This is to certify that the

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COMPUTER SIMULATION OF AN
ACTUAL COGENERATION POWER CYCLE

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Computer Simulation of an Actual Cogeneration Power Cycle

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ABSTRACT

Computer Simulation of an Actual Cogeneration Power Cycle

By

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A computer model has been developed which simulates the thermal performance of an actual power system. The objective of this model was to provide the capability to efficiently simulate the steam system of a actual combined-cycle cogeneration facility. Various software tools were chosen to effectively model the system's actual process operating conditions (flow rates, temperatures, pressures, etc.). The model was then compared and contrasted with actual operating condition data following its development, for verification and accuracy determination. Through simulation of the facility, the model was then used to efficiently perform a thermodynamic analysis of the facility for the numerous cogeneration operating configurations. This information was then used to determine process optimization in regards to auxiliary and emission control steam production, electrical power production, and process steam sold to the customer.

Dedicated to the Memory of Harry W. Daykin, P.E.

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Chapter 1 Introduction

1.0 Problem Description

Historically, combined heat facilities are analyzed, and consequently optimize via a first law and/or second law analysis. This analysis is completed by calculating an overall heat balance for a single operating configuration (usually the steady state maximum facility load), focusing on processes with low adiabatic efficiencies and high irreversibilities, both of which illustrate undesired energy loss. Often this is sufficient to verify process capability and gross process inefficiencies, however, this "energy accounting" is often cumbersome and it takes a great deal of time and effort to perform a thermodynamic first and second law analysis for the numerous process operating conditions available (i.e. transient and extreme load conditions). Such means of process analysis also involves the collection of large amounts of actual device and fluid state data prior to and after each device for each operating configuration. This data is then compiled and used to rigorously perform a number of hand calculations to obtain the desired process performance characteristics and efficiencies for each device and/or sub-system. Therefore, to efficiently perform a thermodynamic analysis of an actual process subject to various operating conditions it is beneficial to develop an appropriate system simulation model using available software tools, such as RANKINE 3.0 and Excel 5.0. The system model

model developed could then be used to expedite and efficiently perform the investigation and subsequent analysis of various operating configurations by simply varying a small number of key user defined process parameters.

It will be the focus of this analysis to develop an actual simulation model of a combined-cycle cogeneration facility's steam system. A complete facility description, from which the model will be developed, is first used to determine the key process devices and their operating characteristics. Various software tools are chosen to effectively model the system of interest, where actual process operating condition data (flow rates, temperatures, pressures, etc.) is collected and analyzed for use in developing the various model operating equations. The model is compared and contrasted with actual operating condition data following its development, for verification and accuracy determination. The model may then be used to efficiently perform a thermodynamic (heat balance) analysis of the facility for the numerous operating configurations. This information may then be used to perform a process optimization in regards to auxiliary and emission control steam production, electrical power production, and process steam sold to the customer.

The resulting analysis and optimization capabilities of the process model may be used in the investigation of future cost reduction measures and/or future facility capacity and efficiency improvements. Realizing it is the company's goal is to improve profit margins, such timely simulation and subsequent analysis will be very valuable in considering future facility improvements.

1.1 Basic Combined Gas-Vapor Power Cycle

The combined cycle process being utilized at the model facility is the gas-turbine (Brayton) cycle topping a steam-turbine (Rankine) cycle. This particular plant process has a higher thermal efficiency than either of the cycles executed individually. Gas-turbine cycles typically operate at considerably higher temperatures than steam cycles. The maximum fluid temperature at the turbine inlet for the steam turbine inlet is 750°F and over 2000°F in the gas turbine combustor. Because of the higher average temperature at which heat is added, the gas turbine cycle has a greater potential for higher thermal efficiencies. However, the gas turbine cycle has one inherent disadvantage: the exhaust gas leaves the gas turbine at very high temperature (approximately 1000°F), which wipes out any potential gain in the thermal efficiency. Therefore, when run independently, the thermal efficiency of gas turbine power plants, in general, is lower than that of steam power plants.

It makes engineering sense to take advantage of very desirable characteristics of the gas turbine cycle at high temperatures and to use the high temperature exhaust gases as the energy source for a bottoming cycle such as a steam power cycle. The result is a combined gas-steam cycle as shown in Fig. 1-1 below.

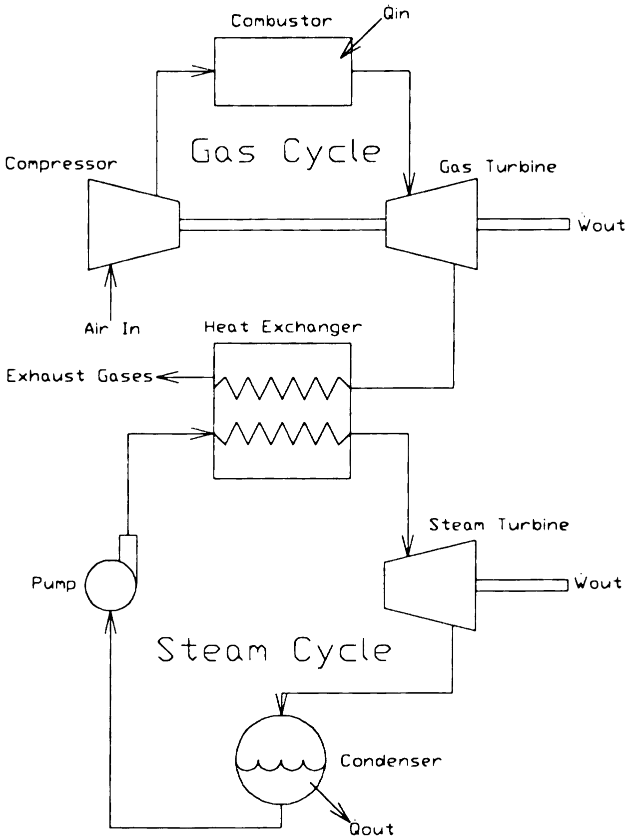

Figure 1-1: Combined Gas-Steam Power Cycle

In this cycle, energy is recovered from the exhaust gases from the gas turbines by transferring heat to the steam in a heat exchanger that serves as a boiler. Note, the heat exchanger linking the gas cycle to the steam cycle is in the case of the modeled facility is the heat recovery steam generator (HRSG) described in Chapter 2. Also, additional energy may be supplied to the HRSG by burning additional fuel in the oxygen-rich exhaust gases [Cengel and Boles 1993]. It was the result of recent developments in gas turbine technology that have made the combined gas-steam cycle economically very attractive to the modeled facility.

1.2 Basic Cogeneration Power Cycle

Often in discussing power cycles the sole purpose is to convert a portion of the heat transferred to the working fluid into work (consequently electricity), which is the most valuable form of energy. The remaining portion of the heat is rejected to a cooling pond, in our case, because its availability (or thermal quality) is too low to be of any practical use. Wasting a large amount of heat is a price we have to pay to produce work, because electrical or mechanical work is the only form of energy on which many engineering devices (such as a pump) can operate.

Many systems or devices, however, require energy input in the form of heat, called process heat. In our case, the customer utilizes process heat for both chemical production and space heating. Companies such as these, that use large amounts of process heat also consume a large amount of electric power. Therefore, it makes economical as well as engineering sense to use the already existing work potential from the steam produced in the HRSGs to supply process steam to the customer as well as produce electrical power, instead of letting such energy go to waste. The result is a plant which produces electricity while meeting the process heat requirements of these industrial processes. In general cogeneration is the production of more than one useful form of energy from the same energy source, natural gas in the present case. The schematic of a practical cogeneration plant is shown in Fig. 1-2.

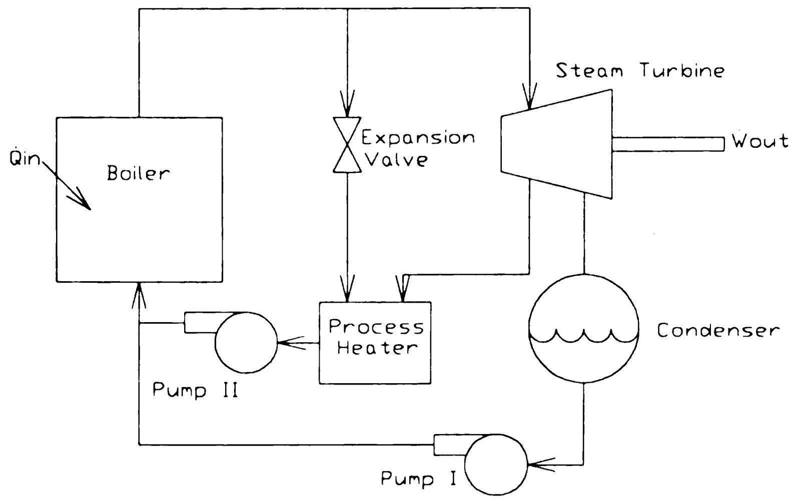

Figure 1-2: Cogeneration Power Cycle

Under normal operation, some steam is extracted from the turbine at some predetermined intermediate pressure. The rest of the steam expands to the condenser pressure and is cooled at constant pressure. The heat rejected from the condenser represents the waste heat for the cycle. At times of high demand for process heat, all the steam is routed to the process heating units and very little to the condenser. The waste heat is zero in this mode. If this is not sufficient, some steam leaving the boiler may be throttled by an expansion or pressure-reducing valve to the desired extraction pressure and directed to the process heating unit [Cengel and Boles 1993]. It is appropriate to define a utilization factor ε_u for a cogeneration plant as

$$\varepsilon_u = \frac{\text{net work output} + \text{process heat delivered}}{\text{total heat input}} = \frac{\dot{W}_{net} + \dot{Q}_p}{\dot{Q}_{in}}$$

$$\text{or } \varepsilon_u = 1 - \frac{\dot{Q}_{out}}{\dot{Q}_{in}}$$

where $\dot{Q}_{out}$ represents the heat rejected in the condenser. Strictly speaking, $\dot{Q}_{out}$ also includes all the undesirable heat losses form the piping and other components, but they are usually small and thus neglected. The utilization factor of actual cogeneration plants have factors as high as 70 percent. The utilization factor for the modeled facility approximately averages 32 percent.

