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Florida Power
CORPORATION

JAMES A. McGEE
SENIOR COUNSEL

February 17, 1995

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399-0870

Re: Docket No. 941101-EQ

Dear Ms. Bayó:

Enclosed for filing in the subject docket are fifteen copies each of the Direct Testimony and Exhibits of the following Florida Power Corporation witnesses:

15 1. Robert D. Dolan - 01973-95
14 copies 2. Charles J. Harper 01974-95
13 copies 3. Henry I. Southwick, III - 01975-95
16 copies 4. Steven A. Lefton - 01976-95

Please acknowledge your receipt of the above filings on the enclosed copy of this letter and return to the undersigned. Also enclosed is a 3.5 inch diskette containing the above-referenced document in Word Perfect format. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony and Exhibits of Florida Power Corporation Witnesses Robert D. Dolan, Charles J. Harper, Henry I. Southwick, III and Steven A. Lefton have been provided by regular U.S. Mail on the 20th day of February, 1995 to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Florida Power Corporation for determination that its plan for curtailing purchases from Qualifying Facilities in minimum load conditions is consistent with Rule 25-17.086, F.A.C.

Docket No. 941101-EQ

Submitted for filing: February 20, 1995

DIRECT TESTIMONY OF STEVEN A. LEFTON

ON BEHALF OF FLORIDA POWER CORPORATION

FLORIDA POWER CORPORATION

DOCKET NO. 941101-EQ

DIRECT TESTIMONY OF STEVEN A. LEFTON

Q. Please state your name and business address.

A My name is Steven A. Lefton. My business address is 1282 Reamwood Avenue, Sunnyvale, California 94089.

Q. By whom are you employed and in what capacity.

A. I am employed by Aptech Engineering Services, Inc. ("Aptech") as Vice President, Special Projects.

Q. Please describe your education and power plant experience.

A. I have a Bachelor of Science Degree in Chemical Engineering from the University of Kansas. I have 25 years of experience involving power plant design, start-up, operation, testing, life assessment, reliability analysis, and cost analysis. In 1969, I was employed as a start-up and test engineer for the Babcock and Wilcox Company ("B&W"). B&W supplied the boilers for Florida Power's Crystal River Units 4 and 5 and Bartow Unit 1. They also supplied the Nuclear Steam Supply System ("NSSS")for the Florida Power Crystal River 3 nuclear plant. As a start-up engineer, I was involved in over 50 power plant start-up and test operations including Jacksonville Electric Authority's Northside 300 MW Unit 1 and Kansas City Power and Light Company's 880 MW LaCygne Unit 1, and outage repairs for Tampa Electric Company at Gannon

Station. I specialized in optimizing boiler and turbine control systems and led a group for B&W that tuned power plant controls in order to minimize cycling damage during unit start-up. I traveled to Canada, North America, and South America as a boiler and power plant controls engineer and as a problem solver performing work on over 50 power plants.

In 1974 for B&W, I was involved with the design and sale of two 550 MW coal-fired boilers for Basin Electric Company, a 400 MW boiler for the City of Austin, Texas, and approximately 10 other large utility boilers.

In 1974, I joined NUS Corporation as Manager of West Coast Operations in Palo Alto, California. I consulted on fossil and nuclear power plant projects including assessing safety and environmental risks of fossil power plants and nuclear power plants. I also dealt with the coal conversion of U.S. power plants for the Federal Energy Administration and storage of spent nuclear fuel and waste.

In 1979, I joined Aptech as a Vice President. One of the first major projects was a review of the operations of the Rancho Seco Nuclear Power Plant. This nuclear unit supplied by B&W is very similar to Florida Power's Crystal River Unit 3. This review involved a dispute over reliability problems and the power sales agreement between Pacific Gas & Electric Company and Sacramento Municipal Utility District.

Aptech's investigation involved aspects of plant reliability, water chemistry, nuclear steam generators, turbine failures, generator failures, and power generation at the Rancho Seco Nuclear Power Plant. I was the Aptech project manager for this investigation.

In 1982 through 1989, I served as an expert in an arbitration proceeding between Cajun Electric Power Cooperative and Riley Stoker. This case involved boilers, pulverizers, plant auxiliaries, fires, explosions, availability/reliability modeling, plant life extension, plant life assessment, and the analysis of plant logs to calculate the impacts of plant unavailability on power production costs and revenue requirements.

I provided expert services for Puerto Rico Electric Power Authority in a heat recovery steam generator lawsuit against General Electric Company. I have provided expert services for Hawaiian Electric Light Company on gas turbines and on the cost of cycling fossil power plants.

I have provided expert testimony to the Illinois Commerce Commission on the effect of operational changes on Illinois Power Company's fossil plant reliability.

In 1994, I was an expert for Pacific Gas & Electric Company in a proceeding involving Copes Vulcan, a valve manufacturer. I provided expert testimony in San Jose Federal Court regarding power plant operations and failure analysis.

I have performed life assessment and failure analysis for numerous industrial and utility clients. Selected reports are listed in my resume attached as my Exhibit No. ____ (SAL-1). During my career, I have worked on or visited at least 500 United States and foreign power plants.

I am a member of the American Society of Mechanical Engineers and the American Nuclear Society and have been a past president of the San Francisco Bay Area American Nuclear Society.

Q. What publications have you authored on the subject of power plant cycling?

A. I have published three papers as follows (see copies attached at Exhibit No.____ (SAL-2)):

1. "A Methodology to Measure the Impact of Cycling Operations and Power Derations on Plant Life and Reliability"

2. "Managing Utility Power Plant Assets to Economically Optimize Power Plant Cycling Costs, Life, and Reliability"

3. "Cycling Cost Assessment Project"

In addition, I have authored many other reports to clients on the subject of power plant cycling.

Q. Please summarize your experience in evaluating utility cycling of power plants in the United States.

A. I have been active in surveying utility cycling procedures and in obtaining cycling cost information at numerous power plants across the continental United States and in Hawaii.

I have been involved in cycling cost assessments for a number of utilities including the Hawaiian Electric Light Company, Los Angeles Department of Water and Power, Florida Power & Light Company, Tennessee Valley Authority, and Florida Power Corporation.

In addition, I served on a panel of experts at the recent 1994 Electric Power Research Institute ("EPRI") conference on power plant cycling. I am currently the principle investigator on an EPRI program to investigate the cost of cycling at the Los Angeles Department of Water and Power. This study involves some nine units and was designed to be a 3-year 2.3 million dollar research program. The program is entering its second year of research.

Q. What is the purpose of your testimony?

A. I will demonstrate that increased cycling of coal-fired baseload power units causes plant component damage which results in significant increases in steam plant operational costs and decreases in unit reliability. I will describe the type of materials degradation that occurs due to cycling and the type of damage it inflicts upon power plant equipment. I will give a range of the cost of cycling for units similar to Florida Power's Crystal River Units 1 and 2. In addition, I will explain that cycling of the Company's nuclear power plant similarly would result in adverse reliability and cost impacts.

Q. What is meant by the term "cycling" in connection with an electric generating unit?

A. Unit cycling refers to the operation of electric generating units at varying load levels, including on/off and low load cycling in response to changes in system load requirements. There are three distinct types of cycles. These include (1) hot starts, (2) cold starts (both of which are on/off cycles), and (3) transient load following during which unit output drops from 100 percent capacity to approximately 35 percent to help cope with system demand changes.

Generally, a hot start is one in which the unit is shutdown less than 12 hours. A cold start has a prior down time at least six times longer than a hot start (greater than 72 hours). In a typical weekday load-following type of plant transient, there is no start involved and all load swings and peak ramp rates are smaller and less damaging than for the start-type on/off transients.

Q. How does cycling physically affect a generating unit?

A. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure cycles. The boiler and turbine components and especially the superheater and reheater tubes normally operate at about 1000°F. Removal from service results in a rapid decrease in the superheater and reheater tubing temperatures as a result of the loss of flame in the furnace and a required air purge of the furnace for safety reasons. The temperature and pressure of superheater and reheater tubing rapidly decreases resulting in cyclic thermal fatigue. Restart of the boiler also contributes to the cyclic thermal fatigue of the superheater and reheater tubing. In addition, the boiler waterwall tubing is adversely affected by the rapid shut-down pressure decreases and restart pressure increases as well as chemistry transients resulting from cycling. The boiler waterwall tubes tend to fail from cyclic fatigue and cyclic corrosion fatigue. All of these cyclic-related phenomenon increase unit maintenance costs, and lower power plant reliability.

Q. Please describe the typical degradation effects of unit cycling.

A. There are several materials degradation phenomena that are accelerated by increased cycling. These include creep, fatigue, creep-fatigue interaction, corrosion fatigue, corrosion (especially during out-of-service periods), erosion, wear, vibration, and other interrelated phenomena that promote accelerated component aging.

Q. What do you mean by the terms "creep,""fatigue" and "creep-fatigue interaction"?

A. These are terms commonly used in engineering mechanics. Creep is the time dependent change in the size or shape of a material due to constant stress (or force) on that material. In fossil power plants, creep-related failures result from the constant stress attributable to the high temperature and pressure in a pipe or tube occurring during constant steady-state baseload operation. Fatigue is a phenomenon leading to fracture (failure) when a material is subjected to repeated, fluctuating stresses. In a fossil power plant, such fluctuating stresses result from large transients in both pressures and temperatures, that typically occur during cyclic operation.

Because baseload fossil units are designed to operate in the creep range, they experience increased outages when they are additionally subjected to cycling-related fatigue. The term creep-fatigue interaction suggests that the two phenomena (creep and fatigue) are not entirely independent, but act in a synergistic manner to cause premature failure. In fact, materials behave in a complex manner when both types of stresses occur. Creep-fatigue interaction is one of the most important phenomena contributing to component failures and can have a detrimental effect on the performance of metal parts or components operating at elevated temperatures. It has been found that creep strains (mechanical deformation as a result of stress) can reduce fatigue life and that fatigue strains can reduce creep life.

A set of American Society of Mechanical Engineers "ASME" creep-fatigue interaction curves is shown on Exhibit No. _____ (SAL-3). The curve reveals how creep-fatigue interaction affects the life expectancies (i.e., life fraction) of three types of materials labelled 1, 2, and 3. For each of these materials, the relevant ASME creep-fatigue curve shown in Exhibit No. _____ (SAL-3) depicts the percent of the total component life fraction which can withstand creep damage and fatigue damage before failure occurs. Curve 1, which is for nickel-iron-chromium Alloy 800H ("Inconel"), shows a linear creep-fatigue interaction. This means that after 50 percent of life creep damage, it still takes 50 percent fatigue damage to cause the material to fail. Most power plants were not built with any Inconel. Instead, most power plants are constructed with ferritic steels like two-and-one-quarter percent chrome/one percent molybdenum steel. This ferritic steel is plotted as Curve 3 on Exhibit No. _____ (SAL-3). I would like to highlight the implication of the non-linear relationship of this curve. A brand new power plant component can withstand a lot of fatigue damage before it fails. However, a material that has gone through 50 percent of its life-cycle creep damage (e.g., baseload operation), as shown by Point A in the exhibit, reaches end of life (failure) with only about 10 to 20 percent fatigue damage. What this means is that older units that were designed for and used for baseload operation over a number of years, are very susceptible to component failure when they are forced to cycle on a regular basis. In general, when this type of material experiences both creep and fatigue, it will fail much faster than if it just experienced creep.

The two stainless steel alloys 303 and 316 depicted as Curve 2 on Exhibit No. _____ (SAL-3) are between the two extremes; however, little stainless steel is used in power plants. The failure characteristics of most power plant components can be bounded by the data shown as Curve 3 on Exhibit No. _____ (SAL-3).

Q. How does your discussion of creep and fatigue relate to power plant costs and reliability?

A. Cycling-related increases in failure rates due to creep and fatigue may not be noted immediately, but inevitably, critical components will eventually start to fail. For example, if an older, baseload plant, that has typically operated with three to six starts per year and has sustained 40 to 80 percent of its design life-cycle creep damage, is now dispatched to operate at 50 starts per year, it may take only 2 to 6 years to accumulate the 10 to 20 percent total fatigue damage needed to cause component failures.

Shorter component life expectancies will result in higher plant equivalent forced outage rates ("EFOR") and/<u>or</u> higher capital and maintenance costs will be required to replace components at or near the end of their service lives. In addition, cycling may result in reduced overall plant life. How soon these detrimental effects will occur will depend on the amount of creep damage already present and the specific types and frequency of the cycling. But it is unquestionably true that cycling exacerbates damage in components that are already creep-damaged due to past baseload operation. The combined effect of baseload operations that produce creep damage and cyclic operations that produce fatigue damage can be expected to significantly reduce the remaining life of power plant components compared to the life expectancy with no such interaction. In fact, I have seen many examples of these effects.

Q. What specific generation unit components are susceptible to such degradation, and what specifically happens?

A. The basic types of component damage resulting from cycling and their causative effects can be categorized into four areas: (1) accelerated boiler failures; (2) turbine damage; (3) chemistry effects; and 4) electrical and control system damage. Cycling influences each damage area as detailed below:

1. <u>Accelerated Boiler Failures</u>

- Fatigue cracking of:
  - Boiler tubes in furnace corners
  - Tube to buckstay/tension bar
  - Tube to windbox attachment

10. A Complete analysis of the safety implications of any proposed operation would be required in order to ensure that there would be no detrimental impact on safety.

Q. Is this an exhaustive list of the cycling considerations and costs relating to the Crystal River 3 nuclear unit?

A. By no means is it intended as such. Because there is limited, if any, experience with the use of nuclear units for load following purposes in the United States, there is no database that can be readily used for this purpose. However, the potential costs, reliability and safety impacts can be significant, and I would not recommend that any significant nuclear cycling activity be considered in the absence of a thorough feasibility and cost analysis.

Q. Does this conclude your testimony?

A. Yes it does.

- Tube to header
- Tube to burner
- Membrane to tube
- Economizer inlet header
- Header ligament

- Boiler seals degradation
- Boiler hot spots
- Drum humping/bowing
- Fatigue cracking due to differential cooling of integrated furnace components otherwise known as downcomer to furnace subcooling
- Expansion joint failures
- Superheater/reheater dissimilar metal weld failures
- Start-up-related tube failures in waterwall, superheater, and reheater tubing
- Burner refractory failure leading to flame impingement and short-term tube overheating
- Reduced life

2. <u>Turbine Damage</u>

- Increased thermal fatigue due to steam temperature mismatch
- Turbine water induction
- Steam chest fatigue cracking
- Steam chest distortion
- Bolting fatigue distortion/cracking
- Blade, nozzle block, solid particle erosion

- Rotor stress increase
- Rotor defects (flaws) growth
- Seals/packing wear/destruction
- Blade attachment fatigue
- Disk bore and blade fatigue/cracking
- Silica and copper deposits
- Lube oil/control oil contamination
- Shell/case cracking
- Wilson line movement (the point where condensation occurs in low pressure turbines moves as a function of unit load)
- Bearing damage
- Reduced life

3. <u>Chemistry Effects</u>

- Corrosion fatigue
- Oxygen pitting
- Corrosion transport to boiler and condenser
- Air, carbon dioxide, oxygen inleakage (requiring ammonia (NH_3) countermeasuros)
- NH_3-Oxygen attack on admiralty brass
- Grooving of condenser/feedwater heater tubes at support plates
- Increased need for chemical cleaning
- Phosphate hideout leading to acid and caustic attack
- Silica, iron, and copper deposits
- Out of service corrosion

4. Electrical and Control System Damage

- Increased controls wear and tear
- Increased hysterisis effects that lead to excessive pressure, temperature, and flow
- Controls not responsive
- Motor control fatigue
- Motor insulation failure due to increased accumulation
- Motor insulation fatigue
- Motor mechanical fatigue due to increased starts/stops
- Breaker fatigue
- Wiring fatigue
- Insulation fatigue degradation
- Increased hydrogen leakage in generator
- Fatigue of generator leads
- Generator retaining ring failures
- Generator end turn fatigue and arching
- Bus corrosion when cool (i.e., Low amps)
- Transformer fatigue degradation

These effects eventually increase the frequency of forced outages, and the utility's required capital and maintenance spending, while reducing component life and plant efficiency.

Q. Are there also increased operational risks due to cycling power plants?

A. Yes. In addition to the direct equipment damage and component failures which I outlined, one often neglected effect of cycling is the increase in operator errors due to the increased personnel involvement that is necessary for cycling activities. Since increased cycling leads to increased opportunities for personnel and equipment malfunction, it follows that there is a higher risk of major damage to the equipment. Such errors can have additional adverse impacts such as:

- Implosion
- Explosion
- Low water in the boiler
- Water induction into the turbine and major resulting damage
- Low load instability
- Improper valve alignment

Such personnel errors typically result in major equipment damage, higher forced outage rates and higher capital and maintenance costs.

Q. **Please summarize the long-term life shortening adverse effects of cycling.**

A. Cycling causes faster degradation of many unit components, which in turn causes increased component failures, higher capital and maintenance expenditures, lower unit availability, and lower unit efficiency. As these effects increase over time, the production costs of the unit become so high that the unit becomes uneconomical. Premature retirement of the unit then becomes inevitable in order for a utility to minimize its overall costs. Particularly in older units that have served a baseload function and thereby experienced much of their life-cycle creep-fatigue, the incremental cost impact of each additional cycling event is quite large.

Q. How do you categorize cycling impacts from a cost perspective?

A. Utilities historically have not specifically quantified all of their cycling-related costs. However, the kinds of impacts which I have described fall generally into at least seven cost categories. They are:

1. Change in maintenance and plant-related capital costs
2. Auxiliary power costs during start-up
3. Start-up fuel costs
4. Long-term plant efficiency loss
5. Heat rate impact due to low load operation
6. Replacement energy and capacity due to higher EFORs
7. Shortening of unit life

Aptech computes the total cost of cycling by estimating the expected values of each of these seven cost components, based upon specific unit characteristics, historic cost and outage experience, and general industry data. The first component - - the change in maintenance and plant-related capital costs - - has the largest individual impact of the various cycling costs.

We have examined the costs of cycling baseload power plants for utilities across the nation and we have found that it is possible to estimate within reliable bandwidths both the life-cycle costs of unit cycling and the incremental cost to the utility of each new cycling event. Obviously, the incremental costs increase later in a unit's normal life cycle as the stresses of cycling begin to impact outage rates and capital costs to a greater extent. What we find routinely in our analysis is that increased cycling activity correlates very closely with increases in capital and maintenance expenditures, outage rates, efficiency losses, heat rate degradation and an overall shortening of a unit's life.

Q. Based on your evaluation of cycling costs for Florida Power and other utilities, are you able to estimate a total range of cycling-related costs for each hot and cold start of a coal-fired unit such as Florida Power's Crystal River 1 and 2 units?

A. Yes. Our studies for other companies and our evaluation of Florida Power's own operating cost history shows that a unit such as Crystal River Unit 2 can be expected to incur costs ranging between about $30,000 and $110,000 for each individual hot start. The corresponding range for a cold start is between about $70,000 and $240,000.

In addition, there are still other Florida Power costs that have not been captured by these cost ranges. For example, the costs associated with the engineering time and engineering/operations analysis of cycling impacts, cycling modifications, and plant modifications for increased cycling, have not been included in my estimates of the cost of cycling. Furthermore, I have not included the costs of replacement power to follow increasing system loads each time that an individual baseload unit is cycled off. This additional cost can be quite significant as stated in Mr. Southwick's testimony.

Q. **Describe how Florida Power's units compare with other similar utility units in terms of cycling effects.**

A. Aptech did a comparative analysis of similar fossil units using extensive industry data from NERC. Exhibit _____ (SAL-4) shows the results of a comparative analysis of the impact of varying numbers of equivalent hot starts (a measure of overall cycling amounts) on equivalent forced outage rates. Each dot on the graph represents a comparable unit in the database. Crystal River Unit 2 is noted on the graph.

The lines on this graph show least squares fits for units of varying operating hours per year. In all cases, the Equivalent Force Outage Rates ("EFORs") tend to increase with increasing numbers of equivalent hot starts. The scatter of the individual data points is exaggerated by this type of plot. This graph indicates that the Florida Power unit is very similar to the other industry fossil units in their responses to the effects of cycling.

Q. From your analysis, is it fair to conclude that if Florida Power were required to shut down a Crystal River coal unit for several hours during a minimum load condition in order to continue purchasing energy from non-utility generators, that costs in the range you have described would be directly attributable to that cycling event?

A. Yes, that conclusion is correct. If a Crystal River coal unit was shut down for several hours and it would be required for generation the next day, it would have to be restarted. This is an off/on hot start cycle as I have described in this testimony. The cost of the hot start cycle for that event (in the range of $30,000 to $110,000) would be directly attributable to that event.

Q. Are you familiar with Florida Power's Crystal River Unit 3 nuclear power plant?

A. Yes, I am generally familiar with that unit and its nuclear steam supply system ("NSSS") made by Babcock & Wilcox Co. I have visited the plant, met with operating personnel and visited the nuclear simulation and training center. In addition, Crystal River 3 is nearly identical to the Rancho Seco nuclear plant in Sacramento, California on which I have performed extensive analysis.

Q. Do you know of any Babcock and Wilcox units like Florida Power Corporation's Crystal River Unit 3 nuclear plant that are dispatched by their owners/operators to follow load?

A. No.

Q. Have you considered the types of costs that Florida Power would incur if it were to cycle its Crystal River 3 nuclear unit?

A. Yes, although I have not performed any extensive cost analysis, cycling a unit like Crystal River 3 would require investigative and design measures and would have cost impacts such as the following:

1. A new and larger boron dilution letdown and charging system would be required to permit boron dilution during load increases.

2. Increased costs would be incurred to process and dispose of water letdown from the reactor coolant system following power increases. The increased costs would be associated with the need for new and larger water cleanup systems, storage facilities, water evaporation systems, disposal costs, increased resin and water usage, and increased chemistry department staff.

3. Reduced power output would be likely due to the inability to accurately calibrate the Incore Monitoring and Nuclear Instrumentation Systems following load changes. The inability to accurately calibrate these systems might result in inabilities to define power distributions accurately enough in order to return to operation at full rated power. New Incore Monitoring and Nuclear Instrumentation Systems procedures would be

required. Implementation of these procedures could result in additional labor costs.

4. Increased fuel cost would be incurred per unit of power generated. The current fuel loads have been optimized for noncycling operation. Maintaining an outage schedule that coincides with minimum system power requirements would require premature removal and disposal of fuel rods and, therefore, higher fuel costs.

