hydroAMP
Asset Management Partnership

Hydropower Asset Management
Using Condition Assessments and Risk-Based Economic Analyses

September 2006

U.S. Department of the Interior
Bureau of Reclamation

Hydro Québec

US Army Corps of Engineers®

Bonneville Power Administration

Disclaimer

Executive Summary

Hydropower Asset Management
Using Condition Assessments and Risk-Based Economic Analyses

Developed by the Hydropower Asset Management Partnership:
Bureau of Reclamation, Hydro-Québec, U.S. Army Corps of Engineers, and
Bonneville Power Administration

Background

Aging and deteriorating hydroelectric powerplant equipment poses considerable risk to reliability and may result in low generating unit availability. Significant investment in replacing, repairing, and refurbishing hydroelectric generating and auxiliary equipment is required to assure the continued viability and cost-effectiveness of existing hydropower assets. Successful strategic planning for capital investments in hydropower facilities requires consideration and balancing of many factors, including the risk of equipment failure. The four organizations involved in the Hydropower Asset Management Partnership (hydroAMP) joined together to create a framework to streamline and improve the evaluation of the condition of hydroelectric equipment and facilities in order to support asset management and risk-based resource allocation.

Condition Assessments

Technical teams comprised of experts from the four hydroAMP organizations developed condition assessment guides for key hydroelectric powerplant components, falling into two classes. The first equipment class includes major power train components, such as circuit breakers, excitation systems, generators, governors, transformers, and turbines. The second class consists of auxiliary components, including batteries, compressed air systems, cranes, emergency closure gates and valves, and surge arresters.

A two-tiered approach for assessing hydropower equipment condition was developed. Tier 1 of the assessment process relies on test and inspection results that are normally obtained during routine operation and maintenance (O & M) activities. Equipment age, O & M history, and other relevant Condition Indicators are evaluated and combined with the test results to compute a Condition Index. An additional, stand-alone indicator is used to reflect the quality of the information available for scoring the Condition Indicators. The Condition and Data Quality Indicators and the Condition Index for each piece of equipment are easily tracked using a Computerized Maintenance Management System or other database tools.

The second, or Tier 2, phase of the condition assessment utilizes non-routine tests and inspections to refine the Condition Index obtained during the Tier 1 assessment. Tier 2 tests often require specialized expertise or instrumentation, depending on the problem or issue being investigated. A low Condition Index or Data Quality Indicator score from the Tier 1 assessment may indicate the need for a Tier 2 evaluation.

Individual equipment condition assessment results can be combined to develop an aggregated assessment of a complete power train unit as well as an entire generating station. These summary indices are designated Unit Index and Station Index, respectively.

Analytical Tools

The path that leads from a condition assessment to an investment decision is vitally important to the management of hydropower facilities. The analytical tools described in this Guidebook are intended to help decision makers develop and maneuver that path. These tools form a link between the technical tasks that make up a condition assessment and the economic and risk analyses that guide maintenance management and resource allocation.

Two types of analyses are presented, designated Type 1 and Type 2. A Type 1 analysis considers equipment condition and cost alone – all that may be needed to make an investment decision in some cases. A more complex analytical approach, described as a Type 2 analysis, is useful for evaluating and prioritizing various investment scenarios. It uses all factors from Type 1 and introduces additional factors that relate to the possible consequences of undertaking or not undertaking a repair or replacement action (e.g., legal, regulatory, safety, environmental, and economic consequences). Several case studies and appendices with supporting information are provided to further describe the risk and economic analysis concepts.

Data Management

A hydroAMP database was developed to allow plants and organizations to input their equipment condition data into a single database in a standardized format. It also allows for individual plant and utility analysis and reporting. The database is real-time and web-accessible, and provides centralized data entry, storage, and retrieval for hydroAMP assessments. The database can be accessed through the internet at the following address: https://secure.bpa.gov/hydroAMP/. An account is required to access the database. Contact your organization's hydroAMP coordinator to establish an account.

Implementation

The condition assessment tools and economic analyses described in this Guidebook are currently being implemented within the hydroAMP organizations. After an initial period of use (approximately 12 to 18 months), feedback from users will be solicited and used to improve and enhance the tools, processes, and results.

Table of Contents

Appendices

[1] Due to the large number and size of the condition assessment guides, they are available as separate electronic files. For more information, contact your organization's hydroAMP coordinator.

List of Figures

List of Tables

Section I: Overview

Background

Successful strategic planning for capital investments in existing hydropower facilities requires consideration and balancing of many factors, including the risks and consequences of equipment failure. The hydropower community has long recognized the importance of assessing the condition of existing equipment in order to make informed and sound business decisions for the replacement of that equipment. Early attempts to develop condition assessment tools, however, were not completely successful.

One formal approach for assessing the condition of hydroelectric equipment existed in the Corps of Engineers' Repair, Evaluation, Maintenance and Rehabilitation (REMR) Research Program undertaken in the early 1990s. Prior to the REMR guidance, numerous test reports and memoranda had to be researched to make a determination of equipment condition. REMR was intended to provide guidance and a standard methodology for making condition assessments, and to consolidate the assessments into a uniform format. However, feedback from the projects using this tool indicated dissatisfaction with the REMR program for the following reasons:

- The equipment evaluation processes tended to be unwieldy, requiring too many tests, inspections, and measurements.
- The evaluation procedures and results were not properly validated and calibrated.
- There was no convenient and consistent method to capture, retrieve, and utilize the data being collected.

As a result of this feedback, there were many discussions concerning the need to revise or rewrite the REMR guidance. Concurrent with these discussions within the Corps of Engineers (COE), other industry leaders were wrestling with this same issue, and in 2001, the Bureau of Reclamation (BOR) and Hydro-Québec (HQ) signed a formal partnership agreement to develop guidance for assessing the condition of their hydroelectric equipment. The Corps of Engineers' Hydroelectric Design Center (HDC) was invited to participate in exploratory discussions in October 2001. The Bonneville Power Administration (BPA) joined the partnership shortly thereafter.

Hydropower Asset Management Partnership (hydroAMP)

Representatives from the four organizations met to discuss their respective goals and objectives. This resulted in a decision to collaborate in the development of hydropower asset management tools related to equipment condition assessments, investment prioritization methods, and evaluation of business risks. The Hydropower Asset Management Partnership (hydroAMP) identified the following concerns:

- A majority of critical equipment in hydroelectric facilities in North America is near or beyond its design life.

- Equipment reliability contributes significantly to system generation availability.
- The need for significant investment in repairing, refurbishing or replacing existing generation and auxiliary equipment within hydroelectric projects is anticipated.
- An opportunity exists to increase generation efficiency through investments in improved control systems, operations, and equipment.
- The process for identifying and prioritizing investments needs strengthening.
- Establishment of an objective, consistent, and valid assessment process is critical.
- Equipment condition assessment tools used in the past have been too complex and costly.

Strategic Goals

The goal of hydroAMP was to create a framework to streamline, simplify, and improve the evaluation and documentation of hydroelectric equipment condition to enhance asset and risk management decision-making. The team recognized that equipment condition assessments support:

- Development of long-term investment strategies.
- Prioritization of capital investments.
- Coordination of O & M budgeting processes and practices.
- Identification and tracking of performance goals.

Principles

The partnership agreed that the following principles would be applied during development of the equipment condition assessment methodology. Specifically, the hydroAMP framework should:

- Be guided and managed through a collective team effort.
- Be designed for fair and equitable application to all hydroelectric projects.
- Result in an objective and repeatable assessment of the major equipment and critical systems in the generation power train.
- Start small (i.e., would not initially include all critical equipment and systems) and grow over time as experience is gained.
- Be streamlined to minimize the time and expense required for testing, evaluating data, developing conclusions, and record keeping.
- Rely on existing O & M records and routine inspections and tests applied at regular intervals.
- Be technically sufficient although not necessarily "perfect."
- Be field-tested and assessed periodically.
- Be open to continuous improvement.
- Be adaptable for different users, purposes, and situations.

Intended Users

This Guidebook was developed for use and implementation by all of the partnership agencies. Therefore, the hydroAMP tools were designed to be open and flexible to fit into existing maintenance, planning, budgeting, and decision-making structures. These processes are also intended to serve multiple users within an agency who may have distinct roles and responsibilities for hydropower asset management. Typical users of the hydroAMP tools include the following:

On-Site Plant Staff. In general, these are the individuals who work with the equipment on a daily basis and will have a direct role in performing the equipment condition assessments. The information provided by the on-site staff is the foundation of the asset management process. Plant staff will typically:

- Perform Tier 1 equipment condition assessments.
- Record the data in the maintenance management system.
- Collaborate with technical specialists conducting Tier 2 tests or inspections.
- Use equipment condition information to manage their operation and maintenance activities.

Plant or Facility Managers. These individuals may use the hydroAMP processes to:

- Support plant maintenance, rehabilitation, or replacement decisions.
- Evaluate equipment condition assessment data and trends, in conjunction with other business decisions factors, to recommend additional analyses for certain components or systems.

Technical Staff. This group consists of engineers, economists, environmentalists, biologists, and other staff and technical specialists who are responsible for preparing detailed evaluations and justifications for larger, more complex decision packages. They may use the risk-based methodologies to analyze data as requested by the decision makers. In summary, technical staff use equipment assessments and prioritization tools to:

- Justify Tier 2 analyses.
- Support economic analyses.
- Support risk analyses.
- Support regional or multiple project analyses.

Asset Managers. These individuals may use the hydroAMP processes to:

- Prioritize competing investment needs.
- Analyze various business cases or justifications for investment decisions.
- Support decisions that consider tradeoffs between competing needs or conflicting requirements.

General Methodology

The equipment condition assessment and decision-making process involves three distinct phases: Tier 1 assessment, Tier 2 assessment, and a Business Decision.[2] Tier 1 represents the start of the condition assessment process and culminates in the determination of an equipment Condition Index. The Tier 1 assessment relies on test and inspection results that are normally obtained during routine operation and maintenance (O & M) activities. Equipment age, O & M history, and other relevant Condition Indicators are evaluated and combined with the test results to compute the Condition Index. The Condition Index is scored on a 0 to 10 numerical scale and results in a good, fair, or poor rating.

An additional, stand-alone indicator is used to reflect the quality of the information available for scoring the Condition Indicators. Given the potential impact of poor or missing data, a Data Quality Indicator is rated as a means of evaluating and recording confidence in the final Condition Index.

Additional information regarding equipment condition may be needed to improve the accuracy and reliability of the Condition Index. If so, Tier 2 inspections, tests, and measurements may be performed. These tests are considered non-routine and may require specialized expertise or test equipment. An outage and some disassembly of the component under test may also be required. Results of the Tier 2 analysis may either increase or decrease the score of the Condition Index. The Data Quality Indicator score may be revised during the Tier 2 assessment to reflect the availability of additional information or test data.

Condition assessment guides are available for the major power train components, i.e., circuit breakers, excitation systems, generators, governors, transformers, and turbines. Assessment guides have also been developed for important auxiliary equipment and systems including batteries, compressed air systems, cranes, emergency closure gates and valves, and surge arresters. It may be desirable to combine individual condition assessment results into an aggregated assessment representing the entire power train unit, or perhaps the entire generating station. Accordingly, a method for performing these calculations is presented in the Guidebook. The resulting summary indices are designated the Unit Index and Station Index, respectively. Condition assessments can also be used to identify condition trends in equipment types of different ages.

This Guidebook outlines several approaches for evaluating risk and prioritizing hydropower investment opportunities. The simplest approach, a Type 1 analysis, uses Condition Indices and cost to prioritize, rank, and sort equipment needs. Alternatively, a more complex business case may be developed using a Type 2 analysis which takes into account legal, regulatory, safety, environmental, economic, and/or other concerns.

Economic analyses may be done horizontally across an organization to determine replacement timing and order for similar types of equipment, for example, a transformer or circuit breaker replacement program. Condition assessment information can also be evaluated vertically using

[2] Definitions of key terms are given in Appendix A

the aggregated Unit Index or Station Index to identify the "weakest link" in the power production chain.

The overall flow of the assessment and analyses processes are illustrated in Figure I-1.

