Methodlogy For Testing And Evaluating Power Plants Using Computer Simulators

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by

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presented at

**1990 Performance Software
User's Group Meeting,
May 1-4, St. Louis,**

sponsored by
EI International, Inc.

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INTRODUCTION

This paper discusses general methodology which has evolved at Exergetic Systems relative to performance evaluation of power plants. Summarized is the general approach, test conditions preferred, reduction of test data and calculational closures necessary to fully understand the thermodynamics of power plants. At the heart of the approach are computer programs capable of detailed boiler and turbine cycle simulations. Indeed, the principal reason for the creation of such simulators as EX-FOSS (boiler), EX-SITE (turbine cycle), PEPSE (turbine cycle) and THERM (turbine cycle) was to allow the performance engineer knowledge of how certain plant conditions can cause efficiency degradations. A full ASME acceptance test, or an In/Out test of high accuracy, can certainly provide unit heat rates with low variances. However, knowledge of the influences of individual components is inherently lacking, or as a minimum, not subject to scrutiny under a variety of operating conditions. However, the system simulators model components as individual subsystems, thus, given a match to local test conditions, will uniquely effect the total system allowing an assessment of their thermal influences.

The essence of the testing methodology is to describe the turbine cycle's individual processes such that key measurements are matched, combine the resultant cycle heat rate with a calculated boiler efficiency and (when available) compare to measured plant efficiency and fuel flow rate. If comparison is had, then although there could be uncertainty in individual degradations, assurance is had that the combination of descriptive boiler combustion process, boiler thermal losses, HP turbine, IP turbine, LP turbine, numerous leakage paths and heat exchanger thermal performances produce the observed effects from the overall unit.

SUMMARY OF METHODOLOGY

To clarify the methods developed by Exergetic Systems, the following sequential steps are presented. These steps are individually important. The steps have been developed over five years and represent the acquired learning from numerous testing projects which involve both the boiler and turbine cycle.

1) PREPARATION OF TURBINE CYCLE SIMULATION

A turbine cycle simulation is prepared using individual design bases for the various components. Note that individual component designs are used as opposed to "standard" Thermal Kit assumptions. It is recognized that equipment vendor assumptions can conflict with those made by the main turbine manufacturer when he constructs Thermal Kits. However, they do reflect the best intent of all manufacturers who supply equipment to the plant, and are judged most appropriate for a design base. Reference to Appendix A should be made for a detailed discussion of the recommended philosophy applicable to simulations.

2) DESIGN SIMULATIONS

A simulation of the turbine cycle is made at Valves-Wide-Open (VWO). This simulation should be compared to the design base at VWO <u>only to confirm reasonable agreement with vendor design performances for individual equipment</u>. Generally, only the shape of the turbine expansion line is compared to the Thermal Kit, the feedwater temperature profile is compared to A/E assumptions, the power and flow consumed by the auxiliary turbine is compared, etc. Heat rate comparisons to Thermal Kit values are not relevant!! As appropriate, the model is then altered to demonstrate reasonable agreement at part-load conditions to available vendor data.

3) SYSTEMS EFFECTS TEST

A "systems effects" test is conducted at a valve point for the purpose of understanding generic degradations (HP/IP or LP turbines, HP or LP heaters). It is strongly believed that typical PTC 4.1 & 6 instrumentation is not warranted for performance evaluations, but rather one based on the philosophy that <u>any</u> measurement must be accompanied with its variance and that only key measurements need be taken. With few exceptions all data taken is backed with a second source instrument. A heat balance program capable of integrating turbine expansion characteristics with heater energy demands will, of course, provide consistent flow and state data around every modeled subsystem. Typically, if a turbine is uniformly degraded, all extraction pressures will be consistently modeled if the degraded wheel efficiency is correctly described. For example, if the LP bowl pressure is matched (say within 1 psi) the flow through (or around) the HP & IP turbines must be adequately described (typically to within 10,000 to 15,000 lbm/hr of the true flow inlet to the LP). Reference should be made to Figure 1 for recommended instrumentation for the boiler, applicable for systems effects testing. Figure 2 presents instrumentation for the turbine cycle systems effects testing. Appendix B contains a sample plant isolation list used for a typical systems effects test.

4) SIMULATION OF SYSTEMS EFFECTS TEST

Next, the turbine cycle simulator is reconfigured to model actual equipment configurations found at the time of systems effects test. The simulation is then input with only as-tested boundary conditions. Individual components are then degraded to reflect the as-tested system response. This process leads to a computer model whose deviations from original design are understood - indeed, forced understanding is had! In detail, this generally involves the following: turbine degradations, degradation to the inlet nozzles of turbine cylinders, use of actual extraction line pressure drops, use of the actual reheater pressure drop, auxiliary turbine performance, TTDs and DCAs. Simulations are not made using the GE "calculational procedure," but one employing the turbine state lines from the Thermal Kit (at a valve point) nearest the tested feedwater flow. The ideal is to test at VWO. Also, it is critical to note that a minimum of test data is used as computer input. As with all simulations, the simulation of the systems effects test does not employ "test points" - all degradations are described from a first principles bases where applicable, forcing an understanding of the individual degradations.

5) SENSITIVITY OF SIMULATION TO FLOWS

Accurate feedwater flow measurement is, of course, of critical importance. Also, the turbine seal flows must be resolved to a reasonable degree. It is important to preform a flow balance on the low pressure side of the seal system, to confirm the reasonableness of the data. Both the feedwater flow and turbine seal flows will effect heater energy balances, thus calculated extraction flows, thus turbine state lines. Frequently, sensitivity studies are required on feedwater flow to obtain a match of gross electrical generation, turbine stage group bowl pressures, etc. Although the instrumentation may be sparse, it is the single systems effects test whose simulation is continually refined throughout the project.

6) COMPONENT SPECIFIC TESTS AND MATCH OF DATA

Refinement of the system simulation comes through "component specific" tests. These tests are designed to well define those areas which degradations are believed present. It is of critical importance, at this point in the process, that the systems effects simulation be well matched to test data given continuing input from component specific tests, degradation of equipment, sensitivity studies, etc. Frequently, such system understanding is achieved <u>without</u> use of full system simulations but rather through hand calculations, talks with equipment vendors, and via First and Second Law analyses techniques (the programs EX-PROP, EX-AIR and FLOWPASS are quite useful). Note, rarely is the LP expansion line adjusted to match power. The LP could be degraded <u>only</u> if systems (or component) testing so indicates (i.e., pressure ratios, unusual stratification effects, etc.). The emphasize of the methodology is to force understanding of individual subsystems before the whole is examined.

7) BOILER ANALYSIS

Next, the boiler is analyzed using the EX-FOSS program using boiler data obtained during the systems effects test (stack temperature, stack concentrations, fuel analysis, air conditions and data associated with non-stack losses). Input to EX-FOSS associated with the turbine cycle <u>is obtained directly from the turbine cycle simulators</u>, no interpretation is made as to consistency with test data (throttle & final feedwater conditions, and cold & hot reheat conditions). The turbine cycle simulation should have achieved close agreement with test conditions, but any errors must propagate through the procedure. EX-FOSS divides boiler efficiency into a combustion efficiency and one involving non-stack losses. Knowledge of each of these terms allows one to address unique areas in the boiler for recovery of efficiency. The PTC 4.1 efficiency is the product of the EX-FOSS's combustion efficiency (relates to stack losses) and absorption efficiency (related to non-stack losses).

8) CALCULATIONAL CLOSURE

When the turbine cycle heat rate, as calculated by a heat balance program, is combined with the calculated boiler efficiency the result should agree with the measured heat rate, if available via the In/Out Method. Significantly, EX-FOSS methodology employs a unity fuel flow rate in computing overall boiler efficiency. As such, the fuel flow rate is then back-calculated consistent with the energy flow deposition to the working fluid from the combustion gas. Thus the fuel flow rate, as back-calculated, is compared to the measured, if available. This process of unit heat rate and fuel flow rate comparisons is termed calculational closure, discussed in more detail in the following section.

