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Condition monitoring and diagnostics of machines — Hydroelectric generating units

Surveillance et diagnostic d'état des machines — Groupes de production hydroélectrique

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ISO copyright office
CP 401 • Ch. de Blandonnet 8
CH-1214 Vernier, Geneva
Phone: +41 22 749 01 11
Fax: +41 22 749 09 47
Email: copyright@iso.org
Website: www.iso.org

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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation of the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT) see www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 108, *Mechanical vibration, shock and condition monitoring*, Subcommittee SC 5, *Condition monitoring and diagnostics of machine systems*.

Any feedback or questions on this document should be directed to the user's national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

Traditionally, hydroelectric generating units (or simply hydro units) have been overdesigned, well-staffed for maintenance and often continuously operated at only baseload conditions over a period of many years. As a result of this, there were few maintenance issues, shutdowns could be planned at fixed intervals, and therefore there was little need for condition monitoring of the units. Simple machine protection systems sufficed, if used at all.

Nowadays, there are more stringent requirements for operational regimes, availability and reliability. Disruption to consumers' needs should be minimized and cash generation for the utilities maximized. The operating regimes for many hydro units have been extended to include synchronous compensation, load-following and peaking, which means there are many starts and stops and partial load operation, sometimes in the rough zones. Many applications are based on pump storage. Moreover, new units are designed more streamlined to the application, less robust, and older units are often refurbished to extend life or to increase rating. This means that machines are more stressed, which can lead to premature or unpredictable failure of the components, and even some new failure modes. At the same time, there is a trend towards fewer maintenance staff and specialists to look after the machines.

Therefore, there is a significantly greater need for an effective condition monitoring strategy, not just a protection system. Moreover, the condition monitoring solution of these machines should be more than just basic vibration monitoring. Due to the complex nature of the hydro unit components, a number of potential failure modes now become apparent under the current stressful conditions, which require a number of different, specialized monitoring techniques and diagnostic expertise. There are few standards for monitoring the hydro units and a general lack of understanding of the monitoring techniques. Even for hydropower stations that have a legacy condition monitoring system installed, the existing condition monitoring requirements for the hydro units are sometimes no longer valid as a result of changing operating conditions or refurbishment of the units.

Condition monitoring and diagnostics of machines — Hydroelectric generating units

1 Scope

This document focuses on recommended condition monitoring techniques for detecting and diagnosing developing machine faults associated with the most common potential failure modes for hydro unit components. It is intended to improve the reliability of implementing an effective condition monitoring approach for hydroelectric generating units (hydro units). It is also intended to help create a mutual understanding of the criteria for successful hydro unit condition monitoring and to foster cooperation between the various hydropower stakeholders.

This document is intended for end-users, contractors, consultants, service providers, machine manufacturers and instrument suppliers.

This document is machine-specific and is focused on the generator, shaft/bearing assembly, runner (and impeller for pumped storage applications), penstock (including the main inlet valve), spiral case and the upper draft tube of hydro units. It is primarily intended for medium to large sized hydro units with more than 50 MVA installed capacity, but it is equally valid for smaller units in many cases. It is applicable to various types of turbines such as Francis, Kaplan, Pelton, Bulb and other types. Generic auxiliary systems such as for lubrication and cooling are outside the scope, with the exception of some monitoring techniques that are related to condition monitoring of major systems covered by this document, such as oil analysis. Transmission systems, civil works and the foundation are outside the scope.

This document covers online (permanently installed) and portable instrument condition monitoring and diagnostic techniques for operational hydro units. Offline machine testing, i.e. that which is only done during shutdown, although very important, is not part of the scope of this document. Nor is one-time acceptance and performance testing within the scope. The condition monitoring techniques presented in this document cover a wide range of continuous and interval-based monitoring techniques under generalized conditions for a wide range of applications. Therefore, the actual monitoring approach required for a specific application can be different than that which is recommended in this generalized document.

2 Normative references

There are no normative references in this document.

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at http://www.electropedia.org/

3.1
hydro unit
entire hydro-generating unit, consisting of the generator, shaft, turbine, and including the immediate intake and discharge components, e.g. the penstock, main inlet valve, spiral case and the upper portion of the draft tube

3.2
machine state
operational process or duty cycle of the *hydro unit* (3.1)

EXAMPLE Running up to speed, synchronized but no load, partial load, full load, coasting down, stopped.

3.3
monitoring technique
measurement or set of descriptors used to detect a *potential failure mode* (3.4) or provide diagnostic information on the type of fault and its location and severity

3.4
potential failure mode
change of condition of a *hydro unit* (3.1) component that can be detected by measurements that indicate an incipient fault is developing, which will eventually lead to failure

3.5
runner
turbine
hydro unit (3.1) turbine

Note 1 to entry: The terms are used interchangeably throughout the text.

3.6
tacho
phase/speed reference sensor, with at least one pulse generated per revolution

Note 1 to entry: The sensor may be a displacement sensor or an optical sensor with TTL or NPN/PNP signal output.

4 Symbols and abbreviated terms

For the purposes of this document, the following symbols and abbreviated terms apply.

AC	Alternating current
AG	Air gap
CM	Condition monitoring
DC	Direct current
DCS	Distributed control system
EMI	Electromagnetic interference
EWV	End winding vibration
FFT	Fast Fourier transform
FOA	Fibre optic accelerometer
MF	Magnetic flux
NPN	Negative-positive-negative pulse (e.g. output signal from a tacho sensor)
N_S	Specific speed, which is a design criterion for sizing a turbine to a specific flow and head
PD, PDA	Partial discharge, partial discharge analysis
PNP	Positive-negative-positive pulse (e.g. output signal from a tacho sensor)

RFI	Radio-frequency interference (electromagnetic interference within the radio frequency band)
RSI	Rotor-stator interaction (e.g. forces)
RTD	Resistance temperature detector
RTU	Remote terminal unit
SCADA	Supervisory control and data acquisition system
S_{max}	Maximum peak displacement for 2-channel shaft vibration according to ISO 20816-5
SNL	Operating condition of the hydro unit where the rotor is turning at synchronized speed but not under load (i.e. speed-no-load)
S_{p-p}	Maximum peak-to-peak displacement value of the two individual shaft vibration channels according to ISO 20816-5
TCP/IP	Transmission control protocol/Internet protocol
TTL	Transistor-transistor logic pulse (e.g. output signal from a tacho sensor)

5 Initial preparations for condition monitoring

Implementing an optimal machine condition-based monitoring strategy for hydro units involves several steps, all of which should be considered in order to maximize machine production, reliability and efficiency and minimize the life cycle costs of the machine. These initial steps, which are beyond the scope of this document, are generalized in ISO 17359 and include evaluating:

— cost benefit analysis of the machine for monitoring;

— machine maintenance history and potential failure modes;

— reliability requirements and criticality audit;

— lead-time-to-maintenance requirements.

After the condition monitoring strategy has been implemented, it should be periodically reviewed and refined as experience is gained and monitoring technology improves.

If a condition monitoring system is already in use, the monitoring and diagnostic functionality of that system may have to be re-evaluated from time to time in order to fulfil current condition monitoring strategy requirements, as described above.

The entire process of implementing a condition-based monitoring strategy is summarized in Table 1, which is in part based on ISO 13379-1:2012, Figure 1.

Table 1 — Implementation of a condition-based monitoring solution for hydro units

CM implementation	Activity	Remarks
CM strategy	CM implementation overview	Described in ISO 17359
	Cost benefits and risk analysis	Partly described in IEC 60300-3-3, IEC 60812, ISO 13379 (series)
CM application	Failure modes, monitoring techniques, descriptors	See Table 2 for a list of standards for specific hydro unit monitoring techniques
NOTE Condition monitoring implementation activities not covered in this document are shaded in grey.		

Table 1 *(continued)*

CM implementation	Activity	Remarks
CM system	Data processing, measurement systems, data management	Partly described in ISO 13374-1, ISO 13374-2, ISO 13374-3
	Sensors	Partly described in this document
CM operations	Detection, diagnostics	Partly described in this document
	Root cause analysis, prognostics	Standards currently under development
NOTE Condition monitoring implementation activities not covered in this document are shaded in grey.		

6 Failure modes of hydro unit components

6.1 General

The implementation of an effective condition monitoring and diagnostics approach for hydro units is directly related to the relevant potential failure modes that can occur on specific machine components. Failure means the component is no longer able to serve its intended function.

6.2 Hydro unit components

The potential failure modes considered in this document are limited to the hydro unit itself, which consists of:

— generator and exciter;

— shaft and bearing assembly;

— penstock (including the main inlet valve), spiral case, stay vanes, guide vanes, wicket gate and injectors;

— runner (and impeller for a pumped storage application);

— draft tube.

A more detailed description of the hydro unit components together with the associated terminology can be found in A.2.

6.3 Potential failure mode identification and prioritization

The actual potential failure modes for a specific application are normally identified and prioritized by reliability and risk analysis methods such as failure mode effects analysis (FMEA), failure modes effects and criticality analysis (FMECA), fault tree analysis (FTA) and other methods (these are partly covered by the standards summarized under CM Strategy in Table 1). The actual method that is most suitable for identifying and prioritizing potential failure modes depends on the user application and requirements. Most of these methods take into account a number of factors directly related to the hydro units themselves, such as:

— original machine design and construction;

— machine refurbishment and modifications;

— maintenance history;

— environmental factors;

— how the machine is maintained and operated;

— condition monitoring and diagnostic expertise.

There exist many potential failure modes for hydro units, some of which can be detected and diagnosed relatively easily, some with more difficulty and some not at all. This document focuses on the potential failure modes listed in A.3, which are generalized for a wide range of applications and machine types, and which can be monitored and diagnosed using the techniques described in Annex C. As the hydro unit design and its operation and maintenance regime can be very different from one application to the next, it is important to highlight that the failure modes described in this document can be different from those of the actual user's application.

7 Monitoring and diagnostic techniques

7.1 General

Monitoring and diagnostic techniques have been developed and refined over the years to detect, identify and evaluate the severity of one or more symptoms of specific potential failure modes before they occur and with sufficient lead-time such that maintenance can be planned ahead of time and production can continue as intended.

7.2 Condition monitoring techniques overview

A summary of the most common monitoring techniques is listed in Table 2, which includes a reference to relevant standards for these techniques. A graphical summary is shown in B.2. More information on the most relevant monitoring techniques together with their corresponding failure modes is provided in B.3. A detailed description for each individual monitoring technique covered by this document is given in Annex C.

There are a number of important monitoring techniques that are currently being measured on hydro units but they do not appear in Table 2. This is the case for operational process parameters, which are normally not part of a condition monitoring system. These measurements, however, play an important role in condition monitoring of hydro units for correlation purposes as described in 7.4, therefore, they need to be saved with a sufficient resolution in value and time.

Some condition monitoring techniques have been successfully used in the past or are currently being used for detecting and diagnosing certain potential failure modes in hydro units but are not listed in Table 2. This is because these techniques are:

— not widely used, so there is insufficient knowledge of the techniques,

— relatively new and there is not enough experience to deem the techniques as "tried and proven",

— very resource intensive, e.g. success with the technique is highly dependent on user expertise that few have,

— relatively old and have since been replaced by newer proven techniques,

— successfully used in other machine types but have a very limited scope of application for hydro units.

Some of the condition monitoring techniques not listed in Table 2 include:

— **Stator bar vibration** – Bar looseness is often found by offline wedge-tightness testing, and thus is not widely used for online monitoring (described briefly in IEEE 1129). This technique is possibly being replaced by the partial discharge analysis and stator end winding vibration with an FOA on the top of the stator bar;

— **Sediment monitoring** – Sediment erosion and abrasion can affect all types of turbines, but most significantly Pelton turbines;

— **Stator core vibration for rotor deformation monitoring** – In addition to the normal purpose for stator core vibration monitoring, as listed in Table 2, investigations are being developed to use this technique to also detect rotor geometric faults;

— **Cavitation monitoring** – There are techniques other than vibration and performance for detecting and monitoring cavitation, such as ultrasound and acoustic techniques;

— **Rotor winding temperature** – Telemetric systems are now available but they are not widely used at present and, thus, there is little experience.

Table 2 — Partial listing of monitoring techniques for hydro unit components

Primary component	Monitoring technique	Description clause	Relevant standards (referenced in the Bibliography)
Generator	Air gap	C.2	IEEE 1129 (briefly mentioned) ISO 20816-5 (briefly mentioned)
	Magnetic flux	C.3	IEEE 1129 (briefly mentioned)
	Partial discharge analysis	C.4	IEEE 1129, IEC/TS 60034-27
	Vibration for stator frame and core, temperature for core, circuit ring, cooling system and winding and voltage for slip ring/brush gear	C.5	IEEE 1129, ISO 13373-7
	Stator end winding vibration	C.6	IEEE 1129, IEC/TS 60034-32
Shaft and bearing assembly	Shaft current and voltage	C.7	IEEE 112, IEEE 115, IEEE 1129
	Oil analysis	C.8	Many standards available such as ASTM D5185 for wear debris analysis and ASTM D6304, ASTM D2896, ASTM D445 for oil condition. Other standards under development.
	Shaft, guide bearing, thrust bearing and bearing housing vibration	C.9	ISO 13373-7, ISO 20816-5, IEEE 1129
	Guide bearing and thrust bearing temperature	C.10	IEEE 1129[a], ISO 13373-7[b]
	Main shaft seal leak monitoring	C.11	
Penstock (including the main inlet valve), spiral case, bulb casing, stay vanes, guide vanes, wicket gate and injectors (Pelton)	Wicket gate shear pin vibration	C.12	ISO 13373-7
	Bulb casing vibration	C.13	
	Stay vanes, guide vane performance monitoring	C.17	IEC 60041
	Injector vibration monitoring	C.9	
	Cavitation and hydraulic disturbance monitoring	C.18	
	Penstock pressure and vibration monitoring (including the main inlet valve)	C.19	
	Pelton runner synchronization monitoring	Table C.14	

[a] This is described for the upper and lower generator bearings only.

