OPTIMISATION OF WIND TURBINE INSPECTION INTERVALS

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ABSTRACT
The choice of correct inspection intervals poses a serious challenge to industries that utilise physical assets. Too short an interval increases operational cost and waste production time while too long an interval increases the likelihood of unexpected asset failures. Failure Modes and Effect Criticality Analysis (FMECA) is a technique that permits qualitative evaluation of assets' functions to predict critical failure modes and the resultant consequences to determine appropriate maintenance tasks for the assets. Delay-Time Maintenance Model (DTMM) is a quantitative maintenance optimisation technique that examines equipment failure patterns by taking into account failure consequences, inspection time and cost in order to determine optimum inspection interval. In this paper, a hybrid of FMECA and DTMM is used to assess the failure characteristics of a selected wind turbine. Optimal inspection intervals for critical subsystems of the wind turbine are determined to minimise its total life-cycle cost.

Key words: Wind Turbine, Maintenance Optimisation, Inspection interval, FMECA, Delay-Time-Model.

1 INTRODUCTION
Condition-Based Maintenance (CBM) is defined as *"...the most cost-effective means of maintaining critical equipment"* [1-2]. A CBM strategy constitutes maintenance tasks being carried out in response to the deterioration in the condition or performance of an asset or component as indicated by a condition monitoring process [3]. Suitable CBM actions for critical components and subsystems of a 600 kW wind turbine were selected in [4]. The selection was based upon identifiable warning signs that are measurable to assess the actual condition of incipient failures. The availability of reasonable time to take proactive action to prevent the failures from escalating to catastrophic events was also considered. CBM actions involve continuous monitoring or inspections carried out at pre-determined intervals. The latter has been popularised in most industries with uncomplicated asset configuration and working environment. However, inspection intervals are often determined subjectively with no quantitative assessment of the inherent technical and economic variables [5-6].

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The wind energy industry is currently exploring the use of condition monitoring systems [7] in conjunction with the traditional preventative (time-based) maintenance regimes. Vibration analysis (VA) is currently employed to monitor the performance of rotating equipment of wind turbines [8-9]. It includes monitoring of the gearbox and its components, generator bearings, main shaft and bearings, etc. The choice of correct inspection intervals for carrying out the vibration analysis poses a serious challenge. Too short an interval increases operational costs and waste production time while too long an interval increases the likelihood of unexpected failures with severe operational, health and safety consequences.

This paper examines the failure characteristics of a 600 kW horizontal axis wind turbine. It uses a hybrid of a quantitative maintenance optimisation technique (*Delay-Time Maintenance Mathematical Model*) and a qualitative technique for selecting maintenance tasks for physical assets (*Failure Modes and Effect Criticality Analysis*). Failure modes of critical subsystems of the wind turbine are identified. Failure consequences of the critical subsystems are determined and expressed in financial terms. Cost of inspections and repairs as well as the failure rates of components of the subsystems are evaluated. Optimal inspection intervals are determined for the subsystems of the wind turbine.

2 RATIONALE AND OBJECTIVE

The time taken by an incipient failure to deteriorate from inception to a complete loss of functional capability is fundamental to determining inspection intervals. This periodicity is usually referred to as a *Potential-to-Failure* (P-F) interval as illustrated conceptually in Figure 1. The P-F intervals for components are usually determined subjectively on the basis of engineering judgement and experience [10]. This often results in inadequate intervals [5] which adversely affect operational costs, productivity and profitability of the asset. The *P-F interval* determines the frequency of CBM inspection activities and is usually carried out at a time $\leq \frac{P-F\ \text{interval}}{2}$ [3]. Moubray [3] suggests five ways to determine P-F intervals for equipment but concludes: *"it is either impossible, impracticable or too expensive to try to determine P-F intervals on an empirical basis"*.

A simple quantitative maintenance mathematical model known as the Delay-Time exists in the field of Applied Mathematics and Operational Research [5]. The model determines optimal inspection intervals for physical assets by taking into account costs, risks and performance. The delay-time is the time between a defect becoming apparent and functional failure actually occurring. This is synonymous with the P-F interval. The model has been applied practically to optimise the inspection intervals of some physical assets with considerable success; for example, optimised inspection intervals for an Oil and Gas water injection pumping system [6] and optimised vibration monitoring interval for paper mill bearings [11]. Thus, the wind industry has a clear opportunity to consider the strategic importance of the delay-time model to solve real-life maintenance problems and to practically implement it so that the potential benefits can be harvested over the life-cycle of wind turbines.

3 APPROACH AND METHODOLOGY

A hybrid of a Failure Mode and Effect Criticality Analysis (FMECA) technique with Delay-Time Mathematical Model (DTMM) approach is applied to a 600 kW horizontal axis wind turbine (Figure 2). The FMECA predicts failure modes of critical components of a system and the resultant effects on the system's operation. This enables the evaluation of the system's failure consequences which in turn facilitate the selection of suitable maintenance tasks. The DTMM assesses equipment's failure consequences, inspection time, failure rates, cost of inspection and repair to determine optimal inspection intervals. The FMECA technique is used to determine the failure modes of critical subsystems of the wind turbine. Failure consequences of the subsystems are determined and expressed in financial terms. Failure rates as well as costs of inspection and repair of components within the subsystems are calculated. The DTMM is used to determine optimal inspection intervals for the subsystems by taking into account the calculated failure consequences, inspection and repair costs, failure rates, and the current inspection intervals of the subsystems.

