POWERPLANT PRODUCTIVITY IMPROVEMENT STUDY

Final Report
Project 1, Task 1

Current Practices in Illinois Utilities
towards Powerplant Productivity

April 5, 1979

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EXECUTIVE SUMMARY

In the last decade, the U.S. electric utility industry has faced substantial challenges brought about by rapid developments on several fronts. Increased uncertainty in load growth, inflation, tight capital markets, licensing and siting delays, and stringent environmental constraints were further complicated in 1974 by the OPEC oil embargo and steeply rising fuel prices. As a result of these pressures, increased attention has been given to the more efficient use of existing generating units as an economic alternative to new construction, and as a mechanism for near-term reductions in scarce fuel consumption.

In March 1975, a Federal Interagency Task Group recommended a thorough analysis of the benefits of improved powerplant reliability in terms of reduced consumption of scarce fuels, reduced utility capital requirements, deferred additions of new capacity, and reduced rates to consumers of electricity (Reference 1). The US Department of Energy has since encouraged increased efficiency in the use of scarce fuels in the electric utility industry under a broad range of programs. The potential for reducing oil consumption nationwide through improvements in the productivity (availability) of baseload coal and nuclear units has been shown to be significant. It has been estimated (Reference 2) that a 5 percentage point improvement in forced and planned outage rates of large coal and nuclear units could result in a net reduction in oil consumption of 54 million barrels per year by 1985 in the Northeast and East Central regions alone. A substantial cost savings potential was also reported.

In 1976, the Department of Energy (Federal Energy Administration) Sponsored the development of a systematic methodology for the identification and analysis of candidate projects which a utility might undertake to improve productivity of baseload units (Reference 3). This methodology also enables the user to estimate project effects on the future performance of the unit. It was developed by Mechanics Research, Inc. (Systems Development Corporation) and applied at three large utilities.

In order to demonstrate and further validate that methodology, and to encourage increased powerplant productivity in the State of Illinois, in 1977 the Department of Energy sponsored a cooperative study project with the Illinois Commerce Commission. Technical assistance was provided to the Commission by the Energy Resources Center, University of Illinois at Chicago Circle, and Trident Engineering Associates, Inc., a subcontractor. The overall project in Illinois consists of the following major tasks.

- o Identification and documentation of current utility approaches to powerplant productivity in Illinois, based on a study of the four largest privately owned utilities in the state.
- o Application of the DOE developed methodology at Illinois Power Company Wood River 5 and Commonwealth Edison Company Quad Cities 1 and 2 units. A total of eight improvement projects were analyzed by Trident for their effect on unit performance.
- o Estimation of costs and benefits to the utility of the eight productivity improvement projects.
- o Survey of historic productivity performance of baseload powerplants in Illinois.
- o Analysis of current regulatory incentives and disincentives to improved powerplant productivity in Illinois and development of candidate regulatory incentive policies for consideration by the Illinois Commerce Commission.
- o Estimation of benefits to utilities and ratepayers in Illinois which would result from modest improvements in powerplant productivity in the state.

OBJECTIVES OF THIS TASK

The intention of this task is to identify and document various approaches and practices currently in use in Illinois utilities to analyze powerplant productivity related questions. These questions relate to evaluating current levels of productivity as well as estimating future levels of productivity. The study covers productivity aspects of only baseload (large) coal and nuclear generating units. Four of the major investor-owned utilities in the state have cooperated in this task.

The current practices towards productivity analyses were documented by gathering data and information on:

- o Measures of productivity and performance in large powerplants.
- o Methods of determining current levels of productivity.
- o Identification of causes and magnitudes of lost productivity.
- o Selection of projects for improving historic plant performance.
- o Methods for evaluating the impacts of selected improvement projects on future performance.
- o Representative case studies of productivity analyses at each utility.
- o Internal organization and responsibilities for productivity and performance.

METHODOLOGY

It has been recognized by the utility industry that accurate measurement of powerplant productivity is a complex task. A variety of performance indices such as availability factor, capacity factor, forced outage rates, etc., are in use in the industry to measure different aspects of powerplant productivity. Hence the approach taken in this task is to document several cases (projects) that involved improvements to different productivity indices. The overall organization for productivity analyses and improvement at each

utility is also shown.

The principal source of information for this task has been the utilities themselves. Broadly speaking the contacts with the utilities consisted of

- o Briefing the top utility management on the overall goals of the DOE/ICC project.
- o Discussion with senior technical and managerial personnel regarding practices towards productivity improvement.
- o Study of various internal documents to establish organization and responsibilities for productivity studies.
- o Visits to powerplants to discuss site procedures with operating personnel.

The identification and documentation task has not been pursued to the same level of detail at each utility. Two of the utilities participated in several other tasks in this project and the procedures used by these two are presented in considerable detail. The other two utilities, in addition to not participating in all tasks of this study, were preoccupied with the coal strike problems during the early parts of 1978. Hence, the procedures at these two utilities, as presented in this report, are less detailed.

As background information, some general statistics - such as annual KWhr output, number of customers, peak capability etc. - are provided for all four utilities.

KEY FINDINGS AND CONCLUSIONS

The efforts of this task indicate that, powerplant productivity is a complex issue that has to take into account economic factors, equipment limitations, system loading characteristics as well as external constraints such as regulatory requirements. Among the specific findings are

- o Utilities in Illinois use the industry wide measures of performance such as capacity factor, availability factor, forced outage rates

etc. Equivalent availability as a measure of productivity is not in common practice in any of the utilities.

- o Several unit performance statistics are collected on a routine basis such as the daily unit status, component outage data, monthly production figures etc. These form the basis of evaluating current levels of individual unit output capabilities and limitations.
- o Identifying major causes of lost productivity at a generating unit appears to be a relatively simple task. Finding economically and technically acceptable corrective actions are generally more difficult.
- o Selection of improvement projects, as well as evaluating their future impacts, is mostly based on operating experience and engineering judgment. Currently, none of the utilities use formal analytical/statistical models to evaluate improvement projects. Standard engineering-economic analyses provide a basis for judging the feasibility of new projects.
- o There generally is a group in every utility-typically called the power production department-with routine responsibilities for the upkeep of unit productivity. However, a number of other departments are also organizationally involved in various aspects of productivity.
- o Recently the Commonwealth Edison Co. has developed a procedure for utilizing the Edison Electric Institute outage data base for analyzing productivity related questions at nuclear plants. This procedure utilizes unit nonoperating hours to measure productivity.

1. INTRODUCTION

In the last few years, the subject of power plant performance, productivity and reliability has received considerable attention from federal and state agencies, utilities, and utility trade associations as well as from public interest groups. There appears to be reasonable consensus among all groups that improved performance of large baseload coal and nuclear units would be beneficial to both utilities and customers. The Department of Energy and the Illinois Commerce Commission (DOE/ICC project) have undertaken this cooperative program on powerplant productivity in Illinois to explore a wide range of productivity related questions.

1.1 BACKGROUND TO DOE/ICC PROJECT

The DOE (and its predecessor organizations) has an ongoing Powerplant Productivity Program. In March 1975, a Federal Interagency Task Group recommended a thorough analysis of the benefits of improved powerplant reliability in terms of reduced consumption of scarce fuels, reduced utility capital requirements, deferred additions of new capacity, and reduced rates to consumers of electricity (Reference 1). The US Department of Energy has since encouraged increased efficiency in the use of scarce fuels in the electric utility industry under a broad range of programs. The potential for reducing oil consumption nationwide through improvements in the productivity (availability) of baseload coal and nuclear units has been shown to be significant. It has been estimated (Reference 2) that a 5 percentage point reduction in forced and planned outage rates of large coal and nuclear units could result in a net reduction in oil consumption of 54 million barrels per year by 1985 in the Northeast and East Central Regions alone. A substantial cost savings potential was also reported.

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In order to demonstrate and further validate that methodology, and to encourage increased powerplant productivity in the State of Illinois, in 1977 the Department of Energy sponsored a cooperative study with the Illinois Commerce Commission. Technical assistance was provided to the commission by the Energy Resources Center, University of Illinois at Chicago Circle, and Trident Engineering Associates, Inc., a subcontractor. The overall project in Illinois consists of the following major tasks.

- o Identification and documentation of current utility approaches to power plant productivity in Illinois, based on a study of the four largest privately owned utilities in the state. (Project 1, Task 2).
- o Application of the DOE developed methodology at Illinois Power Company Wood River 5 and Commonwealth Edison Company Quad Cities 1 and 2 units. A total of eight improvement projects were analyzed by Trident for their effect on unit performance. (Project 1, Task 2).
- o Estimation of costs and benefits to the utility of the eight productivity improvement projects (Project 1, Task 3).
- o Survey of historic productivity performance of baseload powerplants in Illinois. (Project 2, Task 1).
- o Estimation of benefits to utilities and ratepayers in Illinois which would result from modest improvements in powerplant productivity in the state (Project 2, Task 2).
- o Analysis of current regulatory incentives and disincentives to improved powerplant productivity in Illinois and development of

candidate regulatory incentive policies for consideration by the Illinois Commerce Commission. (Project 2, Task 3).

1.2 OBJECTIVES OF PROJECT 1, TASK 1

This report describes the current practices of four major investor-owned utilities in Illinois regarding power plant productivity. The task of identifying and documenting the utility practices towards productivity was pursued in terms of identifying:

- o the measures (or parameters) of productivity and performance currently in use in Illinois utilities.
- o the methods of establishing current levels of productivity.
- o the major causes and magnitudes of loss productivity at generating stations.
- o the methods for selecting projects for improving historic plant performance and also procedure(s) for evaluating their future impacts.

Within the context of this task it has not been possible, nor was it intended, to evaluate the adequacy of the current utility practices towards productivity analyses. The utilities look at productivity improvement on a case-by-case basis and hence general comparisons between utility practices cannot be made with accuracy.

1.3 POWERPLANT PRODUCTIVITY MEASUREMENT

Powerplant productivity is affected by a number of factors that include administrative decisions, operation and maintenance practices, equipment limitations, regulatory influences, etc. Edison Electric Institute (EEI) has established formal definitions for a number of operating parameters or indices that are in use in the industry to measure various aspects of plant performance. These are included in Appendix A. However, there is no single measure

of overall productivity of a powerplant within EEI terminology. The significance of some of the operating parameters, in the context of productivity, is briefly discussed next.

1. Heat rate-Heat rate is the Btu input required to generate one KWhr of electrical output and is the measure of thermodynamic performance.
2. Capacity factor-Capacity factor is the ratio, generally calculated on an annual basis, of the actual energy produced to maximum possible, if the unit had operated at maximum dependable capacity all through the year. The annual capacity factor includes the effects of all causes of lost productivity and is generally viewed by the industry as the single best estimate of productivity of baseload units.
3. Availability factor-Availability factor, generally expressed as percentage, indicates the fraction of time, generally a year, a unit is available for service whether required or not. In baseload units, the bulk of the difference between availability and capacity factors can be accounted for by reserve shutdown hours i.e., the period over which the unit was removed from service for economy or similar reasons.
4. Equivalent Availability-Equivalent availability factor is somewhat similar to availability factor except that all partial outages are evaluated as equivalent (in terms of KWhr) to an outage at maximum dependable capacity. It is obvious from these definitions that for any unit the numerical value of availability factor will be greater than equivalent availability factor. The numerical value of capacity factor will be the smallest of the three numbers.
5. Forced Outage Hours-Forced outage hours are a component of the overall availability (or the unavailability) of a unit and represent the time in hours a unit was removed for service because of equipment or component failure.
6. Reliability-Reliability is generally defined as "...the probability that a unit (or component) will perform the required functions under specified conditions for a specific period of time" and is normally not considered a direct measure of productivity. However, for a baseload unit reliability is closely related to availability and hence provides an indirect measure of productivity. Generally, the computation of reliability of a unit is based on meantime between failure and meantime to repair for components and subsystems of a unit. These two parameters are being used in the DOE developed procedures for productivity analysis in evaluating equivalent availability. Hence within the context of this project reliability of a baseload unit is also indicative of its performance and productivity.