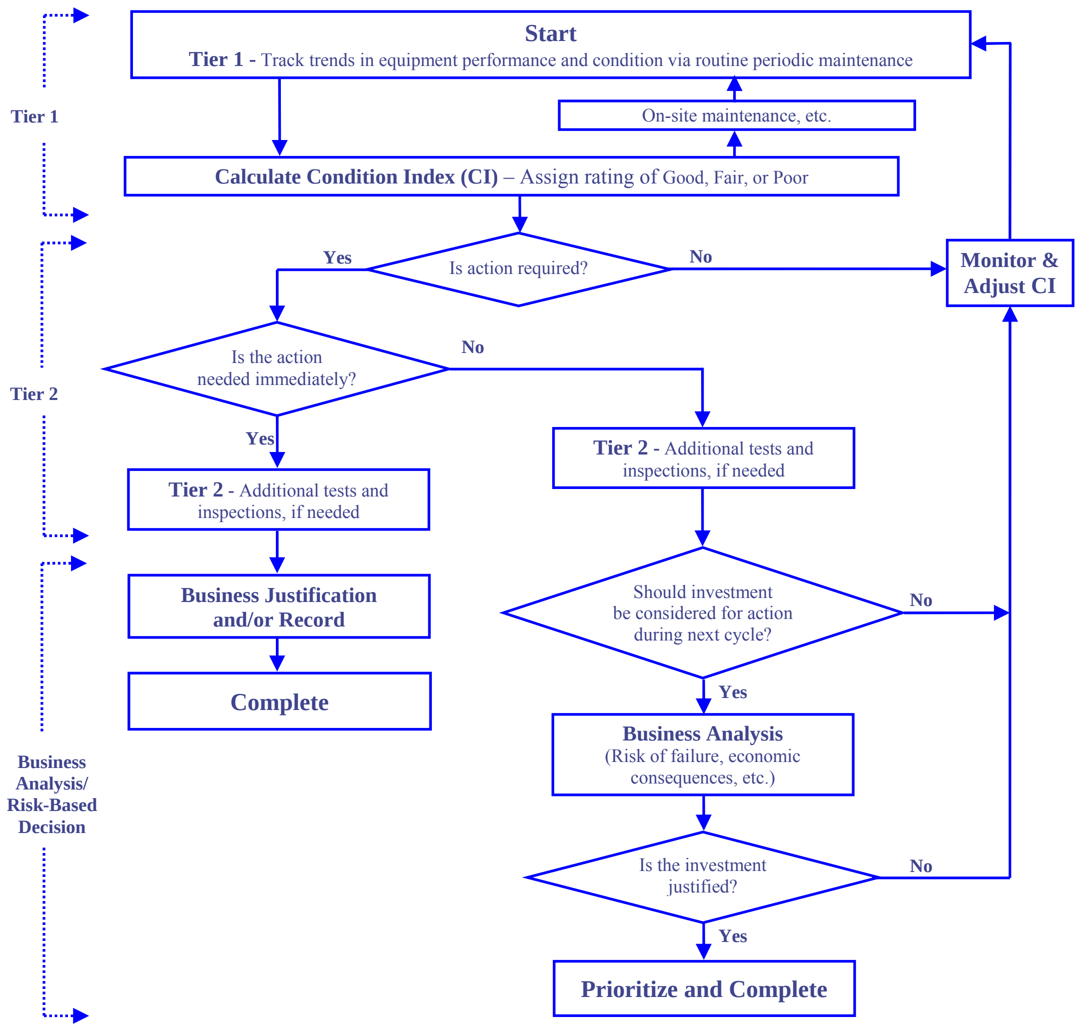


Figure I-1: Overall Flow of Equipment Assessment and Decision-Making Process.

Section II: Equipment Condition Assessment

Introduction

The hydroAMP technical teams have developed equipment condition assessment guides for the following major power train equipment and auxiliary components:

- Batteries
- Circuit Breakers
- Compressed Air Systems
- Cranes
- Emergency Closure Gates and Valves
- Excitation Systems
- Generators
- Governors
- Surge Arresters
- Transformers
- Turbines

The condition assessment guides are presented in Appendix E. Each guide is a stand-alone document developed for evaluating a specific piece of equipment or system. The guides are not intended to define component maintenance practices or provide detailed procedures for performing inspections, tests, or measurements. Utility-specific maintenance policies and procedures must be consulted for such information.

The condition assessment process assumes that inspections, tests, and measurements are conducted on a schedule that provides accurate and current information needed by the assessment. In some cases, however, it may be necessary to acquire additional data prior to the assessment.

Tier 1 Assessment

The methodology outlined in the condition assessment guides is divided into two tiers or levels. A Tier 1 assessment relies on test and inspection results that are normally obtained by on-site staff as part of routine operation and maintenance or by examination of existing data.

Each guide defines the Condition Indicators generally regarded by hydro plant engineers as providing the initial basis for assessing equipment condition. Generally, the following Condition Indicators are used to evaluate the equipment condition:

- Physical Inspection
- Tests and Measurements
- Operation & Maintenance History
- Age or Number of Operations

Numerical scores are assigned to each Condition Indicator using the guidelines provided. The scoring criteria may refer to conditions such as "normal" and "degraded." These relative terms are intended to reflect industry-accepted levels for equipment of similar design, construction, or age operating in a similar environment, or to baseline or previous (acceptable) levels. In some situations, determination of the Condition Indicator scores is subjective and must rely on the experience and opinions of personnel conducting the maintenance or inspection.

Weighting factors are applied to the Condition Indicator scores, which are then summed to compute the Condition Index. Weighting factors account for the fact that certain Condition Indicators reflect the actual equipment condition more than other indicators. The weighting factors also normalize the Condition Index to a score between 0 and 10 and result in a rating system as shown in the following table:

Table II-1: Condition Index Ratings of Equipment

Condition Index (CI)	
$7 \leq CI \leq 10$	**Good**
$3 \leq CI < 7$	**Fair**
$0 \leq CI < 3$	**Poor**

An additional stand-alone indicator is used to denote the quality of the information available for scoring the Condition Indicators. Although reasonable efforts should be made to perform the Tier 1 tests and inspections, in some cases, data may be missing, out-of-date, or of questionable integrity. Any of these situations could affect the accuracy of the associated Condition Indicator scores as well as the validity of the overall Condition Index. Given the potential impact of poor or missing data, a Data Quality Indicator is assigned a value of 0, 4, 7, or 10 as a means of recording confidence in the final Condition Index. The more current and complete the assessment information, the higher the rating for this indicator.

Tier 1 tests may indicate abnormal conditions that must be addressed immediately or that can be resolved via standard corrective maintenance solutions. To the extent that Tier 1 tests lead to immediate corrective actions being taken, appropriate adjustments to the Condition Indicator scores should be made and the new results used to compute a revised Condition Index. The Data Quality Indicator score may also be updated to reflect the availability of additional information or test data.

Tier 2 Assessment

As a result of the Tier 1 assessment, additional information may be required to improve the accuracy and reliability of the Tier 1 Condition Index or to evaluate the need for more extensive maintenance, rehabilitation, or equipment replacement. Therefore, each condition assessment guide describes a "toolbox" of Tier 2 inspections, tests, and measurements that may performed, depending on the specific issue or problem being pursued. A Tier 2 assessment is considered non-routine. Tier 2 inspections, tests, and measurements generally require specialized equipment or expertise, may be intrusive, or may require an outage to perform.

For certain types of equipment, there are many tests that can provide information about different aspects of component condition. The choice of which tests to apply should be made based on the Tier 1 assessment as well as information obtained via review of O & M history, physical inspection, other test results, and company standards. Results of the Tier 2 analysis may either increase or decrease the Condition Index. In some cases, more than one Tier 2 test may be available to detect or confirm a single defect or state of deterioration. It is important to avoid over-adjusting the Condition Index simply because two or more tests confirm or disprove the same suspected problem. In the event that multiple tests are performed to assess the same problem or concern, the test with the largest adjustment would normally be used to recalculate the Condition Index. Since the Tier 2 tests are being performed by and/or coordinated with knowledgeable technical staff, the decision as to which test is more significant and how different tests overlap is left to the experts.

An adjustment to the Data Quality Indicator score may be appropriate if additional information or test results were obtained during the Tier 2 assessment.

Documentation

The condition assessment results are recorded on the Condition Assessment Summary form at the end of each guide. The Tier 1 portion of the form contains a table listing the Condition Indicators with their respective weighting factors. The indicator scores are multiplied by the appropriate weighting factor and then summed to arrive at the Tier 1 Condition Index. In the Tier 2 section, the Condition Index may be adjusted by the results of the Tier 2 inspections, tests, and measurements.

Substantiating documentation is beneficial to support findings of the condition assessment, particularly where a Tier 1 Condition Indicator score is low or where Tier 2 results in subtractions to the Condition Index. Test reports, photographs, O & M records, and other documentation are important to support the equipment condition assessment summary.

Unit and Station Indices

To assist facility managers and other decision-makers, the condition assessment results can be used to develop an aggregated assessment of a complete power train unit as well as an entire generating station. Strategic importance, lost revenues as a result of equipment failure, reliability criticality, forced outage rates, environmental concerns, and other factors are important considerations when developing Unit and Station Indices.

To illustrate a method of determining Unit and Station Indices, consider the fictitious XYZ Hydropower Station. It has six (6) power train units, each consisting of the following components: generator, transformer, turbine, governor, exciter, and circuit breaker as shown in Table II-2. The condition indices for the power train components of the six units have been deliberately selected to illustrate different equipment condition scenarios. A single, distinct component has been designated as the "weak link" in each unit for this illustrative example. The condition color-coding scheme follows that of Table II-1.

Table II-2: Condition Indices of Power Train Components

XYZ Hydropower Station	Unit					
	1	2	3	4	5	6
Generator	2.9	6.8	8.9	6.0	7.8	9.0
Transformer	5.0	6.0	2.3	7.3	5.4	4.0
Turbine	6.4	4.3	8.0	2.3	4.2	5.0
Governor	4.2	6.9	5.0	5.9	2.0	6.3
Exciter	8.4	2.9	6.0	6.7	7.0	3.5
Circuit Breaker	9.0	5.0	7.3	6.5	2.0	9.0

As shown in Table II-3 below, each component in the power train has been assigned a weight based on how critical it is to overall power production. The generator is deemed the most critical component and is weighted 0.30. The circuit breaker is the least critical component and is weighted 0.05. Although the specific component weight rating and scales selected for this example are appropriate, they may not reflect the best weighting for every situation. Therefore, it should be noted that the individual component weights may be varied as long as their sum equals 1.00.

Table II-3: Component Weights

Component	Weight
Generator	0.30
Transformer	0.25
Turbine	0.20
Governor	0.10
Exciter	0.10
Circuit Breaker	0.05
Sum	1.00

A condition threshold value or Condition Index Trigger Value has been set at 3.0, as shown in Table II-4. Accordingly, each component with a Condition Index of 3.0 or higher (i.e., a rating of fair or good) is given a modified component rating equal to the weight assigned to the component. For instance, a generator in fair or good condition is given a rating of 0.30. If the component's Condition Index is less than 3.0 (poor), a rating of zero is assigned. The Unit Index is determined by summing the modified condition ratings, which is simply the sum of the weights for all components in either fair or good condition. As shown in Table II-4, higher Unit Indices result when the more critical components are in good or fair condition.

A power train unit is considered to be in good condition if its Unit Index is greater than 0.85, in fair condition if its index is greater than 0.75 and less than or equal to 0.85, and in poor condition if its index is 0.75 or below. It should be recognized that the Unit Index rating does not affect the actions required to improve the condition of a poor reliability component since the failure of an individual component in the power train can result in a major forced outage.

The Station Index represents the average of the Unit Indices.[3] In this simplified example, the resulting Station Index is 0.83 [(0.7 + 0.9 + 0.75 + 0.8 + 0.85 + 1.0) ÷ 6], indicating that XYZ Hydropower Station is in fair condition.

Table II-4: Condition Ratings of Units and Station

Condition Index Trigger Value	3.0

Modified Condition Ratings	**Unit**					
	1	2	3	4	5	6
Generator	0.00	0.30	0.30	0.30	0.30	0.30
Transformer	0.25	0.25	0.00	0.25	0.25	0.25
Turbine	0.20	0.20	0.20	0.00	0.20	0.20
Governor	0.10	0.10	0.10	0.10	0.00	0.10
Exciter	0.10	0.00	0.10	0.10	0.10	0.10
Breaker	0.05	0.05	0.05	0.05	0.00	0.05
Unit Index	0.70	0.90	0.75	0.80	0.85	1.00
Station Index	0.83					

Unit and Station Ratings	**Good**	**Fair**	**Poor**
Unit Index	>0.85	>0.75 and ≤0.85	≤0.75
Station Index	>0.85	>0.75 and ≤0.85	≤0.75

[3] The condition of the auxiliary components is not considered in the station index calculation.

