<tr>
<th>Farm</th>
<th>kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trégueux</td>
<td>200 MW</td>
</tr>
<tr>
<td>Doberie</td>
<td>140 MW</td>
</tr>
<tr>
<td>La Rance</td>
<td>140 MW</td>
</tr>
<tr>
<td>Trégueux</td>
<td>400 MW</td>
</tr>
<tr>
<td>Doberie</td>
<td>200 MW</td>
</tr>
<tr>
<td>Trégueux</td>
<td>200 MW</td>
</tr>
<tr>
<td>Doberie</td>
<td>350 MW</td>
</tr>
<tr>
<td>Trégueux</td>
<td>650 MW</td>
</tr>
<tr>
<td>Plaine Haute</td>
<td>800 MW</td>
</tr>
</tbody>
</table>

Table 4-12 Maximum power output of offshore wind farms without overloading, with current intensity limits and no grid reinforcement

This means that with the current limits and without the “potential 225 kV reinforcement”, it is possible to connect, without any line overload, either approximately (1) 200 MW to “Trégueux” and 140 MW to “Doberie” and 140 MW to “La Rance”, or (2) 400 MW to “Trégueux” and 200 MW to “Doberie”, or (3) 200 MW to “Trégueux” and 350 MW to “Doberie”, or (4) 650 MW to “Trégueux”, or (5) 800 MW to “Plaine-Haute”.

b) Future limits and no “potential 225 kV reinforcement”

<table>
<thead>
<tr>
<th>Farm</th>
<th>kW</th>
</tr>
</thead>
<tbody>
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<td>Trégueux</td>
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</tr>
<tr>
<td>Rance</td>
<td>300 MW</td>
</tr>
<tr>
<td>Trégueux</td>
<td>210 MW</td>
</tr>
<tr>
<td>Doberie</td>
<td>180 MW</td>
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<tr>
<td>La Rance</td>
<td>180 MW</td>
</tr>
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<td>Trégueux</td>
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<td>Doberie</td>
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<tr>
<td>Doberie</td>
<td>200 MW</td>
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<td>Rance</td>
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<tr>
<td>Trégueux</td>
<td>800 MW</td>
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<tr>
<td>Doberie</td>
<td>500 MW</td>
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<tr>
<td>Plaine Haute</td>
<td>950 MW</td>
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</table>

Table 4-13 Maximum power output of offshore wind farms without overloading, with future intensity limits and no grid reinforcement

c) Current limits, with the “potential 225 kV reinforcement”

<table>
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<tr>
<th>Farm</th>
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<tr>
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<td>La Rance</td>
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<td>Doberie</td>
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<td>Trégueux</td>
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<td>Trégueux</td>
<td>650 MW</td>
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<tr>
<td>Plaine Haute</td>
<td>1200 MW</td>
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</table>

Table 4-14 Maximum power output of offshore wind farms without overloading, with current intensity limits and with the “potential 225 kV reinforcement”

d) Future limits, with the “potential 225 kV reinforcement”

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</thead>
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<td>La Rance</td>
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<td>Trégueux</td>
<td>300 MW</td>
</tr>
<tr>
<td>La Rance</td>
<td>250 MW</td>
</tr>
<tr>
<td>Doberie</td>
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</tr>
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<td>Trégueux</td>
<td>275 MW</td>
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<td>Doberie</td>
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<tr>
<td>Doberie</td>
<td>200 MW</td>
</tr>
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<td>La Rance</td>
<td>350 MW</td>
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<tr>
<td>Trégueux</td>
<td>900 MW</td>
</tr>
<tr>
<td>Doberie</td>
<td>500 MW</td>
</tr>
<tr>
<td>La Rance</td>
<td>450 MW</td>
</tr>
<tr>
<td>Plaine Haute</td>
<td>1400 MW</td>
</tr>
</tbody>
</table>

Table 4-15 Maximum power output of offshore wind farms without overloading, with future intensity limits and with the “potential 225 kV reinforcement”
These results illustrate well the sensible impact of the two potential major changes on the grid in northern Brittany. If these two changes are taken into consideration, the amount of power which can be generated by the offshore wind turbines in the area before any overloading occur increase by around 50%.