The parameters listed above, taken as a composite, constitute power-plant productivity from an operating or engineering point of view. It is evident from the definition of these indices, that a highly productive generating unit measured in terms of one index does not imply that it is as good if gauged by some other index. Hence, in this task the case studies (or productivity improvements) presented indicate improvements as measured by different indices.

1.4 ORGANIZATION OF THIS REPORT

The remainder of this report is organized into five major chapters. Chapters 2 to 5 describe the procedures for productivity analyses at each of the four utilities. All of these chapters are laid out in nearly common form. The first section in each provides an overview of the company with some general statistics to provide the reader with background information on the utility and scale of operation. The second section in each of the chapters briefly describes the methods used in obtaining data and information for the preparation of this report at each utility. The remaining sections of each chapter deal with the organizational structure for productivity, productivity measures and goals. The last section in each chapter describes representative studies of productivity improvement analyses undertaken by each utility.

The documentation effort has not been pursued to the same level of detail at each utility. Two of the participants (Illinois Power Co. and Commonwealth Edison Co.) were also involved in several other tasks of the DOE/ICC project. The procedures at these two utilities are covered in considerable detail.

The coverage on Central Illinois Light Co. and Central Illinois Public Service is in less detail since they were not a part of other tasks and only limited information was available. Also, in the early part of the project

(Dec. 78) these two utilities were preoccupied with coal strike problems and the access to appropriate personnel was limited.

The attached map, Figure I.1, shows the approximate service territories of the four major investor-owned utilities in the state. Table I.1 provides some relevant statistics.

TABLE 1.1

MAJOR INVESTOR OWNED ELECTRIC UTILITIES
STATE OF ILLINOIS - 1977

<u>Utility</u>	<u>Net Capability (MWe)</u>	<u>Net Sales in State (Million Kwh)</u>	<u>Total Average No. of Customers (thousands)</u>	<u>Service Area (Sq. miles)</u>	<u>Primary Fuels</u>
CECo	16,909 (a)	60,603 (60.9%)	2,814	11,500	Coal & Nuclear
IP	3,862 (b)	12,951 (13.0%)	492	15,000	Coal
CIPS	2,409	8,323 (8.4%)	296	20,000	Coal
CILCO	1,244	4,434 (4.5%)	176	3,700	Coal

Notes: (a) Includes Net Capability as of Dec. 31, 1977.

(b) Includes Havana 6 which went line during 1978.

Sources: 1. Internal company reports of the four utilities.

2. Illinois Commerce Commission, Research Bulletin No. 99, June 1978.

3. Annual Reports of the four utilities

FIGURE 1.1

Generalized Service Territories of
Four Major Investor-Owned Utilities in Illinois

Note: Blank areas on the map are served by other utilities

II. COMMONWEALTH EDISON COMPANY (CECo)

2.1 Overview of Company

Commonwealth Edison Company (CECo) is the largest electric utility in the state of Illinois in terms of number of customers and number of kilowatt hours sold during 1977 (Table 1.1). Its general offices are located in Chicago, Illinois.

CECo provides electricity to about 8 million people located in an area of 11,525 square miles in northern Illinois (Figure 1.1). In addition, CECo has a wholly-owned subsidiary, Commonwealth Edison Company of Indiana, which runs the State Line power station located in the northwest corner of Indiana. The State Line power station consists of three coal fired units with a total net capability of 648 megawatts. CECo sold over 60 billion kilowatt hours of electric energy during 1977 in Illinois which accounts for about 60% of the total sales of electricity within Illinois during 1977 (Table 1.1). As of November, 1977 CECo had a net generating capability of about 16,909 megawatts of electric power (Table 2.1) including Collins units 2 and 3 which went on line during 1977 and the State Line Power station. Roughly 50% of CECo's capability was coal, 30% was nuclear and 20% oil. Six large coal units and six large nuclear units installed since 1964 account for over 50% of the 16,909 megawatts (Table 2.2).

Table 2.1

Commonwealth Edison Company
Operating Statistics for 1977

Operating Revenues (x \$1000)	2,095,017
(1)	
Electric System Data	
(2)	
Net Generating Capability	16909 MWe
Peak Load Summer (1977)	13932 MWe
(2)	
Capability	
Coal	8356 MWe (49.4%)
Nuclear	5058 MWe (29.9%)
Oil	3341 MWe (19.8%)
Gas	154 MWe (0.9%)
Total	16909 MWe
(3)	
Net Sales (x million Kwh)	60,603
(1)	
Total Sales (x million Kwh)	61,449

Notes: (1) Includes State Line Power Station.
(2) Net capability as of December 31, 1977.
(3) Excludes sales by Commonwealth Edison Company of Indiana.

Sources: Internal Company Reports
Commonwealth Edison Company 1977 Annual Report
Illinois Commerce Commission Research Bulletin No. 99

Table 2.2

Commonwealth Edison Company
Net Capability of Large Base Load
Units Completed Since 1964

<u>Unit</u>	<u>Type</u>	<u>Year Installed</u>	<u>Net Capability (MWe)</u>
Dresden 2	Nuclear (BWR)	1970	794
Dresden 3	Nuclear (BWR)	1971	794
Quad Cities 1	Nuclear (BWR)	1972	591 (a)
Quad Cities 2	Nuclear (BWR)	1972	592 (a)
Zion 1	Nuclear (PWR)	1973	1040
Zion 2	Nuclear (PWR)	1974	1040
			<u>4851</u>
Joliet 7	Coal	1965	537
Joliet 8	Coal	1966	537
Kincaid 1	Coal	1967	606
Kincaid 2	Coal	1968	606
Powerton 5	Coal	1972	850
Powerton 6	Coal	1975	850
			<u>3986</u>
			<u>8837</u>

NOTE: (a) Excludes 25% of Quad Cities capacity which is owned by Iowa - Illinois Gas and Electric Company.

Source: Internal Company Report.

As of August, 1978 the first three of five generating units have gone on line at Collins station. These units are oil-fired, load cycling, 500 megawatt class units. By April 1979, two more units will go on line which will give Collins station a net capability of 2,500 megawatts. The last two units will also be oil-fired, load cycling units which can be converted to coal-fired.

Excluding the Collins station, the remaining units now under construction by CECO are nuclear (Table 2.3). LaSalle County, Byron and Braidwood should provide CECO with an additional 6,636 megawatts of base load capability by the end of 1982.

Additionally CECO is planning to install two nuclear units at the Carroll County station during 1987 and 88. One-third of the stations' 2,240 megawatt capability will be owned by two other utilities. (Iowa - Illinois Gas and Electric Company and Interstate Power Company).

By the mid 1980's, CECO expects nuclear power plants to account for 48% of its total capability, and to produce about 60% of its generated electric energy.

During 1977, CECO had a peak load of 13,932 megawatts and generated over 63 billion megawatt hours of electric energy. Of this total, coal accounted for 49.9%, nuclear 41.8%, oil 7.6% and gas 0.7% (Table 2.4).

Presently, by virtue of an agreement with Consumers Power Company and Detroit Edison Company, CECO is entitled to 1/3 of the generating capability of the Ludington Pumped Storage Plant. Energy during off-peak hours can be utilized the next day during peak hours by CECO to meet its load.

Table 2.3

Commonwealth Edison Company
Nuclear Units Presently Under Construction

<u>Unit</u>	<u>Type</u>	<u>Operable</u>	<u>Net Capability (MWe)</u>
LaSalle County 1	BWR	1979	1078
LaSalle County 2	BWR	1980	1078
Byron 1	PWR	1981	1120
Braidwood 1	PWR	1981	1120
Byron 2	PWR	1982	1120
Braidwood 2	PWR	1982	1120
			<u>6636</u>

Source: Commonwealth Edison Company 1977 Annual Report.

Table 2.4

Commonwealth Edison Company
 Net Generation During 1977
 By Type of Fuel Burned

<u>Fuel Type</u>	<u>Electric Energy (x million Kwh)</u>	
Coal	31,765.7	(49.92%)
Nuclear	26,568.8	(41.75%)
Oil	4,829.9	(7.59%)
Gas	462.0	(0.72%)
Hydro	<u>10.8</u>	(0.02%)
Total	63,637.3	(100.00%)

Source: Internal Company Report.

2.2 Approach to Task

This task was addressed in several phases. During the first phase, an overview of the utility's operations was obtained by meeting with several senior executives responsible for long-term as well as day-to-day operations. Attending these meetings were the managers of Station Mechanical and Station Nuclear Engineering, General Superintendent of Maintenance, General Superintendent of Production Systems Analysis and other engineering staff. These initial meetings, lasting two days, provided an understanding of the operating procedures, the lines of communication between the station and headquarters and the services available through specialist groups.

In phase two, after the orientation meeting, meetings were held with individuals at the headquarters who had the responsibility for, and knowledge of, maintaining and improving power plant productivity. These individuals provided relevant statistics and reports. In subsequent meetings, these personnel provided further information and clarification about the company's approach and practices towards productivity.

The third phase of this task was plant visitation to ascertain the procedure at a unit and this was conducted at the Zion nuclear unit. One day was spent with the outage coordinator at Zion who has the full-time responsibility for planning the annual refueling outage.

In all of these phases, the major objective was to identify and document the approach and practices currently in use at the utility for improving power plant productivity. Supporting documents and statistics were obtained to the extent possible.

Some of the technical staff of CECO have presented papers at meetings and conferences. These papers were examined during the course of this study

Figure 2.2
Commonwealth Edison Company
Quad Cities Station
Details of Different Sections with
Responsibility for Operating the Station

Figure 2.3
Commonwealth Edison Company
Quad Cities Station
Details of Sections with Responsibility
for Maintenance of Units

and their contents have been integrated into this report.

2.3 Organization for Productivity

Instead of having a single individual with overall responsibility for all aspects of productivity, CECo has divided this responsibility among various departments. Specific responsibilities for maintaining and improving productivity of powerplants in the CECo System are spread around various levels of organization. Additionally there are technical specialist groups in the organization who assist station personnel in project analysis and implementation. In general, the day-to-day operation of stations are the responsibility of individual station superintendents. In addition to the station superintendents, the managers of the production and engineering departments have long-term responsibility for powerplant productivity. Large base load stations, depending on their size and type, employ between 200 and 400 people. Some of the details of organization at a station (Quad Cities) are shown in Figures 2.1, 2.2, and 2.3. A brief description of the activities of the individuals and groups who work at improving powerplant productivity is described next.

Outage Coordinator:

The single largest contributor to lost productivity in any nuclear powerplant is the refueling outage. Refueling has to be undertaken every twelve or eighteen months and an outage can last as long as eight or ten weeks. The obvious way to reduce lost production due to refueling is to increase the interval between refueling and decrease the time for refueling. In addition to refueling, a large number of other projects are undertaken on both the nuclear steam supply side and on the balance of plant during this outage. In

Figure 2.4

Commonwealth Edison Company
Outage Coordination at Zion Station

Functional Direction - - - - -
Line Authority _____

CECo's organization, each nuclear station has a full-time position for planning and coordinating the work during refueling. Normally the planning activity starts about six months before the refueling event. The outage coordinator meets with various section supervisors to ascertain the jobs that need to be done. Materials, tools and labor required to complete the job are estimated and in due course priorities are assigned to each job. The final selection of the projects is made based on the availability of resources and the importance of the project to keep the units' output up. The scheduling of the projects is laid out on a chart to establish the critical paths. (A proprietary computer code for scheduling is currently under test to streamline the operation.) The attached organization chart, Figure 2.4, for outage coordination is indicative of the interactions that occur during refueling.

Reliability & Design Specialist (R&DS) Groups:

The Station Nuclear Engineering Department (SNED) and Station Mechanical Engineering Department (SMED) at CECo headquarters maintain separate reliability and design specialists (R&DS) groups.