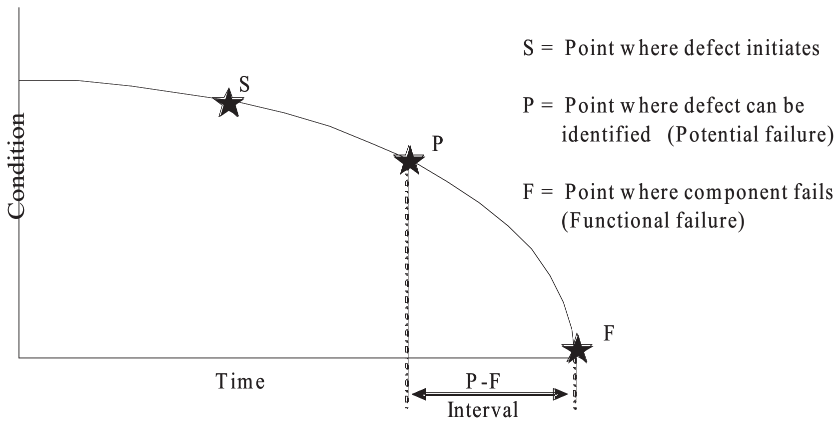

Figure 1 Potential-to-Functional failure interval

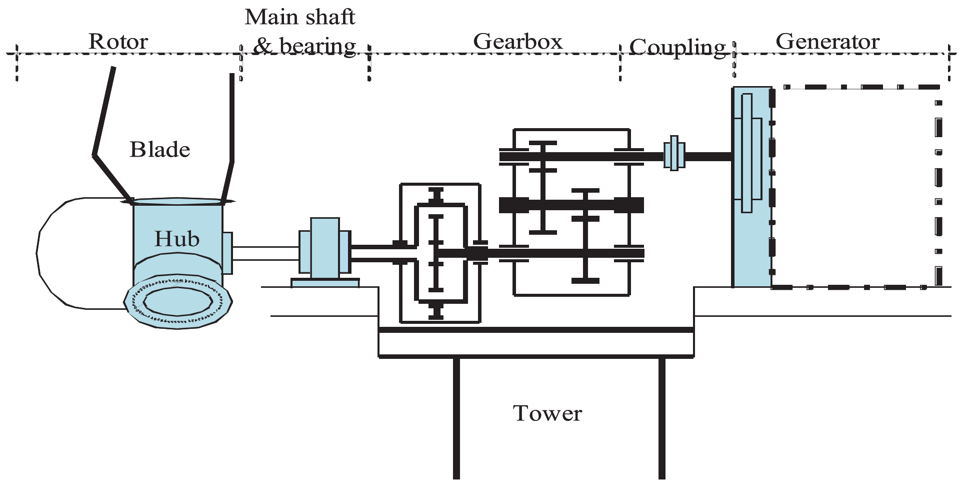

Figure 2 Components and Sub-systems of a 600 kW Wind Turbine

3.1 Failure Mode and Effect Criticality Analysis

The process of Failure Mode and Effect Criticality Analysis (FMECA) involves answering the first four of the seven basic questions of the Reliability Centred Maintenance (RCM) in the sequence shown below [3]:

- What are the functions and associated desired standards of performance of the asset in its present operating context (functions)?
- In what ways can it fail to fulfil its functions (functional failures)?

- What causes each functional failure (failure modes)?
- What happens when each failure occurs (failure effects)?

These questions identify ways in which a wind turbine already in operation can fail to perform its design intentions and the resultant effects on the components and subsystems of the turbine. Critical failure modes and subsystems are identified to enable the calculation of the failure consequences.

3.2 Delay-Time Maintenance Model

The Delay-Time Maintenance Model (DTMM) proposes a Poisson process of defect rate of arrival (α); exponentially distributed delay-times with mean ($1/\gamma$), and perfect inspection. Perfect inspection permits the detection of all expected failure modes. Note the defects rate of arrival connote complete failure of an item or defects found during inspection. Suppose all the gearboxes of wind turbines in a particular wind farm are subjected to regularly spaced inspections (such as vibration analysis) with inspections occurring every Δ in the interval [0, T]; where T is a multiple of Δ as shown conceptually in Figure 3. Two defect arrival scenarios (F_1 and F_2) underpinning the principles of the delay-time mathematical model are shown in the figure. Incipient failure F_1 occurs between inspection intervals, is detected at the next inspection 2 Δ which is then followed by a repair or F_2 occurs, fails catastrophically at t_i before the next inspection 3 Δ

