EPRI

Hydro Life Extension Modernization Guides

Volume 4 - 5 Auxiliary Mechanical and Electrical Systems

Technical Report

Hydro Life Extension Modernization Guides

Volume 4-5 Auxiliary Mechanical and Electrical Systems

TR-112350-V4

Final Report, December 2001

EPRI Project Manager
D. Gray

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

BC Hydro International Ltd.

Acres International Ltd.

ORDERING INFORMATION

Requests for copies of this report should be directed to EPRI Customer Fulfillment, 1355 Willow Way, Suite 278, Concord, CA 94520, (800) 313-3774, press 2.

CITATIONS

This report was prepared by

BC Hydro International Ltd.
6911 Southpoint Drive
Burnaby, British Columbia
V3N 4X8
Canada

Principal Investigators
G.M. Blue
D.A. Delcourt
C.D. Helston, P.Eng.
A. King, P.Eng.
J. Laakso, P.Eng.
T.A. Le Couteur, E.I.T.
G. McCrae, P.Eng.
D.J. McLellan, P.Eng.
C. Mitha, P.Eng.
R. Movold, P.Eng.
J.W. Sanders
B. Tam, P.Eng.

In collaboration with
Acres International Ltd.
140 John James Audubon Parkway
Amherst, New York 14228-1180

Principal Investigators
P.R. Rodrigue, P.Eng.
K. Salmon, P.Eng.

This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Hydro Life Extension Modernization Guides: Volume 4-5 Auxiliary Mechanical and Electrical Systems, EPRI, Palo Alto, CA: 2001. TR-112350V4.

REPORT SUMMARY

These guidelines are the fourth and fifth volumes in a series for assessing the needs and benefits and evaluating the cost and economic justification of life extension and modernization alternatives at hydroelectric plants and for implementing the selected plan. They specifically address the plant auxiliary mechanical systems (Volume 4) and auxiliary electrical systems (Volume 5). They also provide a screening procedure and criteria to enable utility personnel to identify where there are opportunities for modernization.

Background

Hydroelectric power generation is a proven vital source of electricity in the United States and worldwide. Many hydroelectric plants have been reliably generating electricity for more than 50 years. As these facilities continue to age, decisions must be made concerning retirement, continued maintenance and operation, or modernization and redevelopment. As experienced personnel retire and leave utility companies, the need for guidance in making these critical decisions becomes even more important. To address these needs, EPRI have wisely concluded that there is a crucial need for guidance in helping utility managers and owners make critical decisions on the future of their plants. In 1989, EPRI issued 3 volumes of Modernization Guidelines, which have been widely used by the industry. This present series of guidelines will update the 1989 guides and expand them to cover the entire plant.

Objective

To provide technical data and information required for planning and implementing modernization projects for the auxiliary mechanical and electrical systems of hydroelectric plants.

Approach

The project team compiled information on available and developing technology relevant to the modernization of hydropower auxiliary mechanical and electrical systems, including the technical data and information required for implementation.

Results

These volumes of the *Hydro Life Extension Modernization Guides*, covering auxiliary mechanical and electrical systems, provide technical information and data that can be used as input to the life extension and modernization (LEM) planning process as developed in Volume 1. They take the user from establishing a base case, to pinpointing high value alternatives, incorporating them in the overall LEM, and then through selection, procurement, and implementation. Throughout the entire process the focus is on creating value by applying technologies that offer the greatest return. Optimising return requires not only understanding

technologies and their application but keeping an eye to markets and matching technology to market demand.

Volume 4, auxiliary mechanical systems, covers bearing lubrication systems, raw and cooling water, compressed air, potable water, drainage and dewatering, fire protection, heating and air conditioning, and cranes. Volume 5, auxiliary electrical systems, covers unit transformers, station service AC, station service DC, cable and cable support systems, grounding, and lighting.

EPRI Perspective

Deregulation and the privatisation of the electricity industry around the globe offer threats but also opportunities. As the old adage goes, one has to spend money to make money. A comprehensive set of guidelines for life extension and modernization of hydro plants is timely indeed. As the market develops and the energy product becomes unbundled into ancillary services that will ensure demand can be met instantaneously and reliably, hydro assets will become more and more valuable. Making sure that plants have the equipment and processes to meet this evolving role in the supply of electricity to the modern world will ensure that hydro captures the market share it deserves.

Keywords

Asset Management
Compressed Air Systems
Electrical Auxiliaries
Fire Protection Systems
Hydro power
Life Extension
Lubrication Systems
Mechanical Auxiliaries
Modernization
Transformers

ABSTRACT

Under contract to the Electric Power Research Institute (EPRI), BC Hydro is developing a 7 Volume set of Guidelines for Life Extension and Modernization of Hydro Plants. These documents, superseding the three volume 1989 Guides published by EPRI, will provide the means to enable utility personnel to identify which hydroelectric plants are potentially suitable for modernization and which plants promise the most immediate return on investment. They will also provide guidance on design and implementation of the selected plan. Volume 4 covers the auxiliary mechanical systems and Volume 5 covers the auxiliary electrical systems.

ACKNOWLEDGMENT

A number of individuals provided information and contributed to the production of this report. Valuable input and comments were received from representatives of the project team including BC Hydro International Ltd. and Acres International Ltd.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION AND SCOPE

1.1 Volumes 1 to 7

Volume 1 of the *Hydro Life Extension Modernization Guides* [1] (referred to subsequently as 'Volume 1') dealt with how to formulate an integrated plan for an entire plant - from "water to wire". It did not cover the technical specifics for each plant area but required that more detailed technical information for each plant area be acquired.

Volumes 2 to 7 of these guidelines will provide the more detailed information required to successfully utilize the Volume 1 document. Volumes 2 to 7 consist of:

- Volume 2 - Hydromechanical Equipment
- Volume 3 - Electromechanical Equipment
- Volume 4 - Auxiliary Mechanical Systems
- Volume 5 - Auxiliary Electrical Systems
- Volume 6 - Civil and Other Plant Components
- Volume 7 - Protection, Control and Automation

1.2 Volumes 4 and 5 - Plant Auxiliary Systems

1.2.1 Volume 4 - Auxiliary Mechanical Systems

For the purposes of Volume 4 the auxiliary mechanical systems will be subdivided into:

- bearing lubrication systems
- raw and cooling water
- compressed air
- potable water
- drainage and dewatering
- fire protection

[1] Hydro Life Extension Modernization Guides: Volume 1 - Overall Process, EPRI, Palo Alto, CA: 1999. TR-112359-V1

- HVAC
- powerhouse cranes
- tailrace crane

1.2.2 Volume 5 - Auxiliary Electrical Systems

For the purposes of Volume 5 the auxiliary electrical systems will be subdivided into:

- unit transformers
- station service AC
- station service DC
- cable and cable support systems
- grounding
- lighting

1.3 Purpose of Volumes 4 and 5

Volume 1 provides the overall process for developing a life extension and modernization plan (LEM Plan) for a plant. For most steps in the process, technical information is required so that the needs (i.e. life extension requirements) and opportunities (i.e. modernization possibilities) of the plant can be clearly defined and addressed in terms of actual activities or plant projects.

The purpose of Volumes 4 and 5 is to provide technical information and data on plant auxiliary systems which can be used as input to the life extension and modernization planning process as developed through Volume 1. Volumes 4 and 5 are used *after* the screening of facilities is completed and plants suitable for life extension and modernization studies are selected in Volume 1, Section 3. It is a technical resource for engineers and planners to assist them with the development of the LEM Plan for a particular plant and the design of projects for implementation.

Volumes 4 and 5 can also be used as a stand alone document for the condition assessment and review of rehabilitation/upgrade options for plant auxiliary equipment, outside of the overall development of a plant LEM Plan.

1.4 How to Use Volumes 4 and 5

Volumes 4 and 5 are the technical resource for the plant auxiliary equipment in the overall process. Figure 1-1 shows how the various sections provide information to support the development of the LEM Plan. This flowchart should be referred to on an ongoing basis as the user works through the condition assessment and other technical aspects of Volumes 4 and 5 to ensure that all necessary information is fed back into the Volume 1 process. The flowchart is adapted from the flowchart in Figure 1-2 of Volume 1 of these Guidelines.

Volumes 4 and 5 are combined in one document as mechanical and electrical auxiliaries are closely linked in the powerplant. However, separate subsections cover individual components in the overall context.

Volumes 4 and 5 are designed to provide a step by step process to identify and define projects that either extend equipment service life (life extension) or upgrade (modernization) the equipment in terms of performance. The general steps are screening; evaluation of condition and performance; evaluation of "upgradability" and modernization potential; estimation of costs and benefits; feasibility studies and implementation.

Volumes 4 and 5 present a step-by-step method to assess the potential of components for life extension and/or modernization. They are comprised of:

Section 1: Introduction. Explains the needs, concepts, objectives and scope of Volumes 4 and 5. The user will gain an understanding of what the volume contains, whether it will be applicable to the user's needs and how to use these guidelines.

Section 2: Background to Life Extension and Modernization. Discusses a utility's approach to life extension and modernization, including the policies and principles that should be in place.

Section 3: Screening. This is the first step of the life extension and modernization process. The user is led through the necessary steps of a desktop study to screen and prioritize the auxiliary systems of the plant in terms of *most likely to yield benefit from life extension and modernization*

Section 4: Evaluations of Condition and Performance. Focuses the user on a more detailed assessment of the present condition and performance of the auxiliary components of the plant. This assessment is compared to the original design parameters of the plant to determine the scope of life extension activities.

Section 5: Potential for Improvements. Covers the modernization opportunities available for auxiliary equipment and how to assess them.

Section 6: Estimates of Costs and Benefits. Provides the user with cost estimating information for various levels of investigation. Also discusses the benefits, power and non-power, of life extension and modernization activities.

Section 7: Optimization of Alternatives (Feasibility). Covers the more detailed investigative activities available for use during the feasibility stage of the life extension and modernization process. The activities undertaken assist the user to optimize the LEM Plan to be used for the plant.

Section 8: Implementation. Focuses on those activities required to implement the selected life extension and modernization plan and the details required to successfully complete the project.

Appendix A: Annotated bibliography of case histories, reports of new technologies and processes, and other published papers provide supporting information and opportunities for further reading.

Appendix B: US Army Corps of Engineers (USACE) "Condition Rating Procedures/Condition Indicator for Hydropower Equipment". Sections pertaining to auxiliary mechanical and electrical equipment are reproduced. Document is part of the USACE's Repair, Evaluation, Maintenance and Rehabilitation Research Program (REMR).

Appendix C: Glossary of Terms for Fire Protection.

1.5 Definitions

Within the hydropower industry, the terms "life extension", "rehabilitation", "modernization", "upgrade", "upgrading" or "uprating", among others, are employed to indicate the nature, extent, or result of an improvement to a hydro plant or component. These terms often appear to be used interchangeably.

For these Guidelines, the following are the "improvement" terms which are used:

Life Extension - the replacement or improvement of components which have been the cause of higher maintenance repair, or for which failure, due to age, is expected in the foreseeable future. Other terms that are close in meaning and often need interchangeably with "life extension" include: rehabilitation, retrofit, replacement and refurbishment. The term "overhaul" has a slightly different meaning and usually refers to the planned disassembly, cleaning, repair, lubrication and re-assembly of a unit or component.

Modernization - the improvement of level of service and cost of service (refer to Volume 1, Section 2.3.1) measured by plant output and/or flexibility. Other terms that are close in meaning and often used interchangeably with "modernization" include upgrade, upgrading and uprating.

Redevelopment - new construction of an existing plant, including replacement or substantial modification of civil, mechanical, and electrical components [definition from *Hydro Rehabilitation Practices: What's Working in Rehabilitation*].[2] This area is not covered by these Guidelines.

---

[2] *Hydro Rehabilitation Practices: What's Working in Rehabilitation*. HCI Publications, Kansas City, MO 1998

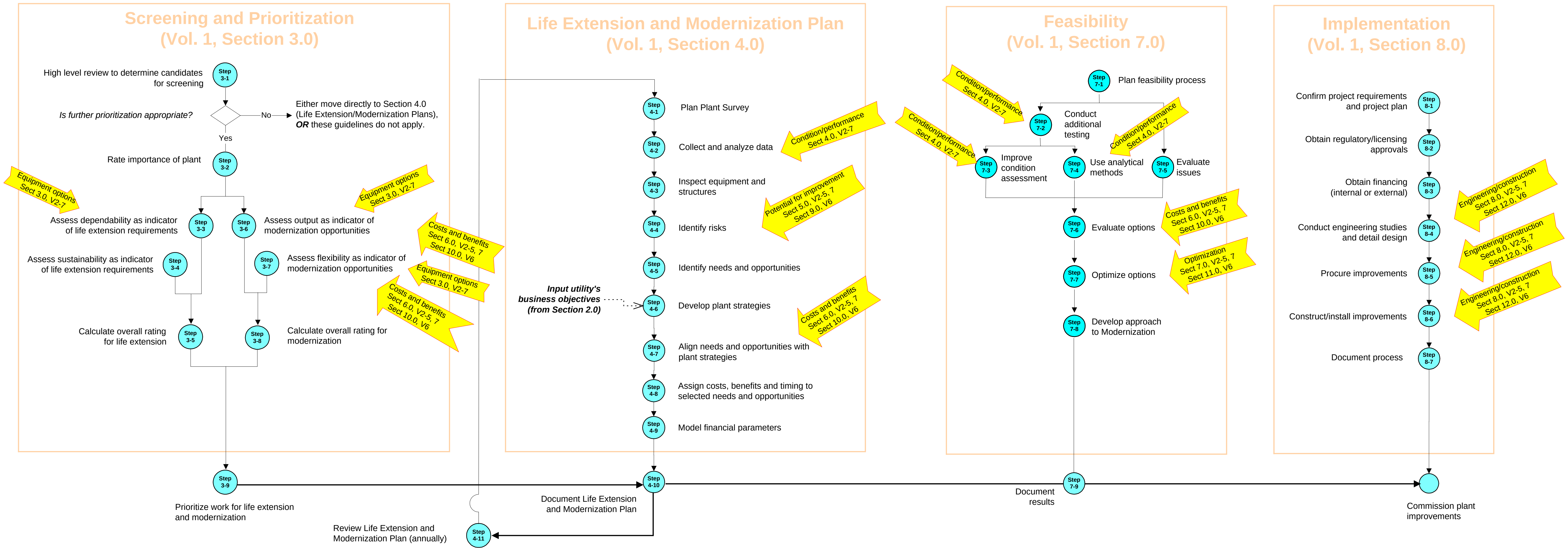

Figure 1-1
LEM Flowchart

2 BACKGROUND TO LIFE EXTENSION AND MODERNIZATION

2.1 Introduction

Volumes 4 and 5 cover the main auxiliary mechanical and electrical systems in a hydro plant. Although these systems are thought of as supporting equipment, some of them, such as bearing lubrication, cooling systems and the main power transformers are critical for generation. Other systems, such as drainage, fire protection, and grounding are important from an environmental or life safety risk perspective. Operational savings, through modernization of lighting, AC and DC station service, and HVAC, along with generation savings by optimizing cooling water, are other important considerations.

It is assumed that the user of the Guidelines has a basic understanding of plant auxiliary systems and therefore descriptions of the equipment are not provided.

Detailed technical information is provided for the following equipment:

Auxiliary Mechanical:

- lubrication systems
- raw and cooling water
- compressed air
- potable water
- drainage and dewatering
- fire protection
- HVAC
- powerhouse cranes
- tailrace crane

Auxiliary Electrical:

- unit transformers
- station service AC
- station service DC
- cable and cable support systems
- grounding
- lighting

2.2 Objectives of Hydro Life Extension and Modernization[3]

Each hydro life extension and/or modernization program or project has its own, sometimes unique, objectives. These are described in detailed in Volume 1 and include:

Plant Life Extension and Restoration of Original Performance Levels

- Extending equipment life
- Halting or decelerating deterioration
- Reducing forced outages or unscheduled down time
- Reducing operations or maintenance costs
- Reducing frequency of overhauls, scheduled downtime
- Reducing undesirable operating characteristics, such as vibration

Plant Modernization to Improve Plant Products and Economics

- Increasing generating capacity
- Improving efficiency
- Improving ability to control equipment data, through remote control and automation.
- Improving ability to deliver "ancillary services" such as voltage support, synchronous condensing capability, black start, etc.
- Matching unit performance characteristics to load or water availability, including removing "bottlenecks" in cascade hydro systems
- Improving plant/personnel safety
- Avoiding obsolescence problems such as lack of manufacturer support or unavailability of replacement parts

Risk Management and Environmental Compliance

- Reduce risk of catastrophic failure
- Improving ability to meet river flow or reservoir level requirements
- Reducing potential for environmental degradation
- Enhancing water quality
- Reducing fish mortality
- Meeting legal/licensing requirements

[3] EPRI, Palo Alto, CA, 1998. WO 5715-01, p 5-1, Hydropower Technology Round-up Report; Part 2: Rehabilitating and Upgrading Hydro

3
SCREENING

3.1 Introduction to Screening Process

Proceeding with an auxiliary equipment screening process is dependent on other prior or parallel steps. Equipment screening is recommended if the results of plant screening in Volume 1, Chapter 3 clearly indicate a need to proceed with a further detailed screening of unit equipment such as turbines (Volume 2, Chapter 3), protection and control (Volume 7, Chapter 3), or generators (Volume 3, Chapter 3) or if the hydro plant owner is considering an action plan driven by generator failure, derating or unreliability.

The plant auxiliary equipment screening procedure is a quick and easy process to evaluate whether life extension and/or modernization should be pursued. Through this process, the user can assess the potential for life extension and/or modernization of the equipment to avoid performing detailed, costly studies of uneconomic alternatives. A question and answer system is used and special measurements or tests are not required.

The screening process uses some of the following "indicators" to assess whether modernization and /or life extension should be considered:

- performance
- age
- reliability
- maintainability
- environmental risk/safety

Rather than screen life extension and modernization separately, at this stage they are treated together. The method used here is to ask questions that may or may not lead the user to the section where a more detailed assessment can be made and an approach to either life extension or modernization can be followed. A more detailed description of the overall screening process for plant/units is set out in Volume 1, Chapter 3 of these Guidelines.

The screening in Volumes 4 and 5 is complementary, but at a greater level of detail to that contained in Volume 1.

3.2 Auxiliary Mechanical Equipment

3.2.1 Bearing Lubrication

Bearing lubrications systems are critical to unit operation. They include piping, pumps (for pumped oil circulation systems), heat exchangers, instrumentation and protective devices for lubrication and cooling in addition to oil lift systems for unit start up and maintenance.

3.2.1.1 Performance as an Indicator

Bearing lubrication is closely linked to proper functioning of the unit in terms of unit alignment, vibration levels and bearing operating temperatures. Questions to ask Operation and Maintenance (O&M) staff:

1. Has there been a history of bearing problems, including consistently high temperatures, restricted operating ranges, or vibration problems?
2. Do oil samples indicate oil contamination and possible sources of the problems?
3. On water-cooled bearings, have their been problems with the filtering system?

If the answer to any of the above questions is YES, then Performance is the driver for life extension or modernization.

3.2.1.2 Age as an Indicator

Questions to ask O&M staff:

1. Is the lubrication system less than 30 years old?
2. Have the coolers been re-tubed in the last 20 years?
3. Have protection devices been updated in the past?

If the answer to any of the above questions is NO, then Age is the driver for life extension or modernization.

3.2.1.3 Environmental Risk/Safety as an Indicator

Lubrication systems are a potential source of oil spill and releases. Questions to ask O&M staff:

1. Is leakage in the system a nuisance problem?
2. Have there been logged events such as loss of oil?
3. Are the oil coolers single -wall?

If the answer to any of the above questions is YES, then Environmental Risk is the driver for life extension or modernization.

3.2.2 Cooling Water Systems

Cooling water systems, supplied from the raw water system, include cooling water to the bearings, shaft seal, generator, heat exchangers, fire protection system, transformers and/or exciters, and HVAC systems.

3.2.2.1 Performance as an Indicator

Questions to ask O&M staff:

1. Are high or increasing temperatures indicated on components that require cooling water?
2. Is there a history of leaks, corrosion, or blockages?
3. Is capacity of systems inadequate for current and future cooling water requirements?

If the answer to any of the above questions is YES, then Performance is the driver for life extension or modernization.

3.2.2.2 Age as an Indicator

Questions to ask O&M staff:

1. Are cooling water and raw water systems less than 40 years old?
2. Have protection devices and instrumentation been updated in the last 20 years?
3. Have the coolers been re-tubed in the last 20 years?

If the answer to any of the above questions is NO, then Age is the driver for life extension or modernization.

3.2.2.3 Environmental Risk/Safety as an Indicator

Questions to ask O&M staff:

1. Is there adequate pressure reduction and pressure relief safety valves to protect systems during such events as penstock over pressure?
2. Are oil/water coolers double-wall?

If the answer to any of the above questions is NO, then Environmental Risk/Safety is the driver for life extension or modernization.

3.2.3 Compressed Air Systems

Compressed air systems in a plant may include unit brake air, station service air, instrument air, synchronous condense air (tailwater depression), governor air (high pressure), and intake structure bubbler air.

3.2.3.1 Performance as and Indicator

Questions to ask O&M staff:

1. Is the capacity of any compressed air systems sufficient for existing and future equipment/station requirements?

2. Do the compressors, receiver and dryers function well?

If the answer to any of the above questions is NO, then Performance is the driver for life extension or modernization.

3.2.3.2 Age as an Indicator

Questions to ask O&M staff:

1. Are any compressors less than 30 years of age?

2. Have the compressor controls been updated in the last 20 years?

If the answer to any of the above questions is NO, then Age is the driver for life extension or modernization.

3.2.3.3 Environmental Risk/Safety as and Indicator

Questions to ask O&M staff:

1. Do the safety valves associated with each air system operate improperly with incorrect settings and ratings?

2. Do the compressors leak?

If the answer to any of the above questions is YES, then Environmental Risk/Safety is the driver for life extension or modernization.

3.2.4 Potable Water Systems

Hydro plants typically have a domestic water system for use by station personnel.

3.2.4.1 Performance as an Indicator

Questions to ask O&M staff:

1. Is there a history of leaks, corrosion, or blockages?
2. Is capacity of the systems inadequate for current and future potable water requirements?

If the answer to any of the above questions is YES, then Performance is the driver for life extension or modernization.

3.2.4.2 Age as an Indicator

Questions to ask O&M staff:

1. Is the potable water systems less than 40 years old?
2. Have protection devices and instrumentation been updated in the last 20 years?

If the answer to any of the above questions is NO, then Age is the driver for life extension or modernization.

3.2.4.3 Environmental Risk/Safety as and Indicator

Questions to ask O&M staff:

1. Does the water quality meet applicable health standards?

If the answer to the above question is NO, then Safety is the driver for life extension or modernization.

3.2.5 Drainage and Dewatering System

Powerhouse drainage systems include all piping, pumps and sumps that collect, treat and discharge water collected in the powerhouse to the environment. Dewatering systems are for the turbine scroll case, draft tube and penstock.

3.2.5.1 Performance as an Indicator

Questions to ask O&M staff:

1. Is there inadequate capacity to prevent powerhouse flooding?
2. Is dewatering time excessive?

If the answer to any of the above questions is YES, then Performance is the driver for life extension or modernization.

3.2.5.2 Age as an Indicator

Questions to ask O&M staff:

1. Are pumps less 30 years old?
2. Have pump controls been updated in the last 20 years?

If the answer to any of the above questions is NO, then Age is the driver for life extension or modernization.

3.2.5.3 Environmental Risk/Safety as and Indicator

Questions to ask O&M staff:

1. Has an oil spill risk evaluation been completed? Have recommendations for oil spill protection and containment been implemented?
2. Do oil spill containment systems meet current local and national standards and regulations?

If the answer to any of the above questions is YES, then Environmental Risk/Safety is the driver for life extension or modernization.

3.2.6 Powerhouse Fire Protection

Fire protection systems include both automatic and manual fire suppressions system, fire protection water piping and pumps, smoke control/ventilation systems, and alarms and signaling.

3.2.6.1 Performance as and Indicator

Questions to ask O&M staff:

1. Is there adequate coverage of plant areas in terms of mechanical fire protection and alarms and signaling?

2. Are all system components properly installed and functioning?

3. Is there adequate smoke control?

If the answer to any of the above questions is NO, then Performance, is the driver for life extension or modernization.

3.2.6.2 Age as an Indicator

Questions to ask O&M staff:

1. Has there been any updating or modernization of plant fire protection systems in the last 20 years?

If the answer to the above question is NO, then Age is the driver for life extension or modernization.

3.2.6.3 Environmental Risk/Safety as and Indicator

Questions to ask O&M staff:

1. Has there been a fire risk study/analysis of the plant fire protection system in terms of equipment and life safety?

2. Have recommended fire risk reduction measures been implemented?

If the answer to any of the above questions is NO, then Environmental Risk/Safety is the driver for life extension or modernization.

3.2.7 HVAC

The HVAC systems include any heating, ventilation and air conditioning (HVAC) components such as louvers, roof or high wall fans, and 100% filtered fresh air supply units, and heating components such as electric heaters or warm air bleeds off the generators.

3.2.7.1 Performance as an Indicator

Questions to ask O&M staff:

1. Are HVAC requirements being met or is there evidence of site modifications to improve performance?

2. Has an energy audit and HVAC system review been done for the plant? Is there the opportunity for station service energy savings with better controls?

3. Have any recommended HVAC improvements been implemented?

If the answer to any of the above questions is NO, then Performance is the driver for life extension or modernization.

3.2.7.2 Age as an Indicator

Questions to ask O&M staff:

1. Is the HVAC system less than 30 years old?

2. Have HVAC controls been updated in the last 20 years?

If the answer to any of the above questions is NO, then Age is the driver for life extension or modernization.

3.2.7.3 Environmental Risk/Safety as and Indicator

Questions to ask O&M staff:

1. Have the HVAC and fire protection controls been integrated to operate together in case of an emergency?

If the answer to the above question is NO, then Environmental Risk/Safety is the driver for life extension or modernization.

3.2.8 Powerhouse Crane/Tailrace Crane

Most powerhouses have a bridge type powerhouse crane. Tailrace cranes can be either gantry type or bridge type depending on the powerhouse configuration.

3.2.8.1 Performance as an Indicator

Questions to ask O&M staff:

1. Can crane perform the current and future operating hoisting duties required?

If the answer to the above question is NO, then Performance is the driver for life extension or modernization.

3.2.8.2 Age as an Indicator

Questions to ask O&M staff:

1. Are crane controls more than 20 years old?

If the answer to the above question is YES, then Age is the driver for life extension or modernization.

3.2.8.3 Safety Risk as an Indicator

Questions to ask O&M staff:

1. Has the crane had its required safety inspection and design review, particularly before heavy lifts?
2. Have the crane wire ropes been inspected as per applicable regulations?

If the answer to any of the above questions is NO, then Safety is the driver for life extension or modernization.

3.3 Auxiliary Electrical Equipment

3.3.1 Generator Transformer

The generator step-up transformers (GSU) usually consists of a three phase or three single phase transformer rated at 6.9kV to 16kV on the Low Voltage (LV) and 69kV to 765kV on the High Voltage (HV). GSU transformers are normally connected LV delta to HV start with an off-load tapchanger in the HV neutral. The GSU transformer rating is based on the generator MVA rating at maximum load power factor. Pre-1970 units or underground powerhouse transformers will likely be cooled through a heat exchanger, or in some older units, through internal cooling coils. Since GSU transformers are typically operated at or near full load, their thermal aging is higher than distribution or transmission classes. Further, GSU transformers may be subjected to more frequent over-excitation usage with possible higher magnetic core and LV winding eddy current losses.

3.3.1.1 Performance as an Indicator

Temperature and noise will be critical indicators. Also routine test results for insulation power factor (Doble Tests), dissolved combustible gases and water content of the insulating oil, and new technologies such as furan analysis are available for further checking of internal conditions.

Questions to ask O&M staff:

1. Has the bushing and winding insulation power factor deteriorated?
2. Have dissolved combustible gas contents exceeded normal increases?
3. Has generation been restricted by transformer temperature?
4. Have higher than normal furan levels been detected?

If the answer to any questions is YES, GSU transformer performance is an indicator of life extension or modernization opportunity.

3.3.1.2 Age as an Indicator

GSU transformers manufactured prior to 1975 will have higher core losses than new units. Otherwise a well maintained and adequately rated unit will continue to provide good service regardless of age.

Questions to ask O&M staff:

1. Is the transformer greater than 35 years old?
2. Are gaskets ineffective and do they allow oil leakage at bushings flanges and piping connections?
3. Would oil escape as a result of explosion or failure and cause an environmental risk of spillage.
4. Has insulation or bushing power factor continued to increase significantly?

If the answer to any question is YES, GSU transformer age is a driver for modernization.

3.3.1.3 Reliability as an Indicator

Transformers built before 1940 have a high reliability due to conservative design and lower HV ratings. After 1970, GSU transformers were again very reliable (except for class/kind problems) due to higher tests standard. In between 1940 and 1970, demand for higher HV transmission voltages (230kV and above) and MVA ratings (>100 MVA 3 phase), resulted in many instances of overhaul and rebuild due to design problems.

Questions to ask O&M staff:

1. Have GSU transformers caused forced outages?
2. Have auxilliaries or cooling caused forced deratings?

If the answer to this and similar questions is YES, Reliability is a driver for Life Extension and/or Modernization.

3.3.1.4 Maintainibility as an Indicator

The external condition of the GSU may reflect maintenance practices and consequentially is of interest in Screening.

Questions to ask O&M staff:

1. Are there significant oil leaks?
2. Has the protective paint coating deteriorated to the point of rusting?
3. Has the tank ground connection corroded?
4. Is the control cabinet equipment corroded?
5. Are temperature and oil level devices proving to be expensive to maintain/replace?

If the answer to any of these questions is YES, then Maintainability is of concern in a Life Extension program.

3.3.2 Station Service - AC

AC Station Service (ACSS) includes the high voltage switchgear, regulators and transformers, LV distribution and panels, LV switches, and final step-down transformers and panels.

ACSS is an essential service and will be duplexed and usually is also fed from an independent emergency power generator or outside source.

For the purpose of Screening, only the main supply transformer/regulator, main LV switchgear and load Control Centres will be reviewed.

3.3.3 Main AC Supply

Most hydroplants should have a multiple HV source for ACSS, e.g. fed from two or more generators at any time.

3.3.3.1 Performance as an Indicator

Operators and electrical maintenance staff will be familiar with the equipment.

Questions to ask O&M staff:

1. Does the AC load, under any operating condition, exceed the rating of any one source (transformer/regulator)?
2. Does the AC regulation exceed $\pm 5\%$?

If the answer to one or more of the questions is YES, it identifies Performance as a driver for life extension or modernization.

3.3.3.2 Age as an Indicator

Most of this equipment will have been installed at the time of the first unit of the powerhouse.

Questions to ask O&M staff:

1. Are the transformer/regulators more than thirty-five (35) years old?

2. Are replacement parts of the regulators and transformer controls obsolete?

If the answer to one or more of the questions is YES, it identifies Age as a driver for life extension or modernization.

3.3.3.3 Reliability as an Indicator

Questions to ask O&M staff:

1. Have there been any recent failures (within last 10 years) of transformers/regulators?

2. Is there a need for manual (operator) intervention in the AC regulation?

If the answer to one or more of the questions is YES, it identifies Reliability as a driver for life extension or modernization.

3.3.3.4 Maintainability as a Indicator

Because ACSS is not seen as critical to power generation, there may be a tendency to overlook maintenance Questions to ask O&M staff:

1. Are preventive mainframe practices and frequencies less than those performed in unit transformers?

2. Does the load or arrangement of physical plant prevent regular isolation of transformer/regulator for maintenance?

If the answer to one or more of the questions is YES, it identifies Maintainability as a driver for life extension or modernization.

3.3.4 Main ACSS Switchgear Panel

The ACSS LV voltage may be as low as 600 VAC and as high as 12 KVAC, depending on plant capacity and unit ratings. However, the critical aspects of the LV switchgear and distribution panel can be screened as a common function.

3.3.4.1 Performance as an Indicator

ACSS will usually have automatic transformer switching of the distribution load and frequently part of the load will be categorized as Essential Service. Questions to ask O&M staff.

1. Does the paralleling of any loads require manual operation of switchgear?
2. Does the fault level, in any appearing mode, exceed the breaker/interrupter ratings?

If the answer to one or more of the questions is YES, it identifies Performance as a driver for life extension or modernization.

3.3.4.2 Age as an Indicator

Question to ask O&M staff:

1. Are replacement parts obsolete?

If the answer to the question is YES, it identifies Age as a driver for life extension or modernization.

3.3.4.3 Reliability as an Indicator

Electrical failures of ACSS switchgear are rare and failures to operate may not have been considered. However, reliable ACSS switchgear is essential. Questions to ask O&M staff:

1. Have there been any electrical failures within the last 10 years? e.g. flashover, failure to interrupt?
2. Is manual intervention necessary to load transformers?

If the answer to one or more of the questions is YES, it identifies Reliability as a driver for life extension or modernization.

3.3.4.4 Maintainability as an Indicator

Usually the design/specification includes provision to maintain LV breakers (draw out provisions in metalclad) and auto transfer devices. Questions to ask O&M staff:

1. Are the LV breakers overdue for regular preventive maintenance?
2. Does the design/layout prevent routine inspection/maintenance of any operating devices?

If the answer to one or more of the questions is YES, it identifies Maintainability as a driver for life extension or modernization.

3.3.5 Load Distribution Centres

This topic includes unit auxiliary power panels, powerhouse lighting panels and motor (fire and drainage pumps) control centres.

3.3.5.1 Performance as an Indicator

Performance is usually taken for granted but it is part of screening AC loads. Questions to ask O&M staff:

1. Have additions or upgrades been undertaken beyond original design provisions?
2. Has there been a recent history (within 10 years) of load breaker grips indicating excessive loads?

If the answer to the question is YES, it identifies Performance as a driver for life extension or modernization.

3.3.5.2 Age as an Indicator

Questions to ask O&M staff:

1. Are replacement parts obsolete?

If the answer to the question is YES, it identifies Age as a driver for life extension or modernization.

3.3.5.3 Reliability as an Indicator

Normally load distribution centres are trouble free unless subject to flooding or fire. Question to ask O&M staff:

1. Has there been incidents of breakers or conductor/connector failures?

If the answer to the question is YES, it identifies Reliability as a driver for life extension or modernization.

3.3.5.4 Maintainability as an Indicator

Load distribution centres are normally maintenance free. Questions to ask O&M staff:

1. Are any breakers repetitively reset, particularly motor circuits?
2. Are the load centres dirty (dust, insects, water damage)?

If the answer to one or more of the questions is YES, it identifies Maintainability as a driver for life extension or modernization.

3.3.6 Station Service - DC

The DC System consists of the battery chargers, batteries, DC distribution panel, and DC load (other than P&C). Normally the chargers and batteries will be duplexed for plant reliability. The chargers also serve as a power supply and in some cases may be called an Uninterruptable Power Supply (UPS) when combined with battery storage. UPSs for specific duty are included with the equipment being supplied.

In older powerhouses, it is probable that the battery charges and batteries will have been replaced at least once. Drawings and data sheets may not have been updated.

3.3.6.1 Performance as an Indicator

Battery charger performance is closely linked to the battery capacity and DC loads.

Questions to ask O&M staff:

1. Does the DC load (with battery disconnected) exceed total charger/UPS output rating? (DC load includes P&C emergency lighting and DC motors.)

2. If the maximum DC load (with battery disconnected) exceeds one charger/UPS capacity, does the battery rating provide less than 8 hours supplementary capacity?

3. Does the battery capacity (without charger/UPS) provide less than 4 hours supply (or the time period to dispatch maintenance personnel to the plant)?

If the answer to one or more of the questions is YES, it identifies Performance as a driver for life extension or modernization.

3.3.6.2 Age as an Indicator

Battery charger technology has advanced significantly with the availability of power electronics.

Questions to ask O&M staff:

1. Is the charger/UPS more than fifteen (15) years old?

2. Are the batteries more than twelve (12) years old?

3. Have emergency or other DC loads increased since the original ratings were established?

4. Are charger/UPS parts obsolete?

If the answer to one or more of the questions is YES, it identifies Age as a driver for life extension or modernization.

3.3.6.3 Reliability as an Indicator

It is essential that the DC system be 100% reliable through redundancy and elimination of common components. Questions to ask operations and O&M staff.

1. Has the DC system failed in the past 10 years? If yes, why?

2. Is the duplex component capability of the DC system tested (battery load test for example) less than bi-annually?

3. Have the DC buses, protectors (fuses, CBs) or panels ever failed?

If the answer to one or more of the questions is YES, it identifies Reliability as a driver for life extension or modernization.

3.3.6.4 Maintainability as an Indicator

The maintenance requirements are usually minimum but critical. Questions to ask O&M staff:

1. Are the batteries requiring excessive "coating"?

2. Is there evidence of chemical corrosion on battery terminals/connectors?

3. Are chargers/UPS frequently out-of-service?

If the answer to one or more of the questions is YES, it identifies Maintainability as a driver for life extension or modernization.

3.3.7 Cables and Cable Support Systems

Medium voltage power cables are often used to connect the generator output terminals to the GSU transformer. In some cases, isophase or open bus may have been used due to higher currents, switching and tap requirements. Since cables are frequently out-of-sight in raceways, conduits and tunnels, they are often overlooked, but nonetheless critical.

3.3.7.1 Performance as an Indicator

Questions to ask O&M staff:

1. Is there a history of cable in-service failure?
2. Have sheath anomalies such as necking or corrosion been observed?
3. Are cables operating at maximum capacity or limiting, due to temperature rise, generator output?

Note: If GSU transformer HV is connected to the switchyard or O/H transmission line by HV cable, similar questions should be raised.

If the answer to one or more of the questions is YES, the generator cables (or buses) are of interest for any life extension or modernization opportunity.

3.3.8 Grounding

Secure bonding of all metal parts to the same electrical potential within the powerhouse and switchyard is essential to the current operation of protective systems and to personnel safety. Grounding or "zero potential" is accomplished by various interconnected grids, equipment ground connections, and a proven bond or very low resistance path to earth - sometimes remotely cabled. The grounding system provides a path for unbalanced AC system frequencies, for fault currents due to equipment ground wall insulation failures and for external sources such as lighting and remote phase-to-ground flashover of the AC lines.

Questions to ask O&M staff:

1. Has corrosion or looseness of equipment ground connections/cables been observed?

2. Was the last measurement of station ground resistance conducted more than 10 years ago?

3. Have major equipment failures to ground caused secondary protection zone types?

4. Have personnel complained of step/touch potentials?

5. Have lighting strikes caused erroneous equipment trip or operations?

If the answers to any of the above is YES, station grounding is a driver for maintenance review as well as life extension and modernization consideration.

3.3.9 Lighting

The lighting system includes general lighting levels and DC emergency lights in the powerhouse, galleries, tunnels and workshops. Regulatory changes over the last twenty years have required higher illumination levels, particularly in work areas such as workshops and offices. Countering this requirement is the increased value of energy (income). Most plants over twenty years old will have an opportunity to upgrade light levels, lighting efficiencies and lighting controls (modernization).

3.3.9.1 Performance as an Indicator

Questions to ask O&M staff:

1. Has a study of illumination deficiencies been conducted during the past 10 years which resulted in recommendations that were not executed?

2. Is the lighting control limited to manual control?

3. Have the emergency DC lights failed to provide adequate levels or duration when called upon or tested?

If the answer to any questions is YES, lighting is a likely modernization opportunity.

Table 3-1
Auxiliary Mechanical and Electrical Equipment
Summary of Screening Indicators

Project: ____________________
Unit: ____________________
Asset No. ____________________
Prepared by: ____________________
Date: ____________________

Is Lubrication System life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	
Is Raw Water and Cooling Water Systems life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	
Is Compressed Air System life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	
Is Potable Water System life extension or modernization indicated by:			
	Yes	No	
- Performance	❑	❑	Comments
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	
Is Powerhouse Drainage and Dewatering Systems life extension or modernization indicated by:			
	Yes	No	
- Performance	❑	❑	Comments
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	
Is Fire Protection life extension or modernization indicated by:			
	Yes	No	
- Performance	❑	❑	Comments
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	

Is HVAC life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	
Is Powerhouse Crane life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Environmental Risk/Safety	❑	❑	
Is Generator Transformer life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	
Is Station Service AC life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	
Is Station Service DC life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	
Is Cable and Cable Support Systems life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
Is Grounding life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
Is Lighting life extension or modernization indicated by:			
	Yes	No	Comments
- Performance	❑	❑	

4
EVALUATION OF CONDITION AND PERFORMANCE

4.1 Introduction

Evaluation of plant equipment performance and condition assessment are key steps to successfully formulating a Life Extension and Modernization Plan (LEM Plan) as described in Volume 1, Chapter 4 of these Guidelines. The Life Extension and Modernization process is iterative and life extension activities are identified in this first stage. The evaluations discussed in this Chapter of Volumes 4 and 5, rely mainly on using existing information and knowledge on the plant or new information that is inexpensive to obtain. The goal is to avoid extensive testing and analysis at this stage but still obtain a reasonable assessment of equipment condition. Additional testing or studies may be justified once the LEM Plan is formulated and projects are more clearly defined. These further tests would be conducted as part of a future feasibility study (refer to Chapter 7 of this Volume). The flowchart (Figure 4-1) describes how each of the subsections contribute to the identification of activities for the LEM Plan.

Chapter 4 focuses on assessing the present performance and condition of the auxiliary equipment, assessing its remaining life and identifying activities that will extend the life of the equipment. Timing aspects of the identified life extension activities are nominated and a schedule of activities is formulated. The assembled information from this Chapter is used to develop tables of Needs and Opportunities (Tables 4-3, 4-4 and 4-5) in Volume 1, which are subsequently used to develop the LEM Plan. To conduct the condition assessment of each piece of equipment and identify life extension activities, an Equipment Condition Assessment Summary Sheet (Table 4-1) may be used for convenience, particularly for site visits, before inserting the information into the extensive tables in Volume 1. Based on the Asset Register (described in Volume 1, Chapter 4.2) assembled for the plant, a worksheet is prepared for each piece of generator equipment. This ensures that all required information for the LEM Plan projects is obtained. This Chapter contains the technical information to assist in completing the worksheet. A similar table for modernization opportunities is completed using Chapter 5 of this Volume in particular.

To assist in following the process, a depiction of Table 4-1 is provided at the start of each subsection. The highlighted portion indicates the part of the worksheet covered by information in the subsection. A periodic review of the overall process in Volumes 4 and 5 is often useful.

To assist in following the process, a depiction of Table 4-1 is provided at the start of each sub-section. The highlighted portion indicates the part of the worksheet covered by information in the sub-section.

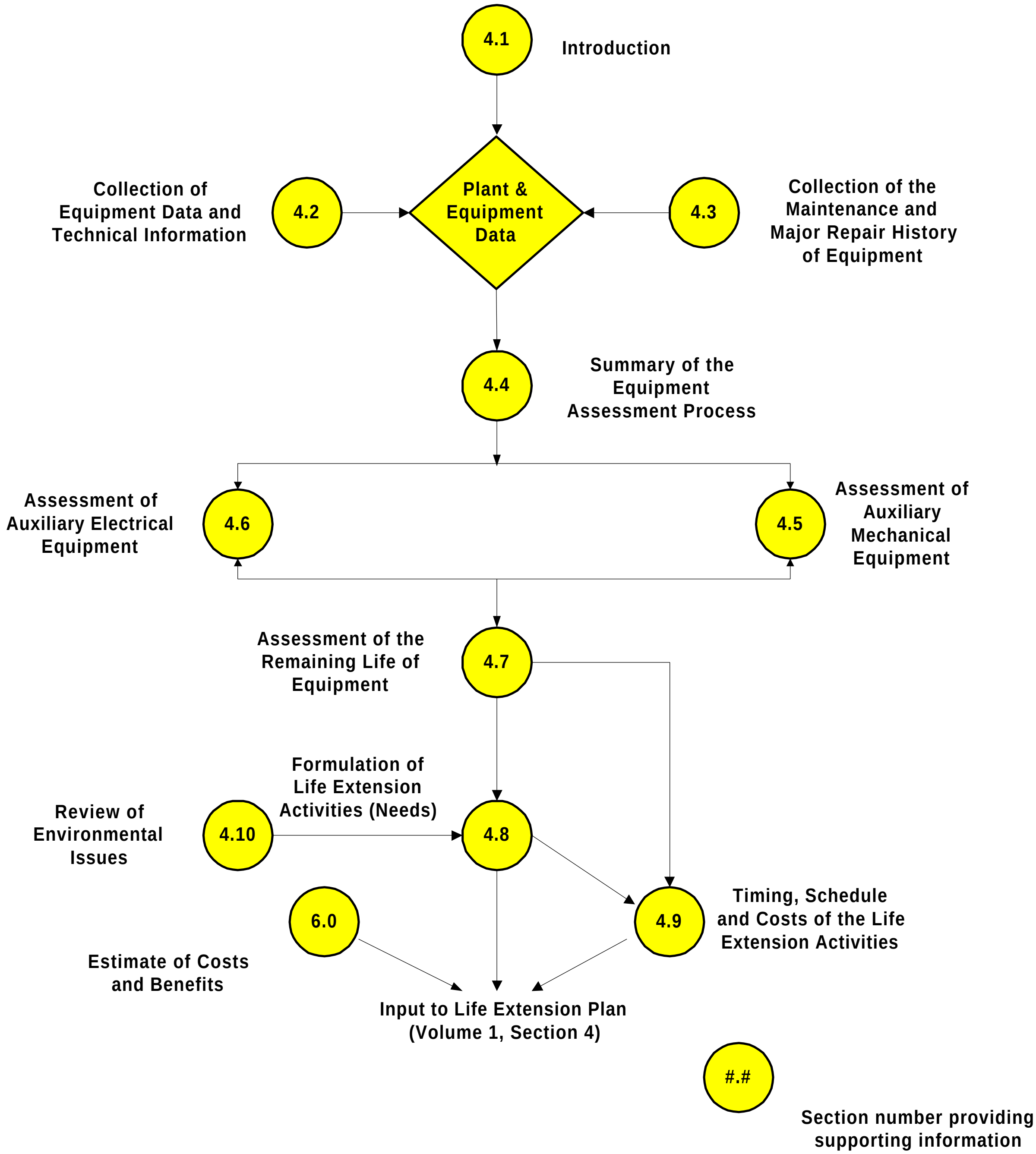

Figure 4-1
Input of Auxiliary Mechanical and Electrical Equipment Data to Life Extension Plan

Table 4-1
Site Worksheet for Equipment Condition Assessment
Identification of Needs

Plant: ____________________________
Equipment Name: ____________________________
Unit No.: ____________________________
Asset No.: ____________________________
Prepared by: ____________________________ **Date:** ________________________

Equipment Data and Technical Information (Section 4.2)	**History of Maintenance and Major Repairs** (Section 4.3)
Condition Assessment of Equipment (Sections 4.4, 4.5 and 4.6)	
Assessment of Remaining Life (Section 4.7)	**Condition Rating (if available)** (Section 4.4)
Repairability Rating (Section 4.4)	**Environmental Issues** (Section 4.10)
Possible Life Extension Activities (Section 4.8)	**Timing and Costs of Life Extension Activities** (Section 4.9)

4.2 Equipment Data and Technical Information

Equipment Data and Technical Information (Step 4-2, Volume 1)	History of Maintenance and Major Repairs
Condition Assessment of Equipment	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities	Timing and Costs of Life Extension Activities

4.2.1 Desk-top Review

The checklists provided in Sections 4.3 through 4.6 provide a summary of the technical data and background information required to conduct a general condition assessment of the auxiliary mechanical and electrical systems and determine the “fitness for purpose” of this equipment.

In assessing the present condition or performance of the plant's auxiliary equipment, it is necessary to begin with the key technical data which describes the existing equipment. This technical data includes nameplate ratings, original design requirements, existing output, efficiency tests, and equipment data, records and reports. This information is put into Tables 4-1 or directly into Tables 4-3 and 4-4 of Volume 1, Section 4.2.

Design and performance data for the original equipment are usually available in the procurement documents (although sometimes the vender will offer an alternate which is different than the specifications), O&M instructions, and commissioning test results.

The data obtained from existing records is not always reliable since changes in the operating conditions or design may have occurred. While existing information from records may not provide accurate information on current operation, in most cases it will indicate the potential performance level achievable by rehabilitating the equipment to the like-new condition. Undertaking new tests may be a costly exercise, beyond the scope of an overview level review.

Typical sources of general plant data and equipment information are:

- Drawings (plant layout and mechanical) - original as-builts and updated revisions
- Engineering study reports for original design
- Feasibility studies for original design or upgrades
- Inspection reports of condition and performance
- Environmental study reports
- Seismic evaluations
- Local Operating Orders
- System Operating Orders

- Operations reports
- Operating logs
- Technical data books
- Investigations into equipment deficiencies
- Commissioning results and reports
- Site test results and reports
- Operations & maintenance manuals
- Preventive maintenance program and records
- Upgrade studies and/or upgrade reports

4.2.2 Site Visit

The purpose of a site visit is to verify, where possible, all information obtained from the desk-top review of the plant equipment. This includes verifying that the asset register is complete and checking nameplate data to ensure that all recorded technical information is correct. Section 4.3 of Volume 1 provides some additional guidance on the objectives of the site visit.

Site personnel are often the greatest source of information, particularly when records of equipment and plant operation changes are unavailable or unorganized. Key personnel who can assist in verifying information obtained from the records include:

- Station Manager
- Maintenance managers, superintendents, area leads
- Plant operators
- Previous project managers for specific plant work
- Environmental co-ordinator
- Station business manager
- "In-house" engineering department technicians and engineers
- Consultants in specific cases
- Manufacturers and suppliers

4.3 History of Maintenance and Major Repairs (Auxiliary Mechanical and Electrical Equipment)

Equipment Data and Technical Information	**History of Maintenance and Major Repairs (Step 4-2, Volume 1**
Condition Assessment of Equipment	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities	Timing and Costs of Life Extension Activities

Tables 4-2 (auxiliary mechanical equipment) and 4-3 (auxiliary electrical equipment) are equipment specific checklists of maintenance and repair work that can form part of an equipment's repair history. These tables should be used as a check that a complete maintenance and repair history for the equipment has been captured.

A review of the maintenance history, repair history and future plans of the equipment is an important step in assessing equipment condition and predicting remaining life. Initially, the following reports should be obtained for the review, if available:

- Annual station reports or year-end summaries for maintenance and capital projects undertaken
- Station maintenance logs
- Operating & maintenance (O&M) annual plans and budgets for upcoming years
- Annual capital project plans and budgets for upcoming years

Using the above reports, the following questions about specific equipment should be addressed:

1. What is the trend in maintenance requirements (costs, hours, downtime, etc.) for the equipment over the years? Is it increasing? Constant? This information should give an indication of deteriorating condition. A chart of annual maintenance and capital costs broken down into the major equipment categories is extremely useful and is worth preparing.
2. Are there chronic problems with the equipment and what are the problems?
3. Does the equipment seem to be a high consumer of maintenance labour and budget?
4. Where is the equipment in its life cycle?
5. Has the level of maintenance been sufficient?
6. Has the maintenance activity been superficial in addressing the symptoms rather than the causes of high maintenance costs?
7. What major repairs have been done on the equipment and did these repairs substantially improve the life expectancy of the equipment? What was the level of rehabilitation?

Table 4-2
Maintenance and Major Repair History of Auxiliary Mechanical Equipment

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred)
1.1.1.4	**Bearing Lubrication System**	• Changed to non-petroleum lubricants • Replaced internal coolers with external coolers. • Installed “on-line” oil filtering. • Added oil mist collection system • Changed the oil viscosity • Added an oil lift system for startup/shutdown • Implemented an oil sampling program • Replaced heat exchangers • Replaced pumps • Replaced piping • Installed new controls/instruments • Flushing of lines • Replaced or upgraded filters
1.1.4.3	**Cooling Water Systems**	• Replaced heat exchangers • Replaced pumps • Replaced piping • Installed anti-sweat insulation piping • Installed new controls/instruments • Flushing of lines • Replaced or upgraded filters
2.1.6	**Compressed Air Systems**	• Rebuilt compressors • Replaced compressors • Piping and valving modifications • New piping supports (seismic) • Upgraded controls • Replaced air receivers of riveted construction • Installation of new systems (such as tailwater depression for synchronous condenser/spinning reserve, air injection in turbine for rough zones or the use of air for improving dissolved oxygen levels or destratifying the reservoir.)

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred)
2.1.7.1	**Raw Water System**	• Replaced pumps • Replaced strainers or filters • Replaced piping • Installed anti-sweat insulation on water supply pipes • Installed new controls/instrumentation
2.1.7.2	**Potable Water System**	• Replaced pumps • Replaced piping • Replaced hydro-pneumatic tanks • Replaced water heaters • Replaced or upgraded water treatment equipment
2.1.8.1	**Dewatering System**	• Replaced or rebuilt pumps • Replaced piping • Replaced valves • Installed new controls
2.1.8.2	**Station Drainage System**	• Replaced or rebuilt pumps • Replaced piping • Installed new controls • Upgrading/installation of oil detection and/or oil-water separation systems • Curbs installed around oil filled equipment • Reaming of drain lines • Oil sumps installed to collect spilled oil • Oil skimmers or oil separators installed • "River rock" gravel installed around oil-filled equipment to quench potential oil fires • Flushing of system

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred)
2.1.9	**Fire Protection System**	
	Water-based Automatic Fire Suppression Systems	• Maintenance items identified in NFPA 25 • Flushing water mains and sprinkler lines • Visual inspection of pipe and bracing
	Gas-Based Automatic Fire Suppression Systems	• Maintenance items identified by manufacturer • Visual inspection of pipe and bracing
	Water Supply and Fire Pumps	• Maintenance items identified by fire pump manufacturer • Visual inspection of pipe and bracing • Weekly test run of diesel fire pumps • Monthly test run of electric fire pumps • Annual performance testing of fire pumps
	Systems and Equipment for Manual Fire Fighting	• Hydrostatic testing of fire hose • Visual inspection of pipe, hose and connections • Check pressure gauges on stored pressure extinguishers • Annual maintenance of portable fire extinguishers • Hydrostatic testing of portable extinguishers
	Smoke Control Systems	Maintenance items identified by manufacturer
	Fire Detection and Alarm Signalling Systems	• Annual testing • Maintenance items identified by manufacturer
2.1.10	**HVAC Systems**	• Has an energy audit been done recently? • Upgrade of controls? • Replacement or upgrade of mechanical systems such as fans, filters, automated louvers, chillers, etc. • Increased/decreased capacity requirements due to additional equipment, energy conservation measures (installation of double-glazed windows, weather-proofing, etc.)

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred)
2.2.1	**Powerhouse Crane**	• Re-painting • Replacement or refurbishing of hoist machinery (i.e. wire ropes, gears, gear boxes, sheaves, wheels etc.) • Replacement of power conductors (down shop and/or trolley and bridge) • Addition/modification of power disconnecting devices to meet current standards • Replacement of mechanical load brakes with electrical load brakes • Replacement of motors • Replacement of control systems • Replacement of control and power wiring or conductor and collector systems. • Replacement of lighting system • Conversion from DC to AC power. • Change crane capacity • Refurbishment of lifting beam
2.2.2	**Tailrace Crane**	• Re-painting • Replacement or refurbishment of hoist machinery (e.g. wire ropes, gears, gear boxes, sheaves, wheels etc.) • Replacement of power conductors • Addition/modification of power disconnecting devices to meet current standards • Replacement of mechanical load brakes with electrical load brakes • Replacement of motors • Replacement of control systems • Replacement of control and power wiring or conductor and collector systems • Conversion from DC to AC power • Replacement of bushings or other components on lifting beam

Table 4-3
Maintenance and Major Repair History of Auxiliary Electrical Equipment

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred)
1.1.9	**Unit Transformers**	• Has there been a change in loading practices of the transformer. • Addition of auxiliary coolers, fans (forced cooling) to uprate the transformer i.e. OW (water cooling) to OA, OA/FA or FOA • Rewinding. • Bushing replacement.
2.1.1	**Station Service AC**	• Replacement of circuit breakers or transformers. • Upgrade of back-up power supply such as installation of a higher capacity diesel generator. • Increase in voltage of stand-by station service.
	Standby Diesel Generator	• Replacement or rebuild of engine or generator. • Re-rating.
2.1.2	**Station Service DC**	• Replacement/repair of Uninterruptible Power Supply (UPS). • Replacement of batteries. • Replacement of battery chargers.
2.1.3	**Cable Support Systems**	• Seismic stability work. • Cable splices or replacement. • Changes in rating due to changes in ambient temperature.
2.1.4	**Grounding Systems**	• Grounding review. • Grounding upgrade.
2.1.5	**Lighting Systems**	• Energy audits conducted. • Upgrade to more efficient lighting systems. • New energy efficient controls installed.

4.4 Summary of the Equipment Assessment Process

Equipment Data and Technical Information	History of Maintenance and Major Repairs
Condition Assessment of Equipment (Step 4-3, Volume 1)	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities	Timing and Costs of Life Extension Activities

While plant performance is the fundamental criterion for evaluating the existing plant, the condition of the plant and the possible future effects of its condition on operating capability, downtime, and reliability are also significant factors in assessing the equipment needs and modernization opportunities. These are the components of "fitness for purpose". The condition of the auxiliary equipment (noted in Tables 4-5 and 4-7) may have deteriorated to such a degree that they are approaching the end of their useful lives, or no longer providing the necessary performance, necessitating repair or replacement. Sections 4.4 through 4.6 discuss methods to assess the auxiliary equipment, components' condition, and criteria to determine whether repair is necessary. Section 4.8 describes the life extension activities that could be implemented based on the outcome of the condition assessment.

The Equipment Condition Assessment Summary worksheet for each piece of equipment (Table 4-1), sometimes referred to as the "site worksheet", may be a convenient way to collect information, particularly during the site visit. Alternatively, information can be entered directly into Table 4-3 of Section 4, Volume 1.

Tables 4-5 (Section 4.5) and 4-7 (Section 4.6) in this section provide the summary of the technical data requirements, typical assessment parameters and common life extension activities for each type of auxiliary mechanical and electrical equipment respectively. The supporting text of Sections 4.5 and 4.6 provide detailed information on the items covered in the tables. Table 4-4 provides a rating system for the assessment of equipment repairability as discussed in Section 4.4.1.

Table 4-6 provides a summary of assessment criteria for auxiliary mechanical equipment. It should be used as a general guide to the condition of the equipment. When a particular condition assessment parameter exceeds the criteria stated in Table 4-6, further investigation of equipment condition and performance is advised.

Example: The following are general steps for using Tables 4-2 through 4-7 in the condition assessment of a cooling water system.

1. Refer to Table 4-5. Look under 2.1.7.1, the asset number for cooling water system.

    (a) Collect the following information and data on the cooling water system as identified in Table 4-5.

- capacity (flow volume rate)location of take-off
- age of system
- any asbestos insulation or pipes?
- existence/type of controls
- filtration/purification
- type of piping
- inlet and outlet pressure of cooling water
- pressure reduction
- type of pumps and type of motors
- bearing oil temperature

(b) Inspect the system if possible, review past maintenance and operations records to gather the major repair history (Table 4-2) and interview site maintenance and operations personnel to obtain information an the following assessment parameters identified in Table 4-5 (Asset Number 2.1.7.1):

- sufficient capacity
- reliability – do strainers/filters block?
- pipe vibration
- pipe corrosion
- pipe cavitation
- systems leakage
- availability of spare parts
- suitable redundancy in equipment and controls

2. Refer to Table 4-6. Compare the data obtained in Step 2(c) above for the condition assessment parameters with the criteria in Table 4-6 for:
   - all pumps, strainers, etc. are operational
   - adequate water supply to satisfy all users
   - redundancy in pumps, strainers and critical components
   - openings in straining media meeting requirements of heat exchangers
   - strainers are self cleaning
   - instrumentation to indicate differential pressure across strainers

3. Further investigation of condition or performance issues may be warranted based on the results. A condition assessment statement by the assessing engineer is made and the relevant information is entered into the site worksheet (Table 4-1).

