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Lightning Damage of OWECS

Part 3: “Case Studies”

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1. INTRODUCTION

1.1 Background

Lightning is a phenomenon that has often caused severe damage to wind turbines. Direct hits may cause for instance structural failure of the blades, whereas indirect hits, e.g. through the electrical infrastructure in the wind farm, may cause damage to vulnerable parts like the controller.

For onshore turbines, a lot of knowledge has been gained on the effects of lightning. The knowledge has been gained by analysing field experience and by R&D activities. Based on this, recommendations and practical guidelines have been developed on how to prevent the turbines from severe damage due to lightning strikes, e.g. [1] and [2]. In [1], a method is presented to determine the risk of lightning for wind turbines. The risk is expressed as the product of the number of lightning strikes times the consequence damage. The consequence damage is partly determined by the lightning protection method for the various components [1]. A method to compare the extra investments for lightning protection with the reduced consequence damage is given in [1].

Statistics on damage due to lightning strikes are given in e.g. [1] and [3]. Some major conclusions presented in [3] are given below.

- In total 914 lightning damages have been reported over 11,364 operational years, which corresponds to 8 incidents per 100 turbine years[1].
- Approximately 25% was reported as a direct lightning strike.
- The 914 lightning damages represent approximately 4% of the total number of reported damages.
- The average downtime per damage is approximately 30 hours.
- The rotor blades seem to be the most vulnerable components. They show the highest frequency, the highest repair costs (approximately € 20.000,-- per incident for turbines above 450 kW), and the longest downtime (approximately 10 days per incident).
- As compared to smaller turbines, the larger and newer turbines show fewer failures in the control system. This suggests that the lightning protection of control systems has improved in recent years.

Presently, plans are being developed in Europe to develop large offshore wind farms. It is to be expected that damage due to lightning may influence the cost effectiveness of such wind farms to a large extent for the following reasons.

1. Costs for repairing lightning damage are higher offshore than onshore, because more expensive transportation equipment (supply vessels or helicopters) and cranes are needed.
2. The downtime for certain damage events and thus the revenue losses will be higher because repair can only be carried out if the weather conditions are suitable for the equipment.

Before developing an offshore wind farm, it is necessary to gain insight in the effects of lightning on the operational costs. To calculate the costs due to lightning damage one has to deal with inherent variability and with statistical uncertainty in the input variables. Inherent variability is a result of the physical process and it can not be reduced; examples are the wind speed, the wave height, the number of lightning flashes during a thunderstorm and the type and amount of damage due a lightning strike. Statistical uncertainty is caused by lack of knowledge about the parameters, and sometimes it can be reduced through further measurements or study, or through consulting more experts. The total uncertainty, which is a combination of inherent variability and statistical uncertainty, results in uncertainty in the calculated results, in this case the total costs. For financiers and insurance companies these uncertainties are considered as a financial risks, which is a complicating factor for financing offshore wind projects.

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[1] Danish and Swedish databases report 3.9 and 5.8 incidents per 100 turbine years [1].

Quantification of the expected uncertainties facilitates the judgement of this risk and is therefore of great importance.

Recently, one of the two offshore turbines in Blyth Harbour has failed. According to the press release [8], a lightning strike was the failure cause. As expected, the repair costs and downtime are high and difficult to estimate. (See Fig. 1.1.)

Fig. 1.1: *Blade failure of an offshore wind turbine in Blyth Harbour (UK) due to a lightning strike [8,9]*

Aspects that contribute to the cost of lightning damage and which are covered with uncertainties are among others the following:

1. The frequency of thunderstorms and lightning flashes at an offshore location.
2. The amount of damage resulting from a lightning strike (which is strongly dependent on the lightning protection of the turbine) and the material costs.
3. The actions needed to repair the damage, including costs for personnel and hiring transportation and lifting equipment.
4. The downtime and revenue losses due to time needed for mobilisation of necessary equipment and time waiting for good weather conditions.

1.2 The Project: “Cost Modelling of Lightning Damage for Offshore Wind Farms”

In order to obtain a better understanding of the costs resulting from lightning damages, ECN has defined the project “Cost Modelling of Lightning Damage for Offshore Wind Farms”. The objectives of this project are threefold:

1. Data Collection

Above, four aspects have been mentioned that contribute to the costs of lightning damage and which are covered with (large) uncertainty or variability.

Parameters with inherent variability, are for instance the frequency of thunderstorms per year, the frequency of lightning flashes per thunderstorm, the current value per lightning flash, the wind speed and the wave height. Such parameters all have their own natural scatter: the number of thunderstorms differs from year to year. This variation can be described by means of statistical distribution functions, for instance a Weibull distribution for the wind speed distribution or a Poisson distribution for the number of thunderstorms in a year. These distribution functions are characterised by one or two statistical parameters. The Weibull distribution has two parameters: the shape parameter and the scale parameter. In order to quantify these statistical parameters, it is necessary to perform measurements over a certain period of time and the longer the measurement period, the more accurate they can be determined including the variability. If desired the variability in the statistical parameters can be dealt with by considering these parameters as stochastic quantities.

Furthermore one has to deal with parameters which are uncertain due to lack of knowledge, for instance the costs of equipment and the availability of equipment. Two types of uncertainty can be distinguished.

1. In case data is derived from generic databases or other generic sources a large amount of scatter might be expected, because information originating from different situations is combined. However, quite often no specific data is available and it is inevitable to use generic data, for instance the types of damage caused by lightning that might be expected.
2. The cost model is mainly applicable for offshore wind farms. However, at the moment only limited or no experience is present with maintaining offshore wind turbines. This implies that experts from the onshore wind industry and experts from offshore maintenance companies have to be consulted. For instance the availability and the costs of equipment are strongly dependent on the contracts. The costs will be different if e.g. a supplier is hired for one day or for a longer period. The costs can be derived from investigating the current market prices and by estimating the upper and lower day rates. However, different experts have different opinions and consequently the estimates are covered with uncertainty. Characteristic for this type of uncertainty is that it can be reduced through feed back of operational experience.

The first objective of this project is to make an inventory of all relevant variables that contribute to the costs and to parameterise them. Not only the most likely values have been determined but if necessary also the scatter and the distribution function. In [4] a description is given of the parameterisation of the relevant variables, a.o.:

- annual frequency of thunderstorms and lightning flashes for offshore locations;
- expected damage distribution due to lightning;
- wind and wave statistics to determine the accessibility of repair equipment and for calculating the revenue losses;
- costs and weather windows for repair equipment, e.g. supply vessels, helicopters and jack-ups;
- costs of labour and of components and materials to repair lightning damages;
- investment costs for lightning protection systems.

2. Development of Probabilistic Cost Model

The scatter and uncertainty of most variables will lead to scatter in the annual costs for lightning damage and the annual downtime. To evaluate the effect of lightning damage on the annual costs and downtime it is necessary to use a probabilistic model. The second objective of the project is to develop such a model. The model has been implemented in MS Excel with the add-in module @Risk [5] to perform probabilistic calculations. With such model, the annual costs and downtime are not only expressed as fixed values. The program provides additional information like the probability that the annual costs will become higher than a certain value. A description of the model can be found in [6].

3. Case Studies and General Conclusions

With the probabilistic model, certain wind farm configurations on various offshore locations can be analysed. The annual costs and downtime can be determined and the influence of e.g. a repair strategy, the size of the turbine and the wind farm, and the effect of lightning protection can be investigated. In total six wind farm configurations have been defined for which sensitivity studies have been performed, see Table 1.1.

The third objective of the project is to draw general conclusions and recommendations from the case studies in order to:

- estimate the annual costs and downtimes due to lightning damage;
- determine the most important cost drivers;
- assess the influence and importance of certain aspects like the offshore location, the repair strategy, the lay-out of the wind farm, etc. on the costs and downtimes;
- derive guidelines on the amount of money that should be spend on lightning protection;
- identify which uncertainty contributes the most to the uncertainty in the outcome of the calculations.

The case studies and the conclusions are the subjects of the present report.

Table 1.1: *Overview of wind farm configurations considered in the case studies*

Near shore (12 km offshore)	**Near shore (30 km offshore)**	**Far offshore (300 km offshore)**
	67 * 1,5 MW turbines	
34 * 3,0 MW turbines	34 * 3,0 MW turbines	
	17 * 6,0 MW turbines, orientated east - west	17 * 6,0 MW turbines
	17 * 6,0 MW turbines, orientated north - south	

1.3 Case Studies

With the probabilistic cost model developed within the current project several analyses have been made for the wind farm configurations summarised in Table 1.1 (case studies). The main objective of these case studies is to draw conclusions and to formulate recommendations with respect to lightning damage in offshore wind turbines as outlined in section 1.2. The approach followed to reach this objective is described in detail in chapter 2 together with the default data for the case studies.

For each configuration the annual costs and downtime due to lightning have been calculated for the default configuration. Mutual comparison of the analyses provide information concerning the influence of the location and the wind farm lay-out. The results of these analyses are presented in chapter 3 and 4.

Furthermore, for the wind farm 30 km offshore with 34 wind turbines several analyses have been made with different maintenance strategies and with different protection levels. The results of these analyses are presented in chapter 5 and 6.

Finally the configuration at 30 km offshore with 34 wind turbines was considered in more detail in chapter 7. These results give more insight in the most important cost drivers and the importance of the uncertainty in the input variables.

The conclusions and recommendations based on the results of the case studies are given in chapter 8.

2. GENERAL DESCRIPTION OF CASE STUDIES

2.1 Approach

Damage due to lightning may influence the cost effectiveness of large offshore wind farms significantly. However for the calculation of these costs a lot of data has to be processed and one has to deal with inherent variability and with statistical uncertainty in the input variables. Inherent variability is a result of the physical process and it can not be reduced; examples are the wind speed, the wave height, the number of lightning flashes during a thunderstorm and the type and amount of damage due a lightning strike. Statistical uncertainty is caused by lack of knowledge about the parameters, and sometimes it can be reduced through further measurements or study. To determine the effects of lightning damage on the operational costs a cost model has been developed [4,6]. This cost model is able to deal with the uncertainties in the input parameters so that it provides possibilities to quantify the uncertainties in the calculated costs per year.

With this cost model a number of case studies has been carried out with the aim to draw general conclusions and recommendations with respect to:

- the expected annual costs and downtime;
- the most important cost drivers;
- the influence and importance of certain aspects, such as the location of the wind farm, the lay-out of the wind farm and the repair strategy;
- the cost effectiveness of lightning protection systems;
- which uncertainty contributes the most to the uncertainty in the outcome of the calculations.

The number of thunderstorms per year and the number of lightning flashes are not constant over the North Sea but vary from one place to another [4]. There is a trend that lightning becomes less severe when going further offshore. Not only the number of lightning storms are less for far offshore locations, but also the number of lightning flashes per thunderstorm becomes smaller. Furthermore the time needed to travel to a wind farm varies with the distance from the coast, and consequently the cost of equipment and the downtime will be location dependent. To study the influence of the location three different locations at the North Sea were considered, viz. (see Fig. 2.1.1):

- a near shore location at 12 km from the coast (denoted as NS1);
- a near shore location at 30 km from the coast (denoted as NS2);
- and a location far offshore at 300 km from the Dutch coast, the Doggerbank (denoted as FO).

Furthermore, to consider the influence of the wind farm layout and the height of the wind turbines, three different park lay-outs were considered, with wind turbines representative for 1,5 MW, 3 MW and 6 MW turbines. These wind farms are denoted by WF_1.5, WF_3.0 and WF_6.0 respectively. The wind farms denoted with WF_1.5 and WF_3.0 have an almost rectangular shape, while WF_6.0 has a more elongated shape. To study the orientation effects on the lightning frequency the wind farm WF_6.0 at 30 km offshore was considered with the rows in north south direction (denoted with NS2-WF_6.0NS) and with the rows in east west direction (denoted with NS2-WF_6.0EW). The number of turbines was chosen, such that the total amount of installed power is about 100 MW.

Table 2.1.1 gives an overview of the configurations and the names of the configurations for which costs analyses have been made.

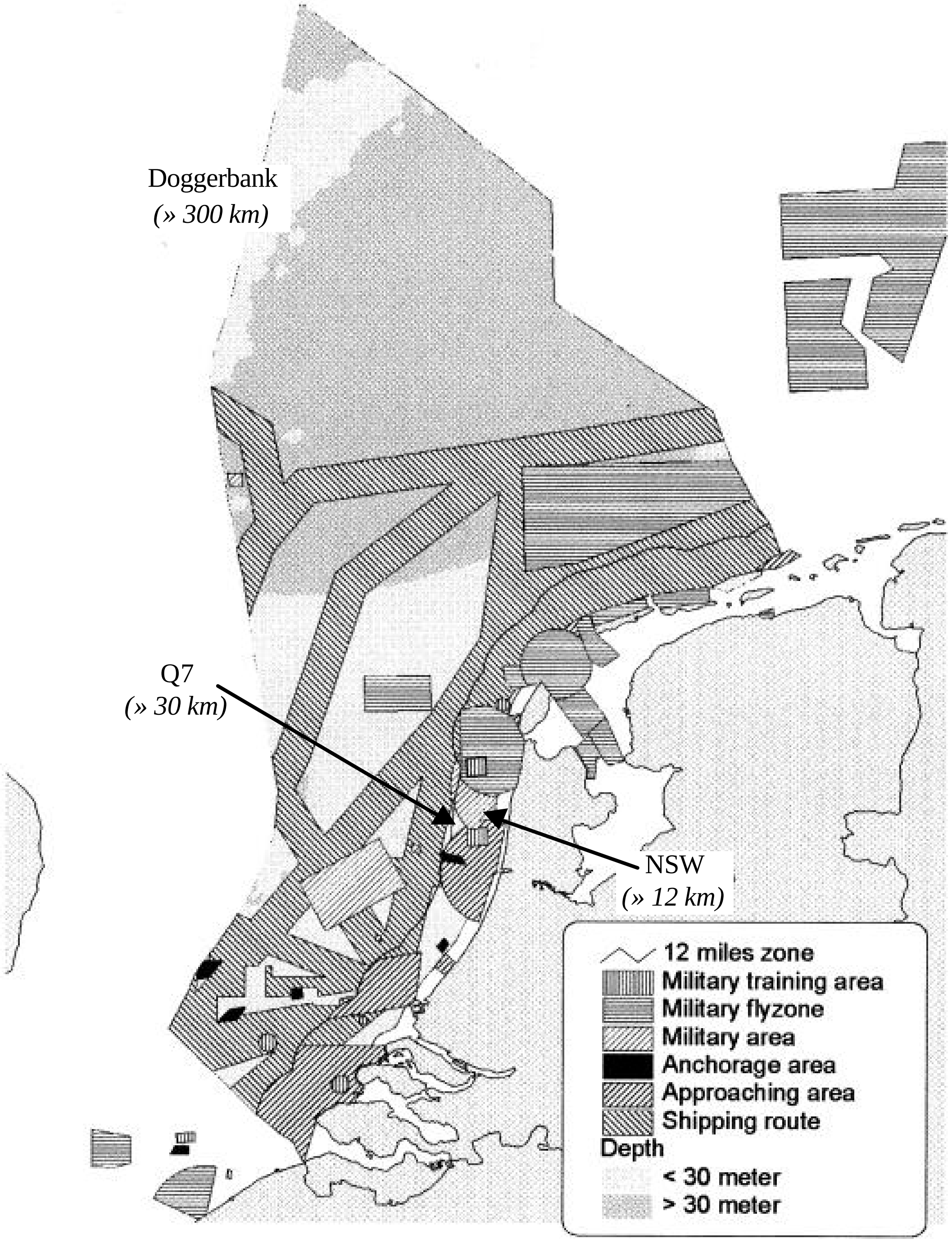

Fig. 2.1.1: *Locations*

For all the configurations summarised in Table 2.1.1 the yearly costs and yearly downtime due to lightning has been calculated, where the following assumptions were made.

- The weather windows for the equipment were calculated using the wind and wave data published by Rijkswaterstaat for the location "IJmuiden Munitiestortplaats" [10].
- The revenue losses were based on the wind data provided by Rijkswaterstaat for the location "IJmuiden Munitiestortplaats" [10].
- The lightning frequency is based on the measurements for the locations considered (see section 2.3).
- The maintenance is done according to a "standard" strategy defined for each type of wind turbine (see section 2.4).

- The wind turbines were equipped with standard protection systems (see section 2.5).

The influence of the location can now be obtained by comparison of the configurations NS1_WF3.0 and NS2-WF3.0 and by comparison of the configurations NS2-WF_6.0EW, NS2-WF_6.0NS and FO-WF6.0. Furthermore the four wind farms defined for the near shore location at 30 km (NS2) are used to draw conclusions concerning the influence of the wind farm lay out. The results of these analyses are presented in chapter 3.

For the wind farm at near shore location 2 with 34 wind turbines with a rated power of 3.0 MW (NS2-WF_3.0) several analyses have been made with different maintenance strategies and with different protection levels. The results of these analyses are presented in chapter 4 and 5.

Finally the standard configuration NS2-WF_3.0 was considered in more detail in chapter 6. These results give more insight in the most important cost drivers and the importance of the uncertainty in the input variables.

Table 2.1.1: *Overview of configurations*

Wind farm lay-out	**Location**		
	Near shore 1 at 12 km	**Near shore 2 at 30 km**	**Far offshore at 300 km**
WF_1.5		NS2-WF_1.5	
WF_3.0	NS1-WF_3.0	***NS2-WF_3.0***	
WF_6.0EW		NS2-WF_6.0EW	FO-WF_6.0
WF_6.0NS		NS2-WF_6.0NS	

2.2 Wind farm and wind turbine configuration

To investigate the influence of the location of the park and the lay-out of the farm six different configuration have been defined, which are specified in Table 2.1.1. The characteristic values of the wind farms and the wind turbines are summarised in Table 2.2.1 [4].

Table 2.2.1: *Wind farm and wind turbine characteristics*.