Computerized Maintenance Management System (Maximo®)

The equipment condition assessment process can be easily adapted to a Computerized Maintenance Management System (CMMS) to:

- Store the Tier 1 equipment condition assessment procedures
- Record and track Condition Indicator scores and weighting factors
- Compute the equipment Condition Index
- Store data for historical analyses

Maximo® is the CMMS that is currently being used by all of the hydroAMP partners. It serves as a tool for facility managers to understand the condition of their equipment and to better prioritize needed maintenance or replacement activities. It also serves to meet applicable facility condition assessment requirements.

The equipment condition assessment procedure is loaded into Maximo® using the following three component applications:

1. Job Plan Application

   A Job Plan application stores definitions that define the ratings that assess the condition of a class of power equipment. A Maximo® job plan has been created for each type of equipment (e.g., turbine, transformer).

2. Preventive Maintenance Application

   A Preventive Maintenance (PM) application links the Job Plan from equipment classification (e.g., transformer) to a specific piece of equipment. After the PM record is established, the PM schedule is set to generate work orders on an annual interval.

3. Condition Monitoring Application

   The Condition Monitoring application establishes and links measurement points to specific equipment. The condition assessment process rates equipment conditions using measurement point values entered in Condition Monitoring or on work orders.

When Maximo® is used to record condition assessment results, the supporting documentation (e.g., test reports, photographs, O & M records) should be attached to the work order.

See Appendix B for a detailed description of loading the equipment condition assessment procedure into Maximo®.

Condition Assessment Database

Even though maintenance management systems such as Maximo® can be used to record the results of condition assessments, the hydroAMP team believed it was valuable to develop a hydroAMP database to store results arising from these assessments. The database has several important features; namely, accessibility through the internet, real-time updating of results, and tracking of trends in Condition Indicators and Indices over time.

BPA engaged its information technology specialists to develop the database based on input from COE engineering and maintenance staff. While the hydroAMP database is currently hosted and maintained on BPA's website (https://secure.bpa.gov/hydroAMP/), it is available for use by any participating hydroAMP organization for data input, storage, and retrieval. The site is password protected with access granted on a case-by-case basis.

Database Input

The database and website use MSSQL and ASP.net technologies. Data entry is largely accommodated through pull-down menus with Condition Indices automatically calculated and ratings assigned. The database can be updated by simply logging onto the website and updating user entry forms within the system. All updates made in this fashion are available immediately via the reporting tools. We are in the development stage of creating a file updating standard and procedure that will allow for export of updates directly from any maintenance management system, such as Maximo®.

Website Menu Options:

- Condition Assessments – Input equipment condition data for Tier 1 assessment.
- Equipment – Add, update and delete equipment for specific plants.
- Reports – View and export condition assessment reports.
- My Account – View and make changes to your account.
- Help – Provides links and contacts for information.

Database Output

The hydroAMP website has been developed such that a number of reports can be generated directly by the system. These reports give summary information and are available directly through the user's web browser. All reports are exportable in multiple formats depending upon user preference; HTML, PDF, Microsoft Excel, Tiff images, CSV, or XML.

Database Users and Contacts

The hydroAMP database is available to operation and maintenance staff, plant managers, technical support staff, and investment decision makers of the hydroAMP organizations. The development of hydroAMP was initially funded by the partner organizations. Implementation and maintenance of hydroAMP is currently being funded by the COE, BOR, and BPA.

Database Access

To access the hydroAMP database, and for security reasons, individuals wanting access to the system are required to open an account. The account will include a log-in, password, and permissions. The permissions involve two parameters – first, what actions you as a user will be performing (e.g., read, read/write, or management review) and secondly, which hydro projects/plants you have authorization to view and/or edit.

All requests for access to this database, and for reporting problems or concerns, should be sent to the hydroAMP e-mail address hydroamp@bpa.gov and must include your full name, e-mail address, phone number, and the plants for which you are requesting access. The hydroAMP administrator will assign log-ins and passwords and respond to you via e-mail.

Section III: Tools for Prioritizing Projects Using a Risk Analysis Approach

Introduction

In the preceding section, we presented detailed steps, including tests and inspections, to assess the condition of major power train equipment and auxiliary components at a hydro plant. These comprehensive condition assessments are a critical factor for planning maintenance and capital investments. But they are not the only factors.

The path that leads from a condition assessment to an investment decision is an important part of managing large hydro plants for maximum benefit. The analytical tools described in this section are intended to help decision makers develop and maneuver that path. They are the link between the technical and engineering tasks that make up a condition assessment and the economic and risk analyses that guide maintenance management and investment decisions.

There are several key factors to consider in these analyses, including cost, consequence, and risk. These factors, along with the condition assessment, inform program priorities and investment decisions.

A cost-effectiveness analysis of a specific piece of equipment at a hydro plant is a complex undertaking. Benefit is derived from actions that lead to efficiency improvements (reduction in losses) and cost savings, or that avoid lost revenues. For reliability investments, the first two areas of benefit can be easily determined, but the benefits are typically small. The third area is more difficult to calculate. In the case of lost revenues, benefit is derived only from making the piece of equipment in question more reliable than the next least-reliable piece of equipment of the power train. Making this calculation and determining how to allocate the benefit among multiple investments on the power train is complicated and involves elements of subjectivity.

A cost-effectiveness analysis on an entire generating unit or plant can more easily be done. An analyst can compare the expected future investments on all equipment components of a generating unit to the future avoided lost-revenue benefits to determine whether the investments would be cost effective overall. If so, investments when needed for individual equipment components can be deemed cost effective, as long as they are consistent with the expected future investments that were analyzed.

There are several techniques and models available for doing unit or plant cost-effectiveness analyses. All require the marginal value of the unit or plant as an input. Some models attempt to optimize the timing of investments by minimizing the present value of future costs and lost revenues. These models require that assumptions be made about the probability and consequence of failure in order to determine the optimum timing for intervention. One such technique that derives an expected net present value of investing in a unit or plant using Monte Carlo simulation is outlined in Appendix C.

In the following hydroAMP framework, we assume that each company has a process in place to determine whether anticipated future investments in units and plants are cost effective. That information is taken as an input into hydroAMP. We do not attempt to optimize the timing of investments, but do consider timing as it relates to risk management. What we outline here is a simple, easy to use, and low cost process for rating equipment condition and prioritizing investments using risk-management tools.

It should be noted that the analytical tools laid out here are not intended to be prescriptive, and we have purposely avoided recommending a particular type of analysis for a specific piece of equipment or situation. Each plant owner has its own circumstances, regulatory and legal obligations, strategic goals, and preferences with regard to risk.

Types of Analyses

Two types of analysis, designated as Type 1 and Type 2 Analyses, are described below. They outline a Business Analysis/Risk-Based Decision prioritization process, and are illustrated through case studies in Section IV.

Type 1 Analysis

A Type 1 analysis considers equipment condition and cost alone, all that may be needed in some cases. For example, a compressor is a relatively inexpensive piece of equipment. If there is budget to do so, the best investment decision may be to replace a compressor that is in poor condition as soon as possible.

The Type 1 analysis considers six cost and condition factors:

- Total Cost: Cost to repair or replace the equipment, including engineering, administration, and commissioning costs.
- Current-Year Cost: Portion of investment cost incurred in the current year.
- Incremental Annual Maintenance: The increase or decrease in maintenance provided by the investment dollars.
- Achievability: Ability to undertake the project in the immediate timeframe.
- Phase of the Project: Defined here as study (S), engineering (E), procurement (P), or construction (C).
- Condition Index: Derived from the most recent performance and Condition Indicators for the equipment as outlined in Sections I and II.

This type of analysis is often used for (but is not limited to) situations involving emergency repairs, failures, and auxiliary systems. Without budget and delivery constraints, investments can be prioritized simply using the condition rating. Where constraints exist, other factors need to be considered.

Type 2 Analysis

For more expensive pieces of equipment where there are several investment alternatives for improving reliability, additional factors need to be considered when setting priorities. A more complex analytical tool, described here as a Type 2 analysis, is useful for prioritizing a list of investments that affect generation.

The Type 2 analysis uses all factors from Type 1 and introduces additional factors that relate to the consequence of undertaking or not undertaking a repair or replacement action. These factors, which may not be appropriate to every situation, are as follows:

- Marginal Value of Generation: Annual value attributed to the piece of equipment. This value is determined outside the hydroAMP framework and may include the value of energy and ancillary services.
- Total Outage Duration: For generation-affecting equipment, the length of time (in years) to restore a unit to service after failure, including both the time required to procure and to install equipment.
- Revenue at Risk: Marginal value of generation times the total outage duration.
- Risk Map Score: A score (explained below) that measures the relative risk for a piece of equipment given its condition rating and the consequence associated with its failure.
- Other Business Factors: Factors important to the decision, including environmental, legal, and safety considerations.
- Priority Rank: Risk map score plus other business factors.

The risk map in Table III-1 is a tool that helps a plant/asset manager prioritize a portfolio of investment needs. As stated above, it measures the relative risk of a piece of equipment given its condition rating and the consequence associated with its failure. The consequence we use here is loss of revenue, but it could include other business factors.

The map is laid out in a grid, with condition values on one axis and the consequence of failure on the other. Values in the grid are the sum of the corresponding beta values for condition and consequence shown in Table III-2. The values in this table are for illustration only and can be changed to meet the specific needs of each company.

Table III-1: Risk Map

Condition Values		Condition Index	Condition Beta										
	Poor	0 to 0.9	10	11	12	13	14	15	16	17	18	19	20
	Poor	1 to 1.9	9	10	11	12	13	14	15	16	17	18	19
	Poor	2 to 2.9	8	9	10	11	12	13	14	15	16	17	18
	Fair	3 to 3.9	6	7	8	9	10	11	12	13	14	15	16
	Fair	4 to 4.9	5	6	7	8	9	10	11	12	13	14	15
	Fair	5 to 5.9	4	5	6	7	8	9	10	11	12	13	14
	Fair	6 to 6.9	3	4	5	6	7	8	9	10	11	12	13
	Good	7 to 7.9	2	3	4	5	6	7	8	9	10	11	12
	Good	8 to 8.9	1	2	3	4	5	6	7	8	9	10	11
	Good	9 to 10	0	1	2	3	4	5	6	7	8	9	10
		Consequence Beta		1	2	3	4	5	6	7	8	9	10
		Risk Level		Low		Medium-Low		Medium		Medium-High		High	

Consequence

Risk Level Results (Map #)
High 17 - 20
Medium-High 13 - 16
Medium 9 - 12
Medium-Low 5 - 8
Low 1 - 4

Table III-2: Beta Tables

Condition Lookup	
CI	Beta
0	10
1	9
2	8
3	6
4	5
5	4
6	3
7	2
8	1
9	0

Consequence Lookup Type 2 Analysis	
Rev @ Risk	Beta
-	1
100	2
200	3
400	4
600	5
800	6
1,000	7
2,000	8
3,000	9
4,000	10

Section IV: Case Studies

Introduction

Analyses described in Sections I, II, and III are illustrated through three (3) examples in this section. Examples 1 and 2 illustrating Type 1 and Type 2 Analyses, respectively, are theoretical in nature. Example 3 describes an actual spare transformer study for the North Pacific Region of the U.S. Army Corps of Engineers.

Type 1 Analysis

The following example illustrates how to use a Type 1 analysis to set investment priorities, given differing budget constraints:

Type 1, Case 1*:* In Table IV-1, we show auxiliary systems in two plants that lend themselves to a Type 1 analysis. The current-year budget for investments is capped at $450,000. Decision criteria used to prioritize the investments are: (1) condition indices, (2) achievability, and (3) incremental annual maintenance costs.

Because the surge arrestors in Plant A and Crane 1 in Plant B are in poor condition, they are priority items for action. The current-year budget request for these items is $365,000, leaving $85,000 available to address other needs.

The second level of budget priority is for items in fair condition with high achievability. Crane 2 in Plant B requires a $100,000 investment in the current year, so there are insufficient funds to start that activity at this time. But Battery 5 in Plant B can be completed for $35,000, which is achievable in the current timeframe. Battery 5 in Plant B therefore gets a higher priority than Crane 2 in Plant B for the current year, which leaves $50,000 available for other investments.

Since there are no other investments with high achievability, the next step is to look at items with potential for high maintenance cost savings. The largest potential is with Crane 1 in Plant A, which has a current-year cost of $50,000 and maintenance cost savings of $50,000 per year. This investment has a medium achievability level and can be funded with the remaining available dollars in the current-year budget.

