Hydro Life Extension Modernization Guide

Volume 7 - Protection and Control

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Technical Report

Hydro Life Extension Modernization Guide

Volume 7—Protection and Control

TR-112350-V7

Final Report, December 2000

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REPORT SUMMARY

Hydroelectric power generation is a proven vital source of electricity in the United States and worldwide. This guideline—Volume 7 in a series—will help hydroelectric utilities assess the benefits of life extension and modernization alternatives for plant protection and control systems, evaluate the economic justification for such alternatives, and implement the selected plan. The guidelines provide screening procedures and criteria to enable utility personnel to identify which hydroelectric plants are suitable for modernization and which plants promise the most immediate return on investment.

Background
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. Furthermore, as experienced personnel retire and leave utility companies, the need for guidance in making these critical decisions becomes even more important. To address these concerns, EPRI issued three volumes of modernization guidelines in 1989. This present series of guidelines will update the widely used 1989 guides and expand them to cover the entire plant. This volume covers the important area of protection and control systems, where huge leverage is possible given the fast moving improvements in instrumentation technology and market pressures to reduce cost.

Objective
To provide technical information and data on hydroelectric plant protection and control systems for use as input to the life extension and modernization (LEM) planning process, as developed in Volume 1 (EPRI report TR-112350-V1).

Approach
The information supplied is the result of an extensive search and review of literature on protection and control systems.

Results
EPRI's hydro life extension modernization guidelines present a comprehensive look at available and developing protection and control systems technologies and their possible implementation. Volume 1 provides the overall process for developing a plant LEM plan. Most steps in the process require technical input, allowing utilities to clearly define plant-specific life extension requirements and modernization opportunities then address them in terms of actual activities or plant projects. Utilities should turn to Volume 7 after they complete facility screening and select plants suitable for LEM studies, according to guidance in Volume 1. Technical content in Volume 7 covers the following topics: 1) Protection and control systems, 2) Programmable logic

controllers, 3) Human-machine interfaces, 4) Data logging, 5) Event recording, 6) Machine condition monitoring, 7) Operating information and data acquisition, 8) Synchronizers, 9) Communication networks, and 10) Control networks.

Protection and control systems technology has advanced further in the past 50 years than any other hydro plant technology. The goal of these guidelines is not for a utility to strive to maintain the whole hydro plant at the very forefront of the technological envelope. Such a goal would require continuous upgrading with unproven technology that could be detrimental to protection and control systems reliability. Rather, these guidelines suggest a stepped approach to technological modifications that will best enhance system availability, reliability, and maintainability over the remaining life of the plant.

EPRI Perspective

EPRI's hydro life extension modernization guidelines provide a technical resource for engineers and planners to promote the development of integrated protection and control systems. The guidelines identify license implications of upgrades along with plant improvements that can decrease environmental impacts. The soup to nuts approach in this series takes the user from establishing a base case, to pinpointing high value alternatives, to incorporating options in the overall LEM—and on through selection, procurement, and implementation phases. Throughout the entire process, the focus is on creating value by applying technologies that offer the greatest return. This requires not only understanding the technologies and their application but also keeping an eye on markets and matching technology to market demand. From the intake gates to the control system for supplying power to the grid, automation provides opportunities to reduce costs and improve reliability—but it cannot be performed haphazardly. Care must be taken to assess corporate strategy, plant mission, equipment class and condition, personnel organizational issues, watershed configuration, and market drivers.

Deregulation and privatization of the electricity industry around the globe pose threats to hydro utilities but also present numerous opportunities for resource growth. Hydro assets will become more and more valuable as new markets develop and energy products are unbundled into ancillary services for meeting demand instantaneously and reliably. EPRI's comprehensive guideline series will help hydro plants implement the necessary equipment and processes to meet evolving electricity demands and thus capture their deserved market share. The complete series of hydro LEM guidelines is as follows: Volume 1: Overall Process, 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, and Volume 7: Protection and Control Systems. Volumes 3-6 are scheduled for delivery in 2001.

Keywords

Life extension
Hydroelectric power
Hydroelectric power generation
Asset management
Control systems
Protection systems

ABSTRACT

Under contract to EPRI, BC Hydro is developing a seven-volume set of guidelines for life extension and modernization (LEM) of hydroelectric plants. These guidelines supersede the three-volume 1989 guides published by EPRI, and will enable utility personnel to identify which hydroelectric plants are suitable for modernization and which plants promise the most immediate return on investment. This guideline—Volume 7 in the series—will help hydroelectric utilities assess the benefits of life extension and modernization alternatives for plant protection and control systems, evaluate the economic justification for such alternatives, and implement the selected plan. Technical content in Volume 7 covers the following topics:

- Protection and control systems
- Programmable logic controllers
- Human-machine interfaces
- Data logging
- Event recording
- Machine condition monitoring
- Operating information and data acquisition
- Synchronizers
- Communication networks
- Control networks

The complete series of hydro LEM guidelines is as follows: Volume 1: Overall Process, 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, and Volume 7: Protection and Control Systems. Volumes 3-6 are scheduled for delivery in 2001.

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INTRODUCTION AND SCOPE

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 and Control

Volume 7—Protection and Control (P&C)

Automating a hydro plant involves modifications to all functional areas of the plant from the intake gates to the control system. The necessary mechanization and instrumentation required to automate a functional area will be discussed in detail in one of the Volumes 2 through 6. Included in that discussion will be a list of requirements for automation. For example, when modernization opportunities of wicket gates are discussed in Volume 2, motor driven gate positioners, self/auto lubrication systems and shear pin monitoring will be listed as necessities for automation. In general, Volumes 2–6 will cover all field devices physically located and functionally associated with the discussed component.

Finally, Volume 7 covers the components that are located at the unit control board as well as the systems common to the entire hydro plant. These systems include (in no particular order):

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

- protection
- Programmable Logic Controllers (PLC’s)
- Human Machine Interface (HMI)
- data logging
- event recording
- machine condition monitoring
- operating information and data acquisition
- synchronizers
- communication networks
- control networks

Figure 1-1 shows the physical boundaries between the unit protection and control panels and the field devices. This is the division between Volume 7 and the other volumes.

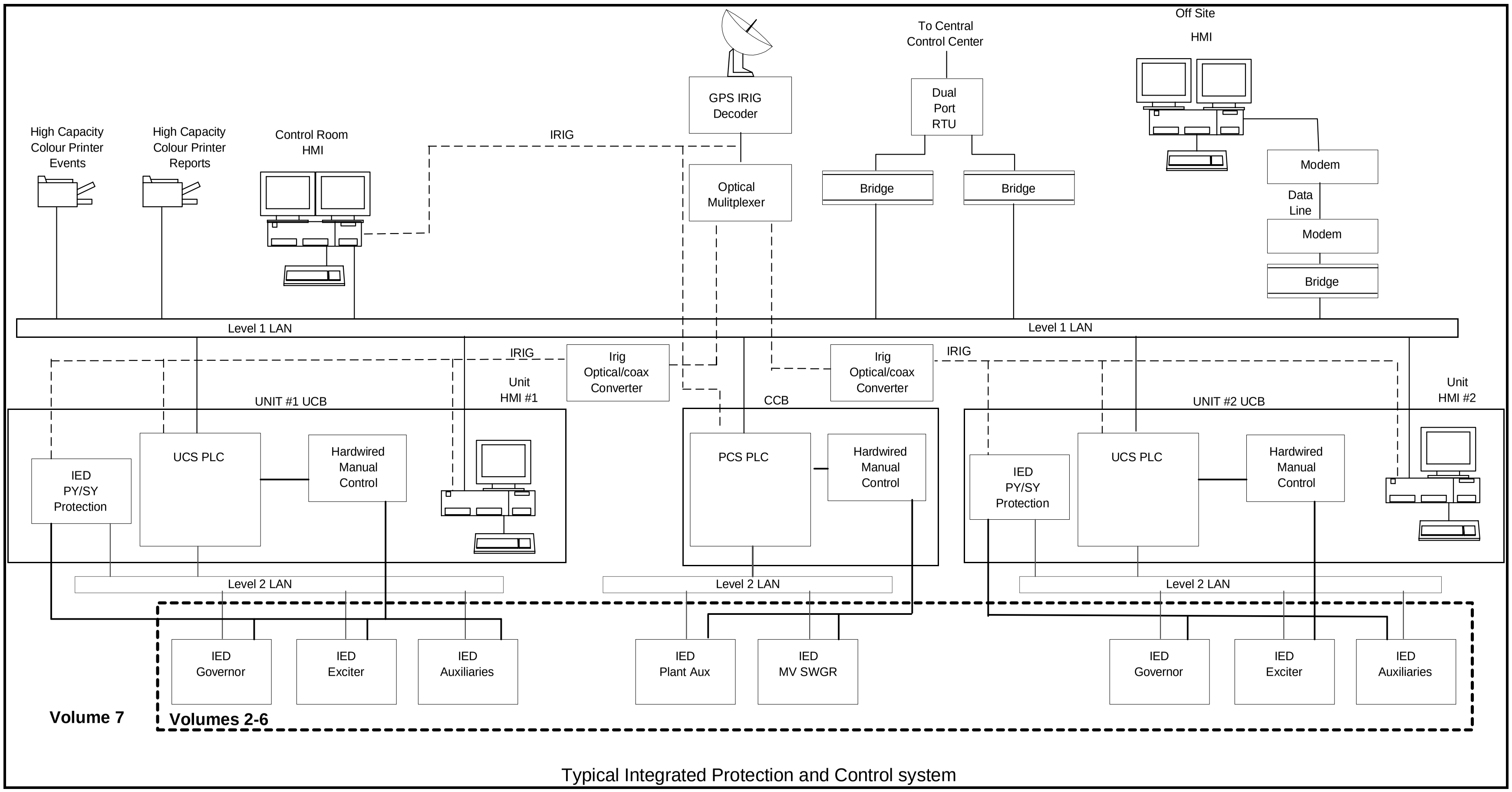

Figure 1-1
Boundaries between Volumes

Volume 7 will also touch on the potential for improvement in upgrading a fully manual plant to a fully automated and remotely controlled plant.

The benefit of organizing the volumes in this manner is substantial. Everything pertaining to the modernization of the intake gates, for example, will be found in Volume 6. The user need only refer to one volume in order to get all the life extension and modernization information on a piece of equipment or component. The modernization of the control system (e.g. the replacement of relay-based controls with PLC-based controls) will be in Volume 7 as will the discussion of integration between the control system and any other power plant systems.

Purpose of Volume 7

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 this Volume is to provide technical information and data that can be used as input to the life extension and modernization planning process as developed through Volume 1. Volume 7 is 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.

Technology, in the area of protection and control systems, has advanced further in the past 50 years than any other technology found in a hydro plant. As anyone who has bought a computer knows, even the latest technology from two years ago can be outdated. The goal of those Guidelines is not to strive to maintain the whole hydroplant at the very forefront of the technological envelope as that would require continuous upgrading with unproven technology that could be detrimental to the reliability of the protection and control systems. These guidelines suggest a stepped approach to technological modifications that will best enhance system availability, reliability and maintainability over the remaining life of the plant.

The following chart is a representation of the advancement of technology and the recommended approach to technical advancement.[2] The exponential curve in the graph is a stylized representation of technological advances. The staircase represents the suggested approach to doing technology upgrades. The "step up" represents an upgrade in hardware and/or software. The "step along" represents a time period of little or no upgrading, where the benefits of the previous upgrade are reaped. In the meantime, technology continues to advance and the quality of new products improve as bugs are worked out. After a time period of 2–5 years, depending on the system, another "step up" can be taken, perhaps not in the same area as the previous upgrade but in a way that compliments the previous upgrade.

[2] Application of Advancing Technology in PC&T, Fred Turner

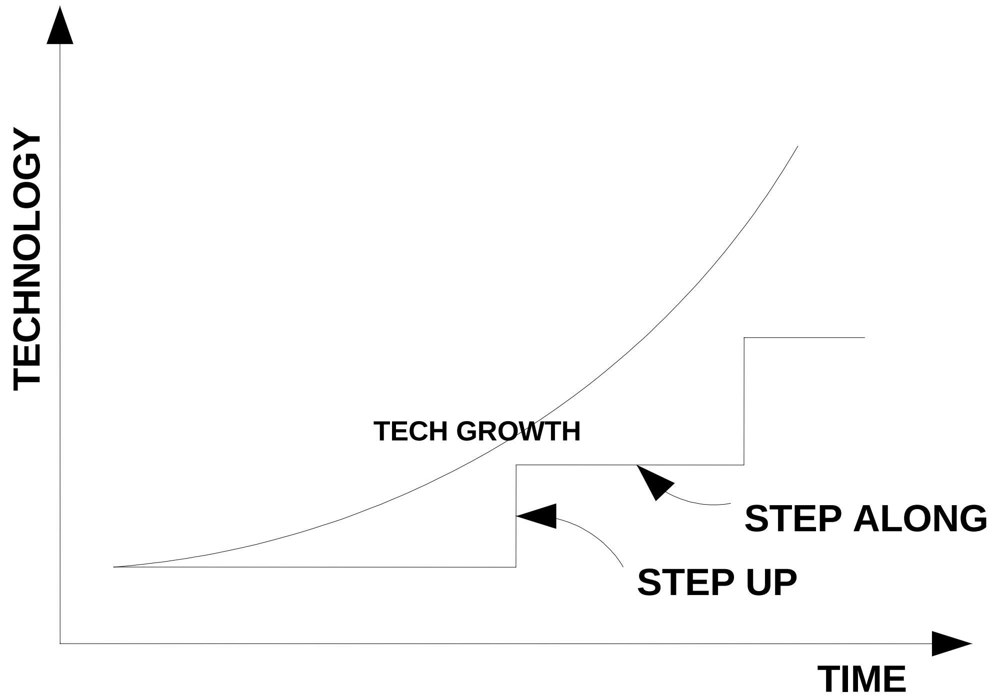

Figure 1-2
Suggested Approach to Technological Upgrades.

How to Use Volume 7

Volume 7 presents a step-by-step method to assess the potential of components for life extension and/or modernization. Volume 7 comprises:

Section 1: Introduction. Explains the needs, concepts, objectives and scope of Volume 7. 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. Summarizes possible objectives of life extension and modernization, also provides examples of recent modernization projects.

Section 3: Screening. This is the first step of the life extension and modernization process. The user obtains the necessary information about the protection and control aspects of the unit. In many cases this information will clearly justify proceeding directly to Section 4 and undertaking a more detailed evaluation of condition and performance. Where it is uncertain, the user is led through the necessary steps of a desktop study to screen and prioritize the plant P&C in terms of *most likely to yield benefit from life extension and modernization*

Section 4: Evaluation of Condition and Performance. Focuses the user on a more detailed assessment of the present condition and performance of the plant protection and control systems. This assessment includes predicting remaining life and identifying activities that will extend life.

Section 5: Potential for Improvements. Covers the modernization opportunities available for protection and control 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 from the protection and control perspective 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: Procurement guides for writing specifications for the purchase of new plant control system including: PLCs, HMIs, protection, monitoring and Supervisory Control & Data Acquisition (SCADA) systems.

Appendix C: Outlines sources of information for contacting potential suppliers of protection and control components for further information.

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

Appendix E: Glossary of Terms

Volume 7 is the technical resource for the protection and control equipment in the overall process. Figure 1-3 shows how the various sections of Volume 7 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 the Volume 7 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.

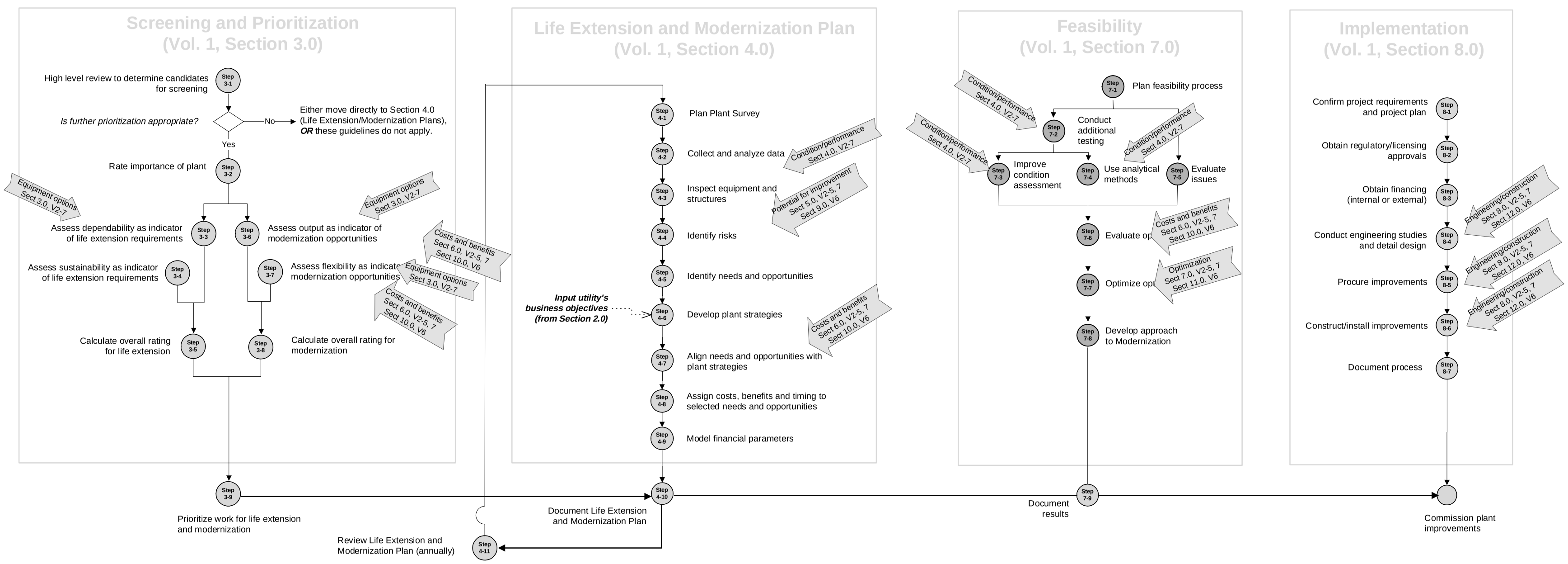

Figure 1-3
LEM Flowchart

Volume 7 is 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:

1. Familiarization with what life extension terms, such as rehabilitation, and modernization really mean and clarification of the objectives of hydro plant rehabilitation (Section 2).

2. Screening (Section 3).

3. Systematic evaluation of the condition and performance level of plant equipment using a defined process (Section 4)

4. Systematic evaluation of the "upgradability" and modernization potential of plant equipment to improve plant performance levels and reduce resource requirements (labour, expenditures) (Section 5).

5. Estimation of the "ball park" costs and benefits of all projects identified and roughly defined in Steps 3 and 4 above for input into the LEM Plan. (Section 6)

6. Based on an iterative approach to developing the LEM Plan, some projects (particularly modernization projects) will require a detailed feasibility study to determine their technical feasibility and economic worth (Section 7). Most of the life extension projects, which only restore equipment to its original condition and level of service, will not require a detailed feasibility study. A simple evaluation of the cost of rehabilitation vs. replacement may be all that is warranted in some cases. Projects that have an impact on overall plant operation or other plant equipment will require more detailed evaluation and optimization of alternative project scenarios.

7. Project implementation (Section 8).

2 BACKGROUND

2.1 Introduction

This Volume covers the protection and control systems in a hydro plant. Protection and Control (P & C) are the non-power-carrying components of an electric system. Protection components automatically initiate disconnection of power-carrying components after a disturbance or abnormal operation. Control components provide a means to adjust the system, either manually or automatically and remotely or locally.

This Volume provides detailed technical information on the following equipment:

- Protective relays
- PLCs (unit control)
- HMIs (human machine interfaces)
- Control and data networks
- Machine condition monitoring (air gap, vibration, temperature and partial discharge monitoring)
- Data logging, alarms and annunciation systems
- Sequence of Event Recording (with Global Positioning System (GPS) time synchronization)
- Synchronizers

It is assumed that the user of the guidelines has a basic understanding of the types of P&C equipment in a hydro plant and therefore descriptions of the equipment are not provided. Appendix E contains a glossary of terms for P&C for reference purposes.

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. Among possible objectives are:

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

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
  - remote control
  - 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

2.3 Trends in Life Extension and Modernization[4]

An industry benchmarking survey was conducted in conjunction with the HydroVision 98 conference. The survey provides a good sampling of general approaches and practices being implemented by hydro owners, primarily in North America, with regard to plant or component life extension and modernization. A total of 66 projects were reported. Relevant information about each P&C or automation upgrade project is provided in Table 2-1. The survey report presents statistics on the reasons for life extension and/or modernization, strategies employed, economic and prioritization criteria, contracting arrangements, and quality control and testing methods.

[4] EPRI, Palo Alto, CA, 1998. WO 5715-01, p 5-4 to 5-6, *Hydropower Technology Round-up Report; Part 2: Rehabilitating and Upgrading Hydro*

Table 2-1
Summary of Recent P&C Upgrade Projects

PLANT	REASON FOR UPGRADE	MODERNIZATIONS	BENEFITS REALIZED	COST
PECO Energy Muddy Run, PA	Eliminate parts and service problems, reduce downtime, provide better information, reduce potential for major failures, improve unit performance and operating results	New instrumentation for wicket gate position, flow, exciter volts and amps, governor and thrust bearing oil levels, governor accumulator tank, stator, oil and bearing temperatures, M-G set phase current, M-G set voltage, vibration at M-G set guide bearing, thrust bearing and pump-turbine bearing, speed, nitrogen pressure, transformer oil temp, fire sys header pressure, computer temps, forebay and tailrace levels and breaker air pressures. All above analogs compared to setpoints for alarming. Total I/O: 496 analog inputs, 8 analog outputs, 824 digital inputs, 160 digital outputs.	Generator output controlled to within ±1MW and plant to within ±2MW.	
R.S. Kerr Dam, OK	Obsolete excitation equipment, under capacity control cables	Relay controls replaced with PLC. Control cables replaced with fibre optic cable. Extensive alarm system added.	Central supervisory control automatically and optimally allocates load among the units. Close control of gate and runner blade positions prevents large load swings and is easier on the units. Steady unit output reduces wear on blade mechanisms and foaming of governor oil. Alarm system readily identifies problems, quickens maintenance response and reduces downtime.	$600,000 for four units
California Water Project	Obsolesence of parts	300 RTUs connected with fibre optic network	High RTU reliability with large common spare parts inventory, implementation of an "expert" system[1] now possible. Increased efficiency, more flexibility, lower maintenance and higher reliability.	

PLANT	REASON FOR UPGRADE	MODERNIZATIONS	BENEFITS REALIZED	COST
AmerenUE Osage, MO	Rising operation and maintenance costs, need for improved efficiency and flexibility to prepare for competition,	New digital control system for automatic start, synchronizing, loading and shutdown, PLC based digital governor, static excitation, auto synchronizer, SCADA system interfacing with central control with unit control and RTUs , new motor operated gate lock, level switch for plant sump pump auto operation, monitoring and alarming of plant fire system	Plant staff has been reduced from 60 to 30. No lost generation due to automation equipment. Quick loading of units from standstill to 85% for emergencies.	
Trangslet Plant, Sweden	Existing plant flooded, lack of confidence in reliability and integrity of old system if restored.	Distributed computer control on each unit, water level sensors, station service and HMI. Wicket gate position, voltages, power, indications, fault signals and energy metering pulses are transmitted to remote control.	Optimization of load sharing, perform water flow calculations for each unit including water level and head losses, record events and timing,	$1,500,000 for three units.
Sackingen Plant, Germany	Market competition and need to produce at a lower cost, shutdowns due to erratic air volume control in governor accumulators	Redundant DC power supply, static excitation, digital generator and transformer protection, new governors, start-stop controls and monitoring systems, replacement of turbine monitoring sensors, central control and monitoring with digital equipment, automatic level controller system	Maximized generation from available river flow, staff reduction from 39 to 15, station is fully automated.	$17,000,000 for entire plant. Expect 7 yr payback.

Note: Expert System refers to a rule based computer algorithm which uses historical data to “learn” correct responses to control system errors.

2.4 Definitions[5]

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 forseeable 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*]. [4] This area is not covered by these guidelines.

Automation—the replacement of manually operated components requiring human intervention with automatic self controlled ones not requiring human intervention. Can also be defined as, for this scope, the application of new advanced protection and control components.

Protection—the non-power carrying components of the electrical system which initiate disconnection of the power carrying components during a disturbance.

Control—the systems or components used to adjust, operate or maintain a desired output either manually or automatically and remotely or locally.

[5] EPRI, Palo Alto, CA, 1998, pgs. 5-6 to 5-7, *Hydropower Technology Round-up Report; Part 2: Rehabilitating and Upgrading Hydro Plants*

3
SCREENING

3.1 Introduction to Screening Process

The Protection & Control (P&C) screening procedure is a quick and easy process to evaluate whether modernization and/or life extension should be pursued. Through this process, the user can assess the potential for modernization and/or life extension of P&C 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 for P&C uses the following "indicators" to assess whether modernization and /or life extension should be considered:

Protection:

- age
- reliability
- maintainability of settings
- functionality
- completeness of protection coverage
- availability of spare parts

Control:

- age
- reliability
- functionality
- maintainability of settings
- location
- water management
- staffing
- availability of spare parts

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 Section 4 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 is set out in Volume 1, Section 3 of these Guidelines.

The screening in Volume 7 is complementary, but at a greater level of detail, to that contained in Volume 1, in that it considers each piece of equipment or component, as appropriate.

3.2 Protection Screening

Age, reliability, maintainability of settings, functionality, completeness of coverage and availability of spare parts of the existing protection equipment has a substantial role in evaluating plant modernization or life extension potential. For example, deterioration and unreliability of the protection equipment could be a reason to consider a modernization or life extension. Additionally, repair and replacement of older protection equipment is often difficult or impossible if the parts or instruments are no longer manufactured. Protection equipment that has deteriorated to the point where there are 2 or more inadvertent trips per year due to aging should be replaced and other similar aged equipment should be examined.

The screening Indicators are described in detail below.

3.2.1 Age as an Indicator

The age of the equipment is a major indicator of whether life extension or modernization may be required. Where the equipment is more than 10 years old it should be inspected and considered for replacement because mechanical relays, wiring insulation, etc., have a finite life.

Age as an Indicator for protection equipment at the screening level can be obtained from a variety of sources including:

- interviews with hydro plant maintenance staff as well as technical specialists
- review of data bases including original design documents or drawings

Age Indicators based on questioning:

- Is the equipment more than 10 years old?
- Are the protective relays electro-mechanical or induction disk types (not digital)?

If the answer to any of the above questions is YES, it identifies that the age of the protection components is a driver for life extension or modernization. It is important to note that indicators are a qualitative assessment of the age based on a review of existing and easily obtainable information. The results of screening questions are summarized in Table 3-1 and then used in Step 3.3 of the screening process in Volume 1

3.2.2 Reliability as an Indicator

Reliability as an Indicator for protection equipment at the screening level can be obtained from a number of sources including:

- operations records of outages for each unit and each component (i.e. how many outages/year were due to protection equipment malfunction on each unit).
- seriousness of outages/cost of outage in terms of lost energy and ancillary services (i.e. was there a lost opportunity cost due to the outage).
- number of forced or unplanned outages compared to planned outages for each piece of equipment.

Reliability Indicators based on questioning:

- Is the reliability now significantly decreased compared to the equipment's original reliability?
- Is the reliability now significantly lower than expected?
- Did any recent protection failures result in significant equipment repair or lost energy costs?

If the answer to one or more of the above questions is YES, it identifies that reliability is a driver for modernization or life extension. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available. The results of the screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.2.3 Maintainability of Protection Settings as an Indicator

Maintainability of Protection Settings as an Indicator for protection equipment at the screening level can be obtained from a number of sources including:

- number of times testing personnel have found settings drifted from desired.
- operations records of outages for each unit and each component (i.e. how many outages/year were due to protection equipment mis-operation on each unit).
- seriousness of outages/cost of outage in terms of lost energy and ancillary services (i.e. was there a lost opportunity cost due to the outage).
- number of forced or unplanned outages compared to planned outages for each piece of equipment.
- comparison of test records for equipment over a number of years.

Maintainability of Protection Settings Indicators based on questioning:

- Are the settings found to be significantly different each time the equipment is tested?
- Is readjustment, repair or replacement of components required.
- Does the protection operate because settings are not the same as what was left?

- Have there been trips that were caused by incorrect settings? Or conversely have there been failures to trip resulting in significant equipment repair costs?

If the answer to one or more of the above questions is YES, it identifies that Maintainability of Protection Settings is a driver for modernization or life extension. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available. The results of the screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.2.4 Functionality as an Indictor

Functionality as an Indictor for protection equipment at the screening level can be obtained from a number of sources such as:

- Physical inspection of the equipment
- Testing records can provide indication of reduced functionality

Functionality Indicators based on questioning:

- Is the functionality now significantly decreased compared to the equipment's original functionality?
- Is the equipment still in service?

If the answer to any of the above questions is YES, it identifies that Functionality is a driver for modernization or life extension. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available. The results of the screening are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.2.5 Completeness of Protection Coverage as an Indicator

Completeness of Protection Coverage as an Indicator for protection equipment at the screening level can be obtained from:

- Examination of drawings for standard protection coverage.
- Examination of operational records for evidence that a protection system did not prevent or minimize damage or barely prevented damage.

Completeness of Protection Coverage Indicators based on questioning:

- Has any part of the generator been damaged at any time by an unforeseen event?
- Is there only primary protection (no backup)?

If the answer to nay of the above questions is YES, it indicates that Completeness of Protection Coverage is a driver for modernization or life extension. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available.

The results of the screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.2.6 Spare Parts as an Indicator

The quantity and availability of spare parts for the Protection equipment is also a useful indication of life extension or modernization potential. A lack of spare parts can mean that reliability and availability will be compromised. Also, a lack of spares can prohibit life extension and force modernization. Indicators of Spare Parts for protection equipment at the screening level can be obtained from a number of sources including:

- number of spare parts on hand (from databases or stores records).
- availability of spare parts from manufacturer or supplier.

Availability of Spare Parts Indicators based on questioning:

- are there spare parts on hand for all aspects of the protection equipment?
- are spare parts still being made by the manufacturer?

If the answer to one or more of the above questions is NO, it identifies that availability of spare parts is a driver for modernization or life extension. Check a “YES” box in Table 3-1 if you answered a “NO” to any of the screening questions. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available. The results of the screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.3 Control Screening

Location, staff, age, reliability, functionality, maintainability of settings, water management and spare parts of the existing control equipment has a substantial role in evaluating plant modernization or life extension potential. For example, a plant with full time staffing could be a reason to consider modernization potential. Repair and replacement of older control equipment is often difficult or impossible if the parts or instruments are no longer manufactured. Water management issues can be reduced for a plant through the addition of automated control. In addition, company policy can dictate control system changes.

Screening Indicators for the Controls are described in detail below.

3.3.1 Age as an Indicator

The age of the equipment is a major indicator of whether life extension or modernization may be required. Where the equipment is more than 10 years old it should be inspected and considered for replacement because mechanical relays, wiring insulation, etc., have a finite life.

Age Indicators for Control equipment at the screening level can be obtained from a variety of sources including:

- interviews with hydro plant maintenance staff as well as technical specialists
- review of data bases including original design documents or drawings

Age Indicators based on questioning:

- Is it electronic based (not electro-mechanical) and greater than 10 years old?
- Is it electro-mechanical based (not digital) and greater than 20 years old?