Name wind farm	**WF_1.5**	**WF_3.0**	**WF_6.0**
Number of wind turbines	67	34	17
Rated power of wind turbine [MW]	1.5	3.0	6.0
Rotor diameter [m]	70	90	120
Height of nacelle above water level [m]	55	70	80
Max. height of tip above water level [m]	90	115	140
Wind farm layout	10 rows	5 rows	3 rows
Distance between wind turbines [m]	400	500	650
Distance between rows [m]	550	700	900
Size [km x km]	3.6 x 3.3	3.0 x 2.8	3.25 x 1.8
Collection area [km^2]	13.1	10.8	8.4

The statistics on lightning frequency for the selected configurations is given in Table 2.2.2 [4].

Table 2.2.2: *Lightning data*

Configuration	Number of thunderstorms per year		Number of lightning strikes per thunderstorm	
	mean	standard deviation	mean	standard deviation
NS1-WF_3.0	2.67	0.44	2.19	0.23
NS2-WF_1.5	2.67	0.24	1.75	0.10
NS2-WF_3.0	2.67	0.24	1.69	0.07
NS2-WF_6.0NS	1.83	0.16	1.55	0.06
NS2-WF_6.0EW	2.17	0.23	1.54	0.07
FO-WF_6.0	1.5	0.15	1.5	0.05

The distribution of thunderstorms over the year is given in Table 2.2.3

Three different types of wind turbines have been considered. These wind turbines considered are generic wind turbines representative for 1.5 MW, 3.0 MW and 6 MW wind turbines. For the calculation of the revenue losses the *P-V* curves depicted in Fig. 2.2.1 are used. Furthermore, the Weibull parameters for the wind speed distribution are based on the data provided by Rijkswaterstaat for the location “IJmuiden munitiestortplaats” [10] and are given in Table 2.2.3 [4].

Table 2.2.3: *Lightning and wind data*.

Season	Lightning	Weibull parameters wind speed distribution	
	Percentage of thunderstorms	Shape parameter [-]	Scale parameter [m/s]
Winter	6 %	1.97	9.23
Spring	6 %	2.09	7.71
Summer	54 %	2.10	7.33
Autumn	34 %	1.85	8.22

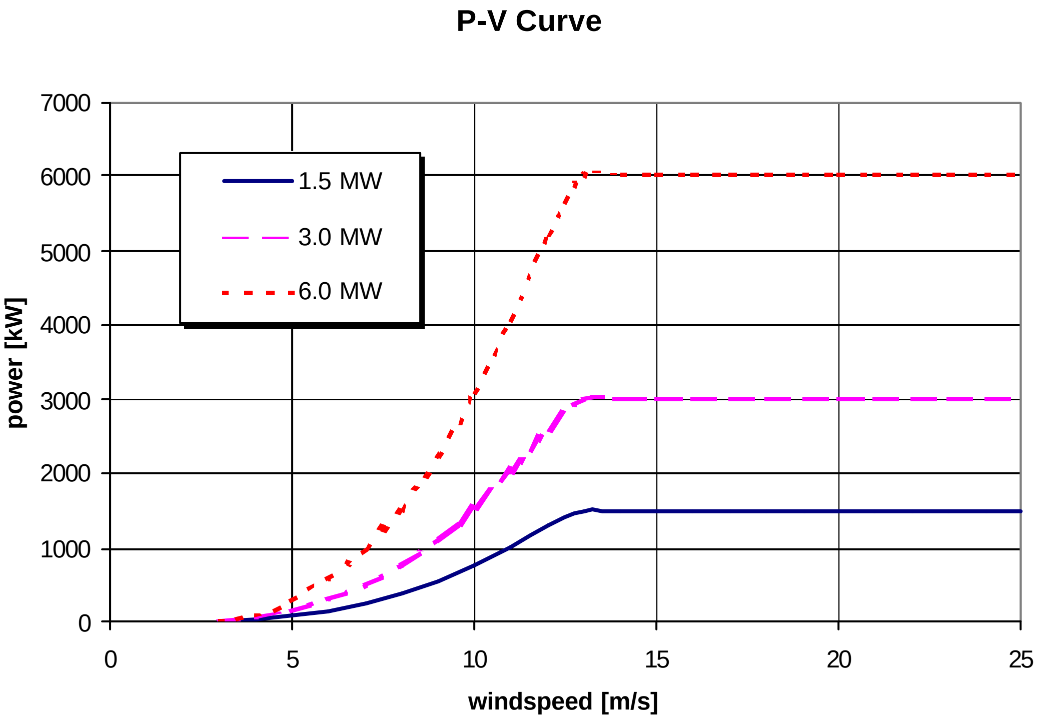

Fig. 2.2.1: *P-V curves for the generic wind turbines of 1.5 MW, 3.0 MW and 6.0 MW.*

The main difference between these three types of wind turbines is their rated power and the way they are designed for maintainability. This latter aspect is addressed in section 2.4. The structural breakdown is assumed to be consistent with the categorisation of the faults in the WMEP database of ISET. Consequently the distribution of faults reported by ISET is used, see Table 2.2.4. Although protection systems were present in some of the turbines of the ISET database, it is assumed that the presented fault distribution gives the probability that a certain type of damage will occur in a wind turbine without any protection system. The reason for this is that it was not possible to distinguish between turbines with and turbines without protection systems. This implies that the assessment of the damage in the cost model might be conservative. The presence of protection systems is accounted for in the cost model, so that the relative influence of protection system can be quantified (see section 2.3).

Table 2.2.4: *Distribution of faults for wind turbine without protection systems.*
FTC1 : Repair, cleaning, reset
FTC2 : Replacement, hoisting inside
FTC3 : Replacement, hoisting outside

component	Fault Type Class (FTC)			Total
	1	2	3	
control system	21.0 %	9.0%		30.0%
electric	10.5 %	13.2 %	2.6 %	26.3%
rotor blades	8.0 %		11.9 %	19.9%
sensors	12.8 %			12.8%
generator	2.1 %	0.6 %	0.3 %	3.0%
hub	1.6 %	0.4 %	0.2 %	2.2%
hydraulic system	0.3 %	1.4 %		1.7%
yaw system	0.2 %	1.0 %		1.2%
gear box	0.2 %	0.7 %	0.1%	1.0%
mechanical brake	0.2 %	0.7 %		0.9%
drive train	0.1 %	0.4 %	0.1%	0.6%
structural parts	0.1 %	0.1%	0.3 %	0.5%

Finally, the kWh price of the produced electricity is 0.06 € and the investment costs all three types of wind turbines is assumed to be 850 €/kW.

2.3 Lightning protection

The initial fault distribution presented in Table 2.2.4 is assumed to be valid for wind turbines without any protection system. The influence of the presence of a protection system is considered in chapter 5. In the analyses presented in the other chapters it is assumed that for all three fault type classes of the electrical system and the control system, of the sensors and of the blades the protection level is 90 %, with the exception of FTC1 of the rotor blades. FTC 1 for rotor blades includes the damage at or near the receptors in the blade and this type of damage is the result of the protection system itself and can not be avoided. It has therefore been set to zero. The efficiency of the standard protection system is summarised in Table 2.3.1.

A protection level of 90 % means that there is a probability of 90 % that the damage for a certain fault type class can be avoided by the use of a protection system. In other words, only 10% of the lightning strikes that hit the turbine will lead to damage of that specific component.

Table 2.3.1: *Efficiency of standard protection system*

component	Fault Type Class (FTC)		
	1	2	3
control system	90 %	90 %	90 %
electric	90 %	90 %	90 %
rotor blades	0 %	90 %	90 %
sensors	90 %	90 %	90 %
generator	-	-	-
hub	-	-	-
hydraulic system	-	-	-
yaw system	-	-	-
gear box	-	-	-
mechanical brake	-	-	-
drive train	-	-	-
structural parts	-	-	-

2.4 Maintenance strategy

In the case study three generic wind turbines, representative for 1.5 MW, 3.0 MW and 6 MW wind turbines have been considered. The 3.0 MW turbine and the 6.0 MW turbine have an identical design for maintainability. These turbines are equipped with large internal cranes that can hoist all components, which have to be replaced. The 1,5 MW turbine does also have an internal crane, but this crane can only hoist medium sized components. For heavy components an external crane is needed. In the case study it is assumed that the maintenance for the near shore wind farms is done from onshore, the helicopters leave from an airport and the suppliers leave from a harbour. The far offshore location is equipped with a substation from which the suppliers do leave. The helicopter still comes from the airport.

In chapter 5, different repair strategies have been considered. The other analyses are based on the standard repair strategy, which is outlined below. All relevant data for the fault type classes can be found in [4]; the relevant data for the equipment are given in Table 2.4.1.

Inspection

For all three types of wind turbines the inspection is done with the help of a helicopter. In case more than one turbine has to be inspected more crews are transported at the same time, so that all inspections can be done simultaneously, while the helicopter does return to base. After completion of the inspections the helicopter flies back to the wind farm to pick up the inspection teams.

During inspection small repairs will be carried out. The probability whether this can be done is dependent on the Fault Type Class. In the case studies the numbers given in table 2.4.2 are used.

Table 2.4.1: *Data of equipment*

INPUT DATA

NEAR SHORE 1 at 12 KM

Nr	Desription	Weather window	T logistic equip. [hr]			T travel (+access) Near shore (12 km) [hr]			Cost equipment for mission (MOB/DEMOB) and travel [Euro]			Cost equipment during waiting and repair period [Euro/unit]			
			min	ML	max	min	ML	max	min	ML	max	min	ML	max	unit 0: hr 1: day
2	Supplier with MOB	11	0.4	0.5	0.7	1.5	2.0	2.8	3,300	4,400	6,160	6,800	8,800	13,600	1
3	Supplier with OAS	10	0.4	0.5	0.7	1.5	2.0	2.8	3,300	4,400	6,160	8,000	8,800	10,400	1
4	Helicopter	2	1.0	2.0	4.0	0.4	0.5	0.6	3,300	4,150	5,750	3,400	3,750	4,100	0
5	Pontoon with tug	6	36.0	48.0	72.0	5.0	6.0	7.0	19,000	22,200	25,400	8,000	8,800	9,600	1
6	Jack-up with crane (positioning)	4	36.0	48.0	72.0	20.0	24.0	36.0	154,000	176,800	235,200	11,200	12,800	16,000	1
7	Jack-up with crane (operation)	1	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0	11,200	12,800	16,000	1

NEAR SHORE 2 at 30 KM

Nr	Desription	Weather window	T logistic equip. [hr]			T travel (+access) Near shore (30 km) [hr]			Cost equipment for mission (MOB/DEMOB) and travel [Euro]			Cost equipment during waiting and repair period [Euro/unit]			
			min	ML	max	min	ML	max	min	ML	max	min	ML	max	unit 0: hr 1: day
2	Supplier with MOB	11	0.4	0.5	0.7	3.0	4.0	5.6	6,600	8,800	12,320	6,800	8,800	13,600	1
3	Supplier with OAS	10	0.4	0.5	0.7	3.0	4.0	5.6	6,600	8,800	12,320	8,000	8,800	10,400	1
4	Helicopter	2	1.0	2.0	4.0	0.8	0.9	1.2	6,300	7,525	10,250	3,400	3,750	4,100	0
5	Pontoon with tug	6	36.0	48.0	72.0	10.0	12.0	14.0	30,000	35,400	40,800	8,000	8,800	9,600	1
6	Jack-up with crane (positioning)	4	36.0	48.0	72.0	40.0	48.0	72.0	218,000	253,600	350,400	11,200	12,800	16,000	1
7	Jack-up with crane (operation)	1	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0	11,200	12,800	16,000	1

FAR OFFSHORE

Nr	Desription	Weather window	T logistic equip. [hr]			T travel (+access) Far offshore (300 km) Sub station available [hr]			Cost equipment for mission (MOB/DEMOB) and travel [Euro]			Cost equipment during waiting and repair period [Euro/unit]			
			min	ML	max	min	ML	max	min	ML	max	min	ML	max	unit 0: hr 1: day
2	Supplier with MOB	11	0.4	0.5	0.7	0.8	1.0	1.3	1,760	2,200	2,860	6,800	8,800	13,600	1
3	Supplier with OAS	10	0.4	0.5	0.7	0.8	1.0	1.3	1,760	2,200	2,860	8,000	8,800	10,400	1
4	Helicopter	2	1.0	2.0	4.0	2.7	3.0	3.6	20,550	23,275	28,250	3,400	3,750	4,100	0
5	Pontoon with tug	6	36.0	48.0	72.0	30.0	36.0	48.0	74,000	88,200	115,600	8,000	8,800	9,600	1
6	Jack-up with crane (positioning)	4	36.0	48.0	72.0	36.0	42.0	54.0	205,200	234,400	292,800	11,200	12,800	16,000	1
7	Jack-up with crane (operation)	1	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0	11,200	12,800	16,000	1

Table 2.4.2: Efficiency of inspection w.r.t. repair.

Fault type class		Probability that repair can be done during inspection
1	Repair, Cleaning, Reset	100 %
2	Replacement hoisting inside	20 %
3	Replacement hoisting outside	0 %

Frequency of damage

In this study it is assumed that each lightning strike that hits a wind turbine without any protection system will cause damage. The frequency distribution of this initial damage is summarised in Table 2.2.4. When a wind turbine is equipped with a protection system the number of damages will decrease. The efficiency of the standard protection system (see section 2.3) is not the same for all components, hence the initial damage distribution will change. The fault distribution for a wind turbine equipped with the standard protection system is given in Table 2.4.3. For reasons of comparison the initial fault distribution is represented also. During the inspection small repairs will be carried out, so that the total number of actual repair actions is reduced further. The distribution damages still present after inspection is given in Table 2.4.3.

This distribution is the starting point for the calculation of the downtime and costs for repair. In Table 2.4.3 the distribution over the Fault Type Classes (FTC) is given also.

Table 2.4.3: *Distribution of damage*

Component	Initial damage distribution	Damage distribution with protection	Damage distribution after inspection
control system	30.0%	3.0%	0.7%
electric	26.3%	2.6%	1.3%
rotor blades	19.9%	9.2%	1.2%
sensors	12.8%	1.3%	0.0%
generator	3.0%	3.0%	0.8%
hub	2.2%	2.2%	0.6%
hydraulic system	1.7%	1.7%	1.1%
yaw system	1.2%	1.2%	0.8%
gear box	1.0%	1.0%	0.7%
mechanical brake	0.9%	0.9%	0.6%
drive train	0.6%	0.6%	0.4%
structural parts	0.5%	0.5%	0.4%
No Failure	0.0%	72.9%	91.7%
TOTAL	100%	100%	100%
FTC1	57.1%	17.2%	0.0%
FTC2	27.5%	7.5%	6.0%
FTC3	15.6%	2.4%	2.4%
No Failure	0.0%	72.9%	91.7%
TOTAL	100%	100%	100%

Repair of 1.5 MW wind turbine

The transportation of personnel and spare parts is done using a supplier with MOB. As the 1.5 MW is not equipped with an internal crane for heavy components, a jack-up is used for the replacement of the following components:

- blades;
- hub;
- generator;
- drive train;
- large structural parts for which outside hoisting is required.

These faults are classified as FTC 3. The blades and the large structural parts are not transported by the supplier but by a pontoon.

Repair of 1.5 MW and 6.0 MW wind turbine

For all types of faults a helicopter or a supplier with MOB is used for transportation of personnel and components. The choice between helicopter and supplier depends on the type of component and the failure type classes, and is specified in Table 2.4.4. For the replacement of large structural parts in the nacelle the internal crane is not applicable and a jack-up is used (FTC 3 of large structural parts). For the transportation of blades and of large structural parts a pontoon is used.

It should be noticed that the use of an internal crane for hoisting outside could be restricted due to bad weather condition. It is assumed that outside hoisting is possible only in case the wind speed is less than 6 m/s. In the costs model this aspect is taken into account by defining an new equipment “external hoisting”, which is only used during the repair.

Table 2.4.4: *Application of equipment for standard maintenance strategy.*
H : helicopter;
S : supplier with MOB.
P : pontoon with tug
J : jack-up with crane

component	1.5 MW			3.0 MW, 6.0 MW		
	Fault Type Class (FTC)			Fault Type Class (FTC)		
	1	2	3	1	2	3
control system	S	S	S	H	H	H
electric	S	S	S	H	H	S
rotor blades	S	S	S+P+J	H	H	S+P
sensors	S	S	S	H	H	H
generator	S	S	S+J	H	H	S
hub	S	S	S+J	H	H	S
hydraulic system	S	S	S	H	H	S
yaw system	S	S	S	H	H	S
gear box	S	S	S+J	H	H	S
mechanical brake	S	S	S	H	H	H
drive train	S	S	S+J	H	H	S
structural parts	S	S	S+P+J	H	S	S+P+J

2.5 Accessibility

In the present case study it is assumed that a wind turbine that is hit by lightning will be shut down all the time. In case the lightning strike did not cause any damage or only minor damage, the wind turbine can be restarted immediately after inspection. In the remaining situations a maintenance action is started after the inspection and the wind turbine will not be restarted until it has been repaired (see fig. 2.1 of [6]). The period of time between the moment the turbine is stopped and the moment it is available for production again is called the Time To Repair (TTR). The TTR due to repair can be split up in several phases as shown in Fig. 2.4.1 [4]. It should be noted that in case of lightning the scheme depicted in Fig. 2.4.1 is preceded by an inspection phase. During the inspection phase a failure of the wind turbine is detected and an inspection is made. For an inspection the same aspects have to be considered as shown in Fig. 2.4.1. Arrangements of personnel and device have to be made. The inspection crew has to travel to the turbine and has to carry out the inspection. For reasons of simplicity the inspection phase has been omitted in this figure, but it has been included in the cost model [6].