1.3 Basic Definitions

In order to provide the reader with a reference for the various terms used throughout, their respective definitions are provided below.

- acoustical barrier - wall made up of laminated steel and foam to reduce the sound energy transfer from one space to another.
- adiabatic efficiency - device parameter value which measures the deviation of an actual process from the corresponding idealized one.
- ambient conditions - surrounding thermodynamic environment of the system (i.e. atmospheric pressure).
- ancillary equipment - auxiliary or supplementary equipment.
- availability - the maximum amount of work a device or system can provide as it undergoes a reversible process from the specified initial state to the state of its environment.
- back pressure steam turbine - steam turbine device that simultaneously produces work and provides back pressure to the supplying steam header such that the resulting header pressure is not significantly lost during operation.
- cogeneration cycle - the production of more than one useful form of energy (such as heat and electrical power) from the same energy source.
- combine cycle - a gas turbine power cycle (Brayton) providing energy to a steam turbine power cycle (Rankine) combined into one overall power cycle.
- condensate - liquid obtained by the condensation of steam vapor.
- condenser - a device in which steam vapor is condensed into liquid form (condensate).
- contract capacity - minimum electrical power production capacity per an agreed contract.
- curve fit - mathematical procedure (usually by means of least squares approximation or computer software) to develop an algebraic equation for a given set of data.

- deareator - device used to remove dissolved air from a working fluid (in this case water).
- demineralized water - water that is devoid of mineral matter or salts.
- deNOx control steam - steam that is injected into the gas turbine combustor to reduce the quantity of nitrogen oxide bi-products of combustion for emission regulation purposes.
- desuperheater - device used to control main fluid temperature via the injection of saturated liquid into a superheated vapor fluid stream.
- duct burners - supplemental energy input to the heat recovery steam generator via the combustion of natural gas.
- electrical losses - electrical resistance losses within the turbine generator.
- Excel 5.0 - commercial spreadsheet software package used for mathematical calculations.
- export steam - superheated water vapor removed from the process cycle and provided to a customer.
- feedwater pumps - pumps used to transport and increase the pressure of saturated liquid from a condenser to a boiler.
- first law of thermodynamics - during an interaction between a system and its surroundings, the amount of energy gained by the system must be exactly equal to the amount of energy lost by the surroundings.
- gas turbine generator - work producing device that drives an electrical generator via the combustion of natural gas.
- header - a main pipe used to transport a fluid in which a number of smaller pipes open into.
- heat recovery steam generator - boiler device used to extract thermal energy from the exhaust gasses of a gas turbine.
- irreversibility - the difference between the reversible work and the useful work produced by a device.
- letdown - throttling process from one high pressure steam header to a lower pressure steam header.

- moisture separator - device used to remove saturated liquid from a two-phase mixture.

- mechanical losses - mechanical losses of a turbine or generator such as bearing and oil pump loss.

- open feedwater heater - mixing chamber device in which different streams of different energies are mixed at constant pressure to form a stream with an intermediate energy.

- positive displacement pumps - device used to increase the pressure of a working fluid, where the work supplied is delivered via an external source through a rotating shaft.

- Procedure for System Analysis - sequence of steps utilized to evaluate the thermal performance of any well posed system.

- process parameters - independent working fluid variables (i.e. temperature, pressure, and mass flow rate) used to define the operating state of the steam system.

- RANKINE 3.0 - software package used for the analysis of actual steam power systems.

- relative humidity - ratio of the amount of moisture air holds relative to the maximum amount of moisture air can hold at the same temperature.

- saturated liquid - thermodynamic state where a liquid is about to vaporize.

- second law of thermodynamics (Kelvin-Planck statement) - for a power plant to operate, the working fluid must exchange heat with the environment as well as the boiler, thus the cycle thermal efficiency must be less than 100 percent.

- sliding pressure control concept - allowance of main steam pressure variance with mass flow rate and temperature to maintain high enthalpy to the steam turbine generator.

- steam blowdown - extracted steam from the process for chemical control purposes to reduce scale and mineral deposits in pipes and equipment.

- steam turbine generators - work producing device that drives an electrical generator via the expansion of a working fluid (i.e. steam - superheated water vapor)

- step-up transformers - electrical device that transfers energy from one circuit to another with an increase in voltage and without a change in frequency via induction of a primary winding onto a secondary winding.

- thermal efficiency - a measure of performance that is the fraction of heat input converted to net work

- throttle valve - device that causes a significant pressure drop in the fluid without a significant change in enthalpy.

- turbine extraction - point at which steam is removed from a steam turbine; usually the end of a stage group.

- utilization factor, ε_u - a measure of performance that is the fraction of heat input to the sum of the net work and heat output.

- working fluid - fluid in which heat is transferred to and from while undergoing a cycle (i.e. steam).

Chapter 2 Facility Description

2.0 Facility History/Overview

The Midland Cogeneration Venture (MCV) was originally designed as a nuclear-powered generating plant where construction was halted in 1984 due to financial constraints. Conversion to a natural gas, combined-cycle cogeneration plant in 1990 incorporated new natural gas turbines and heat recovery steam generators, and also used much of the equipment installed when the facility was being built as a nuclear plant, including existing steam turbine generators, condensers, moisture separators, etc. The facility employs approximately 100 people with an annual payroll of about $4 million and is one of the county's largest taxpayers. Since becoming fully operational in 1990 the facility has provided all of Dow Chemical Company's process steam needs and supplies approximately 15 to 20% of Consumers Energy's electrical needs. The facility also holds the distinguished honor of being America's largest cogeneration plant by producing enough electricity to power one million homes and up to 1.35 million pounds per hour of process steam for industrial use.

2.1 Combined-Cycle Cogeneration Process

The MCV facility utilizes the latest technology and designs for clean, efficient power generation. The technology is called combined-cycle because it produces electricity by two different methods, or cycles. In the first cycle, electricity is generated from the energy produced by the burning of natural gas mixed with air in each gas turbine. The heat rejected from the gas turbines is at a temperature level that is readily used in the steam system (second cycle). The heat rejected from the first cycle enters heat-recovery steam generators (HRSGs). The hot exhaust heats water to 700°F in each HRSG boiler and produces steam. This steam is collected from each HRSG and piped to a steam turbine (second cycle). This turbine produces additional usable electricity. Such a combined cycle system inherently generates power more efficiently than a conventional fossil-fuel plant and assures the most effective possible use of the energy originally produced by burning the natural gas. A further efficiency is achieved by collecting the steam that turns the large steam turbine generators. This steam still contains a very significant amount of useful energy and is piped to the adjacent Dow Chemical/Corning complex and used in a variety of industrial processes. It is this steam that constitutes the cogenerated energy at the facility. Cogeneration means that two kinds of energy are being produced from one fuel source. In this case, process steam and electricity are produced from natural gas.

2.2 Detailed Facility Description

Following is a detailed process description from which the base simulation model can be readily derived.

The process begins when the twelve gas turbine generator (GTG) sets supply heat to twelve heat recovery steam generators (HRSGs), which are headered together on the steam side to provide energy to either of the two steam turbine generators (STG). The twelve GTGs are installed adjacent to the steam turbine building in a single building called the power block. Each gas turbine is enclosed within an acoustical barrier to attenuate noise. Ventilation fans and exhausters provide the building and equipment with a proper operating environment. A 400 ft long piping rack supports the various piping runs between the power block and the steam turbine building. This combination (GTG & STG) of equipment enables approximately 1380 megawatts of electrical generation capability while supplying an average steam flow of 629,000 pounds per of process steam to the customer. The MCV facility also provides 60 MW of electrical power to Dow Chemical Company. The site consists of five basic work areas - the turbine building (housing STG units 1 and 2), power block (housing GTG units 3-14), transmission lines, switchyard, and export steam piping. The power block consists of twelve type 11N Asea Brown Boveri 86 MW gas turbine generators, each paired with a Combustion Engineering dual pressure heat recovery steam generator and stack. Of the twelve HRSGs, six are equipped with natural gas-fired duct burners, used principally to meet peak process steam and power requirements. When in use in conjunction with the GTG, the gas-fired duct burners can supplement enough energy to increase steam production by approximately 60%. In addition, each HRSG is equipped with a deareator, two steam drums, and two feedwater pumps. GT unit 12 was modified with a dry Low-deNOx combustor to demonstrate performance and reliability and does not require deNOx control steam during operation.