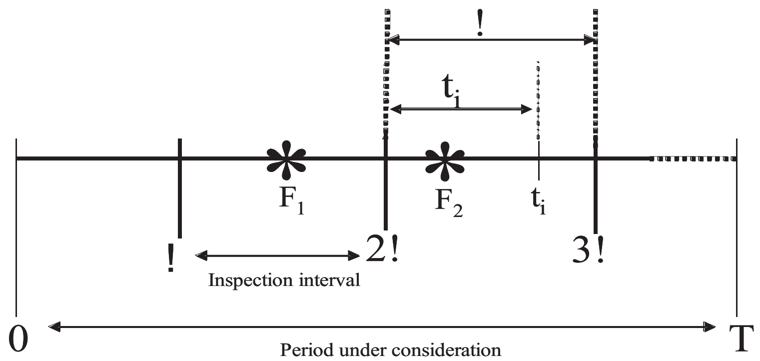

Figure 3 Delay-time concept

Thus, for a component observed over a period of T days with inspections equally spaced at intervals of days, the maximum likelihood estimates satisfy the expressions:

$$\hat{\alpha} = \frac{n}{T} \quad (1)$$

Where; $\hat{\alpha}$ = defect rate, n = total number of defects observed (i.e. the sum of failed and repaired equipments), and T = period under consideration. Also

$$\sum_{i=1}^{k} \frac{\hat{\gamma} t_i}{e^{\hat{\gamma} t_i} - 1} + \frac{(n-k)\,\hat{\gamma}\Delta}{e^{\hat{\gamma}\Delta} - 1} = (n-k) \quad (2)$$

Where k failures are observed at times t, (i = 1,..............,k)from the last inspection and $n - k$ defects are found at inspection. $\hat{\gamma}$ and $\hat{\alpha}$ are estimates of respectively. The optimal inspection interval, Δ^* satisfies the expression

$$(1+\gamma\Delta^*)e^{-\gamma\Delta^*} = 1-\frac{\gamma c_1}{\alpha c_2}, \text{ which has a solution provided } \gamma c_1 < \alpha c_2 \quad (3)$$

Where c_1 is the cost of inspection and repair, and c_2 the cost or consequences of failure. Thus, equating equations 2 and 3 to zero, give equations 4 and 5 respectively.

$$f(\gamma) = \sum_{i=1}^{k}\left(\frac{\hat{\gamma} t_i}{e^{\hat{\gamma} t_i}-1}\right) + (n-k)\left(\frac{\hat{\gamma}\Delta}{e^{\hat{\gamma}\Delta}-1}\right) - (n-k) \quad (4)$$

$$f(\Delta^*) = (1+\gamma\Delta^*)e^{-\gamma\Delta^*} - \left(1-\frac{\gamma c_1}{\alpha c_2}\right) \quad (5)$$

These equations are used to estimate the values of γ and Δ. The values can be obtained by an iterative procedure or trial and error approach. Alternatively, the equations (4 and 5) can be programmed in Excel and the estimate obtained easily by using a Micro Soft solver. The reader is referred to [12] for a detailed study on the concept of the delay-time maintenance mathematical model.

4 A CASE STUDY

This section presents a case study to demonstrate the practical application of the hybrid approach, FMECA and DTMM, to optimise the inspection intervals of critical subsystems of a 600 kW wind turbine.

4.1 Data Collection

Historical failure data pertinent to the critical components and subsystems of the particular type of 600 kW wind turbine were extracted from Supervisory Control and Data Acquisition (SCADA) systems over a period of 9 years. The SCADA systems record failures with the date and time of occurrence; this was used in conjunction with maintenance Work Orders (WOs) of the same period to ascertain the specific type of failure and the components involved. The collated data were grouped according to subsystems and components of the wind turbine and then re-arranged in order of failure modes and dates.

The work presented in this paper focuses on the life-failure data of one type of 600 kW horizontal axis wind turbine. Failure data of main shaft, main bearings, gearbox and generator of the 600 kW wind turbine are presented in Tables 1, 2, 3 and 4 respectively. In order to evaluate the wind farms in anonymity, they were labelled alphabetically (*A to Y*); *WF-C* in Table 1, column 1 denotes *Wind Farm C*. The wind turbines were named according to their respective wind farms; *WF-A-WT-10* (Table 2, column 2) *denotes Wind Farm A-Wind Turbine number 10*.

Activities of inspection and repair of critical components and subsystems were obtained from the collaborating wind farm operators. Current market prices of components were sourced from manufacturers. Information about vibration analysis of components were obtained from vendors of condition monitoring system and validated by Wind Farm Engineers.

Table 1 Failure Data for the Main Shafts of 600 kW Wind Turbine

Wind Farm (*WF*)	Wind Turbine (*WT*)	Component Manufacturer	Fail date dd/mm/yyyy	Main shaft
WF-C	*WF-C-WT-13*	2	"19/11/2003"	F
WF-K	*WF-K-WT-7*	5	"01/03/2004"	F
WF-F	*WF-F-WT-16*	1	"07/05/2004"	F
WF-A	*WF-A-WT-27*	1	"13/06/2004"	F
WF-L	*WF-L-WT-3*	7	"29/12/2004"	F
WF-N	*WF-N-WT-3*	2	"25/07/2005"	F
WF-M	*WF-M-WT-3*	7	"14/06/2006"	F