5. The feedwater heater level control systems would require replacement.

6. There is a potential for increased steam generator damage because of fatigue.

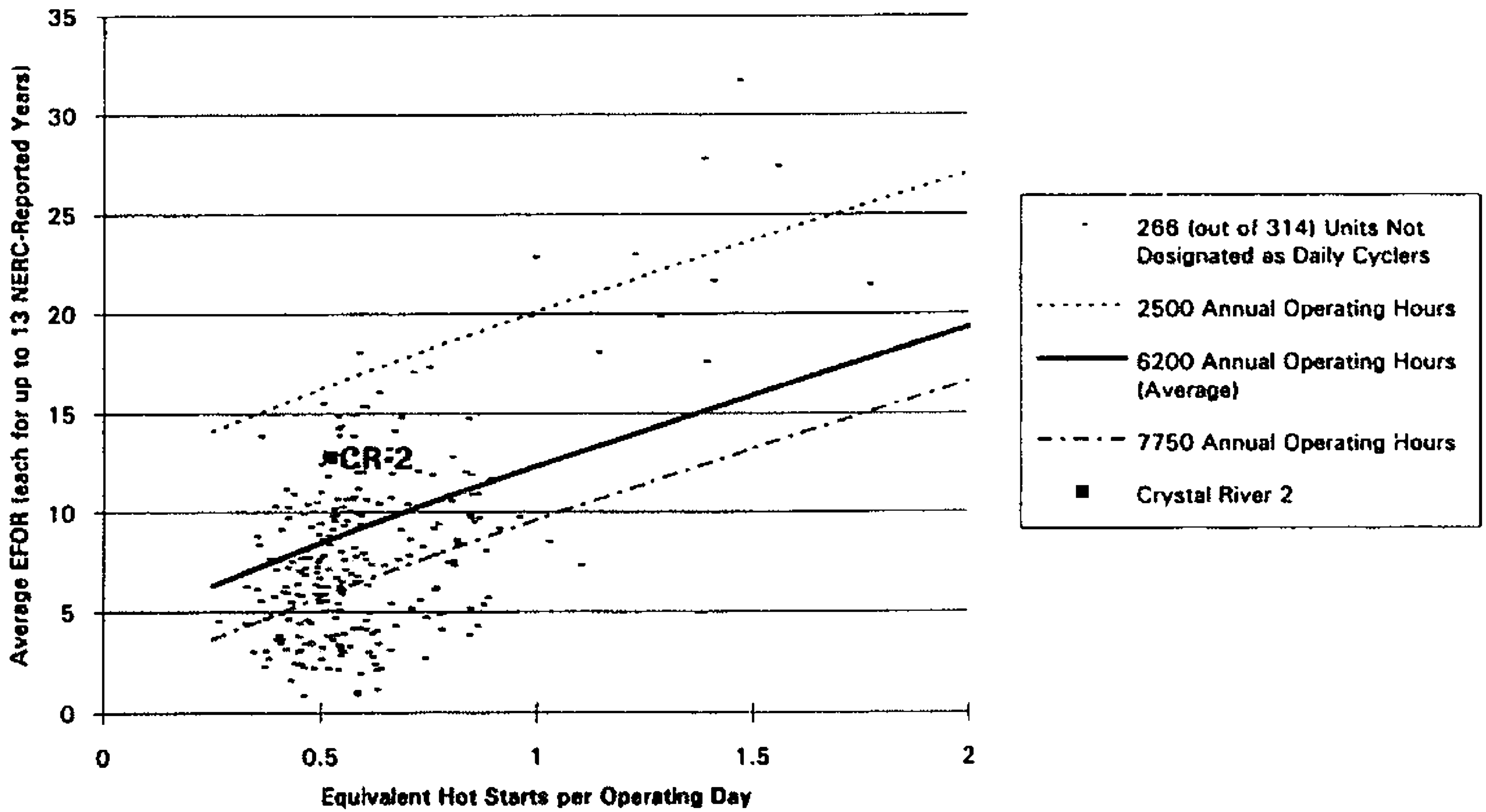
7. There may be an increased fuel rod failure rate due to fuel temperature changes and potential fuel/clad interaction.

8. The ASME III, Class 1 fatigue analyses would have to be reperformed to account for the increased thermal cycles.

9. There is a potential for increased secondary system check valve wear and erosion due to increased operation at lower power levels.

EXHIBITS

Figure C-5a - EFOR vs. Equivalent Hot Starts - Regression Analysis for All Units Not Designated as Daily Cyclers EXCEPT for 20 'Outliers'



FPSC Docket No. 941101-EQ
FPC Witness: LEFTON
Exhibit No. ____, (SAL-4)
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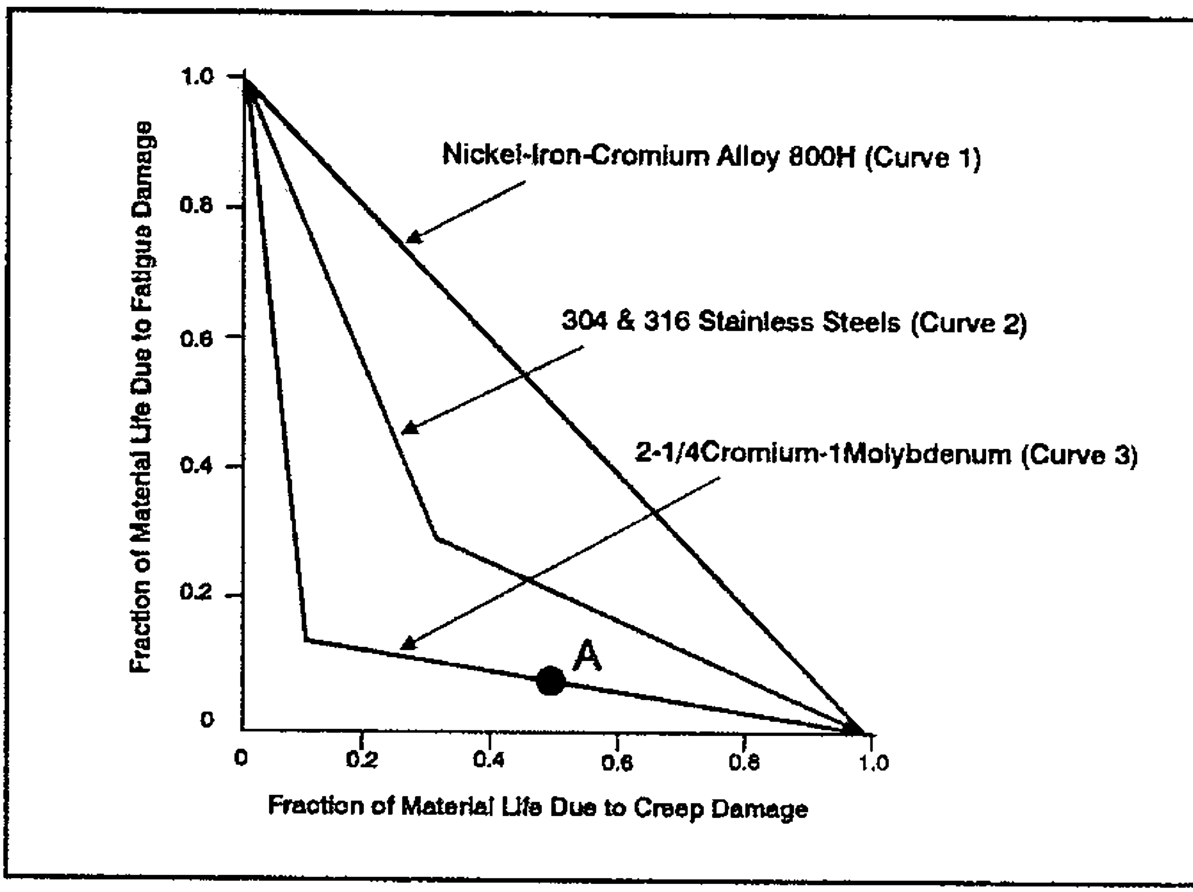

Creep Fatigue Interaction Design Curves for Several Materials.

From Code Cases of the American Society of Mechanical Engineers

STEVEN A. LEFTON

SPECIALIZED PROFESSIONAL COMPETENCE

Management and operational expertise in fossil and nuclear utility power plants, including the construction, start-up, maintenance, and on-line operational procedure writing and check-out of power plant equipment. Experienced in the operation of fuel handling and fuel burning equipment, including pulverizers, fans, sulphur dioxide/particulate control scrubbers, precipitators, water treatment, gas/steam turbines, and ash handling systems. Experienced in the calibration and design of utility boiler-turbine control systems. Expertise in water treatment, feedwater treatment, and boiler water control measures used to prevent deposition and corrosion damage to power plant equipment.

Work experience includes design and implementation of heat rate and efficiency monitoring programs for oil and gas fired boilers; thermodynamic analysis and efficiency calculations of power plant components, such as boilers, turbines, air heaters, pulverizers, and feedwater heaters; analysis of coal slagging and fouling in utility boilers; and oil, gas, and coal burner design and optimization.

Management of a major utility nuclear power plant turbine generator failure investigation with specific emphasis on water chemistry contaminants of the condensate system, steam generator, water, steam purity, turbine, and electrical generator failure analysis.

Past utility fossil power plant related work includes the project management of investigations into the performance of fossil power plant boilers, heat recovery steam generators, turbines, electrical generators, and pulverizers; failure analysis of boiler tubes; analysis to predict the remaining useful service life of boilers, superheaters, reheaters, headers, and tubing; and design and modification of utility power boilers to eliminate tube failures.

Recent work includes project management and expert testimony/litigation support in large utility power plant legal cases. These cases involved boilers, heat recovery steam generators, gas turbines, pulverizers, plant auxiliaries, fires, explosions, availability/reliability modeling, plant life assessment, plant life extension, and the analysis of plant logs to calculate power production costs for revenue requirements based on calculations of damages and production costs. Currently involved in cost analysis associated with cycling large and small fossil power plants.

EDUCATION AND PROFESSIONAL BACKGROUND

- B.S. (Chemical Engineering), Kansas University (1969)
- Pre-Engineering (Kansas State College of Pittsburgh)

- Bailey Meter School for Instrument Engineers (1972)
- Past Chairman, Vice Chairman, Treasurer, Secretary, Finance Chairman, and Public Information Chairman for American Nuclear Society, Northern California Section (1978-1988)
- Manager, Western Operations, NUS Corporation (Involved in Fossil and Nuclear Project Consulting Engineering in the Western United States)
- Power Plant Start-Up and Sales Engineer, Babcock & Wilcox Company (Responsible for Fossil and Nuclear Power Plant Equipment Start-Up, Equipment Performance Testing, and Equipment Sales)
- Analysis of German Utility Power Plants to Explore European Methods of Coal Combustion and Power Plant Auxiliaries, such as Pulverizers, Fans, Ash Systems, etc.
- Control System Start-Up Engineer on the 880 MW Coal Fired Boiler and Limestone Scrubber of Kansas City Power & Light Company's LaCygne Station
- Boiler Service Engineer (Responsible for the Redesign and Recalibration of the 300 MW Northside, Unit 1, Oil-Fired Boiler Turbine Complex for the City of Jacksonville, Florida)
- Chief Engineer for the Construction, Start-Up, and Control Calibration of Unit 4 Boiler Turbine Generator for the City of Manaus, Brazil
- Start-Up Engineer for a Brazilian Boiler Turbine Cogeneration Plant
- Start-Up Engineer on Approximately 20 Boilers and Boiler Control Systems, as well as Procedures Preparation, Operator Training, Water Treatment Requirements, and Chemical Cleaning of These Units
- Water Chemist for the City of Lawrence, Kansas, Water and Sewage Treatment Plants; Licensed Plant Operator in the State of Kansas
- Laboratory Technician for the Kansas City, Missouri, Water Treatment Facility

SELECTED REPORTS, PUBLICATIONS, AND INVITED LECTURES

Review and Improvement of Tennessee Valley Authority (TVA) Estimates of Cycling Costs, APTECH Report AES 92051685-2 (with P.M. Besuner and G. Biggerstaff) (September 1992).

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A METHODOLOGY TO MEASURE THE IMPACT OF CYCLIC OPERATIONS AND POWER DERATIONS ON PLANT LIFE AND RELIABILITY

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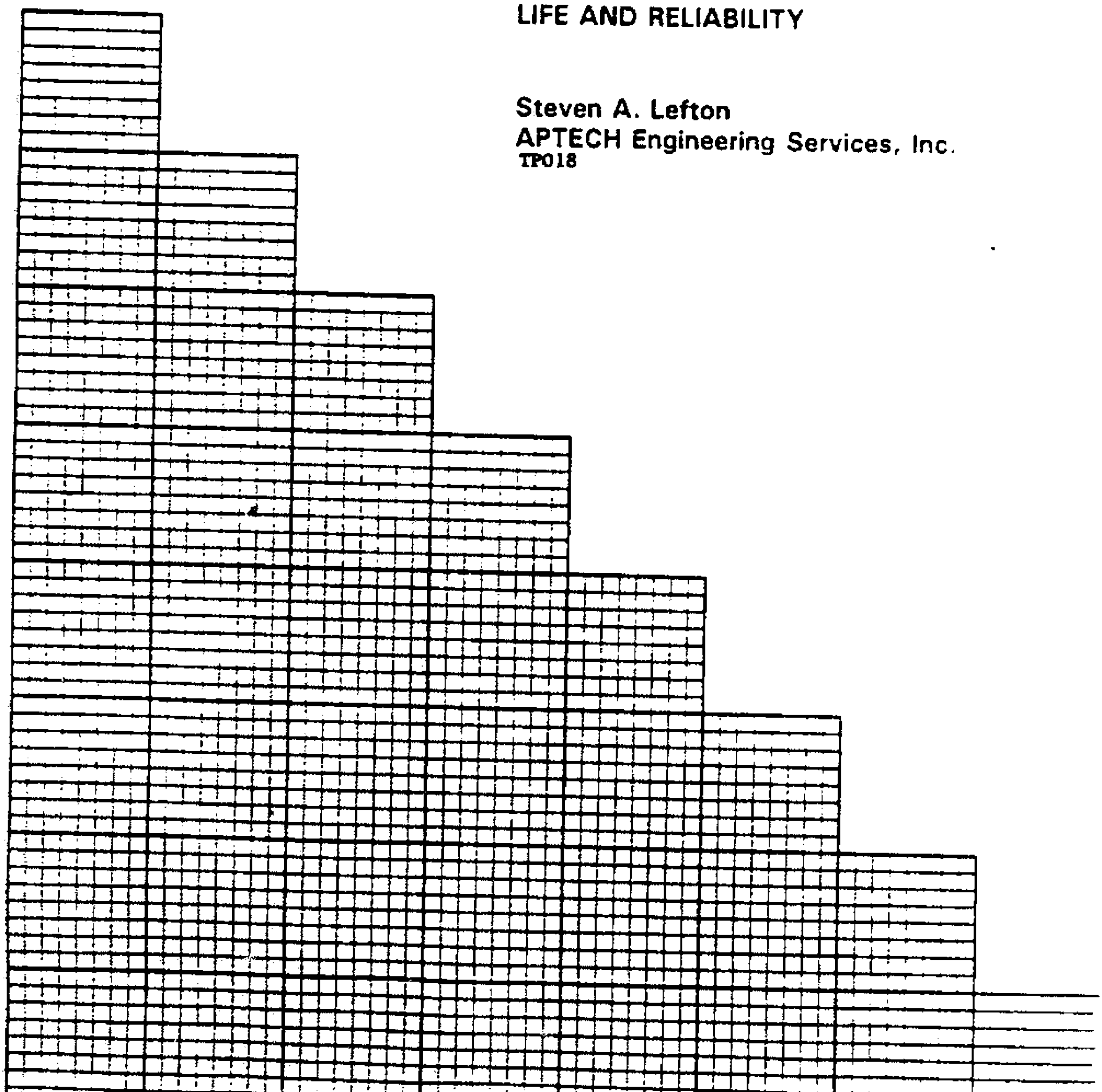

A METHODOLOGY TO MEASURE THE IMPACT OF CYCLIC OPERATIONS AND POWER DERATIONS ON PLANT LIFE AND RELIABILITY

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INTRODUCTION

With changing system requirements caused by varying load demand, increasing cogeneration, addition of new base-loaded generation, etc., utilities find themselves forced to cycle many of their older units. Most of these units were not designed for cyclic duty. Typically, the utilities make their decisions on which units to cycle based on factors such as unit size, age, equipment type, fuel costs, system requirements, production costs, etc. A major cost which has been ignored is the life cycle cost of operational changes. These costs include the capital costs of equipment upgrades and replacements, increased operational costs, increased maintenance costs, and cost impacts due to life reductions. Other questions involve the accurate projection of future costs of these operational changes. The utility plant operator needs to know the effect of the changes on his plant equipment (such as reliability and life-limiting effects) in order to decide how to allocate and recover costs, as well as how best to spend today's dollars to avoid future costs.

This paper discusses two examples: one involving cycling operations and the other involving a power deration in order to present a useful (Calibrated Analysis℠) methodology for optimizing operational changes and calculating their costs.

CYCLIC OPERATIONS

When the system requirements cause utilities to cycle their power plants, one of the major decisions faced by utility power plant operators is not only how to mitigate the effects of cycling their plants, but also at what cost in terms of lost plant reliability and service life. Some effects of cycling on the performance of a power plant include increases in:

- Number of hot and cold start-up and shutdown cycles
- Equipment failure rates
- Maintenance requirements
- Heat rates and start-up fuel usage
- Temperature and pressure transients
- Turbine and boiler stress
- The need for economy and emergency purchases of electricity by the utility due to decreased reliability of the equipment

Utilities often implement new procedures and install additional equipment to reduce these effects of cyclic operations, including:

- Increased monitoring and inspections
- Improved and integrated boiler and turbine control systems
- Systems to bypass steam to the condenser
- Boiler and burner modifications to lower minimum load capability
- Boiler modifications to maintain constant boiler pressure while sliding superheater pressure
- Turbine valve modifications, water induction prevention, and drain automation
- Increased water treatment, instrumentation, and analysis
- Variable speed drives on pumps and fans
- Improved burner flame stability, flame scanning, and monitoring
- Boiler and turbine stress analyzers

These components and procedures often include a wide variety of mitigation measures whose costs and related benefits are hard to estimate.

In these items, there are costs that utility personnel often do not evaluate adequately when considering cycling. These costs are most often associated with three difficult-to-quantify effects of cycling on previously base-loaded units with existing creep damage, and include:

- Increased failure rates (lower availability and increased equivalent forced outage rate (EFOR))
- Decreased component life (higher capital and operating and maintenance expenses)
- Increased power generation requirement (capacity replacements)

Some projected effects of cycling on EFOR are shown schematically in Figure 1. As the unit ages, this graph shows an increase in the equipment failure rate due to cycling, resulting in a higher EFOR. This reduced life leads to the need for more rapid capacity replacements to counter a higher system loss of load probability. This effect can force some utilities to consider significant capacity additions much earlier than anticipated.

Figure 1 also shows the projected transition from the base-loaded EFOR to the cycling EFOR which is expected to take some two to six years. This is explained by reviewing a typical creep fatigue interaction curve for boiler superheater/reheater tube and header material, as shown in Figure 2. Creep fatigue interaction is a phenomenon that can have a detrimental effect on the performance of metal parts or components operating at elevated temperatures. For example, it has been found that creep strains can seriously reduce fatigue life and that fatigue strains can seriously reduce creep life (Ref. (1)).

When applied to a typical base-loaded unit with some accumulated creep damage, this curve shows that it requires only 10% to 20% total fatigue damage to cause a creep damaged component to reach failure. Assuming an older, base-loaded plant had three to six starts per year and then changes to 100 to 200 starts per year, it may take two to six years to accumulate this 20% total fatigue damage. While failure rate increases may not be noted immediately upon cycling, this causes components to reach end of life sooner, thus resulting in the higher plant EFOR. How soon this detrimental effect will occur will depend on the amount of creep damage present and the nature and frequency of cycling. This cycling exacerbates damage in components that are already creep-damaged due to the past base-loaded generation. The combined effect of creep (base load) and fatigue (cycling) leads to the creep/fatigue interaction mechanism that will reduce the remaining life by up to 60% to 90%.

Although not addressed in detail in this paper, it should be mentioned that many units in this country have undergone varying depths of studies to determine present condition and remaining useful life of specific components. Most of this work was done on base-loaded units with the assumption that future operations would be similar to past operations. These results can be questionable for those units that are shifting to different modes of operation. New reinspection intervals and remaining life analyses may be required that account for the operational changes.

We also show in Figure 1 the projected life expectancy curve of newly upgraded equipment (shown by the •• — •• line) which is the result of an extensive plant overhaul in which major components were either replaced in kind or upgraded with components and materials designed for cycling duty. Based on the creep fatigue interaction curve and the extent of the upgrade, this plant may perform initially better than the base-loaded, non-cycling plant and degrade slowly over time. In the long term, an upgraded plant with the mitigation measures and component replacements will perform much better and have a longer life than the base-load plant put into cycling duty without these changes. In effect, what a utility operator is doing when adding these mitigation measures is simply adding the present value of future maintenance dollars. This effect has been reported by Houston Lighting & Power Company (Ref. (2)) in its evaluation of maintenance spending on unit availability.

Need for Present-Value of Revenue-Requirements Analysis

The costs of cycling discussed above are incurred at various points in time. Some of them are incurred during the years that increased cycling occurs and are caused by the direct effects of cycling on heat rates, forced outage rates, fuel costs, and purchase power requirements (i.e., production cost impacts). Increased cycling may also increase the need for (and cost of) planned maintenance and interim overhaul (i.e., cycling mitigation measures) in future years (not just the year of increased cycling). Production costing models (e.g., PROMOD, POWERSYM-PLUS) are very useful in estimating such cost impacts. Costs should not ignore the low frequency but rather severe consequence events, such as low water in the boiler and the turbine rotor/case cracks that occur. Increased cycling may also shorten the expected plant service life, which would require a significant change in capital spending to obtain generation capacity replacements in some future years (say 20 to 30 years into the future).

There may be the need for additional maintenance spending beyond that required to convert the unit to an effective cycling plant to effect the unit's future improvements in EFOR and availability. A very definite relationship exists between maintenance spending and an improvement in unit EFOR or availability. However, there is a time lag between the expenditure of maintenance dollars and the occurrence of the improvement (Ref. (3)).