If the answer to any of the above questions is YES, it identifies that the age of a piece of equipment is a driver for life extension or modernization. It is important to note that Indicators are a qualitative assessment of the age of equipment based on a review of existing and easily obtainable information. The results of the screening questions are summarized in Table 3-1 and then used in Step 3.3 of the screening process in Volume 1

3.3.2 Reliability as an Indicator

Reliability Indicators for Control equipment at the screening level can be obtained from a number of sources including:

- operations records of outages for each unit and each component (i.e. how many outages/year due to Control equipment on each unit).
- seriousness of outages/cost of outage in terms of lost energy and ancillary services (i.e. was there a lost opportunity cost due to the outage).
- number of forced or unplanned outages compared to planned outages for each piece of equipment.

Reliability Indicators based on questioning:

- Is the reliability now significantly decreased compared to the equipment's original reliability?
- Is the reliability now significantly lower than expected?

If the answer to one or more of the above questions is YES, it identifies that reliability is a driver for modernization or life extension. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available. The information for the specific equipment is summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.3.3 Functionality as an Indicator

Functionality as an Indicator for control equipment at the screening level can be obtained from a number of sources such as:

- Physical inspection of the equipment
- Testing records can provide indications of reduced functionality.

Functionality Indicators based on questioning:

- Is the functionality now significantly decreased compared to the equipment's original functionality?
- Is the equipment still in service?
- Is readjustment, repair or replacement of components required?

If the answer to any of the above questions is YES, it identifies that Functionality is a driver for modernization or life extension. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available. The results of the screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.3.4 Maintainability of Settings as an Indicator

Maintainability of settings Indicators for control equipment at the screening level can be obtained from a number of sources including:

- number of times testing personnel have found settings on timers drifted from desired.
- loss of smooth control of setpoints, e.g. stepper motors or potentiometers with blank or flat spots in their sweep range.
- operations records of outages for each unit and each component (i.e. how many outages/year due to protection equipment when not required on each unit).
- seriousness of outages/cost of outage in terms of lost energy and ancillary services (i.e. was there a lost opportunity cost due to the outage).
- number of forced or unplanned outages compared to planned outages for each piece of equipment.

Maintainability of Settings Indicators based on questioning:

- Are timer settings found to be significantly different each time the equipment is tested?
- Is the control of setpoints non linear or jumpy?
- Has there been a mis-synchronization due to drift in synchronizer settings?
- Are automated sequences failing due to poor timer accuracy?

If the answer to one or more of the above questions is YES, it identifies that Maintainability of Settings is a driver for modernization or life extension. It is important to note that Indicators are an assessment of performance, generally qualitative unless accurate records are readily available. The results of the screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.3.5 Location as an Indicator

Plant location relative to populated or industrial areas is a major factor in determining whether or not and to what degree a plant's controls should be modernized. The economic benefits of modern automation can offset the wasted time spent commuting. A power plant that is an integral part of an industrial complex could be manually controlled since the operator is also needed to perform duties not related to the power plant. However, local automation could allow the operator more time to perform industrial plant duties. For a remote power plant automation is a more attractive option.

Location Indicators for the plant at the screening level can be obtained from a variety of sources including:

- Review of topographical maps
- review of location data bases or civil plan drawings

Location Indicators based on questioning:

- Is the plant more than 1/2 hour driving time from the nearest town?
- Are any of the remote equipment: intake, spillway, valves, gates farther than 1/2 hour driving from the plant?

If the answer to any of the above questions is YES, it identifies that the age of a piece of equipment is a driver for life extension or modernization. It is important to note that Indicators are a qualitative assessment of the age of equipment based on a review of existing and easily obtainable information. The results of the screening questions are summarized in Table 3-1 and then used in Step 3.3 of the screening process in Volume 1.

3.3.6 Water management as an Indicator

Automating water management control can often increase plant generation by automatically operating the units to maximize generation for the existing head and flow conditions. Control automation can provide further improvements if operation includes water management or inter-tie agreements to sell and purchase capacity or generation. All power plants have certain operating limitations resulting from water availability, reservoir storage, and the generation requirements. The ability of a plant to respond to daily, weekly, and seasonal load curves, however, is dictated by the availability of water. Control automation can increase generation by optimally controlling these factors. Under manual operation, an operator is required to make unit selections and load changes in response to electric system requirements and the head and water available at the plant. In traditional plants, load changes were made in a stepped manner to make use of the available water. Ideally, to maximize generation, plant operation should follow an automated setpoint derived from a closed loop control and not be based on manual steps. Although it is theoretically possible to manually operate a plant to follow the desired changes in load, it may be too difficult for an operator to continue to respond to a constantly changing situation. However, an automated system can continually monitor and update the operating conditions to optimize generation and follow a changing setpoint

Water Management Indicators at the screening level can be obtained from a variety of sources including:

- Interviews with hydro plant maintenance staff as well as technical specialists.
- Review of data bases including original design documents or drawings.
- Review of legislated flow and fisheries requirements and compliance documents.

Water Management Indicators based on questioning:

- Is there potential for head or flow based control?
- Is there a potential requirement for inter-tie control?
- Could synch-condense operation be used to pass water rather than spilling or diverting?
- Has there ever been a fine or warning for violation of flow and/or fisheries requirements?

If the answer to any of the above questions is YES, it identifies that water management is a driver for life extension or modernization. It is important to note that Indicators are a qualitative assessment of water management based on a review of existing and easily obtainable information. The results of the screening questions are summarized in Table 3-1 and then used in Step 3.3 of the screening process in Volume 1

3.3.7 Staff as an Indicator

The number of personnel required to operate the plant can also be an economic advantage to plant modernization. The number of operators should be limited to the number of full-time equivalent operators and maintenance staff with responsibilities at the power plant, switchyard, and structures that are to be screened. For example, the operating personnel might also be responsible for activities at other hydropower stations or in stations combined with irrigation systems, an industry distribution network, or other supervisory jobs. In such cases, judgement may be required to determine the number of full—time equivalent operators.

Staff Indicators at the screening level can be obtained from a variety of sources including:

- review of employment records
- review of shift schedules

Staff Indicators based on questioning:

- are full time operators required after normal working hours?
- could the number of operation personnel be reduced with modern automated controls?

If the answer to any of the above questions is YES, it identifies that the Staff is a driver for life extension or modernization. It is important to note that Indicators are a qualitative assessment of the staffing levels based on a review of existing and easily obtainable information. The results of the screening questions are summarized in Table 3-1 and then used in Step 3.3 of the screening process in Volume 1

3.3.8 Spare Parts as an Indicator

The availability of spare parts for the control system and instruments is also a useful indication of life extension or modernization potential. Indicators of spare parts for control equipment at the screening level can be obtained from a number of sources including:

- number of spare parts on hand (from data bases or stores records).
- availability of spare parts from manufacturer or supplier.

Spare parts Indicators are based on questioning:

- are there spare parts on hand for all aspects of the control equipment?
- are spare parts still being made by the manufacturer?

If the answer to one or more of the above questions is YES, it identifies that spare parts is a driver for modernization or life extension. It is important to note that Indicators are a qualitative assessment unless accurate records are readily available. The results of the screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

3.4 Summary of Screening Indicators

Table 3-1 below should be filled in for the protection and control system. Plant protection is screened as a single component and the plant control system is screened as another component. If as a result of an affirmative screening, further assessment of the P&C system is required, the detailed assessment will look at each asset (as listed in the asset register) on an individual basis. If the answers to any of the Indicators from any P&C system result in a “Yes” than the user should review Section 3 in Volume 1 before proceeding to Section 4 of Volume 7.

Table 3-1
P&C Equipment Summary of Screening Indicators

Project: ______________________________
Equipment Name: ______________________________
Asset No.: ______________________________
Prepared by: ______________________________
Date: ______________________________

<table>
<tr>
<td>

Is Protection modernization/life extension Indicated by:

	Yes	No
- Age	❒	❒
- Reliability	❒	❒
- Maintainability of settings	❒	❒
- Functionality	❒	❒
- Completeness of protection coverage	❒	❒
- Spare Parts	❒	❒

</td>
<td>

Is Control modernization/life extension Indicated by:

	Yes	No
- Age	❒	❒
- Reliability	❒	❒
- Maintainability of settings	❒	❒
- Location	❒	❒
- Functionality	❒	❒
- Water management	❒	❒
- Staff	❒	❒
- Spare Parts	❒	❒

</td>
</tr>
<tr>
<td colspan="2">

If “Yes” answered to any of the above review Volume 1, Section 3 than proceed to Volume 7, Section 4.

</td>
</tr>
<tr>
<td>Comments:</td>
<td>Comments:</td>
</tr>
</table>

4
EVALUATION OF CONDITION AND PERFORMANCE

4.1 Introduction

Evaluation of plant condition and performance are key steps to successfully formulating a Life Extension and Modernization Plan (LEM Plan) as described in Volume 1, Section 4 of these guidelines. The evaluations discussed in this Volume 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. The Life Extension and Modernization process is iterative and life extension activities are identified in this first stage. 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 Section 7 of this volume).

Section 4 focuses on assessing the present condition and performance of the protection and control equipment, predicting 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 section 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. A periodic review of the overall process in Volume 7 is often useful. The following flowchart (Figure 4-1) describes how each of the sub-sections contributes to the identification of activities for the LEM Plan.

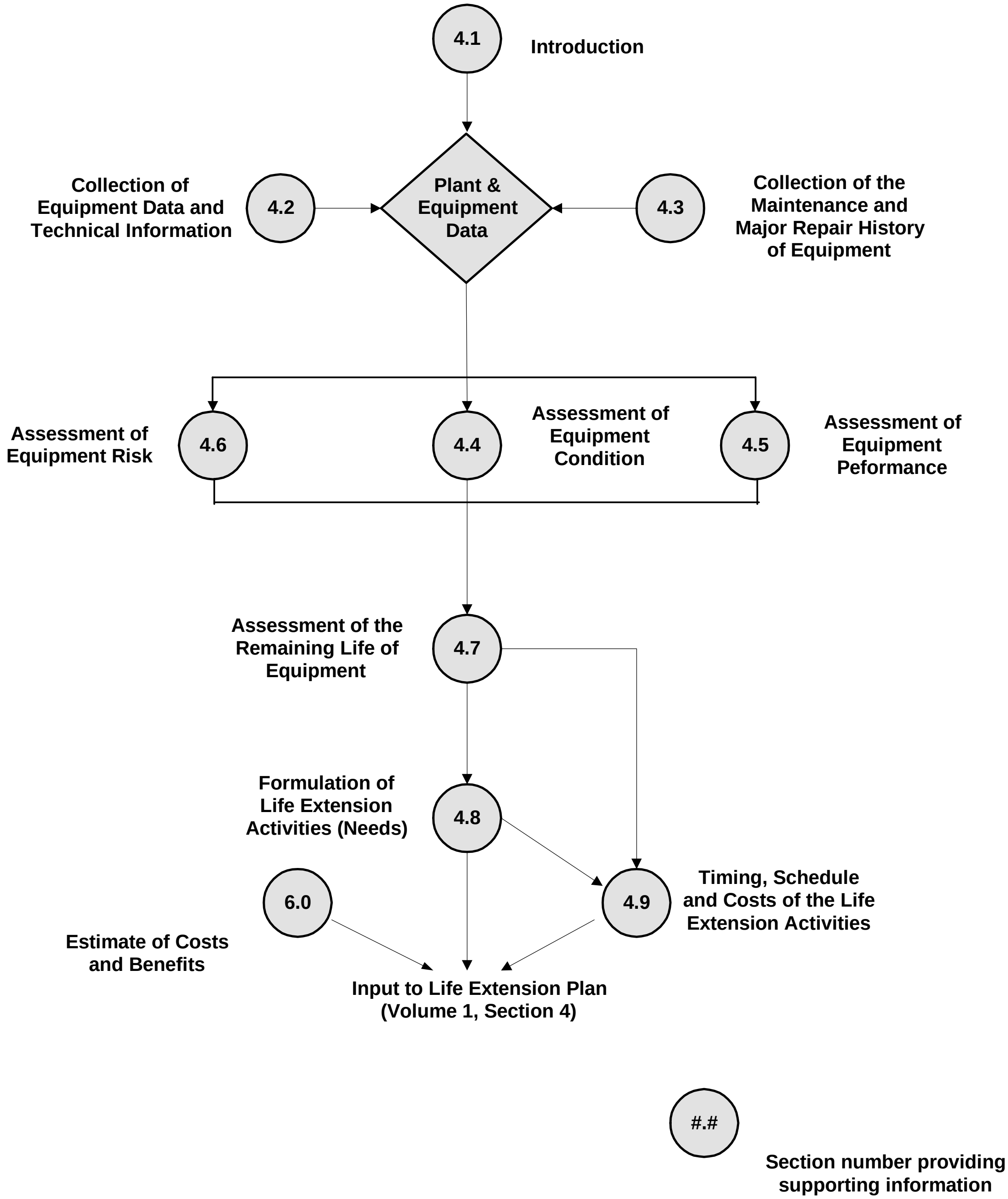

Figure 4-1
Input of Protection and Control Equipment Data to Life Extension Plan

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, Section 4.2) assembled for the plant, a worksheet is prepared for each piece of protection and control equipment. This ensures that all required information for the LEM Plan projects is obtained at the overview level.

This Section contains the technical information to assist in completing the worksheet. A similar table for modernization opportunities is completed using Section 5 of this Volume in particular.

Table 4-1
Equipment Condition Assessment Summary—Identification of Needs

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

<table>
<tr><td colspan="2">Equipment Data and Technical Information
(Section 4.2)</td><td colspan="2">History of Maintenance and Major Repairs
(Section 4.3)</td></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td colspan="2">Condition Assessment of Equipment
(Section 4.4)</td><td colspan="2">Performance and Operational Information
(Section 4.5)</td></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td colspan="2">Risk Evaluation
(Section 4.6)</td><td colspan="2">Assessment of Remaining Life
(Section 4.7)</td></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>Condition Rating (if available)
(Section 4.4)</td><td colspan="2">Maintainability Rating
(Table 4.4, Section 4.4)</td><td></td></tr>
<tr><td></td><td colspan="2"></td><td></td></tr>
<tr><td colspan="2">Possible Life Extension Activities
(Section 4.8)</td><td colspan="2">Timing and Costs of Life Extension Activities
(Section 4.9)</td></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
</table>

Volume 1 Table 4-2 lists the various types of assets normally evaluated when studying modernization opportunities in a hydro plant. The assets (numbered according to their asset register number) that are discussed in Volume 7 are:

- 1.1.6 Unit Protection and Control
  - 1.1.6.1 Unit Protection
  - 1.1.6.2 Unit Control
  - 1.1.6.3 Unit Alarm, Indication and Monitoring
  - 1.1.6.4 Synchronizing System
- 7.0 Control Room Equipment
  - 7.1 Control Room Protection and Control
  - 7.2 Control Room Alarm, Indication and Monitoring
  - 7.3 Control Room Communications

All other protection and control equipment is discussed in the volume that covers that particular asset. 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. The checklists provided in Sections 4.3, 4.4 and 4.5 provide a summary of the technical data and background information required to conduct a general condition assessment of the main protection and control equipment.

4.2 Equipment Data and Technical Information

<table>
<tr><td colspan="2">Equipment Data and Technical Information (Step 4-2, Volume 1)</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating(if available)</td><td colspan="2">Repairability Rating</td><td>Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

4.2.1 Desktop Review

In assessing the present condition or performance of the plant’s protection and control equipment, it is necessary to begin with the key technical data which describes the existing equipment. This technical data includes nameplate, original design, existing output, and equipment, data, records and reports. This information is input into Table 4-1 or directly into Table 4-3 and 4-4 of Volume 1, Section 4.2.

Design and performance data for protective relays are usually available in the procurement specifications and can be confirmed on commissioning test results and preventive maintenance test records. Design and performance data for controls is usually not available. Decisions regarding the performance of the control system must be made on experience. Are replacement components available, is the control system capable of doing what it was designed to do and is it usable (user-friendly)?

Typical sources of general plant data and equipment information are:

- Drawings (plant layout and protection and control)—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
- 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

4.2.2 Site Visit

The purpose of a site visit is to verify, where possible, all information obtained from the desktop 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.

Site personnel are often the greatest source of information, particularly when record keeping of equipment and plant operation changes is 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

- 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

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs (Step 4-3, Volume 1)</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
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<tr><td>Condition Rating (if available)</td><td colspan="2">Repairability Rating</td><td>Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

Table 4-2 is an equipment specific checklist of maintenance and repair work that can form part of an equipment's repair history. It should be used as a check that a complete maintenance and repair history for the equipment has been captured.

Table 4-2
Maintenance and Major Repair History of Protection and Control Equipment

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred?)
1.1.6.1	Unit Protection	Replacement of protective relays Rebuild of electro-mechanical or static relays Replacement of components in static/analog relays (e.g. electrolytic capacitors) Repair or replacement of trip target elements
1.1.6.2	Unit Control	Replacement of relays (e.g. MG by Releco) Timer replacement. (e.g. Agastat by Releco) Repair or replacement of selector switches (e.g. contact barrel on Electro-switch) Repair or replacement of plug-in relay socket Repair or replacement of printed circuit board connectors
1.1.6.3	Alarms Indication Monitoring	Troubleshooting of failure to annunciate Repair of chart recorders Repair or replacement of indicator lamps or assemblies Repair or replacement of temperature displays
1.1.6.4	Synchronizing System	Replacement of synchronizer Troubleshooting/repair of potential select circuit
7.1	Control Room Protection and Control	Repair of remote unit control components Trouble-shooting of failures to operate from remote location
7.2	Control Room Alarms Indication Monitoring	Problems with sequence of event recorder (e.g. contact oscillations filling buffers, slow updates) Repair or replacement of display components Repair of chart recorders
7.3 7.3.1	Communications SCADA (local)	Replacement of RTU processor or cards Repair or replacement of plant interface components

A review of the maintenance and repair history of the equipment and future plans 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 labor and budget?

4. Where is the equipment in its life cycle?

5. Has the level of maintenance been sufficient?

6. Has the maintenance been superficial in addressing the symptoms rather than the causes of high maintenance?

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?

4.4 Condition Assessment of Equipment

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment
(Step 4-3, Volume 1)</td><td colspan="2">Performance and Operational Information</td></tr>
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(Step 4-3, Volume 1)</td><td>Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

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. The condition of the critical protection and control components (noted in Table 4-3) may have deteriorated to such a degree that they are approaching the end of their useful lives, necessitating repair or replacement. Section Condition Assessment of Equipment discusses the critical protection and control components, methods to assess the 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.

Table 4-3
Condition Assessment of Equipment

Use the following assessment parameters in combination with information obtained from the maintenance and major repair history review. A table of criteria that can be used as a preliminary guide for the condition assessment is provided in Table 4-5.

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Life Extension Requirements

1.1.6.1.1
 	
Unit Protection
	Unit Protection (electrical protective relays)	• Type (relay numbers)
		• Age
		• Manufacturer
			• Level of protective coverage
			  • Reverse power
			  • Negative sequence
			  • Gov low oil pressure
			  • Gov accumulator low oil
			  • Vibration
			  • Split phase
			  • Inadvertent energization
			  • 'Out-of-sync' close
			  • Loss of Potential
			  • Loss of motoring power
			  • Cooling water fail
			  • Intake gate droop
			  • Fire protection
			  • Battery/charger undervoltage ground fault
			  • Incomplete start
			  • Overvoltage
			  • Generator differential
			  • Generator/Transformer differential
			  • Overfrequency
			  • Field ground
			  • Overspeed
			  • Generator impedance
			  • Breaker failure type
			  • Stator overtemperature
			  • Stator ground
			  • Creep detection
			  • Loss of field
			• Protection failures (failures to operate and erroneous operations)
				• Repair or replace defective components
				• Replace individual relay with similar or newer technology
				• Add discrete relay to provide specific coverage (e.g. negative sequence)
				• Repair or replace trip targets

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Life Extension Requirements
			• Annual maintenance/service ($/yr) • Obsolescence, parts availability • REMR Rating	
1.1.6.1.2	Unit Protection (non-electrical protective relays)	• Type (relay numbers) • Age • Manufacturer • Associated equipment (e.g. governor)	• See 1.1.6.1.1 above	See 1.1.6.1.1 above Replace non-electrical protective relays such as mechanical fly-ball overspeed detector
1.1.6.2	Unit Control	• Type (relay, PCB, PLC) • Age • Typical component manufacturers (relays, timers, control switches) • General observations	• Amount of burnishing on contacts • History of failed control operations • Annual maintenance/service ($/yr) • Obsolescence, parts availability • REMR Rating	• Repair or replace defective components • Interface with new or revised remote control systems
1.1.6.3	Alarm / Indication Monitoring	• Type of alarm matrix • Number of alarms per unit • Amount of ORing (or grouping) done in alarm matrix • Alarm functions available (individual acknowledge, reset, flashing, etc.) • List of unit data values available • Types of monitoring done (temperature, vibration, air gap, partial discharge) • Display types of monitored data • Availability of historical data (data logging)	• Usability of information (is operator getting alarms & data needed) • Extent of unnecessary callouts due to inadequate information • Annual maintenance/service ($/yr) • Obsolescence, parts availability • Metering accuracy • Coverage of metering • Metering of internal plant losses (Power Smart) • REMR Rating	• Expand alarm matrix • Add chart recorder or PLC for various values • Replace indication lamp type or assemblies • Add fault recorders • Add event recorders or PLC for data acquisition • Replace analog meters with high accuracy digital types • Provide historical trending
1.1.6.4	Synchronization System	• Type • Manufacturer • Age	• Number of failed synchronizations in past year • Annual maintenance/service ($/year) • Obsolescence, parts availability • REMR Rating	• Replace synchronizer • Add synchro-check relay
7.1	Control Room Protection and Control	Type (relay, PCB, PLC) Age Typical component manufacturers (relays, timers, control switches) General observations	• Amount of burnishing on contacts • History of failed control operations • Annual maintenance/service ($/yr) • Obsolescence, parts availability • REMR Rating	• Replace relays and timers with smaller footprint, lower VA types with equivalent contact ratings • Refurbish contact barrels on large control switches (like Electroswitch control switches) • Replace control switches • Interface with new or revised remote control systems

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Life Extension Requirements
7.2	Control Room Alarm Indication Monitoring	• Type of alarm matrix • Age of equipment • Manufacturer of equipment • Number of alarms per unit, for switchyard, stn service, spillways, control room • Amount of ORing (or grouping) done in alarm matrix • Alarm functions available (individual acknowledge, reset, flashing, etc.) • List of unit data values available • Types of monitoring done (temperature, vibration, air gap, partial discharge) • Display types of monitored data • Availability of historical data (data logging)	• Usability of information (is operator getting alarms & data needed) • Scalability (can more points be monitored, both discrete and analog) • Number of unnecessary callouts due to inadequate information • Annual maintenance/service ($/yr) • Obsolescence, parts availability • REMR Rating	• Expand alarm matrix • Add chart recording of various values • Replace indication lamp types or assemblies • Replace chart recorders • Historical trending
7.3	Control Room Communication	• Hardware protocol • Software protocol • Age	• Adequate data update times • Annual maintenance/service ($/yr) • Obsolescence (are devices still being manufactured that use this network) • Scalability (can more points be added) • REMR Rating	• None
7.3.1	SCADA (local)	• Type • Manufacturer • Age	• Usability of information (is remote operator getting alarms & data needed) • Number of unnecessary callouts due to inadequate information • Adequate data update times • Annual maintenance/service ($/yr) • Obsolescence, parts availability • REMR Rating	• None

4.4.1 Methodology

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.

Table 4-3 of this Volume, provides the summary of the technical data requirements, typical assessment parameters and common life extension activities for each type of protection and control equipment. The supporting text of Section 4.4 provides detailed information on the items covered in Table 4-3. Table 4-4 provides a rating system for the assessment of equipment reparability.

Table 4-5 provides typical values of some condition assessment parameters. 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 4-5, further investigation of equipment condition and performance is advised.

Plant operational data is also important background information for assessing equipment condition. Assessment of Condition (Section 4.4) and Performance (Section 4.5) are usually done in parallel. An example of how to use Table 4-3, Table 4-4 and Table 4-5 for the condition assessment of the control room alarms (asset number 7.2) is provided.

Table 4-4
Equipment Reparability Rating System

Maintainability	Repair Characteristics
Good	• Technical complexity: Easy • 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 labor 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 labor 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 labor 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 (example: stainless steel runners must be removed for heat treatment).
Not repairable	• Technical complexity: For technical reasons, equipment cannot be repaired. • Replacement parts: Not available (obsolete) and cannot be made. • Deficiencies: Deficiencies cannot be solved or mitigated.

Table 4-5
Suggested Guidelines for Assessing the Condition of Critical Protection and Control Components

Component	Condition	Criteria
Protective Relays	Failure to trip at setpoint	>1.5–3% error on tested trip time* >1.5–3% error on tested pickup value*
	Failure to operate	>0 failures
	Erroneous Operation	>0 erroneous operations
Controls	Reliability	<95% availability (due to failures and troubleshooting/repair times)
Alarms	Callouts	>10% of callouts can be eliminated if more accurate (non-grouped) alarm information provided
Indication/Monitoring	Callouts, operator incorrect actions	Any additional information that, if provided to the operator, would result in less callouts, confusion or incorrect operator responses
Synchronizer	Reliability	>1 failed synchronization per annum >30 seconds to synchronize
Communications	Reliability	>0 communication errors resulting in unit downtime

*Allowable error depends on function of relay and relay coordination with other devices.

The above table should be used as a guide only. It is not a definitive list of assessment criteria but rather suggests some basic conditions and criteria to be taken into account.

4.4.2 Example

The following are the general steps for using Table 4-3, Table 4-4 and Table 4-5 in the condition assessment of control room alarms.

1. Refer to Table 4-3. Look under 7.2, the asset number for control room alarms.

(a) Collect the following information and data on the control room alarms as identified in Table 4-3.

- Type of alarm matrix
- Age of equipment
- Manufacturer
- Number of alarms per unit, switchyard, station service, spillway, control room, etc.
- Amount of ORing (or grouping) done in alarm matrix
- Alarm functions available (individual acknowledge, reset, flashing, etc.)

– Types of data available from units (temperatures, frequency, MW, MVAR, vibration, etc.)

– Indicate if any data trending is available

(b) Review relevant unit performance information as outlined in Section 4.5 as a background for the condition assessment.

(c) Interview site maintenance and operations personnel and possibly review past operational records to obtain information on the following assessment parameters identified in Table 4-3 (Asset Number 7.2):

– Usability of information (is operator getting alarms & data needed?)

– Scalability (can more points be monitored, both discrete and analog?)

– Number of unnecessary callouts due to inadequate information

– Annual maintenance/service ($/yr)

– Obsolescence, parts availability

2. Refer to Table 4-5. Compare the data obtained in Step 2(c) above for the condition assessment parameters with the criteria in Table 4-5 for:

– >10% of callouts can be eliminated if more accurate (non-grouped) alarm information provided

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).

3. Refer to Table 4-3. Based on the condition assessment of the control room alarms/monitoring and indication, life extension alternatives should be considered. Table 4-3 provides an overview level summary of the options available. The text of Section 4-8 “Life Extension Activities” provides more specific details.

   Life extension options for the control room alarms, as for most P&C equipment, are extremely limited. The most that can be done to extend the usefulness of the control room alarms is to perhaps expand the alarm matrix to reduce the number of grouped alarms. If failures are the problem, then replacing the lamp assemblies with a different type may also be an option.

4. Refer to Table 4-4. Assess the reparability of the control room alarms.

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

4.4.3 Condition Rating System

The evaluation of equipment condition (its wear and deterioration) is, in part, a subjective evaluation based on experience. A condition rating system is usually developed to help provide an objective means of evaluating equipment condition. 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.

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.[6] 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 4-4 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 protection and control equipment are provided in Appendix D to assist with the collection of condition assessment data. The complete REMR guidelines can be obtained from the US Army Corps of Engineers if desired. The Corps is planning to update the REMR guidelines in the Year 2000.

The use of REMR gives a snapshot look and a standardized evaluation of a plant. Many companies and utilities have their own “in-house” condition rating systems which can be used in lieu of REMR.

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

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[6] US Army Corps of Engineers, March 1993, *“The Repair, Evaluation, Maintenance and Research Program (REMR)”*

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 protection and control 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 unit protection, 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 reparability 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 reparability is often required to complement the condition rating index. Table 4-4 provides a preliminary reparability rating system.

4.4.4 Further Physical Condition Assessment Information for Protection and Control Equipment

There are a number of physical condition indicators that can be considered for P&C devices in addition to that listed in Table 4-3. Some suggested points are:

- Wires and cables. Are the conductors corroded or discolored, is the insulation brittle, cracked or discolored?
- Relay contacts and annunciator bulb bases. Is there discoloration or signs of carbonization or arcing, are the contacts cracked or missing?
- Lookout relays. Are the springs weak? Do the shafts bind preventing complete operation?
- Auxiliary and protection relay coils. Is there discoloration due to excessive internal heating?
- Pneumatic timer relays. Are the bellows cracked or hard?
- Meters. Are the needles reading realistic quantities and not pinned on zero or full scale, are the scales still readable?
- Terminal blocks and termination points. Is there corrosion or discoloration due to heating or arcing, are screws still operable?
- Barriers between connection points on devices. Is there evidence of flashovers? Are barriers missing or cracked?

The above is by no means a definitive list. It is provided to assist in assessing physical condition. In the case of some components, e.g. auxiliary relays, it may not be prudent to inspect every single one, however, a random sampling should give an indication of general condition (as long as all are of the same manufacturer and vintage).

The condition assessment cannot be accomplished by looking for physical signs alone but rather must be augmented by historical operational data and actual testing as outlined in the REMR and in Table 4-3.

4.5 Performance and Operational Information (Records)

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information (Step 4-2, Volume 1)</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating(if available)</td><td colspan="2">Reparability Rating</td><td>Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

An examination of performance and operational information records should reveal any unusual circumstances encountered during the service life of the protection and control systems. Operating data should be interpreted very carefully as anomalies in data and data recording practices can lead to wrong conclusions.

4.5.1 Protection

"Because protective relaying is so important to the reliable operation of electric power systems, many utilities have taken considerable trouble to collect and maintain records of how those relays perform. Important performance indicators include security, dependability and availability ..."[7] Consistency in recording and calculating these performance indicators is necessary for proper evaluation of protection system performance. The following approach suggested by E. Udren at ABB Relay Division[8] provides a consistent method of calculation. (Utilities may already have their own standardized calculation methods).

The following equations specifically refer to line protection but can be of great value if modified to apply to generator protection zones.

Availability

$$Availability = \frac{Time\_relaying\_is\_operational}{Total\_evaluation\_time} \times 100\%$$
$$= \left(1 - \frac{Total\_of\_downtime}{Evaluation\_time}\right) \times 100\%$$

[7] "Statistical Performance Measures for Protective Relays", E. Udren, ABB Relay Division, 1996

[8] "Statistical Performance Measures for Protective Relays", E. Udren, ABB Relay Division, 1996

The recommended evaluation period is one year.