At SNED, this group consists of approximately 10 people with prior station experience and expertise in various engineering disciplines such as turbines, radwaste, water chemistry, etc. One of the activities of R&DS-the unit and component unavailability analysis - is described in detail in this report (Section 2.6). The ERC in its discussions with R&DS noticed that this group's major activity is project evaluation (technical and economic feasibility) and review. The attached organization chart, Figure 2.5, indicates the line of communication between R&DS and the senior managerial staff. During the first two years of operation, this group has either evaluated or

Figure 2.5

Commonwealth Edison Company
 Station Nuclear Engineering Department
 (*: Special Responsibility for improving
 plant performance)

implemented about 10 major projects in the Nuclear Units in the company's system. The estimated savings to the company, due to the efforts of this group was of the order of \$16 million as of the beginning of 1977.

The Station Mechanical Engineering Department (SMED) also has a R&DS group, but on a smaller scale than SNED. Two major problems at fossil units are being analyzed by this group. These are the coal handling problems at fossil stations and turbine blade failures due to erosion and fatigue. As the organization chart, Figure 2.6, indicates at SMED there is another group -SPR's Special Studies-that both initiates new projects and assesses the technical and economic feasibility of project requests from other departments.

2.4 Performance Measures and Goals

Commonwealth Edison Co. applies the industry-wide measures for performance of individual units as well as for system-wide performance. These are the unit heat rates, forced outage rates, capacity and availability factors, etc. System-wide performance is generally measured by generation costs in mill/Kwh. Expected performance is based on the planned outage schedule as well as the unit's past performance. The Subsection 2.5 on Identification of Sources of Lost Productivity is also indicative of the performance measures used by CECo.

Performance goals for availability factor and budgetary considerations are set, yearly on a unit-by-unit basis, jointly by the station superintendents and the production departments. These goals are based on projections of past performance modified by the planned outages (Table 2.6).

2.5 Identification of Sources of Lost Productivity

An elaborate system of reporting exists at CECo so that the availability

Figure 2.6
Commonwealth Edison Company
Station Mechanical Engineering Department

(*: Special responsibility for improving plant performance)

status of individual units within the system is known to responsible people at any given period. Monthly, quarterly and annual performance reports are also prepared so that progress of particular projects can be tracked. These reports also contain a considerable amount of financial statistics such as fuel costs, O&M costs, overtime payments, etc. On a day-to-day basis these reports assist in maintaining levels of productivity and identify the major causes of unavailability at individual units. Performance reports that cover a longer interval in time--such as the quarterly or annual reports--indicate the progress of specific projects. This study has been confined to identifying those reports that have relevance to plant productivity aspects.

Daily Unit Status Reports: Each station prepares a unit status report with details of work performed and the work in progress. The status of all units within the system is summarized on one page indicating the maximum capability of the unit for that day. This document is of greater use in economic load dispatch than in monitoring productivity. However, it does identify the unavailability of a unit and the main causes of unavailability. A sample copy of daily unit status report is shown in Table 2.5.

Monthly Unit Performance Reports: Monthly, the General Books Accounting Department prepares performance reports primarily for cost and budget control. However, these reports contain information on availability factor and capacity factor that the unit achieved. These reports also indicate a year-end availability goal for each unit. Unit availability goals are set based on the planned scheduled outages, the past performance of the unit as well as the status of other units in the system. A sample copy for Will County Station is shown in Table 2.6. Additionally, stations prepare monthly reports that

Table 2.3
Commonwealth Edison Company
Daily Unit Status Report

Wednesday, January 11, 1978 Cap. 1-11-78 11,302
Peak Est. 1-11-78 10,800
Peak 1-10-76 10,347

DAILY STATION REPORT

Collins 1040-00-0	U-2 (520):	520 MWe. No Deratings.
	U-3 (520):	520 MWe. No Deratings.
Crawford 175-0-0 93-140	U-7 (248):	175 MWe. Bus #4 O/s (63), HP FW Hrs. O/s (0).
	U-8 (247):	0 MWe. o/s Chem Clean Boiler (247).
Dixon 114-0-1	U-4 (35):	44 MWe. Primary Air limit (3), Coal (2), Pollution (4).
	U-5 (70):	66 MWe. Circ. water temp. (1).
Fisk 388-7-1 73-212	U-18 (244):	42 MWe. 18-1 Blr. o/s (65), 2-3 Coal conditioner (30).
	U-19 (355):	345 MWe. Turbine efficiency (9), 19-4 SWCP o/s (0).
	U-20 (11):	Circ. water temp. (1).
		11 MWe. No Deratings.
Joliet 1184-58-20 51-92	U-5 (96):	35 MWe. Coal (13), 5-3 Recyclers o/s (7), 5-3 Blr. o/s (40).
	U-6 (365):	160 MWe. ID Fan limit (36), Traveling Screens (79).
	U-7 (565):	504 MWe. 72 HP Vibration (50), Circulating water (11).
	U-8 (565):	486 MWe. 81-D mill o/s (70), Circ. water temp. (9).
	U-9 (11):	11 MWe. No Deratings.
Kincaid 0-0-0	U-1 (643):	0 MWe. o/s OWHL (643).
	U-2 (643):	0 MWe. o/s Air htr. cleaning & Misc. repairs (643).
Peaverton 630-0-0	U-3 (900):	630 MWe. Main Transformer limit (270).
	U-2 (900):	0 MWe. Turbine inspections (900).
Ridgeland 566-0-11	U-1 (177):	175 MWe. Circ. water temp. (6).
	U-2 (172):	167 MWe. Circ. water temp. (5).
	U-3 (157):	77 MWe. 31 HP o/s (75), Circ. water Temp. (5).
	U-4 (156):	153 MWe. Circ. water Temp. (3).
State Line 120-0-0	U-1 (183):	20 MWe. Turb. Vib. (5), Blr. & Turbine o/s (158).
	U-2 (150):	100 MWe. Blr. fouling (17), Pollution (15), 2-3 E mill o/s (8), Mill capacity (10).
	U-3 (203):	0 MWe. o/s Turb. Vibration (203).
	U-4 (340):	0 MWe. o/s OWHL (340).
Waukegan 390-0-0 23-68	U-5 (125):	40 MWe. Mill capacity (8), 14 & 16 Blr. o/s (87).
	U-6 (100):	64 MWe. Blr. fouling (40).
	U-7 (157):	280 MWe. 78 CWP o/s (0), Blr. fouling (63).
	U-8 (378):	0 MWe. o/s repairs (378).
Will County 809-0-8	U-1 (167):	130 MWe. Air htr. limit (17), Blr. casing leak (20).
	U-2 (180):	147 MWe. Feedwater flow (13).
	U-3 (278):	0 MWe. o/s OWHL (278).
	U-4 (542):	512 MWe. Circ. water temp. (8), Coal (22).
Windsor 1334-0-0	U-1 (215):	0 MWe. Licensing Modifications (215).
	U-2 (836):	804 MWe. Rod pattern (30).
	U-3 (832):	530 MWe. Fuel depletion (302).
Quad Cities 1300-0-29	U-1 (833):	730 MWe. Preconditioning (83).
	U-2 (833):	550 MWe. Circulating water (29), Fuel depletion (254).
Sion 1770-0-225	U-1 (1085):	860 MWe. Circulating water (225).
	U-2 (1085):	910 MWe. Drain Cooler (175).

TOTAL GROSS CAPABILITY (Excluding peakers): 9,842

Number below station indicates: Available gross capability (Excluding peakers & units in gross emergency available; circulating water temperature limitations. Number in parentheses available - peak ratings. Number beside unit indicates: Rated Gross Capability).

Table 2.4
Commonwealth Edison Company
Monthly Station Performance
WILL COUNTY Station
Month of October, 1977

Availability	Twelve Months Ended	Previous Year	1977 Year-End Goals
Station	68.6	82.9	79.4
Unit 1	79.1	73.2	77.8
Unit 2	73.4	83.9	78.9
Unit 3	71.0	76.2	67.6
Unit 4	62.7	84.2	75.9
Net Capacity Factor	47.2	56.4	
Net Output MWH (000's)	4491	5319	
Number of Employees (End of Period)	355	338	339

Area	Responsibility Center Budget			Year-to-Date		Good or Bad* Compared to Budget
	Current Month					
	Actual	Budget	Last Year	Actual	Budget	
Administrative						
Expense (\$000's)	47	46	36	484	421	63*
Excess Time (Hrs. Worked)	525	530	253	3165	4440	725*
Technical Staff						
Expense (\$000's)	22	19	13	193	184	9*
Excess Time (Hrs. Worked)	175	350	312	3628	3350	278*
Training						
Expense (\$000's)	38	33	30	368	329	39*
Excess Time (Hrs. Worked)	-	-	-	-	-	-
Operation						
Expense (\$000's)	219	231	207	2319	2309	10*
Excess Time (Hrs. Worked)	2259	1465	2433	19252	17395	1757*
Maintenance						
Expense (\$000's)	432	502	355	7138	5409	1729*
Excess Time (Hrs. Worked)	3911	6300	2570	49263	46250	3013*
Total Expenses (\$000's)	758	831	841	10502	8652	1850*
Total Excess Time (Hrs. Worked)	6826	8845	5548	77208	71435	5773*

Source: Internal Company Report (General Books Department File No. 620)

Figure 2.7
Commonwealth Edison Company
Effects on Nuclear Unit 1976 Capacity Factors

Effect

- 1 - Actual Capacity Factor
- 2 - Shutdowns Associated with Refueling & Core Maintenance
- 3 - Testing
- 4 - Voluntary and Precautionary Load Reductions
- 5 - Equipment and Operating Limitations
- 6 - Imposed Conditions

Figure 2.8
Commonwealth Edison Company
Quad Cities Station 1976 Capacity Factor

Figure 2.8 (Continued from previous page)
Key to Effects on Unit Capacity Factors

Shutdown associated with refueling and core maintenance

- A- Scheduled routine refueling
- B- Extension of scheduled routine refueling
- C- Unscheduled refueling or fuel reconstitution
- P- Delay

Testing

- D- Normal routine Testing following refueling
- E- Normal routine surveillance testing
- F- Non-routine testing

Voluntary and precautionary load reductions

- G- Reduced system load requirement
- H- Core stretch-out; end of life
- J- Voluntary capability

Equipment and operating limitations

- L- Nuclear plant equipment malfunction
- M- Restrictions on (rate of load changes due to) fuel
- N- Secondary plant equipment malfunction
- O- Personnel error or administrative deficiency

Imposed conditions

- I- Imposed capability reduction
- K- Licensing delay
- R- Seasonal effects

Table 2.7
Commonwealth Edison Company
Detailed Causes of Low Productivity in
Quad Cities Units 1&2

<u>Ref. Note</u>	<u>Basic Cause of Lost Capacity</u>	<u>Ref. Cause</u>
1	Thermal derating due to condenser performance	N
2	Thermal derating due to river water temperature exceeding 60° F	R
3	Thermal derating due to the Spray Canal temperature versus the river	I
4	CECO Spinning Reserve limitation derating	G
5	PC10MR fuel load rate restriction derating & pre-conditioning ramp	M
6	Scheduled refueling outage	A
7	Control rod pattern change load reduction	M
8	Load limitation due to the service water temperature exceeding and/or approaching 95° F	I
9	Load Limitation due to the condenser backpressure exceeding 5.0"Hg.	I
10	Load limitation due to fuel reactivity depletion	H
11	Load limitation due to end-of-cycle scram reactivity	H
12*	Load limitation due to high Main Steam Isolation Valve temperature	I
13	Feedwater heater water level control problems	N
14*	Recirculation pump discharge bypass valve line repairs	L
15	Reactor feedwater pump heat tracer test tap leak repairs	L
16	Steam Jet Air Ejector problems (Loss of condenser vacuum)	N
17	Outage to investigate drywell steam leaks	L
18*	Load limitation due to Radwaste capacity problems	N
19*		
20*	Outage to plug failed condenser tubes	N
21*	Load limitation due to high off-gas values (failed Fuel)	M
22*	Unit outage caused by loss of auxiliary power	N
	Outage caused by moisture separator high level see 13)	N
24*	Outage due to high reactor water conductivity	L
25	Planned outage to accomodate feedwater system repairs (FW check valve)	L
26*	Outage caused by accidental feedwater pump trip resulting in low reactor vessel water level	N
27*	Outage to repair a feedwater header flush line leak	N
28	Outage to perform feedwater regulating station repairs	N
29*	Core maintenance outage to replace failed fuel	C
30	Outage caused by erroneous turbine stop and control valve calibration signals	O
31*	Load limitation to allow for a reduction in the service water inlet temperature to allow for torus water cooling following High Pressure Coolant Injection System testing	

