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EVALUATION OF POWER PLANT OPERATION FOR THE NATIONAL POWER CORPORATION OF THE PHILIPPINES

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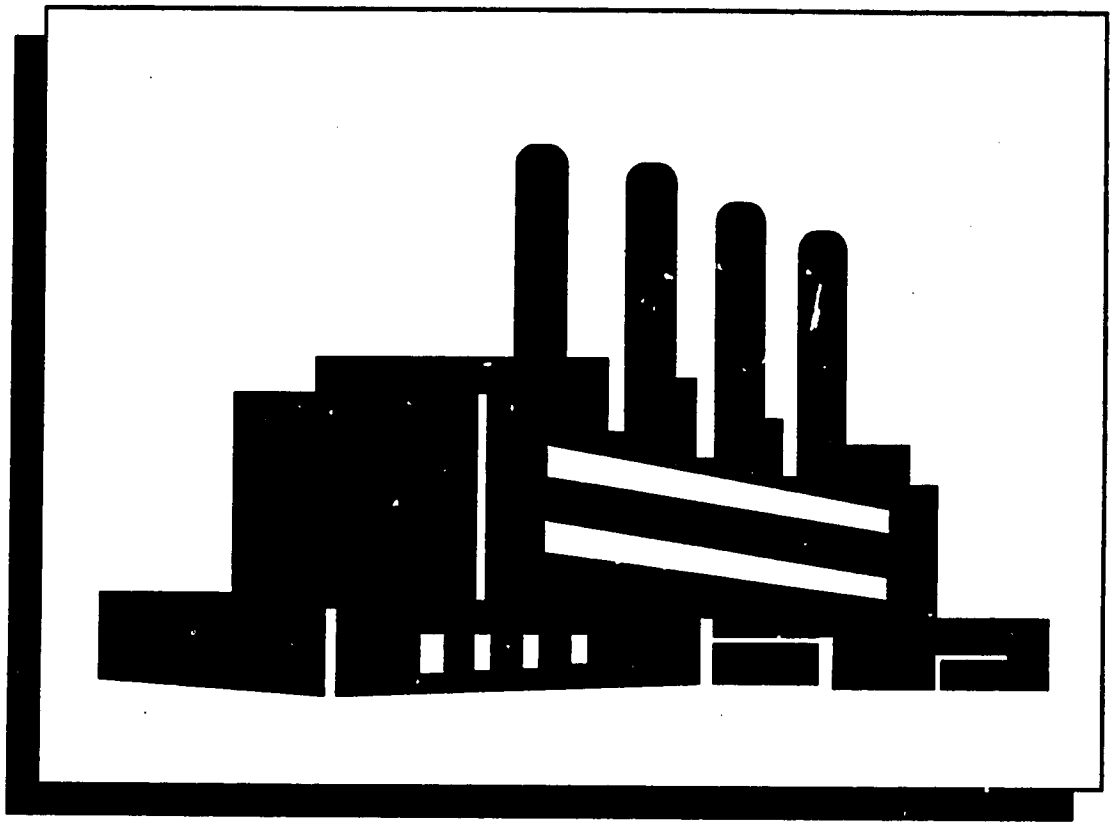

Evaluation of Power Plant Operation

for:

National Power Corporation of the Philippines (NPC)
U.S. Agency for International Development (USAID)

January 1992

Table of Contents

Section		Page
1	**Executive Summary**	**1-1**
2	**Introduction**	**2-1**
	2.1 Purpose	2-1
	2.2 Approach	2-1
3	**Conclusions and Recommendations**	**3-1**
	3.1 Conclusions	3-2
	3.2 Task Recommendations for Immediate Implementation	3-4
	3.3 Intermediate Term Recommendations	3-9
	3.4 System and Organizational Recommendations	3-12
	3.5 Schedule and Skills	3-14
4	**Generating System Observations**	**4-1**
	4.1 Plant De-Ratings and Associated Costs	4-1
	4.2 Availability and Reliability Factors	4-2
	4.3 System Reserve Profile	4-3
5	**Investigation of Originally Specified Problems**	**5-1**
	5.1 Thermal Plant Chemical Control	5-1
	5.1.1 Malaya	5-1
	5.1.2 Batangas	5-3
	5.1.3 Recommendations	5-4
	5.2 Geothermal Plant Chemical Control	5-5
	5.2.1 Mak-Ban	5-6
	5.2.2 Recommendations	5-7
	5.3 Fuel Additive Program	5-8
	5.3.1 Malaya	5-8

5.3.2 Recommendations 5-10
5.4 Batangas Coal Handling System 5-11
5.4.1 Recommendations 5-13
6 Related Generic Plant Problem Areas 6-1
6.1 Boiler Tube Failures 6-1
6.1.1 Recommendations 6-3
6.2 Turbine Blade Failures 6-5
6.2.1 Recommendation 6-6
6.3 High Thrust Bearing Temperature 6-6
6.3.1 Recommendation 6-7
6.4 Turbine IP Rotor Cracking 6-7
6.4.1 Recommendation 6-7
6.5 Root Cause Analysis of Forced Outages 6-7
6.5.1 Recommendation 6-7
7 System and Organizational Issues 7-1

Appendix

A **Scope of Work**

B **Personnel Contacts**
National Power Corporation and
U.S. Agency for International Development

C **Geothermal Chemical Data**
Transmitted to Mr. Dennis Zvinakis, Chief, Office of the Capital Projects
USAID by Jose T. Ramos, Senior Vice President,
Utility Operations, N.P.C.
November 5, 1991

D **NPC Memorandum**
to Vice Presidents, SLRC & VRC, Plant Managers,
MGPP, TGPP, LGPP and PGPP;
from A.G. Plata, Senior Vice President Operations,
Subject: Implementing Guidelines for the Application of
Geothermal Water Treatment Programs, Dated: June 3, 1991

E **Definitions of Outage Categories**
from the North American Electric Reliability Council's (NERC)
Generating Availability Data System (GADS) Data Base

Section 1

Executive Summary

The Philippines National Power Corporation (NPC) requested U.S. Aid Manila to provide immediate technical assistance on improving power plant availability and reliability. U.S. Aid through the Washington D.C. Office of the Energy and Infrastructure/ETIP program commissioned Bechtel Corporation to respond to the request by performing a scoping mission to the Philippines which is the basis for this report. The primary purpose of the mission was to assess capabilities for improvements and scope out services for both immediate and long term assistance in the use of fuel additives for oil fired units, water treatment requirements for fossil and geothermal units and coal handling system design and operation. In addition, the mission evaluated the potential for solutions of generic reliability and availability problems. We also assessed system improvement that could utilize availability improvement and life extension programs coupled with the development of internal NPC capability to address and solve problems.

For this report, operating data was collected by visits to Malaya and Batangas Thermal Generating Stations and Mak-Ban Geothermal Generating Station. The water chemistry practices were evaluated at all three stations. The results of a fuel additive test program at Malaya were evaluated and a preliminary review of the coal handling system problems at Batangas was performed. Based on this and other system data, recommendations for further work are provided to complete the defined scope of work and to provide solutions to other identified generating unit and system problems. Additional work items that NPC should implement are repair of the Malaya 2 phosphate pumps, the provision of a continuous on-line chemistry monitoring panel for Malaya 2, the repair of the Malaya 1 on-line chemistry monitoring panel, and repair of the Malaya laboratory spectrophotometer.

Generating units on the NPC system are de-rated by a total of 450 MW. Much of the de-rating is related to problems such as boiler tube thinning, turbine blade failures, high turbine thrust bearing temperatures and coal handling and combustion. Recommended additional work is directed toward understanding the causes of unit de-rating, preventing the development of further problems which can cause additional equipment failures, returning the units to full design capacity and the development of programs which address controlling long term generic problems.

The required additional work is divided into tasks for immediate implementation, intermediate and longer term recommendations. The tasks are summarized below.

The immediately recommended work is directed toward solving problems which, if not corrected quickly will cost NPC in additional lost capacity, and continued forced and unplanned outages. We estimate that this work can be completed in four to six months. Included within these tasks are problems that were identified in the areas of water treatment, the use of fuel additives, boilers, turbines and coal handling.

I. Recommendations for Immediate Work Tasks

- Condensate Polisher Operational Modifications - Malaya 1 and Sucat 2, 3, and 4

  This task is directed toward improving condensate polisher operation to reduce sodium effluent concentrations for low pressure turbine blade protection.

- Batangas Chemical Limit Modifications

  This task is directed toward modifying boiler chemical limits and operating procedures to protect the unit from condenser leakage.

- Batangas Make-Up Treatment System Evaluation

  The purpose of this task is to evaluate the make-up system in detail and identify equipment modifications required to assure the continued reliable production of demineralized water.

- Thermal Plant Water Treatment Chemical Procurement

  This task will provide technical input required for the purchase of water treatment chemicals.

-7

- Geothermal Plant Chemical Procurement

  This task will provide technical assistance to procurement procedures used in the supply of chemicals used in geothermal plant operation.

- Remaining Station Water Treatment Practice Evaluation

  This task purpose is to evaluate the water treatment practices of the NPC generating stations not evaluated as a part of this report and provide recommendations for improvement as required.

- Fuel Additive Test Program Evaluation at Malaya 2

  This task will provide an independent evaluation of the fuel additive test and develop a program for continuing additive usage as a partial solution to the boiler tube thinning problems.

- Batangas Coal System Improvement - Phase I

  The task of Phase I will be to provide recommendations for operational and maintenance changes or minor capital projects that can be implemented with immediate positive impacts. The scope of the next phases for intermediate implementation will be established.

- Boiler Tube Failure and Reduced Pressure Investigation

  The boiler tube failures at Malaya and Batangas will be evaluated in detail and recommendations for solution provided. Boiler operation at reduced pressure and the effect on reliability, safety and efficiency will be evaluated and recommendations provided for changes.

- Turbine Blade Failure Analysis

  The task will identify the causes of turbine failures which are common on the system and develop retrofit fixes.

- High Thrust Bearing Temperature Analysis

  The task will evaluate the turbine thrust bearing problems and provide recommendations for solutions.

- Turbine I.P. Rotor Cracking Analysis

  The need for Malaya 1 turbine rotor replacement will be evaluated.

Intermediate recommendations are for the completion of the Batangas coal system improvement, the development of a boiler tube failure reduction program, and an evaluation of forced outage causes. These tasks will require 6 to 18 months to complete.

II. Intermediate Recommendations

- Boiler Tube Failure Reduction Program
- Batangas Coal System Improvement - Follow on Phases
- Root Cause Analysis of Forced Outages

The long term recommendations relate to system and organizational issues that should be addressed as the NPC management allocates resources to develop an organization to address and solve the system problems.

4

III. Long Term Recommendations

- Present Plant Equipment Maintenance
- Present Rehabilitation Approach Modifications
- Development of Capability to Address Problems
- Maintenance Delay Modifications

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Section 2

Introduction

2.1 PURPOSE

In the later part of 1991, National Power Corporation of the Philippines (NPC) requested US AID Manila to provide immediate technical assistance in the area of power plant availability and reliability improvement. US AID, through the Office of Energy and Infrastructure/ETIP program in Washington, D.C., commissioned Bechtel Corporation to undertake a technical scoping mission to the Philippines to respond to the request made by NPC. The Scope of Work for the NPC request is shown in Appendix A.

The purpose of the mission was to evaluate the near-term and long-term situation with the reliability and availability of the NPC system and to make recommendations for improvement. The primary objectives were established as follows:

1. Provide technical assistance in the areas of immediate need including: fuel additives for oil fired units; water treatment requirements for fossil and geothermal units; and coal handling system design and operation at the Batangas plant,

2. Evaluate the potential for longer-term solutions to generic reliability and availability problem areas, and

3. Assess NPC system needs including: (a) the potential for improving the operation of the system through a structured Availability Improvement and Life Extension Program; (b) the development of internal capability to address associated problems; and (c) additional methods for improving the productivity of the generating system.

2.2 APPROACH

This report is based on an evaluation that was performed during a 10 day trip to the Philippines in December 1991. NPC provided assistance through visits to specific power plants and by information collection in the home office. The plants visited and evaluated during the trip are shown on Figure 2-1. Personnel from NPC and the U.S. Agency for

.6'

International Development provided technical data and assistance in obtaining the information required for this report. These personnel are shown in Appendix B.

Water chemistry practices were reviewed and evaluated at all three stations. A fuel additive test program was being conducted at Malaya Unit 2 with the goal of developing a program which will address boiler tube thinning problems being experienced at the Malaya and Sucat Stations. A preliminary review of the additive test program and results was conducted. Problems have been experienced at the Batangas Station with the coal handling system. Information on the problems with this system was obtained and evaluated.

The results of the initial evaluation are contained in this report and recommendations are made for future actions to correct the specific problems identified. Item III of the Scope of Work is essentially completed for the Malaya, Mak-Ban and Batangas Plants by this report except for a complete evaluation of the fuel additive test results. In addition, comments are provided and recommendations made to solve the chronic long term generic problems that exist, not only at the stations visited, but at other stations on the system.

Figure 2-1

Evaluated Power Plants
National Power Corporation

Station	Unit No.	Design Capacity, MW	Fuel	Boiler Type	Design Conditions
Malaya	1	300	Residual Oil and Bunker C	Once-through	2700 psig 1000°F/1000°F
	2	350	Residual Oil and Bunker C	Drum	175 kg/cm² 1000°F/1000°F
Batangas	1	300	Local and Australian Coal	Drum	2400 psig 1000°F/1000°F
Mak-Ban	1-6	55 (each)	Geothermal	–	6.5 kg/cm² 162.3°C

8

Section 3

Conclusions and Recommendations

This section summarizes the recommendations that are further detailed and discussed in Sections 4, 5, 6 and 7 of the report. They are presented in this separate section to show the full scope of the proposed work.

An overview of the conclusions of the assessment is provided in Subsection 3.1. Recommendations are provided in three categories as follows:

- Recommendations for immediate implementation. These recommendations will have an immediate impact on very important near-term problems that are currently costing NPC heavily in lost capacity, forced outages and unplanned outages.

- Intermediate recommendations. These recommendations address problems that will require 6 to 18 months to complete.

- Long term recommendations for system and organizational changes. These recommendations address system-wide and organizational needs that will require corporate level decisions to implement. They are long-term in nature and will have a major positive impact on the operation of the NPC generation system.

Technical skills required to implement the recommendations are important considerations in this program and are presented in Section 3.5.

3.1 CONCLUSIONS

The thermal power units on the NPC system are de-rated a total of 450 MW for a number of different reasons as shown on Table 4-1. This is estimated to cost NPC 121 million Pesos per month in additional fuel costs alone. Each plant has some unique reasons for de-rating. However, a number of common generic problems exist that include boiler tube failure, turbine blade failure, turbine bearing overheating and poor condenser vacuum. The evaluation of the Malaya Station determined that the cause of the tube failure problems at that station are, in part, due to slagging/corrosion as a result of poor quality fuel. This may also be the cause of the problems at Sucat and Batangas Stations, but further study is

9

required to confirm this. The units reporting poor condenser vacuum were not evaluated. This is probably caused by a water treatment problem, as is the high feedwater silica concentrations reported at Bataan 2. Correction of these problems can return a significant amount of power to the NPC system.

Many of the problems observed during this evaluation have persisted for many years without being resolved. NPC performs temporary fixes through rehabilitation programs but the root-cause of the problems have not been well understood. The rehabilitation programs implemented in the past have addressed the problem symptoms but have not addressed the fundamental causes. These programs have been directed toward performing deferred maintenance.

Once the immediate problems are addressed and corrected to return the lost generating capacity to the system, an availability improvement and life extension (AI & LE) program can be put in place. This program should incorporate the valuable parts of the rehabilitation approach and include root-cause analysis and condition assessment. Such an approach will better utilize the capital funds available to NPC and permanently eliminate most of the problems now being encountered. Increased training should be provided as a part of this program.

To implement recommendations contained in this report, NPC will need to develop the internal capability to perform the analytical, operational and maintenance activities required. Technology transfer can significantly contribute to the success of this process. The Efficiency and Reliability Department should be chartered to develop the Availability Improvement and Life Extension Program discussed above.

The fuel additive test program appears to offer part of the solution to the boiler tube thinning being experienced at Malaya. Technical assistance is needed in evaluating the test results and in formulating a long term program to procure the most economical and effective chemicals.

Specific water treatment problems were identified at the Malaya and Batangas Stations. Boiler and turbine failures may have been caused in the past by poor water treatment

10

practices. The problems identified in this report should be corrected before further major equipment problems recur.

NPC through extensive testing of chemical programs, has identified chemicals which are effective in meeting the water treatment goals at the geothermal plants. Procurement procedures should be modified to permit purchase of the identified effective chemicals and to assure that a reliable and continuous supply is maintained.

Boiler tube failure in a large number of boilers on the NPC system is a chronic long-term problem. Many tube failures have occurred in the water wall, superheater, reheater and economizer sections and the problems have existed for most of the life of the units. To eliminate this problem, NPC should perform a root-cause analysis of the failures of Malaya, Sucat and Batangas to identify and implement retrofit fixes. In the longer-term, a Boiler Tube Failure Reduction Program should be implemented.

Virtually all of the boilers on the NPC system have operated at reduced pressure and output for long periods of time so as to minimize boiler tube failures. Such operation, if not performed properly, could adversely impact boiler reliability, safety and efficiency. An evaluation of boiler reduced pressure operation should be performed immediately.

Since beginning operation in 1984, the Batangas plant has been plagued with coal related problems that have caused serious reliability problems. It can be expected that the problem at the plant will continue and, indeed, may well deteriorate in the future. A comprehensive coal system improvement project will be required to address this complex problem and develop a permanent solution.

3.2 TASK RECOMMENDATIONS FOR IMMEDIATE IMPLEMENTATION

3.2.1 Water Treatment

3.2.1.1 Condensate Polisher Modifications - Malaya and Sucat - From Section 5.1

The operation of Malaya 1 condensate polishers should be modified to operate with an effluent sodium concentration of less than 2 ppb. This may require changes in the cation/anion resin ratios, regeneration chemical quality and regeneration procedures. The present effluent sodium limit is 10 ppb. Values of up to 17 ppb were observed.

With continued operation with high sodium concentrations, low pressure turbine blade integrity is threatened. Turbine blade failures on this unit may have, in part, been caused by excessive sodium leakage from the polishers. Once-through Sucat units with condensate polishers have also experienced turbine blade problems which may have been caused, in part, by excessive sodium hydroxide in the feedwater. As a part of this task, the Sucat polisher operation should be evaluated and modified, if required, to maintain a sodium effluent concentration of less than 2 ppb. Equipment and operational modifications will be completed and documented working with NPC chemical engineers and operators.

3.2.1.2 Batangas Chemical Limits - From Section 5.1

New chemical operating limits and procedures should be established for Batangas Unit 1 to protect the system from condenser tube leaks. Chloride limits should be established and the phosphate limits should be modified. Procedural changes should be established and documented to define operators reactions to increasing boiler contamination from condenser tube leaks.

3.2.1.3 Batangas Makeup Treatment System - From Section 5.1

The make-up water treatment system for Batangas should be evaluated and recommendations made to correct existing problems which if allowed to persist, will lead to major system difficulties. The major make-up system problems are:

12

a. Not enough capacity exists for condenser leak and unit startup operations.

b. Spare filtration capacity is not provided.

c. Algae is not removed in the pretreatment system and appears downstream in the filters and the demineralizers.

d. Suspended solids removal is not adequate in the pretreatment system and leads to excessive demineralizer vessel pressure drop.

e. There is excessive system deterioration because of the outdoor seaside installation.

f. The regeneration equipment is deteriorated and needs maintenance.

g. The neutralization system does not appear adequate to meet the regeneration requirements.

3.2.1.4 Thermal Plant Water Treatment Chemicals - From Section 5.1

New specifications should be written for all of the water treatment chemicals in use at the thermal power plants and the technical input to the procurement program modified to permit competitive bidding of the chemical supply on an annual basis.

3.2.1.5 Geothermal Plant Chemicals - From Section 5.2

Technical input to the procurement program for providing chemicals to all geothermal plants should be provided. The assistance should include the development of new specifications, new procurement procedures and assistance in developing long term measures to assure a continuous supply of proven chemicals from qualified suppliers.

13

3.2.1.6 Remaining Station Water Treatment Practices - From Section 5.2

Investigations of water treatment practices similar to those performed at Malaya, Batangas and Mak-Ban should be performed at the remaining geothermal and thermal plants. The plants should be visited and operating data collected, equipment and practices observed and procedures evaluated. The information will be evaluated, problems determined, and changes recommended. Data collected to date indicates that all the plants have problems. In the case of a number of the thermal plants, it appears that water treatment problems may be contributing to load restrictions. A common problem is high condenser vacuum which is probably caused by poor cooling water quality. The plants to be evaluated will be Sucat, Bataan, Manila, Cebu, Palinpinon, Tongonan and Tiwi.

3.2.2 Fuel Additive Test Program at Malaya 2 - From Section 5.3

An independent evaluation of the fuel additive test program results should be performed. As a part of this work scope, a long term program for the use of the additives will be developed, technical specifications for fuel oil additives will be written, and assistance provided in selecting a long term chemical supplier.

3.2.3 Batangas Coal System Improvement Project - From Section 5.4

A detailed evaluation of the Batangas coal system should be performed which focuses on the operational and equipment changes required to solve the multiplicity of problems. Alternatives will be developed, evaluated and recommendations made to resolve problems associated with the following system operations:

- Blending
- Pulverizing
- Combustion
- Slag formation

14

- Boiler tube failures

The complexity of the problems and the various factors which must be considered are discussed in detail in Section 5.4.

Due to the complexity of this problem, a 4-phased approach is recommended. Phase 1 of the project should be initiated immediately. Phases 2, 3 and 4 will be described in Section 3.3 - Intermediate Recommendations.

The project goal is to establish capital, operational and maintenance refinements to the Batangas I coal system that effectively improve the availability and efficiency of the plant in line with the needs of the NPC generating system. Phase I of the program will provide recommendations for operational and maintenance changes or minor capital improvement projects that can be implemented with an immediate positive impact on operations. The scope of intermediate phases will also be established in Phase I.

3.2.4 Boiler Tube Failure Investigation - From Section 6.1

Root-cause analyses of the boiler tube failure problems at Malaya and Batangas should be performed to identify the fundamental reasons for the failures that have been occurring during the past five years. This is an immediate need because boiler tube failures are occurring regularly on these boilers and are producing outages. The resolution of these problems will involve knowledge of the combustion process, water chemistry and metallurgy, which will require support from a boiler specialist, a materials specialist, a water chemist and NPC maintenance and reliability personnel. The goal of the task will be to more fully understand the boiler tube failure problems at both plants, determine the root causes of failure, determine fixes, give recommendations for implementation and assist in verification of the solutions. In the case of Malaya 2, specific attention will be paid to the fuel additive program presently being tested to determine if it is fully addressing the root-causes of failure and to determine if additional changes are required to the plant. This task will be closely coordinated with the fuel additive test program evaluation of task 3.2.2.

15

In addition, the boilers at the Malaya, Sucat and Batangas stations have operated at reduced pressure and output in order to minimize the number of boiler tube failure problems. This has caused considerable expense to NPC in terms of reduced revenues and increased operating costs.

Reduced pressure operation must be carefully considered to ensure that the boiler is operated within proper limits. The boiler heat exchange surfaces are designed for specific pressure, temperature differentials and heat flux. Operation outside of these ranges can accelerate creep and thermal fatigue damage to the boiler and adversely impact unit reliability, safety and efficiency. During the visit, it was not evident that an evaluation of the reduced pressure operation had been performed by boiler experts to verify that the boiler operating modes being used were not injurious to the boiler. If such an evaluation has not been performed it should be done immediately.

3.2.5 Turbine Blade Failure Analysis - From Section 6.2

Turbine blade failures have been a significant cause of outages and reduced output for 10-15 years on Malaya 1 and Sucat 2, 3 and 4. To eliminate this problem it is recommended that NPC perform a root-cause analysis of the failures to identify the fundamental reasons why the blades are failing. This approach is utilized in the U.S. to address highly complex blade failure problems. The technology to independently analyze the blade failure problem is available and can be applied at NPC. A study team should be assembled that includes a turbine blade expert, a water chemistry expert, a materials expert, NPC maintenance and reliability experts and, if possible, the equipment manufacturer. The goal of this team would be to fully evaluate the LP blade failure problem, determine the root-causes of failure, develop retrofit fixes, give recommendations for implementation and assist in the verification of the solution.

3.2.6 High Thrust Bearing Temperature Analysis - From Section 6.3

Like turbine blade failures, high thrust bearing temperatures have been a long standing problem with the NPC Siemens steam turbines dating back to the late 1970's. NPC should

16

perform a root-cause analysis of the high thrust bearing temperature problem in the turbines to identify the fundamental reasons for the problem. A study team should be assembled that includes a thrust bearing expert, a rotor-dynamics expert, NPC maintenance and reliability experts and the turbine manufacturer. The goal of the team would be to fully evaluate the thrust bearing problem, determine the root-causes of failures, provide recommendations for solution and assist with verification of the solution.

3.2.7 Turbine IP Rotor Cracking Analysis

During the last rehabilitation of Malaya 1, cracking of the IP rotor was found and replacement of the IP rotor is scheduled for 1993. NPC should perform an analysis of the Malaya 1 IP rotor to determine if replacement is necessary. Weld repairing of this rotor may be possible, thereby saving considerable capital investment in a new rotor.

3.3 INTERMEDIATE TERM RECOMMENDATIONS

3.3.1 Boiler Tube Failure Reduction Program

NPC should implement a company-wide Boiler Tube Failure Reduction (BTFR) Program that is root-caused based and which implements well developed technology to reduce or eliminate boiler tube failure problems, increase reliability and extend life. This approach is highly developed in the U.S. and in other countries and has been very successfully implemented by many electric utilities. The basic structure of a BTFR Program involves four fundamental stages:

- Analysis of failures and identification of root-causes,
- Development and implementation of a root-cause data base,
- Selection of solutions for retrofit, and
- Implementation of fixes and verification of effectiveness.

Such a program requires a dedicated group within the utility organization that has responsibility for its implementation and that has the necessary technical knowledge and skills to ensure success. The Reliability and Efficiency Department recently formed in NPC would be an excellent location to house and develop the BTFR program. A substantial technology transfer activity will be required that includes:

- Technical assistance in the selection of methods and systems,
- Installation and operation of methods and systems,
- Training in root-cause analysis, and
- Implementation of retrofit fixes

It will be necessary to implement the BTFR program in phases as follows:

Phase 1: Development of an Overall Plan

Development of an overall plan for the BTFR program that includes: data-base requirements, organizational integration and operation, resource requirements, technology transfer, continuing support and budgets.

Phase 2: Implementation of the Program

Implementation of the Program into NPC.

Phase 3: Implementation of the Retrofit Fixes

Implementation of the retrofit fixes, verification of effectiveness, and continuing support.

12

3.3.2 Batangas Coal System Improvement Project - Follow-on Phases

Phase II. Coal System Engineering and Economic Evaluation

The objectives: are to perform an engineering and economic evaluation of the coal system and produce a plan that identifies and justifies required plant improvement projects. Root-cause analysis will be performed on the equipment to identify the fundamental causes of equipment failure. Improvement projects will be identified and economically justified.

A Phase II report will be issued that will contain findings, recommended improvement projects, cost estimates and a proposed implementation plan for Phase III.

Phase III. Detailed Design Engineering, Procedures Development and Training Requirements

The scope of Phase III will depend directly on the outcome of Phase II. Implementation of the recommendations from Phase II will include: engineering design, program management and planning, drawing production and verification, specification production, equipment procurement, development of operation and maintenance procedures, development of training programs and planning for Phase IV. The output of Phase III will be a detailed plan for Phase IV that will be contained in a report.

3.3.3 Root Cause Analysis of Forced Outages

The forced outage records of the Malaya and Batangas Stations have been evaluated to identify the major equipment components which have been the greatest contributors to the high forced outage rates. The forced outage rates for the remaining NPC stations should be similarly evaluated. And the major equipment problems identified for root cause analysis and problem solution.

Phase IV. Plant Modification and Equipment Verification

Phase IV will involve the modification of equipment, required construction activities, plant restart, equipment verification, operator training, implementation of improved O&M procedures and construction management.

3.4 SYSTEM AND ORGANIZATIONAL RECOMMENDATIONS

3.4.1 Present Plant Equipment - From Section 7.1

The equipment in the NPC plants is the same as what is used in the U.S., Japan and Europe and the plants are very valuable assets to NPC. U.S. experience shows that these plants can be brought up to proper operating levels through the use of focused availability, and efficiency improvement and life extension programs at a small fraction of the cost of replacement capacity. Therefore, the present set of fossil plants should be kept on the system and improved through capital investment programs.

3.4.2 Present Rehabilitation Approach - From Section 7.2

NPC should perform an assessment of the present rehabilitation approach and determine if it is serving the best interest of the corporation. An availability and efficiency improvement life extension program should then be developed that incorporates the valuable parts of the rehabilitation approach and that includes root-cause analysis and condition assessment. Such an approach will better utilize the capital funds that are available to NPC and permanently eliminate many of the problems now being encountered. In the longer-term, availability and efficiency improvement/life extension activities will become a normal part of maintaining plant equipment and will eliminate the need for major, capital intensive rehabilitation projects.

3.4.3 Capability to Address Problems - From Section 7.3

- NPC should charter the Efficiency and Reliability Department to develop and implement an Availability Improvement and Life Extension (AI & LE) program for

20

NPC. They should also be given responsibility for developing and implementing the root-cause analysis and condition assessment methods required for the AI & LE program and for analyzing equipment and components on a continuing basis. Staffing levels should be increased in line with this responsibility.

- The Efficiency and Reliability Department should be refocused to concentrate on solving availability and reliability problems. Presently, the focus is primarily on efficiency improvement. This change will ensure that NPC will receive maximum value for the department's efforts.

- A technology transfer program for the Efficiency and Reliability Department should be developed and implemented in conjunction with the AI & LE program to ensure that the department is fully capable for performing the work. The technology transfer program should involve availability and life extension methods and include root-cause analysis and condition assessment techniques. The following elements should be included:

  - Personnel training

  - Laboratory requirements, computer hardware and software and test equipment

  - Analytical techniques, procedures and specifications

- Training programs should be developed and implemented for plant maintenance and plant operations personnel in order to implement and sustain the level of performance improvement attained through implementation of the AI & LE program.

3.4.4 Delay of Maintenance Due to System Demand Needs - From Section 7.4

Review the practice of significantly delaying and reducing the scope of maintenance outages in light of the substantial costs to the system that result from the associated degradation in

21

plant reliability. Develop procedures for implementation that can be utilized by plant operations, plant maintenance and system dispatch as a means of minimizing the total cost impact to the generating system as a whole.

3.5 SCHEDULE AND SKILLS

The recommendations for immediate implementation should be completed within four to six months of project funding to correct serious near-term operational problems. Work completion will require technical specialists with expertise in the following areas:

- Boiler operation
- Metallurgy
- Turbines
- Chemical engineering with experience in water treatment and fuel additives.

Trips will be made, as required, to the Philippines to obtain further information and work with NPC operators and engineers on operational and procedural changes and to present the results to NPC management.

Costs and schedules for intermediate term and long term recommendations will be provided at the conclusion of the correction of the immediate problems. Intermediate term recommendations should be implemented within 18 months. Long term system and organizational issues can be addressed as management allocates resources from within NPC to develop and solve system issues.