Dependability

$$Dependability = \frac{Number\_of\_correct\_trips}{Faults\_in\_primary\_zone} \times 100\,\%$$
$$= \left(1 - \frac{Number\_of\_failures\_to\_trip}{Faults\_in\_primary\_zone}\right) \times 100\,\%$$

Security

$$Security = \frac{Number\_of\_correct\_restraints}{Number\_of\_exposures} \times 100\%$$
$$= \left(1 - \frac{Number\_of\_incorrect\_operations}{Number\_of\_exposures}\right) \times 100\%$$

Where “Exposure” is defined as a specific opportunity for false tripping of the relay. There are four exposure criteria. The first two criteria refer to faults which are nearby, yet are external to the protected zone.

- Faults in any non-line protective zone directly adjacent to the protected line, in the station at either end
- Faults on line sections or other apparatus zones connected at the local or remote substations, at the same voltage level

The final two exposure criteria refer to events within the relay itself:

- False trip of relay system for any external fault beyond the marked zones, or for any non-fault circumstance
- Relay hardware component failures which occur without producing an undesirable trip output. (The false trips must also be counted as exposures, even if there was no fault in the marked exposure zone. Hardware failures are also counted, since each such failure presents an opportunity for the relay to false trip. A relay design which avoids tripping for internal failures is thus correctly evaluated as having higher security than one which trips because of the failures.”)[9]

Mis-operation Count

Examine alarm and protection event logs from the plant’s maintenance system database. Look in the operational data for mis-operations due to unknown sources or relay malfunction. See Table 4-6 below.

[9] “Statistical Performance Measures for Protective Relays”, E. Udren, ABB Relay Division, 1996

Table 4-6
Example of Protection Operational Information from a Hydro Plant

History of Split Phase (87SP) Operations

Unit	Date	Flag	Cause of Trip	Mis-Ops	Legit Trip
G4	30/4/98	87SPA-1,T 87SPB-1,T 87SPC-1,T 86G	A visual inspection indicated that the field poles had been damaged since the previous KO. There were some field windings damaged.		√
G4	28/4/98	87SPC-T and other targets	Suspect the split phase operated due to air gap distortion caused by a MW lower command		√
G2	20/3/96	87SPB 87SPC	HK-3, 87SP operated due to vibration. Relay very sensitive	√	
G2	13/6/96	87SPB	Fault field pole.		√
G2	26/3/96	87SPB	Relay very sensitive to vibration. Roofers fixing roof caused vibration.	√	
G2	20/3/96	87SPB	Vibration causes the HK-3 relay to operate.	√	
G2	7/2/96	87SPC	HK-3 relay defective. Very sensitive to vibration. Mis-operation again.	√	
G1	6/3/95	87SP, 87B, 87C, 51VB	Pin and cap insulators on T1 HV side failed.	√	
G6	2/2/95	87SPA 87SPB 87SPC 86-1	Poor synchronization control resulted in high currents and SP operation.		√

Further performance indicators such as responses, Mean Time Between Failures (MTBF), Mean Time to Repair (MTTR), diagnosis of non-relay hardware failures and software failures are also defined in the article by E. Udren of ABB Relaying Division.[10] The article goes on to describe techniques of mapping exposures to facilitate ongoing and automated calculation of security and dependability and is beyond the scope of this volume.

4.5.2 Controls

Measuring or determining performance of control systems is often more difficult than that for protective relaying systems. Rarely are there any hard specifications for control system performance against which to compare actual performance. The best measure of a control system's performance is to look at a list of its capabilities or functions and to determine whether or not they are being met.

[10] "Statistical Performance Measures for Protective Relays", E. Udren, ABB Relay Division, 1996

Suggested functions to check:

Start up and unit synchronizing—The start up sequence might not be repeatable or automatic, generator may over speed, may not synchronize consistently and/or may trip on incomplete sequence (48) due to failed synchronization.

Stopping—Unit might not come to a full stop, operator intervention may be required for the stopping sequence, or the generator may take too long to stop. Bearing lubrication pumps may run for an excessive amount of time due to inadequate sensing of generator zero speed.

Loading & Unloading—Generator MW control may not be accurate or fine enough, may also be “sticky” or un-responsive.

Synchronous Condense (SC)—Switching in and out of SC may not always be bump-less or even possible. In some cases unit may be tripped off line which requires a stop and re-start.

Joint VAR Control (JVC)—JVC may not provide adequate VAR response, generators might be fighting each other.

Automatic Generator Control (AGC)—Generators under AGC may not respond together with sufficient response characteristics and may actually fight each other.

4.6 Risk

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
<tr><td colspan="2">Risk Evaluation
(Step 4-4, Table 4-4, Volume 1)</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating (if available)</td><td colspan="2">Repairability Rating</td><td>Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

The identification of risks, that the hydro plant is exposed to and which relate to life extension and modernization, is an integral part of the Plant Survey process. As discussed in Sections 2.3.2 and 4.4 of Volume 1, risks fall under three broad categories:

- Business critical risks, which relate to the consequences of catastrophic events.
- Life safety risks, which threaten workers and/or public.
- Financial risk, which relate to equipment failures and mis-operation.

The risk identification process is set out in Section 4.4, Volume 1. In essence, a reasoned, systematic approach is necessary to ensure that all risks are identified. Various standard methods exist to assist the user in risk identification. These include:

- Failure Modes and Effects Analysis (FMEA)
- Failure Modes, Effects and Criticality Analysis (FMECA)
- Hazard and Operability Study (HAZOP)
- Fault Tree Analysis (FTA)
- Event Tree Analysis (ETA)

FMEA

IEC Standard 300-3-9 describes FMEA as:

"… a technique, primarily qualitative although it can be quantified, by which the effect or consequence of individual component fault modes are systematically identified. It is an inductive technique which is based on the question "what happens if …?". The essential feature in any FMEA is the consideration of each major part/component of the system, how it becomes faulty (the fault mode), and what the effect of the fault mode on the system would be (the fault mode effect). Usually, the analysis is descriptive and is organized by creating a table or worksheet for the information. As such, FMEA clearly relates component fault modes, their causative factors and effects on the system, and presents them in an easily readable format."

FMECA

FMECA is an extended form of FMEA where each failure mode identified is ranked according to the combined influence of its probability of occurrence and severity of its consequences.

Further details on both FMEA and FMECA can be found in IEC Standard 812.

HAZOP

IEC Standard 300-3-9 describes HAZOP as:

"… a form of fault modes and effects analysis (FMEA). HAZOP studies were originally developed for the chemical industry. It is a systematic technique for identifying hazards and operability problems throughout an entire facility. It is particularly useful in identifying unforeseen hazards designed into facilities due to lack of information, or introduced into existing facilities due to changes in process conditions or operating procedures. The basic objectives of the techniques are:

- to produce a full description of the facility or process, including the intended design conditions;
- to review systematically every part of the facility or process to discover how deviations from the intention of the design can occur; and
- to decide whether these deviations can lead to hazards or operability problems."

FTA

IEC Standard 300-3-9 describes FTA as:

"… a technique, which can be either qualitative or quantitative, by which conditions and factors that can contribute to a specified undesired event (called the top event) are deductively identified, organized in a logical manner and represented pictorially. The faults identified in the tree can be events that are associated with component hardware failures, human errors or any other pertinent events which lead to the undesired event. Starting with the top event, the possible causes or fault modes of the next lower functional system level are identified. Following stepwise identification of undesirable system operation to successively lower system levels will lead to the desired system level, which is usually the component fault mode."

ETA

IEC Standard 300-3-9 describes ETA as:

"… a technique, either qualitative or quantitative, which is used to identify the possible outcomes and if required, their probabilities, given the occurrence of an initiating event. ETA is widely used for facilities provided with engineered accident mitigating features, to identify the sequence of events which lead to the occurrence of specified consequences, following the occurrence of the initiating event. It is generally assumed that each event in the sequence is either a success or a failure."

At the completion of the risk identification process the user can determine, in accordance with the owner's risk tolerance standard what risks require mitigation and the cost of mitigation. The projects associated with mitigation can then be identified for inclusion in the summary of the Needs and Opportunities tables in Volume 1 (Tables 4-6 and 4-7 respectively).

Table 4-5 of Volume 1 is used to capture the results of the risk identification process.

4.7 Assessment of Remaining Life

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life
(Step 4-8, Volume 1)</td></tr>
<tr><td>Condition Rating (if available)</td><td colspan="2">Reparability Rating</td><td>Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

Protection and control components become technically obsolete long before they are at risk of failing. In assessing the remaining life, the engineer must blend a desire to have the latest "bells and whistles" with the plant's actual needs.

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. 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 Canada, U.S. and abroad, have undertaken "remaining life" studies for hydro power equipment over the last couple of years. 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 4-7 lists typical life expectancies for protective relays and control components 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 4-7
Life of Hydropower Plant Systems

Life of Hydropower Plant Systems		
Plant Systems	**Economic Life (years)***	**Considerations which Affect Component Life**
Protection		
Electro-mechanical	40	Operating environment (temperature, cleanliness, technical obsolescence)
Mechanical	40	
Static/analog	20**	
Digital	15–25	
Control		
Relays	25	Operating environment (temperature, cleanliness)
Control Switches	30	
Timers	15–25	
Overloads	15	
Meters	40	
Lamps	5	
Analog circuits	20	

*Economic life is a blend of technical obsolescence, lack of replacement parts, and actual failures. For equipment that requires programming, other factors such as outdated operating systems, non-compatible hardware, lost programming cables or software, etc., also affect the economic life.

**Any systems that use electrolytic capacitors with borax solution substrate, can expect 15–25 years of life (max.) since as these capacitors age, they dry out and their value changes causing unexpected results.

4.7.1 Protection

The expected life cycle of non-electrical protective relays depends on the relay's function. Gas relays, for example, have bellows for sensing gas pressure fluctuations. These bellows deteriorate and crack with age and external factors such as temperature and humidity. Bulb capillary type relays are prone to premature capillary leakage or damage. Static/analog relays are susceptible to component drift in their measurement and comparator circuits resulting in pickup point and time delay inaccuracies.

In general, the expected life cycle for protection relays is typically 40 years. Many factors, however, contribute to lower life cycles. These factors are:

- Abnormally high coil operational voltage,
- High operating temperature,
- Excessive current across the contacts,
- Excessive operations.

Operating quantities over the manufacturer's specifications are deemed "excessive".

4.7.2 Controls

Relay based control systems including relay timers are subject to similar limitations as protection relays. The expected life cycle for an electro-mechanical relay is typically 25 years, however, many factors contribute to lower life cycles including:

- Abnormally high coil operational voltage,
- High operating temperature,
- Excessive current across the contacts,
- Excessive operations.

Operating quantities over the manufacturer's specifications are deemed "excessive".

Printed Circuit Board (PCB) based controls are subject to a limited life cycle as well, and 15–25 years is not uncommon. This is due to factors such as:

- Ratings of electrolytic capacitors changing when the borax solution inside the capacitor dries up. This is due to normal circuit heating over long periods of time,
- Oxidization of solder connections causing poor connections,
- Oxidization of PCBs with tin edge contacts (rather than gold),
- Failures of transistor internal P and N junctions due to age.

PLC (programmable logic controller) processors typically have a mean time between failure (MTBF) of >25 years; however, the input/output cards (I/O) have a MTBF of approximately >15 years. This lower MTBF for the I/O is due, in part, to relay output cards, but where solid state inputs and outputs are used the MTBF approaches the same as that of the processors. The time to a PLC's technical obsolescence is much less than it's time to physical obsolescence. PLC manufacturers are constantly changing and upgrading their product. Long-term support of legacy systems (first generation, technically outdated) becomes the most important issue in assessing life cycle. What is the manufacturer's track record in supporting discontinued product lines? Can I/O cards still be purchased?

Most legacy distributed control systems are rapidly becoming technically obsolete and prohibitively costly to maintain. Perhaps most importantly, proprietary Distributed Control Systems (DCSs) lack the extended system functionality and multivendor interoperability that today's enterprises require to stay competitive.[11]

[11] http://www.foxboro.com/news/Fisher_Dcs.htm

4.8 Life Extension Activities

Equipment Data and Technical Information		History of Maintenance and Major Repairs
Condition Assessment of Equipment		Performance and Operational Information
Risk Evaluation		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

The scope of protection and control projects for a Life Extension and Modernization (LEM) Plan range from the rehabilitation of relays to full-scale control upgrades. Table 4-3 in Section 4-9 (Condition Assessment of Equipment) provides a list of common life extension activities for each type of equipment.

Generally once protection and control components start failing on a regular basis, life extension activities become extremely limited and impractical.

The decision to replace one piece of equipment may affect the scheduling of other life extension activities.

eg.: If a meter is replaced with one incorporating advanced recording features then other planned life extension activities such as chart recorder replacement may be reduced in scope or eliminated altogether.

4.8.1 Protection

Unlike mechanical equipment such as runners that can be welded and re-ground in order to extend life, protection components do not have many options available to extend their life expectancy. Obsolescence of protection components, occurring usually 20 to 25 years after installation, creates a shortage of available spare parts forcing protection engineers to consider:

- Customized manufacturing of parts,
- Dismantling of existing facilities for spares,
- Replacing with modern facilities.

Factors such as drift of settings due to internal components changing value as the equipment ages can be handled with increased testing and calibration. This extra maintenance requires skilled manpower to test, identify and repair the internal workings of the equipment.

If only one type of relay is experiencing problems, then that relay can be replaced. The owner should, however, keep in mind the possibility of replacing the relay with a new version capable of over lapping other existing relay functions. This long-term vision ensures that as other relays fail those functions could be moved into the new relay already installed.

4.8.2 Controls

Control system life can usually be extended by regular preventive maintenance and testing. Relay contact surfaces can be checked, operation confirmed, timer values checked and if faulty relays are suspected, they can be removed and replaced one at a time. In BC Hydro for example, new electronic timing cubes replaced timer relays that incorporated air filled bellows as the timing source. The bellows were found to be cracking and since no replacement parts were available, the only option was replacement. Printed circuit type controls can be maintained by performing component replacements as required. This approach is considered to be condition-based maintenance and relies on suitable replacement parts and adequate maintenance staff troubleshooting expertise. This type of maintenance is prohibitively expensive which can be a motivating factor for modernization.

Life extension to alarm indicating annunciator systems can be handled by installing lower wattage bulbs but usually a failure or lack of expandability will warrant complete replacement. The replacement annunciator can be a small PLC and HMI which can be integrated into an advanced control system down the road.

For metering, there are no definitive life extension activities that can be performed. Once a meter coil or movement fails, replacement is required.

4.9 Timing, Schedule and Costs of Activities

Equipment Data and Technical Information		History of Maintenance and Major Repairs
Condition Assessment of Equipment		Performance and Operational Information
Risk Evaluation		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 Lead Times

Equipment lead time for large, complex or project specific equipment is an important factor in scheduling activities for the LEM Plan.

4.9.2.1 Protection

Approximate procurement lead times of protective relays are given below. These exclude planning, bidding and contract negotiations.

Single function digital relay	4 weeks
Multifunction generator protective relay	6 weeks

Note: Delivery times are based on North American, best case times

4.9.2.2 Controls

Approximate procurement lead times of control system components are given below. These time estimates exclude planning, bidding and contract negotiations.

PLC processors	1 week
Digital I/O cards—non-time stamping	1 week
Digital I/O cards—time stamping	3 weeks
Analog I/O cards	1 week
RTD input cards	1 week
Thermocouple input cards	1 week
Vibration monitoring cards	4 weeks
PLC hardware (chassis, power supplies, etc.)	1 week
Network cable, unarmored	1 week
Network cable, armored	1 week
MMI software	1 week
MMI hardware	1 week
Line synchronization cards	2 weeks
Synchronizers—standalone	3 weeks
Partial Discharge Monitoring System	6–8 weeks
Air Gap Monitoring System	8–10 weeks

4.9.3 Assigning Costs

Section 6.3 provides information on the costs and benefits of life extension activities.

4.10 Input to Life Extension Plan (Section 4, Volume 1)

The condition information collected using the technical data of this Volume is needed to develop a list of life extension activities for the plant protection and control equipment. These activities and cost estimates are entered in Table 4-3, 4-4 and 4-5 of Volume 1, Section 4 as the "seed data" for a life extension plan for the plant. This collated information is one part of the data that populates the economic/financial model (Section 4, Volume 1) used to evaluate the impact of life extension projects on station profitability and cash flow.

Refinement of the life extension plan is an interactive and ongoing process. As the projects proceed to feasibility stage, costs are refined. Some initial results from the model may indicate which projects have the largest affect on plant economics in the near future. The timing of these projects may need to be optimized based on the initial cash flow estimates from the model.

The essential purpose of Section 4 was to identify those technical projects that must be planned in order to extend the life of the plant. How these projects are scheduled and funded involves collaboration between the financial planners and the engineers so that optimal project scopes can be defined for the identified life extension activities.

5
POTENTIAL FOR IMPROVEMENTS

5.1 Introduction

Section 4 of this Volume outlines a methodology to assess the present condition and performance of the plant 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 upgrade opportunities that are available for protection and control equipment to significantly improve plant performance beyond historical levels.

During the condition assessment of the plant, the Condition Assessment Engineer (CA Engineer) is initially assessing the life extension requirements of equipment. 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 (this term and its synonyms are defined in Section 2). Upgrading of one piece of equipment often has an implication on other plant equipment and the desired benefits may not be realized because of other plant limitations.

Section 5 provides the tools and information to identify opportunities for modernization for the LEM plan. Protection and Control improvements can be made in two main areas:

- Plant condition
- Plant operation

More detailed analysis is required at the feasibility level (Section 7) before any modernization activities should be implemented.

The pro forma "Equipment Modernization Opportunities" worksheet (Table 5-1) is provided for recording modernization opportunities during the condition assessment process outlined in Section 4. All opportunities identified should be included on the worksheets and then included in Tables 4-3 "Data Analysis for Hydro Plant" and 4-4 "Data Analysis and Inspection Results for Equipment and Structures" of Section 4 of Volume 1 of these guidelines. This process is outlined in the figure below.

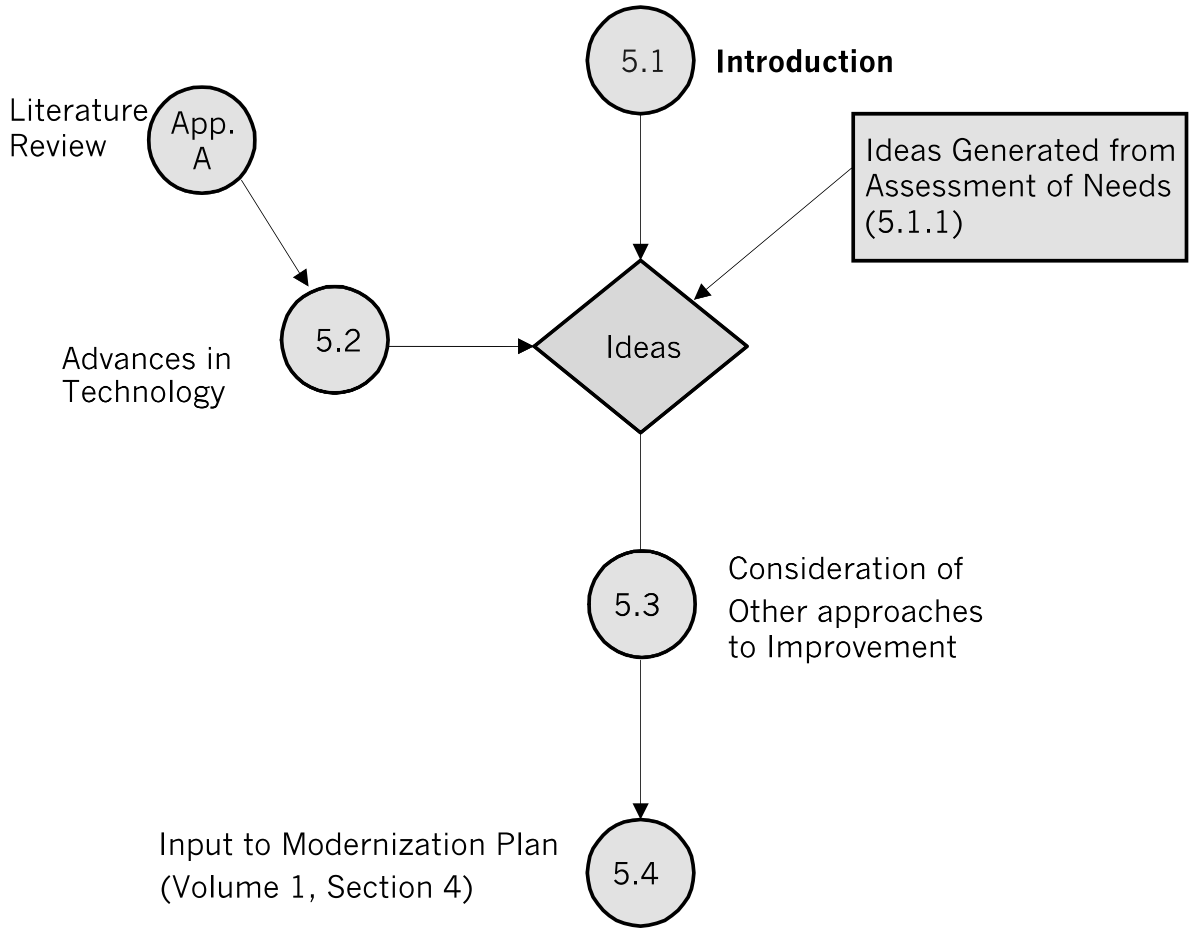

Figure 5-1
Potential for Improvements Process.

Table 5-1
Equipment Modernization Opportunities

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

Modernization Opportunities (Section 5.2)	**Benefits of Modernization** (Section 5.2)
	Equipment:
Further Studies Required (Section 7)	
	Overall Plant:
Impacts of Modernization on Other Equipment	**Other Equipment that Limits Modernization**
Timing & Costs of Modernization (Section 4.9 and Section 6.0)	**Risk Evaluation of Modernization** (Section 4.6)
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

At the initial stage of assessment (i.e. in Section 4 of this volume), 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. The forms at this stage are to ensure that all possible activities are at least identified for consideration and none are deleted off the list too early in the process based only on an impression that the project would be uneconomic. Completing each worksheet, however, should trigger thoughts on the magnitude of the modernization opportunity as well as its impact on plant products and the inter-relationship between modernization activities proposed for different equipment items.

The assessment of the relevancy and appropriateness made during the formulation of Table 4-6 of Volume 1 is not intended to be a thorough analysis, merely a “sensibility” test. A thorough analysis will be conducted during the feasibility stage in Stage 7 of Volume 1 (with information from Section 7 of this volume) if the identified opportunity is included in the selected LEM Plan and taken forward for further consideration.

5.1.2 Possible Improvements to P&C

The reasons for modernizing the protection and control systems in a plant differ from plant to plant, however, the focus tends to be the same. There is a need to replace obsolete or unreliable equipment, provide remote control where none was before, improve operations by better monitoring and control, provide remote access to fault and event data, reduce maintenance costs and add features to increase profits. For example, a generator which has a manual start-up /shutdown sequence, might gain from adding synchronous condenser operation. Instead of running the unit at speed-no-load at times of low demand and in effect, “wasting water”, the unit could be generating VAR’s adding voltage support to the local system. Another example of a fully automated plant is being able to remotely start/stop generator(s) as required, raise/lower ouput on demand and automatically log and clear alarms. Adding better monitoring to a generator allows the operator to reduce risk by intervening before failures and also increases profits by allowing the generator to be run closer to limitations.

The user/owner of a fully manual plant should look seriously at what is required in upgrading the protection and control. Upgrading the protection and control systems usually includes automation, however, it may also require upgrading of a host of ancillary equipment and sub systems. Manually controlled devices and equipment may require upgrading in order to be automatically controlled. Cooling water valves may need actuators installed, excitation and governor systems may require modification to include external setpoint controls and position feedback, etc. Upgrading and automating of these others systems is outside of the scope of Volume 7, but is covered in the Volumes 2–6.

Thought should also be given to including remote control. Although remote control is not covered here (or at least remote control capability), it should be included in a plant wide upgrade. Many of today’s automated protection and control schemes easily integrate remote control and as such it should be included in the design from the outset. To fully automate the Protection and Control systems of a plant only to add remote control at a later date is not the best engineering solution. Much work would be duplicated and time wasted.

Table 5-2 below summarizes reasons for improving P&C and the activities required to achieve the improvements. The biggest potential for improvements is the ability to add features that increase profitability while at the same time do not incur a lot of extra costs to implement. In many cases, the transition to a PLC based control system installs the foundation for many of the features listed below.

Table 5-2
Summary of Modernization Opportunities for P&C Equipment.

Areas of Opportunity	Activities to Achieve Opportunities
1. 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	Activities or measures to improve condition, operation and reliability: • Use digital relays, networked to automatically report self diagnostic test failures and other fault and event data • Use PLC based control systems to eliminate electromechanical means of control such as timers, multi-contact selector switches, relays, etc.
2. Flexibility Improve flexible operation for the plant as a whole (e.g. load factoring, swing, automatic generator control [AGC], joint Var control [JVC])	Implement through networked unit controllers and a plant controller (PLC): • Joint VAR Control (JVC) • Automatic Generator Control (AGC) • Upstream water level, downstream water level, river flow control • Plant load sharing • Generation/ Load Shedding Matrix Other activities to increase flexibility: • Replace lamps and indicators with HMIs that have almost “unlimited” display capacity
3. Profitability (a) Improve output, dependability and flexibility which contribute to profitability Reduce maintenance costs Reduce operational risks by intervention before failure Improved metering for tracing losses and optimizing output	See activities under Dependability and Flexibility. Address maintenance costs and forced outages: • Machine Condition Monitoring (MCM) • Detailed alarms for precise troubleshooting • Sequence of Event Recording • Digital Fault Recording • Replace synchronizers with synch check relays (if new digital governors and exciters are used) • Operational Instrumentation (OI), the feedback of plant information to a centralized database which compares actual values to setpoints and automatically generates maintenance work orders.

5.1.3 Example of Completed “Equipment Modernization Opportunities” Worksheet

The following table (Table 5-3) is an example of a completed “Equipment Modernization Opportunities” worksheet for Unit Control (asset number 1.1.6.2). It was developed using the following:

- The condition assessment process of Section 4, Volume 7 for identification of opportunities.
- Section 5, Volume 7, to further identify and assess the opportunities from a technical basis.
- Section 4, Volume 1 lays out the process for identifying needs and opportunities of equipment and defining them sufficiently for the LEM Plan. The flow of information between the process volume (Volume 1) and the technical volumes (Volumes 2-7), to support the development of the LEM Plan, can be complex. Figure 5-2 shows the flow of information in the process of identifying and defining “modernization opportunities” for the plant’s P&C equipment.

Table 5-3
SAMPLE Equipment Modernization Opportunities

Plant: Plant #1
Equipment Name: Unit Control
Unit No.: 2
Asset No.: 1.1.6.2
Prepared by: I.M. Engineer **Date:** January 31, 2000

<table>
<tr><th>Modernization Opportunities
(Section 5.2)</th><th>Benefits of Modernization
(Section 5.2)</th></tr>
<tr><td>• Replace relay based unit controls with a PLC controller and distributed I/O</td><td rowspan="3">Equipment:
• Easier troubleshooting
• Simple/inexpensive to expand
• Simple/inexpensive to modify
• Increased reliability, dependability and availability
Overall Plant:
Load sharing between units via PLC
PLC communication with control room controller for JVC and AGC</td></tr>
<tr><td>Further Studies Equipment
(Section 7)</td></tr>
<tr><td>• Tie in with governor and exciter upgrade
• Control room should be upgraded at same time
• Should protection be upgraded to digital at same time to take advantage of networking capabilities</td></tr>
<tr><td>Impacts of Modernization on Other Equipment</td><td>Other Equipment that Limits Modernization</td></tr>
<tr><td>• Hardwired interface to control room needs to be evaluated
• Networked interface to digital relays</td><td>• None</td></tr>
<tr><td>Timing & Costs of Modernization
(Section 4.9 and Section 6.0)</td><td>Risk Evaluation of Modernization
(Section 4.6)</td></tr>
<tr><td>• Same time that governor and exciter are being upgraded.</td><td>• Removal of old Control board includes removal of asbestos panels.</td></tr>
<tr><td colspan="2">Modernization Opportunities Selected for Input into Table 4-6, Volume 1</td></tr>
<tr><td colspan="2">• Replace unit control with PLC based control.</td></tr>
</table>

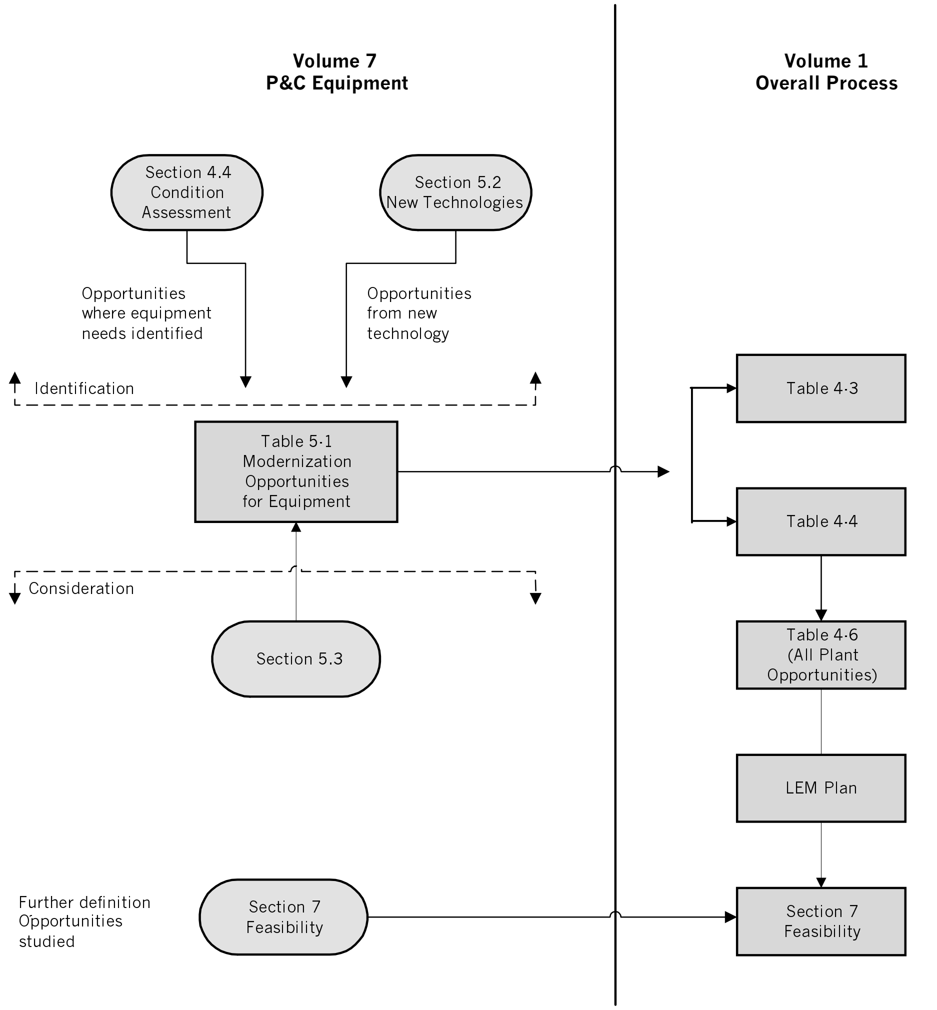

Figure 5-2
Flow of Information for Identifying and Assessing Modernization Opportunities for Protection & Control Equipment.

