D3.1 - O&M Assessment of LEP Repair

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Summary

Due to continuous precipitation impacts, over the course of their lifetime, wind turbine blades are prone to damage from rain induced leading edge erosion (LEE). LEE damage starts as small pits and cracks on the topcoat and can propagate to the substrate if left unchecked. Due to these damages, not only does the aerodynamic performance of the turbine degrade, the structural safety of the turbine is also at risk. Modern wind turbines are thus equipped with leading edge protection (LEP) systems to protect them against LEE damage. While LEPs can sustain more rain drop impact before showing visible damage, they are also susceptible to LEE. Repairing LEPs at appropriate times is crucial to ensure a safe and smooth operation of the wind turbine.

In this study, the current maintenance approach to deal with leading edge erosion is presented. The strategies presented reflect the state-of-the-art approach followed by wind farm operators currently. Key to a successful maintenance effort is identifying and classifying the erosion damage. The classification from the IEA task (https://iea-wind.org/task46/) is presented as a reference. Maintenance actions for different types of repair are modeled using TNO's in-house logistic modelling tool UWiSE. Simulations are carried to select the appropriate start date for carrying out the repair actions.

The Ijmuiden Ver site was chosen for the study as data on relative humidity and precipitation was available at this location for over three years. Two different types of leading edge protection (LEP) methods - soft shell and roll-on LEPs were considered. Repairs at different severity levels of erosion was also modelled for each of the two LEPs. The number of days a turbine would need to be shut down to perform these operations was analyzed. Repairing soft shell LEPs resulted in lower turbine downtime than roll-on LEPs despite needing longer repair times due to the different weather restrictions on the two. The relative humidity levels at the chosen site played a crucial role in this result highlighting the possibility of site specific LEP selection.

Finally, a more holistic and system-wide approach for the selection of this start date incorporating the present work is described.

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1 Introduction

1.1 Background

This report is a deliverable for the TKI Offshore Energy project *PRecipitation atlas for Offshore Wind blade Erosion Support System (PROWESS)*. The project is sponsored by the Netherlands Enterprise Agency (Rijksdienst voor Ondernemend Nederland, RVO) under the project code HER+-00900701. This project is implemented within the framework of the Top Sector Energy. The project aims to lower the cost of damage cause by leading edge erosion (LEE), through its work packages:

1. **WP1 - Monitoring system network for LEE characterization** - wherein the work package objective is to
    - execute an instrumentation and monitoring campaign offshore and onshore with precipitation sensors,
    - couple the resulting information with existing weather stations
    - correlate weather-related variables with LEE
2. **WP2 - Modelling precipitation prediction correlated with LEE**, wherein the work package objective is to
    - generate short- and long-term prediction based on the erosion rates found in WP1, at different sites, to have long-term data with large spatial coverage over the Dutch North Sea.
3. **WP3 - O&M and AEP assessment related to LEE** - wherein the work package objective is to
    - implement the existing O&M cost model with the erosion atlas to create the investment decision support system

The project consortium is composed of (1) TNO, (2) Whiffle, (3) Sky Echo, (4) Equinor, (5) Eneco, and (6) Shell Global Solutions International BV. In this project, TNO is involved:

- The precipitation and wind monitoring campaign
- The medium- and long-term meteorological modelling
- LEE operations and maintenance (O&M) calculations
- Coordination of the project and the dissemination of the results

This report investigates potential economic and logistical benefits of performing LEE repair with different leading edge protection (LEP) systems, as well as at different stages of LEE damage.

1.2 Scope of work

The work in this report focuses on quantifying the potential risks and benefits of performing LEE repair at different damage stages. The results are used in the formulation of a decision support system that takes into account the direct costs of operations and maintenance (O&M), as well as the potential annual energy production (AEP) loss due to turbines being shut down when repairing LEE damage. This decision support system would enable offshore wind service providers to further optimize their LEE repair strategies, thus increasing efficiency and reducing costs. In particular, the scope of work is to:

- identify the progression of LEE damage
- identify types of repair appropriate at different stages of LEE damage
- identify the maintenance actions required to perform these repairs, along with their resource requirements and operational limits
- model and evaluate these maintenance actions in terms of accessibility
- formulate and describe a decision support system that makes use of the above evaluation

1.3 Logistics Modelling - UWiSE

TNO Wind Energy Group is a market leader, developer, and owner of industry-standard O&M strategy modelling tools designed especially for offshore wind. These tools have been used for more than 15 years. TNO provides consultancy and software licenses and has a customer portfolio (O&M) of more than 30 leading companies in the offshore wind energy-related industry, including nearly all developers and wind turbine manufacturers currently active in the offshore wind sector.

UWiSE O&M Planner was developed based on TNO wind group's long-standing expertise in the Excel-based O&M cost simulation tool "ECN O&M Tool", which has been the standard in the wind energy industry since 2005. An upgrade was made in 2011 to a MATLAB-based simulation software "ECN O&M Calculator". As the wind energy industry continues to evolve, the simulation aims to model increasingly complex logistics in O&M planning for larger and upcoming offshore wind farms. As a result, TNO has been developing "UWiSE O&M Planner" and using the software for long-term O&M strategic planning since 2020.

UWiSE O&M Planner is built on a discrete event-based logistic simulation engine UWiSE (Unified Wind farm Simulation Environment), developed by TNO in 2017 onwards. The software enables users to perform multi-year simulations to calculate O&M costs, wind farm availability and energy production while taking into account uncertainties of weather and wind farm component reliability. Multi-year simulations that consider weather uncertainty by using the Monte Carlo sampling technique provide a valuable framework for decision-making in the planning, design, and operation of offshore wind farms. By running simulations for multiple weather years, the software calculates statistical estimates of the frequency and duration of favorable weather conditions for specific operations. This helps to identify patterns, seasonal variations, and the probability of encountering adverse weather. The software presents the impacts on O&M's key performance indicators of deploying different types and numbers of vessels each with their weather limits of operation. Figure 2 shows the user interface of UWiSE O&M Planner.

The software aims to:

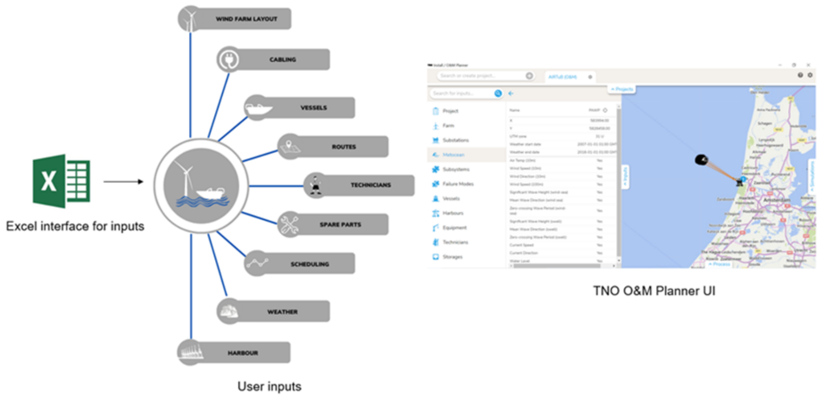

Figure 1.1: UWiSE O&M Planner graphical representation

- Assist wind farm operators in optimizing O&M choices between various transportation types, equipment, personnel shift and spare part stock management options in terms of standard KPIs such as wind farm availability and repair costs.
- Conduct scenario analysis for an O&M project by varying the available resources.
- Provide an overview of preventive and corrective maintenance activities, the delays encountered (weather or resource) and associated costs.
- Provide insights into the wind farm downtime per component failure mode and per maintenance activities.
- Evaluate the O&M cost impacts of innovative concepts (e.g. large component replacement with self-erecting crane).