Variable speed high pressure feedwater pumps supply water to the high pressure steam drum and high pressure section of the HRSG. Pump speed is controlled by varying the frequency of the electrical power feed to the high pressure feedwater pump motors. This allows 450-900 psig variable pressure main steam to drive either of the two converted steam turbine generators (STG units 1 and 2) that were a part of the original nuclear plant. The allowance for variable main steam pressure is termed the sliding pressure control concept and is utilized to maintain high enthalpy steam supply to either high pressure steam turbine. High pressure steam from the twelve HRSGs (700°F, 900 psig) is headered together to provide energy (normally) to steam turbine generator unit 1 (STG unit 1) at full power. At reduced steam turbine outputs, the inlet steam pressure is reduced by the sliding pressure control concept to improve cycle efficiency. The steam temperature is controlled by a desuperheater at a single header location. The low pressure feedwater pump supplies water the HRSG's low pressure steam (275 psig) drum and its associated boiler section. The low pressure steam is used for two purposes. The majority is used in combination with steam turbine extraction steam for control of NOx emissions in the gas turbine combustors. The remainder of the low pressure steam is used to preheat the natural gas fuel. The low pressure steam conditions are approximately 275 psia and 464°F.

The individual GT/HRSG units can be operated in any combination to provide main steam for either one of the STGs deNOx steam for the GTs, and process steam to the customer facilities. A minimum of four (4) GT/HRSG units operating is needed before the steam turbine-generator can achieve reliable stable operation. When ambient conditions are 59°F, and 60% Relative Humidity (R.H.), eleven (11) GTs will achieve the contract capacity of 1132 MW (for 1994). When ambient conditions cause intake mass flow rate to be lower than at 59°F and 60% R.H., additional capacity margin is available with only eleven (11) GT units operating. Below 40°F ambient, the contract capacity of 1132 MW can be achieved with only 10 GT units operating. However, at higher ambient temperatures, the twelfth GT must be run or duct firing must be utilized. Although the supplemental capacity available by duct firing is dependent upon the specific configuration of the plant, a general rule of thumb shows that 100 % duct firing in a unit contributes approximately 15 MW additional, hence, duct firing in 4 of the 6 units fitted for such service can achieve the contract capacity up to 96°F with 11 GT units available and fully operational.

STG unit 1 is regarded as the primary steam turbine-generator and the STG unit 2 is the backup steam turbine-generator. The headered main steam is piped through 4 steam stop valves and into a General Electric (GE) high pressure (HP) steam turbine which is coupled via a shaft to a GE low pressure (LP) steam turbine. The HP steam turbine consists of 16 stages. DeNOx control steam may be extracted after stage 8 and process steam is extracted after stage 11. Process extraction steam from the operating steam turbine (primarily (STG unit 1) will be provided as export steam to the customer via a 48-inch diameter steam line. The normal export steam flow is 629,000 pounds per hour, with a range from 250,000 to 1.5 million pounds per hour and can be provided from a combination of direct letdown from the main steam header throttle valves and either STG unit 1 high pressure turbine extraction, or STG unit 2 high pressure steam turbine exhaust. Export steam temperature is controlled by desuperheater to about 370 °F with the pressure maintained primarily by the action of the steam turbine combined intercept valves. A final pressure control station is located at the steam delivery point, which regulates the delivered pressure to 175 psig. Saturated liquid-vapor with a quality less than one exiting the HP turbine is then routed through a moisture separator where excess water vapor is removed from the steam by forcing it through a torturous path. The result is saturated vapor with a quality of one (1.0). Upon leaving the moisture separator the steam is then expanded through the LP turbine to the unit 1 condenser. Makeup water for the plant condensate/feed water system is received from the Dow Chemical demineralizing water system. Dow Chemical supplies all of the demineralized water required for plant makeup through a 16-inch diameter stainless steel pipeline. There are 7.2 million gallons of makeup water stored on site to cushion against any demineralizer outages. This water is supplied to the steam turbine condensers via the makeup water pumps under automatic control. Cooling water for the steam turbine condensers and other plant cooling systems is obtained from an 880 acre cooling pond. Condensate from the condenser is then pumped back to the power block and made available to each GTG unit deNOx and main boiler feedwater pump where the steam cycle is then repeated. The HP and LP turbines are coupled in series to the unit 1 electric generator which converts the mechanical energy extracted from the HP and LP turbines to electric energy. Under normal conditions, the gas turbine generators deliver 1045 MW, while the steam turbine generator adds 365 MW. The auxiliary load is approximately 30 MW, giving a net generation of 1380 MW. Special care was taken in the design of the facility to assure high availability of the export steam. The gas turbine generators, heat recovery steam generators, and ancillary equipment form trains that are capable of independent operation. The steam from the HRSGs can be routed directly to the export line via a letdown valve from the main steam header to further assure availability of process steam. Also the

steam availability is further enhanced by duct burners in six of the HRSGs. The plant is controlled by a Westinghouse state-of-the-art distributed controls system utilizing dual data highways and redundant controllers. Plant operators are able to start/stop/load the gas turbine generators, steam turbine generators, duct burners, HRSGs, and all ancillary equipment from the central control room. However, under most conditions, the plant is operated in a completely automatic mode, responding to control strategies that were developed during dynamic simulation of the entire plant.

Natural gas fuel is delivered to MCV's metering and regulating station through a 26" diameter high pressure pipe line owned by MCV, but operated, inspected, and maintained by the Michigan Gas Storage Company (MGSCo). This 26 mile long pipeline connects with the in-state gas transmission pipeline and storage system of Consumers Energy Company (CECo). A local interconnection between CECo and MGSCo also provides access to the MGSCo in-state system. CECo and MGSCo receive interstate gas from geographically diverse suppliers and transmission pipelines as contracted by MCV. For continuity of gas supply during peak load conditions, MCV has an agreement with CECo for access to 8 billion cubic feet of gas storage, which can be drawn upon at a rate of 3.5% per day of the amount in storage, up to a maximum of 120 Million cubic feet per day.

Electrical power from the gas turbine generators is cabled to two 138 kilovolt (kV) ring buses via step-up transformers. The CECo grid is fed separately from two 138 kV ring buses and a step-up transformer from the gas turbine generators and the two steam turbine generators. Manually bolted bus sections are configured to assure isolation of the unused steam turbine generation during operation.

2.2.1 Incorporation of the Back Pressure Steam Turbine

In the summer of 1997 an additional steam turbine generator was installed at the MCV. This turbine generator is a 14 megawatt (MW) back pressure steam turbine coupled with a generator, and is piped in parallel to the main steam header with deNOx control steam letdown and the HP steam turbine deNOx control steam extraction. The purpose of this turbine is to (a) increase overall plant electrical production capacity and (b) to provide a more reliable means of extracting deNOx controls steam without being constrained to deNOx letdown.

The back pressure steam turbine generator (BPSTG) increases overall plant capacity by allowing an additional 500,000 pounds per hour of steam to be produced by the HRSGs and run through the BPSTG since the unit 1 STG is limited to an inlet flow of 4.2 million pounds per hour and the HRSG steam production capacity well exceeds that number. Prior to the implementation of the BPSTG the facility was having difficulty controlling the unit HP steam turbine deNOx extraction. The existing control valves are of gate type and poorly controlled the extraction pressure. Often too much steam flow was extracted from this stage of the steam turbine and would greatly reduce the HP turbine exit pressure adversely effecting the performance of the unit 1 LP steam turbine. Thus, to eliminate this problem, plant management decided to obtain supplemental deNOx control steam via the main steam letdown. This was simply a throttle process and obviously a great deal of available energy is wasted. Note, the process extraction steam pressure from the HP steam turbine is accomplished via newly installed globe type valves. These valves have proven to be much more reliable in controlling the stream extraction pressure. Therefore, in order obtain the available energy from the previous throttle process, MCV management decided to incorporate the BPSTG into the steam system.

The BPSTG generator effectively expands steam from main steam pressure (900 psia) to required deNOx control steam delivery pressure (275 psig) supplementing the deNOx steam generated by the HRSGs to provide the required mass flow of deNOx control steam. The BPSTG provides enough back pressure to allow the remainder of the main steam generated by the HRSGs to be transported to the unit 1 STG for normal use. It is important to note that the use of the BPSTG reduces the main steam header pressure and reduces, or depending upon load conditions, eliminates the need for the main steam desuperheater for temperature control. The BPSTG has effectively provided additional production capacity to the facility as well as provide an efficient alternative to the deNOx steam letdown throttling process while an effective solution may be found to effectively control the HP steam turbine deNOx extraction pressures.

Chapter 3 MCV Steam System Simplified Model

3.0 Procedure For System Analysis

Given the two basic models described previously in Chapter 1, the cogeneration and combine cycle, we can effectively model the MCV facility. It was decided to investigate only the steam cycle side of the combined cycle process since this contained more of the aged equipment and provides the most opportunity for process optimization. The GTGs operate primarily as a black box, providing a constant level of thermal energy per unit. Once a unit reaches steady state there are little to no variations in its thermal contributions to the steam cycle, and each GTG is allowed to function independently from all other turbine devices. On the other hand, as stated previously in Chapter 2, the steam system is operated using the sliding pressure control concept. It is this concept and the constantly varying number of GTGs in use that cause various main steam conditions to the unit 1 STG. The steam cycle is also unique in that it is the heart of the cogeneration process where deNOx and process steam is extracted and provided for emissions control and export. It is the number of combinations of process and deNOx control steam extractions that make the steam cycle attractive for modeling, and why the steam cycle was chosen for system analysis.