Final priorities for Type 1, Case 1, $450,000 current-year budget:

1. Arrestors at Plant A $15,000
2. Crane 1 at Plant B $350,000
3. Battery 5 at Plant B $35,000
4. Crane 1 at Plant A $50,000

Table IV-1: Factors for Type 1 Analysis (Case 1)

Type 1: Condition Factors								
Priority Determined by:					Tertiary	Secondary		Primary
Plant	Unit	Equipment	Investment Cost	Current Year Cost	Incremental Annual Maintenance	Achievability	Phase	Condition Index
A	1	Arrestors	15	15	0	H	P	2.8
B	N/A	Crane 1	500	350	-10	H	C	2.9
B	N/A	Battery 5	35	35	-2	H	S	5.4
A	N/A	Crane 1	300	50	-50	M	S	5.3
B	N/A	Crane 2	100	100	-25	H	S	5.0
A	N/A	Compressor 1	15	15	0	M	E	5.2
B	N/A	Compressor 1	15	15	0	L	S	8.3
Total			980	580				

Type 1, Case 2: In Table IV-2, we show the same conditions as in Case 1, but with a current-year budget of $480,000.

Again, the first priority for investment is equipment in poor condition. The combined current-year requirement is $365,000 for the two items in this category, so there is $115,000 remaining for other investment needs. A high achievability project, Crane 2 at Plant B, can be funded with the remaining funds. It becomes number three on the priority list, which leaves $15,000 for other investments.

The costs for either Compressor 1 at Plant A or Compressor 1 at Plant B are low enough to be funded with the remaining funds. But using the priorities we have set, the preferred alternative would be Compressor 1 at Plant A because it has a lower condition rating. Compressor 1 at Plant B is in good condition, so it is unlikely that an investment would be warranted even if funds were available. By coincidence, in this case the funding priority is consistent with the condition rating.

Final priorities for Type 1, Case 2, $480,000 current-year budget:

1. Arrestors at Plant A $15,000
2. Crane 1 at Plant B $350,000
3. Crane 2 at Plant B $100,000
4. Compressor 1 at Plant A $15,000

The cases under the Type 1 analysis show a straightforward path to an investment decision. But not all decisions are that simple, and some require a more sophisticated treatment.

Table IV-2: Factors for Type 1 Analysis (Case 2)

Type 1: Condition Factors								
Priority Determined by:					*Tertiary*	*Secondary*		*Primary*
Plant	**Unit**	**Equipment**	**Investment Cost**	**Current Year Cost**	**Incremental Annual Maintenance**	**Achievability**	**Phase**	**Condition Index**
A	1	Arrestors	15	15	0	H	P	2.8
B	N/A	Crane 1	500	350	-10	H	C	2.9
B	N/A	Crane 2	100	100	-25	H	S	5.0
A	N/A	Compressor 1	15	15	0	M	E	5.2
A	N/A	Crane 1	300	50	-50	M	S	5.3
B	N/A	Battery 5	35	35	-2	H	S	5.4
B	N/A	Compressor 1	15	15	0	L	S	8.3
Total			980	580				

Type 2 Analysis

The following example illustrates how to use a Type 2 analysis to set investment priorities under various budget constraints:

Type 2, Case 1: In Table IV-3, we show power train equipment in three plants, plus a crane at one of the plants. The current-year budget for these investments is capped at $1 million. Decision criteria used to prioritize the investments are: (1) Priority Rank, (2) Risk Map Score, and (3) Condition Index.

The first evaluation criterion is the priority rank, derived from the risk map score and other business factors. The highest priority for investment is Generator 1 at Plant B, with a priority rank of 15. It also has a risk map score of 15 (medium-high risk), derived from a condition beta of 8 and consequence beta of 7 (see Table III-2). The generator, however, has a current-year investment requirement that exceeds the budget, so it cannot be undertaken at this time.

Next in the priority list is Transformer 4 at Plant B, with a risk map score and priority rank of 14 (medium-high risk). Allocating $500,000 for this in the current year leaves $500,000 available for other needs.

There are no other investment needs with medium-high or higher risk, so from a condition versus revenue-at-risk perspective, the remainder of the portfolio (except for the generator that will need to be addressed in the near future) presents no significant risks for the company. There are still equipment components in poor condition, however, that could adversely affect revenues and other business objectives of the company. There is also enough current budget available to consider them.

While Transformer 1 at Plant B has a higher risk map score due to the amount of revenue at risk, Transformer 2 at Plant A has an additional environmental problem that increases its priority rank by 2, making it the preferred investment alternative for the remaining $500,000. A rationale for investing in Transformer 1 at Plant B instead could also be made based on its higher revenue at risk.

Final priorities for Type 2, Case 1, $1 million current-year budget:

1. Transformer 4 at Plant B $500,000
2. Transformer 2 at Plant A $500,000

Table IV-3: Failure Factors for Type 2 Analysis

Type 2: Failure Factors															
Priority Determined by:								***Tertiary***				***Secondary***		***Primary***
Plant	**Unit**	**Equipment**	**Investment Cost**	**Current Year Cost**	**Incremental Annual Maintenance**	**Achievability**	**Phase**	**Condition Index**	**Marginal Value of Generation**	**Total Outage Duration in Years (Including Acquisition)**	**Revenue at Risk**	**Risk Map Score**	**Other Business Factors (Environmental, Legal, Safety, Other)**	**Priority Rank**
B	1	Generator 1	2,500	1,500	(50)	H	P	2.9	600	2.0	1,200	15	0	15
B	4	Transformer 4	800	500	(10)	H	P	2.7	600	1.4	840	14	0	14
A	2	Transformer 2	800	500	(10)	H	P	2.7	190	1.4	266	11	2	13
B	1	Transformer 1	800	500	(10)	H	P	2.7	600	0.8	480	12	0	12
B		Crane 1	500	300	(20)	H	S	5.3	0		0	5	4	9
C	3	Transformer 3	1,000	100	(10)	N	S	4.9	190	1.4	266	8	0	8
A	1	Transformer 1	1,000	100	(10)	M	S	5.2	190	1.4	266	7	0	7
B	1	Breaker 1	200	180	(15)	H	S	5.0	600	0.4	240	7	0	7
C	2	Governor 2	200	180	(15)	H	E	5.0	190	0.2	38	5	0	5
C	1	Breaker 1	200	20	(15)	M	S	6.8	190	0.4	76	4	0	4
Total			8,000	3,880										

Type 2, Case 2: The current-year budget is capped at $1.5 million.

There are two likely alternatives for investment with a $1.5 million budget: Generator 1 at Plant B, which would require the entire available budget for the year, or the three transformers that are in poor condition. The three transformers collectively represent more revenue at risk than the single generator, and there are additional environmental benefits associated with an investment in Transformer 2 at Plant A.

As a result of the analysis, it is apparent that the transformers should receive the investment in the current year. The generator, however, would be a high priority in the next funding cycle, and the company should prepare an operational risk-management plan for the immediate timeframe.

Final priorities for Type 2, Case 2, $1.5 million current-year budget:

1. Transformer 4 at Plant B $500,000
2. Transformer 2 at Plant A $500,000
3. Transformer 1 at Plant B $500,000

Type 2, Case 3: The current-year budget is capped at $2 million.

To minimize the overall outage time for Unit 1 at Plant B, it would make sense to address needs in the entire power train and invest in both the generator and transformer. It would also be desirable to seek an additional $180,000 for the current year in order to include work on the Unit 1 breaker since there would be an incremental lost-opportunity benefit of $240,000 for combining that project with work on the generator and transformer.

Final priorities for Type 2, Case 3, $2 million current-year budget:

1. Generator 1 at Plant B $1,500,000
2. Transformer 1 at Plant B $500,000
3. Breaker 1 at Plant B $180,000 (if additional funds are available)

Type 2, Case 4: The current-year budget is capped at $3.5 million.

With $3.5 million to allocate toward investment needs, there are more options available to the plant/asset manager. The first four items listed in Table IV-3 have relatively high priority rankings and poor condition ratings, making them top priorities for investment. The total funding requirement for these items is $3 million in the current year. As in Case 3, Breaker 1 should be added to the priorities to coincide with generator and transformer work on Unit 1 at Plant B, leaving $320,000 available for other needs. There are safety issues associated with Crane 1 at Plant B, so a $300,000 investment in that item is the next priority.

Final priorities for Type 2, Case 4, $3.5 million current-year budget:

1. Generator 1 at Plant B $1,500,000
2. Transformer 4 at Plant B $500,000
3. Transformer 2 at Plant A $500,000
4. Transformer 1 at Plant B $500,000
5. Breaker 1 at Plant B $180,000
6. Crane 1 at Plant B $300,000

The level of funding in Case 4 represents what a plant/asset manager would need to assure that the three generating plants shown in Table IV-3 deliver performance that is reliable, safe, and environmentally sound.

North Pacific Region Spare Transformer Project

Generator step-up (GSU) transformers connect the low voltage generators to the high voltage transmission system. Depending on plant configuration, the failure of a single GSU transformer can result in an outage of 1 to 4 generators. Procurement and manufacturing time for a large GSU can extend up to 18 months.

In March 2002, Bonneville Power Authority, the federal power marketing agency for Corps of Engineers projects in the North Pacific Region (NPR), requested that HDC develop a spare GSU transformer purchase plan. The Spare Transformer Project covered 20 hydroelectric plants in the Portland, Seattle, and Walla Walla Districts. The study covered 155 transformers ranging from 115 to 500 kV, 13 to 385 MVA, and from 7 to more than 50 years old. The average age of the GSU transformers in the region is over 34 years old, and there are very few spares. The goals of the study were to:

- Assess the condition of the existing transformers
- Determine the risk and economic consequences of failure due to lost generation for each transformer with and without a spare available
- Develop a prioritized Sparing and Placement Plan

Condition Assessment

When the North Pacific Region Spare Transformer Project was initiated, a team of hydroAMP transformer experts was developing a transformer condition assessment guide. Although the guide was not yet complete, the technical team had identified the relevant Condition Indicators, test result thresholds, and rating criteria to be used to perform a transformer condition assessment. Table IV-4 provides an overview of the condition assessment process developed using recommendations of the technical group as well as other industry sources. The assessment utilizes the following information: Oil Analysis [dissolved gas analysis (DGA) and routine physical screening], Power Factor measurements, O & M History, and Age.

For each of the Condition Indicators, test results were divided into four ranges and points were assigned to each range (more points for better test results). The condition assessment was performed using existing test records available from the project or district offices and from external inspections of the transformers. No special testing or internal inspections were performed. Five to ten years of test data were reviewed (when available) for the Oil Analysis and Power Factor tests to evaluate trends.

An overall rating for each transformer was calculated using the following weighting factors provided by the technical group:

Oil Analysis	1.2
Power Factor	1.0
O & M History	0.8
Age	0.5

Table IV-4: Transformer Condition Assessment Guidelines

TRANSFORMER CONDITION ASSESSMENT				
Condition Indicator	**Score**			
	3	**2**	**1**	**0**
Oil Analysis*				
1. Dissolved Gas Analysis (DGA)				
a. Generation Rate (ppm/month)				
Total Dissolved Combustible Gas (TDCG)	< 30	30-60	50-80	> 80
Individual CG	< 10	< 15	< 25	> 50
Carbon Monoxide (CO)	< 70	< 150	< 350	> 350
Acetylene (C_2H_2)	0	0	< 5	< 10
b. Level (ppm)				
Hydrogen	< 100	100-350	350-700	> 700
Oxygen	< 5,000	5k-10k	10k-15k	> 15k
Methane (CH_4)	< 75	75-200	200-400	> 400
Acetylene (C_2H_2)	< 5	5-20	20-40	> 40
Ethylene (C_2H_4)	< 30	30-60	60-100	> 100
Ethane (C_2H_6)	< 30	30-60	60-100	> 100
Carbon Monoxide (CO)	< 200	200-400	400-600	> 600
Carbon Dioxide (CO_2)	< 1,000	1k-3k	3k-5k	> 5k
TDCG	< 450	450-900	900-1,800	> 1,800
2. Oil Quality				
Interfacial Tension (IFT)	> 35	30-35	25-30	< 25
Acid Neutralization No.	0-0.05	0.05-0.15	0.15-0.5	> 0.5
Moisture	0-10	10-15	15-20	> 25
Furans	0-75	75-150	150-250	> 250
3. Power Factor (Doble)**	Normal (0.10 - 0.50)	Minor Degradation (0.50 - 0.80)	Significant Degradation (0.80 - 1.0)	Severe Degradation (> 1.0)
O & M History/ Physical Condition	Normal	Some abnormal operations or additional maintenance	Significant abnormal operations or additional maintenance	Forced outages, major leaks, severe problems, sister unit failures
Age (years)	< 30	30-45	> 45	-

*Overall oil score is lowest of individual scores for each category. Weight "Level" scores less than "Generation Rate" scores by increasing individual gas "Level" scores by one point.

In addition, if the Level of a gas is high but unchanged for 4 to 5 years, reduce weight of individual gas score for each such gas by increasing score by one point.