The software will be used to quantify the differences between the individual maintenance actions, taking into account their operational limits and their required resources.

1.4 Report structure

The remaining chapters of this report describe the approach and results of the assessment. Chapter 2 describes the problem of leading edge erosion, current mitigation strategies and the maintenance process based on stakeholder interviews. Chapter 3 describes the modelling approach, results and discussion of the current study. A holistic predictive maintenance strategy is proposed in chapter 4.

2 O&M for leading edge erosion mitigation and repair

As the cumulative capacity of offshore wind continues to grow, research efforts are focusing more on increasing operational performance and decreasing maintenance costs, and the field of blade maintenance is rapidly growing in importance. In contrast with the maintenance of internal components, which can be monitored by means of increasingly sophisticated condition-based monitoring techniques, blade maintenance is difficult to monitor and currently relies largely on manual inspections and visual imagery. Surface erosion of wind turbine blades, which mostly occurs on the leading edge, is one of the more prominent challenges for wind energy development. This is known as leading edge erosion (LEE). Studies indicate that LEE is a major contributor to unscheduled repair of wind turbines, with erosion damage being 12 times more likely than structural failures [1]. Unscheduled repairs, in total, are reported to account for up to 65% of the O&M costs [2] with blade repairs specifically being about 20%-25% of unscheduled repairs [3]. Thus, LEE damage accounts for a significant portion of O&M costs and labour required for the O&M effort.

2.1 LEE Progression and Classification

Leading edge erosion is mostly caused by the repeated impingement of precipitation such as rain or hail during wind turbine operation. Over time, rain drop (or hail) impacts cause fatigue damage to the surface material of the blade, which leads to material loss and subsequently increased surface roughness. Modeling the progression of erosion on modern wind turbine blades is an ongoing research area. The most important factors that determine the erosion levels are the rain drop size and the relative velocity between the blade and the rain droplets. This phenomena is especially prominent (and is often first seen) close to the tip of the blade, where the relative velocity is the highest.

The progression of LEE is typically modelled through material loss using damage models, such as the Springer model [4] or droplet fatigue models [5], which describes the factors that determine the LEE progression on wind turbines to be

- Precipitation characteristics (e.g. droplet size, velocity, and number of impacts),
- Turbine operation (e.g. rotational velocity), and
- Coating/substrate material properties.

The progression of leading edge (LE) damage for a typical wind turbine is shown in fig. 2.1. This figure, which assumes constant fatigue damage through time, highlights the three phases of leading edge erosion:

1. The incubation period - no visible damage occurs and the duration depends on tip speeds, precipitation characteristics and material properties.
2. A period of linear mass loss - the damage typically starts as small pits and cracks that appear sporadically on the surface of the blade.
3. A period of non-linear mass loss - the small damages accumulates over time which then grow and propagate through the blade laminate structure.

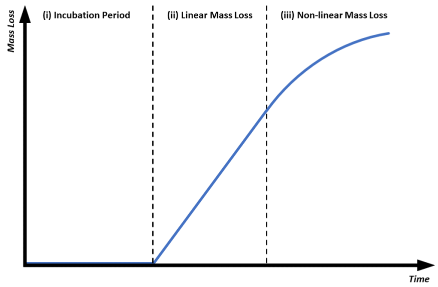

Figure 2.1: Typical damage progression, assuming constant precipitation

Figure 2.2 shows an example of typical erosion patterns throughout the progression of LEE for a modern wind turbine blade. The LEE atlas developed in WP2 of this project seeks to map

Erosion Description	Erosion Depth [mm]	Average Feature Diameter [mm]	Approximate chord coverage	Erosion Pattern
Small pinholes of missing paint distributed across LE with some grouping.	0.1-0.2	2	3%	
Pinholes have coalesced into larger eroded patches.	0.1-0.2	15	3%	
Affected area has increased, with isolated larger patches with a greater depth.	0.3-0.5	20/40	5%	
Patches have coalesced further, and depth has increased.	0.5-0.8	40	5%	
Large areas of LE laminate exposed.	0.8-1.2	>500	8%	

Figure 2.2: Visual description of leading edge erosion patterns, taken from [6]

the erosion risk for wind farm operating in the North Sea and Northwestern Europe based on precipitation simulations, estimation of the incubation period by use of a more physics-based model, presenting an improvement on the classic Springer model [7].

Turbine operators can deal with LEE in one of three ways -

- Accept the damage - Where the operator accepts the damage due to LEE and no efforts are made to counter it. This strategy is risky as in addition to energy losses leading to lost revenue, the turbine will also be susceptible to damage over time which might require expensive repairs or replacements.
- Minimise the damage - Operators can de-rate the turbine under heavy precipitation conditions when erosion is likely to occur. With this strategy, the lost revenue due to

stopping the turbine is offset by reducing the need to repair the turbine blade. One of the main contributors to LEE damage is the relative speed between rain drops and turbine blade, and by down-rating the turbine this speed is reduced keeping the erosion damage to a minimum.

- Mitigate damage by LEPs - Operators can apply leading edge protection (LEPs) devices to protect the surface of the turbine against erosion damage. While there is an extra initial cost, the turbine can operate normally in all conditions and the LEP protects against severe erosion damage avoiding lost revenue due to either energy loss by erosion or down-rating the turbine. A combination of minimising the damage and preventing the damage can also be pursued to further protect the turbine against LEE.

2.1.1 Leading Edge Protection

Modern turbines are typically equipped with LEPs. LEPs can either be retrofit on to existing turbines or can be applied by the manufacturer during the manufacture of the blade. Different LEP products are available in the market and can be categorized into three main types [8] -

1. Shells (also known as soft shell LEPs) which are precast according to the shape of each turbine blade. They are installed on the blade with an adhesive and the edges are sealed with a sealant to prevent water ingress. This LEP type has the highest level of erosion protection. However, there is very little long-term experience with modern soft shells and difficulties are encountered in applying these to turbine tips edges and loss of adhesion at edges.
2. Tapes or Roll-on LEPs which are supplied in rolls. The adhesive is pre-applied on the LEP tape, however, adhesion promoters and application solutions are required during installation. Edge sealant should also be applied to protect the edges from water ingress. This solution provides solid erosion resistance, however, it degrades under the effect of UV radiation.
3. Coating is characterised by higher elasticity and flexibility than the normal paint applied on the other areas of the blade. The solution is suitable in combination with LEP shells with the shell mounted on top.

The LEPs can installed as retrofits or during manufacture. In this study the soft shell type LEPs and the roll-on LEPs are considered. The different layers of a wind turbine blade equipped with LEPs is shown in fig. 2.3. While the LEPs protect the topcoat and the inner layers from being

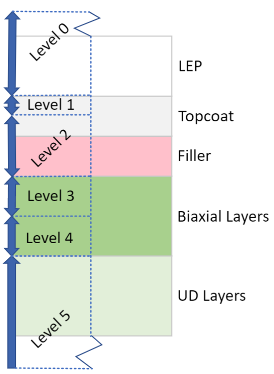

Figure 2.3: Schematic of the layers of a wind turbine blade leading edge with an LEP applied.

eroded, they are themselves susceptible to erosion. The incubation periods of modern LEPs are reported to be in the order of 5-6 years and some like soft shells are reported to be over 20 years as opposed to the 2-4 years for the topcoat. Thus, no visible damage appears for a long time with LEPs and turbines can continue to operate without any aerodynamic loss. However, there is a large uncertainty in determining the incubation periods under turbine operating conditions and operators report damage at earlier intervals. This arises as a consequence of lack of understanding of the material properties of LEPs responsible for determining the damage behavior and the varying erosion risks at different locations. In the absence of a theoretical way to determine the damage behavior of LEPs accurately, empirical approaches to classify the observed damage have been devised.