<table>
<tr><th colspan="4"><i>Time To Repair (TTR)</i></th></tr>
<tr><td rowspan="2"><i>T_logistics</i></td><td rowspan="2"><i>T_wait</i></td><td colspan="2"><i>T_mission</i></td></tr>
<tr><td><i>T_travel</i></td><td><i>T_repair</i></td></tr>
<tr><td>Arrangement of device, personnel and spare parts</td><td>Waiting due to bad weather conditions</td><td>Trip to failed WT</td><td>Repair of WT</td></tr>
</table>

Fig. 2.5.1: *Phases during time to repair.*

The period *T_wait* denotes the period of time during which the device needed for inspection or repair is available for take off, but is not allowed to leave because of expected bad weather conditions. Each device has its own requirements for the maximum allowable wave height H_{max} and the maximum allowable wind speed V_{max} during the mission. For the devices used in the case study these maximum allowable values are given in Table 2.4.1 [4].

Table 2.5.1: *Maximum values for wave height and wind speed*.

Nr	Desription	H_{max}	V_{max}
		m	m/s
1	Supplier with zodiac	0.50	6.0
2	Supplier with MOB	1.00	12.0
3	Supplier with OAS	2.00	12.0
4	Helicopter	-	15.0
5	Pontoon with tug	1.00	6.0
6	Jack-up with crane (positioning)	0.50	6.0
7	Jack-up with crane (operation)	-	6.0

This period *T_wait* is of special interest for the cost calculation for two reasons. First of all during this period the turbine is shut down and will not produce electricity, so one has to deal with revenue losses. Second, it might happen that the device needed has been ordered and is waiting for better weather conditions. Depending on the contract one has to pay for the device during this waiting time.

In [6] it is outlined how the calculation of *T_wait* is done in the cost model. To illustrate the stochastic nature of *T_wait* the cumulative distribution function (CDF) of *T_wait* has been calculated for a number of different types of equipment, for a number of different values of *T_mission*, and for different seasons. The results are depicted in Fig. 2.5.2 – 2.5.5 and will be clarified below. These results are based on the wind and wave data provided by Rijkswaterstaat for the location "IJmuiden munitiestortplaats" [10].

Fig. 2.5.2 shows the CDF of *T_wait* for different devices (helicopter, supplier with OAS, supplier with MOB and a pontoon), where it assumed that the duration of the mission is 8 hours. The failure does occur in the winter season. From this figure it can be seen that a supplier with MOB can leave only immediately in about 24% of the situations and there is probability of 40% that this device has to wait for more than 100 hours. A helicopter can leave immediately in 87% of the situations and the probability that one has to wait for more than 24 hours is about 2%. So if the work can be done with both types of equipment the helicopter has to be preferred in case one wants to reduce the total downtime. Whether this is also true from an economical point of view depends on the costs, which may differ significantly. Fig. 2.5.3 shows similar results as Fig. 2.5.2 for the summer season. As expected the accessibility in the summer is much better than in the other seasons.

The influence of the duration of the mission on the waiting time is shown in Fig. 2.5.4. In this figure waiting times for a pontoon during the winter season are given for a number of values of *T_mission*. It is clear that the downtime can be become very high if a pontoon it needed for a longer period, f.i. 120 hours (5 days).

The influence of the season on the accessibility of a pontoon for a mission of 24 hours is depicted in Fig. 2.5.5. The results for spring and autumn are comparable, while the accessibility is better during summer and worse during winter. In winter the probability that one has to wait for more than 200 hours is about 55%, while in summer this is reduced to about 27%.

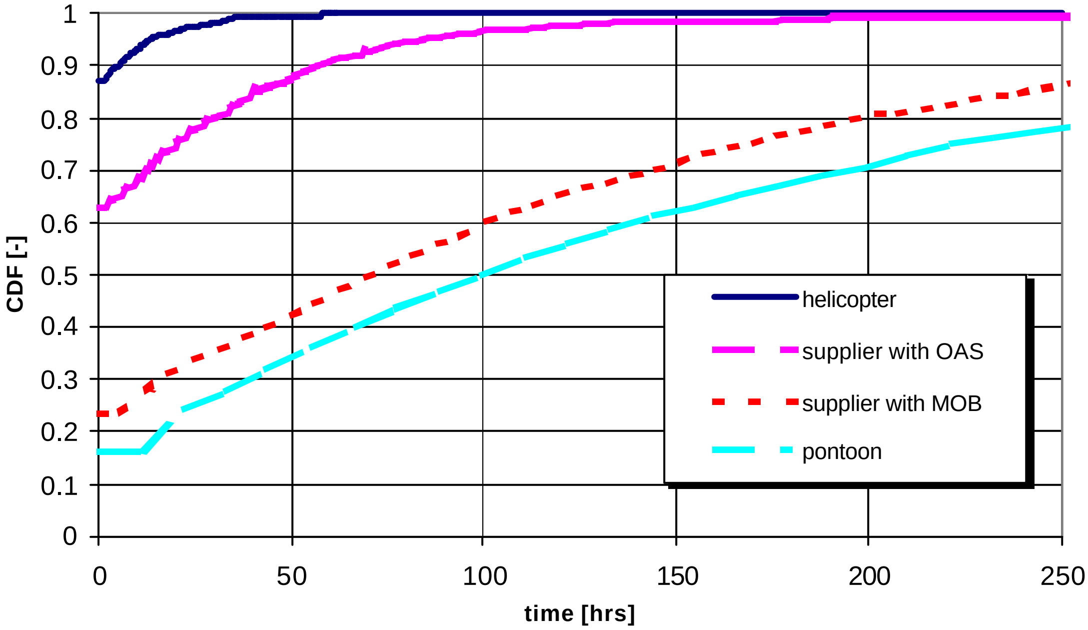

Fig. 2.5.2: *Cumulative Distribution Function (CDF) of waiting time during winter period for different types of equipment. Total duration of the mission is 8 hours*.

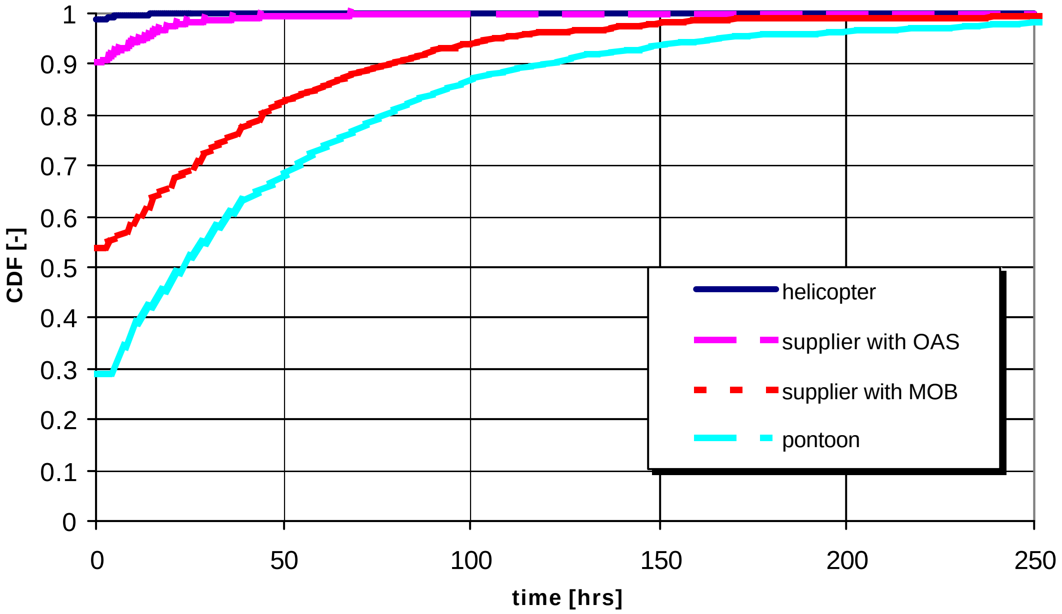

Fig. 2.5.3: *Cumulative Distribution Function (CDF) of waiting time during summer period for different types of equipment. Total duration of the mission is 8 hours*.

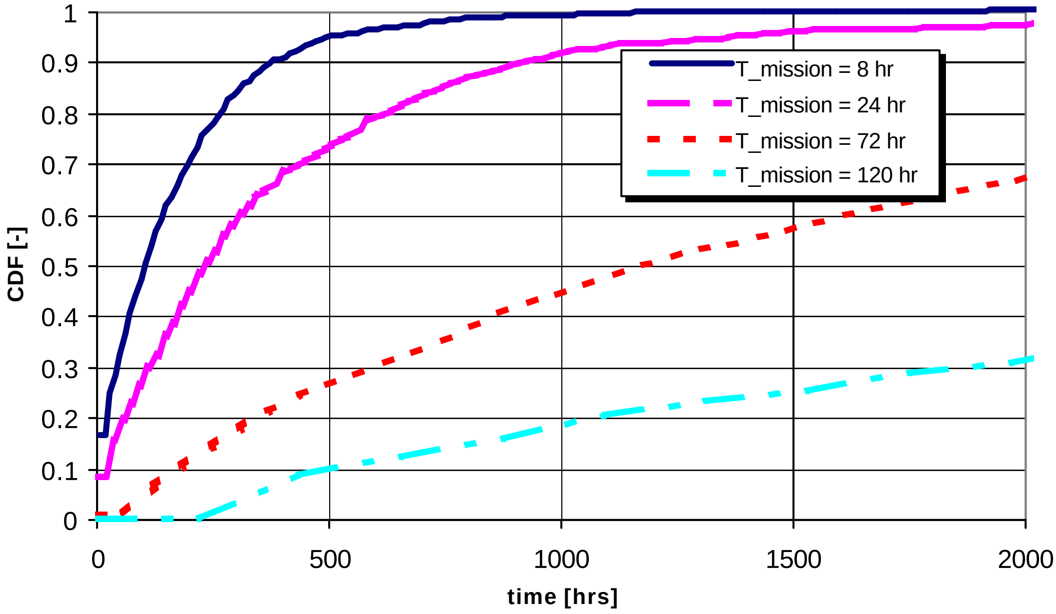

Fig. 2.5.4: *Cumulative Distribution Function (CDF) of waiting time for a pontoon during winter period for several values of the duration of the mission (T_wait).*

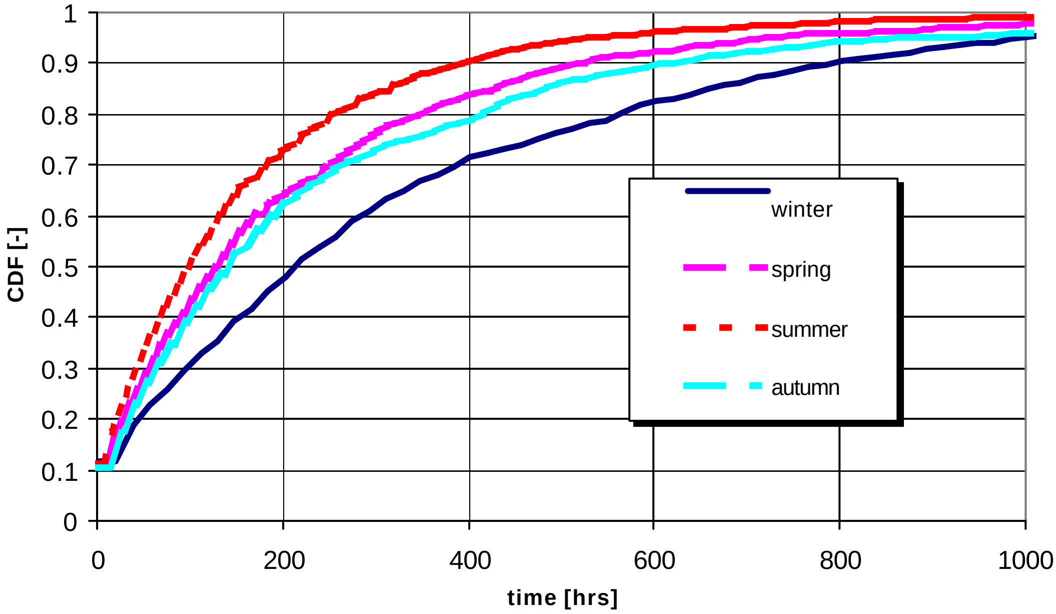

Fig. 2.5.5: *Influence of the season on Cumulative Distribution Function (CDF) of waiting time for a pontoon, duration of the mission is 24 hours.*

3. LOCATION AND LAY-OUT OF WIND FARM

3.1 Introduction

The probability that one or more wind turbines in a wind farm will be hit by a lightning strike depends amongst others on the location, the layout and the orientation of the wind farm. The average number of thunderstorms and the average number of lightning strikes per thunderstorm vary from one place to another. Concerning the layout, the number and the height of the wind turbines are of importance, because these parameters determine the collection area for lightning. The orientation of elongated wind farms should be considered because of the preferred direction in which thunderstorms travel at a certain location. Two opposite effects might occur. On the one hand, a thunderstorm that passes a row of turbines in a direction perpendicular to the row generally will be less severe. However, on the other hand a row of turbines perpendicular to the preferred direction of the thunderstorms will meet more thunderstorms. To investigate the influence of the location, layout and orientation KNMI has made an inventory of thunderstorms and the number of lightning strikes per thunderstorm. The results of this investigation are described in detail in [4] and are summarised briefly below.

To study the influence of the location three different locations at the North Sea were considered, viz. (see Fig. 2.1.1):

- a near shore location at 12 km from the coast;
- a near shore location at 30 km from the coast;
- a location far offshore at 300 km from the Dutch coast at the Doggerbank.

To consider the influence of the wind farm layout at each location three different configurations were considered, with wind turbines representative for 1.5 MW, 3.0 MW and 6.0 MW turbines. The characteristics of these farms are given in Table 2.2.1. The wind farms with the 1.5 MW and the 3.0 MW wind turbines have an almost rectangular shape, while the farm with the 6.0 MW turbines has a more elongated shape (aspect ratio is 1.8). To study the orientation effects on the lightning frequency, the wind farm with the 6.0 MW turbines was considered with the rows in north-south direction and with the rows in east-west direction. So, for each location four configurations were considered. The number of turbines in each configuration was chosen such that the total amount of installed power is about 100 MW. The main conclusions of this investigation are:

- the number of flashes per year per km^2 (the ground flash density) offshore is less than onshore;
- there is a trend that both the number of thunderstorms and the number of lightning strikes per thunderstorm become smaller when going further offshore;
- at the near shore locations a slight discrepancy can be observed between the wind farm with the rows in east west direction and the wind farm with the rows in north-south direction. However, this discrepancy is too small to draw conclusions with respects to the orientation. For this purpose the elongation of the wind farm should be much higher.

It should be noticed that these numbers are based on measured discharges. At locations considered at the North Sea these discharges were not affected by the presence of wind turbines. In this case study it is assumed that the probability that the wind farm is hit, is equal to the ground flash density. The height of the wind turbine is accounted for by defining a collection area around the turbine.

Due to differences in lightning frequency for different locations and orientations of the wind farm, the amount of damage might differ. Hence, the number of turbines shut down and consequently the extension and costs of inspection and repair will be dependent on location and orientation for identical wind farms. Another aspect that causes differences in the yearly costs is the equipment needed for inspection and repair. In case a wind farm is further away from the harbour it takes more time to travel to this farm. This does affect the yearly costs in two ways. First, due to the longer travel times the total downtime will be longer and consequently the revenue losses will be higher. Secondly, depending on the contract (hire per hour or hire per day) the price of the equipment can be come higher because it is needed for a longer period. So, the yearly costs will in general be dependent on location and orientation.

Furthermore the type of wind turbine placed in a wind farm does influence the costs, even if the wind farms should be subjected to identical lightning conditions. Especially the maintainability is of importance. For instance smaller turbine with a rated power of less than 2.0 MW are generally not equipped with large internal cranes, so that special equipment (jack-up) is required for external hoisting.

To study the influence of location, layout and orientation of the wind farm on the total yearly costs and downtime a number of different configurations, given in Table 2.1.1, have been analysed. The influence of the location was analysed by considering two wind farms with 3.0 MW wind turbines and three wind farms with 6.0 MW wind turbines.

3.2 Results

The long term average yearly costs for the six different configurations are shown in Fig. 3.1. Besides the total costs, the costs for inspection, the costs for repair and the revenue losses are depicted. The mean number of thunderstorms and the mean number of lightning strikes for each configuration are given in Fig. 3.2. Finally the results shown in these figures are summarised in Table 3.1.

From these results the following observations have been made.

- For a 100 MW offshore wind farm equipped with standard wind turbines (see chapter 2) in the range of 1.5 MW up to 6.0 MW, the long term average yearly costs of inspection and repair are in the range of 116 – 273 k€. An offshore wind farm of 100 MW and a capacity factor of 0.4 produces approximately 350,000 MWh per year. So the cost of lightning amounts 0.033 – 0.078 €cents/kWh. Typical numbers for maintenance costs of offshore wind farms (including costst for maintaining the park infrastructure, civil structures, etc.) are in the order of 2 €cents/kWh. So lightning contributes for about 1.7 – 3.9% to the total maintenance costs. The unavailability of the wind farm ranges from 0.06% to 0.11%, and the revenue losses due to lightning are maximal about 0.11% of the total yearly revenues.
- The costs of repair amount to 48 – 77 % of the total costs, while the inspection costs and the loss of revenues are respectively responsible for 18 – 35 % and 11 – 18 % of the total costs. So the costs of repair are the dominant factor in the total costs. With respect to these numbers the following should be kept in mind. The efficiency of the protection system is assumed to be 90 %, which implies that most lightning strikes will not lead to damage in the control system, the electrical system, the sensors and the blades, and the turbine can be restarted immediately after the inspection. Furthermore the inspection is being done by means of a helicopter and an inspection is being done each time one or more turbines are hit during a thunderstorm. So in the maintenance procedures applied in this case study a remote reset without inspection is not allowed. In chapter 5 the use of a supplier for inspection will be considered and in chapter 6 the influence of the efficiency of the protection systems will be analysed.
- At the both near shore locations two identical wind farms with 3.0 MW wind turbines have been considered (configurations NS1-WF3.0 and NS2-WF3.0). The number of thunderstorms that pass the wind farms at both locations is the same, so the number of inspections is the same also. However, the difference in inspection costs is considerable (21%) as a result of the shorter travel time for the helicopter to the location at 12 km. The number of lightning strikes is a little less for the location at 30 km, which results in less damages and thus lower repair costs. The total costs for the location at 30 km (NS2) are about 7 % lower mainly due to the lower repair costs.
- Comparison of the results for both wind farms with 6.0 MW turbines at the near shore location at 30 km (configuration NS2_WF6.0NS and NS2_WF6.0EW) with the results for

the wind farm with 6.0 MW turbine at the far offshore location (configuration FO-WF6.0) shows that the number of lightning strikes per thunderstorm for these locations is almost the same. However, the number of thunderstorms is less for the far offshore location. So the number of inspections and the number of turbines that need repair will be less for the far offshore location. Inspection is done by helicopter stationed on land. Although fewer inspections are needed for the far offshore location the total costs for inspection are higher due to the much longer travelling times for the helicopter. In this case study it is assumed that the far offshore wind farm is equipped with a permanently manned substation from which the suppliers leave for maintenance. The distance of this substation to the wind turbines is less than 30 km. This together with fewer turbines damaged leads to lower repair costs and revenue losses.