5.2 Advances in Technology

5.2.2 Protection

Many modernization opportunities exist for protective relays:

- Several electromechanical relays can be replaced with one multifunction digital relay resulting in less panel space.
- High resolution metering with the digital relay.
- Faster system disturbance investigation using digital relay based event records synchronized to global InterRange Instrument Group (IRIG)time signal.
- Accurate event timing using the digital relay with IRIG.

- Improved sensitivity for existing protection. e.g.: negative sequence (unbalanced current), 100% stator ground fault, dual level loss of field.
- New or additional protection in the same package. Eg: inadvertent generator energizing, voltage transformer (VT) fuse loss protection, sequential tripping, oscillographic generator monitoring.
- Built in self-checking.
- Networking of relays for automatic fault report/data collection.
- Improved relay testing, including faster testing during scheduled unit outages using computer based relay testing. Test results can be stored electronically and integrated into corporate work management software. Testing of multifunction relays can be completed quicker than testing individual function based relays.

If the opportunity to increase protection coverage is being considered, a review of current and potential transformer (CTs& PTs) locations and ratings should be performed. It can be costly to add CTs and PTs into existing bus work if not already installed.

5.2.2.1 Digital Relays

Twenty or more functions are required to protect a large hydro generator. There is, however, wide acceptance of digital relays for new installations and retrofits. Industry wide recognition of lower life cycle costs, increased functionality, greater MTBF and new features make the digital relay the relay of choice.

Advanced microprocessor-based protection relays have features that improve distribution and generator protection and aid in system disturbance, fault and event analysis and testing. The digital-protection relay can aid in detecting internal relay failures and allows for changes in protection philosophy and changing system conditions.

A variety of available hardware provides an opportunity to offer protection whose reliability and performance matches the commercial importance of the generator (based on probabilistic risk evaluation), while prudently protecting the third party assets (distribution network and general public) and employee safety.

5.2.2.2 Self-Diagnostics Increases Reliability

Schweitzer Engineering Laboratories quantifies a relay’s reliability by comparing unavailability. “The unavailability, q, is calculated using Mean Time to Repair (MTTR) and Mean Time Between Failures (MTBF). The MTTR is the sum of the mean time to detect plus the mean time to repair or replace. The MTBF is the reciprocal of the failure rate. A relay failure does not mean that the relay is inoperable. A failure exists any time the relay cannot create an accurate representation of sensor data, cannot detect a power system aberration, or cannot operate an output correctly etc. Causes of failure include settings out of calibration, reaction to environmental extremes, and hardware failure. Some failure modes can be corrected but do exist and may not be detected until recalibration occurs.

$$q = \frac{MTTR}{MTBF}$$

For electromechanical relays, a best case estimated MTBF is 40 years. Assume an industry average mean time to repair or replace an electromechanical relay of two days. An industry average schedule for maintenance on these relays is every six years (for some utilities this number is every two years). The time between this maintenance and the failure of an electromechanical relay varies between one second (infant mortality) and six years resulting in an average time to test and detect failure to be three years. This results in a predicted unavailability of 22 days per year.

$$q = \frac{MTTR}{MTBF} = \frac{3yrs + 2\,days}{40\,yrs} = \frac{1097\,days}{40\,yrs} = \frac{40\ days}{year}$$

A probable MTBF of microprocessor relays is 100 years. We consider that the time to detect a failure is negligible if the relay has self-test diagnostics and is communicating this information to an operator or process. Again assume an industry average mean time to repair or replace of two days. This results in a predicted unavailability of 0.02 days per year.

$$q = \frac{MTTR}{MTBF} = \frac{2\ days}{100\,years} = \frac{0.02\ days}{year}$$

The change in unavailability is 22days/0.02days = 1,100 times more available.

Therefore, the simple act of communicating a self-test diagnostic of a microprocessor-based relay to a user or process improves the reliability of protection over electromechanical relays by three orders of magnitude."[12]

5.2.3 Metering

The evolution to digital meters means that utilities can now sample power quality inexpensively and in many areas, which in today's market means value added service. Advanced metering technology can be applied to measure performance at interfaces between the utility and its customers. Where manual or paper chart recording of metering quantities was accomplished, now a digital meter can automatically capture and correlate information such as traditional revenue metering, power quality, and historical events. The information can be served up in several ways: to a central computer over a network or via RTU, into station PLCs directly or via modem connection PCs. If the opportunity to increase metering is being considered, a review of current and potential transformer (CTs& PTs) locations and ratings should be performed. It can be costly to add CTs and PTs into existing bus work if not already installed.

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[12] "Using Information from Relays to Improve the Power System", D. Dolezilek and D. Klas, Schweitzer Engineering Laboratories, Inc.

5.2.4 Control

Upgrading relay or Printed Circuit based controls to PLC-based controls can be done in whole or in part. Equipment downtime costs, however, make it more cost effective to perform an entire unit control (and often protection) modernization at once. Additional benefits from wholesale P&C modernization includes:

- Control enhancements
- Integration of system devices for better monitoring and control. (Network connections between the PLC and protective relays/exciter/governor mean an unlimited amount of recorded data can be brought into the PLC if the other devices are simultaneously upgraded.)

5.2.4.1 PLCs

Relay based control systems are being universally replaced in industry by programmable logic controllers (PLCs). PLC systems are less expensive while at the same time providing increased functionality at a lower cost. PLCs now support a wider range of device and data networks such as Ethernet, Profibus, Devicenet, etc. Faster scan times, hot standby, reduced size and ever increasing installed base make PLC's the choice for retrofit and new applications for controls systems.

Caution should be exercised when selecting a PLC manufacturer . Chose a vendor that has a good track record of supporting legacy (out of date) systems, has been in business for a while and is most likely to be in business in the distant future.

5.2.4.2 Processors

The main advancements in processors have been with speed, memory, cost and MTBF. As anyone who has owned a personal computer knows, processing power has increased in leaps and bounds since the early eighties. The same is true for PLC processors. Many first generation PLC processors were based on 8 bit architectures clocked at a mere 6 Mhz. Limited memory and speed resulted in limited applications in which the PLC could be applied. As technology progressed so did the PLC processor. Gradually the PLC found its way in to many complex control applications. The introduction of ASICs (application specific integrated circuits) and the use of surface mount technology, which is more cost effective to implement, meant dramatic improvements in cost and space savings. These advances have also led to further increases in MTBF figures, since fewer components means fewer solder joints and possible failures.

Memory has also undergone significant advancements. Where first generation PLCs had less than a 1000 words of memory, newer PLCs support over 100,000 words or more of user memory. With the mass production of PCs and consumer electronics, memory has become cheaper due to new technologies and lower production costs. This same explosion of consumer electronics has driven advances in memory from OTP (One Time Programmable) PROM (Programmable Read Only Memory) to UV EPROM (Ultra Violet light Erasable PROM) to EEPROM (Electrically Erasable PROM) to volatile DRAM and SRAM (Dynamic Random Access Memory & Static RAM) and NVM (Non-Volatile Memory) Flash memory. NVM Flash memory retains its memory even without power applied and is electrically erasable and re-programmable in circuit. These newer memory types are cheaper, smaller and have faster access times than the memory of old.

Faster processors means that control systems, historically comprised of discrete relaying and “black box” self-contained controllers, can now be moved into the PLC. Control functions now suitable for the PLC are governor/exciter control and synchronization.

5.2.4.3 Programming Techniques

Hardware

First generation PLCs came with crude hand-held programming terminals. Later PLCs required the user to purchase an expensive dedicated programming terminal. With the proliferation of the desktop and portable PC, PLC manufacturers created generic PC based application software that typically operates under a Microsoft Windows platform.

Software

PLC programming software is changing on a yearly basis. Despite the constant software upgrades, there have been three major paradigm shifts in programming software.

Originally programming was done in ladder logic using DOS based applications.

The second generation of PLC programming software was ladder logic using Windows based applications. As an added benefit, the Windows based applications allowed files from one application to be cut and pasted for use in another application. For example: an I/O list created in Excel during the preliminary design phase of a project could be imported into the PLC software. In addition to portability, the programming instructions sets have grown exponentially and now include canned instructions for PID loops, data type conversion, floating point arithmetic, etc.

The most recent generation of PLC programming software is Windows based IEC 1131-3 compliant. IEC 1131-3 is a programming standard with the following goals and benefits:

- widen the understanding of PLC programs so that the program is accessible not only to the original programmer but to all other plant stake holders such as electricians, technician, managers and process engineers
- standardization of the programming software between vendors to reduce the learning curve for users

The major new features offered by IEC 1131-3 are summarized as follows:

- The programming software should allow for and encourage well structured, ‘top-down’ or ‘bottom-up’ program development. The program should be able to be broken down into functional units.

- Strong data typing is required such that the PLC programming software detects when a programmer erroneously attempts to write the wrong type of data to a variable.
- Full execution control should be provided such that different parts of the program can be executed at different times, at different rates and in parallel.
- Data structures support should be provided so that associated data elements can be passed between different parts of a program as if they were a single entity. For example: a piece of equipment such as a pump may have a status bit, an analog speed setpoint, a temperature reading, etc. All of these data elements should be definable as a single "pump" data structure, then all the data for the pump can be passed as a single variable.
- Software should be vendor independent due to the standardization of languages and methods of program execution. (This particular requirement is rather idealistic and is not being met by PLC vendors who each have their own versions of "IEC 1131-3 compliant" software.)
- Flexible language selection should be provided so that the programmer can choose the programming language best suited to solve part of an application. One program can contain several different languages. Three graphical and two textual languages are defined in the standard. They are:
  - Structured Text (ST)—A high level textual language the encourages structured programming. It has a language structure (syntax) that strongly resembles PASCAL. As this language is one of the hardest for an outsider (i.e. everybody but the original programmer) to understand, it should be used sparingly, in applications where large quantities of data are being handled and manipulated in a repetitive way. This will normally be used for a background type task that will require no troubleshooting or modification after commissioning. Typical applications include alarm routines and sort routines.
  - Function Block Diagram (FBD)—A graphical language for depicting signal and data flows through function blocks. This language is best-suited for analog signal scaling, manipulation and control. It handles discretes as well as the ladder diagram language and thus, to keep a program that uses a blend of discretes and analogs readable, FBD is normally used.
  - Ladder Diagram (LD)—A graphical language that is based on relay ladder Logic from past generation PLCs. It is very "electrician friendly" as it mimics hardwired relay logic. LD is very cumbersome in its manipulation of analog signals. Therefore the best applications for LD have I/O almost entirely composed of discretes and/or a workforce with limited computer skills/exposure.
  - Instruction List (IL)—A low level 'assembler-like' language that is based on similar languages found in a wide range of today's PLCs. This language is used mostly for portability between older generation and newer generation processors.
  - Sequential Function Chart (SFC)—A graphical language for depicting sequential behaviour of a control system. It is best-suited for defining control sequences that are

time or event driven. Generator start, non-lockout shutdown and lock-out shutdown sequences are best implemented using SFCs. [13]

5.2.4.4 Specialized I/O

TIME STAMP MODULES

Specialized input cards are available that use the IRIG (InterRange Instrumentation Group) time code signal received via GPS receivers for time stamping of input signals. Time stamp modules act as normal input cards but also make available time stamps of input state changes for subsequent downloading to the processor. This can significantly reduce or eliminate completely the need for a sequential event recorder (SER) as well as the double wiring of field contacts to both a PLC and an SER.

SYNCHRONIZERS

Some PLC manufactures offer an “in-chassis” line synchronization module (LSM) for line or unit breaker synchronization. It features simultaneous multi-channel A/D conversion, digital zero cross detection, and numerically generated contact closing windows yield accurate, precisely repeatable, breaker closure commands to the PLC. The LSM design enhances system reliability by eliminating extraneous interconnect wiring, frequent adjustments, and re-calibration associated with conventional solutions. The integrated platform contributes to improved machine reliability, minimization of control cabinet space requirements, and maximization of serviceability. Configuration of the module is provided through the same “fill-in-the-blank” I/O configuration software used for all other I/O modules.

Additional features may include:

- Anti-Motoring
- Digital control allows for the implementation of asymmetrical breaker closure windows. This feature provides module based anti-motoring protection.
- Load Sharing
- A load sharing circuit is incorporated for use in multi-generator applications. The LSM regulates generator power output for optimal utilization of the total nameplate ratings.
- Power Monitoring (metering)
- The LSM provides a full feature power monitoring solution. This information may be used for load control, protection, fault location, and line conditioning. [14]

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[13] “Programming Industrial Control Systems Using IEC 1131-3”, R.W. Lewis.

[14] http://www.ab.com/power/prodinfo/pqa/1402_prodover.html, Allen-Bradley.

DISTRIBUTED I/O

Most PLC manufacturers produce some form of Distributed I/O (versus standard chassis-based remote I/O). These low point count I/O systems are intended for mounting near field devices. Benefits include:

- Low installation, wiring and maintenance costs
- Flexibility, allowing user to mix and match digital and analog I/O modules to meet their application needs
- Easy mounting and removal system.
- Small footprint that fits into a field-mounted junction box.
- Easy expansion.[15]

Distributed I/O can be connected back to the main PLC on a variety of networks including remote I/O, DeviceNet and ProfiBus.

5.2.5 Networks

5.2.5.1 Types

A hydro plant control system should have several different types of networks. The networks can be divided into three types:

- device networks
- control networks
- data networks

Device networks are designed for passing many small packets of data from field devices to a main controller. Control networks, like device networks, are designed for passing many small packets of information but are ideal for connecting the major components of a subsystem (e.g. unit) together. The speed of this network is critical. Data networks are designed for passing fewer large packets of data and are best utilized to tie subsystems together so that all of their respective information is available on an HMI. Data throughput is not as critical here and depends primarily on the screen update time for the control room operator. Refer to the example PLC system block diagram in Appendix B.

5.2.5.2 Example Topology

A four unit hydro plant has one unit controller PLC per unit, a dedicated HMI at each unit, a control room PLC for plant control and a control room HMI. A device network can used to bring

[15] http://www.ab.com/io_systems/table.html#distributed, Allen-Bradley.

the unit's I/O into the PLC if it is cost effective to have the type of "smart" field devices that can be networked. In hydro plant retrofits, this is rarely economical, because existing sensors are often reused and, in general, a hydro plant does not have the I/O density to warrant the use of such a network. Normally, field devices (RTDs, limit switches, pressure switches, etc,) will be hardwired to an I/O chassis that will be connected back to the unit PLC through the vendors I/O network. As mentioned above, a control network is used to connect the major components of a subsystem. In this case, the control network would be used to connect the unit PLC to the governor, exciter, unit HMI and any other controllers that contain control logic perform a specific unit function. The control networks are unitized, i.e. one per unit, and are not connected to each other. This keeps the data rates on these networks high for optimal unit control. The final level of networking is the data network that connects the four unit PLCs together, the control room "plant PLC" and the control room HMI. This network carries the small amount of information that needs to pass between units and the plant PLC and the large amount of data for the control room HMI. This network would also contain the bridge to the remote supervisory control enabling the supervisory to issue commands to the plant controller and collect data from all the units.

TYPE	INDUSTRY NAME	DATA RATE*	DESCRIPTION
Device	Sensorbus	Up to 56Kb	Lowest level network, used to connect simple low cost sensors. Transmits small amounts of data. Examples of buses: ASI & Interbus-S.
	Devicebus	Up to 12Mbits/s	Largest general network category providing communication for smart devices that can perform multiple functions and communicate device process and diagnostics information. Examples of buses: CANOpen, DeviceNet, PROFIBUS—DP & Lon Works.
	Fieldbus	Up to 500kbits/s	Supports transmission of larger amounts of data, but generally at slower speeds and requiring more processor power in the device. Some Fieldbus technologies also support the distribution of control functions directly in the device. Examples of Buses: WorldFIP, FOUNDATION Fieldbus & PROFIBUS—PA.
Control	Modbus Modbus+ ControlNet Data Highway+	19.2KB 1MB 5MB 56.2kB	Peer to peer communications typically between higher level control devices such as PLC's, DCS's, etc.
Enterprise	Ethernet 802.3	Up to 100Mb/s	Based on a Bus type network topology. Traditionally the backbone network for the company where business is shared. Predominantly TCP/IP but with other protocols bundled such as FTP, SMNP, SMTP etc.
	Ethernet 802.5	Up to 100Mb/s	Based on a Token ring network topology. Also used as the backbone network for many companies. Predominantly TCP/IP but with other protocols bundled such as FTP, SMNP, SMTP etc.

*Manufacturers use different criteria for measuring data rates. Network overhead can diminish network performance such that its actual data throughput is lower than a much slower network.

5.2.6 Synchronizers

As with protective relaying, synchronizers have undergone a revolution due to the advancements in microprocessor and digital technology. Feature enhancement in synchronizers includes:

- Multiple breakers with unique breaker close times
- Dead bus closing
- Smart voltage adjustment to match AVR regulation scheme
- Smart speed adjustment
- Anti-motoring detection
- Metering of line and unit voltage and unit currents including power calculations for MVA, MW, MVar, pf, kWhr, etc.

Advancements in synchro-check relays include:

- Reclose wait function
- Relay contact output for breaker tripping on dead bus. Added options include: anti-motoring features, and analog outputs for phase, voltage, current, delta F and delta phase angle which can be used by SCADA systems.
- Slip dependent breaker closing phase windows.

With the advent of digitally controlled governors and digitally controlled exciters, the synchronizer is becoming redundant. The digital governor is capable of precise frequency matching with a small amount of programmed slip. As well, the digital exciter is capable of precise voltage matching. All that is required is a synchro-check relay enabled by the control system (PLC) to close the breaker.

5.2.7 Machine Condition Monitoring

Machine Condition Monitoring (MCM) is used to provide a more comprehensive predictive maintenance program. It collects performance data, either continuously or periodically, such as partial discharge, vibration, air gap, temperature, flow rates and power usage. This data, at present, is interpreted “off-line” to attempt to predict maintenance requirements. Many attempts are underway to use condition monitoring systems “on-line” which will continuously monitor parameters and provide “smart” alarms which are more predictive than the present alarms used which simply alert the operator that a set point has been reached (see “Expert systems” below).

Four key benefits of applying MCM technology in generating stations have been identified. They are:

- Value of increased system capacity. The potential of hydroelectric MCM to enable planned “overloading” of generating units which are “monitored” to ensure minimal impact on equipment life and maintenance costs, could add to overall system peak capacity, thus avoiding the incremental cost of acquiring new generating capacity. Less reserve capacity would also be necessary for covering periods of planned and unscheduled outage if these outage are reduced.

- Energy value from utilizing present “spills”. Water is sometimes spilled when there is excess water behind a dam, or when generating units are out of service for maintenance or repairs. The potential for hydroelectric MCM to enable both planned overloading, and reduce maintenance and repair down-time, could permit more water to be run through generating units, thus providing an increased energy output.
- Value of reduced timely maintenance and repair outages. Presently, generating units are usually taken out of service on a time-scheduled (calendar-driven) maintenance program, or when a failure has occurred (machine trip or human detection). An effective hydroelectric MCM system, which enables “condition-driven” maintenance, has the potential to reduce maintenance costs by helping to ensure that maintenance work performed is necessary when undertaken, and ample warning is given to minimize system utilization problems.
- Value of life extension for aging equipment. The implementation of an effective MCM system would enable the informed deferral of equipment rebuilds, as compared to the present system of calendar-driven (“scheduled”) equipment rebuilds.

In addition to these key benefits, other financially tangible and intangible benefits may include:

- improved generating unit operating efficiency,
- improved system efficiency,
- improved risk management on “run-of-the-river” plants,
- improved outage planning (system balancing and substitution),
- improved environmental monitoring,
- improved safety,
- reduced spare parts inventories,
- and improved operational and maintenance skills.

A problem with implementing condition monitoring in a hydro plant situation is that the plant has very slow wear rates. Changes in performance, which provide the trends that condition monitoring relies upon, are very gradual, i.e. over many years and trending of these parameters needs to take this into account.

5.2.7.1 Partial Discharge Monitoring

Discharge activity is characterized by electron and ion current flow within voids and at surface gaps, of high voltage insulation. The term partial is used since there is a solid insulation, such as epoxy-mica, in series with the void or gap, which prevents a complete breakdown. The insulation system and the voids or gaps can be considered to be a series of capacitances with different dielectric constants. Depending on the size of the void or gap, the dielectric constant, and the temperature, the voltage gradient within the void or gap may become high enough for breakdown to occur. In most cases the electric field will not be uniform and this will tend to lower the breakdown voltages. Partial Discharges (PD) are often the result of damage caused by other thermal, mechanical, electromagnetic and chemical forces acting on the stator winding. The progressive development of PD activity is the major symptom of insulation deterioration. These discharges also contribute to the aging of the machine's dielectric system by eroding away or deteriorating the insulation system. As the insulation degrades, the number and magnitude of the PD pulses increase. Although the magnitude of the PD pulses cannot be directly related to the remaining life of the winding insulation, the doubling of PD magnitudes every 6 months or so indicates that rapid deterioration is occurring. Furthermore, if the PD magnitudes from several identical windings are compared by the same test method and conditions, the windings exhibiting higher PD activity are generally closer to failure. Thus a PD test can trend insulation condition over time; indicate certain conditions as a result of PD nature and characteristics e.g. loose wedges, end winding pollution and delamination of insulation.

PD monitoring significantly reduces forced outage time and the possibility of generator damage by giving an early warning of stator insulation deterioration.

A few companies provide portable and on-line continuous PD monitors. These monitors use either a stator slot probe or epoxy-mica capacitive coupler to couple the PD signature from the winding to the monitor. Each PD activity leaves a signature pulse on the 60 cycle waveform. The PD pulse can be relatively small in relation to the 60 cycles in the order of 0.1 to a few volts in magnitude as compared to 6000 to 8000 volts (generator terminal voltage to ground). The PD coupler attenuates the 60 cycles to as little as 100mV with out affecting the PD pulse. PD monitors record and store the PD activity and provide a means to display the results for trending over time.

5.2.7.2 Air Gap Monitoring

The value of clearance (Air Gap) monitoring systems for the analysis of rotating machines has become recognized and accepted worldwide. The clearance between the rotating and stationary parts of a machine may be used to directly analyze the machine's operating condition. Clearance monitoring systems are specified for and installed on new and existing machines. A near real-time, on-line clearance monitoring system can be the basis around which a smart diagnostic system may be configured.

Traditionally air gap readings were performed statically by hand usually after a maintenance outage and before the unit returned to service. As technology advanced, monitor systems were developed to look at the air gap while the machine was on line. For the first time dynamic machine analysis could be accomplished and the effects of heating, electromagnetic forces and other electro-mechanical stresses could be observed. Machine behavior could be understood and machines pushed closer to designed limits. Cases have also been presented where dynamic air gap monitoring has solved long time operational limitations by pinpointing problems and allowing machines to be repaired and limitations to be lifted.

Several methods of air gap monitoring are available each with their own method of sensing: capacitive, acoustic and fiber optic.

Air gap analysis is performed while the unit is run up from stand still, excited, put on line, loaded and heated over time. Analysis can be performed for such effects as: centrifugal force on the rotor from start-up to overspeed, and cold bearing clearance problems during start up, rapid or uneven stator or rotor expansion and or loose rotor poles during excitation and rotor/stator center displacement changes while online due to loading.

5.2.7.3 Vibration Monitoring

Vibration monitoring technology has benefited greatly from advancements in analog and digital circuit technology. With increased computing speeds, programmers are able to write more complex analysis programs and include more real-time analysis. Vibration monitoring has grown with technology, from experienced operators being able to detect increased vibration by touch or hearing to analog tape recorders and real-time analyzers that weighed hundreds of pounds to microprocessor based instruments and hand held monitors. The latest portable monitors include data capture memory that can be downloaded to a central data base for trending.

In the last few years data analysis has gone from time waveform only to the ability to transform time-domain data quickly into frequency domain signatures. With the latest generation of sophisticated analysers, and networked data capturing equipment, the trend now is to automatically gather the data, manage and report it. This reduces the skill level required to acquire and analyze vibration data. This has lead to vibration instrumentation manufacturers striving to provide predictive maintenance tools.

Vibration levels can also be input into the control PLC for indication, alarming, trending and protection. Operating conditions can be monitored such as “rough load” zones, broken wicket gate shear pins, etc.

5.2.7.4 Temperature Monitoring

Direct contact temperature sensing has changed little in recent years, however; non-contact sensing has evolved in recent years with the use of infrared and thermal imaging. Data collection platforms have also changed dramatically. Platforms have progressed from chart recorders to multiplexed and continuous real time monitors. The temperature monitoring platforms of today are continuously on-line and provide real-time as well as historical trending, individual alarm set points for each input and a host of other features. Most new plants have temperature monitoring combined in the unit or plant control PLC. Resistive Temperature Device (RTD), thermocouple or analog input modules are used and a display such as a dedicated PC or remote I/O display provides access to the data. Examples of current technology are the rotor mounted non-contact infrared scanner and stator mounted infrared pole temperature sensing. It provides a continuous on-line indication of the stator winding/pole surface temperatures, indicating any hot spots. Continuous on-line temperature monitoring is an essential component to machine condition monitoring and helps allow generators to be judiciously run at full capacity.

5.2.7.5 Expert Systems

Vibration monitoring systems, air gap monitoring systems, PLCs, and data acquisition PCs can be networked together so that a variety of data can be correlated and operational decisions made by a central processor. Currently, the data from the various sub-systems can only be analyzed by engineers with sufficient experience. These engineers make decisions to prevent unexpected equipment downtime, identify potential operational cost reductions, increase net production capacity and improve product quality. The fundamental decision to act on the data is often left to these “experts”, who must be experienced enough to read between the lines and for see the opportunities. With current technology it is theoretically possible to build expert systems which could monitor trends and identify recommended courses of action for employees. These systems are, however, still under development.

5.2.8 Operational Information

Operational Information or O.I. is a data gathering system based on a networked PLC platform. It is intended to gather actual operating quantities such as: unit and plant MW, Mvar, volts, temperature, flow, breaker operation, etc. from the various plants and present the data to aid managers in day to day operational and financial decisions. The OI system can be a separate or can be married with the unit and or plant control PLCs.

OI data can be tied to enterprise (ERP) software such as: maintenance work order systems and human resources software. These software systems can automatically produce maintenance work orders based on plant data, for example, a setpoint of 100 breaker operations may trigger a maintenance work order for a breaker overhaul.

5.2.9 System Testing

Control system testing of PLC based systems is both easier and yet more difficult than testing of control systems in the past. PLC programs can be tested with simulated I/O that makes testing easier. On the other hand, large PLC programs can be difficult to fully test and maintain integrity of previously tested components through modifications.

Simulation software can also be used for testing PLC-based control systems and for training operators. Simulators, such as PICS from SS Technologies is a real-time I/O simulator that allows users to quickly create a dynamic model on a PC that duplicates the behavior of the actual process and provides the PLC with real-time feedback.

Simulation is used to *stress test* the system and to ensure that performance specifications are being satisfied. As part of the test plan, each component of the system is forced to fail during simulation. This permits testing of the back-up and recovery procedures to ensure that they are adequate and perform as designed.

The role of simulation is also important in training. With simulation, it is possible for operators to be trained in an environment that performs exactly like the real system. Process rates can be accelerated and selected scenarios recreated so that the operators get the maximum benefit from the training sessions. Experience shows that with simulation, the learning time for operation of a new system is dramatically reduced as the operators train without the stress of training on *live* equipment. Operators are able to experiment and to make mistakes without endangering production, equipment or personnel.

The simulation program is usually very simple containing such logic as “when breaker close output received, send breaker closed indication to the PLC”.

There are pitfalls however. Testing of software can be an onerous task. The nature of a program is to take a variable, whether it’s a tag in function block programming or a “contact” in ladder logic programming and use it repeatedly throughout the program. Any modification to the contents of that tag or contact can effect changes throughout the program. Changes made during testing and commissioning can have a ripple effect causing failures in other, previously tested, parts of the program.

5.2.9.1 Software Testing and Checks

Industry is hotly debating the software programming and testing procedures issue. To date, control over who does software programming and to what standard has been left to the end user. Often the end user is not in a technical position to judge the quality of the programming. Although they can see the end results, they cannot see whether or not the code was written in a top-down hierarchical format or even documented properly. Recently, engineering associations in North America have begun to certify software engineers in the hopes that some regulation will help to control the quality of software being written.

The following are typical software checks:

Capability—describes how well the system can perform its intended design function.

- Responsiveness—the time required for the system to produce appropriate responses to a specified combination of external events
- Processing Capacity—The extent to which the system can meet scheduling deadlines under specified sets of conditions
- Storage Capacity—The extent to which the system can retain in memory all the required programs and data under specified sets of conditions

Availability—describes the amount of time the system is ready to perform its intended function.

- Reliability—the ability for the system to continue to perform all of its intended functions over a period of time and range of conditions. An inverse measure of maintainability is mean time between failures (MTBF).
- Maintainability—The ease with which the system can be restored to full capability after the occurrence of one or more faults. An inverse measure of maintainability is mean time to repair (MTTR); availability is often defined by the expression MTBF/(MTBF+MTTR)

- Integrity—The degree to which the system can continue to perform all its functions over a specified range of threats, including both unintended user actions and intentionally hostile actions.

Usability—describes the ease with which a specified set of users can acquire and exercise the ability to interact with the system in order to perform its intended functions.

- Entry requirements—The amount of formal and informal training required before the user can learn to interact with the system (e.g. perquisite educational level, skill-sets in the use of operating systems, windows, menus, etc.)
- Learning requirements—The training required for a user to learn to interact with the system.
- User productivity—the number of operations per unit time which can be performed by a user.
- Congeniality—The extent to which a user prefers to utilize the system software rather than use some alternative way of performing the duty. Is the system user friendly?

Adaptability—describes the ease with which the system may be modified to take on new or modified functions

- Improvability—the ease with which the existing capability, availability and/or usability can be upgraded.
- Extensibility—the ease with which new functionality can be added to the system.
- Portability—the ease with which functionality can be relocated from one system to another.
- Reusability—the ease with which the functional capabilities of an existing software element can be reused in a new or in a different system.[16]

5.2.10 Commissioning

A large portion of the engineering costs in a capital cost estimate are commissioning hours. Commissioning hours can be reduced in two ways: better factory testing, as described in Section 5.2.9, and faster field commissioning. Invariably, when a plant is put into service, some modifications are required in the field. What could have taken days to rewire can be done in a matter of hours or even minutes through software resulting in substantial savings.

5.3 Consideration of Alternative Approaches to Improvements

In some instances, a case for a protection and control modernization cannot be immediately justified. An example would be: A generator which is slated for a complete overhaul in a 5–10 years, however, the condition assessment results identify areas of the P&C that require immediate improvements. If a complete modernization is planned but some areas require immediate attention, consideration can be given to alternatives to modernization.

[16] "Programming Industrial Control Systems Using IEC 1131-3", R.W. Lewis.