9) REGRADING THE SYSTEM

The last process is to simply "regrade" the turbine cycle simulation from the as-tested condition back to the design point. By selectively regrading individual components, direct measure of their unique heat rate deviations is achieved. The analyst has assurance that the net difference between the as-tested simulation and the design point is a valid summation of the differential heat rate. This difference is composed of both recoverable and non-recoverable heat rate. The turbine cycle simulations should be conducted using constant power assumptions, thus feedwater flow is allowed to vary. The simulations should proceed from the LP-end of the system towards the control valve. An abbreviated, but typical listing of sensitivity studies is given in by the following:

Condenser Pressure Regraded to Anticipated
Condenser Pressure from Anticipated to Design
LP Turbine Efficiency
LP Flow Passing Ability (nozzles regraded, rare)
LP Turbine Seals
LP Heaters
LP Extraction $\Delta P/P$
IP-LP $\Delta P/P$
IP Turbine Efficiency
IP Flow Passing Ability (nozzles regraded)
IP Turbine Seals
Hot Reheat Temperature
Hot Reheat Sprays
Heaters Extracting from IP Turbine
IP Extraction $\Delta P/P$
Auxiliary Turbine $\Delta P/P$
Auxiliary Turbine Efficiency
Boiler Feed Pump Efficiency (assuming design flow)
IV & Stop Valve $\Delta P/P$

Reheater $\Delta P/P$
GS W/V_O Ratio to Design
HP Turbine Efficiency
GS Flow Passing Ability (if possible in simulator)
HP Flow Passing Ability (if possible in simulator)
Low Pressure HP Turbine Seals
High Pressure, Inner, HP Turbine Seals
GS N2 or Dummy Seal
Miscellaneous System Leakages
Heaters Extracting from HP Turbine
HP Extraction $\Delta P/P$
Throttle Pressure to Design
Throttle Temperature to Design
Feedwater Flow to Design (w/constant generation)

Generally these studies will comprise over 40 cases. This process is continued such that, after the last case, the original turbine vendor thermal kit is again matched (to demonstrate validity of the sensitivity analyses). After the turbine cycle is completed, the boiler simulation is then regraded to design. Specifically, the boiler excess air, air pre-heater leakage, stack temperature, and radiation & convection losses are typically studied for recoverable heat rate.

Figure 1:

Boiler Instrumentation

for Systems Effects Testing

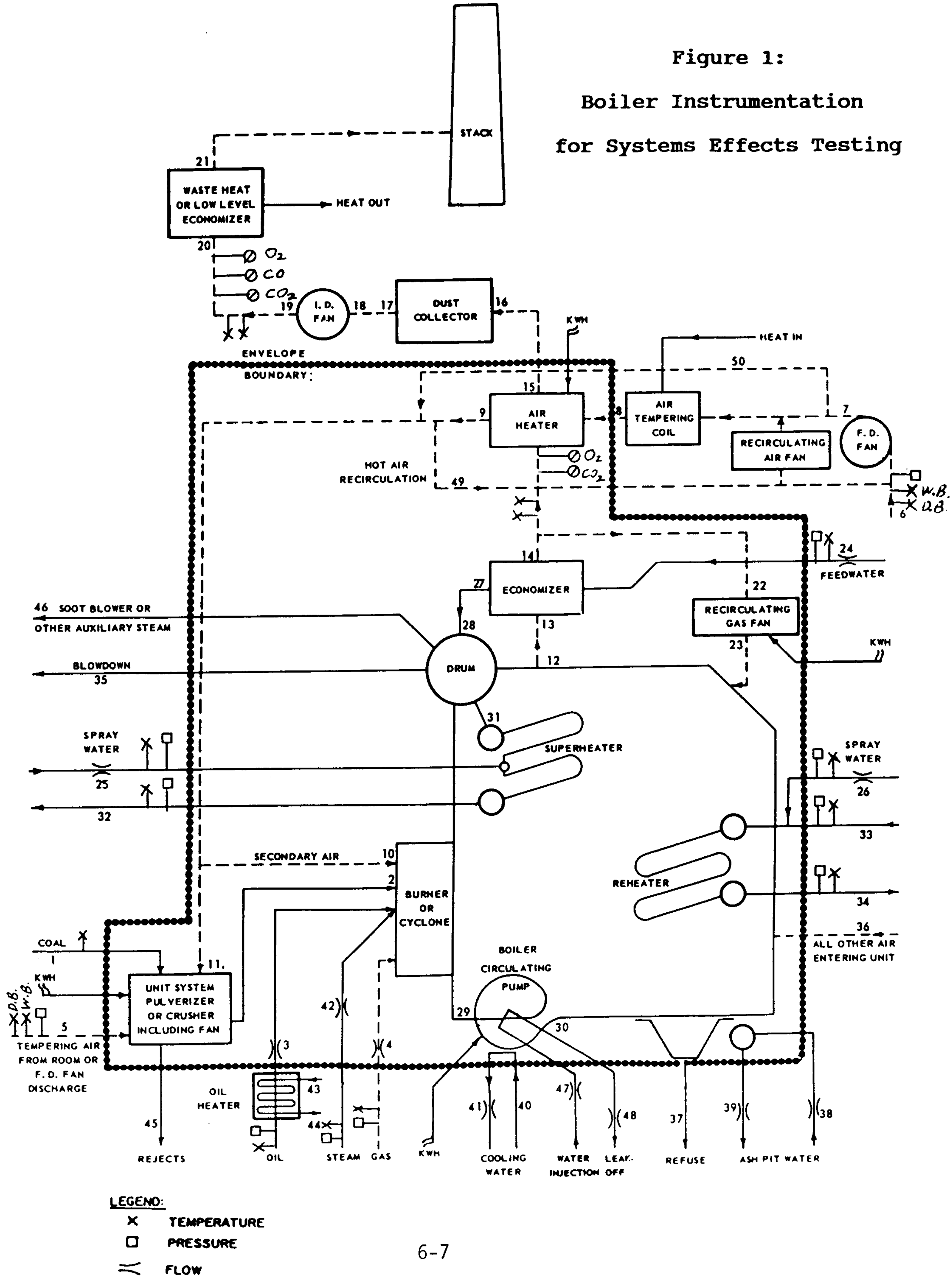
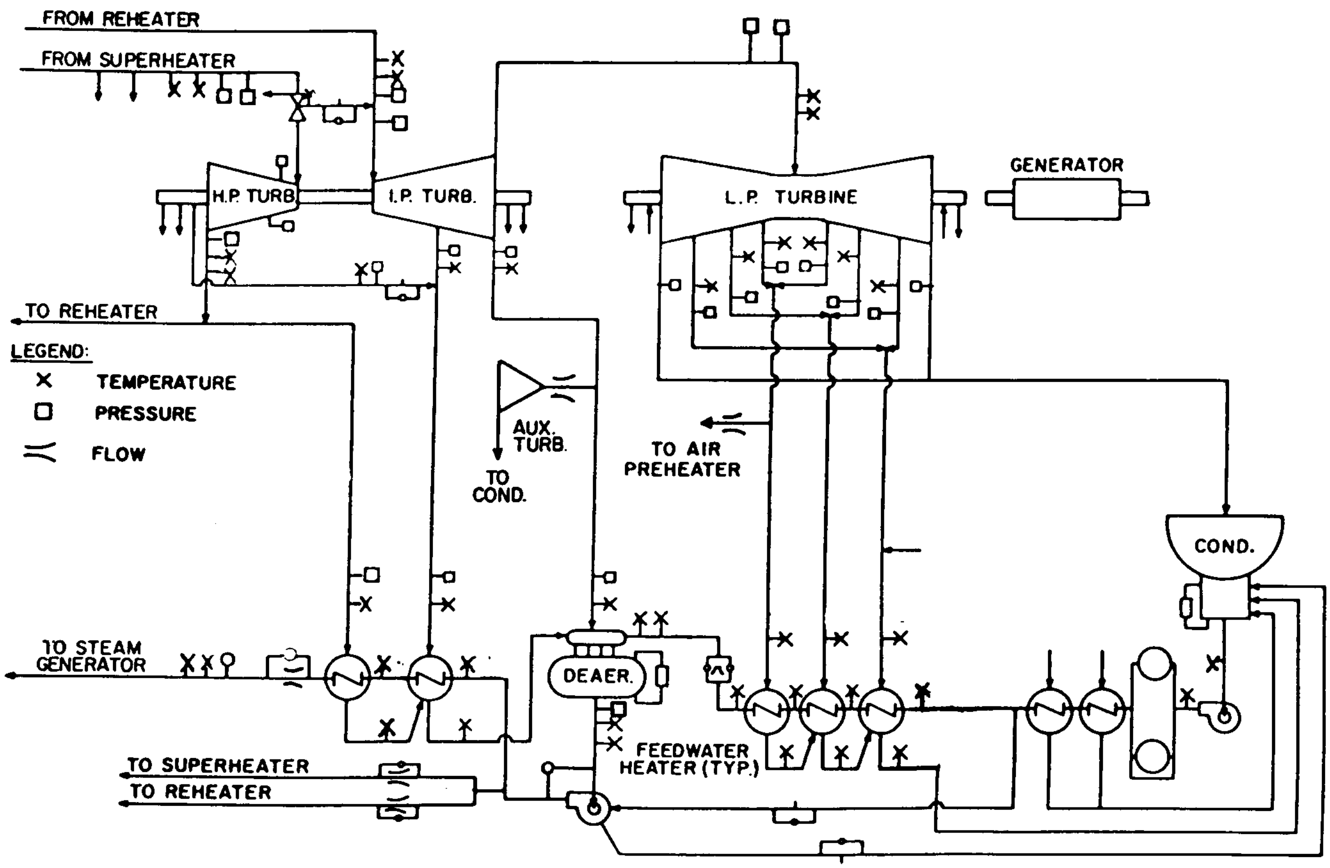