**Values refer to percent power factor on overall tests. Review overall, excitation, and TTR results. Defer to test engineer's assessment if present on report.

The outcome of the condition assessment was an adjective rating (Good/Fair/Poor) describing the overall condition of each transformer. These results were used in conjunction with the Economic Analysis described below to develop the Transformer Sparing Plan.

The overall condition assessment score ranges and associated ratings were:

Good	8.0 to 10.0
Fair	4.0 to 7.9
Poor	0 to 3.9

Economic Analysis Including the Probability of Failure

The simplified economic analysis was intended to determine for which projects at least one spare transformer was economically justified. For the purposes of this analysis, the economic benefit of having a spare transformer was defined as the difference in lost revenue between a long outage without a spare and a short outage with one. It was recognized that there are other costs involved with a transformer failure, including possible damage to adjacent equipment (e.g., bus work, structures, etc.), detrimental environmental impacts, and significant safety hazard to personnel. Having a spare GSU transformer does not mitigate these negative consequences nor do these consequences influence which projects should have spare transformers. Accordingly, these factors were not included in the analysis.

BPA provided annual generation and revenue information for each project to support the economic analysis. Using this information and the configuration for each transformer (i.e., the number of generating units served), lost revenue per year for a failure of each transformer was calculated. To account for planned unit maintenance, baseline annual revenue assumed 90% plant availability. The lost revenue was calculated by subtracting the revenue produced by the plant less the unavailable units (due to the transformer outage) from the baseline revenue.

An evaluation of the need for spare transformers must take into account some element of risk or probability of failure to properly balance the revenue saved by having a spare against the costs of procuring a spare. One measurement of the exposure to an extreme and relatively improbable event is the product of the potential cost of the event and the probability of that event occurring. For this analysis, the revenue expected to be saved (i.e., benefit gained) by having a spare transformer is used instead of the potential additional cost of the outage by not having a spare.

The probability of failure within the next year for a transformer whose condition was rated Good was assumed to be 0.0095 based on recent similar study work performed. For the purposes of this analysis, the probability of failure was increased to 0.0105 and 0.0115 for transformers whose condition was rated Fair and Poor, respectively. Note that the probabilities assigned to the three transformer conditions were somewhat arbitrary, and no analyses were performed in this phase of the work to better quantify appropriate failure probabilities. However, a sensitivity study was performed to demonstrate that the ranking of results is relatively unaffected by assumed failure probabilities.

The probability of a transformer failure at a particular project increases with the number of transformers at the project. Thus, the probability of a failure of any transformer among many identical units was calculated. The Expected Benefit (defined as the product of the probability of a transformer failure and the revenue saved by having a spare transformer) was calculated for each project.

The estimated costs for spare transformers were developed from a review of the costs and MVA ratings of replacement transformers procured during the previous five years and from input from BPA personnel involved in purchasing transformers. The estimated costs for the spare transformers assumed that the spare has the same configuration as the original (single or three-phase). The estimates included design, manufacturing, shipping, erecting, testing costs, and all appurtenances. The estimates did not have allowances for constructing storage facilities, removing or repairing a damaged transformer, or any internal costs associated with procuring a spare transformer.

To reflect the fact that in may cases a single spare transformer can serve as the spare for several banks of transformers, the estimated cost of the spare was divided by the number of transformers for which it would be a direct replacement.

The ratio of the Expected Benefits to the Spare Transformer Costs per unit for each project or type of transformer was calculated; the greater the Benefit/Cost ratio, the more likely that one or more spare transformers would be economically justified.

Benefit/Cost ratios ranged from 0.09 to 161. Ratios of one or greater suggested a spare should be considered. Based on the analysis, results for each project were divided into four categories as follows:

A – Project where one or more spare transformers appear justified and none exists
B – Projects where one or more spare transformers appear justified and one exists
C – Projects where no spare transformers appear justified and none exists
D – Projects where no spare transformers appear justified and one exists

Spare Transformer Plan[4]

The study effort resulted in the development of a near-term plan to mitigate the failure of a GSU transformer for each of the projects included. The system-wide condition assessment and economic evaluation provided a basis for further analysis and indicated steps to be taken to improve the condition of the existing transformers. For those projects where spare transformers appear justified, the process to procure spares has begun.

[4] Because of its length, the spare transformer plan is not included in this report. However, the complete plan is available from the Hydroelectric Design Center, U.S. Army Corps of Engineers, PO Box 2946, Portland, OR 97208-2946.

Conclusion

The preceding cases demonstrate how decision makers can use hydroAMP condition ratings and risk-management tools to prioritize a portfolio of investment needs. The overall unit and station condition information could also be used as an input to the hydroAMP risk analysis. As previously stated, the examples are illustrations and are not meant to prescribe an approach to setting investment priorities. Each plant owner has its own circumstances, regulatory and legal obligations, strategic goals, and preferences with regard to risk that must be applied to its investment decisions.

APPENDICES

Appendix A: Key Terms

Asset Management – A systematic process of maintaining, upgrading, and operating physical assets cost-effectively. It combines engineering principles with sound business practices and economic theory, and provides tools to facilitate a more organized, logical approach to decision-making. Asset management provides a framework for handling both short- and long-range planning. (*Asset Management Primer*, U.S. Department of Transportation, Federal Highway Administration, Office of Asset Management, December 1999, page 7.)

Availability – The annual percentage of time that a piece of equipment is available for power production.

Capacity – The maximum rated output of a piece of equipment.

Certainty – A condition where determinacy exists in the elements that characterize a situation. The likelihood of an event occurring and its consequences are known absolutely.

Computerized Maintenance Management System (CMMS) – The CMMS produces scheduled preventative maintenance to perform the equipment condition assessment. The results of the assessments are captured in the condition monitoring section of the CMMS. The CMMS will be used to generate summary reports showing the equipment condition and the integrated facility assessment.

Condition – The existing state of the component or equipment with respect to function and fitness.

Condition Assessment – The process of objectively evaluating the condition of a piece of equipment or a system using a uniform process and guidelines.

Condition Indicators – Individual components of an overall condition assessment. Typically standardized inspections and tests that are evaluated in a common manner.

Condition Index – The outcome of a condition assessment. An overall numerical rating between 0 and 10 which describes condition, with higher numbers equating to better condition.

Dependability (Reliability) – The probability that a piece of equipment will not perform satisfactorily.

Efficiency – A measure of losses for a piece of equipment; equals output power divided by input power.

Forced Outage – A forced outage occurs when a power plant component fails to perform satisfactorily and causes an unplanned interruption in power production.

Functionality – A subjective evaluation of a piece of equipment or system with regards to its ability to perform the current intended function. Degradation of functionality can be caused by deterioration, changing requirements or obsolescence.

Performance – Normally the combined evaluation of the efficiency and capacity of a piece of equipment.

Planned Outage – A planned outage occurs when a piece of equipment is intentionally taken out of service to perform routine inspections or planned repairs, replacements, and rehabilitations.

Reliability (of hydropower generating equipment) – The extent to which the generating equipment can be counted on to perform as originally intended. This encompasses the confidence in the soundness or integrity of the equipment based on forced outage experience and maintenance costs, the output of the equipment in terms of measured efficiency and capacity, unit availability and the dependability of the equipment in terms of remaining service life (retirement of the equipment).

Risk – The exposure to a chance of loss or injury; the likelihood of adverse consequences. Expressions of risk are composed of the existence of unwanted consequences and the occurrence of each consequence expressed in the form of a probability.

Uncertainty – A condition where indeterminacy exists in some of the elements that characterize a situation. Uncertainty may exist from either probability uncertainty, outcome uncertainty or any of the paths between the initiating event and the consequences.

Appendix B: Maximo® Loading Procedure

Introduction

The development and implementation of Condition Assessment (CA) is driven by the need to monitor the condition of major power plant equipment and meet agency-mandated facility condition assessment requirements. The CA process will serve as a tool for facility managers to understand the condition of their equipment and to better prioritize needed maintenance or replacement activities. Once the CA process is set up in Maximo®, it will be integrated into the facilities' normal maintenance procedures.

Overview

This document details the steps necessary to load the Power Equipment Condition Assessment process into Maximo®. This process assists facility Maximo® coordinators as they load CA job plans into their local database. This process makes the assessment more objective and utilizes information gathered during routine maintenance.

Power Equipment Condition Assessment is loaded into Maximo® using three component applications and their screens:

1. Job Plan Application

   A Job Plan stores definitions that define the ratings that assess the condition of a class of power equipment. A Maximo® job plan has been created for each class of equipment, e.g., turbine runner, transformer, etc. The Job Plan, along with its operation steps and measurement point names, is the first component of Maximo® that must be loaded. This part provides the information, screen images, and cut and paste text to facilitate the loading of condition assessment measurements.

2. Preventative Maintenance Application

   A Preventative Maintenance (PM) links the Job Plan to a specific piece of equipment. The PM transforms the condition assessment process from equipment classification (e.g., transformer) to a specific piece of equipment. To load the PM, a user needs a Job Plan and the specific equipment number. After the PM record is established, the PM schedule is set to generate work orders on an annual interval.

3. Condition Monitoring Application

   The Condition Monitoring application establishes and links measurement points to specific equipment. The condition assessment process rates equipment conditions using measurement point values entered in Condition Monitoring or on work orders. These points can be thought of as specific measurement points that measure a condition of equipment. The condition assessment process defines the name of measurement points.

As an example for transformer condition assessment, a measurement point with a unique point number is created for a specific condition and given the point name "XFMR-AGE". (The condition assessment process defines age as a measurement in the assessment process.) During the assessment process, the measurement point created above is loaded with a number that represents the condition of the equipment relative to its age. This number is defined in the Job Plan for the class of equipment. This number or scoring is loaded within the Condition Monitoring application or on the Actuals tab on PM work orders.

The sequence used to load condition assessment into Maximo® is:

1. Select the appropriate equipment.
2. Create measurement points for every Condition Assessment point identified.
   Note: It is critical that each site use the exact measurement point name to ensure all the reports will work.
3. Enter the Job Plan. If it is possible, the Condition Assessment operational steps can be incorporated into existing Job Plans.
4. Create Preventive Maintenance Plans to schedule the assessment.

It is important that Maximo® be set up correctly for condition assessment. When a work order is generated by the PM application, the Job Plan attached is automatically copied to the work order. Maximo® compares the Job Plan point names and the condition monitoring point names for measurement point names that match. When a match is found, Maximo® inserts the point number onto the work order. Using these points, the Maximo® Coordinator can easily record and store an equipment condition result as defined by the assessment process.

It is critical that the point names are entered exactly as defined by the Power Equipment Condition Assessment process. You must create the condition monitoring point names prior to loading them into Job Plans. The Job Plan Application will not accept point names if they have not been saved in the Condition Monitoring application.

The Maximo® report (CNDASSET) is available in the Condition Monitoring application. This report displays the current condition assessment points on all equipment setup for condition assessment measurements.

For Power Equipment, condition points identified for Transformer, for example, are:

- XFMR-OIL
- XFMR-PF
- XFMR-OM
- XFMR-AGE
- XFMR-RD

A full list of point names is contained in Table B-1 at the end of this appendix.