Table 2.7 (continued from previous page)

<u>Ref. Note</u>	<u>Basic Cause of Lost Capacity</u>	<u>Ref. Cause</u>
32*		
33	Planned outage for snubber inspection and control rod pattern change	E
34	Reactor scram due to feedwater regulator valve failure	N
35	Outage to repair turbine steam seal leaks	N
36	Reactor scram due to instrument calibration error	O
37	Load reduction due to feedwater regulating valve oscillations	N
38	Load reduction for turbine test	D
39	Load reduction for condenser flow reversal	N
40	Generator Outage (Field Ground, July U-1)	N
41	Limitation Due to Spray Canal Out of Service (C.W. Discharge Flume Repair in June-July)	N
42	Outage to repair electromatic relief valve	L
43	Limitation due to spray canal testing	F
44	Limitation due to regulatory restriction on MCPR	M
45	Limitation due to reactor instrumentation problems T.I.P., Aug. U-1	L
46	Limitation due to high LPRM readings	M
47	Outage to balance turbine	N
48	Reactor scram due to low EHC oil pressure	N
49	Load reduction due to operating problems of recirculating pump M/G set.	N
50	Extension of scheduled refueling outage for completion of turbine maintenance	B
51	Reactor scram, cause still under investigation	L
52	Outage due to arc to ground and loss of generator field, subsequent load rejection, and reactor scram	N
53	Outage due to EHC oil leak to #1 turbine control valve causing turbine trip and subsequent reactor scram	N
54	Reactor scram due to excessive water in condensate pit. (Stuck condensate demineralizer vent valve)	
55	Limitation due to high xenon concentration	M
56	Outage to repair feedwater check valve	N
57	Load reduction due to being on 100% flow control line (see 5)	J

* Not used during 1976

contain various performance data such as availability factor, capacity factor, heat rate and outage data.

Annual Nuclear Unit Performance: A special report is prepared every year by CECo for the nuclear units detailing the items that affect individual unit capacity factor. Major factors affecting capacity factor--such as refueling, preventive maintenance, equipment and operating limitations, etc.--are shown in graphical form. This report also lists in detail the basic causes of lost productivity at each unit in the year. Attached copies, Figures 2.7, 2.8 and Table 2.7 are portions of this annual report.

2.6 Systematic Methodology

Method Using Unit and Component Non-Operating (NOP) Hours to Identify Improvement Projects

In recent years the Reliability and Design Specialists (R&DS) group at CECo has developed a method which utilizes existing EEI data to identify and allocate unit and component non-operating hours attributable to various components in the company's nuclear units. Unit NOP hours include the time during which a unit was down (full or partial) because of specific component malfunction. Component NOP hours include hours of component malfunction that did not affect unit output (noncurtailing outages) as well as time required for non-operating system tests. The EEI data base was chosen since it is the most detailed that exists. For the intended purposes of this approach--identification of twenty or so major causes of lost productivity--the EEI data base provides adequate accuracy as well as resolution. The outage events are classified as one of eight outage types for data submittal to EEI. Within each outage type, each event is identified with one of 129 components or activities defined in the data system for nuclear plants. In this approach

each component and activity (inspection, refueling, etc.) is charged with NOP hours. Hence, unit unavailability due to planned maintenance hours is appropriately allocated to components on which work was done during the outage.

The final output of this computerized effort is a list of all individual component NOP hours that add up to total unit NOP hours as well as component NOP hours that include noncurtailing hours and non-operating test hours. These are then ranked in descending order to isolate the top twenty (or so) items that are the major causes of non-operating hours. The method has been applied to all of the nuclear units in the CECO system using EEI data for the last four years.

At the end of the analysis special reports are prepared for company management for review, assisting in setting project priorities among the company departments.

Application of the Method:

Once the major components and activities causing non-productivity have been identified and ranked the R&DS staff meet with the station staff to find appropriate corrective actions. The unit NOP hours are first reviewed and those causes that have either been corrected or are under study are eliminated. Next, the outage history of the component with high NOP is reviewed in depth to see whether operational and maintenance (O&M) procedures were responsible for any NOP hours. If O&M procedures were found to be the main cause these will be corrected first since no additional capital expenses are required. If O&M procedures are not the cause of high NOP hours, then the R&DS group will undertake a special study to identify the root causes. This facet of the improvement project is generally the most complex and time

consuming, and quite often the equipment vendor may be involved. After identifying the root causes of NOP hours various design modifications are developed and estimates of the reductions in NOP hours are made. Generally conservative (lower) estimates of possible reduction in NOP hours are used for making economic and cost/benefit analyses of design modifications for improvement. The benefit estimates are made on the basis of differential fuel costs of nuclear and coal, since the lost production of a nuclear unit in CECo system has to be made up by coal fired units. In view of the size of nuclear units and the differential fuel costs, the cost of lost nuclear production is higher than the cost of most design modifications and most design modifications qualify if they can significantly reduce the number of NOP hours.

Case History:

The use of component NOP hours analysis was initially tested at the Zion Station Nuclear Plant to identify an improvement project. The 1975 EEI outage event data at Zion was computer processed to obtain unit and component NOP hours using the method described earlier. A review of the computer output identified the reactor coolant pump (EEI code 204) as being accountable for 910 unit NOP hours out of a total of 7934 unit NOP hours and 2616 component NOP hours during 1975. At the then current fuel replacement cost, 910 hours of NOP hours was valued at nearly \$10 million a year and it was decided to investigate the root causes of the reactor coolant pump (RCP) outages. An experienced investigative team was formed consisting of two specialists from R&DS and the station engineer for RCP. Additional specialists from the pump vendor were added as the investigation progressed. The outage history was reviewed in detail along with maintenance history, the temporary corrective actions taken and the reasons for continued outages. A detailed failure modes

and effects type of analysis had to be undertaken before practical solutions could be established for all root causes. Approximately nine man-months of effort went into the investigation that identified the failure of RCP as the major cause of lost productivity and resulted in 42 recommendations. The major recommendations were to

- . alter some of the operating procedures
- . modify some design features by adding vent loops
- . add some more instrumentation enabling early detection of failure causes
- . alter procedures to reduce trapped solid particles (cruds)
- . alter several maintenance and inspection procedures

The major benefit of completing this project was the elimination of the majority of unit NOP hours caused by RCP seal failures. An added benefit was that the station increased the time between inspections which has added substantial availability to the unit. The experience gained in this reactant coolant pump seal project is being applied at two new nuclear (PWR) stations under construction (Table 2.3).

It is noted here that this procedure of identifying unit and component non-operating hours, through EEI data, has been applied to all nuclear units in the CECo system. This approach has not been applied to any of CECo's fossil units.

2.7 Case Studies

One of the most commonly used methods of assessing potential improvement projects at CECo is through the use of Special Project Requests (SPR). The use of SPR's allows the company (both station staff and management) to a priori assess the costs of undertaking a project and the expected benefits

to be derived. The costs of undertaking a project are estimated in terms of labor and material. Where applicable, the cost of replacement power is also factored in. The expected engineering benefits such as improved availability or heat rate, are quantified to the extent possible. For instance, standard engineering calculation enables one to calculate the additional MW that a machine can generate in some cases. In some instances, where benefits cannot be rigorously estimated, operating and engineering judgment is called for. This is particularly true if an identified project is expected to improve future availability or capacity factor of the unit. Sometimes a special project may afford a not easily quantifiable benefit, such as providing ease of maintenance. Hence the company treats each project request on a case-by-case basis before approving or rejecting the project.

The responsibility for making a project request is not with any one department, though it appears that a large number of them originate from the stations themselves. Other groups such as Fossil Station Division, Station Mechanical and Nuclear Engineering Departments do request projects. The level of justification for proposed projects depends on the size of the projects--the ones that entail small expenditures are approved with less justification and paper work. The larger ones need detailed analysis and justification and often involve consultation with vendors or outside experts.

Once the cost and engineering benefits of a proposed project have been identified with reasonable accuracy, an economic analysis of the project is undertaken. The inputs to the engineering calculation are: the useful life of the project, the expected dollar benefits of the project, the costs of borrowing money at current interest rates, the type of expenditures to be incurred (i.e., investments or expenses). The output of the analysis is essent-

ially cost benefit analysis and allows the decision maker to either approve or reject a particular project. It has been observed that the economic analysis is normally done by the Statistical Research Department and not the group that initiated the project. Statistical Research maintains up-to-date data on fuel costs, replacement energy costs, carrying charges for the company, etc. The general procedures followed by the company are described in this report for several projects. Since each station generates dozens of SPR's every year it is impractical to include all of them in this report. Hence only examples that had something distinct, but at the same time were representative of Company's procedures are included in the case histories described below. The following case studies are indicative of the various productivity measures that CECo uses in its operation and approach to productivity improvement.

Case 1: Rebuilding of boiler furnace, and air-heater of the coal-fired Kincaid Unit 2.

In 1977 it was noticed that there were a large number of forced outages at the Kincaid Unit 2-a large mine mouth coal station in CECo system. The series of outages had reduced the unit availability to as low as 50% and capacity factor to about 35%. The main cause of the outage was extensive leakage in the water wall of the furnace that caused frequent unit shutdown to patch the repairs. Inspection of samples from the waterwall tube indicated that the tube wall had thinned appreciably from erosion attributable to normal wear and tear. Additionally this particular unit was an early unit of new design, and had some inherent design deficiencies. After extensive discussions with the vendor CECo considered corrective actions. The company had undertaken a similar project at unit 1, and was fairly certain of the expected benefits.

The engineering benefits of this project were assessed in detail in this project since the cost of the project was considerably high. The prior experience with unit 1 indicated that availability factor for unit 2 could be increased from about 56% to 80% by rebuilding the furnace. The dollar benefits of the project depends on the load the unit will be expected to take in the overall system and two capacity factors—one of 50% and another of 60%—were assumed.

The company realized that during the extensive furnace rebuilding the earlier design deficiencies could also be corrected effectively. The prior experience of the Company indicated that this action would uprate the unit by 50 MWe.

The Kincaid Units of CECo are mine mouth units and hence have low fuel cost. Because of low availability and capacity factors, the required power in the CECo system was being replaced by units that have higher fuel costs.

The engineering benefits of improving the capacity factor and uprating the unit will provide dollar benefits in terms of differential fossil fuel costs with other fossil units. This benefit, arrived at by Statistical Research, was evaluated at 5 mills/Kwh.

There is one additional benefit from this project that is not easily apparent. The frequent boiler outage had caused additional maintenance work and a complete redesign and rebuilding would reduce this cost. It was estimated by the company that undertaking the project would decrease operation and maintenance costs by about 1 mill/Kwh.

The data on engineering benefits and the cost of implementation of project as supplied by vendor were fed to the Statistical Research Unit. Since tube erosion is a normal part of the wear and tear, the Statistical Research

assumed that the benefits of this project would last about ten years and not last through the remaining life of the plant. It was estimated that undertaking this project would cause longer-than-normal outage during rebuilding and hence would involve one-time additional energy replacement cost which was added to the total cost.

Based on these data Statistical Research conducted engineering-economic analysis of the proposed project. Even on conservative benefit estimates--only ten year life span and lower of the two estimates of capacity factor--it was found that the project was beneficial and the management of the company approved the project which has since been completed.