Figure 2:

Turbine Cycle Instrumentation for Systems Effects Testing



SUMMARY OF CALCULATIONAL CLOSURE

Calculational closure is testing's raison d'etrè. Without a mechanism which assures that simulations of the as-tested agree with global plant findings (gross unit heat rate and total fuel energy flow), testing offers nothing of value. Yes, tests are performed for regulatory purposes, and to make paper, and for dispatch curves, and because "it was done in the past". However, for a performance engineer, the only constructive reason testing is conducted is for improvement of the plant. Global findings have no value unless the analyst understands how a degraded heat rate and/or high fuel flow can be corrected. If subsystems within a power plant are understood, then, and only then, are global findings validated. Only through the understanding of subsystems can one then understand the means through which problems can be corrected. One must approach performance engineering from a viewpoint of forcing thermodynamic understanding, the mechanism for such understanding is calculational closure of the system.

The following summarizes the calculational closure procedure. First, the boiler efficiency is calculated by dividing its definition into two components, a combustion efficiency and boiler absorption efficiency. The details of this process are quite involved and embedded in the EX-FOSS program; the principles, however, are universal and described below.

$$\eta_B = \eta_C \, \eta_A \qquad (1)$$

The combustion efficiency is defined by terms which are independent of fuel flow:

$$\eta_C = \frac{HPR - HRX}{HHVP + HHBC} \qquad (2)$$

where HPR and HRX are the enthalpy of combustion products and reactants, HHVP is the higher heating value and HHBC is a term related to boiler energy credits. Note: HPR - HRX = Energy Released during Combustion (ERC). The boiler absorption efficiency is related to the boiler's non-stack losses and defined such that it, through iterative techniques, can be computed independent of fuel flow. The boiler absorption efficiency is evaluated as:

$$\eta_A = 1.0 - \frac{HNSL}{HPR + HRX} \qquad (3)$$

where HNSL are the non-stack losses based on unity fuel flow.

After computing the overall boiler efficiency, η_B, the as-fired fuel flow rate, m_{AF}, can be calculated based on the more conventional definition of efficiency:

$$\eta_B = \frac{BBTC}{m_{AF}HHVP + m_{AF}HHBC} \qquad (4)$$

or:

$$m_{AF} = \frac{BBTC}{\eta_B(HHVP + HHBC)} \qquad (5)$$

where BBTC is the "Useful Heat Delivered from Boiler" (where BBTC = ERC - m_{AF}HNSL, affording consistency). Note that the definition of overall boiler efficiency, comprised of η_C and η_A, and that defined by Eq.(4), are <u>identically equal to the definition presented in Power Test Code 4.1</u>.

The result of Eq.(5) is compared to the measured fuel flow rate. If they do not agree, a mis-understanding of the energy flow to the turbine cycle (BBTC) and/or the distribution of cycle mass flows (effecting reheat, thus BBTC) and/or errors in heating value (HHVP) has been made - and further study and testing would be required. EX-FOSS computes an encompassing variance in the combustion and absorption efficiencies, thus the error associated with η_B is generally well defined.

The gross unit heat rate (HR) is, of course, computed as follows:

$$HR = (m_{AF}HHVP + m_{AF}HHBC) \; / \; \text{Gross Power} \qquad (6)$$

For the "as-tested" heat rate, fuel flow, heating value and gross power are obtained from the systems effects test. For the computed value of heat rate, the power and fuel flow are directly determined from the computer simulators. Boiler energy credits are computed or estimated, but generally taken as zero. The result of Eq.(6), based on simulated results, is compared to the heat rate based on as-test results. If they do not agree a mis-understanding of the overall system has been made - and again further study and testing would be required.

RESULTS OF TESTING

Exergetic Systems has been the responsible organization for conducting detailed performance evaluations of ten+ power plants over a five year period. These efforts are equivalent in terms of utility committment to full ASME PTC 4.1 & 6 tests, i.e., projects generally lasting from 3 to 9 months. In almost all cases, these projects are used by utility management as the needed impetus to upgrade in-house performance engineering skills. In numerous cases, the station has chosen to upgrade instrumentation at the time of testing, including computer data acquisition. However, other utilities have chosen to move rented instrumentation from locations required for systems effects testing to locations required for component testing. Many cases have involved data acquisition via hand recording. **In all cases, no test is conducted without the responsible plant and Exergetic Systems engineer witnessing the test.** The engineer will always gain an insight, a visceral comprehension of the system by being there, comprehension which should be factored into the analysis.

These tests do not acquire the typical expenses associated with PTC 4.1 & 6; un-needed instrumentation, unbridled corporate manpower and the use of nonsensical equipment acceptance procedures are not employed. Generally, the power stations have spent one-half to one-quarter of that required by a turbine vendor to perform only the PTC 6 test. The turbine vendor does not provide results which address system closure nor individual component regradation.

An example of typical results is presented in Appendix C. This document is the first portion of a typical Performance Evaluation Report from the ML7A testing. The second portion of these reports contain detailed component engineering. This document illustrates the applications of all important aspects of the methodology and should be reviewed. Also, it is noteworthy that a major overhaul was conducted between the end of the testing and before the performance report was delivered, thus comments were made following the individual findings (in italics) as to actual equipment conditions based on physical inspection.

Testing results for ten+ units are presented in Table 1. Individual results and diagnostic findings are discussed below. With any testing the treatment of variances must be considered. Variances on the fuel flow error, of Table 1, were computed as the larger of either the measurement variance (generally), or the error in the calculated boiler absorption efficiency (for units OB1, MB3 and MB4). Variances in the heat rate are computed as the square root of the sum of the squared individual variances for the following: the variance determined by EX-FOSS for the overall boiler efficiency and the error in the turbine cycle heat rate. The boiler variance is the straight sum of the variances in the combustion efficiency (computed internally by EX-FOSS), and the absorption efficiency (generally the compliment of this efficiency is used, for conservatism). For the turbine cycle, when excellent agreement is had between test data and the simulation, the variance is generally judged to be $\pm$40 Btu/kWh, otherwise it is estimated higher. Given close match of boundary condition pressures and temperatures, resolution of water inventory to $\pm$0.25%, a match of the calculated generation to the measured, confirmation of the feedwater temperature profile to the as-tested, and the choice of <u>system</u> flows which match steam path conditions (especially at the LP bowl), a total of $\pm$40 Btu/kWh error or $\approx$0.40% is deemed conservative.

OB1 This unit was tested quickly, without developed methodology. The low indicated convergence to indicated heat rate is considered luck, its high variance was not acceptable.