To properly account for increased cycling, one should use a present-value analysis technique, and use appropriate values for escalation rates (for capital, O&M, and fuel), interest rates, and discount rates. Assumptions must be made on the type and cost of replacement plants in future years. Life cycle cost analysis can lead to large costs associated with the need to build new generation or for capacity replacements. An example of an engineering economic analysis using revenue requirements methods and production cost modelling is shown in the derating example given in this paper.

METHODS

Calibrating Engineering Models

Most engineering analysts seek to model the physics of governing failure and degradation modes. Of almost equal importance is to reflect credible hands-on, field service experience. This is done by calibrating or "tuning" engineering models to real-world data and experiences.

The most elementary form of calibration is an informal "check." Checking models against experience and experiment is a key part of the Scientific Method. It is also a hallmark of good engineering practice. Besides this checking, we believe that many applications would benefit from more systematic and up-front calibration.

We describe a new procedure to forecast component reliability from sparse data. We have called it both combined engineering analysis and "Calibrated Analysis℠" (CA℠). The procedure is particularly well adapted to failure frequency forecasts and outage predictions for large, expensive apparatus.

For such equipment, data are usually sparse. Accelerated life testing is not appropriate and historical failure data are limited. Data limitations also arise from such factors as variations in power plant operation and maintenance practices, inadequate record keeping, and inherently low failure rates.

To overcome the obstacle of sparse data, the procedure uses a systematic calibration method. This calibration combines only the most credible features of engineering models with real-world experience. Such combination is done by creative use of historical failure event and "incident" databases. We use the data to reduce the uncertainties of engineering parameters that are difficult to estimate.

To handle some statistical aspects of CA℠, we use both probability models and "Bayesian" mathematics. Primary verification of the component failure predictions is made by comparing predicted failure rates with actual past failures. Such comparisons employ several variations of purposely incomplete databases. Predictions from incomplete data are compared with actual annual, seasonal, and geographical frequencies of failures experienced in the complete database.

The special feature of CA℠ is its extraordinary reduction of the uncertainty of forecasts. This reduction is often available by calibrating against very basic observations. One such observation is the increase in power plant outages resulting from cyclic operations.

Good engineers and decision makers often calibrate informally by benchmarking model forecasts with their experience and intuition. Calibrated Analysis℠ allows many of these benchmarks to be built directly, formally, and openly into the engineering model. Our goal is to obtain the best possible estimates and confidence bounds of key statistical parameters. Ultimately, these estimates and bounds will produce the best forecasts of failure and power outage frequencies and costs.

In summary, many an engineering analysis can be imbued with more accuracy and value with CA℠. With CA℠, we optimize the way models are calibrated or "tuned" to real-world data and experiences. When engineering supervisors or management "tune", they often simply accept or reject proposed models based on how well forecasts agree with experience or intuition. Where appropriate, CA℠ formalizes such tuning "up front" within the context of a probability model.

Probability Models

Component reliability analyses can accomplish at least three goals:

1. Account for variation in one or more key engineering parameters, such as stress or strength.

2. Remove the excessive pessimism of typical worst-case engineering analyses that assume simultaneous pessimistic values for all key input and assumption parameters.

3. Allow optimization of maintenance and operational strategies when component rejection and failure rates compete. The optimization tools are especially applicable to degrading mechanical components subject to inspection, repair, operational and maintenance strategies, and life extension.

The models in this paper relate somewhat to the first two goals. They deal mainly with the third goal by seeking to minimize total cost of operating mechanical equipment.

One can always form probability models. The disciplines of statistics and reliability can be applied to both data and the model. However, engineers often state a major objection to such models.

> "I often lack comfort in choosing a single value for a load, stress, or strength. What makes you think you can estimate their entire probability distributions?"

It is usually a hard job to estimate distributions accurately. Yet, besides better data collection, there are at least two answers to such an objection.

The first and most basic answer relates to the second of the three objectives listed above. In typical worst-case analyses we assume that all key parameters take on pessimistic, instead of accurate or probable single point values. This is done to compensate for errors of the model and its parameters.

Likewise, a probability model can use pessimistic, instead of accurate, distributions to compensate for uncertainty. This model is still conservative but it provides a key gain over the deterministic one. The use of distributions avoids stacking the worst single values. In practice, this often removes much excessive pessimism.

The error-reducing features of CA℠ provide a second answer to finding accurate distributions. As introduced above and exemplified next, CA℠ eliminates much of the modeling uncertainty. It calibrates hard-to-estimate parameters that are against basic, credible field service or lab data.

Cyclic Operations Assessment Methodology

The steps involved in the assessment of operation changes on EFOR are described here and by way of two examples -- one on cycling and one a unit power deration -- this methodology is demonstrated. The first step involves the assessment of the baseline projection of the unit's aging when compared to similar units (e.g., fuel type, size range, pressure range). A similar group of units is selected from the larger set of NERC GADS data and the slope of the group's smoothed aging curve is applied to this particular unit's current aging trend. APTECH's methodology has been developed to allow for the successful use of these types of small data sets.

Then, an assessment must be made of the type of cycling to be performed. While low load operation is the least damaging to plant components, the next most damaging type of cycling is on/off cycling with proper restarts and ramp rates when steam temperatures to the turbine are matched to turbine metal temperature. Full on/off cycling with cold starts is the most damaging. Then, the number of yearly hot, warm, and cold starts needs to be estimated and reviewed. While some production cost models (e.g., PROMOD, POWERSYM-PLUS) can do this, these projections must be calibrated and reviewed. Once the initial frequency and severity of cycling is defined, then tests or bounding analyses must be performed on the critical plant components in order to obtain the following:

1. The increase of stress and temperature ranges, as well as absolute temperatures during each type of start-up -- that is, correlate stress and temperature vs. operation.

2. Evaluation of the damaging effects on key components of the stress and temperature increases to determine life (time to failure) and life scatterbands -- that is, correlate relative component failure rate vs. stress and temperature.

3. Calculation of the unit outage rates as a result of individual component failure rates -- that is, correlate component failure rate vs. unit outage rate.

While this process may seem somewhat difficult to calculate, some simplifying assumptions can help bound the data. In Item 1, it has been observed that the start-up operation requires 500 to 1000 times the energy as a step change from 90% power to 100% power (Ref. (4)). When this is translated to increased stress on a turbine rotor bore, start-up stresses are two to four times greater compared to stresses induced by normal operations. Further, cold turbine start-ups that use normal ramp rates create eight to ten times more turbine stress than hot start-ups (Ref. (5)). In Item 2, creep fatigue interaction effects can reduce the remaining useful life by 60% to 90%. In Item 3, estimates of the effect of the boiler, turbine, and balance of plant component failures to the total outage rate can be made. Estimates of the number of components affected by the cyclic stress and temperature rise lead to calculations of creep and fatigue damage. Calculations using damage summation techniques can be made and simplifications made to estimate the total creep life, fatigue life, and the reduction in life due to the creep/fatigue interaction. For example, the boiler contributes to greater then 50% of the outages. Other facts put the effect of increased temperature, stress, and corrosion in perspective (i.e., waterwall, superheater, and reheater tube failures account for more forced outages than all the other boiler components).

Figure 3 has been reproduced from Davison's work (Ref.(8)) on all English coal-fired 500+ MW power plant units. It shows the effect of age on various wear-in, wear-out, and constant failure rate mechanisms that affect the dominant cause of forced outages: boiler tube failures. Davison has classified the failure modes in Figure 3 in some detail. This classification is reproduced herein as Table 1. Note that more than half the failures are classified by Davison as wear-out mechanisms. Obviously, the dominance of wear-out modes can only increase as the English power plant population ages. Figure 4 shows the cumulative effect of failure and other aging mechanisms on EFOR for American coal-fired units. Notice the relative absence of "infant mortality" and the rapid increase in outage rates between 20 and 30 years of unit age.

An Example of the Effects of Cycling on Large Coal-Fired Units

In this example of cycling on an older base-loaded supercritical unit, we have a 600 MW coal-fired unit that was base loaded and then put into cycling duty after 18 years. The unit had approximately three to four cold starts and ten hot starts per year. The unit is put into cycling duty and projected to have some 30 cold starts and some 100 hot start-up cycles per year. As you can see from Figure 5, the effect of cycling is a rapid increase in EFOR and at age 45, the EFOR is 48%. This data shows a much lower EFOR projected for the entire unit's lifetime if it remains base-loaded or is upgraded for cycling duty. Figure 5 also shows data from a 400 MW coal-fired subcritical unit designed for extensive cycling duty and it's EFOR is projected to age 50. This unit performs similar to the upgraded base-loaded unit. While we have not quantified the costs of the cycling described, the next example shows the approximate life cycle costs due to changes in unit EFOR. In the following examples, the value of such large differences in EFOR when evaluated over a life cycle leads to costs or savings in the range of $10,000,000 to $100,000,000.

ILLINOIS POWER COMPANY COAL-FIRED POWER PLANTS

Previous Illinois Power Company System Failure and Outage Forecasting and Economic Analyses

Calibrated Analysis℠ has unique capabilities to determine the impact of operational and maintenance options and changes on power plant availability and economics. We often use it to quantify and bound the effects on outage rates and maintenance costs of changes in utility operation and maintenance practices. For example, we can estimate the economic impact of changes in power output, load cycling, maintenance procedures, and frequency and sensitivity of field service inspections.

Many methods outlined in the introduction have contributed to this specialty. We illustrate the specialty with this second example.

The Effects of Derating on Outage Rates. In Ref. (7), we predicted the effect of deration on the lifetime and forced outage rates of nearly all Illinois Power Company's (IPC) coal-fired plants. Unlike cycling, deration is defined here as a one-time power output reduction, initiated just before 1988 and maintained until retirement. Figure 6 shows the before-and-after effects of deration on the increasing outage rate of an aging power plant.

This ambitious 1.5 man-year study provided IPC with a basis for calculating the financial benefits associated with deration. These benefits came from life extension, reduced failure rates of mechanical components, and reduced EFORs due to changes in the power plant output.

In this study, life extension was defined as the additional time beyond planned retirement age a unit is expected to operate in a derated condition. For the two, twin, large coal-fired units reanalyzed here, the retirement year was taken as 2015. For both units, this is equivalent to a baseline retirement age of 45 years old. After retirement, a new power plant is assumed with the same outage rate as in Figure 6. Thus with no deration, new equipment is assumed to reduce EFORs from 35% to 7% in 2015.

In the original study, we specified that after age 45 the derated unit must operate at or below an "acceptable" EFOR. This acceptable rate was defined as the EFOR predicted to occur at age 45 with no deration. For almost all units, this predicted EFOR was high enough to pose economic problems and justify substantial attempts at reduction. This was certainly true for the subject units with EFOR = 35% predicted at age 45 years.

This analysis emphasized two important mechanical degradation and failure modes and a lower bound estimate of the benefits of power reduction that would accrue to each fossil unit. A lower bound was sought because of certain political and legal controversies related to Ref. (7). The failure modes were fireside corrosion (primarily of boiler tubes) and creep stress rupture. These two modes dominate the forecast outages associated with these aging power plants.

The total CA™ covered the three most critical elements necessary to estimate the effect of power reductions on plant life and forced outage rates. First, we estimated the minimum likely effects of power reduction on components' stress and temperature. Among the tools used were:

1. Bounding computations of the smallest expected changes from deration to critical superheater tube temperatures at three power plants.

2. These computations were checked with several "total-plant experiments" in which key boiler temperatures and pressures were measured during exploratory deration.

3. An innovative analysis was conducted to bound the most critical effects of deration on several turbines. These analyses were comparable to a preliminary design of the turbines. Our goal was to create a temperature and stress model of key turbine components that matched the global specifications and other, very limited, information available from the manufacturer.

We then estimated the minimum benefits of stress and temperature reductions on component lifetime. Lifetime was defined as component age or damage exposure at the point of failure. Finally, we computed the minimum penalties from component aging on total plant reliability and EFOR.

Each of the three critical element models underestimates the benefits of deration. The three models are combined to obtain a lower bound of the forced outages avoided by derating. Finally, the results that have formed the basis of our conclusions were presented graphically for all units. Figures 6, 7, and 8 exemplify these results for two twin IPC units at Baldwin Station.

These figures show that even the lower bound benefits of deration on reduced outages and increased life are substantial. Illinois Power Company analyzed the resulting economic benefits with a comprehensive baseline analysis and sensitivity study (Ref. (8)) of all its plants, including the two largest Baldwin units. Their analysis covered the 39-year period of 1988 through 2026 and is expressed in 1988 dollars. As shown next for the two subject Baldwin units only, these financial benefits, when optimized, are very impressive.

Minimizing the Cost of Operating the Aging Baldwin Units. The second MCA explores tradeoffs among load deration, outage rate, and selected retirement age for twin fossil power plants at IPC. Both our previous outage forecast models and IPC's comprehensive economic analyses are updated and expanded for this paper. The primary improvements were :

- Curve-fit the results of IPC's original baseline economic analysis to account for different power deration and life extension assumptions than in Ref. (7).
- Update the assumptions in Ref. (8) to reflect realistic, rather than conservatively low, estimates of both forced outage and new plant construction costs.
- Maintain the baseline retirement year as 2015, but generalize the life-extension definition beyond the somewhat arbitrary one used in Figures 6 through 8. This allows us to compute the life extension to minimize total cost.

Our goal in this paper is to minimize the total cost of outages, power production, and constructing new plants when the old ones are retired.

Load Deration Effects. Figure 9 shows the economic effects of derating the plant with no life extension (L=0) beyond 2015. By definition, at zero deration there is zero benefit from our baseline. The optimum benefit is $150M for the 39-year period for a permanent power deration PD=7%. This value optimally balances the competing deration effects of:

- Reduced outage costs
- Increased production cost penalty

Plant Life Effects. Figure 10 shows the even more impressive effect on present-value savings of delaying plant replacement (with no deration). This effect would be even greater for older plants with potential retirement dates in the 1990s. (However, as outage rates actually increase, such an analysis should be occasionally updated to reflect changing present-value economics.)

By definition, with no extension beyond the baseline 2015 (L=0), there is no savings. The optimum benefit of almost $250M present dollars is obtained by delaying plant replacement for about L=25 years, until 2040. This delay balances the competing effects on present-value savings of:

- Delayed construction outlays
- Increased age, degradation, and outages of equipment

Combined Life Extension and Deration Benefits. Figures 11 and 12 are cross plots and additions to Figures 9 and 10. Figures 11 and 12 include the combination L=30 years delay and PD=7%. This combination produced an optimum savings of over $250M from the baseline. It is interesting to note the synergism of changing both L and PD. This global optimum (>$250M) exceeds the sum ($215M) of the local optima from changing PD only ($135M) and L only ($80M).

CONCLUSIONS

- Cyclic operations can significantly increase EFOR.
- Creep fatigue interactions reduce component life.
- Projections of unit outages and life cycle cost analysis needs to be performed in order to obtain the actual costs of unit cycling

Illinois Power Company Baldwin Station, Units 1 and 2 Example

- With no life extension, at least $135M present value would be saved during 1988 through 2026 by permanently derating these units by 5% to 10%.
- With no deration, about $80M present value would be saved by delaying unit replacements by 10 or 15 years beyond the initial estimate of 2015.
- Over $250M would be saved by combining the two actions above.

General

Accurate outage forecasts, estimates and bounds are valuable in at least two ways:

- They suggest both the most likely result and range of results of maintenance and operational changes.
- They provide information and suggest strategies that can be very helpful to minimize the total cost of power production.

ACKNOWLEDGEMENT

The author wishes to gratefully acknowledge the valuable input and assistance received from Philip Besuner, Terry Rettig, and Kevin Hara of Aptech Engineering Services, Inc., Wilfred Connell (Vice President) and Phil Licklider (Supervisor, Power Plant Performance) of Illinois Power Company, and G. Paul Grimsrud.

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7. Lefton, S., Prepared Testimony, Illinois Power Company, Illinois Commerce Commission, Docket No. 87-0695, June 1988.
8. Brodsky, Connell, and Eimer, Prepared Testimony (excerpts), Illinois Power Company, Illinois Commerce Commission, Docket No. 87-0695, June 1988.

Table 1.
Davison's Classification of the Central Electricity Generating Board Boiler Tube Failures

Classification	Description of Causes	Total Failure Rate Per Thousand Hours
Slow causes (increasing rate with age)	Long-term overheating; high temperature fireside corrosion; fatigue cracking at attachments and tube header junctions, etc.; ash erosion; fireside corrosion on furnace walls	1.0
Fast causes (independent of age)	Sootblower erosion; transient overheating	0.3
Two-stage causes (decreasing rate with age)	Defective welds; tube manufacturing defects; blockage; wrong material; miscellaneous repair faults	0.4
Unknown causes	Unknown	0.1

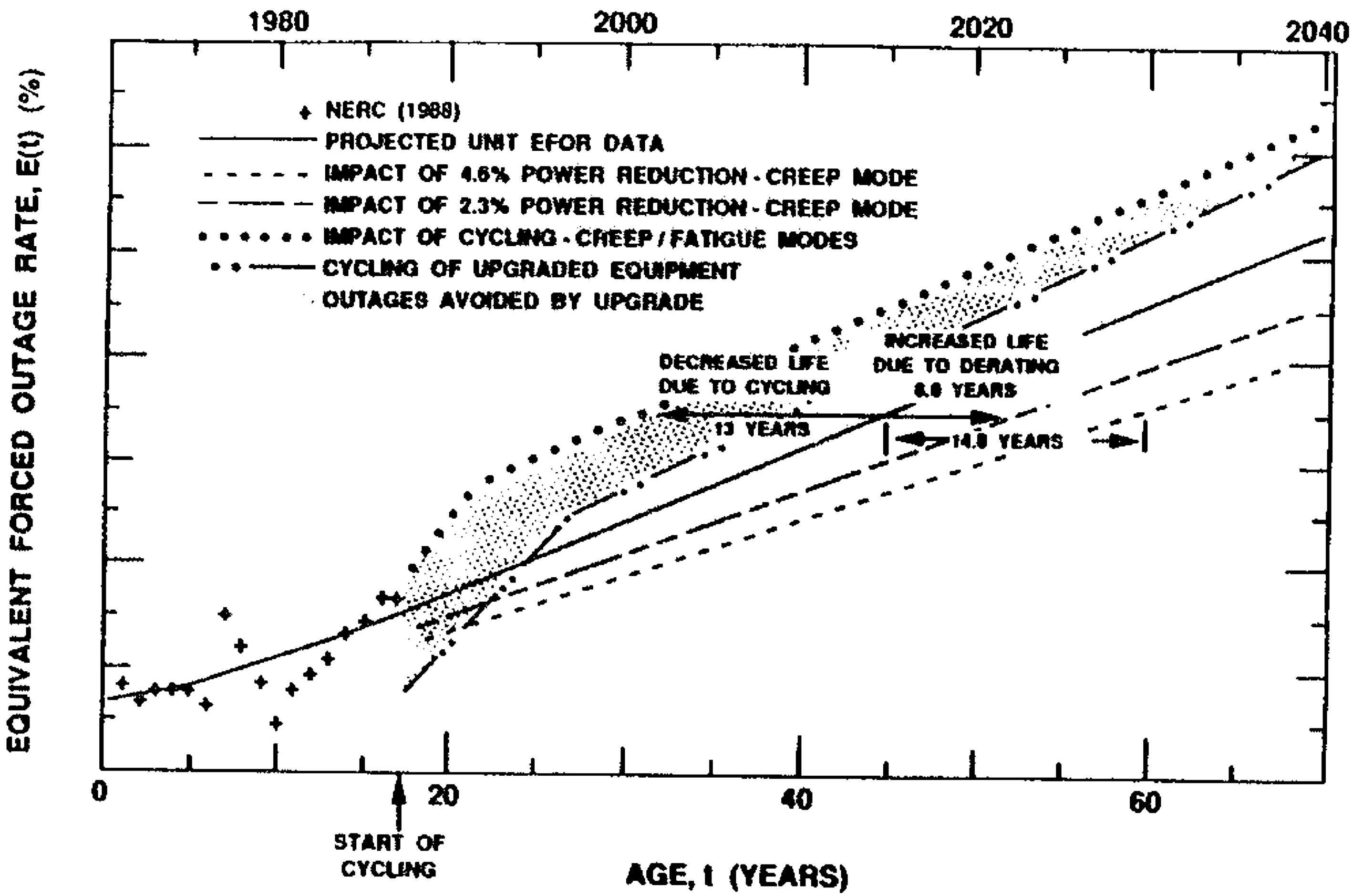

FIGURE 1.
EQUIVALENT FORCED OUTAGE RATE, AS ESTIMATED FOR AN INCREASE IN LOAD CYCLING AND FOR TWO POWER REDUCTION SCENARIOS.

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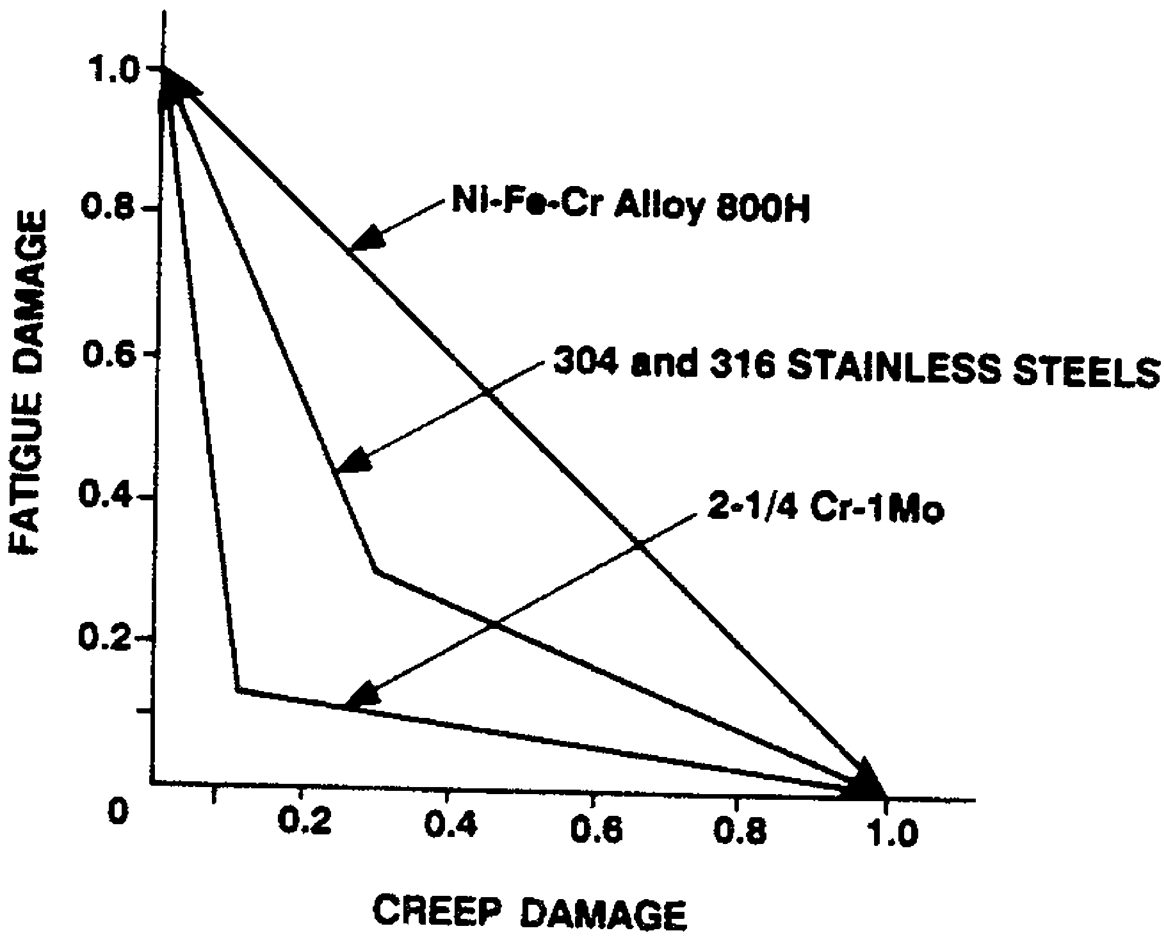

FIGURE 2.
CASES OF ASME BOILER AND PRESSURE VESSEL CODE – CREEP-FATIGUE DAMAGE ENVELOPE.