This example is indicative of the approach used by CECo for improving productivity. The direct benefits in this case were: improved availability and capacity factors, possible uprating of the unit, decrease in system fuel costs and a further decrease in maintenance costs. The primary costs were the labor and material costs as well as the cost associated with longer-than-normal outage. Considering all these, on balance, it was found that the project was beneficial and the company decided to undertake it.

Case 2: Modification of Moisture Separator Reheaters (MSR) at Zion 1 & 2 Nuclear Units

In 1977 the Zion station staff realized that the steam quality at the exit from MSR's was less than 100%. The resulting decrease in the inlet steam enthalpy to Low Pressure (LP) turbine was reducing the unit output and was also causing extra forced outages. The root cause of this was traced to tube failures in MSR's. The direct engineering benefit--estimated by standard engineering calculation was to uprate the unit by 16 MWe, by adding more reheat capability. Redesign eliminates moisture, in the form of water parti-

cles in the LP steam, and hence reduces erosion on LP turbine blades, prolonging blade life. This benefit, though recognized, is not easily quantifiable and was not factored into the cost benefit analysis of the project. It was found that a similar project undertaken by a utility in New Jersey had all but eliminated the outages attributable to this cause.

For conducting the engineering-economic analysis Statistical Research first estimated the cost of doing the redesign. Since all outages are expected to be removed and additionally 16 MWe can be added, the costs of replacement fossil energy was calculated for these conditions at a projected 60% capacity factor. This approach was taken because nuclear production has lower costs than fossil and within the CECo system and when a nuclear unit is not available fossil provides the replacement. The differential fuel cost is the net benefit and it was assumed that the benefits of modification would accrue over the remaining life of the plant. The analysis by Statistical Research indicated that the required investment could be recovered in about a year, in other words had a high benefit to cost ratio and the management had no difficulty in approving the project.

Case 3: Purchase of Spare Spindle for the Coal Fired Unit 7 at Joliet Station

The main units at Joliet station are two 537 MWe coal fired units and are identical in design. An industry-wide survey indicated that high pressure turbine spindle of this particular design had high susceptibility to cracking. The root cause of the problem was thermal fatigue. Unit 7 turbine-generator was due for a longer overhaul in about 3 years and the Fossil Station Division of CECo considered purchase of a spare spindle in case there was a crack. The availability of a spare spindle would reduce

the planned outage time by 9 weeks.

The Statistical Research Department analyzed this SPR for two different scenarios.

- a. purchase a new spindle and repair (or sell) the old one if a crack is discovered.
- b. do not buy a new spindle and repair any crack during overhaul. This option would imply an additional outage time of 9 weeks.

The lead time required to obtain the spindle from the vendor is about 2 years and an early decision had to be made. The analysis by Statistical Research showed that, even without considering fuel cost escalation, the cost of a new spindle would be much less than the power replacement cost for the extra 9 weeks of outage. The strategy in this case was

- a. buy a new spindle for Unit 7.
- b. if Unit 7's old spindle is in a repairable condition repair it and keep it for Unit 8.
- c. discard the old spindle if it is not repairable.

The engineering benefits of this project were reduction in planned outage time.

III. ILLINOIS POWER COMPANY (IP)

3.1 Overview of Company

Illinois Power Company (IP) is the second largest public utility in the state of Illinois in terms of number of customers and number of kilowatt hours sold during 1977 (Table 1.1). Its general offices are located in Decatur, Illinois in the central part of the state.

IP is both an electric and a gas utility with electric operating revenues during 1977 amounting to 68% of its total operating revenue. IP supplies electricity to approximately 13% of the state population. Its electric service area located in north central, central, and southwestern Illinois is about 15,000 square miles (roughly 25% of the total area in the state) (Figure 1.1).

IP sold just under 13 billion kilowatt hours of electric energy during 1977 which is about 13% of the total electric energy sold in the state during 1977 (Table 1.1).

IP currently has a total net generating capability of over 3800 megawatts of electric power (Table 3.1) including Havana 6, a 450 megawatt coal-fired unit, which went into commercial operation during June, 1978. Roughly 85% of IP's capability is provided by coal burning units with the remainder provided by oil excluding 2400 kilowatts of power which is hydro-generated. The Baldwin station, consisting of three 605 megawatt units the last of which became

Table 3.1

Illinois Power Company
Operating Statistics for 1977

Operating Revenues (x \$1000)

Electric	383,567 (67.6%)
Gas	183,820 (32.4%)
Total	567,387

Electric System Data

		(1)	
Net Generating Capability			3862 MWe
Peak Load	Summer (1977)		2846 MWe
Capability	Coal		3263 MWe (84.5%)
	Oil		597 MWe (15.4%)
	Hydro		2 MWe (0.1%)
	Total		3862 MWe

Net Sales (x million Kwh) 12,951

Note: (1) Includes Havana 6 which went on line during 1978.

Sources: Illinois Power Fact Folder - 1978
Illinois Power Company Annual Report 1977

commercial in 1975, provides almost half of IP's capability.

Presently, the Clinton Nuclear Power Station is under construction by IP. Clinton will consist of 2 Boiling Water Reactor (BWR) units each with a net capability of 950 megawatts. Unit 1 is scheduled to go on line in 1982 and unit 2 in 1988. During 1977, IP had a peak summer load of 2846 megawatts.

3.2 Approach to Task

The approach to this task with respect to identifying and documenting IP's procedures regarding powerplant productivity was essentially the same as that used with CECo. Interviews with senior headquarters personnel, station visits and communication through phone and letters provided all of the subject matter. IP responded to written requests for information promptly and these have been a major source for documentation. ICC and ERC personnel visited the Wood River Unit of IP and the discussions with plant personnel, in particular the Results Supervisor, have been very helpful. Finally, considerable time was spent with the Supervisor of Energy Systems Studies discussing improvement projects, their identification, and analysis.

3.3 Organization for Productivity

At Illinois Power the primary responsibility for maintaining and improving plant productivity rests with the Station Manager. The Station Manager is assisted in this task by the Results Supervisor. The Results Supervisor closely monitors the various operating parameters such as pressures, temperatures, vibration levels, etc. Any abnormal event is investigated and appropriate corrective action taken. Depending on the size of the station, the Results Supervisor is assisted by 2 to 8 Results and Assistant Results Engineers. Station organization at Wood River is shown in (Figure 3.1) and is

Figure 3.1
Illinois Power Company
Wood River Power Station

representative of the organization at all IP plants.

The Manager of Power Production has the overall responsibility for power-plant productivity at all of IP's stations. As the organization chart, Figure 3.2, indicates powerplant productivity is only one of the many functions in the Power Production Group. Within this group, the Performance Supervisor monitors the productivity and performance of all the units within the system. All of the EEI outage data is prepared by this section. Within the Power Production Department, the Supervisor of Energy Systems Studies is responsible for feasibility and cost analysis of special project requests. All project requests-whether they are for productivity improvement or otherwise-are analyzed by Systems Studies group. These analyses are conducted as a discussion with station staff, architect-engineer firms, equipment vendors and other utility personnel if required. Once the technical feasibility of a project is established the project undergoes a cost-benefit analysis using standard engineering-economic tools. A major input to this analysis is the displaced power costs-both long term and short term-and the Energy Supply Group is involved in this phase. The Generation Planning Department is involved in project analysis if the proposed project has system wide consequences. Three case histories of project implementation are included in this report and are indicative of the general approach at IP towards improved plant productivity.

3.4 Performance Measures and Goals

In general IP uses standard industry performance definitions-such as heat rate, capacity factor, unit availability, generation costs, etc.- for performance evaluation. The operating performance of an individual unit is measured by its availability and outage statistics. In terms of estimating

the monetary benefits of improvement to a productivity index-such as unit availability-IP indicated that such estimates could vary widely. For instance, IP pointed out that the dollar worth of increasing the availability of a unit during an on-peak period would be substantially higher than the same increase in availability during an off-peak period. IP indicated that it plans the major outages at each unit-specifically annual boiler overhauls-such that system wide there is enough capacity to carry the native load. The overall goal is to maintain the lowest possible generation costs. No annual availability goals are set by IP for its generating units.

3.5 Identification of Sources of Lost Productivity

Illinois Power Company indicated that identifying causes of lost productivity and taking corrective actions is a continuous and ongoing effort. A reporting system exists at Illinois Power which is similar to the system at Commonwealth Edison. A copy of the Powerplant Productivity Review identifying the causes for and magnitudes of lost production for one unit is shown in Figure 3.3. This report is prepared annually for each of IP's generating units by the Power Production Department. It identifies major sources of lost production. A Power Station-Status and Capability Report is prepared daily by IP. Although this report is of greater use in economic load dispatch than in monitoring productivity, it does identify the unavailability of a unit and the main causes of unavailability. A sample copy of this report is shown in Table 3.2. Additionally the Power Production Department prepares the Statistical and Cost Report each month. This report shows generation costs and operating statistics for each of IP's units.

The following are the general guidelines for identifying the causes or production losses and establishing corrective actions:

Table 3.2
Illinois Power Company
Power Station - Status & Capability Report
As of 8.00 a.m. Monday, June 26, 1978

	CROSS GEN	EQUIP STATUS	OR E	DE- RATE	EST. PIN	NET CAP.	SUMMER MAX. RAT'G	Remarks
<u>Baldwin</u>								
Unit 1						575	600	
Unit 2		C	E	0	Next Outage	575	600	2A7-leak
Unit 3		D	E	0	Next Outage	550	600	3C Mill Out.
TOTAL	1507			25		1700	1800	Turbine problem
<u>Wood River</u>								
Units 1-3						150	50 ea.	
Unit 4		D	S	10		90	103	4D Mill Out
Unit 5						390	397	
TOTAL	397					630	650	
<u>Keokuk</u>								
Units 1-5	75					260	52 ea.	
Unit 6	30.6	K	E	225		225	440	'B' condensate pump out
TOTAL	105.6					485	700	#6 off 6/23/78 8.46 P normal on 6/26/78 6:20 A shutdown-cycling
<u>Hennepin</u>								
Unit 1						75	75	
Unit 2						233	233	
TOTAL	113					308	308	
<u>Vermilion</u>								
Unit 1		D	E	13		65	75	1B Mill Out
Unit 2		K	E	0		107	107	1 Ct. Fan Out
TOTAL	68					172	182	
<u>Stallings</u>								
Units 1-4		K	E	22		22 ea.	22 ea.	#1 - no ready lights - will check #2 - maint. this a.m.
TOTAL	0					44	91	
<u>Oglesby</u>								
Units 1-4		K	S	13		13 ea.	15 ea.	#2 overhaul
TOTAL	0					39	60	
<u>Vermilion I. C.</u>								
Jack Willie Jet	0					12	12	
Units 7 Hydro						13	13	
TOTAL	1.2	K	E	5.8	Indef.	7.2	13	2 Jack, Disables 6 3 units at Hannibal out #6 diesel avail for 2 Mw load in emergency
<u>SYSTEM</u>								
TOTAL	2061.8					3410.2	3829	

*EQUIPMENT OFF OR DEBATED

A - T/G F - P.D. Fan
B - Boiler G - B.F. Pump
C - Cyclones H - C.W. Pump
D - Cool Mill J - Tube Leak
E - I.D. Fan K - Orber

Stallings f.o. 88.22
Oglesby f.o. 912
River Level at W. River 408.6

Figure 3.3
Illinois Power Company
Mud River Power Station
Unit No. 5
1977 Productivity Review

Based on Summer Capability 396 MW
Power Production Dept. - 2/1/78

I. Project Selection

Projects are selected for review based on one or more of the following items:

- A. Failure of a generating unit to meet system loading requirements.
- B. Abnormal increase in the generating unit or component outage rate due to failure, including any inability to meet operating requirements at full or reduced capacities.
- C. An increase in one or more of the operating parameters (such as fuel cost, maintenance expense, heat rate, or unavailability) of a station, unit or an integral component.
- D. When anticipated or actual operation of the unit changes from previous operation levels and the resulting changes could result in changes in unit or component availability.