PP7 This unit was tested twice (PP7A & PP7B). Before it was first tested the turbine vendor believed high power loss was caused by low feedwater flow, compounded by low reheat temperature. Systems studies (using the THERM program) indicated gross leakage through and around the HP cylinder, cross-flange leakage was considered most likely. The 1985 fuel flow measurement was in doubt and was the primary source of the high variance in the heat rate error. The high heat rate error was considered "acceptable" in light of great uncertainty in the HP turbine leakage, versus possible errors in the feedwater flow measurement. In 1986 the unit was overhauled. Cross-flange leakage was confirmed, leakage from HP drain valves was confirmed (valves placed backwards), miscellaneous leakages as-reported were repaired, etc. The 1987 test proved recovery of 36.66 MWe (using the PEPSE program), and validated much of the 1985 assumptions. The 1987 project determined that 24.51 MWe could still be recovered, this compared to the remaining recoverable power of 28.92 MWe as based on the 1985 work. This is outstanding agreement given two years of methods refinement and use of different programs.

ES3 This unit represents a classical example of what can go right in performance testing. Only one systems effects test was required, using hand recorded data (no component tests). Given outstanding agreement with system simulators, and essentially no error from the boiler analysis, the analysis was able to predict boiler casing heat losses of approximately 3%. These losses were later confirmed via infrared thermography.

MO1 MO2 These units are coal-fired supercritical systems operating in a warm environment, they employ a cycle with six feedwater heaters. Both units are operated with extreme system flows. This has aggravated degradation of numerous component systems (eroded auxiliary turbine nozzles, broken LP buckets, pump degradation, etc.). Basic recommendations centered on realizable effects from high condenser pressure, high system flows, and the impact of high energy turbine seal flow entering the low pressure heater. An attempt was made to superheat the LP turbine exhaust (failed due to poor thermocouple locations). Predications of turbine nozzle areas were confirmed during the overhaul of MO2.

PP6 This unit is a unique design using two shaft driven pumps from the HP-LP and IP-LP shafts. Testing revealed high N2 package leakage and anomalies with the feedwater train (as with most studies over three dozen recommendations for heat rate and/or power production were made).

ML7 This unit was tested twice (ML7A & ML7B). As a supercritical unit it is unique in its use of a "flash tank" system which allows operation at low loads, while still sustaining minimum flow through the boiler. In 1987 the unit was tested: findings indicated high leakage through the flash tank system, HP turbine degradation, and, surprisingly, degradation of the LP nozzles. Such nozzle degradation is rare (relatively low steam velocities, boiler depositions platting out in the IP, etc.). Accurate turbine cycle simulations with numerous component tests helped convince that the LP nozzles were degraded. Given the HP turbine's response, it was reported that the Speed Match Valve was leaking, causing erosion of the LP nozzles during startup. This was confirmed.

MB3 MB4 These sister units tested well, except for great uncertainty in the indicated feedwater flows. It was reported the indicated flows could be in error by ≈2%, with inconsistencies in the BFP flow meters of ≈16%. This situation forced a sensitivity study of the impact of errors in any turbine cycle simulation, as carried through to the boiler simulation and to the calculated gross heat rate and fuel flow. Work resulted in identifying why MB4 had a historical 100 to 150 Btu/kWh penalty relative to MB3.

RB8 Work on this unit is in progress. The project involves characterizing the LP turbine via systems effects testing and superheating the LP exhaust (main and auxiliary circulatory water flows are monitored, basket tips are instrumented with thermocouples, etc., etc.). Work should be completed in September 1990.

Table 1:

Results of Thermal Performance Evaluations

Unit	Date of Sys.Eff. Test	Design	Fuel	As-Tested Power, MWe	Error in Fuel Flow, %	Error in Heat Rate, ΔBtu/kWh	Recoverable Heat Rate, ΔBtu/kWh	Recoverable Power, ΔMWe
OB1	11/16/84	3515/ 1000	Gas	806.80	(unknown)	-23 ±150	approx. 400	N.A.
PP7A	5/07/85	3515/ 1000	Gas	687.41	(unknown)	-116 ±205	421	65.58
ES3	1/13/86	2415/ 1050	Gas	316.40	-0.067 ±0.267	+1 ±57	360	10.80
MO2	6/27/86	3515/ 1000	Coal	824.09	(unknown)	? ±75	458	0.00
PP6	10/24/86	2415/ 1000	Gas	329.60	+0.003 ±0.961	-14 ±59	223	13.39
PP7B	5/29/87	3515/ 1000	Gas	724.07	+0.005 ±0.250	-2 ±89	236	24.51
ML7A	7/15/87	3690/ 1000	Gas	728.29	+0.789 ±0.464	+32 ±126	511	24.99
MO1	5/04/88	3515/ 1000	Coal	804.97	(unknown)	? ±87	268	17.90
ML7B	9/08/88	3690/ 1000	Gas	738.44	-0.028 ±1.000	+9 ±116	237	3.92
MB3	10/21/88	2415/ 1050	Gas	343.83	-0.560 ±0.200	+7 ±70	273	0.00
MB4	9/21/89	2415/ 1050	Gas	343.60	+0.004 ±0.414	+22 ±72	340	0.00

APPENDIX A:

PHILOSOPHY OF TURBINE CYCLE SIMULATIONS

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PHILOSOPHY OF TURBINE CYCLE SIMULATIONS

The following presents both a statement of philosophy as to how computer simulations of turbine cycles should be prepared, and the details of how such preparations are accomplished. It is presented in a generic manner. This philosophy was first formalized in July 1986, although employed in various stages since 1984. Since 1986 it has become the standard for all turbine cycle simulations performed by Exergetic Systems, when used in performance testing and evaluations. The result of the turbine cycle preparations, discussed herein, is a "design base" simulation from which the as-tested simulation follows. But first, some comments on style.

The user of EX-SITE, THERM and PEPSE should be cautioned to never prostitute natural engineering insight to such devices. It is the nature of turbine cycle engineering that true insight into equipment, acting within a system in coterminous response with the heat source, is of paramount import. If the user does not relegate this insight, this visceral comprehension, beneath an idolatry of computer output he will learn to accurately predict and to judiciously modify with the assistance of such programs, those things on which power production is physically dependent. Applying this philosophy will result in minimizing computer analyses, it will cause increased plant visits by the responsible analyst and will foster contacts with responsible vendor engineers. If this philosophy is alien it is strongly advised to not employ computer simulations.

To summarize the preparations of turbine cycle simulations, individual component design bases are used for all system design studies as opposed to "standard" Thermal Kit assumptions. It is recognized that equipment vendor assumptions can conflict with those made for the Thermal Kits. However, they do reflect the best intent of all manufacturers who supply equipment to the plant, and are judged most appropriate for a design base. The following paragraphs presents the details of now the design bases are prepared and implemented:

1) Establish a simulation geometry which reflects a combination of the design (i.e., clean) conditions and the actual plant configuration with anticipated leakage paths. <u>All geometries should reflect the present piping & equipment configuration (as modified from the</u>

original). "Design" is meant what the plant could do if equipment installed at the plant functioned as individually intended by the various vendors. "Actual" is meant how the plant must operate given an as-tested situation, environmental constraints, operational constraints, etc. For example, spill lines from heaters, boiler feed pump seal flows, flows to the Gland Steam Exhauster from the LP side of the turbine shaft seals, bell & piston seal leakage, etc. should all be modeled. Use of appropriate "zero" flows will alter the simulation as needed for either a design base calculation or an as-tested calculation.

2) Use the turbine vendor's Thermal Kit information to establish the flow passing ability of the various stage groups of the main turbines. Although extraction pressure drops, auxiliary turbine flows (if applicable) and other system differences will affect an exact matching of the turbine vendor's heat balances, the turbine vendor's flow passing ability will be matched.

3) Use "ideal" pressure drops for the reheater and all extraction lines. This implies using calculated data from design methods. Such a calculational procedure will afford consistency of results and can establish a standard for future methods improvement. Obviously, engineering judgement should be applied when setting pressure drops for a system simulation. Special care should be used for the reheater pressure drop.