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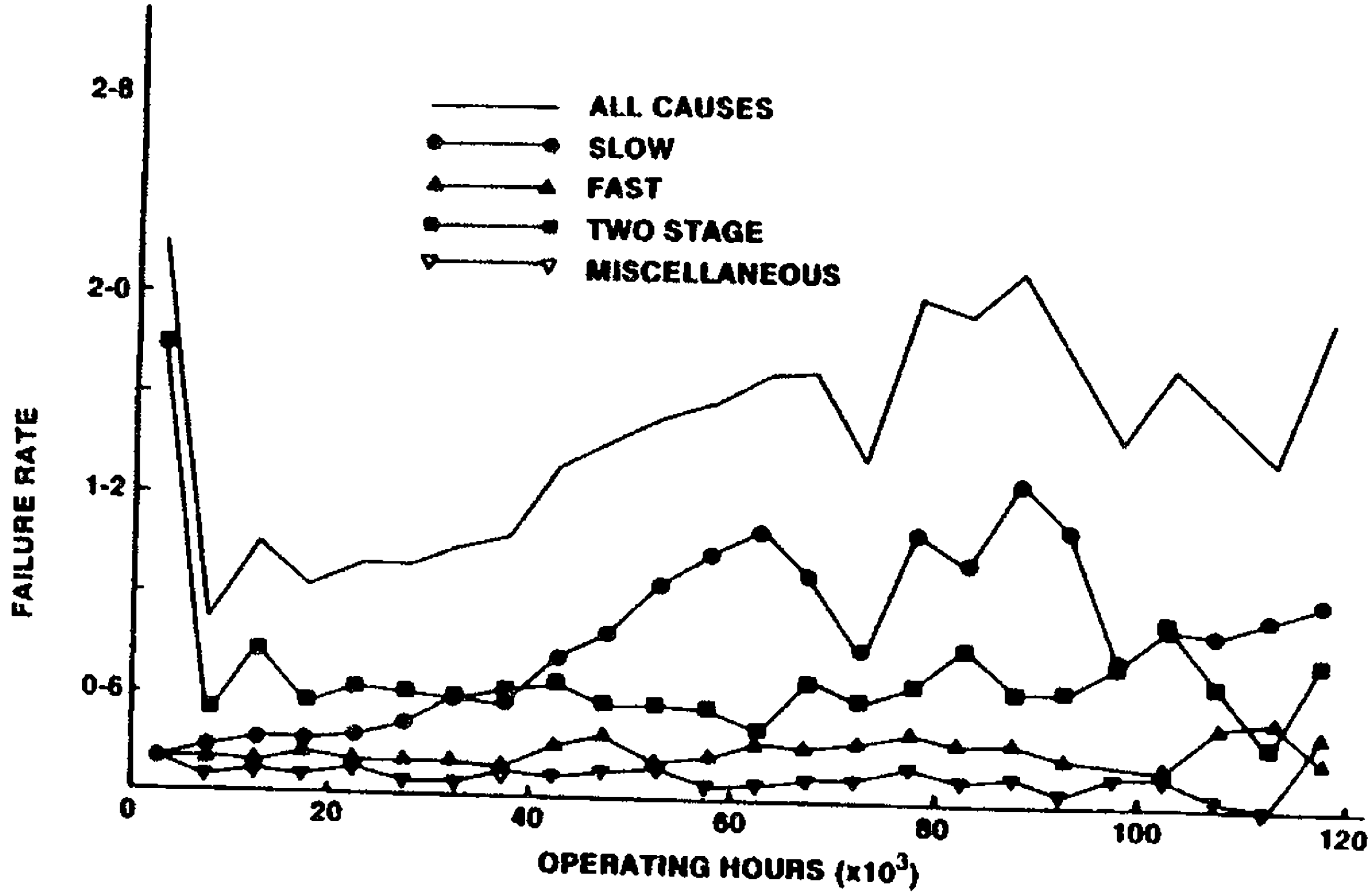

FIGURE 3.
FAILURE RATE VERSUS OPERATING LIFE - AVERAGE FOR ALL CENTRAL ELECTRICITY GENERATING BOARD 500 MW BOILERS (FROM DAVISON 1987).

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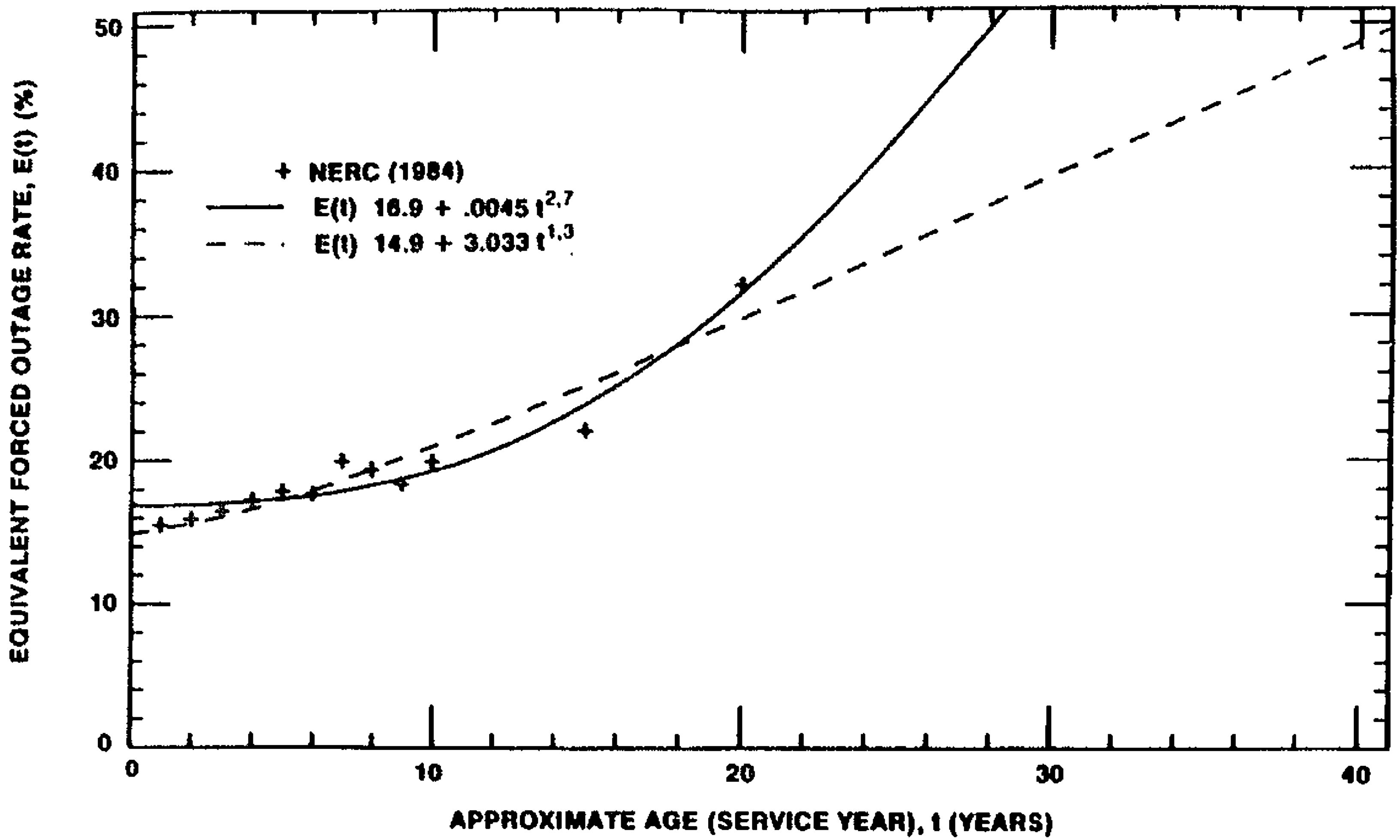

FIGURE 4.
PERFORMANCE OF ALL FOSSIL COAL PRIMARY UNITS 400 MW AND ABOVE. DATA FROM THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL (1984) ENCOMPASSES 174 UNITS OPERATED DURING 1974 THROUGH 1983, INCLUSIVE. DATA FIT TO AN EQUATION THAT APPROXIMATES $E(t) = \lambda_o + \lambda_n t^n$.

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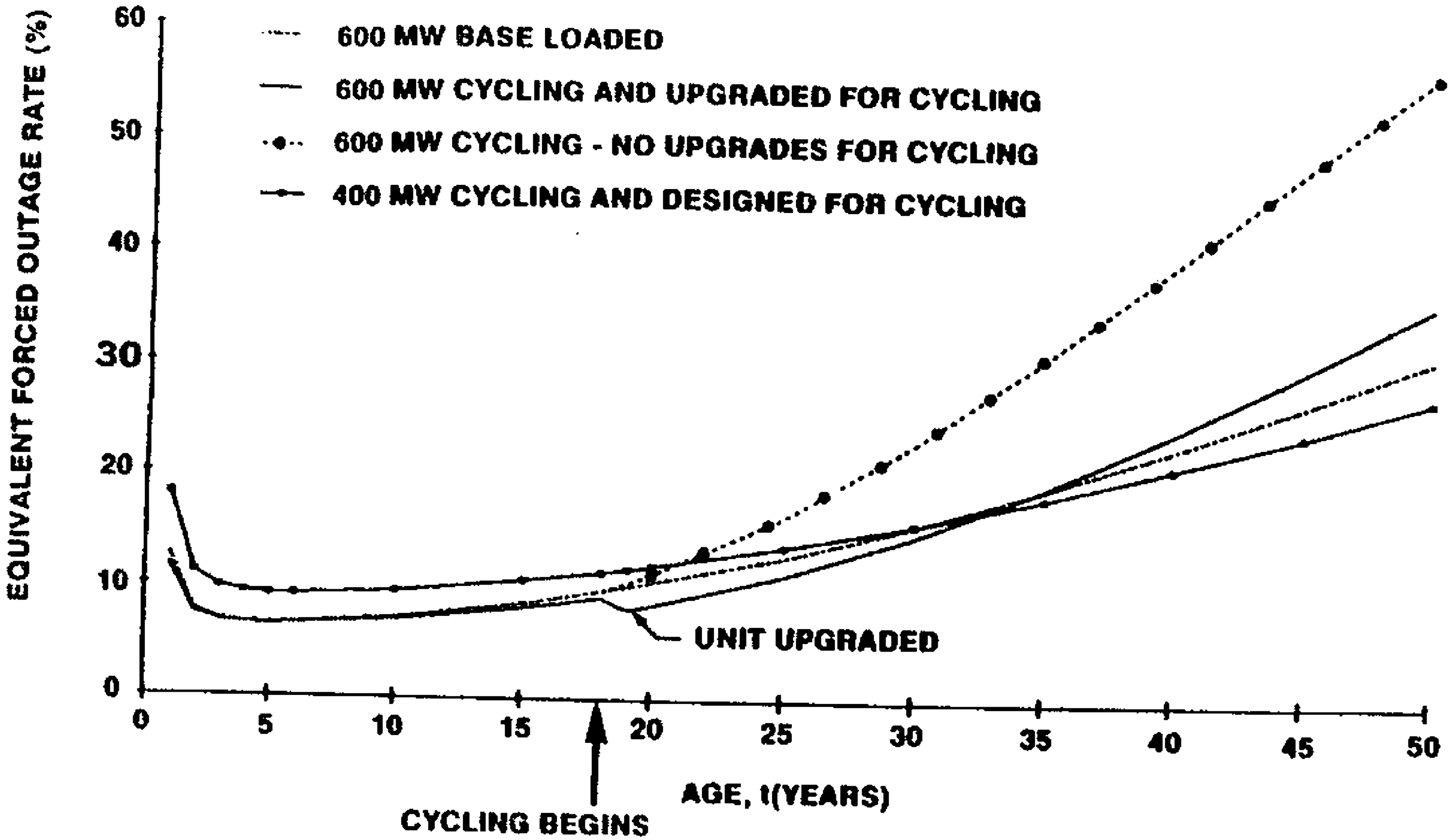

FIGURE 5.
EQUIVALENT FORCED OUTAGE RATE FOR LARGE, COAL-FIRED AGING UNITS DESIGNED OR UPGRADED FOR CYCLING.

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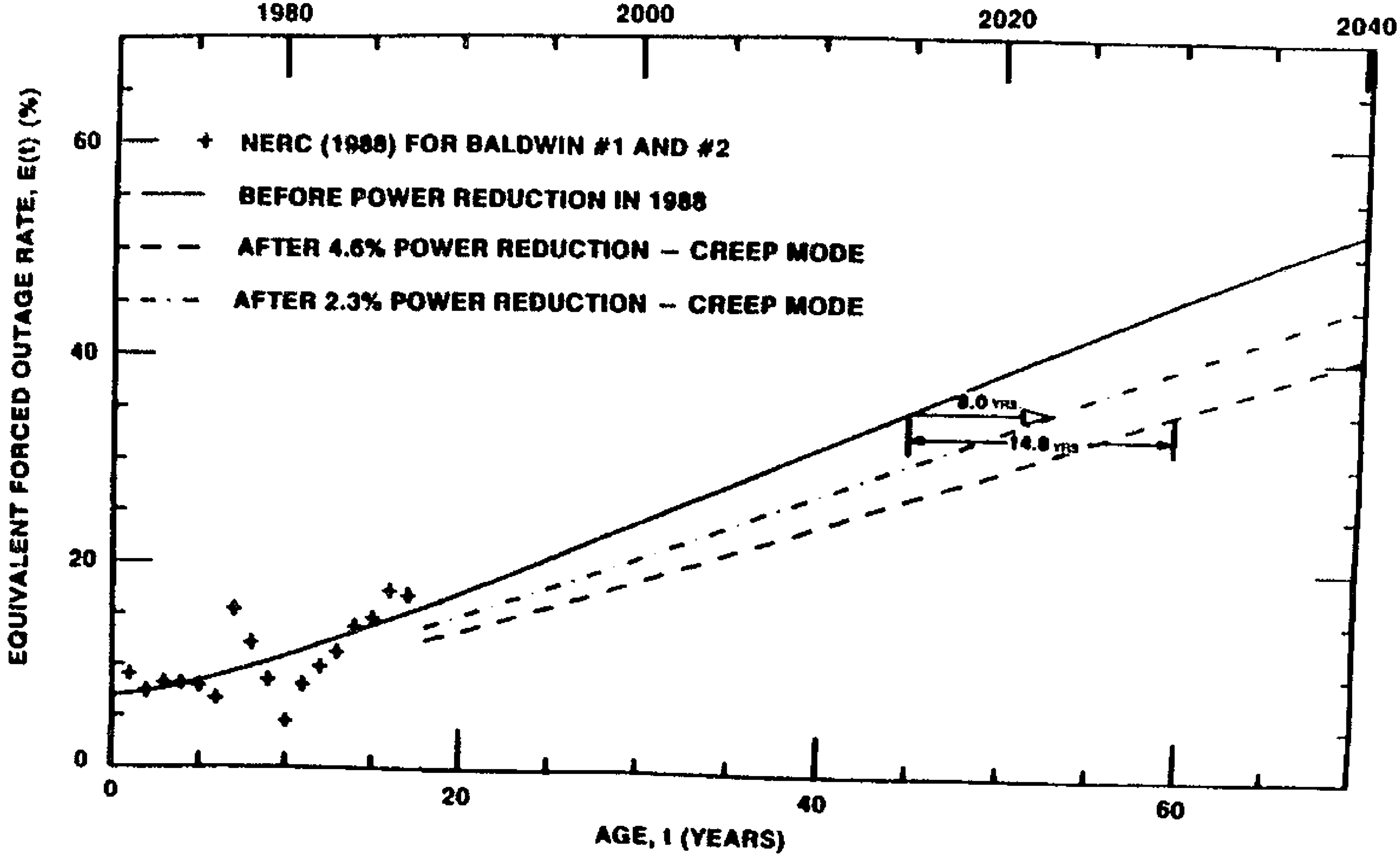

FIGURE 6.
EQUIVALENT FORCED OUTAGE RATE FOR BALDWIN STATION, UNIT 1, AS ESTIMATED FOR TWO POWER REDUCTION SCENARIOS ASSUMING THAT CREEP RUPTURE FAILURE MODE IS DOMINANT.

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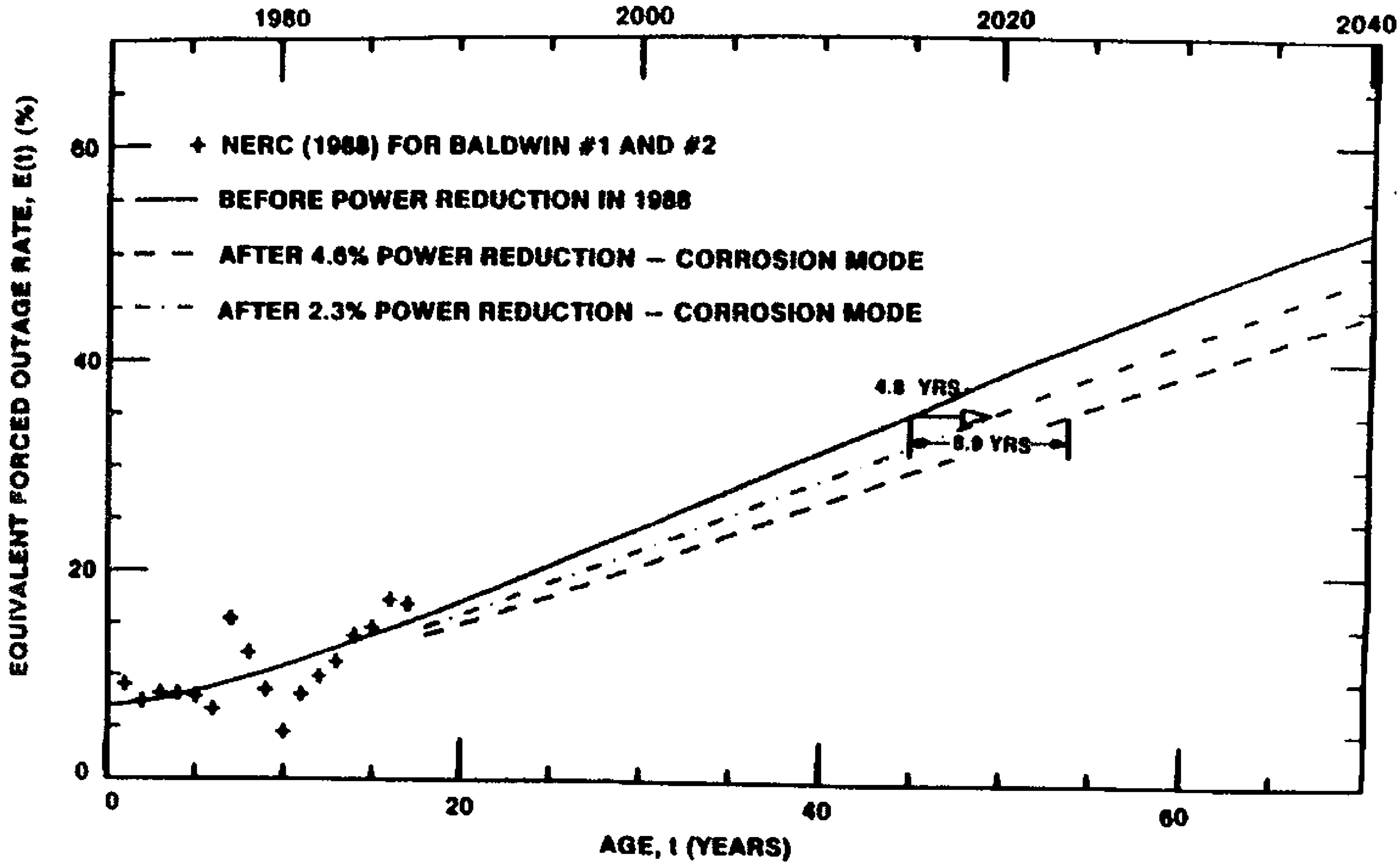

FIGURE 7.
EQUIVALENT FORCED OUTAGE RATE FOR BALDWIN STATION, UNIT 1, AS ESTIMATED FOR TWO POWER REDUCTION SCENARIOS ASSUMING THAT FIRESIDE CORROSION FAILURE MODES ARE DOMINANT.