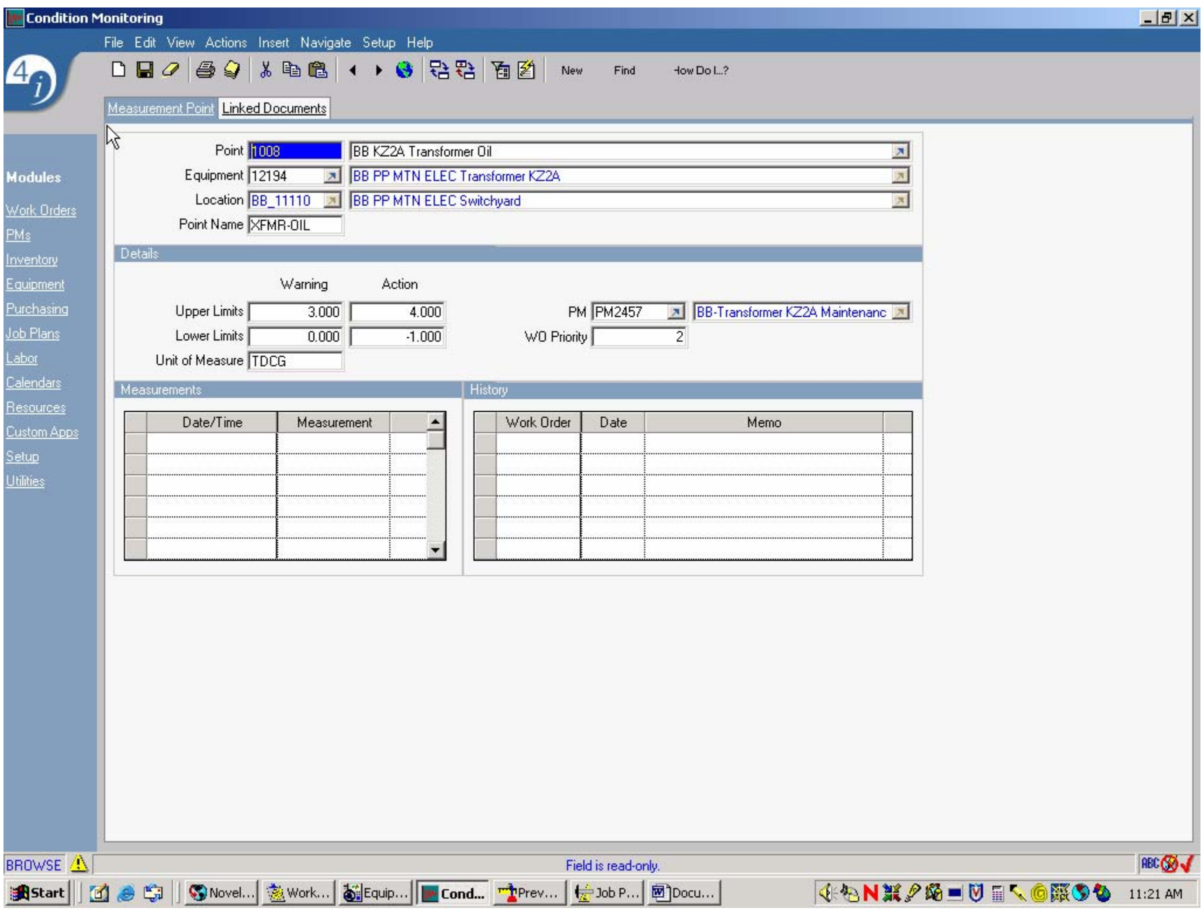
Procedures

The following condition assessment example is for a transformer. The same steps will be needed for each piece of equipment.

This section details the steps for establishing Condition Assessment. You will need to go into the Equipment Module and query for "Transformer" to get a complete list of transformer equipment numbers. This will need to be done for all equipment classifications (see Table B-1).

Refer to the Condition Monitoring Application (Figure B-1).

Figure B-1: Condition Monitoring Application

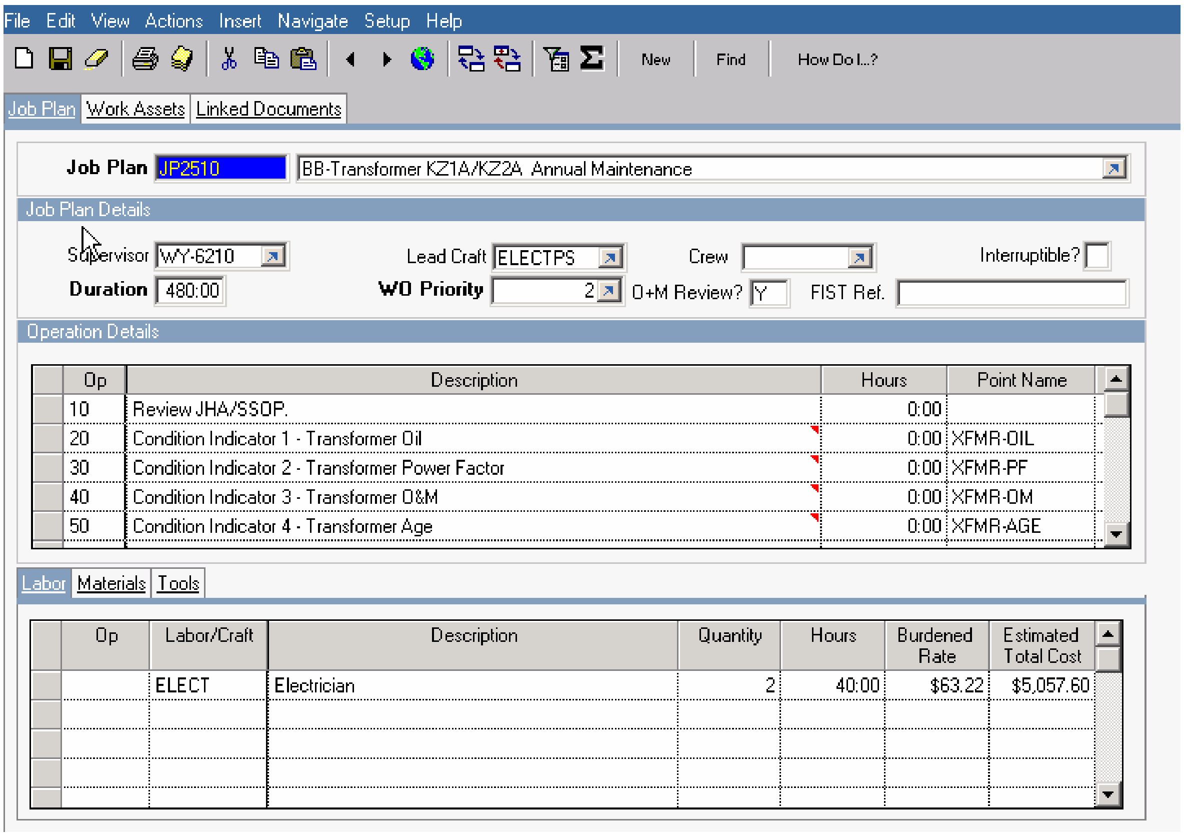


Transformer – The "Point" will be a unique number assigned by Maximo® and will be associated with the specific piece of equipment. Go to INSERT, NEW MEASUREMENT POINT WITH AUTONUMBER. Type in the Description, assign the equipment number (location will automatically populate), then type in the associated point name from Table B-1. These point names must remain exactly as on Table B-1 for consistency throughout all Maximo® sites. Future reports will query from this field. Limits are not required for these set points. (The set point limits will accept a Null.)

You will need to check the condition of this piece of equipment on an annual basis. If you have a current PM for that piece of equipment and plan on just adding to an existing Job Plan, enter the PM number now.

Now you will need to add the Condition Indicator scoring to your job plan. (Refer to Figure B-2.)

Figure B-2: Job Plans

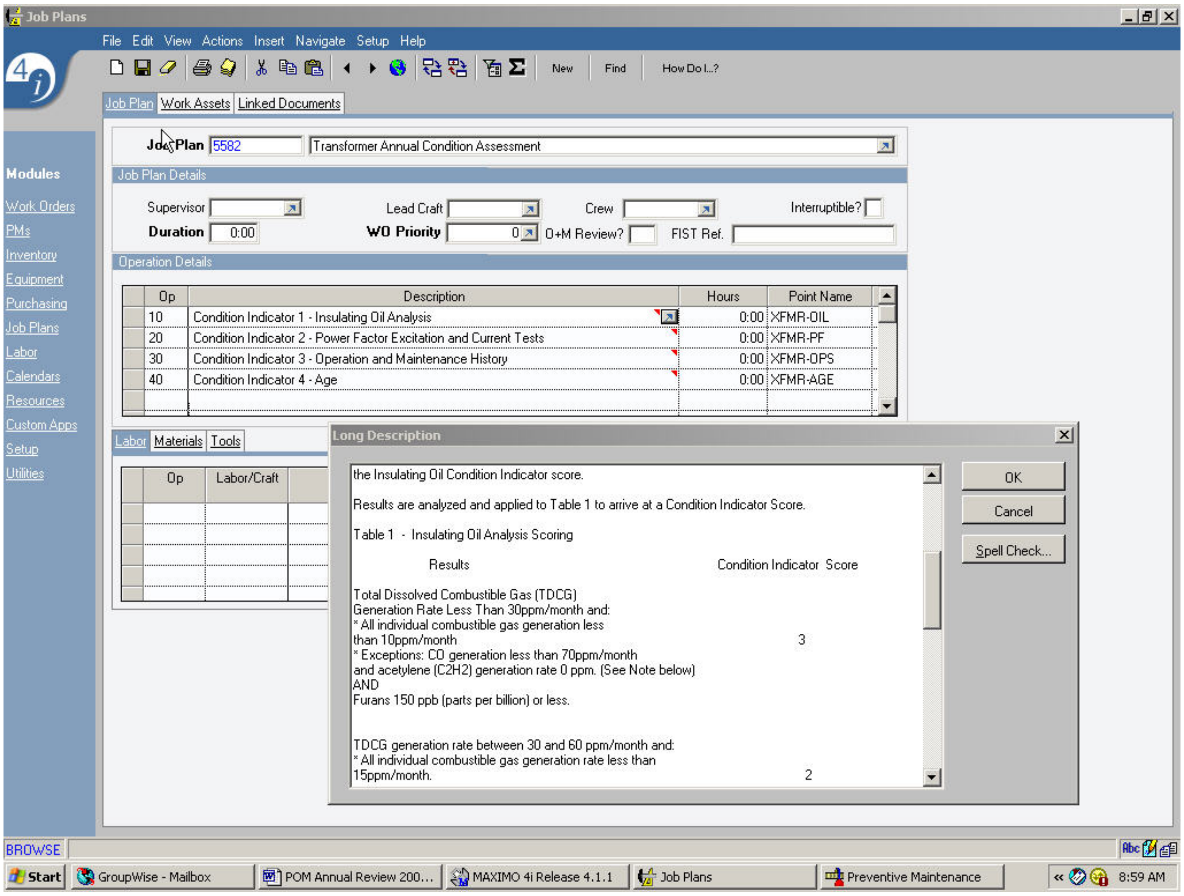


Go into the Job Plan Module and call up your job plan for this transformer. Go to INSERT, NEW ROW. Assign the row an Operational Step number. Tab to the Description column and type "Condition Indicator 1 – Transformer Oil". In the long description, type in the scoring benchmarks from the Condition Assessment Guide.

Example: Long Description of Job Plans

Dissolved gas analysis is the most important factor in determining the condition of a transformer. Insulating oil analysis can identify internal arcing, bad electrical contacts, hot spots, partial discharge, or overheating of conductors, oil, tank, or cellulose. The "health" of the oil reflects the health of the transformer itself. (Refer to Figure B-3.)

Figure B-3: Long Description of Job Plans



SAVE the record. These scoring benchmarks will be the same for each transformer. Once you have typed this information for the first piece of equipment, it can be copied and pasted into the long description for the next transformer. This will speed up the condition assessment process.

Tab to Point Name and type in XFMR-OIL. This Point Name is the link to the condition measurement, the equipment number and the Job Plan (which is linked to the PM, which is also linked to the equipment). This point name must be the same as listed in Table B-1. Repeat these steps for Condition Indicators 2 through 5, adding the scoring benchmarks as stated in the Condition Assessment Guide.

This transformer condition assessment is completed. This procedure will need to be accomplished for each transformer.