II. Project Analysis

In this phase, problem causes are identified and an analysis of the possible solutions made. The method of review will vary from project to project. A typical method for review of a problem is summarized as follows:

- A. A unit's failure to meet system loading requirements.
 - 1. Typically, the problem will be discovered by the power plant operating personnel or the system load dispatcher.
 - 2. The local plant personnel or headquarters engineering staff will begin a review of the problem. If this review indicates the unit's shortcoming is the result of equipment malfunctions or design problems, the equipment manufacturer and/or the power plant design consultant is contacted for assistance.
 - 3. Once the problem causes are identified, possible methods of correction are identified and listed. In some cases, equipment manufacturers and/or consultants are contacted for assistance.
 - 4. The associated costs of each solution are evaluated, reviewed and summarized. Such things as original equipment costs, carrying charges, displaced power cost, plus expected operation and maintenance costs, are considered. The delivery lead time and installation time requirement are reviewed and considered.

B. An increase in equipment or unit outages and failures.

1. Generally, the same methods used for analyzing the problem in subsection II, A are used for analyzing this type of problem.
2. Industry experience is used in analyzing the problems in some cases. Sometimes other utilities that have encountered similar difficulties are contacted. Certain types of problems and related solutions are hypothesized using historical experience or informed judgement.

C. Change in operating parameters.

1. Many of the same methods used in subsection II, A are utilized.
2. In some cases, special testing is performed by the local plant personnel to assist in problem identification and solution.

All of the above discussed methods for project analysis are very general and the requirements of each project determine the specific methods to be used.

III. Project Implementation

All the solutions considered under the project analysis phase (II) are reviewed. A decision is made determining how the project is to be completed. In many cases, funds must be budgeted and materials ordered before implementing the project. The size, nature and significance of a project govern the extent of efforts and funds applied. Many times the repair or improvement is scheduled so that the work will be done in conjunction with another scheduled outage which has already been planned. In some cases, a special outage must be scheduled. All of these factors are considered when developing the time table for project completion.

After the project has been completed, the unit or component's performance is monitored to verify the expected improvement.

Specific applications of the general guidelines are illustrated through the case histories. ERC noted that a majority of improvement projects at the units were initiated by plant operating and maintenance staff. However, it is not uncommon to see instances where other divisions such as the Power Production Department at headquarters initiate large scale projects. Illinois

Power indicated that each project is treated on a case-by-case basis within the framework of the general outlines. Case histories of three projects undertaken by IP are included in this report to indicate the application of the company's guidelines for productivity analysis.

3.6 Case Histories

The case histories presented here are representative of IP's general approach to productivity. They include finding the source of loss, corrective measures, cost benefit analysis and final implementation of projects. The examples presented in this section are not meant to imply that IP uses the same level of detail in analyzing every project.

Case I: Repair and/or replacement of Wood River Unit No. 5 High Pressure Turbine Shaft. This unit is a 398 MWe coal-fired unit.

Problem Identification

During the latter part of 1973, Unit No. 5 was experiencing a high vibration phenomenon during load changes. On December 1, 1973, the unit was removed from service. A meeting was held with General Electric representatives on December 4, 1973. Based on General Electric's experience with two other units with similar symptoms, the decision was made to open the high pressure turbine shell and inspect the turbine rotor for cracks in the area of the first stage wheel.

A crack several inches in depth was found in the inlet side of the second stage wheel.

Problem Analysis

The crack discovered in the high pressure turbine shaft prevented the unit from being returned to service without major repair or replacement. The generally available methods by which this turbine shaft could be repaired were

considered as follows:

1. Order a new high pressure turbine shaft, keeping the unit out of service until the new replacement shaft is available in approximately two years. The displaced power cost for replacing 400 MW of capacity and associated energy would be over \$18 million for this two-year period. The estimated cost of a new high pressure shaft is approximately \$920,000.
2. Temporary repairs could be made to the turbine shaft and the unit returned to service in several months at reduced capability. The unit would operate at reduced capability until a new replacement shaft is available in approximately two years.

The duration of this outage to make temporary repairs to the shaft is four months. The displaced power cost for a four month period would be approximately \$3 million plus \$3 million for the remaining 20 month period the unit is derated.

The estimated cost of the temporary repairs is \$300,000 while the estimated cost for the replacement shaft is \$920,000. The equivalent initial cost for the replacement shaft is \$11.50 per KW ($\$920,000 \div 80,000$ KW). In addition to the capacity derating (80 MW), the unit would experience an estimated increase in heat rate of 150 Btu/Kwhr during the period of derated operation, which would result in an additional fuel cost of \$200,000 for the two year period.

3. Temporary repairs could be made to the shaft with no replacement of the old shaft which would result in a permanent derating of approximately 80 MWs. If this option is chosen, the 80 MW of lost capacity would have to be replaced at an estimated cost of \$24 million, respectively. The cost for the temporary repairs is \$300,000.
4. Another option available would be retirement of this unit. If the unit is retired, the 400 MW of capacity would have to be replaced at a minimum estimated cost of \$120 million. The displaced power cost over a four year period until the capacity is replaced would amount to \$36 million. The increased fuel cost due to the derated capacity would continue thereafter at \$120,000 annually.

Project Implementation

The summary of repair methods (Table 3.2) indicates that method 2 or the temporary repair of the shaft with ultimate replacement, is the most desirable method of repair. This was the method chosen as the problem solution in late 1973. The project was completed in early 1976.

Table 3.3
 Illinois Power Company
 Summary of Methods of Repair
 Wood River Power Station
 Unit No. 3
 1973-1976 High Pressure Turbine Shaft Repairs

Method No.	Type of Repair	Comparison of Costs During 10 year Period					Total Costs	1974 Present Worth of Revenue Requirements For 20 Years Discounted at 8%
		Displaced Power Costs	Increased Fuel Costs	Temporary Repair Costs	Permanent Repair Costs	Fixed charge on Capital Investment for 6-Year Period		
1	No temporary repairs and permanent repair with new shaft.	\$18,000,000	\$ -	\$ -	\$920,000	\$ -	\$18,920,000	\$16,121,816
2	Make temporary repairs and permanent repair with new shaft	6,000,000	200,000	300,000	920,000	-	7,420,000	7,146,444
3	Make temporary repairs but derate unit and replace capacity in 4 years at a capital cost of \$24,000,000 and fixed charges of 17.5%	9,600,000	1,160,000	300,000	-	25,200,000	36,260,000	34,882,752
4	Retire unit and replace capacity in 4 years at a capital cost of \$120,000,000 and fixed charges of 17.5%	\$36,000,000	-	-	-	126,000,000	162,000,000	179,792,100

Case II: Rewinding of Wood River Unit No. 4 generator stator.
This unit is a 103 MWe unit burning low sulfur coal.

Problem Identification

During a high-potential test performed on the generator stator in January, 1974 (during the Unit's overhaul), one set of generator coil bars failed and had to be replaced. These repairs were completed, and the unit returned to service in early 1974.

Problem Analysis

As a result of the 1964 stator coil failure during the high potential testing, the equipment manufacturer and an independent supplier were requested to inspect and make recommendations concerning operation of this equipment. Independently, they recommended the generator be rewound within three years.

The estimated cost for rewinding the stator was \$250,000. The delivery time for the new generator coils was, at that time, approximately 18 months.

In the event no modification was made to the generator stator, there was the potential for failure. If a random failure of an unknown number of stator coil bars occurred, it could result in an extended outage due to the time required to fabricate the replacement coil bars.

If the unit experienced a one year emergency outage to repair the generator, the present worth of future revenue requirements (PWFRR) of the displaced power cost would have exceeded \$1,750,000 through the year 1980. By the planned rewinding of the generator stator, the resulting savings would exceed \$1,500,000. Table 3.4 contains detailed calculations supplied by the Generation Planning Department for this analysis.

Project Implementation

The decision was made in mid-1974 to order the fabrication of replacement coil bars and to rewind the generator stator during the 1976-77 unit overhaul.

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Table 3.4

Illinois Power Company
Wood River Unit 4
Rewinding Generator Stator
Present Worth of Future Revenue Requirements (PWFRR)
(Dollars - 1974)

<u>Year Failure Could Occur (1)</u>	<u>PWFRR For a Failure</u>	<u>Potential Savings if Repair Made in Timely Manner - 1976</u>
1975	1,881,400	- - (2)
1977	1,829,700	1,577,100
1980	1,754,900	1,512,600

(1) Failure occurs at beginning of year

(2) Due to lead time required for ordering materials, repair could not be performed prior to the end of 1975.

Assumptions:

MAR - 8.3%

Escalation Rate - 7%

Gross Receipt Tax - 5.08%

Displaced Power Cost - \$1,560, 861

MAR - Minimum Acceptable Return

Case III. Repair and/or replacement of Furnace Roof Tubes at Hennepin Station Unit 2-This unit is a 233 MWe coal-fired unit.

Problem Identification

During the 1972 through early 1976 period, this boiler experienced an increase in outages due to failures of water wall roof tube failures. The increase in outage duration due to water wall tube failures is illustrated in Figure 3.4.

Problem Analysis

The initial effort to identify the problem was started in early 1975. The boiler manufacturer's recommendations were received in early 1976. These recommendations were to (1) re-orifice the boiler, (2) replace roof tubes, (3) redesign roof tube supports, and (4) develop water chemistry guidelines.

During the first quarter of 1976, it was apparent the rate of water wall roof tube failures had increased. The unit experienced six (6) outages, totaling 224 hours duration, during this period. If this rate of tube failures continued throughout 1976, the present worth of future revenue requirements (PWFRR) of the displaced power costs would have been \$755,618 (Table 3.5). This is based on an estimated displaced power cost of \$35,000 for a 30-hour outage (approximately 7.41 mills/Kwh).

It should be noted that if the tube failure rate follows the 1972-1975 trend (Figure 3.4), the PWFRR of the displaced power costs due to these tube failures would exceed \$366,000 for 1976.

Using the estimated cost for replacement of the roof tubes in this boiler (\$720,000) and the 1972-1975 trend rate, payback could be achieved in less than two years (Table 3.5).

Figure 3.4
 Illinois Power Company
 Hennepin Power Station Unit No.2
 Total Water Wall Tube Leaks
 Duration & Number

Table 3.5

Illinois Power Company

Hennepin Power Station Unit No. 2
Water Wall Roof Tube Failures

Retubing Cost - \$720,000 (1976)

Estimated Average Displaced Power Cost - 7.41 Mill/Kwh

Assumption - 9 %MAR
 8 %Escalation
 5.0% Gross Receipt Tax
 Average 157MW displaced power from Hennepin #2

$$P/A = \frac{B(1-B^n)}{(1+e)(1-B)}$$

$$B = \frac{(1+e)}{(1+x)}$$

e=Escalation
x=MAR
N=No. of Years

Using 1976 trend rate - 672 Hrs/Yr (224 X 3)

$$\text{For one year - PWFRR} = \frac{(672 \text{ hrs}) (7.41 \$) (.91743)}{\text{MWH} (1 - 0.0508)} = \$755,618$$

Using 1972 - 1975 trend rate - 326 Hrs/Yr in 1976

$$\text{For one year - PWFRR} = \frac{(326 \text{ Hrs}) (157\text{MW}) (7.41 \$) (.91743)}{\text{MWH} (1 - 0.0508)} = \$366,565$$

at the 1972 - 1975 rate - payback can be achieved in n years:

$$\frac{(326 \text{ Hrs.}) (157 \text{ MW}) (7.41 \$)}{\left(\frac{\text{MWH}}{0.9492} \right)} \frac{B(1-B^n)}{(1+e)(1-B)} = \$720,000$$

$$\frac{B(1-B^n)}{(1+e)(1-B)} = \frac{720,000}{399,556} = 1.802$$

$$1 - B^n = .01802$$

$$(.9908)^n = .98198$$

$$n = 1.973 \text{ yrs.}$$

Project Implementation

Some temporary changes were made in the unit's operation-early in 1976 in an effort to reduce the tube failure rate until permanent repairs could be considered and completed.