2.1.2 LEE damage classification

As a means to provide a common damage classification system, an IEA Wind TCP Task 46 technical report [9] describes LEE damage with several categories and severity levels, as seen in Figure 2.4. Figure 2.3 also shows the layers of the wind turbine blade that become endangered with increasing severity levels of erosion.

Table 4-1 – Erosion Classification System.

	Severity Level					
Evaluation Criteria	0	1	2	3	4	5
Visual Condition (LEP)		Lightly worn external coating/LEP Instances of reduced LEP adhesion	Notable areas of localized damage on external coating/LEP Individual Instances of LEP adhesive failure.	LEP is largely compromised over a large area and no longer providing protection to underlying layers	Delamination of topcoat with immediate layer underneath clearly visible and exposed	Notable damage to substrate
Visual Condition (No LEP)		Erosion barely visible or pinholes	Localized pitting	Widespread or coherent pits, some gouges		
Mass-loss	Initial factory condition	Coating <10% Laminate 0%	Coating 10-50%, Laminate 0%	Coating 50-100%, Laminate <10%	Coating 100% Laminate 10-100%	Coating 100%, Laminate 100%
Aerodynamic Performance		Normal surface roughness Region 2 Power loss 0 -1%	Region 2 Power loss 1%-2%	Region 2 Power Loss 2%-3%	Region 2 Power loss 3-4%	Region 2 Power loss >4%
Blade Integrity		Initial erosion of topcoat	Erosion through topcoat	Initial exposure of immediate laminate layers	Erosion through immediate laminate layers	Exposure of structural laminate layers

Figure 2.4: Severity of LEE damage as defined in the IEA Task46.

This system allows for the classification of damage according to four criteria:

1. **Visual Condition** - The visually observable level of damage on the surface of the blade (either with or without LEP)
   Present LEE-related maintenance techniques rely heavily on visual inspection, either through rope-access technicians or through drone imagery. These methods allow for a description of surface erosion patterns, which can suggest but not directly quantify the level of damage.

2. **Mass Loss** - The physical amount of mass loss, compared to factory condition
   Having a clear idea of the mass loss can, if used in conjunction with the Springer model, lead to an estimation of estimated future erosion progression. This can, in turn, allow for an estimation of future revenue losses due to lower aerodynamic performance, as well as possible risks to blade integrity.

3. **Aerodynamic Performance** - The reduction in power generation during Region 2 (below-rated) operation

This parameter describes the effect of increased surface roughness on aerodynamic performance, which in turn can indicate likely AEP losses over the long-term. This effect is hardest to measure due to various other factors affecting the AEP.

4. **Blade Integrity** - The structural condition throughout the progression of LEE
   This parameter quantifies the possible risks to the structural integrity of the blade as progressive erosion exposes the inner blade elements. The increase in structural integrity, in addition to posing the risk of blade failure, also increase the difficulty of repair, and in extreme cases necessitate the full removal of the blade using expensive and time-inefficient equipment.

As LEPs themselves are susceptible to erosion, inspection and maintenance of wind turbines for erosion damage must be performed throughout the lifetime of a turbine. The current approach to maintenance of turbines is described in the next section.

2.2 LEE Maintenance Approaches

An example of a typical blade maintenance plan includes a visual inspection conducted every year in the spring, with a visual assessment of the condition of each blade. This visual assessment is then used to estimate the corresponding level of damage for each blade, which is used to create a complete maintenance plan to be carried out that summer. The order of repairs is normally done according to internal guidelines such as the one shown in Figure 2.5.

Figure 2.5: Blade damage categorization [10]

Technicians inspect individual turbine blades and report any observed damage along with the severity levels in the inspection reports. Wind farm operators then examine the reports and assess the reported damage on the entire wind farm to devise the maintenance plan for the upcoming summer period. The operators define the type of repair and the maintenance schedule for the wind farm. Maintenance crews are then dispatched to the wind farm.

2.2.1 LEP repair maintenance actions

Different levels of damage require different types of repair actions. The actions described below are based on extensive discussions with wind farm operators during the course of the project. Stakeholder interviews indicated a number of weather parameters important for LEE repair, for example, the application of an LEP coatings is sensitive to the relative humidity and dew point temperature at the blade, as well as the temperature of the blade itself. Only the relative humidity is considered here. Applications of adhesives also have similar limitations, which if not followed, risk premature de-bonding and failure. Thus, to obtain an accurate estimation of the timeline during which a repair procedure can be followed, the repair procedure must be modelled with high fidelity. To properly model a timeline in this manner, the model must take as input a description of the repair itself, with associated time durations and operational limitations, as well as the weather conditions around the time of repair. Actions for repairing damages up to level 2 and level 4 (as per fig. 2.4) are considered in this study. It is assumed that the turbine blades are equipped with LEPs. The repair actions for the two levels are described below.

2.2.1.1 Level 2 repair

At this severity level, damage is confined to LEP and top layer only. The intention of repairing at this level is to replace the topcoat if needed and the LEP. This action is typically carried out by rope access technicians for offshore wind turbines. Blade repair platforms can also be used for onshore turbines. The key steps in the repair procedure for offshore turbines are -

1. Identify a precipitation-free weather window of at least 2 days to ensure the curing process can be completed without disruptions. Further check if the significant wave height and wind speed requirements to transport the technicians and to perform rope access work are met within this window. In this study, a window of 2 days was considered to be sufficient.
2. Travel to the turbine and turn off turbine operation.
3. Set up the rope access equipment.
4. Check that the relative humidity levels at the turbine blade are within allowable limits for LEP application. Relative humidity at the turbine location is needed to determine the feasibility of repair but cannot be measured accurately from the shore. Thus, operators look for precipitation-free windows and check for relative humidity at the blade before performing the operation. Hence relative humidity is not considered to determine the weather window in step 1 but is checked at the turbine location.
5. Prepare the existing surface for LEP application -
   - Sand the damaged LEP coat,
   - Clean the surface to remove any other impurities,
   - Apply the new LEP product.
6. Wait for the LEP adhesives to cure.
7. Sand the cured surface to ensure proper activation.
8. Dismantle the rope access equipment.
9. Resume turbine operation.

The different restrictions for each of the actions are defined in table 2.1.

2.2.1.2 Level 4 repair

At this severity level, damage has propagated past the LEP and topcoat layers and has reached the laminate of the blade. The damaged laminate must be first replaced before applying a fresh topcoat and LEP layer. This action is also typically carried out by rope access technicians for offshore wind turbines. The key steps in the repair procedure for offshore turbines are -

Table 2.1: Maintenance actions for level 2 repair and their weather limits, duration and technician requirements.