4) Use pump vendor curves for head and efficiency as a function of flow rate for the boiler feed and boiler feed booster pumps (as applicable). The design speed of the pump should be used even if a conflict exists with the design speed of the auxiliary turbine (in all cases the turbine's flow from the steam path has priority. However, demand flow to an auxiliary turbine is normally not a strong function of speed).

5) Use the feedwater heater vendor's TTDs and DCAs as a function of feedwater flow rate. Note that many times this data will conflict with the turbine vendor's Thermal Kit assumptions.

6) Use design assumptions provided as to steam line and final feedwater conditions, system leakage rates and environmental conditions.

7) For the main turbines, use design assumptions for condenser pressure if studying only full load operation. If needed for partial load studies establish a "design curve" of ideal condenser operation

as a function of load and environmental conditions. Establish similar data for the auxiliary turbine, if applicable (note that there is often conflict as to what design auxiliary turbine exhaust pressure is, i.e., between the auxiliary turbine vendor and the main turbine vendor).

8) If applicable, establish from the auxiliary turbine vendor's design data, curves which relate turbine efficiency, speed, first stage pressure and power to turbine steam flow.

9) If applicable, establish design curves for hydraulic couplings, used between the main turbine shaft and the boiler feed pumps, as to power losses as a function of speed, etc.

10) In general, schedules should be established as a function of feedwater flow, etc., to allow the simulations to track the lower power levels.

APPENDIX B:

ISOLATION PROCEDURES FOR TESTING

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Methodology developed to evaluate power plants is focused on finding correctable problems <u>relative</u> to typical operational conditions. Isolating procedures should only secure the system from all inflows of fluid (e.g., auxiliary boiler steam, sister unit cross-ties, etc.). System leakages should be resolved within 0.25% of feedwater flow, as confirmed via condenser hot well drop test. Such water inventory tests are preformed just prior to the planned systems effects test. If leakages are greater than 0.25% of feedwater flow, corrections should be made before the principal test. The procedures involved in isolating a power plant system are divided into three categories: Class A, B and C. These categories have been found to be of great clarity for plant personnel. The following isolation form is taken from a typical test for a subcritical 330 MWe unit.

ISOLATION LIST FOR SYSTEMS EFFECT TEST

Engineering Checklist Approval ______________________ Date ________

Maintenance Checklist Approval ______________________ Date ________

Operations Checklist Approval ______________________ Date ________

This Isolation List is divided into three Classes of valves and/or pipes:

<u>Class A</u> lists valves which should be closed, or confirmed closed, by the start of the test day, and should remain closed until the end of the test (then returned to normal operation);

<u>Class B</u> lists valves which should be closed shortly before the start of the test run and then opened immediately after the test; and

<u>Class C</u> lists runs of piping for which the surface temperatures are required during the test for indication of flow and the recording of certain liquid levels (i.e., which will generally confirm isolation)

All valves closed/opened by operations, confirmed closed, pipe surface temperatures and liquid levels recorded shall bear the initials, time and date of the technician directly responsible.

CLASS A

Valves which should be closed, or confirmed closed, by the start of the test day, and remain closed until the end of the tests (then returned to normal operation).

	CLOSED	BY	TIME/DATE
Isolate the evaporator cross tie with Units 1 & 2 (55700, 80-A).			
Isolate the feedwater cross tie between Units 3 & 4 (55700, 122-A).			
Isolate the feedwater cross tie between Units 1 &/or 2 and Units 3 & 4 (55700, 122-A).			
Chemical injection stop valves at drum and at the BFP discharge.			
Condensate emergency dump to the discharge tunnel (55700, 25-A).			
Economizer recirculation isolation on the inlet header: two valves on one end, one on the other, plus PX 158.			
Drain line isolation valve on line 3K30 (55707, 47-C).			
Isolate IP turbine loop drains.			
Isolate HP cylinder drains on line 3S7 (55707, 15-E).			
Reheater fill line isolation and drain valves on line 3H146 (55707, 5-C).			
Isolate HP steam chest restart on line 3W4 (55707, 5-J).			
Heater #1 bypass.			

	CLOSED	BY	TIME/DATE
Heater #2 bypass.			
Heater #3 bypass.			
Heater #4 bypass.			
Heater #5, #6 & #7 bypass.			

CLASS B

Valves which should be closed shortly before the start of the test run and then opened immediately after the test.

	CLOSED	BY	TIME/DATE
Distilled water tank (Makeup/Rejection) line to hot well (12" line) LCV-28 and LCV-8.			
Isolate sea water evaporator system.			
Isolate the auxiliary steam system to/from all other Units.			

CLASS C

Checklist C lists runs of piping for which the surface temperatures are required during the test for indication of flow and the recording of certain liquid levels (i.e., which will generally confirm isolation).

	TEMPERATURE	BY	TIME/DATE
Heater #1 bypass.			
Heater #2 bypass.			
Heater #3 bypass.			
Heater #4 bypass.			
Heater #5, #6 & #7 bypass.			
Steam trap header & IP drains at condenser, line 3R38 (55700, 37-G).			
Misc. turbine drains at condenser on line 3R-37 (55700, 37-G).			
Gland steam controller spills to the condenser on line 3S8 (55700, 39-J).			
Reheat drain at condenser on line 3H65 (55700, 40-L).			
IP turbine loop drains (55707, 16-E).			
Boiler drain lines on the final superheater inlet & outlet headers.			
Boiler drain lines on the reheater inlet & outlet headers.			
Drain lines from IP extraction #4 on line 3K30 (55707, 47-C).			
Drain lines from the attemperator on the gland steam controller on line 3H152 (55707, 39/46-C).			
Drain line from the gland steam controller on line 3W16 (55707, 33-C).			

APPENDIX C:

SUMMARY OF THERMAL PERFORMANCE

EVALUATION REPORT (Example)

	TEMPERATURE	BY	TIME/DATE
Hot reheat drain lines 3H65 (55707, 60-J).			
HP cylinder drain line 3S7 (55707, 15-E).			
Throttle valve drain lines 3S6 (55707, 15-E).			
Main steam line drains before the building drain connection (55707, 24-H and 5-H).			
Hot restart line to boiler relief valve mufflers, see line 3R29 (55707, 24-D).			
Steam trap header line 3K49 (55707, 47-B).			

	LEVEL	BY	TIME/DATE
Surge tank level; record level every 30 minutes during test.			
Hot well level; record level every 15 minutes during test.			

FINAL REPORT

Thermal Performance Evaluation of

[redacted]

ML7A

by:

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August 1987
Revised January 20, 1988

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1/22/88

EXERGETIC SYSTEMS INC PERFORMANCE ENGINEERING

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PART ONE

FINAL SUMMARY REPORT:

Thermal Performance Evaluation of

[redacted]

EXERGETIC SYSTEMS INC PERFORMANCE ENGINEERING

I. Summary of Project

[redacted] contracted with Exergetic Systems for study of the [redacted] power plant with the objective of understanding equipment thermal performance and methods to improve performance. The testing and analyses work was formerly initiated by Exergetic Systems in November 1986 and concluded, via this report, in early November 1987. Initial testing was scheduled for November 1986 with the final report due January 1987. The initial instrumentation reviews and set-up of system simulations was started in August 1986. However, due to delays, this report is based on the principal testing efforts of July and August 1987; thus, the report is officially dated August 1987.

Work performed consisted of:

- Setting up, debugging and benchmarking to the standards established for the [redacted] a PEPSE computer simulation of the [redacted] turbine cycle (much of this work was performed by [redacted] summer 1986, with some direction from Exergetic Systems).
- Input data preparation and numerous sensitivity studies with the EX-FOSS program for boiler performance evaluation.
- The preparation of a PEPSE model of Unit 7's steam generator, based on EX-FOSS analysis, for complete integration of the boiler and turbine cycles.
- Review of instrumentation, test procedures and operational practices.
- Preparation of test recommendations and the general review and data reduction of two turbine cycle systems effects test; evaluations of several plant walk-downs and general reports of equipment condition; and boiler tests.
- The running and analyses of PEPSE computer simulations of all turbine cycle tests (of July 1987).
- Development of project recommendations and reports.