-22

Section 4

Generating System Observations

To obtain an overall perspective on the problems being faced by NPC with their thermal and geothermal generating plants and to gain an understanding of the value associated with improving the reliability of these plants, a review of the generating system was performed that focused on the following areas:

1. Plant de-ratings and associated costs,
2. Availability and reliability factors,
3. System reserve profile.

The review was based on information obtained from NPC. In addition, similar information was obtained from the North American Electric Reliability Council's (NERC) Generating Availability Data System (GADS). Where appropriate, comparisons were made that would provide an understanding of the improvement potential for NPC's plants.

4.1 PLANT DE-RATINGS AND ASSOCIATED COSTS

As can be seen from Figure 4-1, all but one of the thermal generating plants is operating with a maximum dependable capacity that is lower than the rated capacity. For the system, the total de-rating is 450 MW with an associated cost of 121 million Pesos per month. For the three thermal generating units investigated on this mission (Malaya 1 & 2 and Batangas), the de-rating amounts to 220 MWs. This is 23% of the 950 MW rated capacity and is estimated to cost NPC over 612 million Pesos per month in additional fuel costs alone (Figure 4-1). This is a large cost to the system and would support a significant program to regain the lost capacity and to improve reliability. As will be discussed in more detail in Section 6, the cause of these de-ratings can be attributed to a small number of generic problems - weak boiler tubes, caused partly by poor fuel quality, weak turbine blades and turbine bearings. These are generic problems that have persisted for many years and are similar to those experienced by U.S. utilities in the 1970's and early 1980's. Technology has been developed and implemented that can virtually eliminate the problems and allow the lost capacity to be regained. Detailed recommendations will be discussed in Section 6.

-23

Plant de-ratings of the magnitude and duration utilized by NPC are unusual. Typically, plant de-ratings are utilized as a short-term measure when a reliability problem is experienced. The unit is restored to full capacity when the problem is repaired. For many of the units on the NPC system, significant de-rating has occurred throughout their operating lives. A concerted effort should be utilized to eliminate this problem.

The loss of 450 MWs to the system has a very serious impact on overall system reliability and costs. The implementation of an Availability Improvement and Life Extension Program that utilizes root-cause based approaches and condition assessment would be very valuable to NPC to regain and retain the lost capacity on the system for the long term. This program will be more fully discussed in Section 7.

4.2 AVAILABILITY AND RELIABILITY FACTORS

Availability and forced outage rate information for NPC is shown on Figures 4-2 to 4-5. Information for similar U.S. units to those of NPC is shown in Figures 4-6 to 4-16.

The following general observations can be made from these data:

- Oil Thermal Units:

  - NPC units have an availability factor of approximately 75%. Similar U.S. units have an availability factor of 83%,

  - NPC units have exhibited a steadily increasing forced outage rate from 2% in 1987 to 12.3% in 1991. Similar U.S. units have a forced outage rate of approximately 7.2%,

  - NPC units have an unplanned outage factor of approximately 10%. No similar information is available for U.S. units.

  This information shows that significant potential exists for improving the availability and reliability of NPC's oil thermal units. An eight percentage point improvement in availability factor is of very high value to NPC in terms of reduced new capacity

24

requirements and could be achieved at a small fraction of the cost. The increase in forced outage rate to 12% in 1991 and the 10% unplanned outage factor indicate the need for corrective action to be taken immediately. This should involve the use of root-cause based methods, condition assessment methods and improved maintenance methods.

- Batangas Coal Unit:

  - Batangas has an average availability factor of approximately 84%. Similar U.S. units have an availability factor of 82.4%,

  - Batangas has an average forced outage rate of 4.9%. Similar U.S. units have a forced outage rate of approximately 6.48%,

  - Batangas has exhibited an increasing unplanned outage factor from 3.5% to 14.2% in three years.

Batangas is a relatively new unit and this is reflected in the availability and forced outage rate statistics. The increase in unplanned outage factor indicates that reliability problems may be beginning to take affect and should be investigated.

Definitions for the NERC-GADS outage categories are given in Appendix E.

4.3 SYSTEM RESERVE PROFILE

The NPC system reserve profile is shown in Figure 4-17. This indicates that system reserve capacity is marginal and that the loss of one large unit on the system could necessitate the use of load reduction and cause brownout conditions. In the U.S., in order to ensure adequate system reliability, a reserve margin of 15% -20% of peak demand is maintained. This would predict a needed reserve capacity of 490 MW-650 MW on the NPC system.

These reserve needs bring into focus the value of the 450 MWs of de-rated capacity on the system, the 8 percentage point availability differential on the oil-fired units and the

25

5 percentage point forced outage rate differential on the oil-fired units. Regaining these losses would add an equivalent of 620 MWs of capacity back to the system without the need for new units. Experience in the United States has shown that this can be achieved with a well designed capital program involving availability improvements, enhanced maintenance and life extension at a small fraction of the cost of new capacity.

-26

WBOPOOCC

OIL / COAL THERMAL GENERATING PLANTS
ESTIMATED LOSSES DUE TO PLANT DE-RATING

PLANT	Rated Cap. MW	Present 1/ Maximum Dep. Cap. MW	Monthly Add'l. Fuel Cost 2/ P(x1000)	PRIMARY CAUSE/S OF LOAD LIMITATIONS
MALAYA 2	350	260	24,747.120	Weak boiler waterwall tubes
MALAYA 1	300	210	23,016.960	Weak boiler sec. SH tubes, high thrust bearing temp.
SUCAT 4	300	300	0.000	
SUCAT 3	200	160	9,123.840	Weak boiler RH tubes, high thrust bearing temp.
SUCAT 2 *	200	150	11,404.800	Weak boiler RH tubes, high thrust bearing temp.
SUCAT 1	150	120	8,171.280	Excessive air heater leakage, problem on turbine CV
BATAAN 2 **	150	130	5,581.440	Low steam pressure, high silica of feedwater, deteriorated AH elements/ seals
BATAAN 1 ***	75	50	6,453.000	Excessive air heater leakage, defective burner tips
MANILA 2	100	90	2,656.800	Low condenser vacuum
MANILA 1	100	75	6,755.400	Low condenser vacuum
BATANGAS 1	300	260	13,314.240	Weak boiler SH & RH tubes, poor coal quality & frequent mill troubles
CEBU 2 ****	55	45	3,499.200	Low condenser vacuum
CEBU 1 *****	50	30	6,350.400	Low condenser vacuum, cut-off last stage turbine blades

* On annual overhauling (capability before shutdown was 150 MW).

** Under turbine-generator overhauling (capability before shutdown was 130 MW).

*** On annual overhauling (capability before shutdown was 50 MW).

**** Under turbine-generator rehabilitation (capability before shutdown was 45 MW).

***** On annual overhauling (capability before shutdown was 30 MW).

Notes:

1/ As of November,1991.

2/ Losses due to increase in system generation cost (from oil/coal fired to gas turbine operations).
Figures are based on capacity factor of 30% for gas turbine units.

Figure 4-1

WEGFOOC1

OIL / COAL THERMAL GENERATING PLANTS
AVAILABILITY (%) & FORCED OUTAGE RATE (%)
1987-1991

Unit	Rated Cap. MW	1987				1988				1989				1990				1991 1/			
		UOF	POF	AVAIL	FOR	UOF	POF	AVAIL	FOR	UOF	POF	AVAIL	FOR	UOF	POF	AVAIL	FOR	UOF	POF	AVAIL	FOR
MALAYA 2	550	8.76	1.82	89.42	0.32	5.08	12.46	84.46	0.92	1.00	8.47	90.53	0.99	8.73	5.28	85.99	3.46	5.51	22.73	71.76	7.15
MALAYA 1	300	2.18	72.77	25.05	0.00	3.67	10.51	85.82	2.37	27.36	0.00	72.64	24.08	10.11	0.00	89.89	7.70	46.12	11.48	72.40	12.80
SUCAT 4	300	16.79	12.74	70.47	2.91	21.50	27.91	50.79	29.79	1.94	30.87	67.19	3.44	0.00	83.52	16.48	0.00	5.70	0.99	93.31	2.81
SUCAT 3	200	14.51	18.30	66.99	5.19	6.55	33.29	60.16	5.21	5.66	0.00	94.34	2.08	33.48	0.00	64.52	27.20	10.58	25.96	63.46	6.75
SUCAT 2	200	18.05	0.00	81.95	3.59	6.88	14.50	78.62	8.20	2.48	18.17	79.35	0.19	14.47	0.00	85.53	11.78	8.42	23.32	68.26	0.07
SUCAT 1	150	2.55	0.00	97.45	0.09	10.89	24.38	64.73	8.32	1.70	44.18	54.12	0.00	8.53	3.04	88.43	0.87	1.95	14.11	83.96	0.97
BATAAN 2	150	8.43	11.28	80.29	3.53	17.38	12.10	70.52	11.49	7.77	3.44	88.79	3.15	29.60	17.73	52.67	33.31	34.27	64.63	1.10	96.88
BATAAN 1	75	8.89	9.37	81.74	3.63	14.10	11.01	74.89	9.53	5.40	3.50	91.10	3.71	6.93	9.87	83.18	3.19	2.78	6.88	90.34	2.98
MANILA 2	100	5.94	6.04	88.02	1.71	6.93	0.00	93.07	0.00	4.41	20.11	75.48	3.41	3.63	0.00	96.37	0.96	1.75	16.01	82.24	0.31
MANILA 1	100	3.16	10.77	86.07	2.11	5.08	0.00	94.92	0.38	1.68	16.15	82.17	1.41	2.01	9.64	88.35	1.48	3.56	0.00	96.44	2.83
BATANGAS 1	300	3.91	11.50	84.59	3.25	6.60	10.95	82.45	3.46	8.60	0.00	91.40	7.13	8.14	16.20	75.66	6.04	14.18	0.00	85.82	4.58
CEBU 2	55	1.83	16.09	82.08	0.31	11.60	0.00	88.40	2.07	78.61	0.00	21.39	78.43	100.00	0.00	0.00	100.00	89.05	10.95	0.00	100.00
CEBU 1	50	6.99	31.80	61.21	2.54	17.56	12.58	69.86	9.82	7.29	21.42	71.29	1.62	5.53	13.31	81.16	4.19	8.41	4.63	86.94	3.70

LEGEND:

FOH = FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
POH = PLANNED OUTAGE HOURS
DSH = DEACTIVATED SHUTDOWN HOURS
OH = OPERATING HOURS
PH = PERIOD HOURS
UOF = UN-PLANNED OUTAGE FACTOR, %
POF = PLANNED OUTAGE FACTOR, %
AVAIL = AVAILABILITY, %
FOR = FORCED OUTAGE RATE, %

FORMULA USED:

$$UOF = \frac{FOH + MOH}{PH - DSH} \times 100$$

$$POF = \frac{POH}{PH - DSH} \times 100$$

$$AVAIL = 100 - (UOF + POF)$$

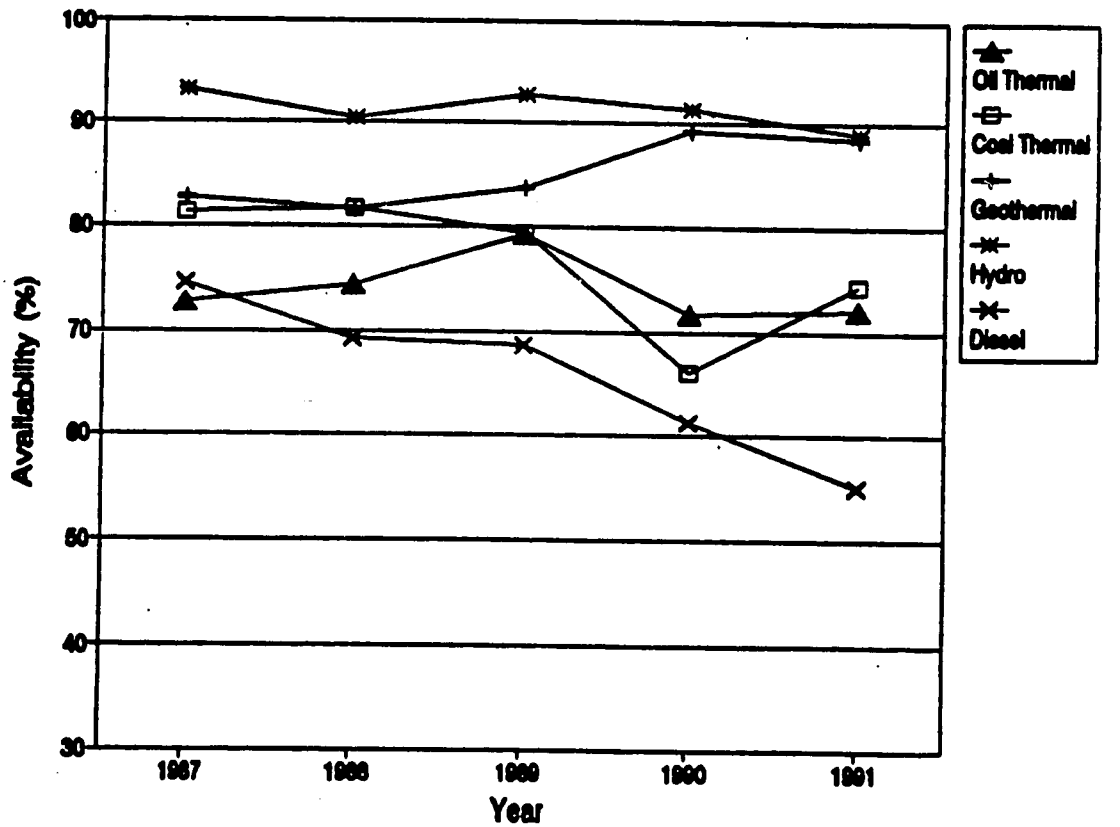
$$FOR = \frac{FOH}{FOH + OH} \times 100$$

1/ Period covered is based from January - October, 1991 except for Cebu 1 & 2 which is from Jan. - Sept., 1991.

Figure 4-2

NPC GENERATING PLANTS
AVAILABILITY (%)
1987-1991

PLANT TYPE	Installed Cap, MW	1987	1988	1989	1990	1991
Oil Thermal	1925	72.69	74.29	79.17	71.63	71.89
Coal Thermal	405	81.36	81.71	79.41	66.07	74.30
Geothermal	865	82.71	81.64	83.71	89.37	88.55
Hydro	2098	93.18	90.46	92.77	91.38	89.00
Diesel	447	74.49	69.33	68.71	61.27	55.14



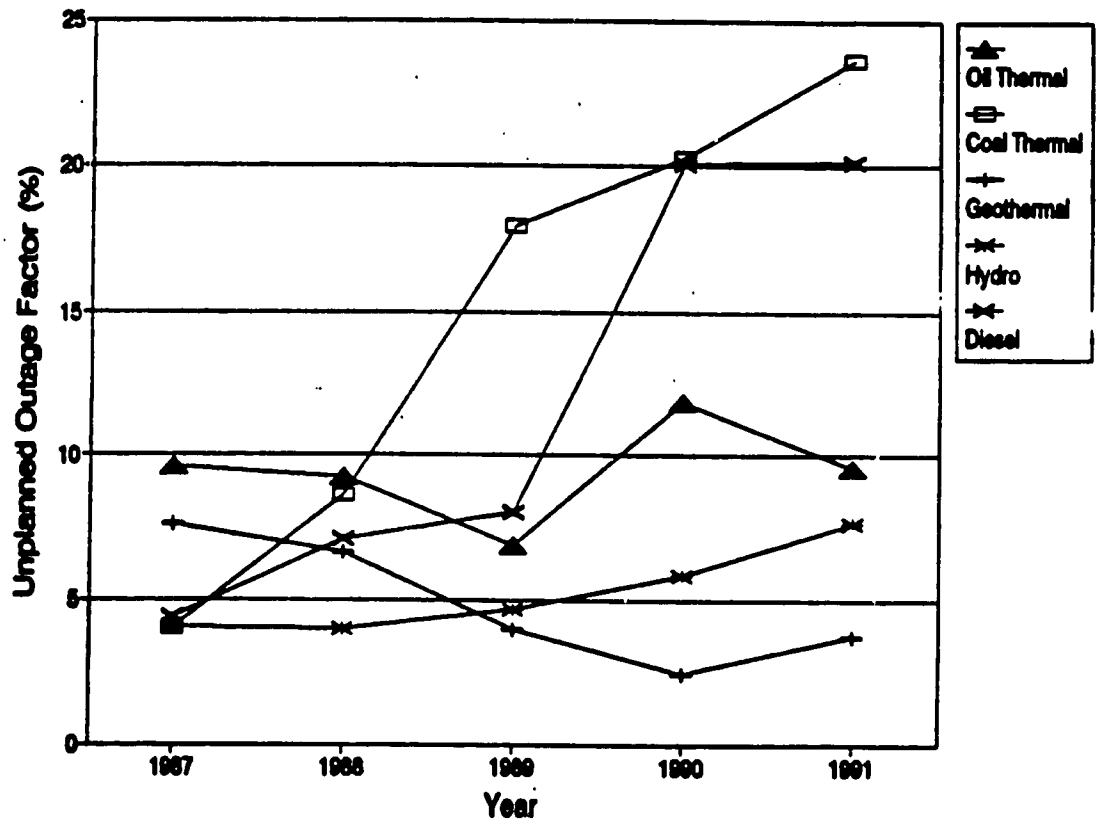
Note:
Figures are weighted according to unit rated capacity

Figure 4-3

29

NPC GENERATING PLANTS
UNPLANNED OUTAGE FACTOR (%)
1987-1991

PLANT TYPE	Installed Cap, MW	1987	1988	1989	1990	1991
Oil Thermal	1925	9.61	9.22	6.86	11.89	9.58
Coal Thermal	405	4.01	8.63	17.95	20.29	23.64
Geothermal	865	7.60	6.63	3.97	2.41	3.75
Hydro	2096	4.07	3.99	4.65	5.84	7.64
Diesel	447	4.40	7.08	8.02	20.10	20.13



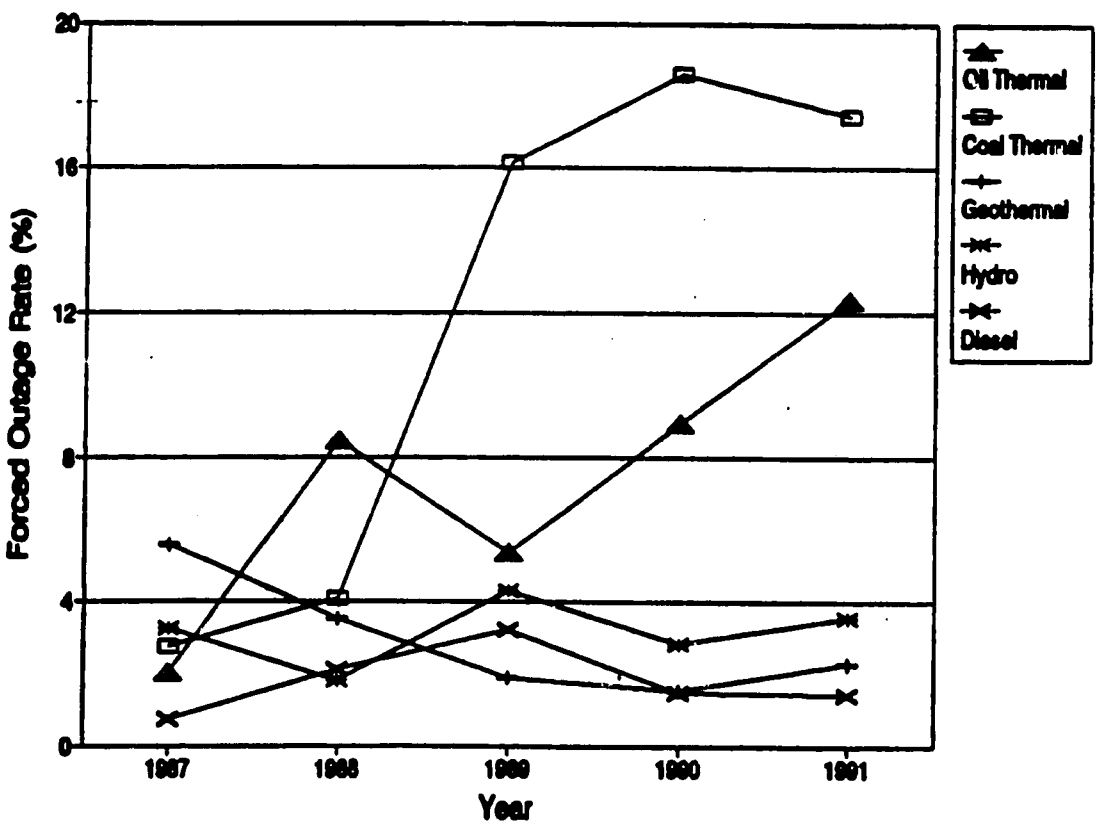
Note:
Figures are weighted according to unit rated capacity

Figure 4-4

30

NPC GENERATING PLANTS
FORCED OUTAGE RATE (%)
1987-1991

PLANT TYPE	Installed Cap, MW	1987	1988	1989	1990	1991
Oil Thermal	1925	2.05	8.51	5.36	8.98	12.34
Coal Thermal	405	2.76	4.06	16.15	18.57	17.43
Geothermal	885	5.58	3.50	1.88	1.51	2.27
Hydro	2098	3.25	1.81	4.30	2.83	3.53
Diesel	447	0.75	2.10	3.21	1.50	1.41



Note:
Figures are weighted according to unit rated capacity

Figure 4-5

31

Summary Statistics

1990 Generating Unit Statistics — All Sizes

Unit Type	# of Units	Age	PCF	SF	NSF	AF	EAF	FOR	EFOR	NSF	POF	SR	ART
FOSSIL - All Fuels	1,467	26.38	50.70	61.19	72.72	84.58	81.86	5.68	8.38	11.73	3.68	95.44	225.86
Coal	866	25.21	59.99	72.25	77.54	84.44	81.60	5.63	8.13	11.24	4.31	98.09	323.93
Oil	184	27.61	29.74	46.04	58.31	85.53	82.72	5.85	9.52	11.61	2.86	88.85	77.64
Gas	387	29.33	29.31	42.14	54.99	84.18	81.80	6.22	9.12	13.02	2.79	98.69	180.74
NUCLEAR - All Types	120	11.16	66.28	71.69	93.02	71.70	68.10	9.97	12.81	20.36	7.94	97.90	1202.43
PWR	69	11.09	67.71	72.73	93.27	72.73	69.56	6.49	8.43	22.21	5.05	97.15	1323.83
BWR	33	12.24	64.23	70.37	93.65	70.37	67.01	16.92	19.43	15.29	14.33	97.82	1354.53
CANDU	18	9.44	63.59	70.03	90.09	70.08	64.32	9.53	16.59	22.54	7.38	100.00	754.74
JET ENGINE	352	18.34	1.37	1.88	63.79	91.00	85.46	60.56	67.92*	6.12	2.88	92.54	3.26
GAS TURBINE	634	18.10	1.69	2.16	66.09	89.70	83.71	61.50	64.82*	6.85	3.45	93.19	4.97
DIESEL	163	21.93	1.44	1.69	69.87	95.08	94.95	58.29	59.52*	2.56	2.36	99.25	4.68
HYDRO	587	38.14	53.26	61.05	87.61	91.01	90.68	3.34	3.35	6.88	2.11	99.29	111.91
PUMPED STORAGE	56	19.21	12.13	25.33	55.42	87.53	86.53	10.31	10.33	9.55	2.91	99.76	9.39
MULTI-BOILER/TURBINE	66	39.41	34.24	44.36	54.53	89.65	84.34	4.41	8.72	8.30	2.04	99.95	97.82
COMBINED CYCLE	25	14.20	31.02	46.65	61.17	87.27	80.39	3.72	6.47	10.93	1.80	96.97	26.09
GEOTHERMAL	22	13.59	63.75	85.40	71.43	88.69	66.99	1.48	25.46	10.03	1.28	96.09	554.17

1986-1990 Generating Unit Statistics — All Sizes

Unit Type	# of Units	Unit-Years	NCF	SF	NSF	AF	EAF	FOR	EFOR	NSF	POF	SR	ART
FOSSIL - All Fuels	1,528	7,247	50.14	60.29	72.83	84.04	81.29	6.37	9.25	11.86	4.10	98.28	204.93
Coal	890	4,237	58.80	70.94	77.42	83.57	80.68	6.24	8.98	11.71	4.72	98.65	283.84
Oil	246	925	31.37	47.76	60.41	84.63	81.76	7.24	10.91	11.65	3.72	97.25	76.69
Gas	459	1,936	30.36	41.73	56.40	84.67	82.34	6.67	9.58	12.34	2.98	98.83	171.96
NUCLEAR - All Types	129	577	63.19	69.84	91.83	69.84	66.32	13.08	15.82	19.64	10.51	97.19	1083.00
PWR	73	328	65.57	71.70	92.32	71.70	68.25	11.01	13.44	19.42	8.87	95.97	1125.08
BWR	38	164	54.98	63.16	90.04	63.16	59.19	19.69	22.72	21.35	15.49	97.69	1161.47
CANDU	18	85	70.90	75.48	92.95	75.51	72.55	8.79	12.15	17.20	7.28	100.00	870.51
JET ENGINE	364	1,640	1.88	2.63	65.84	91.71	85.58	53.40	65.29*	5.28	3.01	93.43	3.76
GAS TURBINE	662	2,776	1.79	2.70	64.03	90.94	84.91	58.70	62.30*	5.23	3.83	92.06	6.09
DIESEL	177	829	1.93	2.30	71.58	95.72	95.60	48.89	50.91*	2.08	2.19	99.62	4.81
HYDRO	607	2,936	50.97	58.59	87.52	90.38	89.63	3.16	3.20	7.71	1.91	99.56	95.09
PUMPED STORAGE	57	275	11.63	25.98	49.46	87.18	85.83	13.03	13.11	8.93	3.89	99.61	9.73
MULTI-BOILER/TURBINE	84	294	39.29	44.39	59.89	89.11	82.76	6.47	11.55	7.82	3.07	99.94	108.27
COMBINED CYCLE	27	119	32.25	47.95	62.34	84.68	76.78	6.83	9.93	11.80	3.31	95.66	24.66
GEOTHERMAL	23	108	72.77	87.43	81.60	88.11	73.71	3.81	19.40	8.42	3.46	95.01	429.23

*Caution: EFOR value may be low since deratings during reserve shutdown periods may not have been reported by a large number of these units.

Note: Lignite-fired units are included in the FOSSIL - All Fuel Types but are excluded from the Coal Primary category.

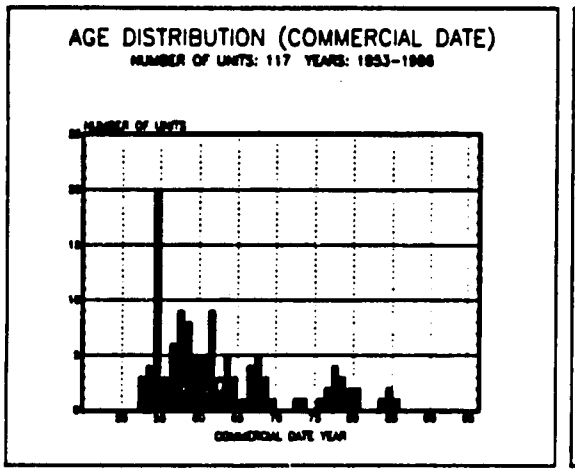
Figure 4-6

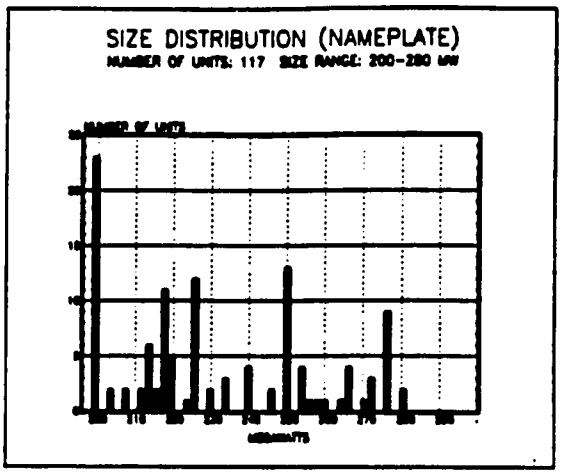
NERC GADS
Generating Availability Report

32

Fossil Units - Coal Primary
200-299 MW 1986-1990

NUMBER OF UTILITIES :	61
NUMBER OF UNITS :	117
NUMBER OF UNIT-YEARS:	574





1986-1990
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	GCF	NCF	SF	GOF	NOF	AF	EAF	FEOR	EFOR	SOF	POF	SR	ART
1986	23.22	59.27	58.77	76.92	78.28	77.61	83.54	81.06	6.68	7.63	11.68	4.66	99.76	398.02
1987	24.12	61.18	60.67	77.01	79.62	78.91	83.39	80.74	6.63	7.66	12.01	4.59	97.02	413.86
1988	25.03	62.72	62.43	77.76	80.90	80.49	84.34	81.92	6.64	7.59	11.00	4.65	99.68	426.52
1989	26.03	63.29	62.88	77.77	81.58	81.03	84.18	82.14	7.10	6.59	9.87	5.94	99.22	447.35
1990	26.84	61.67	61.32	77.63	79.31	79.00	84.41	82.27	4.90	6.58	11.58	4.01	98.50	415.71
1986-90		61.62	61.23	77.26	79.96	79.42	83.97	81.63	5.79	7.06	11.27	4.75	98.77	420.37