[b] Guide bearing temperature is not covered in ISO 13373-7.

[c] This technique is also described in ISO 13373-7 but with a different method.

[d] Pressure is not covered in ISO 13373-7.

NOTE Condition monitoring techniques not completely covered by this document are shown in grey.

Table 2 *(continued)*

Primary component	Monitoring technique	Description clause	Relevant standards (referenced in the Bibliography)
Turbine	Blade clearance (Kaplan and bulb turbines)	C.14	
	Labyrinth seal clearance and temperature (Francis turbines)	C.15	ISO 13373-7[c]
	Francis turbine cover for axial vibration	C.16	ISO 13373-7
	Performance monitoring (efficiency, head and flow)	C.17	IEC 60041
	Cavitation and hydraulic disturbance monitoring	C.18	
Draft tube	Cavitation and hydraulic disturbance monitoring	C.18	
	Draft tube pressure and vibration monitoring	C.20	ISO 13373-7[d]

[a] This is described for the upper and lower generator bearings only.

[b] Guide bearing temperature is not covered in ISO 13373-7.

[c] This technique is also described in ISO 13373-7 but with a different method.

[d] Pressure is not covered in ISO 13373-7.

NOTE Condition monitoring techniques not completely covered by this document are shown in grey.

7.3 Primary descriptors and plots

Each monitoring and diagnostic technique for hydro units is composed of one or more detection and diagnostic measurements, called descriptors, which can be monitored to alarm limits and viewed in plots. The descriptors and plots, which can vary from one monitoring system supplier to another, can be fixed with regards to the configuration parameters or can be user adjustable so they can be set up to a specific application or fine-tuned as experience is gained. The descriptors and plots recommended in this document are considered the most relevant for a wide range of applications and machine types, and are based on time-proven experience and best practices.

Table 3 — Descriptors and plots for hydro unit monitoring techniques

Monitoring technique	Descriptors and plots description clause	Monitoring system requirements clause
Air gap (AG)	C.2.3	C.2.4
Magnetic flux (MF)	C.3.3	C.3.4
Partial discharge analysis (PDA)	C.4.3	C.4.4
Stator end winding vibration (EWV)	C.6.3	C.6.4
Blade clearance (Kaplan and bulb turbines)	C.14.3	C.14.4
Labyrinth seal clearance and temperature (Francis turbines)	C.15.3	C.15.4
Performance monitoring	C.17.3	C.17.4

7.4 Correlation measurements

The primary descriptors listed in Table 3 are often viewed in plots together with corresponding process measurements to better understand the primary descriptor response to specific operating conditions. This makes it easier to compare similar data when analysing fault symptoms and to define alarm limits with regards to an adaptive monitoring strategy as described in 7.5. Typical measurements used for correlation can be other primary descriptors or those specifically related to the process. These include but are not limited to:

— active, reactive power and power factor (e.g. measured by wattmeter or calculated from voltage and current transformers values multiplied by the power factor plus losses);

— speed and phase;

— excitation voltage and current (including voltage drop across excitation system field brushes);

— temperature (such as for oil, water, bearings, windings, cooling air and stator core). Sometimes the temperature is also monitored on the stator pressure plates/fingers, stator end-winding overhang support and stator circuit ring;

— pressure (oil, water, cooling air);

— flow (water, cooling air);

— humidity;

— vibration;

— performance parameters (e.g. water level, flow, water temperature);

— machine signals (e.g. synchronization, pumping, guide vane position).

Correlated measurements serve a critical purpose in those situations where the primary measurements are not very reliable. Moreover, there should be a sufficiently high sampling rate for these types of measurements for proper correlation.

7.5 Adaptive monitoring strategy

Many hydro units run under several operating conditions, so the signal response of the various descriptors of the monitoring techniques can also vary. For automatic early fault detection, the alarm limits should be individually set for each operating condition, based on experience. Process measurements that are typically used for defining individual operating classes can be any of those listed in 7.4 but are often speed, active power, power factor and machine binary signals (e.g. on, off, such as automatic generation control signals and power system stabilizers). There are two major types of operating regimes for hydro units; steady-state and transient. Most of the operating time is spent in steady-state operating classes, which includes:

— full load synchronized generation;

— pumping (for pumped storage);

— partial load synchronized generation;

— no load synchronized (condenser mode for grid stabilization);

— stopped.

Transient regimes include run-up and coast down. Several monitoring and diagnostic techniques, such as vibration monitoring, can be performed during transient conditions to detect or confirm certain potential failure modes that are not readily seen during steady-state conditions.

NOTE Not all descriptors can be monitored in all machine operating modes. A detailed description of some of the descriptors for each monitoring technique is given in Annex C.

7.6 Monitoring and diagnostic technique selection and evaluation

There are a number of techniques available for the monitoring and diagnostics of hydro units but the value each one delivers to the user highly depends on the application and the user requirements. A monitoring and diagnostic technique that is useful for one user can be totally unsuitable for another with similar machines. A simple weighted average method, as described in Annex D, can be used for evaluating similar monitoring and diagnostic techniques from various suppliers or for different monitoring techniques for a specific potential failure mode. The criteria used for evaluating the different techniques can include the following:

— reliability, accuracy and repeatability of the technique;

— detection lead-time to maintenance;

— equipment cost of sensors, signal processing and display;

— ease of installation;

— maintainability and calibration of monitoring equipment;

— diagnostic expertise needed.

NOTE The method described in Annex D is only intended to supplement the relevant cost benefit and risk analysis processes, not replace them.

8 Implementing, operating and maintaining a monitoring solution

8.1 General

The monitoring and diagnostic techniques selected in Clause 7 require a condition monitoring system to process the incoming signals that are indicative of the condition of the machine and deliver actionable information to the relevant operators and other systems for display or further processing. The actionable information is intended to assist making the relevant maintenance and operation decisions in order to minimize the life cycle costs of the machine and maximize production.

8.2 Sensor selection and installation

Retrofit sensors are normally provided and installed by the condition monitoring system supplier. If the user intends to do this task, there are important aspects that should be considered. For several monitoring techniques, the proper selection and mounting of sensors is critical for obtaining a signal that is reliably indicative of the incipient potential fault that it is intended to detect during early stages of development. Incorrect location of the sensor or improper mounting can result in a diminished signal, no signal or even an incorrect signal. Improper wiring and grounding can have the same effect. It is important to follow the sensor installation recommendations from the sensor and/or condition monitoring system supplier. The sensors described in this document are shown in Table 4.

Table 4 — Sensors used for hydro unit monitoring techniques as described in this document

Monitoring technique	Sensor description clause
Air gap (AG)	C.2.2
Magnetic flux (MF)	C.3.2
Partial discharge analysis (PDA)	C.4.2
Stator end winding vibration (EWV)	C.6.2
Bulb casing vibration	C.13
Blade clearance (Kaplan and bulb turbines)	C.14.2
Labyrinth seal clearance and temperature (Francis turbines)	C.15.2
Turbine cover for axial vibration	C.16.2
Performance monitoring	C.17.2
Cavitation and hydraulic disturbance monitoring	C.18.3

Table 4 *(continued)*

Monitoring technique	Sensor description clause
Penstock pressure and vibration monitoring	C.19
Draft tube pressure and vibration monitoring	C.20

8.3 Condition monitoring system evaluation and selection

As a matter of definition, a condition monitoring system is intended to detect and diagnose a fault as early in its development as possible so there is maximum lead-time to cost-effectively plan maintenance ahead of time. Production during this time can continue normally and downtime due to a catastrophic failure is avoided. It is not intended to shut down the machine for safety. This is the purpose of a protection system, which detects a fault late in its development and trips the machine as late as possible. This is intended to minimize downtime and yet still avoid catastrophic damage to the machine, environment or people. In many cases, a protection system includes condition monitoring functionality or can be extended for that purpose.

If there is an existing monitoring system, whether it is a protection system or a legacy condition monitoring system, it should be evaluated to determine if it can be extended to include the necessary condition monitoring functionality for the current hydro unit application requirements. If a new condition monitoring system is needed, there are several solutions from which to select. A condition monitoring solution can be an online system (permanently installed), a portable system or a combination of these. As an online system, it can be a single system consisting of a field monitor installed on a single machine or a rack-based system in the control room for several machines. It can also be a collection of several independent systems including portable units, which can be dedicated to specific hydro monitoring tasks. The system or systems can be independent or integrated together or connected to a process control system, but what is important for many hydropower applications is that there is at least some remote monitoring capability.

Although not within the scope of this document, the condition monitoring system selection is ideally based on cost benefits and risk analysis. In addition to the items mentioned in 7.6 regarding monitoring and diagnostic technique requirements, other requirements should be considered regarding the monitoring system itself, such as:

— **IT resource requirements** — Network, servers, cyber-security, back-up, personnel;

— **System integration requirements** — Data sent to and received from DCS/SCADA, data historian, remote control centre and other monitoring systems (via Modbus, TCP/IP and RTU, which are often used in the hydro industry);

— **Alarming strategy** — How alarm limits are to be established;

— **Downtime needed for installation** — Machines are stopped or disassembled to install sensors/wiring;

— **Specialists needed** — To fulfil requirements to operate system and/or provide expertise to interpret results from measurements and plots;

— **System training needed** — Training requirements to configure, operate and manage the system;

— **System services needed** — Service provider to operate, maintain and upgrade system;

— **Diagnostic services needed** — Service provider to perform monitoring, diagnostics and reporting.

8.4 Daily operation of the monitoring system

Most condition monitoring systems provide automatic alarming functionality (detection descriptors that give a warning when alarm limits are exceeded) that allows potential failure modes to be detected at an early stage of development. Once detected, the faults can be trended and observed over time. Diagnostic descriptors are additional measurements that are used for analysis purposes, to identify the type and location of the fault, evaluate its severity and determine the lead-time to maintenance. Routine activities may also include issuing reports at periodic intervals to summarize the general condition of the machines or give notice when a fault is detected. In special situations, if the necessary monitoring system tools are available, root cause analysis may be performed to avoid experiencing recurring premature faults or prognostics may be implemented to better manage lifetime prediction of components.

The operator workload with the condition monitoring system depends on the type of system selected. Some systems offer facilities for correlating data together in a historian database to improve reliability of diagnoses. Other systems offer automated functionality to reduce the user workload, such as an automatic alarm management system (to reduce repetitive or unnecessary alarms), event recording (for event analysis, which includes post-processing of the saved raw signals) and automatic diagnosis functionality (decision support to reduce diagnostic time and expertise needed). Services are also offered where some or all monitoring, diagnostics and action reports are done by a third party.

Whatever system or services are selected, the common denominator for all is that the condition monitoring solution adds value to the user's business. This means the solution should be benchmarked and evaluated periodically, and refined and updated as necessary.

Annex A
(informative)

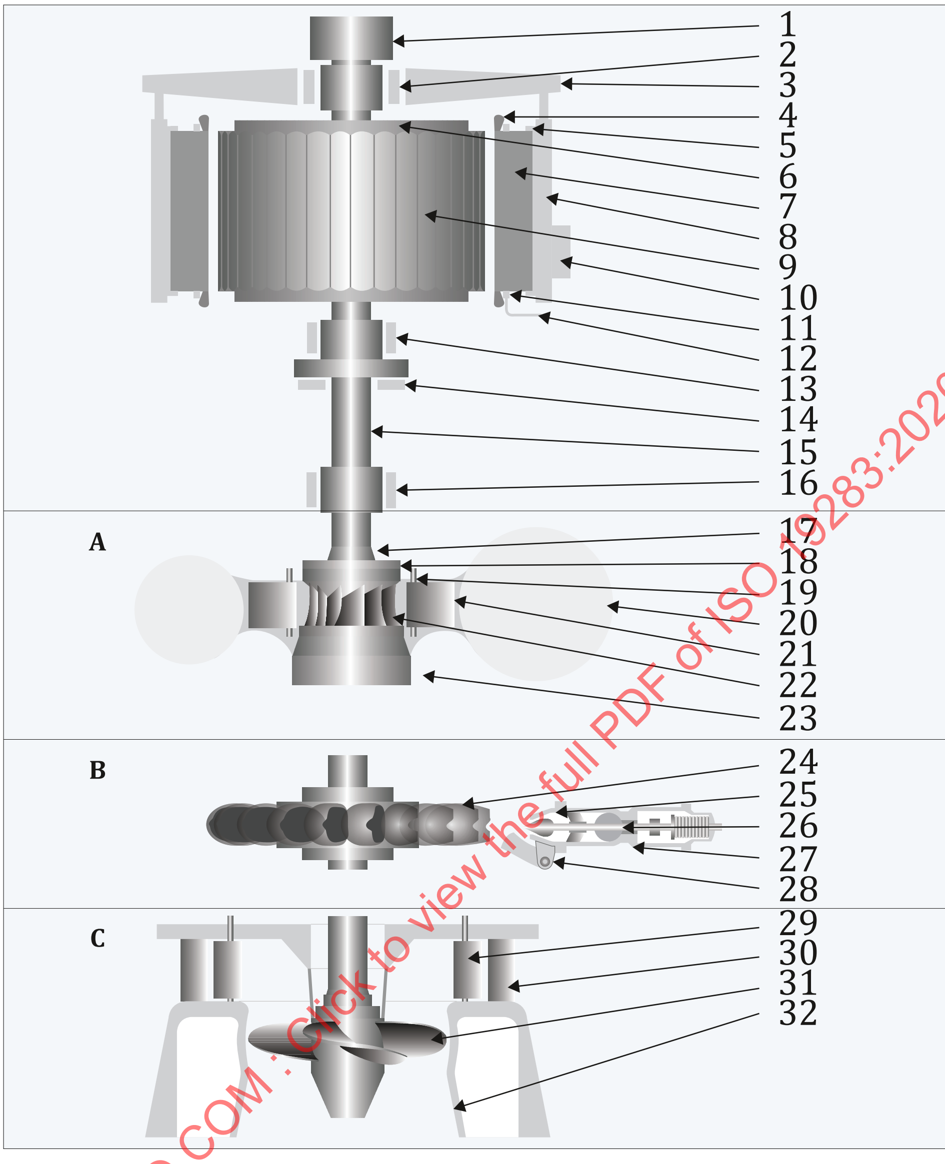
Machine components and failure modes

A.1 General

The relevant hydro unit components shown in Figures A.1 and A.2 are subject to a wide range of potential failure modes, depending on the application. For brevity, a generalized list of the most typical faults is listed in Tables A.1 to A.5.