Refer to Table 4-5. Based on the condition assessment of the cooling water system, life extension alternatives should be considered. Table 4-5 provides an overview level summary of options available. The text of Section 4.8 provides more specific details.

Life extension options for the cooling water system includes:

- install corrosion protection.
- rehabilitate valves and seals
- install pipe vibration and expansion supports
- add acoustic and thermal insulation
- improve filtration/purification
- address cavitation
- upgrade instrumentation and controls
- add anti-sweat insulation
- install self cleaning strainers and/or filters
- oil analysis - check for impurities

4. Refer to Table 4-4. Assess the rehabilitation of the cooling water system using the life extension options selected.

All of the information collected above should be collected using the site worksheet (Table 4-1).

Safety

Overall plant safety regulations should be followed during the inspections. Confined space requirements should also be ascertained before entry into certain areas of the powerhouse (e.g. drainage galleries, sumps).

4.4.1 Condition Rating System

The evaluation of equipment condition (its wear and deterioration) is, in part, a subjective evaluation often based on the experience and expertise of the expert. A condition rating system is usually developed to provide an objective means of evaluating equipment condition, although some subjectivity, more appropriately called "engineering judgement", is always a component. Further development of probable life and life expectancy curves, correlated to equipment age and condition, are tools that can be used for recommending life extension activities or equipment replacement once the equipment condition has been established.

Section 4.4 provides detailed instructions on condition and performance information that should be gathered and the criteria/indicators that are useful for assessing equipment condition. The information obtained on equipment condition can be fed into a condition rating system process, if necessary, or used on its own.

The Repair, Evaluation, Maintenance and Research Program (REMR), developed by the US Army Corps of Engineers, is one of the more developed condition rating systems available in the public domain. It contains useful information for most types of hydro plant equipment. It is provided in this document as an example of a condition rating system. Owners should use their own in-house condition rating systems if they have been developed.

The REMR Condition Index Scale establishes a standard definition of condition. It uses a numerically-based scale, extending from 0 to 100. Measurement of condition is accomplished by using clearly defined condition indicators. These condition indicators are usually either test results from standard tests or visual or other non-destructive examinations that give an indication of current condition. The condition rating obtained by using REMR or another condition rating system should be entered into the Equipment Condition Assessment Summary worksheet (Table 4-1) in Section 4.1 for each piece of equipment so that the condition rating is put into context with other information obtained on maintenance history, performance and condition.

REMR worksheets for the main power transformer and cranes and wire rope gate hoists are provided in Appendix B as an example of condition assessment data worksheets. The complete REMR guidelines can be obtained from the US Army Corps of Engineers. The Corps is planning to update the REMR guidelines.

With any condition rating system, there are a number of issues that need to be considered carefully before using the system in its entirety:

1. Condition indices are a tool to help estimate the remaining life of equipment. Service life, however, is not necessarily the same as useful life. Many types of equipment are replaced for reasons other than condition. The concept of "remaining life" for equipment is discussed in Section 4.7.

2. The usefulness of certain tests and inspections "required" by the condition rating system's methodology should always be evaluated. Existing test reports, where available, should usually be relied upon at this level of assessment. Often the test procedures suggested are cited to trigger an investigation into whether or not data on certain condition indicators exist but the cost of extensive tests are probably not justified at this level of review.

3. The concept of "end of service life" for many types of equipment is difficult to apply. Diligent maintenance and periodic overhauls can keep equipment functional indefinitely. Although maintenance costs increase and obsolescence of parts can be a problem, replacement can rarely be justified on reduced maintenance costs alone. Therefore, the use of condition ratings to predict end of service life may not always be justified.

4. In many condition rating systems, the overall condition rating assigned to a piece of equipment, such as the generator, is the condition rating calculated for the component in the worst condition (i.e. the component with the lowest condition rating). The objective of this method is to flag equipment that has a component in very poor condition. However, the condition rating index does not provide an indication on the repairability of the component. Equipment may be in very poor condition but easily repairable with low cost and resource requirements. A second rating system based on repairability is often required to complement the condition rating index. Table 4-4 provides a preliminary repairability rating system.

4.4.2 Equipment Health Index (EHI)

Equipment Health Index (EHI) is an end-of-life evaluation process being developed by BC Hydro. It provides information for business planners concerning scheduling of repair, rehabilitation and replacement projects for hydroplant assets. It provides input into the overall asset planning process. Presently, the only auxiliary equipment being assessed under EHI are transformers and cables.

Technical assessment of equipment consists of two components:

(a) Health rating (letter grade)

(b) Technical Prescription

When the rating is fair, poor or unsatisfactory, the technical prescription should state:

(a) What to do? (major intervention)

(b) When to do it? (time and tolerance)

(c) How much will it cost? (budget estimate)

(d) Benefits of doing it?

EHI uses the most recent data that is available and the condition is evaluated automatically by a mathematical algorithm based on the key test and inspection data entered into the application. A "specialist engineer" uses all the information to provide the health assessment and offers a technical prescription to business planners for scheduling of capital and maintenance projects.

Table 4-4
Equipment Repairability Rating System

Rating	Repair Characteristics
Good	• Technical complexity: Low • Testing: Extensive testing or investigation is not required. • Replacement parts: Readily available and repair does not require the replacement of any major components. • Cost: Cost of parts and labour easily justified by restoration of equipment performance and avoidance of replacement costs • Outage time: Does not affect total plant outage time or the increased outage time has no economic impact on the plant, (examples, 1. there is no water available or water can be stored during the extended outage; 2. power is inexpensive so revenue losses are very low.) • Deficiencies: Repair would completely solve or mitigate the condition or performance deficiency for a number of years. • Operations: No further limits on operation result from the repair. • Access: Parts easily accessible or repair can be done in-situ.
Moderate	• Technical complexity: Moderate. Extensive testing or investigation is not required but some engineering is required. • Replacement parts: Available and repair does not require the replacement of major components. • Cost: total cost of parts and labour is moderate but cost of repair over the next few years can be justified by the avoided replacement cost. • Outage time: Increases total outage time but plant economic impact of extended outage is low. • Deficiencies: Repair would completely solve or mitigate the condition or performance deficiency for a number of years. • Operations: No further limits on operation result from the repair. • Access: Parts accessible or repair can be done in-situ.
Fair	• Technical complexity: Difficult. Extensive testing, investigation and engineering (design) required. • Replacement parts: Available but expensive; or obsolete but can be custom made. • Cost: Expensive. Total cost of parts and labour is high but replacement is even more uneconomic. Economic justification of the repair is difficult but it may be the only technical alternative other than replacement. • Outage time: Greatly increased by repair requirements; or even a small extension of the outage time means high revenue losses. There is a significant economic impact on plant. • Deficiencies: Repairs would only partially or temporarily solve/mitigate the condition or performance deficiency. Increasingly expensive repairs would be required over the years to avoid replacement. • Operations: New restrictions on operation because deficiencies are only partially repaired. • Access: Parts difficult to access and must be removed for repair (e.g. cooling coils in thrust bearing enclosure can only be removed by dismantling the thrust bearings).
Not repairable	• Technical complexity: Impractical or Impossible. For technical reasons, equipment cannot be repaired (e.g. a compressor is an older design and the manufacturer no longer supplies spare parts). • Replacement parts: Not available (obsolete) and cannot be made. • Deficiencies: Deficiencies cannot be solved or mitigated (e.g. cause of unit rough zones cannot be identified).

4.5 Assessment of Auxiliary Mechanical Systems

Equipment Data and Technical Information	History of Maintenance and Major Repairs
Condition Assessment of Equipment (Step 4-3, Volume 1)	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities	Timing and Costs of Life Extension Activities

The station auxiliary mechanical systems include the balance-of-plant mechanical systems needed to operate the plant and support the operation of the turbine generator units. The information in this section will provide methods to assess the existing balance-of-plant mechanical equipment. The information gathered during the assessment will assist in identifying modernization alternatives for the hydroelectric facility.

Table 4-5 provides a summary of condition assessment parameters and life extension and modernization activities for auxiliary mechanical equipment (see Section 5 for more details on modernization options).

Table 4-6 provides some assessment criteria.

Table 4-5
Condition Assessment of Auxiliary Mechanical Equipment

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
1.1.1.4	**Bearing Lubrication**	• Type of bearings • Age of system/components • Water flow rate • Oil flow rate • Type of pumps • Type of motors • Type of controls • Type of heat exchangers	• Suitable redundancy in equipment and controls to prevent generating unit outage upon failure • Modern instrumentation • Availability of spare parts • Adequacy of the system to provide lubrication and cooling • Maintainability of system • Need of double walled heat exchangers	• Implement oil sampling program • Replace or re--tube heat exchangers • Installation of modern controls and instrumentation • Installation of additional components and/or controls to improve reliability • Increase system capacity • Use of non-petroleum based lubricants • On-line filtering • Add seismic supports • Add oil mist collection • Add oil lift pump system
1.1.4.3	**Cooling Water System**	• Capacity (max. cfs, l/s) • Location of take-off • Age of system • Any asbestos insulation on pipes? • Existence/type of controls • Filtration • Type of piping • Pressure reduction • Type of pumps • Type of motors • Type of controls • Inlet and outlet pressures	• Sufficient capacity for cooling water systems • Reliability – do filters block? • Is blockage indirected by high losses? • Pipe vibration • Pipe corrosion, pin holes • Pipe cavitation • System leakage (cfs, l/s) • Availability of spare pats • Suitable redundancy in equipment and controls to prevent generating unit forced outage • Pipe wall thickness	• Install corrosion protection • Rehabilitate valves and seals • Install pipe vibration and expansion supports • Add acoustic and thermal insulation and heat tracing • Improve filtration • Address cavitation • Upgrade instrumentation and controls. • Add anti-sweat insulation • Install self-cleaning strainers and/or filters

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
2.1.6	**Compressed Air Systems**	• Type of systems (governor air, isolation valve air, instrument air, generator brake air, draft tube depressions systems, station air, circuit breaker air, etc.) • System capacity (pressure and flow) • Type of compressors • Age of compressors/system • Type of controls • Type of motors • Type of air receivers • Are there air dryers for instrument air?	• Sufficiency of system capacity • Problems with condensation • Control and reliability (e.g. is erratic control of air volume in governor accumulators causing shutdowns?) • Availability of spare parts. • Reliable source of brake air • Adequate dry air for instrumentation	• Install high efficiency motors • Convert from merchoid style controls to PLC-based controls (remote controls) • Refurbish compressors • Replace/redesign piping and valving arrangement to improve reliability • Replace reciprocating air compressors with rotary screw type. • Consider drying systems, oil-free compressors and air/oil separation for instrumentation air system. • Add seismic supports. • Add compressors and receivers and other components to increase system capacity or add redundancy.
2.1.7.1	**Raw Water System**	• Capacity (max. cfs, l/s) • Location of take-off • Age of system • Any asbestos insulation on pipes? • Existence/type of controls • Filtration • Type of piping • Pressure reduction • Type of pumps • Type of motors • Type of controls • Inlet and outlet pressures	• Sufficient capacity for cooling water, fire protection and potable water? • Reliability – do filters block? • Is blockage indirected by high losses? • Pipe vibration • Pipe corrosion, pin holes • Pipe cavitation • System leakage (cfs, l/s) • Availability of spare pats • Suitable redundancy in equipment and controls to prevent generating unit forced outage • Pipe wall thickness	• Install corrosion protection • Rehabilitate valves and seals • Install pipe vibration and expansion supports • Add acoustic and thermal insulation and heat tracing • Improve filtration • Address cavitation • Upgrade instrumentation and controls. • Add anti-sweat insulation • Install self-cleaning strainers and/or filters

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
2.1.7.2	**Potable Water System**	• Source (Wells, Take-off from penstock? Bottled water?) • Required volume/flow • Water treatment (Chlorination? Filtration? Ultra-violet?) • Equipment and storage tanks	• Reliability • Adequate capacity • Meets applicable health standards • Availability of spare parts	• Replace deteriorated components • Improve or replace water treatment systems • Replace source of supply (e.g. drill new wells; use bottled water)
2.1.8.1	**Dewatering System**	• Pumping capacity (gpm, ℓ/s) • Age of system/components • Type of sumps • Type of motors • Type of controls • Number of pumps • Time to dewater draft tube • Is the sump an open or closed construction (i.e. is there a risk of flooding the powerhouse?)	• Adequacy of system to unwater unit without difficulty • Can system be used as a backup for drainage system in an emergency? • Reliability of controls • Availability of spare parts	• Replace manually lubed pumps with self-lubing pumps. • Install larger pumps • Replace controls • Install additional pumps

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
2.1.8.2	**Station Drainage System**	• Capacity of oil and water (cfs, l/s) • Required capacity of system (any changes since design such as increased leakage from wicket gates or shaft seals?) • Water does system serve (gallery drains, turbine pit, foundation drains, etc.?) • Type of oil/water separators • Type of pumps • Number of pumps • Age of pumps • Back-up pumps/sumps? • Instrumentation/detection devices • Type of piping • Can the turbine and draft tube unwatering system be routed through the station drainage system? • Is the sump open or closed construction?	• Does system meet drainage capacity requirements? • Reliability of pumps (is tailwater level okay for good pump operation or does it go above the pump discharge line?) • Problems with drain clogging? • Level of risk of contamination of water systems from oil. • Condition of piping and valves/ • Are back-up pumps sufficient to handle extra flow from turbine and draft tube unwatering system if required? • Availability of spare parts • Frequency of pump starts	• Replace manually lubed pumps with self-lubing pumps. • Install higher capacity pumps • Install high-efficiency driving motors • Install additional pumps • Rebuild wearing parts of pump systems and controls. • Add new controls and instrumentation • Reaming or drilling of new drains • Add oil water separation systems. • Improve oil containment systems to reduce risk of contamination
2.1.9	**Fire Protection Systems**			
	Water-based Automatic Fire Suppression Systems	• Type of system • Manufacturer • Model • Age of system • Coverage • Standard applicable at time of installation • Standard applicable at present time • Source and amount of water	• Required water application rate based on hazard • Actual water application rate provided • Presence of obstructions or areas shielded to water spray • Electrical supervision or locking procedures to ensure fire protection water supply	• Flush system • Pig the interior of water mains • Replace damaged or corroded components • Install larger diameter pipe • Install stainless or galvanized pipe or fittings • Provide additional nozzles or sprinkler heads • Add automatic or manual

Asset No.	**Equipment**	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
		supply	valves remain open • Physical condition of system • Maintenance history • Ease of manual shutdown • Seismic restraint • Bonding and grounding • Pressure gage readings • Listed components • Components under recall • Method for activating pre-action sprinkler • Full coverage of transformer by water deluge system nozzles • Cycling systems • Containment for deluge water (for environmental protection) • NFPA 13 for sprinkler systems • NFPA 15 for water spray deluge systems	activation capability • Replace ineffective deluge valves • Move obstructions to sprinkler water spray or relocate sprinkler heads • Install fire pump to boost water pressure • Provide electrical supervision or locking procedures • Provide seismic restraints • Replace regular sprinkler heads with quick-response sprinkler heads • Provide a fire department connection to allow pressure boost • Extend system to unprotected areas • Replace ineffective nozzles with improved nozzles • Provide upgrades to improve conformance with NFPA 13 • Provide upgrades to improve conformance with NFPA 13 • Install new system
	Gas-Based Automatic Fire Suppression Systems	• Type of gas • Local application or total flooding system • Manufacturer • Model • Age of system • Coverage • Standard applicable at time of installation • Standard applicable at present time	• Required volume and rate of gas discharge based on hazard • Actual volume and rate of gas discharge provided • Life safety hazard and means to protect safety • Environmental effects • Physical condition of system • Maintenance history • Ease of manual shutdown	• Remove halon systems • Repair or replace storage vessels, piping and nozzles • Increase amount of stored gas • Provide improved life safety systems • Provide bonding and grounding of pipe • Provide seismic restraints • Provide electrical supervision or locking procedures

Asset No.	**Equipment**	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
			• Seismic restraint • Bonding and grounding • Pressure gage readings • Listed components • Integrity of enclosure for an area protected with total flooding system • NFPA 12 for CO2 systems	• Extend system to unprotected areas • Replace ineffective nozzles with improved nozzles • Provide upgrades to improve CO2 system conformance with NFPA 12 • Install new system
	Manual Fire Suppression Systems	• Type of standpipe system • Location of fire department hydrant • Location of fire hose connections • Presence of an emergency response team or fire brigade • Standard applicable at time of installation • Standard applicable at present time	• Flow and pressure capability • Coverage of fire hose connections • Compatibility with fire brigade equipment • Condition of existing fire hose: cuts, tears, brittle jacketing, and decay • Presence of corrosion in standpipe • Standpipe shut-off valves supervised by the fire alarm system or locked in open position • NFPA 14 for standpipe systems • Coverage of portable fire extinguishers • NFPA 10 for portable fire extinguishers	• Install new hose with appropriate hose nozzles • Repair corroded sections of standpipe • Install fire alarm supervision or lock water supply valves • Install additional hose connections • Install fire department connection • Provide upgrades to improve CO2 system conformance with NFPA 12 • Install new system

Asset No.	**Equipment**	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
	Water Supply and Fire Pumps	• Source of water supply • Continuity of fire protection water supply if other plant systems are shutoff. • Presence of fire pump • Age of fire pump • Type of fire pump • Make and model of fire pump • Fire pump standard applicable at time of installation • Fire pump standard applicable at present time	• Capacity of water supply to provide required fire flows • Continuity of fire protection water supply if other plant systems are shutoff • Presence of corrosion • Pump has a listing from a recognized testing agency • Capacity of fire pump • Reliability of fire pump • NFPA 20 • Condition of supply piping, pressure-reducing valves, etc. • Water supply valves supervised by fire alarm system or locked in open position • Quality of water source • Multiple water source feeds • Tuning of pressure-reducing or pressure-regulating valves • Condition of water supply pipe	• Install new fire protection water supply piping • Install new fire pump if the existing system cannot provide required pressures or flows • Provide fire compartment around pump room • For electric fire pumps, provide power cable with a 1 hour fire-resistance rating from station service to pump room • Provide required gages • Upgrade overloads and disconnects for the fire pump • Provide an approved flow measurement system • Provide a re-circulation relief line • Install a bypass around the fire pump • Replace propane-powered fire pumps with either electric or diesel fire pumps • Provide seismic restraints

Asset No.	**Equipment**	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
	Smoke Control	• Presence and description of smoke control equipment or means of ventilation. • Surface or underground powerhouse. • Presence of manual and automatic operation of smoke control. • Location of high voltage cable with combustible jacketing • Location of oil-filled equipment • Amount of oil	• Does original design concept of smoke control systems meet current needs • Whether or no there is manual and automatic operation of smoke control from the fire alarm panel. • Potential for smoke generation, especially in cable tunnels or cable spreading areas • Areas where sprinklers would be ineffective including areas with high ceilings. • Condition of fans, wiring and controls • Reliability of the power supply for smoke control (presence of emergency supply)	• Replace fans, wiring and controls • Provide existing ventilation fans with smoke removal capacity • Install dedicated smoke control system • Interconnect existing ventilation system with the fire alarm system to permit fan shutdown in the event of a fire

Asset No.	**Equipment**	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
	Fire Detection and Alarm Signalling Systems	• Age of system • Addressable system • Make and model of system • Availability of parts and service • Type of detectors	• Fire detection coverage • Adequacy, reliability and age of the different types of fire detectors • Alarm signalling coverage • Ability of the detection system to control HVAC and smoke ventilation systems • Off-site monitoring station – reliability of emergency personnel notification and response • Presence of monitoring for operation, tampering or leakage • Supervision of water supply valves for fire protection • Adequacy of emergency power supply	• Remove high voltage ionization-type smoke detectors • Upgrade existing fire alarm panel and equipment • Provide additional detection and alarm signalling coverage • Provide monitoring from an off-site monitoring station • Upgrade emergency power supply • Install new emergency power supply • Install new fire detection and alarm signalling system
	Oil Spill Containment	• Location of oil-filled equipment • Amount of oil • Age of existing oil spill equipment	• Adequacy of existing containment, drainage sumps, oil skimmers, and oil interceptors to meet local and national regulatory requirements	• Identify areas of oil spill potential • Inspect vessels and piping for potential leakage and corrosion • Install curbs around oil filled equipment • Install oil sumps to collect spilled oil • Install oil skimmers or oil separators • Install “river rock” gravel around oil-filled equipment to quench potential oil fires • Provide for fire protection

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
2.1.10	**HVAC Systems**	• Forced ventilation? • Design capacity vs current required capacity of the HVAC system (was there a change in building components?) • Louvers and fans? • Is there brushgear dust? • Is auxiliary power separately metered? • Age of control systems. • Current thermostat setpoints. • Do systems use 100% fresh air or recirculate air for cool season? • Any system modifications?	• Is there sufficient heating? • Is there sufficient cooling? • Leakage past louvers. • Is there optimization/control for energy savings. • Age of controls.	• Other than maintenance, most changes would be considered an upgrade. • Installation of new HVAC system with digital control system.
2.2.1	**Powerhouse Crane**	• Type of crane • Crane manufacturer • Number of cranes • Rated capacity of main and auxiliary hooks (tons, tonnes) • Span (ft, m) • Max/min elevations of main and auxiliary hooks • Max/min hoisting speeds of main and auxiliary hooks • Max/min bridge/gantry travelling speed • Max/min trolley speed • Lifting beam type and rating • Control: type of control, local and/or remote • Operating restrictions • Type of lowering broke (drum or disc) • Type of holding brake (drum	• Safe Operation • Does hoisting capacity meet requirement for lift of heaviest component? • Sufficient lift for tallest assembly • Are hoisting speeds appropriate? • Operation of limit switches • Sufficient reach for all areas of powerhouse: • length and width of powerhouse • lowest required points • Condition of paint • Hoist wire rope (corrosion, fatigue cracking). • machinery (drums, bearings, sheaves, etc. • Trolley and bridge (wheels	• Re-paint • Replace or refurbish worn hoist machinery • Replacement of power conductors • Addition/modification of power disconnecting devices to meet current standards • Replacement of brakes • Upgrade for larger capacity • Modify crane or lifting devices for tallest lifted assembly. • Add small capacity hoist to increase hoisting coverage. • Repair or replacement of motors • Replacement of control systems • Replacement of control and power wiring or conductor and collector systems. • Replacement of lighting system

Asset No.	**Equipment**	Description and Background Information	Assessment Parameters	Possible Life Extension or Modernization Activities
		or disc)	and bearings) travel components – wheels, shafts, etc. • Condition of crane structure members (depth of corrosion, cracking, bolts or rivets loose or missing) • Reliability of hoist, trolley and bridge travel motors (spurious trips at different speeds?) • Condition of brakes on all motors • Oil condition of hoist machinery (gear reducers) • Vibration levels and audible noises during operation • Known operating problems from standard cranes tests • Availability of spare parts • Condition and alignment or runway rails • Results from recent testing. • Are manufacturer's maintenance procedures followed?	• Conversion from DC to AC power. • Load testing.
2.2.2	**Tailrace Gantry Crane**	• Rated capacity of main hoist; of auxiliary hoist(s) • Min/max hook elevations • Lifting beams required • Speeds (hoisting of all motions) • Local/remote control • Presence of stack wire rope switch.	• Safe operation? • Appropriate speeds? • Hoisting equipment condition • Structural condition • Reliability • Operation of limit switches • Are manufacturer's maintenance procedures followed?	• Replace/refurbish worn hoisting equipment. • Re-paint structural members • Replace/repair control systems. • Add a load cell and load limiting device.

Table 4-6
Summary of Assessment Criteria for the Auxiliary Mechanical Equipment

Component	Condition	Criteria
Bearing Lubrication	System operation	• All pumps, equipment and instrumentation are operational. • No oil leakage.
	System design	• Bearing temperatures stabilize at or below 80 C (thrust bearings) and 65 C (guide bearings) • Redundancy in all critical components (e.g. pumps, strainers). • Adequate instrumentation to detect critical component failure.
Compressed Air Systems	System operation	• All compressors are operational. • Absence of noticeable air leaks.
	System design	• Adequate protection against loss of brake air. • Redundancy in compressors and air receivers. • Brake air supply is secure even with loss of service air. • Instrument air is moisture free. • Service air hose connections in all critical areas. • No shortage of service air during high demand periods (unit dismantling, cavitation damage repair).
Raw Water and Cooling Water Systems	System operation	• All pumps, strainers, PRVs etc are operational.
	System design	• Adequate water supply (flow rate) to satisfy all users. • Redundancy in pumps, strainers and critical components. • Openings in straining media meeting requirements for heat exchangers – typically 1/8 inch maximum. • Strainers are self-cleaning (for an automatic or unmanned plant). • Instrumentation to indicate differential pressure across strainers.
Potable Water System	System operation	• Adequate water supply for all users.
	System design	• Meets local health standards.
Dewatering System	System operation	• All pumps, equipment and instrumentation are operational.
	System design	• Unit unwatering can be accomplished in 3 to 6 hours.

Component	Condition	Criteria
Station Drainage System	System operation	• All pumps, equipment, level controls and other instrumentation are operational. • Pumps operate no more than 10 % of the time. • Oil skimmers are operating properly.
	System design	• Sump has appropriate high level alarms. • Redundant drainage pumps. • Provision for emergency pumping in the event that drainage pumps are not operational. (e.g. use of dewatering pumps as backup to the drainage pumps) • Appropriate instrumentation to indicate excessive water level in drainage sump. • Oil/water separation system is designed to meet present regulatory requirements. • System has provision to retain oil in the event of a serious oils spill (e.g. transformer, governor sump tank)
Fire Protection System	System operation	• All pumps, equipment and instrumentation are operational. • Fire and smoke dampers are operational.
	System design	• System meets NFPA requirements
HVAC Systems	System operation	• All fans, heaters, motor operated dampers and chillers are operational.
	System design	• Under extreme conditions electrical equipment does not exceed 104°F (40°C) for more than 2 hours. • For plants with no mechanical cooling, the system will maintain powerhouse air temperature within 15°F (preferably 10°F) with warmest outside air temperature. • Minimum air temperature with cool/cold outside air temperature is 50°F in occupied areas. • For powerhouses which depend on waste heat from the generator, there is sufficient supplementary heating to ensure temperatures will not drop to 40°F when no generating units operating. • For powerhouses or powerhouse areas, which are not heated with waste heat from the generator, the area (insulation etc) meets applicable energy conservation code requirements. • The main powerhouse has at least one air change per hour. • Separate ventilation is provided for battery rooms, washrooms and office areas.

Component	Condition	Criteria
Powerhouse Crane	Design?	• Capacity of crane (or combined capacity of two cranes) is sufficient for heaviest lift during equipment dismantling/installation, including allowance for lifting beams. • Allow lifting of tallest assembly.
	Operation	• Crane operates smoothly and can adjust heavy loads within the following tolerances: • hoisting +/- .06 inches • bridge travel +/- .125 inches • trolley travel +/- .125 inches • Hooks can reach all hatches and is able to remove equipment at lowest levels.
	Condition	• Cranes have been inspected in accordance with OSHA and other governing organizations. • Crane and runway have been load tested. • Walkways, handrails etc. meet applicable code requirements • All limit switches are operable.
Tailrace Crane	Capacity	• Crane has sufficient capacity to lift heaviest gate/stoplog section. • Designed for a stalled hoist motor.
	Operation	• For a crane hoist with two lift points and no equalizing connection between the wire ropes for each lift point, the possibility that the full load can be exerted on one lift point should be considered. • Crane operates smoothly and adjusts the design load within the following tolerances • hoisting +/- .125 inches • trolley travel +/- .25 inches • gantry travel +/- .25 inches • All limit switches are operable • Crane hoisting machinery and structure will withstand the stalling torque of the hoist motor as is equipped with a load limiting device.
	Condition	• Crane has been inspected in accordance with OSHA and other governing organizations. • Device (follower beam or equivalent) engages and releases gate sections effectively, even from a submerged condition • Walkways, handrails etc. meet applicable code requirements • All limit switches are operable.

4.5.1 Bearing Lubrication Systems

The bearing lubrication system includes all oil or water pumps, valves, piping, coolers and instrumentation for guide and thrust bearing lubrication. The coolers could also be considered as part of cooling water systems.

Most vertical turbine - generator units have submerged oil bath type bearings. The thrust bearings and some guide bearings have cooling coils within the bearing sumps. Others have external coolers. For external coolers, it should be noted how the oil is circulated (pumps and filters?).

A pumped oil circulation system is provided on some vertical units. Horizontal units often have a pumped lubrication system because of the higher loads on the guide bearings. The system must have provision for safe shutdown of the unit on loss of AC power to the lubrication system pump. This can be done with a DC pump, a shaft driven pump or a head tank. The pumped system may have an external oil to water heat exchanger or just a relatively large sump to provide heat dissipation.

An oil sump drainage pump is required when it is not practicable to drain the sump to the oil storage room by gravity. Capacity should usually be based on draining the sump in 3 - 4 hours.

The key items to check in a conditoin assessment are:

- Satisfactory operation of pumps and controls. There are adequate protective devices are for safe shutdown of the unit in the event of system failure or malfunction.
- The condition of heat exchangers or coolers and parts of the cooling water system. Condition assessment information on these components is provided in Section 4.5.2 “Cooling Water” below.

As part of the review of bearing lubrication systems, the bearing history performance should be reviewed. Items could include:

1. Is there a history of unit alignment problems?
2. Has turbine power been increased at some point?
3. Have there been obvious trends in temperature and vibration vs load or time?
4. Have there been any operating restriction such as restricted load zones or bearing warm up times due to bearing problems?
5. Has there been any bearing damage in the past such as wiped bearings? Was the cause related to any of the following: loss of oil; loss of cooling; excessive or prolonged overspeed; unbalanced loads (generator short, wicket gate shear, unbalanced nozzles); changes in alignment due to powerhouse movement.
6. Have there been any changes to the oil grooving of the bearings?

An important task would be to review the history of oil sampling, determine how often it is done and what it indicates regarding bearing condition. Metal contaminates would indicate some bearing surface contact has occurred. The presence of water would indicate leaks in the system.

Oil consumption and quality data are also important data to analyze. Questions to ask include:

– Where is the oil going?

– Is oil leakage a nuisance problem, an environmental problem or a reliability problem?

– Does it cause contamination of other components such as the brushgear and if so, is there any attempt to mitigate this problem?

– The viscosity of the oil is very important in terms of bearing performance. The viscosity of the oil being used should be checked against the manufacturer's recommendations. The history of any changes in oil viscosity to accommodate or alleviate bearing problems should be investigated.

For thrust bearings, there may be a pump lift system for startup/shutdowns which may be original with the generating equipment or installed at a later date for increased bearing protection. Some questions to ask regarding this system are:

– Is the oil filtered in the system?

– Does it operate automatically during all starts/stops

– If there is no lift pump system, are there restrictions on the temperatures that re-starts can be done?

Water lubricated bearings are another system that should be reviewed. The principle aspect to consider for the lubrication water is whether or not filtering is sufficient to prevent bearing wear or failure.

<u>Oil Handling Systems</u>

There are two types of oil handling systems in hydroelectric stations

- lubricating oils for generator and turbine bearings
- Insulating type oils for tranformers and circuit breakers

Depending on the size of the plant, the oil transfer may be handled in drums using portable pumps and filter units or clean oil may be delivered by tanker truck and removed for outside cleaning.

For larger plants, it is normal practice to install permanent oil transfer and treatment equipment.

Tanks and pipes shall free of leaks and shall be properly tied down and supported. Filters should be regularly checked for cleanliness and if necessary replaced. Glass oil tank gages should have excess flow check valves to prevent oil loss in case of a broken glass and shut off valves should be provided at the entrance to the tank.

An oil retaining structure should be provided at the tanks to prevent oil spills and losses to the environment. An appropriate fire protection system should also be in place.

4.5.2 Raw Water and Cooling Water

Typically hydroelectric generating stations will have several different cooling water systems usually fed from the raw water system which in turn is taken either from the unit penstocks or pumped from the tailrace. Occasionally the turbine head cover will be a good source of clean (filtered) water for cooling. This water is the water than leaks through the runner labyrinth seals and therefore is "filtered". The cooling water requirements at the station will largely determine the design requirements of the raw water system as station service water and domestic (potable) water requirements will be very low in comparison.

The cooling water systems will have varying levels of filtration depending upon its final use.

Depending upon the type of generators or turbines used, the station may have any or all of the following cooling water systems:

- Turbine and generator bearing cooling systems
- Turbine shaft seal systems
- Generator radiator air cooling systems
- Generator fire deluge systems
- Transformer and/or exciter cooling systems
- Heating, ventilation and air conditioning systems
- Fire protection systems

Cooling water is typically required for the turbine and generator bearings, generator cooling, and for the shaft seal. High or increasing temperatures, water chemical properties, or biological factors (bacterial fouling, sludge) on these components over the years may lead to deterioration of the cooling water system. Assessment of the cooling water system should begin with collection of the background information listed in Table 4-5 and a review of the auxiliary cooling water system's maintenance history. The type and frequency of failures will identify those areas that may require attention.

The current design requirements of the cooling water system (i.e. system capacity and flow rates) should be compared to the current estimated capacity of the existing system. Over capacity or under capacity issues in the bearing or generating cooling systems should be evaluated and modernization alternatives such as regulating the flow to individual coolers should be investigated. This is further discussed in Section 5 under modernization alternatives. Records of flowrates and analysis of cooling water flowrate patterns vs ambient and water temperatures will be essential for further analysis of system requirements.

For bearing cooling water systems, a note should be made as to whether the coolers are internal or external of the bearing pots. Advantages may be gained from modifying the system to eternal coolers which are easier to maintain and monitor.

The following general checks should be made for both the raw water and cooling water system equipment:

- The pumps, valves, strainers, intake, intake screen, and piping should be visually inspected for blockage, leaks, and excessive rust or corrosion.
- When the system is inspected, the appropriateness of material selection should be an important factor.
- A water analysis should be performed at some point to determine if there is anything unusual about the water characteristics. For example, high silt content can lead to premature fouling of the system and certain elements may cause excessive corrosion in the coolers or lead deposits.
- A history of water in any lubrication oil systems would indicate a problem with a cooling water system.

<u>Pumps</u>

The pumps should be operated and any unusual noise or vibration noted.

The pump design capacity should be determined from existing plant records and nameplate data and compared with the cooling water requirements. If possible, the actual pump head should be measured and the pump capacity estimated through a capacity test. The capacity test might consist of pumping into a sump or tank and measuring the volume of water pumped for a fixed period of time. Using the design pump curve and the actual pump head, the predicted pump flow can be determined from the design pump curve. This predicted flow compared to the estimated flow indicates the existing pump performance with respect to design.

<u>Valves and Strainers</u>

All valves and strainers within the system should be checked for condition and proper performance including the following:

- All water filtering systems should be inspected to ensure that the system is removing the necessary debris from the water.
- Automatic backwash systems should be checked for proper valve operation and backwashing of debris from the filters.
- Proper setting of the differential pressure control for initiating automatic backwash should be verified.

<u>Coolers</u>

The maximum pressure differential across any of the coolers should be around 10 psi (68.9 kPa) to assure satisfactory cooling. The tube material should be noted and whether or not the coolers are double wall. This will give an indication of the estimated service life of the cooler and its potential for oil losses to the environment. For double wall coolers, regular inspection would not be necessary as long as the leak detection system is regularly maintained.

Tube and piping wall thickness measurements will be useful in determining the rate of wear in the coolers over time. This information can be used to estimate remaining life based on current flowrate and water velocities.

Materials for coolers include Copper, Copper-Nickel, and Stainless Steel. Stainless steel coolers do no usually wear out but Copper coolers over 30 years would definitely warrant a more detailed inspection. Copper-Nickel coolers would probably be slightly more “wear resistant” than copper.

4.5.3 Compressed Air

Typically hydroelectric generating stations can have several compressed air systems, either high or low pressure depending upon the application and the age of the station. High pressure is defined as any system operating above 125 psig. A compressed air system can include single or multi compressors, air receivers, air dryers, safety or pressure regulating valves, and control and alarm systems.

Depending on the number of generating units installed and climatic conditions, the generating station may have any or all of the following compressed air systems.

- Unit brake air
- Instrument air
- Synchronous condense air (tailwater depression)
- Governor air (high pressure)
- Intake structure bubbler air
- Station service air

Low-pressure air requirements, if no synchronous condenser capacity or intake structure bubbler air system is required, can be very low but essential for the safe operation of the generating units.

High-pressure air systems for circuit breakers and governors are essential for unit operation.

For governor air systems, operating pressures can range from 500 psig up to 900 psig.

The turbine equipment manufacturer generally supplies the governor air compressors at hydroelectric generating stations. Air from the existing station service air is boosted up to meet governor operating pressure requirements.

For circuit breaker air systems, operating pressures can range from 230 psig to 3600 psig. The key elements of a circuit breaker air systems is to provide an adequate storage capacity to meet the immediate breaker switching air demands, particularly those caused by a potential major electric system disturbance. In addition, the air dewpoint temperature must be closely monitored. A wet circuit breaker air system can cause catastrophic failure of air blast circuit breakers, where air is used as a dielectric-insulating medium.

Multi-stages reciprocating compressors are typically used for circuit breaker air systems, with automatic regenerative desiccant dryers. Large modern circuit breaker compressed air systems (for example in high voltage switchyards) are PLC controlled to provide automatic switching between compressors and dryers and for troubleshooting.

A regularly calibrated hydrometer to monitor dewpoint is a necessity for circuit breaker air systems.

The first step in assessing the system should be to determine the existing capacity of the air compressor. The capacity can be evaluated by operating the compressor to fill a receiver (or tank) or a known volume to a given pressure for a specific length of time. This estimated compressor capacity can then be compared to the design capacity to estimate any deterioration in compressor performance. In addition to evaluating the compressor performance, the compressed air requirements for the system should be estimated by adding the station's needs. The difference between the compressor capacity and compressed air requirements indicates the existing margin or deficiency in the compressed air system. While it is operating, the compressor should be visually inspected for air and oil leaks, as well as unusual noise or vibration. The condition of the intercoolers, aftercoolers, and inlet air filters should also be assessed. If the compressor is required to provide oil-free air, the drain valves or pneumatic controllers downstream from the compressor should be checked for the presence of oil. Oil at these points would indicate compressor problems.

The air receivers should be visually inspected for structural problems such as cracks, deformations and rust/corrosion. The receiver should be pressurized and checked for air leaks, and maintenance records reviewed to verify that the receiver is routinely drained. The receiver should be inspected to ensure that it is in accordance with the ASME Boiler and Pressure Vessel Code.

Air dryers, if present, should be inspected to determine their effectiveness at removing moisture from the air. Manufacturer's procedures, if available, can be used to check air dryer performance. If not, an indication of air dryer effectiveness can be determined by checking downstream drain valves or pneumatic controllers for the presence of moisture. A history of condensate freezing in compressed air lines would also indicate problems with the air dryers. All pre- and post-filters should be checked and their conditions noted. For a refrigerant-type air dryer, the system should be checked for leaks and the refrigerant system must be properly charged. For a desiccant-type dryer, the condition of the desiccant and the proper regeneration of the desiccant is important for proper operation. If a downstream inspection of drain valves or pneumatic controllers indicates the presence of oil, it is possible that the desiccant is coated with oil and may not be performing properly. The desiccant should be inspected, if possible. The regeneration process for the desiccant should also be checked to ensure that it is being regenerated as required. Improper desiccant regeneration could result in a higher than desired outlet dew point temperature.

Safety valve associated with the compressed air system should be checked for proper operation, settings, and ratings. Other valves in the system (isolation, check, etc.) should also be examined for proper operation.

Reciprocating air compressors as the end of their service life should be replaced with rotary screw compressors.

The following are some key questions to consider during the condition assessment of individual components of the compressed air systems.

Compressors (High or Low Pressure)

- Is there one central air compressor system or are there individual systems? Sufficient valves to separate systems improves reliability. Multi-compressor systems also improve reliability.
- Review any maintenance site records available, looking for the frequency of regular maintenance including oil changes, air filters and major maintenance work.
- Are there any hour meters on individual compressors? If the compressors have motor running hour meters with several years or records, review the annual hours of operation for any signs of increased air consumption. Are any increased hours of operation due to a system expansion or piping leakage? Replacement of compressors may be required.
- Are there any obvious signs of oil leakage? Are there any records of unit oil consumption? Does the trend indicate deterioration?
- Observe the compressors during operation. Typically how long do they run on each cycle? Do they short cycle (run for 2 or 3 minutes and then stop), indicating system leakage?
- Are there any air dryers, particularly on the high pressure systems?
- Are there any unusual or excessive wear or usage trends?

Air Receivers

- Are there independent receivers in multi-compressor installations to service essential services?
- Do the receivers have approved rating data stamped or riveted to the body?
- When were they last pressure tested?
- When was the receiver inspected externally or internally and how? (i.e. ultrasonic thickness survey, etc.)
- Has the vessel been inspected to ASME/ANSI - National Board Standards and to local Boiler and Pressure Vessel Regulations?
- Has all ancillary equipment attached to the vessel (i.e. gauges, switches, relief valves, etc.) been recently inspected, test operated or calibrated?
- Do the receivers have an automatic drain valve?
- Do they have inspection manholes?
- Do they have approved rated pressure relief valves?
- Do they require or have any seismic bracing?
- Is corrosion a concern?

- Can the corrosion rate be established in order to determine the remaining life of the vessel and next inspection?
- Has there been a change in operating conditions or use of the vessel to warrant design review?

Piping including Dryers and Safety controls

On older poorly maintained air systems (35 years plus) where steel pipe work, with flexible connections and screwed or flanged guages have been used, piping leakage can approach 50% of compressor capacity.

- Is the system piping material steel, copper or stainless steel? Is it welded, brazed or screwed?
- Has the piping system been regularly inspected for corrosion and wall thickness? Ferrous piping materials with welded or soldered joints minimize corrosion and air leakage problems.
- Are there any obvious leaks at valves and other places?
- Are there drain valves at all low points in the system? If so, check them for moisture or rust in the pipework.
- Check that automatic drain valves are operating properly.
- Do the systems have air dryers installed? What is the rated dew point of the supplied air?
- Are hydrometers calibrated regularly?
- Are filters, strainers, etc. inspected, maintained and changed-out when required regularly?
- Check the sampling lines are not corroded or blocked and adversely affect monitoring instrumentation. Sampling lines to hygrometers for dewpoint measurements are very sensitive to line type and condition.
- Check that all safety controls and instrumentation are inspected, maintained and calibrated regularly to ensure proper and safe operation.

4.5.4 Potable Water

Hydro plants typically have a domestic water system for use by station personnel. The system design is site specific. Sources for potable water include:

- reservoir/river water
- wells
- local municipal water supplies
- bottled water

The system should be reviewed to ensure that adequate quantity of water is available for domestic use. The water quality should be checked for conformance to applicable health standards. An assessment of the need for water treatment, such as filtration, chlorination or purification (e.g. ultra-violet process) should be done.

Satisfactory operation of equipment such as pumps, hydropneumatic tanks, hot water tanks, controls, etc. should be ensured. Pump capacity tests can be made as discussed for the cooling water system in Section 4.5.2. Storage tanks and piping should be checked for corrosion and general structural condition. Soldered tubing is a concern in terms of lead content.

4.5.5 Drainage and Dewatering

The history of the drainage and dewatering system operation should be reviewed to verify that:

1. the system has had adequate capacity to prevent facility flooding and

2. excessive pumping times during dewatering have not been required.

Pump capacity tests could be performed and compared to the design curve to assess any change in pump capacity. See Section 4.5.2 “Cooling Water” for more information on pump assessment.

Some items to consider in the assessment are listed below:

- Level control systems should be checked to verify proper operation of the drainage and dewatering system pumps and valves. Level control settings should he checked to ensure that the sump levels are being maintained at proper levels.
- Any drainage and dewatering sumps should be visually inspected for the presence of silt and debris that may affect the operation of the system. The inspection should determine the presence of oil in the sump and confirmation that the pump stop level settings preclude the discharge of oil and grease.
- Satisfactory operation of oil/water separators should be confirmed.

<u>Head Cover Drain Pumps on Kaplan Units</u>

Reliability of the head cover drain pumps and power supply is of primary importance to produce maximum safeguard against flooding of the turbine guide bearing and a prolonged unit shutdown. One AC and one DC pump will usually ensure the most reliable installation.

<u>Oil Spill Containment</u>

Hydro plants can contain large volumes of hydraulic oil, insulating oil and fuel in the their equipment and storage areas. Stricter environmental regulations have resulted in progressively more comprehensive containment measures being incorporated into the design of new facilities. However, older facilities require re-assessment as to whether or not they comply with local and national regulatory requirements in terms of releases or potential releases to the environment.

In the absence of containment, an oil spill can easily spread fire as well as an environmental hazard.

Oil spills can increase the size of a fire around spilled equipment, spread fire to other equipment, and are difficult to extinguish. For oil-filled equipment such as transformers and circuit breakers, and fuel and oil storage equipment, a non-combustible curb can be built around the perimeter of the equipment. Drainage and oil interceptors must be provided so that the basin does not overflow with rainwater (for outdoor equipment) or spilled oil. The basin should also be filled with gravel for maximum effectiveness. The oil will flow into the void spaces between the gravel. The gravel acts as a barrier between oxygen and the oil and will prevent the oil from burning.

Many utilities have formalized Oil Spill Containment programs or departments who would already have recommendations on what facilities require improvements and the scope of this work. These programs will have decision processes and risk analysis models in place to prioritize work in the facility fleet. Their information should be inserted into any 20 year plans for a station. The oil spill contaminant program should also be informed of any potential oil spill containment issues that come out of this overview level survey so that they can provide assessment expertise.

From a desktop review and site visit, an inventory of potential sources of oil spills should be made. These may include:

- transformers (current, power, padmount and vault), reactors, breakers, PTs, CVTs, etc.
- potheads, bushings, oil filled cables, oil filled reservoirs
- governor oil systems, including reservoir & accumulators, air compressors
- thrust and guide bearings, including reservoirs
- oil storage and transfer tanks, pumps and piping for the above systems
- heat exchangers for the above systems
- diesel generators, including day tanks, underground storage tanks, fill points
- overhead cranes (powerhouse and tailrace deck)
- water inlet and outlet hyraulic systems, i.e. spill gates, intake gates, turbine inlet valves, penstock relief valves, guard gates
- free oil containers, barrels, pails and cans.
- mobile oil treatment plants, temporary oil storage tanks

Particular areas to check at the facilities include:

- generating units
- machine shops
- diesel generator
- oil storage room
- sumps, separators
- oil transfer room
- portable oil treatment equipment
- temporary oil storage areas

- dedicated fuel storage facilities
- dam and intake hydraulic

The site drainage system should also be reviewed to assess spill escapement routes (both summer and winter). Local operating staff often provide valuable information on spill history, near misses, local sensitivities and well as potential containment schemes.

Other data that should be collected includes:

1. planned or current unrelated capital or maintenance work at the facility
2. station staffing schedule – is it a manned facility? What is the frequency of visits?
3. Temporary equipment that may be on site
4. Local spill response equipment, procedures and intentions.

After the inventory is completed, an assessment of the probability of spill escaping to the environment and the consequences of such a spill need to be assessed in a formalized program. Areas of environmental sensitivity to consider when looking at oil spill containment issues during a site visit include:

- fish
- wildlife
- recreation and aesthetics
- water use

Once a potential oil spill containment issue is identified, the options for spill containment, as listed in Section 4.8 “Life Extension”, should be reviewed and further studies undertaken.

4.5.6 Fire Protection

4.5.6.1 Mechanical

1. General

<u>Introduction</u>

The information contained in this section is an overview of mechanical fire protection systems in existing hydroelectric power generating stations. A glossary of fire protection terms is provided in Appendix C. Mechanical systems are not independent of electrical systems, and any condition assessment should look at both. It is intended that the information in this volume can be used as a guide when assessing the condition of existing mechanical fire protection systems.

The ability to recognize fire hazards, identify system deficiencies, and recommend effective upgrades can only be developed through education and experience. Furthermore, a guide is only a general statement of principles and methods. A strong technical background in fire protection is necessary to effectively assess mechanical fire protection systems.

It is generally accepted that the probability of a fire in a hydroelectric station is low. Subsequently, fire is often not perceived as a threat, and fire protection is often inadequate or not provided at all. There is the potential for a catastrophic loss when a fire does occur.

Hydroelectric generating stations can contain large quantities of combustible materials. Cable insulation, mineral oil, and construction materials form the most significant part of the combustible fuel load in a hydroelectric station. It is the amount of combustible materials that determine the need for mechanical fire protection systems.

Approach

A condition assessment of mechanical fire protection systems should determine what was installed, what was the design objective, and what is the condition the existing systems now.

If the original design is considered adequate, then life extension of the systems should be considered. If there was limited fire protection in the original installation, or the original system is no longer adequate, then modernization should be considered.

A condition assessment is not the same as a fire hazard or fire risk assessment. Such assessments are beyond the scope of this document.

In assessing the condition of mechanical fire protection systems, there are five important points to consider:

1. What is the availability of the fire protection systems? More importantly, is there a means of warning that a system has been taken out of service? For example, if water supply valves for fire protection are not locked open or provided with electrical supervision, then a system might be out of service without warning.

2. Where a mechanical fire protection system has been installed, is it appropriate for the hazard present? Will it be effective at fire suppression? For example, if a room previously used as an office is now used for storage, the sprinkler system will need a higher water application rate to be effective.

3. Is there a fire brigade, emergency response team, or fire department available to perform manual fire suppression? Have systems been provided to facilitate manual fire suppression? Do the existing systems meet the needs of the responding fire fighters?

4. Is there a water supply capable of providing the water flow and pressure needed for both automatic fire suppression and manual fire fighting? Can the system become impaired without the knowledge of station personnel? What is the source of the water supply? Is a fire pump needed to boost pressure and flow? Has the fire pump been designed and maintained to perform reliably?

5. Fire can produce large quantities of toxic smoke that can quickly incapacitate personnel and damage other equipment. How is ventilation provided for the powerhouse? Was smoke control part of the original design? Is the design philosophy behind the smoke control system sound? What condition are the existing smoke control components in now?

2. Automatic Fire Suppression Systems

General

An automatic suppression system is designed to automatically extinguish or control a fire at an early stage. Some types of automatic fire suppression systems have been in use for over a hundred years. The advantages of automatic fire suppression are:

1. provide high effectiveness in control or suppression of fire;

2. provide continuous protection even in unattended areas or stations;

3. improve life safety; and

4. in general, can control a fire with less fire damage or water damage than manual fire suppression.

Automatic fire suppression includes water-based sprinkler systems and gas agent extinguishing systems as follows:

Name	**Type**	**Application**
Wet-pipe sprinkler	Water-based	Most heated interior spaces
Dry-pipe sprinkler	Water-based	Interior spaces with potential freezing conditions
Pre-action sprinkler	Water-based	Interior spaces with water-sensitive equipment
Water-spray deluge	Water-based	Indoor or outdoor apparatus with potential for rapid fire growth
Fixed foam/water systems	Water-based	Liquid pool fires
Halon and alternatives	Gas agent	Halon is no longer permitted – but might be present in existing buildings – alternatives might be found in areas with water-sensitive equipment
Carbon dioxide	Gas agent	Not recommended – but might be present in unoccupied interior spaces
Inert gas	Gas agent	Interior spaces with water-sensitive equipment

Wet-Pipe Sprinkler Systems

A sprinkler system is comprised of automatic sprinkler heads fed by distribution piping and connected by a water main pipe to a water supply. At an elevated temperature, the sprinkler heads open and apply water to the fire. Each sprinkler head activates independently of the other sprinkler heads. The applicable design standard in North America is the NFPA (National Fire Protection Association) 13, "Standard for the Installation of Sprinkler Systems".

The excellent performance of sprinklers is well-documented. In many fires, a single sprinkler head has been able to extinguish the fire and prevented widespread fire damage. An automatic sprinkler head can provide an almost instant response to a fire, and therefore, they can extinguish a fire with far less water than a fire hose stream.

Dry-Pipe Sprinkler Systems

Where freezing temperatures might occur, a dry-pipe sprinkler system is more appropriate than a wet-pipe system. A dry-pipe system is similar to a wet-pipe system except that a water control valve (known as a "dry-pipe valve") is installed at the base of the sprinkler riser and distribution piping is charged with compressed air instead of water. The dry-pipe valve is designed so that the compressed air keeps the dry-pipe valve closed during normal operation. During a fire, open sprinkler heads will release the compressed air from the sprinkler pipes, and the dry pipe valve will open and permit water to enter the system. The pressure provided by the water supply will drive the remaining air from the sprinkler pipe and discharge water through the open heads.

Pre-Action Sprinkler Systems

In areas with water-sensitive equipment, a pre-action sprinkler system should be considered. A pre-action system uses a water control valve (actually a deluge valve) to keep water from entering the (dry) distribution piping. Upon a signal from the fire detection system, the pre-action valve will open and permit water to charge the sprinkler pipe. Water will then discharge only if there is sufficient heat to open automatic sprinkler heads.

Water-Spray Deluge Systems

For areas or equipment with a high potential for explosion or rapid fire spread, a water deluge system is recommended. All the sprinkler heads or spray nozzles in a deluge system have open orifices. A deluge sprinkler system is similar to a pre-action sprinkler system in that it relies on the detection system to open the water control valve. The difference is that a deluge system uses open heads or nozzles and a pre-action system uses closed heads that must be opened by heat before they will discharge water.

Generators and transformers are protected with deluge systems. Generator fire protection, and generator deluge systems, are covered in Volume 3 of this guide.

Fixed Foam/Water Systems

Foam/water systems use a mix of water and foam solution to produce a foam that is highly effective in suppressing liquid pool fires. In hydroelectric stations, these systems are sometimes installed to protect transformers, but their cost, complexity, and maintenance requirements make them a less attractive alternative to water-spray deluge systems. They are more commonly found in the chemical and petroleum industries, and therefore, they will not be covered further in this guide.

Halon and Alternative Gas Systems

If a water-based system is not desired, a gaseous extinguishing system should be considered. There are a number of different agents available, but they all have similar components: a control mechanism operated by the detection system, discharge nozzles fed by distribution piping, and a means of storing the agent.

Halon systems were once common, but they are no longer installed due to ozone-depletion effects. Existing halon systems should be removed from service.

Halon replacement gases have been developed. Some of these gases have global-warming effects, and therefore, they are not completely environmentally benign.

Carbon Dioxide Gas Systems

Carbon dioxide (CO_2) is normally a gas at atmospheric temperature and pressure. It is a natural, albeit small, component of the atmosphere. A carbon dioxide system works by reducing the oxygen content to a level below that which will support combustion.

There are two classes of carbon dioxide system: a “local application” system and a “total flooding” system.

Total flooding is a method which discharges a sufficient volume of carbon dioxide into the protected space to reduce oxygen below a level which will support combustion. These systems are custom designed for the specific application. The quantity of CO_2 required is based on the percentage concentration (by volume) required to extinguish a fire in the type of equipment being protected. A total flooding system will not be effective if there is no enclosure or if the enclosure has significant leakage. There are two types of total flooding system: high-pressure and low-pressure.

A local application system is intended to only protect specific equipment inside a larger area. They are not commonly found in hydroelectric stations.

A high-pressure carbon dioxide system consists of a battery of cylinders, connected together with a manifold together, and connected to distribution pipe terminating in special discharge nozzles.

A low-pressure system differs from the high-pressure system in that instead of hihg-pressure storage cylinders, there is a tank of carbon dioxide kept at low pressure and temperature through the use of a refrigeration system. This design requires less space than a high pressure system, but there is the potential for the refrigeration to fail, in which case, the CO_2 will expand and require venting to the atmosphere.

The standard for these systems is NFPA 12, “Carbon Dioxide Extinguishing Systems”. NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume. A major concern with CO_2 is its hazard to life safety - the concentration of CO_2 required to extinguish a fire is much greater than the concentration required to incapacitate or kill a person.

Carbon dioxide systems were once used extensively in the hydroelectric industry for suppression of fires in generators and other electrical equipment, but they are not generally used for new installations due to life safety hazard, expense, and questionable effectiveness.

Inert Gas Systems

Inert gases include nitrogen, argon, and a blend of the two (small amounts of carbon dioxide gas can also be blended into the mix). Inert gas systems operate on a similar principle to total-flooding carbon dioxide systems. Factors to consider for inert gas systems are the space required to store the agent and the cost premium when compared to a water-based system.

Condition Assessment of Automatic Fire Suppression Systems

When performing a condition assessment of a fire protection system, the following important points should be considered.

1. Based on combustible fuel loading and station design, what areas of the plant should have automatic fire suppression? Keep in mind that protection of all areas is the best practice, but it might be impractical to sprinkler low level galleries or tunnels with little or no fuel load and limited ignition sources.

2. Is there a fire suppression system, and if so, what type of system is installed?

3. What was design objective of the system now installed? Was the initial design adequate? If the use of a space has changed, does the system still provide adequate protection.

4. What is condition of the existing installation? Are some parts of the system shut down? Does piping show signs of damage or corrosion?

5. What is the maintenance history of the fire suppression systems? Was it properly tested and commissioned, and has it been inspected and tested on a regular basis since?

6. Are the automatic suppression systems supervised by the fire alarm system? The fire alarm system should be able to detect activation and impairment of the fire suppression system.

7. Automatic suppression systems should be equipped with a means to shut the system down. Is the manual shutdown identified and located in a conspicuous place?

8. Automatic fire suppression systems should be able to be shut down during maintenance to prevent undesired operation. The fire alarm panel should indicate that a system has been impaired.

9. What is the condition of the fire protection piping? Has fire protection piping been seismically restrained?

10. Is metallic piping bonded and grounded to prevent the build-up of electrical potential?

11. Check that pressure gauges are reading correctly and that they are displaying the required pressure. If the water pressure gauges show a fluctuation in pressure during testing, there could be a problem with pressure-reducing valves or a fire pump.

12. The applicable standard system for sprinkler systems in North America is NFPA (National Fire Protection Association) 13, “Automatic Sprinkler Systems”.

13. Does the sprinkler system use sprinkler systems that have been recalled or de-listed? There have been problems with heads that use an O-ring seal. Furthermore, as of the time of writing, all models of on-off sprinkler heads have been recalled or de-listed.

14. If a sprinkler system is installed in an area subject to possible freezing conditions, have precautions been taken to avoid freezing of the lines? Dry-pipe systems can be used. Dry pipe systems should be sloped and drained

15. If a pre-action sprinkler system is installed, how is the system activated?

16. The applicable standard system for water-spray deluge systems in North America is (National Fire Protection Association) 15, “Water Spray Fixed Systems for Fire Protection”.

17. Transformers are a severe fire hazard at a hydroelectric power generating station. There is a large amount of oil and insulating paper inside a transformer, and the high voltages in the windings creates a potential ignition source. Older transformers or overloaded transformers might be more prone to internal electrical arcing and fire or explosion. The unit power transformers and station service transformers are generally located outdoors on the tailrace deck or in the forebay between the dam and the powerhouse, but in older power stations, these transformers might be located inside the powerhouse, and therefore, the need for fire protection is even more critical.

18. Assess storage, supply, piping, fittings, nozzles, pressure, structural supports, seismic bracing for transformer deluge systems.

19. Transformers that are located in a switchyard remote from the powerhouse are not as critical from a life safety or property damage perspective, but in the event of a fire or explosion, the loss of critical switchyard components will interrupt revenue production.

20. Are the transformers provided with deluge water-spray systems? The nozzles of the transformer deluge system should be positioned to cover the entire transformer and all oil-filled equipment including the radiator, conservator tank, and bushings. The nozzles should also provide coverage to any impervious surfaces around and underneath the transformer.

21. What is the application rate of water from a deluge system? This may be difficult to determine if a hydraulic nameplate is not provided at the deluge valve.

22. Small indoor station service transformers can be protected with ceiling sprinklers if they are separated from the rest of the powerhouse by fire separations or fire barriers.

23. Transformer deluge system should have manual activation capability and automatic activation through the detection system.