Action	Duration	Weather limits	Resources
Travel to turbine		$H_s < 1.5m, W_s < 10m/s$	SOV
Stop turbine operation			
Prepare rope access	2h	$H_s < 1.5m, W_s < 10m/s$	3 Technicians
Surface preparation & LEP application	2h (Roll-on) 7h (Soft shell)	RH $< 85\%$ (Roll-on) RH $< 90\%$ (soft shell)	3 Technicians 3 Technicians
Dismantle rope access	2h	$H_s < 1.5m, W_s < 10m/s$	3 Technicians
Curing	24h	No rain	
Restart turbine and travel back		$H_s < 1.5m, W_s < 10m/s$	SOV

1. Identify precipitation-free weather window of at least 2 days. Further check if the significant wave height and wind speed requirements to perform rope access work are met within this window.
2. Travel to the turbine and set up the rope access equipment.
3. Check that the relative humidity levels at the turbine blade are within allowable limits for LEP application.
4. Grind and remove damaged laminate layers.
5. Chamfer the existing laminate to prepare for application of new layers.
6. Hand lay-up the new laminate layers with vacuum bag.
7. Wait for the laminate to cure before applying the new topcoat and LEP.
8. Prepare the existing surface for LEP application -
   - Clean the surface to remove any other impurities,
   - Apply the necessary coatings.
9. Dismantle the rope access equipment.
10. Wait for the coatings to cure before resuming turbine operations.
11. Travel back to shore.

The different restrictions for each of the actions are defined in table 2.2.

Table 2.2: Maintenance actions for level 4 repair and their weather limits, duration and technician requirements.

Action	Duration	Weather limits	Resources
Travel to turbine		$H_s < 1.5m, W_s < 10m/s$	SOV
Prepare rope access	2h	$H_s < 1.5m, W_s < 10m/s$	3 Technicians
Grinding, chamfering & laying new laminate	4h	Relative Humidity $< 85\%$	3 Technicians
Chamfer old laminate	4h	Relative Humidity $< 85\%$,	3 Technicians
Hand lay-up new laminate	4h	Relative Humidity $< 85\%$	3 Technicians
Curing	24h	rain ≈ 0,	
Surface preparation & LEP application	2h (Roll-on) 7h (Soft shell)	RH $< 85\%$ (Roll-on) RH $< 90\%$ (soft shell)	3 Technicians 3 Technicians
Dismantle rope access	2h	$H_s < 1.5m, W_s < 10m/s$	3 Technicians
Curing	24h	No rain	
Restart turbine and travel back		$H_s < 1.5m, W_s < 10m/s$	SOV

3 Modelling results

3.1 Modelling approach

Due to uncertainty in determining the incubation periods, this study does not consider modeling the progression of erosion itself, but rather focuses on the operational feasibility of performing these repairs. In this study, a comparison was conducted into how feasible it would be to perform a repair given level 2 or level 4 LEE damage (as defined in fig. 2.4). Differences in feasibility in repairing blades with both roll-on and soft shell LEP systems were considered. Soft shell LEPs are reported to have the longest incubation periods but are more expensive.

Table 3.1: Scenarios considered in this study

Scenario	LEP	Damage level
1	Roll-on	Level 2
2	Soft shell	Level 2
3	Roll-on	Level 4
4	Soft shell	Level 4

3.1.1 Location

The location of Ijmuiden Ver was chosen for this study as measurement data of relative humidity at at altitude of $90m$ was available for a period of three years. Wind speed data for this location was derived from the ERA5 database [11] and the significant wave height data from the North Sea Wave Database [12]. Since operators typically perform LEE related repair activities in summer, the results for the summer months (May to September) are presented in this chapter. To quantify the statistical dependence of the results on the actual weather data, data between 2012 and 2014 were considered.

There are plans to build large offshore wind farms at this location as seen in fig. 3.1. Based on the precipitation atlas being developed in this project (see fig. 3.2), this site had relatively high wind speeds of approximately $10m/s$ on average and experienced moderate rainfall of approximately $400mm$ in the year 2014. These conditions result in estimated incubation period of approximately 9 years. However, there are uncertainties in determining this number accurately.

3.1.2 Key performance indicators (KPIs)

As described earlier, operators typically perform inspections in the spring season to identify turbine blades that require repair. Technicians categorize the damage into different severity levels described in chapter 2. Operators then have to make the maintenance plan based on these inspection reports. Once the maintenance plans have been prepared identifying which turbines will be repaired, maintenance crews need to be dispatched to perform these repairs. However, determining the actual start date for these repairs can be challenging considering the various weather restrictions on performing LEP repair (see table 2.1 and table 2.2). In this study, simulations were performed to determine the operational feasibility of different start dates for these repairs at the Ijmuiden Ver site.

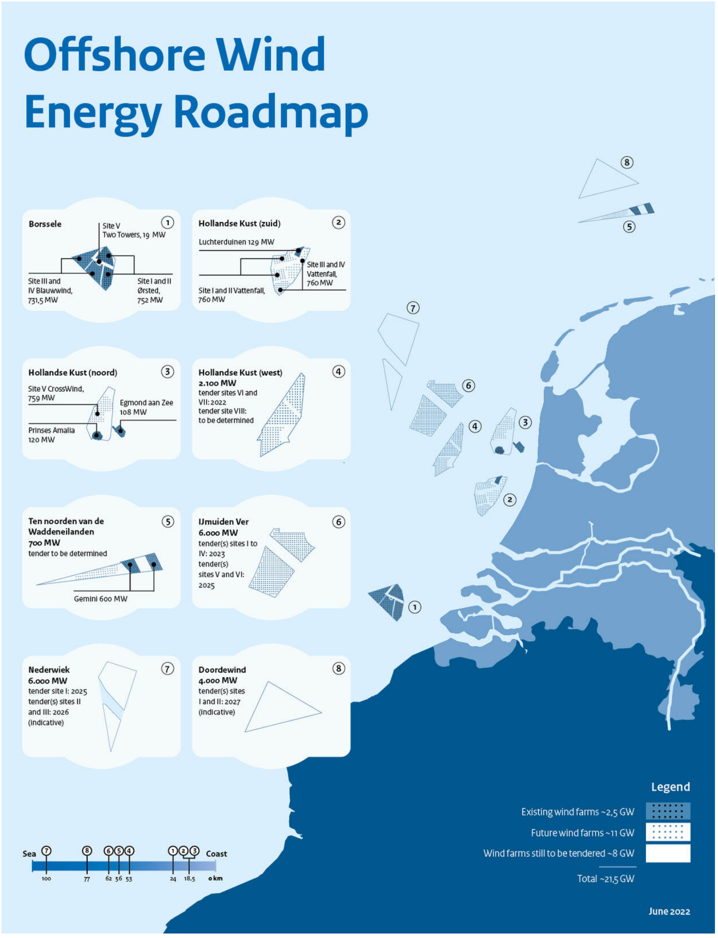

Figure 3.1: Planned wind farms in the Dutch North Sea region.