The sequence of steps utilized to evaluate the thermal performance of any system is independent of the system layout of the working fluid. This sequence of steps is collectively referred to as the Procedure for System Analysis and summarizes the process used to evaluate the thermal performance of any well posed system. The Procedure for System Analysis is stated below [Thelen 1995]

1) The system layout is sketched. The devices representing the various processes are placed and connected according to the system description.

2) The nodes between the devices are numbered. These nodes represent locations within the system where the state of the working fluid is of interest.

3) A table is constructed with the following headings (Assuming a simple compressible substance): Node, Temperature, Pressure, Fluid Phase, Enthalpy, Entropy, Mass Flow Rate, and Availability.

4) With the given operating conditions and system description, all known thermodynamic information is entered on the table.

5) Using the state postulate and the working fluid property tables, all obtainable thermodynamic information is added to the table.

6) The system is traversed, device by device, analyzing the fluid as it passes through each device. This analysis provides additional fluid properties, which when used in conjunction with step #5 systematically completes the table.

7) With the completed table, system information (such as thermal efficiency and work produced is calculated.

By employing the Procedure for System Analysis, any well posed system may be systematically analyzed. In essence, the procedure uses the working fluid property tables, the physical characteristics of each device type, and the 1st and 2nd law of thermodynamics to systematically calculate all unknown thermodynamic information within a well posed system. The repetitive nature of these calculations is ideally suited for a computer application.

3.1 RANKINE 3.0: Steam Power Plant Computer Simulator

RANKINE 3.0 is a PC-DOS compatible program capable of modeling a complex, user specified steam power system and providing a basis for optimization of the design and operation of a steam power system. The user specified system may include up to 100 thermal equipment components commonly found in commercial steam power systems such as boilers, turbines, pumps, pipes, junctions, condensers, open feed water heaters, closed feed water heaters, moisture separators, and reheaters. In addition to the system layout, the user also specifies the system operating conditions and equipment performance parameters required for the analysis. The output generated by RANKINE 3.0 summarizes the results of a first and second law analysis for the system operating under the given conditions. It is the intent of RANKINE 3.0 to provide a fast and detailed thermal analysis which permits innovative steam power system operating conditions to be investigated for the potential of increased system efficiency. Given the straight forward application of the RANKINE 3.0 software to the MCV facilities steam system and it capability to effectively complex user specified systems rather efficiently it was chosen to be the heart of the developed steam system model.

3.2 MCV Steam System Simplified Model Development

The first step in developing the MCV steam system model was to evaluate the detailed process description outlined in Chapter 2 along with the provided schematic layout of the facility shown below in Fig. 3-1. From this a simplified steam system layout is sketched with the devices representing the various processes are placed and connected according to the system description. Next the nodes between the devices are numbered. These nodes represent locations within the system where the state of the working fluid is of interest. Subsequently all devices were defined and the layout reviewed to ensure that all relevant elements were represented. The resulting Steam System Simplified Model is shown below in Fig. 3-1.

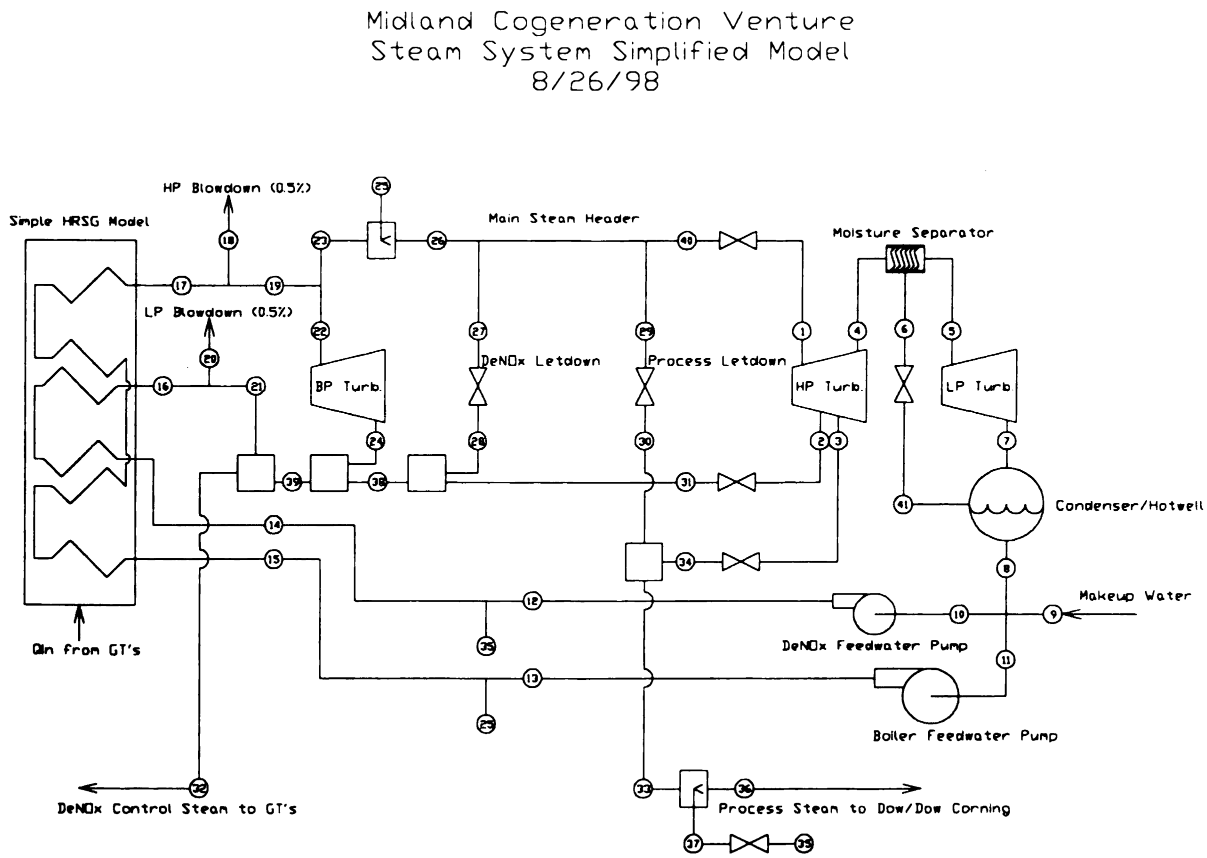

Figure 3-1: MCV Simplified Steam System Layout

From this simplified steam system layout a corresponding base RANKINE 3.0 input file was created to allow for the input of the system operating parameters. The model was then completed by developing a pre-processing worksheet using Excel 5.0 and historical operating data to generate all of the necessary RANKINE 3.0 operating parameters from only a few readily available operating parameters.

3.3 Device Modeling for RANKINE 3.0

The above system layout was traversed device by device to develop the RANKINE 3.0 input file. Each device and its appropriate modeling assumptions are detailed below.

3.3.1 Device #1 HP Steam Turbine

The unit one steam turbine generator set model consists of the first three devices. The STG model begins with the HP steam turbine. The HP steam turbine was modeled using the SIMPLE TURBINE device in the RANKINE 3.0 library. This device converts the energy constrained within the working fluid into rotating mechanical energy and is assumed to be directly connected to an electrical generator to produce electrical energy. The simple turbine model developed contains one inlet and three extractions and thus three stage group efficiencies. The inlet is connected directly to the main steam header, the first extraction provides steam from the turbine to the deNOx steam header, the second extraction provides steam from the turbine to the process steam header, and the third extraction is the HP turbine exit which is subsequently connected to the moisture separator inlet. The required input operating parameters for the RANKINE 3.0 simple turbine device are as follows: inlet mass flow rate and pressure, extraction #1 mass flow rate and pressure, extraction #2 mass flow rate and pressure, exit pressure, and each stage group efficiency. Though the actual turbine is divided into number of stage groups (approximately 18 sets of stator and rotor blades total) for modeling purposes the HP turbine is modeled to have only three stages where the stage group efficiencies where derived for various operating conditions from actual data. This data is provided in Appendix C. Note, each extraction is modeled to be located at the end of each stage. The turbine is assumed to have no generator mechanical or electrical losses and shaft leakage is not modeled.

3.3.2 Device #2 Moisture Separator Model

The moisture separator is modeled to have one inlet and two outlets and is modeled using the SIMPLE MOISTURE SEPARATOR device from the RANKINE 3.0 library. Steam from the HP turbine exit enters the moisture separator inlet where the device removes entrained water vapor from a two phase flow. The device accomplishes this by forcing the water-vapor mixture through a torturous path collecting the condensate and routing it to the condenser via the condensate exit. The condensate piped to the condenser is throttled to condenser pressure via a throttling valve (Device #28). The resulting superheated vapor then exits the moisture separator and is routed to the LP steam turbine for further expansion. The only performance parameter required to be input into the RANKINE 3.0 model is the separator pressure loss, which a function of the HP turbine exit mass flow.