These alternatives can include but are not limited to:

- Increase regular maintenance,
- Perform preventive maintenance,
- Replace individual failing components such as relays with newer units, one by one,
- Replace dysfunctional components with used parts from other like equipment,
- Place reduced operational limits on a unit
- Reduce start—stop cycling of worn equipment

The above alternatives provide a means to prolong equipment life but in many cases may already be in place. By careful planning however, small scale improvements can be made which can be integrated into a complete modernization down the road. Careful selection of the replacement sub-system for integration in the modernized system is a necessity if costs are to be minimized in the long run. An example would be: replacing an old window type annunciator with a PLC based HMI annunciation system which eventually could be used as part of a new automated unit control scheme. In this example, the PLC and HMI could be housed in a new panel beside the unit control board. This panel could eventually replace the UCB (Unit Control Board) entirely in a future modernization plan. In this way the extra cost of the PLC approach can be justified by the future plan. Before the small scale improvements are undertaken, a plan should be in place providing direction so that they fit into the long term goals.

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 the plant economics. Volume 1 Section 4 details the methodology for incorporating identified opportunities into the LEM Plan. This is an important step in the iterative 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, completed by the Condition Assessment Engineer for the protection and control 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
ESTIMATES OF COSTS AND BENEFITS

6.1 Introduction

The costs and benefits of possible life extension and modernization activities for P&C equipment are important factors in any decision regarding the future of a plant.

This section will provide guidance regarding:

- The screening stage of projects (Section 6.2) and cost estimates for the LEM Plan (Section 6.3).
- Cost estimates at the feasibility and project approval stage (Section 6.4)
- Energy and Capacity Benefits (Section 6.5)
- Other Benefits from LEM (Section 6.6)

In all considerations of costs and benefits, care must be taken in using the results presented 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 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 US "Year 2000" dollars. Various indices are available to escalate dollar values for future years, including:

- Handy-Whitman Index of Public Utility Construction Costs.[17]
- Bureau of Reclamation Cost Index.[18]

[17] *Handy-Whitman Index of Public Utility Construction Costs*, published by Whitman, Requardt and Associates LLP, Baltimore, Maryland

[18] *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 at the Screening Level

The cost estimates and delivery times in Section 6.3 below could be used at the screening level if desired although the screening process laid out in section 3 of this manual does not use cost or delivery as an input in the process.

6.3 Cost Estimates for Life Extension and Modernization Plans

Cost estimates for a new protection and control system may vary by as much as 100%. Factors that influence cost and delivery time are: unnecessary options included in package pricing, differences in manufacturers quality, use of custom assemblies, local stocking of components and quality of programming service. However, once the first system is delivered, subsequent application of the same components/design to other generators should be substantially less than the first, regardless of size of the unit. The reason for the cost similarity between generators of different size is the necessity for the same level of protection and basically the same control features. Obviously there will be some small cost differential based on more or less analog points to be measured. The costs and delivery times presented should only be used as general guidelines, however, they can also be used for preliminary estimates that are required for the electronic economic financial evaluation template (Volume 1, Section 9).

The estimates derived from this section can be used in conjunction with work associated with Volume 1, Section 4 and Sections 4 and 5 of this volume. More detailed cost estimates that are required for feasibility level studies should involve input from both manufacturers and stakeholders.

6.3.1 Protection and Control Life Extension Through Rehabilitation Cost Estimate

P&C life extension costs (refer to Table 6-1) will range from the cost of the minimum P&C life extension (on a component by component basis) to a complete P&C system replacement as in Section 6.3.2. The cost for P&C rehabilitation, installation and commissioning as well as delivery can be broadly estimated from the following:

Table 6-1
P&C System Life Extension Costs

Cost for P&C System Life Extension as a Percentage of New P&C System Replacement Costs			
	Minimum Life Extension (%) (% of new P&C replacement cost)	**Major Life Extension (%) (% of new P&C replacement cost)**	**Complete Replacement (%) (% of new P&C replacement cost)**
P&C Rehabilitation Cost	10	75	100
Removal and Installation Cost	5–10	150	100
Delivery Time	1 month	3 to 6 months	3 to 6 months
Installation Time	2–5 days	> 3 months	1 to 2 months
Commissioning Time	1 to 2 days	> 3 weeks	1–2 weeks

An example of a minimum life extension could be replacing a single defective protection relay. This practice costs a relatively small amount in comparison to complete replacement costs, however, the minimum life extension will probably need to be re-visited in the future.

An example of a maximum life extension could be replacing all old control relays with new control relays followed by old protection relays with new protection relays, etc. (using existing cut-outs, wiring and terminal blocks). The cost of a system by system replacement approach is estimated to be more than a complete replacement for the following reasons: tooling up for each system, multiple contractual overheads, many of the same drawings requiring multiple changes and possibly more than one outage or a longer duration outage.

Complete replacement of the P&C system is based on new panels with multifunction protection relays and PLC based control. Often the complete replacement can be done swiftly and effectively since all cables and panels are removed together, the new panels are brought in, new cables pulled and the whole system commissioned at once. If required the new panels can be installed beside the old and cables pre-pulled ready for a fast change over.

6.3.2 Complete Protection & Control Replacement Cost Estimate

The cost of a complete P&C system replacement (per generator) does not depend so much on the size, type or age of the generator but rather on the desired features. The cost for a typical modern replacement P&C system is presented in the table below:

Table 6-2
Cost for Fully Redundant Protection & Control System

Materials Cost of Multi-function Generator Protection & Control System (on a per unit basis)			
Control	Items		Total capital Cost*
	• 2 panels • Aux relays, • FT blocks, • Control switches • Discrete indication • Discrete metering • PLC, • Synchronizer • Temperature monitoring (in PLC) • Inverter • PC with WinNT • MMI Software • 2000 feet of multi pair cable		$200k
Protection			
	• 1 Panel • Aux relays, • Trip blocking switches, • FT blocks, • Protective relays • 2000 feet of multi pair cable		$150k

*Taxes not included, no contingency included. Costs are in US$, are approximate and are shown the same for a 20MW to 400MW unit.

- Control cost estimate includes provision for 128 analog inputs or outputs and 160 discrete inputs or outputs.
- Control cost estimate excludes sensors or sensing devices, GPS time synchronization equipment, Airgap, vibration and Partial Discharge monitoring equipment.
- Protective relays include: two digital multifunction (Primary and Secondary), two digital differential relays, one split phase relay, one breaker failure relay.
- Protection cost estimate excludes mechanical protection devices.
- Engineering typically takes anywhere from 4–10 months depending on experience, the amount of drawings to be created or changed and amount of work required to write specifications. As a guide, add $100k for engineering to the P&C total.

- Installation typically takes 2 electrical/P&C workers 1.5 months to install and test. As a guide, add as a minimum $34k for installation and testing (older plants usually require new cables and cabletrays, etc. and the cost can easily double.)
- Delivery costs should be based on a complete set of P&C panels fitting inside one 5 Ton truck. Ensure air ride suspension is used so that sensitive equipment is not subjected to undue shock. A factor of $100 per hour can be used for estimation purposes.

6.3.3 Project Costs

The estimated costs of a project usually include:

- Direct costs
- Contingency
- Escalation
- Indirect costs
- Interest during construction (IDC)
- Other costs

All the costs above are usually capital costs except for “other costs” which are generally O&M costs.

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 evaluation process. 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.

6.3.3.1 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 and training.
- Contingency—The contingency to provide for inaccuracies in the direct costs estimates depends on the confidence level of the direct costs. For the first pass studies in these guidelines, 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 labor costs. The direct costs determined from these guidelines are in 2000 dollars 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) = $(1 + e)^{n-1}$, **Eq. 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. An indirect cost factor (ICF) of 20 to 40% (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. 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 upgrade 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) **Eq. 6-2**

IDC Factor (IDCF) = $r \times n$ (simple) **Eq. 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 ($r = 0.09$).

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:

Fixed Charge Factor (FCF) = LAFCR x SPVF, **Eq. 6-4**

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:

$$k = \frac{1 + e}{1 + i} ,$$ **Eq. 6-5**

where

i = the present worth discount rate in decimal value, and

n = the number of years in the economic life, and

e = annual escalation rate in decimal value

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:

$PVAF = 1/(1 + i)^t$, **Eq. 6-6**

where

i = discount rate (0.09), and

t = number of years between the study and commercial operating date of plan.

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 Project Approval Stage

While the cost estimates presented in the preceding subsections are suitable for screening and planning studies, estimates with reduced uncertainty will usually be necessary for project approval, prior to implementation. Volume 1, Section 2.3.5 discusses various estimating considerations.

Cost estimates for supply of P&C equipment should be obtained from suppliers, or else developed from actual prices for previous projects of similar types.

In absence of any cost data the information from Section 6.3.2 can be used. Similarly, costs from previous projects should be used for dismantling and re-installation. If this information is not available then the information from Section 6.3.2 can be used.

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.

Indirect cost and interest during construction may require review to check any revision to the owner’s specific financial/economic parameters but 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.

6.5 Energy and Capacity Benefits from Modernization

6.5.1 Energy

The expected energy benefit of a modernization activity will be refined as the planning process moves from the formulation of a LEM Plan through to the feasibility process. An initial estimation of energy benefits from a particular activity can be gained from the methods described in Section 5. During the feasibility process in Section 7 of both Volumes 1 and 7 the initial estimates of energy benefits will be refined through more detailed analysis and discussion with manufacturers.

The benefits of a modernization activity can be compared to the activity's costs and an analysis of the particular activity can be made. Each activity, or group of activities, will also need to be compared against the 'Base Case' for the plant. The Base Case is simply the scenario for the plant which all other plant scenarios is compared against to estimate their relative worth. Usually the Base Case will include all activities necessary to maintain the plant at its present output.

For the existing plant, the average annual generation can be determined from the generation records for at least the past 5 to 10 years, and preferably for the last 10 to 20 years. The historical generation may require adjustment if generation was affected by planned outages or non-representative water years. A power study (refer to Volume 6) may be required to provide a more accurate picture for the plant.

The Model supplied for use with Volume 1, Section 4.9 simplifies the input of benefits for each project. The Model accepts standardized energy value forecasts in its Supporting Tables section. Expected generation benefits can also be inserted in the same area. Refer to the User Materials supplied on the CD-ROM containing the Model for detailed instructions regarding the use of the Model.

Value of Energy

The following discussion regarding the value of energy will be of assistance to these users who may not have easy access to pricing information for a first pass evaluation of a proposed project. Similarly, the present value information is not required if the Model is used as present value calculations are incorporated in the Model.

The value of the generation ($/MWh) depends on whether the generation cannot be stored and is run-of-river or can be stored and scheduled to be used during peak periods as peaking energy. Run-of-river generation should be assessed at new baseload unit costs, while generation from units that have storage and can be used for peaking should be assessed at peaking energy costs. For units that have some storage and can be used partially for peaking, the baseload and peaking generation can be proportioned accordingly. Each user of these guidelines should use values for peak and non-peak power costs and proportioning that reflect the actual situation under consideration. For example, if the hydro generation is offsetting three levels of alternative generation costs—gas turbines (10 percent), coal-fired units (50 percent), and non-peak baseload (40 percent)—then the value of generation (VG) computation will consist of three components rather than two as illustrated in these guidelines. If the value of generation ($/kWh) is unknown, values can be obtained from a publication such as "Power Generation Markets Quarterly"[19]. An escalation rate of 5 percent can be used if the escalation rate is unknown.

[19] *Power Generation Markets Quarterly"*, published by the McGraw-Hill Companies, New York, NY.

The present value of the energy generation from the existing plant before the upgrade on the date of the study can be determined by the following equation:

Present Value of

Energy Generation Before Upgrade = $VG \, x \, k \, x \frac{(1-k^n)}{(1-k)} x \, PVAF,$ **Eq. 6-7**

where

$k = \frac{1+\ e}{1+i}$,

VG = value of annual generation (peak + non-peak) on the date of the study (MWh/yr x $/MWh),

n = no upgrade-evaluation period in years (15),
upgrade—number of years existing plant will produce energy before shutdown for the upgrade,

e = escalation rate (0.05), and

i = discount rate (0.09).

(The suggested values in parentheses can be used if the information is not available.)

This energy value for the existing plant generation is based on study date dollar values.

The present value of the energy generation from the upgraded plant on the date of the study can be determined by applying the present value adjustment factor (PVAF) to Equation 6-7 as follows:

Present Value of

Energy Generation After Upgrade = $VG \, x \frac{(1-k^n)}{(1-k)} x \, PVAF,$ **Eq. 6-8**

where

$k = \frac{1+\ e}{1+i}$,

VG = value of annual generation (peak and non-peak) on the date of commercial operation (MWh/yr x $/MWh),

n = evaluation period in years (15),

e = escalation rate (0.05), and

i = discount rate (0.09), and

PVAF = present value adjustment factor.

6.5.2 Capacity

Capacity benefits will be refined in a similar manner to energy benefits (Section 6.5.1). The plant capacity for each upgrading alternative is determined during development of the alternatives.

The value of capacity depends on whether the capacity is considered to be dependable, which is influenced by whether the plant is a baseload run-of-river plant, has storage for peaking, or is a combination of run-of-river and peaking. As with the energy costs, the capacity attributable to each category should be estimated and proportioned. If the value of capacity is unknown, values can be obtained from publications such as "Power Generation Markets Quarterly"[3].

Capacity can also be tied to the upgraded P&C system in that a modern integrated P&C System allows the Owner to push the units harder due to improved monitoring. Units can be run above nameplate capacity for short periods (peaking) with the aid of PLC control systems that monitor all aspects of the generator. The higher availability of the unit through its modernized P&C also adds to the total capacity.

For units installed in years other than 2000, the capital cost escalation rate of 5 percent, as determined earlier, should be used to escalate the cost to a different year of installation.

The present value of the existing plant capacity before the modernization can be determined on the date of the study by the following equation:

Present Value of Capacity

$$\text{for Existing Plant Upgrade} = \text{VC x k x } \frac{(1-k^n)}{(1-k)} \ , \qquad \textbf{Eq. 6-9}$$

where

$$k = \frac{1+e}{1+i},$$

VC = value of capacity on the date of feasibility study (MW x \$/MW/yr),

n = no upgrade—evaluation period in years (15),
upgrade—number of years existing plant will produce power before shutdown for the upgrade,

e = escalation rate (0.0), and

i = discount rate (0.09).

(The suggested values in parentheses can be used if such information is not available.)

The present value of the upgraded plant capacity in study date dollar values can be determined by applying the present value adjustment factor to Equation 6-10 as follows:

Present Value of Capacity

$$\text{for Existing Plant After Upgrade} = \mathrm{VG} \times k \times \frac{\left(1-k^{n}\right)}{\left(1-k\right)} \times \mathrm{PVAF}, \qquad \textbf{Eq. 6-10}$$

where

$$k = \frac{1+e}{1+i},$$

VG = value of capacity on the date of commercial operation,

n = evaluation period in years (15),

e = escalation rate (0.0),

i = discount rate (0.09), and

PVAF= present value adjustment factor.

Evaluation of capacity credits varies by utility and the contractual agreements of any system interties. Full credit for any increased capacity may not be allowed if the capacity is not considered dependable, that is, if water is not always available for the plant to operate at maximum capacity. If system criteria are available to determine how much of the increased capacity can be considered dependable, these criteria should be considered in the capacity evaluation. If capacity credit criteria are not available, the full capacity should be credited.

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 from a protection and control perspective including:

- reduced forced outages;
- reduced P&C maintenance costs;
- reduced plant equipment maintenance costs (through MCM, trending, & maintenance optimization)
- increase in availability;
- reduced risk costs; and
- increased unit output due to increased monitoring.

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 estimate will take place for any feasibility study conducted.

7
OPTIMIZATION OF ALTERNATIVES (FEASIBILITY)

7.1 Introduction

Sections 4, 5 and 6 of this Volume contribute to the formulation of a Life Extension and Modernization (LEM) Plan for protection and control equipment. The information used to formulate the LEM Plan is obtained largely from existing operational and test data.

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 and 7.3)
  - selecting the best activities (Section 7.4)
  - understanding a sensitivity analysis (Section 7.5)
- proceed with the design (Section 8), and;
- implement the project (Section 8)

This section will outline methods to obtain more detailed information on equipment condition and modernization opportunities.

The additional information required may come from:

- Additional testing (system or individual component testing)
- Additional inspection (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.

Acquiring testing and inspection information will usually require a commitment from the owner to operate each unit in a non-commercial manner and to take the unit out of service for a period of time. The results of the testing will be valuable, even if they do not support the proposed modernization and no further action is taken. The test results will provide a performance base line for any future assessments of the plant.

Figure 7-1 describes how the sub-sections of Section 7 contribute to the feasibility assessment of the life extension and modernization activities identified in Sections 4 and 5.

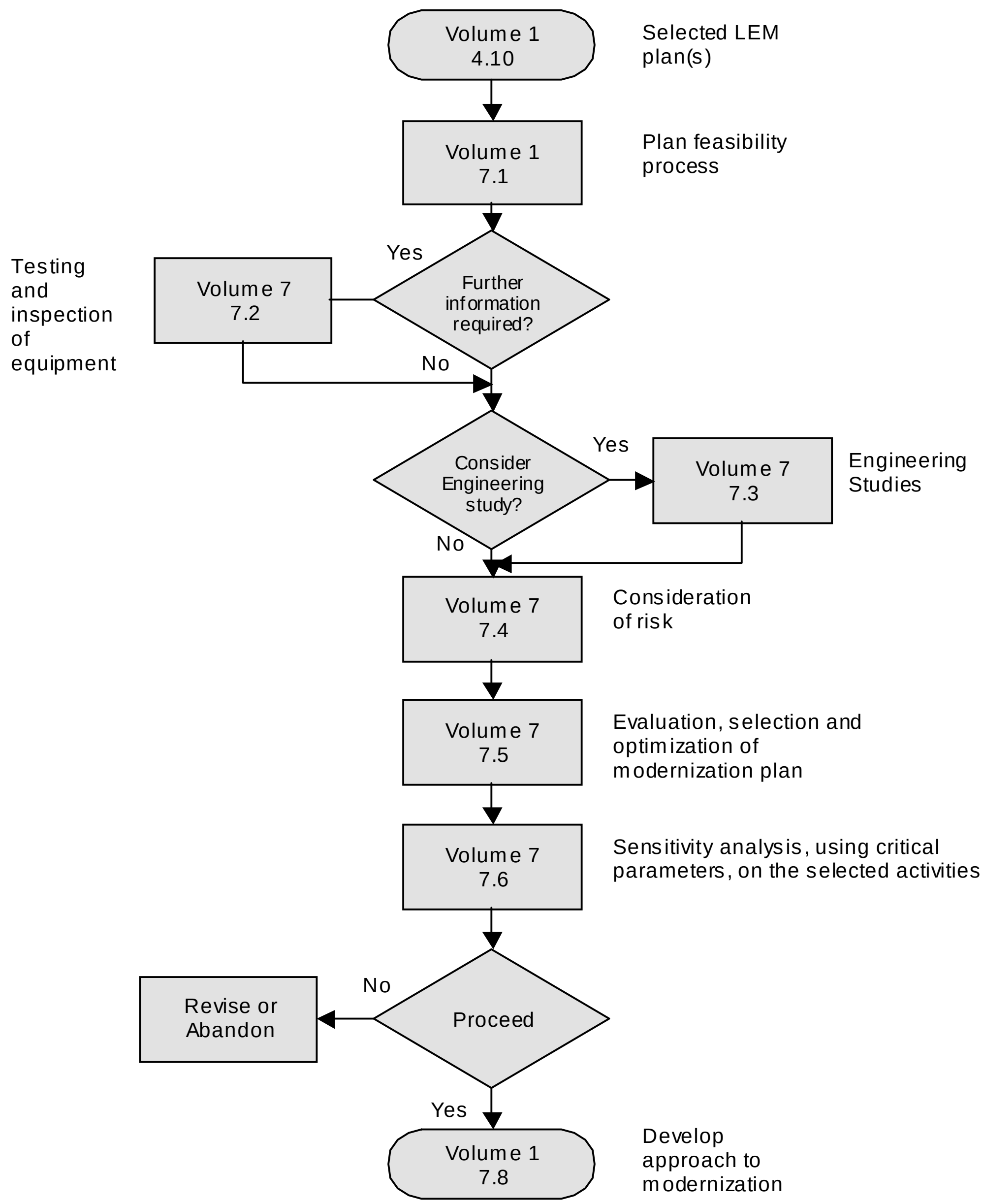

Figure 7-1
Optimization of Alternatives

7.2 Testing and Inspection of Protection and Control Equipment

It is likely that by the time Sections 4 & 5 are completed sufficient information will have been gathered and the need for further testing will not be required.

The decision on which, if any further tests or inspections are to be undertaken is dependent upon the focus of the feasibility study. Because of the complexities inherent in P&C systems, confirmation of questionable initial assessment conclusions may require through additional testing.

It may be that a problem identified in Section 4 as being in the P&C system may actually not be the source of the problem. For this reason, in certain situations detailed sequential testing of the P&C system may be required. Tests may include:

- Monitoring steps in the control logic with the use of a recording instrument in order to pinpoint the actual cause of faulty control operation.
- Performing actual timing and trip testing of protection relays and circuits (if data is outdated or incomplete).

7.3 Engineering Studies

Engineering studies are used to bring the required information together to make rational decisions on the feasibility of specific P&C system improvement activities. The process covers:

- Assessment of previously gathered information (Volume 7, Sections 4 and 5)
- Assessment of results of inspection and testing (Volume 7 Section 7.2)
- Buildability analysis (Volume 1, Section 7.4)
- Value engineering (Volume 1, Section 7.4)
- Improvements in assessment of costs (Volume 7, Section 6.3.3)
- Improvements in assessment of benefits (Volume 7, Section 6.5)
- Selection of best P&C equipment modernization (Volume 7, Section 7.5)

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.

7.4 Risk Considerations

Risk management is the ability to balance risks with the potential gains by making correct or appropriate 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, from a purely P&C perspective, are included in the following box:

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 QA Once work is initiated, increased scope is identified Lack of adequate software documentation and revision control procedures.
Construction	Delayed schedule, longer outages Consequential damage Contractor unfamiliar with specific work High Training costs Poor estimate of cost leading to overruns
Operating	New operation rules not written New operation methods not attainable Operation changes not acceptable by external stakeholders Damage to equipment caused by improper operation / settings New operation does not achieve expected gains

The user should examine all areas above with particular regard to the P&C 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, 4.4 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 a “Plan” for P&C 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 (Section 7.6).

In some cases, the additional data, gathered during the feasibility process, will shed new light on the whole process and the option that moved forward from the formulation of the Modernization Plan will have to be reconsidered. For example, if an item of equipment is more seriously deteriorated than initially thought, or its performance is worse than originally measured, the cost of replacement or repair may be higher than expected, or the case for modernization may become more attractive.

Cost and benefit information should also be reviewed at this point to feasibility level (Refer to Volume 1, Section 7.6 and Volume 7, Sections 6.4 and 6.5) to enable selection of the appropriate modernization plan.

7.6 Sensitivity Analysis Using Critical Parameters of Costs and Benefits

An integral part of the project analysis is conducting a sensitivity analysis on the selected modernization plan using parameters which will be critical to the selected modernization project's success. These parameters can be broken into two categories:

- Costs
- Benefits

Some of the parameters discussed will be applicable in some cases and not in others. For example, delays in construction which extend a unit outage may have consequential costs in some cases but, in other cases, where the plant may be water constrained, an extended outage will not incur any additional lost production costs.

The project under consideration may be a distinct project or part of a program of projects to modernize a plant. The sensitivity analysis for the project may form part of a bigger sensitivity analysis. Usually, however, the sensitivity analysis will be for the modernization process as a whole.

The sensitivity analysis for each identified project is conducted within the electronic template used in Volume 1, Section 4.9. The user guide supplied with the template describes how to conduct the sensitivity analysis within the template. Some of the parameters discussed below will be combined before insertion into the template.

The range used in the analysis for each parameter will depend upon the individual circumstances of each owner and of each plant. These guidelines will not attempt to specify any ranges to be used.

The parameters examined could be combined in a multitude of scenarios. These guidelines will not attempt to distinguish between the possible scenarios as each individual project and plant examined will have its own particular circumstances at any given time.

7.6.1 Costs

Cost parameters to be assessed for sensitivity analysis include:

- Engineering costs
- Construction costs

Engineering Costs

Engineering costs include those associated with the conduct of the detailed engineering design following the decision to proceed.

Construction Costs

Construction costs include all costs associated with the construction process. These may include cost associated with:

- Claims for extras by the contractor(s)
- Consequential costs from the contractor’s claims, e.g. other contractor claims, legal costs, administration costs.
- Delays to the completion of the project works which could incur costs to the owner, e.g. additional administration costs, cost of additional lost production.
- Escalation (if the project is over an extended period).
- Interest rate movements.
- Exchange rate movements

7.6.2 Benefits

Benefit parameters to be assessed for a sensitivity analysis include:

- Capacity
- Efficiency
- Availability
- Value of energy
- Fuel cost

Capacity

The expected capacity improvement from the project is well defined at this stage. A sensitivity analysis of capacity will focus on capacity possibly not delivered by the project.

Efficiency

Efficiency can be treated in the same way as capacity (and, of course, they are related).

Availability

A sensitivity analysis of availability is dependent upon the individual plant under consideration. Availability, for some plants, is not an issue due to system requirements, i.e. its use is flexible or it has water constraints. In the changing market of today, however, availability will be extremely important. Each owner will have to quantify how it wishes to treat availability financially as a benefit. The value to an owner of a flexible plant that is consistently available for service will depend upon the owner's circumstances and market arrangements. Obviously, the greater the availability of the unit the greater the opportunity to take advantage of the market.

A modern integrated P&C system contributes to higher availability of the plant because of higher MTTRs and MTBFs of P&C components.

Value of Energy

The owner, in the electronic template used in Volume 1, Section 4.9, has predicted the expected value of energy in the future but a sensitivity analysis of the prediction may be required. It is difficult to specify a percentage range to assess but, in an open market, this could be high on a short-term basis. Each owner will have it's own particular situation.

Fuel Cost

Fuel, which in the case of hydro plants is water, normally has costs. These are related to water usage, storage or capacity costs. The sensitivity analysis would consider possible changes (increases) in water usage fees.

8
IMPLEMENTATION

8.1 Introduction

At this point, 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. Figure 8-1 outlines the steps involved in preparing proposed life extension and modernization activities for implementation.

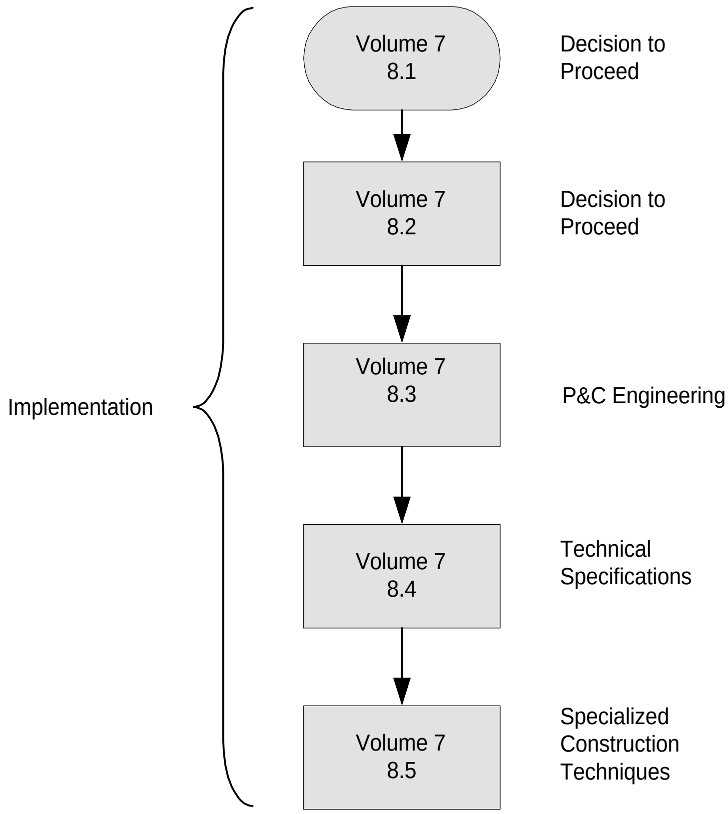

Figure 8-1
Implementation Process

8.2 Project Management

Through the previous sections, a life extension or modernization approach should have been selected and financial and technical viability proved. The first activity in the project definition and implementation phase will be to confirm that this approach meets the overall requirements of the owner before proceeding.

The most accepted way to address the owners requirements is through the use of a standard project management approach. This approach starts with a statement of objectives accepted by the sponsor of the work. Table 8-2 in Volume 1, Section 8 provides a sample statement of objectives.

These objectives are incorporated into the project management process as part of the project plan. The Project plan is the outline of how the project will be undertaken and includes a summary of responsibilities, authorities, costs, schedules and deliverables. The project plan will also include a quality plan to guide the process.

8.3 P&C Engineering

8.3.1 General

Once funding, approvals and the project plan are in place engineering can begin. This includes detailed design work for the modernization activity such as preparing drawings, analysis and upgrade requirements, client verification, selecting equipment and preparing detailed specifications for purchased components and construction.

Fault tree analysis[20] can be applied to both the Protection and Control systems in order to design a more secure system. Fault tree analysis allows the designer to determine the failure rate for a combination of components. This allows the designer to predict failures, ensure redundancy is provided in critical areas, or select devices with lesser failure rates.

Special consideration in the design should be given to susceptibility to electromagnetic and radio frequency interference. Most modern protection and control systems are electronic based and must have definable capability to withstand this interference. Electromagenetic and radio frequency tests are considered successful when no erroneous output is present, no component failure occurs and there is no change in calibration exceeding normal tolerances. Equipment that does not pass the Surge Withstand Capability (SWC) test usually exhibits the following symptoms as a minimum: freezing or locking of processor, erroneous output and misoperation.

Although there is a general requirement for the appropriate testing of any new system the following specific test, SWC, Radio Frequency Interference (RFI) and Radiated Transient Voltage tests, are explained briefly since they are critical for the successful implementation of a new P&C system.

SWC Test

An SWC test is a design or type test applicable to most components of the protection and control system.

Equipment located in generating stations is exposed to potentially damaging transient signals transmitted by connecting wires and cables. These transients can be found on the inputs to PLCs, event recorders, power supplies and many other devices. Transients originate in primary high voltage buses and in secondary control circuits. In primary buses the transients result from lightning, faults and the operation of switchgear (particularly disconnects) which couples into the P&C circuits through electromagnetic and capacitive paths. In the control circuits transients are generated by switching of inductive devices such as relay coils and solenoids. Repeated exposure to SWC can cause irrepairable damage to the silicon junctions in bipolar devices.

[20] Answering Substation Automation Questions Through Fault Tree Analysis by Gary W. Scheer, Schweitzer Eng. Labs.

Testing is generally not applied to production equipment unless specified by the user or as a part of general testing by the manufacturer. It can be considered a destructive test since although undocumented it has been assumed to shorten life span. If production equipment is to be SWC tested, it is usually a type test. Equipment that is SWC tested should be marked with the date of the SWC test for future reference. The standard used for SWC testing is: IEEE standard C37.90.1

Equipment to be SWC tested should be energized and operating normally.

Methods of improving SWC test results include: proper grounding and shielding of cables and electronics as well as proper use of de-coupling components on the sensing inputs and power supply inputs of equipment.

RFI Test

A Radio Frequency Inteference (RFI) test is also a design or type test applicable to most components of the protection and control system.