24. Check the age, make, and model of any existing water deluge valves. Check that the valve used is listed and approved for use by a recognized testing agency.

25. There is a variety of detection system available for transformer deluge systems. Ensure that the detection system has been maintained and performs as per the original manufacturer's specifications.

26. What type of detection is provided for transformer deluge systems? Is the detection system set up for cycling operation? How long is the cycle? The system should shut down after a set period of time if the thermal detectors have reset by the end of the cycle. If the detection system identifies another fire condition, the system should then operate again. If the system is not set for cycling operation, then the system will continue to discharge water until it is shut down manually.

27. Is there a containment system for the deluge water?

28. Carbon dioxide systems are a life safety hazard. To reduce the life safety risk, these systems should be equipped with pre-discharge warning alarms and capability to disable the system to permit personnel to work on the system or in the protected space.

29. Test for leakage in the transformer deluge systems.

30. For carbon dioxide systems, are rescue procedures in place for when personnel are working in the protected space? Is self-contained breathing apparatus available for rescue and re-entry after a discharge? Is portable air-monitoring equipment available to allow personnel to check that the space is safe for re-entry.

31. For carbon dioxide systems, is the system capable of discharging a sufficient amount of gas to protect the volume of the enclosure? NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume.

32. Are there an adequate number of discharge nozzles for the CO_2 system?

33. What is the condition of the CO_2 storage vessels, piping, and nozzles? For a high-pressure system, are the storage cylinders overdue for hydrostatic testing? For a low-pressure system, what is the condition of the tank and refrigeration system? Is the low pressure storage tank equipped with a relief vent valve to discharge excess pressure to the atmosphere? Are the piping and fittings made of the correct material as specified by NFPA? Are the fittings and piping able to handle the burst pressure as specified by NFPA?

34. An area protected with a CO_2 system must be enclosed to prevent loss of agent and reduction of effectiveness. It will generally not be possible to completely prevent leakage, but large openings and holes in the enclosure should be sealed.

3. Manual Fire Suppression Systems

General

Manual fire suppression relies on a plant fire brigade or fire department to attack a fire. In an older building where other fire protection measures may be deficient, manual fire suppression is often the only method of fire suppression. Manual fire suppression includes portable fire extinguishers, hydrants to supply fire department vehicles, standpipe systems for interior fire fighting, and smoke venting.

A standpipe system is a network of pipe and hose connections that provides a water supply for fire fighting. A standpipe system permits fire fighters with a water supply for their hose lines at multiple locations throughout the building, and therefore, they do not need to run hose lines throughout the building to reach a fire. The applicable design standard for standpipes in North America is NFPA (National Fire Protection Association) 14, “Standard for the Installation of Standpipe and Hose Systems”.

Portable fire extinguishers are classified by the type of fires they can be used against. The most useful general-type extinguisher is a multipurpose which can be used Class A (ordinary combustible fires), Class B (flammable liquid fires), and Class C (electrical equipment). Extinguishers should be located throughout the facility as specified by NFPA (National Fire Protection Association) 10, “Standard for Portable Fire Extinguishers” – applicable to most jurisdictions in North America.

Points to Consider

1. Is there a fire brigade, emergency response team, or fire department available to perform manual fire suppression?

2. Have systems been provided to facilitate manual fire suppression? Do the existing systems meet the needs of the responding fire fighters?

3. If a fire department vehicle will be used for fire fighting, have yard hydrants or wall hydrants installed to provide the vehicle with water? Are the threads or coupling on the hydrants compatible with those of the fire department vehicle? Is the pressure and flow available from the hydrants sufficient to prevent cavitation in the vehicle’s fire pump?

4. If a standpipe system is installed, assess the system with respect to NFPA 14, “Standard for the Installation of Standpipe and Hose Systems”.

5. Where have interior hose lines been provided in the station? What is the condition of the interior hose lines? Are the hose lines hydrostatically tested as part of the maintenance schedule?

6. Have standpipe connections been provided inside the powerhouse for use by fire suppression crews? The connections should be compatible with the large diameter (usually 2.5”) hose used by the crews.

7. Standpipe connections for use by the fire brigade as a water supply should be installed near outside transformer banks. The distance from the hydrant connections to the transformer banks should be remote enough so that the fire brigade is not exposed to high levels of radiant heat when coupling hose to the connections.

8. Hose lines should be hydrostatically tested three years after in-service date and for every two years. Some jurisdictions might have different requirements or schedules for hydrostatic testing of fire hose.

9. Are portable fire extinguishers supplied as per NFPA 10 and per applicable relevant fire codes? Is there a maintenance schedule for fire extinguishers? Hydrostatic testing should be included as part of the maintenance schedule.

4. Fire Suppression Water Supply & Fire Pumps

General

Water-based automatic suppression and manual fire suppression rely on an adequate water supply for their effectiveness.

Points to Consider

1. What is the hydraulic demand of the automatic fire suppression systems and manual fire fighting? Is the water supply adequate to meet the flow and pressure required? The water supply might have to provide water to multiple systems (for example, a manual hose station operated at the same time as a deluge system will place additional demand on the water supply system).

2. What pressure and volume flow of water can the water supply system provide? Test the pressure at different flow rates to get an accurate water supply curve.

3. All valves for the fire protection water supply should be supervised by the station fire alarm system. The main fire alarm panel should indicate a trouble signal in the event of a system impairment.

4. What is the source of fire protection water? What is the condition of the water (i.e. is algae growth or silt present)? Is the water treated or strained? What is the available head at the station?

5. Will continuity of fire protection water supply be affected by shutoff of domestic water or other service water supply? Are there multiple sources (i.e. water supply connections to more than one penstock) for the fire protection water supply? Multiple sources permit part of the system to be shut down and work performed without necessarily compromising the fire protection water supply.

6. Pressure-reducing valves and other components must operate correctly so that they do not impair the ability of the system to provide required flow and pressure. These valves can be difficult to tune.

7. What is the condition of water supply pipe? Pressure loss in pipe can be reduced through the use of large pipe, use of stainless or galvanized pipe, selection of proper valves and fittings, and good design. If testing indicates that the water flow and pressure available is inadequate, then examine the components of the water supply system for these features.

8. Stations with a low head might require a fire pump to boost water pressure. If there is an existing fire pump, what type of pump is it? Both the pump and motor should be listed by a recognized testing agency as being suitable for use as a fire pump – check for a label on the apparatus indicating this feature.

9. Diesel and electric pumps are acceptable, but special consideration must be given to diesel fuel storage to ensure that it is not a fire hazard in itself. Electric pumps must be connected to the emergency power supply. Propane-powered fire pump motors are a serious fire hazard due to the presence of propane gas. Propane-powered motors should be removed from service and replaced with either diesel or electric motors.

10. Assess the fire pump for compliance with NFPA 20, “Standard for the Installation of Centrifugal Fire Pumps.” Check for the presence and condition of overloads & disconnects, re-circulation relief, automatic air relief valves on the impeller casing, approved controllers, motor, and impeller. The fire pump should also be equipped with a bypass to permit water flow around the pump in the event that the pump fails.

11. If a fire pump is installed, does it have a permanent connection to drain to permit testing? Has the pump been inspected and tested on a regular basis? Diesel pumps should have been test run on a weekly basis, and electric fire pumps should have been test run on a monthly basis. The pump discharge characteristics should be tested on an annual basis and compared to previous tests to determine if there has been a deterioration in performance.

5. Smoke Control

General

Fire will produce large amounts of smoke. The systems described in this will reduce the amount of smoke generated and the amount of smoke transmitted into other parts of the powerhouse; however, even these measures will likely not be sufficient to completely eliminate smoke contamination.

Many of the older hydroelectric power stations in North America were constructed with limited ventilation and no means of smoke control.

Low concentrations of smoke can injure, incapacitate, or cause death, and therefore, smoke control is an important aspect of fire protection.

Smoke control systems are custom designed for the specific application, and therefore, only general principles are considered in this guide.

NFPA 90A “Standard for Air Conditioning and Ventilating Systems”, NFPA 204M “Guide for Smoke and Heat Venting”, and NFPA 92A, “Recommended Practice for Smoke Control

Systems" are publications that contain useful design information, but it might be difficult to meet the literal requirements of these documents in an existing hydroelectric generating station.

Points to Consider

When performing a condition assessment of smoke control in an existing hydroelectric station, consider the following items:

1. Is there any smoke control or means of ventilation? If so, what was original design? Was the original design concept sound? What condition is the system in now?

2. In order to vent smoke, the affected area must be pressurized with fresh air, and contaminated air must be extracted. Due to the buoyant nature of hot gases, air extraction is best performed at the ceiling of the affected space.

3. Smoke control is of particular concern in underground power stations.

4. Smoke control should have the capability of both manual operation and automatic operation by the fire alarm panel.

5. Check the condition of fans, wiring, and controls. Fans used for smoke removal often need to be specially selected to handle high temperatures, and heat-resistant cable might be required.

6. Could the power supply for smoke control be interrupted by a fire? Is there a provision for emergency power supply?

4.5.6.2 Fire Detection and Alarm Signaling Systems

General

The information contained in this section is an overview of fire detection and alarm signaling systems as applied to existing hydroelectric power generating stations. It is intended that the information contained herein be used as a guide when assessing the condition of existing systems. A technical background in these systems is necessary to perform an effective audit.

The fire alarm and detection system, commonly referred to as the "fire alarm system", detects and alerts occupants of a fire condition at an early stage.

The core of the fire alarm system is the main panel. The logic and control functions take place within the main panel. The panel monitors the field devices for a possible alarm or trouble signal. Field devices include heat detectors, spot-type smoke detectors, linear beam smoke detectors, air duct smoke detectors, manual pull stations, special system monitors, water flow switches, water pressure switches, and valve tamper switches.

Upon receipt of an alarm signal, the fire alarm panel will signal the fire condition through the annunciator panel, fire bells, horns, sirens, and strobe lights. In addition, the fire alarm can activate pre-action sprinkler systems, deluge sprinkler systems, and smoke venting systems, if installed. The fire alarm can also control the HVAC to delay the spread of smoke through the building.

A modern fire alarm system can identify the exact device that is reporting a fire condition or a trouble signal. This feature allows quick location of a fire or maintenance problem.

If desired, the fire alarm system can be provided with remote monitoring capability. In the event of an alarm or trouble signal, the remote station control centre will be alerted and direct appropriate response. Remote monitoring is reliable because the station will be monitored even when it is unattended.

The fire alarm system must have operational capability in the event of a power failure due to its critical nature. An emergency power supply providing backup power for at least 24 hours of supervisory operation plus 30 minutes of full alarm signalling operation should be provided.

If the original design is considered adequate, then life extension of the systems should be considered, but if there was limited fire protection in the original installation, or the original system is no longer adequate, then modernization should be considered.

If fire detection and alarm signaling systems are to undergo testing as part of the condition assessment, steps should be taken to isolate the system to prevent unwanted operation of fire suppression systems or other station equipment. Personnel and station control should be informed that testing will be taking place.

Points to Consider

When assessing the condition of the existing fire detection, there are a number of important points to consider:

1. Is the station equipped with a fire detection and alarm signaling system? Are the generators and transformers equipped with dedicated fire alarm control panels? Does the station fire alarm monitor the unit fire alarm control panel or does it monitor the generator fire detection devices directly? What is the make and model of the unit fire alarm control panel and station fire alarm system? Are parts available for the existing system?

2. Has detector coverage been provided to all areas of the station?

3. Thermal detectors can operate on three different principles: alarm signal when air temperature exceeds a pre-set value, alarm signal when rate of temperature rise exceeds a certain pre-set rate, or a combination of temperature and rate-of-rise criteria. Thermal detectors are reliable and are generally resistant to false alarms. Thermal detectors generally do not require maintenance, but some models are only designed for a single exposure and must be replaced after being exposed to high temperature – check thermal detectors to determine their type.

4. Are smoke detectors provided? Smoke detectors are more sensitive than thermal detectors, and therefore, they give an earlier warning of a fire condition. They can also be prone to

false alarms from dust and particles similar in size to smoke particles. Smoke detectors should be tested with a test aerosol to ensure proper operation.

5. Are there old-style, 240-volt, ionization-type smoke detectors present? All ionization-type smoke detectors use a radioactive element, but the early high-voltage detectors are a particular health hazard if the casing for the element leaks. These detectors must be handled extremely carefully. They should be removed and returned to the manufacturer in compliance with nuclear/atomic energy regulations for handling of these devices. The more modern photoelectric-type smoke detectors do not use a radioactive element and are less prone to false alarms than ionization-type smoke detectors.

6. Is the powerhouse equipped with linear beam detectors at the ceiling of the generator hall? Is adequate coverage provided by the beam detectors? Are the beam detectors calibrated properly?

7. Are there any other detection devices provided in the powerhouse? What was the original purpose of these detectors? Do they still serve an important function? How are they connected to the unit fire alarm control panel or station fire alarm panel.

8. How are personnel alerted to an emergency condition? Has audible signaling been provided? Can the audible signals be heard over ambient noise conditions (including potential sound cancellation)? Is visual signaling provided, especially in areas where audible signaling is not audible?

9. Is the fire detection and alarm signaling system connected to an emergency power supply? How long can the emergency power supply provide supervisory operation? How long can the emergency power supply operate the system in full alarm mode? The simplest method of providing emergency power is to install battery packs in the fire alarm panel.

10. Do the detectors provide a pre-alarm signal to the main fire alarm panel to permit a manual response to an alarm condition and to provide an early warning in the event of a fire?

11. If the generators and transformers are equipped with a fire suppression system, is the system activated by the unit fire alarm control panel or the station fire alarm? Is the system monitored for operation, tampering, or leakage by the unit fire alarm control panel or the station fire alarm?

12. Does the fire detection and alarm system have the ability to control the HVAC and smoke ventilation systems? A fire will produce a large amount of smoke in a short period of time, and ventilation should be activated as soon as possible. By having ventilation automatically operated by the fire detection and alarm system, ventilation can begin at an early stage.

13. Is the station fire alarm panel monitored from a remote alarm monitoring agency or a utility control center? Remote monitoring is an important consideration for stations that are unattended for periods of time. Remote monitoring can also allow a utility to formulate a quicker response to an emergency situation by automatically informing an outside control center of an emergency.

4.5.7 Heating, Ventilation and Air-Conditioning Systems (HVAC)

1. General

- Depending upon the age of the station, climatic location, and whether the unit generators are air or water-cooled, hydroelectric generating stations can have a vast range of system designs.
- There is no overall national standard or codes for the design of HVAC systems in generating stations. Generally National and Local Building Codes should be used for indoor design conditions and minimum fresh ventilation air requirements. Care should be taken when applying these minimum standards.
- Space conditioning of the powerhouse includes the ventilating fans, blowers, louvers, and air conditioning equipment. A general measure of the performance of the space conditioning system is its ability to maintain the design temperatures for the station and operation of the equipment.
- The generating unit and equipment areas are generally very lightly occupied except for routine inspections and maintenance.
- The American Society of Heating, Refrigeration and Air Condition Engineers (ASHRAE) technical handbooks are the recognized North American standard for the design of HVAC systems. Specifically, the "Fundamentals" volume provides data on climatic conditions for major locations in North America and throughout the world. Basic system design and economic evaluation calculations are covered in other volumes.
- Generally only the most modern of stations will have the HVAC and Fire Protection Systems controls integrated to operate together in the case of an emergency. The introduction of computer based control systems has made this easier.

2. Types of Systems:

Depending upon the age and type of generating units, the following range of systems is usual:

- Older stations may have screened windows or openings on the lower or main floors with roof or high wall exhaust fans to ventilate the generating unit areas. Depending upon the outdoor design conditions the exhaust fans may be controlled from a space thermostat and the air inlets may have automatic dampers. Manually controlled warm air is bled off the air or water- cooled generators to heat the larger areas. Space temperatures in these areas would generally range from a low of 50°F to a possible summer high of 100°F.

  Thermostatically controlled electric heaters are used in smaller rooms and either gravity or forced exhaust ventilation in battery or volatile material storage rooms is common.

- More modern stations may have 100% filtered fresh air supply units and high wall or roof exhaust fans. This will provide a positive pressurized supply system to better control space temperatures and reduce outdoor dust or pollen.

  Depending upon the number of supply units and exhaust fans, they may be staged to cycle in turn, controlled from a space thermostat or outdoor sensor.

Depending upon the range of the summer/winter outdoor design conditions and the indoor conditions required, the supply air units may have economizer cycles to re-circulate warm air and reservoir water or DX cooling coils installed.

As in the older systems, warm air may be bled off the generators to heat the station. Some sensitive equipment areas and control rooms may have packaged air conditioning systems.

3. Condition Assessment

The following information should be gathered and points considered during the condition assessment:

- Review any Site data for maintenance records or forced unit outages due to high equipment or space temperatures.
- Is the building insulated?
- Is the HVAC systems electrical supply separately metered or are any of the station auxiliary systems metered?
- Do the HVAC systems appear to operate as originally designed? Have they been Site modified? HVAC systems are regularly and easily modified either due to design failings or a misunderstanding of how they were intended to operate.
- Do chillers or air conditioning systems still used chlorofluorocarbons (CFCs) as the refrigerant?
- Do the systems supply 100% fresh air or do they have any recirculation air for cool season operation? Is electric reheat used in the fresh air supply units?
- Inspect any filter banks for air bypass and automatic louvers to check for excessive leakage. Do they close 100% on fan shut down? This assessment of the air conditioning equipment should include operating the fans and blowers to determine any unusual vibration or noise.
- Louvers should be inspected for proper operation.
- Maintenance and equipment life can be affected by dust, insects, and birds. Therefore, assessment of the space conditioning system should include inspection of ventilator and window screens and the condition of the equipment with regard to contamination.
- Are there fire or smoke dampers separating the ventilation systems in critical areas? Review the control systems:
  - How old are they and have they ever been upgraded?
  - Do the fans operate continuously 24 hours per day or operate only when required to maintain space temperature set points from indoor or outdoor temperatures?
  - Are any offices, control or store room systems controlled separately from the unit area systems?
  - Are the present thermostat set points outside the range of 50F to 80F?

After the above questions have been answered, an informed decision can be made as to whether or not a more detailed HVAC investigation study is required to investigate chronic performance problems or study potential energy savings.

4.5.8 Powerhouse Crane

Hydropower stations are typically provided with powerhouse cranes for use in the assembly and disassembly of the units and for general maintenance. The main purpose of the powerhouse crane assessment is to determine if the crane(s) can perform the current and future hoisting duties.

Condition

Crane nameplate and design information should be reviewed to confirm the design capacity of the crane. This review is especially important for older plants with cranes which were not designed to current crane and OSHA standards. Although a detailed OSHA assessment is beyond the scope of these Guidelines, identifying a potential crane problem should be included in a modernization study of the major plant equipment. Some of the areas to consider are:

– An inspection of the crane and supports should be conducted to identify any visible defects that may affect the crane load rating. Defects could include cracks, deformation, rust/corrosion, or other structural problems.

– Crane controls should be reviewed. Failure to take advantage of the opportunity to uprate the voltage of the powerhouse crane could cause problems when station service voltage is raised later.

– The crane motors, brakes, gears and wire rope should be inspected for proper operation and condition. It is often difficult to inspect ropes on equalizing sheaves. The short length of rope is difficult to inspect because of the flanges and improper lubrication and inspection can lead to rope deficiencies.

– Oil conditon of hoist machinery should be checked.

– Safety devices, such as limit switches, should be checked to verify proper settings and operation.

– There should be confirmation that the crane manufacturer's maintenance instructions are followed.

Heaviest use of the bridge crane is during construction of the powerhouse. If the crane is of a robust design and properly maintained during the construction phase, minimal problems will occur during the balance of the crane’s life.

Gantry cranes also last the life of the project, but require more attention to some maintenance items such as painting and greasing/oiling because of exposure to high/low temperatures, rain, snow, sunlight, etc.

Unlike bridge cranes, gantry cranes do not have intense use during construction, so there is typically less initial wear.

Prior to a capacity lift, a detailed crane inspection should be performed.

Performance

In terms of performance, the following should be reviewed:

1. Does the hoisting capacity meet the requirement for lift of the heaviest assembly?
2. Is there sufficient lift for the tallest assembly?
3. Are hoisting speeds appropriate - do they allow enough control to assemble or disassemble equipment efficiently and with minimal risk of equipment damage?
4. Is there sufficient reach for all areas of the powerhouse?
5. Is the reliability of hoist, trolley and bridge motors good?
6. Are there audible noises and unacceptable vibration levels during crane operation?

4.5.9 Tailrace Crane

Many hydropower stations have tailrace cranes, either gantry type or bridge type depending on the configuration of the powerhouse. The cranes are used for installing and removing draft tube gates as part of unit unwatering.

Tailrace crane assessment should be basically as described above for the powerhouse crane.

4.6 Assessment of Auxiliary Electrical Systems

Equipment Data and Technical Information	History of Maintenance and Major Repairs
Condition Assessment of Equipment (Step 4-3, Volume 1)	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities	Timing and Costs of Life Extension Activities

4.6.1 Introduction

The station auxiliary electrical systems include the electrical components of systems which are necessary to support the electrical operation of the powerplant and switchyard. This section provides methods to assess the condition of existing auxiliary electrical systems. An assessment of the existing equipment can help to identify modernization alternatives for the facility.

Table 4-7 provides a summary of assessment parameters and life extension and modernization activities for auxiliary electrical equipment (see Section 5 for more details on modernization options).

Table 4-7
Condition Assessment of Auxiliary Electrical Equipment

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
1.1.9	**Unit Transformers**	• Type (OA. OA/FA, FOA) • Rated capacity (MVA) • Rated voltage • Rated current • Rated power factor • Insulation fluid • Oil syringe test results • Oil quart sample test results • On-line monitoring data • Test/inspection results for: – dissolve gas analysis – transformer power factor tests – bushing power factor tests – core excitation – turns ratio – internal inspection – external inspection	• Oil leakage • Availability of spare parts • Condition of windings, bushings, core and damping structure, tap changer and tank. • Noise levels	• Replace transformer protection • Maintain proper oil containment • Replace bushings • Re-process insulating oil and decontaminate PCB's • Change loading practices to extend life.
2.1.1	**Station Service AC**	• Capacity of station service panel • Capacity of MCC • Design capacity system vs required capacity • Load flow, short circuit and regulation studies • Oil syringe test results • Oil quart sample test results • Is there a back-up diesel genset?	• Availability of spare parts • Sufficiency of panel and MCC to meet station requirements.	• Add shunt capacitors to improve power factor. • Add panels/capacity to meet station requirements.

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
x.1.1.1	**Standby Diesel Generator**	• Age • Type (CAT, Detroit Diesel, etc.) • Model • Rated output • Maximum Output • Rated speed	• Possible metal fatigue/corrosion due to age & loading • Potential head cracking if overheat condition seen • Reliability – starts on 1st attempt 90+% • Vibration levels • Rated output between 1.2 to 1.6 times required load • Condition of seals • Availability of spares • Availability of technical support	• Replace entire generating set • Remanufacture generating set • Overhaul generating set • Top Overhaul • Weekly starting, 1 hr run • Monthly run on load or load bank
	Block Heaters	• Age • Type (circulatory coolant, oil, etc) • Number • Size	• Level of corrosion damage • Wear on circulating pump • Engine should feel warm before starting	• Replace due to condition
	Starting System	• Age • Type (Electrical or Air) • Manufacturer	• Excess wear of pinion gear • Parts no longer available • Bearing condition <u>Electrical Start</u> • Batteries weak • Improper batteries • Dirty connections • Battery explosion, cracking or drying • Battery charger Failure • Battery age <u>Air Start</u> • Excessive pressure buildup	• Replace pinion gear • Replace starter • Rebuild starter <u>Electrical Start</u> • Replace batteries as required • Test & clean connections/batteries • Check electrolyte level • Perform variable load test on charger • Use only deep discharge batteries designed for

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
			• Lack of lubrication • Vane wear • Insufficient cranking speed	diesel starting Air Start • Ensure pressure relief valves functioning • Replace/refurbish starter • Inspect receiver • Ensure lubrication
	Lubrication System	• Age of oil • Working pressure • Oil specification	• Low temp starts • Oil oxidized from high temperatures • Oil analysis • Leakage • Blockages • Corrosion	• Use 0W30 Lube Oil • Use Esso Procon or equivalent for rust protection • Replace pumps. • Replace filters • Improve filtering • Ensure oil level in range
	Fuel System	• Age of fuel • Type (winter or summer diesel) • Pressure • Containment	• Filter life • Bugs in fuel • Dripping injectors • Leakage • High particulate level • Loss of prime • Spills to environment	• Winter fuel only for long term storage • Ensure adequate fuel supply • Test fuel • Fuel stabilizer • Fuel biocide • Replace fuel • Upgrade to modern, contained and monitored system • Leak detection • Inspect/replace filters • Pressure test piping

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
	Cooling System	• Age of coolant • Type (liquid or air) • Working pressure • Additive package requirements • Antifreeze requirements	<u>Liquid Cooling</u> • Pump condition • Coolant condition by analysis • Pipe & hose condition <u>Air Cooling</u> • Dirty cooling fins • Improper air flow	<u>Liquid Cooling</u> • Renew Coolant by age or condition • Use only diesel coolant • Ensure coolant level in range • Test Coolant • Replace pressure cap • Inspect/replace pipes & hoses <u>Air Cooling</u> • Clean cooling fins • Ensure fan working • Inspect/replace fan drive belts • Ensure shrouds in place • Ensure dampers open
	Aspiration Air System	• Type (from enclosure or direct to outside) • Automated or Manual • Flow requirements	• Engine air flow rate • Air quality • Enclosure depression	• Ensure large ducting for engine combustion air • Ensure filter clean • Ensure automated dampers functioning • Ensure manual dampers open
	Ventilation and Cooling Air	• Type (from enclosure or direct to outside) • Automated or Manual • Flow requirements	• Breathable air required in enclosure • Enclosure temperature • Enclosure depression	• Ensure automated dampers functioning • Ensure manual dampers open
	Protection and Control	• Type • Age • Settings	• Functionality during test and emergencies.	• Regular testing under realistic conditions. • Replace repair individual devices and systems. • Replace with PLC based

Asset No.	Equipment	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
				system
2.1.2	**Station Service DC**	• Fault clearing studies • Battery size/capacity • Battery load tests • Battery charge size		
2.1.3	**Cable and Cable Support Systems**	• Embedded or surface conduits? • Cable tray systems? • Check cable fill volume	• Seismic stability of system • Refer to IEEE Standard 142	• Confirm seismic stability • Remove old, unused cables
2.1.4	**Grounding Systems**	•	• Reliability of ground alarms	•
2.1.5	**Lighting Systems**	• Description of incandescent lighting • Description of HPS lighting • Description of fluorescent or other energy efficient lighting • Existing lighting audit information (total loads and ballast types)	• Whether or not a maintenance program has been implemented	• Group re-lamping of fluorescent lamps is recommended for cost efficiency • Upgrade of fluorescent ballasts to electronic • Install occupancy sensors where suitable • Replace with HPS or metal Halide fixtures upon failure. • Conduct a lighting audit (i.e. total loads, ballast type, etc.) • Group re-lamping of all HPS lights for consistent colour rendition and efficiency

4.6.2 Generator Transformer

The typical generator transformer has two copper conductor windings, insulated with an oil-impregnated paper insulation system and immersed in an oil-filled tank. The tank may be a sealed design having a dry gas or air filled layer at the top of the tank to accommodate thermal expansion of the oil or a conservator type having a separate partially filled oil reservoir, or conservator tank, connected to the main tank to allow for oil expansion. On newer higher voltage units, the conservators may either employ a large bag or a diaphragm to prevent exposure of the oil to moisture-laden ambient air. On older and lower voltage transformers, the conservator space will breathe freely through a desiccant filter to remove moisture from the ambient air before it comes in contact with the oil surface in the conservator.

The oil immersing the windings serves as both an electrical insulating medium and a cooling medium to limit the temperature rise due to electrical losses in the core and the windings. The oil is then cooled by either oil-to-air or oil-to-water heat exchangers with the flow of oil between the tank and the heat exchangers being either convection-driven (natural) or pumped (forced) and the flow of air over the oil-to-air exchangers being either convectional (natural) or ventilation fan-driven (forced). Generally water flow through oil-to-water heat exchangers is always pumped.

The principal factor, which influences the useful life of a generator transformer, is the deterioration of the paper insulation system. Over time, as the paper insulation is exposed to operating temperatures, it ages irreversibly, becoming brittle and losing its dielectric and mechanical strength. Eventually, the transformer windings will be unable to sustain the strains caused by mechanical stresses due to fault currents etc. and failure will result.

During operation transformer oil also ages, with its chemical composition changing due to oxidation and contamination often due to decomposition by-products of the winding insulation. However, the aging effects on the oil can generally be reversed by chemical treatment and degasification. Therefore the aging of transformer oil is not considered to be a life-limiting factor for the transformer, although maintaining the oxidation products, such as acids and water, in the oil at low levels will assist in extending the life of the paper insulation.

The expected service life of a generator transformer is difficult to predict due to variations in operating and ambient conditions. For heavily loaded transformers with high load factors, the useful lifetime may be as little as 20 to 30 years. Conversely, in light duty applications, transformer operating lifetimes of 50 years or more are possible. Operating the transformer beyond its nameplate rating and / or at elevated operating temperatures will accelerate the effects of aging and reduce its life. However, there may be occasions where it is a system operating requirement or economically advantageous to overload the transformer and sacrifice some life due to system conditions or market opportunities. However, there may be occasions when it is economically advantageous to overload the transformer and sacrifice some life due to system requirements or market opportunities. Guides are available for calculating the theoretical loss of lifetime for various overload conditions.

A transformer’s remaining useful life can be estimated from its operating age, service history (i.e. load factor, ambient temperatures, overload situations, etc.), maintenance history and preliminary condition assessment. However, there are now assessment methods by which to more accurately determine remaining life of the paper insulation. These include furan analysis and degree of polymerization (DP) analysis.

The aging of the paper insulation results in the accumulation of various particles called furans in the transformer oil. To detect the presence of furans, and analyse the type and concentrations, a non-intrusive removal of a small, approximately 25ml, sample of the insulating oil is required. With proper laboratory testing and expert analysis a relatively accurate prediction can be made of the remaining useful lifetime of the transformer based on the type and quantities of furans present, and where ever possible a trending of these results over several periodic tests. Treatment of the oil just before or between subsequent tests will tend to negate the test results.

The DP test is probably the most accurate method currently available to assess the actual condition and degree of deterioration of the transformer paper insulation as this test is performed on a sample of paper removed from the transformer. The test measures the remaining mechanical strength of the paper and uses this parameter to estimate the remaining useful life. The test is not always practical as it necessitates an outage and lowering the oil to allow entry into the transformer in order to take the required paper sample.

A complete assessment of a transformer’s condition should also consider the status of ancillary transformer equipment and components such as bushings, leads, tap-changers, fans, pumps, heat exchangers, bushing current transformers, control auxiliaries etc.

4.6.2.1 Temperature and Age

ANSI/IEEE C57.92, stated that transformer insulation ages or deteriorates as a function of time and temperature. Although this standard has now been superseded by ANSI/IEEE C57.91, it is considered that the relationship between temperature and insulation aging, as developed in C57.92 remains as a valid approximation and that these parameters may be applied to conduct aging, and hence, remaining life studies on transformers.

Since temperature distribution in most transformers is not uniform, the area which has the highest operating temperature will ordinarily undergo the greatest deterioration. A typical practice in carrying out insulation aging studies is to consider the aging effects produced by the hottest spot temperature.

The cumulative effects of temperature and time which cause transformer insulation deterioration are not well quantified . Therefore, it is difficult to predict with any degree of certainty the length of a transformer's life even under constant or closely controlled conditions, much less under widely varying service conditions. However, as noted in ANSI/IEEE C57.92, the relationship of insulation deterioration to time and temperature is assumed to follow an adaptation of the Arrhenius reaction rate theory, which states that the logarithm of insulation life is a function of the reciprocal of absolute temperature.

$$\text{Log}_{10}\ (\text{hours of life}) = \frac{A + B}{T}.$$

The actual form of this equation used for transformer insulation expected life is as follows:

$$\text{Log}_{10}\ (\text{hours of life}) = A + \frac{B}{T},$$

where:

T	=	absolute temperature in degrees Kelvin (θ_{hs} + 273),
θ_{hs}	=	hottest spot temperature, °C, and
A and B	=	constants as follows:

For 65°C rise –	A = -13.391 B = 6972.15
For 55° rise -	A = -14.133 B = 6972.15

Figure4-2 shows the power transformer insulation expected life as a function of the hottest spot temperature for transformers with 55°C or 65°C average winding temperature rise. Transformer expected life at various operating temperatures is not accurately known, but the information provided in Figure 4-2 concerning transformer insulation life at elevated temperatures is considered to be conservative and the best that can be produced from current knowledge of the subject. The estimates are considered conservative in that actual insulation life at any temperature is expected to be greater than that indicated.

Various transformer temperatures such as top oil, radiator surfaces, and cooling medium can be measured directly to establish the transformer hot spot temperature, which is the critical factor in determining the maximum capacity and condition of the transformer. The following industry standards provide guidelines for determining allowable transformer loads based on temperature limitations for transformer capacities up to 100 MVA:

- ANSI/IEEE C57.1200-2000 and C57.91-1995
- NEMA TR98 – 1978 (out of print)
- IEC 60354, (1991-10)

Users of these Guidelines should refer directly to these standards to review the specific assumptions made in calculating transformer hot spot temperatures for various transformer ratings. However, a general overview of a method to calculate hot spot temperature is presented in the following.

Figure 4-3 shows the transformer thermal diagram used in IEC 60354. The diagram is based on the following assumptions.

- The oil temperatures increase linearly between the bottom and top of the winding.
- The average oil temperature rise is the same for all the winding in the same column.
- The temperature of the oil at the top of the winding is the same as that of the top oil, and the temperature of the oil at the bottom of the winding is the same as that at the bottom of the coolers. The temperature difference between the top and bottom of the windings is the same for all the windings.
- The average temperature rise of the copper at any location across the winding increases linearly and parallel to the oil temperature rise, as shown in Figure 4-3. The average temperature rise of the copper ($\Delta\theta_{wo}$) is constant across the winding and is the difference between the average temperature rise by resistance and the average oil temperature rise.
- The average temperature rise of the top oil is the top oil temperature rise plus $\Delta\theta_{wo}$.
- The hot spot temperature rise is higher than the average temperature rise of the top oil. To account for the difference between these two temperature rises, a value of 0.1 $\Delta\theta_{wo}$ is assumed for natural oil circulation. This value is also assumed for forced circulation transformers, but will be conservative. Thus, the temperature rise of the hot spot is equal to the top oil temperature rise plus 1.1 $\Delta\theta_{wo}$ (IEC 60354).

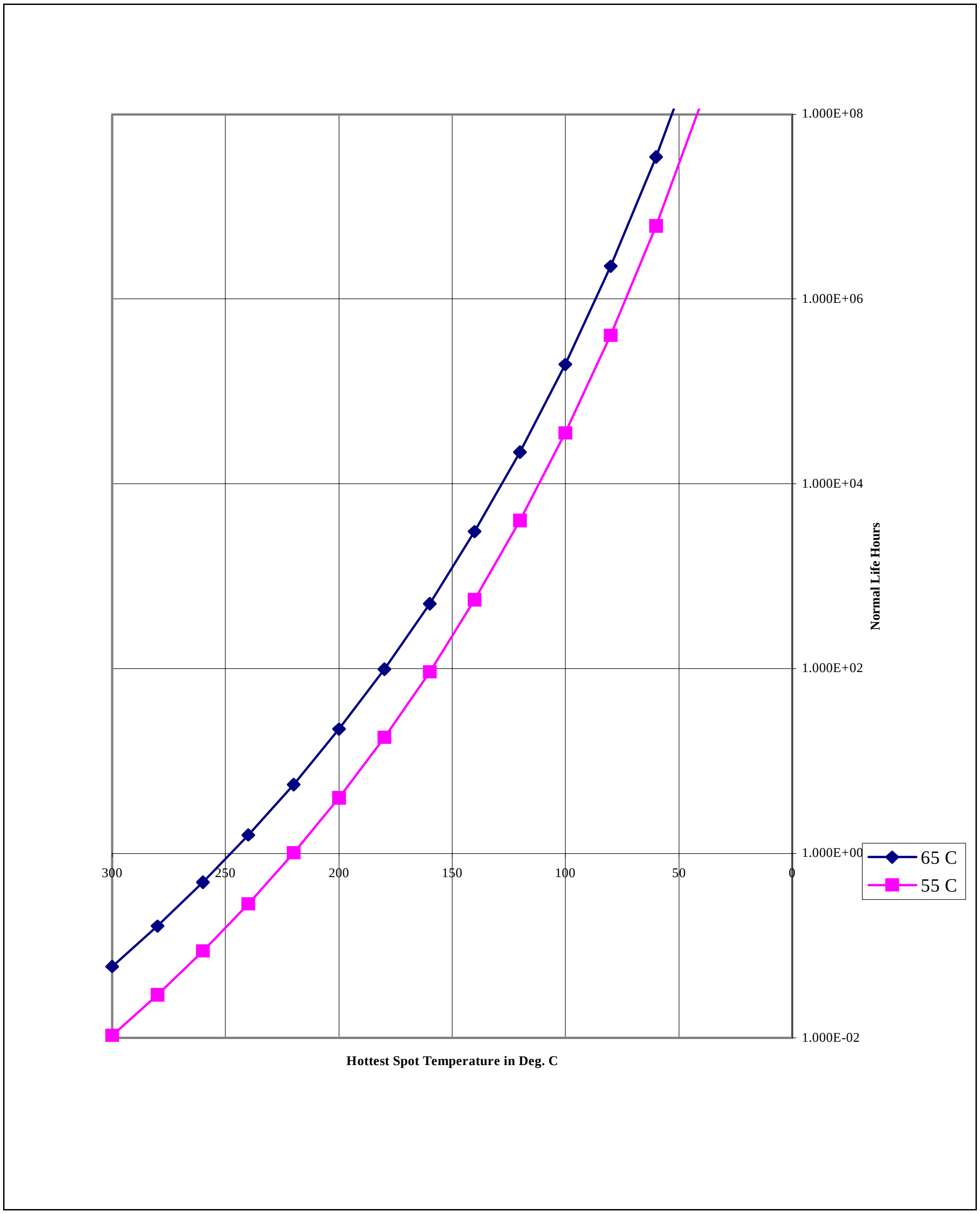

Figure 4-2
Life Expectancy Curve Transformers up to 100 MVA

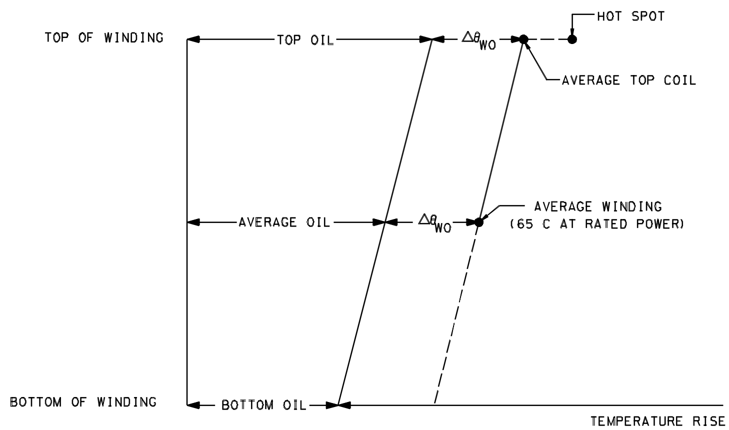

Figure 4-3
Transformer Thermal Diagram
Source: IEC Publication 354

The procedures of IEC 60354 to determine the transformer hot spot temperature require finding the average oil temperature rise and the winding average temperature rise by resistance. The difference between these values is the average temperature rise of the copper ($\Delta\theta_{wo}$) used in Figure 4-3. The average oil temperature rise can be determined with thermometers by measuring the transformer temperature rise of the top and bottom oil. The winding average temperature rise by resistance can he determined using procedures outlined in Sections 5 and 11 of ANSI/IEE C57.12.90-1980, "Test Code for Liquid immersed Distribution, Powers and Regulating Transformers and Guide for Short Circuit Testing of Distribution and Power Transformers."

The procedure involves using dc current to measure the transformer winding resistance and the time for the instrument readings to stabilize when the transformer is cold (no excitation or current in windings for 3 to 8 hours, depending on transformer size). The winding resistance measurements are repeated when the transformer is warm (measurements should be taken) as soon as possible after the unit has been shut down. The measurements should be recorded after the inductive effects disappear by waiting the same time required for the cold resistance measurements to stabilize. Winding resistance measurements should be determined from the average of at least four readings. The time interval between shutdown and resistance measurement should be recorded and should be the same for each measurement. The average temperature of a winding can be determined by the following formula:

$$T = \frac{R}{R_0} (T_k + T_o) - T_k ,$$

where:

T	=	winding temperature in °C, corresponding to hot resistance R winding,
T_o	=	winding temperature in reply to °C at which cold resistance R_o was measured
R_o	=	winding cold resistance, measured according to Section 5 of ANSI/IEEE C57.12.90-1980.
R	=	winding hot resistance (ohms), and
$T_{k=}$	=	a constant depending on the material (235.5°C for copper or 225.0°C for aluminium).

The average winding temperature rise is then the average winding temperature minus the ambient temperature.

The hot spot temperature rise is the top oil temperature rise plus 1.1 $\Delta\theta_{wo}$ (where $\Delta\theta_{wo}$ is the average temperature rise of the winding). The hot spot temperature is the ambient temperature plus the hot spot temperature rise. Generally, the hot spot temperature should not exceed 110°C and transformer life assumes that this temperature is not exceeded. Therefore, hot spot temperatures above 110°C result in accelerated aging of the transformer and shortened life. Hot spot temperature should never be allowed to exceed 140°C. At these temperatures gas bubbles may form in the oil, leading to a drastic reduction in dielectric strength and potentially catastrophic failure in high voltage transformers.

Once the hot spot temperature has been determined, the temperature can be used in Equation 4-29 to estimate transformer life. However, caution must be used in interpreting the results. The expected life assumes continuous transformer operation at hot spot temperature. If the transformer load at the time the temperature was measured was abnormally high or low, the estimate of expected life could be misleading. Also, even if the transformer load was typical, the hot spot temperature measurement does not consider the operating history or the cumulative aging effects of the transformer. If available, transformer operating temperature histories should be reviewed to establish an average lifetime hot spot temperature, which could be used to estimate the transformer's life expectancy. If the temperature histories are not available, hot spot temperatures could be correlated with transformer load over the operating history to estimate expected life.

In general, the transformer expected remaining life which is calculated by the foregoing method should be considered in combination with other parameters, such as physical condition of the components, condition of the oil, and core losses.

4.6.2.2 Oil

The oil in the transformer has two functions, namely, to provide dielectric insulation and to provide cooling by carrying the heat away from the windings to the heat-exchangers. Testing the insulating oil condition in the transformer is a useful means to monitor transformer condition. On the basis of industry experience, analysis of the following parameters provides a reliable indication of the oil condition and permits the dielectric condition to be determined.

Dielectric strength - is the actual break down voltage level of a sample of oil when measured between two specified electrodes in a special test apparatus. It is generally performed in accordance with ASTM-D1816.. The break down strength of oil may be reduced by the presence of any contamination, such as water, carbon or even small fibres of insulating material. Normally, the oil with a poor dielectric withstand can be brought back to new or near-new quality by mechanical filtering and degasification.

- Dielectric loss factor- is a measure of the dielectric losses in the oil. Higher values indicate the presence of contaminants or oxidation products due to deterioration (aging). ASTM method D924 is used for this test.
- Neutralization number - the neutralization number is a direct measurement of the amount acids in the oil. ASTM method D974 is commonly used for this test. If the aging process is allowed to continue, in extreme cases, sludge formation will occur resulting in the loss of cooling efficiency due to restricted cooling passages. The aging effects can be reversed by chemical treatment with Attapulgus Clay (Fuller's earth).
- Interfacial tension - is a test also very sensitive to the degree of aging. The interfacial tension decreases as the oil oxidizes. ASTM method D971 is used to perform this test.
- The content of sludge or products which are not soluble in heptane - this check is performed on only a qualitative basis since corrective measures must be made regardless of the magnitude of this form of contamination.
- Oxidation inhibitor content – oxidation inhibitors are added to oil to retard the aging process. ASTM method D1473 is used for this test. Generally, as long as sufficient active inhibitors are present in the oil, it is not possible to detect aging. The inhibitor content must be known to be able to estimate the further service life of the oil. Presently the two inhibitors used are 2, 6-dietertiary-butyl para-cresol and 2, 6-dietertiary-butyl phenol.
- Water content – high amounts of dissolved water or especially free water in the oil will result in reduced dielectric strength. The water content can be determined using ASTM method D1533 or as a by-product of the results from the gas chromatograph when performing dissolved-gas-in-oil testing.
- Dissolved gas content – the dissolved gas content provides information regarding the condition of the transformer. When insulating oil and cellulose (paper) materials are exposed to higher than normal dielectric or thermal stresses, they decomposes more rapidly to

generate certain combustible gases referred to as fault gases. Dissolved fault gas analysis can be used to detect the presence of a problem usually long before failure or free gas evolution occur. The type of fault such as overheating, partial discharge, core circulating currents, etc. can usually be predicted to a high degree of accuracy by the relative amounts of the dissolved fault gases. The rate of fault gas generation provides an indication of the severity of the fault.

- Normal aging of the insulation also produces small amounts of the some faults gases so low concentrations do not necessarily indicate a problem.
- Detailed information on fault gas analysis is provided in the ANSI/IEEE Standard C57.104-1978 "Guide for the detection and determination of generated gases in oil-immersed transformers and their relation to the serviceability of the equipment".

The laboratory analysis on samples of oil (typically 50 to 200 cc in volume) for dissolved gas as described above is fairly complicated and requires expensive gas chromatograph equipment operated by a highly trained technologist. Detectors have now also been developed and are available from several manufacturers, for installation directly on transformers to allow on-line continuous monitoring of various dissolved fault gases – principally hydrogen. Although these instruments can rather expensive, their ability to provide continuous set-point monitoring can be economically justifiable, particularly in critical applications where an unexpected transformer would have serious economic and operational consequences.

Oil Handling Systems

There are two types of oil handling systems in hydroelectric stations:

- lubricating oils for generator and turbine bearings
- Insulating type oils for tranformers and circuit breakers

Depending on the size of the plant the oil transfer may be handled in drums using portable pumps and filter units or clean oil may be delivered by tanker truck and removed for outside cleaning.

For larger plants, it is normal practice to install permanent oil transfer and treatment equipment.

Tanks and pipes shall free of leaks and shall be properly tied down and supported. Filters should be regularly checked for cleanliness and if necessary replaced. Glass oil tank gages should have excess flow check valves to prevent oil loss in case of a broken glass and shut off valves should be provided at the entrance to the tank.

An oil retaining structure should be provided at the tanks to prevent oil spills and losses to the enviornment. An appropriate fire protection system should also be in place.

4.6.2.3 Transformer Losses

There are two main components making up the losses in a power transformer – no-load or core losses and load or I^2R or copper losses. The transformer no-load or core losses represent the excitation energy required to establish rated magnetic flux within the core and rated open-circuit output voltage. The load or copper losses are equal to the I^2R energy with rated load current in each winding. Transformer core losses remain constant with increasing load, while copper losses increase as a function of the current squared.

Typically transformer loss measurements are part of the transformer factory acceptance test program and are not re-measured on site due to the complexity of obtaining accurate test values and the test instrumentation requirements. In loss test measurements, core losses are determined by measuring the power into the transformer with the transformer energized, but under no-load conditions – open-circuited. Copper losses are then derived by measuring losses (power in minus power out) with the transformer under load. By measuring winding resistance in a separate test, load losses at varying loads and temperatures can be calculated. Losses due to transformer auxiliaries such as cooling fans and pumps typically are supplied from separate station service power supplies and can be measured directly or estimated from nameplate ratings.

Transformer losses can vary among transformer types. Typically, losses are 0.1% of the total transformer capacity in MVA for no-load losses and 0.5% for the load or copper losses, depending on the size and voltage of the transformer.

If site measurement of transformer losses is carried out any change in specificloss values since the factory acceptance test results is a more important indication of transformer condition than the absolute transformer losses.

In general, it is unlikely that load loss values will change significantly over the operating life of a transformer unless a defect such as a faulty internal connection occurs, in which case internal arcing and/or gas production will tend to be more obvious fault indicators than load loss variation would be.

If measured on site and compared to the factory test values, no-load losses can provide clearer indication of age deterioration. Over the years of a transformer's operation, no-load losses can increase due to deterioration of the insulation between core laminations. Increases of 10% to 20% over 30years are possible due to this deterioration. However if abnormally large increases in no-load losses are detected, or if losses jump between successive measurements, it is possible that lamination damage or short-circuits are present within the core and further analysis and possible remedial action will be necessary.

Specific procedures for the measurement of no-load and load losses are detailed in Sections 8 and 9 of IEEE C57.12.90-1999, "Test Code for Liquid-immersed, Distribution, Power and Regulating Transformers." The users of this Guide should refer to this IEEE standard for details on the test procedures.

4.6.2.4 Physical Condition of Equipment

The physical condition of the transformer and its ancillary components and equipment may have deteriorated during the service life of the transformer. The following descriptions identify various deficiencies which may lead to operating problems and reduced capacity and include recommended remedial measures to address each deficiency:

- Inadequate or inefficient cooling due to blocked radiators or cooling coils – Cooling system problems can be identified by temperature measurements, manifesting themselves through abnormally high temperature rise values.

  Blockages in radiator channels may be located by variations in surface temperature measurement along the radiator vanes and by inspection. Blockages can often be removed by back-flushing with oil after closing the inlet and outlet shutoff valves. If back-flushing does not correct the problem, then removal, repair, and/or replacement of the radiator bank may be necessary.

  Blocked oil passages or cooling coil piping within the transformer are more difficult to locate without complete transformer disassembly. In the case of the oil piping back-flushing may not be practical or desirable as dislodged blockage material may be carried into the transformer core and windings.

  In specific cases transformer cooling may be improved by additional fans and/or pumps, although this may represent a poor method to compensate for cooling system blockages.

- High losses - High transformer losses can represent considerable lost revenue over the transformer life. High losses which are due to an old transformer design can only be effectively improved by replacement of the transformer by one with a more efficient design. As previously discussed, high losses which may be due to core lamination damage could require remedial repairs to avoid possible collateral damage to windings.

- Poor oil condition - Deteriorated oil caused by normal aging can be improved by reconditioning the oil. If, however, the transformer has an internal fault, oil reconditioning will only relieve the symptom and not the cause of the problem. Identification and quantification of all gases present by means of a dissolved gas analysis can indicate the presence and type of a fault, which way necessitate transformer replacement.

- Loose clamping bolts - Loose clamping bolts on the core and windings can lead to excessive movement, vibration, and possible deformation if a short circuit should occur. Some manufacturers recommend that the core clamping bolts be checked on a regular basis. However, since the transformer must be opened, this check is typically only performed if looseness is indicated by excessive noise or at major inspection intervals.

- Bushing defects - Bushing defects include surface chips, flaws and cracking of the porcelain, oil leakage, overheated connections and dielectric failures which in extreme cases can be explosive and result in major fires, typically also involving the transformer oil. Bushing condition can be monitored by dielectric power or dissipation factor testing and by visual inspections. Defective or deteriorated bushings should be replaced.

- Oil leakage - Oil leakage is unsightly, environmentally hazardous, and, in large quantities, can create a fire hazard. Renewing gaskets, replacing flanges, uniform torquing of fasteners, and injecting sealants into the flange/gasket space are possible solutions.

- Tap changer defects - On-load tap changers are somewhat troublesome. They should be maintained on a scheduled basis for contact wear, excessive carbon build-up, mechanical deterioration etc.

  Both on-load and off-load tap changers should be regularly exercised through their full range.

- In addition to dissolved gas monitoring systems discussed in section 4.6.2.2, on-line systems are also available to monitor other fault conditions such as:

  (a) partial discharge

  (b) vibration

  (c) acoustical

  (d) bearing sensors for forced oil cooled units

4.6.2.5 Transformer Fire Protection

Transformer fire protection is covered in Section 4.5.6 "Fire Protection Systems".

Transformers are perhaps the most severe fire hazard at a hydro-electric generating station. The transformer contains a large quantity of oil and insulating paper and the high voltages to create a potential ignition source. However, fortunately, transformer fires caused by internal faults are a relatively rare occurrence. Starting a fire requires fuel, oxygen and a source of ignition to be together simultaneously. Unless the tank ruptures before the fault is cleared only the fuel and ignition source are present as the oil itself serves to isolate the fault from oxygen. On the other hand, bushing failures often result in a fire involving the transformer oil as a source of fuel.

4.6.3 AC Station Service (ACSS)

The ACSS System includes the ac supply medium voltage switchgear, the station service transformers, LV bus ducts, LV switchgear, motor control centers, LV distribution panels and emergency generator. For this guideline, ACSS is defined as a system including at least a double bus system independently supplied by two sources, connected through a normally open breaker with an automatic transfer to one source in the event of the other's failure, and with a designated essential ac service section for supplying critical loads such as dc chargers. Automatic transfer schemes should have been provided.

As part of the assessment of the ACSS, the existing connected load should be determined. The connected load can be measured directly by using wattmeters. The use of recording wattmeters would be advantageous in showing time dependence of the load. Alternatively, the connected load can be estimated from the nameplate ratings of connected equipment and the diversity factor. The diversity factor is the ratio of the sum of the individual demands of equipment to the maximum demand of the system. Determining the existing connected load is useful in establishing the reserve capacity in the ACSS, which would be available if additional loads were added to the system.

Assessment of the components in the ACSS should include the following:

4.6.3.1 Medium Voltage Switchgear

- Review of switchgear and bus nameplates ratings to ensure adequacy for rated load and available short circuit currents.
- Inspection of switchgear to ensure proper and secure racking, contact alignment and mating and operation of safety interlocks.
- Review of switchgear operation to ensure positive closing and opening movement.
- Inspection of switchgear enclosure to ensure cleanliness, quality of surface finish, freedom from contamination, correct functioning of ventilation and anti-condensation facilities and security and protection from accidental contact with energized parts.
- Inspection of any control and metering components to ensure secure and correct functioning.
- Inspection of switchgear labelling and circuit identification to ensure correctness, conformity throughout switchgear and conformance with drawings.

4.6.3.2 Station Service Transformers

- Perform secondary voltage regulation measurements:
  - With total AC station service load approximately normal full load, start and operate the largest available motor. Confirm voltage drop at transformer secondary terminals is less than 10% of nameplate voltage;
  - With total AC station service load approximately maximum load, start and operate the largest available motor. Confirm voltage drop at transformer secondary terminals is less than 12% of nameplate voltage;
  - If starting and operating the largest motor under maximum load conditions results in a voltage drop in excess of 12% of nameplate voltage, confirm from nameplates, or otherwise, that all other principal AC station service loads can operate properly under reduced voltage conditions.
- Inspection of transformer(s) to ensure cleanliness, quality surface finish, freedom from contamination, condition of bushings, and correct functioning of all ancillary cooling or ventilation equipment and control and indication components
- Inspection of transformer(s) installation to ensure adequate electrical clearances and sufficient clear space for cooling/ventilation.

4.6.3.3 Generator LV Bus Ducts

- Inspection of LV bus ducts to ensure cleaniness, quality of surface finish, freedom from contamination and condition of enclosures and supports;
- Inspection of LV bus ducts to ensure adequate electrical clearances and sufficient clear space for cooling/ventilation;

- Review of LV bus duct nameplate ratings to ensure adequacy for rated load and available short-circuit currents;

4.6.3.4 LV Distribution Switchgear

- Review of switchgear and bus nameplate ratings to ensure adequacy for rated load and available short-circuit currents;
- Inspection of switchgear to ensure proper and secure racking, contact alignment and mating and operation of safety interlocks;
- Review of switchgear operation to ensure positive closing and opening movement;
- Inspection of switchgear enclosure to ensure cleaniness, quality of surface finish, freedom from contamination, correct functioning of ventilation and anticondensation facilities and security and protection from accidental contact with energized parts;
- Inspection of any control and metering components to ensure secure and correct functioning.
- Inspection of switchgear labelling and circuit identification to ensure correctness, conformity throughout switchgear and conformance with drawings;

4.6.3.5 Motor Control Centers (MCC)

- Review of MCC and bus nameplate ratings to ensure adequacy for rated load and available short-circuit currents;
- Inspection of MCC to ensure proper and secure rackingof starters and circuit breakers, contact alignment and mating and operation of safety interlocks and to confirm correct starter and fuse sizing in accordance with loads and drawings;
- Review of MCC starter operation to ensure positive start and stop operastions;
- Inspection of MCC enclosure to ensure cleaniness, quality of surface finish, freedom from contamination, correct functioning of ventilation and anticondensation facilities and security and protection from accidental contact with energized parts;
- Inspection of any control and metering components to ensure secure and correct functioning.
- Inspection of MCC labelling and circuit identification to ensure correctness, conformity throughout MCC and conformance with drawings;

4.6.3.6 LV Distribution Panels

- Review of distribution panel breakers and bus nameplate ratings to ensure adequacy for rated load and available short-circuit currents;
- Inspection of LV distribution panels to ensure proper and secure breaker installation and operation of safety interlocks;
- Review of breaker operation to ensure positive closing and opening movement;

- Inspection of LV distribution panel enclosure to ensure cleaniness, quality of surface finish, freedom from contamination, correct functioning of ventilation and anticondensation facilities and security and protection from accidental contact with energized parts;
- Inspection of LV distribution panel labelling and circuit identification to ensure correctness, conformity throughout panel and conformance with drawings;

4.6.3.7 Standby Diesel Generator

The station standby diesel generator genset is an important aspect of emergency station service that should be assessed along with the rest of the AC station service equipment.

Firstly, the ability of the generator genset to meet required loads should be evaluated. As a general rule, the generator genset should have a rated output between 1.2 and 1.6 of the required load to allow for current inrush when motor loads are started. Secondly, reliability should be assessed. Starting reliability should be 100% (three start attempts allowed per incident) or work should be undertaken to improve generator performance.

Age is an important factor to consider as for some generator models, availability of spares and technical support may become an issue after 40 years.

From previous inspection and maintenance reports, any metal fatigue, corrosion, head cracking or seal deterioration should be noted. Overheating conditions can be due to emergency shut downs from a loaded condition, coolant system malfunction, etc. and should be addressed.

Acceptable vibration levels should be established during commissioning in consultation with the manufacturer. Unacceptable levels could be due to inbalance, misalignment, support changes or structural failure.

An important aspect of generator condition is the availability and clarity of maintenance records. They should provide a complete history of maintenance, failures, and solutions and vibration levels. If information concerning the particular problems associated with an engine model are known, these should be noted and mitigating activities should be investigated.

The following individual systems should be further evaluated during a condition assessment:

<u>Block Heaters</u> – the level of corrosion should be noted and replacement may be indicated. The engine should feel warm before starting.

<u>Starting Systems</u> – Availability of parts is a key condition assessment parameter for this system. For an electrical starting system, the age and condition of the batteries should also be reviewed. If batteries are over 5 to7 years of age, replacement should be considered. Persistant low electrolyte levels indicate maintenance or charger problems. Selection of batteries specifically designed for starting diesel engines is important. Attention should be given to the state of connections and wiring. Problems include corrosion, looseness and wear. Facility to interrupt the battery supply to the starter should be included to allow engine isolation for safety during maintenance.

For an air start, inspection records of the air receiver should confirm that condition is acceptable and proper functioning of all pressure relief valves should be confirmed. Excessive back pressure build up, lack of lubrication, vane wear and insufficient cranking speed are all condition problems that should be acted upon.

Lubrication system – Previous oil analysis results will indicate if there are problems such as blow by, bearing wear, ring wear, oil cooler corrosion. Any oil leakages, blockages or corrosion of piping may indicate refurbishment or replacement of components. The age and type of oil used should be noted. Replacement with multigrade lube oil should be considered in consultation with the manufacturer.