It is also remarkable that this part of the grid could be fed by up to 1400 MW at the condition the farms are connected to the 400 kV station “Plaine Haute”, as compared to 800 MW without the two changes. These results suggest that much more offshore wind power could be installed in Brittany than the 1500 MW that are currently planned (500 MW in northern Brittany plus 1000 MW near Cordemais), without any serious problems on the grid. Some grid reinforcement could be necessary, but the related costs would be negligible compared to the total costs of the farms.

4.3.1.6 Goal 4: High voltages level

The goal here is to determine the effects of the farms on the voltage level. The voltage level is naturally high in summer. This is not really a problem in Brittany at the moment, but it has to be checked that the offshore wind farms will not increase the voltage level too much. The wind farm itself is certainly not a problem, as its reactive capability helps to lower the voltage level if needed. However, the cables used to connect the farm to the grid generate much reactive power, which tends to increase the voltage level if it is not compensated with the help of additional reactive compensation devices. It is certainly possible to fully compensate the reactive power generated by the cables with reactors. However, in northern Brittany, there were reasons to try to not fully compensate the reactive generated by the cables, or compensate it far from the station the cables are connected to. Indeed, there are a lot of residences in the surroundings of the station “La Rance” and not much space left for the extension of the station. The installation of the several reactors required to fully compensate the reactive power of the cables is not impossible, but RTE would prefer not extend the station for the present reactors if it is not absolutely required. A potential installation of the reactors midway between the coastline and the station is also investigated, but there are only very few convenient places, for there are many residences and protected areas for environmental issues in the area, and, in addition, it would deprive RTE of the possibility to switch off the reactors while the connection cables are still connected in case there is a need for reactive power in the area. There are similar concerns for the station “Trégueux”, but the extension of the station is less problematic than for “La Rance”.

Load flow calculations have been run to investigate this. They conclude that (1) reactors must be installed in sufficient quantity to absorb at least 90 % the reactive power generated in the cables; (2) reactors must be installed close to the cables, to prevent the voltage to increase too much when a fault occur on a line between the reactors and the cable. With such results, the reactors are likely to be installed midway between the coastline and the station “La Rance”, while this is still very uncertain for “Trégueux”.

4.3.1.7 Conclusion – summer case

The three wind farms expected in the context of the call for tenders in Brittany are not sufficiently large to cause major disturbances in the western area of the French distribution network. However, some minor problems could occur. And either small grid reinforcement or occasional power output curtailment measures could be necessary. The future state of the grid, when the wind farms will be built, is still uncertain, and some reinforcement could have been already undertaken for other reasons, which could help avoid problems with the offshore wind farms. The impact of the wind farms on the grid in summer depends a lot of the choice of the stations the farms will be connected to. The scenario 3, i.e. 200 MW in
“Trégueux”, 175 MW in “Doberie”, 175 MW in “La Rance”, is estimated to have the lower impact on the grid and therefore require the fewer measures - no measures at all under certain assumptions. The scenario 1, i.e. 200 MW in “Trégueux” and 350 MW in “La Rance”, has a lower impact than the scenario 2, i.e. 200 MW in “Doberie” and 350 MW in “La Rance”, which is the worst one from the point of view of the measures to be taken in summer. However, as explained in chapter 4.1.3, these considerations are not likely to have an influence on the choice of the stations. In addition, the differences in the cost of the connection lines make that the less costly connection scenario, all costs included, is the scenario 1.

Further investigations on the possible impacts of offshore wind farms that have far higher capacity have also been conducted, and conclude that the most efficient way (financially speaking) to integrate these farms would be to use both grid reinforcement and curtailment mechanisms. If the consumption keep increasing as expected, major grid reinforcement should be undertaken because of winter issues (see next chapter 4.3.2), and curtailment mechanisms could not be needed anymore. The possibility of not fully compensating the reactive generated by the cables, or compensating it far from the station the cables are connected to, has been investigated because of the lack of space around two stations in northern Brittany. However, the results show that this would endanger the electric system in case of high voltage levels.