The operational feasibility was determined by calculating the potential weather delays faced by the operator, once a decision to proceed with the repair on a specific date was made. This calculation included identifying suitable weather windows that not only avoided precipitation for the operations but also considered the relative humidity restrictions for LEP application, as well as wind speed and significant wave height limitations for rope access tasks. The details of each operational step were determined through stakeholder interviews, and compiled to allow for modelling with UWiSE. Then, for each repair procedure, the operational feasibility was calculated given historical weather data at the Ijmuiden Ver wind farm. The high-fidelity nature of UWiSE allowed for a direct calculation of three KPIs considered as results here:

- **Days until shutdown**: the number of days, from the day the decision is made, until the technicians shut the turbine down for repair. This quantity measures the number of days operators have to wait to find a suitable weather window to start performing the operations and travel to the turbine.
- **Days until completion**: the number of days, from the day the decision is made, until the technicians complete the entirety of the repair. The quantity measures the number of days it would take for the technicians to complete the repair starting from the day the decision was made.
- **Downtime**: the number of days the turbine remains shutdown. This KPI measures the amount of time it takes from the moment technicians arrive at the turbine and shut

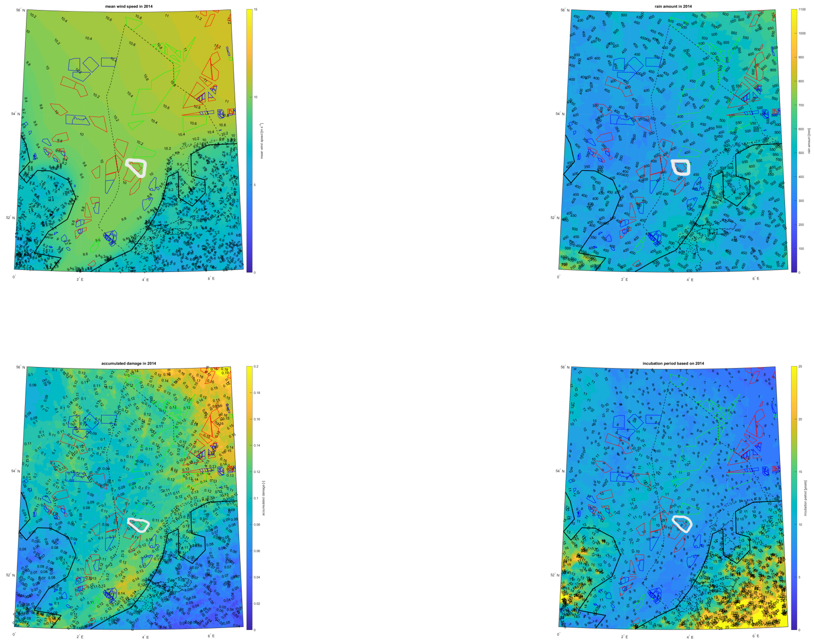

Figure 3.2: Wind speed, rain intensity, accumulated damage and estimated incubation period maps from the PROWESS Erosion Atlas for the year 2014 [13]. The location of Ijmuiden Ver is indicated in white.

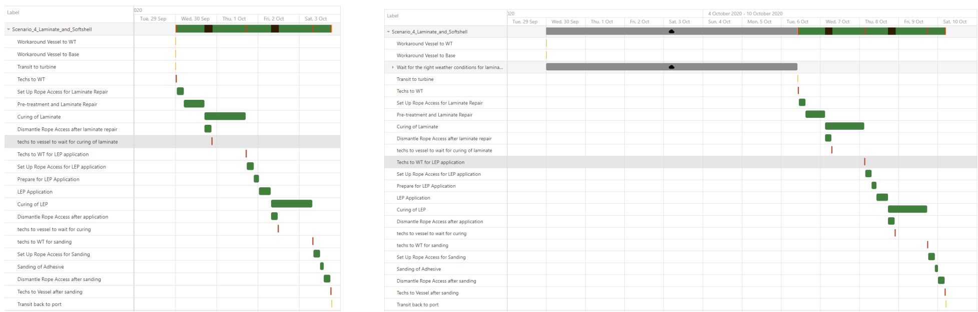

Figure 3.3: Example timelines of blade repair at stage 4 LEE damage (a) in perfect weather and (b) with weather delays

down the turbine to the moment when the repair is completed and technicians can turn it back on. It is also the difference between the two above-mentioned KPIs

Figure 3.3 shows a visual indication, taken from an example simulation similar to the ones conducted in this study, of the extent of these weather delays.

This approach would indicate, considering the extent of delays and downtime, the most suitable part of the summer to schedule repairs. As the repair processes for a blade with stage 4 LEE damage differ from those with stage 2 LEE damage, the potential increase in delay caused by postponing repairs can be quantified. Also, since the application of roll-on coating LEP and soft shell LEP differs in their operational time frames and humidity requirements, the results should reflect the feasibility of using these two types of LEPs at Ijmuiden Ver. This approach can potentially be combined with the incubation period information of the LEPs (like the precipitation atlas) to choose the appropriate LEP for a specific wind farm.

3.1.3 Simulation set up

For each of the scenarios, stochastic simulations were carried out with a beginning date (i.e. the date on which the operator begins to search for a precipitation-free weather window) on every day of the year, to determine the total amount of time that would be needed to complete the entire repair process. For each month, a total of 90 simulations, each with varying weather conditions, were performed and the distribution of results was statistically described with quartiles. LEPs are typically applied to the tip region i.e. approximately the last $30m$ of the blade. The repair times mentioned are considered for a modern $15MW$ turbine.

3.2 Results

In this section, the results of the simulations are presented. Every day in the period between May and September was considered as a decision date for a repair simulation, to capture the variation of weather within the summer period. Results are shown as a boxplot with the median in the center, and the box edges representing the values between the first and third quartiles.

Between fig. 3.4 and fig. 3.7 is the impact of weather restrictions on operational feasibility when conducting a repair at level 2 damage (Scenario 1: roll-on coating LEP system and Scenario 2: soft shell LEP system) and at level 4 damage (Scenario 3: roll-on coating LEP system and Scenario 4: soft shell LEP system).

3.2.1 Level 2

At this level of damage, only the LEP has to be repaired. Simulations were performed for roll-on LEPs (fig. 3.4) and soft-shell LEPs (fig. 3.5. The three KPIs - days until shutdown, days until completion and total downtime are presented from left to right.

For both the LEP types - roll-on and the soft shell, the lowest median days until shutdown was found in July and followed closely by September. The smallest spread of data was observed in the month of June. This indicates it is easiest to find a precipitation-free window in the month of July followed by September and June. The longest delay was observed in the month of August. Similarly, the days until completion was also lowest in July followed by September and June. However, the spread of the data was larger in the months of July and September compared to June. This indicates that it could be difficult to find weather windows with low relative humidity in these months compared to June. Consequently, the lowest downtime was observed in the month of July but the smallest spread in June.

Comparing the KPIs for a soft shell LEP to roll-on LEP, days of downtime was lowest for the repair of soft shell LEP despite their application being more time consuming. This can be attributed to the longer waiting period for a weather window for LEP application with the appropriate relative humidity levels. The requirement for relative humidity to be less than 85% for roll-on LEP is more stringent than the requirement for soft shell which requires the relative humidity to be less than 90%. However, in the month of June the downtime for roll-on LEP was lower. Typically, the number of days from when the decision to repair is made till the day it is completed is approximately a week. This includes waiting for a precipitation-free weather window. The only exception was August where 8-9 days were needed. The turbine remains down for less than 3 days on average.