Fuel System – Dripping injectors, leakage, high particulate levels and contamination of the fuel are all system deficiencies. The loss of prime is common in engines that are run infrequently. Winter fuel only should be used for long-term storage stability and all season suitability. An adequate supply of fuel should be confirmed. Previous fuel analysis may reveal the need for a fuel stabilizer, fuel biocide or replacement of the fuel.

To prevent losses to the environment, containment and leak detection should be installed and pressure testing of the piping should be done on a regular basis.

Cooling System - For liquid-cooled systems, the age and condition of the coolant should be reviewed and the level confirmed. Previous test results can be used and only diesel coolant should be used. Pipe and hose condition should be checked for leaks. The pressure cap may require replacement due to loss of sealing or change of calibration.

For air cooling, dirty cooling fins and improper air flow will be indicated by overheating. The cooling air path should be clean and functional, including manual and automatic dampers. Fan bearings and drive belts require frequent inspection.

Aspiration Air System - Confirm that automated dampers functioning and manual dampers open? It is important to check that filters are clean. Pressure depression at engine intake will indicate whether engine airflow rate requirements are being met.

Ventilation & Cooling Air System – Confirm that automated dampers are functioning and manual dampers are open. Enclosure temperature and depression will indicate whether or not flow requirements are being met.

Protection and Control - Confirm functionality through regular testing and review of previous emergencies.

4.6.3.8 Essential Service

In some configurations, there will be a designated Essential Service AC Bus to carry the DC Battery Chargers, emergency lighting and black start equipment not connected to Batteries or UPS systems. Assessment should include testing of supply (usually the emergency or standby generators), full loading and any automatic provisions. The ac system would include the equipment associated with any Inverter system, which converts dc to ac for essential ac services or a separate station ac backfeed.

Assessment of the ac inverter system should include the following:

- Backup power supply in phase with primary (if indicated).
- Backup power supply capacity compared to primary.
- Fuses or breakers rated for Inverter momentary output.
- Unusual noise or heat emanating from Inverter.
- Inverter cooling fans operating and unobstructed.
- Condition of Inverter room ventilation and cleanliness.
- Emergency lighting operation.
- Transfer switch and associated equipment

4.6.4 DC Station Service (DCSS)

The DCSS provides power for essential protection and control equipment. The dc system includes the dc batteries, battery chargers, battery room, emergency dc circuits, and any emergency dc lighting.

Assessment of the dc system should include the following:

4.6.4.1 Battery Chargers

- Battery charger rating at least 10% of the 8-hour battery rating.
- Disconnect battery charges and verify proper annunciation of battery charger status.
- While battery charger is disconnected, record the voltage and check that the float voltage is less than 105% nominal.
- Reconnect the battery charger, enable the equalization timer, and record the equalized voltage (equalized voltage should be more than 110% nominal).
- Fuse or breaker ratings at least 10 times the 8-hour battery rating.
- Condition of emergency dc circuits (power for governor control, dc control, protection, annunciation, communication, oil pumps, cooling water and/or sump pumps, etc.).
- Condition of battery room cooling vents and drains.

- Emergency lighting operation.
- Panel breakers rated for dc interrupting duty.

Assessment of the battery chargers includes the following:

- Inspection of battery charger(s) to ensure cleaniness, surface finish and condition, correct functioning of indication and metering devices, settings and functioning of float and boost charge functions and correct mounting arrangement with adequate ventilation;
- If implemented, review operating records for periodic battery boost operations;
- Review of battery charger rating to ensure a minimum of 10% battery 8-hour discharge rate;
- Disconnect battery charger output to batteries and verify correct functioning of charger annunciation;

4.6.4.2 Batteries

The plant storage batteries are critical compnents and assessment of their condition will be dependent on the age of the last replacement. Include any associated load breakers and interconnections in the assessment.

Assessment of the batteries includes the following:

- Inspection of battery cells to ensure cleaniness, freedom from battery cell case cracking or deterioration, correct electrolyte levels andd condition of terminals, sealant around terminals and intercell connections;
- Review of maintenance test records including cell voltages, electrolyte measurements, capacity tests, etc. and identification and tracking of pilot cell(s);
- If appropriate, perform battery capacity discharge test;
- With battery charger(s) disconnected measure battery voltage. Confirm less than 5% drop from charger float voltage;
- Inspection of battery racks and battery cell assemblies to confirm cleanliness and freedom from contamination or corrosion, correct anchoring of racks and securing of cells and grounding of racks and isolation of cells if metallic racks are used;
- Inspection of battery room to confirm cleanliness and surface finish, presence of safety facilities - eye wash, shower, etc - explosion-proof fittings and adequate floor drain and ventilation if required for specific type of battery cell;

4.6.4.3 DC Distribution Panelboards

- Review of DC distribution panel breakers and bus nameplate ratings to ensure adequacy for rated load and available short-circuit currents. Confirm main fuses or circuit breaker from batteries rated at least 10 times 8-hour battery discharge rating;
- Inspection of DC distribution panels to ensure proper and secure breaker installation and operation of safety interlocks;
- Review of breaker operation to ensure positive closing and opening movement;
- Inspection of DC distribution panel enclosure to ensure cleaniness, quality of surface finish, freedom from contamination, correct functioning of ventilation and anticondensation facilities and security and protection from accidental contact with energized parts;
- Inspection of DC distribution panel labelling and circuit identification to ensure correctness, conformity throughout panel and conformance with drawings;

4.6.4.4 DC/AC Inverter(s)

- Inspection of inverter(s) to ensure cleaniness, surface finish and condition, correct functioning of indication, metering, switching and forced ventilation devices and correct mounting arrangement with adequate ventilation;
- Review of inverter device ratings including interrupting capacity of switches or fuses;
- Interrupt primary inverter supply to confirm correct transfer to standby supply;;

4.6.5 Cable and Cable Support Systems

4.6.5.1 Wiring

Wiring includes all power and control wiring, except generator terminal cables.

Assessment of the station wiring should include the following:

- Verify that noncarbon compounds are used in sunlight environments.
- Verify that hydroscopic materials are used in wet environments.
- Flame and flame retardant cables should be separated into different cable trays.
- Inspect for evidence of rodent damage.
- Inspect general condition of wiring and terminations.
- Testing (megger) any high voltage cables.
- Remove all unused cable trays.

4.6.5.2 Raceway

Assessment of the raceways should include the following:

- Confirm that cabinet and box classifications are correct and relative to their environment.
- Proper use of flexible conduit and weep holes.
- Raceway properly sealed between classified areas to prevent water intrusion and rodent damage.
- Proper use of expansion joints.
- Outdoor cable tray covered to protect cable from effects of weather and sunlight. Confirm that ventilation exists to avoid heat build-up.
- Water level in manholes maintained below cables.
- Electrical control cabinets or electrical vaults properly vented to avoid heat build-up.
- Fire stops in trays and openings in fire walls or cable shafts.
- Seismic restraints are installed where required.

4.6.5.3 Medium Voltage Cables

In many installations, a transfer bus or cable is connected between the generator and the step-up transformer. Cable designs vary in many ways, including:

- Insulation Material
- Metallic shield or neutral
- Jacketing
- Accessories
- Operating Conditions

For PILC cable, dc potential testing is often used and the PI calculated. For buses and isophase bus, ac potential testing is used. In either case the equivalent of 1.5 E ac or the equivalent dc voltage (x 1.6) should not be exceeded.

The purpose of condition assessment is to use any existing test data, design information and known operating conditions for the cables or buswork to make a best estimate of the remaining life. If no test data is available, or if testing has not been performed in the last three to five years, it may be useful to perform condition assessment testing. The following discusses some of the test data that would be useful for the assessment and guidance on what further testing may be required if initial condition assessment reveals potential deterioration of the cables or buswork. Further information specifically on PILC cables is provided in a tailored collaboration project, EPRI Report No. 1000741 "Condition Assessment of Distribution PILC Cable Assets". Another EPRI report "Review of Emerging Technologies for Condition Assessment of Underground Distribution Cable Assets", Report No. TR-11433 covers XLPE insulated ables.

1. Insulation Condition

Although insulation failure is usually the final breakdown mode in cables, it is rarely the primary cause.

Cable insulation is often subjected to severe conditions including contaminated water, overheating, factory defects, damage during installation, and higher than rated voltage stresses.

Any of these may in time lead to insulation breakdown and therefore what surrounds the insulation and how the cable was operated are important factors to note in the condition assessment.

Assessing insulation condition may be performed in the laboratory, on cable samples, or on-site, using one or more electrical tests. Laboratory assessment is useful for the assessment of remaining life, as discussed in Section 4.6.7.

On-site condition assessment involves some form of electrical test, usually performed on de-energised cable systems. At present, there are a number of tests available, including partial discharge, dissipation factor, voltage recovery and leakage current measurement, to name a few. Unfortunately, no single test will tell you the complete condition of your cable insulation.

Powertech Labs has developed a low voltage dc test method - **L**eakage current (**I**) **p**ico **A**mpere test (LIpATEST) - that has been used successfully to assess the condition of XLPE cables. The test voltage is less than half that of the recommended levels for aged cables using traditional dc hipot testing. The LIpATEST requires less than 10 minutes to perform and the maximum dc voltage is applied for only one minute. The LIpATEST is used for on-site insulation assessment, along with other tests to assess the condition of cable jackets and shields.

2. Metallic Shield or Neutral Condition

Cable metallic shields or neutrals may suffer mechanical damage during installation, or over time from temperature cycling, particularly under cable clamps. Corrosion may also be a serious form of shield damage. Generally, the thinner the metallic shield the more susceptible it is to damage or corrosion. Copper tape shields are particularly susceptible to damage and corrosion, even in fully jacketed cables.

Metallic shield damage may result in heating of the underlying semi-con shield and insulation, which increases voltage stress and accelerates insulation failure. Damaged or corroded shields may be found in a dissection during failure analysis. In an on-site, condition assessment there are specific tests designed to examine the extent of metallic shield or neutral damage.

An initial assessment of the cable neutral or shield is made with a dc resistance meter. If the resistance reading is high, Low Voltage Time Domain Reflectometry (LV TDR) can be used to locate the points along the cable where the neutral or shield is deteriorating. LV TDR is a very low voltage technique (10 V pulse), and does not harm the cable in any way. The LV TDR test equipment is very small and easily transportable.

3. Cable Jacket

Sometimes the cable jacket is compromised during installation or handling of the cables. A damaged jacket is often a first indication that further problems may be encountered. Water ingress in the cable causes neutral or shield corrosion and water tree development in XLPE insulation, which eventually will lead to premature cable insulation failure. Several simple on-site tests can be used to assess the overall condition of the jacket.

4. Cable Accessories

Cable accessories, including joints, terminations and Separable Insulated Connectors (Elbows), are some of the most vulnerable parts of an installation. Failure mechanisms in accessories are varied, but one of the most common causes of failure is improper installation.

To determine the condition of accessories onsite, generally two symptoms are assessed. These are elevated operating temperature or presence of partial discharges. Accessory operating temperature can be measured with fibre optic probes or infrared techniques. In either case, the temperature measurements are best made under the highest possible circuit loading. Even the poorest connector in an accessory will not get hot if it is carrying little or no current.

Partial discharges (pd) can be measured and these sites located using a number of off-line or online techniques. Off-line pd techniques can use higher than normal voltage to determine possible impending failures. On-line techniques use the normal operating voltage, and so detection of pd indicates the accessory is closer to failure. Of course, on-line techniques have the advantage of not requiring an outage.

5. Operating Conditions

One operating condition that can seriously affect cable life is elevated temperature. Normally, cable systems are designed to operate at a maximum current. The design maximum current is based on cable size, and installation conditions. Usually the design maximum current is derived in a conservative fashion to allow for possible "hot spots" caused by unknown conditions or additional heat sources. Consequently, operators usually do not know the exact cable operating temperature. Lack of this key information can mean:

- Failure of the cable at an unknown "hot spot", or
- Under utilization of the cable system

Knowledge of temperature at all points along the cable is now possible using Distributed Fibre Optic Temperature Sensing or DFOTS. DFOTS is a system which can measure the temperature at all points along an optical fibre. If an optical fibre can be installed in a duct along a cable run, then exact locations and temperatures of "hot spots" can be determined. This may be a cost effective method of preventing failures on heavily loaded feeders by mitigating conditions at "hot spots". Knowing the exact temperature of a heavily loaded feeder, may allow deferring of a new cable installation.

Criteria

Any dielectric high potential test failure is unacceptable. PI less than 2 is unacceptable. Any thermal sheath damage or stand-off insulation damage is unacceptable. Leaking oil is unacceptable.

4.6.6 Grounding

The integrity of the installed grounding system should be reviewed to confirm that the system meets IEEE Standard 142 and 181, Article 250 of the NEC, NFPA 780 and local codes. The grounding system provides a nearly equipotential reference point to connect plant equipment. This system includes the buried or embedded grounded mat risers, exposed ground cables, and connectors. The inspection may be difficult because the main part is embedded or buried. In places where part of the installation is reasonably accessible inspect a sampling of the ground mat conductors and connectors. Inspect the risers exposed conductors, and connectors . If there is a question about the effectiveness of the system it should be tested to verify the resistance is not excessive for the available fault current. Soil resistivity in the area of the ground rods and grounding grid around the structures or buildings should be tested. If the system is defective there could be a safety problem with step potential.

To assess the condition of the grounding system and its components the following reviews and technical factors should be considered:

- Inspection and confirmation of grounding connection to:
- Equipment base frames and enclosures,
- Electronic and equipment cabinets, cubicles and switchgear,
- Cable trays, conduit, bus enclosures and junction boxes,
- Hand rails, building columns,
- Inspection and confirmation of properly-grounded operator mats for disconnect switches, circuit breakers, etc.
- Measurement of equipment and metalwork bonding impedances / voltages,
- Measurement of ‘worst case’ touch and step potentials,

4.6.7 Lighting

Assessment of the station lighting should include the following:

- Confirm whether or not an energy or lighting audit has been done for the station and review any recommendations from past audits.
- Confirm/inventory the existing lighting systems and determine if any major repair work listed in Table 4-3 under “Lighting” has been done in the past.
- Comparison of lighting levels to IES standards.
- Lighting fixtures are of proper classification and application
- Investigation of electrical efficiency - lumen output per watts
- Evaluation of the provision of emergency lighting at main control panels, control room areas and fire egress ways.
- Confirmation of emergency lighting system operation (monthly testing)
- Confirmation of the reliability and functional independence of emergency power sources.
- Confirmation of seismic zone compatibility, i.e. lights should be stabilized by diagonal anchor wire braces.

4.7 Assessment of Remaining Life

Equipment Data and Technical Information	History of Maintenance and Major Repairs
Condition Assessment of Equipment	
Assessment of Remaining Life (Step 4-8, Volume 1)	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities	Timing and Costs of Life Extension Activities

4.7.1 Introduction

The prediction of remaining life is the most subjective element of the condition assessment. The aim is to replace, rehabilitate or upgrade equipment at the optimum point in the equipment's life cycle. The scheduling of these activities requires that the approximate year of equipment failure is predicted. Such predictions should be made by an experienced engineer.

Optimum time in this context means the time beyond which the impacts of not intervening will be greater in the long run than the impacts of intervening now. In terms of risk cost, this is the time when the risk costs are minimized. Risk costs include the costs of equipment replacement and the consequences of equipment failure (lost energy, collateral damage, cost increases for purchase or installation of new equipment due to working in an "unplanned" outage situation, etc.).

Most plant owners rely on equipment specialists to assess the remaining life of equipment. It should be noted that it is normal practice for these specialists to provide a conservative assessment of how many years the equipment will last until failure. This assessment says nothing about the optimal time for equipment replacement as discussed above. Often the terms remaining life and replacement time are used synonymously but they are in fact quite different concepts.

Under the auspices of the Canadian Electricity Association (CEA), a consortium of energy companies from both Canada, U.S. and abroad, have undertaken "remaining life" studies for hydro power equipment. The results of this project have been used to develop optimal equipment replacement strategies and computer software tools to assist with the prediction of remaining life and scheduling of equipment replacement. All costs associated with equipment replacement decisions are included in the methodology used to arrive at optimal timing for the equipment replacement.

Table 4-9 lists typical life expectancies for auxiliary mechanical and electrical equipment covered by this Volume. This information, combined with the condition and performance assessment, can assist the engineer in determining an approximate remaining life for each piece of equipment. Comparison of similar equipment in a similar application is useful in estimating the typical service life of equipment.

Table 4-8
Life of Auxiliary Mechanical and Electrical Equipment

Equipment/Systems	Typical Life (years)	Considerations which Affect Component Life
Cables	40	Environment, loading
Cranes	40 - 60	Duty cycle, environment, preventative maintenance program
Pumps	25 - 50	Duty cycle
Compressors	40	Duty cycle
Fans	30 - 50	Duty cycle
Piping and Valves	30 - 50	Environment
Transformers	20 - 30	Duty cycle, extent of overloading
Standby Diesel Generator	40 - 50	Environment, maintenance

The concept of "remaining service life" is not always easy to apply to mechanical and electrical equipment. Certain equipment can be maintained indefinitely as long as parts for repair are available or can be made. In addition, some equipment can be repaired easily and brought back to original condition and performance level without a major rehabilitation project. An equipment's "useful life" can then be quite different than its service life. In other words, although the service life can be extremely long, there are a number of issues that would limit the equipment's useful life. These include:

1. Increasing maintenance costs to keep equipment "in service".

2. Increasing equipment unreliability and outage time associated with the increased maintenance requirements.

3. Increasing obsolescence of spare parts necessitating the costly manufacture of parts.

4. Maintenance problems associated with equipment of a "hybrid" structure after too many repairs and substitute parts have been installed to keep the equipment operational

5. Equipment condition and performance have deteriorated to an extent that it cannot be repaired or rehabilitated to its original condition even though the equipment is still largely operational and can stay in service.

6. A change in operational conditions can mean that a piece of equipment is unable to meet the new requirements of the plant even though it is in relatively good condition.

At some plants where equipment is well maintained and operates under good environmental conditions, a life in excess of the values given in Table 4-8 have been observed.

Often equipment condition is not the driver for replacement and remaining service life is not a factor in the replacement decision. The real driver of equipment rehabilitation or replacement is the upgrade opportunity for increased performance (i.e. plant or system revenue) through increased power and efficiency. Sometimes, the opportunity to supply additional plant products such as peaking capability to capture high electricity rate periods or voltage support is the driver for equipment replacement.

A note should be made in the Equipment Condition Summary worksheet (Section 4.1) when "useful life" is the issue driving equipment replacement rather than "remaining service life".

Probabilistic models for predicting remaining life and optimal replacement timing are available, although the mathematics and analysis involved in using these models can be quite complex and time-consuming. The usual problem with trying to develop and use probabilistic models is the lack of data available on equipment age, history and condition. Furthermore, the presence of too many variables which affect the service life of equipment can make the model overly complex and impractical. The CEA has attempted to address many of these issues in their project that looks at the prediction of "remaining life" for hydropower equipment.

4.7.2 Auxiliary Mechanical Equipment

4.7.2.1 Bearing Lubrication System

Piping and valves have a typical service life of 30 to 50 years. Pumps have a typical service life of 25 to 50 years. The main "wear" items are the coolers. Their life depends on the flow rates, quality and silt level of the water and the material of the cooler. Copper and copper-nickel coolers would require re-tubing every 15 to 20 years.

Instrumentation that is older than 10 years may require replacement.

Trending of oil viscosity over time will give an indication of remaining life of the oil (bearing and governor oil can last for 30 to 40 years in some cases).

4.7.2.2 Raw Water and Cooling Water Systems

Piping and valves have a typical service life of 30 to 50 years. Pumps have a typical serivce life of 25 to 50 years.

Controls older than 10 years may require replacement.

Copper or copper nickel coolers usually require re-tubing every 15 to 20 years.

4.7.2.3 Compressed Air Systems

Well maintained air compressors working in a clean dry environment have a useful life up to 40 years. However, after 20 years, finding parts may become a major problem.

4.7.2.4 Potable Water Systems

See raw water and cooling water systems.

4.7.2.5 Drainage and Dewatering Systems

See raw water and cooling water systems.

4.7.2.6 Fire Protection

A fire protection system can perform its intended function indefinitely if it is tested, inspected, and maintained on a regular basis.

However, replacement of an existing fire protection system should be considered if:

(a) a new system can be justified on a life safety basis;

(b) the existing system had detrimental environmental effects;

(c) a lack of parts availability prevents effective maintenance;

(d) maintenance of the existing system is not cost-effective compared to replacement with a new system;

(e) the existing system has not been maintained and cannot be brought back into service in an economical manner;

(f) a new system will provide a favorable benefit for the cost in terms of asset protection and continuity of production; or

(g) the level of protection provided by the existing system is grossly deficient when compared to current codes, standards, and practices.

4.7.2.7 HVAC

The following are some general guidelines regarding service life of HVAC equipment:

- Regularly maintained low- pressure axial or centrifugal fans operating in clean conditions have a life expectancy of up to 40 years.
- Control system design should be reviewed if the systems are more than 10 years old.
- Automatic louvers and actuators, gravity back-draft dampers, filter banks, and safety and control systems need a regular and well documented maintenance program to stop them becoming a major source of problems and wasted energy.

4.7.2.8 Cranes

The following are some guidelines on assessment of remaining life for powerhouse and tailrace cranes:

- Because bridge cranes are located inside the powerhouse, they typically last the life of the project if maintained properly. This is usually 75 to 100 years.
- Heaviest use of the bridge crane is during construction of the powerhouse. If the crane is of a robust design and properly maintained during the construction phase, minimal problems will occur during the balance of the crane's life, if properly maintained.
- Gantry cranes also last the life of the project, but require more attention to some maintenace items such as painting and greasing/oiling because of exposure to high/low temperatures, rain, snow, sunlight, etc.
- Unlike bridge cranes, gantry cranes do not have intense use during construction, so there is typically less initial wear.

4.7.3 Auxiliary Electrical Equipment

4.7.3.1 Generator Transformers

Power transformers are typically constructed with copper windings insulated with oil-impregnated paper and immersed in oil-filled tanks. The transformer oil both insulates and cools the windings and in turn is cooled by oil-to-air heat exchangers (radiators) or oil-to-water heat exchangers (coolers). The flow of oil through these heat exchangers may be either natural convection or pumped (forced) and the cooling air flow may be either convention or fan driven.

The primary aging mechanism for power transformers tends to be the windings' paper insulation. Over time, the paper insulation loses mechanical and electrical strength and becomes brittle when exposed to operating temperatures. This deterioration of the paper insulation is the principal factor influencing the useful life of a transformer.

The expected service life of a generator transformer varies widely depending on its duty but normally is 20 to 30 years even under the most severe operating conditions with high ambient temperatures and load factors. A precise prediction of total useful life or remaining is difficult to determine due to the virtually infinite variations which might occur in the design, manufacture and operation between even supposedly identical units. Many cases of transformer lifetimes of 50 years or more are well-documented.

The transformer nameplate rating in MVA is the continuous apparent power which can be carried without exceeding rated temperature rise and absolute temperature limits. Operation of transformers at temperatures in excess of rated will significantly reduce transformer expected service life. However, transformer operation above the rated capacity may be possible for short periods of time or for low ambient temperature conditions with no loss of potential life. This operating mode could be important in evaluating the replacement of a transformer after a turbine generator uprating, particularly if the intended operation is primarily for peaking.

As noted the deterioration of paper insulation represents the principal aging factor for power transformers. Therefore assessment of the remaining life of the paper insulation may serve as a useful tool for predicting remaining transformer life. Section 4.6.2.1 details a methodology for assessing the expected remaining life of paper insulation.

4.7.3.2 AC Station Service System

The powerhouse AC station service system includes a variety of components each having its own typical operating life and each subject to similar, but somewhat unique deterioration and aging mechanisms. For virtually all components, the operational environment and duty cycle represent major aging factors.

Typically, detailed assessment of remaining service life is not applied to every AC station service component. Rather, on the failure or impending end-of-life of one major component, such as the station service transformer or switchgear, other associated components, making up the AC station service system, are considered to have also reached the end of their useful operating life and are replaced at the same time. Often the obsolescence of equipment, resulting in the lack of or high cost of adequate spare parts is a determining factor. Design and operational issues such as system reliability improvements and increased functionality to meet plant automation and SCADA requirements ,may also be driving factors for replacement of AC station service components.

As for other power transformers, the station service transformer may be expected to have a useful life of approximately 30 years, however high operating temperatures due to environmental or duty cycle factors will accelerate the insulation aging and potentially result in premature failure. An estimated lifetime of 35 years is quoted for AC switchgear and motor control equipment, although equipment obsolescence and modernization requirements tend to drive their replacement more often than deterioration and aging. Finally, the lifetime of properly designed and rated bus ducts should be almost indefinite but a 40 to 50 year period is often applied, unless other system changes result increased ampacity or short-circuit capacity requirements.

4.7.3.3 DC Station Service System

The effective operating lifetimes of key components of the DC station service system are known with sufficient accuracy to permit their remaining life to be predicted on the basis of their chronological operating age. For example a 20 year operating life is applicable for stationary battery banks with reasonable certainty. As with other electrical equipment, the environment around the battery and its operational duty cycle can impact on that lifetime to some degree but the aging process of a conventional operating battery cannot be significantly altered. Modern battery materials and construction techniques may provide improved life expectations in the future. Load testing provides a good indication of remaining life - reference ANSI 450 - 1987 for assessment.

Other DC station service system components such as the battery chargers (20 to 30 years) and the DC switchgear (35 years) are more dependent on operating environment, duty cycle considerations and obsolesence.

4.7.3.4 Cables

Although insulation failure is usually the final breakdown mode in cables, it is rarely the primary cause. For example, polyethylene cables, which are made without defects, operated within temperature limits, and are kept dry, could last 40 years or more. PILC cables that have not suffered mechanical or corrosion damage have often outlived their designers. Laboratory testing may be one life extension activity recommended to further assess the condition of suspect cables.

Laboratory assessment may be recommended after a failure has occurred. Lab assessment is made to determine whether cables of similar type and age should remain in service. Lab assessment may consist of dissection, water tree counts, and various small sample, chemical tests. If longer samples can be taken, ac breakdown tests are performed. Laboratory tests tell the most accurate story of cable condition and cause of failure, but only tell the story on the sample examined. To understand the state of the insulation of the existing cable, on-site condition assessment is needed.

If a long sample can be removed from a cable installation, an ac breakdown test will give a good indication of the condition of the sample. On new 15 kV cable, ac breakdown may occur at over 150 kV. As the cable ages, the breakdown strength decreases. Cables nearing end of life will breakdown at or below three time operating voltage. For a 15 kV cable, this will be 25 kV line-to-ground or less.

4.7.3.5 Grounding System

In a benign operating environment, the anticipated lifetime of the grounding system components is virtually indefinite – 50 years +. However, the presence of contaminants or corrosive substances, such as acidic ground water, or continuous circulating ground currents, could deteriorate specific parts of the grounding system over a relatively short time – therefore periodic inspection and rehabilitation activities are recommendable.

4.7.3.6 Lighting

Any lighting systems that are over 10 years old may have minimal remaining life due to impending obsolence of some components. For example, the manufacturing of magnetic type fluorescent ballasts will be discontinued in the year 2005. Second generation lighting such as electronic ballasts will probably be the industry norm for years to come. Replacement of older lighting systems with modern equipment usually must be justified by an economic analysis, (energy savings vs. costs) in addition to the argument of obsolescence.

4.8 Life Extension Activities

Equipment Data and Technical Information	History of Maintenance and Major Repairs
Condition Assessment of Equipment	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities (Step 4-5, Volume 1)	Timing and Costs of Life Extension Activities

Tables 4-5 and 4-7 in Sections 4.5 and 4.6 respectively provide a list of common life extension activities for each type of equipment.

The decision to replace a piece of equipment has an effect on the scheduling of other life extension activities typical for a piece of equipment over a 20 year planning horizon. For example, if the decision is made to replace a piece of equipment in 5 years, then typical life extension activities such as painting may be reduced in scope or eliminated altogether from the LEM Plan in the preceding years.

4.8.1 Auxiliary Mechanical Equipment

The following discusses the principal life extension activities for the auxiliary mechanical equipment.

4.8.1.1 Bearing Lubrication System

Life extension activities for the bearing lubrication systems would generally involve replacement or rebuilding of equipment, including pumps, filters, heat exchangers and controls.

The following is a general list of life extension activities to consider:

1. Oil sampling at lease annually is strongly recommended and filters should be replaced as required.
2. Chronic bearing problems may be alleviated by a change in oil viscosity.
3. Consider altering the cooling system if the bearings tend to run hot.
4. Any sources of oil contaminants should be removed.
5. If water in the oil is a problem, sources of water leaks should be investigated and replacement or re-tubing of coolers may be warranted.
6. Rehabilitate the thrust bearing lift pump system if it does not operate reliably.

7. If the thrust bearing does not have a lift pump, consider adding one. In addition to adding protection for the bearings during startup and shutdowns, other restrictions on unit start up (such as temperature requirements) could be eliminated.

8. Install a filter in the oil re-circulating system if the system currently does not have one.

9. Replace/repair piping, valves, filters and instrumentation as indicated by the condition assessment.

For water lubricated bearings, some items to consider are:

1. Improve the filtering system to ensure the cooling water is filtered appropriately to protect bearings.

2. Increase the supply of cooling water if the bearings run hot.

4.8.1.2 Compressed Air Systems

Life extension activities for the various components of station compressed air systems are discussed below.

Compressors and Receivers

The possibility for compressor life extension depends entirely on previous maintenance programs and the availability of spare parts. General service 125 psig rotary screw air compressors complete with air dryers and oil separators are not an expensive item in relation to the overall cost of upgrades in hydroelectric generating stations.

The following are some life extension activities to consider:

- High pressure air systems above 300 psig serving circuit breakers and governors will usually require multi-stage reciprocating compressors depending upon the pressure requirements. If the receivers or piping are subjected to air temperatures below freezing or low dewpoints, regenerative desiccant air dryers will be required and should be installed.
- If a receiver may have been relocated from its originally designed location or application and operating conditions have changed, the vessel's design may need to be reviewed.

- A typical life extension activity would be overhaul or perhaps full replacement of the compressors. The work done as part of overhaul would depend on the type of compressor. For a reciprocating type compressor it could include rehabilitation or replacement of valves, piston rings and bearings. Rebuild or replacement of the compressor motor may be necessary. Rather simple maintenance items such as replacement of belt drives may be warranted. Reciprocating air compressors should be replaced with standard rotary screw compressors with self-lubricated pumps when compressor replacement is warranted.
- Air receiver capacity should be reviewed with a view to adding system air storage capacity to assist with compressor cycling times, which may have been caused due to an increase in system air demands.
- Refrigerated air dryers are an inexpensive method of removing moisture by reducing the system air dewpoint to 45°F. If the system receivers or piping is subjected to below 45°F temperatures, other methods of moisture removal should be investigated. Refrigerant type air dryers can be recharged. Likewise the desiccant in desiccant type dryers may require replacement.
- Air receivers and piping should be replaced if they are in deteriorated condition.
- Miscellaneous valves, moisture separators etc. are generally replaced when they begin to malfunction.
- Control devices are either rebuilt or replaced if they do not function satisfactorily.

<u>Piping Systems</u>

Assuming that the piping systems have been inspected for corrosion and wall thickness and exceed the requirements of the Power Piping Code (ANSI B31.1), with a reasonable margin for a minimum of 20 years of future life expectancy, the following should be considered:

- Look at interconnecting compressors of similar operating pressures to provide back-up capacity and then installing one additional new air compressor as a lead unit.
- Provide priority valves to direct air to essential services such as Brake and Instrument Air should a leak occur in non-essential air supplies (general Station Service Air).
- Repair any of the major items found in the condition assessment that will reduce air leakage.
- If pipe is corroding, perform thickness surveys to establish corrosion rate, remaining life and required inspection intervals.
- Install seismic pipe supports.

4.8.1.3 Raw and Cooling Water Systems

Primary life extension activities for the raw and cooling water systems would consist of replacement or rebuilding of pumps, strainers, coolers and other equipment.

Pumps

Pump rebuilding could include impeller wear ring and bearing replacement. On some pumps, where the volute casing has suffered from sediment erosion, special coatings can be applied minimize the rate of erosion damage. Rebuild or replacement of the pump motor may be necessary.

Strainers

Strainer rebuilding would typically include replacement of the straining media. Brass straining media can be replaced with stronger stainless steel materials.

Valves

Large valves may be rebuilt, including replacement of seats, seals, stems etc. . Replacement of smaller valves is usually more cost effective. Gate valves above about 12 inches are quite costly, and when replacement is necessary, it may be possible to substitute a butterfly valve or a knife gate valve.

Piping

Piping should be replaced if it is badly corroded. New stainless steel piping can be considered for corrosive environments. Plastic and HDPE (high density polyethylene pipe) has also been used for some applications, although care must be taken to ensure they are adequately protected from accidental damage.

Anti-sweat insulation should be replaced if deteriorated; however replacement of asbestos insulation can be costly. Nevertheless, deteriorated asbestos insulation must be removed for health reasons.

Installation of pipe vibration and expansion supports may extend life.

Application of a new protective coating to piping, valves and equipment will also aid in life extension.

Coolers

Heat exchangers should be flushed/cleaned and should be re-tubed if leaking.

Control Devices

Control devices are either rebuilt or replaced if they do not function satisfactorily.

4.8.1.4 Potable Water System

Life extension activities for the potable water system would be similar to that for the cooling water system.

If water quality needs to be improved to meet applicable health standards, filtration, chlorination or purification equipment could be installed.

4.8.1.5 Drainage and Dewatering Systems

Life extension activities for the drainage and dewatering system would be similar to that for the cooling water system.

Oil Spill Containment

The distinction between life extension and modernization activities becomes blurred for oil spill containment. When bringing existing systems into compliance, this could be looked at as a mandatory activity that is required in the plant 20 year plan. It is often not an "optional" modernization activity that can be justified in a benefit to cost analysis. Activities are usually selected on the basis of a risk assessment that:

1. evaluates the risk posed to the environment in terms of the probability of oil spills from existing equipment and the consequences of environmental damage;

2. estimates the total cost of corrective actions;

3. establishes priorities for capital improvements in order of the greatest reduction in risk per dollar spent;

4. selects actions that reduce risk to a target acceptable level.

Containment schemes include both permanent and temporary ones and total or partial containment. The following are spill containment options that are usually considered:

1. surface and sub-surface drainage interception

2. collection pits around specific equipment

3. sump modifications

4. oil water separators

5. oil in water sensors & alarms.

6. Site specific factors, including topography, sub-surface geology, climate and environmental sensitivity must be considered when evaluating containment options.

7. There are numerous effluent control schemes to consider including:

8. flow-through methods such as gravity (API-type) oil-water separators, the IEEE-type oil trap, and gravity or pumped filtered discharge arrangements.

9. flow stop methods – such as oil-absorbing polymer bead drains, oil stop valves and oil sensor (mechanical or electrical) actuated valves and pumps.

10. closed drainage methods – such as large spill ponds and drainage networks to retention pits, which may be drained automatically, manually or by evaporation.

The IEEE Guide for Containment and Control of Oil Spills in Substations (ANSI/IEEE Standard 980 – 1994) is recommended as a useful reference for its discussion of typical containment designs and methods.

4.8.1.6 Fire Protection Systems

1. Mechanical Fire Protection Systems

General

The aim of life extension for mechanical fire protection systems should be to maintain or slightly improve the level of fire protection available. The options for life extension will depend on the type and condition of the existing fire protection systems.

When considering life extension measures, keep in mind the design objectives of the existing systems, the condition of the existing systems, modifications to the existing systems that have been made since initial installation, items that can restore or improve the intended level of protection, and upgrades that can extend the life of the existing system.

Life extension upgrades are generally of a lower cost than a full modernization. Life extension should be considered in the following scenarios:

1. the existing fire protection is acceptable;

2. the value of the station is relatively low;

3. the station has a low annual energy production;

4. it is expected that the station will be decommissioned or redeveloped within the next ten years; or

5. a combination of the above factors.

For stations with limited fire protection, high value, large energy production, or a considerable life span remaining, it might be more cost-effective to modernize the mechanical fire protection systems.

2. Automatic Fire Suppression Systems

General

Life extension of fire suppression systems will involve maintaining and improving the operation and safety of existing systems.

Water-based suppression systems are the most common systems in use.

Water-based systems have demonstrated their effectiveness in extinguishing fires. Experience has shown that the water damage resulting from deluging a unit with epoxy based insulation is minimal. Water systems have proven to be reliable, and at hydro plants, they have the advantage of a virtually unlimited supply of extinguishing agent.

Carbon dioxide or other systems might be present in existing stations. These systems are usually found in areas with water-sensitive equipment.

Points to Consider

When considering options for life extension of a fire suppression system, the following items should be considered.

1. Testing, inspection, and maintenance should be performed on a regular basis.
2. Replace all damaged or corroded components.
3. Can the system be better interconnected with the fire alarm system? Can the fire alarm system handle additional duties? For example, the fire alarm panel could be made to supervise water leakage past a deluge valve.
4. Could automatic or manual activation capability be added at a reasonable cost? Can the manual activation be better identified or moved to a more conspicuous location?
5. All systems should be equipped with a disabling feature to prevent undesired discharge during maintenance.
6. Provide seismic restraint for existing fire protection piping and valves.
7. Install bonding and grounding of fire protection piping to prevent the creation of voltage potential and an electrocution hazard.
8. If a water-based system was installed, check that all components are listed by a recognized testing agency for use in a fire suppression system.

9. For a water-based system, flush fire protection piping. If water is especially dirty or contains scale, the pipe might be in poor condition and might require replacement.

10. Replace recalled or de-listed sprinkler heads with replacement heads. Avoid heads that use an O-ring between the pipe nipple and the seat of the sprinkler head.

11. An option for life extension is to replace existing, older heads with new quick-response sprinkler heads. Ensure that the orifice and K-factor of the new heads are compatible with the existing system.

12. Some older-style deluge valves used a complex pneumatic detection and activation system. Consider replacing problematic older-style deluge detection and valves with simpler components.

13. Consider adding additional water-spray nozzles if the current design of a deluge system does not provide adequate coverage or applied density.

14. If a deluge system is currently not set for cycling operation, consider setting the system to have this feature.

15. For carbon dioxide systems, replace piping and fittings that are not made of the correct material as specified by NFPA. Fittings and piping should be able to withstand the burst pressure specified by NFPA.

16. Carbon dioxide system present a life safety hazard and are not recommended for new installation, but existing system are still common in industry. Maintain existing life protection features. Rescue procedures should be in place for when personnel are working in the protected space, and self-contained breathing apparatus should be available. In the event of a discharge, air-monitoring equipment and self-contained breathing apparatus should be available to allow personnel to check that the space is safe for re-entry.

17. Carbon dioxide systems should be equipped with pre-discharge warning alarms and the capability to disable the system so that personnel can work on the system or in the protected space.

18. Consider the addition of an abort switch for manual shutdown if a CO_2 system is not equipped with this feature.

19. For carbon dioxide systems, is the system capable of discharging a sufficient amount of gas to protect the volume of the enclosure? NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume. Life extension of a CO_2 system might necessitate the addition of more CO_2 storage.

20. Repair or replace CO_2 storage vessels, piping, and nozzles as needed. For a high-pressure system, perform hydrostatic testing of the storage cylinders. For a low-pressure system, maintain the tank and refrigeration system. A low pressure storage tank must be equipped with a relief vent valve to discharge excess pressure to the atmosphere.

21. A total-flooding CO_2 system must be enclosed to prevent loss of agent and reduction of effectiveness. It will generally not be possible to completely prevent leakage, but large openings and holes in the enclosure should be sealed. If these openings cannot be sealed, then an additional amount of CO_2 gas will be required to offset leakage.

22. Existing halon systems should be drained and the halon be captured in an environmentally-benign manner. Halon is an environmental hazard. Consider replacement with pre-action sprinklers, or if a water-based system is not desired, consider another gas agent system.

3. Manual Fire Suppression Systems

General

Life extension of manual suppression systems should take into account how the systems are used. If there is no fire department or plant fire brigade, and staff are not trained or expected to engage in manual fire suppression, then life extension might not be a worthwhile endeavour. However, if the station relies on manual suppression for its fire protection needs, then upgrading these systems might be imperative.

Points to Consider

1. Clean out hydrant and fire department connections. Flush hydrant systems.

2. Water supply mains can be “pigged” to remove scale and other deposits.

3. Assess the standpipe system with respect to NFPA 14, “Standard for the Installation of Standpipe and Hose Systems” and perform minor upgrades as needed to bring the system into conformance with this standard.

4. Replace old or deteriorated interior fire hose lines.

5. Provide additional interior hose lines in any areas with limited hose coverage.

6. In areas with no access to large-diameter standpipe connections, provide additional standpipe connections inside the powerhouse for use by fire suppression crews. The connections should be compatible with the large diameter (usually 2.5”) hose used by the crews.

7. Install standpipe connections for use by the fire brigade near outside transformer banks. The distance from the hydrant connections to the transformer banks should be remote enough so that the fire brigade is not exposed to high levels of radiant heat when coupling hose to the connections.

8. Provide additional portable fire extinguishers as per NFPA 10 and per applicable fire codes.

4. Fire Suppression Water Supply & Fire Pumps

General

Life extension of water supply should concentrate on getting the maximum performance from the existing system. Upgrades can include refurbishing of water supply mains, improving features on an existing fire pump, and adding additional portable fire extinguishers.

Points to Consider

1. If a water-based system is installed, review the water supply. If valves do not have supervision, consider adding this feature. Fire protection water supply should also not be affected by shutoff of domestic water or other service water supply. Maintain pressure-reducing valves and other components so that they do not impair the ability of the system to provide required flow and pressure.

2. If the station has low water pressure, then consider improvements to get the most out of the existing system. For example, undersized or inefficient fittings can cause significant pressure losses.

3. Is there is an existing fire pump? Ideally, the pump and motor should be listed by a recognized testing agency as being suitable for use as a fire pump, but if they are not, these components do not necessarily need replacement; however, they should be maintained in good condition. An exception is the use of propane-powered fire pumps. Propane-powered motors and propane storage are serious fire hazards and should be replaced by diesel or electric motors.

4. If a fire pump is installed, ensure that the packing glands are set at the proper tightness. If the glands are too tight, the pump can overheat. An occasional drip of water coming from the packing glands when the pump is cool generally indicates proper tightness.

5. Diesel fire pumps should be test run on a weekly basis, and electric fire pumps should be test run on a monthly basis. Check the pump discharge characteristics on an annual basis to ensure that the pump can provide the required flow.

6. Ensure that the packing glands on the fire pump are set correctly so that they do not overheat and seize during operation.

7. Test the fire pump performance and compare to previous results to detect degradation of performance.

5. Smoke Control

General

Life extension of other fire protection features will have an improvement on smoke control by reducing the amount of smoke generated by a fire.

Many of the older hydroelectric power stations in North America were constructed with limited ventilation and no means of smoke control, and therefore, there options for life extension might be limited in these stations.

When weighing options for life extension of the smoke control and ventilation system, the following important points should be kept in mind:

1. Is there any smoke control or means of ventilation? If no smoke control is installed and there is only a limited air handling system, then there might not be any options for life extension.

2. If there is an existing building ventilation system, then the design of the system could be reviewed and adjusted to at least minimize the spread of smoke through the building.

3. Smoke control is of particular concern in underground power stations.

4. If there is a smoke control system, or if the ventilation system can be configured to reduce the spread of smoke, then consider adding either automatic and manual operation if needed.

5. Check the condition of fans, wiring, and controls. Fans used for smoke removal often need to be specially selected to handle high temperatures, and heat-resistant cable might be required. Older low-efficiency fans could be replaced with newer high-efficiency models. Conventional cable could be replaced with heat-resistant cable.

6. Fire Detection and Alarm Signaling Systems

<u>General</u>

The aim of life extension for fire detection and alarm signaling systems is to maintain or slightly improve the level of fire protection available. The options for life extension will depend on the type and condition of the existing system.

Life extension upgrades are generally of a lower cost than a full modernization. Life extension should be considered in the following scenarios:

1. the existing fire protection is considered to be acceptable;

2. the value of the station is relatively low;

3. the station has a low annual energy production;

4. it is expected that the station will be decommissioned or redeveloped within the next ten years; or

5. a combination of the above factors.

For stations with limited fire protection, high value, large energy production, or a considerable life span remaining, it will possibly be more cost-effective to modernize the fire detection and alarm signalling system.

Fire Detection and Alarm Signaling

Due to the primary importance of this system, a life extension program should not overlook fire detection and alarm signalling.

Basic life extension for these systems will involve testing, maintenance, replacing outdated components, and replacing damaged components.

In addition, the following measures could be considered for life extension of an existing system.

1. If there is a lack of fire detection coverage, and more devices can be added to the system, install additional fire detection devices.

2. If ambient noise prevents audible alarms from being heard, the volume might need to be increased, or consider additional audible alarm signaling. Conversely, the sound level of devices in offices and control rooms is often set too loud and could disrupt operations during an emergency. Volume in these areas could be adjusted down.

3. If the ambient sound frequency cancels the sound from a fire bell, consider replacing fire bells with horns. Horns produce an audible signal of varying frequency and therefore, their signal will be outside of the cancellation range at least some of the time.

4. Review the need for additional visual devices especially in areas with high sound levels or other audibility problems. Ensure that visual devices are visible in all areas (for example, unit control boards can often block the visual signal to certain areas of the generator floor).

5. Does the fire alarm panel have automatic control of the HVAC? If so, could the system be improved to give improved smoke control?

6. Would the fire alarm panel benefit from enclosure inside a cabinet built for industrial use? Some of the commercial cabinets were intended for use in office or apartment buildings and might not provide proper protection for the fire alarm circuitry in an industrial environment.

7. Consider bracing the unit fire alarm control to resist seismic movement.

8. Consider off-site monitoring if the station fire alarm system has this capability. Remote monitoring is an important consideration for stations that are unattended for periods of time. Remote monitoring can also allow a utility to formulate a quicker response to an emergency situation by automatically informing an outside control center of an emergency.

4.8.1.7 HVAC

Life extension activities for typical components of an station HVAC system include:

- Ductwork: Internally clean all ductwork. Check air flows against design. Check balance damper and fire damper operation. Check for excessive positive or negative pressure in any areas. Add fire dampers where a fire rating is required between critical areas.
- Fans: Clean casings internally, check RPM against the original design; mega the motors; replace the belts and drives if necessary. Older centrifugal fans usually operate at a lower RPM than today's selections and could be speeded up to give more air supply if required.
- Louvers and automatic dampers: Clean and or repair all louvers and screens; replace any damaged seals on automatic dampers and confirm that they can cycle from full open to closed on a fan shut down. Consider replacing actuators with rods with direct acting units.
- Review the control system logic to see that the supply and exhaust fans, duct heaters and cooling systems are not fighting each other. Control devices are either rebuilt or replaced if they do not function satisfactorily.
- If the thermostats or sensors are more than 10 years, consider replacement with newer more accurate units.
- Chillers would often be overhauled. Refrigerant would be replaced.
- Heat exchangers should be flushed/cleaned and should be replaced if leaking.

4.8.1.8 Powerhouse Crane

Life extension include the following:

- Increase inspection and maintenance frequency.
- Develop a maintenance strategy for the crane based on remaining life of the project.
- Replace/refurbish components that detract from the crane's performance.
  - Hoist, trolley drive and bridge drive motors and brakes may be rebuilt or replaced.
  - Controls may be replaced with modern solid state controls, including radio control hoist operation.
  - Satisfactory hoist and trolley limit switches should be verified.
  - Wire ropes are replaced if worn or corroded.
  - Gears and bearings for the hoist should be inspected and replaced if necessary.
  - End trucks and wheel bearings may require overhaul.
  - The integrity of crane end stops can be reviewed.
- Change crane rating:
- De-rate an existing crane that may not be cost effective to maintain at rated capacity.

- Upgrade an existing crane if heavier/taller lifts are required.
- Add a jib crane or modify the auxiliary hoist to improve powerhouse coverage (increase vertical and/or horizontal range covered by the crane).
- Change hoist speeds to better suit site needs. This applies mainly to auxiliary hoists where the speeds can be more easily changed and the capacity lift is not defined. The capacity of the main hook of a bridge crane is dependent on the rotor weight. The capacity of auxiliary hook is a percentage (approximately 10% to 20%) of the main hook capacity. Changing the speed of the main hook almost always affects the capacity.
- Where possible, install identical motors (hp, motor speed, etc) on the main and auxiliary hoists. This allows the motors to be exchanged in an emergency.
- Enhance inching capabilities on hoisting, trolley movement and bridge movement.
- Modify existing lifting beam or provide new lifting beam if there is a new or different lifting requirement.
- Realign the bridge end trucks if the crane is ‘steering’ (i.e. not travelling straight down the runway). In addition, guide wheels can be added to the end trucks to keep the crane tracking straight on the rails and preventing the wheel flanges from rubbing on the side of the railhead.
- Realign the crane rails or change the method of connecting the rails to the runway. Problems with the crane steering can result in the rails becoming misaligned even after the rails are realigned as part of the crane upgrade. The rail to runway connection can be a floating design. After realignment and during the first time the crane travels on the rails, the steering effect can cause the wheel flanges to rub on the railheads, causing the rails once again to become misaligned. The rail to runway connection design may be changed from a floating rail to a fixed rail.
- The protective coating system on the crane should be renewed as necessary.

4.8.1.9 Tailrace Crane

Life extension activities for the tailrace crane would be the same as for the powerhouse crane.

Unlike the powerhouse crane hoist, the tailrace gantry crane hook is not visible when picking up the draft tube gate. If the pressure across the gate is not equalized or the lifting beam does not engage properly or the rope gets jammed the full breakdown torque of the motor is applied to the machinery and structure. Installation of a load limiting device would prevent this potential overload.

4.8.2 Auxiliary Electrical Equipment

The following discusses the principal life extension activities for the auxiliary electrical equipment.

4.8.2.1 Generator Transformers

The principal life extension activity for generator transformers would be the treatment and/or replacement of the transformer oil. As previously noted the build-up of contaminants in the transformer oil, in the form of oxidation products, water, combustible gases, etc. can directly contribute to accelerated aging of the winding paper insulation and in extreme cases to internal faults due to loss of the oil's dielectric strength.

A second potentially effective life extension measure would be the upgrading and/or rehabilitation of the transformer's cooling system components. By clearing blockages within the cooling system oil-flow conduits and possibly increasing air flow with additional fans or oil flow with uprated pumps, it is possible to decrease the hot spot operating temperatures and, as previously noted, this will have a direct impact on the rate of paper insulation aging.

The final suggested life extension measure for generator transformers is the upgrading and modernization of transformer monitoring and testing. This could include more rigorous and extensive oil testing and periodic maintenance testing of winding dielectric values and all ancillary components, and retrofitting of modern upgrade monitoring equipment such as gas-in-oil incipient fault detectors, partial discharge analyzer systems and vibration and acoustical detectors. Although the upgraded testing and monitoring may not directly affect the aging process, they will permit the optimization of maintenance activities, such as oil treatment, and the early detection and possible remediation of defects before they can develop into major life-threatening failures. In this way there is a real possibility of extending the useful operating lifetime of the transformer.

4.8.2.2 AC Station Service System

Life extension activities for the AC station service system principally comprise of the replacement of components. Typically this should provide added benefits to the system as modern equipment with increased functionality replace old components. In the case of the station service transformer(s) new dry-type transformers in place of older oil-filled units provides environmental benefits.

Alternative life extension measures for the AC station service equipment include improvements to the operating environment through better ventilation for transformers and buses and reduction in contaminants through air filters and anti-condensation heaters for switchgear. Redistribution of loads within the system and/or increased capacity in key equipment could reduce overload and circulating current conditions within the system. In specific instances consideration could also be given to increasing voltage levels and converting 120 V and 220 V motors and other loads to 480 V or 575 V operation to reduce load current.

4.8.2.3 DC Station Service System

As for the AC station service system, the principal life extension activity for the DC station service system would be the replacement of components. Particularly for key equipment such as the station batteries, modern technological developments provides the probability of improved performance and longevity for the replacement equipment.

The introduction of a second redundant DC system will benefit the overall powerhouse electrical system through improved reliability of this essential power supply and will also tend to decrease the duty cycle of components within the DC station service system, thereby increasing their operating life expectancy.

4.8.2.4 Cable and Cable Support Systems

If the neutral or shield is corroded at many points along the length of the cable, a recommendation to replace the entire cable may be made. If the corrosion is isolated to only a few points, these locations may be cut out and new sections of cable spliced in place. This technique may save the cost of entire cable replacement, and provide confidence that the remaining cable neutral or shield is in good condition and the cable is unlikely to fail suddenly.

The seismic stability of the system should be reviewed. Diagonal bracing should be installed where required.

4.8.2.5 Grounding System

The integrity of the installed grounding system should be reviewed to confirm that the system meets IEEE Standard 142 and 181, Article 250 of the NEC, NFPA7780 and local codes. In addition to periodic inspections, bonding measurements and step and touch voltage measurements should be routinely made.

Soil resistivity in the area of the ground rods and grounding grid around the structures or buildings should be tested both for the purpose of the original grounding system design and at any time it is suspected that environmental conditions may have changed. In this regard consideration should be given to confirming resistivity during all climatic conditions to ensure that, in northern locations, the grounding system remains safe even with frozen ground conditions.

4.8.2.6 Lighting

A typical life extension activity and the simplest upgrade is cleaning the reflective surface of all the High Pressure Sodium (HPs) and fluorescent luminaries to improve the light output.

Group relamping of the fluorescent and metal halide lights is more cost effective and maintains the lumen output levels.

Fluorescent lights are four times as efficient compared to incandescent for the same input wattage, therefore upgrading or retrofitting a large area in older buildings would required ¼ fewer luminaries, yet maintain the original lumen output.

Retrofitting with new luminaries offers an opportunity to change the original system. A comprehensive lighting analysis should be considered to achieve a higher quality lighting design.

The analysis needs qualified people to evaluate the visual tasks and the environment to be lighted, not just considering the lumens and power consumption.

The manufacturing of the magnetic type fluorescent ballasts will be discontinued in the year 2005. If the physical condition of the existing lights, i.e. sockets and lenses are acceptable, then consider converting older T12 lamps and magnetic ballasts to new T8 lamps and electronic ballasts, or replace them with new luminaries when upgrading existing HPS lights. The ANSI codes of the lamp and ballasts must match.

Lighting is designed to provide a substantially uniform level of illumination through a building area, taking into account the visual task in specific areas.

The recommended illumination levels as set out by the Illuminating Engineering Society of North America and local building codes should be used for designing and evaluation of lighting systems. The Advanced Lighting Guidelines 2001 - developed by the New Buildings Institute (NBI) is a good current reference for information about energy-effective technologies.

4.9 Timing, Schedule and Costs of Activities

Equipment Data and Technical Information	History of Maintenance and Major Repairs
Condition Assessment of Equipment	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	Environmental Issues
Possible Life Extension Activities	**Timing and Costs of Life Extension Activities (Step 4-8, Volume 1)**

4.9.1 Assigning Activities

The condition assessment should provide the early framework for a Life Extension and Modernization (LEM) Plan. Equipment maintenance, rehabilitation and replacement activities have been identified and now need to be organized into a 20 year (or other planning horizon) plan. Before specific activities can be assigned to a particular year in the LEM Plan, certain policies and guidelines on the assignment of activities must be established. The following are some of the questions that must be answered:

1. Is the general philosophy concerning life extension and modernization opportunities one of consolidation? i.e. try to do as much work as possible during an annual shutdown? This would be the philosophy if lost revenue due to shutdowns was high and over-shadowed the capital requirements for the actual work.

2. Are there limits on the capital available in any one year? This may limit the scope of work for a particular year even though there would be benefits to combining work activities instead of completing them over several years.

3. Is there a preference in maintaining a constant level of annual expenditure and staffing? i.e. life extension and modernization activities should be spread out to avoid years of very high capital requirements and to level out staffing requirements?

Once these questions have been answered, the life extension and modernization activities can be scheduled over the required planning horizon on both technical and financial factors.

Probabilistic models have been developed to assist with determining optimal timing of equipment replacement before failure. These can be quite complex and are only valuable if sufficient data is available to populate the model.

4.9.2 Equipment Overhauls

An evaluation of the existing levels of maintenance and whether or not they are adequate must be made. Major overhauls or rehabilitation are usually required at regular intervals. An optimal schedule of equipment overhauls must be established and the associated costs inserted directly into the LEM Plan.

4.9.3 Equipment Lead Times

Equipment lead time for large, complex or project specific equipment which has a long order time is an important factor in scheduling activities for the LEM Plan. Delivery times for some auxiliary equipment are provided in Section 6.

4.9.4 Assigning Costs

Section 6 provides information on the costs and benefits of some life extension activities.

4.10 Environmental Issues

Equipment Data and Technical Information	History of Maintenance and Major Repairs
Condition Assessment of Equipment	
Assessment of Remaining Life	Condition Rating (if available)
Repairability Rating	**Environmental Issues (Step 4-4, Volume 1)**
Possible Life Extension Activities	Timing and Costs of Life Extension Activities

The purpose of Section 4.10 is to briefly identify some of the environmental issues that apply specifically to projects involving the auxiliary mechanical and electrical equipment. Environmental issues surrounding hydro plant projects can be very complex and a detailed explanation of all hydro plant environmental impacts is beyond the scope of these Guidelines.

Table 4-9 is a general summary of environmental impacts that can be associated with certain activities associated with station auxiliary equipment.

Table 4-9
Auxiliary Mechanical and Electrical Equipment

Activity	Associated Impact
Lubricating Systems (and Oil Tanks)	
Generation/disposal of oil or grease.	• Contamination of soil, surface water and ground water.
Compressed Air Systems (air compressors, dryers, etc.)	
• Escape of ozone depleting substances.	• Air contamination (odour, smoke).
• Generation/disposal of metal and solid wastes, absorbents, pads, paint and oily rags, waste desiccants, filter media.	• Containment of soil, surface water and ground water.
• Removal of vapour.	• Air contamination (odour, smoke).
Domestic Water supply	
Escape of contaminated water.	• Contamination of soil, surface water and ground water.
Generation/disposal of solid wastes, fuel, oil, grease, rags mercury (pumps).	• Contamination of soil, surface water and ground water.
Drainage and Dewatering Systems	
Escape of contaminated water.	• Contamination of soil, surface water and ground water.
Escape of sewage effluent.	• Contamination of soil, surface water and ground water. • Air contamination (odour, smoke).
Generation/disposal of solid wastes, rags, absorbent pads, special wastes, mercury (pump switches).	• Contamination of soil, surface water and ground water.
Generation/disposal of fuel, oil, grease.	• Contamination of soil, surface water and ground water.
Fish entrainment (when draft tube is drained).	• Fish mortality.
Sewage Treatment	
Escape of sewage effluent.	• Contamination of soil, surface water and ground water. • Air contamination (odour, smoke).
Spill/disposal of hypochloride.	• Contamination of soil, surface water and ground water. • Air contamination (odour, smoke).
Generation/disposal of special wastes, heavy metals and hydrocarbons.	• Contamination of soil, surface water and ground water.
Fire Protection System (pumps)	
• Discharge of CO2.	• Air contamination (odour, smoke).
• Spill/disposal of dry chemical.	• Contamination of soil, surface water and ground water. • Air contamination (odour, smoke).
• Spill/disposal of fuel, oil, grease.	• Contamination of soil, surface water and ground water.
• Spill/disposal of mercury.	• Special waste storage depletion. • Contamination of soil, surface water and ground water.
• Use of detergents	• Contamination of soil, surface water and ground water.
• Escape of ozone depleting substances (Halon systems).	• Air contamination (odour, smoke).