A.2 Hydro unit components

The terminology used here is based on IEC/TR 61364.



Key

Generator and shaft assembly

1 exciter (slip ring and brush assembly)
2 upper generator guide bearing
3 spider/upper support bracket
4 stator end winding
5 pressure plate/finger
6 rotor rim
7 stator core
8 stator frame
9 rotor pole
10 stator cooling system
11 end winding support and circuit ring(s)
12 main and neutral terminals
13 lower generator guide bearing
14 thrust bearing
15 shaft
16 turbine guide bearing

A – Francis

17 main shaft seal
18 turbine cover
19 distributor
20 spiral case
21 guide vane
22 runner
23 draft tube

B – Pelton

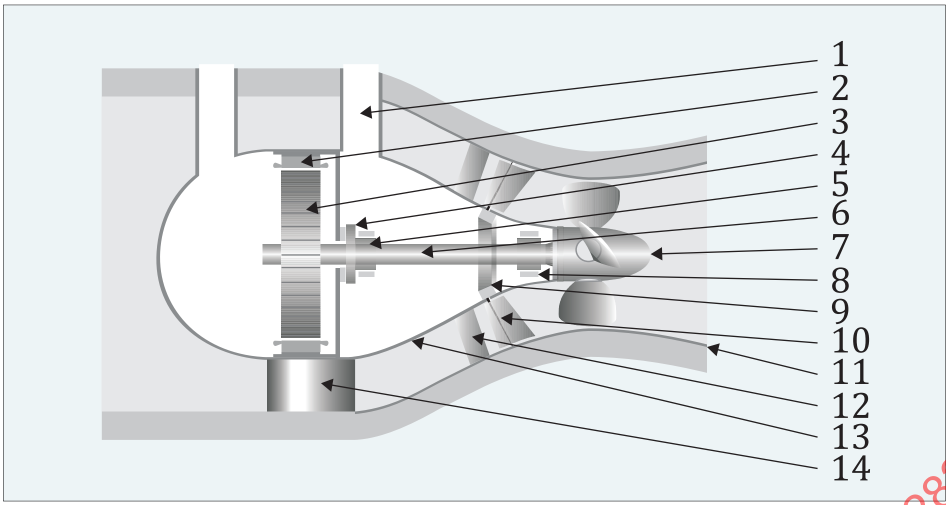
24 runner (bucket)
25 nozzle
26 spear
27 injector
28 deflector

C – Kaplan

29 guide vane
30 stay vane
31 runner blades
32 draft tube

NOTE There are several types of generators used in hydro units, including motor/generator types and vertical and horizontal configurations, but for the sake of simplicity, only a vertical salient pole synchronous generator is shown here.

Figure A.1 — Components for Francis, Pelton and Kaplan turbine hydro units



Key

1.	access shaft	5	generator guide bearing	8	turbine guide bearing	11	draft tube
2	stator	6	shaft	9	wicket gate	12	stay vane
3	rotor	7	runner	10	guide vane	13	bulb casing
4	thrust bearing					14	bottom support

Figure A.2 — Components for a bulb hydro unit

A.3 Hydro unit component failure modes

The failure modes shown in Tables A.1 to A.5 are by no means an exhaustive list. Only some typical examples are shown for simplicity. Users are encouraged to prepare a complete list of the potential failure modes for their specific application, preferably using a reliability and risk analysis method suitable to their needs.

Table A.1 — Hydro unit generator failure modes

Sub-component	Failure mode	Failure cause	Failure effect
Rotor	Shorted winding turns (turn to turn), ground fault (turn to rotor) and ground to feedline	Winding insulation breakdown due to aging, overheating, load cycling, contamination, and/or turn-to-turn movement	Unbalanced magnetic pull resulting in excessive vibrations on the structure and bearings. The ampere-turn for the pole is reduced, so more field current is needed to maintain load, which can result in a higher operating temperature because of increased field current. If there are several unevenly spaced shorts, this can cause excessive vibration. Production efficiency will be reduced. If a single earth fault occurs, the unit can still run but if two earth faults occur in the rotor shorting several poles, significant damage can happen.
	Plastic deformation of rotor rim creating looseness, or movement during overspeed	Excessive load and/or load cycling, or load shedding	Rotor poles can inadvertently extend toward the stator thus creating uneven air gap. This creates magnetic unbalance that can result in excessive vibrations on the structure and bearings. If unchecked, it can result in a stator-rotor rub, which would be a catastrophic failure. Shrunk-fitted rotor ring supports can be subject to fatigue cracking, especially for rotor rings that are not pre-stressed at nominal speed. This can have an influence both on the radial and vertical position of the rotor rim. Rim movement can also be caused by an out of round stator where one or more instances of small air gap can significantly increase magnetic attraction of rotor to stator in those locations and deform the rotor, which could also result in damage to rotor pole mountings.
Stator	Degraded stator bar insulation	Stator bar insulation breakdown due to aging, overheating, load cycling, contamination, stator core vibration and/or loose stator bar vibration	If the insulation fails and there are no provisions for limiting the fault current, a shorted stator bar will result in a catastrophic failure that will require replacement or refurbishment. Stator bar insulation breakdown will be a ground-wall insulation issue. In applications of multi-turn stator windings, insulation breakdown can result in shorted turns which will cause localized heating and if not repaired, can eventually lead to ground-wall insulation failure.
	Stator shape deformation	Deformed or broken stator foundation bolts, or concrete foundation degradation. Also caused by uneven cooling	Uneven air gap creates magnetic unbalance that can result in excessive vibrations on the structure and bearings. This can result in a stator- rotor rub, which would be a catastrophic failure. Stator shape deformation is more prominent in stators that are built in sections and assembled on-site rather than stators that are completely piled and wound on-site. As noted above uneven air gap could contribute to failure of rotor pole attachments.

Table A.1 *(continued)*

Sub-component	Failure mode	Failure cause	Failure effect
	Loose end-windings or loose wedging	Vibration wear of the insulation	Vibration increases with more looseness, thus increasing the insulation wear more. If the insulation fails, a shorted stator bar will lead to a catastrophic failure. It can also fatigue the stator bar to crack or break, possibly leading to a catastrophic failure.
	Overheating	Clogged cooling ducts or defective cooling system	Excessive heat in the stator reduces the life of the insulation, which can lead to a catastrophic failure of the generator. It can also cause deformation of the stator, which will create an uneven air gap that can excessively load the bearings due to the electromagnetic imbalance.
	Circuit ring or terminal failure	Thermal and cycle fatigue	Outage and possible catastrophic failure.

Table A.2 — Hydro unit shaft, bearing and main shaft seal failure modes

Sub-component	Failure mode	Failure cause	Failure effect
Thrust bearing	Oil film thickness reduced	Malfunctioning oil delivery system or uneven seal wear on high-head units. Excessive load/overload, a rotor system severe misalignment, or an axial clearance that is too tight leading to possible rubbing and/or bearing fatigue.	Thrust bearing rub can lead to a catastrophic failure in very little time.
Guide bearings	Excessive clearance	Bearing wear, possibly enhanced by load cycling or due to excessive vibrations during partial load. Can also be misalignment	Excessive vibrations stress the structure and can cause a labyrinth seal leak for Francis turbines or a blade draft tube rub for Kaplan turbines. Excessive bearing clearance can also lead to a change in the rotor dynamic properties of the shaft. A critical speed can gradually shift to the nominal speed range, resulting in increasing vibration and, if not monitored by a protection system, can lead to a catastrophic failure. Excessive bearing clearance also decreases the bearing load capacity (quantitively speaking, the Sommerfeld number is reduced).
	Insufficient clearance	Bent or misaligned shaft, improper assembly or high bearing temperature	Excessive heat generation can reduce the life of the bearings.
	Shaft current and voltage	Inadequate bearing insulation	Damaged bearings
Shaft	Unbalance, misalignment, bent shaft	Can be caused by hydraulic, mechanical, thermal and/or electromagnetic causes	Excessive vibrations can stress structural components and prematurely wear the guide bearings.
Main shaft seal	Excessive leaking	Wear, improper seal selection or installation	Loss of efficiency, corrosion, excessive air compressor operation during synchronous condenser operation, degradation of civil works.

Table A.3 — Hydro unit turbine, penstock (including the main inlet valve), spiral case, stay vanes, guide vanes and injector (Pelton) failure modes

Sub-component	Failure mode	Failure cause	Failure effect
Wicket gate shear pins and bushings	Loose or worn pins and bushings	Wear, abrasion	Excessive vibrations, reduced efficiency
	Broken shear pin	Fatigue or overload due to locking of a guide vane (due to foreign object lodged between the guide vanes). Excessive wear on guide vane bearing or bushing, or debris between the cover and guide vane, can also lead to shear pin failure.	The affected vane will cause flow disturbance with excessive vibrations that will stress structures and reduce operating efficiency.
Penstock (including the main inlet valve), spiral case, stay vanes, guide vanes	Structural damage, hydraulic loading	Hydraulic loading due to vortex shedding, von Karman turbulence, hydraulic imbalance, water hammer, penstock pressure pulsations or damage due to foreign object intake	Weakened and fatigued structures with reduced operating efficiency
	Profile erosion	Cavitation, abrasive sediment, deposits	
Guide vane ends	Leaking	Excessive end clearance, due to wear, abrasive sediment erosion	Reduced operating efficiency
Injector, buckets	Structural damage	Injector synchronization problems	Weakened and fatigued structures with reduced operating efficiency
	Profile erosion	Cavitation, abrasive sediment, deposits	

Table A.4 — Hydro unit turbine (Francis, Kaplan) failure modes

Sub-component	Failure mode	Failure cause	Failure effect
Francis turbine Labyrinth seal, Kaplan blade clearance	Excessive leakage	Wear, shaft eccentricity	Reduced operating efficiency.
	Rubbing	Axial hydraulic load due to hydraulic disturbance. Can also be caused by uneven seal wear in high-head units	Reduced operating efficiency and in a worst-case scenario catastrophic failure.
Runner	Profile erosion	Cavitation, abrasive sediment, deposits	Reduced operating efficiency.
	Water hammer	Improper valve shutdown	Stressed turbine cover bearings and other structures.
	Fatigue cracks	Long-term cyclic stress	Weakened structure, can lead to a catastrophic failure.
	Structural damage	Hydraulic loading due to vortex shedding, von Karman turbulence, partial load pressure pulsations, hydraulic imbalance or damage due to foreign object intake. Also rotor-stator interaction forces (RSI), i.e. force variation between the guide vanes and runner blades can stress the runner, especially for pump-turbines	

Table A.5 — Hydro unit draft tube failure modes

Sub-component	Failure mode	Failure cause	Failure effect
Draft tube lining	Structural damage, fatigue	Hydraulic loading due to vortex shedding, von Karman turbulence, partial load pressure pulsations, hydraulic imbalance or damage due to foreign object intake	Weakened and fatigued structures with reduced operating efficiency
	Erosion	Cavitation, abrasive sediment, deposits	

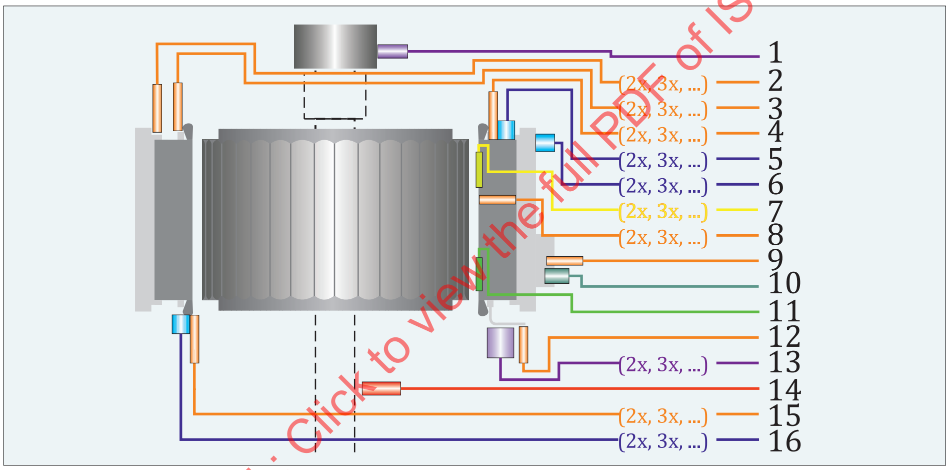
Annex B
(informative)

Monitoring techniques for hydro unit components and failure modes

B.1 General

Typical monitoring and diagnostic techniques for specific hydro unit components and failure modes are listed in this annex.