The decision was made in mid-1976 to follow the boiler manufacturer's recommendation which included replacement of the roof tubes during the unit's major turbine overhaul, scheduled in the fall of 1976.

The project was completed in December, 1976.

During 1977, only one water wall tube failure has been experienced.

IV. CENTRAL ILLINOIS PUBLIC SERVICE COMPANY (CIPS)

4.1 General Overview of Company

Central Illinois Public Service Company (CIPS) is the third largest public utility in the state of Illinois in terms of number of customers and number of kilowatt hours sold during 1977 (Table 1.1). Its general offices are located in Springfield, Illinois in the central part of Illinois.

CIPS operates in 65 of Illinois' 102 counties and serves an estimated 7% of the state population. Its service area is approximately 20,000 square miles (roughly 35% of total area in the state) located in the west central, east central, south and southeastern parts of Illinois (Figure 1.1). CIPS is both an electric and a gas utility with electric operating revenues during 1977 amounting to 82% of its total operating revenues.

CIPS sold over 8 billion kilowatt hours of electric energy during 1977 which is about 8% of the total electric energy sold in the state during 1977 (Table 1.1). CIPS's generating stations with the exception of 2 small peaking units and one cycling unit burn coal exclusively.

CIPS currently has a total net generating capability of about 2400 megawatts of electric power (Table 4.1) including Newton 1, a 590 megawatt coal burning unit, which went into commercial operation during November, 1977. Newton 2, which is similar in size and type to Newton 1, is scheduled to go on line during 1981. A late 1980's unit of similar size is planned, but the

Table 4.1

Central Illinois Public Service Company
Operating Statistics for 1977

Operating Revenues (x \$1000)

Electric	288,128 (82.4%)
Gas	61,590 (17.6%)
Total	349,718

Electric System Data

Net Generating Capability	2409 MWe
Peak Load	Summer (1977) 1813 MWe
	Winter (1977-78) 1620 MWe
Capability	Coal 2156 MWe (89.5%)
	Oil 253 MWe (10.5%)
Total	2409 MWe

Net Sales (x million Kwh)	8,323
-----------------------------	-------

Source: Central Illinois Public Service Company
Annual Report 1977

site has not yet been selected. During 1977 CIPS had a peak summer load of 1813 megawatts and a peak winter load of 1620 megawatts.

4.2 Approach to Task

An initial meeting was held at the central offices of CIPS in Springfield, Illinois. Representatives from CIPS, ICC and ERC discussed the methods currently being used by CIPS to improve the productivity of its generating units. Based on these discussions, a formal request for more information was sent to CIPS.

Several subsequent phone conversations between representatives of CIPS and ERC took place and CIPS responded formally to ERC and ICC concerning the methods which it is currently using to monitor the performance of its generating units, identify sources of lost productivity and assess the cost effectiveness of projects intended to improve the historical productivity of its generating units.

Additional phone conversations between CIPS and ERC staff took place to clarify methods used by CIPS to improve productivity.

4.3 Organization for Productivity

Within CIPS the Power Production Department Performance Engineering Section has power plant performance as its major responsibility (Figures 4.1 and 4.2). The manager of the Power Production Department reports to the Vice-President of Power Supply who in turn reports to the Executive Vice-President of CIPS. Also reporting to the manager of the Power Production Department are the station superintendents. Within the Power Production Department are four staff groups: Administrative Services, Environmental Affairs, Performance Engineering and Plant Engineering.

Figure 4.1

Central Illinois Public Service Company

All personnel within the Power Production Department have improved power-plant performance as a part of their job responsibility and thus any person within this department can initiate or suggest a possible productivity improvement project. There is a Performance Analyst within the Performance Engineering group whose major responsibility is to monitor performance and recommend improvements.

Supervisory personnel shown on Figure 4.2 including the power station superintendents have the responsibility of assessing and documenting candidate productivity improvement projects. The Administrative services group is involved with projects relating to air and water quality matters. The plant engineering group is involved with the station personnel and sometimes with outside architect engineers and equipment manufacturers in trouble shooting problem areas and deciding whether to replace or modify faulty equipment. There are a number of chemists in the performance engineering group who are involved in analyzing water, lubricants, and fuel problems.

Within the power stations there are two different types of organization. Figure 4.3 is a organization chart of the Meredosia Power station showing the Superintendent-Assistant Superintendent approach. Figure 4.4 is a organization chart of the Coffeen Power station showing the Superintendent-Plant engineer approach.

4.4 Performance Measures and Goals

Performance Monitoring

In general, CIPS uses the following as measures of productivity (not necessarily in order of importance):

1. generation budget
2. unit and boiler availability

Figure 4.2

Central Illinois Public Service Company
Power Production Department

Figure 4.3
Central Illinois Public Service Company
Meredosin Power Station

3. cost/MW (incremental cost)
4. service hours of units
5. scheduled outage hours
6. forced outage hours
7. partial outage hours
8. log summary sheets from each plant
9. heat rate data
10. other parameters

Note that in some cases the measure pertains to system performance and not individual unit performance. In general Edison Electric Institute (EEI) definitions are used by CIPS. Factors which influence the above measures of productivity and which are closely monitored by CIPS include:

- a) coal quality and cost
- b) start-up cost
- c) boiler and turbine efficiency
- d) condenser back pressure
- e) equipment limitations
- f) steam temperature and pressure
- g) environmental restraints

CIPS indicated that forced outage hours are monitored very closely. In general CIPS tries to project forced outage rate based on historical data and CIPS tries to improve on historic forced outage rates for its units. CIPS also indicated that capacity factor is used as a measure of productivity but not in its day-to-day operations. Presently equivalent availability (EA) is not used by CIPS although EEI calculates EA for CIPS' units based on the data submitted by CIPS to EEI. CIPS also indicated that heat rate is monitored

very closely and that projects are implemented to keep heat rate at reasonable levels.

CIPS indicated that goals in the form of a generation budget for each unit are set for each month by the System Operation department. These goals are based on historical data, load forecasts, maintenance outage forecasts, incremental costs, fuel costs and other factors. CIPS indicated that within the company there are no punitive or reward programs for failing to meet or exceeding these goals.

4.5 Identification of Sources of Lost Productivity

CIPS indicated that the sources of lost productivity are identified by analyzing:

- a) forced outages
- b) reduced load capability due to fuel quality or faulty systems
- c) Improper maintenance programs

In particular major malfunctions which could cause further serious damage or threaten personal safety are studied to determine the root causes.

CIPS indicated that the improved productivity which is likely to result from the implementation of a candidate productivity project is estimated and a dollar value is placed on the benefits which are likely to occur. A dollar value is placed on the benefits which are likely to occur by multiplying the expected additional production times the average replacement power costs whether internally generated by another CIPS unit or purchased from another utility. The estimates of improved performance are generally based on operating experience and engineering judgment. Quite frequently the experiences of other utilities that have undertaken similar projects are factored in.

CIPS indicated that in many cases projects are obviously cost effective and no sophisticated cost/benefit analysis is necessary. Examples of such projects are projects which significantly improve unit capability and projects which significantly improve or restore efficiency of a generating unit. Examples of the latter type are projects aimed at reducing operating and maintenance costs and projects which will improve boiler operation in order to generate steam at the design temperature and pressure.

CIPS also indicated that cost/benefit analyses are not always done when a project is aimed at meeting environmental rules.

As is the case with other utilities major planned maintenance e.g., boiler and turbine overhauls, are scheduled well in advance by CIPS. Work phases of these outages are analyzed, planned and scheduled using CPM/PERT methods. Particular emphasis is placed on manpower utilization by using outside contractors, hiring temporary employees to do labor-type work (freeing regular employees to do more skilled work), using skilled field representatives from vendors to direct work and utilizing company personnel to minimize outage time.

Presently, CIPS is considering the adoption of a computerized inventory system called Material Management System (MMS). This system is in the design phase and is currently being considered for implementation. If this system is installed, computer terminals will be installed at all stations so that information pertaining to inventory can be instantaneously obtained.

4.6 Case Studies

The following examples were provided by CIPS and are illustrative of their procedures for analysis of projects intended to improve powerplant performance.

I. Meradosia No. 5 boiler

This boiler has had a large number of forced outages due to the general deterioration. The original design pressure of the steam from this boiler was 2100 psi, but due to deterioration it has been operating at 1800 psi. The decrease in the enthalpy of steam, due to reduced pressure, has caused a 53 MWe derating on the unit. The company's analysis indicated that by rebuilding the damaged portions of the boiler, the output steam pressure could be restored to the original design value and hence the derating could be removed. The benefits from the added production capability more than justified the cost of rebuilding the boiler.

II. Coffeen No. 2 Boiler

Coffeen No. 2 is a coal-fired unit with net capability of 520 MWe which came on line in 1972. In one instance it was noticed that the induced draft fan was being overloaded with outside air instead of flue gas due to a defective expansion joint. With an overloaded fan not enough coal could be burned and this had caused a 10MW derating. By replacing the defective expansion joint it was possible to regain the 10MW. As in the previous case, this is a case of comparing the costs of load loss versus the cost of restoration and was easily justified.

V. CENTRAL ILLINOIS LIGHT COMPANY (CILCO)

5.1 General Overview of Company

Central Illinois Light Company (CILCO) is the fourth largest public utility in the state of Illinois in terms of number of customers and number of kilowatt hours sold during 1977 (Table 1.1). Its central offices are located in Peoria, Illinois.

CILCO is both an electric and a gas utility with electric operating revenues during 1977 amounting to 65% of its total operating revenues. Its electric service area is approximately 3700 square miles (about 7% of the total area in Illinois) located in central and east central Illinois (Figure 1.1). This service area contains a population in excess of 400,000 which is about 4% of the state total.

CILCO sold over 4 billion kilowatt hours of electric energy during 1977 which is about 4% of the total electric energy sold in the state during 1977 (Table 1.1).

With the exception of two gas fired combustion turbines, CILCO's generating stations burn coal exclusively.

Currently, CILCO has a total net operating capability of about 1244 megawatts of electric power (Table 5.1). Three units Duck Creek 1, Edwards 3 and Edwards 2 which went on line in 1976, 1973, and 1968 respectively, account for 942 megawatts or about 76% of CILCO's net generating capability. The last unit to go on line was Duck Creek 1 which is a coal fired unit with a net

Table 5.1

Central Illinois Light Company
Operating Statistics for 1977

Operating Revenues (x \$1000)

Electric	183,626 (65.3%)
Gas	97,451 (34.7%)
Total	281,077

Electric System Data

Net Generating Capability	1244 MWe
Peak Load	Summer (1977) 975 MWe
	Winter (1977-78) 817 MWe
Capability	Coal 1212 MWe (97.4%)
	Gas 32 MWe (2.6%)
Total	1244 MWe

Net Sales (x million Kwh)	4,432
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Source: Central Illinois Light Company 1977 Annual Report

capability of 370 megawatts. Duck Creek 2, a coal fired unit with 400 megawatt nameplate capability, is currently scheduled to go on line during 1982. During 1977, CILCO had a peak summer load of 975 megawatts and a peak winter load of 817 megawatts.

5.2 Approach to Task

The same approach was followed regarding CILCO as was followed with CIPS. An initial meeting was held in Peoria, Illinois at the company's general offices.

CILCO responded formally to ERC and ICC concerning the methods it employs to monitor performance of its generating units, identify sources of lost productivity and assess the cost effectiveness of productivity improvement projects. Additionally, phone conversations between CILCO and ERC transpired to clarify the methods which CILCO employs.

5.3 Organization for Productivity

CILCO, the smallest of the four utilities studied by ERC, has indicated that it presently has no formal system for improving the productivity of its power plants. Equipment Status Reports are prepared weekly for each unit showing all equipment which limited performance during that week. Items which caused a capability reduction (derating) or a forced outage are studied.