- The wind farms defined have a total installed power of about 100 MW. To reach this goal different types of wind turbines can be used. In this case study wind turbines representative for 1.5 MW, 3.0 MW and 6.0 MW have been considered. Comparing the 1.5 MW turbine and the 3.0 MW turbine it appears that the costs for the smaller turbine are considerably higher due to higher repair costs, about a factor 2. The 1.5 MW turbine is not equipped with a large internal crane and for some types of repair external hoisting equipment has to be arranged. Comparing the results of the 3.0 MW and the 6.0 MW turbines it is concluded that the wind farm with the larger turbines shows less damage due to lightning, because the number of inspections and the number of turbines that have to be repaired is less for the farms with larger turbines. This is due to the fact that the collection area for a wind farm with larger turbines is smaller, under the condition that the total installed power is the same. Although fewer turbines are damaged, the revenue losses for the 6.0 MW turbines are higher. These higher revenue losses are amply compensated by the lower inspection and repair costs, so the total costs for a wind farm of a certain size decrease if the rated power of the wind turbines installed increases.

Table 3.1: *Results of case studies for different locations and orientation of wind farms*

Configuration	**Costs [kEuro]**			
	Total	**Inspection**	**Repair**	**Revenue losses**
NS1-WF3.0	182.9	41.8	118.7	22.4
NS2-WF1.5	287.6	50.8	221.9	14.9
NS2-WF3.0	170.9	50.7	100.7	19.5
NS2-WF6.0EW	167.4	41.2	95.5	30.7
NS2-WF6.0NS	141.2	34.7	80.6	25.9
FO-WF6.0	148.6	52.3	72.1	24.2

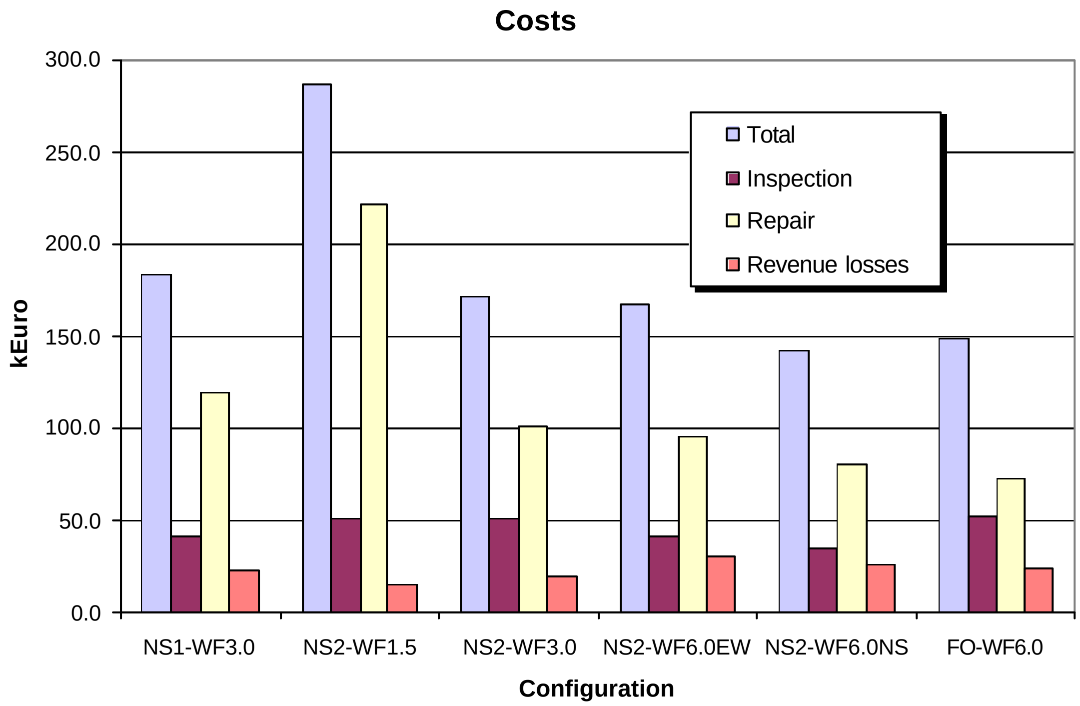

Fig. 3.1: *Long term average yearly costs*

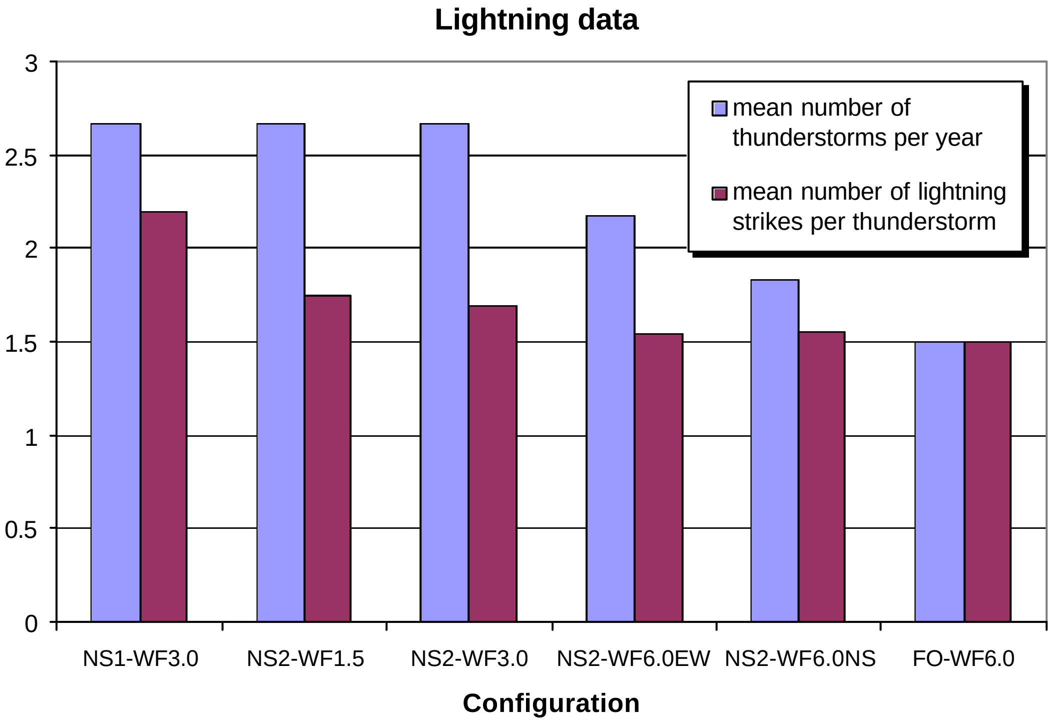

Fig. 3.2: *Lightning data*

3.3 Conclusions

Based on these results the following conclusions can be drawn.

Lightning damage

- The ground flash density per km^2 offshore is less than onshore. So lightning damage will be less severe for offshore farms if identical wind turbines are used.
- There is a trend that both the number of thunderstorms and the number of lightning strikes decrease when going further offshore. This trend is observed analysing measurements for only two near shore locations and one far offshore location, so further research should be done to underpin this trend. Similar trends have been observed in Denmark (see Fig. 2.3 in [4]).
- For the locations in which the lightning frequency has been measured no wind turbines are present yet. The impact that high structures like wind turbines will have on the number and the charge of the lightning strikes is not clear.
- The damage that might be expected in a wind turbine after it has been hit by a lightning is mainly based on the information present in public databases. These databases only contain reports when damage actually did occur, so the fraction of lightning strikes that did not cause any damage is not known. For this reason it is recommendable to equip offshore wind turbines with sensors by which it can be measured when a turbine has been hit. In this way the efficiency of the protection systems can be evaluated also. Furthermore, good diagnostics may lead to less inspection visits.

Lightning costs

- For an 100 MW offshore wind farm with wind turbines equipped with a lightning protection system for the electrical system, the control system, the sensors and the blades with an efficiency of 90%, the costs due to lightning damage are about 1.7 – 3.9 % of the total maintenance costs.
- If the turbines are equipped with the standard protection system the costs of lightning are only minor as compared to the total maintenance costs. Therefore, it is not worthwhile to optimise the costs of lightning separately for these turbines. Efforts to lower the costs of lightning damage should be made as part of an integral maintenance optimisation approach only.
- The most important contribution to the total costs are the repair costs. So primarily effort should be undertaken to optimise the repair costs.
- In the current case study it was assumed that inspection is always needed after one or more turbines have been hit after a thunderstorm. A way to reduce the costs of inspection can probably be achieved by considering the possibilities of a remote reset of the turbines in order to skip or to postpone a whole inspection to the moment of scheduled preventive maintenance.
- The orientation of strongly elongated parks might be of importance for lightning costs. However, the elongation of the parks considered here was not sufficient to quantify this effect. The effect depends on the preferable direction in which thunderstorms pass the wind farm and should be considered in connection with the total investments cots for the wind farm.
- It is recommended to equip offshore wind turbines with internal cranes, which can do most of the external hoisting. The use of jack ups causes higher repair costs. It should be noted that the case studies have been performed with the current knowledge and availability of repair and hoisting equipment. It is very likely that new equipment will be developed in the near future.
- For the design of a wind farm with a prescribed size for the installed power it is recommended to use fewer but greater wind turbines.

4. REPAIR STRATEGY

4.1 Introduction

For each type of wind turbine standard repair strategies were defined and described in chapter 2. Choosing another strategy by deploying another type of equipment (f.i. a supplier instead of a helicopter) will bring about a different breakdown of the total costs. To study these effects different repair strategies have been defined and applied for the near shore wind farm located at 30 km from the coast with 67 wind turbines with a rated power of 3.0 MW. This standard configuration of this wind farm is denoted by NS2_WF3.0.

A repair strategy is defined by choosing a relation between the types of damage that can occur and one or more devices to be deployed for a specific type of damage. To categorise the damage that may occur in a wind turbine due to lightning a structural breakdown is applied based on the classification used in the WMEP database of ISET (see Table 2.2.4). As these components can fail in different manners it is necessary to consider a number of failure types for these components. For instance, on the one hand damage of a blade can mean that the whole blade is destroyed and has to be replaced. On the other hand a minor damage of the receptor is categorised as blade damage also. For this reason three fault type classes (FTC) have been defined.

FTC-1: Repair, Cleaning, and Reset
A visit of two technicians is required. In this failure type class, the toolbox with small spare parts and consumables is sufficient to carry out the repair. The technicians can also make use of spare parts present in the turbine. Only personnel need to be transported to and from the turbine.

FTC-2: Replacement
After the inspection is carried out, an additional visit from two technicians is required. The small spare parts and consumables that are either in stock in the turbine or in the toolbox are not sufficient. Other (larger) spare parts should be transferred to the turbine, lifted from the supplier (or helicopter) into the tower (or nacelle) and hoisted with an internal winch to the nacelle.

FTC-3: Failure of large components
This class includes failures of components that need to be hoisted outside the tower. One can think of the gearbox, generator, blades, hub, or entire nacelle.

For each FTC a default repair strategy in terms of equipment to be applied has been defined. In chapter 3 these default repair strategies (RPS) have been considered. To study the effects of applying different types of equipment a number of different repair strategies has been considered. Table 4.1 gives an overview of the analyses that have been made. It should be noted that RPS1 in Table 4.1 corresponds with the standard strategy, which was outlined in chapter 2. The wind turbines are equipped with the default lightning protection system, as specified in Table 2.3.1.

In Table 4.1 in total 11 different approaches are given, which can be split up into three groups.

1. In this group a helicopter is used for inspection and different types of equipment are deployed for the subsequent repair. This group includes RPS1 through RPS5. In RPS2 a supplier with OAS is considered instead of a supplier with MOB. In RPS3 and RPS4 all the repair is done by a supplier and the helicopter is not used anymore. RPS5 describes the situation that the wind turbine is not equipped with a large internal crane and that a jack-up with a crane is needed for external hoisting. The results of these different strategies can be compared mutually.

Table 4.1: *Overview of analyses.*

Component	**FTC**	**RPS**										
		1	2	3	4	5	6	7	8	9	10	11
control system	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
electric	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB	OAS	MOB	OAS	MOB	MOB	OAS	MOB*	MOB*	OAS*	OAS*
rotor blades	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB PNT	OAS PNT	MOB PNT	OAS PNT	MOB PNT J-U	MOB PNT	OAS PNT	MOB* PNT	MOB* PNT	OAS* PNT	OAS* PNT
sensors	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
generator	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB	OAS	MOB	OAS	MOB J-U	MOB	OAS	MOB*	MOB*	OAS*	OAS*
hub	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB	OAS	MOB	OAS	MOB J-U	MOB	OAS	2	MOB*	2	OAS*
hydraulic system	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB	OAS	MOB	OAS	MOB	MOB	OAS	MOB*	MOB*	OAS*	OAS*
yaw system	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB	OAS	MOB	OAS	MOB	MOB	OAS	MOB*	MOB*	OAS*	OAS*
gear box	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB	OAS	MOB	OAS	MOB J-U	MOB	OAS	MOB*	MOB*	OAS*	OAS*
mechanical brake	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
drive train	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	3	MOB	OAS	MOB	OAS	MOB J-U	MOB	OAS	MOB*	MOB*	OAS*	OAS*
structural parts	1	H	H	MOB	OAS	H	MOB	OAS	H	MOB*	H	OAS*
	2	MOB	OAS	MOB	OAS	MOB	MOB	OAS	MOB*	MOB*	OAS*	OAS*
	3	MOB PNT J-U	OAS PNT J-U	MOB PNT J-U	OAS PNT J-U	MOB PNT J-U	MOB PNT J-U	OAS PNT J-U	MOB* PNT J-U	MOB* PNT J-U	OAS* PNT J-U	OAS* PNT J-U
Inspection		H	H	H	H	H	MOB	OAS	H	MOB*	H	OAS*

Fault Type Classes

1 : Repair, Cleaning Reset
2 : Replacement, hoisting inside.
3 : Replacement, hoisting outside.

Equipment

H : helicopter
MOB : supllier with MOB, hired by contract
OAS : supllier with OAS, hired by contract
MOB* : supllier with MOB, available on announcement
OAS* : supllier with OAS, available on announcement
PNT : pontoon with tug
J-U : jack-up with crane

2. This group comprises RPS6 and RPS7 and is characterised by the fact that all the work, so inspection and subsequent repair, is done by a supplier. As in all strategies a pontoon and a jack-up are needed for the exchange of large structural parts. The results of RPS6 and RPS7 can be compared mutually, but also with the results of RPS3 and RPS4.
3. In group 1 and group 2 the suppliers had to be hired from third parties and it was assumed that one has to pay for these suppliers during the period they can not leave the harbour due to bad weather conditions, the so called waiting time. For RPS 8 through RPS11 it is assumed that the suppliers are available on demand and that only the actual time that the supplier is at sea has to be paid for. So during the waiting time the only costs are due to the downtime. These results can be compared with the results of RPS1 and RPS2 to get insight in the influence that contracts can have on the costs.

4.2 Results

The long-term yearly average costs for the three groups of repair strategies are shown in Fig. 4.1 through Fig 4.3. Finally the results shown in these figures are summarised in Table 4.2.