B.2 Monitoring techniques vs. hydro unit components



Key

Exciter/Slip ring
1 current/voltage

Pressure plate/finger
2 temperature

End winding support
3 temperature

Stator core
4 temperature
5 absolute vibration

Stator frame
6 absolute vibration

Rotor/stator clearance
7 air gap

Stator bar
8 temperature

Cooling system
9 temperature
10 pressure

Pole windings
11. magnetic flux

Main/neutral terminal
12 temperature

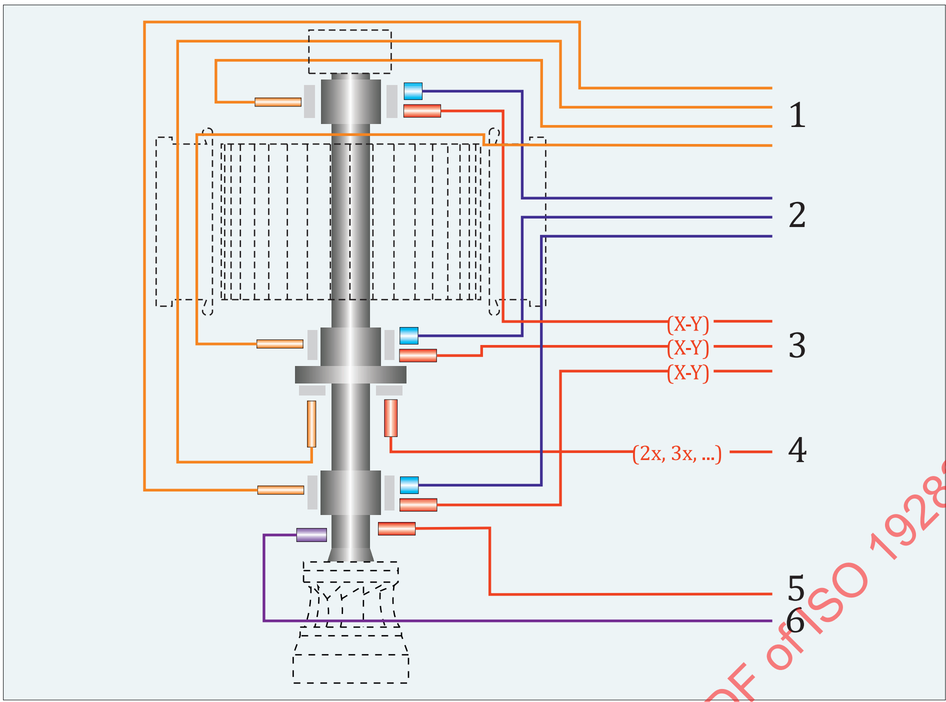
Stator windings
13 partial discharge

Shaft
14 speed and phase

Stator end windings
15 temperature
16 absolute vibration

NOTE The quantity of each kind of sensor depends on the application.

Figure B.1 — Monitoring techniques covered by this document for the generator



Key

Radial and thrust bearings and pads
1 temperature

Shaft/bearing
3 relative position and vibration

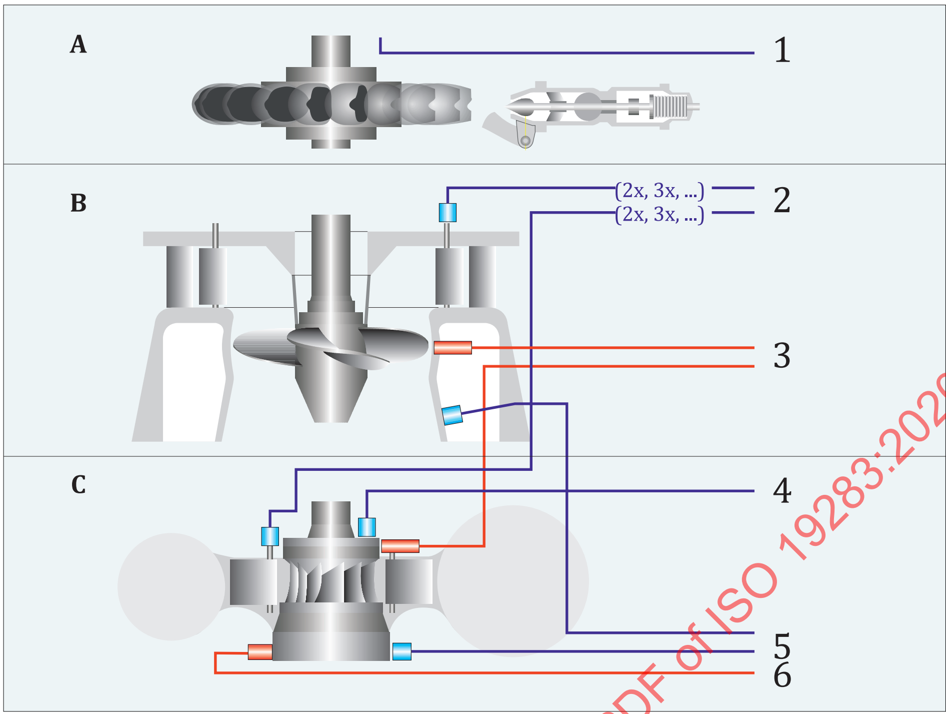
Thrust bearing
4 relative position and vibration

Shaft
5 speed and phase
6 current

Bearing housing
2 absolute vibration

NOTE The quantity of each kind of sensor depends on the application.

Figure B.2 — Monitoring techniques covered by this document for the shaft and bearings



Key

A – Pelton

Pelton turbine

1 normally monitored from turbine bearing

B – Kaplan

Guide vane, shear pin

2 absolute vibration

Blade/seal

3 relative position and vibration

C – Francis

Turbine cover

4 absolute vibration

Draft tube

5 absolute vibration

6 Pressure

NOTE The quantity of each kind of sensor depends on the application.

Figure B.3 — Monitoring techniques covered by this document for the turbine — Pelton, Kaplan and Francis

B.3 Monitoring techniques vs. failure modes

The relevant monitoring techniques for detecting and diagnosing failure modes are shown in Tables B.1 to B.4. It is important to highlight that although vibration monitoring techniques are the primary monitoring techniques for detecting the most failure modes in a typical hydro unit, the generator failure modes are considered the most critical, where vibration monitoring techniques are not the primary technique for detection or diagnostics of generator potential failure modes.

Table B.1 — Hydro unit generator failure modes

Failure mode	Monitoring technique											
	Vibration, (accelerometer, velocimeter, displacement)	Air gap	Magnetic flux	PDA	Temperature	Pressure	Flow	Performance calc.	Shaft current, voltage	Exciter current, voltage	Power	Oil analysis
Shorted rotor winding turn	□	□	•		•					□	□	
Loose rotor rim (uneven air gap)	□	•	□								□	
Damaged rotor pole attachments (uneven air gap)	□	•	□								□	
Deformed spider (uneven air gap)	□	•	□								□	
Damaged stator foundation holding bolts (uneven air gap)	□	•			□						□	
Stator foundation creep (uneven air gap)	□	•			□						□	
Loose or damaged stator frame (uneven air gap)	□	•			□						□	
Loose or damaged stator core laminations[a]	•				□						□	
Stator core hotspots[a]					•						□	
Defect stator bar insulation	□			•							□	
Loose stator end windings	•										□	

• = primary technique;

□ = correlation technique.

[a] These can occur in various portions of the core including near to stator teeth, so they are very difficult to detect unless the vibration and/or temperature sensor are coincidently close by.

Table B.2 — Monitoring techniques vs. failure modes for shaft, bearing and main shaft seal assembly

Failure mode	Monitoring technique										
	Vibration, (accelerometer, velocimeter, displacement)	Air gap	Magnetic flux	PDA	Temperature	Pressure	Flow	Performance calc.	Shaft current, voltage	Exciter current, voltage	Power	Oil analysis
Damaged, worn bearings	•				□							□
Bearing damage due to current	□				□				•			□
Shaft unbalance	•	□	□		□							
Bent shaft	•	□										
Loose shaft	•	□										
Misaligned shaft	•	□										
Insufficient thrust bearing oil film	•				□							□[a]
Main shaft seal leak					□				•			

• = primary technique;

□ = correlation technique.

[a] If the oil film was broken temporarily.

Table B.3 — Monitoring techniques vs. failure modes for turbine

Failure mode	Monitoring technique											
	Vibration, (accelerometer, velocimeter, displacement)	Air gap	Magnetic flux	PDA	Temperature	Pressure	Flow	Performance calc.	Shaft current, voltage	Exciter current, voltage	Power	Oil analysis
Cavitation[a]	•							•				
Eroded blades, runner	□					□	□	•				
Sheared or loose wicket gate pin[b]	•											
Excessive blade clearance	•											
Excessive seal clearance	•						•[c]					

• = primary technique;

□ = correlation technique.

[a] There are also ultrasound and acoustic techniques for detecting cavitation.

[b] There are also dedicated monitoring systems for detecting this potential failure mode.

[c] This is done primarily for the upper clearance seal.

Table B.4 — Monitoring techniques vs. failure modes for draft tube

Failure mode	Monitoring technique											
	Vibration, (accelerometer, velocimeter, displacement)	Air gap	Magnetic flux	PDA	Temperature	Pressure	Flow	Perfor-mance calc.	Shaft current, voltage	Exciter current, voltage	Power	Oil analysis
Vortex turbulence	•					•						
• = primary technique; ☐ = correlation technique.												

Annex C
(informative)

Primary monitoring and diagnostic techniques

C.1 General

This is a description of the primary techniques for hydro units that have been used over the years. Other techniques that are relatively new and unproven are not included here. If the monitoring technique is described more completely in other standards, a reference is made to such standards and only a brief description is given in this annex.

C.2 Air gap (AG)

C.2.1 General

The generator air gap, the radial distance between the stator and the rotor, is where all the rotational energy of the rotating rotor is transformed to electrical energy in the stator. Monitoring the air gap is important for identifying machine behaviour and seeing its effect on the quality of the produced energy. To achieve good operating efficiency, it is necessary that the rotor and stator have good roundness and are concentrically positioned with respect to each other. The air gap can be very small in relation to the large diameters of hydro units, especially on some of the slower turning hydro units. Variations in the air gap will have an effect on the mechanical and electromagnetic balance of the generator, and can result in increased loading and vibration on machine components, such as the bearings. An extreme case would be a rub between the stator and rotor, which can lead to a catastrophic failure. For this reason air gap monitoring has become an accepted part of the machine condition monitoring strategy of many hydro units. Air gap monitoring is normally not so important if there is more than 2 mm to 3 mm nominal air gap per 1 000 mm rotor diameter.

Variations in air gap are typically affected by a change in the stator and rotor geometry, which can be caused by any number of different mechanical, magnetic and thermal forces within the hydro unit structure and by varying operating conditions. Causes for a variation in the air gap can be:

— eccentricity between rotor and stator;

— misalignment;

— electrical unbalance;

— uneven thermal expansion;

— stator and rotor roundness.

For the rotor, it could be caused by:

— dislocation of the poles, loose poles;

— loose rotor rims;

— deformed rim;

— centre-line offset;

— defective floating rim;

— turn-to-turn shorts;

— rotor thermal dilatations;

— rotor dilatation due to run-up and overspeed centrifugal forces during load shedding;

— rotor dilatation due to electromagnetic forces when excitation is turned on and load is increased;

— fatigue cracks on the rotor rim.

For the stator, it can be caused by:

— concrete growth;

— jammed hold-down bolts;

— core/frame separation;

— uneven temperatures in the stator core;

— uneven friction in the stator frame supports;

— stator core thermal dilatation.

An air gap monitoring system on hydro units makes it possible to monitor the behaviour of both the rotor and stator structures dynamically while the generator is in operation. Such a system can identify many geometric problems with the rotor and stator (including those that reduce efficiency) such as eccentricity, misalignment, magnetic unbalance, rotor shorted turns, and loose pole or stator movement that might lead to damage from magnetically induced heating or a rotor-to-stator rub.

Air gap monitoring is only briefly described in IEEE 1129, therefore a more thorough evaluation of this technique is given in this document.

C.2.2 AG sensors

The sensors used for monitoring air gap are summarized in Table C.1 and the AG sensor installation is shown in Figure C.1. The air gap sensor is typically a non-contact, capacitive type distance measuring transducer that is glued on to the stator inner face. It is a low-profile sensor with a preamplifier built into the cable to minimize the thickness of the sensor. The air gap sensor should be immune to magnetic fields, dust, oil vapour, EMI and RFI. The capacitive AG sensor operates by producing an electrostatic field between two electrodes in the sensor. When a pole face approaches the field, the capacitance and subsequently the AC current in the oscillator circuit changes. When the oscillator amplitude reaches a certain threshold, the trigger circuit sends out a voltage or current signal that is proportional to it. Subsequent signal processing linearizes this output. The principle of operation of the capacitive AG sensor is shown in Figure C.2.

The AG sensor can also be based on the electric field principle using a transmitter and receiver electrode.

Table C.1 — AG sensors

Sensor type	What is measured	Technology	Location, wiring	Quantity per machine	Description of sensor operation
Air gap	Distance	Primarily capacitive but can also be based on the electric field principle.	Glued on inner wall of stator. See Figure C.1. Some stator air cooling vents may be covered by the sensors. Different size sensors available.	See Table C.2 and Figure C.1	The principle of operation for a capacitive sensor is shown in Figure C.2.
Phase/speed reference sensor	Tacho pulse per revolution	Typically inductive eddy current, but can also be an optical sensor with TTL or NPN/PNP output.	Bracket over the shaft with a pulse trigger	1	Signal pulse is generated for each rotation of the hydro unit. This synchronizes the AG measurement to each rotor pole and stator sensor position for a complete rotation.

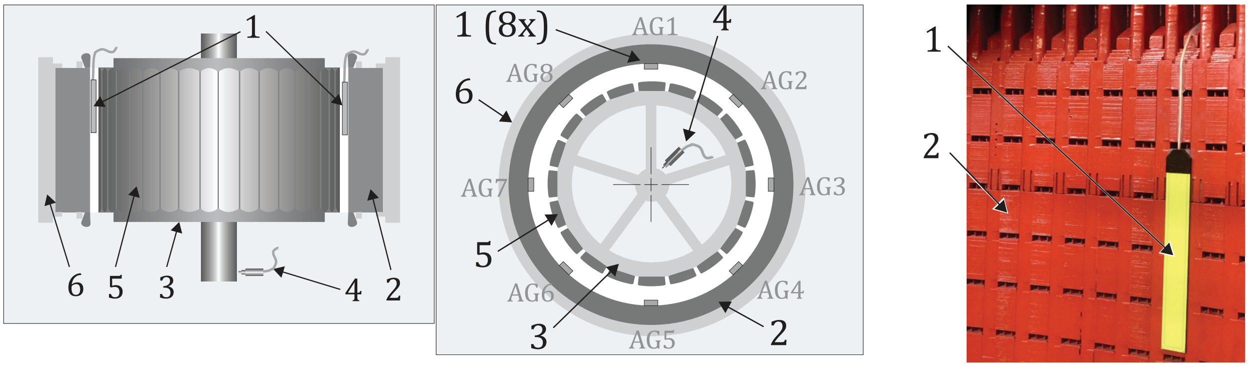
The number of sensors to install on the stator varies from 1 to 16 in one plane (more than 16 would not be practical). The greater the number of sensors, the more information that is available about the stator geometry using specialized monitoring techniques, as described in Table C.2. By contrast, only one air gap sensor is needed to determine rotor shape, but a single air gap sensor can give no information on the stator shape. If the generator height is greater than 1,6 m, two planes should be considered to be monitored, one on the top and one on the bottom, to detect geometrical variation along the vertical axis of the stator.