Table 2 Failure Data for the Main Bearings of 600 kW Wind Turbine

Wind Farm (*WF*)	Wind Turbine (WT)	Component Manufacturer	Fail date dd/mm/yyyy	Main bearings
WF-A	*WF-A-WT-10*	1	"29/01/2003"	F
WF-B	*WF-B-WT-4*	2	"09/05/2003"	F
WF-A	*WF-A-WT-13*	1	"19/05/2003"	F
WF-A	*WF-A-WT-3*	1	"27/06/2003"	F
WF-C	*WF-C-WT-4*	2	"31/07/2003"	F
WF-D	*WF-D-WT-13*	1	"05/11/2003"	F
WF-A	*WF-A-WT-34*	4	"10/02/2004"	F
WF-E	*WF-E-WT-2*	3	"15/05/2004"	F
WF-A	*WF-A-WT-22*	1	"15/12/2004"	F
WF-D	*WF-D-WT-13*	1	"27/12/2004"	F
WF-A	*WF-A-WT-26*	1	"17/01/2005"	F
WF-A	*WF-A-WT-34*	3	"18/01/2005"	F

Table 3 Failure Data for the Gearboxes of 600 kW Wind Turbine

Wind Farm (*WF*)	Wind Turbine (WT)	Component Manufacturer	Fail date dd/mm/yyyy	HSS bearing	IMS bearing	Gear wheels	Gearbox catastrophic
WT-F	WF-F-WT-1	8	"24/11/1999"	F	S	S	F
WT-F	WF-F-WT-18	8	"13/01/2000"	F	S	F	F
WT-F	WF-F-WT-24	8	"26/03/2001"	F	S	S	F
WT-F	WF-F-WT-07	8	"23/07/2001"	F	S	S	S
WT-F	WF-F-WT-15	8	"19/11/2001"	F	S	F	S
WF-A	*WF-A-WT-8*	9	"05/05/2003"	F	F	S	S
WF-A	*WF-A-WT-14*	9	"06/06/2003"	F	F	S	S
WF-A	*WF-A-WT-23*	9	"04/08/2003"	F	S	S	S
WF-A	*WF-A-WT-9*	9	"27/08/2003"	F	F	S	S
WF-B	*WF-B-WT-6*	9	"11/09/2003"	F	F	S	S
WF-B	*WF-B-WT-10*	9	"04/11/2003"	S	S	S	S
WF-B	*WF-B-WT-6*	10	"04/11/2003"	S	S	S	S
WF-B	*WF-B-WT-14*	9	"22/11/2003"	S	S	S	S
WF-F	*WF-F-WT-19*	9	"18/06/2004"	S	S	F	S
WF-G	*WF-G-WT-9*	9	"30/06/2004"	F	F	S	F
WF-A	*WF-A-WT-33*	8	"09/10/2004"	S	S	F	F
WF-A	*WF-A-WT-1*	8	"18/10/2004"	S	S	S	S
WF-A	*WF-A-WT-19*	8	"30/10/2004"	S	S	S	S
WF-C	*WF-C-WT-7*	11	"01/11/2004"	F	S	F	S
WF-D	*WF-D-WT-20*	10	"04/02/2005"	S	S	F	S
WF-A	*WF-A-WT-19*	10	"02/04/2005"	S	S	F	S
WF-D	*WF-D-WT-2*	8	"11/05/2005"	S	S	S	S