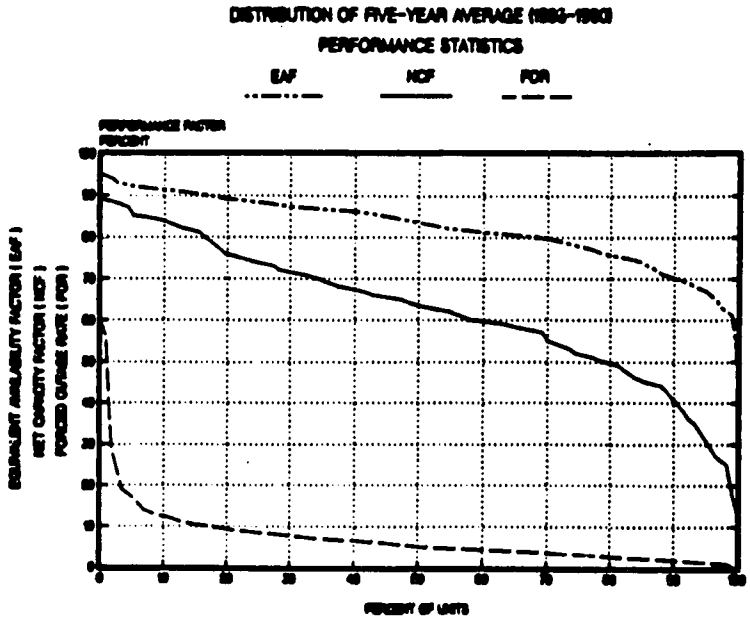
		1986	1987	1988	1989	1990	1986-90
Unit-Years	:	113	115	116	115	116	574
Maximum Capacity (MW)	Gross:	243	243	244	244	244	243
	Net:	229	229	230	230	230	229
Dependable Capacity (MW)	Gross:	241	241	242	242	243	242
	Net:	228	228	228	228	228	228
Actual Generation (MWh)	Gross:	1,292,938	1,303,076	1,345,421	1,353,119	1,320,206	1,[illegible]7,146
	Net:	1,182,674	1,220,430	1,261,423	1,268,336	1,237,516	1,[illegible]34,263
Attempted Unit Starts	:	16.75	16.80	16.01	16.36	16.66	16.31
Actual Unit Starts	:	16.71	16.30	15.94	15.23	16.40	16.11
Service Hours	:	6,650.90	6,745.72	6,830.86	6,613.07	6,817.63	6,772.10
Reserve Shutdown Hours	:	667.47	559.18	579.16	560.66	576.37	588.12
Number of Occurrences	:	6.47	6.09	6.10	4.62	5.80	5.85
Pumping Hours	:	.	.	.	.	.	.
Synchronous Condensing Hours	:	.	.	.	.	.	.
TOTAL AVAILABLE HOURS	:	7,318.37	7,304.90	7,[illegible]	7,373.95	7,394.00	7,360.21
Forced Outage Hours	:	401.23	402.63	408.72	521.11	361.43	416.96
Number of Occurrences	:	10.68	10.77	10.22	9.64	9.64	10.19
Planned Outages:							
Planned Outage Hours	:	907.44	962.63	914.13	896.59	799.92	915.80
Number of Occurrences	:	1.53	1.38	1.58	1.33	1.34	1.43
Planned Outage Ext. Hours	:	4.93	21.99	12.71	24.77	29.19	18.17
Number of Occurrences	:	0.03	0.03	0.04	0.06	0.07	0.05
Maintenance Outages:							
Maintenance Outage Hours	:	127.41	167.66	139.61	143.60	165.46	153.54
Number of Occurrences	:	2.37	3.10	3.01	3.15	3.63	3.03
Maintenance Outage Ext. Hours	:	0.83	.	0.06	.	.	0.13
Number of Occurrences	:	0.01	.	0.01	.	.	.
TOTAL UNAVAILABLE HOURS	:	1,441.84	1,455.09	1,375.22	1,386.08	1,366.99	1,404.61
TOTAL PERIOD HOURS	:	8,760.01	8,759.98	8,784.03	8,760.03	8,759.99	8,764.82
Equiv. Forced Hours	:	137.70	160.70	141.88	107.03	121.16	133.66
Equiv. Scheduled Hours	:	30.03	25.64	24.62	24.62	24.00	25.79
Equiv. Forced Hours During RS	:	5.76	11.50	6.71	3.74	2.07	5.91
TOTAL EQUIVALENT DERATED HOURS	:	167.73	186.54	166.41	131.66	145.16	159.45

Figure 4-7

NERC GADS
Generating Availability Report

33

Fossil Units - Coal Primary
200-299 MW 1986-1990



1986-1990
OUTAGE AND DERATING STATES BY COMPONENT CAUSE CODE CATEGORIES
(PRIMARY CAUSE OF OUTAGE OR DERATING)

	FORCED OUTAGES		PLANNED OUTAGES (WITH EXTENSIONS)		MAINTENANCE OUTAGES (WITH EXTENSIONS)		FORCED DERATINGS		SCHEDULED DERATINGS (WITH EXTENSIONS)	
CAUSE CODE CATEGORIES	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	EQUIV HOURS	NUMBER OF OCC	EQUIV HOURS
BOILER	6.31	263.27	0.82	559.38	1.33	74.61	21.06	63.18	4.49	14.51
BALANCE OF PLANT	1.53	42.94	0.07	22.96	0.46	21.30	7.72	30.48	1.33	4.71
STEAM TURBINE	1.28	50.97	0.44	187.36	0.64	36.65	1.80	8.72	0.73	2.23
GENERATOR	0.48	24.91	0.03	19.02	0.13	7.55	0.24	0.53	0.06	0.12
POLLUTION CNTL.	0.11	4.25	0.06	29.38	0.44	22.38	2.75	9.61	0.64	1.85
EXTERNAL	0.15	7.48	0.01	0.22	0.02	0.05	2.32	6.67	0.06	1.09
REGULATORY	0.03	0.26	0.00	0.06	0.01	0.18	2.41	7.45	0.18	0.78
PERSONNEL ERRORS	0.28	22.53	0.00	0.21	0.01	0.22	0.13	0.29	0.01	0.01
PERFORMANCE	0.00	0.00	0.00	0.00	0.01	0.01	0.04	0.06	0.25	0.66

1986-1990
TOP 25 SYSTEM/COMPONENT CAUSE CODES
FORCED AND SCHEDULED OUTAGES AND DERATINGS
BY AVERAGE MWH PER UNIT-YEAR
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE	AVG NO. OCC PER UNIT-YR	AVERAGE MWH PER UNIT-YR	AVERAGE MWH PER OCCURRENCE	SYSTEM/COMPONENT CAUSE CODE DESCRIPTION
1000	0.67	85237	190641	BOILER OVERHAUL
4400	0.13	31161	236274	MAJOR TURBINE OVERHAUL
1010	0.36	34006	96062	BOILER INSPECTIONS
1000	2.22	19442	8775	FURNACE WALL
1040	0.96	9686	10009	FIRST SUPERHEATER
1099	0.81	8866	9229	BOILER, MISCELLANEOUS
4401	0.08	7586	94648	INSPECTION
1060	0.69	7452	10774	FIRST REHEATER
8860	2.50	7065	2820	ELECTROSTATIC PRECIPITATOR PROBLEMS
1080	0.62	6862	11178	SECOND SUPERHEATER
9900	0.23	6161	26860	OPERATOR ERROR
5410	0.06	4171	4060	FEEDWATER PUMP
4261	0.46	3887	8000	CONTROL VALVES
4420	0.51	3804	7402	VIBRATION OF THE TURBINE GENERATOR UNIT
8860	0.88	3763	4364	ELECTROSTATIC PRECIPITATOR FOULING
1060	0.39	3302	8575	ECONOMIZER
1850	3.12	3013	964	BOILER WATER CONDITION (NOT FEEDWATER WATER QUALITY)
0810	3.03	2707	892	PULVERIZER MILLS
4212	0.06	2346	70833	BUCKETS OR BLADES
4860	0.01	2317	189860	MAJOR OVERHAUL
4600	0.02	2271	130379	ROTOR WINDINGS
3810	0.23	2270	9872	CONDENSATE/HOTWELL PUMPS
0860	0.24	2035	8548	BURNERS
0640	0.04	1960	53644	REHEAT STEAM PIPING UP TO TURBINE STOP VALVES
1070	0.14	1933	13366	SECOND REHEATER

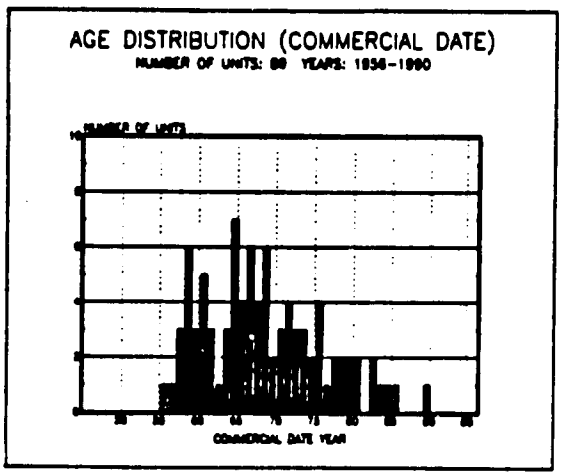
NERC GADS
Generating Availability Report

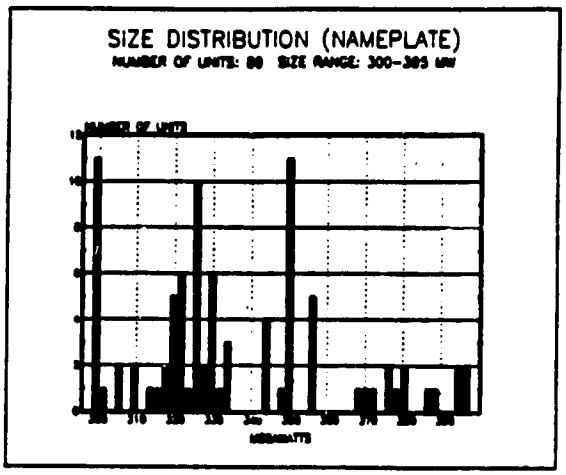
Figure 4-8

34

Fossil Units - Coal Primary
300-399 MW 1986-1990

NUMBER OF UTILITIES :	47
NUMBER OF UNITS :	89
NUMBER OF UNIT-YEARS:	440





1986-1990
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	GCF	NCF	SF	GOF	NOF	AF	EAF	PER	EFOR	SOF	POF	SR	ART
1986	17.32	49.48	49.01	68.42	71.58	70.94	78.32	74.83	9.48	13.12	14.51	7.16	88.32	284.63
1987	18.44	53.81	53.45	72.16	73.89	73.42	78.83	76.58	7.90	10.87	14.87	6.16	88.91	279.53
1988	19.32	56.21	55.86	74.71	74.51	74.07	82.42	78.47	6.66	8.77	13.09	4.48	87.48	292.58
1989	20.32	55.70	55.21	73.43	75.22	74.61	81.20	77.28	7.24	11.06	13.06	5.73	86.60	301.70
1990	21.08	56.35	55.90	74.34	75.06	74.58	80.83	76.96	6.75	10.13	13.79	5.38	95.48	318.36
1986-90		54.31	53.88	72.82	74.09	73.56	80.33	76.63	7.36	10.99	13.66	5.79	87.38	294.60

		1986	1987	1988	1989	1990	1986-90
Unit-Years	:	88	87	88	88	89	440
Maximum Capacity (MW) Gross	:	347	346	346	346	347	346
Net	:	326	324	324	324	325	325
Dependable Capacity (MW) Gross	:	345	343	343	343	344	343
Net	:	325	323	323	322	323	323
Actual Generation (MWh) Gross	:	1,503,668	1,628,258	1,707,817	1,687,672	1,704,672	1,646,632
Net	:	1,400,803	1,520,036	1,592,820	1,570,159	1,586,814	1,534,178
Attempted Unit Starts	:	21.38	22.87	23.01	22.07	21.46	22.18
Actual Unit Starts	:	21.03	22.62	22.43	21.32	20.49	21.58
Service Hours	:	6,086.80	6,322.87	6,662.52	6,432.18	6,462.14	6,357.47
Reserve Shutdown Hours	:	865.45	583.02	677.19	681.18	585.33	674.39
Number of Occurrences	:	8.66	10.17	12.68	12.81	10.70	11.20
Pumping Hours	:	.	.	.	.	.	
Synchronous Condensing Hours	:	.	.	.	.	.	.
TOTAL AVAILABLE HOURS	:	6,951.25	6,906.89	7,239.72	7,113.34	7,047.47	7,031.85
Forced Outage Hours	:	627.01	542.72	384.06	502.60	469.82	537.38
Number of Occurrences	:	14.13	13.93	12.76	12.63	12.46	13.18
Planned Outages:							
Planned Outage Hours	:	992.99	1,067.53	945.81	914.53	822.07	988.28
Number of Occurrences	:	1.87	2.84	2.06	1.34	1.26	1.79
Planned Outage Ext. Hours	:	82.01	22.22	3.96	38.15	29.99	31.28
Number of Occurrences	:	0.17	0.08	0.03	0.08	0.08	0.09
Maintenance Outages:							
Maintenance Outage Hours	:	213.55	229.21	167.82	188.67	244.76	214.50
Number of Occurrences	:	3.50	4.29	4.13	3.59	3.47	3.79
Maintenance Outage Ext. Hours	:	1.18	2.42	2.63	4.45	5.18	3.18
Number of Occurrences	:	0.08	0.06	0.09	0.10	0.18	0.10
TOTAL UNAVAILABLE HOURS	:	1,896.75	1,864.10	1,544.27	1,646.70	1,671.61	1,722.31
TOTAL PERIOD HOURS	:	8,748.00	8,758.99	8,783.99	8,760.05	8,719.28	8,754.17
Equiv. Forced Hours	:	244.76	212.21	288.66	287.60	237.71	250.25
Equiv. Scheduled Hours	:	32.87	42.53	28.18	36.87	58.59	39.64
Equiv. Forced Hours During RS	:	28.06	10.90	27.26	23.26	31.61	24.26
TOTAL EQUIVALENT DERATED HOURS	:	277.43	254.74	316.84	304.17	297.30	290.16

Figure 4-9

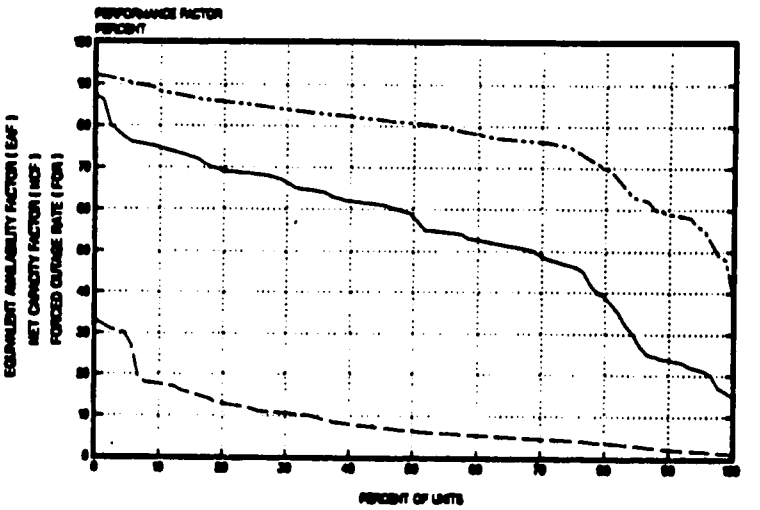
NERC GADS
Generating Availability Report

35

Fossil Units - Coal Primary
300-399 MW 1986-1990

DISTRIBUTION OF FIVE-YEAR AVERAGE (1986-1990)
PERFORMANCE STATISTICS

EAF — NCF — FOR



1986-1990
OUTAGE AND DERATING STATES BY COMPONENT CAUSE CODE CATEGORIES
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE CATEGORIES	FORCED OUTAGES		PLANNED OUTAGES (WITH EXTENSIONS)		MAINTENANCE OUTAGES (WITH EXTENSIONS)		FORCED DERATINGS		SCHEDULED DERATINGS (WITH EXTENSIONS)	
	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	EQUIV HOURS	NUMBER OF OCC	EQUIV HOURS
BOILER	7.77	334.25	1.03	653.22	1.84	117.35	31.61	118.37	3.30	22.31
BALANCE OF PLANT	1.93	44.28	0.08	17.07	0.56	24.97	10.52	70.01	1.94	12.95
STEAM TURBINE	1.75	59.54	0.62	284.77	0.66	35.94	2.18	8.64	0.21	0.51
GENERATOR	0.76	57.64	0.05	37.13	0.28	11.55	0.34	3.41	0.01	0.01
POLLUTION CNTL.	0.20	6.78	0.02	5.49	0.42	21.03	3.22	11.71	0.29	3.17
EXTERNAL	0.23	1.41	0.00	0.00	0.01	2.93	4.26	5.14	0.00	0.00
REGULATORY	0.02	0.34	0.00	0.28	0.02	0.75	4.43	31.32	0.02	0.61
PERSONNEL ERRORS	0.52	2.78	0.00	0.00	0.01	2.74	0.20	0.13	0.00	0.00
PERFORMANCE	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.09	0.15

1986-1990
TOP 25 SYSTEM/COMPONENT CAUSE CODES
FORCED AND SCHEDULED OUTAGES AND DERATINGS
BY AVERAGE MWH PER UNIT-YEAR
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE	AVG NO. OCC PER UNIT-YR	AVERAGE MWH PER UNIT-YR	AVERAGE MWH PER OUTAGE	SYSTEM/COMPONENT CAUSE CODE DESCRIPTION
1800	0.78	146401	187814	BOILER OVERHAUL
4400	0.45	72491	159480	MAJOR TURBINE OVERHAUL
1000	2.50	32649	13128	FURNACE WALL
1810	0.22	31582	143260	BOILER INSPECTIONS
1040	0.93	16582	17863	FIRST SUPERHEATER
1060	1.03	15232	14861	FIRST REHEATER
0780	0.06	14637	246019	HEADERS BETWEEN TUBE BUNDLES
1080	0.89	12319	13828	ECONOMIZER
1050	0.60	11118	18590	SECOND SUPERHEATER
4401	0.06	8806	154980	INSPECTION
1480	0.82	7828	8297	PRIMARY AIR HEATER (REGENERATIVE)
4212	0.04	7066	172456	BUCKETS OR BLADES
3410	1.39	6832	4964	FEEDWATER PUMP
8560	0.93	6509	7036	ELECTROSTATIC PRECIPITATOR PROBLEMS
1010	0.36	5991	16887	CYCLONE FURNACE (IN CYCLONE AREA ONLY)
1999	1.16	5832	5068	BOILER, MISCELLANEOUS
4420	0.69	5851	8524	VIBRATION OF THE TURBINE GENERATOR UNIT
1100	5.20	5674	1091	FURNACE WALL
0310	4.18	5670	1358	PULVERIZER MILLS
1850	4.10	5168	1261	BOILER WATER CONDITION (NOT FEEDWATER WATER QUALITY)
4499	0.68	4960	5075	OTHER MISCELLANEOUS STEAM TURBINE PROBLEMS
4560	0.26	4807	18718	GENERATOR VIBRATION
4260	0.21	4663	22548	MAIN STOP VALVES
9620	1.18	4543	3869	PARTICULATE STACK EMISSIONS - FOSSIL STEAM UNITS
4730	0.05	3961	75775	GENERATOR CURRENT AND POTENTIAL TRANSFORMERS

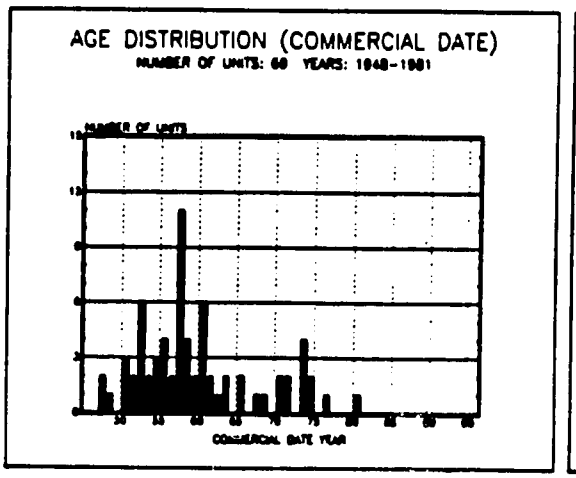
NERC GADS
Generating Availability Report

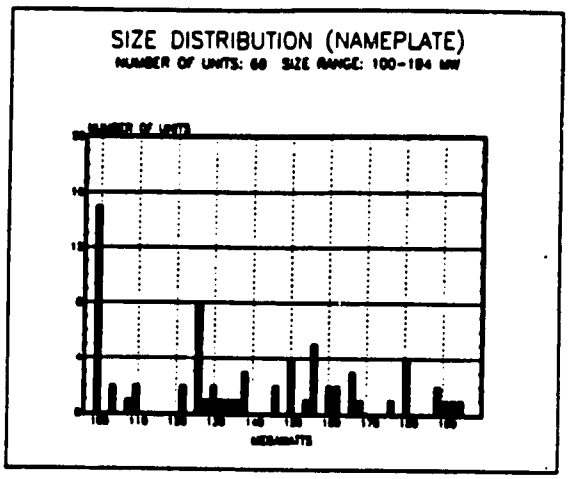
Figure 4-10

36

Fossil Units - Oil Primary
100-199 MW 1986-1990

NUMBER OF UTILITIES :	32
NUMBER OF UNITS :	60
NUMBER OF UNIT-YEARS:	234





1986-1990
ANNUAL UNIT PERFORMANCE STATISTICS

1986	26.62	33.43	33.00	52.99	59.29	58.59	84.82	81.34	7.14	11.31	11.10	4.07	99.50	96.39
1987	26.17	31.63	31.23	53.80	58.46	57.82	86.11	82.00	6.25	9.82	11.30	3.59	99.63	101.96
1988	27.20	37.30	36.80	60.17	61.44	60.64	86.15	83.00	6.04	9.40	9.98	3.87	99.65	144.04
1989	28.82	38.93	37.56	59.54	64.75	62.56	82.71	79.61	5.62	8.52	13.74	3.55	99.81	145.17
1990	26.73	36.38	34.89	58.24	60.47	59.77	86.87	83.18	5.86	10.02	9.40	3.62	86.04	99.50
1986-90		35.09	34.47	56.66	60.80	59.80	86.07	81.76	6.22	9.84	11.17	3.75	96.79	113.70

		1986	1987	1988	1989	1990	1986-90
Unit-Years	:	55	52	45	45	37	234
Maximum Capacity (MW)	Gross:	142	146	137	140	148	143
	Net:	135	140	130	133	143	136
Dependable Capacity (MW)	Gross:	140	145	136	138	146	141
	Net:	134	138	129	132	141	134
Actual Generation (MWh)	Gross:	416,760	408,960	449,342	478,639	484,862	440,365
	Net:	392,617	383,324	421,934	440,861	437,121	412,604
Attempted Unit Starts	:	48.40	46.48	36.82	36.00	59.59	45.13
Actual Unit Starts	:	48.16	46.31	36.69	36.93	51.27	43.68
Service Hours	:	4,641.88	4,721.18	5,284.96	5,218.10	5,101.44	4,966.29
Reserve Shutdown Hours	:	2,787.73	2,734.16	2,251.61	2,029.48	2,517.15	2,499.90
Number of Occurrences	:	46.56	45.50	36.82	33.62	41.97	41.24
Pumping Hours	:	.	.	.	.	.	.
Synchronous Condensing Hours	:	0.44	.	0.71	.	.	0.24
TOTAL AVAILABLE HOURS	:	7,430.16	7,455.37	7,567.29	7,245.56	7,618.59	7,466.43
Forced Outage Hours	:	367.28	315.18	340.32	310.99	317.84	329.52
Number of Occurrences	:	8.31	8.73	7.89	8.16	8.61	8.53
Planned Outages:							
Planned Outage Hours	:	757.52	811.57	877.45	1,014.43	686.14	792.25
Number of Occurrences	:	1.47	1.25	1.49	1.49	1.61	1.48
Planned Outage Ext. Hours	:	48.06	31.24	70.22	22.76	18.68	38.23
Number of Occurrences	:	0.07	0.08	0.11	0.11	0.16	0.10
Maintenance Outages:							
Maintenance Outage Hours	:	143.48	134.42	123.73	166.73	103.82	135.67
Number of Occurrences	:	2.62	2.63	2.31	2.71	1.78	2.45
Maintenance Outage Ext. Hours	:	10.42	8.26	5.04	0.59	13.63	7.57
Number of Occurrences	:	0.15	0.13	0.07	0.02	0.03	0.09
TOTAL UNAVAILABLE HOURS	:	1,329.84	1,304.63	1,216.75	1,514.50	1,141.41	1,308.21
TOTAL PERIOD HOURS	:	8,760.00	8,760.00	8,784.04	8,760.09	8,760.00	8,764.64
Equiv. Forced Hours	:	216.17	184.93	192.87	183.18	234.56	187.46
Equiv. Scheduled Hours	:	28.66	13.18	18.99	32.20	18.63	22.36
Equiv. Forced Hours During RS	:	70.58	53.73	43.78	32.60	60.08	57.62
TOTAL EQUIVALENT DERATED HOURS	:	244.83	198.11	212.86	186.38	251.38	219.82

Figure 4-11

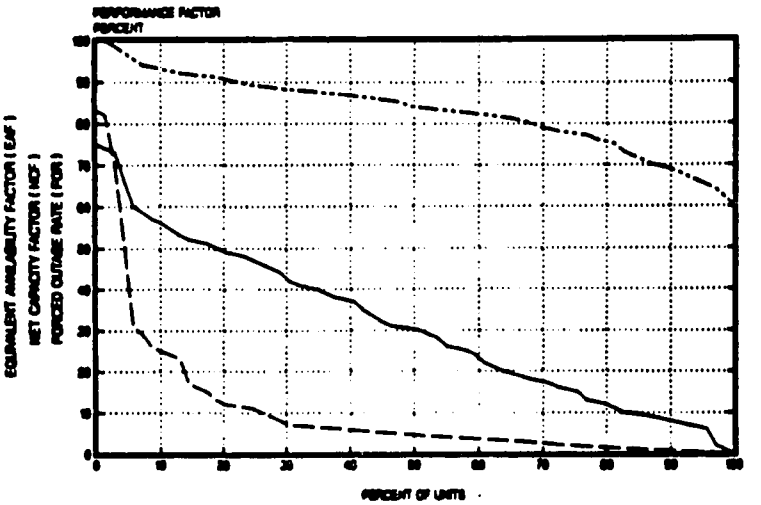
NERC GADS
Generating Availability Report

-37-

Fossil Units - Oil Primary
100-199 MW 1986-1990

DISTRIBUTION OF FIVE-YEAR AVERAGE (1986-1990)
PERFORMANCE STATISTICS

EAF — NCF — FOR



1986-1990
OUTAGE AND DERATING STATES BY COMPONENT CAUSE CODE CATEGORIES
(PRIMARY CAUSE OF OUTAGE OR DERATING)

	FORCED OUTAGES		PLANNED OUTAGES (WITH EXTENSIONS)		MAINTENANCE OUTAGES (WITH EXTENSIONS)		FORCED DERATINGS		SCHEDULED DERATINGS (WITH EXTENSIONS)	
CAUSE CODE CATEGORIES	NUMBER OF OOC	OUTAGE HOURS	NUMBER OF OOC.	OUTAGE HOURS	NUMBER OF OOC	OUTAGE HOURS	NUMBER OF OOC	DERAT HOURS	NUMBER OF OOC	DERAT HOURS
BOILER	4.76	182.77	0.90	468.73	1.42	84.47	9.13	87.84	0.98	4.32
BALANCE OF PLANT	1.86	32.86	0.04	8.50	0.44	16.61	13.46	97.18	2.65	14.51
STEAM TURBINE	0.98	34.71	0.41	301.23	0.36	27.10	0.74	4.06	0.30	1.67
GENERATOR	0.62	35.03	0.04	7.16	0.16	9.32	0.46	0.77	0.01	0.62
POLLUTION CNTL.	0.03	0.82	0.00	0.59	0.04	1.35	0.11	0.66	0.06	0.33
EXTERNAL	0.16	11.37	0.00	0.00	0.01	0.11	0.07	0.30	0.00	0.00
REGULATORY	0.06	23.66	0.03	17.81	0.00	0.22	1.58	5.77	0.01	0.00
PERSONNEL ERRORS	0.16	1.14	0.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00
PERFORMANCE	0.02	0.46	0.06	1.60	0.00	0.00	0.11	0.14	0.07	0.73

1986-1990
TOP 25 SYSTEM/COMPONENT CAUSE CODES
FORCED AND SCHEDULED OUTAGES AND DERATINGS
BY AVERAGE EMH PER UNIT-YEAR
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE	AVG NO. OOC PER UNIT-YR	AVERAGE EMH PER UNIT-YR	AVERAGE EMH PER OUTAGE	SYSTEM/COMPONENT CAUSE CODE DESCRIPTION
4400	0.50	40050	80101	MAJOR TURBINE OVERHAUL
1800	0.46	31008	67160	BOILER OVERHAUL
1810	0.33	14654	44861	BOILER INSPECTIONS
1000	1.46	12532	8661	FURNACE WALL
1340	0.01	4406	515493	TUBE MODIFICATIONS (INCLUDING ADDITION AND REMOVAL OF TUBES)
1050	0.39	4181	10607	SECOND SUPERHEATER
3410	1.04	3299	3164	FEEDWATER PUMP
1999	0.67	3230	8640	BOILER, MISCELLANEOUS
1030	0.55	2881	5226	BOILER SCREEN, WING WALL, OR SLAG SCREEN (WATER TUBES ONLY)
1060	0.46	2779	6806	ECONOMIZER
9990	0.02	2770	163058	OTHER MISC. OPERATIONAL ENVIRONMENTAL LIMITS - ALL STEAM UNITS
1480	0.61	2723	6309	PRIMARY AIR HEATER (REGENERATIVE)
3110	3.47	2671	771	CONDENSER TUBE LEAKS
1040	0.65	2584	4580	FIRST SUPERHEATER
0360	0.66	2460	3726	BURNERS
4401	0.06	2402	46844	INSPECTION
4212	0.03	2313	77322	BUCKETS OR BLADES
1090	0.16	2197	13896	OTHER BOILER TUBE LEAKS
0620	0.21	2186	10663	CASING
4360	0.19	2179	11589	MAIN STOP VALVES
4600	0.24	2061	8725	ROTOR WINDINGS
3441	0.41	1966	4742	OTHER HIGH PRESSURE HEATER PROBLEMS
9320	0.13	1946	15160	OTHER MISCELLANEOUS EXTERNAL PROBLEMS
4420	0.18	1481	8454	VIBRATION OF THE TURBINE GENERATOR UNIT
0740	1.36	1361	996	BOILER RECIRCULATION PUMPS

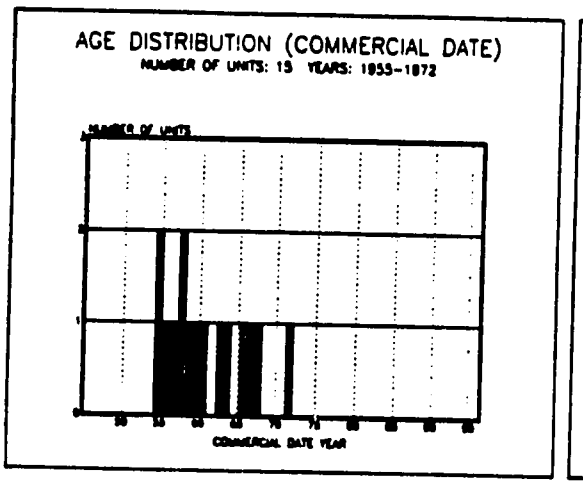
NERC GADS
Generating Availability Report

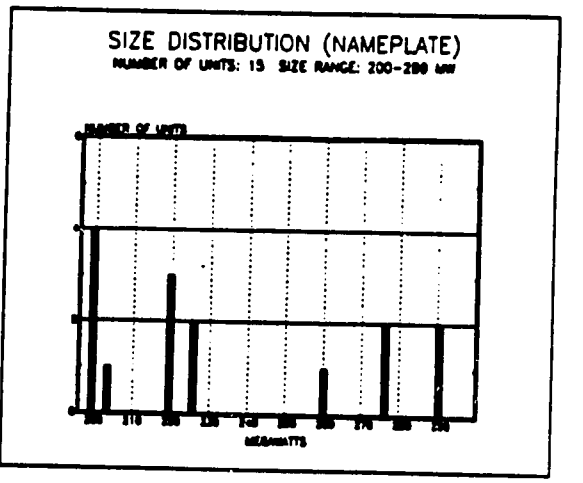
Figure 4-12

38

Fossil Units - Oil Primary
200-299 MW 1986-1990

NUMBER OF UTILITIES :	10
NUMBER OF UNITS :	15
NUMBER OF UNIT-YEARS:	57





1986-1990
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	GCF	NCF	SF	GSF	NSF	AF	SAF	FOR	EFOR	SOF	POF	SR	ART
1986	24.17	24.18	23.99	39.00	62.02	61.64	84.30	81.22	12.82	17.13	8.96	5.73	97.66	61.20
1987	26.14	20.64	20.55	35.91	55.23	57.48	78.49	77.13	8.12	10.03	18.34	3.17	98.37	73.27
1988	26.64	21.87	21.85	34.24	63.70	63.26	84.96	82.26	14.19	18.74	8.38	6.66	99.20	45.01
1989	27.40	22.29	22.15	37.57	59.79	59.56	80.50	78.10	14.11	17.93	13.31	8.19	98.06	72.36
1990	28.50	16.91	16.68	29.63	54.09	53.32	83.28	86.69	10.04	15.79	8.41	3.30	98.77	108.15
1986-90		21.13	20.91	35.44	59.52	59.31	83.03	80.66	11.81	15.72	12.22	4.74	98.38	65.54