If there are air gap variations between the newly installed AG sensors on an otherwise round concentric stator, this could be due to variations in the glue thickness. This should be taken into account in the AG monitoring system.

Table C.2 — AG sensors — Guidelines for quantity of sensors

Monitoring or diagnostic technique	No. of sensors in one plane[a]		
	1	2	4+
Minimum air gap – Measured from each sensor	•	•	•
Maximum air gap – Measured from each sensor	•	•	•
Average air gap – Calculated from each sensor	•	•	•
Maximum neighbouring poles difference	•	•	•
Rotor poles profile	•	•	•
Stator centre position			•
Rotor centre position		•	•
Rotor rotation centre position		•	•
Stator shape – stator deformations			•
Minimum air gap – Calculated with respect to the stator shape			•
Rotor dynamics		•	•

[a] 2 planes if generator height >1,6 m. There can be one or more sensors on the secondary plane. Four or more sensors are needed on at least one plane to determine the geometrical condition of the stator.



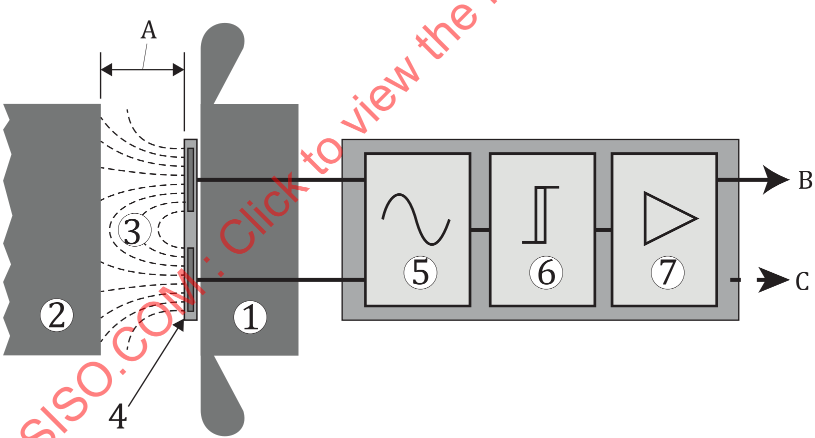
a) **Side view** b) **Top view (8 sensors shown)** c) **Upper front view from inside the stator**

Key

1. air gap sensors (AG1, AG2, ... upper and/or lower part of stator)
2 stator core
3 rotor rim
4 tacho
5 rotor pole
6 stator frame

NOTE The quantity of sensors depends on the application.

Figure C.1 — Air gap sensor installation



Key

Rotor pole

A air gap distance
1 stator
2 rotor (pole face)
3 electromagnetic field

Sensor

4 sensor body

Signal conditioner

5 oscillator
6 trigger
7 switching amplifier

Output

B AG time signal (V) for CM monitoring
C peak-hold min. AG (V) for protection (can be done elsewhere)

Figure C.2 — AG sensor operation principle (capacitive type sensor shown)

C.2.3 AG descriptors and plots

A summary of the descriptors and plots used for monitoring AG is shown in Table C.3. The raw AG time signal and the processed circular plot are sufficient for visual diagnostic analysis, but these cannot be used for automatic condition monitoring to alarm limits. For this purpose, the time signal is typically conditioned to scalar values for each pole (e.g. average, minimum and maximum), which are stored and trended to alarm limits. Alarm limits for these scalar values should be based on actual installation conditions and monitoring strategy requirements.

Table C.3 — Detection and diagnostic descriptors and plots of AG

Descriptor	Plot	Detection/ diagnosis	Process values for correlation	Operation conditions under which signal changes	Subsequent behaviour of signal over time
Minimum AG (from hardware)[f]	Primarily for machine protection				
AG time signal for one rotation	— Time signal for each sensor (or bar graph) — Difference between each pole and its neighbour — Circular AG plot - Rotor and stator	Variations in the stator-rotor air gap	— Bearing vibration — Magnetic flux — Rotational speed	— Active power — Reactive power — Excitation current and voltage	Variable
— Average AG[a,b] — Minimum AG[a,b] — Maximum AG[a,b] — Stator[b] roundness[c] — Rotor roundness[c] — Stator[b] offset[d] — Rotor offset[d] — Stator tilt[e]	Trend				

[a] For each sensor.

[b] At least four sensors needed for these calculations to take into account stator shape.

[c] Maximum air gap minus minimum air gap with respect to centre of rotation.

[d] Relative position of geometric centre to centre of rotation.

[e] Multiple air gap sensors have to be installed in two planes.

[f] Shape of stator not taken into account.

C.2.4 AG monitoring system requirements

A summary of the monitoring equipment requirements for AG is shown in Table C.4. AG monitoring is normally done with an online system. Although fault development is slow, detailed trends are important since they are not necessarily linear.

Table C.4 — Monitoring equipment requirements for AG

Item	Remarks
Preferred data acquisition unit	Online system for powering the sensors, taking in the sensor signal, doing preliminary signal conditioning, exporting the data to other systems and operating relays for alarming.
Signal processing requirements	— A single value minimum AG is extracted for each pole from the AG time signal. — The scalar descriptive values shown in Table C.3 are calculated from the minimum AG from each pole (these can be processed in the data acquisition unit or in the monitoring software). — Should be monitored to various machine states. — A tacho signal is used to sample the AG signal for one rotation and for matching the AG time signals to the corresponding passing poles and position.
Data import/export	— Process data used for correlation is imported from DCS. — Primary monitoring information is exported to DCS/SCADA. — Transfer of time signals via the appropriate communication protocol.
Relays	— Minimum AG used for protection sometimes. — Other alarm violations for annunciation (no protection).
Monitoring software and database	The software enables system configuration, alarming and viewing plots. Some of the AG time signal processing can also be done in the monitoring software.

C.3 Magnetic flux (MF)

C.3.1 General

An MF field is generated around each of the pole windings by the exciter DC power during unit operation, which in return generates power in the stator. This field, measured in Tesla, is heavily influenced by the exciter current and voltage but should always be equal for all poles under normal conditions. The primary purpose for monitoring the MF is to detect a short circuit in the winding for an individual pole or between poles. If there is a short, the MF around the pole is reduced but sometimes is not noticeable unless there are several turns shorted. Shorted turns reduce the generator efficiency and, in extreme cases, can cause magnetic unbalance, unless the shorts are symmetrically opposed to each other. Such an unbalance will result in vibrations that can excessively load the bearings and induce vibrations in the stator. A shorted turn generally occurs if the winding insulation is damaged or degrades over time. Ideally, MF should be monitored at all times. In some situations, it is considered ideal to monitor MF only during speed-no-load excited conditions (SNL) for best detecting shorted turns. This is because the stator magnetic field tries to even out the magnetic variations of the poles under load (especially at high loads). However, temperature changes during load and non-load conditions can influence the presence of shorted turns. Moreover, the stator magnetic field influences the MF shape, especially the higher harmonics, so there is useful MF information also during loaded conditions.

MF can be used for detecting eccentricity and non-circularity of the rotor with respect to the rotational axis and therefore should be correlated with the AG measurements. Sometimes, there are “strong” poles and “weak” poles with no faults. In such a case, after refurbishment, if the “strong” poles are incorrectly mounted all on one side, this can create a magnetic unbalance that can be detected by MF.

MF can also be used for detecting broken damper bars, but this is more of a challenge since the damper bars are only active during transient conditions. The actual MF response has to be compared to a no fault condition that corresponds to the same transient conditions.

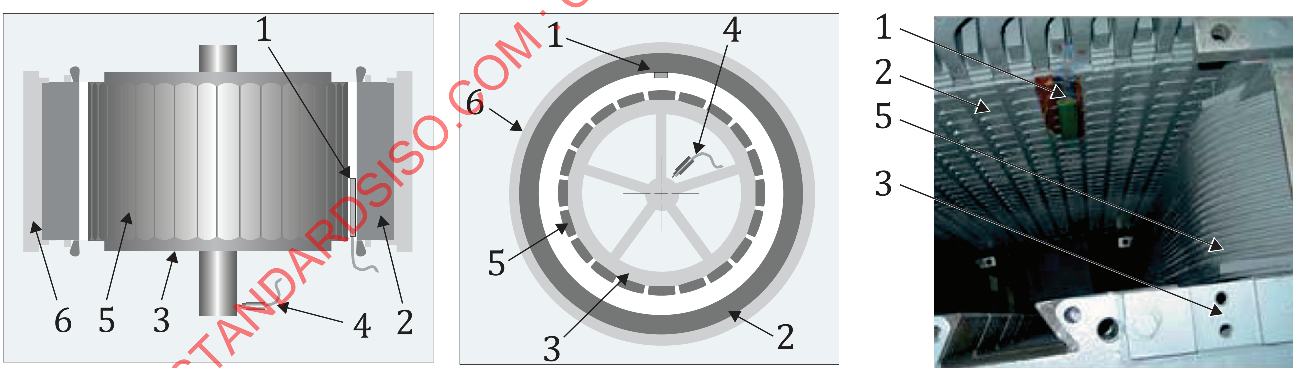
MF monitoring is only briefly described in IEEE 1129; therefore, a more thorough evaluation of this technique is given in this document.

C.3.2 MF sensors

The sensors used for monitoring magnetic flux are summarized in Table C.5 and the MF sensor installation is shown in Figure C.3. There are two basic types of stator-mounted magnetic flux sensors: Hall-effect (primary type) and inductive. Normally, one sensor per generator is sufficient but there are some operators who use several, possibly to compensate for not using air gap sensors. The Hall-effect MF sensor detects the presence of the magnetic field around the windings of each passing pole. Due to the Hall effect, a voltage signal is generated proportional to the detected magnetic field. The principle of operation of the MF sensor is shown in Figure C.4.

Table C.5 — MF sensors

Sensor type	What is measured	Technology	Location, wiring	Quantity per machine	Description of sensor operation
Magnetic flux	Magnetic flux of each passing rotor pole	Capacitive (Hall-effect) or inductive	Glued on inner wall of stator (See Figure C.3). Some stator air cooling vents may be covered by the sensor	1	Principle of operation is shown in Figure C.4.
Phase/speed reference sensor	Tacho pulse	Typically inductive eddy current, but can also be an optical sensor with TTL or NPN/PNP output.	Bracket over the shaft with a pulse trigger	1	Signal pulse is generated for each rotation of the hydro unit. This synchronizes the MF measurement to each rotor pole for a complete rotation.

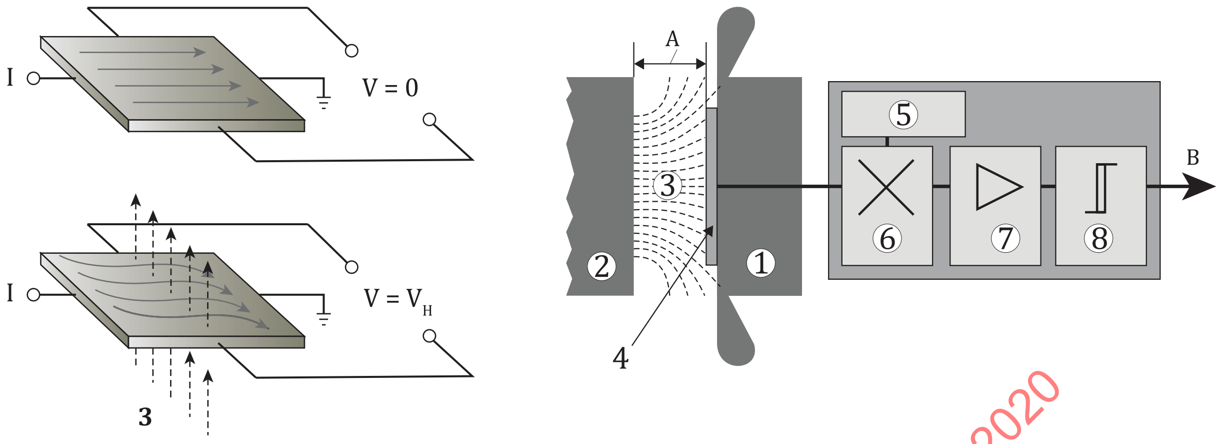


a) Side view b) Top view c) Top view of the stator

Key

1 MF sensor (upper or lower part of stator)
2 Stator core
3 Rotor rim
4 Tacho
5 Rotor pole
6 Stator frame

Figure C.3 — Magnetic flux sensor installation



a) Hall effect principle

b) Magnetic flux sensor operation

Key

Rotor pole		Sensor		Signal conditioner		Output	
A	magnetic field strength	4	sensor body	5	regulator	B	time signal (V)
1	stator			6	hall element		
2	rotor (pole face)			7	amplifier		
3	magnetic field			8	trigger		

Figure C.4 — Hall-effect magnetic Flux sensor principle of operation

C.3.3 MF descriptors and plots

A summary of the descriptors and plots used for monitoring MF is shown in Table C.6. The raw magnetic flux time signal and the processed circular plots can be used for visual diagnostic analysis but these cannot be used for automatic condition monitoring to alarm limits. For this purpose, the time signal is typically conditioned to scalar values for each pole (e.g. average, minimum and maximum), which are stored and trended to alarm limits. Alarm limits for these scalar values should be based on actual installation conditions and monitoring strategy requirements. Moreover, variations in the magnetic flux measurements can be small, so an accurate measurement is required for each pole. As an example, on a 72 pole machine with 20 turns/pole, a single shorted turn will reduce the magnetic flux measured by only 5 %.