4.3.2 Winter

Issues are entirely different in winter. As there is only few power plants in Brittany, most of the power consumed there is generated elsewhere, and potential overloading of the lines supplying Brittany is the most probable risk faced. Moreover, the lack of power plants do not allow sufficient voltage support in the area, and maintaining a sufficiently high voltage level in winter in Brittany is also a major challenge. Actually, it if very unlikely that any major trouble happens in the very next years, because important grid reinforcement are built sufficiently in advance to face the expected increase in the consumption for around 5-7 years. Hence, the simulation of the system with the current grid and the consumption level expected in 2015 will not indicate any need to reinforce the grid, as such reinforcement has already been built. The interest of this simulation of the impact of the farms on the grid in winter is to help optimising the reinforcement to be decided for winter in the very next years, which correspond to the reinforcement required to face the consumption level as expected in winter 2020. The future reinforcement included in the simulation are limited though to the ones that are already been decided or the ones that are about to be decided. They are the same that the ones taken for the summer case.

The future wind turbines will have positive impacts on the expected problems, as they will reduce the electricity imports. However the fact that their output is intermittent and not controllable has for consequence that the risks will certainly be reduced but will not disappear. Studies have been conducted to estimate what will be the risks of overload in 2020 and how far the installation of the offshore wind farms will reduce the risk. Just as in summer, the wind farm connected to “Cordemais” has not much impact on the electric system, and most of the chapter focuses on northern Brittany. Assuming the scenario 1, i.e. 350 MW in “La Rance” and “200 MW” in “Trégueux”, the results displayed in table 4-16 have been found. They indicated what faults can potentially lead to an overload, what lines risk being overloaded, the maximal loading, i.e. the loading which is expected in the worst situation (in percentage of the “20 min limit” (see 3.1.3)), the expected hours per year the line become overloaded without the wind farms, and then with the wind farms. The method that leads to these results is similar than the ones used in chapter 4.3.1. It is described in details in appendix 3. When the maximal loading exceeds the “1 min limit” (see 3.1.3), the overloading is put in red and bold type.
It is noticeable that the wind farms have an important positive impact on the expected overload time: it is approximately divided by 2. The only line that is not much impacted is “DOBERIE” - “LA RANCE”. It was predictable because the power flows from the east to the west, and thus the farm connected to “La Rance”, to the east of the line “DOBERIE” – “LA RANCE” (see figure 4.3, chapter 4.1.2), tends to increase the power flow on this line, even if the farm connected to “Trégueux” still reduces it. However the wind farms do not reduce the maximum overloading: indeed, this corresponds to the worst possible scenario and in this scenario the wind farms do not generate anything. As explained in 3.1.3, it is not really a problem if the “20 min limit” is exceeded from times to times, as long there exist mechanisms to solve the problems within reasonable time. It could be for instance advanced load management measures or local, temporary power cuts. However the risk to exceed the “1 min limit” should not be taken, because of the lack of time available to solve the problem before the line is disconnected. Thus, in case the “1 min limit” is exceeded “under the N-1 assumption”, major reinforcement measures should be undertaken. It could be, for instance, changing the lines in order to increase the intensity limits, but this measure does not help for voltage issues, which are described below.

Another investigation has been conducted for the voltage level, which will fall far too low in 2020 in case of a fault on the line “DOMLOUP” – “PLAINE HAUTE”. The aim was to determine, with and without the offshore wind farms, the maximum load which does not lead to an unacceptable voltage drop at the station “Plaine Haute” under the “N-1 assumption”, i.e. in case of a fault on the 400 kV line “DOMLOUP” – “PLAINE HAUTE”. The results are: (1) without the offshore wind farms, the load can reach up to 18 000 MW in the “western grid area”, as illustrated in figures 4-1 and 4-2, before unacceptable voltage drops are detected under the “N-1 assumption”; this load is expected to be reached in 2018; (2) with the offshore wind farms, the load can reach up to 18 500 MW; this load is expected to be reached in 2019. Hence, the conclusions are that the farms have actually a small positive impact, but this is not enough to solve the expected problem. Moreover, just like for the “1 min limit”, voltage problems require quick reaction times, which makes load management measures not adequate. Thus grid reinforcement measures should be taken. It could be for instance, adding capacitors or other compensation devices (see 3.1.5 and 2.5.2)).