3.3.3 Device #3 LP Steam Turbine

The unit one steam turbine generator set is completed with the modeling of the LP steam turbine. Similar to the HP steam turbine, the LP steam turbine was modeled using the SIMPLE TURBINE device in the RANKINE 3.0 library. Similar to the HP turbine, it is assumed that the LP turbine is to be directly connected to an electrical generator to produce electrical energy. Where the addition of the electrical energy produced from the LP turbine and the HP turbine will equal the gross total unit one steam turbine generator power produced. The simple turbine model developed contains one inlet and one extraction and thus one stage group efficiency. The inlet is connected directly to the moisture separator, and the extraction is the LP turbine exit which is subsequently connected to the condenser. The required input operating parameters for the RANKINE 3.0 simple turbine device are as follows: inlet mass flow rate and pressure, extraction #1 pressure (condenser pressure) and stage group efficiency. Though the actual turbine is divided into number of stage groups, for modeling purposes the LP turbine is modeled to have only a single stage where the stage group efficiency is derived for various operating conditions from actual data. The turbine is assumed to have no generator mechanical or electrical losses and shaft leakage is not modeled.

3.3.4 Device #4 Condenser/Hotwell Model

The condenser consists of two inlets and one exit and is modeled using the SIMPLE CONDENSER device in the RANKINE 3.0 library. The main inlet is directly connected to the LP turbine exit and the second inlet is connected to the moisture separator. The exit is connected to the main condensate header which supplies required saturated liquid

to the power block HRSGs. The condenser rejects the steam energy from the LP turbine to the cooling pond. The condenser is modeled to be ideal, where the liquid-vapor mixture in the condenser experiences no pressure drop as it travels through the condenser and the fluid exits the condenser as a saturated liquid at constant temperature 97.5°F. This exit temperature is taken from historical operating condition data. No other inputs are required for this device.

3.3.5 Device #5 Junction from Condenser and Makeup to Feedwater Pumps

Process and DeNOx control steam is continuously leaving the steam system along with high pressure and low pressure blowdown. The blowdown steam is extracted from the HRSG just after the high and low pressure boiler sections for chemical control purposes (to reduce scale and mineral deposits in pipes and equipment). For this reason demineralized makeup water must be added to the system to compensate for the fluid loss. This is modeled using the SIMPLE JUNCTION model from the RANKINE 3.0 library. Quite simply it allows the for the connection of the fluid streams from the condenser and the demineralized makeup water (nodes 8 and 9) and transported to the deNOx and main boiler feedwater pumps (nodes 10 and 11). This model does not effect the thermodynamic state of the fluid streams (temperature and pressure remain unchanged) it only ensures conservation of mass flow. Thus, the model assumes that the saturated fluid exiting from the condenser is the same temperature and pressure and the makeup water. Though the actual mixing pressures are the same the actual mixing temperatures are often quite different. Usually the makeup water temperature is 20°F less than the temperature of the condenser. This temperature difference is neglected and the mixing temperature is assumed to be 97.5°F, the exit temperature of the condenser, since it has little effect when considering the temperature rise within the HRSG to be 600°F. The input parameters required for this device are the condenser exit and the makeup water mass flow rates. The condenser exit mass flow rate is equal to the HP turbine mass flow and the makeup water mass flow rate is the sum of the required deNOx control and process steam mass flow rates exiting the system.

3.3.6 Device #6 DeNOx Feedwater Pump Model

As stated in the facility description, each HRSG has its own individual deNOx feedwater pump to provide low pressure saturated water to the HRSG. If we were to model them all individually the gross work required for all operating pumps would be found by simply adding the resulting work required together. Therefore, in order to simplify the model, it was chosen to model all deNOx feedwater pumps as a single pump, using this fact of superposition that the net work required to obtain the desired pressure rise is obtained from summing the work required from each individual pump. The SIMPLE PUMP device from the RANKINE 3.0 library is used to model the deNOx feedwater pump(s). The input parameters required are the discharge pressure and the pump efficiency. The discharge pressure is simply the deNOx steam header pressure which is a function of the main steam mass flow rate and the adiabatic pump efficiency was assumed to be constant 80%. This number is an approximate efficiency value most positive displacement pumps such as these operate.

3.3.7 Device #7 Main Boiler Feedwater Pump Model

Similar to the deNOx feedwater pumps, each HRSG has its own individual main boiler feedwater pump to provide high pressure saturated water to the HRSG. If we were to model them all individually the gross work required for all operating pumps would be found by simply adding the resulting work required together. Therefore, in order to simplify the model, it was again chosen to model all main boiler feedwater pumps as a single pump, using this fact of superposition that the net work required to obtain the desired pressure rise is obtained from summing the work required from each individual pump. Again the SIMPLE PUMP model from the RANKINE 3.0 library is used to model the main boiler feedwater pump(s). The input parameters required are the discharge pressure and the pump efficiency. The discharge pressure is simply the main steam header pressure which is a function of the main steam mass flow rate and the adiabatic pump efficiency was assumed to be constant 80%. This number is an approximate efficiency value most positive displacement pumps such as these operate.

3.3.8 Device #8 DeNOx BFW Pump to HRSG and Process Desuperheater Junction

Low pressure saturated water must be supplied to the process steam header desuperheater for temperature control. Therefore, it was decided to add a SIMPLE JUNCTION just after the deNOx boiler feedwater pump to provide saturated water to the desuperheater so that it may be mixed with the process steam as required to lower process steam header temperature. The actual desuperheater receives its low pressure saturated water via its own separate pump, however since we were able to model the deNOx boiler feed water pumps as a single pump it was decided to also incorporate this pump into that model. This is justified by the fact that (1) the mass flow required for the desuperheater is small and the resulting work required to raise the pressure is negligible compared to the low pressure water being provided to the HRSG and (2) we may argue the same superposition idea for the desuperheater pump to be incorporated into the deNOx boiler feedwater pump model.

3.3.9 Device #9 Main BFW Pump to HRSG and Main Steam Desuperheater Junction

High pressure saturated water must be supplied to the main steam header desuperheater for temperature control. Therefore, it was also decided to add a SIMPLE JUNCTION just after the main boiler feedwater pump to provide saturated water to the desuperheater so that it may be mixed with the main steam as required to lower main steam header temperature. The actual desuperheater receives its high pressure saturated water via its own separate pump, however since we were able to model the main boiler feed water pumps as a single pump it was decided to incorporate this other pump into that model. This is justified by the fact that (1) the mass flow required for the desuperheater is small and the resulting work required to raise the pressure is negligible compared to the high pressure water being provided to the HRSG and (2) we may argue the same superposition idea for the desuperheater pump to be incorporated into the main boiler feedwater pump model for which this is.

3.3.10 Device #10 Combine HRSG Boiler Model

Similar to how we modeled both the deNOx and main boiler feedwater pumps, I modeled the twelve HRSG units as one single boiler unit. Again, using superposition, the net effect of all operating HRSGs could be considered one large boiler. Since the main

objective of the steam system analysis focuses on the utilization of the BP steam turbine, main header letdowns, and the HP turbine extractions, the individual analysis of the individual HRSGs can be neglected. Thus the 'lumped' HRSG model is comprised of the SIMPLE BOILER device from the RANKINE 3.0 library with one reheat leg. The reheat leg is utilized to model the boiler's transfer of heat to the low pressure (deNOx) section of the HRSG. This reheat leg permits the saturated liquid to enter the boiler at low pressure and generate a portion of the required deNOx steam as stated in the facility description. For both the main steam and deNOx portions of the HRSG, it successfully models the heat transfer originating from the number of operating GTs' combustion gasses to the saturated liquid, creating superheated vapor. This heat addition occurs at a constant pressure process for each respective section (high/low pressure). The boiler is modeled to have no pressure loss since the actual pressure drop within the boiler is negligible from the collection of raw data. The input parameters required are the main steam header temperature, and deNOx header temperature. The main steam header temperature is a function of the main steam mass flow rate and the deNOx header temperature may be modeled as a constant 460°F.

3.3.11 Device #11 Main Steam Blowdown Junction

As mentioned earlier , for chemical control purposes and to reduce the potential of mineral deposits within the steam system, steam is blown down, or removed from the system at a rate of approximately 0.5% of the main steam flow. This is accomplished using the SIMPLE JUNCTION from the RANKINE 3.0 device library. As stated earlier, this device simple performs a conservation of mass among its three nodes. Therefore,

only two input parameters are required, the main steam mass flow from the HRSG and the mass flow steam blowdown, which is 0.5% of the previous value. The rejected steam in practice is collected and routed the cooling pond. This is not modeled, rather, it is shown to be released to ambient conditions. The blowdown is included to illustrated a potential source of energy which may be recoverable even though it is 0.5% of the supplying mass flow.

3.3.12 Device #12 DeNOx Steam Blowdown Junction

The purpose of this device parallels the aforementioned main steam blowdown junction as mentioned previously. Again, only two input parameters are required, the deNOx steam mass flow from the HRSG and the mass flow steam blowdown, which is 0.5% of the previous value. The rejected steam in practice is collected and routed to the cooling pond. This is not modeled, rather, it is shown to be released to ambient conditions. The blowdown is included to illustrated a potential source of energy which may be recoverable even though it is 0.5% of the supplying mass flow.

3.3.13 Device #13 Junction from Main Steam Header to BP Steam Turbine

Similar to the previously described junctions, this junction provides a means of the main steam flow to be diverted to the back pressure steam turbine. The inlet mass flow is determined from the previous junction and the diverted flow to the BP turbine is a user input parameter. The main flow through this junction is to the main steam header desuperheater.