In Fig. 4.1 the results for the 1st group are given. For this group the inspection is done by helicopter, so the costs for inspection is the same for all five repair strategies. In the standard repair strategy RPS1 most of the repair is done with a helicopter or with a supplier with MOB. Only for the replacement of large structural parts a jack-up and a pontoon are needed also. In RPS2 the supplier with MOB is replaced by a supplier with OAS. In RPS3 a supplier with MOB is used instead of the helicopter. In RPS4 a supplier with OAS is used instead of the helicopter. It appears that the total costs for these four repair strategies differ up to 6% at the most. The inspection is identical, so these differences in total costs are caused by differences in the costs of the equipment together with differences in revenue losses. As the prices of the equipment are based on best guesses and the differences are not very pronounced it is more objective to compare these repair strategies based on the revenue losses. Using a supplier with OAS instead of a supplier with MOB will lead to less downtime and consequently less revenue losses. This

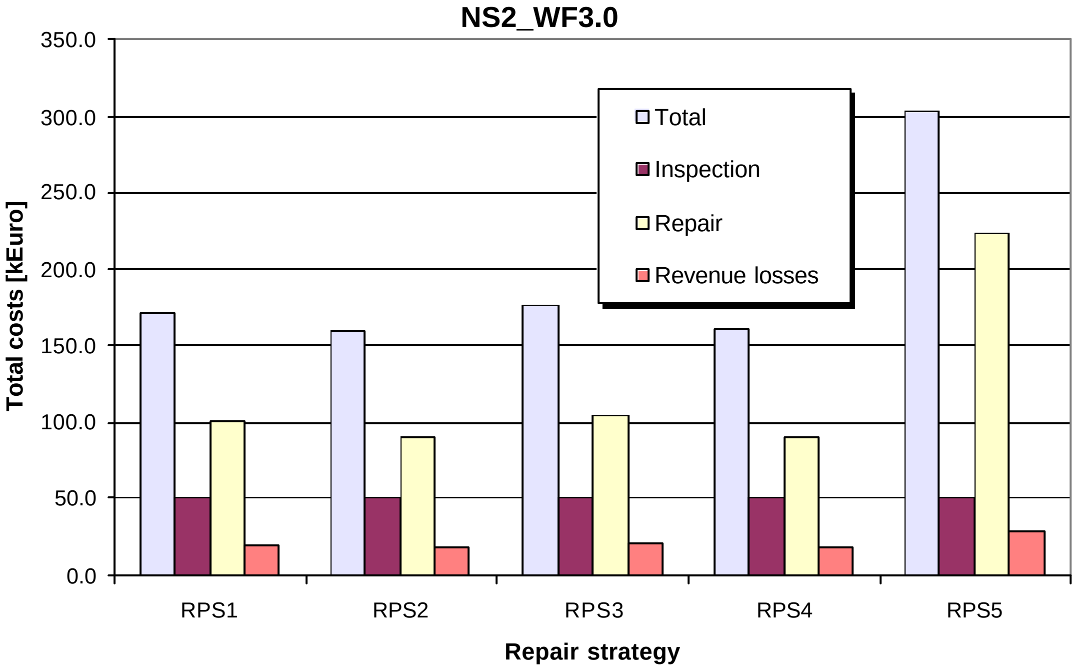

Fig. 4.1: *Comparison of total costs for repair strategies of group 1.*

reduction in revenue losses is about 4% in combination with a helicopter (RPS2 vs. RPS1) and is about 9% when the supplier is used for all repairs (RPS4 vs. RPS3). When a supplier with MOB is used for all repairs the total downtime and the revenue losses will increase with 6% (RPS1 vs. RPS3), while this increase is only 1% for the supplier with OAS (RPS2 vs. RPS4). This trend could be expected, as the weather window for a supplier with MOB is more severe than for a supplier with OAS, while the weather window for the helicopter is less severe.

RPS5 represents the situation that no internal crane for is available for external hoisting, and a jack-up has to be deployed. In this case the total costs will increase with about 77%.

Fig. 4.2 shows the results for group 2, where the inspection is done with a supplier instead of a helicopter. In RPS6 a supplier with MOB and in RPS7 a supplier with OAS is used for the inspection. The subsequent repair for RPS6 and RPS7 is identical to RPS3 and RPS4 respectively. When a supplier with MOB is used for the inspection, the costs of the inspection will increase with a factor 3 and the total downtime and consequently the revenue losses will increase with about 60%. This increase in costs and downtime is caused by the fact that due to the weather window the supplier with MOB has to stay in the harbour for a longer period and during this waiting period one has to pay for the equipment. The downtime does not increase proportional to the inspection costs, as the downtime is the sum of the downtime due to inspection and the downtime due to repair. Using a supplier with OAS instead of a helicopter for inspection will lead to about 20% higher inspection costs and about 10% higher revenue losses. It should be noticed that the prices of the equipment are best guesses and will generally strongly depend on the contract. So the difference in inspection costs should be considered with care due to large uncertainties.

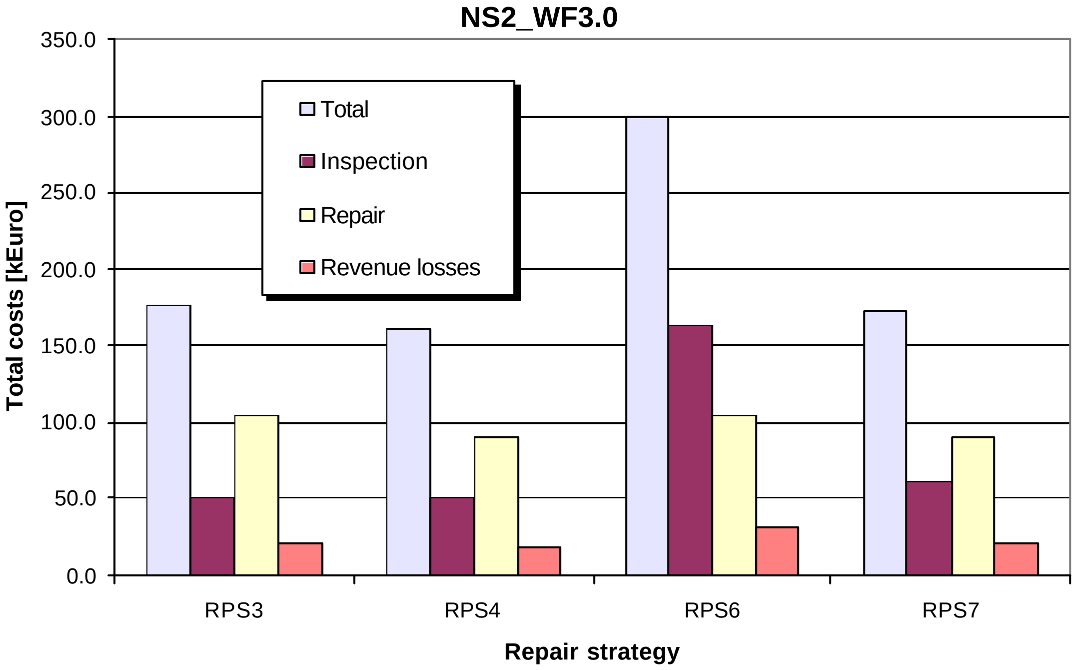

Fig. 4.2: *Comparison of total costs for repair strategies of group 2.*

In the previous examples it was assumed that the equipment has to be hired from third parties and that one has to pay during the waiting time. During the waiting time the equipment is ready for take off but can not leave the harbour due to bad weather condition. For the repair strategies classified in group 3 it is assumed that the suppliers (MOB or OAS) are available on demand and one has to pay only for the time these suppliers are actually at sea. The calculated long term yearly average costs for this group are depicted in Fig. 4.3. IN RPS8 and RPS9 a supplier with

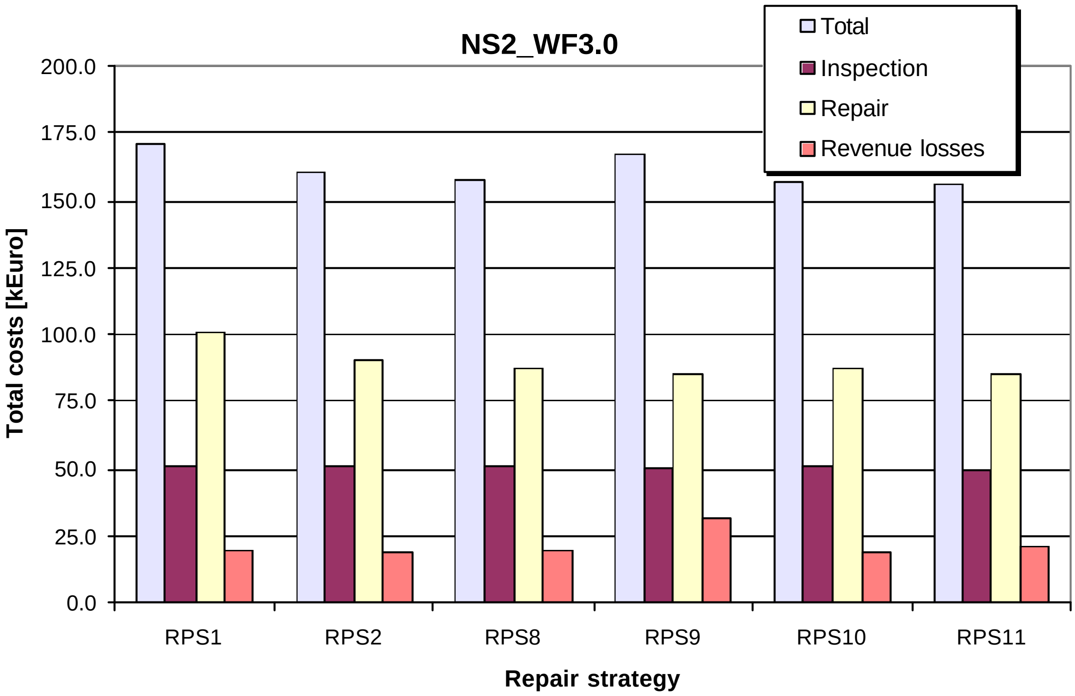

Fig. 4.3: *Comparison of total costs for repair strategies of group 3.*

MOB is deployed, while a supplier with OAS is used in RPS10 and RPS11. In RPS9 and RPS10 the inspection is done with a helicopter and in RPS9 and RPS11 the inspection is done with the supplier. For reasons of comparison RPS1 and RPS2 are shown also. The use of suppliers on demand does not affect the downtime, only the costs during the waiting time can be avoided. It appears that for RPS8 – RPS11 both the costs for inspection and the costs for repair are of the same magnitude. As mentioned before these costs strongly depend on the prices of the equipment and these prices are subjected to agreements made in the contracts.

Table 4.2: *Results of case studies for different repair strategies*

Identification	Costs [kEuro]			
	Total	Inspection	Repair	Revenue losses
RPS1	170.9	50.7	100.7	19.5
RPS2	160.2	50.7	90.8	18.7
RPS3	176.3	50.7	104.8	20.7
RPS4	160.7	50.7	91.0	18.9
RPS5	303.2	50.7	223.4	29.0
RPS6	299.2	163.0	104.8	31.4
RPS7	172.6	60.6	91.0	21.0
RPS8	157.7	50.7	87.5	19.5
RPS9	167.0	50.1	85.5	31.4
RPS10	156.8	50.7	87.4	18.7
RPS11	155.5	49.2	85.3	21.0

4.3 Conclusions

Based on these results the following conclusions can be drawn. It should be noticed that these conclusions are based on analyses for a 100 MW wind farm with 34 wind turbines of 3.0 MW, which is located at about 30 km from the coast.
Furthermore repair strategies were considered where most of the repair can be done by a helicopter in combination with a supplier or with a supplier alone. Only for the replacement of large structural parts a jack-up and a pontoon are needed additionally. The inspection can be done by helicopter, a supplier with MOB or with a supplier with OAS.

Repair

- To reduce the downtime a combination of a helicopter with a supplier with OAS (RPS2) is preferred although the difference with the strategy with an OAS alone (RPS4) is marginal. The use of a MOB instead of a OAS for repair gives slightly higher downtimes.
- The revenue losses are only a small part of the total costs and because the prices of the equipment are uncertain due to its dependence on negotiations and contracts it not possible to make an objective comparison based on costs.
- Depending on the contracts the repair strategies using a helicopter in combination with a supplier or using a supplier alone without a helicopter might be competitive.
- The use of a jack-up and a pontoon should be restricted to the replacement of large structural parts only. The repair costs will increase significantly in case a jack-up has to be used for all types of external hoisting.
- The yearly repair costs for a wind farm with wind turbines not equipped with a large internal crane are about 130 k€ higher (RPS5 vs. RPS2). Over a lifetime of 20 years this is about 76 k€ per wind turbine. The investment costs of a large internal crane are about 100 k€, so it is not completely profitable to equip a turbine with an internal crane for lightning damage only, but it will be profitable if all corrective maintenance is considered.

Inspection

- The use of supplier with OAS for inspection instead of a helicopter will lead to a slightly higher downtime of 11%. For a supplier with MOB this increase is about 60%. The costs of the inspection strongly depend on the prices of the equipment, which are the results of negotiations and contracts. Depending on the contract a supplier might be competitive with a helicopter. To select the most favourable option both the costs of the equipment and the revenue losses have to be taken into account.

It should be noticed that lightning damage contributes only for a very small amount to the total maintenance costs of wind turbine, so it is not relevant to carry through the optimisations mentioned above for lightning separately.

5. PROTECTION

5.1 Introduction

In the previous chapters analyses have been made for wind turbines with the standard lightning protection, as specified in Table 2.3.1. Standard, only the control system, the electrical system, the sensors and the blades are equipped with a protection system, while the other components are not protected. The efficiency of the protection system is assumed to be 90%, which means that there is a 90% probability that no damage will occur in these components. It is stated by experts in the field of lightning protection that this efficiency of 90% can be reached by using protection methods for the different systems with the highest protection level (see chapter 3 of [4]). For the blades a distinction between the fault type classes has been made. FTC1 for rotor blades includes the damage at or near the receptors and this type of damage can not be avoided, hence the efficiency of the protection system for FTC1 of the rotor blades is always equal to 0%.

To study the influence of the protection system on the costs, a number of analyses has been made with different values for the efficiency of the protection system. These analyses can be split up into two groups.

1. In this group the efficiency of the protection for the control system, the electrical system the sensors and the blades is varied (0%, 80%, 90%, 95% and 98%), while for the other components no protection is assumed to be present (efficiency for this latter group is 0%).
2. The efficiency of the protection for the control system, the electrical system the sensors and the blades is fixed at 90%, while for the other components the protection is varied (0%, 50% and 90%).

Mutual comparison of the results gives a justification of the investments in protection systems that can be done in an economic sound manner.

The analyses are made for the 100 MW wind farm with 34 wind turbines of 3.0 MW situated at the near shore location at about 30 km from the coast. The inspection and the repair is done according to the standard procedure as described in chapter 2. (see also RPS1in chapter 4). The inspection is done by helicopter, while for the repair both the helicopter and the supplier with MOB are used. Only for the replacement of large structural parts a jack-up with pontoon are required additionally.

Furthermore the effect of protection on the failure rate of the severe damages (FTC3) has been considered. For FTC3 external hoisting either by a large internal crane or by a jack-up is required.

5.2 Results

The long-term yearly average costs for the two groups of analyses with different protection systems are shown in Fig. 5.1 and Fig. 5.2. Besides the total costs, the repair costs and the revenue losses are depicted in these figures. The costs of inspection are omitted as these are the same for all different levels of protection. The results shown in these figures are summarised in Table 5.1.

Fig. 5.1 shows the results for group 1, where the efficiency of the protection for the control system, the electrical system the sensors and the blades is varied, while the other components do not have a protection system. It is believed that an overall efficiency of 90% for these components can be achieved by protecting the several separate systems in a component using protection system of the highest protection level. Comparing the results for 0% protection and for 90% protection it appears that the long-term yearly average costs for the wind farm are lowered by about 185 k€. Over a lifetime of 20 years this is about 108 k€ per wind turbine. So the total costs (investment and maintenance costs) of a protection system for the control system, the electrical system the sensors and the blades together should not exceed 108 k€. According to

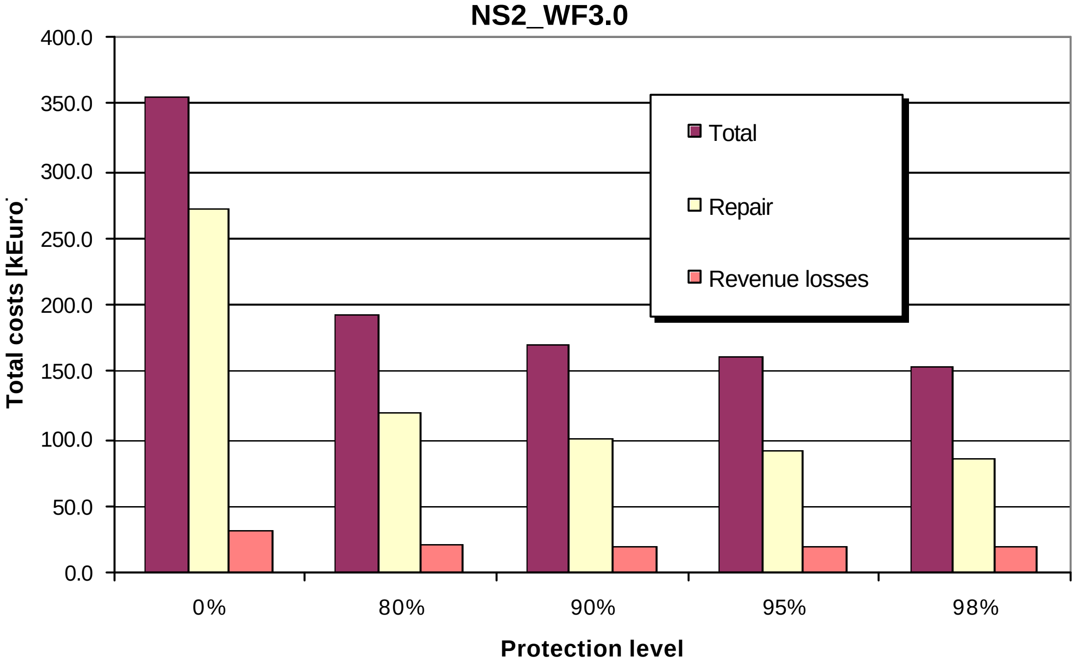

Fig. 5.1: *The effect of lightning protection. The costs are given as function of the efficiency of the lightning protection, which is applied only to the control system, the electrical system, the sensors and the blades. The other components are not equipped with a lightning protection system.*

[4] the investment costs for a protection system for the blades are in the range of 7.5 – 9.5 k€ and the additional hardware costs to protect the supply voltages and the sensors against over voltages is estimated to be 14 k€. The total investment costs of the lightning protection is in the range of 21.5 – 23.5 k€. Increasing the efficiency to 98% will lead to a further reduction in the costs of only 16.4 k€ for the whole wind farm, or 500 € per wind turbine per year.

To judge whether it is useful to invest in protection systems or to develop design adjustments for the other components, analyses have been made where it was assumed that the other components were equipped with a protection system. Fig. 5.2 shows the calculated costs for wind turbines where the efficiency of the protection for the control system, the electrical system the sensors and the blades is fixed at 90%, and for the other components the protection is varied (0%, 50% and 90%). A 50% efficiency leads to a costs reduction of about 46.2 k€ for the wind farm, or 1.4 k€ per wind turbine per year. With an efficiency of 90% an additional cost reduction of 1.1 k€ per wind turbine per year is achieved.