Table 4 Failure Data for the Generators of 600 kW Wind Turbine

Wind Farm (WF)	Wind Turbine (WT)	Serial number	Component Manufacturer	Fail date dd/mm/yyyy	Bearings	Generator catastrophic
WF-F	WF-F-WT-1	GSN-1	4	"24/02/1997"	S	F
WF-F	WF-F-WT-22	GSN-2	4	"15/02/1998"	F	S
WF-F	WF-F-WT-15	GSN-2	4	"01/06/2000"	S	F
WF-F	WF-F-WT-15	GSN-3	4	"01/03/1999"	F	S
WF-F	WF-F-WT-18	GSN-4	4	"01/06/1999"	F	S
WF-F	WF-F-WT-12	GSN-5	4	"01/12/2000"	S	F
WF-F	WF-F-WT-12	GSN-6	4	"01/10/1999"	S	S
WF-F	WF-F-WT-17	GSN-7	4	"15/12/1999"	S	S
WF-F	WF-F-WT-15	GSN-7	4	"01/01/2002"	S	S
WF-F	WF-F-WT-15	GSN-7	4	"01/07/2002"	S	S
WF-F	WF-F-WT-5	GSN-8	4	"08/01/2000"	F	S
WF-F	WF-F-WT-24	GSN-9	4	"08/01/2000"	S	F
WF-F	WF-F-WT-16	GSN-10	4	"01/11/2000"	F	S
WF-F	WF-F-WT-7	GSN-11	4	"01/06/2002"	F	S
WF-D	WF-D-WT-26	GSN-12	4	"21/01/2003"	F	S
WF-A	WF-A-WT-29	GSN-13	4	"29/01/2003"	F	S
WF-A	WF-A-WT-20	GSN-14	4	"09/04/2003"	F	S
WF-C	WF-C-WT-11	GSN-15	4	"09/05/2003"	F	S
WF-A	WF-A-WT-18	GSN-16	4	"09/06/2003"	S	S
WF-A	WF-A-WT-8	GSN-17	4	"24/06/2003"	F	S
WF-D	WF-D-WT-4	GSN-18	4	"07/08/2003"	F	S
WF-D	WF-D-WT-2	GSN-19	4	"28/08/2003"	S	S
WF-D	WF-D-WT-27	GSN-20	4	"15/09/2003"	F	S
WF-A	WF-A-WT-21	GSN-21	4	"11/11/2003"	F	F
WF-H	WF-H-WT-11	GSN-22	4	"13/11/2003"	F	S
WF-A	WF-A-WT-7	GSN-23	4	"29/12/2003"	F	S
WF-A	WF-A-WT-20	GSN-24	4	"29/01/2004"	F	S
WF-C	WF-C-WT-8	GSN-25	4	"04/03/2004"	F	S
WF-E	WF-E-WT-20	GSN-26	4	"25/03/2004"	S	S
WF-F	WF-F-WT-20	GSN-27	4	"25/03/2004"	S	S
WF-I	WF-I-WT-1	GSN-28	4	"20/04/2004"	F	S
WF-D	WF-D-WT-15	GSN-29	4	"23/04/2004"	S	S
WF-A	WF-A-WT-1	GSN-30	4	"04/05/2004"	F	F
WF-D	WF-D-WT-27	GSN-31	4	"07/05/2004"	F	S
WF-E	WF-E-WT-4	GSN-32	4	"18/06/2004"	F	S
WF-I	WF-I-WT-6	GSN-33	4	"26/06/2004"	F	S
WF-G	WF-G-WT-9	GSN-34	4	"08/07/2004"	S	S
WF-A	WF-A-WT-29	GSN-35	4	"13/07/2004"	F	S
WF-A	WF-A-WT-17	GSN-36	4	"16/07/2004"	F	F
WF-C	WF-C-WT-19	GSN-37	4	"30/07/2004"	S	S
WF-C	WF-C-WT-10	GSN-38	4	"12/08/2004"	S	F
WF-E	WF-E-WT-11	GSN-39	4	"17/09/2004"	F	S
WF-D	WF-D-WT-28	GSN-40	4	"21/09/2004"	F	S
WF-E	WF-E-WT-16	GSN-41	4	"25/10/2004"	S	S
WF-E	WF-E-WT-13	GSN-42	4	"07/11/2004"	S	S
WF-I	WF-I-WT-7	GSN-43	4	"29/12/2004"	S	S
WF-A	WF-A-WT-24	GSN-44	4	"02/01/2005"	S	S
WF-A	WF-A-WT-6	GSN-45	4	"28/02/2005"	F	F
WF-I	WF-I-WT-13	GSN-46	4	"07/04/2005"	F	S
WF-A	WF-A-WT-19	GSN-47	4	"26/04/2005"	F	S
WF-J	WF-J-WT-9	GSN-48	4	"12/09/2005"	F	S

4.2 Results and Discussion

This subsection presents the results and discussion of the practical application of the hybrid FMECA and DTMM techniques to the 600 kW horizontal axis wind turbine.

4.2.1 FMECA

The Failure Mode and Effect Criticality Analysis (FMECA) technique has been used to predict the failure modes of the 600 kW horizontal axis wind turbine. The result is logically presented in Table 5. The '*WT*' in the table represents "*wind turbine*" and the first and second figures denote the type of *functional failure* and the corresponding *failure modes* respectively. The table shows the primary function of a wind turbine and the associated functional-failure and failure-modes.

The primary function of a wind turbine is to convert wind kinetic energy into electrical energy within a defined speed limit (cut-in and cut-out wind speed). In view of the primary function, three functional failures were defined. These include complete loss of energy conversion capability, partial loss of energy conversion capability and over speeding. The failure modes associated with each of the functional failures were scrutinised and presented logically.

Suitable Condition-Based Maintenance tasks to mitigate the effects of the failure modes were determined in [4]. Vibration analysis was identified as the suitable condition based maintenance task to mitigate dominant causes of failure modes *WT-1-3, WT-1-4, WT-1-5, WT-1-6, WT-1-7, WT-1-8, WT-1-12, WT-2-7* and *WT-2-8* while strain gauge measurements were employed for dominant causes of failure modes; *WT-1-1, WT-1-2, WT-2-1, WT-2-2, WT-2-4, WT-2-5*, and *WT-2-6*. Catastrophic failures of wind turbine's critical subsystems such as the blades, main bearings and shaft, gearbox and associated components, the generator and associated components, towers and foundations, should therefore be detectable and prevented through the application of the appropriate CBM activities.

4.2.2 Vibration Analysis

All rotating equipment produces ultrasonic or acoustic vibration regardless of the state of lubrication [13]. Vibration analysis (VA) is used for monitoring the failure behaviour of rotating equipment such as the wheels and bearings of the gearbox, generator bearings, main shaft and bearings of the wind turbine. The principle of vibration monitoring to detect incipient faults is illustrated in Figure 4. Vibration monitoring involves using sensors to register the local motion or vibration characteristics of the monitored component. The sensors employed are determined by the frequency range of the equipment to be monitored. Low frequency range equipment requires position transducers [14], middle frequency require velocity sensors [14] and high frequency requires accelerometers [14]. Appropriate vibration sensors are mounted rigidly on the monitored component/subsystem.