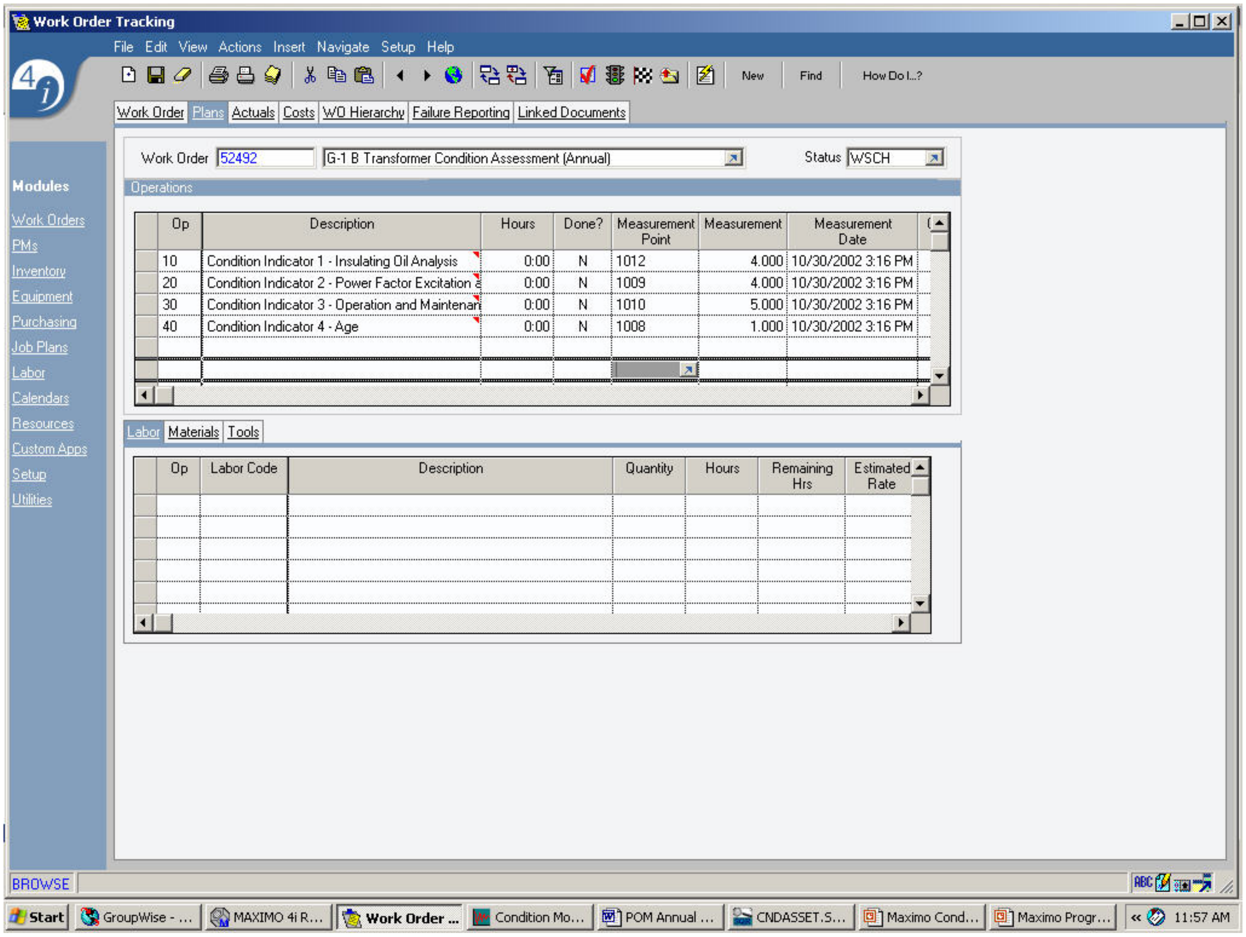
Then repeat the procedure for each of the other equipment listed in Table B-1.

Recording Set Point Values on Work Order

When the condition assessment work order is generated, there will be a space on the work order for the maintenance person to enter each set point value. (Refer to Figure B-4.)

When the work order is closed, the set point values will then be entered in the Maximo® work order module. This will associate the set point values with the appropriate equipment.

Figure B-4: Work Order Tracking



Condition Assessment Report

There will be a report that can be run annually that will:

- Calculate the condition of each equipment based on the set point values recorded.
- Generate a list of the current condition of facilities equipment.

Refer to the Report Viewer (Figure B-5).

Figure B-5: Report Viewer

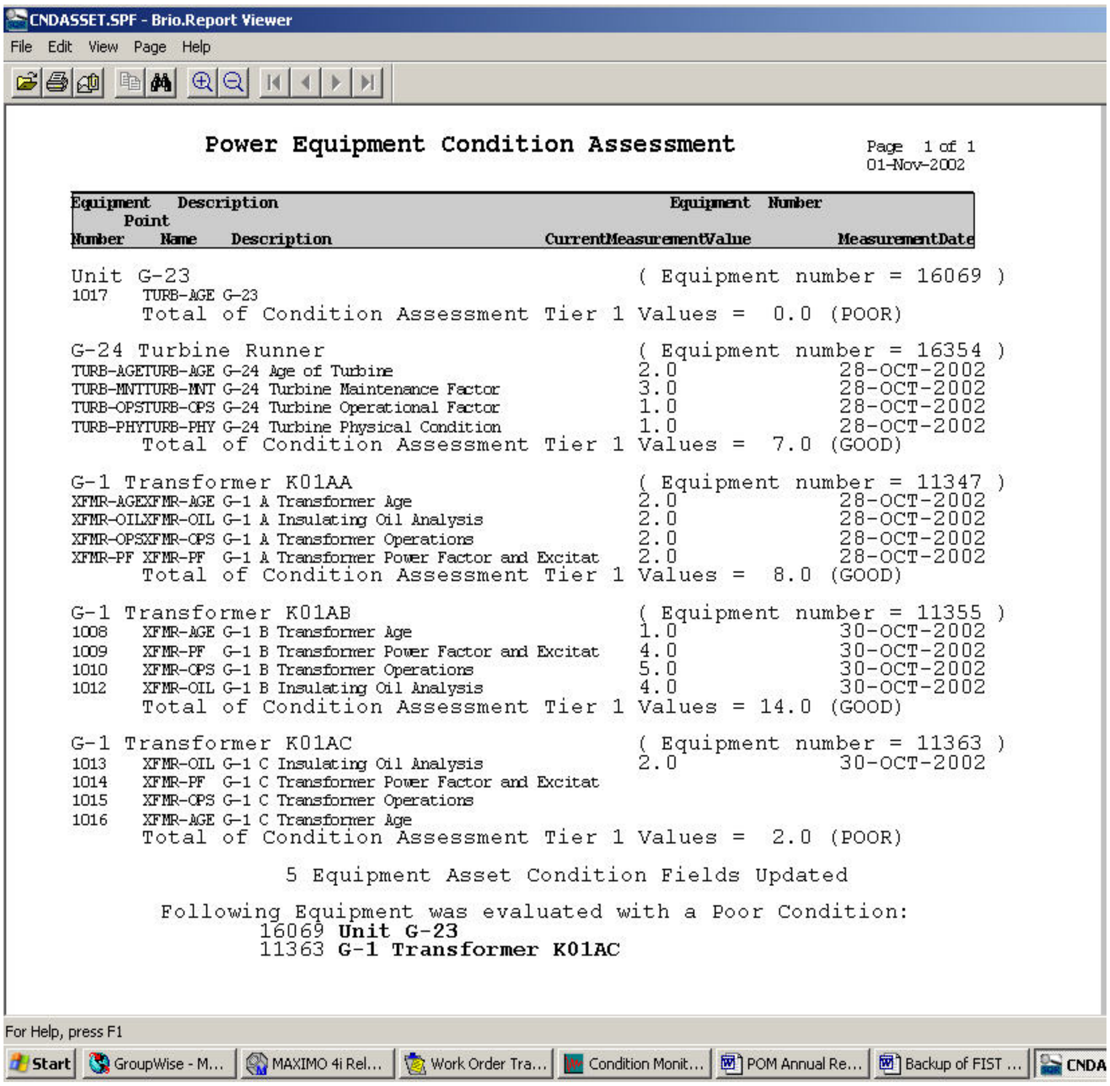


Table B-1: Equipment / Set Point Name List

Equipment	Point Name	Unit of Measure
Turbine		
Turbine Age	TURB-AGE	NUMBER
Turbine Physical Condition	TURB-PHY	NUMBER
Turbine Operations	TURB-OPS	NUMBER
Turbine Maintenance	TURB-MNT	NUMBER
Transformer		
Transformer Oil	XFMR-OIL	NUMBER
Transformer Power Factor	XFMR-PF	NUMBER
Transformer Operations and Maintenance (O & M)	XFMR-OM	NUMBER
Transformer Age	XFMR-AGE	NUMBER
Transformer Data Quality Indicator	XFMR-RD	NUMBER
Generator – Stator		
Stator O & M	STAT-OM	NUMBER
Stator Physical Inspection	STAT-PHY	NUMBER
Stator Insulation Resistance and Polarization Index	STAT-IR	NUMBER
Stator Winding Age	STAT-AGE	NUMBER
Stator Data Quality Indicator	STAT-RD	NUMBER
Generator – Rotor		
Rotor O & M	ROTR-OM	NUMBER
Rotor Physical Inspection	ROTR-PHY	NUMBER
Rotor Insulation Resistance and Polarization Index	ROTR-IR	NUMBER
Rotor Winding Age	ROTR-AGE	NUMBER
Rotor Data Quality Indicator	ROTR-RD	NUMBER
Circuit Breakers – Air Magnetic, Air Blast		NUMBER
Breaker Dielectric Test	BKRA-DT	NUMBER
Breaker O & M	BKRA-OM	NUMBER
Breaker Contact Resistance	BKRA-CR	NUMBER
Breaker Number of Operations (Cycles)	BKRA-CYC	NUMBER
Breaker Data Quality Indicator	BKRA-RD	NUMBER
Circuit Breakers – Bulk Oil		NUMBER
Breaker Dielectric Test	BKRB-DT	NUMBER
Breaker O & M	BKRB-OM	NUMBER
Breaker Contact Resistance	BKRB-CR	NUMBER
Breaker Number of Operations (Cycles)	BKRB-CYC	NUMBER
Breaker Data Quality Indicator	BKRB-RD	NUMBER
Circuit Breakers – SF6		NUMBER
Breaker Dielectric Test	BKR6-DT	NUMBER
Breaker O & M	BKR6-OM	NUMBER

Breaker Contact Resistance	BKR6-CR	NUMBER
Breaker Number of Operations (Cycles)	BKR6-CYC	NUMBER
Breaker Data Quality Indicator	BKR6-RD	NUMBER
Circuit Breakers – Vacuum		NUMBER
Breaker O & M	BKRV-OM	NUMBER
Breaker Data Quality Indicator	BKRV-RD	NUMBER
Governor		
Governor Age	GOV-AGE	NUMBER
Governor O & M History	GOV-OM	NUMBER
Governor Availability of Spare Parts	GOV-SP	NUMBER
Governor Performance	GOV-P	NUMBER
Governor Data Quality Indicator	GOV-RD	NUMBER
Exciter		
Exciter Age	EXC-AGE	NUMBER
Exciter O & M	EXC-OM	NUMBER
Exciter Availability of Spare Parts	EXC-SP	NUMBER
Exciter Power Circuitry Tests	EXC-PCT	NUMBER
Exciter Control Circuitry Tests	EXC-CCT	NUMBER
Exciter Data Quality Indicator	EXC-RD	NUMBER
Battery		
Battery Visual Inspection	BATT-VI	NUMBER
Battery Age	BATT-AGE	NUMBER
Battery Routine Testing	BATT-RT	NUMBER
Battery Data Quality	BATT-RD	NUMBER
Surge Arrester		
Surge Arrester Thermal Imaging	SA-TI	NUMBER
Surge Arrester Data Quality	SA-RD	NUMBER

Appendix C: Example Economic Analysis of a Facility Upgrade – Generator and Turbine Replacement

This is an example of an economic analysis applied to a hydropower scenario. In this example, the powerplant has four generating units that have reached a condition where replacing the generators and turbines are being considered. These components are still functional and could remain in operation indefinitely with continuous maintenance, but more efficient components are available and being considered. Other components, besides the generators and turbines, are in satisfactory condition or are included in the cost estimates for these replacement parts.

This example reflects costs and benefits based on "real" cash flows, not reflecting any changes that would occur due to inflation. Therefore, the discount rate that is used is also a real discount rate, not including any inflationary component. The real discount rate of 3.1 percent, as suggested by Office of Management and Budget (OMB), Circular No. A-94, Appendix C for 2005, is used in this example. This is the rate for cost-effectiveness analysis for projects of 30 years or more. This rate changes every year, on or about February 1, and is appropriate for analyses in which inflation in costs is not considered. There are specified rates published by OMB for analyses that include inflation. The discount rate required in an economic analysis is dependent on many factors, however, these factors will not be considered here.

The design engineers have provided two alternatives to consider. Alternative A provides a generator and turbine combination similar to original equipment, but due to engineering improvements leading to greater efficiency, this alternative will provide an increase in capacity of 1.5 megawatts (MW) per unit. Alternative B provides the powerplant with even more efficient components at a higher cost. Alternative B provides components that will increase capacity by 2 MW per unit. The gains for either alternative are due to improvements in both the generator and turbine, and are shown in one combined number.

Table C-1 shows the costs of the replacement components. Alternative A requires a total expenditure of $5,100,000 per unit based on the costs of the generator ($2,300,000) and turbine ($2,800,000), as shown. Alternative B is more expensive, costing $7,100,000 per unit with more expensive components due to the greater cost of design and construction. Therefore, if alternative A is chosen, a total initial cost of $20,400,000 will be required to replace the four units, whereas the total initial cost for alternative B is $29,200,000. Each component will be paid for at the beginning of the year in which it will be installed.

Table C-1: Cost of Replacement Components for Each Unit

Component	Alternative A	Alternative B
Generator Cost	$ 2,300,000	$ 3,300,000
Turbine Cost	$ 2,800,000	$ 3,800,000
Total Cost per Unit	$ 5,100,000	$ 7,100,000

The life of the turbines is assumed to be 50 years and the life of each generator is 25 years. The analysis will be performed based on the life of the turbines, but because the generators will wear out, they will need to be replaced after the first 25 years. This allows the analysis to be performed over the 50 year time horizon. All of the costs and benefits for these 50 years are discounted back to the beginning of the first year for benefit-cost analysis.