Activity	Associated Impact
Heating, Ventilation, Air Conditioning (HVAC)	
• Escape of ozone depleting substances.	• Air contamination (odour, smoke).
• Generation/disposal of waste filter media, desiccants, absorbent pads and detergents.	• Contamination of soil, surface water and ground water.
• Generation/disposal of fuel, oil, grease.	• Contamination of soil, surface water and ground water.
• Generation/disposal of paint and oil rags, solid waste.	• Contamination of soil, surface water and ground water.
Pressure Vessels	
• Disposal of fuel, oil, grease (lubricating oil, diesel engines).	• Contamination of soil, surface water and ground water.
Powerhouse Bridge Cranes	
Generation/disposal of asbestos waste.	• Air contamination (odour, smoke). • Contamination of soil, surface water and ground water.
Generation/disposal of carbon brush dust.	• Air contamination (odour, smoke).
Generation/disposal of solid wastes, metal wastes, rags, paints, coatings, detergents.	• Contamination of soil, surface water and ground water.
Generation/disposal of fuel, oil, grease.	• Contamination of soil, surface water and ground water.
Oil Filled Transformer	
Generation/disposal of sand-blasting and pressure washing wastes.	• Contamination of soil, surface water and ground water.
Generation/disposal of paints and coatings.	• Contamination of soil, surface water and ground water.
Contamination of oil and grease (oil drum containment requirements).	• Contamination of soil, surface water and ground water.
Contamination/disposal of filter media, oil and paint rags, waste absorbent pads, desiccants, and filter media.	• Contamination of soil, surface water and ground water.
Diesel Engines and Fuel Tanks	
Generation/disposal of solid wastes, metal wastes, waste filter media (foil filters, rags, absorbent pads.	• Contamination of soil, surface water and ground water.
Generation/disposal of fuel, oil, grease.	• Contamination of soil, surface water and ground water.
Generation of emissions.	• Air contamination (odour, smoke).
Removal of vapours.	• Air contamination (odour, smoke).
Pressure washing run-off.	• Contamination of soil, surface water and ground water.
Spill/disposal of anti-freeze	• Contamination of soil, surface water and ground water.
Batteries (Lead Calcium, Nickel Cadmium, Lead Antimony, Valve-regulated Lead Acid)	
Generation/disposal of waste batteries (recycling programs?).	• Contamination of soil, surface water and ground water.
Removal of vapours (lead calcium batteries).	• Air contamination (odour, smoke)
Spill/disposal of acid or electrolyte.	• Contamination of soil, surface water and ground water.
Generation/disposal of paint and oil rags, solid waste.	• Contamination of soil, surface water and ground water.
Generation/disposal of asbestos waste (battery charges on lead acid).	• Air contamination (odour, smoke). • Contamination of soil, surface water and ground water.

Section 4.10 does not cover impacts associated with construction activities during implementation of the project. Guidelines on how to manage environmental considerations during implementation are provided in Section 8.

The International Organization for Standardization (ISO) Standard 14000 for implementing effective environmental management systems is an international standard designed for individual companies to set their own environmental goals and commitments to environmental policy. ISO 14000 guides the company to formulate a plan and carry out a policy to identify significant activities that affect the environment in the production of a good or service. The company then trains personnel in environmental practices, and creates an internal audit review system to ensure the program is implemented and maintained. A registration audit by a third party may be carried out, and subsequent surveillance audits may be conducted to maintain registration. An alternative method is for a company to perform an internal review and evaluate itself for conformity with the standards.[4]

As highlighted in a 1998 EPRI Journal article, worldwide movement or accreditation in all sectors of industry is increasing.[5] The power industry is no exception. The ISO 14000 Info Center reports that 11% of the US companies registered as of June 1998 represent the power/utility sector. The framework of ISO 14000 is a flexible set of criteria, which is aimed at improving the process of environmental management. The criteria encourage setting goals and seeking ways to implement and measure progress towards achieving better environmental performance. Further information on the ISO certification process can be found on the ISO web site: www.iso.ch.

[4] EPRI, Palo Alto, CA, W05715-01 December 1998, "Hydropower Technology Round-up Report", Part 1 *"Using Environmental Solutions to Lubrication"*

[5] "Environmental Management with ISO 14,000", EPRI Journal, March/April 1998, p. 24

5
POTENTIAL FOR IMPROVEMENTS

5.1 Introduction

Section 4 of Volumes 4 and 5 outlines a methodology to assess the present condition and performance of the auxiliary mechanical and electrical systems and provides input to the life extension portion of the Life Extension and Modernization (LEM) Plan. Section 5 provides input to the modernization portion of the LEM Plan. It provides information on assessing the modernization opportunities that are available for equipment to improve plant performance beyond historical levels.

Figure 5-1 shows how the sub-sections of Section 5 contribute to the identification and assessment of modernization opportunities for the LEM Plan for the entire plant.

During the condition assessment of the auxiliary mechanical and electrical systems, the life extension requirements of equipment are identified. When significant life extension work in the form of rehabilitation or replacement is required, an informed decision needs to be made concerning whether modernization is warranted (the term "modernization" and its synonyms are defined in Section 2). Modernization of equipment is complex as changes of one piece of equipment often has implications on other plant equipment and the desired benefits may not be realized because of other plant limitations.

Appendix B in Volume 1 of these Guidelines provides a general discussion on how to identify modernization opportunities. Modernization opportunities are classified into the following main categories:

- energy
- portfolio services - i.e. capacity, storage, river system regulation, etc.
- ancillary transmission services
- operational flexibility
- automation
- other services

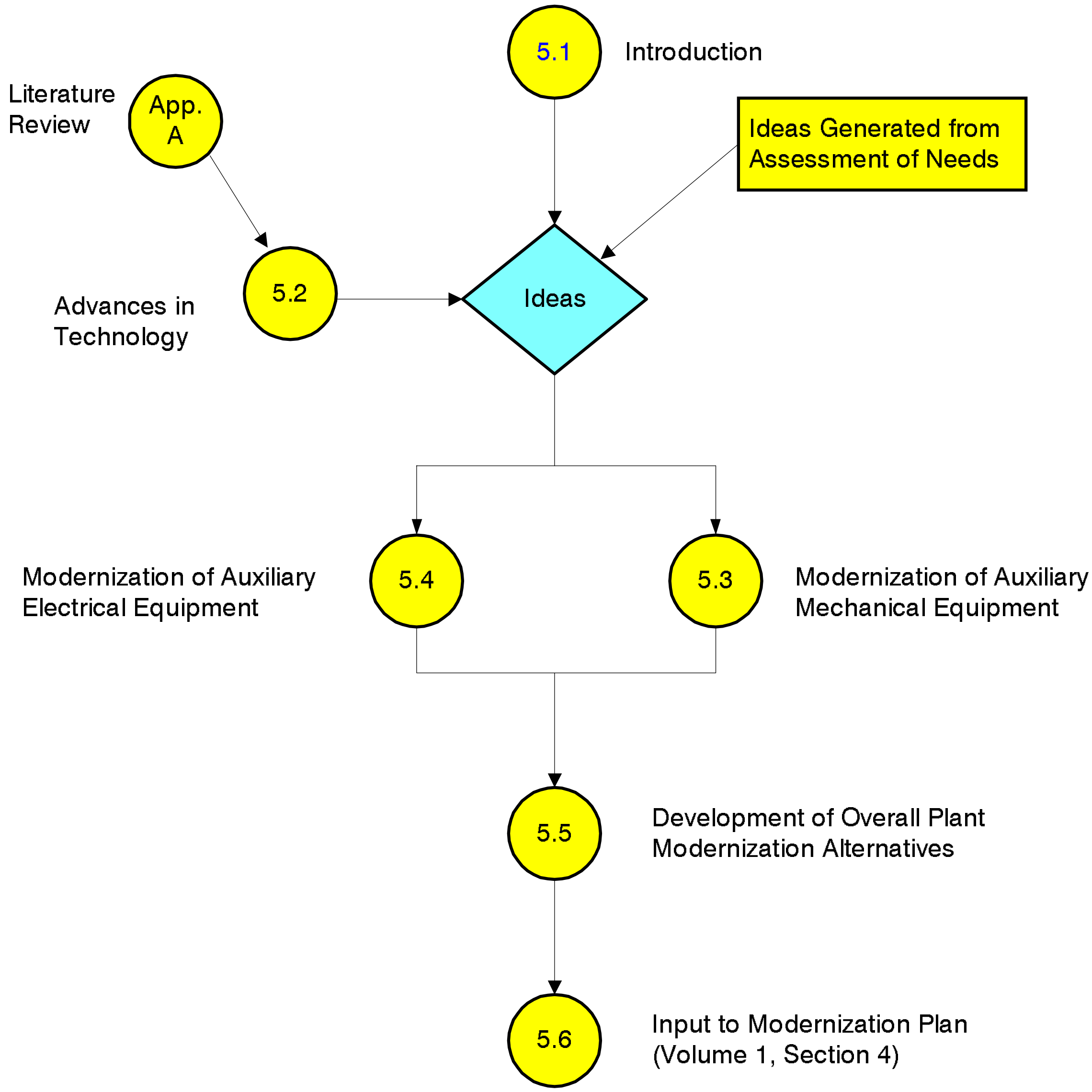

Figure 5-1
Potential for Improvements Process

The pro forma "Equipment Modernization Opportunities" worksheet (Table 5-1), sometimes referred to as the "site worksheet", may be used for recording modernization opportunities during the condition assessment process outlined in Section 4, Volumes 4 and 5. All opportunities identified should be included on the worksheets and then included in Tables 4-3 "Data Analysis for Hydro Plant" and Table 4-4 "Data Analysis and Inspection Results for Equipment and Structures" of Section 4, Volume 1. Alternatively, the data can be entered directly into these tables.

To assist in following the process, a depiction of Table 5-1 is provided at the start of each sub-section of Section 5. The highlighted portion indicates the part covered by the text included in the sub-section.

Table 5-2 is a summary of the areas of opportunity and activities to achieve these opportunities.

At the initial stage of assessment (i.e. in Section 4, Volumes 4 and 5), potential opportunities are identified but not quantitatively evaluated. This will be done when all opportunities from across the plant have been collected in Table 4-6 of Volume 1. Table 5-1 is used at this stage to ensure that all possible activities are at least identified for consideration and none is deleted from the list too early in the process based only on an impression that the project would be uneconomic.

A thorough analysis is usually conducted during the feasibility stage in Section 7, Volume 1 (with information from Section 7 of this Volume) if the identified opportunity is included in the selected LEM Plan taken forward for further consideration.

Table 5-1
Site Worksheet for Equipment Modernization Opportunities

Plant: ____________________________
Equipment Name: ____________________________
Unit No.: ____________________________
Asset No.: ____________________________
Prepared by: ____________________________ Date:__________________

<table>
<tr><th>Modernization Opportunities
(Sections 5.2, 5.3, 5.4)</th><th>Benefits of Modernization
(Sections 5.2, 5.3, and 5.4)</th></tr>
<tr><td></td><td rowspan="3">Equipment:

Overall Plant:</td></tr>
<tr><td>Further Studies Required
(Section 7)</td></tr>
<tr><td></td></tr>
<tr><td>Impacts of Modernization on Other Equipment
(Sections 5.3, 5.4 and 5.5)</td><td>Other Equipment that Limits Modernization
(Sections 5.3, 5.4 and 5.5)</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Timing & Costs of Modernization
(Section 6.0)</td><td>Risk Evaluation of Modernization</td></tr>
<tr><td></td><td></td></tr>
<tr><td colspan="2">Modernization Opportunities Selected for Input into Table 4-6, Volume 1</td></tr>
<tr><td colspan="2"></td></tr>
</table>

Table 5-2
Areas of Opportunity for Auxiliary Mechanical and Electrical Systems

Areas of Opportunity	Activities to Achieve Opportunities
1. Output (a) Increase plant capacity (for the plant, this can mean an increase in firm, high load hours and low load hour capacity) (b) Increase plant energy (head, flow, efficiency)	Activities or measures to increase efficiency/output - Improve cooling water system if generator or transformer is limiting unit output - Upgrade transformer if transformer is limiting unit output - Improve efficiency with new transformer (very small increase) - Reduce station service load by installing cooling water pumps with increased efficiency, and upgrading HVAC and lighting systems. - Provide pumped cooling water system using water from tailrace, rather than water from penstock with pressure reducing valve on high head plants. - Modulate cooling water flows based on equipment temperatures.
2. Dependability (a) Age/equipment condition - identified equipment needs suggest areas of opportunity (b) Address operational improvements required (c) Address chronic equipment/plant problems (d) Increase plant/equipment reliability (e) Reduce outage durations by upgrading service equipment, or providing additional service equipment	Activities or measures to improve condition, operation and reliability - Upgrade instrumentation and systems to improve protection and control and reduce probability of outage. - Provide redundant cooling water pumps to minimize possibility of outages - Provide redundant strainers/filters to minimize possibility of outages - Provide self cleaning strainers to improve efficiency of operation - Installed double circuit (closed loop) cooling water system to reduce fouling of generator coolers - Provide backup to brake air system to minimize possibility of loss of brake air. - Provide backup governor air compressor to minimize possibility of loss of governor air.

Areas of Opportunity	Activities to Achieve Opportunities
	- Increase capacity of service air system to allow more efficient use of air tools during outages - Upgrade powerhouse crane to allow easier and more precise operation; therefore reduce unit dismantling/assembly time. - Provide electric turbine pit hoists rather than manual chain hoists. - Improve ventilation/cooling system to reduce operating temperature of miscellaneous electrical equipment. - Add seismic upgrading of cable supports. - Improved battery systems and cell monitoring.
3. Sustainability Reduce environmental risks; improve environmental compliance	- Add oil separators and filters - Add double wall heating exchangers. - Improve fire protection - Add draft tube aeration to increase dissolved oxygen levels
4. Flexibility Improve flexible operation for the plant as a whole (e.g. load factoring, swing, automated generation control [AGC])	- Add draft tube aeration system to reduce rough operation and power swings. This will increase the range of generation unit operation. - Add tailwater depression system (compressed air) to allow for spinning reserve and synchronous condenser operation - Add a lift pump system for bearings as part of the start-up and shut-down sequences.

<u>Example of Completed "Equipment Modernization Opportunities" Worksheet</u>

Table 5-3 is an example of a completed "Equipment Modernization Opportunities" worksheet for a cooling water system. It was developed using the following:

1. Section 4 and Appendix B of Volume 1 for identification of opportunities.
2. The condition assessment process of Section 4, Volumes 4 and 5 for identification of opportunities.
3. Section 5, Volumes 4 and 5, to further identify and assess the opportunities from a technical basis.

Section 4, Volume 1 clearly lays out the process for identifying needs and opportunities of equipment and defining them sufficiently for the LEM Plan.

Table 5-3
Sample Equipment Modernization Opportunities

Plant: Plant #1
Equipment Name: Cooling Water System
Unit No.: 2
Asset No.:
Prepared by: I.M. Engineer **Date:** January 31, 2001

Modernization Opportunities (Sections 5.2, 5.3, and 5.4)	**Benefits of Modernization** (Sections 5.2, 5.3and 5.4)
• Replace manual cleaned basket strainers with self cleaning strainers. • Provide duplicate strainers for reliability	• Allows unattended plant operation • Reduces operating costs • Reduces forced outages due to loss of cooling water
Further Studies Equipment (Section 7)	
• Location and layout of modernized system • Size of strainer openings • Additional motors (for strainers) must be accommodated in motor control center • Wiring to motors and automatic valves	
Impacts of Modernization on Other Equipment (Sections 5.2, 5.3 and 5.4)	**Other Equipment that Limits Modernization** (Sections 5.2, 5.3 & 5.4)
• Utilizes spare in motor control center	
Timing & Costs of Modernization (Section 6.0)	**Risk Evaluation of Modernization**
• Installation to be completed during next annual outage. Careful planning in pre-installation required to ensure that outage is not extended. • Cost $90K per generating unit	• Forced outages reduced by an estimated 5 hours per year • If combined with other modernization activities to allow unattended plant operation, operating costs reduced $300K per year
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	
• Modernize cooling water system by installing duplicate self-cleaning strainers.	

5.2 Advances in Technology

Modernization Opportunities (Step 4-5, Volume 1)	Benefits of Modernization (Step 4-5, Volume 1)
Further Studies Required	
Impacts of Modernization on Other Equipment	Other Equipment that Limits Modernization
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

Tables 5-4 and 5-5 below provide a quick reference for the modernization opportunities discussed in this Section. Appendix A contains a bibliography, which provides references for further reading on equipment modernization topics.

There have been many developments in the technology associated with the hydroelectric industry. The drivers for the use of new technologies for modernization are:

- the fierce competition amongst suppliers for a share of the market.
- more efficient, more reliable and hence more profitable equipment.
- environmental lobby for more environmentally friendly equipment.
- many plants reaching the end of their economic lives and requiring decisions regarding their future.

The opportunities presented by the use of newer technology are: improved profitability, reliability and environmental performance. They can be achieved through:

- reducing any adverse effects that the power plant may have on the environment
- increasing output and efficiency of equipment and hence the existing plant
- reducing operating and maintenance costs

Table 5-4
Summary of Advances in Technology for Mechanical Auxiliaries

EQUIPMENT	ADVANCES IN TECHNOLOGY
Bearing Lubrication Systems	• Teflon bearing pads Green" environmentally friendly lubricants
Raw Water and Cooling Water Systems	• Higher efficiency pumps Double wall coolers
Compressed Air Systems	• lower cost screw type compressors PLC type compressor controls
Raw and Potable Water Systems	• relatively low cost variable speed pump drives double wall heat exchangers
Drainage System	• oil separation and detection systems variable speed pumps
Fire Protection Systems	• These are recent or new fire protection technologies: Quick-response sprinkler heads Computer-based fire detection and alarm signalling systems Air-sampling smoke detection Transformer explosion suppression (very new - not yet listed for use in North America) Linear beam smoke detection Flame detection cameras Gaseous fire suppression agents with very low or zero environmental or health impacts
HVAC	• variable speed fans computerized energy monitoring systems digital controls
Powerhouse and Tailrace cranes	• digital crane controls variable speed drives radio control

Table 5-5
Summary of Advances in Technology for Electrical Auxiliaries

EQUIPMENT	ADVANCES IN TECHNOLOGY
Unit Transformers	• Oil-free, high temperature superconductors (HTS) transformers for efficiency, environmental and space-saving benefits • Efficiency improvement through the use of low loss steel for cores and more uniform core profiles • Oil-free resin impregnated bushings instead of porcelain bushings. • Condition monitoring for continuous data on such variables as dissolved oxygen in oil, temperature change, noise, etc.
Station Service AC	• Higher ratings; faster, more compact • Station service auxiliary transformers - use of dry transformers to mitigate fire and environmental risks; efficiency improvements
Station Service DC	• Batteries - reduced maintenance and slightly longer lives with new types such as Ni-CAD batteries • Automated monitoring of individual cell systems
Lighting Systems	• Digital addressable lighting interface and integrated lighting control systems • Improved motion and occupancy sensors. • New digital dimming ballasts that are addressable. • Pulse start lamp and ballasts. • Second generation LEDs • Electronic ballasts - multi-voltage and multi-wattage

In general, the use and development of computer-based technology has been a catalyst for enabling many of the developments outlined below.

The information which follows is current but, over time, will become dated. The user is encouraged to check for developments since the publication of this document in technical journals and conference proceedings and with manufacturers and suppliers.

5.2.1 Mechanical Auxiliaries

5.2.1.1 Lubrication Systems

New technologies for bearings which impact the lubrication systems include the use of oil lubricated Teflon thrust bearing pads instead of oil lubricated Babbitt pad.

An important area of study is the use of environmentally friendly “green” hydraulic oils. Various reports have been published on this topic. See Appendix A for references.

5.2.1.2 Raw and Cooling Water Systems

Modern pump designs have increased efficiency, which can result in lower operating costs. Variable speed controls are becoming more economical and in certain situations this option can be an economic alternative to modulating (flow control) valves for controlling flow through generator air-to-water heat exchangers.

For bearing and governor oil cooling systems, the use of double wall heat exchangers will minimize the possibility of oil being discharged into the environment and/or ingress of water into the oil.

A new type of generator cooling called "evaporation cooling" uses a coolant with high insulation performance instead of water. The hollow conductors of the stator winding are used as the circulation passage.

5.2.1.3 Compressed Air Systems

Modern service air compressors are rotary screw type for increased efficiency. They can be provided with built in air dryers and oil separators.

Modern compressors can be oil free which reduces environmental risk.

Modern compressor controls are PLC type, which provides improved control flexibility.

5.2.1.4 Drainage and Dewatering Systems

New oil spill detection equipment and oil separator technology are being produced by manufacturers regularly. Equipment manufacturers should be contacted for literature on the latest commercial products.

The pumps for unwatering and drainage systems typically operate infrequently. Therefore improvement in pump efficiency is usually of minimal benefit. When used in conjunction with oil-water filtration/separation equipment, a variable speed pump may be of some benefit in that for the majority of the time the pump discharge can be regulated to a very low flow, which will improve the effectiveness of oil filters.

5.2.1.5 Fire Protection Systems

Recent or new fire protection technologies include:

- Quick-response sprinkler heads
- Computer-based fire detection and alarm signalling systems

- Air-sampling smoke detection
- Transformer explosion suppression (very new - not yet listed for use in North America)
- Linear beam smoke detection
- Flame detection cameras
- Gaseous fire suppression agents with very low or zero environmental or health impacts

5.2.1.6 HVAC

Assuming that the modernization options under Section 5.3 have been reviewed, the following items could be considered in terms of new technology available for HVAC systems. It is difficult to make an economic case for these items in the short term simply on energy savings.

- If any fans have high HP motors sized for cooling loads that vary by the time of day or year, variable speed drives should be considered.
- Direct Digital Control (DDC) systems offer possibilities for finer control, self-calibration, off-site monitoring, software upgrading and trouble shooting. Real time graphics packages for each system located in the front end computer allow station staff, not normally involved with the HVAC system, to more easily understand the operation. DDC facilitates efficiency improvements by optimizing HVAC operation.

5.2.1.7 Powerhouse Cranes

Advances in crane technology have been mainly related to crane controls. Modern controls are digital, which reduces cost and provides more control flexibility. Hoist and drive motors are often induction type with static frequency converters to provide variable speed operation.

Cranes are now commonly provided with radio control to allow the operator to be closer to the load being handled.

Radio control in conjunction with variable speed drives allows more precise handling and positioning of loads, which can result is more efficient dismantling and reassembly operation with reduced potential for damaging equipment during handling operations.

An innovative way to load test the crane is to use test loads made up of bags filled with water. Several firms provide this service and load testing can be very quick with this method (1 to 2 days).

5.2.1.8 Tailrace Cranes

Most of the items discussed in (a) above also apply to tailrace cranes. Improved control of tailrace cranes will reduce the time required to install and remove gates, which will result in shorter time required to unwater and inspect a turbine.

5.2.2 Auxiliary Electrical Equipment

5.2.2.1 Generator Transformers

Advances in transformer design and construction technologies which may be considered when planning the modernization of generator transformers include:

- very low loss core lamination steel, configured with advanced computer analysis and design programs to provide highly efficient magnetic cores, with consistent properties and performance;
- core configuration, shape and fixation designs to reduce the production and transmission of sound as an environmental improvement;
- oil-free, resin impregnated high voltage bushings to reduce environmental impact, fire hazard, and moisture absorption and to increase mechanical strength;
- oil-free HV transformer design using cable technology in place of conventional oil-impregnated paper insulated windings to reduce environmental impact and fire hazards;
- although still only in the experimental prototype stage, high temperature superconductor (HTS) technology offers the possibility of significant reduction in losses and being oil-free, will reduce that environmental impact;
- advanced design and modelling techniques facilitate transformer designs with more uniform flux and current distribution for reduced hot spot temperatures, improved performance and more precise design parameters;
- Digital condition monitoring instruments and systems for continuous measurement, analysis and reporting on parameters such as dissolved gas-in-oil, rate-of-change of temperature, noise and vibration, etc. for more accurate assessment of equipment condition.

5.2.2.2 Station Service AC

New technologies for station service ac system include closer monitoring of equipment using additional instrumentation such as voltage, current and temperature sensing, protection sensor targeting, trip and test facilities, remote control and indication. The addition of voltage regulators may be necessary to maintain a proper level of voltage and tominimize the range of voltage swing between light and heavy station service load periods. The addition of current-limiting reactors will protect switchgear against higher than rated fault currents. The addition of grounding resistors to station service transformers neutral will limit the ground fault current to station service equipment.

Replacement of old and outdated surge arrestors can provide adequate protection to major equipment.

When a powerplant is undergoing major modernization, new switchgear, motor control centers, switchboards, and panelboards are often required since modifications to existing equipment will likely result in extensive shutdown of the equipment.

New technologies associated with standby generators are best discussed with the generator manufacturers. However, most technology advances forms on:

1. PLC based protection and control systems.

2. New models of generators with electronic injection control.

Developments in the area of station service and auxiliary transformers have centred on the use of "dry" transformers to mitigate fire and environmental risks.

5.2.2.3 Station Service DC

New technologies for station service dc system include new electronic charger replacements, dc circuit ground detection, reallocation of dc control and protection circuits for improved selectivity for circuit faults, protective device co-ordination, remote indication.

The following should be considered to improve the overall security, reliability and safe operation of the dc system.

- provision of output blocking diodes for battery chargers to prevent the possible discharge of the battery through a short circuit inside the battery charges.
- dc overvoltage protection for battery charges to prevent battery damage due to overcharging and to protect dc loads from excessive overvoltage.
- dc ripple filtering for battery chargers
- charger failure sensing
- dc undervoltage alarm
- battery breaker open or battery fuse blown alarm
- use of separate batteries for field flashing which do not supply protection and control circuits.

The main developments of DC systems have been in the area of batteries:

- modern batteries have reduced maintenance requirements and slightly longer lines (some examples of Ni-Cad batteries are in use but the most popular are still the lead acid types).
- automated monitoring of individual cell systems (reduces staff time to monitor and log battery condition).

5.2.2.4 Cables and Cable Support Systems

National Electrical Code provide design guidance for safety requirements in raceway systems. If the raceway system is embedded or underground and spare ducts have to been provided, direct burial cables or new direct burial plastic conduits can be installed above or beside existing duct banks thus using the present routing.

Cellular floor are widely used in control room to provide maximum versatility of routing control and communication cables.

From the life extension standpoint it is important to consider measures to retard the spread of fire through the cable tray system.

5.2.2.5 Grounding

The use of fuseable welding and compression connection technology improves the reliability of electrical connections.

5.2.2.6 Lighting

New technologies for lighting include the following:

Controls

- Digital addressable lighting interface and integrated lighting control systems.
- Retrofit fluorescent dimmers do not require additional wiring or optional remote controls.
- Improved motion and occupancy sensors.

High Intensity Discharge (HID)

- Metal halid lamps that can be used with high pressure sodium ballasts up to 400 watts.
- Reduced mercury content in HID and fluorescent lamps.
- New digital dimming ballasts that are addressable.
- Pulse start lamp and ballasts are replacing the old standard metal halide lamps and ballasts.
- Dual constant power (DCP) electronic metal halide ballasts produce constant lamp colour, better lumen maintenance and lamp life.
- End of life circuitry protects restarting lamps.

Fluorescent

- Self ballasted compact fluorescent lamps in higher wattages are available to replace incandescent lamps.
- H.I.D. technology for end of life has been built into some compact flourescent lamps.
- Some T8 fluorescent lamps combined with low factor ballasts consume fewer watts per two lamps luminaire.
- Some T8 lamps used in conjunction with program start ballasts achieve longer lamp life.
- Electronic ballasts are available in multi-wattage and multi-voltage.
- Dimmable ballasts for some T5 lamps.

Exit Signs

- Second generation more intense light emitting diodes (L.E.D.s) are available.

5.3 Auxiliary Mechanical Equipment

<table>
<tr><td>Modernization Opportunities
(Step 4-5, Volume 1)</td><td rowspan="2">Benefits of Modernization
(Step 4-5, Volume 1)</td></tr>
<tr><td>Further Studies Required</td></tr>
<tr><td>Impacts of Modernization on Other Equipment</td><td>Other Equipment that Limits Modernization
(Step 4-5, Volume 1)</td></tr>
<tr><td>Timing of Modernization</td><td>Risk Evaluation of Modernization</td></tr>
<tr><td colspan="2">Modernization Opportunities Selected for Input into Table 4-6, Volume 1</td></tr>
</table>

A comprehensive list of life extension and modernization alternatives that can be generally applied to the auxiliary mechanical systems is not possible because of the specific conditions that make each hydroelectric facility unique. Consequently, specific modernization alternatives for each plant must be developed from the results of the individual component assessments.

All of the components within the auxiliary mechanical systems, with possibly the exception of the fire protection system, could be sensitive to the uprating of other plant systems. Any equipment modifications identified for the particular piece of equipment should be input into their Equipment Modernization Opportunities worksheet (Table 5-1) for future consideration as part of the LEM Plan.

Table 5-6 summarizes the possible equipment modifications.

Table 5-6
Upgrading Activities - Auxiliary Mechanical Equipment

Asset No.	Equipment	Upgrade/modernization Activities
1.1.1.4	Bearing Lubrication Systems	• add oil mist collection system • installation of a lift pump system • "on-line" oil filtering • Use oil "additives" • separation of shared lubrication systems • improve filtering of oil and water • add treatment of water retention in the oil • upgrade coolers to Copper-Nickel, stainless steel, titanium or double wall • add booster pumps to deal with marginal cooler capacity (low head plants) • replace internal coolers with external • add equipment redundancy and instrumentation • improve oil containment • use of environmentally friendly "green lubricants" • add flow control valves (bypass) to maintain a constant bearing oil temperature.
1.1.1.3	Raw and Cooling Water	• for high head plants, pump water from tailrace • modulate cooling water using control valves or variable speed pumps based on equipment temperatures • convert open system to a closed loop system • change source of cooling water (headcover, tailrace) • upgrade instrumentation • install redundant equipment • upgrade to stainless steel pipe • install automatic backwash strainers • For small units, consider air to oil heat exchangers • Upgrade coolers (larger surface area, new materials, better fin design)
2.1.6	Compressed air	• replace system with state-of-the-art system with same capacity • increase system capacity • replace system with a state-of-the-art system with increased capacity • Upgrade individual components such as compressors, compressor controls and piping systems • Add equipment redundancy • Modify system valving and piping to improve reliability of critical systems (provide back-up supply, isolate operation)

Asset No.	Equipment	Upgrade/modernization Activities
2.1.7.1/2.1.7.2	Potable water	• increase system capacity • replace existing system • install modern self cleaning strainers • improve potable water treatment method • provide alternative supply of potable water
2.1.8.1/2.1.8.2	Drainage and dewatering	• replace pumps • add oil separation/filtration equipment • add redundant equipment • increase capacity • decrease dewatering times • improve level controls
2.1.9	Fire Protection	• improve - automatic fine suppression systems - manual fire fighting equipment - water supply equipment and fire pumps - fire detection and alarm signalling
2.1.10	HVAC	• conduct HVAC audit • replace fans • install additional fans • install new modern digital control system • add air conditioning equipment to the control room • intergate with fire protection • separation of unit ventilation systems from equipment spaces
2.2.1/2.2.2	Powerhouse and tailrace cranes	• modernize controls • add load limiting devices • increase lifting capacity • add additional crane • replace existing crane • improve safety (rails, fall arrest attachment points)

5.3.1 Bearing Lubrication System

Modernization of the bearing lubrication systems focuses on improving bearing performance and reliability. Possible modernization activities include:

1. Replacement of piping, valves and other system components to reduce or eliminate leakage. This reduces environmental risk and maintenance on other equipment.

2. Add an oil mist collector. Oil mist can be a serious problem that causes contamination of the brushgear and other generator components. In some plants, oil can be seen dripping from surrounding equipment. Collection systems are very often custom designed and involve collecting the oil mist and condensing the oil in a separate reservoir.

3. Installation of a lift pump system for the thrust bearing to protect the bearing during start up and shutdown and to remove any start up restrictions.

4. If contaminants in the oil are found to be a problem through oil analysis, add an “on line” filtration system. Better filtration systems will extend equipment bearing life. Treatment of water retention in the oil is also an alternative.

5. Some unusual turbine-generator designs incorporate a shared lubrication system between several bearings. Overall unit reliability may be improved if the systems were separated.

6. For water lubricated bearings, improvements in filtering may lead to longer bearing life and increased reliability.

7. Consider adding control valves to maintain a constant bearing oil temperature in the pots (prevents thermal cycling).

8. For coolers, there are several modernization options:

   (a) Replace Copper coolers with Copper-Nickle or stainless steel ones.

   (b) Increase cooler size if high bearing temperatures are a problem.

   (c) On low head plants, booster pumps may be the economical way to deal with marginal cooler capacity.

   (d) Add double wall coolers. This is not a common practice but for very environmentally sensitive applications, a reduction in oil spill risk may be warranted.

   (e) Consider new designs with larger surface area and improved fin design).

   (f) Consider replacing internal coolers with external coolers to further reduce the risk of undetected leaks leading to water in the oil. Sometimes this solution is easier than replacing an internal cooler and it has the added advantage that oil filtration can be added at the same time. However, the disadvantage is that it adds complexity to the system.

(g) For small units, consider air to oil coolers.

9. Equipment redundancy and instrumentation to reduce outages or outage time. The system should have adequate valving to allow a piece of equipment to be taken out of service while keeping the station running.

10. Addition of oil drip pans and other oil retention barriers.

11. Use of environmentally friendly "green" lubricants.

12. Consider "additives" to improve bearing performance.

13. Consider changes to the thrust bearing arrangement such as moving cooling coils closer to the fact of the thrust shoes.

5.3.2 Raw Water and Cooling Water Systems

The modernization alternatives to be considered for the raw water system should be based on the operating history of the system, the results of the component assessment, and any increased cooling water requirements resulting from the uprating of other unit equipment.

Modernization alternatives for the cooling water system should include improvements if the existing system has experienced frequent failures. Improvements might include the addition of redundant equipment such as pumps and strainers. Where cooling water quality has caused corrosion or clogging of pipes, improvements in material selection and design should be considered. In extreme cases of poor water quality, a double circuit system with an open primary circuit and closed secondary circuit may be the only reliable solution. Modernization alternatives which might be appropriate include the following:

- Increase cooling system capacity by adding additional equipment.
- Design and installation of a new cooling water system, considering other sources of cooling water such as pumping from the tailrace or using head cover (labyrinth seal leakage) water which is already "filtered" through the seals.
- Consideration of tailrace pumping for high head plants to maximize water use for generation.
- Provision of adequate redundancy and backup to reduce outage. The system should have adequate valving to allow a piece of equipment to be taken out of service while keeping the station running. (This items also applies to other services such as lubrication).
- Provision to modulating valves or variable speed pumps on the generator cooling water supply to reduce cooling water demand, minimize thermal stressing on the generator, prevent condensation in the generator enclosure, and increase pump efficiency (variable speed drive).
- Provide modern and improved instrumentation to sense strainer/filter blockage, pump failure, etc. This will improve overall reliability. This is also applicable to other systems.
- Change carbon steel pipe to stainless steel in corrosive water environment. This will reduce long term maintenance.

- Change internal bearing heat exchangers to external heat exchangers that can be easily cleaned, particularly at plants where fouling is a problem.
- Replace duplex strainers that require frequent manual cleaning with automatic backwash strainers.
- At plants with very poor water conditions, a closed loop cooling water system can be installed in place of a once through system.

5.3.3 Compressed Air

The modernization alternative for the compressed air system should be based on the operating history of the system, the results of the component assessment, and any increased compressed air requirements from maintenance considerations or the uprating of other unit equipment. Overall modernization strategies that may be appropriate include the following:

- Replace existing compressed air system equipment with new state of the art equipment.
- Add additional compressed air system equipment to increase system capacity.
- Replace existing compressed air equipment with new higher capacity equipment.

Air compressors are not a major capital cost in relation to their importance to the station, brake, instrument air and possible synchronous condense air systems. Modernization options for individual components are summarized below.

Compressors and Receivers

- Modern rotary screw compressors can be provided with built in air dryers and oil separators.
- Each compressor can have a built-in PLC complete with a screen for programming and to provide details of unit warm up and run time, compressor pressure set points, etc. Dry contacts can be provided for various alarms.
- Multi compressor installations can have manufacturer- supplied control systems to provide automatic or manual lead/lag control operation.
- Install independent air receivers off the above system to service essential services.
- Install manual or preferably automatic cycling drain valves on each receiver.
- Provide a means to track and trend system operation and performance. This would assist in troubleshooting problems, minimizing forced outages and improving system reliability.

Piping Systems

- If possible, a common station service air compressor system (e.g. at 125 psig or higher depending on system pressure requirements) should be provided with multi-compressors to service brake and instrument air, synchronous condense air (if required) and general station service air. Installation of priority valves to drive the air to these receivers in the case of a major piping leakage in the other systems may be warranted.
- Provide sufficient isolating valves to separate each system.

- Wherever possible, use non-ferrous piping materials with welded or soldered joints to minimize corrosion and air leakage problems.
- Ensure pipework is seismically supported and braced.

5.3.4 Potable Water System

Modernization alternatives for potable water systems will depend on the design and operating histories of the existing system. New water treatment equipment may be installed. In some cases a new alternate source of potable water may be provided.

5.3.5 Drainage and Dewatering Systems

Development of modernization alternatives for the drainage and dewatering systems will depend on the existing condition of the installed equipment and whether or not the uprating of other equipment in the plant has increased the demand on the system. Modernization alternatives that might be considered include the following:

- Replace existing pumps with more modern equipment. The pumps for dewatering and drainage systems typically operate infrequently. Therefore improvement in pump efficiency is usually of minimal benefit. When used in conjunction with oil-water filtration/separation equipment, a variable speed pump may be of some benefit in that for the majority of the time the pump discharge can be regulated to a very low flow, which will improve the effectiveness of oil filters.
- Replace existing pumps with higher capacity pumps.
- Replace long shaft pumps with new submersible pumps.
- Provide redundant systems to improve reliability
- New oil spill detection equipment and oil separator technology are being produced by manufacturers regularly. Equipment manufacturers should be contacted for literature on the latest commercial products.

The distinction between life extension and modernization activities becomes blurred for oil spill containment. When bringing existing systems into compliance, this could be looked at as a mandatory activity that is required in the plant 20 year plan. It is often not an “optional” modernization activity that can be justified in a benefit to cost analysis. Activities are usually selected on the basis of a risk assessment that:

1. evaluates the risk posed to the environment in terms of the probability of oil spills from existing equipment and the consequences of environmental damage;
2. estimates the total cost of corrective actions;
3. establishes priorities for capital improvements in order of the greatest reduction in risk per dollar spent;
4. selects actions that reduce risk to a target acceptable level.

Containment schemes include both permanent and temporary ones and total or partial containment. The following are spill containment options that are usually considered:

1. surface and sub-surface drainage interception
2. collection pits around specific equipment
3. sump modifications
4. oil water separators
5. oil in water sensors & alarms.

Site specific factors, including topography, sub-surface geology, climate and environmental sensitivity must be considered when evaluating containment options.

There are numerous effluent control schemes to consider including:

1. flow-through methods such as gravity (API-type) oil-water separators, the IEEE-type oil trap, and gravity or pumped filtered discharge arrangements.
2. flow stop methods – such as oil-absorbing polymer bead drains, oil stop valves and oil sensor (mechanical or electrical) actuated valves and pumps
3. closed drainage methods – such as large spill ponds and drainage networks to retention pits, which may be drained automatically, manually or by evaporation.

The IEEE Guide for Containment and Control of Oil Spills in Substations (ANSI/IEEE Standard 980 – 1994) is recommended as a useful reference for its discussion of typical containment designs and methods.

5.3.6 Fire Protection

1. General

The modern standard for fire protection is more advanced than what was considered acceptable in the past. Fire protection technology has improved, but the greatest improvement has been in the attitude towards fire protection and the realization of the need to protect against fire.

Upgrading an existing hydroelectric station to a modern standard can be a daunting task. The layout of an existing station might make it impossible or at least very costly to install all of the modern fire protection features.

When reviewing options for modernization, the benefit to be gained should be balanced against the cost incurred by the upgrade.

Therefore, stations that will make a good candidate for modernization are those with:

1. high value,

2. large annual energy production,

3. a long remaining service life, or

4. where a station has limited fire protection installed.

The objective of modernization is to significantly improve upon the existing level of fire protection and reduce the potential for extreme fire losses.

The options for modernization included in this section were originally developed for medium-to-large hydroelectric stations (minimum capacity of 100 MW), and therefore, some of the options might not be practical or cost-effective for small stations.

A benefit/cost analysis might be useful in making a decision on the cost-effectiveness of upgrading. The analysis could account for the frequency of fire, estimated fire losses, insurance coverage, and the cost and installing fire protection. The analysis should accounts for both the relatively low probability of fire and the potential for a major loss where fire protection is inadequate.

2. Automatic Fire Suppression Systems

If there is no existing fire suppression system or the existing system is ineffective or has other associated problems, then consider the installation of a water-spray deluge system as an option for modernization. Water-based systems have demonstrated their effectiveness in extinguishing generator fires.

When reviewing options for modernization, keep the following important points in mind:

1. Fire suppression systems should be supervised by the unit fire alarm control panel or the station fire alarm panel for discharge and tampering. In most cases, the operation of the fire suppression system should be inter-locked with the fire detection system.

2. Install both automatic and manual activation capability. Manual activation should be readily identifiable, easily located, and prevented from accidental operation.

3. Fire suppression systems should have a means of manual shutdown located in a conspicuous location and readily identifiable.

4. The system must have lock out capability for testing, commissioning, and maintenance.

5. New fire protection piping should be seismically restrained.

6. To prevent the creation of voltage potential and an electrocution hazard, new fire protection piping must be bonded and grounded.

7. New sprinkler systems should be installed to NFPA 13, ‘Automatic Sprinkler Systems”.

8. New water-spray deluge systems should be installed in compliance with NFPA 15, “Fixed Water Spray Systems for Fire Protection”.

9. A water-spray deluge system for generators should be designed to provide a spray of water droplets directly onto the insulated portions of the upper and lower winding structures including the stator windings, stator terminals, circuit rings, winding endheads, field windings and damper windings.

10. Carbon dioxide systems are no longer as common for new installations as they were previously. If a CO_2 system is desired, it should be installed in accordance with NFPA 12, “Standard for Carbon Dioxide Systems”. A sufficient volume of agent must be available to extinguish a fire. NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume.

11. For carbon dioxide systems, piping and fittings must be of the correct material as specified by NFPA 12. Fittings and piping should be able to withstand the burst pressure specified by NFPA 12.

12. To reduce the life safety risk associated with CO_2 systems, they should be equipped with pre-discharge warning alarms and provision for disablement to prevent unwanted discharge for when person are working on the system or working in the protected space. Rescue procedures must be developed for when personnel are working in the protected space. Self-contained breathing apparatus must be available for rescue purposes. Portable air-monitoring equipment and breathing apparatus must be available to allow personnel to check that the space is safe for re-entry.

13. Carbon dioxide systems should be equipped with pre-discharge warning alarms and the capability to disable the system (i.e. lock-out) so that personnel can work on the system or in the generator enclosure. An abort switch for manual shutdown is also required.

14. An enclosure protected with a total-flooding CO_2 system must be enclosed to prevent loss of agent and reduction of effectiveness. It will generally not be possible to completely prevent leakage, but large openings and holes in the enclosure should be sealed. If these openings cannot be sealed, then an additional amount of CO_2 gas above the calculated value will be needed to offset leakage.

3. Manual Fire Suppression Systems

General

Modernization should be considered where the existing systems are deficient or the station is heavily reliant on manual suppression for fire protection.

Points to Consider

1. The applicable standard for new standpipe systems in North America is NFPA (National Fire Protection Association) 14, “Standard for the Installation of Standpipe and Hose Systems”.

2. A new standpipe system should have 2.5 inch hose connections, with a thread compatible with the fire department (or station fire brigade) hose, so that fire fighters have access to a water supply on all levels of the station. To provide life safety to firefighters, install hose connections inside exit stairs or other protected areas.

3. Install standpipe connections for use by the fire brigade near outside transformer banks. The distance from the hydrant connections to the transformer banks should be remote enough so that the fire brigade is not exposed to high levels of radiant heat when coupling hose to the connections.

4. If station personnel are trained in the use of interior hose lines, then interior hose lines should be provided.

5. Wall hydrants should be located at main entrances to the powerhouse and other auxiliary buildings to provide a water supply for fire department vehicles.

4. Fire Suppression Water Supply & Fire Pumps

General

Modernization of water supply and fire pumps will be required if the existing installation can not meet the demand of the automatic and manual fire suppression system. This may be the case where new deluge or sprinkler systems are installed as part of the modernization program.

Points to Consider

1. All valves for the fire protection water supply should be supervised by the station fire alarm system. The fire protection water supply should also not be affected by shutoff of domestic water or other service water supply. Pressure-reducing valves and other components must operate correctly so that they do not impair the ability of the system to provide required flow and pressure. The system must be capable of providing water to multiple systems.

2. If the station has a low head and the water supply system can not provide the necessary pressure and flow for fire suppression, a fire pump will be required to boost water pressure.

3. If a new fire pump is required, the North American standard is NFPA (National Fire Protection Association) 20, “Standard for the Installation of Centrifugal Fire Pumps.” All components should be listed and labelled by a recognized testing agency for use as a fire pump.

4. A new fire pump should be installed inside an enclosure having a fire separation having at least a 1 hour fire-resistance rating (a.k.a. “1 hour fire separation”) to protect it from a fire in the adjacent floor area.

5. If a new diesel-powered pump is installed, special consideration must be given to diesel fuel storage to ensure that it is not a fire hazard in itself. Diesel fuel should be stored inside a liquid-tight room with a 2 hour fire separation enclosure.

6. The power supply cables to the electric fire pump should have a 1 hour fire-resistance rating or be enclosed in construction having a 1 hour rating. Provision must also be made for emergency power supply in the event that station service is lost.

5. Smoke Control

Many of the older hydroelectric power stations in North America were constructed with limited ventilation and no means of smoke control. Therefore, these systems are prime candidates for modernization. Smoke control is of particular concern in underground power stations.

A smoke control design should incorporate the entire powerhouse and not just the generator enclosure because the smoke from a generator fire will affect the entire powerhouse.

Smoke control is a complex issue that requires specialized knowledge to design an effective system.

When considering options for modernization, the following important points should be kept in mind:

1. Any new systems should be designed and installed in accordance with NFPA 90A “Installation of Air Conditioning and Ventilating Systems”, NFPA 204M “Guide for Smoke and Heat Venting”, and NFPA 92A, “Recommended Practice for Smoke Control Systems”.

2. In order to vent smoke, the affected area must be pressurized with fresh air, and contaminated air must be extracted. Due to the buoyant nature of hot gases, air extraction is best performed at the ceiling of the affected space. In general, fresh air should be introduced at a low elevation.

3. Any modernization of smoke control should provide the capability for both manual and automatic operation (through the fire alarm system).

4. Existing air-handling systems may be incorporated into a smoke control system if they are approved for use in such a system. Smoke control equipment must be able to withstand higher temperatures than ordinary air-handling equipment.

5. Duct-type smoke detectors might be required in air supply passages to indicate the presence of smoke. These detectors will be part of the fire alarm system.

6. The operation of the smoke control should be integrated with the main fire alarm panel.

5.3.6.1 Fire Detection and Alarm Signalling Systems

General

If there is no existing fire detection and alarm signalling, or if the existing system is ineffective, then the best option is modernization. Modernization of fire detection and alarm signalling systems will generally involve removal of existing systems and replacement with new systems.

Fire Detection and Alarm Signaling

A suggested modernization of the fire detection and alarm signalling system could include the following features related to generator fire protection

(a) all components listed by a recognized testing agency;

(b) operate on low voltage (24 volt) DC power;

(c) a micro-processor based main station fire alarm panel;

(d) detector sensitivity readout/printout for the main panel;

(e) laptop computer field programmability for the main panel;

(f) remote monitoring dial-up capability for the main panel;

(g) interactive video display terminal with colour graphics software for the main panel – install in the control room - to allow the fire to be located;

(h) a networked panel connected to the main panel, with alpha-numeric display and control pad - locate at the main entrance to the powerhouse building to enable the location of the fire to be identified;

(i) sub-panels (or “unit fire alarm control panel”) for transformer or generator fire suppression systems that can stand alone if the main panel is disabled (it is recommended that sub-panels be relay-based);

(j) supervision of all fire protection valves, fire pumps, fire detectors, and fire suppression systems (the transformer and generator fire suppression system should be supervised by the unit fire alarm control panel);

(k) audible and visual alarm signaling throughout the station;

(l) strobe lights mounted on flexible conduit to be placed in the turbine pit during overhauls;

(m) detection coverage throughout the station;

(n) duct-type smoke detectors and thermal detectors in the generator;

(o) detection for transformers (including outdoor transformers);

(p) linear beam smoke detectors at the powerhouse ceiling above the units;

(q) photo-electric smoke detectors for most parts of the station;

(r) thermal detectors for areas of high humidity, dust, or smoke from work operations;

(s) ability to control the HVAC system and the smoke control system to prevent the spread of smoke in the event of a fire;

(t) an emergency power supply capable of supplying 24 hours of supervisory operation plus a set time of full alarm operation (a minimum of at least 30 minutes is recommended).

5.3.7 HVAC

Unless unit forced outages have occurred due to high space or equipment temperatures to which a lost monetary value can be assigned, it is very difficult to make an economic case for major system upgrades especially if the existing equipment has not reached the end of its useful life. This also will not be helped if value that a utility places on electrical energy used for auxiliary systems is artificially low.

Due to site specific plant conditions, it is difficult to identify general modernization alternatives. Although the development of modernization alternatives must be done on a case-by-case basis for each hydroelectric facility, there are certain factors to consider when developing various modernization alternatives.

- The driver to improve HVAC performance has been the requirement to improve net power output from the hydro plant. Digital control systems have allowed the optimization of HVAC performance by reducing overall energy consumption.
- The development of any HVAC modernization alternatives must consider any electrical or computer equipment added as part of the uprating of other plant systems. These may require a controlled environment.
- An energy audit or HVAC review should be conducted for any facility that does not have a modern HVAC system.
- The HVAC control system should be reviewed if it is more than 10 years old.
- In a multi unit generating station, utilizing the cooling and ventilation systems on a unit basis provides better control of space temperatures and some backup should one system fail.
- Separation of the unit ventilation systems from the equipment spaces not only provides better temperature control but better smoke and fire control and staff evacuation in the case of an emergency.
- The HVAC system controls should be integrated with the Fire Protection System operation.

5.3.8 Powerhouse and Tailrace Cranes

The need to modernize powerhouse or tailrace cranes results from problems identified during the crane assessment, or because of the need to increase the crane lifting capacities to handle heavier uprated plant components. Modernization of cranes will often involve upgrading or replacement of controls including the provision of radio control.

Alternatives for addressing crane structural or operational problems identified during the assessment must be developed on a case-by-case basis. However, the following are some of the modernization options:

- Change crane controls to frequency controls.
- Add radio controls.
- Address safety issues.
  - Provide safe access to maintenance intense areas
  - Add walkways and hand rails
  - Add fall arrest attachment points and include fall arrest equipment in operator's cab.
- Include fire-fighting equipment in operators cab (usually minimal: a fire extinguisher)
- Sometimes bridge crane capacity increases can be achieved with minimal strengthening of the powerhouse superstructure. Crane runways are designed for a capacity lift acting at the closest approach the crane trolley can make to the runway. This position is determined with the trolley against the end stops on the bridge. Typically, the size of the component making up the design lift prevents the trolley from moving very far from the center of the bridge. This results in the load being more evenly shared with the two runways (i.e. the load seen by the runways is less than the design load). If the upgraded capacity lift is restricted to near the center of the crane bridge, the resulting bridge end truck loads will increase, but perhaps will remain within, or close to, the original design capacity.
- Install load limiting devices.

Uprating the cranes to a higher capacity requires identifying the loads to be lifted. Normally, the heaviest lift a powerhouse crane must handle is the generator rotor; for smaller units, the entire generator assembly is the heaviest load. If the heaviest lift or rotor weight is not available, the rotor weight can be estimated from the following equation:

$$R_w = 55\ (MVA/n^{0.5})^{0.74},$$

where:

R_w = rotor weight in tons for rotors with standard inertia,

MVA = rotor rating at 60°C temperature rise, and

n = rotor speed, 90 rpm minimum

In evaluating the modernization plans, modifications to the crane and structure can usually increase the hoisting capacity of existing cranes up to 30%. The potential for increase should be confirmed by the crane manufacturer or a qualified Engineer. Greater increases in crane capacity may require the purchase and installation of a new crane or a second crane. If an increase in the hoisting capacity of an existing or new crane is considered, the bearing capacity of the supporting powerhouse structure must also be examined.

5.4 Modernization of Auxiliary Electrical Equipment

Modernization Opportunities (Step 4-5, Volume 1)	**Benefits of Modernization (Step 4-5, Volume 1)**
Further Studies Required	
Impacts of Modernization on Other Equipment	**Other Equipment that Limits Modernization (Step 4-5, Volume 1)**
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

A summary of modernization activities for auxiliary electrical systems are summarized in Table 5-7 below.

The station auxiliary electrical systems, with the exception of the auxiliary power supply, would most likely be modernized for reasons of safety, convenience, or ease of operation, since the operation of those systems is not directly related to unit capacity. The auxiliary power supply system, however, is dependent on the modernization or uprating of other plant systems. Therefore, the modernization of the auxiliary power system must be consistent and compatible with the modernization and uprating plans for these systems and, if additional electrical loads are added, the auxiliary power supply system must be upgraded to support the additional loads. Since most auxiliary power supply system components, such as bus ducts, etc. are common to the utility industry, detailed design procedures are not provided in this guide. Modernization of the auxiliary power supply system to capacities compatible with the modernized plant rating should be based on current electrical utility design standards for the plant electrical systems.

Table 5-7
Upgrade/Modernization Activities for Auxiliary Electrical Equipment

ASSET NO.	EQUIPMENT	UPGRADE/MODERNIZATION ACTIVITIES
1.1.9	Generator Transformers	• Changes in loading practices • Uprate transformer with the addition of auxiliary coolers, fans, etc. (forced cooling) I.e. OW (water cooling) to OA, OA/FA or FOA • Uprate by rewinding • Bushing replacement with high resin bushings instead of porcelain bushings • Improve oil containment systems • Upgrade transformer protection • Efficiency improvements by re-coring with modern high efficiency core steel • Replace motors wit high efficiency ones • Continuous on-line for monitoring of dissolved combustible gas content, vibration, partial discharge, insulation power factor, temperature etc. to assess transformer condition and provide incipient fault detection.
2.1.1	Station Service AC	• Add shunt capacitors to improve power factor. • Add autobus transfer to improve reliability and reduce losses. • Upgrade emergency generator - new model, replace controls with PLC based
2.1.2	Station Service DC	• Upgrade batteries, control system, improve fuel storage. • Add automatic monitoring of batteries, facilities, install duplex fuel filter system.
2.1.3	Cable and Cable Support Systems	• Remove unused cable trays. • Install seismic diagonal bracing • Improving ventilation and lower ambient temperatures near cables.
2.1.4	Grounding Systems	• Upgrade to meet current standards. • Improve lighting protection.
2.1.5	Lighting Systems	• Upgrade to more efficient lighting systems (HPS or metal Halide fixtures) • New PLC-based controls installed • Conduct a lighting audit.
	Standby Generator	• Add autostart • Add load-shedding capabilities

5.4.1 Generator Transformer

In most cases, the generator is directly linked to a generator transformer, which transmits to the network the generator active and reactive power. To determine the possibility of increasing the unit output, the existing transformer rating needs to be considered.

This example is presented as a rough check on the existing transformer capacity (Figure 5-2)

Turbine rated output $p = 5$ W

Power Factor $\cos\alpha = 0.8$,

Generator capacity $S_G = \dfrac{P}{\cos\alpha} = \dfrac{5}{0.8} = 6.25$ MVA, and

Existing transformer rating $S_T = 6.5$ MVA
(Non-standard rating used for this example)

The transformer rating is a standard ANSI rating as shown in Table 5-8. In a majority of cases, the transformer rating will exceed the generator rating and the additional capacity may be available for a runner uprating.

Old hydroplants were often designed for a lower power factor, 0.7 to 0.8, to supply reactive power into the possibly isolated distribution system. Such low power factors may not be necessary for the current systems, which permit an increase in active power simply by limiting the reactive power under full-load condition.

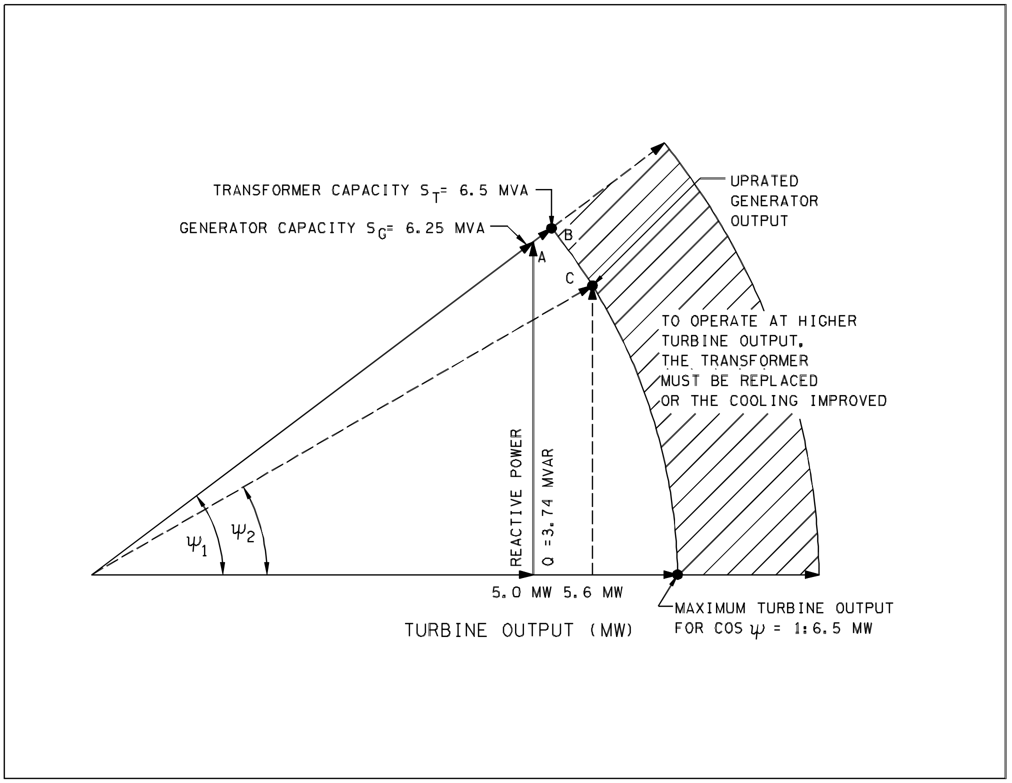

Figure 5-2
Transformer Capacity

Table 5-8
Transformer Ratings According to ANSI C57.12.10.1988

Kilovolt-Ampere Ratings		Self-Cooled (OA) and Forced Air-Cooled ((FA) Rating			
		Singe-Phase		Three-Phase	
Single-Phase	Three-Phase	OA	FA	OA	FA
kVA	kVA	kVA	kVA	kVA	kVA
833	750	833	958	750	862
1,250	1,000	1,250	1,437	1,000	1,150
1,667	1,500	1,667	1,917	1,500	1725
2,500	2,000	2,500	3,125	2,000	2,300
333	2,500	3,333	4,167	2,500	3,125
5,000	3,750	5,000	6,250	3,750	4,687
6,667	5,000	6,667	8,333	5,000	6,250
8,333	7,500	8,333	10,417	7,500	9,375
	10,000			10,000	12,500

Self-cooled (OA), Forced-Cooled First Stage and Forced-Cooled Second Stage

Kilovolt-Ampere Ratings

Single-Phase, kVA			Three-Phase, kVA		
OA	OFA First Stage	OFA/FA or FOFA Second Stage	OA	OFA First Stage	OFA/FA or FOFA Second Stage
10,000	13,333	16,667	12,000	16,000	20,000
			15,000	20,000	25,000
			18,000	24,000	30,000
			20,000	26,667	33,333
			21,000	28,000	35,000
			24,000	32,000	40,000
			25,000	33,333	41,667
			27,000	36,000	45,000
			30,000	40,000	50,000

First Stage (OFA): Capacity will be increased by 33% by means of forced air cooling

Second Stage (OFA/FA or FOFA): Capacity will be increased by 67% by means of either doubling of the forced air cooling or additional forced air circulation.