CILCO has a department called Methods and Results whose manager along with the three plant managers reports to the Assistant Vice President of Energy Supply (Figure 5.1). Personnel within the Methods and Results Department are brought in to study problem areas (particularly problem areas which are recurring). Based on discussions among the plant managers, the manager of Methods and Results and the Assistant Vice-President of Energy Supply, a project to

eliminate a derating or avoid future forced outages may be considered. Usually, this project would either be initiated by the plant manager or the manager of the Methods and Results Department.

In some cases, a cost/benefit analysis of the proposed project is done by the Methods and Results Department along with the Budget and Special Studies group of the Finance Department.

After the project has been studied, it is reviewed by the Methods and Results Department, plant managers and the Assistant Vice-President of Energy Supply. A decision is made then whether to cancel, implement or defer the project.

Because of other considerations, e.g., budget or system loading requirements, even if a project is cost beneficial, it may be decided to defer the project until a later time. Also, in certain cases, a project may be implemented even though the benefits/cost ratio is less than one because of other factors, e.g., environmental regulations.

5.4 Performance Measures and Goals

CILCO had indicated to ERC that the primary goal is the ability of a unit to pick up its share of the load. Equivalent Availability is currently not computed by CILCO for its units although the necessary data is supplied to EEI.

In monitoring unit performance CILCO has indicated that it uses the following performance measures: capacity factor, heat rate, cost per kilowatt-hour, forced outage rate and monthly unit performance vs. target unit performance.

CILCO has indicated to ERC that it monitors heat rate very closely. Recent historical heat rate as a function of load is plotted periodically and

Figure 5.1

Central Illinois Light Company

compared with the design curve for each boiler in order to determine boiler efficiency. If there has been a gradual increase in the heat rate of a boiler, corrective measures are undertaken to improve the performance of the particular boiler.

The Methods and Results Department, based on past unit performance and anticipated load, sets a target output factor monthly for each unit. CILCO indicated that regular evaluations of supervisors are partially based on to what extent their unit has been meeting its goals.

CILCO uses the IEEE definitions, which in general are identical to the EEI definitions, to define the measures of productivity such as availability factor, output factor, capacity factor, etc.

5.5 Identification of Sources of Lost Productivity

As indicated before, CILCO reviews the weekly Equipment Status Reports for each unit and studies items which have caused deratings or forced outages. Items which have caused forced outages are studied particularly if the forced outages have been a recurring problem. If a fix can be determined, then a decision is made whether or not to implement the fix.

In the case of the boiler, the recent historical heat rate vs. load is compared to the design curve to determine if boiler repairs should be considered.

Section 5.6 Case Study

The following example was provided by CILCO to illustrate their procedures for analysis of a project to improve powerplant performance.

I. Edwards 3 Heater Drain Pump

Edwards is a 322 megawatt coal-fired steam turbine unit which went on line

during 1968. After reviewing and analyzing the heat rate data for this unit, it was determined that, due to a faulty heat or drain pump system, the heat rate at higher loads was too great.

It was estimated by CILCO engineers that repairing and modifying the heater drain pump system would save in excess of 100 MBTU/hour at higher loads.

The repairs and modifications included installing a check valve, Vortex breaker, additional piping supports, complete pump rebuilding and installation of a new pump motor.

A relatively low figure of only 100¢/MBTU was used for coal cost. Comparing the amount of money saved with the cost of the modifications, it was determined that the modification would pay for itself in a short time and CILCO decided to implement the project.

VI. OBSERVATIONS AND FINDINGS

Many of the utilities interviewed by ERC indicated that in the future more emphasis will be laid on maintaining high levels of productivity at large base-load units. The sharp increase in fuel cost that has occurred in the last few years has dramatically increased generation costs. These increased costs have put a high premium on performance and many expenses for performance improvements that could not be justified on a cost-benefit basis a few years ago can now be undertaken. However, the utilities indicate that improvements to performance, particularly in older units, are limited and it is unrealistic to expect dramatic changes.

All four utilities indicate that change over to the use of low sulfur coal-necessitated to meet sulphur emission standards-has demonstrably affected plant performance. The plant equipment was not originally designed to handle this type of coal and has caused some reduction in plant output. The components whose forced outage rates have increased due to burning of low sulphur coal are the pulverizer mills, feeders, boiler furnace and precipitators. Utilities believe that large scale modification to accommodate burning low sulphur coal would be prohibitively expensive.

Because of nature of the technology of power production, in a broad sense, all utilities have a somewhat similar outlook towards productivity. The ability to carry the native load on the system at any given point in time appears to be the major objective of all Illinois utilities. This implies that instantaneous availability of a unit is oftentimes more important than a productivity index such as availability factor, which is calculated over time. The need to achieve this with the most economical available unit in the system

(unit with the lowest fuel cost) has been pointed out by all utilities. However, the actual procedures for maintaining productivity vary somewhat among utilities and could become quite complicated in a utility with large number of units. At smaller utilities this economic loading order is relatively simple. Hence the formal procedures--such as organization, reporting and justification--depend on the relative size of the company.

The efforts of this task indicate that, powerplant productivity is a complex issue that has to take into account economic factors, equipment limitations, system loading characteristics as well as external constraints such as regulatory requirements. Among the specific findings are

- o Utilities in Illinois use the industry wide measures of performance such as capacity factor, availability factor, forced outage rates etc. Equivalent availability as a measure of productivity is not in common practice in any of the utilities.
- o Several unit performance statistics are collected on a routine basis such as the daily unit status, component outage data, monthly production figures etc. These form the basis of evaluating current levels of individual unit output capabilities and limitations.
- o Identifying major causes of lost productivity at a generating unit appears to be a relatively simple task. Finding economically and technically acceptable corrective actions are generally more difficult.
- o Selection of improvement projects, as well as evaluating their future impacts, is mostly based on operating experience and engineering judgment. Currently, none of the utilities use formal analytical/statistical models to evaluate improvement projects. Standard engineering-economic analyses provide a basis for judging the feasibility of new projects.
- o There generally is a group in every utility--typically called the power production department--with routine responsibilities for the upkeep of unit productivity. However, a number of other departments are also organizationally involved in various aspects of productivity.
- o Recently the Commonwealth Edison Co. has developed a procedure for utilizing the Edison Electric Institute outage data base for analyzing productivity related questions at nuclear plants. This procedure utilizes unit nonoperating hours to measure productivity.

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APPENDIX B GLOSSARY OF TERMS

This appendix contains definitions of terms that were useful in preparing this report. Most of the definitions used in this appendix are the "standard" EEI definitions. The interested reader is also referred to the paper by Cook, Ringlee and Whooley listed in Appendix A which contains the IEEE definitions.

Availability Factor: $(AH/PH) \times 100$
where AH is Available Hours
and PH is Period Hours.

Available: The status of a unit or major piece of equipment which is capable of service, whether or not it is actually in service.

Available Hours (AH): The time in hours during which a unit or major equipment is Available. $(AH = SH + RSH)$

Base Load: The minimum load over a given period of time.

Base Load Unit: A generating unit which is normally operated to take all or part of the Base Load of a system and which, consequently, operates essentially at a constant output. (Average annual Service Hours for Base Load Units normally exceed 5500.).

Capability: The maximum load which a generating station, or other electrical apparatus, can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity Factor: $(\text{Total Gross Generation in Mwh} \times 100) / (PH \times MDC)$ where PH is period hours and MDC is Maximum Dependable Capacity.

Cycling Unit: A unit that is generally run but at a load which varies widely with system demand. (Average annual Service Hours for Cycling Units are normally in the range 1500 to 5500.)

Equivalent Availability (EA):
 $(AH - (EFOH + ESOH)) \times 100 / PH$
where AH is Available Hours,
EFOH is Equivalent Forced Outage Hours,
ESOH is Equivalent Scheduled Outage Hours, and
PH is Period Hours.

Equivalent Forced Outage Hours (EFOH):
 $\Sigma \text{ Forced Partial Outage Hours} \times \text{Size of Reduction} / MDC$

Equivalent Scheduled Outage Hours (ESOH):
 $\Sigma \text{ Scheduled Partial Outage Hours} \times \text{Size of Reduction} / MDC$

Forced Outage: The occurrence of a component failure or other condition which requires that the unit be removed from service immediately or up to and including the very next weekend.

Forced Outage Hours (FOH): The time in hours during which a unit or major equipment was Unavailable due to a Forced Outage.

Forced Outage Rate: $(FOH \times 100) / (SH + FOH)$
where FOH is Forced Outage Hours
and SH is Service Hours.

Forced Partial Outage: The occurrence of a component failure or other condition which requires that the load on the unit be reduced 2% or more immediately or up to and including the very next weekend.

Forced Partial Outage Hours: The time in hours during which a unit or major equipment is Unavailable for full load due to a Forced Partial Outage.

Heat Rate: A measure of generating unit thermal efficiency, generally expressed in Btu per net kilowatthour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatthour generation.

Maintenance Outage: The removal of a unit from service to perform work on specific components which could have been postponed past the very next weekend. This is work done to prevent a potential Forced Outage and which could not be postponed from season to season.

Maintenance Outage Hours (MOH): The time in hours during which a unit or major equipment is Unavailable due to a Maintenance Outage.

Maximum Dependable Capacity (MDC): the dependable main-unit capacity winter or summer; whichever is smaller.

Net Capability: The capability of a generating unit as demonstrated by test or as determined by actual operating experience less power generated and used for auxiliaries and other station uses. Capability may vary with the character of the load, time of year (e.g., due to circulating water temperatures in thermal stations) and other causes.

Noncurtailing Equipment Outage: The removal of a specific component from service for repair, which causes no reduction in unit load or a reduction of less than 2%.

Non-Operating System Test: A scheduled test or required operation of a back-up system which is not normally operating (e.g., nuclear safety system test).

Output Factor:

$(\text{Total gross generation in Mwh} \times 100) / (\text{SH} \times \text{MDC})$

where SH is Service Hours

and MDC is Maximum Dependable Capacity.

Peaking Unit: A unit that is usually shutdown and is operated only during high demand periods. (Average annual Service Hours for Peaking Units are normally less than 1500.)

Period Hours (PH): The clock hours in the period under consideration. (Generally one year or 8760 hours.)

$(\text{PH} = \text{AH} + \text{FOH} + \text{POH} + \text{MOH})$

Planned Outage: The removal of a unit from service for inspection and/or general overhaul of one or more major equipment groups. This is work which is usually scheduled well in advance (e.g., annual boiler overhaul, five year turbine overhaul).

Planned Outage Hours (POH): The time in hours during which a unit or major equipment is Unavailable due to a Planned Outage.

Planned Outage Rate:

$(\text{POH} / (\text{CH} + \text{POH})) \times 100$

where POH is Planned Outage Hours

and SH is Service Hours.

Reserve Shutdown: The removal of a unit from service for economy or similar reasons. This status continues as long as the unit is out but Available for operation.

Reserve Shutdown Hours (RSH): Reserve Shutdown duration in hours.

Service Hours (SH): The total number of hours the unit was actually operated with breakers closed to the station bus.

Scheduled Outage: An outage which can be planned in advance or for which the starting date is controllable beyond the weekend of the week during which a component trouble occurred. This type of outage may be separated into Planned Outages and Maintenance Outages.

Scheduled Outage Hours (SOH): The time in hours during which a unit or major equipment is Unavailable due to a Scheduled Outage.

Scheduled Outage Rate:

$(\text{SOH} / (\text{SH} + \text{SOH})) \times 100$

where SOH is Scheduled Outage Hours

and SH is Service Hours.

Scheduled Partial Outage: The occurrence of a component failure or other condition which requires that the load on the unit be reduced 2% or more but where this reduction could be postponed past the very next weekend.

Scheduled Partial Outage Hours: The time in hours during which a unit or major equipment is Unavailable for full load due to a Scheduled Partial Outage.

Unavailable: The status of any major piece of equipment which renders it inoperable because of the failure of a component, work being performed or other adverse condition.