		1986	1987	1988	1989	1990	1986-90
Unit-Years		12	14	11	10	10	57
Maximum Capacity (MW)	Gross:	243	244	243	243	243	243
	Net:	233	234	233	233	233	233
Dependable Capacity (MW)	Gross:	241	242	241	242	242	242
	Net:	231	232	231	232	232	232
Actual Generation (MWh)	Gross:	518,365	445,607	467,677	475,060	330,067	2,036,777
	Net:	490,026	421,306	443,980	452,823	320,377	427,936
Attempted Unit Starts		57.17	43.64	57.36	46.50	24.30	48.18
Actual Unit Starts		55.83	42.93	56.82	45.90	24.00	47.40
Service Hours		3,416.55	3,145.40	3,007.43	3,299.64	2,596.56	3,106.48
Reserve Shutdown Hours		3,968.24	3,730.34	4,456.56	3,751.67	5,136.11	4,171.15
Number of Occurrences		53.83	41.86	69.27	43.90	23.10	48.74
Pumping Hours		.	.	.	.	.	.
Synchronous Condensing Hours		.	.	.	.	.	.
TOTAL AVAILABLE HOURS		7,384.82	6,875.74	7,462.99	7,051.61	7,733.66	7,277.61
Forced Outage Hours		502.51	277.98	487.46	642.36	289.67	416.08
Number of Occurrences		14.87	10.79	12.09	14.10	8.10	12.14
Planned Outages:							
Planned Outage Hours		583.86	1,148.62	648.86	991.44	573.03	785.43
Number of Occurrences		0.92	1.83	1.00	1.80	0.80	[illegible]
Planned Outage Ext. Hours		49.39	282.73	0.21	.	.	[illegible]
Number of Occurrences		0.08	0.21	0.09	.	.	[illegible]
Maintenance Outages:							
Maintenance Outage Hours		226.16	163.67	266.88	155.70	154.72	[illegible]
Number of Occurrences		4.08	3.50	4.27	3.10	2.60	[illegible]
Maintenance Outage Ext. Hours		13.27	11.06	7.76	18.90	8.72	[illegible]
Number of Occurrences		0.58	0.43	0.27	0.70	0.30	[illegible]
TOTAL UNAVAILABLE HOURS		1,375.18	1,884.26	1,321.01	1,708.36	1,026.34	1,487.02
TOTAL PERIOD HOURS		8,760.00	8,760.00	8,784.00	8,760.00	8,760.00	8,764.63
Equiv. Forced Hours		178.58	87.29	170.70	156.56	179.09	145.96
Equiv. Scheduled Hours		41.51	14.28	15.93	21.86	13.56	21.53
Equiv. Forced Hours During RS		56.78	18.61	59.97	56.66	83.06	51.73
TOTAL EQUIVALENT DERATED HOURS		220.09	81.57	186.63	178.44	192.64	167.46

Figure 4-13

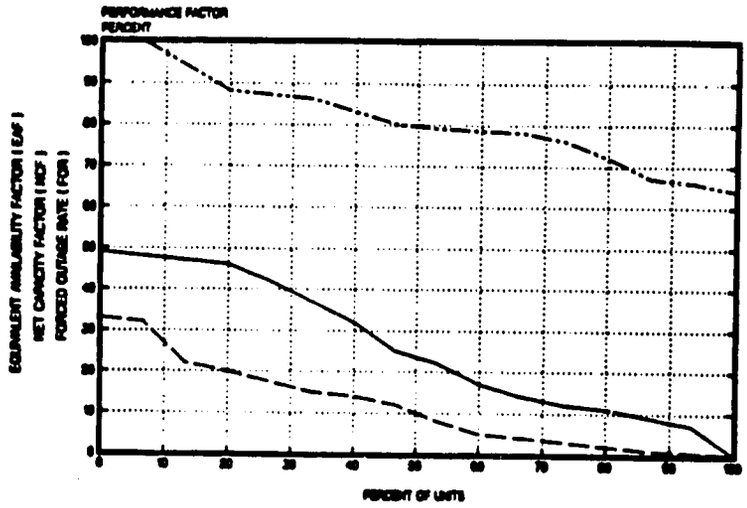
NERC GADS
Generating Availability Report

39

Fossil Units - Oil Primary
200-299 MW 1986-1990

DISTRIBUTION OF FIVE-YEAR AVERAGE (1986-1990)
PERFORMANCE STATISTICS

EAF — NCF — FOR



1986-1990
OUTAGE AND DERATING STATES BY COMPONENT CAUSE CODE CATEGORIES
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE CATEGORIES	FORCED OUTAGES		PLANNED OUTAGES (WITH EXTENSIONS)		MAINTENANCE OUTAGES (WITH EXTENSIONS)		FORCED DERATINGS		SCHEDULED DERATINGS (WITH EXTENSIONS)	
	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	EQUIV HOURS	NUMBER OF OCC	EQUIV HOURS
BOILER	6.30	322.62	0.79	546.09	1.86	123.81	7.96	48.30	0.62	3.91
BALANCE OF PLANT	1.91	41.24	0.19	99.12	0.96	61.39	11.89	84.54	4.49	16.17
STEAM TURBINE	1.26	44.14	0.28	207.77	0.53	23.57	0.47	9.16	0.04	1.41
GENERATOR	0.46	6.36	0.02	11.71	0.14	6.02	0.44	1.16	0.00	0.00
POLLUTION CNTL.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EXTERNAL	0.11	0.62	0.00	0.00	0.00	0.00	0.02	0.06	0.00	0.00
REGULATORY	0.04	0.49	0.00	0.00	0.04	0.83	0.06	2.44	0.00	0.00
PERSONNEL ERRORS	0.07	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PERFORMANCE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

1986-1990
TOP 25 SYSTEM/COMPONENT CAUSE CODES
FORCED AND SCHEDULED OUTAGES AND DERATINGS
BY AVERAGE MWH PER UNIT-YEAR
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE	AVG NO. OCC PER UNIT-YR	AVERAGE MWH PER UNIT-YR	AVERAGE MWH PER OCCURRENCE	SYSTEM/COMPONENT CAUSE CODE DESCRIPTION
1800	0.40	74491	184606	BOILER OVERHAUL
1000	3.23	44700	13847	FURNACE WALL
4400	0.16	42917	271809	MAJOR TURBINE OVERHAUL
1810	0.42	28661	67806	BOILER INSPECTIONS
1340	0.07	14267	203161	TUBE MODIFICATIONS (INCLUDING ADDITION AND REMOVAL OF TUBES)
3344	0.16	9741	61696	DEAERATOR (INCLUDING LEVEL CONTROL)
1060	1.06	9404	8834	ECONOMIZER
3248	0.07	8820	78869	OTHER COOLING TOWER PROBLEMS
3110	1.47	6131	3482	CONDENSER TUBE LEAKS
1050	0.26	4669	17741	SECOND SUPERHEATER
0640	0.06	4623	85838	REHEAT STEAM PIPING UP TO TURBINE STOP VALVES
4240	0.16	4460	28376	BEARINGS
1090	0.37	4271	11562	OTHER BOILER TUBE LEAKS
3410	0.61	4222	6875	FEEDWATER PUMP
3112	4.60	3444	749	CONDENSER TUBE FOULING TUBE SIDE
3441	0.37	3316	9000	OTHER HIGH PRESSURE HEATER PROBLEMS
1040	0.36	3199	8116	FIRST SUPERHEATER
4420	0.23	3170	13897	VIBRATION OF THE TURBINE GENERATOR UNIT
3113	3.66	3153	864	CONDENSER TUBE AND WATER BOX CLEANING
3440	0.75	3069	4069	HIGH PRESSURE HEATER TUBE LEAKS
3411	0.14	2948	21007	FEEDWATER PUMP DRIVE - MOTOR
1806	0.14	2797	19930	FIRESIDE CLEANING
4830	0.02	2684	153666	MAJOR OVERHAUL
3662	0.02	2692	133445	OTHER VOLTAGE CONDUCTORS AND BUSES
1430	0.07	2636	37643	AIR SUPPLY DUCTS

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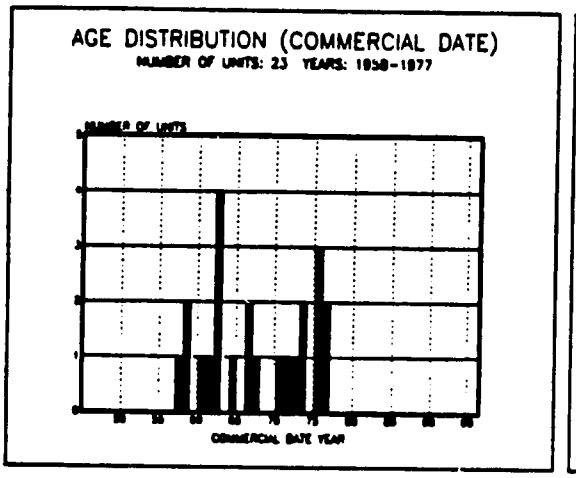
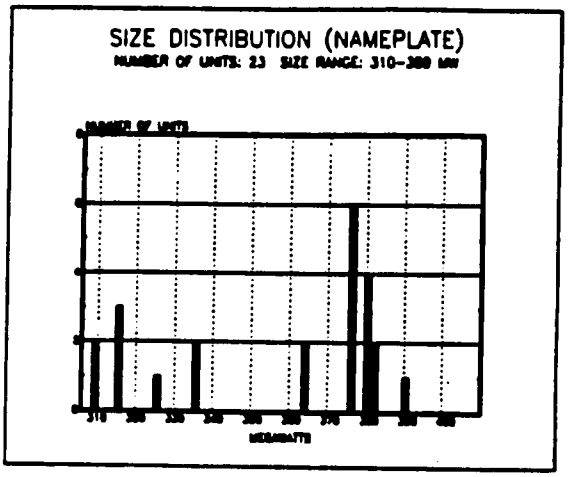
Figure 4-14

- 40

Fossil Units - Oil Primary
300-399 MW 1986-1990

NUMBER OF UTILITIES :	10
NUMBER OF UNITS :	23
NUMBER OF UNIT-YEARS:	109





1986-1990
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	SCF	NCF	OF	EFOR	NOF	AF	EAF	POR	EPOR	EUF	POF	SA	ART
1986	17.52	36.84	36.60	58.56	61.61	61.33	82.03	78.73	7.61	12.41	13.00	4.00	98.57	93.35
1987	18.52	39.39	39.13	60.93	63.77	63.30	81.55	78.85	7.37	11.13	13.59	4.85	100.00	111.97
1988	19.52	44.79	44.50	63.96	69.34	68.86	82.36	80.16	7.77	10.60	12.25	5.38	99.87	145.46
1989	21.00	48.50	47.52	67.30	71.35	69.90	84.42	81.88	4.82	7.67	12.17	3.41	99.74	167.82
1990	22.00	37.49	37.16	55.47	68.84	66.21	76.67	74.67	7.50	9.80	16.63	4.50	46.78	142.75
1986-90		41.46	41.03	61.25	66.86	66.13	81.42	78.77	6.98	10.29	13.98	4.60	84.60	128.40

		1986	1987	1988	1989	1990	1986-90
Unit-Years	:	21	21	21	23	23	109
Maximum Capacity (MW)	Gross:	375	376	376	374	376	375
	Net:	361	362	362	361	363	362
Dependable Capacity (MW)	Gross:	374	376	376	373	373	374
	Net:	360	362	362	359	359	361
Actual Generation (MWh)	Gross:	1,211,114	1,299,565	1,480,726	1,592,143	1,236,670	1,365,699
	Net:	1,159,939	1,243,741	1,418,205	1,504,612	1,182,384	1,303,327
Attempted Unit Starts	:	58.18	47.67	38.67	35.22	68.76	49.42
Actual Unit Starts	:	54.95	47.67	38.62	36.13	34.04	41.61
Service Hours	:	5,129.70	5,337.75	5,617.04	5,696.54	4,650.07	5,368.32
Reserve Shutdown Hours	:	2,056.26	1,806.55	1,616.29	1,499.55	1,674.71	1,757.60
Number of Occurrences	:	39.14	36.57	26.19	36.04	22.17	29.61
Pumping Hours	:	.	.	.	.	.	.
Synchronous Condensing Hours	:	.	.	.	.	.	.
TOTAL AVAILABLE HOURS	:	7,185.96	7,144.30	7,234.13	7,305.09	6,733.78	7,126.93
Forced Outage Hours	:	435.11	425.07	473.42	299.06	384.23	403.23
Number of Occurrences	:	14.16	12.38	12.29	10.66	9.17	11.67
Planned Outages:							
Planned Outage Hours	:	950.51	899.46	764.12	911.36	1,339.56	878.66
Number of Occurrences	:	1.67	1.67	1.86	1.83	1.91	1.78
Planned Outage Ext. Hours	:	43.82	46.31	55.68	10.72	50.41	40.99
Number of Occurrences	:	0.29	0.10	0.24	0.13	0.30	0.21
Maintenance Outages:							
Maintenance Outage Hours	:	141.87	232.85	255.86	143.77	242.02	202.85
Number of Occurrences	:	2.46	3.29	2.96	3.22	3.09	3.01
Maintenance Outage Ext. Hours	:	2.63	12.16	0.80	.	.	3.01
Number of Occurrences	:	0.19	0.38	0.08	.	.	0.12
TOTAL UNAVAILABLE HOURS	:	1,574.04	1,615.89	1,549.87	1,364.61	2,026.22	1,626.73
TOTAL PERIOD HOURS	:	8,760.00	8,760.19	8,784.00	8,760.00	8,760.00	8,754.66
Equiv. Forced Hours	:	261.56	220.41	173.76	189.26	126.77	183.02
Equiv. Scheduled Hours	:	10.32	16.46	19.51	19.93	17.59	18.04
Equiv. Forced Hours During RS	:	47.66	32.41	11.00	9.96	9.05	21.73
TOTAL EQUIVALENT DERATED HOURS	:	271.88	236.89	193.27	209.21	144.36	209.86

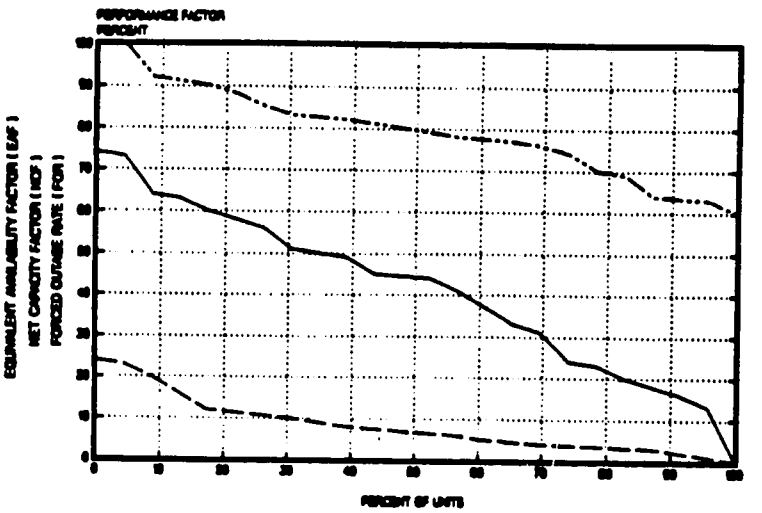
Figure 4-15

NERC GADS
Generating Availability Report

Fossil Units - Oil Primary
300-399 MW 1986-1990

DISTRIBUTION OF FIVE-YEAR AVERAGE (1986-1990)
PERFORMANCE STATISTICS

EAF — NCF — FOR



1986-1990
OUTAGE AND DERATING STATES BY COMPONENT CAUSE CODE CATEGORIES
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE CATEGORIES	FORCED OUTAGES		PLANNED OUTAGES (WITH EXTENSIONS)		MAINTENANCE OUTAGES (WITH EXTENSIONS)		FORCED DERATINGS		SCHEDULED DERATINGS (WITH EXTENSIONS)	
	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	OUTAGE HOURS	NUMBER OF OCC	EQUIV HOURS	NUMBER OF OCC	EQUIV HOURS
BOILER	6.22	200.97	1.03	533.96	1.60	106.39	14.66	66.97	0.94	4.92
BALANCE OF PLANT	2.33	46.17	0.12	19.02	0.59	20.06	16.23	69.67	0.70	6.36
STEAM TURBINE	1.48	60.69	0.58	392.64	0.39	62.99	1.43	25.73	0.25	1.00
GENERATOR	1.14	87.98	0.06	36.74	0.44	17.42	0.18	1.29	0.04	0.23
POLLUTION CNTL.	0.00	0.00	0.02	32.92	0.00	0.00	2.71	8.99	1.08	3.99
EXTERNAL	0.07	1.61	0.00	0.00	0.00	0.00	0.26	0.43	0.01	0.06
REGULATORY	0.06	0.14	0.01	4.37	0.00	0.00	0.25	0.28	0.00	0.00
PERSONNEL ERRORS	0.39	5.74	0.00	0.00	0.00	0.00	0.06	0.09	0.00	0.00
PERFORMANCE	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.12	0.02	0.26

1986-1990
TOP 25 SYSTEM/COMPONENT CAUSE CODES
FORCED AND SCHEDULED OUTAGES AND DERATINGS
BY AVERAGE EMH PER UNIT-YEAR
(PRIMARY CAUSE OF OUTAGE OR DERATING)

CAUSE CODE	AVG NO. OCC PER UNIT-YR	AVERAGE EMH PER UNIT-YR	AVERAGE EMH PER OUTAGE	SYSTEM/COMPONENT CAUSE CODE DESCRIPTION
1800	0.83	135407	163993	BOILER OVERHAUL
4400	0.61	120890	200687	MAJOR TURBINE OVERHAUL
1000	3.49	58115	16670	FURNACE WALL
1810	0.31	35084	114976	BOILER INSPECTIONS
4520	0.06	18046	303399	STATOR WINDINGS, BUSHINGS, AND TERMINALS
4280	0.09	17583	191436	OTHER LUBE OIL SYSTEM PROBLEMS
8520	0.01	11404	1242994	MECHANICAL PRECIPITATOR PROBLEMS
4090	0.38	10279	28728	OTHER HIGH PRESSURE TURBINE PROBLEMS
4830	0.04	9480	258342	MAJOR OVERHAUL
1080	0.98	9374	9540	ECONOMIZER
3410	0.84	9066	11087	FEEDWATER PUMP
4260	0.18	7707	42004	MAIN STOP VALVES
1060	0.43	7707	17873	SECOND SUPERHEATER
1040	0.53	7668	14467	FIRST SUPERHEATER
3520	0.28	7062	24832	MAIN TRANSFORMER
3090	0.87	6258	9345	OTHER MISCELLANEOUS BALANCE OF PLANT PROBLEMS
4012	0.02	6210	338467	BUCKETS OR BLADES
1480	1.36	6080	4362	PRIMARY AIR HEATER (REGENERATIVE)
1810	0.09	5720	62347	WATER SIDE CLEANING (ACID CLEANING)
0740	2.81	5429	1934	BOILER RECIRCULATION PUMPS
1205	0.19	5407	28067	FIRESIDE CLEANING
4500	0.06	4968	108078	ROTOR WINDINGS
8560	3.67	4771	1300	ELECTROSTATIC PRECIPITATOR PROBLEMS
1590	0.02	4770	259863	STACKS
0840	0.05	4284	93401	REHEAT STEAM PIPING UP TO TURBINE STOP VALVES

NERC GADS
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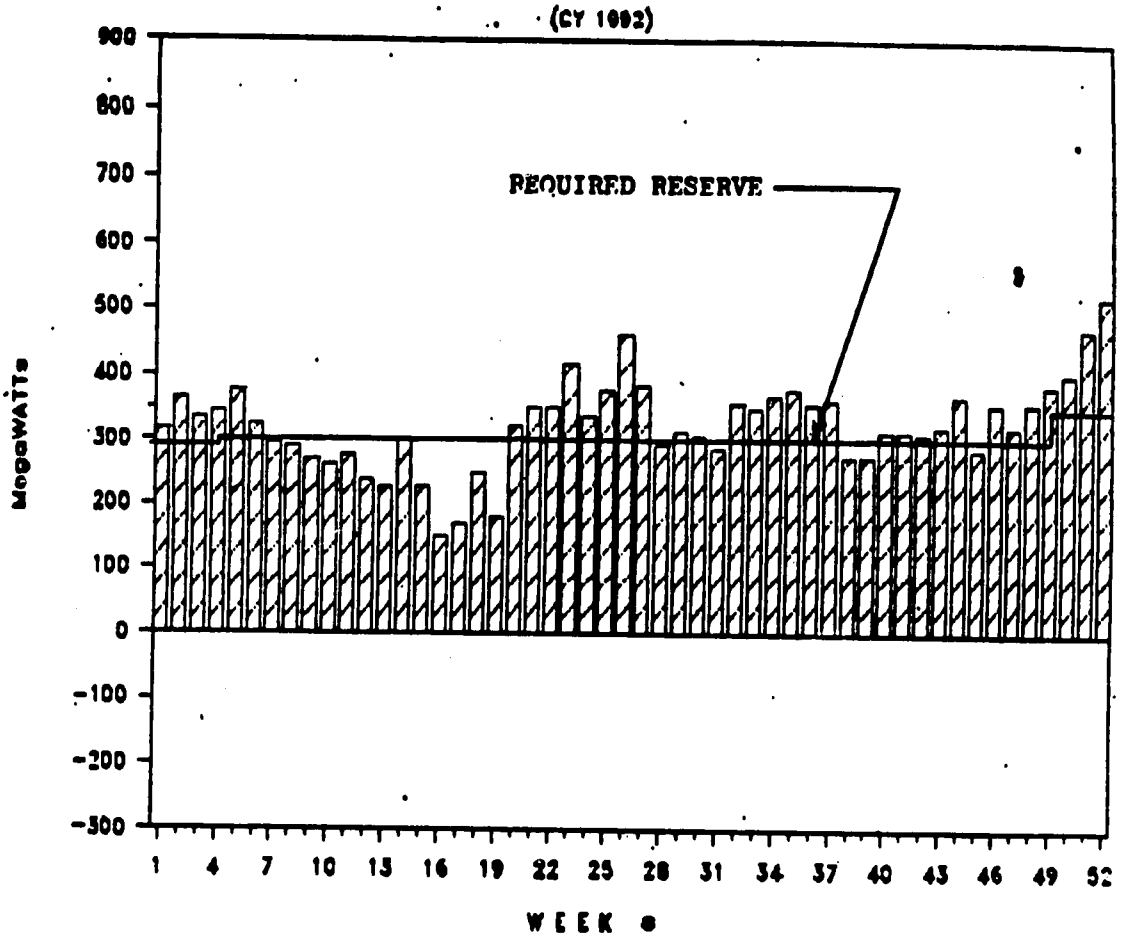
Figure 4-16

- 42

SYSTEM RESERVE PROFILE

(CY 1992)



SYSTEM PEAK = 3250 MW
% GR. = 6.5 %

ADDITIONAL PLANTS:

1. NAVOTAS UNIT 5 (30 MW) = APR. 1992
2. LAND BASE GT (30 MW) = JUL. 1992
3. BATAAN CC STAGE 1(3 x 70 MW) = DEC.1992

TOTAL = 270 MW

Figure 4-17

43

Section 5

Investigation of Originally Specified Problems

5.1 THERMAL PLANT CHEMICAL CONTROL

NPC has concerns about the effectiveness of the water treatment programs at their coal and oil fired thermal generating plants. Data collected at the NPC offices indicated that load restrictions at the plants may be related to water treatment problems. The Malaya and Batangas plants were visited and data collected to evaluate the water treatment practices and to recommend changes. Significant other water treatment problems exist at the other plants which were not investigated as shown by Figure 4-1. These other facilities should be evaluated by on-site investigations to identify all water treatment related problems and to make recommendations for operating improvement.

5.1.1 Malaya

The Malaya Station, in the past, had serious problems with their water treatment control practices as reported in the JICA report of their investigation in 1982. Many of the recommendations made in the report seem to have been implemented which has in general improved the practices. The chemical control limits and normal operating concentrations are given in Figure 5-1. Serious problems exist with the operation of the condensate polishing system of Unit 1 which should be corrected before they lead to major equipment failure.

Unit 1 is a subcritical once-through unit with externally regenerated deep beds. The regeneration system includes the provisions for operation beyond the ammonia break through. The present sodium effluent limit is less than 10 ppb. Sodium concentrations of up to 17 ppb were observed. By operating the polishers with high sodium effluent concentrations, the low pressure turbine is exposed to a caustic environment which may lead to blade failure. Since Unit 1 has experienced low pressure turbine blade failures, the method of polisher operation must be suspected as a contributing factor. Polisher operation should be improved and a new sodium effluent limit of less than 2 ppb should be adopted and adhered to. The Sucat once-through units with condensate polishers have also experienced low pressure turbine blade failures. These failures, and the water treatment practices at Sucat, should be investigated in detail.

44

The chemical limits of both Malaya units are typical for the types of units and the metallurgy in use (see Figure 5-2). Unit 2, which is a drum type unit that is intended to be on phosphate internal boiler chemical control, has not been fed sodium phosphate for over one year because the phosphate pumps are inoperative. Without phosphates in the boiler and with the occurrence of a major condenser tube leak, serious boiler out of specification chemistry conditions may occur which can contribute to boiler tube failures. The phosphate pumps should be repaired immediately and the internal phosphate limits maintained under all operating conditions.

The boiler waterwall and superheater tube thinning does not appear to have been caused by improper water treatment practices. These problems are, in part, related to fireside fuel slagging problems which are discussed in detail in Sections 5.3 and 6.1.

Unit 2 does not have a dedicated on-line continuous monitoring sample panel. A panel should be provided to detect and alarm any out of specification operating conditions. The flame spectrophotometer in the laboratory is out of service. The instrument should be repaired as no method exists in the laboratory for determining sodium concentrations and for verifying the accuracy of the on-line monitor in service with the condensate polishers. The continuous monitors of Unit 1 should be repaired and upgraded as required.

The make-up water treatment system appears to be in good operating condition and produces demineralized water within specification. However, output is limited by the capacity of the water well. To avoid any future problems related to a shortage of demineralized water, the water supply capacity should be increased either by development of another well or by developing a lake water supply. If the lake water is to be used, the quality must be evaluated and any required pretreatment equipment installed. The procedures for chemical cleaning, system layup and system startup in use are technically proper and will provide the necessary system protection.

Generic water treatment chemicals are used at Malaya and at Batangas. The specifications for the chemicals should be reviewed and revised to assure that the proper quality is being purchased. Also the supply should be bid competitively on an annual basis to assure that the most economical supply is being utilized.

45

5.1.2 Batangas

Batangas Unit 1 is a drum unit with the metallurgy shown in Figure 5-3. The chemical control limits are shown in Figure 5-4. Chemical logs indicate that except during condenser tube leaks, the limits are normally maintained. Recent condenser tube failures have contributed to problems in meeting the boiler chemistry limits. However, thinning of boiler superheater and reheater tubes do not appear to be the result of water side chemistry, but are, in part, caused by fireside tube erosion associated with slag formation and by tube cutting by sootblowing operations. These tube failure mechanisms are discussed in more detail in Sections 5.4 and 6.1.

Condenser tube failures are a result of inlet end erosion caused by coal fines in the cooling water and appear to be a one time problem. NPC is solving the problem by installing inlet end tube inserts.

Problems observed at Batangas, other than the condenser tube failures, are related to the make-up demineralizer design and operation and the chemical control units used for the boiler water. The make-up demineralizer and pretreatment equipment receives its water supply from a river and from a well. The pretreatment system design is inadequate for good suspended solids and organic removal for protection of the ion exchange system. Reduced demineralizer runs are being experienced as a result of high filter and demineralizer vessel pressure drop from silt entering the system. Algae was observed growing in sight glasses and will eventually foul the ion exchange resins. An evaluation of the demineralizer system design and operation should be performed and modifications made to resolve these problems.

Batangas is a sea water cooled plant and the boiler water chemical control limits should be modified to provide protection from condenser leaks. There are presently no limits for chloride in the boiler water and no procedures have been established for boiler operational changes with chloride concentrations in excess of the limits. A normal operating limit of 0.5 ppm chloride should be established and various action level chloride concentrations should be established to modify operation as the chloride concentrations increase. Coordinated phosphate limits of 5 to 10 ppm phosphate in the boiler should be established

46

to provide better protection. The present phosphate limit of 0.3 ppm provides inadequate protection. Under no circumstances should the system be operated with all volatile chemical control as no chemical buffering protection will be available for boiler tubes in case of a condenser tube leak.

5.1.3 Recommendations

The following recommendations are made for immediate implementation to avoid major equipment problems:

a. A detailed evaluation should be made of the Sucat, Bataan, Manila and Cebu water treatment practices to identify problem areas and to recommend operational and equipment changes. Information available indicates that there may be significant water treatment problems at these stations.

b. The polisher operation and resin volumes at Malaya Unit 1 should be modified to permit operation at less than 2 ppb sodium in the effluent. Changes may be required at Sucat to attain the same goals. The present operation at both stations may have contributed to low pressure turbine blade problems.

c. The on-line chemical monitoring and laboratory equipment at Malaya should be upgraded to provide the means for assuring that the limits are met.

d. The Malaya 2 sodium phosphate pumps should be repaired and phosphate feed to the boiler maintained under all operating conditions.

e. The Batangas make-up demineralizer system should be evaluated in detail and recommendations made for correcting problems with poor silt and organic removal.

f. Chemical limits should be modified at Batangas to add a chloride limit and to increase phosphate concentrations to provide better condenser leak protection.

g. New specifications should be written for the water treatment chemicals at all plants. The supply of chemicals should be bid competitively on an annual basis.

5.2 GEOTHERMAL PLANT CHEMICAL CONTROL

NPC has a total geothermal generation capacity of 891 MW provided by four (4) plants as shown on Figure 5-5. The history of the chemical control programs and the present practices at each station are contained in Appendix C.

The units utilize direct contact condensers and the cooling water treatment goals are to minimize the corrosion of carbon steel cooling system components (<15 mpy), reduce deposition in the lube oil and hydrogen gas coolers and to control biological growth. Non-proprietary chemicals; caustic, lime and calcium hypochlorite; have been used with and without proprietary chemicals to attain the treatment goals. The proprietary chemical suppliers have included Nalco, Drew/PIPC, Atom Chemicals, Peter Blaise, Mainchem, Phyrox, Maxwell, Bauer, Enertec, Calgon, Kemichroff, and Houseman.

Various blends of chemicals have been tested at the four stations with a variety of results. Different chemicals and chemical combinations may be required at each station depending on the cooling water chemistry which determines the corrosion rates and the potential for the support of biological growth. The chemical blends presently in use at each station are shown on Figure 5-6 with the resulting carbon steel corrosion rates and the degree of success of biological growth control.

General recommendations for each station should not be made with the data provided without a more detailed evaluation of specific, site-collected, data. As a part of this report, a detailed evaluation was made for the Mak-Ban Station. However, it is apparent from the data of Appendix A that the present chemical treatment programs at the Palinpinon Station and Tiwi Units 2, 3 and 6 do not meet the treatment goals. Data collection and evaluation specifically for the Palinpinon, Tongonan and Tiwi Stations are recommended as further work for optimizing the geothermal chemical control programs. These evaluations should be made as soon as possible to provide the required protection for the units.