Fig. 5.3 gives the failure rate per year of the severe damages (FTC3) for all components together. For each configuration, defined in table 2.1.1, two situations have been considered. On the one hand, the situation where no protection is present, and on the other hand the situation where the wind turbines are equipped with the standard protection system. In case no protection is present 77% of the severe damages do occur in the blades. If the turbines do have a standard protection system 50 % of the severe damages do occur in the blades. Fig. 5.3 shows that for configuration NS2_WF3.0 the failure rate for FTC3 decreases from 0.7 per year to 0.11 per year. So for this wind farm with wind turbines without protection every 1.4 year a maintenance action with external hoisting is needed. If a standard protection system is used every 9 years a maintenance action with external hoisting is needed.

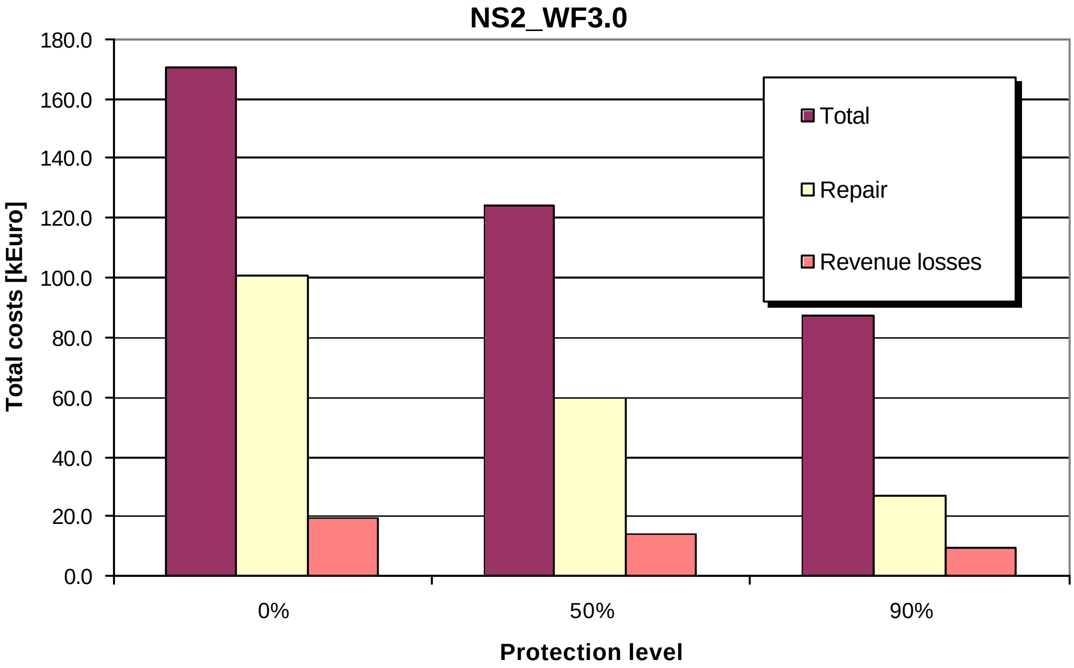

Fig. 5.2: *The effect of lightning protection. The efficiency of the lightning protection for the control system, the electrical system, the sensors and the blades is fixed at 90%. The efficiency of the protection system for the other components is varied and the costs are given as function of the efficiency for these other components.*

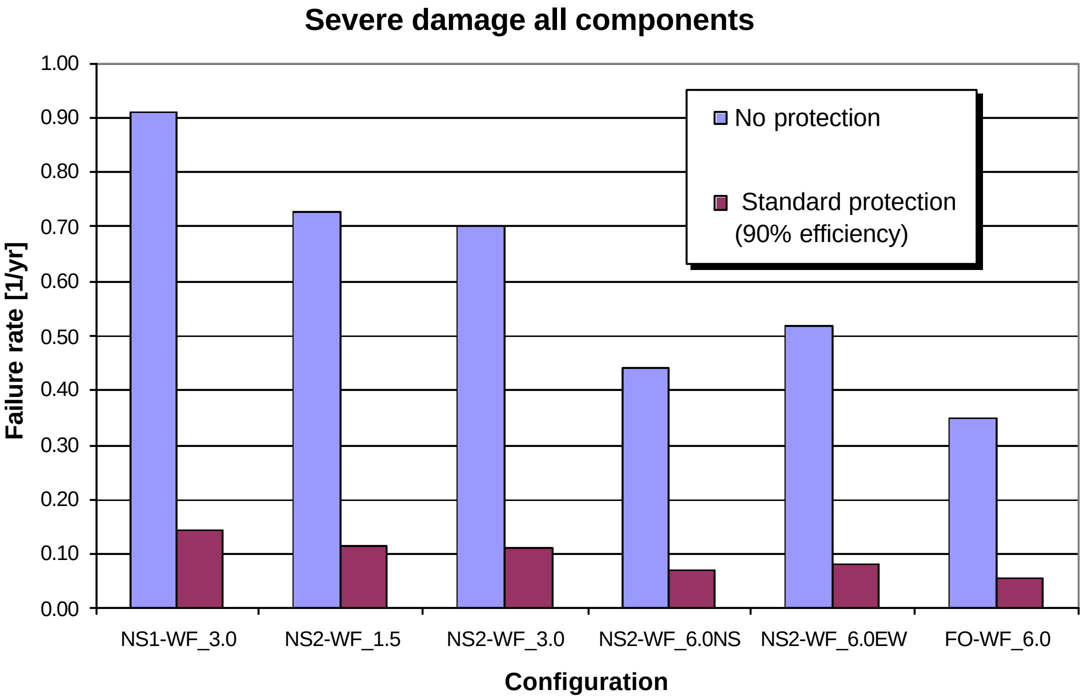

Fig. 5.3: *Failure rate per year of severe damages (FTC3).*

Table 5.1: *Results of case studies with different protection level*

Efficiency of protection system		**Costs [k €]**		
control system electric system sensors blades	other components	**Total**	**Repair**	**Revenue losses**
0%	0%	355.8	273.0	32.1
80%	0%	191.5	119.8	20.9
90%	0%	170.9	100.7	19.5
95%	0%	160.6	91.1	18.8
98%	0%	154.5	85.4	18.3
90%	50%	124.7	59.9	14.1
90%	90%	87.8	27.3	9.7

5.3 Conclusions

The amount of damage due to lightning can be reduced in two ways.

1. Equipping the wind turbine with commercial available lightning protection systems. Such systems are available for the electrical system, the control system, sensors and for the blades.
2. Adjusting the design so that the wind turbine is less vulnerable for lightning. This can be considered for those components or system for which no protection systems are available.

For both measures investments have to be made, while some systems need maintenance also. To judge whether it is economically sound to equip a wind turbine with protection systems or to carry through design adjustments, the cost of these measures have to be compared with the reduction in costs of lightning damage. Table 5.2 gives the reduction in costs that can be achieved with different levels of protection for a wind farm with 34 wind turbines of 3.0 MW located 30 km from the coast.

Table 5.2: *Maximum reduction of costs by lightning protection*

Efficiency of protection system		**Cost reduction [kEuro]**		
control system electric system sensors blades	other components	**per year**	**per year per wind turbine**	**Per turbine over lifetime of 20 year**
80%	0%	164.4	4.8	96
90%	0%	184.9	5.4	108
95%	0%	195.2	5.7	114
98%	0%	201.4	5.9	118
90%	50%	231.1	6.8	136
90%	90%	268.1	7.9	158

6. REFERENCE CONFIGURATION

6.1 Introduction

In this chapter the near shore wind farm NS2_WF3.0 is considered in more detail. This wind farm consists of 34 wind turbines representative for the 3.0 MW class and is located at 30 km from the coast. The lightning data for this wind farm are given in Table 2.2.2 and in Table 2.2.3. The characteristics of this 100 MW wind farm and of the 3.0 MW wind turbines are summarised in Table 2.2.1. The wind turbines are equipped with the standard lightning protection, as specified in Table 2.3.1. Standard, only the control system, the electrical system, the sensors and the blades are equipped with a protection system, while the other components are not protected. The efficiency of the protection system is assumed to be 90%. For the blades a distinction between the fault type classes has been made. FTC1 for rotor blades includes the damage at or near the receptors and this type of damage can not be avoided, hence the efficiency of the protection system for FTC1 of the rotor blades is always equal to 0%. The inspection and the subsequent repair is done according to the standard procedures as described in chapter 2 (see RPS1 in chapter 4 also). So, the inspection is done by helicopter, while for the repair both the helicopter and the supplier with MOB are used. Only for the replacement of large structural parts a jack-up with pontoon are required additionally.

In the previous chapters the long-term yearly average costs due to lightning have been calculated for several situations. Below the following has been considered:

- the distribution of the cost over the yearly seasons;
- the break down of the total costs and the downtime;
- uncertainty in the total costs and the downtime;
- a sensitivity analysis to identify which uncertainty contributes the most to the uncertainty in total costs and downtime.

6.2 Season effects

The lightning intensity, the wind speed and the accessibility vary over the year, as can be seen in Table 2.2.3 and in Fig. 2.5.5. These factors do not affect the costs of lightning damage in the same way. On the one hand, most thunderstorms occur in summer (54% of yearly total) and most of the maintenance has to be done in summer. On the other hand, during the summer the accessibility is the best and the mean wind speed the lowest, which is favourable for the total downtime and the revenue losses during this downtime. The capacity factors for the 3.0 MW wind turbines are given in Table 6.2.1. To quantify these effects the costs and downtime have been calculated for the four yearly seasons and the results are shown in Fig. 6.2.3 and Fig. 6.2.4. To clarify these figures the lightning data are depicted in Fig. 6.2.1 and Fig. 6.2.2.

Table 6.2.1: *Capacity factors for 3.0 MW wind turbine in near shore wind farm at 30 km from the coast.*

Season	**Capacity factor**
Winter	48%
Spring	38%
Summer	34%
Autumn	41%
Year	41%

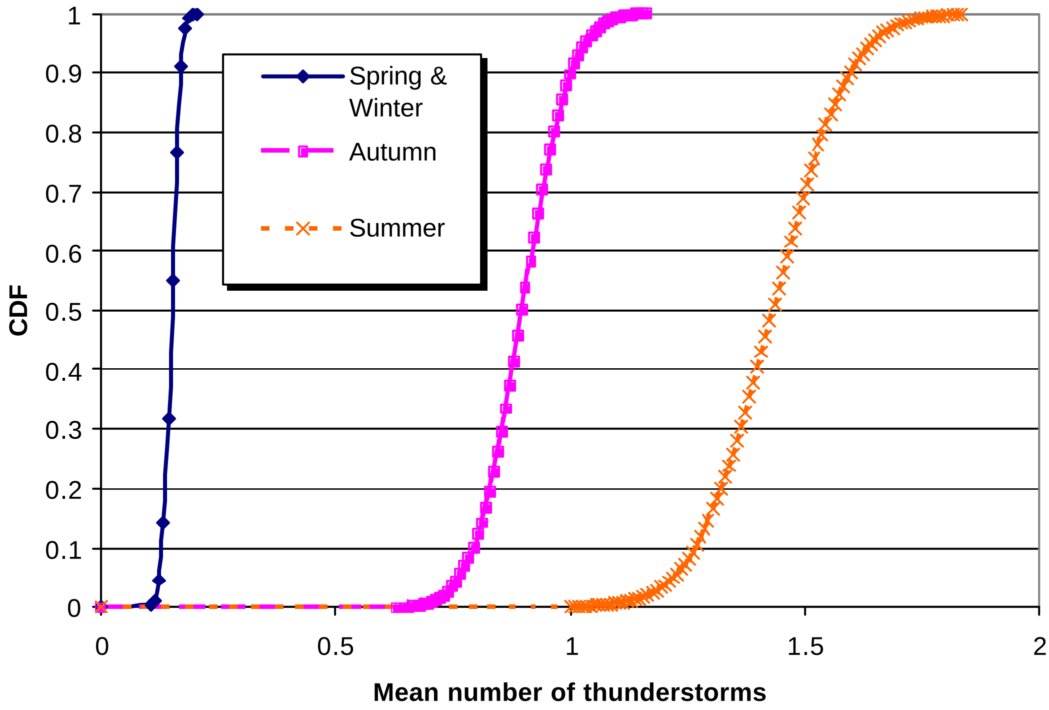

Fig. 6.2.1: *Cumulative Distribution function of the mean number of thunderstorms for configuration NS2_WF3.0*

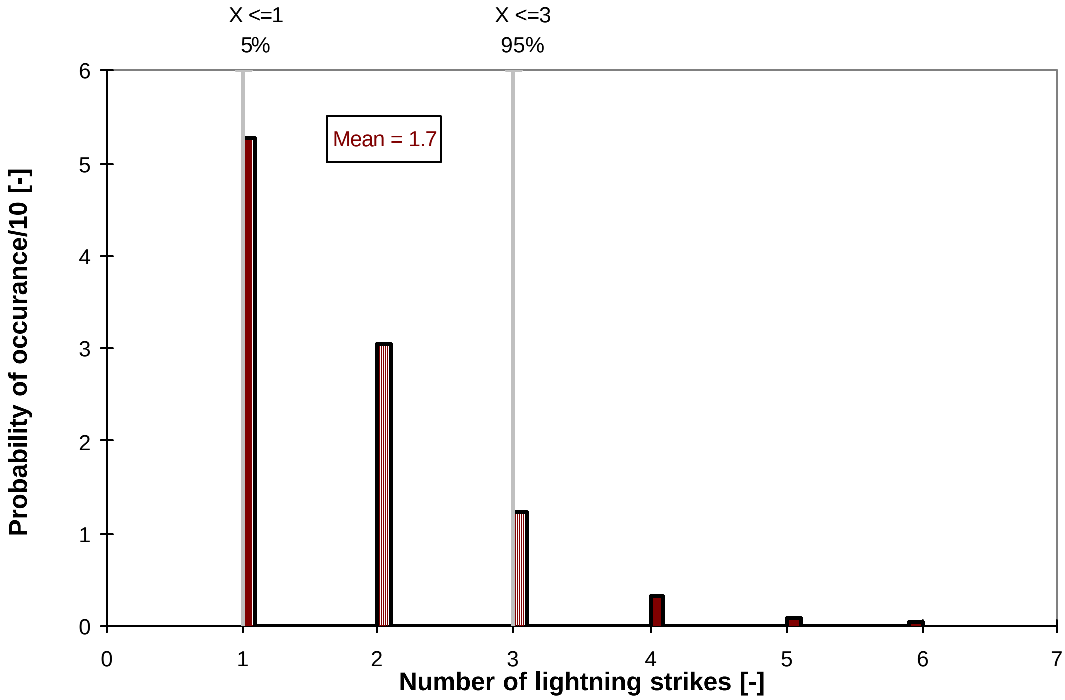

Fig. 6.2.2: *Frequency distribution of number of lightning strikes per thunderstorm for configuration NS2_WF3.0*

Fig. 6.2.1 shows the Cumulative Distribution Function (CDF) of the mean number of thunderstorms per season. These numbers are based on measurements during six year, and due to this limited period the results show statistical uncertainty, which is the highest for the summer. The frequency distribution of the number of lightning strikes per thunderstorm is given in Fig. 6.2.2. The Poison process describes the number of lightning strikes per thunderstorm, and from Fig. 6.2.2 it can be seen that there is a probability of 5% that there will be more than 3 lightning strikes during a thunderstorm.

The downtime (total and divided into inspection and repair) for the four seasons is shown in Fig. 6.2.3 together with the revenue losses. The downtimes shown are the total downtimes of all wind turbines. As could be expected from the lightning data in Fig. 6.2.1 the downtime is the highest in summer and the lowest in winter and spring. During summer the mean wind speed is the lowest, the capacity factor in summer is only 34%, while in winter it is 48%. This brings about that the revenue losses are not proportional with the downtime, as is clear from Fig. 6.2.3.

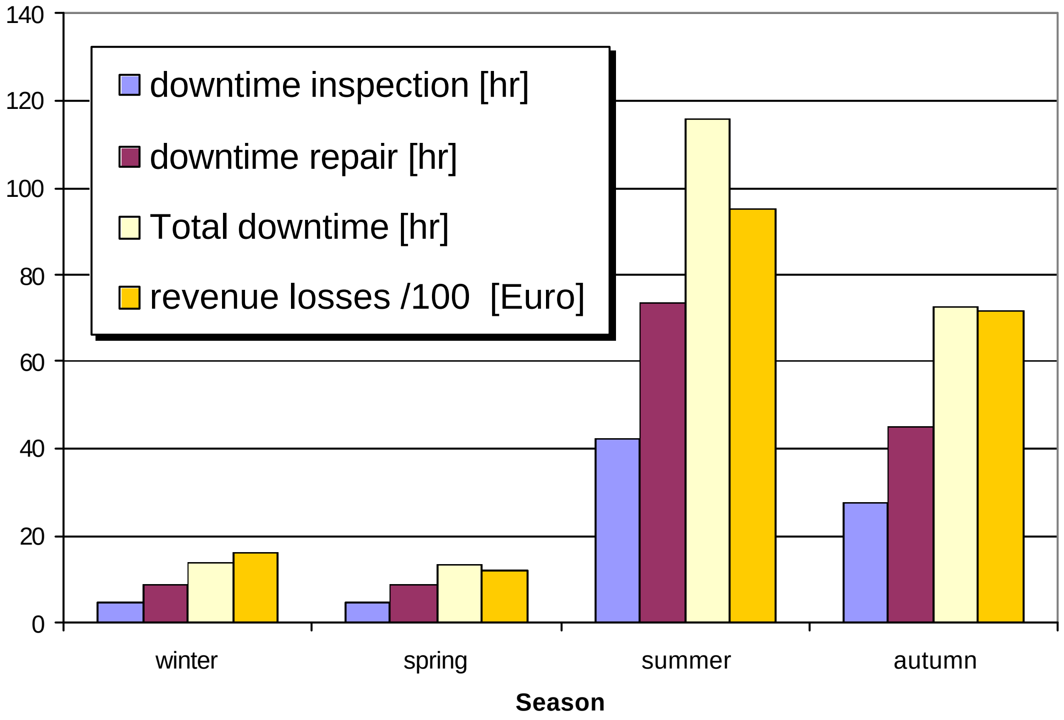

Fig. 6.2.3: *Long term average downtime and revenue losses per season for configuration NS2_WF3.0.The number shown are the totals over all turbines*

The long-term average costs per season are depicted in Fig. 6.2.4. Besides the total costs, the costs of the inspection, the repair costs and the revenue losses are given per season. Similar to the revenue losses the costs of inspection and the costs of repair are not proportional with the mean number of thunderstorms, because the accessibility in summer is much better than in winter. This effect is more pronounced for repair than for inspection, as inspection is done by helicopter alone and for repair suppliers and a jack-up with pontoon are deployed also and the weather window these devices are more severe than for a helicopter.