RFI can be emitted from any number of sources such as handheld VHF radios, Cell phones and cordless phones. A transmitter and antenna can be used to test the susceptibility of equipment from radiated RFI. The test is performed with the equipment energized and under normal operating conditions. The antenna is brought to within 1 meter of the exposed circuits in the equipment under test. Typically the following transmissions are tested:

- VHF nominal 158 MHz to 173 MHz at 10 watts RF output (measured at the antenna),
- UHF nominal 450MHz to 470 MHz at 5 watts RF output (measured at the antenna),
- UHF nominal 832 MHz at 0.06 watts RF output (measured at the antenna).

The above test is a simple practical test using readily available test equipment. A more exact test is available in IEEE standard C37.90.2 but requires sophisticated test equipment and a special test chamber.

Methods of improving RFI test results include: proper grounding and shielding of cables and electronics.

Radiated Transient Voltage Test

This test simulates a “worst case” industrial noise environment consisting of high voltage relays operating in close proximity to solid state equipment. This test differs from the SWC test in that SWC is a conducted transient and this is a radiated transient test. Refer to IEEE standard 518-1982-5.3.1 (Relay noise test).

Methods of improving Radiated Transient Voltage Test results include: proper grounding and shielding of cables and electronics as well as proper use of metal oxide varistors or commutating diodes across relay coils

8.3.2 Control

The modernization of the control system should include evaluation of the latest technology available for automated plant control. As stated in Section 5 many possible options exist for the automated control system. Careful planning of the plant control network topology should be done from the onset of the design. A network topology plan is a good way of seeing what devices need to be connected and how much data through-put there will be. Bottlenecks can be reduced before they become a problem. Where ever possible, use fiber optic cables to link the various nodes of the control network to improve noise immunity. The ground potential indifference of fiber optic cables is ideal for the generating station environment. Control system security is also a big factor in the design process. Redundancy of key portions and control of unauthorized access should be considered. The designer should ensure that approximately 10–20% spare I/O is installed and extra I/O space is planned for both in the panel and from external on the network. Appendix B gives suggested design specifications for the control system.

8.3.3 Protection

The objective for the design of hydroelectric generator protection is to achieve a high level of reliability, availability, maintainability and operational performance. The designer should therefore give careful attention to factors affecting the protection performance, co-ordination, redundancy and spare parts.

The first step in the protection design is to draw an accurate 1-line diagram of all high voltage power system components including: generators, transformers, breakers and disconnects (At this stage it is likely that the basic configuration is similar to that before modernization or has been modified by others to satisfy new operating requirements, however, the existing level of protection should not be assumed to be adequate). With this configuration information, system data and the nameplate ratings of the power components, perform a fault analysis to determine fault currents. With the data from the fault analysis and the configuration information determine appropriate protection zoning and coordination requirements then select appropriate relaying and metering devices and circuits and add these to the 1-line diagram. From the coordination study individual relay settings can be developed.

Risk vs. Protection

The cost of providing various levels of backup protection needs to be balanced with the allowable risk (cost of failures and third party liabilities). An analysis of a Risk Based Approach to the Application of Generator Protection[21] resulted in the following conclusions.

Although utilities strive for more cost effective systems in general most rightfully remain conservative in the application of Protection and control solutions. This direction in design is supported by all relay manufacturers who advocate some form of redundancy. Although “Fault

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[21] A Risk Based Approach to the Application of Generator Protection, By BC Hydro Power Supply Engineering Report No. PSE117.

Tree Analysis" has been applied to protection reliability, it is not commonly used in business case preparation.

From a strictly financial point of view, a single digital relay offers the lowest life cycle cost. At the same time, a small but measurable risk in loss of life serious environmental damage or adverse effect on the interconnected equipment decreases with the application of more than a single digital relay. In addition to safety concerns, the generator owner has the responsibility to clear the in-plant faults in the shortest possible time to minimize any potential affects on the electric system stability. The financial evaluation, combined with the concerns regarding safety, environmental and electric system impact, led to the conclusion that some sort of protection redundancy is crucial.

8.4 Considerations for Technical Specifications

Specifications and contracts are the means of transferring risk from owner to contractor. It is important to ensure that the specification is designed 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 contingency the contractor will build into its price.

This section is designed to provide assistance, at an overview level, to the user when preparing specifications. Most owners will have a procurement policy with standard documentation in place. The information given does not seek to replace the owner's standard documentation; rather to augment it.

8.4.1 Specifications

The Protection and control specifications should be two separate specifications. A single qualified control company may not be a qualified protection company.

The first step is to prepare the specifications in a tender document, select the potential bidders and send out the tender.

Control system specifications

Many qualified system integrators exist and their names can be drawn from talking to PLC manufacturers. As well the manufacturers usually have a section on their Web page listing qualified integrators with links to their own Web pages.

The Tender should include the following information as a minimum:

- All available generator data,
- 1-line, 3-line, schematics, wiring and layout drawings of the systems to be refurbished,
- Generator trip table
- Design basis memorandum for control

- List of all known deficiencies,
- Overhaul schedule,
- Support services provided by the owner,
- Bid date,

Protection specification

Many qualified protection companies exist and their names can be drawn from protection relay manufacturers.

The tender should include the following information as a minimum:

- All available generator data,
- 1-line, 3-line, schematics, wiring and layout drawings of the systems to be refurbished,
- Generator trip table
- Existing protection setting sheets,
- Protection planning document,
- List of all known deficiencies,
- Overhaul schedule,
- Support services provided by the owner,
- Bid date.

8.4.2 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 refurbishment 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.

8.4.3 Bid

The bid should include the following:

- Details of qualifications, experience and list of commercial references of contractor,
- Standard lump sum cost to supply materials including control or protection panels, cabling and or additional equipment,
- Standard lump sum cost for installation and commissioning labour,

- Per diem rate, overtime rate and travelling expenses to supply services of installation and commissioning labour beyond the standard lump sum,
- Per diem rate, overtime rate and travelling expenses to supply services of a supervisor during installation and or commissioning,
- Cost for on-site training including training course materials,
- Per diem rate, overtime rate and travelling expenses to supply services of a trainer,
- Prices for optional items (if required),
- List of recommended spare parts including prices.

The standard scope of supply includes:

- Factory integration and acceptance witness testing of new equipment with customer,
- Delivery of equipment to site,
- Removal of existing equipment (may not be included in scope as work performed by site labour),
- Installation of new equipment,
- Commissioning and acceptance tests.

8.4.4 Bid Evaluation, Bid Negotiations

The owner's personnel or an outside engineer will evaluate the bids received. All competitive bids will be adjusted to the same technical level by negotiations to enable meaningful price comparison. The Owner will usually want to award the contract to the lowest bidder, however, factors such as qualifications, work history and reference check should be factored in.

8.4.5 Contract

The contract consists of the bid proposal and any agreements made during the contract negotiations. The protection and control supply contracts should be co-ordinated (if these are separate contracts).

8.5 Specialized Construction Methods

8.5.1 General

For PLCs, digital meters and other microprocessor based equipment to operate repeatably and within calibrated tolerances, consideration must be given to construction techniques. In this section, construction methods for newer digital devices is covered. Traditional electrical construction methods such as panel grounding and wiring termination details will not be covered here.

8.5.2 Control Cabling

It is common practice in power facilities to use overall copper shielded cable, with the shield grounded to the ground grid at both ends and unused conductors grounded at one end only for control circuits. This practice minimizes induced noise and transients, however, caution must be taken to ensure that the ground grids at both ends are solidly bonded as damage to the cable, equipment and persons can result.

Ideally control cables should be run perpendicular not parallel to high voltage lines. High voltage transients can induce voltages in control cables high enough to be misinterpreted as actual control signals. A perpendicular layout reduces the amount of electromagnetic coupling between the cables.

8.5.3 Analog Signal Shielding

The shielding of analog signals is very important to the quality of the signal and ultimately the stability of the controlled system. Shielding of analog signals should be carried from the measuring system through terminal blocks to the sensor. Generally instrumentation practice is to ground the individual shield at the station panel end only, not at the sensor. The shield should never be grounded along the way at terminal block interfaces or at the sensor itself. Grounding the shield at more than one place can cause voltage level differences or ground loops to form which can harshly affect the analog signal and even the input to the measuring device. Like control cables, analog cables should be run perpendicular to high voltage cables. It is good practice in a re-development to run new, shielded cables to all electronic devices, following the proper shielding practices.

8.5.4 Grounding

The newer electronic equipment is very sensitive to proper grounding practices. The addition of this noise sensitive equipment may require improvements to the existing station ground grid. The grounding of equipment can only be effective when the ground grids of the interconnected equipment are very solidly grounded. The proper grounding of a PLC, for example, is crucial. The processor and input/output cards can misoperate or suffer irreparable damage if not grounded according to the manufacturers specifications. The designer must be careful to avoid ground loops especially in a power station where voltage levels between two points can be high with respect to the control system operating voltage.

8.5.5 Terminal Block Interfaces

Many PLC and terminal block manufacturers supply pre-wired harnesses and terminal block combinations for use with PLC input and output cards. These termination devices offer quick low cost installation.

The wiring arm is supplied separate from the I/O card with a cable pigtail attached. Typically the other end of the cable is terminated with a D-sub type connector that plugs into a DIN rail mountable terminal block assembly. Depending on the size of the control wiring these terminal block assemblies can become troubleshooting nightmares. If the control cable size is #16 AWG or higher, usually the stacked arrangement of the terminal assembly provides the neutral jumpering on the bottom row. The top row of wires covers these terminations making troubleshooting and access difficult. If an input card has only one common reference signal, this problem would not be apparent.

8.5.6 Fiber Networks

Where a control system of PLCs is distributed around a generating station, fiber optic cables offer many advantages over traditional copper cables for networking the system. Fiber is immune to noise, both RFI and Electromagnetic Interference (EMI) and is also immune to ground loops. Care must be taken when specifying and installing so that the right cable is used for the right job. Indoor, outdoor, riser rated, gel filled, loose tube, tight buffer need all be considered. All fiber cables have specified minimum bend radiuses and these must be observed during installation. A distributed system of multi-fiber cables run from a central location such as a control room to each generator can provide many parallel uses such as network communications, IRIG time signal, voice and other data requirements all on the same cable.

8.5.7 Disconnect Facilities

Disconnecting terminal blocks with test jacks should be used for all analog inputs and outputs. These blocks facilitate the easy isolation of loops for calibration and testing purposes.

8.5.8 Interposing Relays

In most PLC control systems interposing relays are used between the PLC and the field devices such as circuit breaker trip coils, large motor starters, etc. A couple of reasons exist for their use. They are used where the PLC output may not be capable of handling the inrush current of a larger motor starter or breaker coil. They are also used as an isolation point between different voltages such as between a 24Vdc PLC ouput and a 125Vdc device. Interposing relays should be kept to a minimum where possible, otherwise the panel wiring starts to emulate a relay based control system. Many newer PLCs have output modules with isolated relay contacts suitable to drive most starters and contractors.

A
LITERATURE REVIEW

Volume 7 Annotated bibliography of literature on Protection Control and Automation

V 7.1

TITLE	Achieving the benefits of fully automatic hydro operations
AUTHOR	Bader, Julie and Baum, Stephen COUNTRY USA
PUBLICATION	*Hydro Review.* Vol. XVII, *No. 4, P. 50-56.*
DATE	June 1998
KEY FOCUS	Automation SCADA system
SUMMARY	The automation of the Headgate Rock plant on the Colorado River took less than a year, improved efficiency by 12% and reduced power costs to the operator by 95%. This peer reviewed article includes a detailed description of the SCADA system installed. Author affiliated with US Bureau of Reclamation at Hoover Dam.

V 7.2

TITLE	**Advances in microprocessor-based distribution relays**
AUTHOR	E. Schweitzer and M. Feltis **COUNTRY** USA
PUBLICATION	Schweitzer Engineering Laboratories, Inc. website*: <u>www.selinc.com</u>*
DATE	
KEY FOCUS	Protective relay event reporting Relay programmable logic
SUMMARY	Advantages of microprocessor-based relays are discussed.

V 7.3

TITLE	**Automating existing hydrostations: a cost-effective rehabilitation option**		
AUTHOR	Jarvis, D. And Bevivino, J.P.	**COUNTRY**	USA
PUBLICATION	*Hydro Review.* Vol. X, No. 7, p. 12-18.		
DATE	October 1991		
KEY FOCUS	Automation Personnel management Project planning		
SUMMARY	The focus of this paper is on the process adopted by Union Electric company in the lead up to the automation of two of its aged plants. In particular, the justification analyses carried out and the personnel issues faced. In relation to the latter the company adopted an approach built on good communication, information sharing follow up and training. In this way initial skepticism gave way to enthusiastic support for the project.		

V 7.4

TITLE	**Automating hydro: keeping old plants profitable**		
AUTHOR	Herrin, R., Brookshire, B., Hunter, J and Johnson, R.	**COUNTRY**	USA
PUBLICATION	*Hydro Review.* Vol. XVIII, No. 2, p. 18-27.		
DATE	April 1999		
KEY FOCUS	Automation Control systems Electronic governors		
SUMMARY	Three recent hydro automation case studies are presented: a program to automate several generation systems; the integrated automation of six plants in a river cascade group; and the automation of two small plants (13 MW and 3 MW) on a water delivery system. In each case there has been increased productivity, and reduced operations and maintenance expense. Lessons learned by the three utilities involved are presented for the benefit of other owners.		

V 7.5

TITLE	**Automating hydro: pitfalls and opportunities**		
AUTHOR	Beck, J.W.	**COUNTRY**	USA
PUBLICATION	*International Journal on Hydropower & Dams*. Vol. 3, No. 6, p. 83-84.		

DATE	1996
KEY FOCUS	Automation Project planning
SUMMARY	Good software will never overcome a bad design. An automation scheme must be properly engineering and implemented. The limitations and functions of PLC's are discussed. Author affiliated with North American Hydro.

V 7.6

TITLE	**Automation ensures efficient power generation by Wertach hydro power station**		
AUTHOR	Lock, R.	**COUNTRY**	USA
PUBLICATION	*Engineering and Automation*. Vol. 17, No. 1, p. 24-25.		
DATE	Jan-Feb 1995		
KEY FOCUS	Automation Power plant control		
SUMMARY	The comprehensive automation system installed for a small hydro facility is described. Author affiliated with Siemens AG, Munch.		

V 7.7

TITLE	**Automation links remote sites**		
AUTHOR	Preheim, J. And Abruzere, G	**COUNTRY**	USA
PUBLICATION	*Power Engineering*. Vol. 102, No. 9, p. 21-26.		
DATE	September 1998		
KEY FOCUS	Automation Control Systems		
SUMMARY	With nine powerhouses and 23 turbine units generating 1,000 MW over a very large geographic area, Southern California Edison's Big Creek Hydroelectric Project, Southern California, selected the Westinghouse Ovation Control & Information system for its modernization program rather than a traditional distributed control system (DCS). Ovation allows for the use of-the-shelf Pentium PC controllers that provide a high degree of flexibility in system design and architecture. The system and its future applications are described. Authors affiliated with SCE and Westinghouse Process Control.		

V 7.8

TITLE	**Automation of Tacoma's hydroelectric plants**		
AUTHOR	Kirchmeir, R.R. & Orth, J.A.	**COUNTRY**	USA
PUBLICATION	*IEEE Technical Applications Conference and Workshops. Conference Record. Northcon '95.* IEEE, New York, NY.		
DATE	1995		
KEY FOCUS	Automation Power plant control		
SUMMARY	The planning, process and implementation of automation of Tacoma's hydroelectric plants is detailed. Authors affiliated with Bentley Co., Portland, Or.		

V 7.9

TITLE	**Control system automation project for the Duke Power hydroelectric system**		
AUTHOR	Herrin, R. & Sloop, M.	**COUNTRY**	USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.* Vol. 1. ASCE, New York, NY. p. 672-683.		
DATE	1997		
KEY FOCUS	Automation Control systems		
SUMMARY	North Carolina's Duke Power's US$290 million Hydrovision Program will upgrade several of the company's aging plants. One of the goals is to provide a system which will enable complete operation, monitoring and control of all hydro units from a centralized location. An open hardware platform was used to evaluate the alternatives for control automation. A detailed account is given of the process. Authors affiliated with Duke Power and Duke Engineering, Charlotte, NC.		

V 7.10

TITLE	**Control system availability in hydropower plants: a case study**		
AUTHOR	Lacey, W.	**COUNTRY**	USA
PUBLICATION	*International Water Power and Dam Construction.* Vol. 46. No. 7. p. 25-27.		
DATE	July 1994		

KEY FOCUS	Automation Control systems
SUMMARY	The refurbishment of the Republic of Ireland's Electricity Supply Board's 95 MW Ardnacrusha hydro plant included the installation of a new control and information system which maximizes as far as possible reliability and availability. A redundant control system configuration was chosen because of the advantages it offered. It is still available on the failure of a components. Author affiliated with PCAS (E.D.), Carlow, Ireland.

V 7.11

TITLE	**Controlling nine hydro plants from a single control room**		
AUTHOR	Wacker, J.	**COUNTRY**	USA
PUBLICATION	*Hydro Review.* Vol. XVII, No. 2. p. 18-25.		
DATE	April 1998		
KEY FOCUS	Automation Power plant control		
SUMMARY	The decision to automate nine Oregon plants from a single control room using Allen-Bradley programmable controllers rather than a SCADA system cost US$4.5M Cost savings of more than US$8M over 8 years are expected. The reasons for the choice of system, its design and the installation procedures are discussed. Author affiliated with Enron Portland General Electric Company, Portland, Oregon.		

V 7.12

TITLE	**Flexible requirements for hydro plant control**		
AUTHOR	Müller, S. & Meisel, J.	**COUNTRY**	Germany
PUBLICATION	*International Journal on Hydropower and Dams.* Vol. 3. No. 6. p. 85-87.		
DATE	1996		
KEY FOCUS	Automation Power plant control		
SUMMARY	Three case studies describe control systems based on the flexible Prokon-LSX system, but tailor-made for the different plants' requirements. Authors affiliated with Siemens AG, Germany.		

V 7.13

TITLE	**Hoover PMSC system**		
AUTHOR	Lennon, C.	**COUNTRY**	USA
PUBLICATION	IEEE Power Engineering Society. (1999). *1999 Winter Meeting. 31 January –4 February. 1999. New York City, New York, USA*. IEEE, Piscataway, NJ. p. 206-208.		
DATE	1999		
KEY FOCUS	Power plant control		
SUMMARY	A new system, the Hoover Programmable Master Supervisor Control (PMSC) system developed internally by USBR is fully operational at Hoover Dam, controlling water and power delivery from hoover Davis and Parker powerplants. The system dynamically maximizes the efficiency of the three plants and automatically controls the generation based on requests from the dispatch center. Central to the system is a real-time distributed database which provides connectivity to 12 other modules. A unique feature of the system is the distribution of the functions to the lowest level possible. The paper gives an overview of the system modules, the challenges faced in developing the system, lessons learned from the process and future development.		

V 7.14

TITLE	**How the Hydroelectric Design Center's experience ensures new SCADA systems are successful**		
AUTHOR	Gantenbein, Chris	**COUNTRY**	USA
PUBLICATION	*Waterpower '95. Proceedings of the International Conference on Hydropower.* Vol. 2. (1995). ASCE, New York, NY. p. 1565-1574.		
DATE	1995		
KEY FOCUS	Control systems Quality control SCADA		
SUMMARY	Quality control and testing procedures at the USBR Hydroelectric Design Center, Portland, OR, are described.		

V 7.15

TITLE	**Hydro automation: finding the right approach**		
AUTHOR	Rogers, C.S., Webb, J. & Gant, J.	**COUNTRY**	USA
PUBLICATION	*Hydro Review.* Vol. 15, No. 2. p. 16-27.		

DATE	April 1996
KEY FOCUS	PLC systems
SUMMARY	Case studies are presented outlining how modern PLc systems have been used to upgrade obsolete control systems located at two pumped-storage facilities and one conventional hydroelectric generating facility. Authors affiliated with PECO Energy Co., Grand River Dam Authority and California Department of Water Resources.

V 7.16

TITLE	**Hydro automation: Rock Reach hydroelectric project**		
AUTHOR	Mettler, J.	**COUNTRY**	USA
PUBLICATION	IEEE Power Engineering Society. (1999). *1999 Winter Meeting. 31 January –4 February. 1999. New York City, New York, USA*. IEEE, Piscataway, NJ. p. 202-204.		
DATE	1999		
KEY FOCUS	Automation Power plant control		
SUMMARY	A brief paper on the replacement of the Rocky Reach DEC PDP mini computer based control system with one of the first hydro control systems to use Windows NT based plant control, and PLC's for the auxiliary systems. Components and features of the 1287MW plants' system are discussed.		

V 7.17

TITLE	**Hydro control technology: making plants more efficient, effective**		
AUTHOR	Byers, W.	**COUNTRY**	Various
PUBLICATION	*Hydro Review Worldwide.* Vol. 3. No. 4. p. 18-22.		
DATE	Autumn 1995		
KEY FOCUS	Automation Control systems – design		
SUMMARY	This report on hydro control technology, based on interviews with suppliers and users, focuses on trends in control and automation systems, applications of the systems and benefits being obtained from them. Three main trends emerge: a focus on functional effectiveness over technological capability; designs that are flexible, adaptable and easily upgraded; and development of "smart" systems which help operators analyze options and make decisions about appropriate actions. Examples of various systems are used.		

V 7.18

TITLE	**Hydropower upgrades focus on automation**		
AUTHOR	Giovando, CarolAnn	**COUNTRY**	USA
PUBLICATION	*Power,* p. 59-66.		
DATE	March / April 1998		
KEY FOCUS	Remote monitoring		
SUMMARY	Rehabilitation projects recently undertaken by 4 leading US power producers are described. In each case the focus has been on remote monitoring, automation, use of advanced IT systems, which are referred to in some detail.		

V 7.19

TITLE	**IEEE guide for computer-based control for hydroelectric plant automation**		
AUTHOR	IEEE Power Engineering Society	**COUNTRY**	USA
PUBLICATION	Institute of Electrical and Electronic Engineers. Power Engineering Society. Energy Development and Power Generation Committee. *IEEE guide for computer-based control for hydroelectric plant automation.* IEEE Standard 1249-1996. IEEE, New York, NY. 64pp.		
DATE	1997		
KEY FOCUS	Control systems Standards		
SUMMARY	Standard for hydro plant control systems.		

V 7.20

TITLE	**Latest developments in integrated hydropower plant and substation control systems**		
AUTHOR	Bruaner, C.	**COUNTRY**	Austria
PUBLICATION	IEEE. *Proceedings EMPD '95. 1995 International Conference on Energy Management and Power Delivery.* IEEE, New York, NY. Vol. 2. p. 668-673.		
DATE	1995		
KEY FOCUS	Control systems New technology Power plant control		

SUMMARY	Latest developments in integrated hydropower plant and substation control systems.

V 7.21

TITLE	**Lowering cost through advances in technology**		
AUTHOR	B. Coflan	**COUNTRY**	Canada
PUBLICATION	Schneider Automation website: *www.modicon.com*		
DATE			
KEY FOCUS	PLC automation		
SUMMARY	Changes in PLC technology lower costs without sacrificing support of earlier products.		

V 7.22

TITLE	**Making an automated monitoring system work at Tolt Dam**		
AUTHOR	Marilley, Jil & Myers, Barry	**COUNTRY**	USA
PUBLICATION	*Hydro Review.* Vol. XV, No. 6. p. 10-14.		
DATE	September 1996		
KEY FOCUS	Automation Dam monitoring		
SUMMARY	As part of its major dam upgrade program, Seattle Water Department installed an automated condition monitoring and advance warning system at Tolt Dam, with positive results from both an operating and public relations perspective. A detailed technical account of the Automated Data Acquisition System (ADAS) is given, and lessons learned from the program, including the effect of severe weather conditions are detailed. Well illustrated with diagrammatic charts.		

V 7.23

TITLE	**Making money by improving plant efficiency**		
AUTHOR	Robitaille, Al, Robert, S. & Welt, F.	**COUNTRY**	Canada
PUBLICATION	*Hydro Review.* Vol. XV, No. 5. p. 92-97.		
DATE	August 1996		

KEY FOCUS	Automation Economic aspects Optimization Software
SUMMARY	Greater efficiency and significant savings have resulted from the development of Hydro-Quebec's advanced computer-based water management program, GESTEAU, to better understand the causes of efficiency related water spillage and energy losses. Its new version integrates forecasted data which can be processed through a series of hydraulic, optimization and analysis models. Hydro-Quebec expects that optimal levels resulting from the installation of the software in its plants across Quebec will postpone the need for construction of additional hydro plants and provide more energy for export. Charts to illustrate efficiency gains included.

V 7.24

TITLE	**Managing the people part of hydro automation**		
AUTHOR	Spicer, Rex, Dunlop, Drew, Jarvis, Dan & Byers, Ward	**COUNTRY**	Canada / USA
PUBLICATION	*Hydro Review.* Vol. XVI, No. 2. p. 18-27.		
DATE	April 1997		
KEY FOCUS	Automation Personnel management		
SUMMARY	The experiences of 3 hydro producers show that the successful transition to advanced control and monitoring systems requires understanding and careful management of the effects on staff. Authors affiliated with Niagara Mohawk Power Co., Potsdam, NY, BC Hydro, Burnaby, BC, and Union Electric Company, Eldon, MO.		

V 7.25

TITLE	**Modular I&C systems for hydro powerplants**		
AUTHOR	Loibl, L. & Stach, W.	**COUNTRY**	Austria / Germany
PUBLICATION	*International Journal on Hydropower and Dams.* Vol. 5, Issue 4. p. 46-49.		
DATE	1998		
KEY FOCUS	Power plant control		
SUMMARY	A system developed in Germany for powerplant monitoring and control is described in detail in relation to small, medium and large plant applications. The authors are associated with Siemens AG.		

V 7.26

TITLE	**Nantahala control upgrades provide cost savings**
AUTHOR	Neumeuller, Scott, Wright, Jerry **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.* Vol. 1. ASCE, New York. p. 704-712.
DATE	1997
KEY FOCUS	Control systems Economic aspects Turbines
SUMMARY	The upgrade of two generating units, one vertical Francis, the other a single-needle Pelton, at the Queen's Creek and Nantahala powerhouses in North Carolina, has considerably reduced start-to-synchronized time, improved unit protection and reduced costs. Authors affiliated with Woodward Governor Company and Nantahala Power and Light.

V 7.27

TITLE	**Networking and control strategies for generating stations**
AUTHOR	Gagnon, Don & Wikinson, M. **COUNTRY** Canada
PUBLICATION	Canadian Electrical Association. *Hydraulic Power Generation Stream, March 1999, Vancouver.* CEA, Montreal, Quebec. 20p.
DATE	1999
KEY FOCUS	Automation Networking Power plant control SCADA
SUMMARY	This extensive paper discusses the impact of networks on control systems in generating stations, with particular relevance to the Niagara Plant Group in Niagara Falls, Ontario. It looks at the evolution of networks, factors governing the success of using networks in control systems, connectivity, commonality of control and business networks and planning for change. The authors from the Hydroelectric Business Unit of Ontario Hydro, have written for a wide audience. The result is very readable and informative, as well as detailed.

V 7.28

TITLE	**Open systems revolutionize plant automation**
AUTHOR	Zink, John **COUNTRY** USA

PUBLICATION	*Power Engineering.* p. 28, 32-33.
DATE	September 1998
KEY FOCUS	Control systems – design
SUMMARY	Control system vendors have taken advantage of developments in off-the-shelf hardware and software to produce systems which can enhance operating practices, and offer greater information and communications capabilities to a wider range of personnel. This paper offers an overview of these “open systems” and the development of a fieldbus system to be used with them. It stresses that the real value of the new systems lies in the fact that operators, plant engineers and management can access the same information simultaneously. The operators themselves, effectively in multiple locations at once, can be responsible for multiple tasks at the same time, but, freed of the need to be in a single control room, can also perform other functions.

V 7.29

TITLE	**Optimizing unit allocation: the Norwegian experience**		
AUTHOR	Browne, M. & Vinneg, L.	**COUNTRY**	Norway
PUBLICATION	*Hydro Review Worldwide.* Vol. 3, No. 4. p. 24-27.		
DATE	Autumn 1995		
KEY FOCUS	Automation Optimization Simulation models Software		
SUMMARY	Traditional methods of optimizing load allocation are less than effective in the new power markets. State-of-the-art optimization software allows for the development of simulation models which offer an accurate analysis of operating constraints and realistic measurement of potential energy gains and benefits. Norway, where 99.5% of electricity is hydro-produced, has been using such technology for many years, with substantial economic benefits. Supplementary functions include machine condition monitoring and the ability to analyze rehabilitation and uprating options.		

V 7.30

TITLE	**Out with the old intake gates**		
AUTHOR	Chaput, P., Gawish, D. & Limoges, M.	**COUNTRY**	Canada
PUBLICATION	*International Water Power & Dam Construction.* Vol. 50, No. 1. p. 28-31.		
DATE	January 1998		

KEY FOCUS	Automation Intake gates
SUMMARY	As part of the refurbishment of the Beauharnois station 74 gates are being rehabilitated by either replacement, refurbishment of corroded and deformed gate guides, or installation of individual hoists. The inspection and testing methods for the old gates and the process used to determine the refurbished designs is discussed. Charts and diagrams used. Authors affiliated with Hydro-Quebec.

V 7.31

TITLE	**PC based control systems for large hydro projects**		
AUTHOR	Miska, E.P. & Mahar, J.	**COUNTRY**	USA
PUBLICATION	IEEE Power Engineering Society. *(1999). 1999 Winter Meeting. 31 January –4 February. 1999. New York City, New York, USA*. IEEE, Piscataway, NJ. p. 213-217.		
DATE	1999		
KEY FOCUS	Power plant control		
SUMMARY	Working with partner Bonneville Power, the USACE Northwest Division has developed a generic data and control system (DACS), based on the experience and knowledge of Corps site staff and its HDC (Hydroelectric Design Center). The PC based system is modular, easily maintained and cost effective. In contrast with its previous system, the new system places a high priority on fault tolerance, and the ability to handle unusual project conditions and system anomalies. It covers the full range of control functions.		

V 7.32

TITLE	**Recent developments in hydro plant control systems**		
AUTHOR	Soerensen, E.	**COUNTRY**	
PUBLICATION	*International Journal on Hydropower and Dams.* Vol. 2. No. 1. p. 38-40.		
DATE	January 1995		
KEY FOCUS	New technology Power plant control Software		
SUMMARY	Different software modules, implemented in the same computer, give a higher degree of integration, require less space, and lead to reduced costs, and greater reliability.		

V 7.33

TITLE	**A retrofit that worked: upgrading Trangslet Station's controls**		
AUTHOR	Andersson, Svan	**COUNTRY**	
PUBLICATION	*Hydro Review Worldwide.* Vol. 4, No. 4. p. 16-18.		
DATE	August 1996		
KEY FOCUS	Power plant control		
SUMMARY	An evaluation of a control retrofit based on ten years of operation. The plant owners credit goal-setting and an emphasis on adaptable technology for the success. Author affiliated with Stora Power AB.		

V 7.34

TITLE	**Schweitzer Engineering Laboratories' SEL-300G relay brings new protection to electrical generators**		
AUTHOR	News Release	**COUNTRY**	USA
PUBLICATION	Schweitzer Engineering Laboratories, Inc. Website: *www.selinc.com*		
DATE	2000		
KEY FOCUS	SEL-300G generator protection relay		
SUMMARY	Describes features and benefits of the new SEL-300G generator protection relay.		