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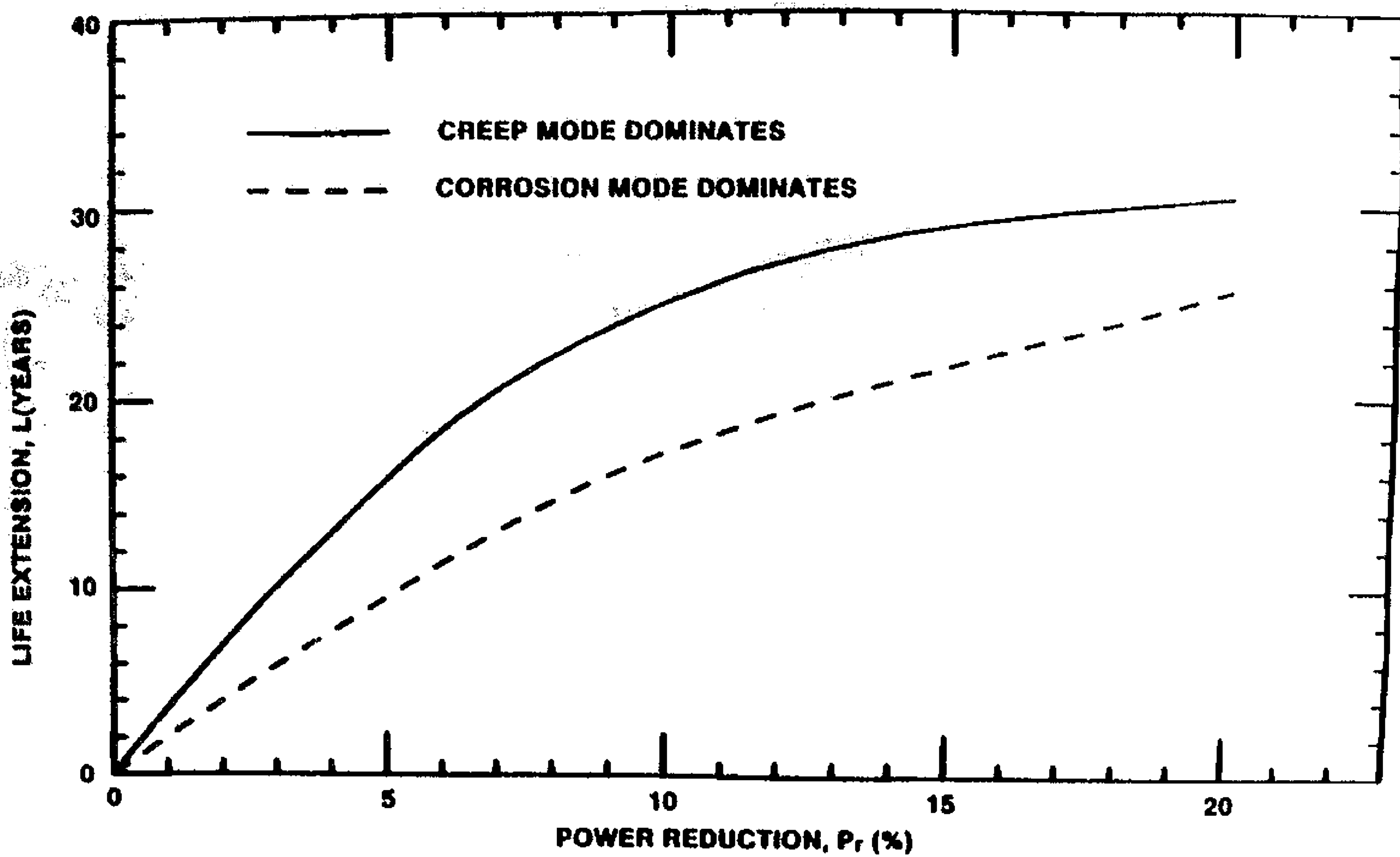

FIGURE 8.
MINIMUM LIFE EXTENSION BEYOND 2015 ATTRIBUTABLE TO POWER REDUCTIONS AT BALDWIN STATION, UNIT 1.

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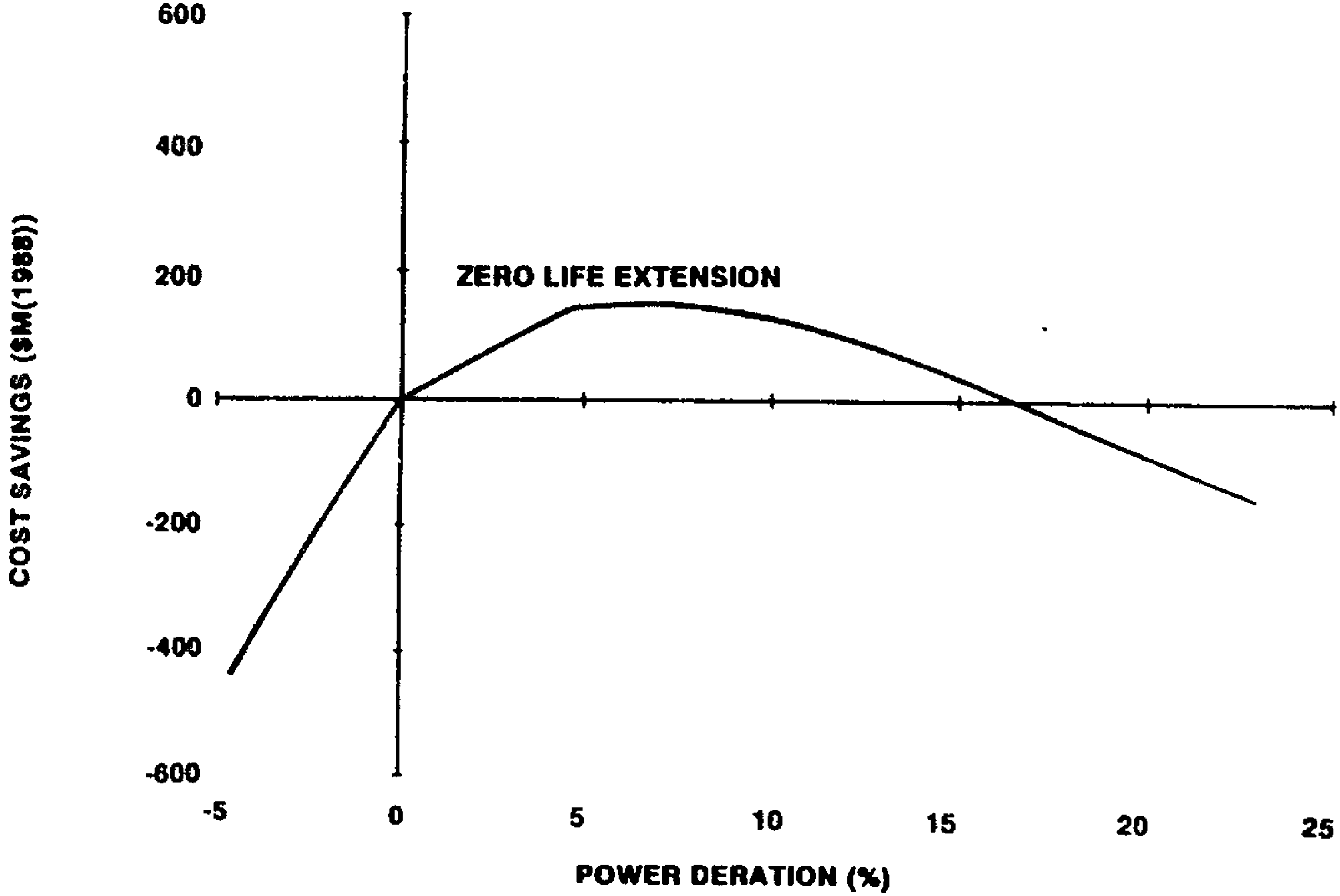

FIGURE 9.
SAVINGS FROM DERATION OF TWO 587 MW COAL-FIRED UNITS.

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SAVINGS FROM LIFE EXTENSION OF
TWO 587 MW COAL-FIRED UNITS

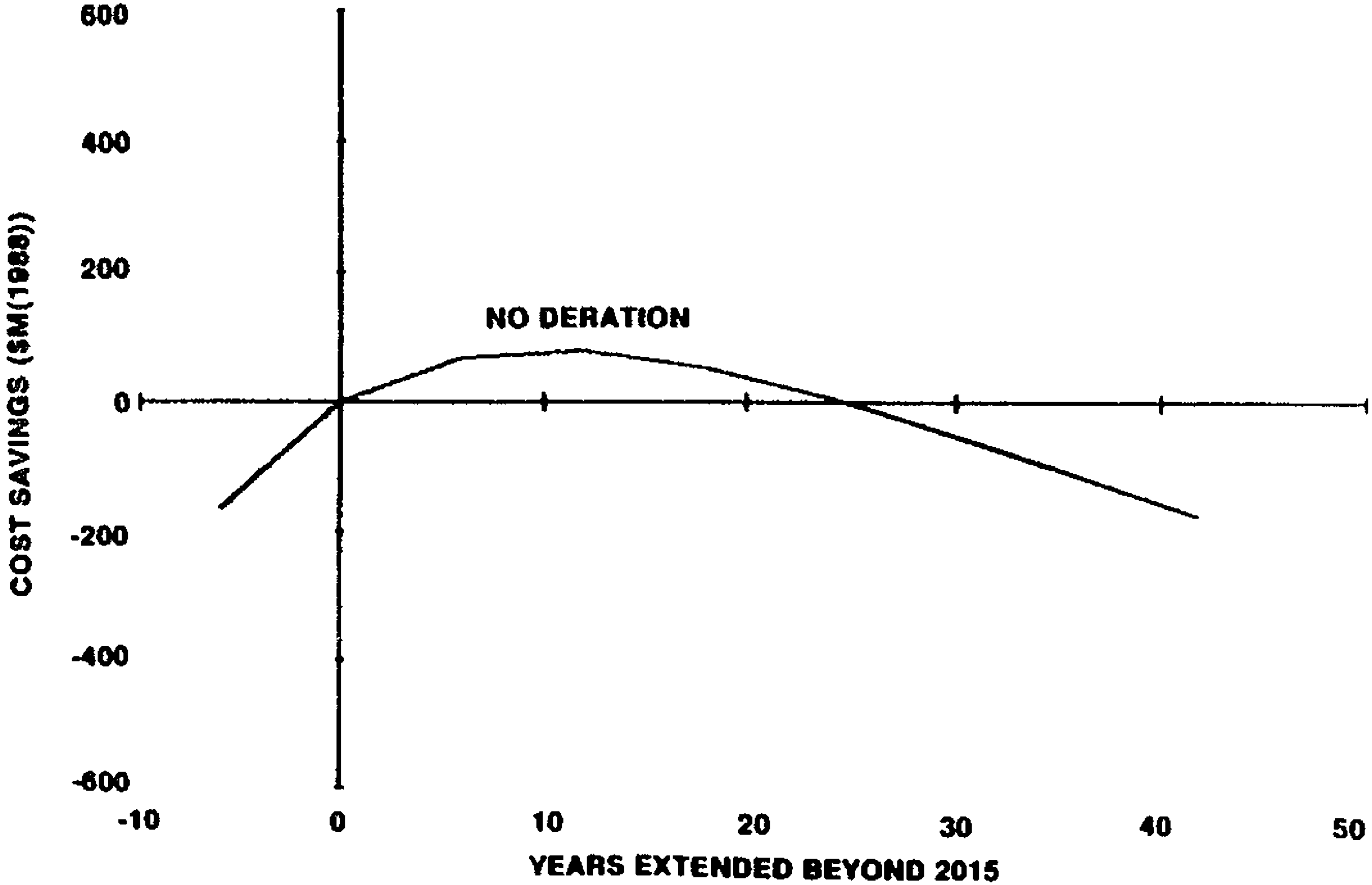

FIGURE 10.
SAVINGS FROM LIFE EXTENSION OF TWO 587 MW COAL-FIRED UNITS.

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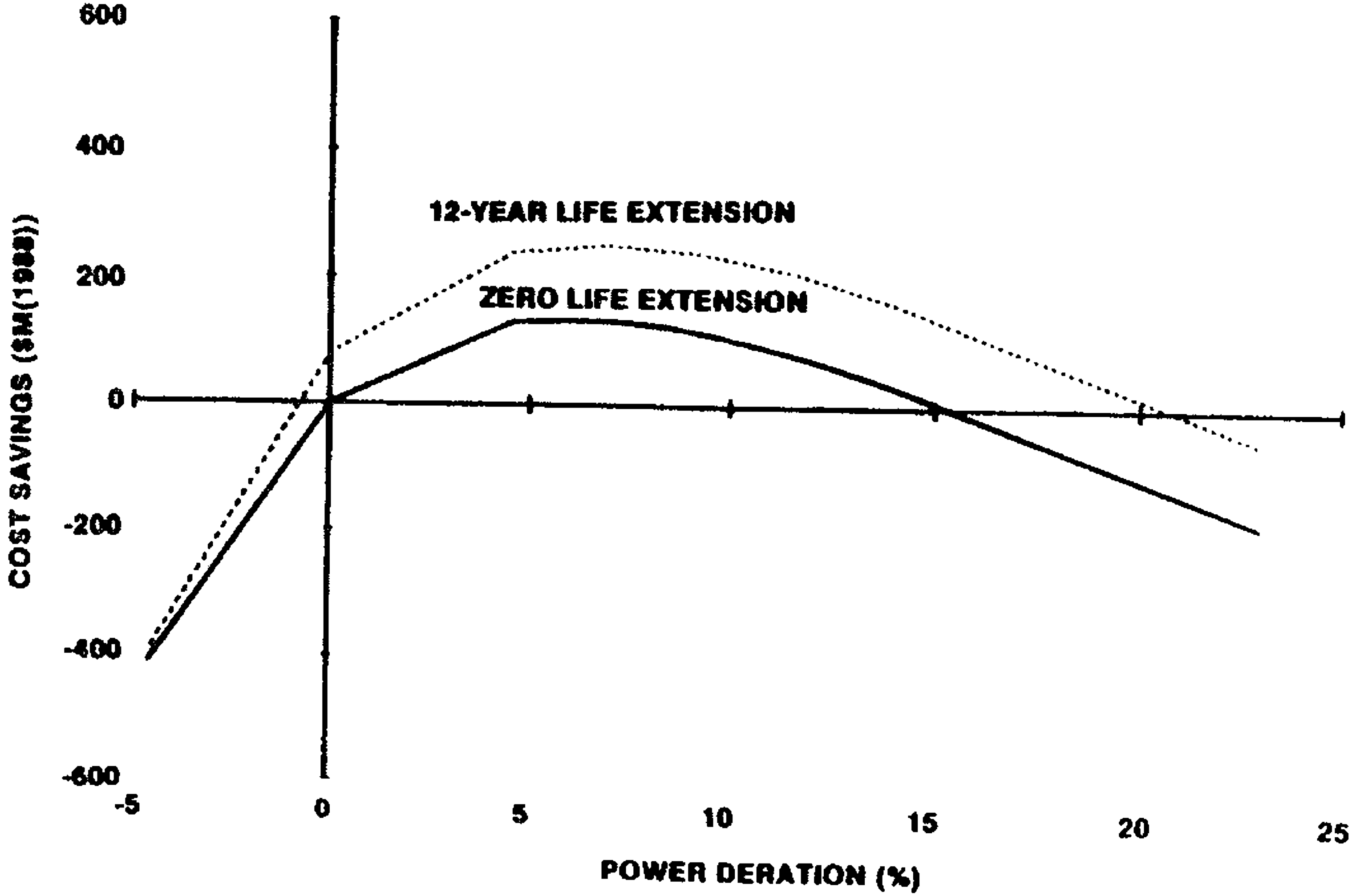

FIGURE 11.
SAVINGS FROM DERATION OF TWO 587 MW COAL-FIRED UNITS.

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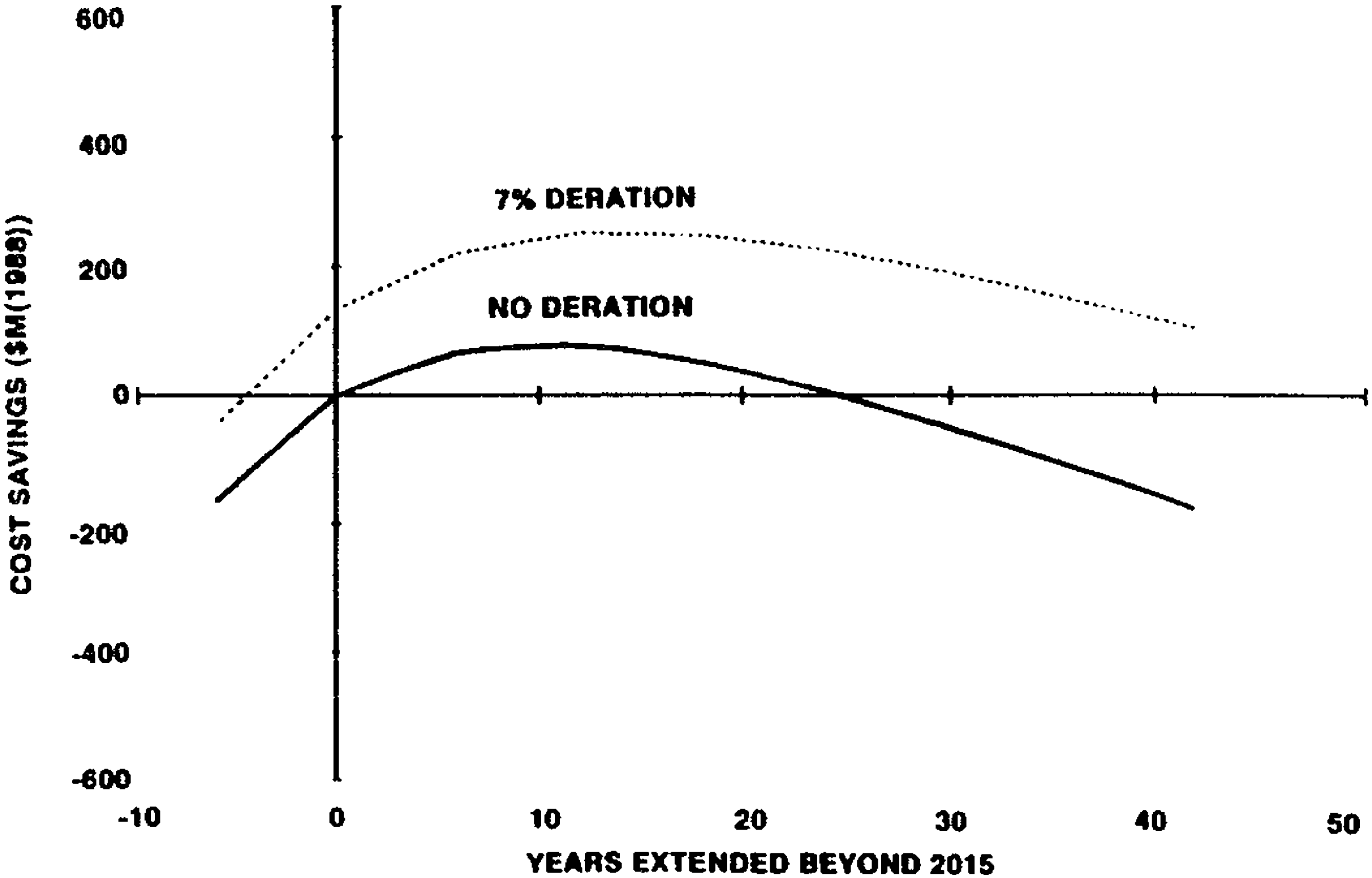

FIGURE 12.
SAVINGS FROM LIFE EXTENSION OF TWO 587 MW COAL-FIRED UNITS.

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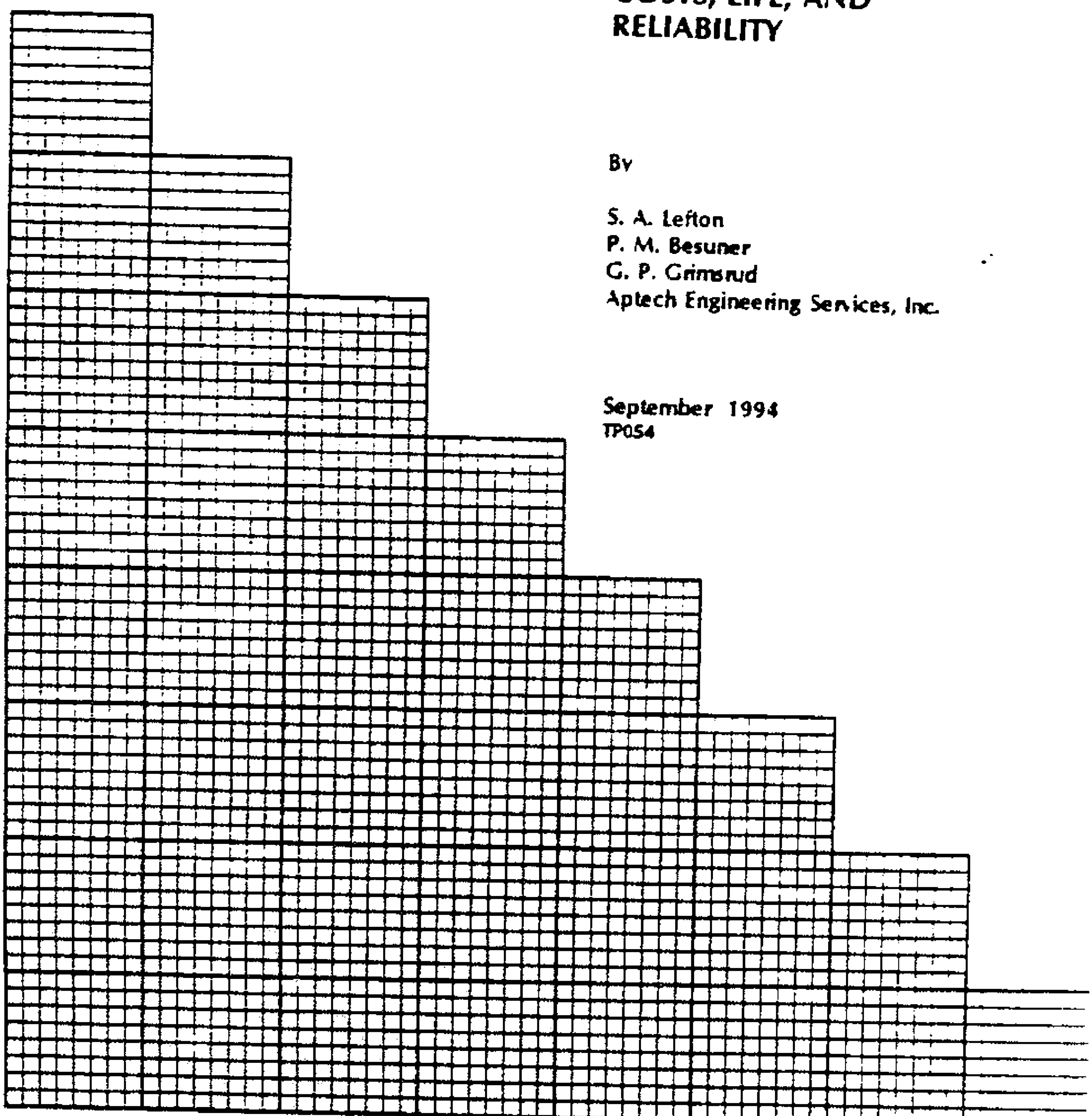
MANAGING UTILITY POWER PLANT ASSETS TO ECONOMICALLY OPTIMIZE POWER PLANT CYCLING COSTS, LIFE, AND RELIABILITY



By

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September 1994
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MANAGING UTILITY POWER PLANT ASSETS TO ECONOMICALLY OPTIMIZE POWER PLANT CYCLING COSTS, LIFE, AND RELIABILITY

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Abstract

This paper describes the need to assess and manage fossil power plant cycling costs, life expectancy, maintenance strategies, dispatch strategies, and plant reliability, and it presents a methodology that addresses these various needs. This methodology can be used to optimize capital and maintenance spending in order to minimize system-wide revenue requirements.