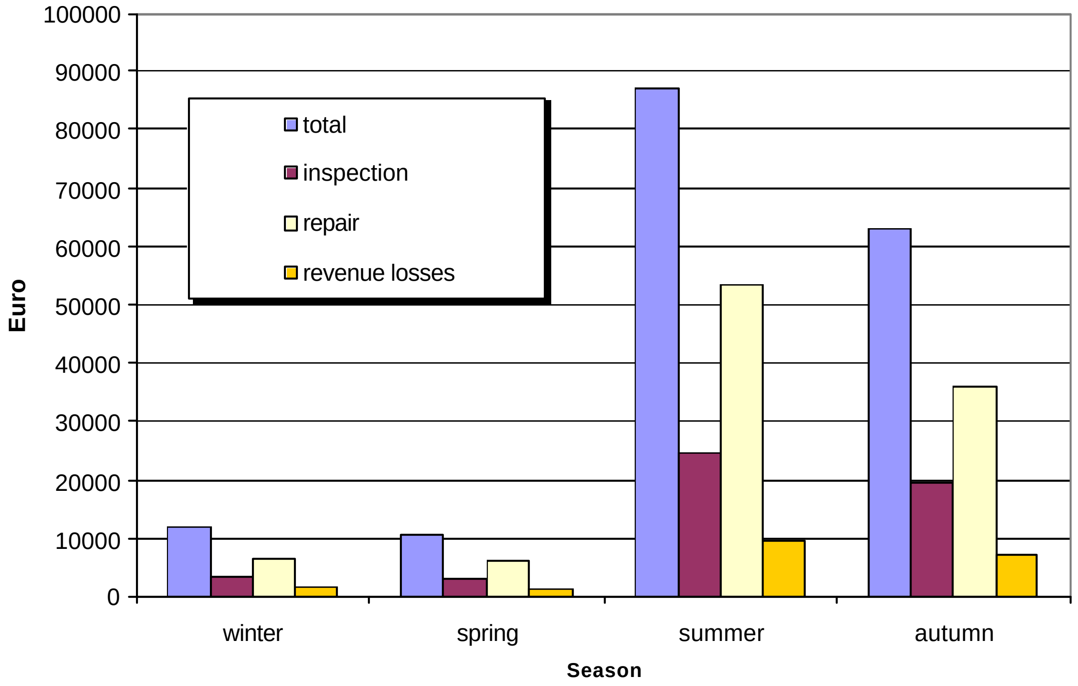

Fig. 6.2.4: *Long term average costs per season for configuration NS2_WF3.0*

6.3 Breakdown of downtime and costs

In this case study it is assumed that a wind turbine will be shut down always after it has been hit by a lightning strike. Due to a lightning strike it might happen that no damage is present at all or the damage is only small and can be repaired during the inspection. In these cases the wind turbine can be restarted immediately after the inspection. In case the damage can not be repaired during the inspection a maintenance action will be initiated after the inspection and the wind turbine remains out of operation until the repair has been completed. Hence the total downtime can be split up into downtime due to inspection and downtime due to repair. For the wind farm configuration NS2_WF3.0 the long-term yearly average total downtime is 213 hr, or the whole park will be down for about 6 hours per year. The subdivision in is shown in Fig. 6.3.1.

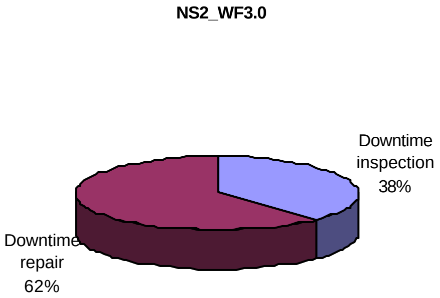

Fig. 6.3.1: *Subdivision of total downtime in downtime due to inspection and downtime due to repair*

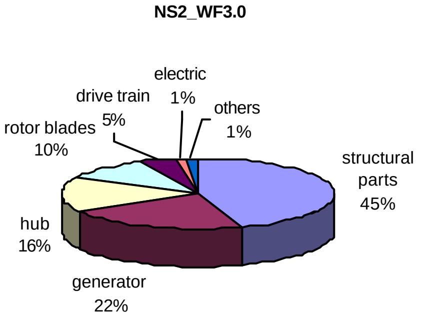

Fig. 6.3.2: *Distribution of downtime due to repair over components.*

In Fig. 6.3.2 the distribution of the downtime due to repair over the components is shown. It appears that the repair of structural parts takes most of the time. This is caused by the fact that for the replacement of large structural parts a jack-up and pontoon are used, and the weather windows for these devices are relatively stringent. It should be noticed that the probability on damaged structural parts is relatively low, see section 2.3

The long-term yearly average costs for configuration NS2_WF3.0 amount to 171 k€ and consists of the costs of inspection (30%), the costs of repair (59%) and the revenue losses (11%), see Fig. 3.1. The costs of inspection consist of labour costs and the costs of the equipment, while for repair the costs of the materials are important also. This subdivision is shown in Fig. 6.3.3 and 6.3.4. It appears that labour costs are only marginal. Hence the costs of inspection are determined by the costs of the equipment (98%), which is a helicopter in this situation. The costs of the equipment used and the costs of spare parts determine the costs of the repair.

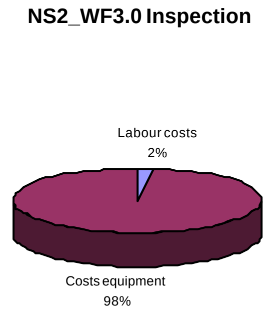

Fig. 6.3.3: *Subdivision of inspection cost*

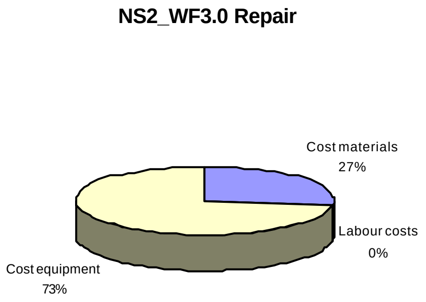

Fig. 6.3.4: *Subdivision of repair cost*

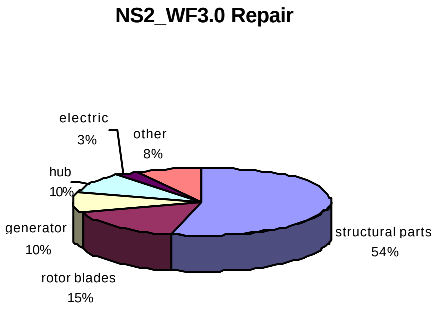

Fig. 6.3.5: *Distribution of repair costs over components*

The distribution of the costs of the materials and the equipment over the components is depicted in Fig. 6.3.5. Although the probability that the structural parts will be damaged by lightning and need to be repaired subsequently is the lowest (see section 2.3), it appears that the repair of the structural parts contributes the most to the total costs of repair (54%). This is caused by the fact that for the replacement of large structural parts a jack-up and a pontoon are needed. These types of equipment have stringent weather windows so that the waiting time is relatively long. After the structural parts, the repair costs for the rotor contribute the most to the total costs. The probability that rotor blades will be damaged and have to be repaired after the inspection is ranked secondly. The probability that electrical systems have to be repaired after inspection is the highest, but these components contribute only for 3% tot the total costs. The repair of electrical systems is done by helicopter or by a supplier with MOB, while for the replacement of blades a pontoon is needed also. The accessibility by a pontoon is much worse than for a helicopter or a supplier, with the result that the waiting times are much longer.

6.4 Uncertainty in downtime and costs

The calculated downtimes and the calculated costs due to lightning damage show scatter as a result of the inherent variability and the statistical uncertainty in the input variables. Inherent variability is a result of the physical process and it can not be reduced; examples are the wind speed, the wave height, the number of lightning flashes during a thunderstorm and the type and amount of damage due a lightning strike. Statistical uncertainty is caused by lack of knowledge about the parameters, and sometimes it can be reduced through further measurements or study, or through consulting more experts. The total uncertainty, which is a combination of inherent variability and statistical uncertainty, results in uncertainty in the calculated results, in this case costs and downtime. To gain insight in the amount of uncertainty one can consider the Cumulative Distribution Function (CDF) of a statistical variable. In general the CDF of the statistical variable X is denoted by $F_X(x)$. Here X can denote the downtime, the loss of production, or the cost. The CDF is defined as

$$F_X(x) \equiv P(X \leq x)$$

or $F_X(x)$ gives the probability that the value of the stochastic variable X is less or equal than x. The CDF's of the long-term yearly average downtime, loss of production and the costs have been calculated and are depicted in the Fig. 6.4.1 through Fig. 6.4.4. In Table 6.4.1 the mean value, the standard deviation and the 5% and 95% probability values are summarised. The 5 % and the 95% probability value, denoted by x_5 and x_{95} respectively, are defined as $F_X(x_5) = 0.05$ and $F_X(x_{95}) = 0.95$.

The CDF of the downtime is depicted in Fig. 6.4.1. Besides the total downtime, the downtime due to inspection and the downtime due to repair are shown. It is clear from this figure that the uncertainty in the total downtime is caused mainly by the uncertainty in the downtime due to repair. The corresponding loss of production due to the total downtime is shown in Fig. 6.4.2. The mean value of the loss of production is 241 MWh. However it might also be much higher,

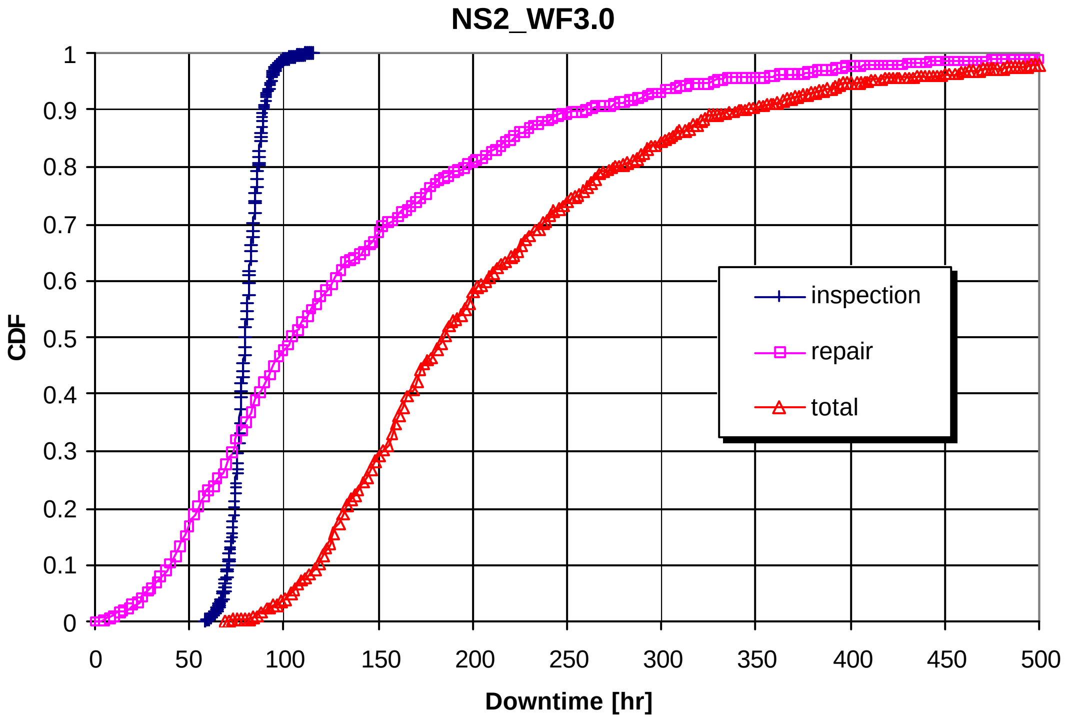

Fig. 6.4.1: *Cumulative Distribution Function of downtime for configuration NS2_WF3.0*

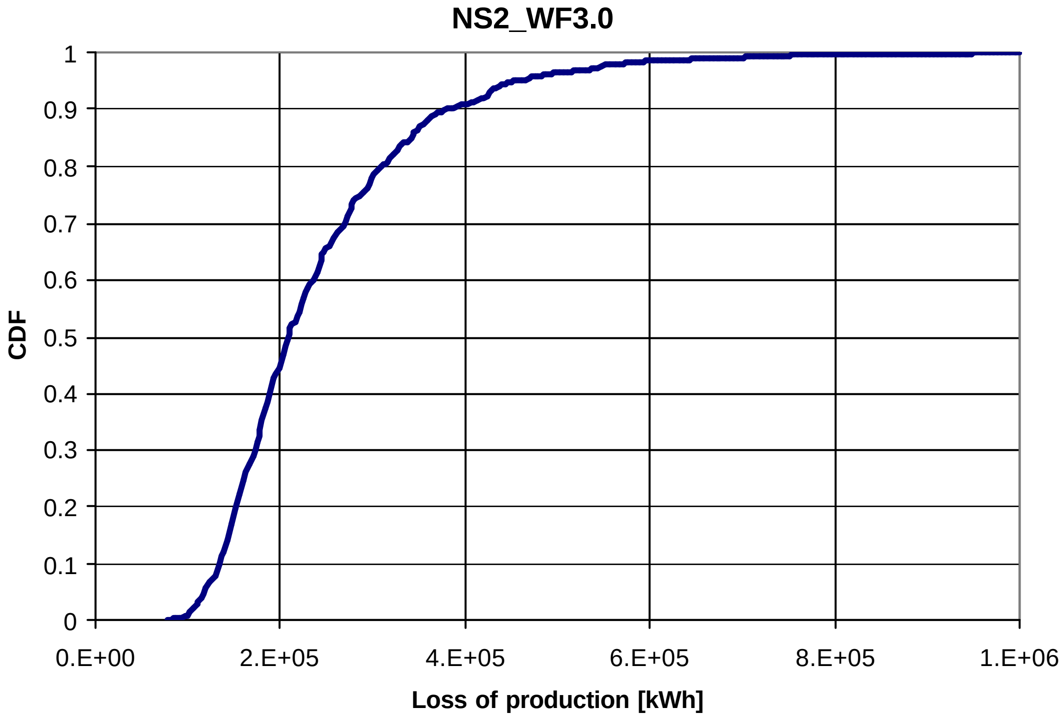

Fig. 6.4.2: *Cumulative Distribution Function of loss of production for configuration NS2_WF3.0*

or lower. The probability that the loss of production will be higher than 346.6 MWh is 5%, while there is a probability of 5% also that the loss of production will be less than 199 MWh. (see Fig. 6.4.2 and Table 6.4.1).

The CDF of the long-term yearly average costs is depicted in Fig. 6.4.3. Besides the total costs, the costs for inspection, the costs for repair and the revenue losses are shown. It is clear from this figure that the uncertainty in the total costs is caused mainly by the uncertainty in the costs for repair. The costs for repair in its turn consist of the cost of materials and the cost of equipment. The CDF of these two types of costs are shown in Fig. 6.4.4 together with the CDF of the total repair costs. The labour costs are not considered, as these are very low and can be neglected with respect to the total costs. Fig. 6.4.4 shows that uncertainty in the repair costs is caused mainly by the uncertainty in the cost of the equipment. So the uncertainty in the total costs is caused mainly by the uncertainty in the costs of the equipment. However the uncertainty in the total costs and in the costs of the equipment also is caused by the uncertainty in the input parameters. In the next section this will be considered in more detail.