Accelerometers are commonly used to monitor the rotating equipment of the wind turbine [8]. Displacement sensors seem more appropriate for monitoring the performance of the main bearings and shaft since they operate at a lower speed. However, wind turbines differ from other mechanical equipment because they operate on both steady and dynamic loads as well as high and low rotational speeds. These varying operating load and speed make vibration signal analysis and diagnostic very difficult [8]. Thus, a specialised knowledge is required to carry out the signals analysis and diagnosis. Supplier of the monitoring systems often executes the vibration analysis and diagnostic as well as the maintenance of the monitoring systems.

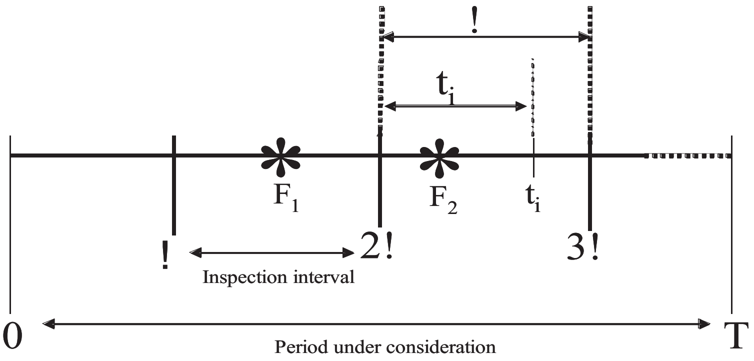

Figure 4 Fault detection model

The cost of installing a condition monitoring system on a wind turbine is expected to be covered by the benefits of preventing the consequences of catastrophic2 failures. The trade-off between the cost of installing vibration monitoring systems on the drive trains of 600 kW wind turbines and the benefits of preventing the consequences of failure of critical subsystems in a 26 x 600 kW wind farm has been carried out in [4].

Vibration information from a wind turbine's drive train is collected on a monthly basis by a trained employee. A portable device is utilised to register the vibration characteristics of the components from the mounted sensors. These are downloaded to a system and the results are compared with the threshold and previous results, to determine if there are deviations as indicated conceptually in Figure 3.

4.2.3 Failure Consequences of Subsystems

The failure consequences (C_2) of critical subsystems of the 600 kW wind turbine represented by failure modes *WT-1-1, WT-1-3, WT-1-4, WT-1-6* and *WT-1-8* were determined and expressed in financial terms. The result is presented in Table 7. The failure consequences were calculated by taking into account the total cost of material (TC_{MT}), total cost of labour (TC_{LB}), total cost of access (TC_{AS}) and production losses (P_{LS}). The consequence of catastrophic failure of a gearbox is about £78,468. The generator, main bearings and the main shaft have failure consequences of £35,964, £22,374 and £29,114 respectively. The reader is referred to [4] for a detailed calculation of the failure consequences of critical subsystem of the 600 kW wind turbine.

4.2.4 Cost of Inspection and Repair of Components

The cost of inspection and repair (C_1) of components of the subsystems are present in table 8. The cost per hour and the time required to repair each component were estimated from the information obtained from collaborating wind farm operators. The cost and time needed to inspect the components of the subsystems are estimated from the information obtained from the vendors of condition monitoring systems. In the table, the total cost of labour (TC_{LB}) is a product of repair time, cost of labour per hour and the number of repair crew. Also, the total cost of inspection (TC_{INP}) is a product of the cost of inspection per hour, inspection duration and the number of inspection crew. The total cost of material (TC_{MT}) includes cost of transportation, loading and off-loading, and the value added tax (VAT) at 17.50%. Thus, C_1 is the summation of TC_{INP}, TC_{LB} and TC_{MT}. For example, the C_1 of high speed shaft (HSS) bearings and intermediary shaft (IMS) bearings of the gearbox are £2,230 and £2,742 respectively.

Table 5 Functional Failure and Failure Modes for Horizontal Axis Wind Turbines adopted from [4]

Function	Functional failure	Failure modes
WT-F to covert wind kinetic energy into electrical energy within defined speed limit (cut-in and cut-out)	*WT-1* Complete loss of energy conversion capability	*WT-1-1* Catastrophic blade failure *WT-1-2* Catastrophic hub failure *WT-1-3* Main bearing failure *WT-1-4* Main shaft failure *WT-1-5* Shaft-gearbox coupling failure *WT-1-6* Gearbox failure *WT-1-7* Gearbox-generator coupling failure *WT-1-8* Generator failure *WT-1-9* Meteorological system failure *WT-1-10* Premature brake activation *WT-1-11* Electrical system failure *WT-1-12* Tower failure *WT-1-13* Foundation failure
	WT-2 Partial loss of energy conversion capability	*WT-2-1* Crack in blade *WT-2-2* Deteriorating blade root stiffness *WT-2-3* Blades at different pitches *WT-2-4* Dirt build-up on blades *WT-2-5* Ice build-up on blades *WT-2-6* Damping in blades *WT-2-7* Hub spins on shaft *WT-2-8* Low speed shaft misalignment *WT-2-9* Nacelle not yawing *WT-2-10* Nacelle yaws too slowly *WT-2-11* Nacelle yaws too fast *WT-2-12* Large yaw angle *WT-2-13* Cable twist *WT-2-14* Wind speed measurement error *WT-2-15* Wind direction measurement error
	WT-3 Over speeding	*WT-3-1* Controller failure *WT-3-2* Hydraulic system failure *WT-3-3* Pitching system failure *WT-3-4* Mechanical brake failure *WT-3-5* Grid connection failure