V 7.35

TITLE	**Small hydro automation – two case studies**		
AUTHOR	Hunter, John & Johnson, Ron	**COUNTRY**	USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.* Vol. 1. ASCE, New York, NY. p. 684-693.		
DATE	1997		
KEY FOCUS	Automation Economic aspects		
SUMMARY	Case studies of the cost-effective automation of two small plants are presented. Authors associated with Salt River Project. Phoenix, Arizona.		

V 7.36

TITLE	**Statistical performance measures for protective relays**		
AUTHOR	E. Udren, ABB Relay Division	**COUNTRY**	
PUBLICATION	*Western Protective Relay Conference*		
DATE	1996		
KEY FOCUS	Protective relay performance analysis		
SUMMARY	A standardized approach to relay performance assessment is proposed based on availability, dependability, security, hardware MTBF, relaying MTBF and repair time. The concept of "Exposure" is introduced.		

V 7.37

TITLE	**Synchronizing upgrade for hydroelectric plants**		
AUTHOR	Harlow, James	**COUNTRY**	USA
PUBLICATION	*Waterpower '93. Proceedings of the International Conference on Hydropower.* Vol. 3. ASCE, New York. p. 1564-1573.		
DATE	1993		
KEY FOCUS	Automation Remote control Turbines		
SUMMARY	Upgrading of the automatic synchronizing system for the turbines of two plants to ensure that the synchronizing function is dependable when started remotely. The author reports excellent results. Detailed diagrams of the relay systems included. Author affiliated with Beckwith Electric Company Largo, FL.		

V 7.38

TITLE	**Systems to optimize conversion efficiencies at Ontario Hydro's hydroelectric plants**		
AUTHOR	Phnrajah, R.A., Witherspoon, J. & Galiana, F.D.	**COUNTRY**	Canada
PUBLICATION	*IEEE Transactions on Power Systems.* Vol. 13, No. 3. p. 1044-50.		
DATE	August 1998		
KEY FOCUS	Load dispatching Optimal dispatch systems Power plant control		

SUMMARY	This technical paper describes an optimal dispatch system used at two Canadian installations, one controlling three stations near Thunder Bay, and the other at R.H. Saunders generating station on the St. Lawrence river. The validated benefits amount to 15GWh per year, which is about 0.25% of the annual production at the respective stations. Secondary benefits arising from this system include increased decision support through improved access to plant data, and an overall improvement in the operational performance. Illustrated with tables and figures. Authors affiliated with Ontario Hydro, Toronto, Canada.

V 7.39

TITLE	**Tennessee Valley Authority hydro automation programme**		
AUTHOR	Terry, W.	**COUNTRY**	USA
PUBLICATION	IEEE Power Engineering Society. *(1999). 1999 Winter Meeting. 31 January –4 February. 1999. New York City, New York, USA*. IEEE, Piscataway, NJ.		
DATE	1999		
KEY FOCUS	Power plant control		
SUMMARY	The TVA has embarked on a program to completely automate the operation of all of its 29 conventional hydro plants over an eight year period. This paper, presented in the second year of the program, provides overview of the general design concepts, the Hydro Dispatch Control Cell design, and the plant automation system. The TVA has in the past implemented SCADA at various facilities. The limitations of the old system, and the advantages of the new system are briefly discussed in relation to various functions.		

V 7.40

TITLE	**Total system automation in North Georgia**		
AUTHOR	Brookshire, Barry & Jones, Durl	**COUNTRY**	USA
PUBLICATION	*Waterpower ‘97. Proceedings of the International Conference on Hydropower.* Vol. 3. ASCE, New York, NY. p. 1623-1632.		
DATE	1997		
KEY FOCUS	Remote monitoring Power plant control		

SUMMARY	Recent changes in operating practices and mandated flow requirements required a more advanced and versatile control scheme for the six hydro plants of the Georgia Power Company's North Georgia Hydro Group (NGHG). The complete automation upgrade has resulted in a much more complete remote control system providing full monitoring and control capabilities to a central operator, as well as individual unit control including VAR and volt control. Charts of network overview, operator's view and plant monitor are provided. Authors affiliated with GPC.

V 7.41

TITLE	**The universal relay: the engine for substation automation**		
AUTHOR	M. Pozzuoli	**COUNTRY**	
PUBLICATION	GE Power Management website: *www.ge.com*		
DATE	1998		
KEY FOCUS	The Universal Relay		
SUMMARY	Describes features and benefits of the new GE Universal Relay.		

V 7.42

TITLE	**Upgrading generator protection using digital technology**		
AUTHOR	C. Mozina	**COUNTRY**	
PUBLICATION	Beckwith Electric Company Website: *www.beckwithelectric.com*		
DATE			
KEY FOCUS	Protective relay upgrades		
SUMMARY	Areas of improvements available for generator protection through the use of microprocessor based relays.		

V 7.43

TITLE	**Using information from relays to improve the power system**		
AUTHOR	D. Dolezilek and D. Klas	**COUNTRY**	
PUBLICATION	Schweitzer Engineering Laboratories, Inc. Website: *www.selinc.com*		
DATE	1998, 1999		
KEY FOCUS	Protection system design Protective relay upgrades		

SUMMARY	Description of data retrieval methods from microprocessor-based relays. Protection system integration and automation.

V 7.44

TITLE	**VIMOS condition monitoring for hydropower machines**		
AUTHOR	Eriksson, K. & Eriksson, S.	**COUNTRY**	Sweden
PUBLICATION	*ABB Review*. No. 1. p. 15-20.		
DATE	1992		
KEY FOCUS	Condition monitoring New technology Software Turbines		
SUMMARY	A condition monitoring system developed to address the need for mechanical protection of hydropower generator-turbine sets. The features of the system and its future development are described. Authors affiliated with ABB Generation, Vaesteraas, Sweden.		

V 7.45

TITLE	**Why Upgrade Generator Protection**		
AUTHOR	C. Mozina, Beckwith Electric Company	**COUNTRY**	USA
PUBLICATION	*23rd Western Protective Relay Conference. Proceedings.*		
DATE	1996		
KEY FOCUS	Protective relay upgrades		
SUMMARY	Areas of improvements available for generator protection through the use of microprocessor based relays.		

IEEE Standards

IEC 1131-3, 1993, PLC Programming Languages

IEEE (ANSI) C37.90.1, 1989, IEEE Standard Surge Withstand Capability (SWC Test for Protective Relays & Relay Systems)

IEEE 518-1982 Relay Noise Test

B
PROCUREMENT GUIDES

The following are detailed procurement (design and technical specifications) guides for:

Replacing a Protection system
Replacing a Control system

This procurement guide is based on one specific scenario and many other possible LEMs could have been identified.

Generally these guides are intended to show the user the areas that require coverage in specifications of this type. These guides also supply some of the words that can be used directly in a specification if the user desires.

B1 Control

B1.1 Control System Design and Configuration

The power plant should be designed as an automated plant controlled and monitored from the plant HMIs. Additionally, the plant should have the capability to be controlled and monitored from an off-site HMI connected by dedicated data lines to an area control center. Control and monitoring may also be necessary through remote terminal units (RTUs) already installed at the site and used in the existing SCADA system.

The plant control system should be a three tiered distributed network of integrated, intelligent electronic devices (IEDs) operating in a real-time environment combined with a limited amount of local hard-wired controls.

Level I IEDs should be accessible by the plant HMIs via a Level 1 LAN using a open system public protocol. The off-site HMI may access the Level 1 system through a LAN bridge/modem.

Level II IEDs should be accessed only by the Level II unit control system for control commands, data transfer and alarm information. Access to Level II IEDs should be through a ***unitized*** Level II LAN, separate from other Level II LANs and from the Level I LAN or, if necessary, through communication ports to a bridge with a connection to the Level II LAN.

The third tier of control shall be a backup control system consisting of local manual control of certain equipment and functions.

Figure B-1 represents a typical configuration of the integrated protection and control system.

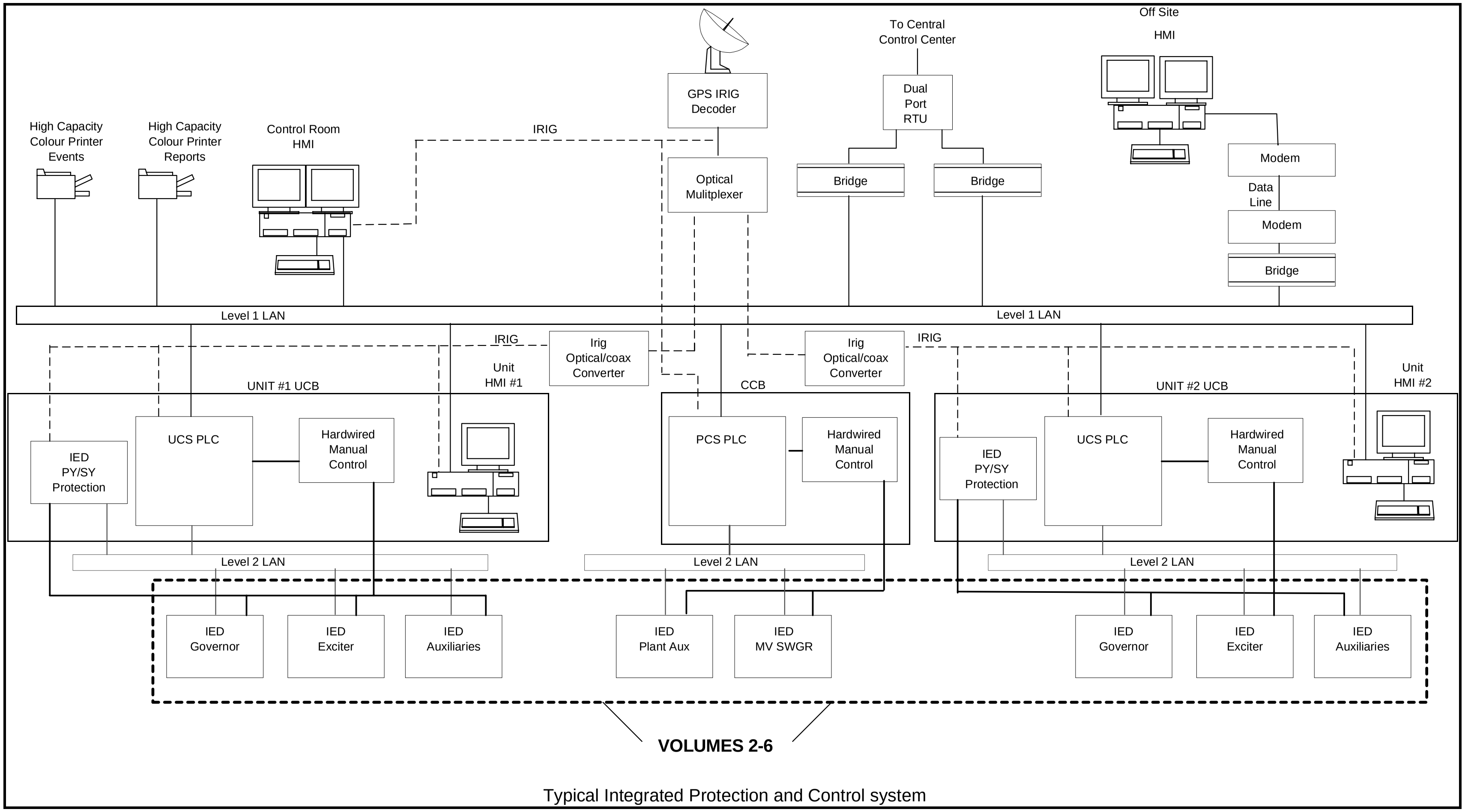

Figure B-1
Protection and Control System Design Layout

B1.2 Control System Level I Hardware

Level I of the plant control system (PCS) should consist of a PLC, in-plant and off-site HMIs, and the Level I LAN. The following sections detail the design and specification of the components.

B1.2.1 Plant Control System PLC

The PCS PLC should be provided with:

- A current technology CPU
- Large CPU capacity and sufficient RAM with I/O throughput to run the data acquisition and control logic via the LAN without performance degradation. This means it should be able to service the data needs of the HMIs while still running a large application program. This is not a location to economize in the control system. The largest, fastest processor available is usually the best choice to cover unexpected processing needs. To minimize spares, this processor can be identical to the ones used in the Unit Control System PLC.
- PLC I/O card time stamping of vital digital protection (and some switchgear status) inputs to 1 ms resolution. Specialized input cards are available that use a GPS time synchronization signal to time stamp inputs for subsequent downloading to the processor at a convenient time. This eliminates the need for a sequential event recorder (SER) as well as the double wiring of field contacts to both a PLC and an SER.
- sufficient I/O and processor memory to meet the intended control requirements with at least 20% spare capacity without degradation to the overall system. This is the one case where bigger is better, don't scrimp on processor size and leave plenty of spare inputs in each I/O chassis.
- analog to digital conversion having 12 bit resolution with at least 0.2% accuracy
- sufficient storage capacity for logged events and data files
- communication interfaces for the Level I and Level II LANs
- power supply that operates at power plant battery voltage (125VDC, 48VDC), this prevents any additional unreliability caused by the voltage converter.
- I/O cards that are hot-swappable
- EEPROM backup of processor memory

B1.2.2 Level I LAN

The Level I LAN should have the following properties:

- multi-vendor LAN support
- IEEE 802.3 and Ethernet TCP/IP protocols (other protocols such as Modbus+, Genius Bus or ControlNet may be appropriate for certain companies who have standardized on Modicon or Allen-Bradley products)

- server with LAN to IED polling management system with current and historical records of good replies, no replies, bad quality replies and failures to poll, as well as LAN collision and packet error detection.
- a LAN management system capable of handling burst speeds necessary to support the 2 second update time for all IED statuses and data acquisition programs at the plant HMIs.
- bridge interface hardware for conversion of LAN fibre optic signals to modem or RTU compatible signals.

B1.2.3 Level II LAN

The Level II LAN should have the following properties:

- a protocol for Level II IED communications.
- LAN to IED polling management system with current and historical records of good replies, no replies, bad quality replies and failures to poll, as well as LAN collision and packet error detection.
- a LAN management system capable of handling burst speeds necessary to support the 2 second update time for all Level II IED alarms and statuses.

B1.2.4 Plant HMIs

There should be at least one HMI per unit control board as well as one in the control room (if there is a control room). The HMI should consist of:

- a workstation class computer with multi-tasking, multi-windowing operating system environment with the highest priority for the control and data acquisition programs. The workstation will concurrently support multi-user access and multiple real-time database updates.
- computer-peripherals should include a high capacity hard disk (4.0GB or more), 24 bit color - 1024 x 768 resolution video display card, 16 bit sound card, shielded powered speakers and a Level I LAN communication card.
- one 17” (minimum) high-resolution (1024 x 768 minimum) color monitor.
- a keyboard and robust pointing device to allow operator selection and execution of control functions, alarm acknowledgement and setpoint input.
- a commercially available, user-friendly, field configurable HMI software for creating operator control and monitoring screens. The HMI software should have a suitable “canned” alarm processing package so that little or NO processing of alarms needs to be done within the PLC. The software should also handle data archiving and trending in a ***fast*** useful manner with a time axis resolution and scaling suitable to plant operations. Additional features such as flexible report generation, select/execute control loops and tag importing are desirable.
- a high speed/ large memory color printer with a paper tray for printing alarm lists, trends and reports.

- the control room HMI shall be identical to the unit control board HMIs except it shall include a CD ROM writer for archiving data files.

B1.2.5 Off-site HMI

Due to the remoteness of a facility or the system control structure, it may be necessary to include an off-site HMI. This HMI should have the same features as described above in the B1.2.5 Plant HMIs section. Care should be taken to ensure a reliable, secure communication link between the off-site HMI and the Level I LAN.

B1.2.6 GPS Clock System

A GPS clock system for synchronization of PLC clocks, protective relays, time-stamping input cards and other time sensitive IEDs should consist of:

- a GPS receiver and antenna
- a GPS time signal fibre optic transmitter
- one GPS fibre optic receiver per unit if physical location is remote enough to warrant more than one run of fibre from the fibre optic transmitter

The GPS signal is ***directly*** connected to the IEDs that require accurate time inputs. Time information transfer over the LAN as regular data (non-interrupt) introduces unacceptable inaccuracies in the time signal.

B1.3 Control System Level II Hardware

The Level II control system should consist primarily of IEDs for the control of the generator I/O, governor and excitation systems. Components and elements are specified as follows.

B1.3.1 Unit Control System PLC

There should be one unit control system (UCS) PLC for each unit and it should have:

- A current technology CPU
- Large CPU capacity and sufficient RAM with I/O throughput to run the data acquisition and control logic via the LAN without performance degradation. This means it should be able to service the data needs of the HMIs while still running a large application program. This is not a location to economize in the control system. The largest, fastest processor available is usually the best choice to cover unexpected processing needs. To minimize spares, this processor can be identical to the ones in used in the Plant Control System PLC.
- PLC I/O card time stamping of vital digital protection (and some switchgear status) inputs to 1 ms resolution. Refer the Chapter 5, Specialized I/O for details.
- sufficient I/O and processor memory to meet the intended control requirements with at least 20% spare capacity without degradation to the overall system. This is the one case where

bigger is better, don't scrimp on processor size and leave plenty of spare inputs in each I/O chassis.

- analog to digital conversion having 12 bit resolution with at least 0.2% accuracy
- sufficient storage capacity for logged events and data files
- communication interfaces for the Level I and Level II LANs
- polling of all Level II IEDs at a selectable rate to provide 2 seconds or less update of all unit IEDs status and telemetry.
- power supply that operates at power plant battery voltage (e.g. 250VDC, 125VDC, 48VDC), this prevents any additional unreliability caused by the voltage converter.
- I/O cards that are hot-swappable
- EEPROM backup of processor memory

B1.3.2 Turbine Governor IED

Each governor should have Level II LAN communication ability and a port for an external programming laptop computer (RS232 for use of the computer COM ports rather than something that requires a specialized PCMCIA card). The IED should communicate with the Level II UCS PLC for load setpoint changes and start/stop sequence initition. Speed adjustments from the automatic synchronizer should be hardwired to eliminate a variable time constant introduced by Level II LAN communication rates. As an option the governor IED could be an algorithm in the unit control system PLC.

A more detailed description of the governor functions are found in Volume 2, Hydromechanical.

B1.3.3 Voltage Regulator IED

The excitation/ voltage regulator IED should have Level II LAN communication ability and a port for an external programming laptop computer (RS232 for use of the computer COM ports rather than something that requires a specialized PCMCIA card). The IED should communicate with the Level II UCS PLC for voltage setpoint changes and start/stop sequence initition. Voltage adjustments from the automatic synchronizer should be hardwired to eliminate a variable time constant introduced by Level II LAN communication rates.

A more detailed description of the governor functions are found in Volume 3, Electromechanical.

B1.3.4 Primary and Backup Protection IEDs

The primary and backup protection IEDs should be equipped for time stamping of protective events. If the IED takes the form of another PLC, it should come with time stamping input cards. No matter what the format, the time stamping capability of this IED should meet the 1ms accuracy requirements. Detected events and their associated time stamps should be communicated to the UCS PLC via the Level II LAN where all time stamp data is assembled for transmission to the HMI via the Level I LAN.

B1.3.5 Back-up Plant Control System

Levels of manual back-up provided in power plants is a hotly debated issue at many utilities. The amount of manual back-up provided could be as simple an E-stop button on the unit control board to a complete relay based control system for starting, stopping and running the unit. The reliability record and the ease of troubleshooting PLC processors and their I/O system have all but eliminated need for the latter. Effective backup can be obtained using hot standby processors and in cases where extreme reliability is required redundant LANs or I/O systems. Experience with PLC systems has shown that failure tends to occur with individual field devices as it would with a relay based control system. These problems rarely cause unit outages and are more easily repaired in PLC based systems than in hardwired relay based systems.

Typical manual backup could be:

- E-stop
- 86S relays
- hard wired governor shut-down solenoid which de-energizes upon a control or protection system fault causing the wicket gates to close
- lift pump operation (fails to ON when processor faults)
- all 480V or 600 V starters should have local start/stop pushbuttons and Hand-Off-Auto switch for maintenance either at the motors or at the MCC.
- synchronizer raise/lower outputs and synchro-check relay should be hardwired unless a PLC system with a rack mounted synchronizer is used

B1.3.6 Unit Control Boards

The unit control board (UCB) should be a free standing metal cubicle(s), CSA Type 1, with the unit specific protection and controls in it, including:

- Level II UCS PLC (processor with I/O chassis)
- additional I/O chassis that, depending on plant layout and I/O distribution, makes sense to have situated in a central location
- Primary and Standby Protection IEDs (including lockout and non-lockout relays)
- E-stop
- UCS HMI
- terminal blocks for landing cables before wiring to panel devices, ensure at least 25% spare TBs are provided

B1.4 Control System Functions

B1.4.1 Unit Control Functions

Each generating unit should be controlled by the Plant Level II control system, the heart of which is the UCS (unit control system) PLC. The standard automated generating unit controls should include:

- pre-start interlock checks and unit ready to start indication
- auxiliary equipment start sequence leading into a unit start sequence (can be divided into two separate actions)
- unit start sequences
- loading sequences
- generator breaker and bus disconnect control
- unit voltage, power factor and MW control (unit setpoints or from plant control based setpoints)
- unloading sequences
- shutdown sequences
- data acquisition and trending
- alarm and annunciation functions
- active generator flow calculations
- active generator capability curve lookup table

The UCS PLC should communicate through the Level II LAN with the governor, exciter and protection system associated with the unit and should collect and process all data and information downloaded from them. The UCS PLC should communicate with HMIs, expert systems and other systems needing plant data via the Level I LAN. In this way, the UCS PLC controls access to the Level II devices from devices sitting on the Level I LAN.

Manual operator initiatd control may or may not be required as a backup to fully automated.

B1.4.2 Plant Control Functions

The Level I control system, directed by the PCS (plant control system) PLC should include:

- total water flow control through the turbines by providing reference flow setpoints to the unit PLCs
- joint MW and voltage control by providing reference MW and kV setpoints to the unit PLCs
- bus and line disconnect/breaker control
- plant equipment control
- 480/600V switchgear equipment control

- MCC starter control for equipment not under UCS PLC control
- alarms, annunciation and data logging
- display intake statuses and plant discharge
- display dam spillway discharge

Under normal operating conditions, the Plant PLC will be controlling the units by providing the flow, kV and MW setpoints. Accordingly, the plant PLC should have:

- tailwater curve lookup table
- intake flow losses and exit flow losses lookup table

The generator capability curve lookup table should be stored in the UCS PLC for "limiting" the reference from the plant PLC. This system eliminates redundant capability curve lookup tables in the plant PLC.

The lookup table data can be used by the plant PLC to determine:

- when the gross head is sufficient to start up a unit during the refill of the reservoir
- when a change in the discharge is sufficient to start up a unit or bring on an additional unit
- the plant discharge to maximize the energy generated from the available flow

B1.4.3 Modes of Operation

The possible modes of operation based on this model of plant control system are:

- **Manual mode**: the unit is controlled through hardwired relays and pushbuttons and local control stations, this mode may be entirely eliminated depending on the amount of backup control provided.
- **Local Auto mode**: the unit is controlled through the UCS HMI, setpoints entered into the local screen are used by the unit control system to control the generator
- **Remote Auto mode**: the unit is controlled by the control room HMI and PCS PLC or an off-site supervisory (RTU, etc.), setpoints entered or calculated are transmitted to the UCS PLC for unit control

Selection between Local and Remote control is made at the UCS HMI and feeds directly into the unit PLC. Only when control has been handed from the unit to the plant control system will setpoints from the plant or supervisory system be used.

Selection between the plant (control room) and supervisory system is made at the control room HMI and feeds directly into the plant PLC. Only when control has been handed from the control room to the supervisory system will setpoints or actions from the supervisory be used.

B1.5 Data Logging, Alarms and Annunciation Systems

Many of the IEDs connected to either the Level I LAN or Level II LAN will have their own data logging and alarm processing capabilities. The role of the plant control system software is to integrate this data into a coherent database of information that can be used for retrieval, processing and display. The format of the data will be highly device and software dependent and a significant amount of forethought will be required during the design phase to amalgamate the data sources.

B1.5.1 Time stamping: IEDs and I/O cards should time stamp certain events, protection statuses and certain switchgear statuses, to a one millisecond resolution. The time stamping device should sort the events according to order of occurrence before transmission.

B1.5.2 Waveform capture: IEDs doing waveform capture should do so at a minimum sampling rate of 12 times per cycle and store this data in an event buffer until transmission. Examples of the type of devices performing this function are protective relays and power monitors. Without a significant amount of custom programming, it is unlikely that any one software will be able to download waveforms from the variety of protection relays and power monitors that may be installed at a plant. As a result, it may be necessary to download data from certain “oddball” devices directly onto a laptop using the devices serial connection.

B1.5.3 Alarm Display: Alarms should be displayed using the HMI software package’s “canned” alarm package. Pure alarm bits (unlatched and at the most, time delayed, by the PLC) should be sent to the HMI in a contiguous data file for alarm processing. The HMI package should differentiate new, unacknowledged alarms from acknowledged alarms and from old alarms. Alarm resetting and acknowledgment should be done through the HMI package, removing the processing burden from the PLC. Alarm processing, when done in the PLC, can represent up to 50% of the processor scan time and seriously degrade processor performance.

B1.5.4 Report Generation: The alarm handling software should produce automatic reports detailing abnormal events, time stamps and return to normal statuses.

B1.5.5 Data Archival: Automatic data archiving on read-writeable (RW) CD ROMs is a must for any system doing alarming, trending or waveform capture. In a very short time, a large amount of data can overwhelm the harddrive of the HMI and start degrading the computer’s performance. Automatic batch routines should archive the data at set time intervals and replace the data files with empty seed files.

Additional PLC Specifications

When specifying PLC hardware the following should be considered:

- Contractor should provide at least 20% spare I/O, and,
- 25% spare available CPU user memory in the processor,
- Maximum processor Scan time should be specified (typically 50ms).

B2 Protection

B2.1 Scope

The following protection and metering devices and equipment should be provided:

- generator protective relays
- main transformer protective relays
- station service system equipment protective relays
- switchgear and line protective relays
- lockout relays (1 primary, 1 backup)
- control hardware for assured shutdown sequences
- metering equipment
- system cubicles
- DC distribution panels (2)

B2.2 System Requirements

B2.2.1 Protective Relays

- The protective relaying system should be an integrated system of IEDs consisting of fully segregated, separately fusal primary and backup multi-function digital relays and single function discrete relays (if required). The IEDs should be capable of the intended protective functions, displaying and storing current, fault and historical values of protective relay operations data.
- The multi-functional relays should be microprocessor-based using digital signal processing technology to provide multiple protection functions for each major electrical equipment group. They also should incorporate a self-checking feature that can warn of impending failure. Discrete relays should also be microprocessor based digital type IED or solid-state electronic type.
- Each protective relay IED should have a means of data collection and a separate port for a laptop computer. Often this will be done through a second RS232 port although relays are becoming available with other types of LAN connectivity.
- Given success in acquiring protective relays with LAN or RS232 connectivity, the data needs to be transmitted to the Level I HMI for archiving and displaying. There may be a need for an intermediary processor that talks to each of the relays and then to the Level I LAN for transmission to the HMI. Until relays start having Ethernet or Modbus+ or similar connectivity, the collection of protection data will be a cumbersome task.
- Protective relay IEDs should be capable of recording current and voltage waveforms and digital inputs and outputs. The waveforms should be recorded at a minimum rate of 12

samples per cycle for post-fault analysis. Each "event" should have at least 100ms of pre-fault data and 1 second of post-fault data.

- Each protective relay should have a GPS time synchronization port

Protective functions

The following protective functions should be provided as a minimum:

Protective function	IEEE C37.2-1996 Device Number	Protective function	IEEE C37.2-1996 Device Number
Generator differential *	87G	100% Generator stator ground fault	59N
Generator – transformer differential*	87U	Negative sequence relay	46
Generator split phase* (depends on windings)	87SP	Generator over/under voltage	59/27G
Generator over/under frequency	81G	Reverse power	32
Ground overvoltage for generator winding	64G	Field winding ground fault**	64
Generator neutral 3rd harmonic	59N3	Volts/Hz protection for generator over-excitation**	24
Voltage restrained time overcurrent	51/V	Loss of field**	40
Stator over temperature +current	49	Generator pole slip**	78F
Voltage balance relay	60	Excitation transformer overcurrent**	50/51

*No back up protection required.

**This protection may be covered by a digital exciter.

B2.2.2 Metering

The following electrical quantities require metering:

- generator terminal voltage
- bus/line voltage
- generator output current
- transformer high side current
- line current

- MW
- MVAR
- MWhr
- power factor (lead/lag)
- frequency

This data can often be acquired without the addition of several expensive dedicated meters. Devices such as synchronizers and power monitors can provide all of the above metering information in one or two devices.

The metering devices should connect to the Level II LAN if they are measuring unit quantities so that the data is available for display on the UCS HMI. The UCS PLC can also put the data out on the Level I LAN for display on the plant HMI. Level I LAN connectivity is require for all non-unit specific metered quantities.

B3 Machine Condition Monitoring

B3.1 Air Gap Monitoring

B3.1.1 System requirements:

Hardware

- Rotor and Stator mounted sensing.
- The sensing portion must be capable of operating in a harsh environment of high temperature, windage, g-force, EMI, RFI and voltage.
- The system must be operator safe from any excessive voltage being coupled back from the sensors.
- Capable of measuring to with-in 0.5 millimeter resolution.
- Operational range 1 to 50 milimeters.
- Capable of retrieving and storing real time sensing data from all sensors simultaneously with machine operational information such as MW, kV, Stator temp and current as well as time.
- Capable of being event triggered (externally and internally) and storing data from all sensors. At least a few revolutions of pre and post event data should be captured.
- Connection to SCADA or plant server for remote data collection.
- Protective and alarm functionality. Individual alarm and trip set points should be included. Air gap rate of change alarm should also be included.
- Instrumentation to convert sensed signals to air gap data for diagnostic & display PC.

Software

- PC based diagnostic & display software for real time viewing of air gap data in polar or list formats.
- Data storage, retrieval and analysis capability.
- Software adjustable alarm and trip set points.

B3.1.2 Implementation

Air gap sensors typically require some sort of unit outage to be installed. Most other parts of the system can be installed before the outage so that once sensors are in place they can be tested back to the instrumentation. Once the system is installed several tests should be performed during initial start of the unit. Air gap data should be stored for the following (with a cold generator and bearings): monitoring of rotor displacement during initial start, rotor expansion during speed up, rotor and stator interaction during field flashing, unit synchronization and subsequent loading until unit fully heated (at least 24 hours at full load). This data will form the base line for subsequent analysis.