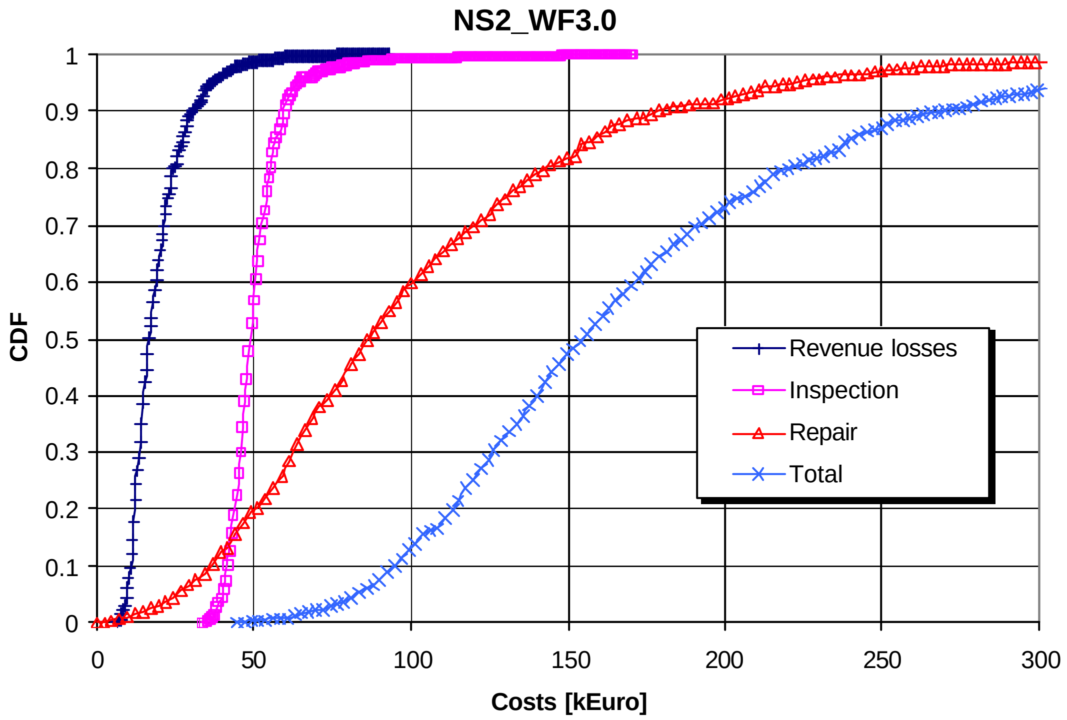

Fig. 6.4.3: *Cumulative Distribution Function of the costs for configuration NS2_WF3.0*

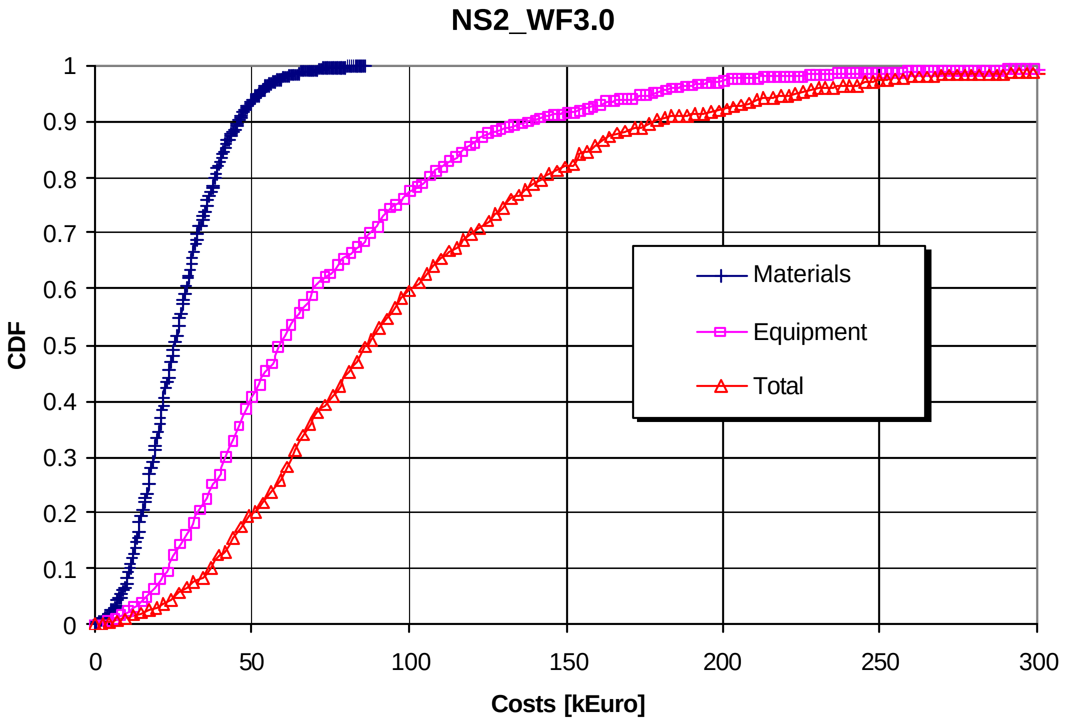

Fig. 6.4.4: *Cumulative Distribution Function of the repair costs for configuration NS2_WF3.0*

Table 6.4.1: Summary of results for configuration NS2_WF3.0

Name		Mean	Std Dev	x_5	x_{95}
Downtime inspection	[hr]	80.1	7.8	67.8	93.3
Downtime repair	[hr]	133.4	105.0	27.0	327.6
Total downtime	[hr]	213.5	106.5	103.4	406.5
Loss of production	[kWh]	241331.3	118320.0	119275.3	465854.8
Costs inspection	[€]	50713.1	10983.5	40053.0	63793.4
Cost materials repair	*[€]*	*27285.9*	*13872.2*	*8290.3*	*52630.8*
Cost equipment repair	*[€]*	*73405.3*	*53611.5*	*16803.8*	*177209.2*
Costs repair	[€]	100930.7	64040.3	25283.7	224208.5
Revenue loss	[€]	19306.5	9465.6	9542.0	37268.4
TOTAL COSTS	[k€]	170952.5	74684.0	83141.1	312006.7

6.5 Sensitivity analysis

In the previous section it was derived that the total costs can only be assessed with a great uncertainty, which is mainly caused by the uncertainty in the repair costs (see Fig. 6.4.3 and Fig. 6.4.4). The scatter in the calculated results is the result of the uncertainty in the input parameters. To gain insight in the degree to which uncertainty in the repair costs is affected by uncertainty of the individual input variables within the model, a sensitivity analysis can be made with @Risk [5,7]. Tornado charts provide a pictorial representation of the results of a sensitivity analysis. The results of the sensitivity analyses for the repair costs is shown in Fig. 6.5.1. The coefficients depicted in this @RISK sensitivity graph are calculated with the so called multivariate stepwise regression analysis method. A regression value of 0 indicates that there is no significant relation between the input and the output. To explain the results of the regression, an output variable *Z*, with standard deviation s_Z,, is considered. The regression coefficient of a certain input variable *X* with standard deviation s_X, is denoted with ?. This coefficient can either be positive or negative. A change in the input variable of 1 standard deviation (s_X) will lead to a change of ?·s_Z in the output variable. It is standard practice to plot the variables from the top down in decreasing size of correlation. In general the tornado chart is very useful for identifying the key variables and uncertain parameters that are driving the result of the model. It makes sense that, if the uncertainty of these key parameters can be reduced through improved knowledge, the total uncertainty in the calculated results will be reduced too. However, to judge whether a reduction in uncertainty can be achieved a distinction has to be made between input variables with inherent variability and input parameters with statistical uncertainty. Inherent variability is a result of a physical process and it can not be reduced. Only a reduction in the scatter of parameters with statistical uncertainty can cause a reduction in the uncertainty of the final result, f.i. through carrying out more measurements or through improved knowledge.

From Fig. 6.5.1 it appears that the number of lightning strikes per thunderstorm is by far the most important parameter with respect to the uncertainty in the long-term yearly average repair costs. Lightning is a physical phenomenon, which is accompanied by inherent variability in the number of lightning strikes per thunderstorm. The occurrence of lightning strikes during a thunderstorm can be considered as a Poisson process [7]. In Fig. 6.2.2 the probability distribution for the number of lightning strikes per thunderstorm is depicted, and the large amount of scatter in the number of lightning strikes that that can be expected is clear. This scatter can not be decreased as it the results of a physical process. The next three parameters are related to the waiting time of equipment. During the waiting time the equipment can not leave the harbour or can not start its activities due to bad weather conditions. The waiting time depends on the weather conditions and the weather window of the equipment. The weather

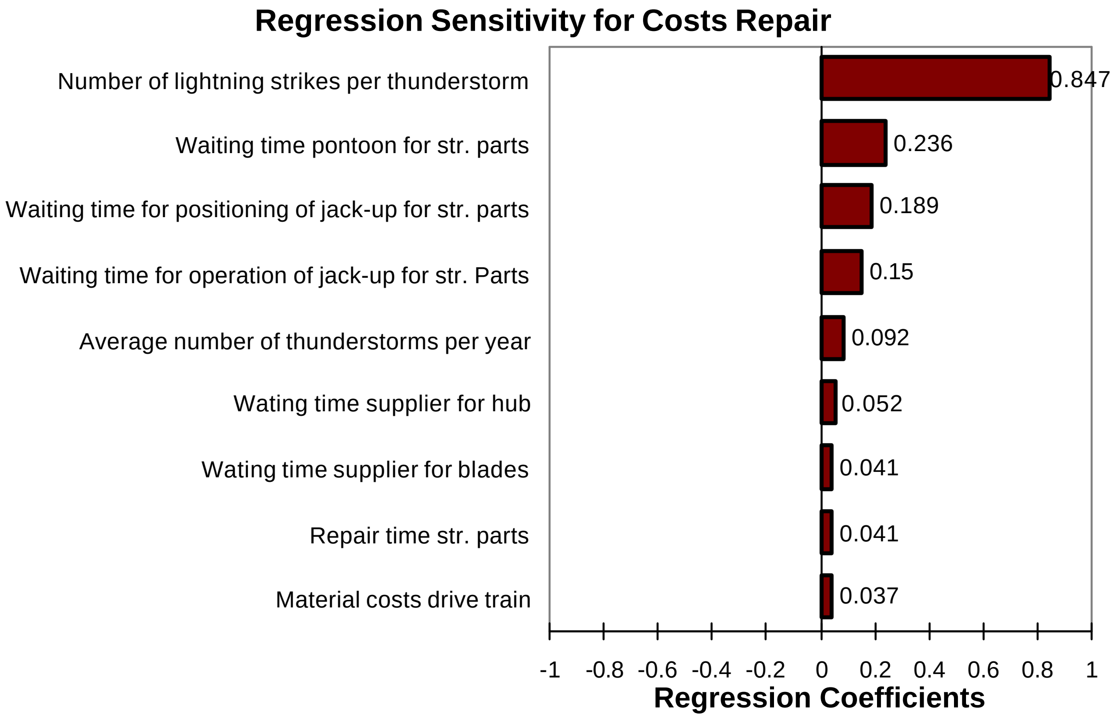

Fig. 6.5.1: *Regression coefficients for repair costs of configuration NS2_WF3.0*

conditions (wind and waves) do have a very stochastic nature with inherent variability, which can not be influenced given a certain repair strategy. The waiting time is dependent on the weather conditions and the weather window of the devices to be deployed. The weather conditions are the result of nature and can not be influenced, while the weather windows are fixed.

So the upper four input parameters do have inherent variability and the uncertainty in the repair costs can not be reduced through these parameters. The first parameter that does have statistical uncertainty is the average number of thunderstorms per year. The average number of thunderstorms per year is determined on six year measurements [4]. Based on these measurements the average number thunderstorms is described by a normal distribution with mean 1.69 and standard deviation 0.07. By considering more measurements this standard deviation can probably be reduced. However, the regression coefficient for this parameter is relative small, so that it will not affect significantly the uncertainty in the repair costs.

6.6 Conclusions

Based on the more detailed analyses for the standard configuration NS2_WF3.0, the following conclusions can be drawn.

- Most thunderstorms occur in during summer (54%) and autumn (34%) and consequently most costs are made in these seasons. In summer the capacity factor is relatively low and the weather conditions are good, which is favourable for accessibility, the downtime and the waiting time. The cost in summer are 51 % of the total, which is a little less than could be expected when only the number of thunderstorms is considered. However, the costs in autumn are 37% of the total, which is a just a little higher than could be expected on basis of the number of thunderstorms.
- In the standard configuration the control system, the electrical system, the sensors and the blades are equipped with a protection system. The efficiency of the protection is assumed to be 90%. As a result of this 72.9 % of the lightning strikes will not cause damage anymore.

Furthermore after inspection only 8.3% of the lightning strikes have caused damages that need repair after inspection. Of these remaining damages most concern the electrical system (15.7%) and the rotor blades (14.5%), while the structural parts contribute only for 4.8%. However the repair of the structural parts contribute towards the total repair costs for 45%. This is caused by the fact that for the repair of structural parts a pontoon and a jack-up are needed and these devices are responsible for relative long waiting times due to their weather windows.

- Although lightning strikes will most of the times hit a rotor blade, an efficient protection system can make that only 10% of the total repair costs are for the blades.
- The calculated costs show a large uncertainty. The coefficient of variation, which is defined as the standard deviation divided by the mean value, is about 44 % for the total costs. The scatter in the total costs is mainly caused by the scatter in the repair costs.
- The uncertainty in the repair costs is caused by the uncertainty in the input variables. The parameters that contribute the most to the uncertainty in the repair costs are the number of lightning strikes during a thunderstorm and the waiting time of the equipment needed for the repair of structural parts. The uncertainty in these most important input parameters is caused by weather conditions and has to be classified as inherent variability. The importance of the parameters with statistical uncertainty is limited as compared to these inherent variability, so the uncertainty in the repair costs is mainly caused by the stochastic nature of the climate (lightning, wind and waves). Hence the scatter in the costs of lightning damage is inevitable, and the parties involved with lightning damage have to find a way to deal with this uncertainty.

7. CONCLUDING REMARKS

With the probabilistic cost model [6] a number of analyses have been made in order to:

1. estimate the annual costs of lightning damage;
2. assess the influence of the location and the lay-out of the offshore wind farm on the costs;
3. assess the influence of the repair strategy on the costs;
4. provide guidelines on the amount of money that could be invested in lightning protection systems;
5. determine the most important cost drivers;
6. identify the most important input parameters w.r.t. the uncertainty in the calculated costs.

The general description of the case studies and the assumptions made are outlined in detail in chapter 2. The most important aspects are given below.

- It is known that not every lightning strike will lead to a shutdown. However, no information is available to quantify this, and the conservative assumption has been made that each lightning strike will cause a shutdown, and the wind turbine will not be started again until the inspection following an alarm has been completed.
- The frequency distribution is based on the data in the WMEP database of ISET. Although protection systems were present in some of the turbines in this database, it is assumed that the presented fault distribution gives the probability that a certain type of damage will occur in a wind turbine without any protection system. The reason for this is that it was not possible to distinguish between turbines with and turbines without protections systems. This implies that the assessment of the damage in the cost model might be conservative. Furthermore it was assumed that one lightning strike causes only damage in one damage class. The phenomenon of multiple damages due to one lightning strike is not considered here. This may lead to less conservative results.
- The wind turbines are standard equipped with a lightning protection system for the electrical system, the control system, the sensors and the blades only. The efficiency of this lightning protection system is assumed to be 90% as a default value.
- The small wind turbines (1.5 MW) are not equipped with an internal crane for heavy equipment.
- The maintenance for the near shore wind farms is done from a nearby harbour, while the far offshore wind farm is equipped with a substation at which the suppliers are stationed.
- The data (cost etc.) for the equipment is based on generic numbers. For a specific case these data can be tuned to the situation considered.
- The data for lightning and the wind data used to determine the accessibility are not correlated. Thunderstorms mostly do not occur at high wind speeds, and consequently the waiting time is overestimated.

In the analyses the long term average yearly costs have been calculated. This has been done as follows. First the long term average costs per season have been calculated and these numbers are added up to obtain the yearly numbers. The long term averaged costs per season have been calculated as follows. The long term costs per lightning strike are multiplied by the expected number of lightning strikes to get the long term costs per thunderstorm, and next this number is multiplied with the average number of thunderstorms per season. In fact the statistical distribution of the long term costs per thunderstorm are calculated.

The 6 points mentioned in the beginning are treated in detail in the chapters 3 through 6. Each chapter is closed with the conclusion w.r.t. the specific analyses described in that chapter. Based on these results the following main conclusions can be drawn.

- For offshore locations less lightning damage will occur as compared to onshore locations. There is a trend that going further offshore a further decrease in lightning damage can be achieved. This trend is based on measurements for two near shore locations and one far offshore location. Further research should be done to underpin this trend for the development of new sites for OWECS.

- For a 100 MW offshore wind farm equipped with a standard protection system with an efficiency of 90%, the inspection and repair costs due to lightning are in the range of 116 - 273 k€ per year, which is about 1.7 – 3.9 % of the total maintenance costs. As the costs of lightning are only minor as compared to the total maintenance costs it is not worthwhile to optimise the costs of lightning separately. Efforts to lower the costs of lightning damage should be made as part of an integral maintenance optimisation approach only.
- A way to reduce the costs of inspection can probably be achieved by considering the possibilities of a remote reset of the turbines so that it might occur that a whole inspection could be skipped or postponed to the moment of scheduled preventive maintenance.
- For the design of a wind farm with a prescribed size for the installed power it is recommended to use fewer but greater wind turbines.
- The use of a helicopter, a supplier with OAS or a supplier with MOB will lead to different downtimes. However, the revenue losses due to these downtimes are only a small part of the total costs, and because the prices of the equipment are uncertain due to its dependence on negotiations and contracts it not possible to make an objective comparison based on costs. Depending on the contracts the repair strategies using a helicopter in combination with a supplier or using a supplier alone without a helicopter might be competitive.
- It is recommended to equip offshore wind turbines with internal cranes, which can do most of the external hoisting. The use of a jack-up and a pontoon should be restricted to the replacement of large structural parts only. The repair costs will increase significantly in case a jack-up has to be used for all types of external hoisting.
- For the electrical system, the control system, the sensors and the blades, protection system are available, which can lead to a reduction of damage in these components of about 90%. When the 3.0 MW wind turbines in a 100 MW wind farm are equipped with these protection system a yearly reduction in costs due to lightning damage of 5400 € per year per turbine can be achieved. For a wind farm with a life time of 20 years this justifies an investment of 108 k€ per turbine.
- For a 100 MW offshore wind farm with 3.0 MW turbines equipped with a standard protection system with an efficiency of 90% the unavailability due to lightning will be less than 0.2%. For severe damages (FTC3) for which a maintenance action with external hoisting is needed, the failure rate will decrease from 0.7 per year to 0.11 per year when the standard protection is applied as compared to the situation where no protection is present. So if a standard protection system is used it is expected that every 9 years a maintenance action with external hoisting is needed.
- In the standard configuration the control system, the electrical system, the sensors and the blades are equipped with a protection system. The efficiency of the protection is assumed to be 90%. As a result of this 72.9 % of the lightning strikes will not cause damage anymore. Furthermore after inspection only 8.3% of the lightning strikes have caused a damage that need repair after inspection. Of these remaining damages most concern the electrical system (15.7%) and the rotor blades (14.5%), while the structural parts contribute only for 4.8%. However the repair of the structural parts contribute towards the total repair costs for 45%. This is caused by the fact that for the repair of structural parts a pontoon and a jack-up are needed and these devices are responsible for relative long waiting times due to their weather windows. Although lightning strikes will most of the times hit a rotor blade, an efficient protection system can make that only 10% of the total repair costs are for the blades.
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costs of lightning damage is inevitable, and the parties involved with lightning damage have to find a way to deal with this uncertainty.

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