3.3.14 Device #14 BP Steam Turbine

Similar to the unit one steam turbine generator the BP steam turbine was modeled using the SIMPLE TURBINE device in the RANKINE 3.0 library. The BP turbine is directly connected to an electrical generator to produce electrical energy. The simple turbine model developed contains one inlet and one extraction and thus one stage group efficiency. The inlet is connected directly to the to the main steam header junction, and the extraction is connected to a mixing chamber on the deNOx control steam header (device #21). The required input operating parameters for the RANKINE 3.0 simple turbine device are as follows: inlet mass flow rate, extraction #1 pressure (deNOx header pressure) and stage group efficiency. Though the actual turbine is divided into number of stage groups, for modeling purposes the BP turbine is modeled to have only a single stage where the stage group efficiency is derived for various operating conditions from actual data. This data is given in Appendix C and from this data it is concluded that the adiabatic efficiency is a constant value of 78%. The turbine is assumed to have no generator mechanical or electrical losses and shaft leakage is not modeled.

3.3.15 Device #15 Main Steam Desuperheater

The main steam header contains a desuperheater. This device is used to control the temperature of the main steam prior to entering the unit one HP steam turbine. This is a mixing chamber in which main steam and saturated liquid enter and combine to reduce the temperature of the main steam to an intermediate value. This is a constant pressure process and pressure drops within the device are not modeled and are assumed negligible. The device chosen to model this process is the SIMPLE OFW HEATER from the RANKINE 3.0 library. This device is a simple open feedwater heater where the assumed saturated outlet condition has been suppressed and the outlet is allowed to be super heated vapor. The states of the mixing fluids are determined from previous devices and the only input parameter required is the injected saturated liquid mass flow rate which is given as a function of the main steam mass flow rate.

3.3.16 Device #16 Main Steam to DeNOx and Process Letdown

Similar to the previously described junctions, this junction provides a means of the main steam flow to be diverted to either the deNOx control steam header and/or the process steam header via throttling valves. The inlet mass flow is determined from the exit condition of the main steam desuperheater and the diverted flow to either deNOx or process steam letdown is a user input parameter. The main steam mass flow through this junction, steam that is not diverted to either letdown, is routed to the unit one HP steam turbine.

3.3.17 Device #17 & #18 Steam Letdown Throttling Processes

The steam that is diverted from the main steam header to either the deNOx steam header or to the process steam header must undergo a throttling process. Either of these processes are assumed to be adiabatic and the pressure differential is determined to be the difference between the main steam header and the respective header pressure, either deNOx or process. This throttling process is modeled using the SIMPLE PIPE device from the RANKINE 3.0 device library. This device allow us to specify a pressure drop without any enthalpy loss (i.e. the adiabatic throttling process). Each device is connected between the main steam header and its respective deNOx or process steam header, and the required input parameter for each is the main steam header to deNOx/process steam header pressure difference.

3.3.18 Device #19 & #23 HP Extraction to DeNOx/Process Header Pressure

The steam that is extracted from the HP steam turbine to either the deNOx steam header or to the process steam header must undergo a throttling process so the number of fluid steams down line may mix. Either of these processes are assumed to be adiabatic and the pressure differential is determined to be the difference between the respective HP extraction and the respective header pressure, either deNOx or process. Similarly to the previous throttling processes, this throttling process is modeled using the SIMPLE PIPE device from the RANKINE 3.0 device library. This device allows us to specify a pressure drop without any enthalpy loss (i.e. the adiabatic throttling process). Each device is connected between the respective HP extraction and its associated deNOx or process steam header, and the required input parameter for each is the HP extraction to deNOx/process steam header pressure difference.

3.3.19 Device #20-22 & #24 Mixing of DeNOx/Process Letdown and Extraction Flows

In order to combine the BP turbine extraction, deNOx letdown and HP turbine extraction fluid steams into the deNOx steam header and similarly the process letdown and the HP turbine extraction fluid streams into the process steam header, a mixing chamber model must be developed. This is done in practice by combining the various fluid steams via simple pipe junctions, however in order to accurately model this mixing process of streams at various temperatures and constant pressures the SIMPLE OFW HEATER

model was chosen from the RANKINE device library. The open feedwater heater model allows various streams at various energies mix to form a stream with an intermediate energy. This is shown in the system layout, Figure 3-1, where three open feedwater heater models are combine in series to effectively mix the fluid streams from the HRSG, BP turbine extraction, deNOx letdown, and the HP turbine extraction to complete the deNOx steam header. Similarly on Figure 3-1, it is shown how an open feedwater heater model was used to mix the contributing mass flow from the process letdown and the HP turbine extraction to the process steam header. This device is a simple open feedwater heater where the assumed saturated outlet condition has been suppressed and the outlet is allowed to be super heated vapor. The states of the mixing fluids are determined from previous devices.

3.3.20 Device #26 Process Steam desuperheater

Similar to the main steam header, the process steam header also contains a desuperheater. This device is used to control the temperature of the process steam prior to leaving the facility and transported to the customer. Again this is a constant pressure process and pressure drops within the device are not modeled and are assumed negligible. The device chosen to model this process is the SIMPLE OFW HEATER from the RANKINE 3.0 library. This device is a simple open feedwater heater where the assumed saturated outlet condition has been suppressed and the outlet is allowed to be superheated vapor. The states of the mixing fluids are determined from previous devices and the only input parameter required is the injected saturated liquid mass flow rate which is given as a function of the required process steam mass flow rate.

3.3.21 Device #25, #27, & #28 Misc. Pressure Losses and Throttling Processes

The saturated liquid that is pumped from the deNOx feedwater pump to the process steam header desuperheater must be throttled to the process steam header pressure to allow for mixing in the desuperheater, this is accomplished using device #25. Similarly the condensate from the moisture separator must be throttled to the condenser pressure, and the main steam header pressure losses from the power block to the unit one steam turbine HP inlet are to be model using devices #28 and #27 respectfully. Each of these processes are assumed to be adiabatic and the pressure differential is determined to be the difference between the respective devices which they are connected. Similarly to the previous throttling processes, this throttling process is modeled using the SIMPLE PIPE device from the RANKINE 3.0 device library. This device allow us to specify a pressure drop without any enthalpy loss (i.e. the adiabatic throttling process). Each device is connected between the respective components and the required input parameter for each is the required pressure difference between the components.

3.4 Excel 5.0 Pre-Processing Worksheet Development

Now that the basic RANKINE 3.0 model skeleton has been developed in the previous section it is shown that in order to fully define the system 42 input parameters must be known and entered into the system. In performing a system analysis it was determined that a number of the required parameters where functions of only a few key parameters. With this observation data was collected over a period of four days, under various system operating conditions, and compiled using an Excel spreadsheet. It is determined that a number of the system thermodynamic states where primarily functions of the main steam and various device mass flow rates. Intuitively this makes sense, as the number of GTs in operation varies from 4 to 12 the resultant main steam mass flow, temperature, pressure, etc. will increase due to the additional energy added to the system. From the collected data, eight key process parameters where identified. Of the eight process parameters three remained statistically constant over the range of operating conditions. These parameters are the required process steam delivery pressure, deNOx steam delivery temperature, and the condenser exit temperature. The next key parameter is the customer required process steam mass flow rate, which is customer driven and usually constant. From the remaining four key process parameters, three are facility operation specific. These are the percent mass flow rate of required process steam through and extracted from the HP steam turbine, the percent mass flow rate of the required deNOx steam through and extracted from the BP steam turbine, the percent mass flow rate of the required deNOx steam through the main steam header letdown. And finally, the most important parameter is the HRSG main steam supplied to the system. Note, the HRSG main steam supplied mass flow rate is a function of the number of GTs in operation, weither or not duct firing is being utilized, and the ambient conditions. Since the steam cycle is the primary focus of the analysis, the main steam mass flow rate will be provided and the actual operating configuration of the GTs will be implied. From these eight parameters the remaining forty-two may be calculated from the functions described below. The required input operating parameters are calculated from curve fit data from actual operating conditions obtained from the facility August 21 through August 24, 1998. From this data the various operating parameters may be derived to be functions of the eight specified key operating parameters. The equations and curve fit results are given below for each device.

3.4.1 Device #1 HP Steam Turbine

The HP steam turbine requires 10 input parameters to define the device model. First from actual collected data it is shown that the adiabatic efficiency of each stage was found to be statistically constant and as follows. Stage one adiabatic efficiency is 78%, stage two adiabatic efficiency is 100%, and the stage three adiabatic efficiency is 91%. Actual stage efficiencies do fluctuate with the operating conditions, and generally decrease with low inlet mass flow rates, however these effects had little effect on the system as a whole, therefore the assumption to model the efficiencies as constant may be made. The inlet mass flow of the HP turbine is simply found from the equation

$$\dot{m}_{\text{HP Inlet}} = \dot{m}_{\text{HRSG Main}} - \dot{m}_{\text{BP Turbine}} - \dot{m}_{\text{deNOx Letdown}} - \dot{m}_{\text{Process Letdown}}$$

Where $\dot{m}_{\text{HRSG Main}}$, $\dot{m}_{\text{BP Turbine}}$, and $\dot{m}_{\text{deNOx Letdown}}$ are user specified values and $\dot{m}_{\text{Process Letdown}}$ is found from

$$\dot{m}_{\text{Process Letdown}} = \dot{m}_{\text{Process Required}} - \dot{m}_{\text{Process HP Extraction}}$$

where $\dot{m}_{\text{Process HP Extraction}}$ and $\dot{m}_{\text{Process Required}}$ are user specified values. The remaining required flow rates for the HP steam turbine are given by $\dot{m}_{\text{Process HP Extraction}}$, a user specified value, and $\dot{m}_{\text{deNOx HP Extraction}}$ where this value is calculated from

$$\dot{m}_{\text{deNOx HP Extraction}} = \dot{m}_{\text{deNOx Required}} - \dot{m}_{\text{BP Turbine}} - \dot{m}_{\text{deNOx Letdown}} - \dot{m}_{\text{deNOx HRSG}}$$

where the above mass flow rates are either user specified or calculated known values. The $\dot{m}_{deNOx\ HRSG}$ value is calculated from the curve fit equation in Figure 3-2, which is a linear function of the HRSG main steam flow.