Since the costs are incurred at the beginning of each year for the first four years, the present value (PV) of the initial costs for alternative A is $19,498,227. Additionally, the generators will need to be replaced again beginning in year 26. The present value of these replacements of four generators in years 26 through 29 is $4,099,078. The sum of the present values is $23,597,305. A summary of the analysis of costs is provided in Table C-2.

The present value for alternative B is calculated in a similar way. For the initial installations, the present value is $27,144,590. The replacement generators in years 26 to 29 have a present value of $5,881,285, totaling $33,025,876 for the present value of costs for this alternative. These values are summarized in Table C-2. Note that the "Cost" column expresses costs without being discounted.

Table C-2: Comparison of Costs between Alternatives

Year	Alternative A		Alternative B	
	Costs	PV of Costs	Costs	PV of Costs
1	$ 5,100,000	$ 5,100,000	$ 7,100,000	$ 7,100,000
2	$ 5,100,000	$ 4,946,654	$ 7,100,000	$ 6,886,518
3	$ 5,100,000	$ 4,797,918	$ 7,100,000	$ 6,679,455
4	$ 5,100,000	$ 4,653,655	$ 7,100,000	$ 6,478,618
Subtotal	$ 20,400,000	$ 19,498,227	$ 28,400,000	$ 27,144,590
26	$ 2,300,000	$ 1,072,164	$ 3,300,000	$ 1,538,322
27	$ 2,300,000	$ 1,039,926	$ 3,300,000	$ 1,492,068
28	$ 2,300,000	$ 1,008,658	$ 3,300,000	$ 1,447,205
29	$ 2,300,000	$ 978,330	$ 3,300,000	$ 1,403,690
Subtotal	$ 9,200,000	$ 4,099,078	$ 13,200,000	$ 5,881,285
Total	$ 29,600,000	$ 23,597,305	$ 41,600,000	$ 33,025,876

It is assumed that there are months during the year when water flows are lower and at least one unit is idle. The installation of the replacement components will be scheduled during this period so that there is no lost generation or spillage resulting from this activity.

Other assumptions in this example include a constant plant factor of 45 percent. While plant factors change in most hydropower plants and these changes normally are modeled in an economic analysis, plant factors are assumed to be constant for this example. The economic value of the generation is also assumed to be constant and equal to $55 per megawatt hours (MWh).

Given a plant factor of 45 percent, 8,760 hours in a year, and an increase in capacity of 1.5 MW per unit for alternative A, the increase in generation will amount to 5,913 MWh (0.45 × 8760 × 1.5). Assuming a value of $55/MWh, this equals $325,215 (5,913 × $55) annually per unit. A similar calculation for alternative B shows that the increase in generation will be 7,884 MWh (0.45 × 8760 × 2) equal to $433,620 (7,884 × $55) per unit. In addition, for each alternative there will be a savings in maintenance costs of $50,000 annually for each unit. This $50,000 reflects the costs that would occur keeping the original equipment operating.

In each of the first four years, one unit is scheduled for replacement and assumed to be finished at the end of the year. Therefore, each unit adds value when it goes online. At the beginning of the second year, the benefits from one unit occur and are recognized in the analysis, as this is the first year of increased benefits. At the beginning of the third year, benefits from two units begin, continuing through the four units.

The benefits for each alternative include both the increase in generation resulting from the new components plus the savings in maintenance costs. The increase in generation for each alternative is shown in Table C-3. For alternative A, the increase in generation is worth $325,215 per unit per year, as previously calculated. During the first year of operation (year 2), the benefits include the increased generation for one unit; in the second year of operation (year 3) the benefits include two units; the third year of operation (year 4) provides benefits from three units; and then for the remaining 46 years (years 5 through 50), the benefits result from the four units having been replaced. To properly compare benefits to costs, the present value of the benefits for 50 years needs to be discounted back to the current year. These discounted values are shown in Table C-3 as the present value of the benefits equaling $30,706,822. Similar benefits are shown for alternative B. The benefit resulting from each unit is $433,620 per year and the present value of 50 years of benefits is $40,942,430.

Table C-3: Increases in Benefits for Each Alternative

Years	**Alternative A**		**Alternative B**	
	Benefits	**PV of Benefits**	**Benefits**	**PV of Benefits**
2	$ 325,215	$ 315,436	$ 433,620	$ 420,582
3	$ 650,430	$ 611,904	$ 867,240	$ 815,872
4	$ 975,645	$ 890,258	$ 1,300,860	$ 1,187,011
5 through 50	$ 1,300,860	$ 28,889,224	$ 1,734,480	$ 38,518,965
Total	$ 61,790,850	$ 30,706,822	$ 82,387,800	$ 40,942,430

In addition to the changes in generation resulting from the replaced components, benefits include the savings in maintenance costs of $50,000 per unit per year. The present value of these decreased costs total $4,721,003. These values are shown in Table C-4. The decreased maintenance costs are the same for both alternatives.

Table C-4: Savings in Maintenance Costs

Years	Decreased Maintenance Costs	Present Value of Decreased Maintenance Costs
2	$ 50,000	$ 48,497
3	$ 100,000	$ 94,077
4	$ 150,000	$ 136,872
5 through 50	$ 200,000 each year	PV total for years 5-50: $ 4,441,558
Total	$ 9,500,000	$ 4,721,003

The total benefit in the economic analysis is the sum of the present value of the increased generation shown in Table C-3 and the decreased maintenance costs shown in Table C-4 for each alternative. The total benefit for alternative A is $35,427,826 as shown in Table C-5. For alternative B, the total benefit is equal to $45,663,433. Table C-5 also shows the total of the present value of costs previously provided in Table C-2. Subtracting the present value of costs from the present value of benefits gives the net present value for each alternative. For alternative A, the net present value is $11,830,521. For alternative B, the net present value is $12,637,557. Table 5 also shows the benefit-to-cost (B/C) ratio often cited in studies. For alternative A, the B/C ratio is 1.50 whereas for alternative B the ratio is 1.38.

Table C-5: Summary of Results

Summary of Results:	Alternative A	Alternative B
Present Value of Benefits	$ 35,427,826	$ 45,663,433
Present Value of Costs	$ 23,597,305	$ 33,025,876
Net Present Value	$ 11,830,521	$ 12,637,557
B/C Ratio	1.50	1.38

The preferred alternative is the one that provides the highest net present value. At times, other methods are used in the decision process, including the B/C ratio, payback method, and internal rate of return. However, these methods are inferior to the net present value calculation.

The B/C ratio has traditionally been a popular method, but has a fatal flaw when comparing two or more alternatives. This method shows the discounted benefits per dollar of discounted cost. One problem with the B/C ratio is the sensitivity to the definition of benefits and costs. A negative benefit can be considered a cost, which would affect the ratio, moving from the numerator to the denominator. A second problem is the size effect. As a project gets larger, the size of the discounted benefits may decrease for each additional dollar of cost, reducing the ratio. But if the added benefit is greater than the added cost, then this increase is beneficial and should be undertaken even if the B/C ratio is reduced. One situation where the B/C ratio is beneficial is when several projects are chosen; ranking them by the ratio allows implementation under a limited budgeting process.

The payback method determines the length of time in years that the benefits take to pay back the cost of the project. The annual benefits are divided into the cost to determine this value. The alternative with the shortest payback becomes the preferred alternative. However, this method has problems since the method fails to consider the time value of money in the analysis and it fails to consider all the cash flows. The alternative that is shown to be inferior may have large positive cash flows beyond the payback period which are then ignored and not captured. Therefore, the payback method is not a good method for decision-making.

The internal rate of return (IRR) method is the method that defines a discount rate that equates costs and benefits. The criterion requires that projects or alternatives are accepted where the IRR is greater than a default opportunity cost of capital or the alternative that shows the greatest IRR. However, this method may choose the alternative that should not be the preferred one. Values of benefits and costs may vary depending on the discount rate, as the mathematics assumes a single discount rate over the life of the project, implying reinvestments at the IRR. At different IRR values, then different alternatives will appear to be preferred. Also, the IRR method usually can provide multiple, conflicting results providing several viable rates of return where costs equal benefits.

Net present value is the method that provides the correct choice for the preferred alternative. Acceptable projects are those that have a net present value greater than zero; those that provide benefits greater than the costs. When the projects are mutually exclusive, such as choosing one alternative among many, the preferred project is the one that provides the greatest net present value. In our example, while alternative A has a higher B/C ratio, it provides a lower net present value, so is the inferior choice and alternative B is preferred. Alternative B provides the greater amount of value; providing $807,036 higher value to society.

Appendix D: hydroAMP Team Members and Contributors

Ernie Bachman, Bureau of Reclamation (Governor Guide)

Steve Bellcoff, Bonneville Power Administration (Website Database)

James Boag, U.S. Army Corps of Engineers (Emergency Closure Gate and Valve Guide)

Bernard Bourgeois, Hydro-Québec (Guidebook)

James Calnon, U.S. Army Corps of Engineers (Compressed Air System Guide)

Ben Canno, Bureau of Reclamation (Circuit Breaker Guide)

Roger Cline, Bureau of Reclamation (Turbine Guide)

Jim Clune, Bonneville Power Administration (Guidebook, Compressed Air System Guide)

Scott Cotner, U.S. Army Corps of Engineers (Circuit Breaker Guide, Transformer Guide)

Marcos Ferreira, Bonneville Power Administration (Generator Guide)

Doug Filer, U.S. Army Corps of Engineers (Surge Arrester Guide)

Erin Foraker, Bureau of Reclamation (Guidebook, Turbine Guide)

John Germann, Bureau of Reclamation (Crane Guide)

Thierry Godin, Hydro-Québec (Excitation System Guide)

Phil Gruwell, U.S. Army Corps of Engineers (Excitation System Guide)

Sarah Jones, U.S. Army Corps of Engineers (Crane Guide)

Bill Joye, Bureau of Reclamation (Compressed Air System Guide)

James Kerr, U.S. Army Corps of Engineers (Emergency Closure Gate and Valve Guide)

Nathalie Laberge, Hydro-Québec (Guidebook, Governor Guide)

Francine Lefrançois, Hydro-Québec (Crane Guide)

Mark Lindstrom, U.S. Army Corps of Engineers (Crane Guide)

Deborah Linke, Bureau of Reclamation (Guidebook)

Duke Loney, U.S. Army Corps of Engineers (Guidebook, Compressed Air System Guide, Turbine Guide)

Tom Manni, Bureau of Reclamation (Generator Guide)

Ken Maxey, Bureau of Reclamation (Guidebook)

Steve Melavic, Bureau of Reclamation (Emergency Closure Gate and Valve Guide)

Ronnie Murphy, Hydro-Québec (Guidebook)

Brian Moentenich, U.S. Army Corps of Engineers (Turbine Guide)

Richard Nelson, U.S. Army Corps of Engineers (Guidebook)

Phat Vinh Nguyen, Hydro-Québec (Compressed Air System Guide)

Jim Norlin, U.S. Army Corps of Engineers (Guidebook)

Duc Ngoc Nguyen, Hydro-Québec (Generator Guide)

Gary Osburn, Bureau of Reclamation (Guidebook, Surge Arrester Guide, Plant Battery Guide, Transformer Guide)

Shawn Patterson, Bureau of Reclamation (Excitation System Guide)

Abel Pereira, Bonneville Power Administration (Surge Arrester Guide, Transformer Guide)

Mark Pierce, U.S. Army Corps of Engineers (Generator Guide)

Lori Rux, U.S. Army Corps of Engineers (Guidebook, Generator Guide)

Mitch Samuelian, Bureau of Reclamation (Guidebook)

Jay Seitz, Bureau of Reclamation (Guidebook)

Phil Thor, Bonneville Power Administration (Guidebook, Generator Guide, Emergency Closure Gate and Valve Guide)

Robert Thouin, Hydro-Québec (Turbine Guide)

Jean-Paul Rigg, Hydro-Québec (Guidebook)

Ginette Vaillancourt, Hydro-Québec (Governor Guide, Turbine Guide)

Rich Vaughn, U.S. Army Corps of Engineers (Governor Guide, Compressed Air System Guide)

Appendix E: Equipment Condition Assessment Guides

Condition Assessment Guides have been developed for the following equipment:

- Batteries
- Circuit Breakers
- Compressed Air Systems
- Cranes
- Emergency Closure Gates and Valves
- Excitation Systems
- Generators
- Governors
- Surge Arresters
- Transformers
- Turbines

Note: Due to the size of the condition assessment guides, they are available as separate electronic files.