Table C.6 — Detection and diagnostic descriptors and plots of MF

Descriptor	Plot	Detection/diagnosis	Process values for correlation	Operation conditions under which signal changes	Subsequent behaviour of signal over time
MF time signal for one rotation	Time signal	— Reduction in pole flux - One or more winding shorts (within a pole and between poles) — Variation in MF – Change in magnetic balance due to variations in the stator-rotor air gap	— Vibration — Exciter field current and voltage — Winding temperature — Air gap	— Active power — Reactive power — Excitation current and voltage	— Shorted turns - Value remains fixed until another short occurs — Magnetic balance - Signal can vary in any manner
Max. rectified time signal for each pole	Circular MF plot (showing all poles on rotor)				
— Average MF — Minimum MF — Maximum MF	Trend				

NOTE Statistical analysis of measurements over several full turns of the rotor can help reduce the influence of stochastic variations of the measurements and increase accuracy.

C.3.4 MF monitoring system requirements

A summary of the monitoring equipment requirements for MF is shown in Table C.7. MF monitoring is normally done with an online system. MF changes due to winding shorts normally occur with little advanced warning.

Table C.7 — Monitoring equipment requirements for MF

Item	Remarks
Preferred data acquisition unit	Online system for powering the sensors (if necessary), taking in the sensor signal, doing preliminary signal conditioning, exporting the data to other systems and operating relays for alarming.
Signal processing requirements	— The MF time signal is often rectified and a single value minimum MF is extracted for each pole. — The scalar descriptive values shown in Table C.6 are calculated from the minimum MF from each pole (these can be processed in the data acquisition unit or in the monitoring software). — Should be monitored to various machine states. — A tacho signal is used to sample the MF signal for one rotation and for matching the MF time signals to the corresponding passing poles and position.
Data import/ export	— Process data used for correlation is imported from DCS. — Primary monitoring information is exported to DCS/SCADA. — Transfer of time signals via the appropriate communication protocol.
Relays	— Normally protection is not used. — Alarm violations for annunciation.
Monitoring software and database	The software enables system configuration, trending (e.g. minimum MF, maximum MF, average MF), alarming and viewing plots. Some of the MF time signal processing can also be done in the monitoring software.

C.4 Partial discharge analysis (PDA)

C.4.1 General

As the stator winding insulation degrades, voids and fissures form within the insulation that gradually increase in size and number up until complete dielectric breakdown occurs, resulting in a stator winding short. It is possible to detect this fault at an early stage of development by monitoring partial discharges (PD) that can occur through the early stage voids within the insulation while the hydro unit is operating. External discharge activity on the insulation surface can manifest itself in the form of corona, phase to phase (gap) discharges, or slot discharges. Partial discharge analysis (PDA) is used as a tool to detect different insulation aging processes that result in partial discharges.

There are several methods to monitor PD in hydro units, but the method most often used employs coupling capacitive type sensors that are mounted singly or in pairs on each phase of the stator windings, terminals or bus bars. The current and/or voltage pulses that correspond to the multitude of discharges are measured, including information on the magnitude, rate and polarity of the discharges. This information is trended over time to monitor insulation degradation up until the period when maintenance has to be done.

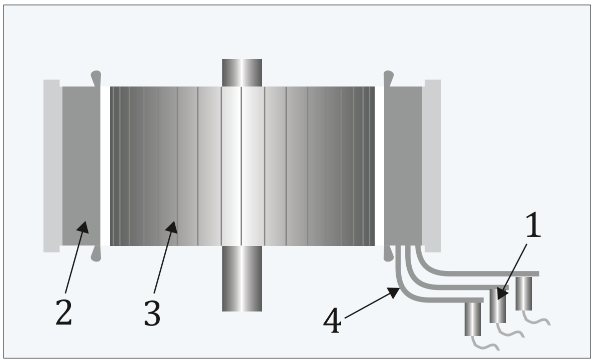
This monitoring technique is sufficiently described in IEEE 1129, IEEE Std 1434-2000, IEC 60270 and IEC/TS 60034-27.

C.4.2 PDA sensors

The sensors used for monitoring PDA are summarized in Table C.8 and the PDA sensor installation is shown in Figure C.5. The primary monitoring component is the high voltage coupling capacitor (coupler). The small capacitance of the coupler (typically 80 pF to 1 nF) allows only high frequency PD current/voltage pulses to pass through and be measured — all other signals are eliminated. At least one coupler is connected to each phase from the generator. By using a minimum of two couplers on each phase, the PDA system can distinguish between power system noise and the machine partial discharge signal by evaluating pulse shape and the time of arrival of the pulses from each coupler. Reliability of permanently installed PDA sensors is of critical importance, since once installed within the generator, electrically they are an integral part of the stator winding (see IEC 60034-27-2:2012, 6.4.3). The principle of operation of the PDA sensor is shown in Figure C.6.

Table C.8 — PDA sensors

Sensor type	What is measured	Technology	Location, wiring	Quantity per machine	Description of sensor operation
Capacitive	Voltage or current amplitude and frequency	Capacitance	— Installed on stator winding, bus bars or terminals — Coaxial cable 50 ohm See Figure C.5	1 or more per phase	Principle of operation is shown in Figure C.6.



a) Side view

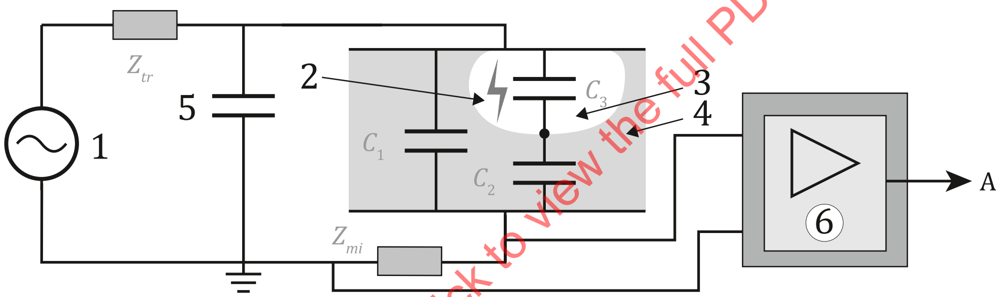
b) Top view of stator

Key

1 PDA couplers (at least one per phase) 2 stator 3 rotor 4 stator bus bar

NOTE The quantity of couplers depends on the application.

Figure C.5 — PDA sensor installation



Key

Stator power	**Stator insulation**	**Sensor**	**Signal conditioner**	**Output**
1 generator	2 partial discharge	5 PDA coupler	6 amplifier	A pulses
	3 void in the insulation			
	4 normal insulation			

Figure C.6 — PDA sensor principle of operation

PD within voids of the insulation is picked up as high frequency pulses. As the voids increase in size and number during insulation degradation, so do the number of pulses and their amplitude (in Figure C.6, C_1 is the normal capacitance of the insulation, C_2 is the total capacitance between voids of the degraded insulation, C_3 is the void capacitance, Z_{tr} is the transfer impedance and Z_{mi} is the measuring impedance).

C.4.3 PDA descriptors and plots

This aspect is briefly described in Table C.9, but more completely described in IEEE 1129, IEEE Std 1434-2000 and IEC/TS 60034-27. IEC 60034-27-2:2012, Annex A, provides examples of PD patterns interpretation.

Table C.9 — Detection and diagnostic descriptors and plots of PDA

Descriptor	Plot	Detection/ diagnosis	Process values for correlation	Operation conditions under which signal changes	Subsequent behaviour of signal over time
Magnitude q of an individual pulse (mV or nC)	2D or 3D plots, amplitude of pulse vs. phase angle Φ	Partial discharge due to defective insulation	Voltage, temperature, humidity, load		Increasing activity

C.4.4 PDA monitoring system requirements

PDA monitoring can be done using portable or continuous, permanently installed instruments, as described in Table C.10.

Table C.10 — Monitoring equipment requirements for PDA

Item	Remarks
Preferred data acquisition unit	— Portable or online system, but online is preferred because trends are more accurate.
Signal processing requirements	— Analogue or digital, single or multiple PD sensor inputs. — Should be monitored to various machine states.
Data import/export	— Process data used for correlation, such as stator voltage, temperature, humidity, etc., is imported from DCS and saved with the data. — Primary monitoring information is exported to DCS/SCADA.
Relays	— Protection not normally used. — Other alarm violations for annunciation.
Monitoring Software and database	— Collecting data from PD sensors and machine operating parameters, providing triggers and alerts. — Data storage to be accessible for data display and generation of various pattern and trend plots.

C.5 Vibration for stator frame and core, temperature for core, circuit ring, cooling system and winding and voltage for slip ring/brush gear

The stator consists of the laminated core, stator conductor bar (or coil) windings and a frame to hold everything together. There are a number of potential failure modes on the stator core and frame that can be detected by vibration and temperature measurements.

The core is designed to carry the electromagnetic flux from the rotor and manage the intense magnetic field densities around the stator slots and the outside frame connection points, and minimize eddy-current losses. The core laminations within the stator core can become loose due insufficient pressure from the clamping system or due to wave or buckling affects from a damaged stator frame. Loose core laminations can consequently cause fretting of the insulation between laminations, resulting in local heating due to parasitic eddy currents, which can in return accelerate the development of other faults, such as corrosion. Lamination looseness can also lead to plate fatigue and fracture. If the loose laminations shift, this can damage the stator bar insulation.

The rotating magnetic field of the rotor induces voltage into the stator bars. The stator bars are the most critical components of the stator. If the insulation is damaged, a short will shut down the hydro unit.

The stator frame holds the stator core in place while the core itself is held together with the pressure plates/fingers and bolts. The stator has to be designed to resist the torque resulting from the electromagnetic coupling between the stator and rotor. A loose or damaged stator frame can not only result in loose stator core laminations, but also affect the stator core roundness and concentricity. The electromagnetic forces that result from this can cause other components to fail pre-maturely, such as the guide bearings. The stator core is monitored by an array of accelerometers to detect loose laminations. These measurements can be correlated to end winding vibrations/stator bar vibrations if monitored to help identify the source of the vibration. The risk for looseness is typically greater for those stator cores and frames that are built in segments. Some stator cores are factory-built in sections and assembled onsite, while some stator cores are piled and wound onsite. This is important in determining location of air gap sensors as the core splits are generally weaker and subject to more motion. If the section bolts become loose, this can result in wearing down the insulation. Looseness at the sections is typically detected by monitoring the 2× line frequency vibration from accelerometers close to the connection points. It is important to distinguish between bolt looseness vibration from the normal stator deflection from the core to the frame and foundation.

The brush gear delivers current from the exciter to the rotor field winding. Any extra power increase from the exciter is dissipated in the form of heat on the slip rings. The integrity of the brush gear assembly will degrade over time. For this reason, the voltage and current are monitored, as for example the voltage drop across the brushes. It is also possible to use thermographic imaging for monitoring the temperature. For brushless exciters, it is possible to monitor directly the voltage, current and temperature from the main exciter field winding. The diode bridge temperature can also be monitored, but a telemetric measuring system would be required for this.

Generator temperature monitoring, always a standard part of the generator delivery, provides important information on problems with the cooling system. This can be, for example, blocked air ventilation, clogged filters, inadequate water cooling or a defective cooling system. Pressure differential monitoring of the air cooling fan can also give an indication on the condition of the air cooling system.

Temperature monitoring of the stator core provides limited information on the existence of hot spots (e.g. caused by lamination looseness, excessive leakage magnetic flux from synchronous condenser operation), but these can occur anyplace and there are a limited number of sensors. The pressure plate/fingers are also monitored sometimes for temperature, or better yet for vibration, but monitoring these components isn't so widespread.

Temperature monitoring of the stator winding, end-winding, circuit rings or can be used to identify cooling problems, as well as outside grid anomalies such as unbalanced loads and short circuits in the transmission lines. Telemetric rotor winding temperature monitoring is currently not well established in the industry. Other methods employing a laser or infrared light data transmission are also new technology and not widely used. Rotor winding temperature is sometimes calculated using the Resistance method, as explained in IEEE 112, but this would be an average for the entire rotor. Anytime there are winding losses in the stator or rotor, this will result in heat being generated that can be monitored. It is important to understand that excessive heat in the stator or rotor also reduces the life of the insulation, which can lead to a catastrophic failure of the generator. It can also cause deformation of the stator or rotor, which will create an uneven air gap that can excessively load the bearings due to the electromagnetic imbalance.

IEEE 1129 describes in sufficient detail how stator core lamination and stator frame looseness can be detected by absolute vibration measurements at strategic locations (1× and 2× vibration frequency, 2× line frequency and harmonic components should be at least used for this purpose), and where temperature sensors can be installed.

C.6 End-winding vibration (EWV)

C.6.1 General

The stator end winding is the portion of the winding extending beyond the stator core. The primary forces acting on the windings during operation are due to the electromagnetism effect of two parallel current carrying conductors at line frequency resulting in a force at twice line frequency (100/120 Hz). This force is predominantly in the radial direction (between the rotor and the stator and between the top and bottom bars). However, there is also a significant force in the tangential direction (circumferential around the end winding basket between two adjacent bars and the rotor to stator interaction). If the end winding is loose or there is insufficient support, these forces will cause the end winding to vibrate. Excessive vibration will fatigue the conductors and cause them to crack and eventually break, leading to arcing and failure.

End winding vibration is typically not a problem for most hydro units since these have small connection arms that are not likely to vibrate at high amplitudes. This can be a problem, however, for higher speed hydro units and pumped storage machines. It can also be a problem for older units where the end winding support structure becomes loose over time. This is compounded by the fact that the industry is trending towards longer periods between outages so it can be difficult to identify the problem solely by inspection. Continuous monitoring of the end winding vibration is therefore important in those particular cases.