B3.2 Partial Discharge Monitoring

B3.2.1 System requirements:

Hardware

- Capable of measuring PD from at least two couplers simultaneously. (Can use a multiplexer for switching between 18 maximum pairs.)
- Capable of measuring PD pulses in terms of polarity, pulse rate and peak amplitude.
- Capable of filtering out non-generator PD i.e.: PD from the external system traveling down the bus into generator should be ignored (time of pulse arrival from both couplers < 6 nsec = noise. Should be programmable) As well slow rising pulses such as SCR switching noise (rate of rise to slow >1 to 40ns. Should be programmable).
- Bandwith of acquisition capture circuit, 20-350Mhz minimum.
- Voltage range of input +/- 0.05 to +/- 4.0 volts.
- Minimum pulse rise time 3 nano seconds.
- 16 magnitude steps (steps of resolution) as a minimum.
- Pulse resolution of > 5 micro seconds between pulses.
- Polarity, both positive and negative PD.
- Two couplers should be mounted on each phase as a minimum. Coupler location can be directionally on the bus as close to the generator winding as possible or in a differential mode a few turns in on the winding (preferable). On multi-parallel windings couplers should be installed on each parallel for better coverage of all the winding.

- Couplers should be rated and certified tested to be corona free to at least 1.5-2 times maximum operating voltage.
- System should be capable of connection to central computer or SCADA for archiving and display of trended PD data.

Software

- Capable of on-line real time PD data gathering and storage for long term trending, 2D plotting with pulse rate and magnitude as well as 3D waterfall plotting with phase, magnitude and pulse rate.
- Alarm output capability for excessive PD.
- Data should be tagged and stored with generator parameters such as MW, Volts, MVar, stator temp, humidity and time.

B3.2.2 Implementation

A partial discharge system requires a unit outage so that coupling capacitors can be installed on the bus or the windings. Instrumentation and cabling outside of the generator enclosure can be installed prior to the outage. Once the system is installed verification of operation should be conducted and test data stored.

A set of commissioning PD readings should be taken under the following conditions:

- Unit excited but off line (CB open) for 20 min,
- Synchronized but no load for 20 min,
- At 50% load for 20 min, and
- At 100% load for 45 min,

A set of on-line PD readings for an operational system includes:

Synchronized but no load for 20 min.,

- Full load data collection after rapid increase from no-load and,

Full load data collection after the winding temperature has stabilized (after about 1 hour).

B3.3 Vibration Analysis

B3.3.1 System requirements:

Hardware

- At least 2 displacement probes per bearing (Shaft X and Y),
- At least 1 acceleration probe per bearing (preferably 2, X only and Y)
- One key phasor probe,

- Alarm, trip and watchdog outputs,
- Frequency response of 1-600Hz

Software

- Selectable filtering of 1x, 2x,
- Shear pin failure detection,
- Real time trending of displacement,
- Rough load zone desensitization

B3.3.2 Implementation

A vibration monitor system requires a unit outage so that the sensors can be mounted and cabled back to the monitor system. Connection of the monitor's trip output into the unit protection and alarm output in to the PLC (for event recording and annunciation) is usually required. The vibration system must be commissioned and alarm and trip settings programmed based on manufacturer's data and test results.

C
VENDORS

List of Suppliers

The global marketplace for the supply of protection and control (P&C) equipment is complex and ever-changing. Recommended sources of up to date information regarding the suppliers and goods and services connected with P&C equipment include:

- *Hydro Review Industry Sourcebook* published yearly by HCI Publications, 410 Archibald Street, Kansas City, MO 64111-3046, USA.
- *International Water Power and Dam Construction* Yearbook published yearly by Wilmington Business Publishing, Wilmington House, Church Hill, Wilmington, Dartford, Kent DA2 7EF, UK.

Over time, with mergers and acquisitions in the industry, it has become, in some cases, difficult to identify the current "Original Equipment Manufacturer" (OEM) for a particular brand of equipment. The following list has been prepared to assist with the identification process. The list is not exhaustive. Colloquial names have been used in lieu of formal company names for ease of identification.

Item	Vendor	URL
PLC's		
	Allen Bradley	http://www.ab.com/
	Modicon	http://www.modicon.com/
	GE Fanuc	http://www.gefanuc.com/
	Siemens	http://www.sea.siemens.com/
	Square D	http://www.industry.net/squared
	Texas Instruments	http://www.ti.com/
	Omron	http://www.omron.com/

Vendors

Open Platform HMI Software		
	Wonderware	http://www.wonderware.com/
	Factory Link	http://www.usdata.com/
	Intellution	http://www.intellution.com/
	Rockwell Software	http://www.software.rockwell.com/
Protective Relays		
	ABB	http://www.abb.com/
	Alstom	http://www.gecalstom.com/
	Basler Electric	http://www.basler.com/
	Beckwith Electric Co.	http://www.beckwithelectric.com/
	GE Multilin	http://www.ge.com/
	Schweitzer Engineering	http://www.selinc.com/
Automatic Generator Synchronizers		
	Beckwith Electric	http://www.beckwithelectric.com/
	Allen Bradley	http://www.ab.com/
	Basler Electric	http://www.basler.com/
Time Synchronization		
	Datum Inc	http://www.bancom.com/
	Monaghan Engineering	http://www.monaghan-engineering.com/
	TrueTime	http://www.truetime.com/
	Hewlett Packard	http://www.hp.com/
	Control Technology International	
Vibration Monitors		
	Bently Nevada	http://www.bently.com/
	Entek IRD	http://www.entek.com/
	Vibro-meter	http://www.vibro-meter.com/

On-line Partial Discharge Monitors		
	IRIS Power Engineering	http://www.irispower.com/
	BC Hydro	http://www.bchydro.com/
Air Gap Monitors		
	MCM Enterprises	http://www.mcmenterprise.com/
	Vibro-meter	http://www.vibro-meter.com/
	Siemens	http://www.sea.siemens.com/
Revenue Class Power Monitors		
	Allen Bradley	http://www.ab.com/
	Bitronics Inc.	http://www.bitronic.com/
	Power Measurements	http://www.pml.com/

D
REMR CONDITION ASSESSMENT PROCEDURES

This appendix includes reproductions of the appropriate sections for equipment covered in this volume of the US Army Corps of Engineers' Condition Rating Procedures/Condition Indicator for Hydropower Equipment. The document was produced by the USACE as part of the repair, Evaluation, Maintenance and Rehabilitation (REMR) Research Program.

As discussed in Section 4.4.3 the condition rating procedures are provided as an example of a condition rating procedure. The USACE intends to review the procedures commencing in 2000.

Our thanks to Messrs. Jim Norlin, Paul Willis and Craig Chapman of the USACE in 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

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Working Document

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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.

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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.

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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

PART I: INTRODUCTION

1-1. The Corps of Engineers owns and operates 76 hydroelectric powerhouses located throughout the United States. These powerhouses have a combined total capacity of nearly 21,000 megawatts, making the Corps the largest single operator of hydroelectric facilities in the United States.

The Corps' system of hydropower projects is unique and significantly different than other large producers of hydropower in several ways. We do not supply power to a single system, but rather to many large and small power distribution systems throughout the country. We are involved only with hydropower and power production, and have no direct involvement in power distribution or sales. Our funding for repair and replacement of equipment is appropriated by congress, and not derived from power sales.

Planning for major repairs or replacement of hydropower equipment presents some unique difficulties to the Corps. Funds are provided as a part of the overall Operation and Maintenance budget for the Corps. The funding is thus intermingled with funds for dredging, navigation, flood control, recreation and most other aspects of the Corps' involvement with civil works activities. The funding requirements for the O&M of hydropower facilities is a relatively small portion (5-6%) of the overall Corps of Engineers O&M budget.

The cost of routine operation and maintenance activities can be programmed relatively easily based upon historical efforts. The non-routine effort is much more difficult to forecast. This program is a key step in the development of a reliability centered maintenance program. This program will provide comprehensive projections of the need for and benefits derived from specific, non-routine maintenance work.

Concept

1-2. The Hydropower Equipment Condition Indicators Program is being developed at the direction of HQUSACE as a part of the Operations Management Problem Area of the Repair, Evaluation, Maintenance and Rehabilitation Research Program (REMR). REMR Management Systems are designed to be decision support tools for determining when, where, and how to effectively allocate maintenance and rehabilitation dollars for Civil Works facilities. These systems are being developed to provide:

a. Objective condition assessment procedures.

b. Means for comparing the condition of facilities and tracking change over time.

c. Procedures for life-cycle cost analysis of different maintenance policies and rehabilitation alternatives.

d. Computer software for storing and organizing data, performing calculations, and producing a variety of reports.

There are many independent factors that must be considered as key elements of an overall maintenance management program. The items in the following list are all pertinent, but the list is not necessarily all inclusive.

1 - Policy / Planning / Mission
2 - Condition / Function / History/Performance
3 - Importance of facility
4 - Economic Analysis
5 - Risk / Consequences of failure
6 - Repair lead time
7 - Budget / Current - Future
8 - User Cost
9 - Return on Investment

10 - Resource availability
11 - Future performance

One of the primary goals of the REMR Operations Management System is to take all of these factors and place them into a single, large computer program that will be used as a management tool. It is anticipated that the final product could take as much as 10-20 years to fully develop, test, refine and implement. A program of this nature must be developed one step at a time.

The chosen starting place is the technical area. This is item 2 on the list above. Factors that can be considered relevant to the Condition / Function / History/ Performance of a piece of hydropower equipment are as follows:

1 - Current Condition
2 - Current Performance
3 - Past Condition and Performance (History)
4 - Future Condition and Performance (Estimate or prediction)
5 - Trends
6 - Equal comparison of facilities condition / performance
7 - Definition of required function

The items on this list can be separated into two general categories, equipment condition and performance of function.

The current program is limited to looking at the category of equipment condition only. The performance of function factors will be considered at a later time.

The initial step in determining the current condition of a piece of equipment is to establish a standard definition of condition. This has already been established as the REMR Condition Index scale. This scale is numerically based, extending from 0 to 100, without units. REMR Technical Note OM-CI-2 which further defines and explains the condition index scale is included in this report as Appendix A.

The second step is to develop a standard method of measurement of condition. A standard indicator is something that is specifically definable, and repeatable. An example of definable and repeatable is the measurement of “volts”. There is a specific definition for “volts”, and calibrated test instruments for measuring voltage. As a result, there is no confusion or misunderstanding when someone says that a particular piece of equipment is designed to operate at 110 volts AC, for example. The indicators and methods used to define the condition of equipment should strive to be equally as well defined and repeatable. The point being that when two project engineers on opposite sides of the country each say their turbines have “bad cavitation damage”, the actual extent of damage to each turbine is comparable.

Generally speaking, Condition Indicators are either test results from standard tests, or visual or other non-destructive examinations that give an indication of the current condition of a piece of equipment. Factors such as usage, history of maintenance, availability of parts and economic factors are not to be considered when defining current condition. These are important elements, but they will be considered elsewhere in the overall REMR Operations Management System.

The Condition Index, by definition, is a snapshot look at the absolute condition of a facility or piece of equipment. Time, age and money related factors are not included in the development of this index. It is a standardized evaluation of the condition of the equipment based strictly upon test results and inspection by visual or other means. The condition index algorithm should allow for the additional *condition information* that is available from a detailed inspection if the equipment is partially or totally dismantled for other reasons, but should not require this type of inspection.

Just as a chain is only as strong as the weakest link, the current condition of most pieces of hydropower equipment is only as good as the poorest indicator. This method of overall evaluation allows for an easy method of determining the work necessary to improve the condition and the extent of overall improvement. An exception to this general rule is made when several different tests or inspections are used for evaluating the same thing. The best example of this is the myriad of tests used to evaluate the condition of generator stator winding insulation.

Snapshots of the equipment condition can be taken at regular or irregular intervals. Regular intervals would normally include two separate condition evaluations at each major maintenance interval (for example -quadrennial). The initial evaluation would reflect the condition of the equipment as it was removed from service for maintenance. The second evaluation should reflect the improvement in condition as a result of maintenance procedures. For example, during a turbine overhaul, normal maintenance procedures call for weld repair of areas damaged by cavitation. The two evaluations of condition should accurately reflect the improvement in the condition of the turbine as a result of these weld repairs.

Other measurements that will affect how well equipment can be expected to survive, such as hours of usage, severity of usage and levels of routine maintenance will be used to predict the future rate of condition index deterioration. This will be developed during a later phase of the overall REMR Operations Management System.

Limitations

1-3. Condition indices are a tool to help estimate the remaining service life of equipment. Service life, however, is not necessarily the same as useful life. Powerhouse Automation Systems, for example, are most often replaced for reasons other than condition.

Example

1-4. The example used to demonstrate how Conditions Indicators for mechanical and electrical equipment are used, is something that everyone is familiar with, an automobile. The condition of a specific automobile is something that can be determined by an automotive diagnostic center. Through testing and inspection, they can evaluate the condition of the vehicle and provide a detailed listing of the items that are not properly operational.

However, the diagnostic center cannot provide all of the information that is necessary to determine the extent of repairs that should be performed, or if the vehicle should be replaced. Economics obviously will play a major part of this decision. The functionality of the vehicle for the purpose it is needed also plays a part. You wouldn’t buy a two seat sports car if you need to transport 4 people and their luggage on a regular basis. Finally, the diagnostic center cannot predict how long it will be before the vehicle sustains a major failure.

We need to eliminate factors that are not relevant to condition before proceeding to those factors that are relevant. The age of the automobile is the first factor to eliminate. Assume that the theoretical design life for an automobile is 15 years. Many cars will last well past that age, but a great number will see a wrecking yard as a result of mechanical failure much sooner. However, the condition of a vehicle is not dependant upon its age. Consider all of the collector cars that are in better condition now than they were when they were new. Likewise, consider the new car that has a transmission failure in the first 10 miles because a mechanic forgot to put oil in the gearbox.

It is therefore easy to eliminate age as being irrelevant to condition.

The next factor to eliminate is usage. The diagnostic center cannot tell what use or abuse a car has seen. Three similar cars, each with 99,000 miles on the odometer may each have seen dramatically different service. One may be all stop and go city miles, another highway miles and the third may actually have 299,000 miles on the odometer.

Thus, we also eliminate operational history or usage.

Maintenance history can also be eliminated. The diagnostic center does not have access to the maintenance records, nor are they familiar with the skills of the mechanic. However, they can get a good indication of the level of maintenance from visual inspection. Rusty body panels along with tape and bailing wire repairs are very obvious. This would indicate a car in much poorer condition than another vehicle with a freshly waxed paint job and all bolts where they belong.

Maintenance history is eliminated, but a thorough visual inspection is included.

The diagnostic center, in addition to completing a thorough visual examination, will perform many different types of tests. These tests will check out the various electrical and mechanical systems of the vehicle. A compression test combined with a leak-down test and an examination of the lubricating oil will give a relatively good indication of the mechanical condition of the engine. These tests can be run on virtually all cars. Tests on other systems may vary depending upon the vehicle. For example consider the fuel supply system. There are carburetors, mechanical fuel injection systems, electronic fuel injection systems and turbocharged versions of each. They all perform the same function in a different manner. Certain tests, such as an exhaust gas analysis, can be used to get a very basic indication of the condition of any of these systems. Other, more specialized tests are relevant to only one type of system. However, these tests can give a better indication of condition.

We have included only these basic tests for most of the items of hydropower equipment. In many cases, more detailed tests could be run, but the value of performing them on a routine basis is questionable.

Categories of Equipment

1-5 The following categories of hydropower equipment are included as part of this program:

ELECTRICAL

Hydrogenerator Stators
Excitation Systems
Circuit Breakers
Main Power Transformers
Powerhouse Automation Systems

MECHANICAL

Turbines
Thrust Bearings
Intake Valves
Governor System
Cranes & Wire Rope Gate Hoists
Hydraulic Actuator Systems

STRUCTURAL

Emergency Closure Gates
Power Penstocks

REMR RATING SYSTEM

PART VII: POWERHOUSE AUTOMATION SYSTEMS

Program, Format and Method

Explanation of Program

The condition index for a powerhouse automation system may range from 0 to 100 and is based on the Repair, Evaluation, Maintenance and Rehabilitation (REMR) Condition Index scale, which is shown below. The overall condition index for the system is determined from the condition indices obtained for the following five condition indicators:

1. System availability

2. Processing equipment

3. I/O interface equipment

4. Display generation equipment

5. Communications equipment

Value	Condition Description	
85–100	Excellent	No Noticeable defects. Some aging or wear may be evident.
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 D-1

The Condition index for each condition indicator may range from 0 to 100 and is based on REMR Condition Index scale. The condition index for condition indicator 2-5 is based on the results of diagnostics run on individual items of equipment and on the configuration of the equipment; these condition indicators will be evaluated in a similar manner. System availability will be evaluated by a different method.

Explanation of Format

This section on powerhouse automation systems will follow the following format:

1. Overall Powerhouse automation System Condition.
   - Introduction.
   - Filling Out Data Evaluation sheet.
   - Sample Data Evaluation Sheet for Powerhouse Automation System.
2. System Availability Condition Indicator.
   - Introduction
   - Instructions for Evaluation
   - Filling Out Data Evaluation sheet.

- Frequency of Testing.
- Sample Data Evaluation Sheet for System Availability Condition Indicator.

3. Other Powerhouse automation system Condition Indicators.
   - Introduction
   - Instructions for Evaluation
   - Filling Out Data Evaluation sheet.
   - Frequency of Testing.
   - Sample Data Evaluation Sheet for Powerhouse Automation System Condition Indicators.

There will not be a separate description for each condition indicator since most are evaluated in a similar manner. There are no inspection formulas since none of the condition indices are based on inspections.

Explanation of Method

In order to determine an overall condition index for the system, the system will be divided into subsystems; the subsystems will be divided into types of equipment; and finally, the types of equipment will be divided into individual items. Condition indicators 2-5, listed above, are equivalent to the subsystems.

The condition index for the system will be equal to the lowest condition index obtained for each condition indicator that is evaluated. The condition index for condition indicators 2-5 will be equal to the lowest condition index obtained for each type of equipment that is evaluated. The condition index for a type of equipment will be the mean of the condition indices obtained for each individual item of the type of equipment. The condition index for an individual item of equipment will be obtained by running diagnostics.

Overall Powerhouse Automation System Condition

Introduction

The overall powerhouse automation system condition index is calculated using five condition indicators: system availability, processing equipment; I/O interface equipment; display generation equipment; and communications equipment. A condition index is determined for each condition indicator: the lowest condition index obtained is considered to be the condition index for the overall system.

Filling Out Data Evaluation Sheet

Column 1 lists the five condition indicators that are being used for evaluation. In column 2, indicate whether the test was performed. In column 3, indicate the date the test was completed. In column 4, enter any notes or remarks about the condition index. For instance, if a condition index was low, indicate why it was low. In column 5, enter the condition index. This number is obtained from the box in the lower right corner of the data evaluation sheet for each condition indicator.

In the lower right corner, enter the powerhouse automation system condition index. This number is the lowest condition index obtained for each condition indicator that is evaluated.

Sample Data Evaluation Sheet for Powerhouse Automation System

A sample powerhouse automation system data evaluation sheet is shown in Figure D-2. Information that would be completed at the site is shown in script text.

REMR Hydropower Condition
Indicator Program

Data Evaluation Sheet
Powerhouse Automation System Condition

Project:	*Old Hydro plant*	Unit No.	*N/A*
Prepared by:	*I. M. Spector*	Date:	*7/31/90*

Item	Date of Inspection or test	Remarks	Condition Number 0-100
System Availability	6/15 – 7/27/90	Availability = 99.55%	73
Processing Equipment	7/1/90	Diagnostics indicated problems on CPU #1	63
I/O Interface Equipment	7/1/90		100
Display Generation Equipment	7/1/90		100
Communications Equipment	7/1/90		100
Overall Powerhouse Automation System Condition Index Rating			63

Figure D-2

System Availability

Introduction

In order to determine system availability, an availability test, as described in the following section will be conducted. For this test, the SCADA system will be monitored for system failures, which are defined as follows:

1. Failure to properly support operator interface operations to at least one CRT monitor and keyboard in the control room;
2. Failure to properly communicate with, gather data from, or perform control actions through the RTUs;
3. Failure to properly perform supervisory or automatic control operations;
4. Failure to properly alarm events;
5. Failure to properly maintain data for the support of logs, reports, history files, or external communications.

Instructions for Evaluation

The availability test will be conducted under regular plant operating conditions. The test will be conducted on a 24-hours per day, 7-days per week basis. While the test is underway, all time will be classified as uptime, downtime, or administrative time. The duration of the test, which will be determined from the sum of uptime and downtime, will be 1000 hours.

When a system failure occurs, downtime will be measured, as the time required for maintenance personnel to make the failed function again available. Failures which do not result in degraded performance due to automatic failover provisions which cause the affected function to be performed by another component, in addition to its normal functions, will not be counted as downtime while the failed component is being repaired or replaced. When performance degradation results from a failure in an RTU and the degraded performance is restricted to the affected RTU, downtime shall be accumulated as the product of degraded operating time and the fraction resulting from dividing the number to malfunctioning RTUs by the total number of RTUs.

Uptime will be measured as the time during which the system is properly performing its primary system functions, as indicated above. When performance degradation results from a failure in an RTU and the degraded performance is restricted to the affected RTU, uptime shall be accumulated as the product of operating time and the fraction resulting from dividing the number of fully operational RTUs by the total number of RTUs.

If the test must be suspended for any reason, that period will be classified as administrative time. For example, when a system failure has occurred any time that maintenance personnel are not working on the problem will be considered administrative time; this includes time required to obtain the part if it is not available at the project. An administrative-time period will not be counted as a discontinuity in the test.

The system availability will be determined by the formula:

$$\text{AVAILABILITY} = \frac{\text{UPTIME}}{\text{UPTIME} + \text{DOWNTIME}} \times 100$$

The condition index will be calculated using the appropriate formula:

a. If 99.5 ≤ AVAILABILITY ≤ 100:

$$\text{CI} = (\text{AVAILABILITY} - 99.5) \times 60 + 70$$

b. If 95 ≤ AVAILABILITY < 99.5:

$$\text{CI} = (\text{AVAILABILITY} - 95) \times 20/3 + 40$$

c. If 0 ≤ AVAILABILITY < 95:

$$\text{CI} = (\text{AVAILABILITY} - 99.5) \times 8/19$$

Filling Out Data Evaluation Sheet

Operations and maintenance personnel should fill out the data evaluation sheet. In the “Date/Time” column on the “start” line, indicate the date and time the availability test began. If a system failure occurs (as previously defined), indicate the date and time on the line for interval 1. The elapsed time for this interval is the number of hours between this time and the time on the preceding line. This time is entered in the appropriate column (uptime, downtime, or administrative time). The total accumulated time is calculated as the sum of uptime and downtime since the test began; enter this in the final column. In addition, on a separate sheet, indicate the date and time of the failure and provide a complete description. Continue filling out the data evaluation sheet (and the supporting data) until the total accumulated time reaches 1000 hours. Enter the totals for each time category (uptime, downtime, and administrative time). Then calculate the availability and the condition index using the formulas provided.

Frequency of Testing

The availability test should be run approximately once a year.

Sample Data Evaluation Sheet for System Availability Condition Indicator

A sample system availability condition indicator data evaluation sheet is shown on the next page (Figure D-3). Information that would be completed by the field is shown in script text.

For this example, the test is assumed to have begun at 0900 on 6/15. It is assumed that two failures occurred during the test: the first at 2200 on 6/28, and the second at 0900 on 7/10. It is assumed that, when the first failure occurred not maintenance personnel were available until 0730 on 6/29 and that it took one hour to troubleshoot and repair that problem. It is assumed that, when the second failure occurred, it took 3.5 hours to restore the system to proper operation. The test concluded at 1030 on 7/27 since, at that point in time, the total accumulated time reached 1000 hours. Since the availability was calculated to be 99.55%, formula “a” was used to calculate the condition index.

REMR Hydropower Condition
Indicator Program

Data Evaluation Sheet Powerhouse Automation System Availability

Project: *Old Hydro plant*	Prepared by: *I.M. Spector*
Note: An explanation for each interval of downtime and administrative time should be provided and attached to this test record. For downtime, this should include a complete description of the failure and the corrective action taken.	

Interval	Date Time	Elapsed time (Hours) Uptime	Downtime	Admin.	Total Acc. Time
Start	6/15 0900				325
1	6/28 2200	325			325
2	6/29 0730			9.5	325
3	6/29 0830		1		590.5
4	7/10 0900	264.5			594
5	7/10 1230		3.5		1000
6	7/27 1030	406			
7					
Total					

Availability = 99.55%
Condition Index = 73

Figure D-3

Other Powerhouse Automation System Condition Indicators

Introduction

Powerhouse automation systems vary from one to another, based on the type of equipment comprising the system and on the equipment configuration. In addition, these systems are often required to have expansion capability, with the result that a particular system may not have the same configuration over its lifetime.

As indicated previously, each subsystem may contain various types of equipment. The breakdown of equipment into types will be based on how the equipment is configured and functions; therefore, it will differ from one system to another. For example, assume a system has two CPUs and two disks. If each CPU has a dedicated disk, i.e. the CPU and disk function as one unit, the CPU/disk would be considered one equipment type; however, if either CPU can use either disk, the CPU and disk would be considered separate equipment types. Also, a powerhouse automation system often has multiple items of a particular type of equipment (e.g. often there are two CPUs); the precise number of items will differ from one system to another.

Instructions for Evaluation

Because of the variation in powerhouse automation systems, the data evaluation sheets for these condition indicators do not list types and items of equipment. These should be filled in, as appropriate, for the particular system.

If a system does not have any equipment belonging to a particular subsystem, that subsystem should be omitted. For example, some systems do not have separate display generation equipment. Also, other subsystems may be added, if appropriate.

An item of equipment that has components which functions as a unit (such as the CPU and dedicated disk previously referred to) may have diagnostics available that test each component separately. If this is the case, the condition index for the item is based on the poorest test result.

Filling Out Data Evaluation Sheet

In column 1, list the appropriate equipment by type and, under each type, list the individual items of equipment.

For the individual teams of equipment, fill out columns 2-5. In column 2, indicate whether the test was performed. In column 3, indicate the date the test was performed. In column 4, enter any notes or remarks about the condition index. For instance, is a condition index was low, indicate why it was low. In column 5, enter the condition index. This number is obtained from Table D-1 and is based on the results of diagnostics.

For each type of equipment, enter the condition index in column 5. This number is the mean of the condition indices obtained for each item of the type of equipment.

In the lower right corner, enter the condition index for the condition indicator. This number is the lowest condition index obtained for each type of equipment that is evaluated.

Table D-1

Condition Index Based on Diagnostics	
Diagnostics run successfully	100
Diagnostics output indicates errors/problems	25
Diagnostics could not be run; no output	0

Frequency of Testing

Diagnostics should be run if the system is not operating properly; it is not necessary to run them at regularly scheduled intervals. After the equipment has been repaired or replaced, diagnostics should be run again to document the resulting improvement in the equipment condition.

Sample Data Evaluation Sheet for Powerhouse Automation System Condition Indicators

A sample powerhouse automation system condition indicator data evaluation sheet is shown on the next page (Figure D-4). Information that would be completed at the site is shown in script text.

For this example, the system is assumed to have two CPUs and two disks and to be configured so that either CPU can use either disk. The CPU actually consists of a CPU, main memory, and various device controllers; however, these components all function as a unit. There are diagnostics available which test these various components.

The sample shows the processing equipment subsystem, Within this subsystem there are two types of equipment: CPUs and disks. For each of these equipment types, there are two individual items of equipment, which are designated “#1” and “#2”. It is assumed that the results of diagnostics for the individual items of equipment are as shown. The condition index for the CPUs is the mean of the condition indices obtained for each CPU, i.e. (25 +100)/2]= 63. The condition index for the procession equipment is equal to the condition index of the CPUs, i.e. 63, since this number is lower than the condition index for the disks.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet Powerhouse Automation System Condition

Project:	*Old Hydro plant*	Unit No.	*N/A*
Prepared by:	*I. M. Spector*	Date:	*7/31/90*

Equipment Tested	**Date of test**	**Remarks**	**Condition Number 0-100**
CPU #1	7/27/90		73
CPU #2	7/1/90	Memory diagnostics indicated problems	25
CPU’s			63
Disk #1	7/1/90		100
Disk #2	7/1/90		100
Disks			100
Overall Powerhouse Automation System Condition Index Rating			63

Figure D-4

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet **Powerhouse Automation System Condition**

Project:	Unit No.
Prepared by:	Date:

Item	Date of Inspection or test	Remarks	Condition Number 0-100
Overall Powerhouse Automation System Condition Index Rating			

Figure D-5

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet Powerhouse Automation System Availability

Project:	Prepared by:
Note: An explanation for each interval of downtime and administrative time should be provided and attached to this test record. For downtime, this should include a complete description of the failure and the corrective action taken.	

Interval	**Date Time**	**Elapsed time (Hours)** Uptime	Downtime	Admin.	**Total Acc. Time**
Start					
1					
2					
3					
4					
5					
6					
7					
Total					

Availability =
Condition Index =

Figure D-6

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet Powerhouse Automation System Condition

Project:	Unit No.
Prepared by:	Date:

Equipment Tested	**Date of test**	**Remarks**	**Condition Number 0-100**
Overall Powerhouse Automation System Condition Index Rating			

Figure D-7

E
GLOSSARY OF TERMS

A/D	Analog to Digital
AGC	Automatic Generator Control
ANSI	American National Standards Institute
CEA	Canadian Electrical Association
CSA	Canadian Standards Association
CT	Current Transformer
DSC	Distributed Control System
EEPROM	electrically erasable/programmable read only memory, a digital memory module that can be written to repeatedly and is non-volatile (retains data without power)
EMI	Electro Magnetic Interference
ETA	Event Tree Analysis
FMEA	Failure Modes and Effects Analysis
FMECA	Failure Modes and Effects and Criticality Analysis
FTA	Fault Tree Analysis
GPS	global positioning system, a set of earth orbiting satellites that transmit position and time data to receivers on land.
GPS	Global Positioning System
HAZOP	Hazard and Operability Study
HMI/MMI	Human Machine Interface / Man Machine Interface
I/O	inputs and outputs, refers to the signals coming into a PLC and the controls signals out of the PLC
I/O	Inputs and Outputs
IEC	International Electrotechnical Commission
IED	intelligent electronic device, any piece of electronic equipment with a processor, usually has communication capability as well

IEEE	Institute of Electrical and Electronic Engineers
IRIG	Inter Range Instrumentation Group. The instrumentation arm of the US Army's missile testing group.
IRIG	Inter Range Instrument Group
IRIG-B	A time code format devised by the Telecommunications working group of the IRIG. Used for synchronizing time clocks in remote locations.
JVC	Joint VAR Control
LAN	Local Area Network
LSM	Line Synchronization Module
MCC	motor control center, centralized switchgear for low voltage (480V, 600V) motor starters
MTBF	Mean Time Between Failures
MTTR	Mean Time to Repair
P&C	Protection and Control
PCB	Printed Circuit Board
PD	Partial Discharge
PLC	programmable logic controller, an industrial rack mounted processor and its associated input and output cards
PCS	Plant Control System
PT	Potential Transformer
PY	Primary
RAM	Random Access Memory
RF	Radio Frequency
RFI	Radio Frequency Inteference
ROM	Read Only Memory
RTD	Resistive Temperature Device
RTU	Remote Telemetry Unit
SC	Synchronous Condense
SCADA	Supervisory Control and Data Acquisition
SCR	Silicone Controlled Rectifier
SER	Sequence of Events Recorder

SWC	Surge Withstand Capability
SY	Secondary
UCB	Unit Control Board
UCS	Unit Control System
UHF	Ultra High Frequency
VAR	Volt Amps Reactive
VHF	Very High Frequency
VT	Voltage Transformer

Target:
Hydropower Operations and Asset Management
Relicensing Forum
Plant Maintenance and Life Management

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