48

5.2.1 Mak-Ban Geothermal Station

The Mak-Ban Station, as at the other stations, has tested a broad range of proprietary and non-proprietary chemicals (Appendix A). The most successful blend, which meets the goals of less than 15 mils per year (mpy) carbon steel corrosion, minimal heat exchanger deposition and good biological growth control is presently in use. The chemicals used in Units 1 through 4 are caustic (NAOH) and proprietary corrosion inhibitors and biocides from Mainchem Chemical Company. Units 5 and 6 are obtaining the same results with caustic and chemicals from the Phyrox Chemical Company. The Phyrox chemicals are of the same basic composition as the Mainchem chemicals.

Corrosion rates approaching 5 mpy are attained. Biological growth is well controlled as indicated by dip slides and visual observation. Quarterly unit shut-downs are required for 6 to 8 hours to remove by brushes soft, non-temperature related deposits from the hydrogen and turbine lube oil coolers. A single 100% capacity hydrogen cooler is provided for each generating unit which requires a unit shut down to perform the cleaning.

Unit shut-downs related to chemical control, in addition to the quarterly cleaning requirements, are for annual descaling of the turbines and for piping replacement. Piping replacement has normally only been required at the discharge of the hotwell pumps. This piping is now being replaced with fiberglass on most of the units.

The units have been tested with supplemental lime for pH and calcium residual control. Lime usage has resulted in an increase in the cleaning requirement to every month for the hydrogen coolers and the deposition of three times the amount of sludge in the cooling tower basins than without the use of lime. Annual sludge generation rates of 80 to 100 - fifty five gallon drums per unit were reported when lime was used.

Mak-Ban is able to meet their treatment goals with the present chemical programs. However, chemical procurement problems have prevented continuing maintenance of a proven effective program and may in the future restrict continuance of the program. Because of procurement procedural changes, Units 3 through 6 were without chemicals from September through November 1991. Procurement procedures should permit bidding

49

by only proven suppliers and contracts should be awarded for one year to assure that no break in the supply of chemicals is experienced.

5.2.2 Recommendations

The following recommendations are made for immediate implementation to assure that all geothermal plants are on a chemical treatment program that meets the treatment goals and that treatment is maintained continuously.

a. The Palinpinon units and Tiwi units 2, 3 and 6 have excessive corrosion rates and poor algae control. Investigations at these plants and the Tongonan Station should be conducted similar to that done for the Mak-Ban Station. The results of the investigations should be used to assist the plants in establishing a treatment program which will permit all units to meet the treatment goals.

b. The use of lime is required by the Procurement Department under certain conditions as defined by the memorandum included as Appendix C. Lime is a difficult chemical to dissolve and feed properly. It's use also results in increased system deposition which can increase the need for unit outages for cleaning and in an increased cost for sludge disposal. Test results indicate that no added benefit in corrosion protection is obtained by the use of lime. As demonstrated at Mak-Ban, caustic alone or in combination with proprietary corrosion inhibitors provides good corrosion inhibition without the use of lime. Any additional costs for caustic and proprietary chemical usage should be more than compensated for by the reduced costs for unit outages and sludge disposal associated with the use of lime. It is recommended that lime not be required for corrosion protection at any of the geothermal units.

50

5.3 FUEL ADDITIVE PROGRAM

NPC currently uses poor quality fuel oils with high vanadium, sodium and sulfur concentrations. Combustion of these fuels can result in furnace reheater and superheater tube fouling and corrosion as well as boiler cold end corrosion. Boiler tube thinning problems which may be related to poor fuel oil quality are being experienced at the Malaya and Sucat stations. The Malaya problems are related, in part, to the use of poor quality fuel oil. The problems at Sucat may also result from the same cause, but this must be confirmed by a more complete on-site investigation. At both stations, the tube thinning has resulted in load limitations of 25% or greater. The use of fuel oil chemical additives is being tested on Malaya 2 as a possible corrective measure which can be used at both stations to control boiler tube thinning.

A related problem, which is caused by fuel quality, is increased corrosion on the cold end of the boilers; in the air preheaters, ducts and stacks. This low temperature corrosion is caused by three phenomena: (1) vanadium in oil-ash deposits is a good catalyst for the conversion of SO_2 to SO_3; (2) ash particles in the flue gas reduce the amount of SO_3 vapor in the flue gas; and (3) the ash lacks the ability to neutralize any acid deposits on equipment surfaces. The Malaya units, and probably other boilers on the system, have significant corrosion problems on the cold end. Fuel oil additives are also a method of reducing and controlling this low temperature sulfuric acid corrosion. The additives react with the SO_3 to form sulfates. By removing the SO_3 gas, the dewpoint of the flue gases are sufficiently reduced to protect the metallic surfaces. The sulfate compounds formed are relatively dry and easily removed by normal sootblowing.

Batangas 1 has reported tube thinning problems that are related to erosion as a result of slagging and sootblower steam cutting.

5.3.1 Malaya

Malaya 1 and 2 are operating at reduced steam pressure to protect weak boiler tubes. Weak secondary superheater tubes are reported in Malaya 1 and the maximum steam pressure has peen reduced to 2100 psi to prevent tube rupture (design is 2700 psi).

Malaya 2 maximum steam pressure has been reduced to 140 kg/cm^2 (design is 175 kg/cm^2) to protect weak boiler waterwall tubes. Both units have reported excessive cold end corrosion of the air preheaters, gas ducts and stacks. The fuel is a mixture of residual oil and Bunker C fuel oil (Figure 5-7).

To correct these problems, a fuel and flue gas dual feed additive test program was begun on September 18, 1991 in Malaya Unit 2. The products being fed and system monitoring are provided by Centrosphere Industrial Corporation under the supervision of Apollo Technologies Corporation. The test is to continue for a period of 4 months.

The test is based upon the use of two chemical additives: (1) a slurry containing a mixture of combustion catalysts and ash modifiers injected into the fuel oil; and (2) an acid neutralizing powder (MgO) injected into the flue gas stream at the inlet of the air preheaters. Test results through December, 1991 are positive even though the boiler was not clean at the start of the test. Significant reductions in the particulate emissions, the combustible material in the ash and the ash free acidity have been obtained. The pH of the ash has also been increased from 2.4 to 4.6. Visual observations indicate an improvement in the nature and a reduction in the amount of the deposits on the boiler tubes.

The impact of the chemical usage on the boiler cold end problems has been impressive. The air heaters have remained clean. Corrosion rates in the air heaters and gas ducts have been significantly reduced.

Based upon the test results through this time period, fuel oil additive use appears to offer one potential solution to the tube thinning and cold end corrosion being experienced at Malaya. The product in use, although effective, may not be the most economical product available. The Apollo chemical costs for Malaya 1 and 2 at the present feed rates will be approximately $500,000 per month with 76% of the cost being for treatment of the boiler cold end corrosion.

Because of the cost and the significance of the program in returning lost generating capacity to the NPC system, an independent evaluation of the test results and the approach to future chemical usage should be obtained. The independent party should, as a part of the

. 52

program, determine the need for chemical usage at Sucat and Batangas and the approach to implementing these programs. The independent scope of work should include:

1. Evaluate the results of the Malaya 2 tests.

2. Investigate with other suppliers the availability and cost for equivalent chemicals.

3. Develop a long term program for chemical usage at Malaya and other units, if needed.

4. Develop specifications for product supply.

5. Assist NPC in competitively obtaining a supplier.

6. Provide follow-up assistance in resolving program problems and for continuing results review.

5.3 2 Recommendations

a. A detailed evaluation of the fuel related problems at the Sucat Station, which has resulted in load restrictions due to boiler tube thinning, should be performed. This evaluation should be conducted in conjunction with the water chemistry evaluation at Sucat to determine if the tube wall thinning has been caused by fireside or waterside operations.

b. An independent review of the Malaya 2 fuel additive test results should be conducted. This evaluation should not only include the results of the additive usage, but an evaluation of availability of similar products with required dosages and costs. The evaluation should include an outline for a future program to utilize additives in the units where tube thinning exists, and for the selection of comparable additives on a competitive basis.

5.4 BATANGAS COAL HANDLING SYSTEM

Batangas 1 is a 300 MW coal-fired plant that went into commercial operation in 1984. The plant uses a Foster Wheeler, 2400 psig, drum-type boiler and has four pulverizers. Coal is received by ship and is transferred to the plant using a coal storage yard with three active coal stacks, two stacker reclaimers and a belt conveyor system The storage yard conveyor system converges to a single transfer point from which the coal is conveyed on a single belt to a crusher house and then into four raw coal bunkers. Each bunker feeds a pulverizer that, in turn, feeds one of the four levels of burners in the boiler.

Since beginning operation in 1984, the plant has been plagued with coal related problems including: coal handling equipment design problems and failures, fugitive coal smoke and dust, very poor coal quality, boiler slagging and fouling, poor combustion and boiler tube failures due to erosion and overheating.

The problems experienced by the plant are very complex and are summarized as follows:

- Coal Quality. The Philippine coal (Semirara Mine) that is being delivered to the plant is of much poorer quality than that for which the plant was designed. Apparently, the mine was not fully characterized and the boiler was designed to specifications based on limited information. When firing the Semirara coal only, the boiler suffers severe slagging and fouling that limits the maximum load to approximately 220 MW. To reduce this problem and to achieve full load, the plant is using Australian coal that is burned in a 50/50 mixture. This approach has been used since 1985. While the Australian coal has a low slagging and fouling potential, it is high in silica and causes erosion problems in the superheaters and reheaters.

- Coal Handling. The Semirara coal presently being used causes many coal handling problems. During the rainy season, total moisture in the coal can reach 33% and the coal turns into a slurry making it impossible to handle. When the Semirara coal becomes very wet the plant uses Australian coal alone. In the dry season, since the coal is pyrophoric , it smokes extensively during unloading and in the coal pile. Also, it creates a fugitive dust problem that causes problems with the local community.

54

A number of coal handling equipment problems have been experienced requiring design changes and equipment modifications. The most notable of these was a problem with coal silos in which the coal would bridge and cause the pulverizers to starve. Equipment modifications have been made but problems still exist in the silo feed system.

To achieve the 50/50 blend of Semirara and Australian coals, the plant uses both stacker/reclaimers operating simultaneously to feed coal from two active piles to the single transfer point in the conveyor system. The blended coal is then fed to all four rows of burners.

- Boiler Tube Failures. Even though the unit is relatively new, a significant number of boiler tube failures have occurred. Failure incidents have increased rapidly in the past two years. These have been mostly in the superheater and reheater sections. The primary cause of these failures is erosion due to excessive use of sootblowers to reduce the slagging and fouling problems. The unit is presently de-rated by 40 MW due to weak superheater and reheater tubes. This problem can be expected to continue throughout the life of the unit.

  In addition to the sootblower erosion problem, fouling causes gas channelling that increases velocities through the superheater and reheater sections. With the use of the highly erosive Australian coal, tube failure can be expected in these regions. There is also evidence of overheating failures in the reheater and superheater sections caused by overfiring of the boiler. Tube leaks have also occurred in the economizer caused by erosion.

- The 80/20 Scheme. In August 1980, an $8 million renovation contract was awarded to make modifications to the coal handling system. The objectives of this work were to eliminate various equipment problems and to allow an 80/20 blend of Philippine/Australian coal to be burned (the 80/20 Scheme), thereby increasing the use of Philippine coals. Modifications were made to the coal supply system that would allow Australian coal to be fed to the lowest of the four burner rows (20% of

55

coal feed) and Semirara coal to be fed to the top three burner rows (80% of coal feed). The work began in October 1990 and was completed in April 1991.

In May 1991, a 72 hour acceptance test of the 80/20 Scheme was "successfully" completed by Foster Wheeler and accepted by NPC. However, according to plant personnel, the 80/20 Scheme was only used during the 3 day test and not since. The major reasons for not using the 80/20 Scheme were that the boiler would slag-up heavily and that the use of sootblowers was required at a much higher frequency. Because of the weak state of the superheater and reheater sections it was feared that additional tube failures would occur due to the increased use of sootblowers.

Retubing of sections of the superheaters and reheaters is planned in the next maintenance outage in early 1992 and plant personnel indicate that the 80/20 scheme will be retried after the maintenance outage. From an objective viewpoint it appears unlikely that this approach will be successful in the long-term. The problem of erosion failures in the superheater and reheater sections, will in all likelihood, require the reduction of boiler pressure and a de-rating of the unit may be required.

5.4.1 Recommendations

The coal related problems at Batangas have been chronic and pervasive ever since the unit went into operation. Looking at the present situation and understanding the history, it can be expected that the problems at the plant will continue and indeed may well deteriorate from where they are now. Because the Batangas plant is critical to the operation of the NPC system, it is recommended that a coal system improvement project be initiated in the very near future. It is further recommended that this project be comprehensive and involve all aspects of the problem including: the coal handling system, coal pulverizers and burners, boiler combustion and combustion control, boiler slagging and fouling and boiler tube failures.

This comprehensive approach is required because changes to one part of the coal system strongly affect other parts of the system and may have a major negative effect on boiler reliability. A good example of this is the 80/20 scheme. While utilizing 80% of Semirara

90

coal may make sense from the viewpoint of maximizing the use of indigenous coal, the present boiler design may not be capable of using this much Semirara coal and operating in the reliable manner required by the system. The use of 80% Semirara will cause de-ratings and lost capacity. Therefore, the coal system improvement project must balance all of the different factors in the coal system and produce an optimum solution. Some of the factors that must be considered are as follows:

- The economics of using indigenous coal versus Australian coal and the need to use this coal,

- The ability of the present boiler design to burn the coals available without causing major reliability problems in the form of slagging and fouling and boiler tube failures, etc., and their affect on boiler efficiency,

- Changes required to the coal handling system to properly handle Semirara coal especially when it is very wet and when it is very dry,

- The ability of the pulverizers to grind the coal from a capacity and a reliability standpoint, and the ability of the burners and combustion control system to burn the coal from a reliability and an efficiency standpoint,

- The effectiveness of the 80/20 Scheme and the changes required to maximize the utilization of Semirara coal while maintaining adequate reliability and efficiency in the boiler,

- The proper ratio in which to burn Semirara coal and Australian coal taking into account all of the foregoing factors,

- A general evaluation of the adequacy of auxiliary equipment including fans, air heaters, particulate collection and ash handling,

- Changes required to minimize the fugitive dust and smoke problem,

- Methods required to minimize the incidents of boiler tube failures due to erosion and overheating, etc. in the superheater, reheater, economizer and water-wall sections,

- Operating and maintenance changes required for the boiler, coal handling system and auxiliaries to maximize reliability and efficiency.

- Training required for plant personnel to improve operation and maintenance,

Due to the complexity of this problem a 4-phased approach is recommended as follows:

5.4.1.1 Batangas Coal System Improvement Project

The goal is to develop and execute a program of capital, operational and maintenance refinements to the Batangas I coal system to improve the availability and efficiency of the plant in the most cost effective manner and in line with the needs of the NPC generating system.

5.4.1.2 Phase 1. Coal System Improvement Program Plan Development

Phase I of the program will develop an overall plan for the 4-phase program that will include: program scope-of-work, program team development, cost estimates and program schedule. Recommendations will be provided for operational and maintenance changes or minor capital improvement projects that can be implemented with an immediate positive impact on operations. Major improvements will be identified for evaluation in Phase II.

5.4.1.3 Phase II. Coal System Engineering and Economic Evaluation

The Phase II objective is to perform an engineering and economic evaluation of the coal system improvements identified in Phase I and produce a plan that identifies and justifies required plant improvement projects.

A Phase II report will be issued that will contain findings, recommended improvement projects, cost estimates and a proposed implementation plan for Phase III.

5.4.1.4 Phase III. Detailed Design Engineering, Procedures Development and Training Requirements

The scope of Phase III will depend directly on the outcome of Phase II. Implementation of the recommendations from Phase II will include: engineering design, program management and planning, drawing production and verification, specification production, equipment procurement, development of operational and maintenance procedures, development of training programs and planning for Phase IV.

5.4.1.5 Phase IV. Plant Modification and Equipment Verification

Phase IV will involve the modification of equipment, required construction activities, plant restart, equipment verification, operator training, implementation of improved O&M procedures and construction management.

54

Figure 5-1
Chemical Limits and Normal Operating Concentrations
Malaya Station

	Unit 1		Unit 2	
	Limit	Normal Concentration	Limit	Normal Concentration
Feedwater				
pH	9.2 -9.4	9.2	9.2 - 9.4	9.2
Oxygen, ppb	<7	<7	<7	<7
Copper, ppb	<2	–	<5	–
Iron, ppb	<10	–	<10	–
Hydrazine, ppb	<60	50-60	<60	50-60
Cation Conductivity, μS/cm	<0.3	<0.2	<0.3	<0.3
Silica, ppb	<20	<10	–	<12
Sodium, ppb	<10	<10*	–	–
Boiler Water				
Phosphate, ppm			1-2	**
Silica, ppm			<0.2	<0.2
Conductivity, μS/cm			20	<10
pH			9.2 - 9.5	9.2

*Values of up to 17 ppb were observed.
**No phosphate fed during 1991 because pumps were inoperative.

Figure 5-2
Materials of Construction
Malaya Station

Equipment	Unit 1	Unit 2
Main Condenser	90/10 - Cu/Ni	Aluminum Brass
Air Cooler	90/10 - Cu/Ni	90/10 - Cu/Ni
L.P. Heaters	304SS	304SS
H.P. Heaters	Carbon Steel	Carbon Steel

Figure 5-3
Materials of Construction
Batangas Unit 1

Main Condenser	Aluminum Brass
Air Cooler	Titanium
L.P. Heaters	Stainless Steel
H.P. Heaters	Carbon Steel

- 62

Figure 5-4
Chemical Operating Limits
Batangas

	Limit
Feedwater	
pH	9.3 - 9.5
Copper, ppb	<5
Iron, ppb	<10
Hydrazine, ppb	30
Cation Conductivity, μS/cm	<0.3
Boiler Water	
pH	9.3 - 9.5
Chloride, ppm	–
Phosphate, ppm	0.3
Silica, ppm	<0.2
Conductivity, μS/cm	<5.0

63

Figure 5-5
Geothermal Generation Capacity
National Power Corporation

Project		Capacity, MW	Initial System Synchronization	
Tiwi	1	55	Dec.	1978
	2	55	May	1979
	3	55	Dec.	1979
	4	55	May	1980
	5	55	April	1982
	6	55	July	1982
Mak-Ban	1	55	April	1970
	2	55	July	1979
	3	55	April	1980
	4	55	June	1980
	5	55	June	1984
	6	55	Sept.	1984
Tonogona	Pilot Plant	3	July	1977
	1	37.5	June	1983
	2	37.5	April	1983
	3	37.5	March	1983
Palinpinon	Pilot 1	1.5	Sept.	1980
	Pilot 2	1.5	Oct.	1980
	1	37.5	Nov.	1982
	2	37.5	Feb.	1983
	3	37.5	May	1983

64

Figure 5-6
Geothermal Present Chemical Treatment
National Power Corporation

Station	Corrosion Inhibitors	Biocide/Dispersant	Results
Mak-Ban 1, 2, 3 & 4	NAOH Cooltreat 70A (Mainchem)	Hatacide 12 & 17 (Mainchem)	<15 mpy corrosion Good algae control
Mak-Ban 5 & 6	NAOH Phyrox Blend	Phyroxal 411C & 381C	<15 mpy corrosion Good algae control
Palinpinon	Lime NALCO 7384	Dichlorophen (Panacide) Hatamine (Mainchem)	57 mpy corrosion Good biological growth control
Tongonan	NAOH Lime	Hatacide 17 (Mainchem)	Corrosion rate not reported Good biological growth control
Tiwi 1, 4 & 5	Hatamine 3 (Mainchem)	Hatacide 12 & 17 (Mainchem)	<15 mpy corrosion Good algae control
Tiwi 2, 3 & 6	Lime	Calcium Hypochlorite	<40 mpy corrosion Poor algae control

Figure 5-7
Fuel Oil Quality
Malaya Thermal Plant

Parameter	Bunker C	Residual
API Gravity @ 60°F, min.	12 (17.0)	8.5 (11.8)
Viscosity, SSF @ 122°F, max.	245 (80)	750 (620)
% BS & W, max.	1.0 (0.20)	1.0 (0.20)
Heat Valve, Btu/lb, min.	18,100 (18,500)	17,000 (18,130)
% Sulfur, max.	2.5 (2.7)	5.3 (4.0)
% Ash, max.	0.1 (0.02)	0.1 (0.04)
% Asphaltenes	–	–
ppm Sodium, max.	70 (10)	130 (20)
ppm Vanadium, max.	100 (65)	150 (75)
% Carbon Residue (C), max.	15 (10)	16 (13)

NOTES:

1. Analysis for sodium, vanadium and carbon residue represents estimates of most probable percentages of the elements based on available records.

2. Figures in parenthesis are average values.

- 66

Section 6

Related Generic Plant Problem Areas

In addition to investigating the specific problem areas discussed in Section 5 of this report, another objective of the evaluation was to determine the potential to provide solutions to generic availability, reliability and life extension issues. Some of these issues were discussed in general terms in Section 4. This section will discuss these generic problem areas in more detail and provide recommendations for improvement.

Information associated with the present condition of the Malaya and Batangas stations was reviewed in order to determine generic problems. Also, historical reports dating back to the early eighties were reviewed to get an understanding of the longevity of these problems and to determine long-term trends.

From this information, it became clear that a number of generic failure problems were present and that they had existed for a long time. Typically, these problems affected plant operation in the form of unit de-ratings, increased forced outages and increased unplanned outages. Details of related generic problem areas for Malaya and Batangas are shown in Tables 6.1 to 6.3. In conjunction with this information, historical reports for Sucat were reviewed and the findings are discussed in the following sections where appropriate.

6.1 BOILER TUBE FAILURES

Boiler tube failures in units on the NPC system is a chronic, long-term problem. Many tube failures have occurred in the water walls, superheater, reheater and economizer sections of these boilers and the problem has existed for most of the life of the units. Boiler tube thinning and failure is a leading cause of troubles at Malaya, Batangas and Sucat. A large number of these failures have been attributed to tube thinning caused by fireside erosion and corrosion. Evidence also shows that water-side corrosion problems occurred in the early operation of some of these units. However, changes to boiler water chemistry have reduced the potential for these problems.

The most obvious cause of tube thinning and tube failures is the quality of fuel being burned. In Malaya and Sucat, heavy fuel oil is used that is high in vanadium and sulphur. This results in corrosive slag build up on water walls and erosion in the convective sections

67

of the boiler. The situation at Batangas was described in Section 5.4 and indicates that boiler tube failures can, in part, be attributed to coal quality problems.

The typical method at NPC of dealing with the tube thinning and tube failure problem is to reduce boiler pressure and, as a result, to reduce plant output. Boiler heat exchange surfaces are designed for specific pressures, temperature differentials and heat flux and operation outside of the design parameters can adversely affect unit reliability, safety and efficiency. During the investigation, it was not apparent that an evaluation of the reduced pressure operation had been performed by a boiler operations expert to verify that the operating modes were not injurious to the boiler. Such an evaluation should be performed if it has not already been done.

Even with reduced boiler pressure, boiler tube failures continue to occur. Later, during a maintenance outage, the affected sections of the boiler are replaced. When the problem becomes severe, rehabilitation of the boiler is performed in order to return the boiler to rated pressure and capacity. This approach does not address the root-causes of the boiler tube failure problems. Therefore, the problem will keep recurring throughout the future life of the boiler. By identifying the root-causes of the boiler tube failures, it is possible to solve the problem permanently.

As can be seen from Tables 6-1 to 6-3 and from historical reports, boiler tube failures are the most significant cause of outage problems for NPC. This is true for Malaya, Batangas and Sucat and may be true of other plants.

At Malaya, a fuel additive program is being tested and is apparently having a beneficial effect. At Batangas, sootblower operation is being modified, and coal quality is being changed to mitigate the problem. At Sucat, a major rehabilitation program on all four units is under way. While these methods will have a positive impact on plant reliability, experience in the U.S. and in other countries shows that these problems can be expected to recur unless a highly focused effort is employed that addresses the root-causes of the problems and implements known technical fixes to eliminate the problem permanently.

68

Fixes for these problems are available for application when the fundamental failure mechanisms have been identified. Failures may originate from a number of sources including: water chemistry, fireside erosion and corrosion, boiler operation, materials selection, plant design and maintenance practices etc. Specific expertise is required to analyze all salient factors to determine root-causes and identify appropriate fixes.

6.1.1 Recommendations

- NPC should perform root-cause analyses of the boiler tube failure problems and thoroughly evaluate the method of reduced pressure operation at Malaya and Batangas to identify the fundamental reasons for the failures that have been occurring during the past five years and determine if boiler operation is proper. Boiler tube failures are occurring regularly on these boilers. A study team should be assembled that includes a boiler expert, a materials expert, a water chemist and NPC maintenance and reliability experts. The goal of the team would be to fully evaluate the boiler tube failure problems at both plants, determine the root causes of failure, determine fixes, give recommendations for implementation and assist in verification of the solutions. In the case of Malaya 2, specific attention would be paid to the fuel additive program presently being tested to determine if it is fully addressing the root-causes of failure and to determine if additional changes are required within the plant. The reduced pressure operation evaluation would determine if operation is appropriate from a reliability, safety and efficiency standpoint. If found to be necessary, boiler operating instructions would be modified to ensure correct operation. This recommendation should be implemented on an immediate basis.

- NPC should implement as an intermediate recommendation a company wide Boiler Tube Failure Reduction (BTFR) Program which implements well developed technology to reduce or eliminate boiler tube failure problems, increase reliability and extend life. This approach is highly developed in the U.S. and in other countries and has been very successfully implemented by

many electric utilities. The basic structure of a BTFR Program involves four fundamental stages:

- Development and implementation of a root-cause data base
- Analysis of failures and identification of root-causes
- Selection of solutions for retrofit
- Implementation of fixes and verification of effectiveness

Such a program requires a dedicated group within the organization that has responsibility for its implementation and that has the necessary technical knowledge and skills to ensure success.

The Reliability and Efficiency Department recently formed in NPC would be an excellent location to house and develop the BTFR program. A substantial technology transfer activity will be required that includes:

- Technical assistance in the selection of methods and systems,
- Installation and operation of methods and systems,
- Training in root-cause analysis, and
- Implementation of retrofit fixes

It will be necessary to implement the BTFR program in phases as follows:

70

6.1.1.1 Phase 1: Development of an Overall Plan

Development of an overall plan for the BTFR program that includes: data-base requirements, organizational integration and operation, resource requirements, technology transfer, continuing support and budgets.

6.1.1.2 Phase 2: Implementation of the Program

Implementation of the program within NPC.

6.1.1.3 Phase 3: Implementation of the Retrofit Fixes

Implementation of the retrofit fixes, verification of effectiveness, and continuing support.

6.2 TURBINE BLADE FAILURES

Turbine blade failures have been a significant cause of outages and reduced output for 10-15 years on Malaya 1 and Sucat 2, 3 and 4. The problem appears to be manufacturer related since all these machines were manufactured by Siemens. This appears to be a generic problem with Siemens machines in the 200 MW to 300 MW size range. Another common factor is that the boilers on these units are sub-critical, once-through machines with condensate polishers. The problem has occurred in the last rows of the LP sections of each affected machine.

Identifying the root-cause of generic failures in long blades is complex and requires very specialized expertise. Such failures may be caused by a combination of factors that includes steam chemistry, design stresses (static and dynamic), materials (type of material and heat treatment) and under-frequency operation. Typically, utilities rely on the equipment manufacturer to solve problems that are this complex. Assuming that the manufacturer has been involved since the early eighties it appears that they are not forthcoming with an effective solution. Similar situations have arisen in the U.S. where manufacturer specific, generic failures in long blades have occurred. This was a chronic problem in the U.S. in the 1970's and 1980's.

In order to mitigate the problem, analytical and testing methods have been developed independently of the manufacturer to perform a third-party assessment and to develop retrofit solutions. This technology is available for application to the NPC problems and a strong likelihood exists that, in conjunction with the manufacturer, a retrofit fix can be developed that will permanently solve the turbine blade failure problems.

The blade failure at Malaya 1 occurred in the last row at about mid-length on the blade. This would appear to be high-cycle fatigue possibly assisted by corrosion. The solution may require blade design changes to reduce the alternating stresses on the blades. Modifications to the polishing system operation are required to minimize the potential for a corrosive steam environment as discussed in Section 5.1.

6.2.1 Recommendation

The LP turbine blades in the NPC Siemens turbines have been failing since the early 1980's. To eliminate this problem it is recommended that NPC perform on an immediate basis a root-cause analysis of the failures to identify the fundamental reasons for failure. This approach is utilized in the U.S. to address highly complex blade failure problems. The technology to independently analyze the blade failure problem is available and can be applied at NPC. A study team should be assembled that includes a turbine blade expert, a water chemistry expert, a materials expert, NPC maintenance and reliability experts and if possible the equipment manufacturer. The goal of this team would be to fully evaluate the LP blade failure problem, determine the root-causes of failure, develop retrofit fixes, give recommendations for implementation and assist in the verification of the solution.

6.3 HIGH THRUST BEARING TEMPERATURES

Like turbine blade failures, high thrust bearing temperatures have been a long standing problem with the NPC Siemens steam turbines dating back to the late 1970's. This has caused significant load reductions in several units and has had a costly impact on system operations. Like turbine blade failures, this problem is highly complex and needs specialized expertise and technology to develop permanent solutions. In addition, the two problems may be linked because after the failure of LP turbine blades, the interim approach to keep

the turbine on-line is to remove the affected row of turbine blades. This can have the affect of exerting higher loading on the thrust bearing.

6.3.1 Recommendation

NPC should perform a root-cause analysis of the high thrust bearing temperature problem in Siemens turbines to identify the fundamental reasons for the problem. A study team should be assembled that includes a thrust bearing expert, a rotor-dynamics expert, NPC maintenance and reliability experts and the turbine manufacturer. The goal of the team would be to fully evaluate the thrust bearing problem, determine the root-causes of failures, provide recommendations for solution and assist with verification of the solution.

6.4 TURBINE IP ROTOR CRACKING

During the last rehabilitation of Malaya 1, cracking of the IP rotor was found and replacement of the IP rotor is scheduled for 1993.

6.4.1 Recommendation

NPC should perform an analysis of Malaya 1 IP rotor to determine if replacement is necessary. Weld repairing of this rotor may be possible, thereby, saving considerable capital investment in a new rotor.

6.5 ROOT CAUSE ANALYSIS OF FORCED OUTAGES

The identified major equipment problems of Malaya and Batangas were confirmed by an evaluation of the forced outage records. A similar evaluation for the remaining NPC units should be performed.

6.5.1 Recommendation

An evaluation of the forced outage records of all of the NPC thermal generating units, exclusive of Malaya and Batangas, should be performed to identify the equipment and

-13

systems which are the major causes of outages. With this identification, root cause evaluations of the equipment failures can be performed and solutions developed.

74

Section 7

System and Organizational Issues

Observations of the NPC system and organization are discussed below with recommendations for improvement.

7.1 PRESENT CONDITION OF EQUIPMENT

Overall, plant equipment and systems are in a degraded state with regard to reliability, availability and efficiency. This is due, in part, to original design problems, deferred and delayed maintenance, certain operating practices, fuel quality and personnel training. The Batangas coal system problem is an example that includes all of the foregoing elements.

In many ways, the situation with the system is similar to what happened to most U.S. utilities in the 1970's. Correcting the situation required the development and application of technology designed to permanently solve the problem. This process took place during the 1970's and 1980's and was implemented through availability improvement, efficiency improvement and life extension programs. The performance of U.S. power plants greatly improved as a result of this work. The technology developed in the U.S. is available to be applied to the NPC system.