Table 6 Estimates of time to failures of critical components

Sub-system	Components	Inspection interval Δ (Months)	Time to failure T_i (months)			Mean (μ) T_i
			Lower	Most likely	Upper	
Blade	Blade					
Main shaft	Shafts	1	0.93	0.95	0.97	0.95
Main bearing	Bearings	1	0.85	0.90	0.95	0.90
Gearbox	Gears	1	0.70	0.80	0.90	0.80
	HSS bearings	1	0.85	0.90	0.95	0.90
	IMS bearings	1	0.75	0.85	0.95	0.85
Generator	Bearings	1	0.70	0.80	0.90	0.80

Table 7 Cost of failure of critical components of a 600 kW wind turbine adopted from [4]

Failure Modes	Failure consequences F_C (£)				
	TC_{MT}	TC_{LB}	TC_{AS}	P_{LS}	Total (C_2)
WT-1-1 Catastrophic blade failure	34,545.00	2,400.00	8,460.00	1,663.20	47,068.20
WT-1-3 Catastrophic main bearings failure	9,851.49	2,400.00	8,460.00	1,663.20	22,374.69
WT-1-4 Catastrophic main shaft failure	11,133.36	4,800.00	11,280.00	1,900.80	29,114.16
WT-1-6 Catastrophic gearbox failure	61,687.50	3,600.00	11,280.00	1,900.80	78,468.30
WT-1-8 Catastrophic generator failure	23,441.25	2,400.00	8,460.00	1,663.20	35,964.45

Table 8 Cost of inspection and repair of critical components

Sub-system	Activity & Component	Repair duration (hrs)	Inspection duration (hrs)	Cost of inspection per hour(£)	Cost of repair per hour (£)	Inspection & Repair crew	TC_{INP} (£)	TC_{LB} (£)	TC_{MT} (£)	Total (C_1)
Blade	Replace blade									
Main Shaft	Replace shaft	32	2	12	17.5	3	72.0	1,680.0	11,133.4	12,885.4
Main Bearing	Replace bearing	16	2	12	17.5	3	72.0	840.0	9,851.5	10,763.5
Gearbox	Replace gear wheels	16	2	12	17.5	3	72.0	840.0	7,270.0	8,182.0
	Replace HSS bearing	16	2	12	17.5	3	72.0	840.0	1,318.0	2,230.0
	Replace IMS bearing	16	2	12	17.5	3	72.0	840.0	1,830.0	2,742.0
Generator	Replace bearing	16	2	12	17.5	3	72.0	840.0	1,420.0	2,332.0

Table 9 Defects rate and Mean Time Between Failures of critical components

Sub-system	Components	Equipment-years	No of defects repaired	No of defects failed	Total defects observed	Defects rate (α) x 10^{-2}	MTBF (Equipment-years)
Blade	Blade						
Main shaft	Shafts	308	0	7	7	2.27	44
Main bearing	Bearings	231	0	12	12	5.19	19.25
Gearbox	Gears	539	7	5	12	2.22	44.92
	HSS bearings	539	12	5	17	3.15	31.71
	IMS bearings	539	5	5	10	1.86	53.9
Generator	Bearings	616	31	9	40	6.49	15.4

4.2.5 Defects Rate

The defects rates (α) of components of the critical subsystem of the 600 kW wind turbine is presented in Table 9. The (α) were estimated by determining firstly the *wind turbine operational years* which are the product of the number of wind turbines assessed (77 turbines) and the period under consideration. From tables 1-4, the period under consideration for the main-shaft, main-bearings, gearbox and the generator are 4, 3, 7 and 8 years respectively. These result in *wind turbine operational years* of 539, 616, 308 and 231 for the gearbox, generator, main shaft and bearings respectively. The (α) of each component is obtained by dividing the component's total number of defects observed (the sum of number of defects failed and defects repaired) by the corresponding *wind turbine operational years.* For example, twelve (12) HSS bearings of the gearbox failed and were replaced while 5 gearboxes failed catastrophically (see table 3). Thus, the total number of defects observed for the HSS bearing is 17 in the 7 years under consideration. Similarly, thirty one (31) bearings of the generator failed and were replaced while 9 generators failed catastrophically (see table 4). Therefore, the total number of defects observed for the bearing of the generator is 40 in the 8 years under consideration. Hence, the defects rates (α) of the HSS bearing of the gearbox and the bearing of the generator are 0.0315 and 0.0649 respectively. The components' defects rates were further converted to their respective *Mean-Time-Between-Failures* (MTBF). The MTBF is the inverse value of (α). For example, the MTBF of the main bearings is $\frac{1}{5.19 x 10^{-2}}$ which gives 19.25 *wind turbine years* as shown in the table 9.