This project has identified several major, and numerous minor, sources of efficiency degradation and has established corrective recommendations from a thermodynamic viewpoint. Reports of findings consist of this summary report, Part One, and a Final Engineering Report, Part Two, which presents broad details of the analyses and general support for the recommendations. It should also be noted that a preliminary report of findings was prepared in late August 1987 in anticipation of a Unit 7 LP turbine overhaul starting in October. A copy of the preliminary report is presented in Appendix F. Essentially all of these preliminary recommendations, as well as the more detailed recommendations discussed in this report, were verified by physical inspection of the LP turbines in October and November 1987 during the scheduled overhaul and general plant maintenance.

Economic impacts of the recommendations were not studied. Economics must be assessed in light of operational practices, projected rates of return, etc. which are outside of the scope of this project. However, as a conservative commercial standard for [redacted] the value of 1.0 Btu/kWh improvement in heat rate is estimated to be worth at least [redacted]year net increase in profit.

EXERGETIC SYSTEMS INC PERFORMANCE ENGINEERING

II. Recommendations and Findings

If instituted, the following recommendations could result in the recovery of over 500 Btu/kWh in unit heat rate from the turbine cycle, and approximately 25 MWe in power. The boiler was found in near perfect condition, a recoverable heat rate of 21 Btu/kWh was quoted. These findings are based on computer simulations which are fully benchmarked against detailed turbine cycle and boiler testing. The recoverable heat rate recommendations are all thermodynamically valid. However, individually the recommendations may not be economically justified or may be impractical from an operations viewpoint. Economical judgments must be made by plant personnel, they have not influenced the thermal evaluation.

The magnitude of recoverable heat rate and power is high. However, consider that over half of the identified recoverable losses (264 Btu/kWh) stem from only one area in the plant: leakages associated with the HP and IP steam paths. The next two important areas for improvement are repair of the inlet nozzles of the LP turbine (if the IP-LP pressure drop was not originally degraded by design practice), and upgrade of instrumentation and subsequent testing of the auxiliary turbine to fully assess its degradation.

The recoverable heat rate is part of the total identified difference of 510 Btu/kWh when compared to the [redacted] design bases simulation of the turbine cycle, and near ideal boiler operation. The <u>un</u>recoverable heat rate of -22 Btu/kWh, net, is principally assigned to the condenser (+24 Btu/kWh) and via the conservative methods applied to the reheat temperature, pressure drop effects and LP heaters (-46 Btu/kWh).

The recommendations and findings which are summarized below should be read in light of a performance evaluation project which is not considered complete. Two areas require further attention. The authors strongly recommend that accurate data be obtained, using improved instrumentation, on the auxiliary turbine steam flow and flow measurement of the HP & IP turbine seals as discussed with plant engineers. These tasks are critical to the complete understanding of Unit 7 efficiencies. For this work, these flow data were estimated using engineering judgement and some test data.

The following recommendations and findings are based on two major systems effects test, evaluations of plant walk-downs and general reports of equipment conditions, major boiler tests involving numerous readings, analysis of fuel compositions, over six dozen turbine cycle analyses and numerous EX-FOSS steam generator analyses. Note that in Section III, Part Two, presentation is made as to what the target power and unit heat rate should be, based on tested conditions and reasonable boiler performance. As will be seen, the calculational closures for the two tests are +32 and -18 Btu/kWh. These quoted closures must be viewed in light of the author's engineering judgments, influenced by fuel flow analyses, heating value variances and turbine cycle leakage assumptions, which suggest that true closure is most likely ±80 Btu/kWh (discussed in Part Two). Also, presented in the next section, is the calculated "[redacted]design bases" turbine cycle results, prepared for this project to illustrate calculational closure of the sensitivity studies used to evaluate the turbine cycle recommendations.

Recommendations and findings are not listed in order of importance. Listed heat rate differences with a "UR" next to the numeric value indicates an unrecoverable deviation; that is, one which is constrained by either the environment or by obvious operational practice relative to original design or commercial standards. Justifications and explanations of analyses are contained in the Final Engineering Report. Additionally, please note that the following listed heat rate deviations were based on sensitivity studies using the full load test of 7/15/87. Comparison of these values to those associated with the 3rd valve point test indicated excellent agreement, except for a few cases discussed in Part Two. Also, the following list contains *italicized sentences* which relate to predictions made in the preliminary report of August 1987. This August report is presented in Appendix F for direct comparison between predictions of performance degradations, and the actual findings discovered during the recent LP turbine overhaul.

	Heat Rate Effect (Btu/kWh)
BOILER:	
■ Test indicated an overall boiler efficiency of 85.822 ±0.631% for the full load test, and 85.545 ±0.665% for the 3rd valve test. Unit 7's boiler tested to be in excellent condition, indicating no outstanding degradations. Based on highly consistent data, EX-FOSS analyses indicated: 9.06 and 9.56% excess air for the two tests; 10.69 and 12.33% by weight air leakage; heat exchangers with reasonable cleanliness factors relative to design (except the economizer and primary superheater); and very low combustion efficiency variances, of ±0.133 and ±0.167%. If the stack O_2 was reduced to 3.0% (from 3.6 and 3.9%), the efficiency would improve only 0.17 and 0.23% $\Delta\eta$ for the two tests; thus the quoted efficiency improvement.	21
■ It is recommended that whenever gas fuel flows, volumetric heating values and gas specific gravities are quoted in laboratory reports that their associated reference temperature and pressure be quoted in the same document.	0
■ Monitor fuel flow using the updated American Gas Association latest standard.	0
■ Recommended is to form procedures to establish a [redacted] design bases for boilers.	0

- **Recommended is to improve fuel monitoring techniques, with regards to flow, heating value and specific gravity. Specific gravity should be determined with greater consistency (average γ = 0.5954 via the plant process computer, versus** γ = 0.6045 via [redacted] - a 1.5% difference). **The fuel flow manometer used should have a** higher range. For spot checking, during the same hour for a given test, the fuel heating value was read at 1050.5 Btu/ft^3 via the plant process computer versus 1057.9 Btu/ft^3 from [redacted] - a 0.7% or 64 Btu/kWh difference.

0

TURBINE CYCLE:

- Repair the miscellaneous leakages within the HP and IP steam portions of the unit. The total leakage, of over 158,000 lbm/hr, was determined from energy balances and matching (reasonably well) the turbine stage pressures. Sources of potential leakages include: Speed Matching Valve, Turbine Blow-Down Valve, Turbine Bypass Valve, LP-side of the throttle valve stem leakages, drain line valves, and major steam traps. As examples: walk-downs indicated that the 1st, 2nd & 3rd extraction line drains leak, the reheat drains leak, the flash tank drain leaks, main steam lead drains leak, etc. See [redacted] memo from [redacted] to [redacted] of 8/10/87. The recoverable power was computed at +25.524 MWe. *The Speed Matching Valve and the Turbine Blow-Down Valve were found to leak badly.* — 264

- Tests of 7/16 & 7/17/87 indicated that "ASME PTC 6 type" of valving versus methods used for this work indicated a difference of 301 $\pm$60 Btu/kWh. Clearly this supports the conclusion that substantial flow is leaving the steam path. — 0

- It is recommended that all future Input/Output testing with Units 6 & 7 be conducted with the normal operational valving as used for this work. This type of isolation is better suited for understanding day-to-day performance. — 0

- Repair should be made to the HP and IP shaft gland seals: <3> through <9>. The recoverable power, a loss, was determined at -0.104 MWe. 16

- Repair of the HP turbine given slight degradation, of 1.11% $\Delta\eta$ (with high uncertainty); most likely such degradation is due to erosion of nozzle areas. The 1st stage is estimated to be degraded in areas by 6.89%, the 2nd stage by 3.12%, and the inlet to the 3rd <u>group</u> by 0.47%. This is considered minor erosion, not in need of immediate repair. Recoverable power was determined at +4.511 MWe. 26

- Repair should be made to the throttle valve stem leakages. Recoverable power was determined to be +2.025 MWe. 20

- Recommended, at all turbine overhauls, is that the throat dimensions of the first nozzle blocks be measured and recorded. 0