If the transformer rating is not adequate for the uprated turbine, there are options available to achieve the extra capacity using the existing transformer. These options include:

- Increasing the generator power factor.
- Increased output due to operation at average ambient temperatures and average winding rise less than limiting values.
- Addition of forced air or water cooling systems.

The feasibility of selecting a new power factor needs to be determined on a case by case basis depending on the characteristics of the power system to which the hydro unit is connected. The following example shows what power factor would need to be selected based on the existing transformer capacity in order to be satisfactory for an uprated turbine output:

Old turbine output P	=	5 MW,
New turbine output P'	=	5.6 MW (+12%), and
Transformer capacity S_T	=	6.5 MVA

Based on this data, the new power factor can be calculated from:

$$\cos\alpha,\ \max = \frac{5.6\ \mathrm{MW}}{6.5\ \mathrm{MVA}} = 0.86, \bullet$$

The new power factor can also be read using Figure 5-2. The following information is necessary for Figure 5-3:

$$r = \frac{\text{old turbine output (MW)}}{\text{existin gtransformer capacity (MVA)}} = \frac{5}{6.5} = 0.77 \bullet$$

$$\text{Increase in turbine output} = \frac{0.6}{5} = 12\% \bullet$$

Entering Figure 5-3 at 12% increase in output and using the r = 0.75 line as a pivot point, the power factor is also found to be 0.84.

As stated earlier, additional loading of the transformer is also possible if the transformer operates at an average ambient temperature and average winding rise less than limiting values. Table 5-9 shows the ANSI/IEEE C57.92-1981 recommendations for decreasing/increasing the load for ambient air temperatures other than 30°C and average winding rise less than limiting values. These recommendations apply to transformer capacity ratings of 100 MVA and below. For higher ratings, eddy-current losses from stray flux can produce high localized temperatures which make the approximations no longer valid. Transformers rated above 100 MVA should be limited to operation up to rated capacity until loading guidelines similar to those for smaller transformers can be adopted. For more details, refer to the relevant loadings in the ANSI, MEMA, and IEC guides.

The use of the criteria in Table 5-9 allows the determination of the continuous allowable load for a certain ambient temperature and/or cooling water temperature, if the nameplate is missing and the rated capacity is unknown. For such a case, the transformer is loaded with an estimated definite constant load. The hot spot temperature of the transformer is determined and the difference between the final hot spot temperature and 110°C is the maximum allowable hot spot temperature. The increase or decrease in transformer load can be calculated using the difference and the percentages of Table 5-9.

For example, assume the following temperatures were measured for an existing transformer:

Ambient air temperature	50°C
Final average winding temperature	85°C (measured by winding resistance)
Hot temperature	85°C + 15°C = 100°C
Difference from 110°C (maximum hot spot temperature)	110°C - 100°C = 10°C reserve

From Table 5-9 for a self-cooled transformer a 1% increase in load per 1°C lower temperature is possible. Therefore, the load can be increased 1% x 10 (°C) = 10%.

Transformer upgrading and/or uprating is possible by improving the transformer cooling. Often, the transformer capacity based on ambient air cooling can be increased by improving the transformer cooling by adding forced air cooling fans, oil circulating pumps, or spray water cooling. The following general guidelines are provided to estimate transformer capacity increases. However, the actual Increase due to cooling improvements should be verified with the manufacturer.

Improved Cooling Method	Transformer Capacity Increase
Forced Air Cooling	Up to 33%
Forced Air Cooling and Oil Circulating Pumps	Up to 67%

Although water spray cooling is a simple method to cool the transformer, it should only be used as a temporary solution in emergency situations. If water spray cooling is used , the transformer capacity increase should be determined by the manufacturer and should only be used until a new transformer can be supplied'.

The water spray technique should be used with extreme caution. Typically transformer-winding temperatures are simulated, not directly measured. The top oil temperature is measured by a sensor in a well on the lid of the transformer. A small current from a CT, proportional to the load current, is fed to a heater on the well to provide the top oil to winding temperature gradient. As water sprayed over the transformer has a much greater affect on the outside surfaces of the transformer than on the windings where the cooling is really required, the indicated temperatures may provide a false sense of security, i.e. the actual winding temperature may be much higher than the temperature indicated on the winding gauge.

Table 5-9
Loading Base of Temperature

Loading on Basis of Temperatures (Ambient other than 30°C and Average Winding Rise Less than Limiting Values) (For Quick Approximation) Ambient Temperature Range 0°C to 50°C)		
	% of Rating	
Type of Cooling	Decrease Load for Each °C Higher Temperature	Increase Load for Each °C Lower Temperature
Self-cooled - OA	1.5	1.0
Water-cooled - OW	1.5	1.0
Forced-air-cooled - OA/FA, OA/FA/FA	1.0	0.75
Forced-oil-cooled - FOA, FOW and OA/FOA/FOA	1.0	0.75

Source: ANSI/IEE c57.92-1981

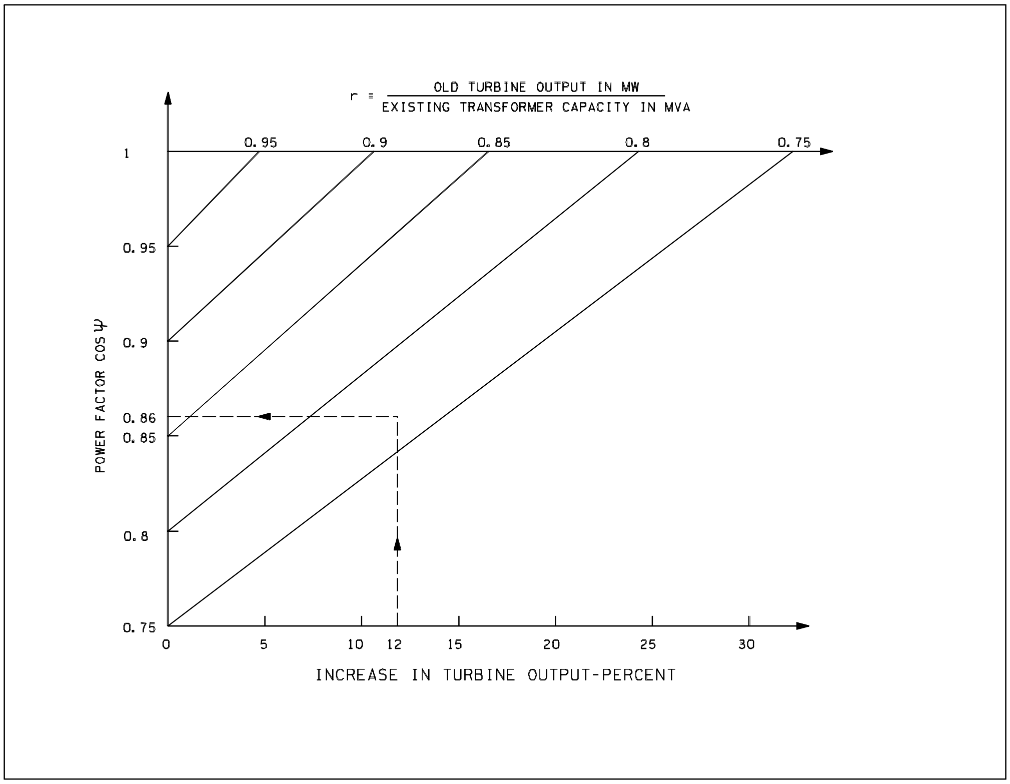

Figure 5-3
Increase Turbine Output, Original Transformer Capacity Results in Power Factor Reduction

5.4.2 AC Station Service

The station service system is used to support operation of the plant. Choice of supply sources for the station can impact on powerhouse general arrangement, single line diagram, choice of HV or generator voltage breakers and plant switching configuration.

The following considerations shall be made to ensure continuous power is available to the station auxiliary loads under various operating conditions.

<u>Power Supply Sources</u>

The possible sources of supply are:

- Using high voltage source form the system transformer sand step down into utilization voltages. This configuration can provide a very reliable supply basically independent of the mode of operation of the generators. The cost for this scheme, however, can be prohibitive when no system transformers with tertiary winding are used.

- Using generator bus sources. Satisfactory performance can be obtained with a minimum of two generator sources in service especially when the generators are in the base mode of operation.
- Using an external source to backup the generator sources as outlined above, when the number of generators in-serviced are reduce and as the main source when no generators are in-service. This method can reduce the frequency of switching sources when the generators are in the peaking mode of operation.
- A standby diesel generator unit should also be considered to supply essential loads and to allow black starting of the units.

For small powerplants, the use of multiple sources may be necessary.

Transfer Scheme

Automatic transfer schemes should be provided when multiple sources of station service supply are used. The scheme(s) will allow connection of the station service buses to a normal, standby or emergency source. These are a large variation in the combination used. One of the scheme used in large powerplant is to group the station service loads into two main buses and an essential bus. Two separate normal sources are connected to each main bus and an emergency course will be connected to the essential bus. Upon loss of one normal source, the main bus connected to that source will be transferred to the second normal source. Upon loss of both normal sources, the main buses will be isolated and the essential; bus will be connected to the emergency source. This scheme requires that one normal source is capable of supplying the entire station auxiliary load. Re-transfers can be implemented when the normal source is returned to service.

To avoid the complexity of synchronizing two normal sources, the main supply, breaker should be opened before the alternate or standby breaker is closed. Short interruptions are allowed when critical loads are supplied by dc, UPS or ac inverters.

Overload trip devices are used to trip the associated breakers and to block any transfers since the tripping of breakers by overloads can be caused by a station service bus fault. Alarms will be provided when the transfer is not successfully completed.

Demand Load

The connected KVA of powerplant ac loads should be tabulated and a demand factor applied to each. The demand KVA is used to size the station service transformers. If powerplant expansion is planned in the near future, the estimated demand load of the expansion should be considered in the transformer size. If expansion is planned in the near future, it may be economically advantages to plan for the addition of a transformer at expansion time.

Essential Loads

Some powerplant loads must be maintained. They include:

- battery charges
- transformer cooling
- low voltage ac circuits to power circuit breakers
- governor oil pumps
- drainage pumps
- fire pumps
- fire protection system
- turbine head cover drainage pumps
- turbine shaft seals
- essential lighting
- spillway gates
- elevators
- field flashing for static excitation system when ac source is used
- bearing lubrication system
- high pressure bearing oil lift pumps
- cooling water pumps
- critical ac control circuits
- critical HVAC loads
- inverter power supply

UPS

The modernization of the powerplant control system may require the addition or replacement of the UPS system. UPS is used to power systems that are related to data collection and storage and critical control.

System Fault Currents

Modernization or expansion of the powerplant can result in fault interrupting duty of the existing station service equipment. A fault study should be made to determine whether the existing switchgears, motor control centers and panelboards have adequate fault interrupting duty. Installation of current limiting reactors can be a most effective method of reducing short circuit current to a value below the interrupting duty of the existing equipment.

<u>Emergency Generator</u>

Due to the wide range of individual requirements for each plant, technology advances in standby generators will not be discussed here and are best discussed with manufacturers. The focus of any replacement emergency generator task is the sizing and reliability of the replacement unit. The emergency generator capacity should be adequate to support essential loads. If additional essential loads are required from plant modernization or rehabilitation, a study is necessary to ensure the existing emergency generator can supply these loads. If a larger motto load is needed, a voltage drop study should be performed for both the normal distribution system and the emergency generator. Reliability is vital due to the emergency purpose of the generator.

Modernization of standby diesel generators include:

1. Upgrading to a newer model for improved reliability and increased efficiency.
2. Replacement of protection and control with a PLC-based system.
3. Upgrading of fuel storage facilities to a modern, contained and monitored system.
4. Installation of duplex fuel filter system with bypass.

5.4.3 DC Station Service

During plant rehabilitation the dc system should be reviewed for adequacy for continued plant operation, including dc system loading, equipment age and fault clearing co-ordination.

The dc system in a modernized powerplant should:

- operate safely and reliably
- have a high degree of maintainability
- provide dependable downstream water control
- provide critical service in the event of second contingency failure (e.g. a total ac station service failure and failure of standby generator to start)
- provide for component maintenance or replacement without loss of service
- have proper fault co-ordination
- monitoring of all branch circuits for loss of service
- maintain all emergency lighting loads

Large powerplants will require a two or three battery system to meet the above requirements.

- to service dual protection and control (primary and standby) systems
- to enable safely shutdown of the units
- to enable operation of all power circuit breakers

The use of two dedicated batteries with load transfer facility between the batteries will enable one battery to be taken out of service without reducing the integrity of the P&C system. A third battery should be considered if it is necessary to keep the P&C system free from the adverse effects of field flashing and emergency lighting loads.

Transfer schemes of dc systems should constitute a temporary parallel, i.e. a make before break scheme. The use of thermal magnetic breakers can present difficulty in fault co-ordination. It may be advantageous to use non-automatic breakers and current limiting fuses in order to achieve co-ordination.

5.4.4 Cable and Cable Supports

Seismic diagonal bracing should be installed throughout the cable tray system to stabilize it in a seismic event. All unused cable in the trays should be removed to decrease fire risk and loading.

5.4.5 Grounding

The bonding of all non electrical metallic parts to a ground system will reduce the electric shock hazard to personnel. It also provides adequate current carrying capability permitted by the overcurrent protection systems and a low-impedance return path for ground-fault current.

Transient power system voltages and high-frequency leakage currents can result in computer system malfunctions. Electronic equipment must meet strict shielding standards to prevent electrical noise from entering or leaving the equipment. All electronic equipment installed in a powerhouse should be tested for electrical interference, surge withstand capability and radio frequency interference.

5.4.6 Lighting

Modernization of the lighting system should consider that in the last 10 years newer energy efficient products have been developed yet owners and end users have only upgraded about 10% of the existing lighting systems. The lighting in a building can typically consume from 15 to 25% of the total electrical energy depending on the function of the building. New energy efficient lighting equipment has become paramount to economical operation of a lighting system. Fluorescent and high intensity discharge system typically provide a higher efficiency (lumens per watt) than a incandescent lighting system.

A simple retrofit of older T12 fluorescent lamps and ballasts with new electronic ballasts and more efficient T8 lamps may appear attractive. However unless it is designed properly, i.e. with a good knowledge of ballast factors, it can introduce improper light levels, lower lighting and power quality. Electronic ballasts must meet FCC Part 18:A for FRI and EMI emissions.

Replace mercury lights with metal halide systems or metal halide in combination with HPS for maximum benefits.

A more thorough approach would be to carry out a comprehensive lighting analysis that considers multiple retrofit options, this will result in a better quality lighting effect and save energy. Some other options to consider are the proper application and installation of occupancy sensors, daylight sensors, and electronic dimming ballasts. Installing spectacular reflectors can improve thermal and optical efficiency of a fixture by about 15%. Replacing old yellowed diffuser lenses with new acrylic lenses that do not discolour will improve the appearance and light output. The cost of this improvement should be assessed as it may be close to the cost of a new luminaire with all these advantages.

Direct replacement of existing incandescent lamps with new compact fluorescent sources that have a medium - screw - shell base will reduce maintenance costs. The use of 130 volt rated incandescent lamps rather than 120 volt rated lamps is another way of saving maintenance labour costs. If the reduced lumen output is a concern, then the next higher wattage can be used.

The three common high intensity discharge (HID) lighting sources are mercury vapour (MV), high pressure sodium (HPS) and metal halide (MH).

The new metal halide with pulse-start system can reduce the number of lights required as a retrofit or as a new installation. They will need compatible lamps, ballasts, and starters. These lights are more efficient (up to 110 lumen per watt), have improved lumen maintenance (up to 80%), are more consistent in lamp to lamp colour, and the restrike and warm up are 50% faster. These are suitable for exterior and interior applications and would be a replacement for HPS or MV systems.

Exit lights have a common problem with the burned-out incandescent lamps. This can be eliminated by replacing the unit with a new one containing light-emitting diodes (LED) that consume only 2 watts compared to the incandescent 20 watts per unit.

For emergency lighting upgrades where incandescent-beam-units are not used, consider using fluorescent and compact fluorescent lamps powered by an invertor or UPS supply.

5.5 Development of Overall Plant Modernization Alternatives

<table>
<tr><td>Modernization Opportunities</td><td rowspan="2">Benefits of Modernization</td></tr>
<tr><td>Further Studies Required</td></tr>
<tr><td>Impacts of Modernization on Other Equipment
(Step 4-7, Volume 1)</td><td>Other Equipment that Limits Modernization
(Step 4-7, Volume 1)</td></tr>
<tr><td>Timing of Modernization</td><td>Risk Evaluation of Modernization</td></tr>
<tr><td colspan="2">Modernization Opportunities Selected for Input into Table 4-6, Volume 1</td></tr>
</table>

This Volume has focused on auxiliary mechanical and electrical equipment. These equipment and systems may be modernized on an individual basis, or as part of an overall plant modernization program. When part of an overall plant modernization program, the overall plan will be driven to a large extent by the major mechanical and electrical equipment. For example:

- An increase in cooling water system capacity could be required if the generator is uprated (which in turn would depend on turbine uprating).
- An increase in powerhouse crane capacity may be necessary if the generator is replaced or significantly modernized.
- Uprating of a transformer may be necessary if the generator (and turbine) is uprated.

Modernization of the major auxiliary mechanical and electrical equipment and development of an overall plant modernization plan are discussed in Volumes 2 and 3 of these Guidelines.

5.6 Input to Modernization Plan

The final task in the initial selection of modernization activities is to input them into the Life Extension and Modernization Plan (LEM Plan) in order to see their impact on plant economics. Volume 1, Section 4 details the methodology for incorporating identified opportunities into the LEM Plan. This is an important step in the interactive process of selecting life extension and modernization activities, as it will assist in determining whether the benefits of modernization justify the additional expenditure over the life extension alternative. The information on the pro forma "Equipment Modernization Opportunities" worksheet (Table 5-1), completed for each piece of equipment or system, should provide all of the necessary information for the LEM Plan at this pre-feasibility stage.

After initial financial and economic results are available for the preliminary LEM Plan, further studies are required to confirm that the selected modernization opportunities are feasible both technically and economically. Further inspection, testing and studies for the feasibility stage of analysis are described in Section 7 of this Volume entitled "Optimization of Alternatives".

6 ESTIMATE OF COSTS AND BENEFITS

6.1 Introduction

The costs and benefits of possible life extension and modernization activities for auxiliary mechanical and electrical equipment are important factors in any decision regarding the future of a plant.

This section provides guidance for overview level cost estimates, which can be used in the early stage development of the Life Extension and Modernization (LEM) Plan.

Care must be taken in using the results from generic curves, tables and processes such as those given in these Guidelines. The results are only approximations. Each plant and each individual unit studied by the user will have its own unique situation which will require consideration before using the information provided in this section. The costs associated with modernization and/or uprating depend on many factors such as the design of the original equipment, extent of the uprating, plant location relative to manufacturer's service shop, and prospective contractor shop workloads.

The Life Extension and Modernization Plan process is iterative and accordingly the accuracy of estimates will be required to improve with each iteration. Estimating considerations are discussed in Volume 1, Section 2.3.5.

All prices used in this section are in year 2001 dollars (US). Various indices are available to escalate dollar values for future years, including:

- Handy-Whitman Index of Public Utility Construction Costs.[6]
- Bureau of Reclamation Cost Index.[7]

[6] *Handy-Whitman Index of Public Utility Construction Costs*, published by Whitman, Requardt and Associates LLP, Baltimore, Maryland

[7] *Bureau of Reclamation Cost Index* published at the end of each quarter in Engineering News Record, published by the McGraw-Hill Companies, New York, New York

6.2 Cost Estimates and Delivery Times

6.2.1 Auxiliary Mechanical Systems

6.2.1.1 Bearing Lubrication Systems

Cooler replacement is the most common life extension or modernization activity for bearing lubrication systems. The following are some general guidelines:

- Internal coolers typically cost in the order of $10,000 to $30,000 for Copper-Nickel material.
- Stainless steel coolers typically cost 20% more than Copper-Nickel ones.
- Double wall cooler costs will depend signficantly on design.
- External coolers typically cost $15,000 to $30,000 including pumping systems.
- At least 2 months should be allocated for delivery time of coolers.

6.2.1.2 Cooling Water

Estimating the cost of upgrading an existing auxiliary cooling water system (generator and bearing systems) is difficult because of the numerous potential alternatives that are available. However, for the purposes of modernization studies performed using these Guidelines, the cost to overhaul an auxiliary cooling water system can be estimated to be 25% of the cost of a new system. Similarly, the cost to uprate the system capacity by 30% can be estimated to be 50% of the cost of a new auxiliary cooling water system.

Figure 6-1 shows the approximate costs for new typical single circuit cooling water systems. The costs are installed costs for an open circuit cooling system including pumps, valves, and piping for one generating unit. For double circuit systems (that incorporate a closed loop system), the costs should be doubled. Coolers are not included in the estimates. See Section 6.2.1.1 for some guidelines on the cost of coolers for bearings.

6.2.1.3 Compressed Air System

Estimating the cost of upgrading an existing compressed air system is difficult because of the numerous potential alternatives. However, for the purpose of the modernization studies conducted in these Guidelines, the cost to overhaul a compressed air system can be estimated to be 25% of the cost of a new system. Similarly, the cost to upgrade the capacity by 30% can be estimated to be 50% of the cost for a new system.

Costs for a new compressed air system, including air compressor, air receiver, and associated piping and valves, are listed in Figure 6-2.

The following are some general points to consider:

- low pressure rotary screw air compressors complete with dryers and oil separators are inexpensive (for example, a 400 scfm @ 125 psig unit can cost approximately $30,000). Delivery of a typical unit from approval of shop drawings is approximately 12 to 14 weeks
- High pressure multi stage reciprocating air compressors can be much more expensive (for example, a 60 scfm @ 900 psig unit costs approximately $75,000). Delivery of a typical unit is approximately 20 weeks from approval of shop drawings.
- High pressure regenerative, desiccant dryers are similar in prices to the high pressure air compressors (for example, a 120 scfm @ 900 psig unit costs approximately $75,000). Delivery of a typical unit is approximately 20 weeks approval of shop drawings.
- In a major circuit breaker air system, a minimum of 2 compressors, 2 dryers and 2 air receivers are typically installed and the dryers are rated at twice the capacity of the compressors. The above equipment arrangement have been found to provide effective separation and backup in the event of equipment component failure.

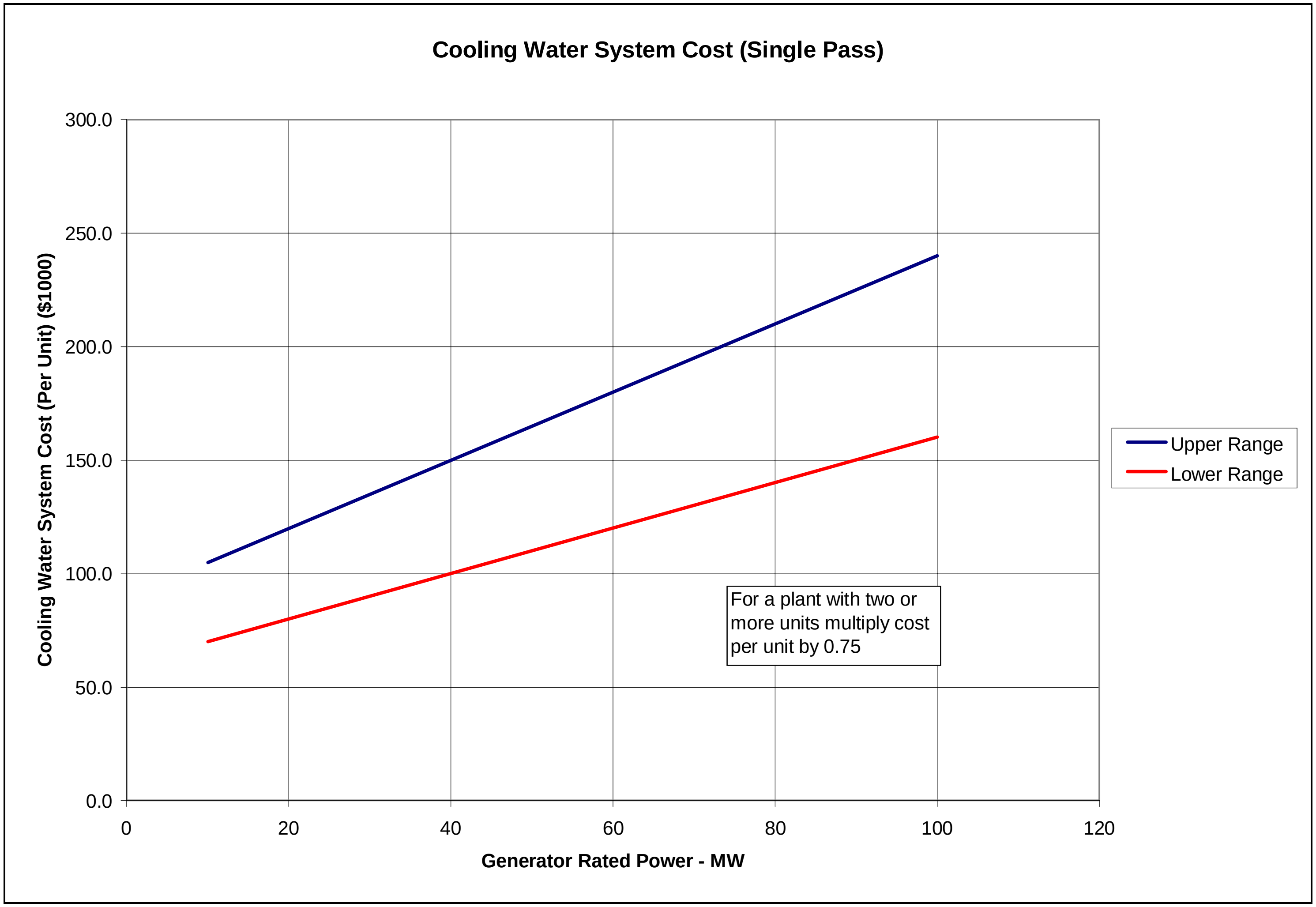

Figure 6-1
Cost for Cooling Water System (Single Pass)

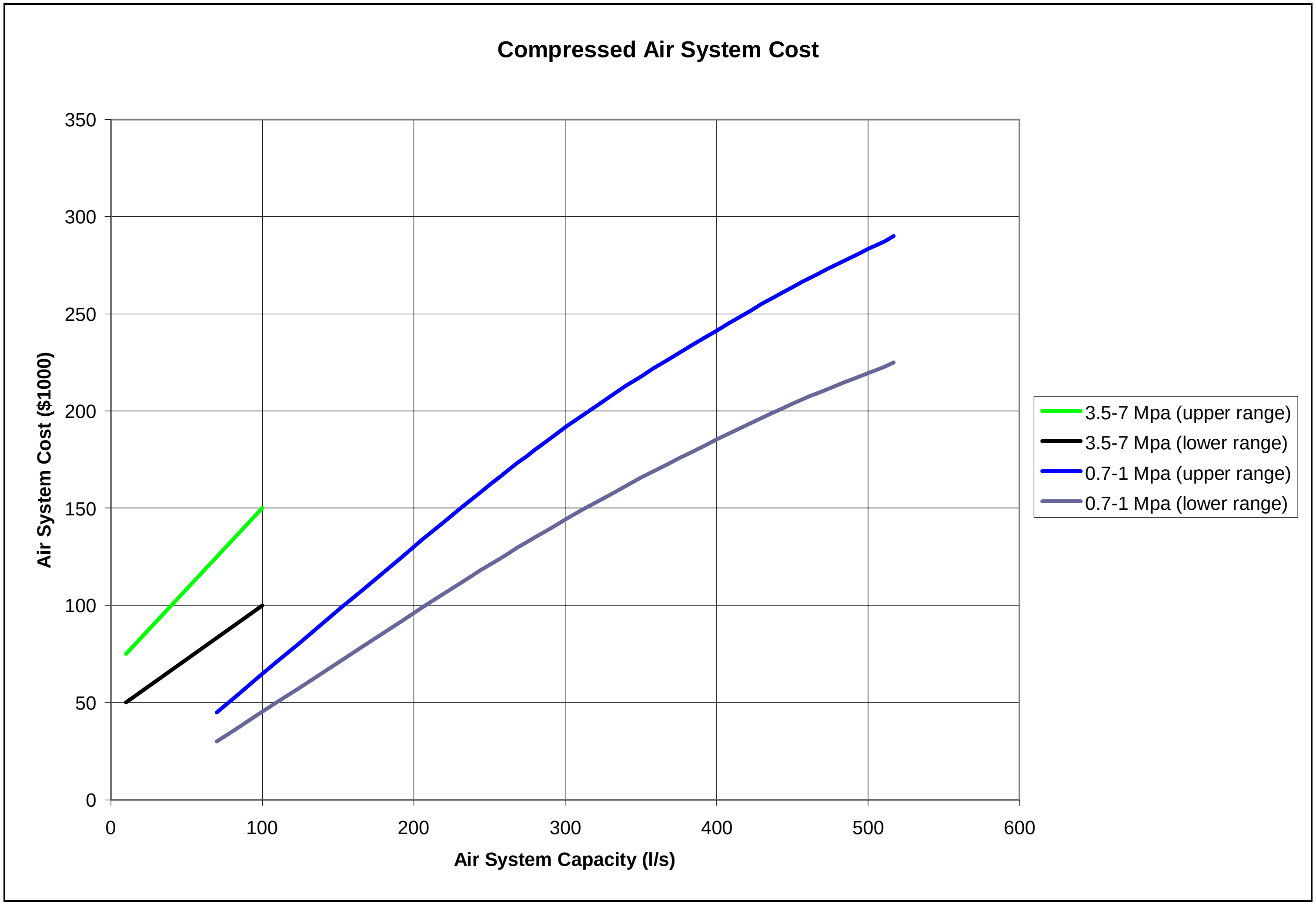

Figure 6-2
Cost for Compressed Air System

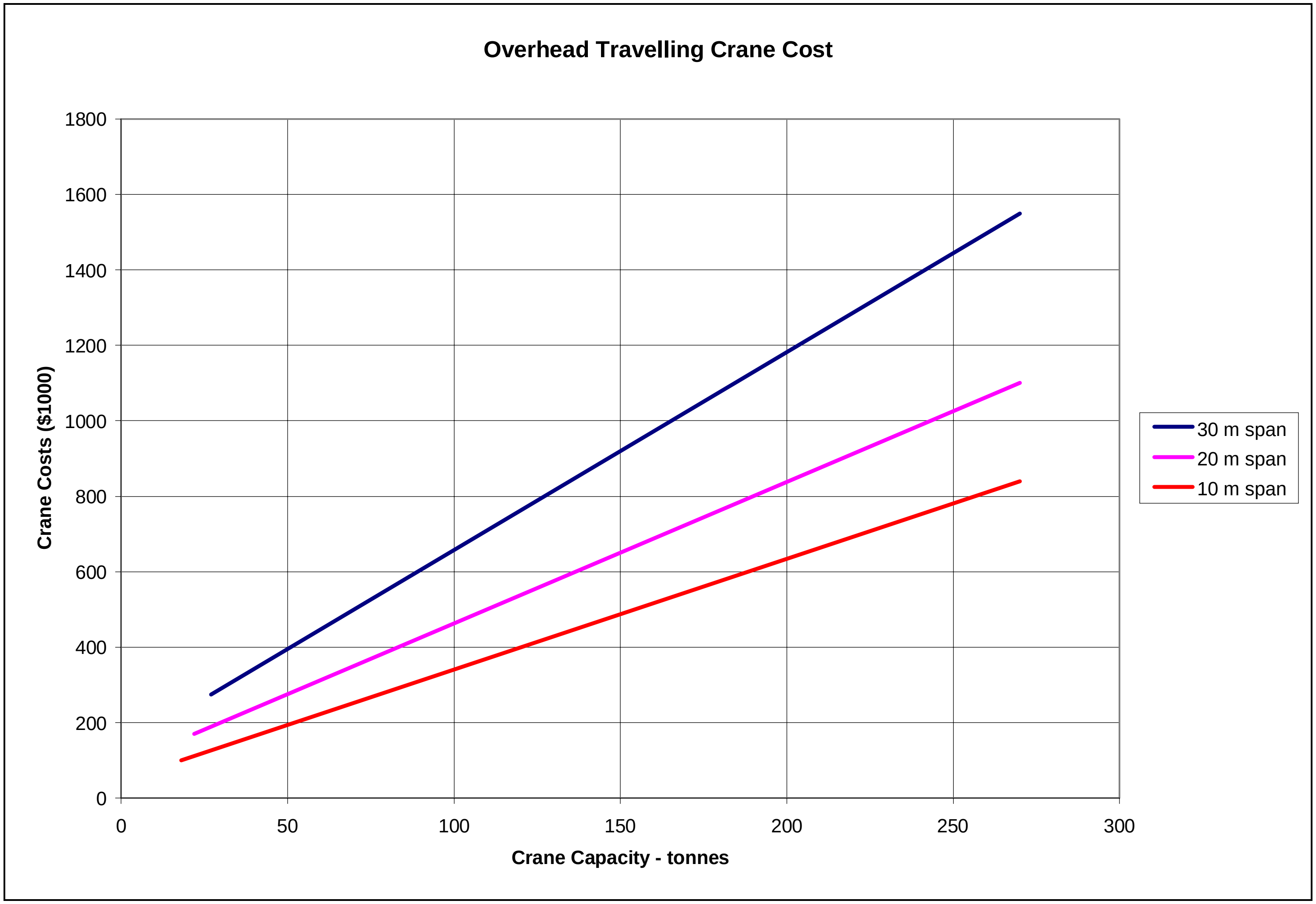

Figure 6-3
Cost Data for Overhead Travelling Cranes

6.2.1.4 Drainage and Dewatering Systems

The major components in the drainage and dewatering system include the pumps, piping, and level controls. Because of plant specific conditions, it is not possible to provide general cost data for the upgrade of the drainage and dewatering systems; however, this catalogue information is available from pump vendors. If sump modifications are required, the cost for modifying the drainage and dewatering system could be very high.

6.2.1.5 Fire Protection System

In practice, cost estimates for fire protection systems are produced on the basis of previous experience. Current market conditions will influence the cost of contracting design and installation.

Any method of cost estimating should include the following factors:

1. labour rates for electricians, mechanics, sprinkler fitters, fire alarm technicians, and other construction trades;

2. the expected number of work hours required form each trade;

3. travel and accommodation for personnel;

4. fire alarm - cost of main panel, field devices and wiring;

5. mechanical systems - cost of pipe (based on diameter, type, quantity), valves and trim, fittings, sprinkler heads, nozzles, bracing for pipe runs;

6. fire pump and associated equipment;

7. other materials - fire stop material, structural material, fire doors, fire dampers.

The following factors can be estimated as a percentage of the labour and materials cost:

1. schematic design engineering;

2. detail design engineering;

3. field inspection;

4. final testing and commissioning;

5. administration, contingency and other corporate overheads

6.2.1.6 Powerhouse Crane and Tailrace Cranes

Cost data for new overhead travelling cranes is shown in Figure 6-3. This data includes supply, transportation and installation costs in year 2001 dollars.

Delivery times for new cranes can be estimated using the following general guidelines:

- Allow 2 months for tendering if the owner provides detailed design.
- If a performance specification is used (ie no detailed design specifications), allow 3 months for tendering.
- Allow 1.5 months for tender evaluation.
- Allow 8 months to 1 year for fabrication depending on size and type of crane.
- If the owner is to approve drawings prior to fabrication, an additional 1 to 2 months must to be added to the schedule to allow for drawing approval.

6.2.1.7 HVAC

Estimating the cost of modernizing or installing new space conditioning equipment is difficult because of the numerous potential alternatives that are available. However, costs can be developed on a case-by-case basis for various space conditioning modernization alternatives using manufacturers' equipment and catalogues.

For non-essential systems, package water or air cooled, refrigerated, heating, ventilation and air conditionings units are relatively inexpensive and could be delivered in 10 to 12 weeks from approval of shop drawings.

If the reservoir water temperature is low enough during the summer months and the water value for generation is also low (a low head station), packaged units with reservoir water cooling coils could be proposed. These would be used in lightly occupied equipment areas where the space temperature could be allowed to rise up to 75°F to 80°F for short periods. These units are generally more expensive and of larger dimensions than the refrigerated units for the same load. Deliveries could be up to 20 weeks.

6.2.2 Auxiliary Electrical Equipment

6.2.2.1 Generator Transformer

If the existing transformer does not have sufficient capacity, it must be replaced. Figure 6-4 gives estimates of the weight and costs for both single and three phase transformers rated up to 50 MVA and 138 kV. Table 6-1 shows sample transformer cost data from recent supply contracts. It is worth noting that low sound level transformers will be more expensive. Lower noise levels require operating the transformer core at lower flux densities. This is typically achieved by either an increase in core cross-sectional area or more turns per winding to reduce the volts/turn ratio or by employing a combination of the two. The result is more materials will be required and the transformer will probably be very slightly larger. Pricing will also be sensitive to shop loading (how busy the manufacturers are) and fluctuations in material costs (e.g. copper, core steel, Kraft paper, etc.)

Transformer dimensions are dependent on the type, cooler arrangement, conservators, and high-voltage bushings. These factors vary widely, which makes general space requirements difficult to formulate. Generally, a volume factor of 70 cubic feet per MVA for three single-phase and 50 cubic feet per MVA for three-phase units can be used to estimate the transformer space requirements and dimensions. The weight of replacement transformers can be determined from Figure 6-4.

Costs for modification of the cooling system will depend on the design parameters and will need to be determined with the assistance of a transformer manufacturer.

For a rough estimate of the cost for uprating the transformer capacity using a forced cooling system, a factor of 0.3 times the transformer cost for first stage cooling can be used and a factor of 0.5 for second stage cooling.

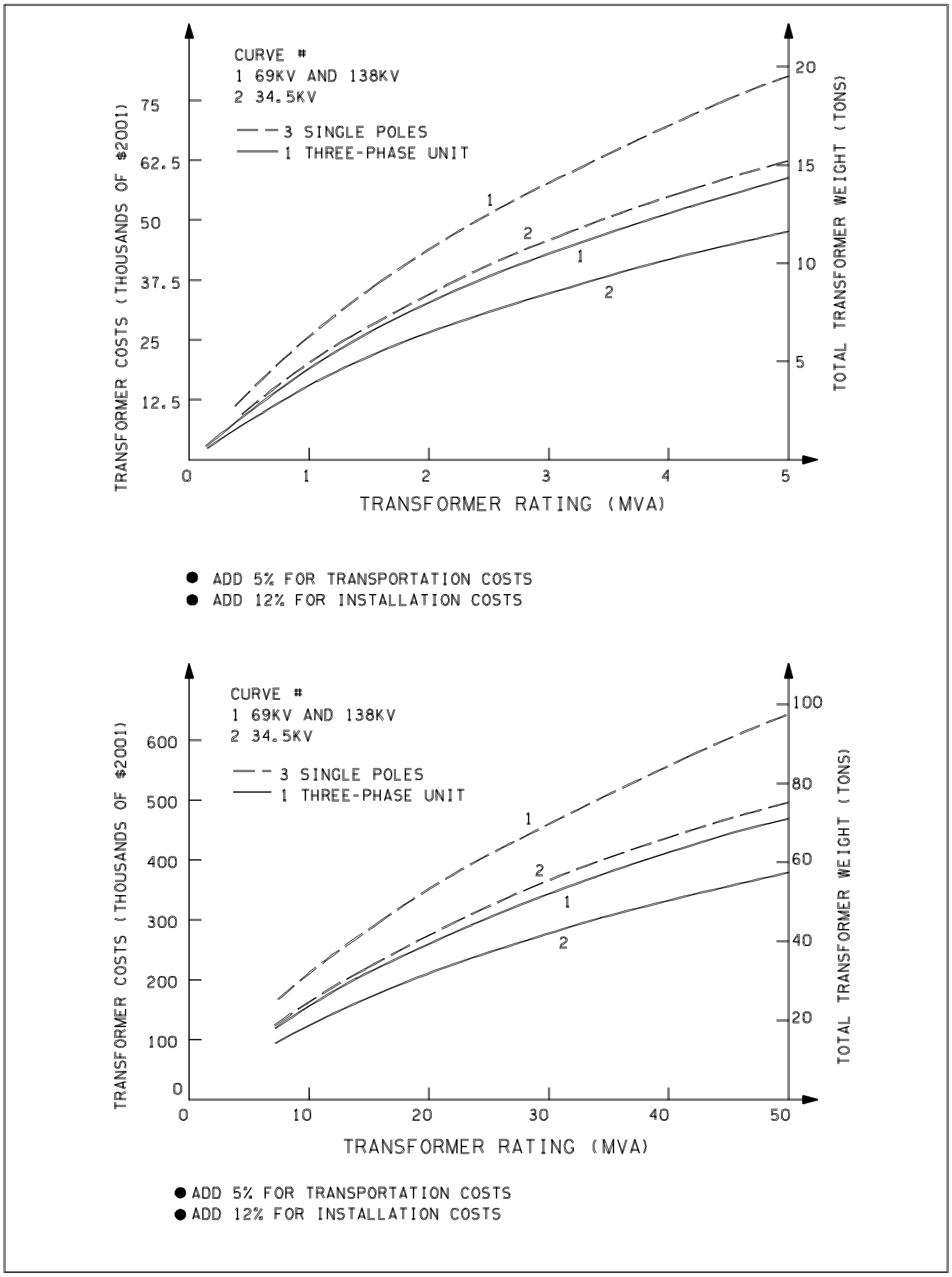

Figure 6-4
Transformer Costs and Weights

Table 6-1
Generator Set-Up Transformers

Year	ONAN	Capacity (MVA) ONAF	ONAF(2) or OFAF	Primary Voltage kV	Secondary Voltage kV	Cost 2001 ($1000)	Cost/kVa
1999	15	20		63	7.2	$360	22
2000	17	24		63	7.2	$500	29
1999	55	73		230	13.8	$750	14
1999	70	93		230	13.8	$900	13
1999	86	115		230	13.8	$1000	13
1998	81		135	66	13.8	$950	12
2001	35	46.7		66	13.2	$500	14

Lead and Delivery Times

New Transformers	
Procurement	3 months
Delivery after order	12 to 15 months
Delivery time for standard size transformer	8 to 10 months
Transportation	2 to 6 weeks
Installation	1 to 2 weeks
Cooling Improvements	
Investigation and design	2 months
Modification	2 to 5 months*
Outage for installation	½ to 1 month if modified at the powerhouse 1 to 2 months if modified in the manufacturer's shop, plus any transportation

* Depending on the scope.

6.2.2.2 Station Service AC and DC

Typical costs for component additions or replacements to the station Auxiliary Electrical system are shown in Table 6-2. Typical delivery times for the various components are also presented Table 6-2.

Table 6-2
Typical Costs and Lead Time for Station Auxiliary Electrical System Components

Item	Cost ($2001)	Typical Deliver Time (weeks)
AC distribution (panelboard)	15,000	6 to 12
DC distribution (panelboard)	10,000	6 to 12
AC/DC rectifier (battery charger)	15,000	10 to 18
Battery	20,000	8 to 14
Inverter	15,000	24 to 32
Auxiliary transformer	15,000	40 to 52
Cast resin transformer	30,000	30 to 40
Switchgear (per vertical section)[a]	25,000	24 to 32
Motor control centers (per vertical section)[a]	5,000	16 to 24
Raceway (per foot)[b]	4.00	na
Power cable (per foot)[c]	1.50	na

[a] Equipment cost only; installation is 0.15 times lump sump price.

[b] Equipment cost only; installation is 1.75 times lump sum price.

[c] Equipment cost only; installation is 2.0 times lump sum price.

As a rule of thumb, standby diesel generator sets can be estimated at approximately $1500/kW.

6.2.2.3 Grounding

The required ground grid size within a station ground mat depends on the type of soil (resitivity), available area and the ultimate single line to fault current. A computer program can be developed for estimating purposes using per unit costs for trenching, cable laying and bonding.

6.2.2.4 Lighting

Many existing lighting systems e.g. old incandescent lights, may need to be replaced with more energy efficient fluorescent lights. No cost to benefit analysis needs to be conducted for these cases.

Most other lighting systems should have an energy audit and cost to benefit analysis made to establish the justification for a retrofit.

6.3 Project Costs

The estimated costs of a project usually include:

- Direct costs
- Contingency
- Escalation
- Indirect costs
- Interest during construction (IDC)
- Other costs

Capital costs are those that result in an asset improvement and include all the costs above except for "other costs" which are generally under the heading of Operations and Maintenance.

Each of the areas above will be discussed briefly below for completeness. The use of the example electronic economic/financial evaluation template provided with Volume 1, Section 4.9 will simplify the process for evaluating the impact of the activities on the plant. The template eliminates the need to calculate individual contingencies, escalation and IDC for each identified project, as these are set for all projects entered into the template in the "Assumptions" area of the template. Costs are also used as input in the optimization of improvements.

6.3.1. Capital Costs

Capital costs for a project consist of the direct costs, contingency, escalation, indirect costs, and interest during construction.

- Direct Costs - Direct costs include the costs of all direct equipment, material, and construction costs associated with disassembly, assembly and testing.
- Contingency - The contingency to provide for inaccuracies in the direct costs estimates depends on the confidence level of the direct costs. For the estimates for LEM Plans, a contingency factor of 20 percent (CF = 0.20) is suggested.
- Escalation - Escalation is the annual increase in costs due to inflation and other factors, such as material and labour costs. The direct costs determined from these Guidelines are in 2001 dollars (US) and should be escalated to the midpoint of the construction period, as determined from the Milestone Schedule. The escalation factor can be determined from the following equation:

- Escalation Factor (EF) = $(1 + e)^n - 1$, [6-1]

  Where

  e = annual escalation rate in decimal value, and

  n = number of years between the date of direct cost dollar values and the date of midpoint of construction.

The value to be used for escalation can be determined from either the Handy-Whitman or USBR indices as described in Section 6.1. A suggested value is 3.0 percent per year (e = 0.03).

- Indirect Costs - Indirect costs consist of the costs for administration permits, licensing, engineering, construction management, training, and startup. For the runner modernization considered in these Guidelines, an indirect cost factor (ICF) of 20 percent (ICF = 0.20) is suggested.
- Interest During Construction (IDC) - IDC is the interest paid on the money borrowed to finance the implementation of the plan. IDC is calculated from the midpoint of the Milestone Construction Schedule to the date of commercial operation of the modernized system. IDC is only applicable to plan costs treated as capital improvements where the costs are to be included in a rate base. For plans in which costs are treated as maintenance costs, IDC should not be applied. Similarly, for modernization projects completed in less than a year, interest during construction is insignificant and may be excluded. The rates to be used can be determined from one of the following equations:

IDC Factor (IDCF) = $(1 + r)^n - 1$ (compounded) [6-2]

IDC Factor (IDCF) = r x n (simple) [6-3]

where

r = interest rate in decimal value, and

n = number of years from the midpoint of construction to the date of operation.

Interest rates are typically 3 to 5 percent above the escalation rate. A suggested value is 9 percent (r = 0.09).

6.3.2 Present Value of Total Capital Cost

In present value evaluations, the total capital costs of a plan are not the dollar value used for the evaluation. The value required is the present value of costs incurred due to the commitment of the total capital costs. These costs include taxes, insurance, depreciation, return on investment, finance charges, and other administrative costs. These costs are called “fixed charges” and are typically assessed as a percentage of the total capital costs each year. Therefore, the fixed charges vary each year as the total capital costs vary. To simplify economic evaluations, the fixed charges can be converted to uniform annual payments called levelized annual fixed charges. This uniform annual payment is computed by dividing the sum of the present valued annual fixed charges over the economic life of the project by the sum of the present value factors. The uniform annual payment divided by the total capital cost is the levelized annual fixed charge rate.

The present value of these fixed charges corresponds to the date of commercial operation. This value needs to be present worthed to the date of the study and is the dollar value required for total present value evaluations in these guidelines. The present value of the total capital costs is the fixed charge factor times the total capital costs. The fixed charge factor is calculated as follows:

$$\text{Fixed Charge Factor (FCF)} = \text{LAFCR x SPWF}, \qquad [6\text{-}4]$$

where

LAFCR = the levelized annual fixed charge rate in decimal value, and

SPVF = the sum of the present value factors for the economic life of the modernization.

SPVF is calculated as follows:

$$\text{SPVF} = \frac{(1+i)^n - 1}{i(1+i)^n} \qquad [6\text{-}5]$$

where

i = the present worth discount rate in decimal value, and

n = the number of years in the economic life.

For organizations with ongoing improvements, these values may be readily available. However, when the values cannot be easily calculated, suggested values for FCF are 1.10 for public agencies and 1.30 for investor-owned utilities. The fixed charge factor is a number developed to quickly calculate the present value of the total capital cost in lieu of calculating the annual present value of the fixed charges and summing.

The present value fixed charges presented previously are based on the date the upgrade plan is put into commercial operation. These costs must be adjusted to the date of the study by multiplying by the present value adjustment factor. The present value adjustment factor (PVAF) is calculated as follows:

$$\text{PVAF} = 1/(1+i)^t\ , \qquad [6\text{-}6]$$

where

i = discount rate (0.09), and

t = number of years between the study and commercial operating date of the plan.

6.3.3 Other Costs

Any other costs should be estimated and added to the total cost. For example, such costs might include the increased operation and maintenance (O&M) costs incurred while a unit is modernized.

The sum of the present value of the following costs - total capital and other costs - gives the total present value of upgrading, which is then compared to the operating benefits of the modernization plan. The present value of these costs should be at the date of the study.

6.4 Cost Estimates at the Feasibility and Project Approval Stage

While the cost estimates presented in the preceding subsections are suitable for screening and planning studies, estimates with reduced uncertainty will be necessary for project approval, prior to implementation. Volume 1, Section 2.3.5 discusses various estimating considerations.

Indirect cost and interest during construction may require review to check any revision to the owner's specific financial/economic parameters. The use of the Model will reduce or negate this requirement if the appropriate parameters are initially entered into the Supporting Tables portion of the Model.

Cost estimates for supply of auxiliary equipment should be obtained from suppliers, or else developed from actual prices for previous projects of similar type and capacity.

Installation costs can be based on costs for previous projects of similar scope.

Estimating guides such as "Means" may also be useful particularly for projects involving significant piping, valves, cables, conduit, cable tray, etc.

In addition, cost information is also used as input for any optimization studies for auxiliary equipment.

Depending on the confidence in the cost estimate, it may be possible to reduce the contingency to as low as 10 percent of direct cost. The owner's policy on contingencies however, will determine the contingency percentage to be included.

6.5 Energy and Capacity Benefits from Modernization

Modernization of auxiliary mechanical and electrical equipment will usually be part of an overall modernization program involving turbines or generators, or both. This major equipment will dictate the modernization requirement. Usually there will be no easily defined energy and capacity benefits attributed directly or solely to a particular auxiliary service; the benefits are typically evaluated as part of the turbine and generator modernization effort. The methods for determining energy and capacity benefits for this major equipment is described in Section 6 of Volumes 2 and 3.

Nevertheless there are exceptions where the auxiliary equipment has a direct effect on efficiency or capacity. Some examples are:

- If the output of a generating unit is restricted because of an inadequate cooling water system, upgrade of the system will allow an increase in capacity and energy.
- If a cooling water system at a high head plant utilizes water from the penstock with a pressure-reducing valve, the benefit of a pumped system will be an increase in energy due to the more efficient use of head. The benefit is directly attributed to the system.
- Installation of a new transformer with higher efficiency will have a direct effect on energy.

For the first two items listed above, an economic evaluation of the benefits of modernization is often made using simplified economic analysis. The capital cost of the modification is compared with present worth of the capacity or energy benefit over a 10 to 25 year life. Alternatively, a more exact analysis can be made using the methods described in Volumes 2 and 3.

For the third item described above, the difference in efficiency is usually very small (and for this reason increase in efficiency is rarely the reason for transformer replacement). However the benefits can be evaluated by simplified methods mentioned above or using the approach described in Volumes 2 and 3.

6.6 Other Benefits from Improvement

In addition to the improvement in performance, there may be several other benefits to a life extension and modernization program covering the auxiliary electrical and mechanical equipment including:

- reduced repair costs;
- reduced maintenance costs;
- increased value of the asset;
- increase in availability;
- increase in operating flexibility;
- reduced risk and insurance costs; and
- more environmentally friendly equipment.

Each benefit will require assessment for each individual project proposed. Some benefits will be difficult to define financially and may be better treated using a Value Based Management approach if the owner is inclined to use such a system. The use of risk cost benefits in the evaluation of the project/plant benefits will also be dependent upon the owner's requirements. There is provision for risk costs benefits to be incorporated into the Model if desired.

6.7 Input to Life Extension and Modernization Plan

Input to the LEM Plan will include cost estimates into the early stages of the LEM plan formulation in Section 4 of Volume 1 (Tables 4-6 Needs and Opportunities) along with cost and benefits inputs into the Model in Section 4.9 of Volume 1. Additional input will feed into Section 7 of Volume 1 when a revision of costs and benefit estimates will take place in any feasibility study conducted.

7
OPTIMIZATION OF ALTERNATIVES (FEASIBILITY)

7.1 Introduction

Sections 4, 5 and 6 of Volumes 4 and 5 contribute to the formulation of a Life Extension and Modernization (LEM) Plan for auxiliary mechanical and electrical equipment. The information used to formulate the LEM Plan is obtained largely from existing test data and reports.

At the completion of the LEM Plan, the most favourable LEM activities, perhaps with an alternative or two, will be selected to be studied in more detail at the feasibility level. The projects identified in the selected Plan(s) may require more accurate, up to date information in order to:

- verify the technical feasibility by:
  - identifying and optimizing alternative activities (Sections 7.2, 7.3 and 7.4)
  - selecting the best activities (Section 7.5)
- proceed with the design (Section 8)
- implement the project (Section 8)

Section 7 will outline methods to obtain more detailed information on equipment condition and modernization opportunities.

The additional information required may come from:

- Additional testing of components or systems to better establish their performance and operating characteristics
- Additional inspections (with equipment out of service)
- Engineering studies

The information gained from these activities will enable the feasibility of the life extension and/or modernization activities proposed for the plant to be determined.

7.2 Additional Testing and Inspection of Auxiliary Mechanical and Electrical Equipment

The tests and inspections conducted at the project feasibility study stage will depend on the specific equipment and services being studied.

7.2.1 Auxiliary Mechanical Equipment

The following provides examples of further tests and inspections for auxiliary mechanical equipment.

Bearing Lubrication Systems

- Oil pump operational tests
- Oil Sampling Program
- water quality testing program - at different times of the year
- pipe wall thickness testing (ultrasonic)
- oil leakage tests

Raw and Cooling Water Systems

- measurement of head-flow characteristics of pumps (cooling water, drainage, dewatering)
- measurement of heat exchanger performance
- water quality tests
- pressure drop tests in system to determine if line blockages are a problem
- pipe wall thickness testing (ultrasonic)

Compressed Air System

- pipe wall thickness testing (ultrasonic)
- operational and capacity tests of compressors
- pressure vessel inspections
- test of air dryer effectiveness
- system tests to determine leakage rates and existing capacities

Drainage & Dewatering Systems

- measurement of head-flow characteristics of pumps
- water quality analysis from oil/water separator discharges
- measurement of dewatering times.

Fire Protection System

- functionality testing of all mechanical fire protection equipment.
- functionality testing of all fire protection alarms and signalling.

HVAC Systems

- ventilation system temperature and airflow rates
- review of operating data to determine trends in powerhouse and ambient temperatures vs. equipment reliability.

Powerhouse & Tailrace Cranes

- complete regulatory inspection
- crane operating speed tests
- minimum crane hook, trolley and bridge movement (for positioning of loads)
- crane load tests

7.2.2 Auxiliary Electrical Equipment

The following provides examples of further testing and inspections for auxiliary electrical equipment.

Generator Transformer

- oil analysis/oil reclamation
- internal inspections

Station Service – AC

- operational tests of standby generators

Station Service – DC

- load tests on batteries

Cable and Cable Supports

Laboratory assessment may be recommended after a failure has occurred. Lab assessment is made to determine whether cables of similar type and age should remain in service. Lab assessment may consist of dissection, water tree counts, and various small sample, chemical tests. If longer samples can be taken, ac breakdown tests are performed. Laboratory tests tell the most accurate story of cable condition and cause of failure, but only tell the story on the sample examined. To understand the state of the insulation of the existing cable, on-site condition assessment is needed.

If a long sample can be removed from a cable installation, an ac breakdown test will give a good indication of the condition of the sample. On new 15 kV cable, ac breakdown may occur at over 150 kV. As the cable ages, the breakdown strength decreases. Cables nearing end of life will breakdown at or below three time operating voltage. For a 15 kV cable, this will be 25 kV line-to-ground or less.

Grounding

- soil resistivity measurements

Lighting

- illumination levels
- station service consumption

7.3 Engineering Studies

Engineering studies are used to bring the required information together to make rational decisions on the feasibility of specific improvement activities. The process covers:

- Assessment of previously gathered information (Volumes 4 and 5, Sections 4 and 5)
- Assessment of results of further inspection and testing (Volumes 4 and 5, Section 7.2)
- Power Studies (Volume 6)
- Buildability analysis (Volume 1, Section 7.4)
- Value engineering (Volume 1, Section 7.4)
- Improvements in assessment of costs (Volumes 4 and 5, Section 6.3 and 6.4)
- Improvements in assessment of benefits (Volumes 4 and 5, Sections 6.5 and 6.6)

The iterative nature of the LEM planning process is intended to optimize outlays and not to commit large amounts to studies which should not be conducted until preliminary studies indicate that the project proposed has merit.

Bearing Lubrication Systems

The scope of further studies is very dependent on whether the objective is to solve a pre-existing problem or to modify the bearing lubrication and cooling system to achieve an improvement beyond historical levels. Further studies would include the following:

- analysis of the benefits of a lift pump system for start up and shutdown.
- review of operating data for the bearings to determine if modifications to the oil delivery systems would improve unit performance (better filtration, different oil viscosity, etc.).

Raw and Cooling Water Systems

- Cooling water savings studies for the various cooling water systems, particularly the generator cooling water system. Options to reduce or modulate the flows would be assessed using a benefit to cost ratio analysis. Preliminary estimates of system modifications would be compared to the potential to use "saved" cooling water for generation through the units and the value of that additional energy.
- Studies on alternatives for supply – penstock, pumped from tailrace, etc.

Compressed Air System

- Engineering studies for the compressed air system would include an analysis of the reliability of the various station compressed air systems and an evaluation of various modifications or improvements to improve system performance and reliability.

Drainage & Dewatering Systems

A review of station drainage requirements to prevent powerhouse flooding may be required if system demands have changed since commissioning.

If the condition assessment reveals that oil spill containment needs to be reviewed at a particular site, a more detailed risk evaluation and equipment study needs to be performed. The following information should be gathered for this study:

- site general layout drawings
- system schematics
- site equipment lists
- topographic maps
- soil and groundwater information
- photos
- environmental sensitivity/impact information

Fire Protection System

A complete fire hazard and risk study is an important study carried out by specialist Engineers in fire protection. It is a comprehensive review of such aspects as:

- identification of hazards (equipment and life safety)
- risk/probabilities of fires
- review of the chance of a fire spreading
- assessment of value of potential property/equipment damage
- review of means of mitigating fire risk
- benefit to costs analysis (cost of modernizing fire protection systems vs the potential fire losses).

HVAC Systems

A detailed energy audit of a station looks at both lighting and HVAC as major consumers of station service. A study of HVAC energy savings opportunities would typically be done if the existing HVAC systems are more than 10 years old. The study would include:

- development of an inventory of the existing HVAC systems;
- assessment of the suitability of the existing equipment;
- recommendations on which equipment should be replaced, justified either on condition or performance deficiencies or the opportunity for station service (energy) savings.