Background

Competition in the utility sector is increasingly being driven by Qualified Generating Facilities (QFs), Non-Utility Generators (NUGs), and Open Transmission Line Access (OTLA). This competition makes it necessary for utilities to critically examine, analyze, and understand the bases for capital and maintenance costs associated with long-term operation of their power plants. Competition associated with QFs, NUGs, and OTLA, and with the presence of a utility's own nuclear power plants on the generating system, often results in an over abundance of baseload capacity. This situation generally requires fossil units that were designed for baseload operation to begin cycling. (Herein, cycling refers to on/off operation, low-load operation, and load following.)

When a utility begins to cycle its fossil plants, it typically observes either (1) a significant increase in equivalent forced outage rate (EFOR) due to the increased component failure rate, or (2) additional capital and maintenance expenditures. Figure 1 compares EFORs for typical baseloaded units, cycling units that were upgraded from baseload, cycling units that were not upgraded from baseload, and cycling units that were designed for cycling. It also plots the effects of capital and maintenance expenditures. Increased capital and maintenance spending typically lags power plant component failures by approximately 1 to 2 years, and these failures lag cycling operations. The expenditures may lead to much higher, non-competitive costs for the cycling units. The higher capital and maintenance costs for these cycling units, and the reduced generation, yield a higher average generation cost. The net effect is a self-perpetuating cycle of increased cost, non-competitiveness, decreased generation, and finally further increases in cost per megawatt-hour of generation. The non-competitiveness and increases in cost per megawatt-hour often lead a utility to consider early retirement of the unit and the associated high-cost capacity replacement. Early retirement may also be brought upon by the increased forced outages and unexpected capital requirements.

This paper presents findings from engineering studies that Aptech Engineering Services, Inc. (APTECH) has performed at five major utility systems to quantify the economic effects of unit cycling. These studies included extensive review of failure data, application of methods to predict future forced outages, and analysis of individual power plant capital and maintenance data. Generally these studies identify the costs associated with a specific type of power plant operation, including cycling and unit derating (1). While most of these studies have been performed under a strict confidentiality agreement, APTECH is able to discuss cost-of-cycling calculations made for Hawaiian Electric Light Company and an EPRI-funded research project for the Los Angeles Department of Water and Power's nine Los Angeles Basin fossil-fired power plants. This paper also describes many of the techniques utilized in these and other studies. However, it is clear from past work that each study must be customized to a specific utility's needs and its available cost and reliability data bases.

Effective Management of Utility Power Plant Assets

Today's competitive environment places increased demands on a utility to be aware of its costs and the origins of these costs in operating and maintaining its power plant assets. Plant capital and maintenance spending needs to be fully understood. Plant operation characteristics that cause equipment wear and tear need to be understood and quantified.

Operations that typically increase unit wear and tear include cycling the unit on/off line by hot, warm, and cold starts and cycling the unit up and down the load range from maximum continuous rating to minimum loads. Unit shutdowns and unit trips are also very hard on equipment. Methods used to start up and shut down a plant, including ramp rates, temperature limits, hold times, etc., especially for plant shutdowns, have been noted to have a major effect on unit reliability and longevity and, therefore, the wear-and-tear costs. Significant damage and reduced service life have also been observed to occur when units operate above their design ratings or operating limits.

Operations that typically *reduce* costs include steady-state baseload operation at or below the design rating. This is generally achieved by derating units some 3 to 5% of rated power. Carefully increasing the time between major overhauls when there are no major impediments to increasing these overhauls can also reduce costs.

Once a utility understands the effects of these operations on their unit wear-and-tear costs, it can begin to minimize these costs by selectively changing its power plant operational modes. This process can and will lead to a "system optimization" and minimization of the total revenue requirements. For example, Figure 2 shows that by reducing cycles per year on selected power plants, system costs can be reduced and an optimum balance achieved. This balance can be achieved by determining the true cost to cycle each plant and then defining the mission of each plant to achieve the lower costs. The concept of a mission statement for each plant is a very important one because the mission statement must be compatible with economic unit capabilities, e.g., the plants identified with lower cost per cycle should have the mission to cycle more than the higher cost units.

Cycling-Related Degradation Phenomena

All cycling cost analyses should take into account cycling-related degradation phenomena. There are several materials degradation phenomena that are likely to be accelerated by increased cycling. These phenomena include creep, fatigue, creep/fatigue interaction, corrosion (especially during out-of-service periods), erosion wear, vibration, and other interrelated phenomena that promote accelerated component aging. Because baseload units are designed to operate in the creep range, they experience increased outages when subjected to the fatigue range of cycling. Creep-fatigue interaction is one of the most important phenomena contributing to component failures and can have a detrimental effect on the performance of metal parts or components operating at elevated temperatures. For example, it has been found that creep strains can seriously reduce fatigue life and that fatigue strains can seriously reduce creep life (e.g., Ref. (2)). A typical set of creep-fatigue interaction curves is shown in Figure 3. These are conservative design curves, but APTECH has data that approaches them for certain types of cycling conditions.

Consider the example of a major component of a typical old baseload unit with 50% accumulated creep damage (50% creep damage is defined herein to be enough to exhaust half the component's life without fatigue cycling). The curves show that it requires only 10% to 20% total fatigue damage to cause a 50% creep damaged component to reach failure. If this older, baseloaded plant (that used to have three to six starts per year) is now dispatched to operate at 50 starts per year, it may take only 2 to 6 years to accumulate the 20% total fatigue damage required to cause component failure.

Thus, while cycling-related increases in failure rates may not be noted immediately, critical components will soon start to fail. Shorter component life expectancies can result in higher plant EFORs or higher capital and maintenance costs to replace components at or near the end of their service lives. In addition, it can result in reduced overall plant life. How soon these detrimental effects will occur will depend on the amount of creep damage present and the specific types and frequency of the cycling. Cycling exacerbates damage in components that are already creep-damaged due to past baseload operation. The combined effect of creep (base load) and fatigue (cycling) will reduce the remaining life to as low as 10%-25% of the life expectancy with no interaction.

Figure 3 shows this effect for a variety of materials in fossil power plants. There is no creep/fatigue interaction for the line labeled Ni-Fe-Cr alloy 800H. This line corresponds to the linear-damage failure criterion

Creep Damage + Fatigue Damage = 100% at Failure

The worst case is 2¼Cr-1Mo steel. For this material extensively used in fossil power plants, the total life can be as low as 25% of the life calculated by simple addition (linear combination) of fatigue damage plus creep damage. The two stainless steel alloys are between these extremes. The failure of most fossil power plant components can be bounded by this data.

The effects of cycling on power plant components can be dramatic and surprising. One often neglected effect is the increase in operator errors due to the increased personnel involvement that is necessary to cycling activities. Specific component effects can also be identified. Tables 1 through 4 list a number of power plant component problems due to cycling. While a number of these effects were not initially thought to be the result of cycling operations, research has shown that cycling activities are at least partially a cause.

Cost-Of-Cycling Equation

APTECH has developed a cost-of-cycling equation which, when properly applied to a utility power system, calculates the true cost of cycling in a cycling power plant. This equation consists of seven cost elements.

True Cost of Cycling	= Δ	**Maintenance and Overhaul Cost**
	+ Δ	**Forced Outage Recovery Cost**
	+ Δ	**System Production Cost**
	+ Δ	**System Long-Term Generation Capacity Cost**
	+ Δ	**General Engineering and Management Cost**
	+ Δ	**Capital Cost of Cycling Improvements**
	+ Δ	**Cost of Unit Dispatch**

Here Δ refers only to those costs attributed to cycling.

The first cost element is the additional maintenance and overhaul costs that are attributed to cycling, typically the long-term, wear-and-tear costs associated with additional maintenance and additional overhauls required on cycling units. Experience shows that maintenance and capital spending typically increases and overhaul times lengthen with increased cycling. The many effects of cycling on unit heat rate are also included in this element.

The second cost element is the forced outage recovery cost. Forced outages are typically more frequent and of longer duration in cycling units than in baseload units. The recovery costs for additional forced outages should include outages due to operator error, which have in the past included boiler explosions, boiler implosions, generator out-of-phase synchronization, generator motoring, miscellaneous operator valving errors, miscellaneous errors involving humans and automatic equipment and control system failures. Increased cycling obviously results in increased opportunities for error.

The third cost element, system production cost, includes the cost of having to increase utilization of less economical generation units (or purchase power) due to lower availability of the cycled units. Another typically smaller component of this cost includes fuel and chemicals needed for unit startup.

The fourth cost element in Equation 1 is system long-term generation capacity costs. These costs include both the need for short-term purchase of replacement capacity due to higher plant outages and acceleration of the need for cost expenditures to build new capacity due to shortened life of the units being cycled.

The fifth cost element, general engineering and management cost, includes the cost of cycling studies, the general engineering study costs associated with modifications and upgrades to plants to make them cycle better, and the management costs associated with optimizing the units to cycle more efficiently.

The sixth cost element is the capital cost of cycling-related improvements. These improvements would include turbine bypass systems, stress analyzers, and equipment to upgrade automatic operation such as automatic burner insertion, burner management systems, controls upgrades, chemistry upgrades, and turbine water-induction protection.

The seventh and final cost element in Equation 1 is the increased cost to properly dispatch the unit in cycling. Determining the optimal dispatch strategy is a very complex optimization procedure, and the cost of developing an appropriate dispatch algorithm for use in system operation should be accounted for.

The results of these calculations and studies are shown below:

TRUE UNIT COST PER CYCLE

Unit Type	Typical Industry Value (Without Consideration of True Cycling Cost)	Potential Range of True Cost
Small Drum	$5,000	$15,000 - $100,000
Large Supercritical	$10,000	$30,000 - $500,000
Gas Turbine	$100	$300 - $5,000

The cost of cycling conventional boiler/turbine fossil power plants can range from between $15,000 and $500,000 per start-stop cycle, depending on the specific unit size, type, fuel, pressure, and design features. Research shows that utilities typically estimate these costs at a factor of 3-10 *below* actual costs and, thus, often significantly underestimate their true cycling costs. The result would be that their units are cycled far more than they should be to truly minimize system long-term revenue requirements.

Assessing the Cost of Cycling and Other Power Plant Operational Changes

APTECH has developed a unit load, computer analysis tool to evaluate past generation on an hourly basis. Past hourly generation can be examined at 0% to 110% in increments of 10% of rated load, including all load changes, all start/stops, shutdowns, and hot, cold, and warm startups. The developed model calculates damage under steady cyclic and loads of any magnitude that interact with each other in a nonlinear fashion. It accounts for any combination of load peaks and valleys, time of load peaks, ramp rates, load changes with time, and differences among hot, warm, and cold starts. The APTECH methodology also involves a review and analysis of past NERC GADS outage data. The outage data is broken down into forced and planned outages and the high-impact or critical components are listed with their respective contributions to the EFOR. Plant visits, examination of failure records, maintenance costs, and capital costs; and data acquisition of key startup, shutdown, and load following data are all key to development of a useable data base that would include pressures and temperatures of the boiler, turbine, feedwater heaters, condensers, as well as chemistry data and data on corrosion product transport during cycling. Examples of this data are shown in Figures 4 and 5.

APTECH has also developed and refined a plant questionnaire to help determine the future effects of cycling as well as current cycling problems.

Advanced condition assessment of critical parameters in a unit is also a part of the methodology. This assessment may include strain gages on boiler waterwall tubes, boiler heat flux devices for furnace heat flux monitoring, solid particle sampling and monitoring devices for steam line solid particles, and chemistry monitoring and testing to determine amounts of oxygen chlorides, iron, and copper in various feedwater and heater drains. APTECH has developed a data acquisition system and now routinely monitors cycling boilers remotely via modem for critical parameters during startup and shutdown, as shown in Figures 6 and 7.

Application of the methodology typically involves calculation of fatigue and creep damage on a per-cycle basis on critical components, through use of finite element models and other engineering models of cycling effects on boiler tubes, headers, turbine rotors and cases, feedwater heaters, condensers, and other critical power plant components.

Another part of the methodology involves calculation of the equivalent hot starts from past records and the assessment of damage from critical components. APTECH typically calculates the damage from cold starts, warm starts, and hot starts, as well as load following from full load to three different lower loads in order to determine the damage per cycle. Typical shutdowns and unit trips are always included in the damage calculations, as these do occur often and are very significant.

The next step is to correlate the equivalent hot starts to both capital and maintenance cost, using multi-variable regression statistical analysis. These starts are then correlated to heat rate and to EFOR changes and their associated costs (see Figures 7 and 8). This data is then integrated into utility production cost modeling codes, such as PROMOD and POWERSYM, which are used to calculate operational cost impact. It is necessary to project future unit reliability, overhaul, and maintenance spending accurately when using these production cost models. Then the costs are totaled using Equation 1. Figure 8 shows actual data for ten similar 125 MW Fossil units with average EFOR correlated to equivalent cycles. Note that EFOR peaks 7 years, 5 years, and 2 years after significant cycling and tends to generally lag cycling. This suggests that adding a cycle creates a lag time for EFOR and that the lag time for EFOR tends to be consistent with the creep/fatigue interaction curves shown in Figure 3. Figure 9 shows a relationship between unit cycling and efficiency (e.g., heat rate). While there is not the best correlation, there appears to be good evidence that cycling contributes to significant increases in a unit's heat rate due to turbine seal wear, turbine blade erosion, air heater fouling at low loads, and a host of cycling-related heat rate impact variables.

Production cost models are developed to give the utility the opportunity to forecast future costs based on future operating scenarios, and an optimization analysis is performed. The optimization process typically looks at a series of runs of production cost models to determine the least-cost generation plan. The expected levels of cycling and unit constraints based on mission statements are accounted for in the production cost model runs. One of the key features of this work is the incorporation of good future reliability estimates of each plant under each operating scenario with the unit's mission defined. The optimization process attempts to help the utility

- Cycle the units that are less costly to cycle, taking all cost of cycling factors into account
- Make the best load dispatch decisions based on both short-term and long-term objectives
- Reduce capital and maintenance expenditures
- Increase unit reliability

- Reduce total long-term revenue requirements
- Avoid the temptation to make decisions based on fuel costs alone

Conclusion

The true cost of cycling units that were originally designed for baseload operation is greater than most utilities have estimated and accounted for in their system dispatch programs. The true cost of cycling for each unit type should be carefully assessed by utility management to ensure that their generator assets are used in an optimal way

The APTECH methodology is an engineering and statistical analysis system designed to help a utility optimally manage its power plant assets. It accounts for past operations and future expected effects of cycling (or other operational plans) on cost, life, and reliability. The bottom-line effects of such an analysis can lead to cost savings in the range of $10 to $200 million when evaluated over the life cycle of a typical 600 MW coal-fired power plant. Even more significant cost savings can be obtained when a complete utility system is analyzed and optimized. Such savings are going to be essential in the future competitive world where low-cost providers, those that best optimize their systems to minimize long-term average cost, are likely to emerge as the preferred electricity suppliers.

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2 "Metals Handbook - Tenth Edition, Volume 1 - Properties and Selection Irons, Steels, and High-Performance Alloys." ASM International

Table 1

ACCELERATED BOILER FAILURES DUE TO CYCLING

- Fatigue Cracking of
  - — Boiler Tubes in Furnace Corners
  - — Tube to Buckstay/Tension Bar
  - — Tube to Windbox Attachment
  - — Tube to Header
  - — Tube to Burner
  - — Membrane to Tube
  - — Economizer Inlet Header
  - — Header Ligament
- Boiler Seals Degradation
- Tube Rubbing
- Boiler Hot Spots
- Drum Humping/Bowing
- Downcomer to Furnace Subcooling
- Expansion Joint Failures
- Superheater/Reheater Tube Leg Flexibility Failures
- Superheater/Reheater Dissimilar Metal Weld Failures
- Startup-Related Tube Failures in Waterwall, Superheater, and Reheater Tubing
- Burner Refractory Failure Leading to Flame Impingement and Short-Term Tube Overheating

Table 2

TURBINE EFFECTS DUE TO CYCLING

- Increased Thermal Fatigue Due to Steam Temperature Mismatch
- Steam Chest Fatigue Cracking
- Steam Chest Distortion
- Bolting Fatigue Distortion/Cracking
- Blade, Nozzle Block, Solid Particle Erosion
- Rotor Stress Increase
- Rotor Defects (Flaws) Growth
- Seals/Packing Wear/Destruction
- Blade Attachment Fatigue
- Disk Bore and Blade Fatigue/Cracking
- Silica and Copper Deposits
- Lube Oil/Control Oil Contamination
- Shell/Case Cracking
- Wilson Line Movement
- Bearing Damage
- Reduced Life

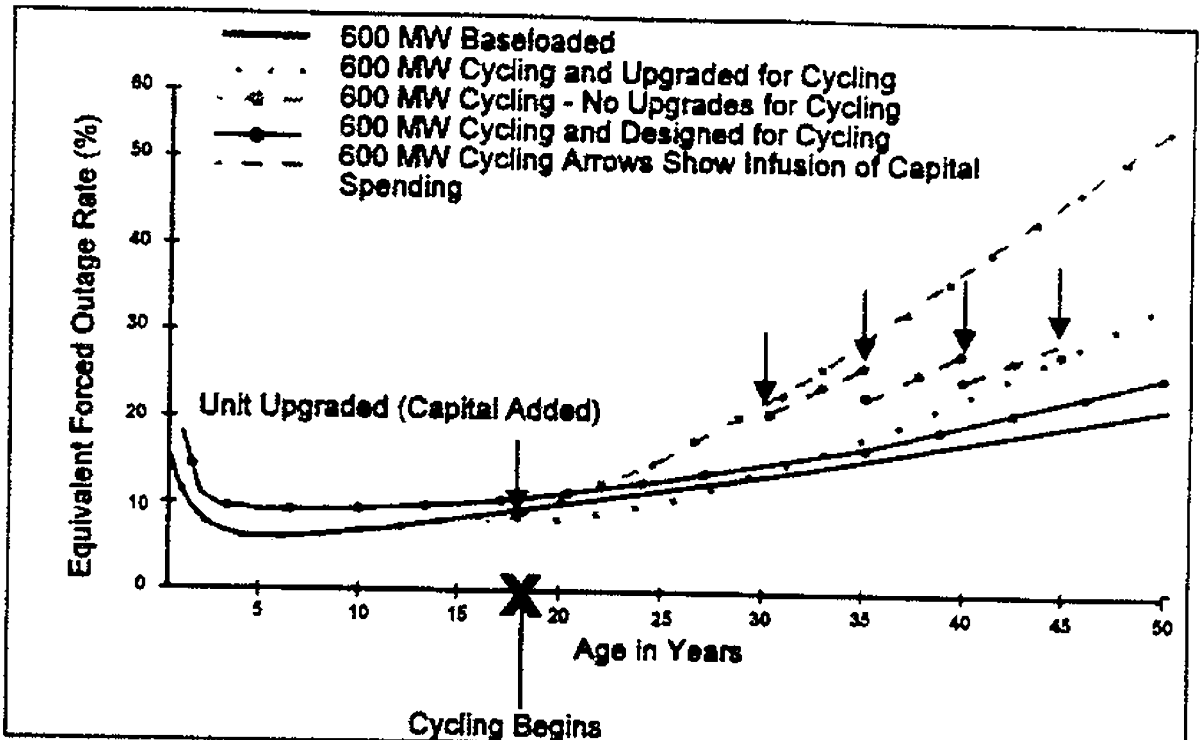

Figure 1 - Schematic of Typical EFORs and Capital Infusion Effects for Large, Aging, Coal-Fired Units Designed or Upgraded for Cycling.