As explained above, these are the results of scenario 1, i.e. 200 MW in “Trégueux” and 350 MW in “La Rance”. The results of the two other scenarios will not be described as they are very similar and lead to the same conclusions. These results are based on the assumptions that the intensity limits are the current ones and not the future ones (see 3.1.3), and that the “potential 225 kV reinforcement” is not built. If the future limits and the “potential 225 kV reinforcement” certainly help for the overloading issues, in particular by solving all the “1 min limit” overloading, they do not help for the voltage issues.
Considering that both problems of overloads and voltage level could be solved by the installation of a new thermal plant, RTE plans to start a call for tenders to get one installed in the area. However as explained previously, there is a strong local opposition. Indeed, many people claim that the assumptions of consumption for 2020 are far too pessimistic and that strong load reduction measures should be taken in order to keep the consumption at its current level, which would certainly be another solution to solve the foreseen problems. It is not up to RTE to take these decisions, but RTE would have enough influence to advocate efficiently such measures, if it was decided so.

4.4 Conclusion of the part

Some problems are foreseen on the transmission network in Brittany, which are impacted by the expected installation of several offshore wind farms in the area. These problems are very different depending on the season. Indeed, in summer, there are problems of overload BECAUSE OF the wind farms, for the lines that carry the power from the shore toward the 400 kV voltage grid could be overloaded, while in winter, there are problems DESPITE the expected help of the wind farms, provided the level of consumption is taken at its expected 2020 level. The impact of these offshore wind farms on the grid has been investigated by means of many simulations, and with the help of an estimated distribution of the power output of the turbines built for the occasion.

Assuming the total capacity of the offshore wind farms remains at its current expected level (550 MW in northern Brittany and 1000 MW in southern Brittany), only minor problems are detected in summer, and curtailment measures could solve them at minor costs. However, more serious problems are expected in winter (higher levels of overload, problems of low voltages), while no simple measure is capable of solving them: curtailment measures are not adequate in winter, and such measures as load management are not sufficient. As, because of the uncertainty of their output, the offshore wind farms reduce the risks but do not make them disappear, important reinforcement measures are needed despite the help of the offshore wind farms. It could be a new thermal plant, or the installation of both reactive compensation devices and new lines. Even if the new thermal plant is certain a more robust solution, installing new lines would solve the expected problems in winter caused by the wind farms. It is important having in mind, though, that the expectation of severe troubles in winter is a consequence of the assumption that the consumption will keep increasing until 2020, which could certainly be avoided by adequate measures.
5 Conclusion of the thesis

The purpose of this thesis was to investigate two issues: first the rules and the practices in use in Europe in regard to the connection of offshore wind farms to the grid, and then the impact of three expected offshore wind farms on the grid in Brittany. The common underlying aim of these investigations was to help RTE finding the best solutions, i.e. the cheapest solutions “for society”, for the connection of these offshore wind farms to the grid.

France has no offshore wind farms yet, and rules are in constant evolution, with the purpose of being as efficient as possible when the first farms are built. Part 2 concluded that, in France, the rules currently in use and the practices as planned in the future are quite similar to what is done in more experienced European countries. There are still several important points that deserve further investigation. They are, by order of importance, (1) the method used for the call for tender and the assumption of 5 MW/km², (2) the reluctance to use large HVDC connection lines up to 1300 MW, (3) the rules used to design the AC connection lines, (4) the reactive power range required when the active power output of the wind turbine is low, (5) the ownership of the offshore platform and the reluctance to install reactors offshore, (6) the time-delay of the reactive response in case of voltage drop. In particular, the two first points, and also the third one to a lesser extent, should be dealt with urgently, considering their considerable implications for the call for tenders.

The findings of part 4 are quite uncertain, as the investigation of the future impacts of the farms on the grid requires taking under consideration many possible assumptions. It is clear though that much more offshore wind power than currently planned (1500 MW) could be connected to the grid in Brittany without any important need for grid reinforcement. Some could be necessary, but the related costs would be negligible compared to the total costs of the offshore wind farms. Nevertheless, it is also clear that the wind farms will not help solving the expected problems of electricity supply in winter in Brittany, and that much additional reinforcement is required in case the consumption keeps increasing until 2020. Would it not be more fashionable however, to take adequate measures and break once and for all this tendency?
6 References

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[56] RTE. http://www.rte-france.com/fr/
[58] Cersat-Ifremer, "Ocean surface wind". http://cersat.ifremer.fr/data/discovery/by_parameter/ocean_wind
7 Appendices

7.1 Appendix 1: Database of wind farms and their transmission systems

Below, the characteristics of the connection systems of many offshore wind farms are given. All the operational offshore wind farms in Europe above 100 MW are included. Many other farms are also included, when sufficient information is available. These are mostly cancelled projects in France and future farms in UK.