Powerhouse & Tailrace Cranes

For a bridge crane upgrade where increased capacity has been identified as desirable, typical additional engineering studies include:

- Structural analysis of crane bridges including end trucks;
- Analysis of crane trolley and hoisting equipment;
- Structural analysis of powerhouse crane rail runways and supporting superstructure. Sometimes bridge crane capacity increases can be achieved with minimal strengthening of the powerhouse superstructure. Crane runways are designed for a capacity lift acting at the closest approach the crane trolley can make to the runway. This position is determined with the trolley against the end stops on the bridge. Typically, the size of the component making up the design lift prevents the trolley from moving very far from the center of the bridge. This results in the load being more evenly shared with the two runways (ie the load seen by the runways is less than the design load.) If the upgraded capacity lift is restricted to near the center of the crane bridge, the resulting bridge end truck loads will increase, but perhaps will remain within, or close to, the original design capacity.
- Structural analysis of powerhouse foundations.

Transformers

Engineering studies for the generator transformers may include:

1. study of optimal timing for maintenance intervention.

2. study of the application of new technologies such as the oil-less transformers, particularly in areas with strict environmental standards.

These are two excellent sources for the latest research on transformer life expectancy. The Canadian Electricity Association (CEA) has a project which is studying the life assessment of hydro assets, including generator transformers. Hydro Tasmania also has published some papers on the same topic.

Station Service – AC

For the station standby generator, further studies may include analysis of:

- Available equipment and possible alternative standby supply, eg fuel cells, batteries, microturbines.
- Current load and anticipated future growth.
- Changes in regulations

Station Service – DC

A review of options for replacement battery systems is sometimes undertaken.

Cable and Cable Supports

A review of cable seismic supports is often applicable.

Grounding

An engineering review of conformance of the station ground system to current codes is often required.

Lighting

A lighting audit would typically be carried out if the lighting system or components were more than 10 years old. The audit would consist of:

- development of an inventory of the existing lighting systems;
- assessment of the suitability of the existing equipment;
- recommendations on which equipment should be replaced, justified either on condition or performance deficiencies or the opportunity for station service (energy) savings.

7.4 Risk Considerations

Risk management is the ability to balance risks with the potential gains by making wise decisions.

As part of the feasibility study process, it is advisable to assess the risks associated with each option being assessed. Each risk, along with the potential mitigation available, can be identified. Risk areas to be considered are summarized in Table 7-1

Table 7-1
Risk Considerations

AREA	RISK
Technical and technological	• Proposed modernization activity does not work • New equipment does not meet performance levels • Technology changes make modernization obsolete • Inadequate assessment of condition • Incorrect designs and inadequate quality assurance (QA) • Once work is initiated, more is identified
Construction	• Cost overruns • Delayed schedule, longer outages • Consequential damage • Contractor unfamiliar with specific work • Poor estimates of cost
Environmental	• Impacts on land/water due to construction • Pollution and spills
Operating	• New operation rules not written • New operation methods not attainable • Operation changes not acceptable by external stakeholders • New operation does not achieve expected gains

The user should examine all areas above with particular regard to the activities resulting from work associated with this Volume.

The risks identified by this process need to be examined for their acceptability. If some risks are apparently unacceptable as they stand then the mitigation available to reduce the risks to acceptable levels has to be identified. If the cost of mitigation is uneconomic then the risks are confirmed as unacceptable and the project or activity is not feasible. If the mitigation can reduce risks to an acceptable level at an economic price, then the costs of the mitigation will be included in the financial evaluation conducted during the feasibility study.

Volume 1, Sections 2.3.2, 4.6 and 7.5 all deal with risk identification and management and should be used as a reference. More detailed evaluation and management of risk issues is beyond the scope of these Guidelines.

7.5 Evaluation, Selection and Optimization of Modernization Plan

Modernization activities (opportunities) were identified, assessed and screened as part of Section 5 of this Volume and Volume 1, Section 4. This provided an LEM Plan for auxiliary equipment in the context of the overall plant. The next stage in the process was to evaluate the proposed activities in more detail and to optimize the activities. To do this required additional testing and inspection of equipment (Section 7.2), engineering studies (Section 7.3) and the identification and evaluation of the risks associated with each proposed activity or project (Section 7.4).

With the results of the work associated with Sections 7.2, 7.3 and 7.4, all options explored during feasibility can now be evaluated. This will enable a final modernization plan to be selected and optimized before undergoing a final sensitivity analysis.

8
IMPLEMENTATION AND MODERNIZATION PLAN

8.1 Introduction

Previous sections of Volumes 4 and 5 have provided information for the user to identify, evaluate and select an appropriate life extension and modernization plan for auxiliary mechanical and electrical systems and confirm the feasibility of selected activities. Section 8 assists the user in formulating a general plan for implementing this modernization plan.

Figure 8-1 outlines the steps involved in preparing proposed life extension and modernization activities for implementation.

8.2 Design and Engineering Studies

Design and engineering studies relating to life extension or modernization of auxiliary mechanical and electrical equipment would primarily be “desktop” type studies to ensure that the change or modification of a particular system is fully compatible with the existing facility and major equipment to which it is interconnected. Care must be taken to ensure that important or critical features of the original design are not overlooked.

Typical examples:

- Modification or replacement of a tailrace crane. – Ensure that all clearances with existing structures are adequate. Check that crane bumpers are compatible with the runway endstops. Ensure that the features and equipment for lifting the gates are suitable and that lifting clearances are satisfactory.
- Addition of an oil-water separator/filter to a drainage system. - Ensure that the capacity of the new equipment is compatible with the discharge characteristics of the pumping system.
- Addition of a new strainer to the cooling water system - Ensure that the pressure drop across the new strainer is not significantly higher than that for the existing strainer.

In some cases the studies may require site measurements and tests on the existing auxiliary systems to establish or confirm their design and operating parameters.

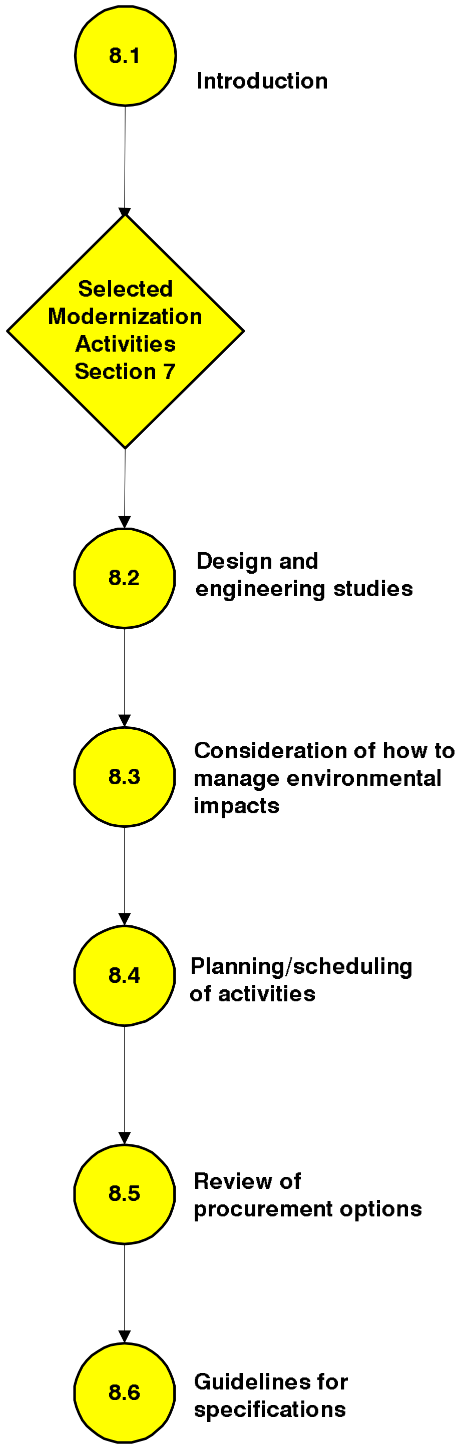

Figure 8-1
Implementation Process

8.3 Environmental Management Considerations

The implementation of a modernization activities for auxiliary mechanical and electrical systems will generally not have as significant an environmental impact as modernization of major equipment. It is likely that the activity will not have licensing implications. Nevertheless, an environmental management plan as discussed in 8.3.1 will still be necessary.

8.3.1 Environmental Management Plans (EMP)

In order to ensure sound environmental management and to demonstrate due diligence to regulatory authorities and the public, an environmental management plan is required for most projects, from painting projects to equipment replacements and operational changes.

The purpose of an EMP is to ensure that the potential environmental impacts of a proposed activity (which does not require a legislated environmental impact assessment) are evaluated, and eliminated, mitigated or compensated for appropriately, and that these considerations are communicated appropriately in a responsible manner. EMPs also ensure that all required permits, authorizations and approvals are obtained and documented for due diligence purposes.

Like other environmental assessment tools, EMPs consider a proposed activity in the context of the existing environment in order to identify potential impacts and mitigation measures, provide an appropriate level of environmental protection, and ensure compliance with appropriate legislation and guidelines.

The content of an EMP depends upon the scope of the proposed undertaking. Depending upon the complexity of a proposed activity, and the environmental sensitivity, an EMP can be:

- instructions presented in a pre-job meeting
- a memo or letter
- clauses in tenders and contracts
- a stand-alone document
- all of the above

An EMP is also a valuable communication tool for the transmission of information in-house and to other stakeholders.

A reference collection of all existing EMPs, permit and authorization information and other useful material should be collated for easy reference on future projects.

An EMP will usually include the following sections:

1.0 Introduction

2.0 Project/Activity Description

3.0 Environmental Setting/Valued Ecosystem Components

4.0 Regulatory Requirements

5.0 Potential Environmental Impacts

6.0 Mitigation/Compensation

7.0 Literature Cited

Appendices:

Appendix 1 Project - Specific Environmental Protection Plan

Appendix 2 Environment Compliance Monitoring

Appendix 3 Regulatory Permits and Authorizations

Appendix 4 Emergency Contact List

Appendix 5 Material Safety Data Sheets (MSDS) Forms

Appendix 6 Test Results (analyses of paint, etc.)

Appendix 7 Spill Prevention and Response Measures

Appendix 8 Environmental Incident Reporting Procedures

Appendix 9 Suppliers (sorbents, etc.)

Appendix 10 Monitoring Forms

A very important part of any EMP is the monitoring requirements for the project. Environmental monitoring requirements should be well laid out and included as clauses in any external contracts for the work.

8.3.2 Construction Phase

Environmental management during the construction phase involves the consideration of the following aspects:

Interference with the existing environmental management systems (such as drainage systems) in the plant.

Losses to the environment due to mishaps during construction.

Existing Environmental Systems

When part of a plant is out of operation due to a construction project, the security of the environmental systems in the in-service portion of the plant may be reduced. For example, work on the station drainage system may limit the plant's capability of containing an oil spill occurring in the "in service" portion of the plant. Close coordination is required during the construction phase to avoid this type of situation. Daily coordination meetings between those involved in the construction project and those involved in plant operations can minimize the risks.

Losses to the Environment

The most common environmental risk with construction work is that of direct loss of construction materials and effluent to the environment (e.g. oil spill from a transformer during replacement or modifications). The mitigation of these risks lies with the contractor and the construction management team. The responsibilities and penalties associated with working to the required environmental regulations must be clearly defined for all parties at the start of the project. Daily coordination meetings, which include a discussion on activities that are potentially harmful to the environment, can be used as a risk mitigating activity.

8.4 Project Definition and Implementation Planning

To date, the life extension and modernization process has moved through its investigation and decision making phases. Once the decision is made to proceed with a particular project a new phase of the process is commenced - implementation.

Implementation consists of defining the project to be commenced and conducting and completing the defined project. Activities include:

- Project management
- Engineering
- Procurement
- Construction
- Construction Management
- Testing and Commissioning
- Documentation

Volume 1, Section 8 covers the project definition and implementation portion of the process in detail. It is recognized that each user will normally have procedures in place for these activities. Accordingly, the information presented is general in nature and intended to prompt some consideration of alternatives that may not currently be utilized by the user.

Who carries out the project activities will depend on the resources available and the contracting philosophy of the owner. All project activities may be undertaken by the owner's own engineering, maintenance and construction staff or all, or part , of the work may be contracted out.

8.5 Procurement Options

Procurement options are covered extensively in Volume 1 of these Guidelines. The options available to the user usually depend on the philosophy of the Owner. A modernization program for auxiliary systems is usually much smaller in scale than one involving major equipment, and the scope and extent of the program can vary significantly depending on the specific system.

Options for contracting include:

- Design by owner (or owner's engineer), procurement by owner, and installation by owner’s maintenance staff. This would typically usually apply to small projects where the Owner has basically all the resources required to undertake the work. This type of contract would be applicable to auxiliary services involving standard “off-the-shelf” components (e.g. drainage system or station batteries).
- Design by owner (or owner’s engineer), procurement by owner, and installation by a contractor. The owner retains procurement of the majority of equipment; therefore generally has better control of specific components that are purchased. This type of contract would also be applicable to auxiliary services involving standard “off-the-shelf” components.
- Design by owner (or owner’s engineer), procurement and installation by a contractor. This is similar to the approach described above; however the owner's involvement in procurement and installation is minimized.
- Design, procurement and installation by a contractor. This is basically a turnkey type approach.
- Procurement by the owner using a performance specification for design by the manufacturer. Installation by a contractor. This is common for larger specialty or custom designed equipment such as a crane or transformer.
- Procurement by the owner using a performance specification for design, supply and installation by the manufacturer. This is also common for larger specialty or custom designed equipment.

Contacts for equipment supply only are usually fixed price type. Contracts for installation, or the installation portion of contracts, can be:

- Cost reimbursement type
- Fixed price

In cost reimbursement type contracts, the owner pays the contractor for the actual cost of the work plus an additional amount representing the agreed profit. The owner assumes most of the risk in this type of contract. Moreover the owner must survey the quality and quantity of the work closely to ensure that the work is sufficient, of acceptable quality and performed expeditiously.

In a fixed price contract the contractor agrees to do the required work for a fixed price. The contractor assumes most of the risk. However, if the actual work scope cannot be clearly identified, a fixed price contract can be difficult, as the contractor may have to build in added cost to allow for unknowns. Turnkey type projects are also generally fixed price contracts.

8.6 Considerations for Technical Specifications

Specifications, along with the contracts they are associated with, are the means of transferring risk from owner to contractor. Therefore, it is important to ensure that the specification is designed not only to correctly transfer risk but also to minimize the risk payment that the contractor will seek from the owner. The more unknowns built into the specification, the more risk cost the contractor will build into its price.

This section is designed to provide assistance, at an overview level, to the user when preparing specifications. The scope and contents of the specification will depend on the type of contract and scope of work. The specifications for procurement of small standard design equipment components should be relatively brief, whereas the specifications for custom designed equipment and services may be quite detailed.

8.6.1 General

This section provides general guidelines to assist the user in contracting for equipment refurbishment work. It is not possible to adequately describe the equipment procurement and/or condition to allow contractors to prepare fixed price bids for overhauls without the contractor incorporating a large risk premium. Prior to bidding, contractors may be requested to inspect the equipment, but these inspections will only reveal superficial defects and can give a rough indication of the duration and cost of the refurbishment.

Therefore, the repair of defects found during the refurbishment will require that some work be billed according to actual expenditures or on a unit price basis.

8.6.2 Request for Qualifications and Proposals

The first step is to select the potential bidders and prepare a Request for Qualifications and Proposals which is sent to each of the selected bidders.

The Request for Qualifications and Proposals should include the following information:

- All commercial terms (contractual obligations)
- All technical specifications for the work.
- Drawings (as applicable)
- Date of pre-bid inspections (as applicable)
- Schedule
- Support services provided by the owner
- Bid date

Inspection

A site inspection should be conducted prior to the submission of bids to allow contractors to identify general site conditions including access (or lack thereof). During the site inspection the owner should provide a knowledgeable contact person on site to answer questions and clarify the scope of the modernization work. It is important that there is only a single source of information from the owner to ensure that all parties receive the same advice so that the bids received are all based on the same information.

Bid

The bid should be divided into two parts:

- Standard overhaul lump sum cost.
- Unit quantity cost (including salaries and expenses) for unexpected or unspecified additional work. In some cases this could be arranged as fixed price for particular works if they arise. Also, the costs could be fixed hourly rates for labour with an invoice plus a fixed percentage handling fee for materials.

Bid Evaluation, Bid Negotiations

The bids received will be evaluated by the owner's personnel or an outside engineer. All competitive bids will be adjusted to the same technical level by negotiations to enable meaningful price comparison. The contract for the modernization work is usually signed with the lowest bidder (this does not just include price), unless unusual circumstances require the selection of another bidder.

Contract

The contract consists of the bid proposal and any agreements made during the contract negotiations.

Extra Scope Work

The inspection of equipment after site construction work has started might reveal unexpected repair work, potential for improvements, and the need for spare parts. Generally, this additional work is authorized by the owner following negotiations and agreement of the additional scope and costs for this work.

8.7 Innovative Methods of Construction

Innovative methods of construction usually develop from an unusual problem that must be solved in the planning stages of a project. Hydropower magazines and journals often present case studies of interesting construction projects which are good sources for keeping abreast of new construction techniques that reduce costs and time.

1. **Use of "in-house crews" for rehabilitation and upgrade projects.**[8]
   Sometimes, due to high contractor charges and lump-sum bids combined with the cost of contract specification preparation, administration and inspection, the use of company personnel to form construction crews can save money.

2. **Uprating of Cranes**
   A not uncommon large expense associated with turbine rehabilitation, runner replacement, or generator upgrade is the requirement to upgrade the powerhouse cranes. If the rotor was constructed in situ, the crane may not have the rated capacity to lift the complete rotor. A cost-saving measure may be to limit the uprating of crane capacity to the portion of the crane required for removal/installation of the heaviest component (usually the rotor). Limiting crane travel at a certain load may reduce uprating requirements on both the crane rails and bridge and the supporting powerhouse structure.

[8] Olson, C., Holmberg, M., Kries J. and Lancor K., *"Renovating Chippewa Falls Hydro, Innovative Planning, Management"* in Hydro Review, August 1996.

A
LITERATURE REVIEW

Volume 4/5 Annotated bibliography of literature on Auxiliary Mechanical and Electrical Systems

V 4/5.1

TITLE	**Advances in Hydro Generator Refurbishment Technology**		
AUTHOR	Moore, W.G.	**COUNTRY**	USA
PUBLICATION	*International Journal on Hydropower & Dams, Volume 8, No. 3*		
DATE	2001		
KEY FOCUS	Cooling Systems		
SUMMARY	Improving a machine's ventilation can increase its total possible uprating. The ventilation flow distribution and the overall flow velocity can be analyzed for these opportunities. This paper discusses two methods of ventilation analysis and presents a case history.		

V 4/5.2

TITLE	**Are You Prepared? Protecting Your Hydro Plant from Lightning Strikes**		
AUTHOR	Clemen, D.M.	**COUNTRY**	USA
PUBLICATION	*Hydro Review* Vol. XIV, No. 8. p.66-75		
DATE	December 1993		
KEY FOCUS	Grounding		
SUMMARY	Rehabilitation and modernization projects offer opportunities to enhance the standard of lightning protection. The author discusses lightning basics preliminary to presenting a number of schemes for lightning protection to meet different building/equipment/location scenarios.		

V 4/5.3

TITLE	**Boom time**		
AUTHOR	Hindley, Martin	**COUNTRY**	
PUBLICATION	*International Water Power & Dam Construction*. Vol. 47, No. 12. p. 24.		
DATE	December 1995		
KEY FOCUS	Cranes New technology		
SUMMARY	A review of the features of several state-of-art hydro cranes and the control technology used to operate them.		

V 4/5.4

TITLE	**Capacity upgrading of Mica and Kootenay Canal Powerhouse bridge cranes**		
AUTHOR	Pocher, J. P.	**COUNTRY**	Canada
PUBLICATION	Canadian Electrical Association. *Electricity 94. Conference Proceedings of the Engineering and Operating Division*. *Volume 33.* [CD-Rom].CEA, Montreal, Quebec.		
DATE	1994		
KEY FOCUS	Bridge cranes Cranes		
SUMMARY	The rated hoisting capacity of the Mica and Kootenay Canal powerhouse bridge cranes was increased to permit lifting of fully assembled generator motors. Mica's capacity was uprated from 282 to 455 tonne, Kootenay's from 123 to 191 tonne. Design considerations, modifications made, erection procedures and load testing measures are described for each. Savings of $250,000 were made through an innovative approach to renewing an existing lifting beam.		

V 4/5.5

TITLE	**Control of hydraulic gates**
AUTHOR	Lewin, J. **COUNTRY** United Kingdom
PUBLICATION	*International Journal on Hydropower and Dams.* Vol. 2, No. 4. p. 81-83.
DATE	July .
KEY FOCUS	Control systems Gate operating systems
SUMMARY	Where complex and sometimes conflicting requirements need to be met, the automated control of hydraulic gate operations using programmable logic controllers (PLC's) is the trend. This article discusses different types of control systems available. Good reference list included.

V 4/5.6

TITLE	**Cooling water systems for hydropower stations**
AUTHOR	Leyland, B. **COUNTRY** New Zealand
PUBLICATION	*International Journal on Hydropower & Dams*. Vol. 1, No 3. p. 31-34.
DATE	May 1994
KEY FOCUS	Cooling systems
SUMMARY	As auxiliary systems can have a major effect on the cost, reliability and efficiency of a generating plant, their careful design is critical. In the case of cooling water systems the site conditions, water quality, the type and size of the unit(s) and the premium on overall efficiency and reliability all influence the optimum design. The paper looks at the alternative sources of cooling water and the merits and shortcomings of a variety of cooling system options. Author affiliated with Leyland Consultants, Auckland, NZ.

V 4/5.7

TITLE	**Cooling and Uprate Analysis of Hydro Generators**
AUTHOR	Poteet, M.S. & Keith, G.O. **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.* (1997). Vol. 2. ASCE, New York, NY. p. 740-749.
DATE	1997
KEY FOCUS	Cooling systems
SUMMARY	A brief examination of tests which can be used to establish potential generator uprating capabilities. Includes assessment and data analysis of heat losses, internal heat balance and heat load for air, water and electrical heat.

V 4/5.8

TITLE	**Criteria for the implementation and life cycle management of a major 330 kV protection system upgrade**
AUTHOR	Kerr, D.J. **COUNTRY** Australia
PUBLICATION	*Fifth International Conference on Developments in Power and System Protection,* IEE, London. p.180-5.
DATE	1993
KEY FOCUS	Protection systems Economic aspects
SUMMARY	The author documents the development of portion of a six year A$6.1 million upgrade project to provide duplicated and segregated 300 kV protection schemes on the Snowy Mountains Scheme and includes a comparison between main transformer and transmission line protections as previously installed and now in existence. The major difficulty was to reach an agreeable 'cut-off' point to maintain the scope of work within acceptable practical and financial constraints.

V 4/5.9

TITLE	**Design of the generators for the Bieudron hydro plant**		
AUTHOR	Howard, W.	**COUNTRY**	Switzerland
PUBLICATION	*The International Journal on Hydropower & Dams*. Vol.2, No. 5. p. 28-30		
DATE	September 1995		
KEY FOCUS	Bearings Cooling Systems		
SUMMARY	Three record breaking synchronous machines at the Bieudron power plant are described. New design features of the bearings and the cooling system are detailed.		

V 4/5.10

TITLE	**Developments in hydraulic gates**		
AUTHOR	Erbiste, P.C.F.	**COUNTRY**	General
PUBLICATION	*International Journal on Hydropower & Dams*. Vol. 1, No. 1.p. 51-56.		
DATE	January 1994		
KEY FOCUS	Gates		
SUMMARY	A detailed technical paper which presents, with illustrations, an overview of the main types of gates for dams and hydro plants, with a particular focus on the options for gates to be used in relation to dam heightening.		

V 4/5.11

TITLE	**Electrical engineering aspects of the Cleuson-Dixence project**
AUTHOR	Nicolet, A. **COUNTRY** Switzerland
PUBLICATION	*International Journal on Hydropower & Dams*. Vol.2. No.5. p. 21-27
DATE	September 1995
KEY FOCUS	Electrical systems
SUMMARY	The Cleuson-Dixence extension project, Valais, Switzerland, set a number of world records for the capacity of the turbines and the gross head of 1883m. This technical paper gives an overview of the design and operating roles of the electrical equipment for the 15 sites and auxiliary substations, the preliminary considerations and the perceived advantages of choices made. The units, isolated phase bus ducts , isolated conductors, step-up transformers, switchgear and auxiliary supply, control and protection systems are described and illustrated. Author affiliated with Amenagement Cleuson-Dixence, Sion, Switzerland

V 4/5.12

TITLE	**Emergency Hydraulic Drives Ensure Safe Operation of Radial Gates**
AUTHOR	Wright, T. & Delves, K. **COUNTRY** Canada
PUBLICATION	*Hydro Review.* Vol. XVII. No. 1. P. 58-59
DATE	February 1998
KEY FOCUS	Gate operating systems
SUMMARY	Great Lakes Power Limited and Acres International Limited have developed an emergency hydraulic drive system for operating radial (tainter) gates. The system consists of a portable hydraulic power unit that operates fixed hydraulic motors and can be coupled quickly to the gate hoist mechanism at individual generating stations. It is cost effective and much safer for workers than traditional methods. Six plants have been modified to accept the emergency hydraulic drive system, and modifications are planned at two more plants.

V 4/5.13

TITLE	**Engineering guidelines for the evaluation of hydropower projects**
AUTHOR	FERC **COUNTRY** USA
PUBLICATION	Federal Energy Regulatory Commission Office of Hydropower Licensing. (1997). *Engineering Guidelines for the Evaluation of Hydropower Projects*. FERC , Washington. 100p.
DATE	1997
KEY FOCUS	Evaluation criteria Guidelines
SUMMARY	Comprehensive guide to the recommended procedures and criteria for reviewing and evaluating hydropower plants in relation to FERC regulations for relicensing.

V 4/5.14

TITLE	**Enhancing Operations: Thrust Bearing Improvements at Limestone**
AUTHOR	Crahan, M.E. & Ghate, A. **COUNTRY** Canada
PUBLICATION	*Hydro Review* Vol. XIX, No. 5. p. 58-65
DATE	April 2000
KEY FOCUS	Thrust bearings
SUMMARY	A peer reviewed article which details modifications to the thrust bearings at Manitoba Hydro's 1333 MW Limestone plant will result in savings of more than Cdn. $250,000 per year.

V 4/5.15

TITLE	**Fire engineering design guide**
AUTHOR	Buchanan, A.H. (ed) **COUNTRY** USA
PUBLICATION	Buchanan, A.H. (ed). (1996). *Fire engineering design guide.* ASCE, New York, NY. 204p.
DATE	1996
KEY FOCUS	Fire engineering Fire protection
SUMMARY	Design guidelines for fire protection.

V 4/5.16

TITLE	**Fire protection at the Grand Coulee hydro project**		
AUTHOR	Corbin, E., & Sale, J.W.	**COUNTRY**	USA
PUBLICATION	*Waterpower '87. Proceedings of the International Conference on Hydropower.*(1988). Vol. 3 ASCE, New York, NY. p. 2091-2099.		
DATE	1988		
KEY FOCUS	Fire protection Powerplant safety		
SUMMARY	The fire system analysis, water supply, alarm and protection, ventilation and emergency systems, resulting from a thorough review of Grand Coulee's fire protection, after a series of fires in the early 80's. Authors affiliated with USBR, Grand Coulee, and Ebasco Services, Bellevue, WA.		

V 4/5.17

TITLE	**Generator motor air cooler improvements within hydroelectric power generation**		
AUTHOR	Carsen-Mee, D.J. & Moss, W.O.	**COUNTRY**	Wales
PUBLICATION	*ImechE 2000: Hydropower Developments: New Projects and Rehabilitation. Fluid Machinery Committee of the Power Industries Division of the Institution of Mechanical Engineers, London, UK.* p. 41-47		
DATE	November 2000		
KEY FOCUS	Cooling Systems		
SUMMARY	It has been estimated that a 10°C temperature increase on generator motor windings will significantly reduce generator life. At Dinorwig power station Wales, this problem has been addressed by introducing new plate fin heat exchangers. The exchangers have also demonstrated better resistance to fin damage, improved vibration characteristics, quick assembly times and reduced fouling rates. Innovative fin designs are also being trialled at Ffestiniog power station. The future applications of this technology are also considered. Authors affiliated with Edison Mission Energy and First Hydro Co., UK.		

V 4/5.18

TITLE	**Generators for Miranda**		
AUTHOR	Angiolini, G. et al	**COUNTRY**	Brazil
PUBLICATION	*International Water Power & Dam Construction* Vol. 52, No. 10. p. 24-27		
DATE	October 2000		
KEY FOCUS	Cooling systems Excitation systems		
SUMMARY	In the two years since their installation, the three generators at Miranda power plant have completed stringent commissioning tests indicating a potential for increasing the power output in the near future. The paper discusses the design of the units including state-of-the-art features of the bearings, cooling and excitation systems and the studies undertaken.		

V 4/5.19

TITLE	**Generator Temperature Rise Calculation with Direct Water Cooling in the Stator Winding**		
AUTHOR	Kalmykov, I. et al	**COUNTRY**	Argentina
PUBLICATION	*International JOurnal on Hydropower & Dams, Volume 8, No. 3*		
DATE	2001		
KEY FOCUS	Cooling Systems		
SUMMARY	The effective cooling of generators can improve their efficiency and increase their operating life. The authors explain the calculations necessary to achieve this at the design stage, and to ensure that the temperature fluctuations of the cooling fluids remain within the required limits.		

V 4/5.20

TITLE	**The guide to hydro power mechanical design**		
AUTHOR	ASME Hydro Power Technical Committee	**COUNTRY**	USA
PUBLICATION	American Society of Mechanical Engineers. Hydro Power Technical Committee. (1996). *The guide to hydropower mechanical design*. HCI, Kansas City. 400p.		
DATE	1996		
KEY FOCUS	Air conditioning Auxiliary mechanical systems Cranes Environmental control Fire Protection Gates Lifting equipment Trashracks Water systems		
SUMMARY	An outstanding and definitive reference to hydromechanical equipment and auxiliary mechanical systems. Also covers the environmental, layout, maintenance and operation considerations of hydro plants, hydraulic transients, inspection and testing.		

V 4/5.21

TITLE	**Healthy Thrust Bearing Key to Reliable Machine Operation**		
AUTHOR	Khoral, P.	**COUNTRY**	Canada
PUBLICATION	*Hydro Review*. Vol. XIX , No. 1. p.58-60		
DATE	February 2000		
KEY FOCUS	Cooling Systems		
SUMMARY	Ontario Power Generation modified the bearing cooling system at its 66 MW Little Long Generating Station, with immediate and dramatic results. The problem and solution are discussed.		

V 4/5.22

TITLE	**Hydro Fire Monitoring & Protection - 21st Century**		
AUTHOR	Poteet, M. et al	**COUNTRY**	USA
PUBLICATION	In *Waterpower XII: Advancing Technology for Sustainable Energy.* July 9-11, 2001. Salt Lake City, Utah, USA.: Technical Papers. [CD Rom].		
DATE	2001		
KEY FOCUS	Fire protection		
SUMMARY	Because of changes in NFPA fire codes and fire protection technology since original installations, the Tennessee Valley Authority has developed a multi-year plan to systematically upgrade its fire suppression, fire detection and fire alarm systems. Existing CO_2 and Halon systems, replacement options and their implications, design, installation, testing and maintenance considerations are discussed with an emphasis on the integrated process adopted by the TVA to balance remaining life, available technologies, suitability logistics and project economics against the need to provide protection for plant assets.		

V 4/5.23

TITLE	**Hydro Plant Electrical Systems**		
AUTHOR	Clemen, D. M.	**COUNTRY**	USA
PUBLICATION	*HCI Publications:* Kansas City, MO, 1999		
DATE	1999		
KEY FOCUS	Auxiliary electrical systems		
SUMMARY	Provides an overview of existing practice at hydroelectric projects with an emphasis on selecting, installing, testing and maintaining electrical equipment. Also looks at state-of-the-art applications.		

V 4/5.24

TITLE	**Hydro Power Monitoring (HPM)**		
AUTHOR	Märke, Martin	**COUNTRY**	Switzerland
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.*(1997). Vol. 3. ASCE, New York, NY. p. 1134-1143.		
DATE	1997		
KEY FOCUS	Condition monitoring Software		
SUMMARY	The HPM (Hydro Power Monitoring) concept offers an integrated machinery condition monitoring system for large hydro machinery applications. Modules synchronize the collection of data relating to vibration level, partial discharge activity, air gap and temperature levels and this in then integrated into the plant control system. The advantages of the HPM, and the features of the data acquisition system and the data visualization systems described. This technical article is amply illustrated. Author affiliated with ABB,Birr, Switzerland.		

V 4/5.25

TITLE	**IEEE guide for the commissioning of electrical systems in hydroelectric power plants**		
AUTHOR	IEEE	**COUNTRY**	USA
PUBLICATION	Institute of Electrical and Electronics Engineers. (1998) *IEEE guide for the commissioning of electrical systems in hydroelectric power plants.* Report # 1248. IEEE, New York.		
DATE	1998		
KEY FOCUS	Standards Electrical systems		
SUMMARY	Up-to-date revised guide to design and application of power plant electrical systems. Essential reference. New Standard Report.		

V 4/5.26

TITLE	**IEEE guide for the rehabilitation of hydroelectric power plants**
AUTHOR	Power Generation Committee of the IEEE Power Engineering Society — **COUNTRY** USA
PUBLICATION	Institute of Electrical and Electronic Engineers. Power Engineering Society. Power Generation Committee. (1996). *IEEE Guide for the rehabilitation of hydroelectric power plants.* Standard report # 1147-1991. IEEE New York, NY. 48 p.
DATE	1996
KEY FOCUS	Control systems Electrical systems Generators Monitoring
SUMMARY	An essential reference guide to assist in decision-making and design for the rehabilitation of hydroelectric plants covering the assessment of the economic feasibility, the rehabilitation of generators, waterways and electrical equipment and a bibliography of standards, recommended practices and guides.

V 4/5.27

TITLE	**IEEE Guide for substation fire protection**
AUTHOR	IEEE — **COUNTRY** USA
PUBLICATION	Institute of Electrical and Electronic Engineers. Power Engineering Society. Substations Committee. (1994). *IEEE Guide for substation fire protection.* IEEE : New York, NY. IEEE Std. 979-1994. 25pp.
DATE	1994
KEY FOCUS	Fire protection
SUMMARY	Guide to determining the design, equipment and practices necessary for fire protection of substations. Includes extensive bibliography of IEEE and ANSI/NFPA Standards.

V 4/5.28

TITLE	**Implementing an economical circuit breaker retrofit**
AUTHOR	Dayton, Lauri — **COUNTRY** USA
PUBLICATION	Hydro Review. Vol. XVII, no. 1. p. 18-23
DATE	February 1998
KEY FOCUS	Circuit breakers
SUMMARY	In 1992 Grant County, WA, PUD began a program to replace all 22 circuit breakers at the Priest Rapids and Wanapum hydroplants with state- of the art equipment following some catastrophic equipment failures. Prior to this such a program had been considered economically unjustifiable. The paper gives an account of alternative upgrade programs considered, basis of the decision analysis, technical details of the equipment selected, (HG-2 SF-6, 5000-amp rated breakers), and installation procedures. The retrofit cost between $215,00 and US$220,000 per unit , only 44% of the lowest estimate for replacement with like units. Maintenance costs have reduced by a factor of 20.Author affiliated with Public Utility District No. 2, Grant County, WA.

V 4/5.29

TITLE	**Improving the performance of generator coolers**
AUTHOR	Fenwick, G. — **COUNTRY** Canada
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.*(1997). Vol. 3. ASCE, New York, NY. p. 1006-1015.
DATE	1997
KEY FOCUS	Cooling systems Generator coolers
SUMMARY	The replacement of generator coolers provides the opportunity to specify changes which result in more cooling, longer cooler life and improved reliability. This detailed technical paper focuses on general construction features, material choices, factors affecting thermal performance and common problems requiring maintenance. Author affiliated with Unifin International, London, Ontario.

V 4/5.30

TITLE	**Keeping Your Cool**
AUTHOR	Shiying, F. **COUNTRY** China
PUBLICATION	*International Water Power & Dam Construction*, Vol. 52, No. 7. p 42-43
DATE	July 2000
KEY FOCUS	Cooling systems
SUMMARY	At the Lijaxia power station, one of the four 400 MW generators is being successfully cooled by a newly developed evaporation cooling system. This is a self-circulation system which uses a liquid with a high insulation performance and low boiling point to absorb heat. The paper discusses the technology, design parameters and operation of the system.

V 4/5.31

TITLE	**Loss prevention data: hydroelectric power plants**
AUTHOR	Factory Mutual Engineering **COUNTRY** USA
PUBLICATION	*Loss prevention data: hydroelectric power plants*. (1985). Factory Mutual Engineering, Norwood, Mass. (Data Sheets 5-3/13-2). 10p.
DATE	1985
KEY FOCUS	Auxiliary mechanical systems Fire protection Hazards
SUMMARY	Information on hazards related to major components of hydrogenerating units and safeguards which may be implemented.

V 4/5.32

TITLE	**Manitoba Hydro fire manual**		
AUTHOR		**COUNTRY**	Canada
PUBLICATION	Manitoba Hydro. (1993). *Manitoba Hydro Fire Manual*. Manitoba Hydro: Winnepeg. 300p.		
DATE	1993		
KEY FOCUS	Fire protection		
SUMMARY	Extensive guidelines in two parts. Part I contains operating and maintenance instructions for fire prevention and protection. Part II contains guidelines, rules and standards for FP&P required by the design and administering personnel of the corporation.		

V 4/5.33

TITLE	**Modernizing control and excitation systems**		
AUTHOR	Stach, W. & Reimann, M.	**COUNTRY**	Germany
PUBLICATION	*International Water Power and Dam Construction.* Vol. 43, No. 10.		
DATE	October 1991		
KEY FOCUS	Control and excitation systems Modernization		
SUMMARY	It makes sense to evaluate control systems at the same time as generating units are being refurbished or upgraded. Several approaches to the modernizing of control systems are presented. The Thyripol static excitation system is discussed in detail.		

V 4/5.34

TITLE	**Raccoon Mountain Generator Thrust Bearing Cooling Project**
AUTHOR	McDonald, G.L. **COUNTRY** USA
PUBLICATION	In *Waterpower XII: Advancing Technology for Sustainable Energy.* July 9-11, 2001. Salt Lake City, Utah, USA.: Technical papers. [CD Rom].
DATE	2001
KEY FOCUS	Cooling Systems
SUMMARY	Following a history of thrust bearing overheating, associated vibration problems and shortened life, a TVA program to uprate the Raccoon Mountain pump turbine generators required the reduction of excessive thrust bearing temperatures which had occurred since unit commissioning. Modifications to the cooling systems to address the problem resulted in unexpected benefits related to reduction in vibration levels and increased reliability in the thrust bearing shoes and runner shaft and rotor manifold seals.

V 4/5.35

TITLE	**Recommended practice for fire protection for hydroelectric generating plants**
AUTHOR	NFPA **COUNTRY** USA
PUBLICATION	National Fire Protection Association. Technical Committee on Electric Generating Plants. (1996). *Recommended practice for fire protection for hydroelectric generating plants*. NFPA-851.NFPA, Boston, MA. 42p.
DATE	1996
KEY FOCUS	Fire protection
SUMMARY	American National Standard for recommendations (not requirements) for fire protection and fire prevention for hydroelectric plants. Originally issued in 1987, and revised in 1992, this new edition contains minor changes to clarify life safety recommendations and generator windings protection

V 4/5.36

TITLE	**Refurbishing generators puts pressure on cooling**		
AUTHOR	Fenwick, Gerald	**COUNTRY**	Canada
PUBLICATION	*International Water Power and Dam Construction*. Vol 49, No. 1.Pp.17-20		
DATE	January 1997		
KEY FOCUS	Cooler systems		
SUMMARY	A cooling system for an uprated generator must dissipate more kW, but is limited to the size and flow of the constraints of the old generator. The author, affiliated with Unifin, London, ONT., presents a comprehensive list of design considerations. See also *Improving the performance of generator coolers* by the same author.		

V 4/5.37

TITLE	**Repair of Diablo Powerhouse Crane Beams**		
AUTHOR	Grant, B., Satendra, J. & Ogi, I.	**COUNTRY**	USA
PUBLICATION	*Waterpower ‘95. Proceedings of the International Conference on Hydropower.*Vol. 2.(1995). ASCE, New York, NY. p.1078-1086.		
DATE	1995		
KEY FOCUS	Cranes		
SUMMARY	Cracks in the reinforced concrete crane beams at Seattle City Light’s Diablo Powerhouse, Washington were seen to open and close under load. Remedial measures had to take into account the preservation of the showpiece building’s integrity. This paper describes the observation and analysis of the problem, testing, and repair procedures using surface-applied epoxy gel and injection of epoxy resin. Authors affiliated with Raytheon Infrastructure Services and Foster Wheeler, Bellevue, WA., and Seattle City Light.		

V 4/5.38

TITLE	**Replacement of DC exciter with AC generator**
AUTHOR	Summers, D., Sigmon, B., Powell, S., Sigmon, J. & Brinson, E. **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.*(1997). Vol. 3. ASCE, New York, NY. p. 1633-1640
DATE	1997
KEY FOCUS	AC generators
SUMMARY	Duke Power Company replaced two hydraulic turbine driven DC exciters with auxiliary AC generators to satisfy environmental requirements for minimum continuous flow, while providing additional generational benefits. Design considerations, implementation and assessment of the modification, and perceived merits are addressed. Authors affiliated with Duke Engineering & Services.

V 4/5.39

TITLE	**Replacement of water-operated needle valves at US. Bureau of Reclamation facilities**
AUTHOR	Arrington, R. & Gerbig, L. **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.* (1997). Vol. 2. ASCE, New York, NY. p. 1056-1065.
DATE	1997
KEY FOCUS	Needle valves
SUMMARY	Following a catastrophic needle valve failure at one of its dams, and a similar failure elsewhere, the US Bureau of Reclamation embarked on a program to replace all needle valves with jet-flow gates. The logistics of the program, the reasons for the selection of the gates and the outcomes of the replacement program are detailed. Authors affiliated with USBR and Woodward-Clyde Consultants, Denver, CO.

V 4/5.40

TITLE	**Time for a change? Assessing environmentally acceptable lubricants**
AUTHOR	Beitelman, Alfred, D. **COUNTRY** USA
PUBLICATION	*Hydro Review*. Vol. XVII, No.2. p. 46-48, 61.
DATE	April 1998
KEY FOCUS	Environmental aspects Lubricants
SUMMARY	The Construction Engineering Research Laboratory of the US Army Corps of Engineers has undertaken an evaluation of environmentally acceptable lubricants, which involves a review and analysis of existing and new technology, surveys and evaluation of Corps experience. and assessment of the cost of conversion to environmentally acceptable standards. This technical article considers the characteristics of the alternative lubricants available, an overview of survey results and the factors to be considered in making a change of lubricant type. Author affiliated with the USACE research laboratory, Champaign, IL.

V 4/5.41

TITLE	**Trends and Advances in Hydroelectric Equipment**
AUTHOR	Ogihara, K., Tomochika, H. & Miyazawa, C. **COUNTRY** Europe
PUBLICATION	*Hydro Review Worldwide*, Vol. 8, No. 5. p.8-15
DATE	November 2000
KEY FOCUS	Gate operating systems
SUMMARY	Included in this paper on new equipment and innovative applications, is a non-polluting 8MW pump turbine. Its greaseless wicket gates are operated by an electric actuator. A special spring in the actuator rod, which compresses after closure, assures proper sealing. Three other features are discussed: the blade control mechanism of the oil-free blade runners; the hydrostatic turbine bearings, which includes a ceramic surface lining; and the water servomotors used to operate the butterfly valves, roller gates and safety devices.

V 4/5.42

TITLE	**Understanding Electrical Grounding at Hydroelectric Plants**
AUTHOR	Clemen, D.M. **COUNTRY** USA
PUBLICATION	*Hydro Review*. Vol. XIX, No. 1. p. 50-57
DATE	July 2000
KEY FOCUS	Grounding
SUMMARY	Grounding is a general term used to describe numerous functions leading to considerable confusion about the design requirements for grounding systems. The aim of this paper is to briefly clarify the various purposes and design standards of present systems for AC power system neutral grounding; grounding of equipment and enclosures; lightning protection; and eliminating transient surges. By the same author: Hydro Plant Electrical Systems, HCI, Kansas City Mo. 1999.

V 4/5.43

TITLE	**Upgrading of Hydrogenerator Excitation Systems**
AUTHOR	Corbett, F.M. **COUNTRY** Canada
PUBLICATION	*CCECE 2000 - Canadian Conference in Electrical and Computer Engineering, Nova Scotia (IEEE)*. 7 - 10 May, 2000 , p. 523-526
DATE	2000
KEY FOCUS	Excitation systems
SUMMARY	This paper compares typical retrofitting options ranging from replacement of pilot exciters and rheostatic voltage regulators to complete replacement of the excitation systems by thyristor-based equipment.

V 4/5.44

TITLE	**Using Environmentally Friendly Lubricants at Hydro Plants**
AUTHOR	Fulton, E. **COUNTRY** Canada
PUBLICATION	*Hydro Review* Vol. XIX, No. 3. p.10-12
DATE	May 2000
KEY FOCUS	Lubricants
SUMMARY	An update on "green" lubricants which includes the experiences of PG & E Generating's use of a vegetable-based oil in trashrake mechanisms at seven of its plants, and the USBR's application of a crop-based wicket gate grease on its four units at Parker Dam. The need for the establishment of industry standards is discussed.

IEEE Standards

Electric Machinery

43-2000 *IEEE Recommended Practice for Testing Insulation Resistance of Rotating Machinery.*

56-1977 *(R1991) IEEE Guide for Insulation Maintenance of Large Alternating-Current Rotating Machinery ([10000 kVA and Larger].*

60-1990 *IEEE Guide for Operation and Maintenance of Turbine Generators.*

95-1977 *(R1991) IEEE Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage.*

100-1996 *Dictionary of Electrical and Electronic Terms*

115-1995 *IEEE Guide: Test Procedures for Synchronous Machines, Part 1 Acceptance and Performance Testing, Part II Test Procedures and Parameter Determination*

275-1992 *IEEE Recommended Practice for Thermal Evaluation of Insulation Systems for Alternating-Current Electric Machinery Employing Form-Wound Preinsulated Stator Coils for Machines Rated 6900 V and Below.*

286 *Recommended Practice for Measurement of Power - factor Tip-up of Rotating Machinery Stator Coil Insulation.*

304-1977 *IEEE Test Procedure of Evaluation and Classification of Insulation Systems for DC Machines.*

429-1994 *IEEE Recommended Practice for Thermal Evaluation of Sealed Insulation Systems for AC Electric Machinery Employing Form-Wound Preinsulated Stator Coils for Machines Rated 6900V and Below.*

433-1974 *IEEE Recommended Practice for Insulation Testing of Large AC Rotating Machinery with HIgh Voltage at Very Low Frequency.*

434-1973 *(R1991) IEEE Guide for Functional Evaluation of Insulation Systems for Large High-Voltage Machines.*

492-1999 *IEEE Guide for Operation and Maintenance of Hydrogenerators.*

522-1992 *IEEE Guide for Testing Turn-to-Turn Insulation on Form-Wound Stator Coils for Alternating-Current Rotating Electric Machines.*

792-1995 *IEEE Recommended Practice for the Evaluation of the Impact Voltage Capability of Insulation Systems for AC Electric Machinery Employing Form-wound Stator Coils.*

1043-1996 *IEEE Recommended Practice for Voltage-enhance Testing of Form-wound Bars and Coils.*

1129-1992 *IEEE Recommended Practice for Monitoring and Instrumentation of Turbine Generators.*

1310-1996 *IEEE Trial Use Recommended Practice for Thermal Cycle Testing of Form-Wound Stator Bars and Coils for Large Generator*s

Power Generation

125-1988 *(R1996) IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators.*

421.1-1986 *(R1996) IEEE Standard Definitions for Excitation Systems for Synchronous Machines 24 pages.*

421.2-1990 *IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems.*

421.3-1997 *IEEE Standard for High-Potential Test Requirements for Excitation Systems for Synchronous Machines.*

421.4-1990 *IEEE Guide for the Preparation of Excitation System Specifications.*

450-1995 *IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented Lead-Acid Batteries for Stationary Applications.*

484-1996 *IEEE Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Stationary Applications.*

485-1997 *IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications.*

505-1977 *(R1991) IEEE Standard Nomenclature for Generating Station Electric Power Systems.*

665-1995 *IEEE Guide for Generating Station Grounding.*

666-1991 *(R1996) IEEE Design Guide for Electric Power Service Systems for Generating Stations.*

946-1992 *IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations.*

1010-1987 *(R1992) IEEE Guide for Control of Hydroelectric Power Plants.*

1020-1988 *(R1994) IEEE Guide for Control of Small Hydroelectric Power Plants*

1046-1991 *(R1996) IEEE Application Guide for Distributed Digital Control and Monitoring for Power Plants*

1050-1996 *IEEE Guide for Instrumentation and Control Grounding in Generating .*

1095-1989 *(R1994). IEEE Guide for Installation of Vertical Generators and Generator Motors for Hydroelectric Applications.*

1106- 1987 *IEEE Recommended Practice for Maintenance, Testing and Replacement of Nickel-Cadmium Storage Batteries for Generating Stations and Substations.*

1147-1991 *(R1996) IEEE guide for the rehabilitation of hydroelectric power plants.*

1249-1996 *IEEE Guide for Computer-Based Control for Hydroelectric Plant Automation*

1375-1998 *IEEE Guide for the Protection of Stationary Battery Systems*

IEC Standards

60076-8 *(1997-11) Power transformers*

60085 *(1984-01) Thermal Evaluation and Classification of Electrical Insulation.*

60545*(1976-01) Guide for Commissioning, operation and maintenance of hydraulic turbines.*

61116 *(1992-10) Electromechanical equipment guide for small hydroelectric installations.*

ANSI Standards

C50.10 *(1990) American National standard for Rotating Electrical Machinery Synchronous Machines.*

C50.12 *(1989) Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications, Requirements for Salient Pole Synchronous.*

ASTM Standards

ASTM D4496	*Test Method for D-C Resistance or Conductance of Moderately Conductive Materials*
ASTM A34-96	*Practice for Sampling and Procurement Testing of Magnetic Materials*
ASTM A343-97	*Test Method for Alternating-Current Magnetic Properties of Materials at Power Frequencies Using Wattmeter-Ammeter-Voltmeter meter and 25-cm Epstein Test Frame*
ASTM A717-95	*Test Method for Surface Insulation Resistivity of Single-Strip Specimens*
ASTM A937-95	*Test Method for Determining Interlaminar Resistance of Insulating Coatings Using Two Adjacent Test Surfaces (Franklin Test)*
ASTM D3276-96	*Guide for Painting Inspectors*
ASTM D3359-95a	*Test Methods for Measuring Adhesion by Tape Test*

NEMA Standards

NEMA MG 5.1	*Large Hydraulic-Turbine-Driven Synchronous Generators*
NEMA MG 5.2	*Installation of Vertical Hydraulic Turbo-Driven Generators*

B
REMR CONDITION ASSESSMENT PROCEDURES

This appendix includes reproductions of the appropriate sections of the US Army Corps of Engineers' Condition Rating Procedures/Condition Indicator for Hydropower Equipment for equipment covered in this volume (Part V - Main Power Transformers and Part XI - Cranes and Wire Rope Gate Hoists). The document was produced by the USACE as part of the Repair, Evaluation, Maintenance and Rehabilitation (REMR) Research Program.

As discussed in Section 4.4.1 these condition rating procedures are provided as an example of a condition rating procedure. The USACE intends to review the procedures.

Our thanks to Messrs. Jim Norlin, Paul Willis and Craig Chapman of the USACE for ensuring that the REMR procedures are reproduced here.

US Army Corps of Engineers

REPAIR, EVALUATION, MAINTENANCE, AND REHABILITATION RESEARCH PROGRAM

REMR MANAGEMENT SYSTEMS–HYDROPOWER FACILITIES

**CONDITION RATING PROCEDURES/
CONDITION INDICATOR
FOR
HYDROPOWER EQUIPMENT**

by
Department of the Army
Hydroelectric Design Center
North Pacific Division
Corps of Engineers
PO Box 2870
Portland, Oregon 97208-2870

March 1993

Working Document

Approved For Public Release; Distribution Unlimited

Prepared for DEPARTMENT OF THE ARMY
US Army Corps of Engineers
Washington, DC 20314-1000
Under Civil Works Research Work Unit 32672

The following two letters used as part of the number designating technical reports of research published under the Repair, Evaluation, Maintenance, and Rehabilitation (REMR) Research Program identify the problem area under which the report was prepared:

	Problem Area		Problem Area
CS	Concrete and Steel Structures	EM	Electrical and Mechanical
GT	Geotechnical	EI	Environmental
HY	Hydraulics	OM	Operations Management
CO	Coastal		

COVER PHOTOS:

TOP - Lost Creek Flood Control/Hydropower Project, Rogue River, Oregon.

BOTTOM - The Dalles Navigation/Hydropower Project, Columbia River, Oregon.

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

1. AGENCY USE ONLY (Leave Blank)

2. REPORT DATE
March 1993

3. REPORT TYPE AND DATES COVERED
Working Document

4. TITLE AND SUBTITLE
Condition Rating Procedures/Condition Indicator for Hydropower Equipment

5. FUNDING NUMBERS
Civil Works Research Work Unit 32672

6. AUTHOR(S)
James A. Norlin, Darilynne Allen, Donald J. Campbell, Marc Frey, Jerry Joy, Mark Pierce, David C. Raisanen, Richard Vaughn, and Glenn Woodward

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
US Army Corps of Engineers
North Pacific Division
Hydroelectric Design Center (CENPD-PE-HD)
PO Box 2870
Portland, OR 97208-2870

8. PERFORMING ORGANIZATION REPORT NUMBER

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)
US Army Construction Engineering Research Laboratories (USACERL)
PO Box 9005
Champaign, IL 61826-9005

10. SPONSORING/MONITORING AGENCY REPORT NUMBER

11. SUPPLEMENTARY NOTES

12a. DISTRIBUTION/AVAILABILITY STATEMENT
Approved for public release; distribution unlimited.

12b. DISTRIBUTION CODE

13. ABSTRACT (Maximum 200 words)

The Hydropower Condition Indicator Manual is a maintenance management tool for condition assessment and evaluation of electrical and mechanical equipment in hydroelectric powerhouses.

Data on various pieces of hydropower equipment is gathered by field inspection and testing. Uniform procedures are applied to evaluate the data and assign a Condition Index (CI) to the equipment. The CI indicates the condition of the equipment. The CI thus affords a means for the uniform and quantitative comparison of the condition of equipment to that in another.

The collected data will eventually yield curves documenting the deterioration of equipment based upon age and usage. Such curves can be used to predict future condition so that maintenance managers can optimally prioritize and budget maintenance and rehabilitation money.

14. SUBJECT TERMS
hydropower, condition, maintenance management, testing, evaluation

15. NUMBER OF PAGES
422

16. PRICE CODE

17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT
Unclassified	Unclassified	Unclassified	SAR

NSN 7540-01-280-5500

Standard Form 298 (Rev. 2-89)
Prescribed by ANSI Std 239-18
298-102

PREFACE

The study reported herein was authorized by Headquarters, US Army Corps of Engineers (HQUSACE), as part of the Operations Management problem area of the Repair, Evaluation, Maintenance, and Rehabilitation (REMR) Research Program. The work was performed under Civil Works Research Work Unit 32672, "Development of Uniform Evaluation Procedures and Condition Index for Civil Works Structures," for which Dr. Anthony M. Kao (CECER-FMM) is the Principal Investigator. Mr. James A. Norlin **(CENPD-PE-HD),** Hydroelectric Design Center (HDC). is the Principal Investigator and Mr. Craig Chapman (CECW-OM) is the Technical Monitor for this study.

Mr. Jesse A. Pfeiffer, Jr. (CERD-C) is the REMR Coordinator at the Directorate of Research and Development, HQUSACE. Mr. James E. Crews (CECW-O) and Dr. Tony Liu (CECW-ED) serve as the REMR Overview Committee; Mr. William F. McCleese (CEWES-SC-A), US Army Engineer Waterways Experiment Station (WES), is the REMR Program Manager. Dr. Anthony M. Kao (CECER-FMM) is the Problem Area Leader for the Operations Management problem area.

This work was conducted by the Hydroelectric Design Center under the general supervision of Glenn R. Meloy, Chief of CENPD-PE-HD.

Acknowledgement is given to the Field Review Group members and to the numerous individuals at many of the Corps' operating projects that have reviewed, tested and commented on the procedures outlined in this manual. Their input has been invaluable in the acceptance and useability of this document.

COL Daniel Waldo, Jr., is Commander and Director of USACERL, and Dr. L.R. Shaffer is Technical Director.

Contents

Mechanical Equipment

Blank Forms

PART V: MAIN POWER TRANSFORMERS

Program, Format and Method

Explanation of Program

5-1. The overall transformer condition number is a number between 0 and 100 2which will be used to define the present condition of the system. The number will be used in the REMR Condition Index Scale which is shown below.

The overall condition index is calculated from eight condition numbers determined form various tests and inspections done on the transformer. The seven tests and inspections are: dissolve gas analysis, transformer power factor tests, bushing power factor tests, core excitation, turns ratio, internal inspection and external inspection. The criteria behind these inspections and tests are such that they can be performed during the transformer annual maintenance period (generally one week or less). For that reason, emphasis has been placed on dissolved gas analysis and power factor tests which provide information about general condition and can be done quickly. Additional diagnostic tests such as winding resistance (by low resistance "Ductor"), insulation dielectric tests (such as DC voltage ramp) or acoustic tests can be performed as needed based on results of the general tests in order to more clearly identify the specific problem. It should be noted that on-line monitoring equipment for transformers, incorporating groups of sensors and performing multiple tests, is becoming increasingly available. Emerging optical fiber technology promises to make this equipment more capable if not less expensive. Within 10 years, such equipment may be capable of providing the bulk of the test information needed for condition assessment.

Condition Index Scale

Value	Condition Description	
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate.
25.-39	Poor	Serious deterioration in at least some portions of equipment. Function is inadequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure 5-1

The tests described are for transformers which are of the oil filled generator step-up type, in either single or three phase configuration.

Interpretation of results must be done in conjunction with the analysis and comparison of previously obtained test results. This is done to determine trending and possible equipment changes. This is particularly significant for dissolved gas tests, where rapidly changing readings may indicate imminent failure. When test results indicate possible problems, test frequency should be increased to provide data needed to determine the course of action to be taken to avoid catastrophic failure. Since trending is so necessary to determine transformer condition, accurate record keeping is an absolute requirement in a successful Condition Indices Program.

Conditions such as obsolescence, lack of features and lack of spare parts are not discussed in this section since these do not relate to condition of equipment. Previously obtained t4st results are helpful in determining trending and possible equipment changes. In addition to the written records required for trending, records such as photos, and in some cases, a video tape of the area of concern, along with a narrative of the items which are of concern may be included.

Detailed procedures for performing these tests are not covered in this Condition Indices Program. Standard publications such as the Doble Power Factor Test Data Reference Book, and the Transformer Maintenance Institute publication, A guide to Transformer Maintenance are valuable resources for the test engineer.

It is assumed that personnel evaluating transformer condition have had experience in transformer testing. Only experienced individuals should attempt to perform specific transformer test due to both personal danger and potential for damage to equipment.

Explanation of Format

5-2. The condition indices for transformers all have a similar format. The first section is an introduction which describes the test or inspection. The second section gives generalized instructions on how to perform the test or inspection. The third section explains how to perform evaluation of the data and how to fill out the appropriate part of the Data Evaluation Sheet. The final section gives the recommended frequency for performing the test or inspection.