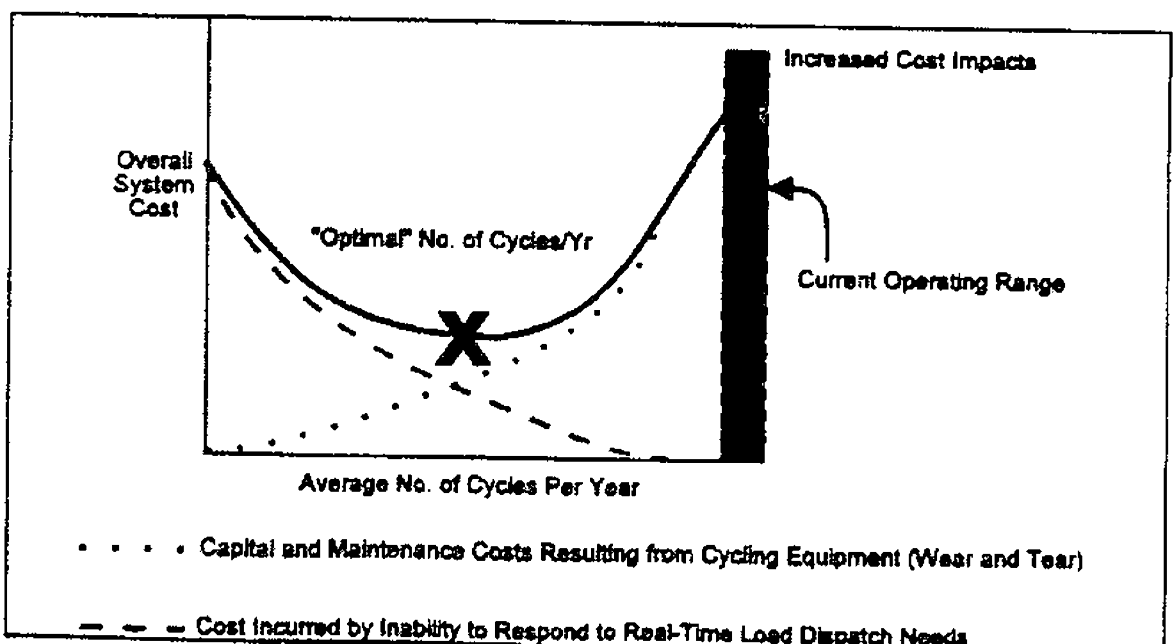

Figure 2 - Overall System Costs Versus Average Cycles Per Year for Utility Power Plants

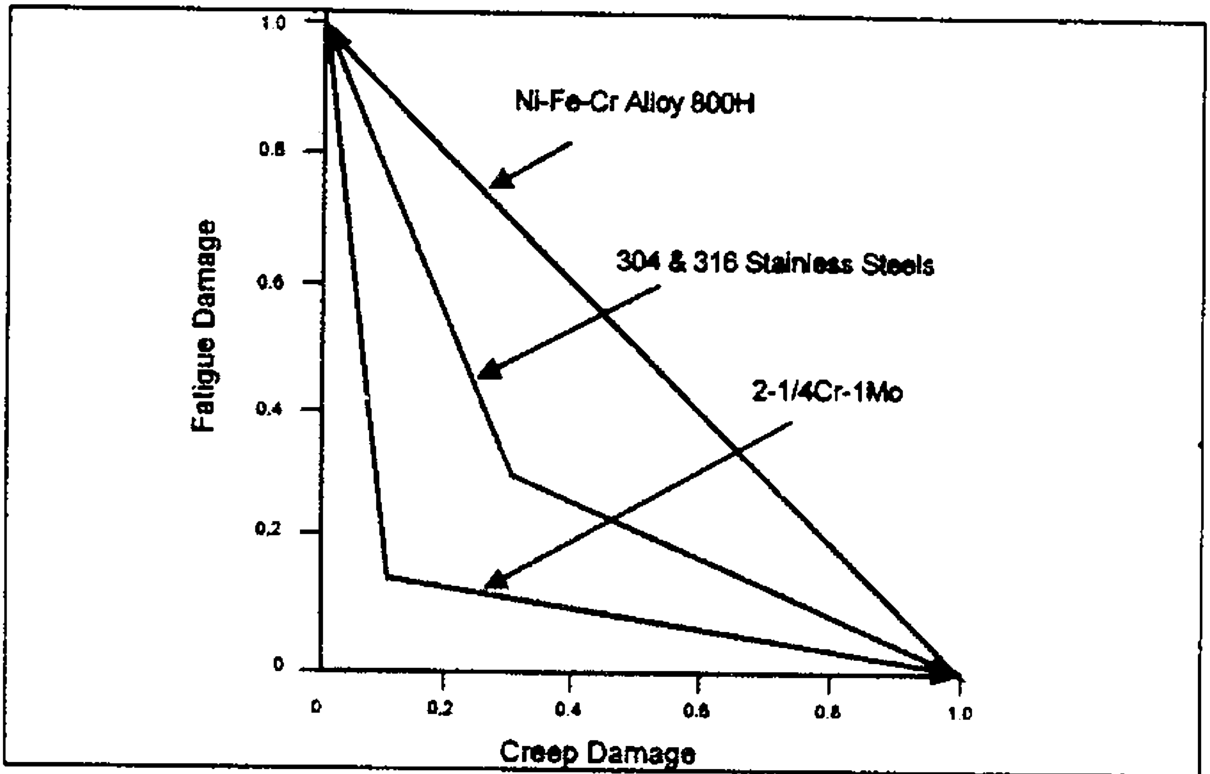

Figure 3 - Creep Fatigue Interaction.

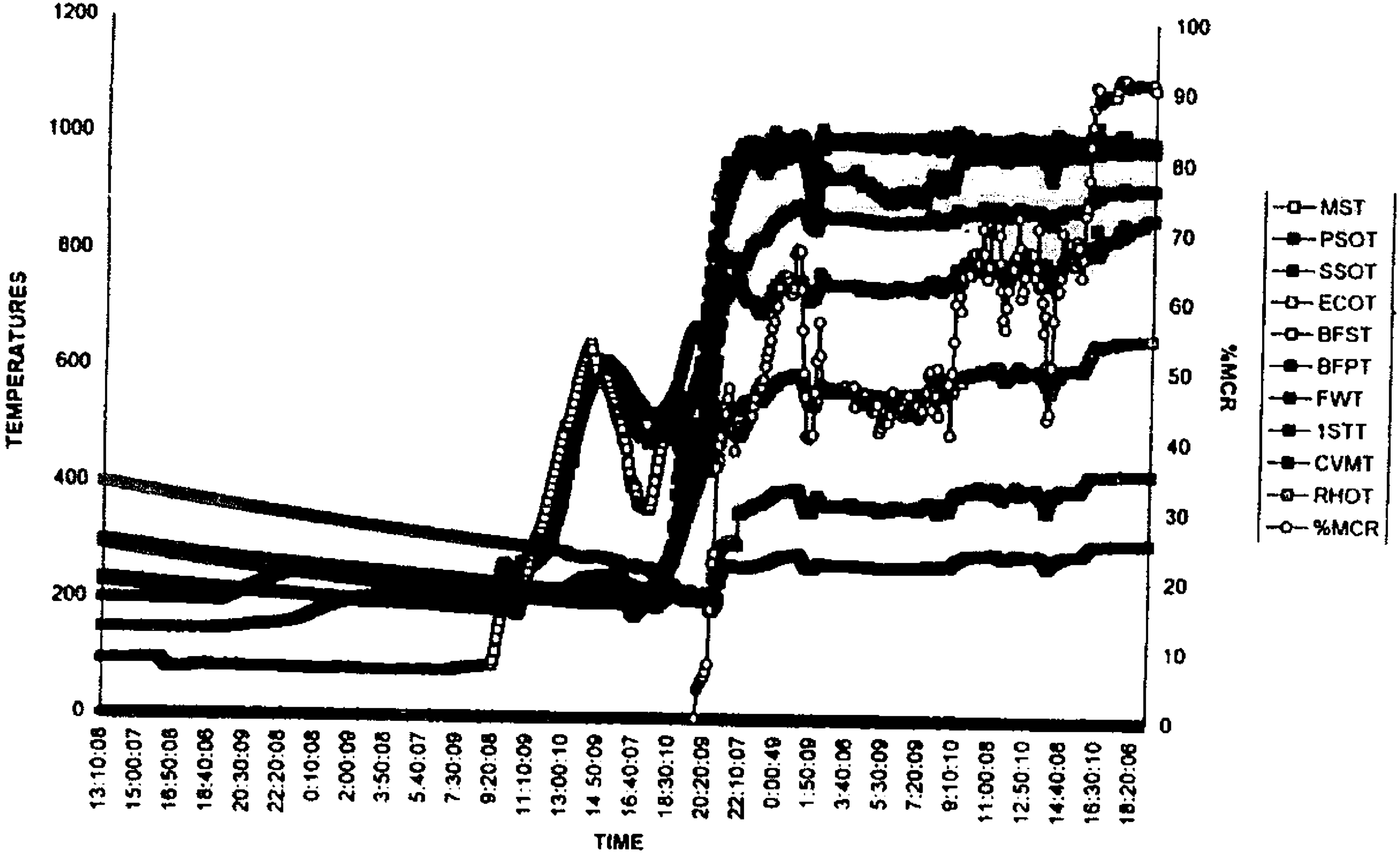

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Figure 4 Cold Startup Temperatures

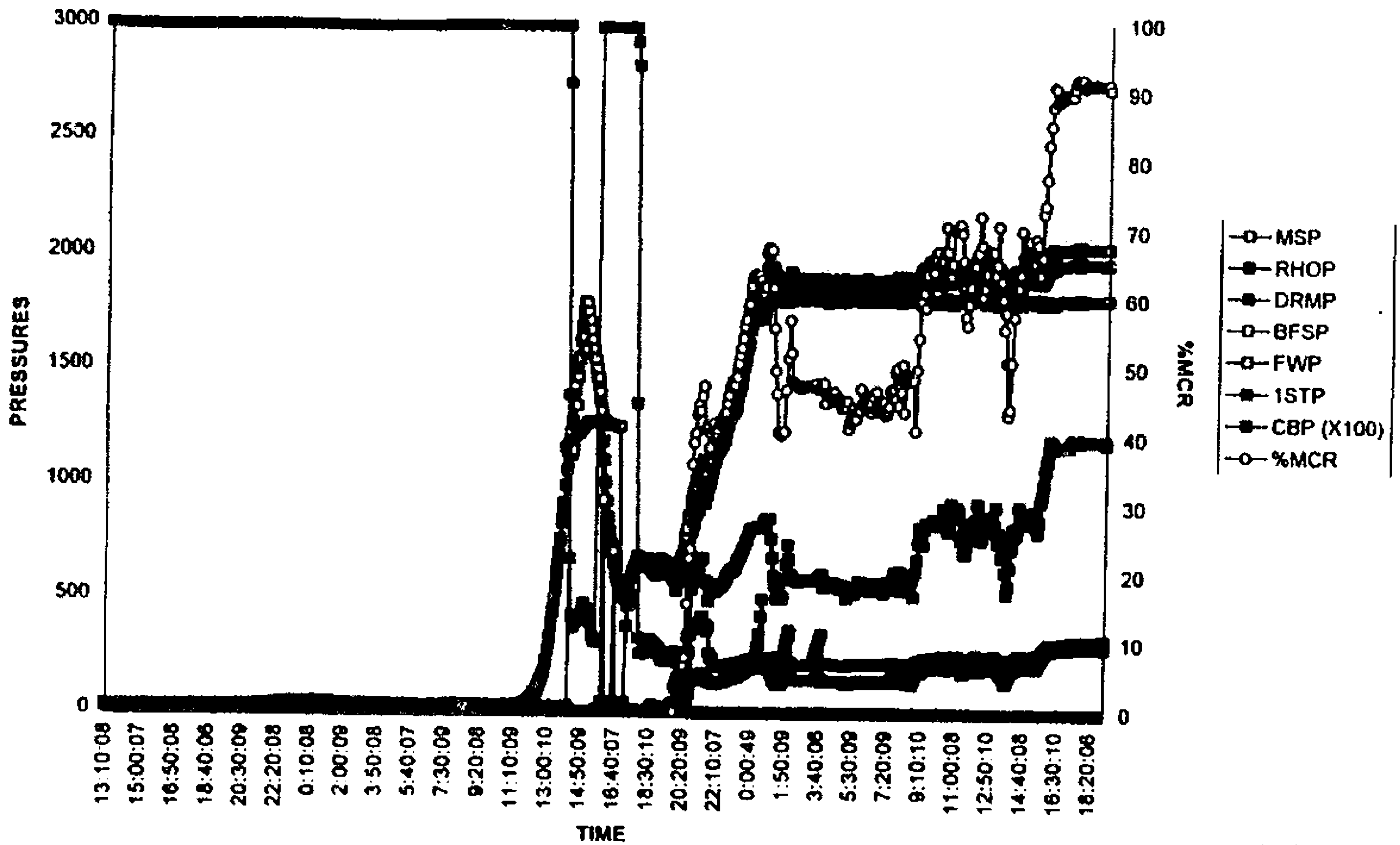

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Figure 5 — Cold Startup Pressures

Figure 6 — Data Acquisition and Modem Panel.

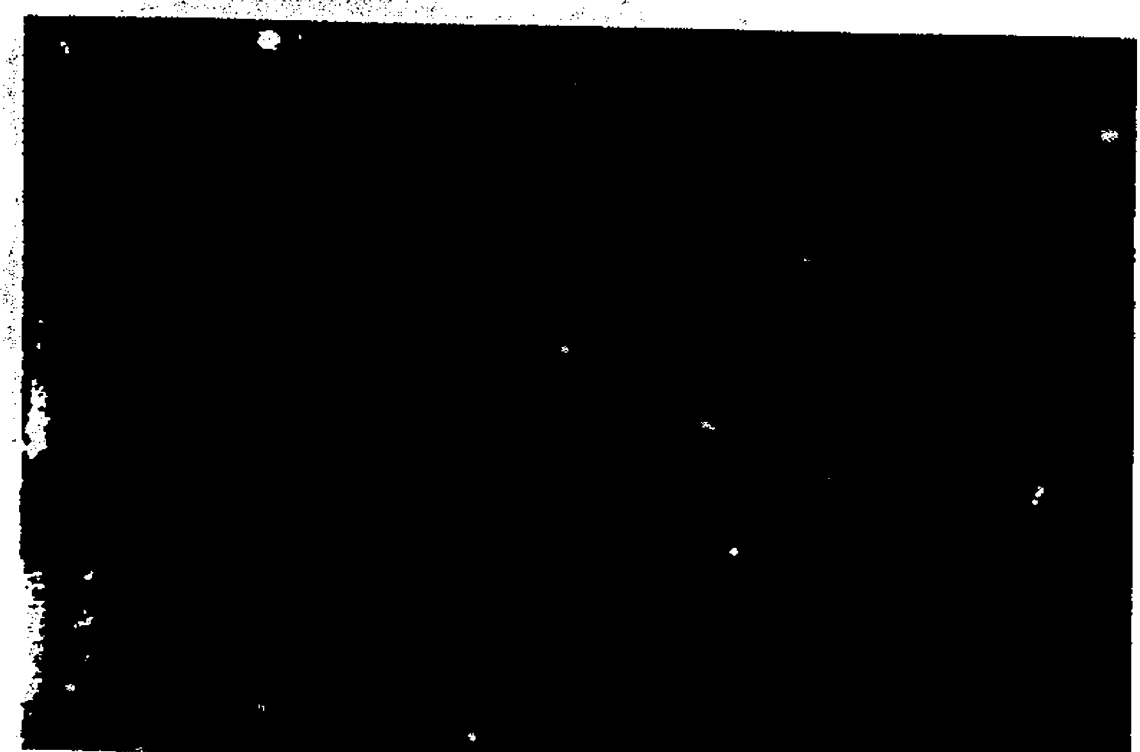

Figure 7 — Boiler Waterwall Tube Strain Gages and Heat Flux Monitors

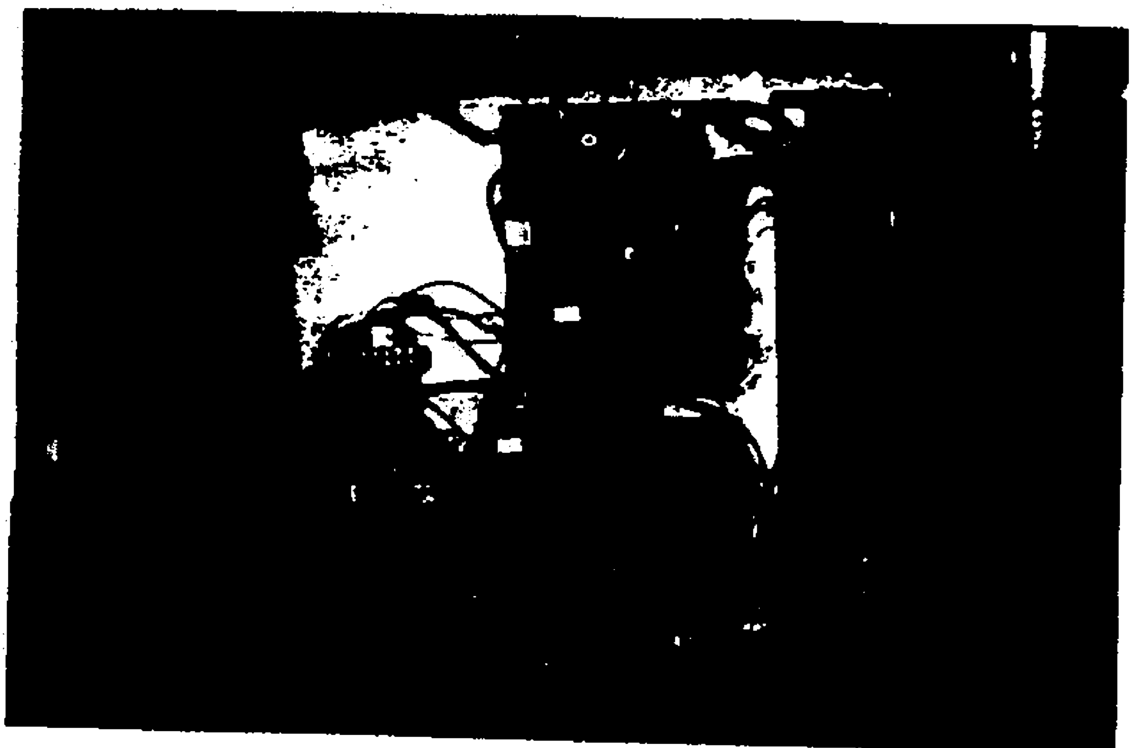

Figure 6 — Data Acquisition and Modem Panel

Figure 7 — Boiler Waterwall Tube Strain Gages and Heat Flux Monitors

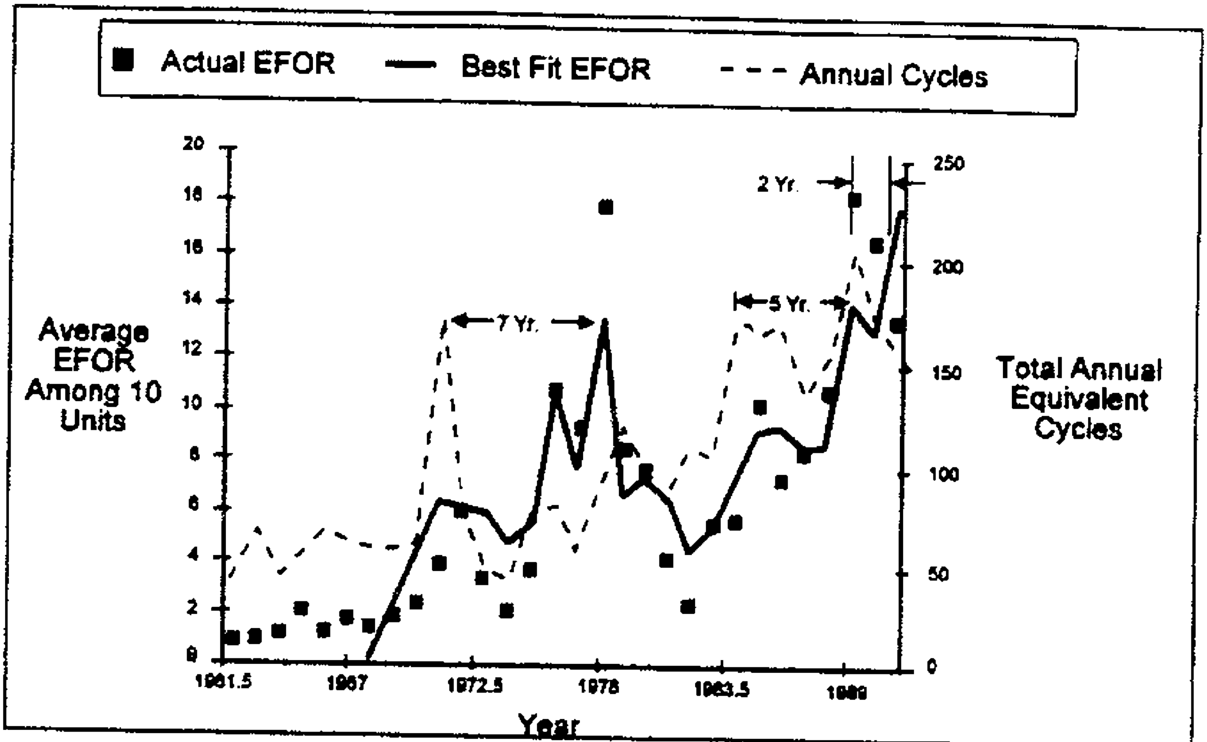

Figure 8 - Cycling Effects on Plant Reliability

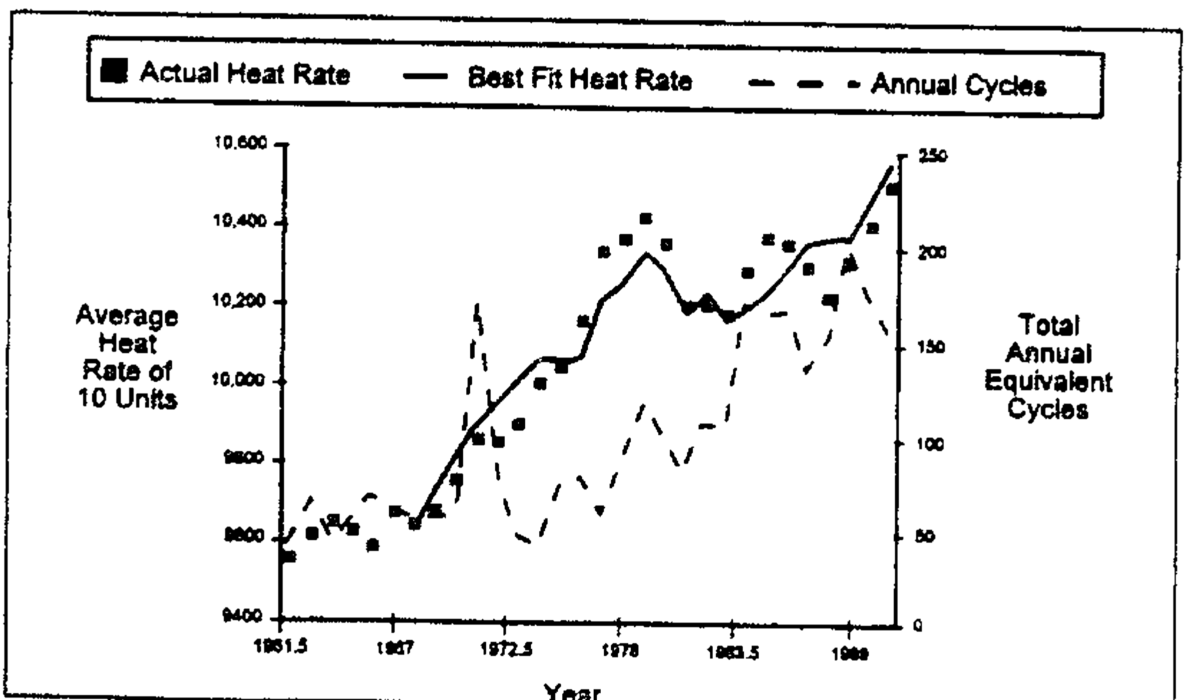

Figure 9 - Cycling Effects on Heat Rate

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Exhibit No. _____ (SAL-2)
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CYCLING COST ASSESSMENT PROJECT

By

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September 1994
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Abstract

The Department of Water and Power (DWP) of the City of Los Angeles operates twelve fossil-fueled generating units in the Los Angeles Basin. All but one of these units were designed and built in the 1950s and 1960s for baseload operation. However, present power system conditions have necessitated operational changes. These changes include cycling and setting new operating limits.