The equipment in the NPC plants is the same as what is used in the U.S., Japan and Europe and the plants are very valuable assets to NPC. U.S. experience shows that these plants can be brought up to proper operating levels through the use of focused availability, and efficiency improvement and life extension programs at a small fraction of the cost of replacement capacity. Therefore, the present fossil plants should be kept on the system and improved through capital investment programs.

If methods are not put in place to improve the operation of existing plants, then any new plant that is added to the system will be subjected to the same kind of degradation. As a result, adding new capacity to the system, with the present practices in place will, to some extent, be self defeating and require more capacity than anticipated at very high cost. The methods developed for existing plants will also be applicable to new units to keep these units at maximum productivity.

15

7.2 REHABILITATION APPROACH

The present approach to plant rehabilitation at NPC appears to entail overhauls, upgrades and direct replacements and does not include root-cause analysis and condition assessment. Root-cause analysis is vital to any plant improvement program, in that it identifies the fundamental causes of failures and allows changes to be implemented that will solve the problem permanently. Condition assessment is also vital, in that, it evaluates potential future failures and allows changes to be made to plant equipment so that unanticipated failures can be avoided.

The present rehabilitation work is in some ways a deferred maintenance program and corrects problems that arise due to lack of consistent maintenance. Also, the rehabilitation program replaces equipment and components on a like/kind basis that will suffer from the same degradation and require replacement again in the future. This approach results in very expensive rehabilitation projects that must be performed periodically to bring the equipment back to an acceptable level of productivity.

7.2.1 Recommendation

NPC should perform an assessment of the present rehabilitation approach and determine if it is serving the best interests of the corporation. An availability and efficiency improvement/life extension program should then be developed that incorporates the valuable parts of the rehabilitation approach and that includes root-cause analysis and condition assessment. Such an approach will better utilize the capital funds that are available to NPC and permanently eliminate many of the problems now being encountered. In the longer-term, availability and efficiency improvement/life extension activities will become a normal part of maintaining plant equipment and will eliminate the need for major, capital-intensive rehabilitation projects.

7.3 CAPABILITY TO ADDRESS PROBLEMS

To implement recommendations contained in this report, NPC will need to develop the internal capability to perform the analytical, operational and maintenance activities required. This will involve some organizational changes and considerable technology transfer.
NPC has recently formed the Efficiency and Reliability Department that is chartered to develop efficiency and reliability programs for the company. The following observations can be made regarding this group:

1. The group is severely understaffed (10 personnel) to address the problems being faced by NPC. The staff size should be increased in line with the need for the solution of reliability and efficiency problems.

2. The present focus is more on efficiency improvement than on reliability improvement. The group should be refocused to address the reliability and availability problems of NPC because that is where the most value for the company will be derived. Later, when the reliability and availability problems are under control, efficiency improvements can be re-emphasized.

3. This group would be an excellent organizational entity in which to develop and apply the availability improvement and life extension programs discussed in the previous section. They could also be chartered to develop and implement the root-cause analysis and condition assessment methods required for these programs.

4. Considerable technology transfer will be required in order for the group to become effective in implementing availability and life extension programs.

7.3.1 Recommendations

- NPC should charter the Efficiency and Reliability Department to develop and implement an Availability Improvement and Life Extension (AI & LE) program

for NPC. They should also be given responsibility for developing and implementing the root-cause analysis and condition assessment methods required for the AI & LE program and for analyzing equipment and components on a continuing basis. Staffing levels should be increased in line with this responsibility.

- The Efficiency and Reliability Department should be refocused to concentrate on solving availability and reliability problems. Presently, the focus is primarily on efficiency improvement. This change will ensure that NPC will receive maximum value from the department's efforts.

- A technology transfer program for the Efficiency and Reliability Department should be developed and implemented in conjunction with the AI & LE program to ensure that the department is fully capable of performing the work. The technology transfer program should involve availability and life extension methods and include root-cause analysis and condition assessment techniques. The following elements should be included:

  - Personnel training

  - Laboratory requirements, computer hardware and software and test equipment

  - Analytical techniques, procedures and specifications

- Training programs should be developed and implemented for plant maintenance and plant operations personnel in order to implement and sustain the level of performance improvement attained through implementation of the AI & LE program.

7.4 DELAY OF MAINTENANCE DUE TO SYSTEM DEMAND NEEDS

In each plant visited, system demands took precedence over maintenance. Typically, maintenance activities were delayed by several months and reduced in scope depending on system demands. This practice can have a serious negative effect on plant and system reliability and should be minimized. System reserve margins are very low and it may be difficult to modify the present practice. However, a balanced approach should be developed that allows the plants to be adequately maintained. Failure to do this will result in a decline in plant reliability and availability over time and will contribute to the need for major rehabilitation projects.

7.4.1 Recommendation

Review the practice of significantly delaying and reducing the scope of maintenance outages in light of the substantial costs to the system that result from the associated degradation in plant reliability. Develop procedures for implementation that can be utilized by plant operations, plant maintenance and system dispatch as a means of minimizing the total cost impact to the generating system.

19

APPENDIX A

SCOPE OF WORK

Appendix A

Scope of Work

PHILIPPINES NATIONAL POWER CORPORATION

I. Consultancy Service

A. Fuel Additive Treatment for Oil-Fired Power Plants
- Formulate long term measures to solve or lessen fireside and coldside corrosion in steam generators to improve combustion efficiency and reduce maintenance downtime.
- Prepare/recommend technical specifications for fuel additives.
- Evaluate effectiveness of fuel additives that will be utilized

B. Water Treatment for Fossil Fired and Geothermal Power Plants
- Evaluate existing water treatment program.
- Formulate long term measures to improve existing water treatment programs.
- Prepare/recommend technical specifications for water treatment chemicals.
- Evaluate effectiveness of water treatment chemicals that will be utilized.

II. Technical Training/Grants in the Following Areas of Thermal Power Plant Operations

A. Fuel Additive Treatment
B. Water Treatment Program

III. Thermal Power Plants Technical Visit

A. Observation of the Operation Plant Systems of the Following:
- Fuel additive system
- Water treatment program

B. Feedback of Operating Experience

91

APPENDIX B

PERSONNEL CONTACTS

National Power Corporation
and
U.S. Agency for International Development

Appendix B

Personnel Contacts

NATIONAL POWER CORPORATION AND U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT (AID)

The following NPC and U.S. A.I.D. personnel provided technical background or assistance in developing the information contained in this report.

NPC PERSONNEL

Main Office

Mr. Samuel A. Piedad	–	Asst. to the Senior Vice President
Mr. Francisco T. Delgado	-	Senior Vice President – Engineering
Mr. Jose T. Ramos	–	Senior Vice President – Systems Operations
Mr. Pedro Fernandez	–	Superintendent–Regional Engineering Services – Chemical Section
Mr. Diosdado Macapagal	–	Chemical Engineer – Regional Engineering Services – Chemical Section
Mr. Manuelito Posadas	–	Chemical Engineer – Quality Assurance Department

Malaya Thermal Plant

Mr. Jaime Abella	–	Manager Operations
Mr. Carlos Castillo	–	Principal Engineer B
Mr. Tito Villuna	–	Principal Engineer B – Results Engineering
Mr. E. Labadan	–	Operations Superintendent

Batangas Thermal Plant

Mr. Alvin Kintanar	–	Manager Operations
Ms. Fe Torrefranca	–	Principal Engineer – Steam/Water Laboratory
Mrs. Malou M. Fabela	–	Principal Engineer – Fuel Laboratory
Mr. Felipe Tinansan	–	Superintendent – Mechanical Maintenance
Mr. Henry V. Alcalde	–	Manager Maintenance

Mak-Ban Geothermal Plant

Mr. Efren San Sebastian	–	Operations Manager
Mr. Jesse Tanpo	–	Principal Engineer
Mr. Pepito Median	–	Operations Superintendent

83

Appendix B

Personnel Contacts

NATIONAL POWER CORPORATION AND U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT (AID)

U.S. A.I.D. MANILA PERSONNEL

Malaya Thermal Plant

Mr. Kenneth P. Lue Phang – Office of Capital Project Energy and Special Projects Division
Ms. Conchita C. Silva – Project Manager – Office of Capital Projects
Mr. Dennis Zvinakis – Chief – Office of Capital Projects

APPENDIX C

GEOTHERMAL CHEMICAL DATA

November 5, 1991

Mr. Dennis Zvinakis
Chief, Office of the Capital Projects
USAID
Ramon Magsaysay Center
1680 Roxas Boulevard
Ermita 1000, Manila

Attn: Ms. Conchita C. Silva
Project Manager, ETP

Dear Mr. Zvinakis,

This pertains to our request for technical assistance we need in our Fuel Additive and Water Treatment Programs.

In reference to our letter PMS-91-031 dated 02 October 1991, we are transmitting herewith the specific data requested by Mr. Statton for our four (4) Geothermal Power Plants namely Palinpinon GPP, Makban GPP, Tiwi GPP, and Tongonan GPP.

May we request your good office to forward the aforementioned data to Mr. Statton of Bechtel as soon as possible.

We also would like to reiterate our request for the early dispatch of specialists to perform a detailed assessment of our Fuel Additive and Water Treatment Programs.

Very truly yours,

JOSE T. RAMAS
Senior Vice-President
Utility Operations

PMS 91-040

Republic of the Philippines
National Power Corporation
Palinpinon Geothermal Power Plant
Valencia, Negros Oriental

WATER TREATMENT for PALINPINON GEOTHERMAL POWER PLANT

I. Presently Used Cooling Water Treatment Chemical

a. Corrosion Inhibitors

1. Lime
2. Nalco 7384

b. Biocide, Main

1. Dichlorophen (Panacide)

c. Alternating Biocide/Dispersant

1. Aliphatic Amine Acetate (Hatamine 3)

II. Summary of Problems Encountered

a. Lime - Normally without corrosion inhibitor treatment, corrosion rate at hot side (20-40 mpy) is lower than cold side (40-70 mpy). Upon implementing lime treatment at optimum dosage (20-30 ppm calcium hardness) to prevent fouling of air coolers, the trend in corrosion rate is reversed, with hot side at 50-60 mpy while cold side is at 28-48 mpy. Increasing lime dosage (30 to 50 ppm calcium hardness) will lead to frequent servicing of air coolers, usually within a span of 15 days.

b. Use of Nalco 7384D, a zinc-based corrosion inhibitor which is on its last month of its 2-month evaluation, has resulted to an average of 57 mpy for both sides, way below the targetted corrosion rate at 15 mpy.

c. Biocide/Dispersant

Among biocides previously evaluated only the aliphatic amine acetate and dichlorophen-based biocides were found successful in preventing microbiological fouling without sacrificing unit operation. Use of other biocides, quaternary amines and other surfactants has led either to the following:

1. No effect on microbiological growth
2. Unit tripping due to foaming at the SGE system. While other plants could tolerate foams, PGPP does not.

In cases where stock of these biocides run out, calcium and sodium hypochlorites are used as supplementary biocides.

III. Analyses of Steam and Cooling Water

	Steam	Cooling Water
pH	4.9-5.0	6.5-7.5
Alkalinity, Mo, ppm	-	30-40
Conductivity, us/cm	180-200	200-400
Hardness, total, ppm	-	5-30
Hardness, Calcium, ppm	-	3-25
H_2S, ppm	30	1-3
Chlorides	0.2-.3	0.6-2
Silica	.005-.02	0.4-80
Total Iron	.005-.24	0.6-2
Total Solids	3-8	100-200

IV. Previous Treatment Used and Assessment

To date, a total of five (5) suppliers of proprietary chemicals has been evaluated. These are Nalco, Drew/PIPC, Atom Chemicals, Peter Blaise and Mainchem. Of these, only Mainchem has successfully passed the criteria of 15 mils per year with an average 14 mpy using a zinc synergist as corrosion inhibitors. Other inhibitors which were tested and found unsuccessful are, zinc-phosphonate, polyphosphate, zinc-dispersant, versenelignin, zinc-phosphate and amine-based. Use of chromates was dicouraged because of environmental concerns.

Republic of the Philippines
National Power Corporation
Mak-ban Geothermal Power Plant
Laguna

REPORT ON THE WATER TREATMENT PROGRAM FOR MAK-BAN COOLING SYSTEM

I. INTRODUCTION

The Chemical Laboratory of the plant started their studies on the characteristics of the cooling water on the early part of 1980. During this period, caustic soda is the only chemical being used to minimize the corrosivity of the cooling water. As the units continued to operate, it encountered problems such as corrosion, deposition and microbiological growths and other common problems related to cooling systems. The units were then subjected to trial treatments from different chemical companies who have expertise in these area. A comparative performance of the different programs undertaken is shown in the attached Table I.

II. CHEMICALS PRESENTLY USED:

1. Caustic soda
2. Lime
3. Corrosion Inhibitor
4. Bio-dispersant
5. Microbiocide

Caustic soda is being used to raise the pH of the cooling water at the range of 6.5 to 7.5, and lime is injected to introduce low level of Ca-Hardness to the system. The inhibitor is added to reduce the corrosion rate of the system below the 15 mpy level along with the two alternating biocides which protects the cooling tower's wooden portion and prevent underdeposit corrosion.

III. STEAM AND COOLING WATER ANALYSIS

A. Steam

Chloride	0.10
Silica	0.10
pH	4.17
Total Solids	8.94
Total Iron	0.22

B. Cooling Water

Chloride	1.35
Silica	0.66
Total Solids	291
pH	6.60
Total Iron	1.67

Note: Analysis data for the First half of 1991.

IV. REMARKS

1. Problems usually are encountered when treatment is not continuous.

2. Consultancy/training/seminar should be provided to laboratory/chemical personnel.

I COMPARATIVE PERFORMANCE OF VARIOUS COOLING WATER TREATMENT (cwt) PROGRAMS

	CORROSION RATE, mpy			TREATMENT COST		
	COLD SIDE	HOT SIDE	AVERAGE	NaOH	WT CHEMICAL	T O T A L
A) CAUSTIC SODA ONLY Average for Units 1 to 6	43.20	34.90	39.00	103,738.00	0.00	103,738.00
B) LIME TREATMENT W/ CALCIUM HYPOCHLORITE Average for 3 Units	39.90	23.30	31.60	90,801.00	10,883.00	101,684.00
C) PROPRIETARY CHEMICAL TREATMENT 1) Under Contract (Average for 4 Units)	15.00	9.60	12.30	90,511.00	120,839.00	211,350.00
D) PROPRIETARY WITH LIME (Average for 4 Units)	11.60	6.60	9.10	123,508.00	133,010.00	256,518.00

NOTE: 1 - Allowable maximum corrosion rate is 15.0 mpy
2 - NaOH cost varies every year

10/10/91

. EXISTING WATER TREATMENT PROGRAM:

PLANT A		PLANT B		PLANT C	
UNIT NO. 1	UNIT NO. 2	UNIT NO. 3	UNIT NO. 4	UNIT NO. 5	UNIT NO. 6
ı) NaOH ı) Lime # :) Bio-dispersant	A) NaOH B) Lime # C) Bio-dispersant	A) NaOH B) Lime # C) Proprietary Chem. 1. Inhibitor 2. Bio- cides	A) NaOH B) Lime # C) Proprietary Chem 1. Inhibitor 2. Bio- cides	A) NaOH B) Lime # C) Proprietary Chem 1. Inhibitor 2. Dispersant 3. Bio- cides	A) NaOH B) Lime # C) Proprietary Chem 1. Inhibitor 2. Dispersant 3. Bio- cides

NOTE: # Lime dosing intermittent, depending on Hydrogen Gas Cooler Stator Temperature.

. RECOMMENDATION/PLANNED PROGRAM:

ı) NaOH :) Lime :) Inhibitor ı) Dispersant :) Bio-cides	A) NaOH B) Lime C) Bio-cides D) Dispersant	A) NaOH B) Lime C) Inhibitor D) Dispersant E) Bio-cides	A) NaOH B) Lime C) Inhibitor D) Dispersant E) Bio-cides	A) NaOH B) Lime C) Inhibitor D) Dispersant E) Bio-cides	A) NaOH B) Lime C) Inhibitor D) Dispersant E) Bio-cides

NOTE: 1 - No more treatment for Units 3, 4, 5 and 6 from September 3, 1991 to present due to non-delivery of chemicals.
2 - Unit #2 needs no inhibitor due to FRP pipes.

10/10/91

Republic of the Philippines
NATIONAL POWER CORPORATION
Tiwi Geothermal Power Plant
Tiwi, Albay

WATER TREATMENT for TIWI GEOTHERMAL POWER PLANT

I. Presently Used Cooling Water Treatment Chemicals

	CORROSION INHIBITOR	BIOCIDES	OTHER
Unit # 1	Hatamine 3 (Amine-based)	Hatacide 17 & 12	NaOH
Unit # 2	Lime	Cal. Hypochlorite	-do-
Unit # 3	Lime	Cal. Hypochlorite Phyroxal 411 C Phyroxal 381 C	-do-
Unit # 4	Hatamine 3	Hatacide 17 & 12	-do-
Unit # 5	- do -	- do -	-do-
Unit # 6	Lime	Cal. Hypochlorite	-do-

II. Summary of Problems Encountered

1. Dosing interruptions due to exhaustion of chemical stock.

2. pH upsets wherein the pH value of the cooling water either increase or decrease the recommended range.

3. Breakdown of feed pumps, leakages in the feed system, clogging of feedline, out of order agitator and other similar troubles.

4. Exhaustion of dipslides for microbiological growth levels, coupons for installation, reagents/chemicals and other pertinent needs in monitoring treatment parameters.

5. System abnormalities such as trippings and shutdown of the Unit.

III. Typical Steam Quality Values

Parameters	
pH	4.0 to 5.0
Chloride, ppm	less than 0.10
Silica, ppm	less than 0.10
Total Iron, ppm	less than 0.10
Conductivity, umhos/cm	35.9
Total Dissolved Solids, ppm	19.6
Sulfate, ppm	3.0
Sulfide, ppm-s	11.0
Ammonium, ppb-N	1,654
Calcium, ppm	0.10
Magnesium, ppm	0.04

IV. Typical Cooling Water Quality Values (at Coldside)

Parameters	
pH	6.5 to 7.5
Chloride, ppm	8.5
Silica, ppm	7.0
Total Iron, ppm	0.20
Conductivity, umhos/cm	198
Total Dissolved Solids, ppm	108
Temperature, C	28 to 30
Sulfate, ppm	58.0
Sulfide, ppm-S	2.0
Ammonium, ppb-N	2,258
Calcium, ppm	0.55
Magnesium, ppm	0.43

WATER TREATMENT HISTORICAL DATA
UNIT NO. 1

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1984	NALCO	Mar. 28 - Apr. 23 (BASELINE)	16.0	48.0	-	Chemicals Used:
		Apr. 27 - May 27	16.0	24.2	-	GEOPOWER IV - Corrosion Inhibitor (Phosphate-based) GEOPOWER II - Catalyst for H2S abatement. GEOPOWER III - H2S scavenger and bactericide. N - 7328 - A biocide. CAUSTIC SODA
		June 1 - July 1	20.3	22.5	₱ 313,883.27	
		July 4 - Aug. 3	9.09	23.1	491,787.45	
		Aug. 6 - Sept. 5	81.4	30.2	467,593.97	Corrosion rates for last two treatment periods were high due to dosing interruptions and pH upsets. Nalco program resulted to high caustic soda consumption. Bacterial counts and algae growth were acceptable.
		Sept. 20 - Oct. 15	159	40.9	574,017.11	
1985	NALCO	Feb. 22 - Mar. 24	34.4	15.0	₱ 322,860.10	Chemicals Used:
		Mar. 25 - Apr. 7 (13 days only)	46.7	38.4	89,997.17	GEOPOWER IV - Corrosion Inhibitor with active ingredient changed to Zinc-based. GEOPOWER V - Dispersant. N - 7328 - A biocide. CAUSTIC SODA
		Apr. 10 - Apr. 25 (15 days only)	46.9	16.8	139,941.00	
		June 10 - July 10	34.5	26.9	242,423.00	Caustic soda usage and cost of Nalco program reduced due to changes in chemicals used. Bacterial counts and algae growth were acceptable.
		July 12 - Aug. 12	46.4	19.2	171,955.00	
		Aug. 20 - Sept. 19	36.3	18.3	287,410.00	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 1

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1986	MAINCHEM	Dec.26,'85 - Jan. 14	38.5	8.21	164,796.47	Chemicals Used:
		Mar. 5 - Apr. 4	15.4	9.25	268,177.50	COOLTREAT 70A - Corrosion Inhibitor (Zinc-based) HATACIDE 17 and 12 - Biocides. CAUSTIC SODA
		Apr. 5 - May 5	38.4	11.6	248,957.50	
		May 14 - June 12	42.3	11.4	293,826.20	Mainchem program improved corrosion rates at hotside. Bacterial counts and algae growth were acceptable.
		July 8 - Aug. 7	33.8	12.1	358,651.50	
		Aug. 8 - Sept. 7	43.6	8.35	248,093.15	
		Oct. 1 - Oct. 31	25.8	9.12	289,624.20	
1987	ATOM	Jan. 16 - Feb. 15 (BASELINE)	21.8	9.10	P 18,758.10	Chemicals Used:
		Feb. 18 - Mar. 14	40.6	18.6	108,681.00	HYDROSOLV 2706L - Corrosion Inhibitor (Phosphate-based) BETZ 2020 - Dispersant BETZ J-12 and HYDROSAN 400 - Biocides. CAUSTIC SODA
		June 21 - July 21	17.6	24.4	127,706.20	
		July 22 - Aug. 21	13.8	22.4	100,211.20	Control of algae growth acceptable.
		Oct. 22 - Nov. 21	21.4	24.0	95,307.60	
		Dec.17,'87 - Jan.16,'88	41.6	43.1	119,702.70	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 1

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1988	ATOM	Feb. 3 - Mar. 4	-	-	-	Not evaluated due to early pull-out of coupons on February 16 caused by dewatering of corrosion racks.
1989	PHYROX	July 3 - Aug. 2, '88 (BASELINE)	45.8	15.4	P 83.803.50	Chemicals Used: DISPERSANT-BIOCIDE PROGRAM ONLY PHYROXAL P-560 - A Dispersant. PHYROXAL P-411 and P-381 - Biocides. Bacterial counts and algae growth were acceptable.
		Jan. 13 - Feb. 12	20.7	15.7	117,482.50	
		Feb. 13 - Mar. 15	25.9	14.2	87,207.40	
		Mar. 15 - Apr. 14	15.0	8.84	51.592.40	
	MAINCHEM	Apr. 13 - May 13	18.2	14.2	P 236.235.06	Chemicals Used: HATAMINE 3 - Corrosion Inhibitor (Amine-based) HATACIDE 17 and 12 - Biocides. CAUSTIC SODA Microbiological levels and algae control were acceptable
		May 25 - June 24	19.5	14.0	177.159.78	
		July 3 - 23 (20 days only)	14.3	13.3	128.262.34	
		July 26 - Aug. 25	13.8	16.6	176,175.18	
		Aug. 26 - Sept. 17 (21.8 days only)	26.0	11.7	136,692.21	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 1

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1989	MAINCHEM	Sept. 20 - Oct. 20	7.85	6.57	160,189.12	Chemicals Used: - do -
		Oct. 20 - Nov. 19	19.2	12.4	143,941.44	Average caustic soda reduction in consumption for 1989 - 58.8%
		Nov. 19 - Dec. 19	22.2	11.6	178,469.82	Last period with incomplete treatment chemicals.
		Dec.20,'89 - Jan.19,'90	17.2	8.96	40,608.44	
1990	- do -	Jan. 20 - Feb. 19 (BASELINE)	25.4	11.6	P 59,636.70	Chemicals Used: - do -
		Feb. 19 - Mar. 21 (BASELINE)	24.1	10.9	46,346.58	Microbiological levels and algae control were acceptable. Average NaOH reduction in consumption is 57.7%.
		Apr. 10 - May 10	5.88	4.86	186,605.82	
		May 12 - June 11	4.02	3.30	159,324.98	
		June 11 - July 11	7.62	2.98	155,570.40	
		Sept. 24 - Oct. 24	55.8	7.16	197,472.72	
		Oct. 26 - Nov. 25	4.98	11.8	168,624.36	
		Nov. 26 - Dec. 26	5.62	12.9	174,063.42	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 1

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1991	- do -	Dec. 27,'90 - Jan. 26	5.54	12.4	P 165,773.34	Chemicals Used: Same as above. Microbiological levels and algae control were acceptable.
		Jan. 28 - Feb. 27	12.2	11.6	73,069.02	
		Mar. 20 - Apr. 19	4.34	6.38	187,288.28	
		Apr. 25 - May 25	7.98	9.15	210,252.24	
		June 18 - July 18	7.91	4.92	231,234.39	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 2

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1984	DREW	July 5 - Aug. 4 (BASELINE)	149	20.9	-	Chemicals Used: DREWGARD 189E - Corrosion Inhibitor (Zinc-based) DREWSPERSE 734 - Dispersant and sequestrant. DREWSPERSE 738 - Antifoulant and Dispersant. BIOSPERSE 240 and 280 - Biocides. CAUSTIC SODA Microbiological growth control was unsatisfactory.
		Oct. 18 - Nov. 19	38.3	30.3	P 360.676.59	
1985	- do -	Dec. 7, '84 - Jan. 6	16.8	8.22	175,008.15	
		Mar. 15 - Apr. 15	15.2	9.74	487,206.80	
		Apr. 17 - May 17	17.1	6.73	405.177.65	
	MAINCHEM	June 14 - July 14 (BASELINE)	40.0	14.6	P 137,138.40	Chemicals Used: COOLTREAT 70A - Corrosion Inhibitor (Zinc-based). HATACIDE 17 and 12 - Biocides. CAUSTIC SODA Biocides achieved acceptable bacterial and algal control.
		July 18 - Aug. 17	27.4	5.78	313,423.14	
		Aug. 20 - Sept. 19	18.1	1.86	243,780.00	
		Oct. 2 - Oct. 19 (17 days only)	16.9	5.08	123,887.62	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 2

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1985	MAINCHEM	Dec.29,'85 - Jan. 28	23.1	7.16	P 294,074.12	Chemicals Used: - do -
		Jan. 31 - Mar. 2	22.7	7.95	277,771.38	Corrosion rates increased during 4th to 7th periods due to underdosage of inhibitor from April to August. 1986.
		Mar. 5 - Apr. 4	11.5	9.33	279,968.50	
		Apr. 5 - May 5	41.7	12.3	248,967.50	Biocides achieved acceptable bacterial and algal control.
		May 11 - June 10	47.3	10.1	293,626.20	
		July 15 - Aug. 14	42.7	13.3	366,413.00	
		Aug. 16 - Sept. 15	28.6	6.89	255,515.00	
		Oct. 1 - 31	33.4	14.2	289,624.20	
1987	ATOM	Jan. 16 - Feb. 9 (BASELINE) (24.25 days only)	10.5	12.5	P 12,675.60	Chemicals Used: HYDROSOLV 2706L - Corrosion Inhibitor (Phosphate-based). BETZ 2020 - Dispersant. BETZ J-12 and HYDROSAN 400 - Biocides. CAUSTIC SODA
		Mar. 28 - Apr. 27	18.8	3.80	199,866.80	
		Apr. 29 - May 29	16.0	6.24	126,337.34	Bacterial and algal levels were controlled and acceptable except on periods where there was absence of biocide.
		June 1 - July 1	16.1	18.4	120,277.60	
		July 7 - Aug. 6	22.1	15.6	135,074.50	
		Aug. 6 - Sept. 5	24.1	14.8	118,877.13	
		Sept. 17 - Oct. 17	17.8	10.5	92,678.07	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 2

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1988		WITH CAUSTIC SODA TREATMENT ONLY				
1989	LIME	NO BASELINE				Chemicals Used: LIME - Corrosion Inhibitor CALCIUM HYPOCHLORITE - A Biocide. CAUSTIC SODA
		Apr. 4 - May 4	21.6	7.62	P 59,376.34	
	LIME Revised Program	May 6 - May 26 (20 days only)	32.1	25.4	29,154.03	Lime revised program started from 2nd test period. with calcium hardness being monitored instead of total hardness.
		June 9 - July 9	27.9	20.2	50,278.80	
		July 17 - Aug. 16	26.3	17.8	50,971.14	Poor algae control. Microbiological levels were however acceptable.
		Aug. 17 - Sept. 16	15.6	11.2	56,148.59	
		Sept. 16 - Oct. 12 (26 days only)	32.0	24.2	52,359.78	
		Oct. 19 - Nov. 18	30.0	8.28	55,562.91	
		Nov. 18 - Dec. 18 (BASELINE)	26.3	12.8	44,718.48	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 2

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1990	LIME Revised Program	Apr. 13 - May 13	19.4	13.6	P 62,254.06	Chemicals Used: - do -
		May 17 - June 16	30.2	27.4	48,296.75	Poor algae control. Microbiological levels were however acceptable.
		June 17 - July 17	26.6	32.9	46,308.43	Average NaOH reduction in consumption is 47.3%.
		July 18 - Aug. 17	8.88	10.4	40,096.14	
		Aug. 18 - Sept. 17	22.0	13.9	46,943.39	
		Sept. 20 - Oct. 20	28.2	71.3	70,143.78	
		Oct. 27 - Nov. 26	19.2	15.2	52,428.27	
		Nov. 27 - Dec. 12 (15.2 days only)	25.1	19.0	13,792.83	
1991	- do -	Feb. 20 - Mar. 22 (BASELINE)	15.8	14.2	P 45,285.30	Chemicals Used: - do -
		May 4 - June 3	12.3	13.2	67,788.86	Poor algae control. Microbiological levels were however acceptable.
		June 18 - July 18	30.3	20.2	36,211.66	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 3

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1984	MAXWELL	June 3 - July 3 (BASELINE)	35.7	8.56	-	Chemicals Used: CORROSTOP P - Corrosion Inhibitor (Phosphate-based). NILCOR C and E-71 - Biocides. CAUSTIC SODA Microbiological levels and algae control were acceptable.
		July 23 - Aug. 7 (15 days only)	7.51	3.47	P 192,712.50	
		Sept. 9 - Oct. 9	4.09	0.12	152,049.00	
		Oct. 17 - Nov. 16	7.62	5.06	162,429.81	
		Dec. 1 - 31	11.8	6.51	171,348.87	
1985	- do -	Jan. 16 - Feb. 15	7.50	6.66	P 162,615.11	
		Feb. 16 - Mar. 18	8.29	2.47	169,081.79	
		Apr. 6 - May 6	7.63	5.96	245,547.50	
		Aug. 23 - Sept. 23 (BASELINE)	23.0	13.6	27,210.00	
		Sept. 29 - Oct. 19 (20 days only)	3.60	10.7	163,606.50	
		Oct. 26 - Nov. 25	15.9	10.0	213,335.50	
		Dec. 10 - 23 (12.9 days only)	8.00	8.38	105,083.70	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 3

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1986	MAXWELL	Sept. 29 - Oct. 29	19.0	11.4	P 221,740.00	- do -
1987	ATOM	Feb. 20 - Mar. 22 (BASELINE)	22.8	13.5	P 26,058.60	Chemicals Used: HYDROSOLV 2706-L - Corrosion Inhibitor (Phosphate-based). BETZ 2020 - A Dispersant. BETZ J-12 and HYDROSAN 400 - Biocides. CAUSTIC SODA
		Apr. 6 - May 6	10.1	7.33	129,536.41	
		June 5 - July 5	12.3	18.2	119,802.10	
		July 6 - Aug. 6	14.2	10.4	128,640.10	Microbiological levels were acceptable and algae control was satisfactory at some particular parts of cooling tower.
		Aug. 6 - Sept. 5	10.2	12.8	136,155.84	
		Sept. 17 - Oct. 17	11.2	11.3	111,639.10	
1988	LIME	Aug. 6 - Sept. 6 (BASELINE)	28.1	15.1	P 35,416.20	Chemicals Used: LIME - Corrosion Inhibitor. CALCIUM HYPOCHLORITE - A Biocide. CAUSTIC SODA
		Sept. 14 - Oct. 14	33.2	4.94	56,578.00	
		Oct. 14 - Nov. 13	65.7	37.4	54,610.80	Poor algae control but bacterial and fungi levels were acceptable.
		Nov. 15 - Dec. 15	27.7	4.67	99,979.23	pH upset occurred in 2nd test period. Total hardness was monitored during lime program.