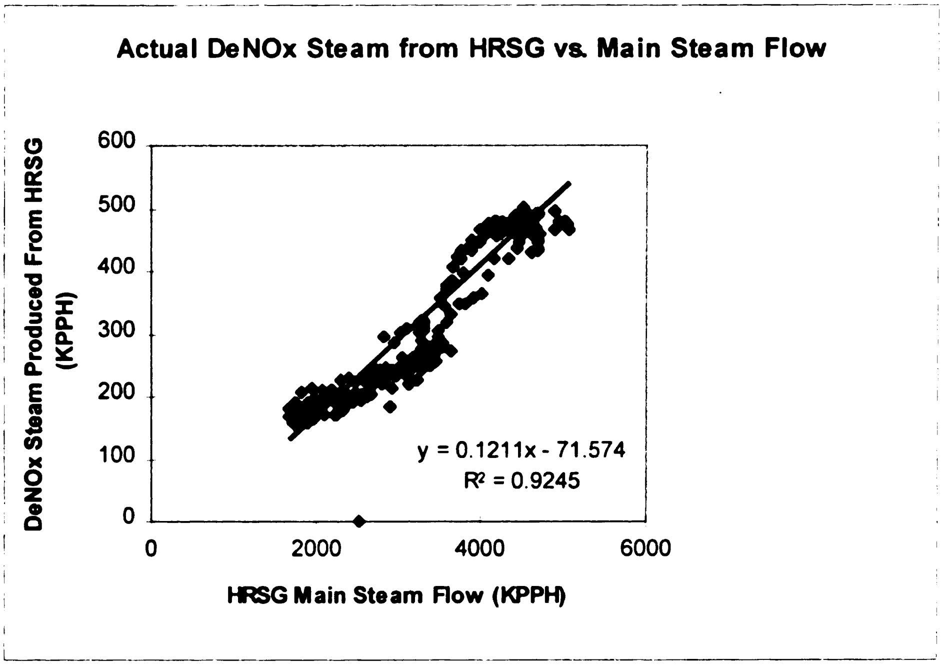

Figure 3-2: DeNOx Steam Produced from HRSG Actual Data and Curve Fit

With the various mass flow rates now known, the remaining device conditions can be derived using curve fitting techniques on the actual data collected. Actual HP inlet pressure versus the HP inlet steam mass flow is shown below in Figure 3-3, along with the data curve fit and its resulting equation. The HP turbine inlet pressure is determined from the equation shown on Figure 3-3 below. Note this equation is 6th order to approximate the lower bound constant pressure condition of approximately 475 PSIA for HP inlet flows less than 2000 KPPH.

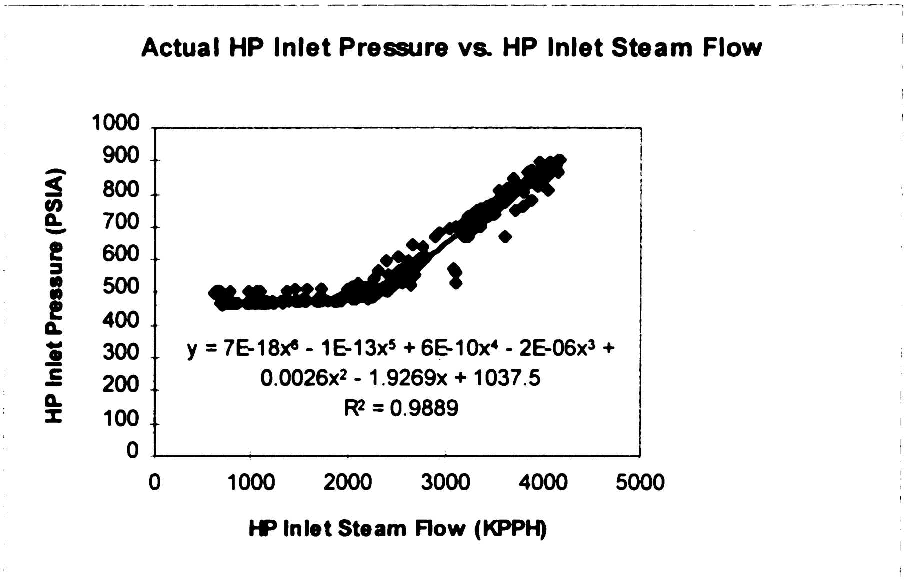

Figure 3-3: HP Inlet Pressure Actual Data and Curve Fit

Similarly the remaining extraction pressures may be obtained utilizing this technique. HP deNOx extraction pressure is determined from the equation shown on Figure 3-4 below. Also, HP process extraction pressure is determined from the equation shown on Figure 3-5, and the HP exhaust pressure is determined from the equation shown on Figure 3-6. Note, these equation are linear and are functions of the steam mass flow traveling through their respective stage.