Explanation of Method

5-3. A condition number between 0 and 100 is determined for each test or inspection based on the results of the tests and inspections. The overall condition index for the transformer is the lowest value of any of the condition number values.

TX-1-FRM.PM4 PAGE 1 OF 1

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Transformer Condition

Project: *Old Hydro Plant* Unit No. *1*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Dissolved Gas Analysis	*7/3/90*	*Code 101*	*45*
Transformer Power Factor	*7/3/90*	*p.f. = 0.2%*	*95*
Bushing Power Factor	*7/3/90*	*No change from previous readings*	*100*
Core Excitation	*7/3/90*	*Excitation current 2% over nameplate*	*88*
Turns Ratio	*7/3/90*	*Ratio within 5% of nameplate*	*100*
Internal Inspection	*7/3/90*	*No inspection made*	*N/A*
External Inspection	*7/3/90*	*Minor Oil Leaks*	*95*
		Overall Transformer Condition Index Rating	*45*

Overall Transformer Condition

Introduction

5-4. The overall transformer condition is calculated using seven condition indicators: dissolve gas analysis, transformer power factor tests, bushing power factor tests, core excitation, turns ratio, internal inspection and external inspection. Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various tests and inspections which are discussed later.

Filling Out Data Evaluation Sheet

5-5. Column 1 lists the seven condition indicators which are used for evaluation. Others may be added in the future. Fill in the date the test or inspection was made in column 2. Insert any notes or remarks about the condition index in column 3. Put the condition number for the particular 'condition indicator in column 4. The overall transformer condition index is the lowest of the individual condition indicator numbers. This number is placed in the box in the lower right corner of the Overall Transformer Condition Data Evaluation Sheet. A sample of this form is shown on page 5-5. Information to be completed by the field is shown in script text.

Dissolved Gas Analysis (Rogers' Ratios)

Introduction

5-6. It is assumed that periodic oil condition tests are being performed. There should include color, water content, dielectric withstand, acid neutralization number, interfacial tension, power factor and, as necessary, tests of oxidation inhibitor. These tests provide information about oil condition. Dissolved gas analysis, on the other hand, provides information about processes from which inferences can be made about transformer condition.

Decomposition of insulating paper and oil caused by elevated temperature or arcing produces gases which dissolve in the transformer oil. Analyses of dissolved gases by modern gas chromatograph is readily available. It has been demonstrated in the work of R.R. Rogers that ratios of certain of these gas produce accurate information as to whether the gas is produced by partial or full (arcing) discharge, by overtemperature or by normal aging.

The technique involves measuring concentrations of five gases; methane (CH_4), acetylene (C_2H_2, ethylene (C_2H_4), ethane ($C_{2H}6$) and hydrogen (H_2). They are related in the following three ratios; (a) acetylene/ethylene ($C_2H_2/_2H_4$), (b) methane/hydrogen (CH_4/H_2) and (c) ethylene/ethane ($2_2H_4/C_2H_6$). Depending on the value of each ratio, a number from 0 to 3 is assigned to that ratio. The resulting three digit code correlates to a particular fault type. For more information, including code tables, refer to Rogers papers in the 1975 and 1977 Doble Conference minutes.

Instructions for Evaluation

5-7. Evaluation is based on the gas ratio code of the form (a) (b) (c), where a, b and c are numbers corresponding to the gas ratios above. Transformer condition deterioration suggested by dissolved gas ratios is as follows:

Minor: - 0 0 0 - Normal aging - condition number is 100.

Moderate: - 020 - Incomplete impregnation - condition number is 60.

- 1 2 0 Tracking or insulation perforation - condition number is 50.

- 1 0 1 - Conductor overheating - condition number is 45.

Major: - 1 1 1 - Hot spots (250°-700°0 - condition number is 39.

- 1 1 2 - Hot spots (700°C) - condition number is 25.

- 2 0 1 - Low energy density sparking - condition number is 24.

- 3 0 2 - High energy density sparking - condition number is 10.

Filling out Data Evaluation Sheet

5-8. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes in column 3. In column 4 enter the condition number based on the criteria listed above.

Frequency of Inspection

5-9. Perform every year. This may be supplemented at 6 month intervals by total combustible gas tests or by use of continuous dissolved gas monitors. The frequency of full dissolved gas analyses may be increased based on the results of the supplemental tests.

Transformer Power Factor Testing

Introduction

5-10. This evaluation is used to determine the condition of the transformer based on power factor testing. Insulation power factor test sets (such as those manufactured by the Doble Company) test the insulation of the transformer and bushings. The power factor value is a measure of general insulation performance. Higher power factor is associated with higher current leakage through the insulation or tracking over the insulation. This may be due to deterioration of the kraft paper insulation or to contamination of the transformer oil by water or polar breakdown products of oil or paper.

The power factor of the transformer is expressed in percent, corrected to 20°C. Typically, the power factor reading for a new transformer at acceptance should not exceed 0.5% at 20°C. Where power factor elevation is due to the presence of water, significant improvement (reduction of power factor) is normally seen following vacuum processing of the oil. Fuller's earth filtration yields similar improvement where suspended polar contaminants are the problem. Where neither process produces significant improvement, the problem may be paper insulation breakdown or severe sludging.

Instructions for Evaluation

5-11. The power factor test results which are considered for this index program are performed on the high voltage windings. Condition degradation as indicated by power factor testing is as follows:

Minor: This category provides a condition number from 100 to 75 corresponding to power factor values of 0.1% to 0.59'0. For power factor readings between these values, use linear interpolation to determine the proper condition number.

Moderate: This category provides a condition number from 74 to 40 corresponding to power factor readings of 0.51% to 1.0%. For power factor readings between these values, use linear interpolation to determine the proper condition number.

Major: This category provides a condition number from 39 to 24 corresponding to power factor readings of 1.01% to 2.0%. For power factor readings between these values, use linear interpolation to determine the proper condition number. Power factor values higher than 2.0% may indicate of a serious insulation problem and should be followed up by diagnostic testing and inspections to confirm condition.

Filling Out Data Evaluation Sheet

5-12. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes in column 3. In column 4 enter the condition number based on the criteria listed above.

Frequency of Inspection

5-13. Perform every year. Frequency should be increased if oil tests or casual inspections suggest a potential problem. Consider increasing frequency following abnormal events such as line faults or failed surge arrestor which could indicate transformers have been subjected to high through-current or voltage surges.

Bushing Power Factor Testing

Introduction

5-14. Bushings are sealed assemblies with insulation systems which undergo the same aging mechanisms as the transformer insulation itself. Bushing explosions (usually caused by oil leaking out of the bushing or water leaking into it) are responsible for a substantial number of transformer forced outages. Unlike the transformer, the bushing has a sealed oil system which does not lend itself to oil sampling and testing, making the power factor test a singularly important indicator of bushing condition.

Instructions for Evaluation

5-15. After the bushings have been cleaned and dried they should be power factor tested by the ungrounded specimen method. Acceptable readings may vary significantly by manufacturer and bushing type. Consult manufacturer or Doble literature for threshold levels. Rates of change of power factor (or watts loss) from test to test are particularly important. Condition degradation as indicated by bushing power factor testing is as follows:

Minor: For a power factor consistent with published standards and little change since previous tests, the condition number should lie within the range of 40 to 84.

Moderate: For gradual rise of power factor still within limits, condition number should be in the range of 40 to 84.

Major: Where power factor is rising at an accelerating rate or where it is above industry standards, the condition number should lie in the range 10 to 39.

Filling out Data Evaluation Sheet

5-16. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes in column 3. In column 4 enter the condition number based on the criteria listed above.

Frequency of Inspection

5-17. Perform every year. Frequency should be increased if inspections indicate significant oil loss or overheating or if there is reason to suspect water may enter the bushing.

Core Excitation Test

Introduction

5-18. The core excitation test measures core excitation current. The test can be limited to the high voltage winding only. Higher levels of excitation current may indicate shorted turns or core faults such as shorted lamination or core bolt insulation failure. The test should be run in all tap positions. It can be performed at reduced voltage using a power factor test set.

Instructions for Evaluation

5-19. Core excitation tests made using the power factor test set will be performed at reduced voltage so values will not be directly comparable to factory values. Even if reduced voltage core excitation data is not available for a given transformer, mean values from tests of identical units can be used for a reasonable baseline. Equipment condition deterioration based on core excitation tests is as follows:

Minor: For excitation current levels up to 5% over new or baseline values, the condition number should lie within the range of 70 to 100. Use linear interpolation to determine the proper condition number.

Moderate: For excitation current levels between 5% and 10%, over new ,or baseline values, the condition indicator should lie within the range of 40 to 69. Use linear interpolation to determine the proper condition number.

Major: For excitation current levels higher than 1Wo over new or baseline values, the condition indicator should be 15.

Filling out Data Evaluation Sheet

5-20. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes in column 3. In column 4 enter the condition number based on the criteria listed above.

Frequency of Inspection

5-21. Perform every 5 years. Frequency should be increased at least temporarily following unusual events such as high through-currents associated with close-in faults, unexplained transformer temperature rises or sudden increases in transformer noise.

Turns Ratio Test

Introduction

5-22. The turns ratio test may detect shorted turns and failed tap changers. The test can be performed relatively quickly using a commercial turns ratio tester. It should be done for each position of the tap changer.

Instructions for Evaluation

5-23. Equipment condition deterioration based on turns ratio testing is as follows:

Minor: Where the turns ratio test yields a ratio within + or -5% of the nameplate ratio, the condition number is 100.

Major: Where the turns ratio test yields a ratio which deviates from the nameplate ratio by more than 5%, the condition number is 10. The number would be lower except that the transformer, having been in service before 'being taken down for inspection, has not "failed" in the strict sense. However, the transformer should not be reenergized until the problem and the risk has been identified.

Filling out Data Evaluation Sheet

5-24. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes in column 3. In column 4 enter the condition number based on the criteria listed above.

Frequency of Inspection

5-25. Perform every year.

Internal Inspection

Introduction

5-26. If the transformer is partially or fully drained, an internal inspection should be performed. The inspection should cover windings, including leads and "wet" ends of bushings, core and damping structure, tap changer and tank. Results should be well documented and should include pictures or video tapes of the areas in questions.

Instructions for Evaluation

5-27. Quantification of condition based on inspection includes a subjective element. For this reason, it is desirable that the evaluator has had previous experience in transformer inspection. Previous inspection reports for each transformer, with photos and sketches, are of great value in developing comparative data. Whenever possible the same inspector, or an inspection team incorporating some common members, should perform successive inspections on given transformers.

The following condition deterioration descriptions are offered as guidelines. Not all defects listed in a condition category may be observed. The condition number range shows the latitude of deviation permitted in that category as determined by the evaluator.

Minor - No rust found anywhere on core or tank surfaces. Some slight sediment buildup in the bottom of tank- No tracking or burn marks (generally seem as stains on paper insulation) observed on windings, bushings, core or tank. No displacement of leads evident. Eddy current shields are in place and all bolts are tight. The core clamping structure is tight. Bushings ends inside the show no cracks or chips and end cap is tight. The draw lead, if present, clears the bushing end without kink or short radius. Paper insulation wraps on coils and leads are tight and smooth. The tap changer is intact and operating properly. No discoloration is evident at any current carrying joint or on the core frame or tank, particularly adjacent to coil ends. The core ground is intact. The condition range is 70-100.

Moderate - Sediment has collected in the bottom of tank and sludge is visible on the winding as a fine haze. Rust may be visible at the bottom of the tank or core frame. Some very minor tracking may be present. There are general signs of loosening of fasteners and winding blocking but no indication that movement of core or winding has occurred. Some eddy current shields may be loose. All ties, core wrapper sheets and oil flow control barriers are place although some loosening may be observed. The core ground may be loose or disconnected. The condition number range is 40-65.

Major - Significant amounts of sediment and paper debris are present in the bottom of the tank. Sludge is visible on horizontal surface and on the winding. Bolted conductor connections may show discoloration due to overheating. There may be significant signs of core looseness and winding or lead movement. Bushing draw leads may show signs of having been pulled taut at the bottom of the bushing. Rust may be visible on core frame, core or tank at areas near the sediment at the bottom. Eddy current shields may be missing bolts or may have fallen out of place. Bushings may show signs of cracking or crazing of porcelain. Tap changer operation may be stiff' or erratic or parts may have fallen off. Core frame or tank at winding ends may show discoloration due to localized overheating. Paper insulation may not appear tight, may show signs of wrinkling and may show some lifting at edges. Oil control sheets or baffles have fallen out of position. The condition number range is 10-39.

Note: During inspection, consider removal of a paper sample for degree of polymerization (DP) testing. A furan analysis of the oil should also be performed. DP testing is a technique for measuring insulating paper mechanical properties which relate, in turn, to insulation life. Analysis of furans, a class of cellulose breakdown products, has shown correlation to DP test results. DP tests and furan analysis show the potential to become part of the condition indicator program at a later date. Refer to 1991 Doble Minutes for additional information on these tests and techniques for paper sampling.

Filling Out Data Evaluation Sheet

5-28. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes in column 3. In column 4 enter the condition number based on the criteria listed above.

Frequency of inspection

5-29. Whenever oil is partially of fully drained and whenever oil reclamation is performed. Also consider performing *inspection if* severe high current or overexcitation events have occurred.

External Inspection

Introduction

5-30. A through external inspection of the transformer should be performed. It should include infrared thermography of bushings and connection as performed with the transformers in service. Noise levels and characteristics should be noted as accurately as possible for comparison to previous tests or for use as a baseline for test to follow. Bushings and surge arresters should be checked for cracked porcelain and evidence of tracking. Bushing oil levels should be carefully tracked. Conservator or gas blanket oil preservation systems should be checked for proper operation and annunciation in case of failure. Leaks anywhere should be noted as should bulges in the tank, distortions or cracks in structural members and coil coolers, and abnormal bushing angles.

Instruction for Evaluation

5-31. Quantification of condition based on inspection includes a subjective element. For this reason, it is desirable that the evaluator has had previous experience in transformer inspection. Previous inspection reports for each transformer, fully documented with photos and sketches, are of great value in developing comparative data. Whenever possible the same inspector, or an inspection team incorporating some common members, should perform successive inspections on given transformers.

The following condition deterioration descriptions are offered as guidelines. The condition number range shows the latitude of deviation permitted in that category as determined by the evaluator:

Minor - Infrared thermography shows temperature rises of bushings and connections not over 5°C higher than those another phase or on identical transformers at the same loads. Noise level (as measured by sound meter on "C" scale) and character of noise from transformer has not changed appreciably from previous tests or is not significantly different than that from an identical unit, in a similar acoustical environment, at the same load. Bushing and surge arrestor porcelain shows no cracking or tracking and only a minor amount of pitting or chipping. Bushing oil levels, taking into account temperature variations, have not dropped. The gas blanket system maintains positive pressure, conservator diaphragm is intact and air inlet desiccant is functional. No tank, cooler or structure bulges, cracks or leaks are seen. Oil leaks at flanged connections and valve shaft packing, if any, are minor seeps. The condition range is 70-100.

Moderate - Thermography shows temperature rise above 5°C at bolted connection of bus to bushing. Noise level and character of noise is unchanged since last inspection. Substantial chips are noted on bushing or surge arrestor rainsheds; some tracking indications. Oil seep from bushing with very gradual oil level reduction. Gas blanket makeup system is not always capable of maintaining rated positive pressure or conservator diaphragm is ruptured allowing oil contact with atmosphere (desiccant not functional). There are considerable numbers of slow leaks at valves and pipe couplings such that large catch pans or sorbent pickup materials are needed. No tank or structure deformation or crack are evident; bushing angles are normal. The condition number range is 40-69.

Major - Thermography shows a large part of a bushing to be overtemperature. Transformer noise loudness has increased significantly. Bushing oil level may be dropping rapidly enough that replacement is being planned. Cracks may be present in bushing or surge arrestor porcelain. Leaks from valves and pipe couplings are numerous and the coolers or heat exchangers may be leaking or may have leaks sealed by temporary repairs. Tank cracks are evident. Bushing might be slightly askew (due to effects of magnetic forces on close-in fault or of high wind, earthquake or etc.) The condition number range is 10-39.

<u>Filling out Data Evaluation Sheet</u>

5-32. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes in column 3. In column 4 enter the condition number based on the criteria listed above.

<u>Frequency of Inspection</u>

5-33. Yearly. Supplement with additional inspections following unusual events.

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Transformer Condition

Project: ____________________________ Unit No. ____________

Prepared by: ________________________ Date: _______________

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Dissolved Gas Analysis			
Transformer Power Factor			
Bushing Power Factor			
Core Excitation			
Turns Ratio			
Internal Inspection			
External Inspection			
		Overall Transformer Condition Index Rating	

PART XI: CRANES AND WIRE ROPE HOISTS

Program, Method and Format

Explanation of Program

11-1. This document applies to determining condition index for the following types of equipment:

powerhouse bridge and gantry cranes

intake gantry cranes

draft tube gantry cranes

wire rope gate hoists

The overall condition index is a number between 0 to 100 which is used to define the present condition of the hoist. The equipment condition correlating to this number is shown in the REMR Condition Index Scale shown below.

Condition Index Scale

Value	Condition Description	
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate.
25.-39	Poor	Serious deterioration in at least some portions of equipment. Function is inadequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure 11-1

The overall hoist condition number is calculated from condition index numbers for five condition indicators listed below.

ELECTRICAL

1 Operation of Controls and electrical Equipment

STRUCTURAL

2 Corrosion

3 Fatigue Cracks

4 Bolt or rivet defects

MECHANICAL

5 Hoist and Trolley/Bridge/Gantry Drive Machinery Condition

Explanation of Format

11-2. The condition indices each have a similar format. The first sheet is an explanation sheet which describes the test or inspection, give instructions on doing the test or inspection, and explains how to fill out the data-evaluation sheet. Next, there are tables or figures which are used to determine the condition number based on the results of an inspection or test. Following this is the data evaluation sheet where information is recorded and calculations made. Also attached is a sample filled out data evaluation sheet.

Explanation of Method

11-3. A condition number between 0 and 100 is determined for each condition indicator based on the results of inspections. Periodic inspections should be performed in accordance with the standards set forth in ANSI B30.2 for Bridge and Gantry Cranes and ANSI b30.7 for Wire Rope Gate Hoists. It is anticipated that the forthcoming revision to the Corps' Safety Manual, EM385-1-1, will require these inspections. The inspections required by these standards may include inspection requirements that are unrelated to Condition Indicators. Each explanation sheet gives instructions on testing and evaluation. The overall condition index for the crane or hoist is the lowest value of nay of the condition indices. Many of the problem identified will be routine in nature. The inspector should apply sound judgement in these cases as routine items should not have an effect on condition index. If the nature of problems is such that it would require a contract to fix or requires justification of additional funding to the project, then it should be considered to affect condition index. All applicable provisions and references contained in EM-385-1-1, US Army Corps of Engineers Safety and Health Requirements manual, shall be observed in the evaluation and inspection procedures.

Overall Hoist Condition

Introduction

11-4. Each of the five condition indicators is assigned a condition index number. The overall hoist condition is the lowest of these, i.e. the condition of the weakest link.

Filling Out Data Evaluation Sheets

11-5. Column 1 lists the condition indicators. Fill in the date of the test or inspection in column 2. Put in any notes about the condition index, including a brief description of damage found in column 3. Put the condition index number for the corresponding indicator in column 4. Fill in the lowest of the six condition index numbers in the box in the lower right hand corner of the sheet. This is the overall condition index number for the crane or hoist.

CR-1-FRM.PM4 PAGE 1 OF 6

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Overall Wire Rope Hoist Condition

Project: *Old Hydro Plant* Unit No. *Intake Gate*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Electrical	*7/3/90*	*Main hoist motor trips out at high-speed*	*30*
Corrosion	*7/3/90*	*Bottom of north upstream crane leg (inside)*	*50*
Fatigue	*7/3/90*	*Cracks - places*	*23*
Bolt or Rivet Defects	*7/3/90*	*Loose Bolts - places*	*60*
Hoist Machinery Condition	*7/3/90*	*Wire rope - corrosion of inner strands*	*40*
		Overall Crane or Hoist Condition Index Rating	*23*

Operation of Controls and Electrical Equipment

Introduction

11-6. This indicator relies on operation of the crane to check whether the electrical equipment is functioning. Many problems will be routine in nature and will not have an appreciable affect on condition index.

Instructions for Evaluation

11-7. Each hoist should be operated in the raise and lower modes at all speed points or through the full speed range. If the system has other operating modes, test these as well. Trolley and bridge/gantry travel shall be operated at all speed points or through the full speed range. If a test load is available, the crane should be operated with at least 1/3 of rated load. When evaluating wire rope gate hoists, omit any tests pertaining to trolley and bridge gantry travel. In many cases, a fault in the control system may not be found during a one time test. Therefore, it will be helpful to talk to the crane operators to determine if the crane has demonstrated control system faults. If so, the inspector shall find out the specific description of the fault and duplicate the problem conditions. The crane (or gate hoist) should be operated to check for the following items as listed in Table 11-1. The condition index will not be lowered for items that are routine in nature and will therefore remain at 100. The condition index will be as listed in Table 11-1 for non-routine problems.

Table 11-1
Condition Index Number - Operation of Controls and Electrical Equipment

Item	Condition Number	
	Marginal (Problem exists)	Unsatisfactory (not suitable for use)
Main Hoist - Raise/Lower	50	35
Auxiliary Hoist(s) - Raise/Lower	54	39
Trolley Travel	50	35
Bridge/Gantry Travel	50	35
Trolley conductors and collectors	54	39
Bridge/Gantry conductors and collectors	54	39
Main Hoist brake(s) and clutch(s)	39	25
Auxiliary Hoist brake(s) and clutch(s)	39	25
Trolley brake (s)	55	39
Bridge/Gantry brake(s)	55	39
Main Hoist motor	50	35
Auxiliary Hoist Motor	55	39
Trolley Motor	55	39
Bridge/Gantry Motor(s)	55	39
Contacts	55	39
Coils, Shunts, Fuses	55	25
Wiring	39	35
Circuit Boards	50	39
Motor Controls	39	20
Resistors	55	39
Master Switches	55	39
Load Indicators	60	45

CR-1-FRM.PM4 PAGE 2 OF 6

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Crane or Hoists - Operation of Controls

Project: *Old Hydro Plant* Unit No. *Intake Gantry*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Trolley Brakes	*7/3/90*	*Brake does not release*	*39*
		Crane Control Operation Condition Index Rating	*39*

Filling Out Data Evaluation Sheet

11-8. List the malfunction in column 1. Fill out in the date of inspection in column 2. Column 3 gives space to include any notes on the nature of problems or failures. If necessary, use a continuation sheet. The condition index number for each of the evaluation criteria is determined using Table 1 and written down in column 4. The condition index number for the electrical equipment is the lowest number in column 4.

Frequency of Inspection

11-9. This inspection should be performed annually for cranes which would be considered to have normal service as defined by ANSI B30.2. The inspection frequency can be increased to as long as every 10 years for cranes and hoists that are in standby service.

Corrosion

Introduction

11-10. The condition index number is determined by visual or ultrasonic inspection of members of the crane structure.

Instructions for Evaluation

11-11. All structural members, including trolley frames should be visually inspected over 100% of the area. Where accessible or if cover plates are available, the inside of box girders and columns should also be inspected. It is possible for water to accumulate in some of these members and cause considerable damage. In general, only outdoor cranes and gate hoists will be inspected for corrosion. Therefore, powerhouse bridge cranes would not normally require this type of inspection. Where corrosion is present it should be scraped away in strategic sampling areas and the maximum depth of corrosion should be determined with a depth gauge. If corrosion depth is significant and appears to have a measurable effect on the strength of the structure, the revised design stress for the member must be calculated for the worst case member(s), The revised design stress should be calculated by considering any changes which have occurred in section properties due to the corrosion. After calculating the revised design stress at rated load, including dead load, liveload plus 10% impact, the condition index number can be obtained from Table 11-2 based on the worst case member(s). Revised design stress must be calculated by a qualified individual. Where access to the inside of box members is not possible and visual inspection points to a likelihood of interior corrosion, the use of Ultrasonic Testing (UT) should be considered to determine the corrosion depth. Normally, this requires removal of paint in the areas to be tested. If the paint bond is good, as evidenced by no significant back reflection at the paint interface, the testing can sometimes be successfully performed without paint removal. This type of testing can be performed by numerous testing agencies. The testing should be done by a qualified individual. However, thickness testing does not require the rigorous qualifications of weld inspection.

Table 11-2

Condition Index Number - Corrosion

Revised design stress	Condition Index Number
No corrosion	100
Light corrosion near bolts, rivets welds, corners, edges	80
Same as above plus scattered paint failures on flat surfaces	65
Same as above plus widespread paint failures on flat surfaces	50
Significant corrosion and revised design stress <45% of yield	50
Significant corrosion and revised design stress <45-50% of yield	45
Significant corrosion and revised design stress <51-55% of yield	40
Significant corrosion and revised design stress <56-60% of yield	30
Significant corrosion and revised design stress >60% of yield	20

Filling Out Data Evaluation Sheet

11-12. Column 1 lists the location where the corrosion was found. Fill in the date of inspection in column 2. Column 3 gives space to include any notes on the depth of corrosion and the calculated "revised design stress". The condition index for each of the areas of serious corrosion is determined using Table 2 and written down in column 4. The condition index for corrosion is the lowest number in column 4.

Frequency of Inspection

11-13. This inspection should be performed annually for cranes which would be considered to have normal service as defined by ANSI B30.2 The inspection frequency can be increased to as long as every 10 years for cranes and hoists that are in standby service.

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Crane or Hoists Corrosion

Project: *Old Hydro Plant*	Unit No. *Intake Gantry*
Prepared by: *I.N. Spector*	Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Bottom of south upstream crane leg (inside)	*7/3/90*	*Corrosion depth - 0.60" Revised design stress = 50% of yield*	*45*
Bottom of north upstream crane leg (inside)	*7/1/90*	*Corrosion depth - 0.125" Revised design stress = 55% of yield*	*45*
		Crane or Hoist Corrosion Condition Index Rating	*45*

Fatigue

Introduction

11-14. The inspector should look for fatigue cracks in the mechanical components, and structural members. Typically, fatigue cracks would be found in rotating mechanical components such as shafts. Loading in structural members is not completely static so the possibility for fatigue exists there too. If there is cyclic loading and the stress at some point exceeds the corrected endurance limit of the material (S_e), fatigue cracks will occur after a given number of loading cycles. Fatigue cracks are most likely to be found at notches, filets, holes, welds, and connections. Initially, the cracks are microscopic. Eventually, the cracks will grow large enough to be found with visual inspection, magnetic particle, dye-penetrant, ultrasonic or radio-graphic testing. Visual inspection is the least sensitive and will detect only larger cracks. When the cracks are large enough that they can be found by any of the above methods, they are considered serious and must be repaired as soon as possible.

It is likely that fatigue may be limited to an underdesigned mechanical component, structural joint or member. If fatigue is not widespread, repair can sometimes be used to replace "fatigued" material and allow more years of operation. In some cases, grinding out the 'rack and welding is an ineffective repair since the adjacent material will also have cracks which continue to grow. As the condition of the crane worsens, the number of separate locations where cracks are found increases and the likelihood that the crane can be repaired decreases.

The condition index will be based upon the number of locations at which fatigue cracks are found. No attempt is made to base the condition number upon the size of cracks because once the cracks are large enough to be detected with common methods, they will grow rapidly. Also, no attempt will be made to differentiate fatigue cracks from weld cracks that originated during fabrication.

Instructions for Evaluation

11-15. In order to make this process reasonably efficient, the inspector must first obtain information as to the location of potential fatigue problems The shop drawings and Contractor's design calculations are a good starting point. The inspector should limit the effort to these key areas to reduce the total area to be inspected and increase the thoroughness with which problem areas are checked.

Visual inspection will be used to locate fatigue cracks. If no cracks are found, this phase of the inspection is considered complete. If any fatigue cracks are found with visual inspection, the potential fatigue problem areas of the structure should be investigated further with magnetic particle (MT), liquid penentrant (PT), ultrasonic (UT) or radiographic (RT) testing. The person performing the MT, PT , UT or RT should be qualified at the appropriate level in accordance with the current edition of the American Society for Non-Destructive Testing Recommended Practice, No. SNT-TC-1A. In most cases, this would require the services of company which performs non-destructive testing. There may be many cracks at one location, for example the connection between the bridge girders and the end trucks. However, the condition number will be independent of the quantity of cracks at anyone location. It is dependent on the number of locations at which cracks are found. After performing the visual inspection or NDT and recording the results, the condition number can be determined using Table 11-3.

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Crane or Hoists - Fatigue

Project: *Old Hydro Plant* Unit No. *Intake Gantry*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Connection of main girder to crane leg upstream, south	*7/2/90*	*1 crack, visual inspection*	*50*
Connection of main girder to crane leg, upstream south	*7/2/90*	*1 crack, visual inspection*	*40*
Trolley, reducer supports member	*7/2/90*	*3 cracks, visual inspection*	*32*
Trolley, drum bearing support	*7/2/90*	*1 crack, visual inspection*	*23*
		Crane or Hoist Condition Index Rating	*23*

Filling out Data-Evaluation Sheet

11-16. Column 1 lists the location of the fatigue crack(s). In column 2, fill in the date of inspection. Column 3 gives space to include any notes concerning the cracks. The condition index number is determined using Table 3, based upon the number of fatigue crack locations, and written down at the bottom of column 4.

Table 11-3

Condition Index Number - Fatigue

Number of crack locations	Condition Index Number
0	100
1	50
2	40
3	32
4	23
5	15
6	14
7	13
9	12
10 or more	11

Frequency of Testing

11-17. This testing should be performed annually for cranes which would be considered to have normal service as defined by ANSI B30.2. The inspection frequency can be increased to as long as every 10 years for cranes and hoists that are in standby service.

Bolt or Rivet Defects

Introduction

11-18. Structural bolts should have been originally installed with a) turn of the nut method, b) torque wrench, c) bolt tension, d) load indicating washers. The integrity of bolted connections is dependent upon the bolts being properly tightened by one of these methods. Improperly tightened bolts lead to fatigue or bolt failure due to lack of load sharing in friction connections. If the bolt were installed with methods a), b) or c), the most practical method for the inspector to check the bolt is to use a torque wrench. With load indicating washers it is possible to check for proper bolt tension using a feeler gauge, provided the bolt manufacturer is known and the bolt literature is available. However, load indicating washers have not been widely used on COE cranes.

Some cranes and wire rope hoists have riveted construction. Rivet integrity may be checked by using a hammer to determiner if the rivets are loose.

Instructions for Evaluation

11-19. Random samples of structural bolts or rivets at each connection should be checked. Check at least ten percent of the bolts or rivets at a connection but not less than two bolts or rivets. If any loose bolts or rivets are found, all bolts or rivets at that connection shall be checked.

Recommended bolt torques are listed in Table 11-4 below. If the bolt torque is below 2/3 of these values, the bolts will be defined as "loose". Bolt torque should be checked by turning the nut clockwise and if slip occurs, noting the torque at which slip first occurs. For "click type" torque wrenches, set the torque at 2/3 the value called for in Table 11-4. If the nut turns before the wrench clicks, the bolt is "loose". The inspector should also use feel to detect yielding of the bolts when they are torqued to indicate cracks or other defects. The torque wrench has serious limitations in accuracy since weathering will tend to seize the threads. The results are further distorted if a hardened washer was not used under the nut. Despite the above disadvantage, the torque wrench provides the most practical inspection method.

Table 11-4

Bolt Size	Grade 1 ASTM A307	Grade 5 ASTM A325	Grade 8 ASTM A490
1/2	35	90	125
5/8	70	180	250
3/4	124	320	450
7/8	200	470	730
1	300	710	1100
1 1/8	425	960	1500
1 1/4	600	1340	2200
1 3/8	800	1790	2500
1 1/2	1040	32340	3800

Recommended Bolt Torque (ft.-lbs)

For riveted structures, use a hammer to impact rivets with a hard side blow. If any movement is detected, the rivet is considered to be "loose". After determining the quantity and location of loose bolts or rivets, the inspector can determine the condition index number using Table 11-5. Only critical structural or mechanical connections need be checked. Non-critical connections such as those on trolley housings, etc. are not to be evaluated. Loose rivets, A490 bolts or galvanized A325 bolts must be replaced and not retightened.

Note that galvanized structures/bolts behave differently than regular steel.

Table 11-5

Condition Index Number - Bolt and Rivet Defects

Number of Bolted or Riveted Connections with more than 10% of the Fasteners being "Loose	Condition Index
0	100
1	75
2	60
3	45
4	39
5	35
6	32
7	29
8	26
9	25
10 or more	24

Filling out Data Evaluation Sheet

11-20. Column 1 lists the location of the bolt or rivet defects. Fill in the date of inspection in column 2. Column 3 gives space to include any notes concerning the loose bolts or rivets. The condition index number is determined using Table 5, and written down in column 4. The overall condition index number is the lowest of all numbers in column 4 and is written in the block at the lower right corner of the data evaluation sheet.

Frequency of Inspection

11-21. This testing should be performed annually for cranes which would be considered to have normal service as defined by ANSI B30.2. The inspection frequency can be increased to as long as every 10 years for cranes and hoists that are in standby service.

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Crane or Hoists - Bolt or Rivet Defects

Project: *Old Hydro Plant* Unit No. *Upstream Gantry*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Crane leg to bottomtie connection downstream, south	*7/1/90*	*12 of 20 bolts loose*	*75*
Crane leg to main girder connection downstream, north	*7/1/90*	*20 of 48 bolts loose*	*60*
		Crane or Hoist Bolt or Rivet Defects Condition Index Rating	*60*

Hoist Machinery, Trolley and Bridge/Gantry Drive Condition

Introduction

11-22. The hoist machinery and trolley and bridge/gantry drive components should be checked for damage and the condition index number determined after the inspection. The main hoist and auxiliary hoist(s} should both be checked. Components to be checked include brakes, clutches, motors, gear reducers, external gears, drums, shaft, bearings, wire rope and blocks. If there is a failed component(s) and the crane is non-functional, the condition index will be 0. Otherwise, the Instruction for Evaluation describe the methods to determine condition index.

Instructions for Evaluation

11-23. The crane or wire rope hoist should be tested by operating the crane or hoist with 125% of rated load. In some situations, a test load of this weight may not be available or practical and the inspector must select a suitable test load based on the available resources. A condition index number will be determined for each mechanical component and the lowest of these is the condition index for the entire hoist.

There are several acceptable techniques to employ in assessing the condition of the machinery including: visual and audible inspection, oil condition, vibration meter (displacement and velocity), vibration spectrum analysis and motor current analysis. The decision of which method to employ rests on the user who must consider the impact of crane downtime, the possible length of crane downtime, the complexity and cost of the crane, cost of instrumentation and or training as well as the factors.

"Audible" inspection (listening for unusual noises) is the least sensitive method. However, it requires less formal training and investment and is widely used. The big disadvantage is that impending failures of gears, bearings motors etc. may be overlooked and may occur at the most inconvenient time. It is not really a "predictive" tool but more of a "breakdown maintenance" tool. The disadvantage is that unless cause and degree of damage is obvious through past experience (it's usually not) then the only real options are to wait until the machine breaks or to disassemble to investigate further . Since audible inspection can't be quantified and different people will interpret sounds differently, it can only be used to determine condition index when there is no problem with a particular component, i.e. condition index = 100. Audible inspection will be a screening tool, and visual inspection will be used as the next step if there is damage.

Visual inspection is accurate and normally indisputable, the drawback is that many components must be disassembled in order to see any problems. Also, for components which are damaged but have not failed, condition index is difficult to quantify accurately. On some components, large gear boxes for example, disassembly can be minimal. Inspection covers are used and these can be removed to inspect the condition of gears. On some components, for example, drums and rope, visual inspection is the only practical method, but there is no disassembly required.

To determine condition index with visual inspection, the inspector should look at the criteria which is listed below for gears, bearings, motors clutches, brakes, drums, sheaves, shafts and wire rope.

More sophisticated methods have now been developed to help the user to pinpoint the cause and degree of failure so that time of failure can be predicted and the repair can be scheduled appropriately. These methods avoid disassembly of the equipment until the time it is necessary to do the repairs.

Oil condition is an appropriate alternative for determining the condition of gear reducers. An oil sample should be taken after operating the crane 15-30 minutes to circulate the oil in the reducer. The oil sample should be sent to a reputable laboratory for spectrochemical analysis and viscosity and water content testing. The spectrochemical analysis checks wear metals, iron, copper, chromium, lead, tin, and aluminium; additives, zinc, magnesium, calcium, phosphorous; contamininants, silicon. Additional tests are done to establish water content and viscosity. The laboratory will determine and report if the level is high (wear metals and contaminants), low (for additives), normal, requires monitoring, or immediate action required. Based upon the worst item, the condition index can be determined. Wear metals are the parameter most directly relating to condition of the reducer. Contaminants are also important but in some cases where usage is low the condition of the equipment may be good even if there is high contamination. Additives and viscosity give an indication as to whether the oil should be changed but don't necessarily indicate if the equipment in bad condition. Some problems such as gear misalignment or improper bearing preload would not be discovered until the problem starts to generate wear particles from gears or bearings.

Table 11-6

Condition Index based on Oil Condition

	Wear Metals	Silicon	Water	Oil Additives	Oil Viscosity
Normal	100	100	100	100	100
Low	-	-	-	65	65
High	50	65	65	-	-
Monitor	45	60	60	60	60
Imm. Action	30	40	35	45	45

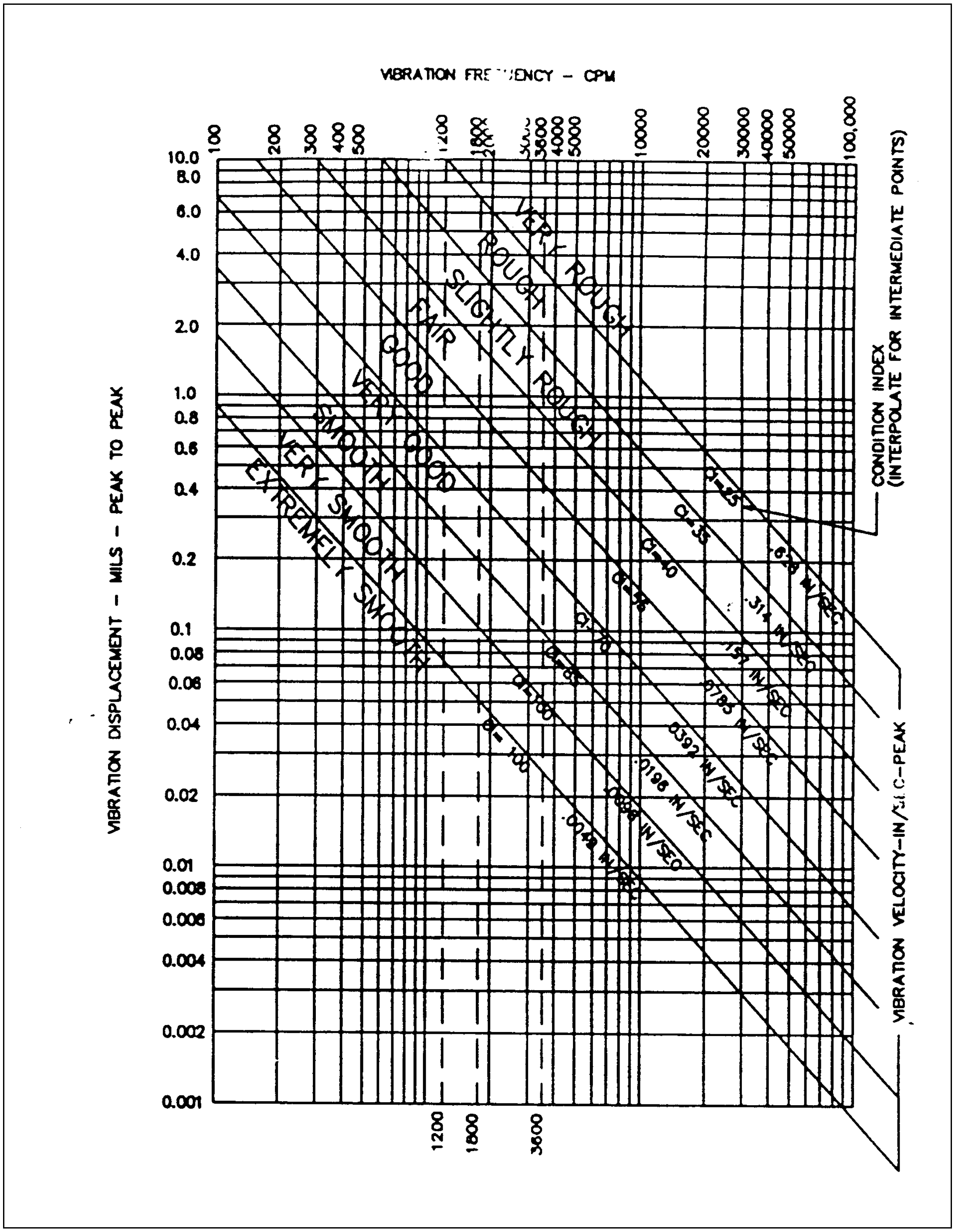

Figure 11-1: Condition Index based on vibration

The vibration meter is considered to be more accurate in quantifying problems than the human ear. The instrument requires minimal instruction to operate. Typically the meter output is velocity (in/sec, peak). Corrections must be made to use data below if the meter output is rms. The method measures only the overall level of vibration not the amplitude at any specific frequency. It would not identify which gear in a reducer is bad, for example. Figure 1 can be used to determine condition index if peak velocity is known. The chart is a reasonable guide to warn against impending failures but some judgement must always be applied when using it. This particular chart is referenced from ASME, "Vibration Tolerances for Industry". There are other similar charts and industry standards such as ISO 2372 and proposed AGMA 426.xx which have also been developed by industry to predict the condition of machines. This method is usually reliable for predicting failures but in some cases, a single component can fail without drastically increasing the overall level of vibration of the machine. Though the method has some drawbacks, it very well suited to use in the REMR program since it is fast, repeatable, can be readily related to a condition index scale, requires only minimal experience and investment in equipment, and no disassembly of equipment is required to determine the condition index. It is particularly suited to used on motor, gearboxes, pillow block bearings, wheel bearings and any other moving components which would otherwise require disassembly in order to assess the condition.

Vibration spectrum analysis and motor current analysis are predictive tools which help determine both the location and severity of the problem(s). They are the most accurate methods but also require more expensive equipment and training. With these methods, data is taken and observed on a regular scheduled basis. A substantial change at a signature frequency would indicate degradation or impeding failure.

Historical data is collected over a period of time in order to relate the data to the condition of the machine. Lacking adequate historical data, Figure 1 can be used to relate displacement and frequency to condition index. Each component,. bearing, gear, etc. will have at least one signature frequency which is a function of the number of bearing elements, gear teeth, etc. and the rotation speed. For example, a ball bearing with 10 balls, rotating at 600 rpm (10 rev/sec.), would have signature frequencies at 10 HZ and 100 Hz. 10 Hz would apply if one ball was bad, 100 Hz would apply if all 10 balls were bad. Motor current analysis is a newer process and there is less information available on implementation. Except on cranes and hoists which have very heavy usage or for which downtime is critical, these two methods are considered to be more extravagant than necessary.

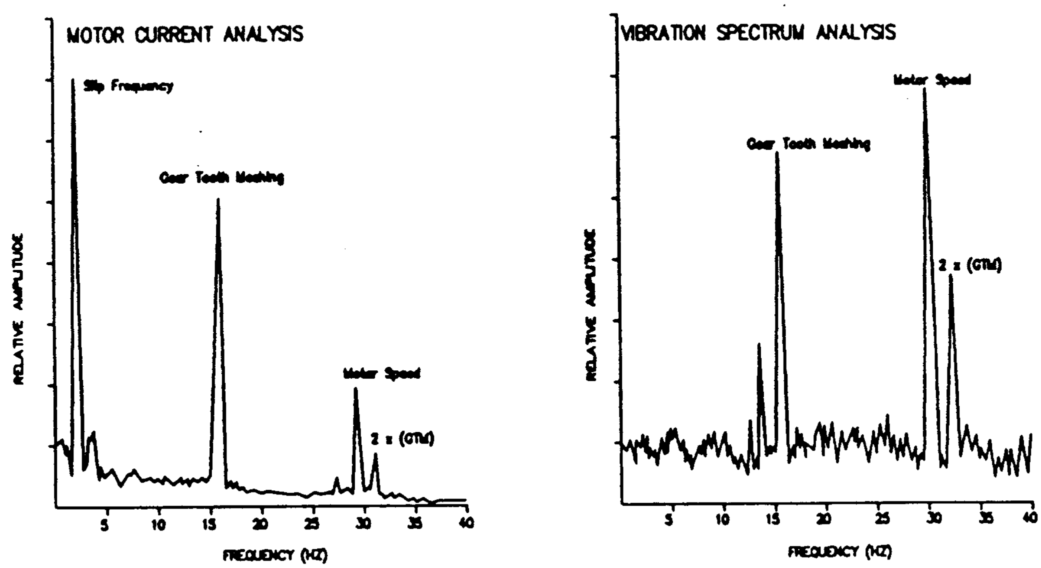

Figure 11-2: Typical vibration and motor current spectra

Some possible references to consult are listed below:

Vibration Tolerances for Industry, R.L. Baxter and D.L. Benlhard, an ASME publication for Plant Engineering and Maintenance Conference , Detroit, Michigan, April 1967

How to monitor motor driven machinery by analyzing motor current, R.C. Kryter and H.D. Haynes, Oak Ridge National Laboratory , *Power Engineering* , October 1989.

Machinery Vibration Diagnostics, Naval Civil Engineering Laboratory, Tech Data Sheet 88-15.

Industrial Noise and Vibration Control, J.D. Irwin and E.R. Graf, Auburn University) Prentice Hall, Inc., Englewood Cliffs, New Jersey

Monitor Machinery Condition for Safe Operation, D.E. Bently, *Hydrocarbon Processing,* November 1974.

Mechanalysis Instruction Manual .Vibration Analysis and Dynamic Balancing, IRD Mechanalysis Inc. , 1961

Real Time Spectrum Analysis of Machinery Dynamics, *Sound and Vibration,* Apri11975.

Gears

12-24. Each gear reducer and external gear of the main and auxiliary hoists, bridge, trolley and gantry drives should be checked. If oil condition, vibration meter, vibration spectrum analysis or motor current analysis are used, the condition index may be determined as described above. If audible inspection is used and unusual noises are discovered, the reducer should be visually inspected until the problem is found. Oil should be drained and visually checked for metal particles or other contamination. Next remove gear inspection covers and or bearing covers as necessary. Inspect each gear set. Below is a list of common gear failures and the associated condition index.

Excessive wear -Material has been worn away from the tooth profile causing a visible change in profile. Condition index = 15, if reducer is non-functional condition index = 0

Abrasive wear - Contacting surfaces of teeth show signs of lapped finish, radial scratches or grooves due to excessive amounts of abrasive particles in the lube oil. Condition index = 35, condition may worsen into other categories such as excessive wear with further use.

Corrosive wear - Surface shows evidence of corrosive pitting, usually due to acidity , water or extreme pressure additives. Condition index = 35, condition may worsen into other categories such as excessive wear with further use.

Scoring - Localized overheating due to failure of the oil film allows surface welding and metal removal. Radial tear marks are visible. Condition index = 30, condition may worsen into other categories such as excessive wear with further use.

Pitting - Surface fatigue causes loss of metal on the contact surfaces. Once surface fatigue becomes visible, it will normally progress rapidly.

Condition index = 50 (pitting on 0-5% of tooth surface), condition index = 30 (pitting on 5-10% of tooth surface), condition index = 15 (pitting on more than 10% of tooth surface or visible change of tooth profile), condition index = 0 (if reducer is non-functional

Breakage -Breakage of gear teeth due to beam bending failure. Condition index = 0.

Improper tooth contact -Visual inspection of the gear teeth should indicate a wear pattern distributed evenly over the center portion of the tooth. Condition index = 50, condition will worsen into other categories if corrective action is not taken.

Drums

12-27. The drum groove should be visually inspected for abnormal wear. The grooves should be smooth and should be about 1/32" wider than the rope diameter. If the wire rope imprint is visible in the groove, the wear is considered severe.

Table 11-8

Condition Index - Drums

Problem	Condition Index
No problem	100
Visible drum groove wear	70
Wire rope imprint visible	30
Drum crushing, visible change in drum profile	30
Drum does not turn true due to bent shaft	30

Bearings

12-28. Bearings and bushings on reducers, external gears, drums, sheaves, line shafts, and wheels should be checked. If necessary , disconnect couplings on input and output shafts. Rotate shaft or inspect bearings to check for bearing failure. On most bearings, visual inspection of the rolling elements, and races will not be possible without disassembly. Since major disassembly is not intended, bearing condition will be based on noise and or feel (where shafts can be rotated by hand). Because the bearing working surfaces will not be visually inspected, condition index can only be assessed in broad categories.

Table 11-9

Condition Index -Bearings

Problem	Condition Index
No problem	100
Unusual noise from bearing, or vibration level "rough", or vibration spectra shows problem but bearing is functional	50
Unusual noise from bearing, bearing is not functional	0

Sheaves

12-29. The sheave grooves should be visually inspected for abnormal wear and corrosion. The grooves should be smooth and should be about 1/32" wider than the rope diameter. If the wire rope imprint is visible in the groove, the wear or corrosion is considered severe.

Table 11-10

Condition Index -Sheaves

Problem	Condition Index
No problem	100
Visible wear or corrosion	70
Wire rope imprint visible	30

Wire Rope

12-30. The rope should be checked for the following damage:

Worn and abraded wires. Look for wear on the outer wires of the rope which exceeds 1/3 the wire diameter .

Broken wires -For running ropes, check for six or more randomly distributed broken wires in one rope lay. Also, check if there are one or more randomly broken wires at the base of a fitting, such as a socket. If there are any wire breaks in the valleys of the rope lays, this is abnormal and serious.

Reduction of rope diameter -Measure the rope diameter. Check if rope diameter reduction equals or exceeds the following.

3/64" for rope diameter up to 3/4"

1/16" for rope diameter 7/8" to 11/8"

3/32" for rope diameter 11/4" & over

Corrosion - To be effective, the rope must be opened with a marlin spike as it is common to have corrosion of the core wires while no corrosion is evident on the exterior. It is very important to check sections of the rope which operate underwater continuously or intermittently.

Crushed, flattened or jammed strands.

Unlayed strands, bird cages, kinks or bulges.

Heat damage, torch burns, electric are strikes. Look for discolored areas on the rope. The damaged areas are normally blue. Since the wires are hardened material, the heat damage drastically reduces its strength.

Table 11-11

Condition Index -Wire Rope

Problem	Condition Index
No problem	100
Worn or abraded wires, broken wires reduction of rope diameter corrosion, crushed, jammed or flattened strands, unlayed strands, bulges or bird cages, heat damage, torch burns, electric arc strikes	30

Wheels

12-31. The first criteria to investigate is whether all wheels are properly contacting the rail. Check by travelling the crane or trolley down the rails. If all wheels do not rotate, unequal load sharing between the wheels exists. This problem can lead to frequent bearing failures. Next, check the wear pattern on the wheels, specifically for significant wear occurring on the flanges of any of the wheels. If there is wear on the flanges, investigate further to determine if the crane or trolley "racks" as it travels down the rail or if there is any interruption of smooth travel due to rail misalignment or crane fabrication inaccuracies.

Check for presence of pitting on the tread surface of the wheels which indicate surface fatigue and the end of useful wheel life. Thin flakes of steel with the appearance of graphite are often found on the rails. This is normal and does not affect condition index.

Table 11-12

Condition Index -Wheels

Problem	Condition Index
No problem	100
All wheels do not contact the rail	35
Racking or binding of the bridge or gantry during travel	35
Pitting of wheel tread surface	40

Shafts

12-32. Shafts should be checked for straightness, damaged keyways, splines. Fatigue cracks are addressed above **Fatigue.**

Table 11-13

Condition Index - Shaft

Problem	Condition Index
No problem	100
Bent Shaft	30
Damaged keyway or splines	30

Filling out Data Evaluation Sheets

12-33. Column 1 lists the location of the hoist and drive machinery components. There are only six spaces, so if more than six problems are found, use a continuation sheet. Fill in the date of inspection in column 2. Column 3 gives space to include any notes concerning the damage found. The condition index number is determined using the information in Instructions for Evaluation. The worst condition number is written down at the bottom of column 4. This is the condition number for the hoist and drive machinery.

Frequency of Testing

12-34. This testing should be performed annually for cranes which would be considered to have normal service as defined by ANSI B30.2. The inspection frequency can be increased to as long as every 10 years for cranes and hoists that are in standby service.

CR-1-FRM.PM4 PAGE 6 OF 6

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Hoist and Drive Machinery Condition

Project: *Old Hydro Plant* Unit No. *1*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Main hoist gear reducer	*7/2/90*	*Vibration, 09.050 in/sec peak*	*66*
Bridge drive gear reducer	*7/2/90*	*Vibration, 0.020 in/sec peak*	*85*
Auxiliary hoist clutch	*7/2/90*	*Lining wear*	*80*
Main hoist drum support bearing	*7/2/90*	*Vibration, 0.79 in/sec peak*	*55*
Sheaves - main hoist block	*7/2/90*	*Corrosion of groove surface, visible but not severe*	*80*
Wire rope - main hoist	*7/2/90*	*Corrosion of inner strands*	*40*
		Hoist Machinery Condition Index Rating	*40*

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Overall Wire Rope Hoist Condition

Project: ____________________________ Unit No. ____________

Prepared by: ________________________ Date: _______________

Item	Date of Inspection or test	Remarks	Condition Number 0 - 100
Electrical			
Corrosion			
Fatigue			
Bolt or Rivet Defects			
Hoist Machinery Condition			
		Overall Crane or Hoist Condition Index Rating	

CR-1-FRM.PM4 PAGE 2 OF 6

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Cranes or Hoists - Operation of Controls

Project: ____________________________ Unit No. ____________

Prepared by: ________________________ Date: _______________

Item	Date of Inspection or test	Remarks	Condition Number 0 - 100
		Overall Control Operation Condition Index Rating	

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Cranes or Hoists - Corrosion

Project: ____________________________ Unit No. ____________

Prepared by: ________________________ Date: _______________

Item	Date of Inspection or test	Remarks	Condition Number 0 - 100
		Crane or Hoist Corrosion Condition Index Rating	

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Cranes or Hoists - Fatigue

Project: ____________________________ Unit No. ____________

Prepared by: ________________________ Date: _______________

Item	Date of Inspection or test	Remarks	Condition Number 0 - 100
		Crane or Hoist Condition Index Rating	

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Cranes or Hoists - Bolt or Rivet Defects

Project: ____________________________ Unit No. ____________

Prepared by: ________________________ Date: _______________

Item	Date of Inspection or test	Remarks	Condition Number 0 - 100
		Crane or Hoist Bolt or Rivet Defects Condition Index Rating	

REMR Hydropower Condition

Indicator Program

Data Evaluation Sheet
Hoist and Drive Machinery Condition

Project: ____________________________ Unit No. ____________

Prepared by: ________________________ Date: _______________

Item	Date of Inspection or test	Remarks	Condition Number 0 - 100

Hoist Machinery Condition Index Rating

C
GLOSSARY OF TERMS

Fire Protection - Definitions

The following are common fire protection terms:

Access to exit means that part of a floor area that provides a path to an exit.

Closure means a device or assembly for closing an opening through a fire separation. Closures include shutters, wired glass, doors, and related components: closing devices, frames, and anchors. Closures must have a fire-protection rating appropriate for the fire-resistance rating of the fire separation.

Deluge system means a sprinkler system employing open sprinklers or nozzles. The piping is connected to a valve that is opened by a detection system. When this valve opens, water flows into the piping system and out the opened sprinklers. Deluge systems are used to protect equipment that has a high potential for an explosion or rapid fire spread.

Dry pipe system means a sprinkler system containing compressed air, the release of which permits water to enter the system and flow out the opened sprinklers. Such a system is used in areas where temperatures might approach the freezing temperature of water.

Duct-type smoke detector means a specialized smoke detector for use in an HVAC system.

Exit means a protected facility (i.e. constructed with rated fire separations) that leads to an exterior open space. Exits shall be readily accessible from all floor areas. Exits include exit stair shafts, exit doorways, and exit corridors.

Fire department connection means a connection through which the fire department can pump water into the sprinkler or standpipe systems.

Fire detector means a device which detects a fire condition and automatically initiates an electrical signal to inform the fire alarm panel of the fire condition. This definition includes smoke detectors, duct-type smoke detectors, heat detectors, linear beam detectors, and camera-type detectors

Fire protection rating means the duration that a closure will withstand the passage of flame when exposed to fire under the specified conditions of the standard in force. The tested duration is not necessarily equivalent to the duration in an actual fire.

Fire-resistance rating means the duration that a construction assembly will withstand the passage of flame and the transmission of heat when exposed to fire under specified test and performance conditions of the standard in force. The tested duration is not necessarily equivalent to the duration in an actual fire. Construction assemblies which achieve a fire-resistance rating are listed by testing agencies.

Fire separation means a construction assembly that acts as a barrier against the spread of smoke and fire. Fire separations can be constructed with or without a fire-resistance rating, and conversely, the provision of a fire-resistance rating does not necessarily mean that an assembly is a fire separation. A fire separation with a 2 hour fire-resistance rating is often called a "2 hour fire separation".

Fire separation (horizontal) means a floor or roof assembly constructed as a fire separation. It can be constructed with or without a fire-resistance rating.

Fire separation (vertical) means a wall assembly constructed as a fire separation. It can be constructed with or without a fire-resistance rating. A vertical fire separation is distinct from a firewall.

Firestop means the protection of openings within fire separations created by the penetration of pipes, cables, or other services. Means of providing this protection includes sealants, noncombustible materials, and protective collars. A firestop system must have a fire-resistance rating equivalent to the assembly through which it penetrates.

Firewall means a type of fire separation of noncombustible construction which subdivides a building and which has a minimum 2 hour fire-resistance rating and the structural stability to remain intact under fire conditions without support from the building structure.

Flow switch means a device which is attached to a water pipe or valve that produces an electrical signal upon a defined change in water pressure or flow. Such devices are used by the fire alarm system to monitor the operation of valves and fire suppression systems.

Listed means that a component or system has been tested to a specific test standard and approved by a recognized listing agency.

Noncombustible means that a material that will not ignite, burn, support combustion, or release flammable vapours when tested to a recognized standard.

Noncombustible construction means that type of construction in which a degree of fire safety is attained by the use of noncombustible materials.

Preaction sprinkler system means a dry pipe sprinkler system whose operation is interconnected with that of a detection system. Water will only be applied if both the automatic sprinklers and the detection system activate. Such a system is often used in areas where an accidental discharge would damage critical equipment.

Hold-open device means an electromagnetic device that holds a door open, but upon receipt of an alarm signal from the fire alarm panel, it will allow the door to close. These devices are used on doors through fire separations. They permit easy access through the separation during normal operation while maintaining the integrity of the separation in the event of a fire. Their installation precludes the use of wooden wedges which compromise the fire separation.

Sprinkler system means an integrated system of piping and automatic sprinkler heads connected to a water supply. At an elevated temperature, the sprinkler heads open and apply water to the fire. Each sprinkler head activates independently of the other sprinkler heads. The applicable design standard is NFPA 13, "Standard for the Installation of Sprinkler Systems".

Standpipe system means an arrangement of piping, valves, and hose connections for the purpose of discharging water through attached hose and nozzles. A standpipe system is often referred to as "interior hose facilities". Such systems are designed and installed to NFPA 14, "Standard for the Installation of Standpipe and Hose Systems".

Wet pipe system means a sprinkler system containing water so that the water discharges instantly when heat from a fire opens the sprinklers.

Targets:

Hydropower Operations and Asset Management

Relicensing Forum

Plant Maintenance & Life Management

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

EPRI. Electrify the World

TR-112350-V4

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com