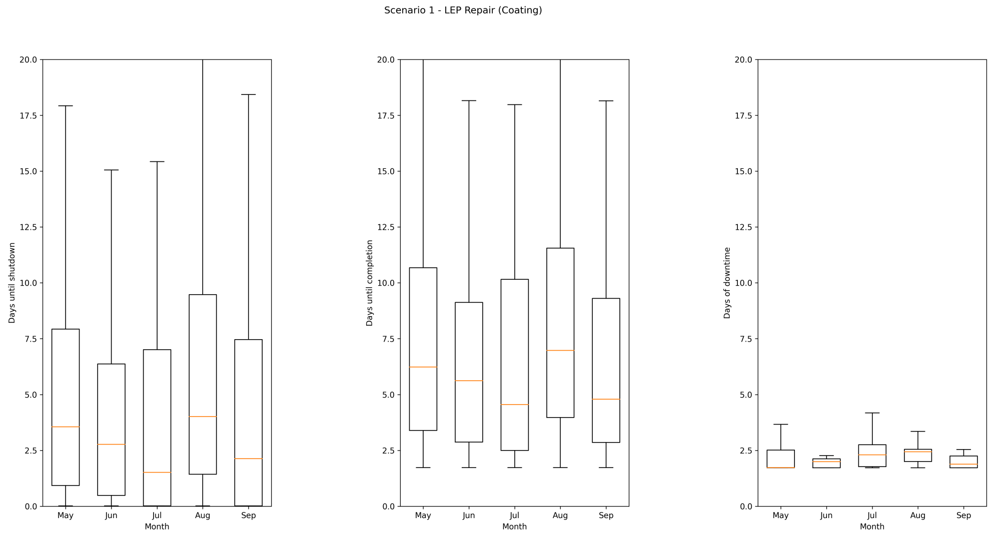

Figure 3.4: The impact of weather restrictions on repairing a blade at stage 2 LEE damage with a roll-on coating LEP system. The days until shutdown, days to completion of repair and the total turbine downtime are shown from left to right.

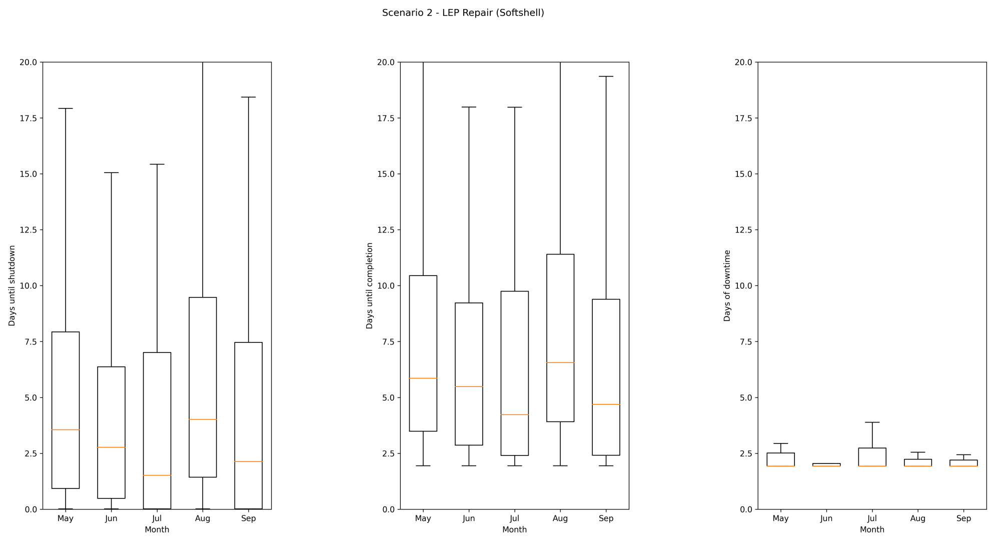

Figure 3.5: The impact of weather restrictions on repairing a blade at stage 2 LEE damage with a soft shell LEP system. The days until shutdown, days to completion of repair and the total turbine downtime are shown from left to right.

3.2.2 Level 4

At this level of damage, technicians need to repair the laminate layers and re-apply the LEP. This repair takes considerably longer than level 2. Under perfect weather conditions a total of 4 days for both soft shell and roll-on LEPs.

Once again, the days until shutdown is lowest is July followed by September and June indicating the ease of finding a precipitation-free window. The days until completion is however lowest in June followed by September and then July. This reflects the ease of finding weather windows

Table 3.2: Median values of the KPIs for scenarios 1 and 2.

(a) Days until shutdown.

Month	Roll-on LEP	Soft shell
May	5.067	5.067
June	4.880	4.880
July	3.692	3.692
August	6.562	6.562
September	4.633	4.633

(b) Days until completion.

Month	Roll-on LEP	Soft shell
May	7.590	7.568
June	7.321	7.343
July	6.459	6.206
August	9.052	8.838
September	6.932	6.879

(c) Total downtime in days.

Month	Roll-on LEP	Soft shell
May	2.522	2.500
June	2.441	2.463
July	2.767	2.513
August	2.489	2.275
September	2.298	2.245

with lower relative humidity levels once technicians reach the turbine location. Since longer repairs need to be performed at this level of damage, longer periods of low relative humidity levels are required. The median total downtime is the lowest in September compared to the other months. This KPI combines the earlier two KPIs and hence the combination of ease of finding weather windows with no precipitation and lower relative humidity levels make September the best month for this repair. Once again, the repairing soft shell LEPs had lower

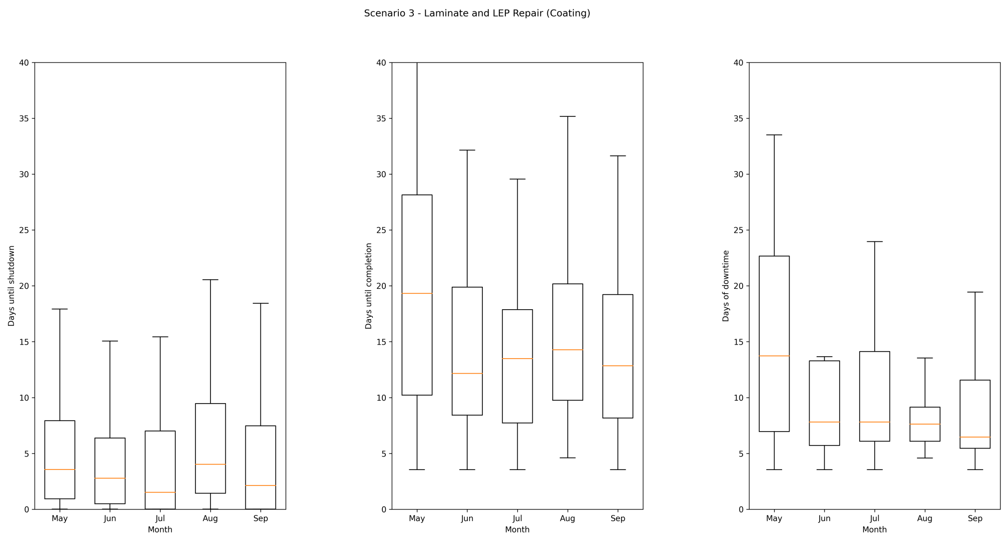

Figure 3.6: The impact of weather restrictions on repairing a blade at stage 4 LEE damage with a roll-on coating LEP system. The days until shutdown, days to completion of repair and the total turbine downtime are shown from left to right.

downtime than roll-on LEPs due to relative humidity requirements. The median downtime was significantly higher than level 2 damage. While expected, it should be noted that while the total turbine down time was less than 3 days for level 2, it was in the order of 9-15 days for level 4. Similar to level 2 repair, the soft shell LEP had lower down times. The total time of repair from decision to completion including waiting for precipitation-free windows varied between 14 days to 20 days for the roll-on LEP and between 12 days to 19 days for the soft shell. The resulting down time was lower of the soft shell due to less stringent relative humidity