Evidence is mounting that the "total" cost of these operational changes is not being completely quantified. For example, cycling causes significant additional wear and tear on

the units However, the effects of this additional wear and tear on production cost and equivalent forced outage rate (EFOR) are not being accurately accounted for Having this information on cost and EFOR would allow DWP to optimize dispatch and cycling practices, and thereby achieve more reliable and lower cost operation as an alternative to replacement Installed generating capacity that remains cost-competitive for the next twenty years may very well be the least-cost capacity available over this period

This paper describes an EPRI-sponsored R&D program to develop a systematic approach to quantifying the "total" cost of cycling, including its effect on production cost and EFOR The work scope of this R&D program calls for a baseline survey, condition assessments and tests, and the development of a set of cycling cost assessment tools

Background

The capability of a utility to optimally balance the sometimes conflicting goals of a plant's power generation performance, availability, and mechanical integrity is a necessity in today's startlingly competitive economic environment. Traditionally, a utility can obtain short-term economic gains by operating the unit beyond the original design envelope, such as by cycling (defined here as load following, low-load operation, and on/off operation).

For example, units which were originally designed for baseload operation are now being cycled by many utilities, including the Los Angeles Department of Water and Power However, this type of operation generally leads to additional wear and tear This is because several materials degradation mechanisms, such as creep, fatigue, and creep-fatigue interaction, are known to be accelerated by increased thermal cycling This usually causes either long-term cost penalties or decreased long-term unit reliability and availability Absent a significant increase in capital and preventive maintenance spending, the O&M costs and EFOR of these baseload units will eventually increase This will make it more difficult for the utility to compete in the marketplace

Currently installed capacity that remains available for the next 20 years may very well be the least-cost capacity if it remains available at low O&M cost. However, many of the O&M costs imposed on the generating units by cycling and other changes in operation are not included in most utilities' avoided cost calculations. To evaluate the cost of cycling, many utilities include only fuel and auxiliary power costs and, perhaps, maintenance and overhaul costs We believe that many other cost items should be included in the calculation Such cost items include the following

- Forced outage recovery cost
- Maintenance and overhaul cost
- System long-term generation capacity cost
- General engineering and management cost
- Capital cost of cycling improvements

- Cost of dispatch of units

The implications of not accounting for these cost items include the following

- Increase in long-term equipment wear and tear
- Future operating problems and component failures
- Selection of long-term resource mix will not be "least-cost"
- Increase in overall revenue requirements over the long-term
- Premature retirement due to excessive operations and maintenance (O&M) costs

Until recently, these costs of cycling could not be fully documented because of a lack of a systematic approach to addressing and categorizing them. The intent of this R&D program is to develop such a systematic approach by focusing on DWP's generating units. The lessons learned and the tools developed during this project will have broad applicability to the generating units of all of EPRI's member utilities.

Objectives

The overall objectives of this project are as follows:

- Develop a systematic program for determining the effects of cycling operation and changes in unit operating limits on the total cost of power production and on the availability of fossil-fired generation stations.
- Apply this program to DWP's L. A. Basin units so that the results can be used improve decisions on unit dispatching, operating modes, pricing of power sales transactions, O&M budgeting, and long-term generation planning

Schedule

This is a three-year project, beginning in October, 1993, and ending in October, 1996. Within this length of time are the outage periods planned by DWP for scheduled inspection and repair of their L. A. Basin fossil units

Scope Of Work

To achieve the objectives of this project, the following seven tasks will be performed

- Task 1 Baseline Survey
- Task 2: Analysis and Assessment Methods
- Task 3 Unit Assessments and Testing
- Task 4 Cost and Reliability Algorithms

- Task 5 Cycling Assessment Tools
- Task 6 Cycling Decision Analysis Methods
- Task 7 Technology Transfer and Commercialization

The objectives and methods of these tasks are described below Progress has been made on Task 1 (Baseline Survey), Task 2 (Analysis and Assessment Methods) and Task 3 (Unit Assessments and Testing)

Task 1: Baseline Survey

Objective

To document the cycling modes of selected Department units and the basis for these modes, and to assess how DWP currently calculates its cycling costs.

Method

Eleven of DWP's Los Angeles Basin fossil units will be surveyed. Three representative units will be selected for detailed study. Supercritical and subcritical oil- and gas-fired units will be included. The selection criteria will be based on DWP's interest in the cost, remaining useful life and other effects of unit cycling, and on unit availability for inspections and condition assessments. Also, the operating modes (e.g., cycling) of the three units will be representative of those of the rest of the units in the Basin system At least one of the units selected will be one that has experienced the most severe cycling duty

The following data and information will be included in the survey report

- General description of the unit and its auxiliary components
- Nameplate information (boiler, turbine, and generator) and operating hours
- North American Electric Reliability Council/Generating Availability Data System (NERC/GADS) outage data
- Identification of the existing O&M databases at each plant
- Documentation of the types of cycling for the three units (e.g., hot starts, warm starts, cold starts, and low load operation)
- The key components' operating pressures, temperatures and ramp rates that occur during cycling as a function of time ("signature" data)
- A summary of the results of previous inspections and condition assessments
- Methods by which DWP calculates its unit O&M costs
- Current costs, benefits and operational reasons for cycling the units
- Types of data that the load dispatchers currently use for decision making and details on their needs for improved data and information on the total cost of cycling
- Mission statements for each of the three units

This report will define how each unit fits into DWP's generating and storage system as a whole, and will provide a basis for the rest of project's tasks

Progress

The net dependable system capability of the Los Angeles DWP, including out-of-L. A. Basin and in-Basin sources, is over 7,200 MW The twelve in-Basin fossil units represent an installed capacity of 3,200 MW To begin this task, DWP provided 1982 to 1993 NERC/GADS data in electronic format for the in-Basin units The process of reducing and analyzing these data began by ranking the forced outages by Cause Code. For example, the ranking for Haynes Generating Station, Unit 5, showed that only three components -- the furnace waterwall tubing (tube leaks), the feedwater pumps (breakdown) and the high pressure feedwater heaters (tube leaks) -- accounted for over 50 percent of the total forced outage hours These types of results were used to provide focus and guidance for the cycling condition assessments in Task 3

Next, data on generation history were obtained from dispatch personnel in the Energy Control Center (ECC) The first types of data received were nine years worth (7/84 through 11/93) of hourly generation (MW-hr) recordings in electronic format These data, which covered 13 units, were in a 14 megabyte file -- equivalent to 7,000 pages of numbers. We extracted global and cycling-related statistics on the operation of the units, including load changes and types of starts (cold, warm, hot) These data will be used to reveal how the plants were operated, specifically with respect to their cycling and operating limits. The ECC also provided, in both electronic format and hard copy, Daily Load Curves for their entire system for a typical year (1993). A follow-up visit was made to the ECC to meet the senior load dispatchers The main topics of discussion were how dispatch is done at present, and how the cost algorithms from the present project would be used by ECC

Continuing the search for information, boiler condition assessment reports and memos were identified and obtained. The turbine outage reports for all units were located and reviewed. The available records of the major maintenance activities on balance of plant equipment were examined

The above information, along with the units' outage schedules, were used to select the three candidate units for detailed scrutiny during the project. Unit 5 at the Haynes Generating Station in Long Beach was the first unit selected. It is a 367 MW unit with a supercritical Babcock & Wilcox boiler and a General Electric cross-compound, double-reheat turbine. It is representative of the group of three similar supercritical units in DWP's L. A. Basin system. The decision was made to perform a cycling condition assessment on Unit 5 during its outage in the Fall of 1994

The review of the data and information needed to complete this survey is continuing. The close cooperation of DWP was crucial in achieving our excellent start on this task.

Task 2: Analysis And Assessment Methods

Objective

To develop a customized cycling condition assessment method (one that focuses on the effects of cycling) and the engineering and cost analysis methods for identifying the incremental costs of cycling and changing operating limits.

Method

An Engineering Procedures Manual will be developed. It will contain the following information:

- Methods for assessing the damage accumulation and reliability impact on the critical equipment caused by cyclic operation
- Methods for assessing the impact of operating limit changes for 95% to 105% maximum continuous rating (MCR)
- Component damage calculation procedures
- A list of the critical equipment. This equipment will include those components which are currently known to cause major outages. As mentioned above, analysis of NERC/GADS outage data and review of major component outage contributors will assist in identifying the critical equipment.

The Engineering Procedures Manual will include descriptions of the following approaches for engineering analysis and wear and tear cost estimation

- Top-Down Approach — This approach uses historical trends for "sister" units (e.g., NERC/GADS outage database) to find the relation between availability and spending. It includes the opinions of experts in the field to determine the likelihood of failures of critical equipment and the impact of these failures on other equipment
- Bottom-Up Approach — Starts with the current expected life of critical equipment (obtained from a condition assessment), and then estimates the incremental decrease in equipment life or increase in EFOR caused by the proposed operating mode.
- Engineering Damage Models — Uses industry-accepted mathematical models for various anticipated damage mechanisms. Examples include creep-fatigue models and finite element models of critical components

Descriptions of how these approaches and models will be applied also will be included in the Engineering Procedures Manual

Progress

Progress was made on collecting and organizing key information on the methods for analyzing and assessing the economic impact of cycling and changing operating limits. Information on both industry-accepted and novel methods are being sought.

The types of information collected thus far have included the following:

- Critical equipment lists by type of plant
- Fossil plant condition assessment techniques
- Unit rating test methods
- Descriptions of mechanisms for component damage, life consumption and failure
- Mathematical models of the above mechanisms
- Existing EPRI and APTECH software for remaining life prediction
- Proposed cycling-related cost algorithms

The equipment covered thus far has included steam-cooled tubing, water-cooled tubing, high- and low-temperature headers, high energy piping, turbine/generator, feedwater system, fuel and air system, emissions system, and instrumentation and controls.

Information sources thus far have included the following:

- EPRI cycling guidelines and reports on relevant R&D projects
- Papers and reports on national and international experience with cycling
- Studies by DWP regarding system modifications for cycling
- APTECH's condition assessment experience and calibrated models for life prediction

Progress will continue on collecting and reviewing the body of information on existing cycling-related analysis and assessment methods. This information will be compiled into the Engineering Procedures Manual.

Task 3: Unit Assessments And Testing

Objective

To determine the current condition of critical equipment for the three selected units and determine the effect of unit operating limit and cyclic operation on future damage accumulation rates.

Method

Cycling condition assessments of the critical equipment, as determined by the critical equipment list developed in Task 2, will be done at each of the three selected units. Using EPRI and APTECH multi-level condition assessment techniques, the critical equipment will be evaluated to "baseline" their current condition and to determine the extent of past cycling-related damage

Following the prescribed nondestructive examinations (NDE), additional instrumentation will be installed to monitor equipment stresses and temperatures. Unit rating testing then will be performed to determine the operational impact of various cyclic operating modes on individual critical components. Testing is planned during startup, shutdown, on/off cycling and low load cycling as well as at 95%, 100%, and 105% of MCR. The resulting data will be used to forecast future costs associated with cyclic operation.

Progress

As mentioned above under Task 1, Unit 5 of the Haynes Station was selected as the first of the three units to undergo a cycling condition assessment. The assessment was performed during a November, 1993, to April, 1994, outage period. The results are summarized below.

Turbine APTECH turbine engineers visited Haynes Unit 5 to discuss the ongoing major overhaul of the turbine with personnel from the plant and the turbine manufacturer's representative. An inspection prior to overhaul had revealed blading damage and shell cracks. Interestingly, the manufacturer's representative attributed all of the damage to cycling duty. We subsequently requested the following items from the plant:

- Types and locations of existing monitoring instrumentation
- Strip chart data for turbine operating modes, including normal operation, cold starts, warm starts, hot starts, load following, and any abnormal shutdown. These data will allow us to optimize our selection of instrumentation for our damage monitoring activities.
- Samples of the blades that were removed from the rotor. The damage will be studied to see if it correlates with cycling operation.

We subsequently received ten turbine blades and one boiler feed pump blade from the Haynes plant. Our visual examination of the turbine blades revealed that damage to the first and seventh stage blades was caused by solid particle erosion (e.g., exfoliated scale from heat exchanger tubing), and that the dominant damage mode for the second stage blades was foreign object impact (e.g., metal particles from inside the turbine). Destructive testing of these blades was deemed not to be necessary at this time. The feed pump turbine blade exhibited severe pitting corrosion, which probably is due to exposure to oxygenated water droplets during downtimes.

In December, 1993, two APTECH metallurgists performed selected NDE (magnetic particle and replication) on the available components, which included the two (inner and outer) upper shells. Seven indications were found and examined. One of these was judged to be definitely cycling-related and still growing, and recommendations were made with regard to reinspection intervals and the possible need for repair in the future.

Boiler Tubing and Headers. Following a walkdown and planning meeting in December, 1993, the cycling condition assessment of Haynes Unit 5 boiler began in January, 1994. The assessment included visual inspections and nondestructive examinations of those components susceptible to cycling-related damage.

Accordingly, our examinations focused on the furnace waterwalls, superheaters, reheaters and economizer inlet header. On the furnace waterwalls, distortion (by one or two tube diameters) due to overheating was noted on many of the waterwall panels, particularly in the buckstay attachment areas. Because of tube leaks and corrosion fatigue damage, some of these walls had been replaced within just the last three years. Ultrasonic testing and videoprobe examinations were done to attempt to detect internal damage, such as corrosion fatigue-related axial cracking caused by thermal cycling. Metallurgical analysis of furnace waterwall tube samples revealed early indications of corrosion fatigue damage.

The examination of the economizer inlet header included external visual and internal videoprobe inspections. The videoprobe examination of both the inlet and outlet ends of the header revealed borehole cracking in both areas. This was judged to be thermal cycling-related.

Inspection of the tertiary superheater showed that the tubing alignment was generally good, but that some corrosion attack was occurring on the stainless steel tubing. Roof refractory was missing, probably due to thermal cycling.

The alignment of the pendant reheater sections was poor, and failed alignment clips were common. This is likely the result of cyclic operation and high temperatures.

In the penthouse, severe discoloration and exfoliation was noted on the tube stubs on the high temperature/low pressure reheat outlet headers. Ultrasonic testing was used to measure the thicknesses of the wall and internal oxide scale on the tube stubs. We found that most of the tube wall thicknesses were below the specified minimum. This is most likely due to by excessive temperatures, which caused both internal oxidation and external exfoliation. The suspicions of overheating were backed up by a review of plant thermocouple data. These data showed significant temperature excursions in the reheaters during load changes, especially during decreases in load.

In general, our examinations indicated that the current plant operating mode, including cycling, has taken a toll on the critical equipment in Unit 5. To learn more about how damage may be accumulating, the next step in the program was to install monitoring instrumentation The waterwalls were chosen to receive this instrumentation, due not only to their obviously damaged condition but also because waterwall leaks caused about 40 percent of the unit's forced outage hours over the previous 10 years.

Accordingly, an instrumentation plan was developed and the sensors were purchased. The sensors included three strain gauges, nine thermocouples, and three heat flux measuring devices. A PC-based data acquisition system (DAS) was also procured.

Under Aptech supervision, the sensors were installed by Department personnel. The sensors then were wired into the DAS computer. This computer was placed near the Haynes 5/6 control center Installation and check-out of the sensors and the DAS were completed before the initial start-up of Unit 5 on April 27, 1994. Acquisition of data began immediately. Currently, data are being continuously collected and automatically stored by the DAS computer Data files periodically are transferred by modem up to APTECH's headquarters in Sunnyvale, California.

Boiler Feedwater Heater. As mentioned above, our analysis of NERC/GADS outage data revealed that heater breakdown was one of the three leading causes of forced outages for Unit 5. To shed some light on this situation, we interviewed the plant's chemist and maintenance supervisor, examined tube failure records, and visually examined the most troublesome heater (6B). Since the unusually small tubing precluded the taking of samples for metallurgical testing, nondestructive testing was done to map the wall thicknesses of the tubes in the tube bundle. From these NDE data, we selected those tubes with wall losses of greater than 60% to be plugged. These tubes were plugged by DWP before the heater was sealed up.

Boiler Feed Pump. The NERC/GADS data also identified the boiler feed pump as being responsible for a significant number of the forced outage hours at Haynes 5 To get started on analyzing the situation, we spoke with personnel in General Services at DWP It appears that most of the maintenance problems were associated with the mechanical couplings Maintenance records going back 15 years are available They will be reviewed as this task continues.

High Energy Piping. Unit 5 has eight piping lines, five of which are high pressure/temperature systems. To begin the process of determining the effect of cycling operation on the piping, a preliminary cold walkdown was performed Many hangers were found to be in need of adjustment. Follow-up work will include a hot walkdown and stress analysis, as well as NDE at high-stress locations to evaluate potential in-service material degradation

Task 4: Cost And Reliability Algorithms

Objective

To develop and verify a set of prototype algorithms that will be used to calculate the total cost (and the effects on reliability) of cycling operation and of changing the operating limits for the three selected units.

Method

The key types of costs that comprise the total cost of cycling the three selected units will be delineated, and preliminary estimates of these costs will be provided.
During the project, these cost estimates will be improved by using feedback from the engineering condition assessments, review of past O&M expenditures, allocation of these past O&M expenditures to cycling related operations, and detailed cycling-related cost algorithms from other tasks. Prototype cost algorithms that will calculate the total cost of cycling will be developed and verified.

Task 5: Cycling Assessment Tools

Objective

Develop a comprehensive set of cycling impact tools to be used for future data collection, unit operating limit assessment, and cycling condition assessment of the units. These tools will be able to be upgraded and then applied to all of the system units

Method

The cycling assessment tools will be IBM-compatible PC-based software Three cycling assessment tools will be developed:

- Cycling Database System, which will provide a computerized "roadmap" for the utility to evaluate the damage and cost effects of cycling, methods of mitigating the harmful effects of cycling, and the benefits of cycling. The database will include the effects of cycling on critical power plant components and systems and on their reliability (e.g., cycles vs EFOR, cycles vs. heat rate, cycles vs. degradation, cycles vs. cost)
- Life Consumption Expert System, which will assess life consumption rates of selected components from the critical equipment list, caused by various cyclic operating modes and changes in unit operating limits. It will have built-in algorithms for evaluating the impact of damage and associated costs due to cycling.

- Cycling Advisor, which will be used to advise DWP of the least-cost cycling operating modes for the three selected units. The Cycling Advisor will be calibrated using Department-specific data to provide the optimum least-cost cycling operation regimen for the three selected Department units. It is anticipated that this would include optimum limits on the number of annual low-load and on/off unit cycles.

To enable utility personnel to enter and obtain needed information quickly and easily, the cycling assessment software will use interactive graphics and other features of a PC-based "hypermedia" product. The look and feel of the software will be similar to that in EPRI's State of the Art Power Plant (SOAPP) product.

Task 6: Cycling Decision Analysis Methods

Objective

To assist DWP in the integration of the incremental unit costs of lowering the operating limits and unit cost of cycling into DWP's economic unit generation models in order to produce an optimum least-cost generation planning tool.

Method

This task will demonstrate how to properly take the benefits and costs into account and how to more cost-effectively meet projected loads with a lower total system cost of power generation. Also, the expected errors in cycling cost estimates will be thoroughly investigated to quantify the effects of these errors on load dispatch and O&M decisions. The method will incorporate such factors as the mix of DWP's operating units and their operating modes (e.g., cycling vs. baseload), rates of maintenance expenditures and ratings.

Task 7: Technology Transfer and Commercialization

Objective

To consolidate the results of all tasks, transfer the technology to Department personnel, and write a commercialization plan for the products developed in this project.

Method

Develop training sessions that explain the benefits of a formalized approach to estimating the impact of cycling on fossil units. The hands-on training sessions will illustrate the use and application of the software products developed in this program. The target audience will include management personnel, operations personnel, maintenance personnel and planning staff

The commercialization plan will be based on an alliance between APTECH and EPRI and will include the following elements

- Specific product/performance characteristics
- Identification of potential users
- Market size estimates
- Target utility users
- Competitive technologies
- Date of market entry
- Key milestones
- Key participants
- Barriers to commercialization
- Related experience
- Costs to maintain and update codes

Future Activities

Near-term activities will include completing Tasks 1 and 2, and continuing the assessment of Haynes Unit 5 under Task 3. The Tasks 1's formal survey will concentrate, into one comprehensive document, the available historical information on how DWP's fossil units have been operated. In Task 2, the analysis and assessment methods appropriate for use in cycling cost projects will be compiled in the Engineering Procedures Manual. Under Task 3, the Haynes 5 waterwall monitoring data will be collected during everyday operation and during planned rating tests. These data will be reduced and analyzed with a view towards correlating them (and their associated operating modes) with damage accumulation.

Longer-term activities will include producing preliminary estimates of the total cost of cycling (based on the top-down approach), performing the cycling condition assessment and instrumentation of the second fossil unit, and preparing prototype software for the first of the cycling assessment tools, the Cycling Database System.

Conclusions

This paper briefly summarized the early progress on this R&D program, the objective of which is to quantify the "total" costs of cycling and changing operating limits. The first Task, the unit survey, will produce a useful planning tool both for our immediate use on this program and for DWP's engineers and dispatchers in the future. The Engineering Procedures Manual from Task 2 will be a valuable compilation of information on cycling-related engineering and economic analysis and assessment methods. Under Task 3, the experience gained during the condition assessment and instrumentation of the first unit, Haynes 5, will be used to calibrate the methods compiled in the Engineering Procedures Manual. This experience will guide the condition assessments of the next two units

We believe that our progress to date indicates that the development of a systematic approach to quantifying the total cost of cycling is an achievable goal. For utilities faced with the economic necessity of cycling or changing operating limits, the results of this R&D program will help them to cycle "smarter," and thereby achieve reliable and lower cost operation as an alternative to unit replacement.

Acknowledgments

The authors wish to acknowledge the contributions of the following people at the Department of Water and Power for providing the data and information needed for our unit survey, and for supporting the condition assessment and instrumentation of Haynes Unit 5

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- Ken Silver and Mark Ward -- Load Dispatching, PO&M Division
- Terry Brungard -- Station Engineer, Haynes Generating Station, PO&M Division
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- Jose Gutierrez -- Power Design and Construction Division

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