WATER TREATMENT HISTORICAL DATA
UNIT NO. 3

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1989	LIME	Dec. 17, '88 - Jan. 16	52.1	10.8	P 69,553.69	Chemicals Used: - do -
		Jan. 17 - Feb. 16	27.5	4.77	68,696.78	Poor algae control but bacterial and fungi levels were acceptable.
		Feb. 17 - Mar. 19	25.3	8.32	53,910.00	pH upset occurred during Dec.-Jan. lime period.
	LIME Revised Program	Mar. 20 - Apr. 19	18.2	11.1	47,134.56	Calcium hardness was monitored during revised lime program instead of total hardness.
		Apr. 19 - May 19	11.2	9.37	53,651.32	Average caustic soda reduction in consumption:
		May 20 - June 19	19.9	5.34	57,250.65	1988 - 46.3%
		June 26 - July 26	10.1	5.82	56,763.57	1989 - 27.1%
		July 26 - Aug. 17 (21.4 days only)	28.2	7.26	34,232.11	
		Aug. 25 - Sept. 24	24.5	7.66	37,009.12	
		Sept. 26 - Oct. 26	15.4	9.60	44,303.52	
		Oct. 26 - Nov. 26	26.2	6.30	50,527.63	
1990	LIME Rev. Program with Phyrox Biocides.	Jan. 30 - Mar. 1	21.7	9.12	P 46,682.24	Chemicals Used: LIME - Corrosion Inhibitor. CALCIUM HYPOCHLORITE - A Biocide. P-411C and P-381C - Phyrox Biocides. CAUSTIC SODA
		July 18 - Aug. 17	20.5	5.68	76,551.76	
		Aug. 20 - Sept. 19	16.7	9.40	42,495.90	
		Sept. 19 - Oct. 19	16.8	9.71	33,798.63	Microbiological levels were acceptable while algae control was satisfactory.
		Oct. 20 - Nov. 17	28.7	6.56	26,040.04	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 3

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1990	- do -	Dec. 14 - Jan.4. '91 (20.72 days only)	23.1	11.4	P 47,572.58	Chemicals Used: - do - Microbiological levels were acceptable while algae control was satisfactory.
1991	- do -	Jan. 14 - Feb. 13	26.3	7.68	P 56,348.04	Average caustic soda reduction in consumption:
		Apr. 29 - May 29	8.11	3.86	96,735.21	1990 - 66.6%
		May 30 - June 29	19.8	4.99	104,571.15	1991 - 92.8%
						High % reduction in caustic soda consumption was achieved in 1991 due to use of a good quality lime which is Guanzon lime.

WATER TREATMENT HISTORICAL DATA
UNIT NO. 4

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1983	HOUSEMAN	Feb. 24 - Mar. 18 (BASELINE)	44.7	4.83	-	Chemicals Used: COOLTREAT 70A - Corrosion Inhibitor (Zinc-based). HATACIDE 17 & 12 - Biocides. CAUSTIC SODA
		May 17 - June 17 (BASELINE)	-	22.4	-	
		July 11 - Aug. 10	17.7	1.11	P 130,858.70	Algae control and bacterial levels were acceptable.
		Aug. 22 - Sept. 22	27.4	13.9	175,701.11	
		Oct. 1 - Nov. 2	24.2	7.64	149,700.00	
		Nov. 3 - Dec. 3	16.4	3.49	-	
1984	- do -	Apr. 23 - May 23 (BASELINE)	24.5	17.4	-	Chemicals Used: - do -
		June 7 - July 7	25.6	9.26	P 360,800.00	High cost of first period due to increase in corrosion inhibitor consumption and dosing of Hatacide 12 only which was costlier.
		Aug. 1 - 31	17.1	7.65	242,740.00	High cost of 4th period attributed to increase in consumption of treatment chemicals.
		Sept. 1 - Oct. 1	11.9	7.62	228,605.00	
		Oct. 3 - Nov. 2	36.4	20.7	341,455.00	pH upsets/fluctuations experienced in 4th and 5th periods.
		Nov. 21 - Dec. 22	39.7	9.40	264,990.00	Control of algae and bacterial levels was acceptable.

WATER TREATMENT HISTORICAL DATA
UNIT NO. 4

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1985	HOUSEMAN	Jan. 17 - Feb. 16	27.0	8.02	P 273.611.00	Chemicals Used: - do -
		Mar. 6 - Apr. 5	16.8	7.16	273.996.00	No dosing of Hatacide 12 and interruption of Hatacide 17 dosing during 3rd period.
		May 9 - June 9	17.0	9.58	214.866.00	
		June 22 - July 22	22.4	14.3	248,892.50	Algae control and bacterial levels generally acceptable.
1986	MAXWELL	Nov. 4 - Dec. 4,'85 (BASELINE)	29.0	11.8	P 33,094.00	Chemicals Used: CORROSTOP P - Corrosion Inhibitor (Phosphate-based). NILCOR C and E-71 - Biocides. CAUSTIC SODA
		Dec. 18,'85 - Jan. 17	4.90	11.6	233.230.00	
		Jan. 18 - Feb. 17	3.84	9.14	274,399.06	Algae control was not satisfactory.
		Feb. 19 - Mar. 9 (17.4 days only)	13.8	10.5	137,064.50	During the 6th and 7th test periods, disruptions in chemical dosing occurred.
		Apr. 7 - May 7	5.33	7.80	265.339.00	
		May 10 - June 9	6.00	6.80	239,565.00	
		June 9 - July 9	13.2	8.26	191.620.00	
		Nov. 19 - Dec. 19	12.2	17.7	197,230.24	
		Dec. 20,'86 - Jan. 19,'87	14.7	5.67	212,778.39	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 4

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1987 1988 1989		Unit was more often on shutdown due to insufficient steam supply. There was only caustic soda treatment during period of operation.				
1990	BAUER	Feb. 10 - Mar. 12, '89 (BASELINE)	34.2	17.2	P 58,370.40	DISPERSANT-BIOCIDE PROGRAM ONLY Chemicals Used: ALBAPHOS 135 - A Dispersant. LABUCID 193 and 197 - Biocides. CAUSTIC SODA Algae control and microbiological levels were acceptable.
		Jan. 27 - Feb. 26	29.1	12.6	106,578.90	
		Feb. 26 - Mar. 29	24.4	4.66	86,386.52	
		Mar. 29 - Apr. 28	27.2	7.06	77,550.84	
		Apr. 28 - May 28 (29.7 days)	22.7	18.6	63,840.00	
		May 29 - June 28 (29.47 days)	25.1	7.60	97,146.72	
		July 2 - Aug. 1	35.6	9.58	80,908.50	
	MAINCHEM	Oct. 17 - Nov. 13 (26.4 days)	36.1	10.8	P 104,816.88	Chemicals Used: HATAMINE 3 - Corrosion Inhibitor (Amine-based) HATACIDE 17 and HATACIDE 12 - Biocides. CAUSTIC SODA
			Pretreatment Cost —		128,772.00	

10

WATER TREATMENT HISTORICAL DATA
UNIT NO. 4

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1991	MAINCHEM	Dec. 18,'90 - Jan. 17	24.9	13.2	P 156,694.50	Chemicals Used: - do -
		Feb. 14 - Mar. 16	24.6	8.04	118,423.78	Algae control and microbiological levels were acceptable.
		Mar. 23 - Apr. 8 (16.46 days only)	-	-	-	Caustic soda reduction in consumption:
						1990 - 55.7% (1st test period).
						1991 - 49.9% (Ave. of two test periods).

WATER TREATMENT HISTORICAL DATA
UNIT NO. 5

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1983	ENERTEC & CALGON	Aug. 8,'82 - Feb. 22,'83 (BASELINE, 197.8 days)	-	13.9	-	Chemicals Used: CHEMETICS NCT - Corrosion Inhibitor (Phosphate-based) from Enertec. H212 and H303 - Biocides from Calgon. CAUSTIC SODA
		July 12,'82 - Feb. 22,'83 (BASELINE, 224.8 days)	13.0	-	-	
		June 29 - Aug. 13 (45 days)	8.44	8.67	-	Algae control not acceptable.
1984	ENERTEC	Jan. 20 - Feb. 20 (BASELINE)	18.5	14.2	P 60,321.29	Chemicals Used: CHEMETICS NCT - Corrosion Inhibitor (Phosphate-based). BIOCIDES A and B CAUSTIC SODA
		Mar. 24 - Apr. 22	7.05	2.88	119,147.02	Algae control not acceptable.
		June 26 - July 27	7.86	3.75	P 338,370.00	Chemicals Used: CHEMETICS NCT and HYDREX GCT - Corrosion Inhibitors (Phosphate-based). AF1 and AF2 - Biocides. CALCIUM HYPOCHLORITE (HTH). CAUSTIC SODA Algae control not acceptable, but bacterial counts were acceptable.

WATER TREATMENT HISTORICAL DATA
UNIT NO. 5

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1984	ENERTEC	Sept. 11 - Oct. 12	32.6	4.56	P 237.211.38	Chemicals Used: HYDREX GCT - Corrosion Inhibitor (Phosphate-based). AF1 and AF2 - Biocides. CAUSTIC SODA Bacterial, fungi counts and algae control were not acceptable.
		Nov. 3 - Dec. 3	25.8	5.10	P 323,398.55	Chemicals Used: Same as above with addition of Calcium Hypochlorite. Bacterial, fungi counts and algae control were not acceptable for this test period.
		Dec. 5 - Jan. 4, '85	22.1	3.38	P 306.342.66	Chemicals Used: - do - Algae control not acceptable, but bacterial and fungi counts improved.

WATER TREATMENT HISTORICAL DATA
UNIT NO. 5

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1985	ATOM	Apr. 13 - May 13 (BASELINE)	25.1	6.34	P 74,164.03	Chemicals Used: HYDROSOLV 2706-L - Corrosion Inhibitor (Phosphate-based) BETZ 2020 - Dispersant. HYDROSAN 400 and BETZ J-12 - Biocides. CAUSTIC SODA
		Sept. 3 - Oct. 3	24.0	9.19	155,934.57	
		Oct. 16 - Nov. 15	4.46	10.2	190,350.45	Algae control and bacterial levels were satisfactory.
		Nov. 27 - Dec. 27	12.7	12.2	207,748.83	
1986	- do -	Jan. 7 - Feb. 6	4.66	13.1	P 223,899.20	Chemicals Used: - do -
		Feb. 10 - Mar. 12	16.1	8.77	249,089.79	Algae control was acceptable during 1st and 2nd periods, but unsatisfactory on the 3rd.
		May 13 - June 12	24.1	10.8	237,339.53	Bacterial levels were satisfactory.
	DREW	Aug. 29 - Sept. 28	35.0	13.4	P 743,154.50	DISPERSANT-BIOCIDE PROGRAM ONLY Chemicals Used: DREWSPERSE 739 and 794 - Dispersants. BIOSPERSE 250 and 290 - Biocides. CAUSTIC SODA
		Oct. 2 - Nov. 1	44.0	13.1	336,912.80	
		Nov. 6 - Dec. 6	45.2	12.4	147,949.09	Algae control was poor. High cost of 1st period was due to high chemical dosages and high cost and consumption of caustic soda. Cost of 2nd and 3rd periods were low due to incomplete or disruptions in chemical dosings.

WATER TREATMENT HISTORICAL DATA
UNIT NO. 5

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1987	DREW	Oct. 5 - Nov. 4 (BASELINE)	46.0	17.6	P 80,701.50	COMPLETE PROGRAM Chemicals Used: DREWGARD 189E - Corrosion Inhibitor (Zinc-based). DREWSPERSE 739 - Dispersant. BIOSPERSE 250 and 350 - Biocides. CAUSTIC SODA
		Nov. 28 - Dec. 28	44.4	18.8	236,184.00	Algae control and bacterial levels were satisfactory.
1988	- do -	Feb. 23 - Mar. 24	25.4	29.5	P 373,549.00	Chemicals Used: - do - Algae control was satisfactory while bacterial levels were generally unsatisfactory.
1989	PHYROX	Aug. 20 - Sept. 19, '88 (BASELINE)	50.4	24.7	P 84,111.80	DISPERSANT-BIOCIDE PROGRAM ONLY Chemicals Used: PHYROXAL P-560 - A Dispersant. PHYROXAL P-411 and P-381 - Biocides. CAUSTIC SODA
		Jan. 25 - Feb. 24	31.5	13.8	122,260.00	
		Feb. 25 - Mar. 27	20.5	9.16	97,396.00	Bacterial levels and algae control were acceptable.
	MAINCHEM	May 21 - June 20	26.7	20.8	P 255,859.38	Chemicals Used: HATAMINE 3 - Corrosion Inhibitor ([illegible] based). HATACIDE 17 and 12 - Biocides. CAUSTIC SODA
		June 23 - July 23	23.6	15.4	184,605.12	
		Aug. 12 - Sept. 11	21.0	5.27	198,249.60	
		Sept. 14 - Oct. 14	-	-	188,775.00	Algae growth was very satisfactory and bacterial levels were acceptable.

WATER TREATMENT HISTORICAL DATA
UNIT NO. 5

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1989	MAINCHEM	Oct. 17 - Nov. 16	14.5	10.7	166,430.04	Chemicals Used: - do -
		Nov. 16 - Dec. 16	8.79	14.0	170,744.04	Algae growth was very satisfactory and bacterial levels were acceptable.
		Dec. 17 - Jan. 16, '90	26.7	12.9	48,412.26	Incomplete treatment during last period of 1989.
1990	- do -	Jan. 25 - Feb. 24 (BASELINE)	26.1	11.6	P 29,161.08	Chemicals Used: - do -
		Feb. 25 - Mar. 22 (BASELINE)	28.7	11.5	5,571.72	Algae growth and microbiological levels were acceptable.
		Mar. 24 - Apr. 23	12.2	7.74	195,322.86	Average increase in NaOH consumption is 21.7% compared with baseline.
		Apr. 23 - May 23	4.62	9.76	173,845.53	
		May 23 - June 22	11.0	10.9	165,746.70	
		July 12 - Aug. 11	11.0	8.08	161,009.79	
		Aug. 11 - Sept. 10	20.2	10.8	197,517.78	
		Sept. 11 - Oct. 11	6.27	5.86	204,669.36	
		Oct. 11 - Nov. 10	7.50	10.9	215,559.54	
		Nov. 10 - Dec. 10	3.31	57.2	156,352.14	
		Dec. 13 - Jan. 12, '91	7.08	11.5	232,148.07	

116

WATER TREATMENT HISTORICAL DATA
UNIT NO. 5

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1991	MAINCHEM	Jan. 13 - Feb. 12	9.36	14.4	P 167,175.61	Chemicals Used: - do -
		Apr. 4 - May 4	3.12	6.75	196.386.40	Algae control and microbiological levels were acceptable.
		May 12 - June 11	-	-	255,872.82	Third period of 1991 was without rate results for MS due to unavailability of MS coupons.
		June 30 - July 30	6.80	9.20	259,174.44	
		Aug. 12 - Sept. 11	7.00	4.64	258,822.90	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 6

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1983	CALGON	July 12,'82 - Feb. 22 (BASELINE, 224.8 days)	6.68	-	-	Chemicals Used:
		Aug. 8,'82 - Feb. 22 (BASELINE, 197.8 days)	-	10.7	-	CL-246W - Corrosion Inhibitor (Phosphate-based) H212 and H303 - Biocides CL 95 - Dispersant
		Mar. 8 - Apr. 19 (45 days)	15.1	13.3	P 132.081.00	LIME - Supplied free of charge FILM FORTIFIER - Supplied free of charge CAUSTIC SODA
		May 31 - July 15 (45 days)	30.0	5.74	232,019.27	Microbiological levels were acceptable.
1984	- do -	Mar. 8 - Apr. 8 (BASELINE)	28.4	8.91	-	Chemicals Used: - do -
		May 10 - June 9	23.5	4.90	P 322.901.26	The 3rd period for 1984 had no lime dosing. It had dosing interruptions.
		June 26 - July 27	11.1	5.58	373,309.88	Microbiological levels were acceptable.
		Aug. 16 - Sept. 15	44.2	40.4	405,912.25	
		Nov. 21 - Dec. 21	9.22	3.67	329,158.70	
		Dec. 22 - Jan. 21,'85	8.52	6.91	380,818.23	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 6

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1985	CALGON	Feb. 3 - Mar. 5	3.96	7.32	P 373.095.19	Chemicals Used: - do -
		Mar. 7 - Apr. 6	3.66	6.45	315.888.79	Microbiological levels were acceptable.
	KEMICHROFF	June 9 - July 9 (BASELINE)	35.0	10.7	P 65,757.50	Chemicals Used: KYKLOS 415 - Corrosion Inhibitor KYKLOS 416 and KYKLOS 417 - Biocides. CAUSTIC SODA
		July 15 - Aug. 14	14.2	9.02	171,328.88	
		Aug. 16 - Sept. 15	15.7	6.32	212,210.40	Poor algae control.
		Sept. 19 - Oct. 19	10.4	12.4	197,051.40	
		Oct. 22 - Nov. 21	9.96	12.5	212,289.00	
		Nov. 27 - Dec. 27	10.6	10.3	233,381.34	
1986	- do -	Jan. 8 - Feb. 7	10.9	14.4	P 217,839.84	Chemicals Used: - do -
		Feb. 8 - Mar. 10	28.0	17.2	208,236.18	The 4th test period had chemical dosing interruptions. Only caustic soda and the corrosion inhibitors were dosed.
		Mar. 16 - Apr. 15	27.7	15.1	229,106.34	
		Apr. 27 - May 27	24.3	14.4	191,098.22	Poor algae control.
		June 16 - July 16	37.4	12.2	209,602.49	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 6

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1986	DREW	Sept. 13 - Oct. 13	30.6	30.3	P 556,516.10	Chemicals Used:
		Oct. 14 - Nov. 13	41.6	20.0	270,249.50	DREWSPERSE 739 and 794 - Dispersants. BIOSPERSE 250 and 230 - Biocides. CAUSTIC SODA
		Nov. 13 - Dec. 13	47.7	26.0	262,358.02	
		Dec. 16 - Jan. 15, '87	28.4	19.8	229,890.69	Poor algae control.
1987		WITH CAUSTIC SODA TREATMENT ONLY				
1986	MAXWELL	Feb. 3 - Mar. 4 (BASELINE)	45.4	23.2	P 81,446.10	Chemicals Used;
		Mar. 20 - Apr. 19	24.8	3.48	261,248.20	CORROSTOP P - Corrosion Inhibitor (Phosphate-based). NILCOR C and E-71 - Biocides. CAUSTIC SODA
		Apr. 20 - May 20	37.4	11.3	143,732.41	
		May 21 - June 20	44.6	3.47	312,046.05	The 1st and 2nd test periods used only the two biocides and caustic soda for treatment.
		June 21 - July 21	46.2	6.44	246,681.67	Corrosion inhibitor was implemented only on the 3rd test period.
		July 23 - Aug. 22	33.0	6.80	118,298.02	Incomplete set of treatment chemicals was used for the 5th test period. Microbiological levels were acceptable.

120

WATER TREATMENT HISTORICAL DATA
UNIT NO. 6

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1989	LIME	Feb. 20 - Mar. 15 (BASELINE. 22.8 days)	44.0	12.2	P 53.600.00	Chemicals Used:
		Mar. 17 - Apr. 16	36.7	12.6	64,112.10	LIME - Corrosion Inhibitor CALCIUM HYPOCHLORITE - Biocide. CAUSTIC SODA
		Apr. 21 - May 21	47.7	17.8	79.640.34	
	LIME Revised Program	May 24 - June 23	44.1	14.8	43,281.99	The 5th test period had no Calcium Hypochlorite dosing througout the test period.
		Aug. 12 - Sept. 11	47.3	15.2	42,828.41	Average NaOH reduction in consumption for 1989 was 59.8%.
		Sept. 15 - Oct. 15	38.8	18.8	38,246.27	Poor algae control. Microbiological levels were however acceptable.
		Oct. 17 - Nov. 16	39.2	16.2	54,444.38	
		Nov. 16 - Dec. 16	28.3	16.4	52,653.96	
1990	LIME Revised Program	Dec. 21, '89 - Jan. 10 (BASELINE, 20.2 days)	53.2	15.6	P 21,020.91	Chemicals Used: - do -
		Jan. 20 - Feb. 19	47.4	21.1	28,557.16	Poor algae control. Microbiological levels were however acceptable.
		Feb. 19 - Mar. 21	16.8	23.0	26,749.50	
		Mar. 22 - Apr. 21	20.7	18.3	32,133.72	
		Apr. 26 - May 26	44.8	19.2	33,274.08	
		July 21 - Aug. 20	35.4	16.9	47,809.06	

WATER TREATMENT HISTORICAL DATA
UNIT NO. 6

YEAR	PROGRAM	TREATMENT PERIOD	MS CORROSION RATE, MPY		COST	REMARKS/COMMENTS
			COLDSIDE	HOTSIDE		
1990	LIME Revised Program	Aug. 22 - Sept. 19 (28.5 days)	26.2	17.5	48,510.08	Chemicals Used: - do - Poor algae control. Microbiological levels were however acceptable. Average NaOH reduction in consumption in 1990 was 82.2%
		Dec. 16 - Jan. 15, '91	31.8	9.21	28,369.36	
1991	- do -	Jan. 16 - Feb. 15	37.2	8.78	P 40,802.64	Chemicals Used: - do - Poor algae control. Microbiological levels were however acceptable.
		Feb. 20 - Mar. 22 (BASELINE)	26.4	10.5	21,840.66	
		Apr. 29 - May 29	37.0	12.1	37,716.94	
		June 30 - July 30	39.6	10.4	27,579.51	
		Aug. 12 - Sept. 11	40.4	10.4	43,000.71	

Republic of the Philippines
National Power Corporation
Leyte Geothermal Power Plant
Tongonan, Ormoc City, Leyte

Water Treatment for Leyte Geothermal Power Plant

Page

I. LGPP - I Water Treatment Chemicals 1

II. Problems Encountered and Action Taken 2

III. Analysis of Steam Condensate 3

IV. Typical Analysis of Spring Water 3

V. Typical Water Chemistry at Different Sections of Cooling Line 4

VI. Previous Chemical Treatment 5

VII. Review and Assessment of the Previous Treatment 6-7

122

PROBLEMS ENCOUNTERED AND ACTION TAKEN

1. Clogging of Caustic Soda (NaOH) line to the cold basin.

   Action taken:
   1. Reduced caustic soda discharge concentration to 0.5 - 2% NaOH from the KRTA recommended concentration of 10 - 20% NaOH.
   2. Provided water flashing line (rubber hose) to rectify clogged lines.

2. Increased sludge volume due to undissolved lime in the cold basin.

   Action taken:
   1. Provided a lime mixing tank with agitator for this purpose.
   2. Elevated the suction elevation of the lime tank to minimize the undissolved solids going with the lime slurry to the cold basin.

3. HATACIDES 17 produces foams.

   Action Taken:
   1. Minimized foaming with the use of anti-foam chemical,
   2. or in the absence of anti-foam, regulated the dosage so as not to affect the condenser vacuum.

124

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Tongonan, Ormoc City

Analysis of Steam Condensate

pH	-	4.3 - 4.6
Chlorides	-	<1 ppm
SiO2	-	<1 ppm
T-Fe	-	<1 ppm
Total Solids	-	<8 ppm
Elect'l Conductivity	-	70 - 120 micromhos/cm
Dissolved H2S	-	70 - 150 ppm

Typical Analysis of Spring Water - used as initial fill of the tower basin.

pH (pH units)	-	6.5 - 7.5
p alkalinity as ppm CaCO3	-	0
m alkalinity as ppm CaCO3	-	20 - 50
Ca hardness as ppm CaCO3	-	60 - 80
Na hardness as ppm CaCO3	-	10 - 20
Chlorides as ppm CaCO3	-	30 - 80
Total Iron as ppm Fe	-	0.01 - 0.05
Total Solids ppm	-	150 - 130
Electrical Conductivity	-	200-260 micromhos/cm

125

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LEYTE GEOTHERMAL POWER PLANT - I
Tongonan, Ormoc City

WATER TREATMENT CHEMICALS

CHEMICAL	FUNCTION	METHOD OF DOZING	CONTROL LIMITS
CAUSTIC SODA (NaOH)	to neutralize acidity of steam condensate	continuous	pH 6.5 - 7.5
HATACIDE 17	Biocide-Dispersant (to control microbiological growth and minimize deposition)	slug doze (once per month or as necessary)	<50 ppm amine
LIME Ca(OH)2	reduce corrosivity of cooling water & caustic soda consumption	continuous (in slurry form)	30 ppm CaCO3 max.
GRANULAR CHLORINE	Chlorination of domestic water supply	continuous (injected to the water line through a chemical feeder)	0.2 ppm Cl2 max. (residual

REMARKS:

1. Caustic Soda is injected at 1 - 2% NaOH.
2. Hatacide 17 is a biocide - dispersant (proprietary) based on quaternary amine.
3. Granular Chlorine is sometimes applied to the cooling tower when the need arises. This is also to control algae growth in the ACWP & GECWP area and surrounding areas.
4. Chemical treatment cost is less than ₱3.00/MWH generated.

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126

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Tongonan, Ormoc City

NATURE OF ENVIRONMENT (TONGONAN COOLING WATER SYSTEM)
TYPICAL WATER CHEMISTRY

LOCATION	Temp. C	pH	H2S	MO ALK	T-Fe	Cl	Ca H	SO4	T.S.	L.I.
MAIN COOLING LINE	28-31	6.8-7,5	0.2-0.7	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.55
HOT WELL PUMP DISCHARGE LINE	39-42	6.5-7.2	0.8-1.2	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.58
AUXILLIARY COOLING WATER PUMP DISCHARGE LINE	28-31	6.8-7.5	0.2-0.7	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.55
GAS EXTRACTION COOLING WATER PUMP DISCHARGE LINE	28-31	6.8-7.5	0.2-0.7	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.55
MAIN CONDENSER	45-48	6.5-7.2	0.8-1.5	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.66
AFTER/INTER CONDENSER	55-95	4.8-6.0	10-30	10-15	0.3-6.0	5-40	0.5-10	50-200	150-600	-3.79
GENERATOR AIR COOLER	36-43	6.8-7.5	0.2-0.7	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.60
LUBE OIL COOLER	36-40	6.8-7.5	0.2-0.7	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.50
ACWP / GECWP	28-31	6.8-7.5	0.2-0.7	10-25	0.3-6.0	5-40	0.5-10	50-200	150-600	-2.55

NOTE :
1. Concentration of impurities are in ppm.
2. L.I. - Langlier Index

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National Power Corporation
LEYTE GEOTHERMAL POWER PLANT - I
Tongonan, Ormoc City

P R E V I O U S C H E M I C A L T R E A T M E N T

SUPPLIER	CORROSION INHIBITOR	DISPERSANT	BIOCIDE
1. PETER BLAISE	Blaise 696 - Polyphosphate	Blaise 505 - lignosulfonate	Blaise 466A - Oxidizing biocide Blaise 466B - Non-oxidizing biocide
2. NALCO	GEOPOWER IV, ZINC, PHOSPHONATE	GEOPOWER V, Synthetic Polymer	NALCO 7328 - Non-oxidizing biocide
3. JARDINE NEW HOUSEMAN	Cooltreat 70A - Zire, Organic	HATACIDE 17	HATACIDE 12 - Non-oxidizing biocide
4. JOSEPH LONDON GROUP	CORROSTOP P - Ortho-phosphate, Phosphonate	incorporated in the inhibitor	NILCOR C - Non-oxidizing biocide MAXWELL E-71 - Non-oxidizing
5. ATOMS INDUSTRIAL SALES - ARMAN	ATOMINE 166 - Amine	HYDROSOLVE 2501 - Surfactant	HYDROSAN 400 - Non-oxidizing biocide
6. CHEMICROFF ASIA INDUSTRIES	K-418-Amine, aldehyde	K-416-Biodispersant	K-417 - Non-oxidizing contact biocide
7. MAIN CHEM	HATAMINE 3-Amine, SODA ASH	H A T A C I D E 17 Quaternary Amine	

128

REVIEW OF THE PREVIOUS TREATMENT & ASSESSMENT

1. PETER BLAISE PROGRAM

The Peter Blaise 696 (Polyphosphate) and Blaise 505 (lignosulfonate) when applied to the system caused lowering of the cooling water pH. With this treatment, the Caustic Soda requirement to maintain the required pH is 3-4 times the normal caustic soda consumption.

The lowering of the water pH maybe attributed to the formation of acid Sulfate (enhanced by SO_4 forming bacteria). The chemical additive (polyphosphate) is a good nutrient for bacteria. The treatment program was discontinued due to high caustic consumption and poor performance.

2. NALCO PROGRAM

The Nalco GEOPOWER program did not performed satisfactorily when tested in the cooling water system. The Zinc inhibitor reacted with the H_2S in the cooling water forming a precipitate of ZnS which has a low solubility product (1×10^{-23} moles/liter). The mechanism of corrosion inhibition with Zinc is that it will deposit at the cathodic areas as $Zn(OH)_2$, forming a barrier film. The reduction of cathodic areas will in effect reduce the rate of anodic reactions. Due to interference with Hydrogen Sulfide the required Zinc residual cannot be attained due to reaction with hydrogen sulfide. Treatment was discontinued due to incompatibility of the additive to the inherent chemistry of the cooling water.

3. JARDINE NELL HOUSEMAN PROGRAM

JARDINE NELL HOUSEMAN program with cooltreat 70A (Zinc Organic inhibitor) did not worked effectively when tested in the cooling system. The same thing with the GEOPOWER IV of NALCO the cooltreat 70A reacted with the H_2S in the cooling water forming a precipitate of ZnS, thus the required level of Zinc residual to maintain good corrosion protection was not attained. However, the HATACIDE 17 Biocide-dispersant was effective in controlling microbiological count. The Zinc treatment program was confirmed not workable in the cooling water system.

4. JOSEPH LONDON GROUP PROGRAM

The corrostop P (orthophosphate, phosphonate) corrosion inhibitor of JOSEPH LONDON GROUP also did not performed effectively when applied to the cooling water pH. The same with Peter Blaise 696 the corrostop P caused water pH lowering that needs 3-4 times the normal caustic consumption to maintain the required pH. The biocides NILCOR C & MAX E-71 also did not performed effectively. The phosphate treatment was confirmed not workable in the cooling system.

5. ATOMS INDUSTRIAL SALES PROGRAM

The Atoms Industrial Sales (Atomic 166) amine program did not performed effectively in the cooling water system. Although there was no increase in the caustic requirement the results of corrosion rate and microbiological count monitoring did not yield satisfactory results. The treatment program was discontinued.