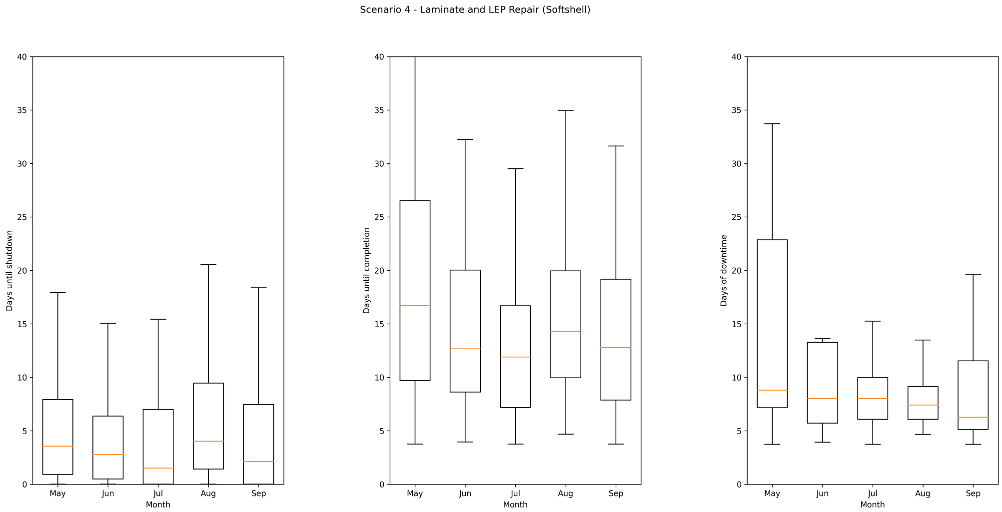

Figure 3.7: The impact of weather restrictions on repairing a blade at stage 4 LEE damage with a soft shell LEP system. The days until shutdown, days to completion of repair and the total turbine downtime are shown from left to right.

requirements.

Table 3.3: Median values of the KPIs for scenarios 3 and 4.

(a) Days until shutdown.

Month	Roll-on LEP	Soft shell
May	5.067	5.067
June	4.880	4.880
July	3.692	3.692
August	6.562	6.562
September	4.633	4.633

(b) Days until completion.

Month	Roll-on LEP	Soft shell
May	19.855	18.878
June	14.727	14.979
July	13.562	12.721
August	16.070	16.056
September	14.916	14.829

(c) Total downtime in days.

Month	Roll-on LEP	Soft shell
May	14.787	13.819
June	9.846	10.098
July	9.870	9.028
August	9.507	9.494
September	10.282	10.195

3.3 Discussion

The results suggests that applying a new soft shell LEP system results in lower turbine down time at this site, which could result in lower revenue losses in addition to the advantage of having a longer incubation period. A full comparison would have to take into account the higher upfront cost of a soft shell LEP system over the traditional roll-on coating. This result also highlights the possibility of site specific LEP selection based on historical precipitation data.

In the period under consideration, there were 643 days with no rainfall in this location. In this period, relative humidity was lower than 85% for 67% of the time and lower than 90% for 82% of the time. This can explain the shorter down times observed for the soft shell LEP than roll-on LEP despite the former requiring more repair time. Between the months of May to September, the lowest mean daily rain fall was recorded in the month of June followed by July (see fig. 3.8). The most number of days with no precipitation was in July and June and September. The relative humidity was the lowest in September and had the smallest spread in June.

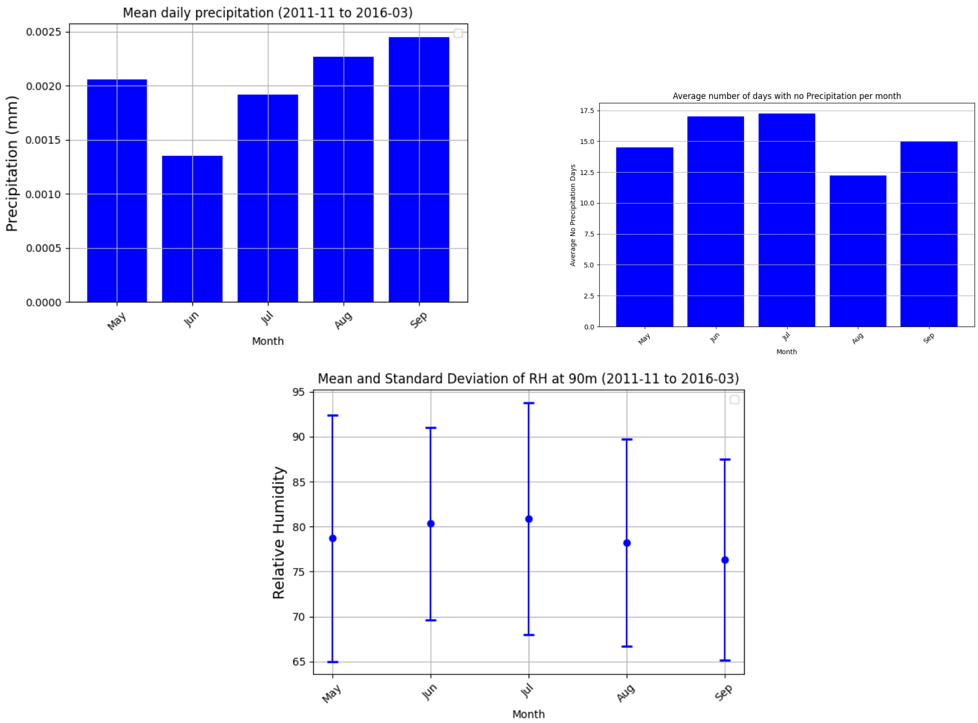

Figure 3.8: Monthly averages of relative humidity and precipitation levels at the Ijmuiden Ver location.

Another conclusion is that the risk of waiting until stage 4 LEE damage is quite high, with the calculated downtime values for level 4 increasing by several times higher than level 2, regardless of which LEP system is applied after repair. This additional revenue loss is important to take into consideration when estimating the optimal repair date for LEE repair.

3.4 Conclusions

In this study simulations were carried out to study the operational feasibility of repairing LEP damage on wind turbines at the Ijmuiden Ver wind farm site. Two types of LEPs were considered - roll-on LEPs and soft shell LEPs. Two different levels of repair were considered - level 2 and level 4. Historical weather data from years 2012 to 2014 was considered in the simulations. The key weather requirements were relative humidity and precipitation for repairing LEPs and significant wave heights and wind speeds for setting up rope access. Repair procedures were defined based on stakeholder interviews.

It was found that at the Ijmuiden Ver site repairing soft shell LEPs resulted in lower downtime than repairing roll-on LEPs due to less stringent relative humidity requirements. However, the difference was marginal. Overall, the downtime to perform level 2 repair was less than 3 days in all cases considered. Repairing the damage at level 4 was significantly longer than level 2, being in the range of 9-15 days which would result in large revenue losses and repair costs. This highlights the need to intervene and repair erosion damage as early as possible. Further, with data about precipitation, relative humidity at a wind farm location, site specific LEPs can be chosen to minimise the need for repairs.

4 Future Work

In this study, the selection of repair date was analysed based only available weather windows without any consideration of the costs. An optimal O&M strategy would determine the appropriate starting date for which the total associated cost is lowest.

4.1 Improved mitigation strategies for LEE

While this study focused on comparing the operational feasibility of repairing different types of LEP systems and at different stages of damage, this trade-off is one of many that should be considered when considering a preventive maintenance strategy. However since erosion is a gradual process, it is preferable to have a more proactive approach to mitigating erosion damage by considering the erosion damage process of LEPs, potential energy loss due to eroded blades, control strategies that can minimize erosion damage during heavy precipitation events among other factors. In this section, a possible preventive maintenance algorithm is proposed, as a strategy to define an optimal repair date.