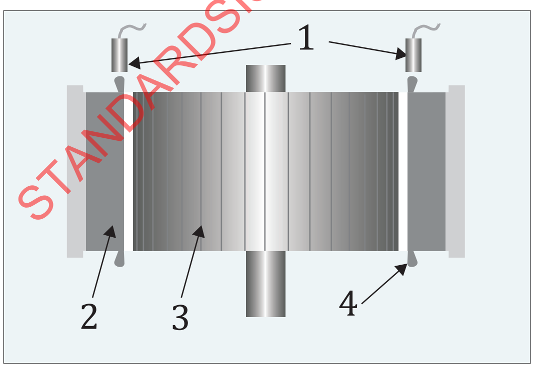
End winding vibration monitoring is covered in IEEE 1129 and IEC/TS 60034-32. However, IEC 60034-32 is focused on relatively fast 2-pole and 4-pole synchronous generators driven by steam and gas turbines. From a construction point of view these types of generators are different from the slow speed salient pole synchronous generators typically used in hydropower applications.

C.6.2 EWV sensors

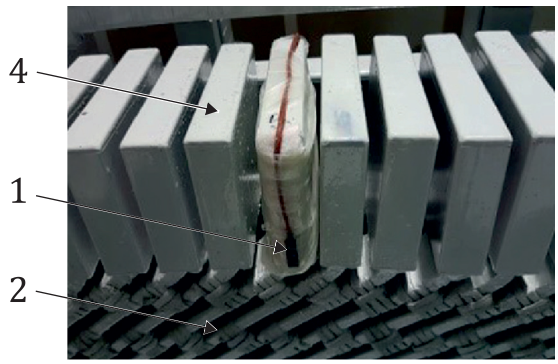
The sensors used for monitoring EWV are summarized in Table C.11 and the EWV sensor installation is shown in Figure C.7. Fibre optic accelerometers (FOA) are the recommended sensors for monitoring stator end wind vibration, as these are immune to the very strong electromagnetic field surrounding the stator windings. There are several types of FOA available, but those based on light intensity variation are probably the most common type used in hydro applications. A simple intensity-based sensor (a type without reflective mirrors) is shown in Figure C.8.

Table C.11 — EWV sensors

Sensor type	What is measured	Technology	Location, wiring	Quantity per machine	Description of sensor operation
Fibre optic vibration sensors	Absolute acceleration vibration	Fibre optic, dual or single axis	Stator end winding (see Figure C.7)	1 sensor per each circuit of each phase (example: 3-phase 3-circuit machine would have 9 sensors installed)	Principle of operation shown in Figure C.8.



a) Side view



b) Upper front view of stator

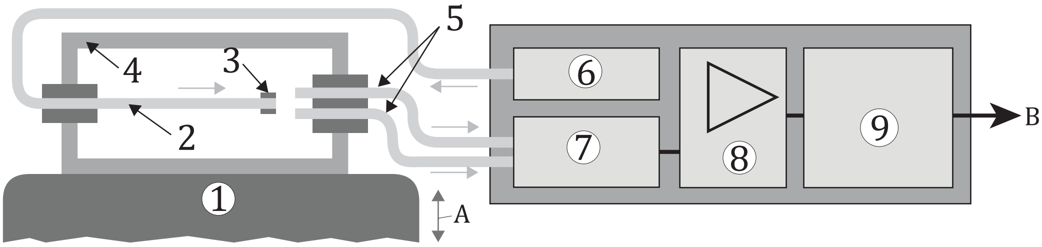
Key

1 EWV sensor
2 stator
3 rotor
4 stator bus bar

NOTE The quantity of sensors depends on the application.

Figure C.7 — End winding vibration sensor installation

The amplitudes of the frequency response function of a bump test can be compared to optimize the locations for the sensor installation.



Key

Stator end winding
A acceleration vibration
1 end winding of stator

Sensor
2 light emitter
3 seismic mass
4 sensor housing
5 light receiver

Signal conditioner
6 light source
7 photo detector
8 amplifier
9 frequency demodulator

Output
B time signal (V)

Figure C.8 — End winding vibration sensor principal of operation (fibre optic accelerometer based on light intensity modulation)

Light is emitted from the light emitter tip, which will vibrate in proportion to the stator end winding vibration. The light intensity detected by the photo detector is proportional to the variation of acceleration of the light emitter tip.

C.6.3 EWV descriptors and plots

A summary of the descriptors and plots used for monitoring EWV is shown in Table C.12.

Table C.12 — Detection and diagnostic descriptors and plots of EWV

Descriptor	Plot	Detection/diagnosis	Process values for correlation	Operation conditions under which signal changes	Subsequent behaviour of signal over time
— Displacement (mil pk-pk or µm pk-pk) — Velocity (mm/s pk) — Acceleration (g, pk or RMS)	— Spectra — Time signal	— Excessive vibration — Looseness — Wear	— Stator core temperature — Active and reactive power		— Increase in amplitude — Harmonics — Excites the resonance of other components — 100/120 Hz signal of interest

C.6.4 EWV monitoring system requirements

An online system is recommended, as shown in Table C.13.

Table C.13 — Monitoring equipment requirements for EWV

Item	Remarks
Preferred data acquisition unit	— Fibreoptic sensor connected to an online system
Signal processing requirements	— FFT — Should be monitored and correlated to various machine states
Data import/export	— Process data used for correlation, is imported from DCS/SCADA — Primary monitoring information is exported to DCS/SCADA
Relays	— Protection not normally used — Other alarm violations for annunciation
Monitoring software and database	— Display, system setup, database for trending

C.7 Shaft current and voltage

Shaft current is primarily caused by an asymmetric magnetic flux in the hydro unit, which can result from the unit design, construction, faults, etc. A split stator core construction, for example, can carry with it a greater risk for creating shaft current. The resultant circulating flux from this dissimilarity can consequently induce a voltage on the shaft. Oftentimes there is an insulated flange on the shaft between the generator and turbine. Normally, the shaft is grounded via the turbine in the water, and a grounding brush is used on the generator portion of the shaft. All guide bearings are insulated. If, however, the bearing insulation is damaged or missing, this can allow a portion of the shaft current to pass through the bearing, thus damaging it. If the shaft voltages are excessive, shaft currents can cause arcing between the shaft and the bearing. The arcing elevates the temperature enough to cause the metal to vaporize and result in pitting of the bearings.

Usually, shaft currents are measured by a shaft current transformer, which is placed between the turbine and the generator in the hydro unit. Frequency components of the spectrum, which depend on the hydro unit configuration, are analysed for detecting a shaft current. Shaft voltage (DC and AC) should be monitored on isolated bearings, usually with a brush or slip ring assembly.

IEEE 112 provides a brief description of shaft current and voltage measurement methods, and a comparison of different techniques is given in IEEE 115, while IEEE 1129 gives a short summary of causes and instrumentation used. There is no standardized approach in the selection of sensors, their location or methods used for data collection.

C.8 Oil analysis of bearings

Oil analysis is used for both monitoring the condition of the lubricant (degradation and contamination) as well as for monitoring the condition of the shaft and bearings (wear debris). Wear debris monitoring can be correlated with bearing/shaft monitoring to more reliably detect developing bearing/shaft wear and faults. Most oil analysis is done offline in laboratories, but online systems are being developed for this purpose. In practice, however, the high oil volume with slow flow rates associated with hydro units makes it a challenge to reliably detect oil debris using current online systems.

Unfortunately, there is no overview standard covering oil analysis for condition monitoring purposes. Instead, there is a wide range of standards from different organizations that deal with specific test procedures and topics on oil analysis that are too numerous to list here. In practice, oil analysis is often done only on a yearly basis with offline filtering as part of the regular maintenance program. Sometimes, it is done immediately following an event.

C.9 Shaft, guide bearing, thrust bearing and bearing housing vibration

The shaft and bearing assembly, which transfers the rotational energy of the turbine to the generator rotor, is traditionally the most monitored component of the hydro unit. This is because the symptoms of so many mechanical, hydraulic and electro-magnetic potential failure modes can be seen as vibration signatures in the bearing and shaft assembly, and with sufficient lead-time such that service can be cost-effectively planned ahead of time. For this reason, vibration monitoring of these components represents the single most important monitoring strategy for hydro units.

There are a number of potential failure modes that can occur on the shaft and bearings, which are amply covered in ISO 13373-7. In general, vibration detection and diagnostic techniques on the shaft and bearings for specific failure modes are well documented in the literature. Protection consideration is covered in ISO 20816-5 for the bearings and casing vibration. IEEE 1129 provides guidelines for vibration monitoring as well. A description of a couple of the sensors used for vibration monitoring and the principle of operation are described as follows:

— displacement sensors, see Figure C.11;

— accelerometers, Figure C.14.

The potential failure modes that can be detected by vibration sensors on the guide bearings are not limited to the shaft and bearings themselves, but include a wide range of other hydro unit components. These are briefly described in Table C.14, which also includes a reference of detection techniques other than vibration.

Table C.14 — Detection of potential failure modes of other hydro unit components that can be monitored by shaft/guide bearing vibration, as well as by other monitoring techniques described in other clauses

Component	Failure mode	Detection/diagnostic technique	Reference
Generator	Uneven air gap due to out-of-roundness of rotor and/or stator, eccentricity of the rotor	Air gap	C.2
		Magnetic flux	C.3
		Radial relative vibration from the generator guide bearings	ISO 13373-7
	Shorted rotor windings	Air gap	C.2
		Magnetic flux	C.3
		Radial relative vibration from the generator guide bearings	ISO 13373-7
Wicket gate shear pin	Broken shear pin (guide vane position not uniform)	Displacement vibration sensors (or limit switches) on each shear pin	C.14.2
		Turbine guide bearing vibration measurement (runner blade passing frequency)	ISO 13373-7
Runner	Defect runner blade	Turbine guide bearing vibration measurement (guide vane passing frequency)	ISO 13373-7
		1x vibration frequency (running speed)	ISO 13373-7
		Axial accelerometer on the turbine cover and/or thrust bearing	

Table C.14 *(continued)*

Component	Failure mode	Detection/diagnostic technique	Reference
Pelton turbine	Misalignment and lack of synchronisation between the runner bucket and injectors will reduce the efficiency of the turbine and can create excessive vibration and loading that can lead to premature failure of components such as the guide bearings. It can also lead to excessive wear on the splitter that will result in even more loss of efficiency. Misalignment can also cause thrust bearing overload/failure if the load is not axially symmetric.	Turbine guide bearing vibration measurement. As best practice, misalignment should be less than ±1 % of the bucket width.	

NOTE The average shaft position/shaft centreline vibration monitoring technique is mentioned in ISO 13373-7 but not described in detail. It is important to state that this plot function is extensively used for monitoring shaft misalignment in the generator in hydro units and hydraulic pull.

As explained in ISO 13373-7, it is important that vibration sensors are selected with the proper sensitivity and sufficient data acquisition rate for hydro applications.

C.10 Guide bearing and thrust bearing temperature

There are a number of factors that affect the bearing temperature, such as:

— misalignment;

— imbalance (mechanical and electro-magnetic);

— improper installation;

— bearing fatigue;

— excessive load (hydraulic and power);

— insufficient bearing clearance;

— contaminants, water in the oil;

— insufficient lubricant cooling;

— lack of lubricant;

— increased ambient temperatures;

— looseness.

Most of these potential failure modes result in increased bearing temperatures. An elevated bearing temperature in itself can significantly affect the condition of the bearing and lead to premature failure. By monitoring the bearing temperature and correlating this with shaft vibration/displacement, this enables the user to not only monitor the condition of the bearing but also detect other potential failure modes present more reliably. In the case of regulated cooling systems, it is equally important to monitor the temperatures and flow of the cooling system as the system will work harder to maintain the temperature of a bearing in trouble.

The monitoring technique for bearing temperature is described in IEEE 1129 but focuses only on the upper and lower generator guide bearings. This same methodology can also be applied the turbine guide bearing as well. Monitoring the thrust bearing is different from that for monitoring the guide bearings in that there is very little time to react in an alarm situation for the thrust bearing in order to avoid a catastrophic failure. If the oil film thickness is reduced to zero, there is the risk of rubbing which can destroy the hydro unit quite quickly.

Bearing temperature monitoring is normally delivered with the hydro unit.

C.11 Main shaft seal leak monitoring

The main shaft seal prevents excessive water leaking from the turbine. Excessive leaking reduces the efficiency of the hydro unit and can cause corrosion of the surrounding structure and degradation of the civil works. A worn or improper seal design or installation can also result in excessive air leakage during synchronous condenser operation, which can exceed the capacity of the originally installed air compressors.

Some leakage is necessary to sufficiently cool and lubricate the sealing faces.

Leakage flow measurement is the most typical technique for detecting excessive leaking and trending it. Monitoring the seal face temperature is another technique. Monitoring the distance from the seal to the shaft with a displacement sensor is another technique, though it can be difficult in some cases to properly install the sensor.

C.12 Wicket gate shear pin displacement vibration (Francis, Kaplan, bulb turbines)

The wicket gate assembly controls the quantity of water for power generation and the water intake angle for maximum efficiency. The wicket gate mechanism, which controls the opening of the guide vanes, is operated by servo motors and consists of a number of components such as the linkages, operating ring, bushings and pins. Bushing and pin wear are difficult to detect at an early stage, but the increased looseness at more advanced stages of wear shows itself as increased vibration due to hydraulic disturbance. A broken shear pin is a critical failure mode. It is designed to break during overload situations in order to prevent damage to the larger wicket gate components, but often a broken shear pin, if not detected in time, can create a hydraulic imbalance that can damage the runner, labyrinth seals, turbine guide bearing and result in breaking other shear pins. There are various monitoring systems on the market that are used for specifically monitoring broken shear pins. Individual displacement sensors (or limits switches) on each pin are recommended for larger hydro units, but often the absolute vibration sensor on the turbine guide bearing housing is sufficient for detecting this condition for smaller and medium sized hydro units. The primary potential failure mode for the wicket gate mechanism is shown in Table C.15.