4.2.6 Delay-Time

The P-F interval of a component is synonymous with its delay-time. Historical maintenance data were sourced from collaborating wind farm operators to calculate the mean delay-time ($1/\gamma$) of the components of the subsystems. The estimated $1/\gamma$ are used in conjunction with the calculated consequences of failure (C_2), cost of inspection and repair (C_1), and the defects rate (α) to determine optimal inspection intervals (Δ^*) for the subsystems.

Table 6 contains the estimated times to failure (T_i) for the components of the critical subsystems. The *lower, most-likely* and *upper* values of the times-to-failure are presented in the same table. Ideally, if inspection intervals are equally spaced and failure occurs between the inspections, then the period from the date of last inspection to the time failure actually occurs is the delay-time of the component. This type of data is seldom available in the wind energy industry due to poor management of maintenance and failure data. Furthermore, vibration monitoring is not well established in the wind energy industry. It is worth noting therefore, that table 6 was established through discussion with wind farm engineers. The current inspection intervals for the subsystems are also presented in the same table.

The total number of defects observed (n), the defects repaired (k), the times-to-failure (T_i) and the current inspection intervals (Δ) were assessed using Equation 4 to determine the mean delay-times ($1/\gamma$) of the components. n and k are presented in table 9 while T_i and Δ are presented in table 6. The result of the assessment is presented in Table 10. Note that each of the defects repaired was assumed to have failed at the estimated mean time to failure presented in table 6. The mean delay-time for the gear wheels, HSS and IMS bearings of the gearbox are 0.918, 1.469 and 0.735 respectively. The generator's bearings, main shaft and bearing have mean delay-times of 1.948, 0.038 and 0.038 respectively.

Optimal inspection intervals for the critical subsystems were determined by using Equation 5. The failure consequences of the subsystems (c_2) is in table 7, the cost of the inspection and repair (c_1) in table 8, the components' defects rates (α) in table 9, and the mean delay-times ($1/\gamma$) is in table 10. The result of optimal inspection intervals for the subsystems is presented in table 11. Recall that the prerequisite to determining the optimal inspection intervals using the delay-time mathematical model is $\gamma C_1 < \alpha C_2$. Thus, the result in table 11 shows that the main bearing and shaft, the gearwheels and IMS of the gearbox have no optimal inspection interval as the pre-condition is not satisfied. The HSS bearing of the gearbox and the bearing of the generator have optimal inspection intervals of 3.035 and 3.349 months respectively; given the assessed failure data.

Subsystem's optimal inspection interval depends on the individual optimal inspection interval of its components. For instance, the optimal inspection interval for the gearbox is dependent on the optimal interval for the HSS bearings, gearwheels, IMS bearings, etc. The norm is to err on the safe-side, that is, to adopt the lowest optimal inspection interval among the components for the subsystem.

Table 10 Mean Delay-Time for critical components of the wind turbine

Sub-system	Components	Mean delay-time $1/\gamma$ (months)	$\gamma*C_1$	$\alpha*C_2$
Blade	Blade			
Main shaft	Shafts	0.038	338,012.12	661.68
Main bearing	Bearings	0.038	282,345.78	1,162.28
Gearbox	Gears	0.918	8,913.07	1,746.97
	HSS bearings	1.469	1,517.77	2,474.87
	IMS bearings	0.735	3,731.79	1,455.81
Generator	Bearings	1.948	1,196.98	2,335.32

Table 11 Optimal inspection intervals for critical components of the wind turbine.

Sub-system	Components	Total number of defects	Defects rate α	Mean delay-time $1/\gamma$ (months)	Inspection Cost C_1 (£)	Failure Cost C_2 (£)	Optimal inspection interval Δ^* (months)
Blade	Blade						
Main shaft	Shaft	5	0.0227	0.038	12,885.00	29,114.00	No optimal
Main bearing	Bearings	12	0.0519	0.038	10,763.00	22,374.00	No optimal
Gearbox	Gears	12	0.0222	0.918	8,182.00	78,468.00	No optimal
	HSS bearings	17	0.0315	1.469	2,230.00	78,468.00	3.045
	IMS bearings	10	0.0185	0.735	2,742.00	78,468.00	No optimal
Generator	Bearings	40	0.0649	1.948	2,332.00	35,964.00	3.349

5 CONCLUSION

This paper has presented a quantitative optimisation of condition-based maintenance inspection intervals for critical subsystems of 600 kW wind turbines using a hybrid of Failure Mode and Effect Criticality Analysis (FMECA) and delay-time mathematical model (DTMM). Industrial data pertaining to the wind turbine was sourced from wind farm operators and was collated to determine failure characteristics and inspection activities of the wind turbines. Current market prices of critical components of the wind turbines as well as the activities of condition monitoring were sourced from manufactures and vendors. The FMECA approach was used to determine failure modes of the wind turbines. Failure consequences of critical subsystems were determined and expressed in financial terms. The costs of inspection and repair as well as the failure rate of the components of the subsystems were calculated. The DTMM was used to determine mean delay-time and optimal inspection intervals for the critical subsystems of a wind turbine. The optimal inspection interval for the HSS bearing of the gearbox and the bearings of the generator, are 3.045 and 3.349 months respectively. The main shaft and bearings, the gearwheels and the IMS bearing of the gearbox have no optimal inspection; given the assessed failure data and the methodology applied.

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