4.1.1 Key parameters when planning LEE repair

The key parameters that are necessary to consider for a holistic LEE mitigation maintenance strategy are

- **Damage behavior of LEPs** - Visual inspection reports can be used to estimate the current state of the LEP and combined with the damage models like Springer model to predict the future state and estimate whether the LEP will experience level 2 repair. The IEA Wind TCP proposed a model wherein an inspection estimates the amount of mass loss (by using a visual assessment as a proxy), and uses that to estimate the remaining useful life of the blade. Future inspections would then be able to for corrective purposes, illustrated by fig. 4.1. An approach such as this, done for all the blades in the wind farm, can allow the service provider to properly prioritize the repairs. An advantage of incorporating this model is that one can quantify the benefits of performing preventive maintenance at the right time - such as when the erosion is still in the incubation phase. Improvements in monitoring technologies would play a large role in improving this system by reducing the uncertainty in these calculations.
- **Precipitation conditions at the site** - In the Dutch part of the North Sea, winters are typically rainier, windier, and with higher significant wave heights than in the summer period. The favourable weather conditions for performing repair in the summer, combined with lower revenue losses due to lower wind speeds, is why repairs are generally done in the summer. However, higher temperatures and relative humidity levels may also have an influence on the optimal repair date, depending on the chosen procedure and the chemical applications involved. In addition, historical or predicted precipitation conditions are needed for the damage models to determine the estimated damage level of LEPs. Precipitation conditions can also be used to estimate the time it takes to go from one severity level to another. For instance, if a turbine is estimated to reach level 4 from level 2 within a year, it is prudent to schedule the repair early.

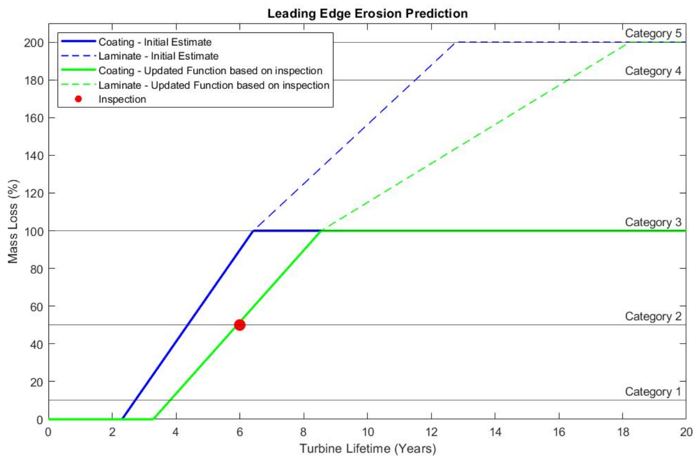

Figure 4.1: Blade damage categorization [9]

- **Cost estimation** - Estimating the energy loss due to different levels of erosion can give operators an estimate of the revenue loss due to LEE. The aerodynamic performance of damaged turbine blades is worse and tends to get progressively lower as erosion progresses. Operators can also de-rate turbines under heavy precipitation conditions to avoid erosion damage and the costs associated with such a strategy also needs to be accounted for. Further, the operators can also determine the cost of the repair actions at a given time based on current state of LEP and predicted states in the future. Based on the different costs, the optimal period to perform the repair can be chosen.

4.1.2 Predictive maintenance strategy

As mentioned previously, the decision to repair depends on different parameters, and thus it is important to understand the relationship between them. One possible approach is to execute algorithm that provides an optimal repair date for LEE repair, based on optimising the associated costs. In this section, an example of such an algorithm (shown visually in Figure 4.2) is qualitatively described. This approach directly ties the optimal repair date to the total associated cost, which comprises all costs incurred from the initial moment the algorithm is executed, to the moment the repair is completed.

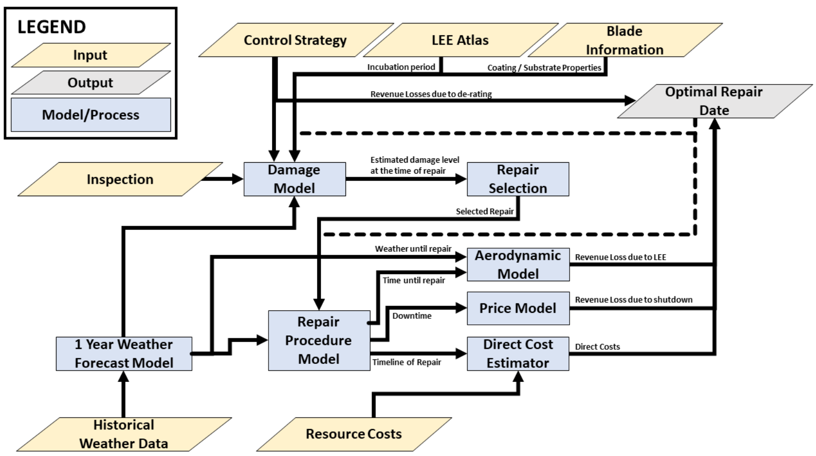

Figure 4.2: The relationship between key parameters relevant in LEE decision support

This algorithm defines the optimal repair date as the repair date for which the total associated cost is lowest. This cost is composed of four component costs which either are, or can be, influenced by the choice of repair date. Estimating revenue loss due to LEE, shutdown and the use of innovative control strategies is beyond the scope of this report and is not described here. The repair costs are described in more detail below.

The *direct costs of repair* are the costs of the resources that are required to perform the repair procedure. This is the sum total of the various technician, vessel, and equipment costs throughout the duration of the repair. These costs may not have a clear trend with respect to the repair date, but are a direct consequence of factors such as the inherently fluctuating nature of the resources themselves, but also the chartering strategy of those resources. For example, the marginal cost of using a vessel for LEE repair tasks chartered long-term is likely to be far lower than that of a short-term, as the former would be chartered anyways to perform other maintenance tasks. In this same manner, the incorporation of direct marginal costs can also include the implications of the maintenance strategy at large, as the operator can decide here whether to charter additional resources for these actions, or to use existing ones. The closer incorporation of the overall wind farm maintenance strategy could also have implications for the revenue losses, although that is left out of the current formulation for simplicity. Assuming no close coupling of this algorithm to the maintenance strategy at large, the algorithm must still consider a direct cost estimation model that considers:

- the marginal costs of the resources, which in turn depends on the chartering strategy of the resources considered, and
- the timeline of the repair

A visual of one possible approach to this sort of coupling is shown in fig. 4.3.

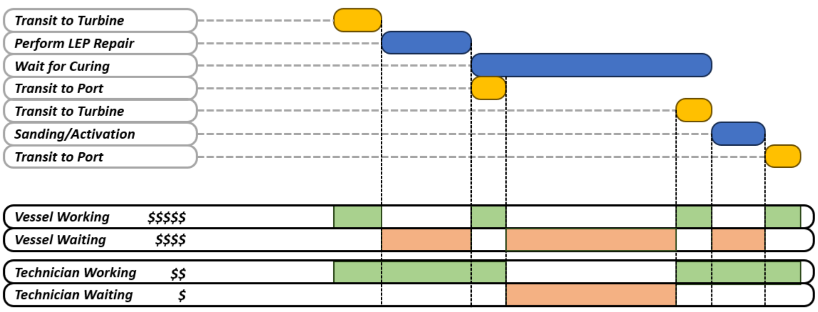

Figure 4.3: A possible approach to estimating direct costs from marginal costs repair timeline

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