6. THE CHEMICROFF ASIA INDUSTRIES AMINE PROGRAM

The Chemicroff Asia industries treatment program with K-418 (amine aldehyde) corrosion inhibitor, K-416 (Biocide-dispersant), and K-417 (non-oxidizing biocide) also did not worked effectively in the cooling system. The corrosion rate and microbiological count monitoring did not yield satifactory results. The treatment was discontinued.

7. MAIN CHEM PROGRAM

The Main Chem program with HATAMINE 3 (amine based) corrosion inhibitor and Hatacide 12 was relatively effective compared to the aforementioned treatment programs. The caustic consumption was significantly reduced and the microbiological count is also very low ($<10^3$ colonies/mL) with sometimes a reading of zero (0) colonies/mL. Hatacide 17 biodispersant is until now being applied in the system and is slug-dozed once a month or as necessary. The Hatamine 3 was discontinued and was replaced with Industrial lime.

130

APPENDIX D

NPC Memorandum transmitting: Implementing Guidelines for the Application of Geothermal Water Treatment Programs

REPUBLIKANG PILIPINAS
Pambansang Korporasyon Sa Elektrisidad
(NATIONAL POWER CORPORATION)

MDAD-91-239
June 3, 1991

MEMORANDUM TO:

Vice-Presidents, SLRC & VRC
Plant Managers, MGPP, TGPP, LGPP & PGPP

SUBJECT : Implementing Guidelines for the Application of Geothermal Water Treatment Programs

Recognizing the established limitations of the lime treatment program in our geothermal power plants, management has decided to also adopt water treatment chemicals in safeguarding the integrity of plant equipment in contact with geothermal cooling water. Along this line, the following implementing guidelines shall be instituted as a matter of policy:

1.0 COVERAGE AND APPLICATION

As a general rule, the need for water treatment chemicals shall be governed by the following:

1.1 Plants with experienced corrosion rates greater than 15 mpy and excessive algal growths shall adopt any of the applicable treatment schemes below:

a. Those with substantial caustic soda savings (>20%) using lime treatment shall adopt complete water treatment chemicals in combination with lime.

b. Those with no or minimal caustic soda savings (<20%) using lime treatment shall adopt complete water treatment chemicals only.

1.2 Plants with experienced corrosion rates greater than 15 mpy but with minimal algal growth shall utilize any of the applicable treatment schemes below:

a. Those with substantial caustic soda savings (>20%) using lime treatment shall utilize corrosion inhibitor in combination with lime.

b. Those with no or minimal caustic soda savings (<20% using lime treatment shall only utilize corrosion inhibitors.

1.3 Plants with experienced corrosion rates below 15 mpy but with excessive algal growths shall implement any of the applicable treatment schemes below:

w/ Addendum

a. Those with substantial caustic soda savings (>20%) using lime treatment shall implement biodispersant and microbiocide as an alternate biocide in combination with lime.

b. Those with no or minimal caustic soda savings (<20%) using lime treatment shall only implement biodispersant and microbiocide as alternate biocide.

1.4 Plants with experienced corrosion rates below 15 mpy with no or minimal algal growths shall adopt any of the below schemes:

a. Those with successful experience using lime treatment shall continue to adopt lime as treatment.

b. Those with successful experience using caustic soda shall continue to adopt caustic soda as treatment.

1.5 Plants with cooling water that does not inherently require caustic soda for pH correction need not implement lime treatment.

1.6 Plants with cooling water pipings made of FRP or with stainless steel lining need not use any chemical treatment unless such experiences excessive algal growths. In this case, biodispersant and microbiocide as an alternate biocide may be used.

2.0 WATER TREATMENT CHEMICAL SPECIFICATIONS

When required in accordance with Item 1.0 above, water treatment chemicals to be procured shall be as follows:

2.1 Scale and Corrosion Inhibitor, with synergistic formulation of zinc, molybdate, organo phosphate and amino compounds, nonchromate-based, liquid or solid form, completely soluble in cooling water with pH ranging from 6.5 to 8.0, nonprecipitating at high hydrogen sulfide levels, environmentally safe based on NPCS and/or EPA standards and with target corrosion rate in combination with other water treatment chemicals (biodispersant & microbiocide) and lime, when required, of less than 15 mpy.

2.2 Biodispersant, broad spectrum biocide with quarternary amines (liquid form) or aliphatic amine acetate (waxy solid form), with dispersing and filming properties, effective against a wide range of bacteria, fungi and

algae, blended with surfactants, non-foaming, biodegradable, completely miscible in cooling water with pH ranging from 6.5 to 8.0, environmentally safe based on NPCC and/or EPA standards and compatible in combination with other water treatment chemicals (scale/corrosion inhibitor & microbiocide) and lime, when required.

2.3 Microbiocide, broad spectrum biocide for effective control of resistant algae, fungi and slime, with polymethylene dichloride or carbonate compounds or benzalkonium chlorides, tributly tin oxide and anti-foam agents as active ingredients, liquid form, biodegradable, completely soluble in cooling water with pH ranging from 6.5 to 8.0, environmentally acceptable based on NPCC and/or EPA standards and compatible in combination with other water treatment chemicals (scale/corrosion inhibitor & biodispersant) and lime, when required.

3.0 GENERAL REQUIREMENTS

In addition to the above generic specifications for water treatment chemicals, the general requirements below shall be made part of the procurement documents, as applicable:

Prequalification of Suppliers/Contractors

a. Only suppliers/contractors whose water treatment chemical products are proven effective based on previous plant experience shall be considered automatically prequalified to participate in biddings for chemical water treatment programs.

Previous suppliers/contractors whose water treatment chemical products failed and/or were not successful based on plant experience but previously passed NPC's prequalification requirements shall furnish to the NPC the below submittals subject to NPC acceptance before being allowed to participate in the bidding for chemical water treatment programs:

b.1 Comprehensive written report on their study and analyses of the failure root cause of their previous water treatment programs applied to NPC geothermal plants.

b.2 Improvements to be undertaken to ensure success and preclude recurrence of failure of their water treatment program previously applied to NPC geothermal plants.

b.3 Results of their laboratory scale testing after applying Item b.2.

c. New suppliers/contractors shall only be allowed to participate in bidding for chemical water treatment programs subject to the following:

c.1 Compliance to NPC accreditation and pre-qualification requirements.

c.2 Satisfactory results of their laboratory scale testing of their water treatment chemicals.

Note: Laboratory scale testing of prospective bidder shall be closely coordinated with the of the concerned plant.

3.2 Prequalified Supplier/Contractor Submittals

Prequalified suppliers/contractors as well as those allowed to participate in biddings for water treatment programs in accordance with Item 3.1 above shall submit the following:

a. Bidders Proposal providing a complete description of their water treatment program in accordance with Item 3.3.

b. Certification of Registration and Clearance from National Pollution Control Commission (NPCC) of their chemical products. In case of proprietary chemicals, they should have the corresponding environmental approval from the country of origin, e.i., EPA (Environmental Protection Agency).

c. Original (from manufacturer) literatures/brochures/bulletins specifying the important physical and chemical properties of their products as well as their base components and corresponding recommended effective dosages.

d. List of active ingredients of each of their proposed water treatment chemicals together with representative samples (in 1-liter plastic

container) for purposes of conformity checking against manufacturer literature/brochure/bulletins specified physical/chemical properties and reference during receipt inspection.

In addition to the above, the bidder shall require its principal manufacturer to submit directly to NPC on or before the bidding date, an authenticated certificate of exclusivity for the bidder to represent the manufacturer and/or distribute its product in the Philippines

3. Water Treatment Program Proposals

For purposes of determining the completeness of bidder submitted water treatment program proposals, the following shall be considered, as applicable:

a. Bidders shall provide in their offer the quantity and types of chemicals to be used under their proposals as well as itemized cost and list of consumables, equipment rentals and services to be supplied at plant site. If pre-treatment is necessary, the bidder shall also provide separate and itemized cost for such for the duration of their proposal.

b. Treatment program proposals shall include pre-treatment (as necessary) and maintenance treatment as a package and shall sufficiently detail recommended schedules and dosages considering actual cooling system design peculiarities operating data and control parameters to be maintained.

The treatment program proposal shall provide targets in terms of corrosion rate, algal growth and micro-organism count (both algal and fungi) considering the baseline data established by the plant.

d. Bidder shall state in their proposal whether the chemical to be supplied are pre-mixed by their principal manufacturer or repacked/formulated or mixed by the bidder itself. In all there cases, the bidder shall indicate the active ingredients, potential pollutants and solvents used, if any.

136

e. Water treatment proposals shall also describe the method of application (feeding system) for each chemical to be used under the program and include appropriate implementing procedures to be adopted to ensure control and effective realization of program targets.

When required to be used with lime, bidder water treatment program proposals shall also consider their compatibility and suitability with the plant's lime treatment program.

The proposal shall provide for installation of corrosion rack in accordance with the requirements of NACE TPC Publications No. 1. Corrosion racks to be installed in connection with the water treatment program shall have a portion with clear glass/plastic to assure that the sides of the coupon do not touch the pipe during installation and for monitoring of corrosion coupon condition.

h. Water treatment proposals shall consider provision/availability for adequate personnel (preferably chemical engineer) having full background and knowledgeable on the water treatment to be applied for the duration of the contract to:

h.1 Maintain chemical inspection equipment

h.2 Perform chemical charging functions

h.3 Collect water samples for analysis

h.4 Analyze/resolve water treatment problems

h.5 Perform related functions in connection with their water treatment programs as may be required by the plant

3.4 Water Treatment Program Implementing Guidelines

a. Prior to implementing a water treatment program, the concerned plant shall established baseline data for each of their operating units. During baseline data gathering, the cooling water of the unit under consideration shall only be treated with caustic soda, or where lime treatment has been proven successful, with lime. As a minimum, operating parameters/conditions to be maintained/monitored during baseline data gathering shall be as follows:

Parameters/ Conditions	Limits	Frequency of Analysis/ Monitoring
1. pH at 25°C	6.5-7.5	Every 2 hrs.
2. Alkalinity	As Recorded	Every Shift
3. Hardness	10 ppm(max.)	Daily
4. Chloride	As Recorded	-do-
5. Sulfate	150 ppm(max.)	-do-
6. Total Iron	5 ppm(max.)	-do-
7. H_2S	As Recorded	-do-
8. Silica	-do-	-do-
9. Total Solids	500 ppm(max.)	Weekly
10. Electrical Conductivity	800 umho(max.)	Every 2 hrs.
11. Temperature	As Recorded	-do-
12. Flow Rate(racks)	3-5 ft./sec. (5-7 gpm)	Every Shift
13. Microbiological Count	As recorded	Weekly

Note: Sampling points shall be at discharge (hot and cold sides) of corrosion racks. Period of baseline data gathering should be 30 days. Aside from cooling water, ph and steam quality of steam condensate shall also be gathered.

b. Baseline data gathering shall also include reference information such as frequency of cleaning of suction pit strainers/hydrogen coolers/cooling tower distribution basins and other system components directly in contact with treated water, temperature differentials of heat exchangers, unit forced outage/derating due to related operational causes, visible algal growth and extent, etc.

c. Unspecified water treatment parameters/limits shall be agreed upon by the plant and the supplier/contractor prior to the start of the treatment. These include among others corrosion rates, algae growth rates, baseline caustic soda consumption and integrity/strength of wood materials of the cooling towers.

d. Corrosion coupons shall be pre-treated prior to installation in the corrosion racks. The coupons shall be jointly sealed for security purposes. Also, prior to installation of the coupons, the

cooling water flow rate thru the corrosion racks shall be adjusted between 3-5 ft/sec (5-7 gpm). while the cooling water pH shall be maintained within 6.5 to 7.5.

e. Availability of necessary water treatment program resources (chemicals, equipment, personnel, etc.) and compliance to schedules, dosages and frequency of dosing, sampling and analysis shall be observed at all times for the duration of the treatment program. Also, supplied feeding and monitoring instruments shall be adequate and calibrated.

f. Microbiological count (bacterial & fungal count) using dipslides and algae growth monitoring by visual inspection and photographing shall be done regularly and compared against baseline data/ reference information.

g. Wooden structures, louvers, end walls and other parts of the cooling tower which do not receive sufficient biocide treatment shall be periodically cleaned.

h. In case of plant/unit interruption, corrosion coupons shall be secured in submerged state thru isolation of corresponding valves. Installed coupons are considered valid subject to the following conditions:

h.1 Cummulative plant/unit interruption during the treatment period does not exceed three (3) days or seventy-two (72) hours. In such case, the interruption could be considered part of the water treatment program period. Commulative interruptions beyond such period shall require the water treatment program to be restarted anew.

h.2 Coupons that have been exposed to a minimum of twenty-five (25) continuous plant/unit operating days including any allowable interruption cited in Item i.1 can already be retrieved for corrosion rate determination.

i. Biocide application during pre-cleaning stage of the water treatment program shall not be limited to dosing into the system. Applicable methods such as spraying when deemed necessary must also be utilized.

j. Minor changes in inhibitor/dispersant/biocide treatment (frequency and quantity/amount) may be allowed during the implementation stage of the water treatment program. Such changes shall be requested in writing by the supplier/contractor for evaluation and approval by the plant prior to implementation.

k. Except for minor changes allowed and approved by plant recommended dosage rate (pre-treatment and maintenance) of the water treatment programs as provided for in the original proposals/brochures shall be strictly followed at all times.

3. Evaluation of Water Treatment Programs

The cooling water treatment program shall be deemed a failure or ineffective if any of the following conditions or combinations thereof exist:

a. Corrosion rate based on test coupons exposed for at least twenty-five (25) days continuous operation proximeter baseline data or exceeds 15 mpy. with accompanying pitting corrosion.

b. Total microbiological count (bacteria, fungi and algae) repeatedly exceeds 100,000 organism per ml of cooling water during any phase of the water treatment program implementation. For this purpose, microbiological count before and after application of biocide shall be conducted to verify reduction in microbiological growth and improvement by the biocide treatment.

c. Any chemical under the water treatment program expires during implementation phase.

d. The chemical's effluent results to visible death of marine life at the discharge of treated water, an indication that such contain toxic chemicals or heavy metal in excess of NPCC limits.

e. The water treatment program results to prolonged (more than one week) uncontrollable heavy growth of filamentous algae inspite continuous use of biocide. For purposes of comparison, the scrape and weigh method shall be used in evaluating the degree of microbiological growth on wooden structure. Also, the treatment program results to excessive accumulation of microbiological organic substances

such as dust, silt, scale fragments, corrosion by products and other debri at the cooling tower basin causing uneven distribution of cooling water flow and clogging of metering orifices. Pictures of plant auxiliaries shall be taken before and after treatment periods to provide additional information in support to visual inspection and evaluation of the water treatment program.

f. The application of the treatment program results to plant operational/maintenance constraints that consequently affects unit/plant reliability as follows:

f.1 Heat transfer and fouling problems on heat exchangers either short-term (4-8 hours after chemical application) or long-term (several days or weeks). Fouling tendencies shall be evaluated by temperature change or pressure drop across such heat exchangers.

f.2 Strainer clogging.

f.3 Low condenser vacuum.

f.4 Cooling tower structure deterioration.

The chemical treatment application results to excessive foaming at the cooling tower and condenser affecting unit operation or causing recurrent unit protective device false alarm annunciation/indication or causing the unit to trip.

h. The water treatment program results in excessive caustic soda consumption above 20% of established base line data.

4.0 TERMS AND CONDITIONS

4. The contract duration for water treatment programs shall be three (3) months excluding plant outages. Starting date shall be two (2) weeks after signing of the contract.

4. Delivery of water treatment chemicals to the concerned plant shall be done on a monthly basis at quantities corresponding to the estimated one (1) month consumption. Additionally, a stock good for another one (1) month consumption shall be maintained at any

time and [illegible] for delivery to the plant to preclude treatment interruptions. The contractor shall closely coordinate with the plant with regards to the quantity to be delivered taking into account forthcoming scheduled plant outages as well as other relevant factors.

4.3 Payment shall be done on monthly basis in the amount corresponding to the actual quantity of chemicals consumed or delivered, whichever is lesser provided that the treatment program is considered successful. In case that the program has been declared a failure or considered ineffective based on Item 3.5 above, only 50% of the actual cost of chemicals used shall be paid.

4.4 The contractor/supplier shall exercise due diligence during the implementation of their water treatment programs. It shall also be responsible for the effective implementation of their program within the bounds of NPC requirements and protocols.

4.5 Operational upsets caused by NPC which result to additional increase in chemical consumption shall be charged to NPC. On the other hand, operational upsets due to the contractor shall be for their account.

4.6 NPC has the option to terminate or rescind its contract with the supplier/contractor if it deems the furtherance of the treatment program is detrimental and disadvantageous to its own interests as determined from Item 3.5.

In connection with the above, all previously issued directives that are inconsistent with this memorandum are deemed superceded.

Please be guided accordingly.

C. PLATA
Sr. Vice-President
Operations

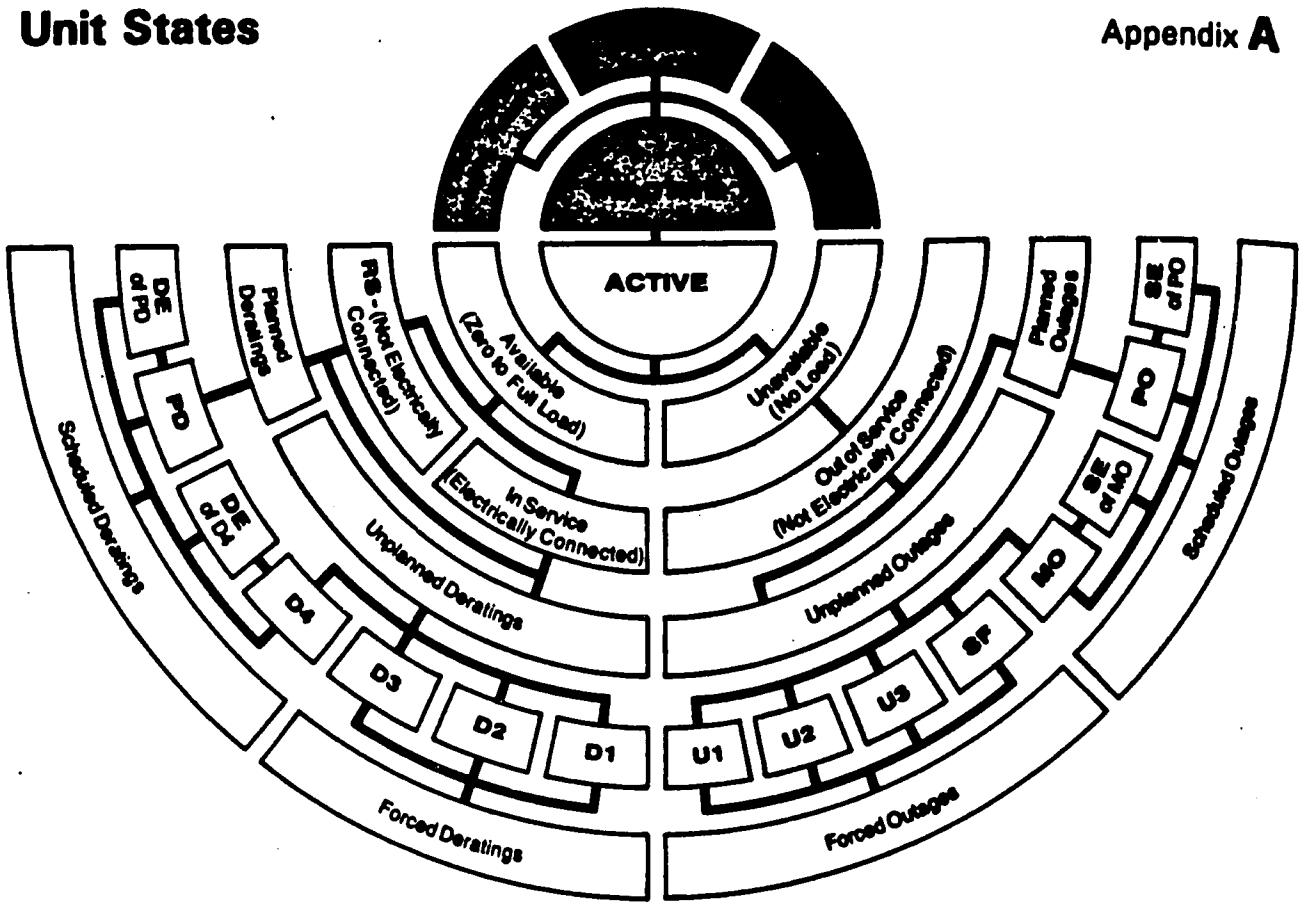
cc : O. M. Cruz, QAD-Optns.
P. J. Benavidez, R & DD

142

APPENDIX E

Definitions of Outage Categories from the North American Electrical Reliability Council's (NERC) Generating Availability Data System (GADS) Data

Unit States



Allowable Event Type Changes

FROM \ TO	U1	U2	U3	SF	MO	PO	SE	RS	DE
U1 – Immediate	YES	NO	NO	YES	YES	YES	NO	YES	
U2 – Delayed	YES	NO	NO	YES	YES	YES	NO	YES	
U3 – Postponed	YES	NO	NO	YES	YES	YES	NO	YES	
SF – Startup Failure	YES	NO	NO	YES	YES	YES	NO	YES	
MO – Maintenance	YES	NO	NO	YES	YES	YES	YES	YES	
PO – Planned	YES	NO	NO	YES	NO	YES	YES	YES	
SE – Extension	YES	NO	NO	YES	NO	NO	YES	YES	
RS – Reserve Shutdown	YES	NO	NO	YES	YES	YES	NO	YES	
D1 – Immediate	IEEE Standard 762 does not recognize transition to/of deratings from/to other event types except as shown.								NO
D2 – Delayed									NO
D3 – Postponed									NO
D4 – Maintenance									YES
PD – Planned									YES
DE – Extension									YES

Possible transitions between event types (available or unavailable unit states) are shown in the matrix above. The left-hand column lists the possible event types before a transition and the top row lists the event types to which a unit may change. A "yes" or "no" defines the ability to make a transition. *All of the event types listed above, with the exception of Scheduled Outage Extensions (SE), can be initiated from the in-service state; therefore, the In-service category is not shown on the matrix.* An acceptable transition would be from a RS to a MO event type, but not from a RS to a U2. The RS to U2 transition is not permissible since a U2 can only be initiated when a unit is in service and operating at some power level.

Definitions

Operation and Outage States

Actual Unit Starts
Number of times the unit was actually synchronized.

Age
The number of years the unit(s) has been in commercial service.

Attempted Unit Starts
Number of attempts to synchronize the unit after being shut down. Repeated failures to start for the same cause, without attempting corrective action, are considered a single attempt.

Available
State in which a unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

Forced Derating (D1, D2, D3)
An unplanned component failure (immediate, delayed, postponed) or other condition that requires the load on the unit be reduced immediately or before the next weekend.

Forced Outage (U1, U2, U3, SF)
An unplanned component failure (immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed from service immediately or before the next weekend.

Maintenance Derating (D4)
The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Maintenance Outage (MO)
The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, MOs may occur any time during the year, have flexible start dates, and may or may not have predetermined durations.

Maintenance Outage Extension (SE of MO)
The extension of a Maintenance Outage (MO).

Planned Derating (PD)
The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Planned Outage (PO)
The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing).

Planned Outage Extension (SE of PO)
The extension of a Planned Outage (PO).

Reserve Shutdown (RS)
A state in which a unit is available but not in service for economic reasons.

Scheduled Deratings (D4, PD)
A combination of maintenance and planned deratings.

Scheduled Derating Extension (DE)
The extension of a maintenance or planned derating.

Scheduled Outages (MO, PO)
A combination of maintenance and planned outages.

Scheduled Outage Extension (SE)
The extension of a maintenance or planned outage.

Unavailable
State in which a unit is not capable of operation because of the failure of a component, external restriction, testing, work being performed, or some adverse condition.

145

Time

Available Hours (AH)
Sum of all Service Hours (SH), Reserve Shutdown Hours (RSH), Pumping Hours, and Synchronous Condensing Hours, or;

Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH), and Maintenance Outage Hours (MOH).

Equivalent Forced Derated Hours (EFDH)*
The product of the Forced Derated Hours (FDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Forced Derated Hours During Reserve Shutdowns (EFDHRS)*
The product of the Forced Derated Hours (FDH) (during Reserve Shutdowns (RS) only) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Planned Derated Hours (EPDH)*
The product of the Planned Derated Hours (PDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Scheduled Derated Hours (ESDH)*
The product of the Scheduled Derated Hours (SDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Seasonal Derated Hours (ESEDH)*
Net Maximum Capacity (NMC) less the Net Dependable Capacity (NDC), multiplied by the Available Hours (AH) and divided by the Net Maximum Capacity (NMC).

Equivalent Unplanned Derated Hours (EUDH)*
The product of the Unplanned Derated Hours (UDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Forced Derated Hours (FDH)
Sum of all hours experienced during Forced Deratings (D1, D2, D3).

Forced Outage Hours (FOH)
Sum of all hours experienced during Forced Outages (U1, U2, U3, SF).

Maintenance Derated Hours (MDH)
Sum of all hours experienced during Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Maintenance Outage Hours (MOH)
Sum of all hours experienced during Maintenance Outages (MO) and Maintenance Outage Extensions (SE of MO).

Period Hours (PH)
Number of hours a unit was in the active state.

Planned Derated Hours (PDH)
Sum of all hours experienced during Planned Deratings (PD) and Scheduled Derating Extensions (DE) of any Planned Deratings (PD).

Planned Outage Hours (POH)
Sum of all hours experienced during Planned Outages (PO) and Planned Outage Extensions (SE of PO).

Pumping Hours
The total number of hours a turbine/generator unit was operated as a pump/motor set (for hydro and pumped storage units only).

* Equivalent hours are computed for each derating and then summed.
Size of Reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

Time (cont)

Reserve Shutdown Hours (RSH)
Sum of all hours experienced during Reserve Shutdowns (RS).

Some classes of units, such as gas turbines and jet engines, are not required to report Reserve Shutdown (RS) events. Reserve Shutdown Hours (RSH) for these units may be computed by subtracting the reported Service Hours (SH), Pumping Hours, Synchronous Condensing Hours, and all the outage hours from the Period Hours (PH).

Scheduled Derated Hours (SDH)
Sum of all hours experienced during Planned Deratings (PD), Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4) and Planned Deratings (PD).

Scheduled Outage Extension Hours (SOEH)
Sum of all hours experienced during Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Scheduled Outage Hours (SOH)
Sum of all hours experienced during Planned Outages (PO), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Service Hours (SH)
Total number of hours a unit was electrically connected to the system.

Synchronous Condensing Hours
Total number of hours a unit was operated in the synchronous condensing mode.

Unavailable Hours (UH)
Sum of all Forced Outage Hours (FOH), Maintenance Outage Hours (MOH), and Planned Outage Hours (POH).

Unplanned Derated Hours (UDH)
Sum of all hours experienced during Forced Deratings (D1, D2, D3), Maintenance Deratings (D4), and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Unplanned Outage Hours (UOH)
Sum of all hours experienced during Forced Outages (U1, U2, U3, SF), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

Capacity and Energy

Gross Actual Generation (MWh) (GAG)
Actual number of electrical megawatthours generated by the unit during the period being considered.

Gross Available Capacity (GAC)
Greatest capacity at which a unit can operate with a reduction imposed by a derating.

Gross Dependable Capacity (GDC)
GMC modified for seasonal limitations over a specified period of time.

Gross Maximum Capacity (GMC)
Maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other deratings.

Net Actual Generation (MWh) (NAG)
Actual number of electrical megawatthours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.

Net Availability Capacity (NAC)
GAC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Dependable Capacity (NDC)
GDC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Maximum Capacity (NMC)
GMC less the unit capacity utilized for that unit's station service or auxiliaries.

Equations

Age
[Years in commerical service/Number of units]

Availability Factor (AF)
[AH/PH] x 100 (%)

Average Run Time (ART)
[SH/Actual Unit Starts]

Equivalent Availability Factor (EAF)
[(AH - (EUDH + EPDH + ESEDH))/PH] x 100 (%)

Equivalent Forced Outage Rate (EFOR)
[(FOH + EFDH)/(FOH + SH + EFDHRS)] x 100 (%)

Forced Outage Factor (FOF)
[FOH/PH] x 100 (%)

Forced Outage Rate (FOR)
[FOH/(FOH + SH)] x 100 (%)

Gross Capacity Factor (GCF)
[GAG/(PH x GMC)] x 100 (%)

Gross Output Factor (GOF)
[GAG/(SH x GMC)] x 100 (%)

Net Capacity Factor (NCF)
[NAG/(PH x NMC)] x 100 (%)

Net Output Factor (NOF)
[NAG/(SH x NMC)] x 100 (%)

Scheduled Outage Factor (SOF)
[SOH/PH] x 100 (%)

Service Factor (SF)
[SH/PH] x 100 (%)

Starting Reliability (SR)
[Actual Unit Starts/
Attempted Unit Starts] x 100 (%)

Average Number of Occurrences Per Unit-Year

$$\text{AVG NO OCC PER UNIT-YR} = \frac{\sum \text{Outage and/or Derating Occurrences}}{\text{Unit-Years}}$$

Average MWh Per Unit-Year

$$\text{AVG MWh PER UNIT-YR} = \frac{\sum \text{Hours for Each Outage and/or Derating Type x NMC (MW)}}{\text{Unit-Years}}$$

Average MWh Per Outage

$$\text{AVG MWh PER OUTAGE} = \frac{\sum \text{Hours for Each Outage and/or Derating Type x NMC (MW)}}{\text{Occurences}}$$

Average Hours Per Unit-Year

$$\text{AVG HRS PER UNIT-YR} = \frac{\sum \text{Hours for Each Outage and/or Derating Type}}{\text{Unit-Years}}$$

Average Equivalent Hours Per Unit-Year
Computed as shown in the equation for **Average Hours Per Unit-Year** above, except the deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each individual unit. These equivalent hours are then summarized and used in the numerator of the **Average Hours Per Unit-Year** equation.

148

Equations

Computation Method

Each of the statistics presented is computed from summaries of the basic data terms required in each equation. Each term is totaled and then divided by the number of unit-years in that data sample. This unit-year averaged term is then used in computing the statistics shown. Examples of these computations are shown below:

$$\boxed{EFOR = \frac{FOH + EFDH}{FOH + SH + EFDHRS} \times 100\ (\%)}$$

Where: $FOH = \dfrac{\sum_{i=1}^{N} FOH_i}{N}$ $\qquad SH = \dfrac{\sum_{i=1}^{N} SH_i}{N}$

$EFDH = \dfrac{\sum_{i=1}^{N} EFDH_k}{N}$ $\qquad EFDHRS = \dfrac{\sum_{i=1}^{N} EFDHRS_k}{N}$

$$\boxed{FOF = [FOH/PH] \times 100\ (\%)}$$

Where: $FOH = \dfrac{\sum_{i=1}^{N} FOH_i}{N}$ $\qquad PH = \dfrac{\sum_{i=1}^{N} PH_i}{N}$

$$\boxed{NCF = \frac{NAG}{PH \times NMC} \times 100\ (\%)} = \frac{\text{Net Energy Produced}}{\text{Maximum Potential Energy (MPE)}} \times 100\ (\%)$$

Where: $NAG = \dfrac{\sum_{i=1}^{N} NAG_i}{N}$ $\qquad MPE = \dfrac{\sum_{i=1}^{N} (PH \times NMC)_i}{N}$

i = individual unit in any individual year
k = individual derating occurrence
N = unit-years