Table C.15 — Potential failure modes of wicket gate mechanism as described in other clauses

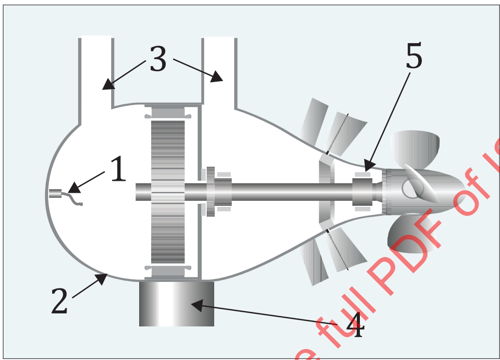
Component	Failure mode	Detection/diagnostic technique	Reference
Shear pins and bushings	Loose or worn pins and bushings	Turbine guide bearing vibration	ISO 13373-7
		Performance monitoring	C.17
		Individual shear pin monitoring by axial relative vibration	ISO 13373-7
	Broken shear pin	Draft tube vibration	C.20
		Turbine guide bearing vibration	ISO 13373-7
		Performance monitoring	C.17
		Individual shear pin monitoring by axial relative vibration	ISO 13373-7
		Turbine cover vibration	C.16

C.13 Bulb casing vibration

The bulb turbine hydro unit has special potential failure modes associated with it because of its unique construction. The entire hydro unit, consisting of the generator, shaft and turbine, as shown in Figure C.9, is typically supported by an upper and a lower stay column in the water stream. These stay columns can be subjected to excessive loading if there is hydraulic disturbance or hydraulic imbalance passing over the bulb hydro unit over a period of time. This hydraulic disturbance, such as von Karman turbulence, can result from a partial blocking of the trash racks. In such a case, the entire bulb unit can pitch or yaw, creating stress in the stay column connection to the bulb casing itself or to the water passage lining, which can lead to fatigue cracks and possibly complete fracture of the structure. It is recommended to monitor pitching or yawing of the hydro unit bulb casing by placing an accelerometer in the furthest extension from the stay columns, i.e. within the bulb nose.

It is also important to monitor the bulb casing vibration together with the guide bearing vibration as a correlation. The upstream guide bearing (generator end) can be located a distance from the casing support and therefore be directly affected by the casing vibration. The downstream guide bearing (turbine end) is affected by the flow conditions more than the upstream bearing, which can be correlated with the casing vibration.

The principle of operation of the accelerometer is described in C.16.2 and in Figure C.14.



Key

1 accelerometer
2 bulb casing
3 upper supports (access shafts)
4 bottom support
5 turbine guide bearing

Figure C.9 — Bulb turbine casing vibration monitoring

C.14 Blade clearance (Kaplan and bulb turbines)

C.14.1 General

There are five primary reasons for monitoring the Kaplan or bulb blade tip clearance to the draft tube:

— monitor blade tip erosion;

— monitor change of blade position due to runner dynamics;

— identify a condition where there is a risk of blade tip contact with the draft tube;

— monitor the blade angle;

— identify foundation instability or hydraulic disturbance.

Abrasive erosion of the blade tips can occur if there is sufficient sediment suspended in the water. This can occur in a number of different situations, as for example during heavy rains where there is runoff with sand and soil that flow into the reservoir or river. Turbine efficiency is reduced if the Kaplan blade tip clearance to the draft tube is increased due to erosion.

By continuously monitoring the blade tip clearance, it is possible to trend blade tip wear in much the same way as guide bearing radial clearance is determined using an X-Y orthogonal displacement sensor installation, as described in ISO 13373-7. It is also possible to see if the blades are too close or trending to be too close to the draft tube. Blade contact with the draft tube can have catastrophic effects. This can occur, for example, if there is excess guide bearing clearance on the shaft, or if there is hydraulic, mechanical or electromagnetic imbalance. Monitoring the blade clearance also gives an indication of foundation instability, which can be permanent or seasonal.

For optimal efficiency, each of the turbine blades should be pitched at the proper angle for the application. Sometimes, however, defects with the blade angle linkage system can result in one or more of the blades having a different angle, thus reducing the operational efficiency. By using two sensors mounted in the same vertical plane, typically above and below the runner centreline, it is possible to monitor blade clearance and also calculate the blade angle based on the time difference between the two sensors as the blade passes them. The angle of each blade can be individually monitored this way. This is especially useful for units without mechanical feedback on blade position.

C.14.2 Blade clearance sensors

Water resistant displacement sensors are used that can withstand 5 bar. The number and location of the sensors depends on the application. If the Kaplan runner has a history of a wide variation of orbital displacement, it would be advisable to install two sensors orthogonally placed 90 ° from each other on the discharge tube. These should be placed on that portion of the draft tube that is closest to the blade tips. They should also be mounted in a recessed hole so that the sensor tip can never touch the blade tip. Four sensors can be used in extreme cases. If on the other hand erosion is the primary fault of interest, one sensor would be sufficient. If the blade angle is also to be monitored, an extra sensor is necessary. It should be mounted a short distance vertically from one of the other sensors, preferably both of the sensors offset from the runner centreline.

The displacement sensor oscillator generates a constant frequency sine wave that is sustained by the power input. As this signal passes through an inductive coil, the electromagnetic field is amplified in front of the sensor face. When a target metal object comes close to this field, some of the electromagnetic energy is transferred to the metal object being monitored, where eddy currents are produced. This transfer of energy reduces the amplitude of the oscillator, which is sensed by the Schmitt trigger. When an amplitude drop is detected, the trigger switches the output on where the oscillator amplitude is monitored. The change of amplitude is inversely proportional to the distance of the target metal object being monitored to the face of the sensor.

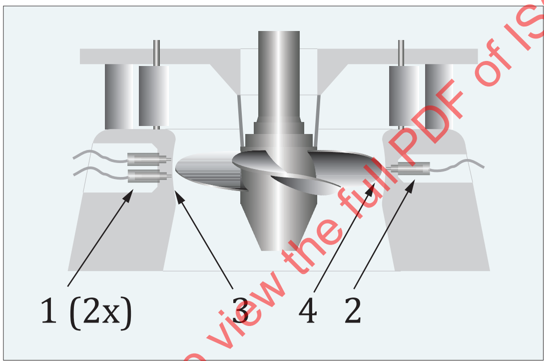
The sensors typically used are shown in Table C.16, installation is shown in Figure C.10 and the principle of operation is shown in Figure C.11.

Table C.16 — Blade clearance sensors

Sensor type	What is measured	Technology	Location	Quantity per machine	Description of sensor operation
Displacement sensor	Relative displacement and vibration	Eddy current inductive	Installed through a hole in the draft tube across from the blade tips, as shown in Figure C.10.	1 or 2	Principle of operation is shown in Figure C.11.

Table C.16 *(continued)*

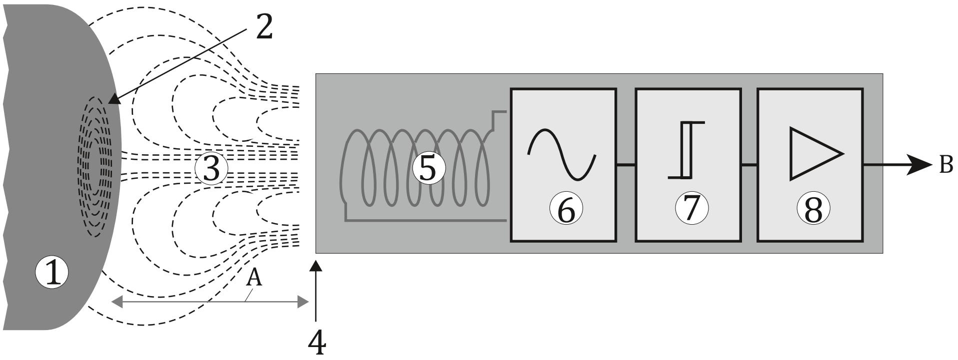
Sensor type	What is measured	Technology	Location	Quantity per machine	Description of sensor operation
Phase/speed reference sensor	Tacho pulse	Typically inductive eddy current, but can also be an optical sensor with TTL or NPN/PNP output.	Bracket over the shaft with a pulse trigger	1	Signal pulse is generated for each rotation of the hydro unit. This synchronizes the blade tip measurement to each specific blade for a complete rotation. Phase reference information can be used for making an orbit plot of the runner and for correlating this orbit and the individual blade measurements to the orbit of the guide bearings and other components, for diagnostic purposes.



Key

1 blade angle sensors
2 blade clearance sensor
3 draft tube
4 Kaplan blade tip

Figure C.10 — Blade angle and blade clearance sensor installation



Key

Blade tip (or other metal target)

A displacement and vibration
1 blade tip
2 eddy current in the blade tip
3 magnetic field

Sensor and signal conditioner

4 face of sensor
5 inductive coil
6 oscillator
7 Schmitt trigger
8 amplifier

Output

B time signal (V)

Figure C.11 — Displacement sensor operation principle

The magnitude of the inductive coil electromagnetic field is inversely proportional to the field generated by the eddy currents, which is inversely proportional to the relative distance between the sensor face and the target metal.

C.14.3 Blade clearance descriptors and plots

A summary of the descriptors and plots used for blade clearance monitoring is shown in Table C.17. If a single sensor is used, the blade clearance as a displacement and dynamic movement is measured and trended. If two orthogonally placed sensors are used, the measurements and plots used for blade tip clearance detection and trending is the same as those used for monitoring the vibration orbit of the guide bearings, as described in ISO 13373-7. If two sensors located above each other in the vertical plane straddling the runner centreline, the blade clearance is monitored as with a single sensor installation plus the blade angle is calculated and trended for each blade.

Table C.17 — Detection and diagnostic descriptors and plots of blade clearance

Descriptor	Plot	Detection/ diagnosis	Process values for correlation	Operation conditions under which signal changes	Subsequent behaviour of signal over time
Minimum clearance	Primarily for machine protection				

Table C.17 *(continued)*

Descriptor	Plot	Detection/ diagnosis	Process values for correlation	Operation conditions under which signal changes	Subsequent behaviour of signal over time
Blade clearance time signal for one rotation	— Time signal — Circular plot	— Erosion, wear — Insufficient clearance due to runner movement	— Guide bearing displacement and vibration — Efficiency	— Hydraulic disturbance — Mechanical imbalance, misalignment, eccentricity — Guide bearing clearance — Electromagnetic imbalance	— Increase in clearance due to wear, erosion — Reduction in clearance due to runner movement — Reduction in efficiency due to increase in clearance
Clearance: — Average — X-Y Minimum — X-Y Maximum — S_{max} — S_{P-P}	Trend				
Blade angle	Trend for each blade (a calculated value)	Defective blade pitch link for one or more blades	Efficiency	None	Reduction in efficiency

C.14.4 Blade clearance monitoring system requirements

Blade clearance monitoring is normally done with a permanently installed online system, as shown in Table C.18.

Table C.18 — Monitoring equipment requirements for blade clearance

Item	Remarks
Preferred data acquisition unit	— Online system
Signal processing requirements	— FFT — Monitored to various machine states — Calculated measurement (blade angle)
Data import/export	— Process data used for correlation, is imported from DCS/SCADA — Primary monitoring information is exported to DCS/SCADA
Relays	— Protection possibly used for minimum blade clearance — Other alarm violations for annunciation
Monitoring Software and database	— Display, system setup, database for trending.

C.15 Labyrinth seal clearance and temperature (Francis turbines)

C.15.1 General

The labyrinth seal on a Francis turbine minimizes water leaking from the runner through the top and bottom covers. A certain amount of leakage is needed in some cases, however, for cooling purposes. If the seals become too warm, they can rub, which can lead to a catastrophic failure. Over time, the gap of the seal between the runner and the stationary turbine covers increases due to wear, allowing more water to pass. If the water contains abrasive sediment, this process is accelerated. If there is excessive leaking, this reduces the efficiency of the turbine. The amount of efficiency loss depends on the turbine design, but it can be significant for turbines with a low specific speed (v_S). As the leakage is basically constant at all loads, the percentage of efficiency loss is greater at part loads. In addition to efficiency losses, leakage can also cause corrosion. The increased wear of the seals can change the axial loading on the thrust bearing. If the leak is uneven along its circumference, this can create unbalanced hydraulic loads on the guide bearings.

The distance between the stationary and rotating parts of the labyrinth seal can be monitored to detect if there is too much or too little clearance. Temperature sensors are sometimes used to monitor too little clearance or rubbing.

C.15.2 Labyrinth seal clearance sensors

There are several Francis runner designs, primarily based on the specific speed for the application, so there are consequently several labyrinth seal configurations as well. In most cases, there is an upper and lower seal but because of space restrictions, it is sometimes not possible to monitor both. In many cases, the lower seal is the most accessible. If the rate of wear is the same for both seals, it is not necessary to monitor both.

The number and location of the sensors for the upper and/or lower seal depends on the application. If the Francis runner has a history of a wide variation of orbital displacement, it would be advisable to install two sensors orthogonally placed 90 ° from each other on one of the seals. If two sensors are used, these can be synchronized to a tacho signal to physically identify that portion of the runner portion of the seal being monitored. The sensors are mounted below the seal surface to avoid damage; this requires an adjustment mechanism to set gap.

The sensors typically used are shown in Table C.19. The preferred sensor is the water-resistant displacement sensor that can withstand 5 bar (see C.14.2 and Figure C.11 for a description of this sensor). Sometimes a thermocouple or RTD temperature sensor is used to detect close proximity between the stationary and rotating part of the seal.

Table C.19 — Seal gap clearance sensors

Sensor type	What is measured	Technology	Location	Quantity per machine	Description of sensor operation
Accelerometer[a]	Absolute acceleration vibration	Piezo-electric	Head-cover close to seals, as shown in Figure C.13.	1	Principle of operation described in C.16.2 and shown in Figure C.14
Thermocouple or RTD	Temperature		Installed through a hole in the turbine cover	2	Sensor picks up temperature increase due to metallic seal contact.
Displacement sensor	Relative displacement and vibration	Eddy current inductive	Installed through a hole in the turbine cover, as shown in Figure C.12.	1 or 2	Principle of operation described in Figure C.11.

[a] This optional measurement is considered primarily for protection, not for condition monitoring.