- The inlet nozzles to the IP turbine are degraded in area by 3.79% $\Delta A/A$, and the wheel efficiency appears degraded by 2.27% $\Delta\eta$. This is considered serious erosion, in need of repair at the next overhaul. Its continued degradation will lead to marked decrease in heat rate and power. Recoverable power, a loss, was determined to be -1.706 MWe, this due to the limitations of simulation programs in modelling nozzle erosion and conservatism in the modelling of efficiency degradation. 8

■ Improved instrumentation of the turbine steam seal system is an necessity. *The Preliminary Report discusses the details of this recommendation. No action or inspections have occurred.*		0
■ In 1986 the <u>Unit 6</u> inlet nozzles of the HP and IP turbines were inspected without finding significant damage due to solid particle erosion.		0
■ The Intercept Valve relative pressure drop, $\Delta P/P$, was found slightly high.	UR	1
■ The reheater pressure drop was found high.	UR	-17
■ Reheat spray flows were found via plant instrumentation to be excessive, over 80,000 lbm/hr (when the reheat temperature was 1020 F!). Methods should be investigated to reduce this flow, and/or reduce the temperature via improved flue gas dampening positions. Recoverable power, a loss, was determined to be -9.405 MWe given the conservative methods used for the simulations, see Section VIII for discussion.		22
■ The reheat temperature should be controlled to 1000 $\pm$3 F; during the test the temperature was held at 1020 F given unique stability. Reducing this temperature to design, reduces power by -7.850 MWe. This effect was treated as an unrecoverable loss given its large value, so as not to bias results (normally this would be recoverable via operations).	UR	-20

- The superheat sprays were found to have flows in excess of 273,000 lbm/hr for the test of 7/7/87. This is indicative of either poor flue gas dampening positions, or a poor vendor design of boiler heat exchanger placement. 0

- Repair and/or maintenance is strongly recommended for the auxiliary turbine steam line orifice. Proof that the auxiliary turbine is, or is not, degraded depend on this measurement. No definitive analysis of Unit 7's auxiliary turbine is possible without accurate steam flow measurements. 0

- Repair the auxiliary turbine only <u>if further testing proves the assumptions used in this report</u>. There is great uncertainty as to the turbine's efficiency; assumptions used herein produced 55.8% cylinder efficiency with a recoverable power of +3.675 MWe. 38
  This was suggested in 8/87; all data and findings continue to support the instrumentation for accurate data.

- **Repair should be made to the inlet nozzles of the LP turbine <u>only</u> if low load testing, and review of historical test data (especially first startup), indicates a similar relative pressure drop as found for this** work. If low load data indicates a marked drop in $\Delta P/P$, then the last IP stage most likely has choked flow and the problem is not with the LP. If the same $\Delta P/P$ was historically observed, then the LP is flawed by design. It is estimated the inlet LP nozzles could be degraded in throat 45 (cont'd) area by no more than 7.89% ΔA/A <u>if not a design problem</u>. For the LP turbine, such degradation is very serious and will aggravate performance if not corrected. If not a design problem, such repair will reduce the very large pressure drop across the IP to LP cross-over, of 7.4% ΔP/P. If the IP to LP cross-over was designed with a high ΔP/P, then 43 Btu/kWh, of the 45 Btu/kWh, is unrecoverable. *No serious damage was found to the IP - LP cross-over pipe. The inlet LP nozzles <u>were found to be degraded</u>. measurements are being attempted (10/87) to assess the relative damage. Further low load testing and historical review still needed.*

- In 1986 the <u>Unit 6</u> LP was inspected: the 1st LP stage was in excellent condition except for slight orifice inlet object damage. The 2nd and 3rd stages appeared in excellent condition. The 4th, 5th & 6th stage may of had deposits. The 7th & 8th stages were in excellent condition. These findings suggested that, for Unit 7, LP inlet nozzle erosion should <u>not</u> be anticipated, i.e., low inlet pressures were to be expected. 0

- Differential temperatures were found in the 6th extraction lines. *Inspection of the 6th. 7th & 8th LP stages indicated steam cutting from the nozzle area to the downstream side of the buckets. causing high extraction temperatures (a possible cause for the high "stratification" of temperatures observed in GE turbines.* 0

- It is strongly recommended that the IP to LP pressure drop, $\Delta P/P$, be monitored (the LP pressure must be taken at the turbine's bowl). 0

- Repair should be made to the boiler feed pump recirculation system and miscellaneous pump drain lines as high flows are suspected. Recoverable power was determined to be +1.469 MWe. *Inspection found several valves within the recirculation and drain systems which leaked.* 14

- The top two feedwater heaters are slightly degraded and require servicing. Most likely both their level controls and vent systems require maintenance. Plant walk-down indicated 1A & 2B spills were open during the 7/15/87 test. During the 7/7/87 test the 1B spills were open. Heater 2B's vent system is badly in need of repair. Recoverable power was determined to be -9.801 MWe (i.e., a classical example of improved heat rate at the expense of power given constant feedwater flow). 16

- Feedwater heat #3 was found degraded with regards to its level controls (both the "A" and "B" heaters). Recoverable power was computed at +0.303 MWe given a strong bias towards improved condensing at the cost of poor drain cooler performance. For the 7/15/87 test the #3 drains appeared to be blowing through. 3

- The LP feedwater heaters were found to be near design, except that heater #7 was found to spill badly. UR -3

■	The turbine cycle extraction line pressure drops were found to be improved relative to design, determined via [redacted] design methods.	UR	-7
■	The boiler feed pumps were found to be in excellent condition relative to efficiency; pump 7-1 was found degraded in head by 2.57% $\Delta H/H$.		0
■	The feedwater flow has, what is believed, to be a biased differential flow split at the inlets to the boiler feed pumps. The base data was highly questionable (53.71% of the total flow was delivered to the 7-1 pump), but the sensitivity study indicated a -0.171 MWe change when returning the flow split to 50%. Of course, cycle performance is improved <u>if the flow is biased to the shaft driven pump</u>. This would be true even if the auxiliary turbine was not seriously degraded.		-2
■	Study is recommended of the new controls being installed for Unit 6 & 7; candid conversation with plant operators is also recommended in light of these controls. The new controls employ voltage/current control, versus current/voltage, resulting in little control feedback. With the new controls a push on a demand setting results in a step change in the <u>indicated</u> signal; not an analog change. This is clearly not amenable for close control. The old controls apparently allowed a potentiometer adjustment which provided an "instant" control feedback: the operator could see a response in the demand		0

(cont'd) signal which was proportional to the feedback. Operators must be given sensitivity controls if controllable parameters are to be optimized.

- When sliding pressure the operators should check that at the third valve point, or the second (the point of initial constant valve position), that indeed the valves are properly aligned. 0

- Increased stability was observed when the values-wide-open (VWO) position was achieved during certain Unit 7 tests, which is in keeping with experience. Operators appeared reluctant to achieve this condition for fear of <u>instability</u>. The point of operation yielding minimum throttle valve losses is at VWO. If <u>lower</u> throttle pressures are necessary to achieve VWO as a normal operational practice, then that clearly requires investigation. 0

- Monitor the throttle pressure and temperature with more care. The recoverable power due to 128 Δpsi low pressure (during the 7/15/87 testing), and 2 ΔF low in temperature, was determined to be +1.877 MWe. Although a low pressure was needed to achieve valves-wide-open conditions, operators should be reminded of the sensitivity. 12

- Recommended is to better calibrate the video display of main steam temperature used by operators. The indicated valve does not correspond to test instrumentation. Every 1 ΔF in throttle temperature is worth 1 Btu/kWh. 0

■ Reduce the condenser pressure to anticipated levels, considered to be an average value of 1.56 in-HgA. Design pressure was established at 1.25 in-HgA. Recoverable power was determined to be +2.904 MWe.	UR	29 24
SUMMATION OF TURBINE CYCLE RECOVERABLE HEAT RATE		511
SUMMATION OF TURBINE CYCLE <u>UN</u>RECOVERABLE HEAT RATE		-22
SUMMATION OF BOILER RECOVERABLE HEAT RATE		21
SUMMATION OF BOILER <u>UN</u>RECOVERABLE HEAT RATE		0
TOTAL IDENTIFIED HEAT RATE RELATIVE TO THE TURBINE CYCLE [redacted] DESIGN BASES, AND BOILER DESIGN DATA		510

III. Validity of Findings

The following presentations of turbine cycle and overall unit efficiency for [redacted] Unit 7 are prima facia evidence of a valid analysis. In the ideal: after individual sensitivity studies, using PEPSE, are established for a series of studied degradations, their sum should be the difference between a reference starting condition (the [redacted] design base) and the actual plant condition as-tested. If this is accomplished, it assures that, although errors might exist in individual studies, the trend of the individual studies is true, implying correct overall conclusions. This process is termed calculational closure. Excellent calculational closure was had for both the 7/15/87 and 7/18/87 simulation studies. The full load study of 7/15/87 is presented below; see Tables VII.0-4 & -5, Part Two.