Three figures are needed to give all the characteristics of a farm, and the figures 7-1 to 7-6 should be read as indicated here:

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<thead>
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<th>Figure 7-1</th>
<th>Figure 7-2</th>
<th>Figure 7-3</th>
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<td>Figure 7-4</td>
<td>Figure 7-5</td>
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</table>

Figure 7-6 Database of offshore wind connections
7.2 Appendix 2: Intensity limits for the lines in Brittany

This Appendix is confidential and cannot be viewed in the public version of the report
7.3 Appendix 3: Method of the grid study in winter

The scenario under investigation corresponds to the situation expected in winter 2020, i.e. November, December, January, and February 2020.

The following assumptions are taken:
- 240 MW in the hydro plant in “La Rance” (full output)
- 1000 MW of offshore wind power in “Cordemais” (full output)
- 2500 MW in the thermal plants in “Cordemais” (full output)
- 160 MW and 285 MW, respectively, in the thermal plants in “Brennilis” and “Dirinon” (full output)
- The angle of the phase shifting transformer in “La Rance” is 0°
- No major grid reinforcement, and in particular the “potential 225 kV reinforcement” is not taken into account
- Current limits for the intensity in the lines
- The power output of the onshore wind farms is assumed constant at 20% of the total capacity
- The offshore wind farms in northern Brittany are connected according to scenario 1, i.e.
- 350 MW in “La Rance” and “200 MW” in “Trégueux”

The load follows a typical load duration curve between 20000 MW and 11000 MW, which are respectively the estimated maximal and minimal load expected in winter 2020, while the power output of the offshore wind farms follows the duration curve estimated in figure 4-8. In table 4-16, the maximal loadings are calculated based on the assumptions the load is at its maximal level (20000 MW), while the farms do not generate anything.

Problems of line overload under the “N-1 assumption” occur only when the load is above 17000 MW. In order to calculate the expected overload time, the range of the load between 17000 MW and 20000MW has been divided into six equal parts of 500 MW each. For each of these parts, represented by a mean load (for example, 17250 MW for the part “17000 MW - 17500 MW”), the critical load factor of the offshore wind farms is determined for each major fault and each potentially overloaded line, i.e. the minimal load factor necessary to avoid the overload of the line when the fault occurs. For instance, the results for one specific fault (on the line “DOMLOUP” - “PLAINE HAUTE”) and one specific overloaded line (“LAUNAY” - “LA RANCE”) are displayed in table 7-2:
<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
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<tr>
<td>Range of the load</td>
<td>Representative load</td>
<td>Hours per winter of such load (in 2020)</td>
<td>Expected overload time (hours)</td>
<td>Critical load factor for offshore wind farms</td>
<td>Probability that the critical load factor is exceeded</td>
<td>Expected overload time (hours) With offshore wind farms</td>
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<td>16500 - 17000 MW</td>
<td>16750 MW</td>
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<td>0%</td>
<td>100%</td>
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<td>19%</td>
<td>70%</td>
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<td>17500 - 18000 MW</td>
<td>17750 MW</td>
<td>320</td>
<td>3,2</td>
<td>37%</td>
<td>56%</td>
<td>1,408</td>
</tr>
<tr>
<td>18000 - 18500 MW</td>
<td>18250 MW</td>
<td>160</td>
<td>1,6</td>
<td>54%</td>
<td>46%</td>
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<td>18500 - 19000 MW</td>
<td>18750 MW</td>
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<td>65%</td>
<td>41%</td>
<td>0,531</td>
</tr>
<tr>
<td>19000 - 19500 MW</td>
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<td>78%</td>
<td>33%</td>
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<td>18%</td>
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</tr>
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<td>1650</td>
<td>11</td>
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<td>4,63</td>
</tr>
</tbody>
</table>

Table 7-1 Expected overload time of a specific line for a specific fault in winter