<u>Validity of Turbine Cycle Study</u>

	POWER (MWe)	[redacted] HEAT RATE (Btu/kWh)
Simulation of 7/15/87 Test Without Normalization of LP Expansion:	728.287	7,827
Total Turbine Cycle Recoverable:	+24.994	- 511
MAXIMUM ANTICIPATED TURBINE CYCLE OPERATION AT TESTED CONDITIONS:	**753.281**	**7,316**
Identified Differences due to Throttle Flow Rate (Case X less Y):	+ 3.739	+ 0
Correction for Identified Miscellaneous Unrecoverable Losses (Cases D, Q, R, T and U):	- 9.467	+ 46
Correction for Identified Unrecoverable Losses due to Condenser Effects (Cases Z less AA):	+ 2.509	- 24
[redacted] DESIGN BASES AT RATED CONDITIONS (indicating 749.491 MWe & 7,343 Btu/kWh):	750.062	7,338

The following lists parameters leading to the determination of gross unit heat rate for both systems effects tests. All assigned variances are independent and are determined by mass/energy flow considerations unless noted. The net variance on the gross heat rates is determined via the square root of the sum of the squared individual variances; for the calculated value this includes those of: combustion & absorption efficiencies, and the turbine cycle.

<u>Validity of Overall Unit Study for 7/15/87 Full Load Test</u>

	PARAMETER	VARIANCE
Measured Fuel Flow Rate, lbm/hr (2)	288,318	±0.464%
Higher Heat Value, Btu/lbm-A.F. (1)	23,133	±1.000%
Measured Power, kWe (3)	728,780	±0.067%
OBSERVED GROSS UNIT HEAT RATE, Btu/kWh	9,152	±1.104%
EX-FOSS Calculated Fuel Flow, lbm/hr (6)	286,044	±0.379%
EX-FOSS Calculated Combustion Efficiency	86.252%	±0.133%
EX-FOSS Calculated Boiler Absorption Efficiency	99.502%	±0.498%
EX-FOSS Calculated Gross Boiler Efficiency	85.822%	±0.631%
PEPSE Gross Turbine Cycle Heat Rate, as Corrected, Btu/kWh (4,5)	7,827	±1.278%
CALCULATED GROSS UNIT HEAT RATE, Btu/kWh	9,120	±1.378%
Error in Unit Simulation, Btu/kWh, Btu/kWh	+32	±126

Notes:
(1) Based on a single laboratory test.
(2) Based on two independent calculations using a single set of measurements; having ±0.464% difference.
(3) Variance is based on analysis of data.
(4) Variance is based on engineering judgement of ±100 Btu/kWh, which is considered high, but appropriate given uncertainties in the auxiliary turbine performance and HP & IP steam path leakages.
(5) The simulation was <u>not</u> automatically normalized to measured power.
(6) Variance based on total stack gas flow error, see Steam Generator Report, page 2A.

Validity of Overall Unit Study for 7/18/87 3rd Valve Pt. Test

	PARAMETER	VARIANCE
Measured Fuel Flow Rate, lbm/hr (2)	247,991	±0.464%
Higher Heat Value, Btu/lbm-A.F. (1)	23,183	±1.000%
Measured Power, kWe (3)	617,248	±0.029%
OBSERVED GROSS UNIT HEAT RATE, Btu/kWh	**9,314**	**±1.103%**
EX-FOSS Calculated Fuel Flow, lbm/hr (6)	246,542	±0.439%
EX-FOSS Calculated Combustion Efficiency	85.973%	±0.167%
EX-FOSS Calculated Boiler Absorption Efficiency	99.502%	±0.498%
EX-FOSS Calculated Gross Boiler Efficiency	85.545%	±0.665%
PEPSE Gross Turbine Cycle Heat Rate, as Corrected, Btu/kWh (4,5)	7,952	±1.509%
CALCULATED GROSS UNIT HEAT RATE, Btu/kWh	**9,296**	**±1.598%**
Error in Unit Simulation, Btu/kWh, Btu/kWh	-18	±149

Notes:
(1) Based on a single laboratory test.
(2) Based on two independent calculations using a single set of measurements; having ±0.464% difference.
(3) Variance is based on analysis of data.
(4) Variance is based on engineering judgement of ±120 Btu/kWh, which is considered high, but appropriate given uncertainties in the auxiliary turbine performance and HP & IP steam path leakages.
(5) The simulation was not automatically normalized to measured power.
(6) Variance based on total stack gas flow error, see Steam Generator Report, page 2A.

IV. Summary of Testing

The following lists the tests performed as part of this project and the generic findings of those tests. All performance analyses of Unit 7 concentrated on simulating the systems effects tests of 7/15/87 and 7/18/87, using natural gas fuel.

Test Date	Results
11/5/86	Inspected [redacted] Unit 6 HP, IP and LP turbines. Notable findings included: GS upper nozzles were in good condition with less than 1% erosion, lowers had solid particle erosion; IP inlet nozzles had slight object erosion; LP gland seals were found in good condition; first stage LP nozzles were in excellent condition (except the orifice side, which showed very slight object damage), finding confirms the use of the measured LP inlet pressure for flow confirmation; 2nd & 3rd LP stages looked in good shape; the 4th, 5th & 6th LP stages had deposits (apparently silicon); and the 7th & 8th LP stages looked like new.
2/87	Performed a "final" review of the instrumentation selection and placement, and conducted an initial walk-down of the turbine cycle.
6/12/87	Prepared and delivered thermocouples to be used for the LP turbine testing involving superheating.
6/23 - 6/25/87	Conducted initial dry run testing to confirm the reasonableness of instrumentation and the data acquisition system. Numerous recommendations were made concerning instrumentation.

Test Date	Results
6/30/87	Ran a preliminary systems effects test; later discarded due to inconsistent data.
7/7/87	A systems effects test was conducted but discarded due to faulty data. Attempt was made at resolving the turbine's measured steam seal flows.
7/15/87	A systems effects test was conducted at valves-wide-open; this test was used as the principal test for future analyses. Data from the auxiliary turbine's steam flow indicated excessive flow, both from the flow orifice data and from the stage pressure; both measurements later proved false.
7/16 - 7/17/87	A series of tests was conducted to characterize the effects of isolation valving; that is, valving according to ASME PTC 6 philosophy versus this project in keeping with operational practices.
7/18/87	A systems effects test was conducted at the 3rd valve point; this test was to establish the sensitivity of performance to load. The system was walked-down, considerable leakage from drains and traps was noted.
8/87	A series of tests were conducted to help resolve the turbine's steam seal flows, without success. An accurate measurement of steam flow to the auxiliary turbine was also attempted. However, without a recent inspection of the auxiliary steam line orifice or a known β ratio, the uncertainty in the auxiliary turbine flow was considered high.

Test Date	Results
9/23 - 10/27/87	The Unit 7 LP turbines were disassembled for overhaul. Inspection of the LP's first stage nozzles indicated erosion. Inspection of the LP inner casing flanges indicated flow bypassing the stages immediately in front of the 6th, 7th and 8th extractions; judgement suggested minimal impact on heat rate from this leakage <u>relative</u> to the steam path. However, the impact on the LP heaters could result in differential extraction temperatures. Inspection of the IP to LP cross-over indicated cracking in the inner expansion covers with missing pieces. No flow restrictions were in evidence in the IP to LP cross-over piping.