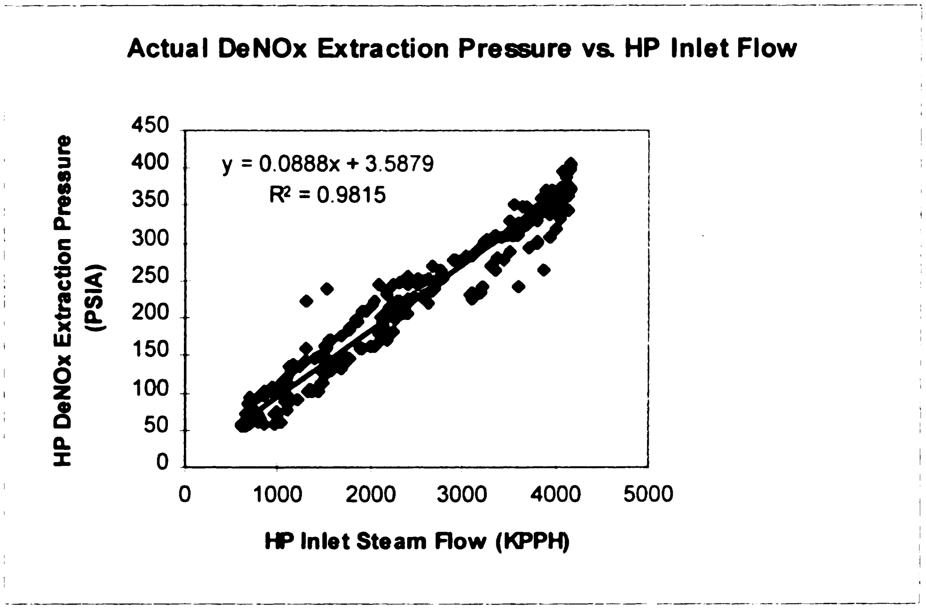

Figure 3-4: HP DeNOx Extraction Pressure Actual Data and Curve Fit

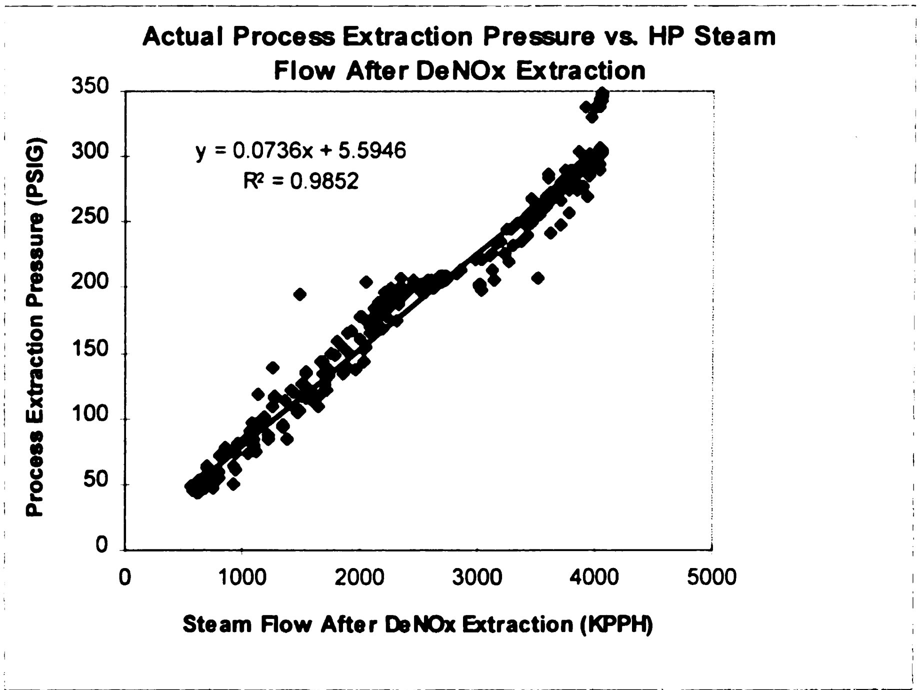

Figure 3-5: HP Process Extraction Pressure Actual Data and Curve Fit

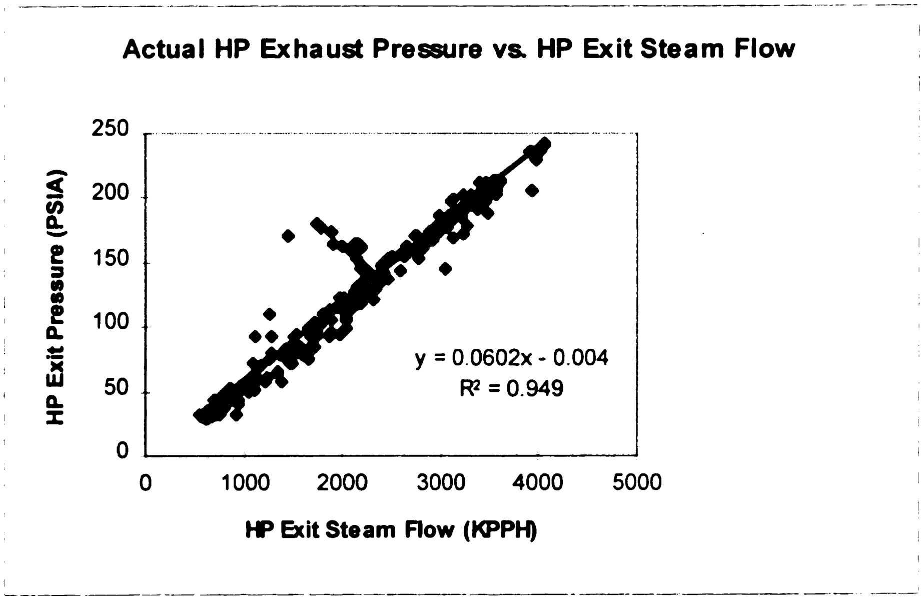

Figure 3-6: HP Exhaust Pressure Actual Data and Curve Fit

Using the above equations the outline required device performance parameters may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.2 Device #2 Moisture Separator Model

The only device parameter required for the modeling of the moisture separator is the pressure drop between the HP turbine exit and LP turbine inlet. This pressure loss is simply found by subtracting the LP turbine inlet pressure from the HP exhaust pressure. The LP inlet pressure is given below in Figure 3-7 as a linear function of the HP turbine exit mass flow rate, where

$$\dot{m}_{\text{HP Exhaust}} = \dot{m}_{\text{HP Inlet}} - \dot{m}_{\text{deNOx HP Extraction}} - \dot{m}_{\text{Process HP Extraction}}$$

Thus the separator pressure loss simply becomes

$$\Delta P_{\text{Separator Loss}} = P_{\text{HP Exhasust}} - P_{\text{LP Inlet}}$$

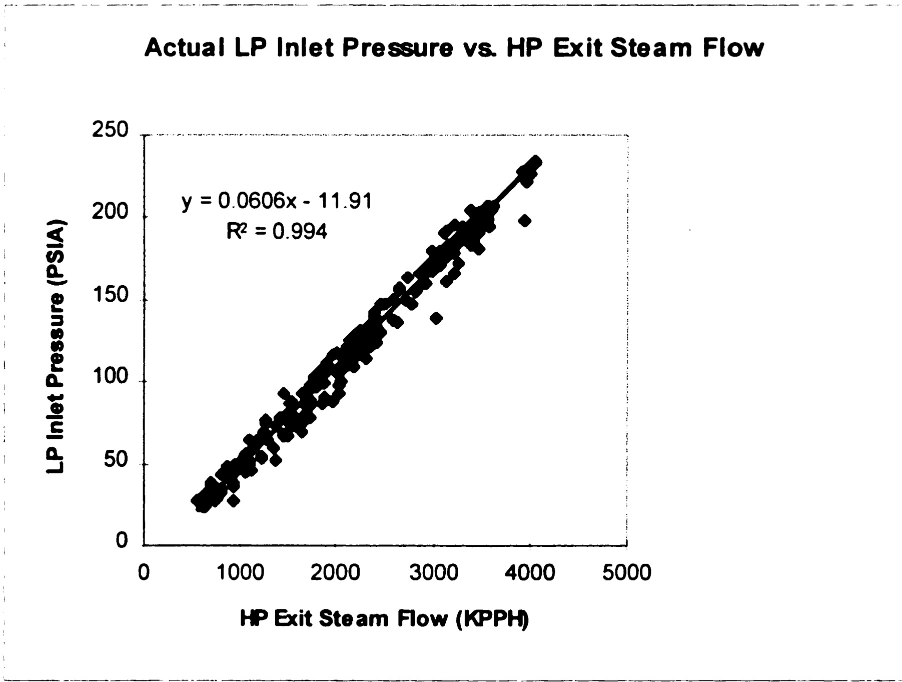

Figure 3-7: LP Inlet Pressure Actual Data and Curve Fit

Using the above equations the required device parameters may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.3 Device #3 LP Steam Turbine

The device parameter required for the modeling of the LP Steam Turbine is the exhaust or condenser pressure. From the compiled actual data and using curve fitting techniques this value was obtained as a function of the HP turbine exhaust flow rate. The HP exhaust flow rate was chosen because it was readily available and it is assumed the condensate removed from the fluid stream prior to the LP turbine had negligible effect on the condenser pressure. The LP exhaust/condenser pressure is given below as a function of the HP exhaust flow in Figure 3-8. Using the curve fit equation in Figure 3-8 the required device parameter may be easily calculated and input into the RANKINE 3.0 input data file.

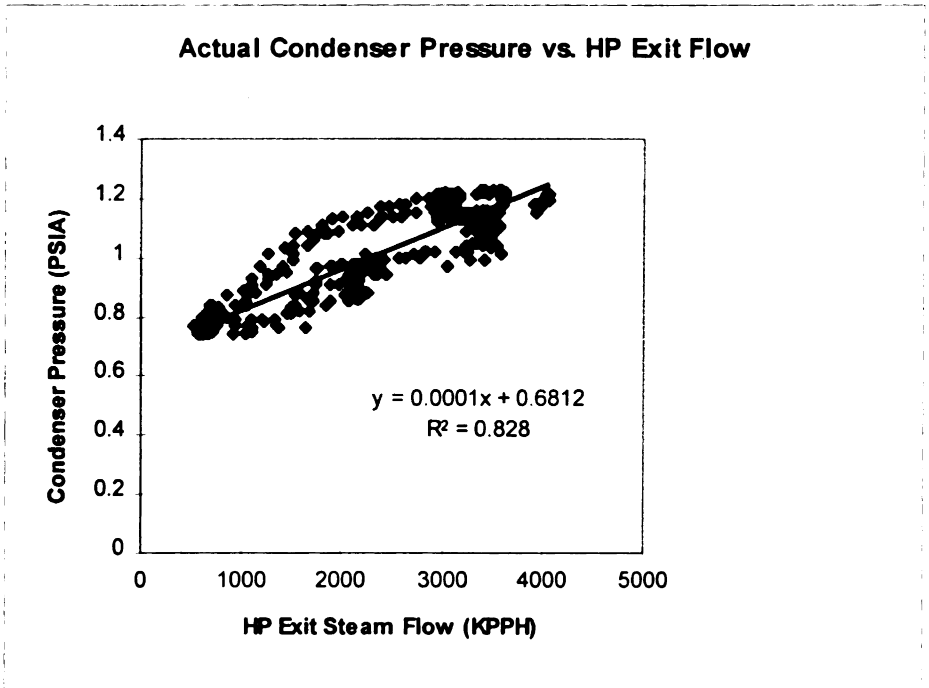

Figure 3-8: LP Exhaust/Condenser Pressure Actual Data and Curve Fit

3.4.4 Device #4 Condenser/Hotwell Model

The device parameter required for the modeling the condenser/hotwell is the condenser outlet water (saturated liquid) temperature. This is a user specified input parameter and is assumed to remain constant for various load conditions (main steam mass flow rates). This parameter value is dependent upon the ambient conditions and is easily obtainable via facility instrumentation. During the four day period when system data was collected this value remained approximately at 97.5°F, and this value was chosen for our model and analysis.

3.4.5 Device #5 Junction from Condenser and Makeup to Feedwater Pumps

The device parameters required for the modeling the feedwater makeup junction are the condenser outlet mass flow rate and the feedwater makeup mass flow rate. Both of these values are simply obtained algebraically as follows

$$\dot{m}_{\text{Condenser Outlet}} = \dot{m}_{\text{HP Exhaust}}$$

and

$$\dot{m}_{\text{Feedwater Makeup}} = \dot{m}_{\text{deNOx Required}} + \dot{m}_{\text{Process Required}} + \dot{m}_{\text{HRSG LP Blowdown}} + \dot{m}_{\text{HRSGHPBlowdown}}$$

where the feedwater makeup mass flow rate is equal to the sum of all of the mass flow rates of the fluid steams exiting the system. The required deNOx steam required is given below as a cubic function of the HRSG main steam flow in Figure 3-9. The cubic approximation of the data was chosen to model the upper bound deNOx steam requirements for high HRSG main steam flows. Using the curve fit equation in Figure 3-9 the required device parameter may be calculated and used in the above equation.

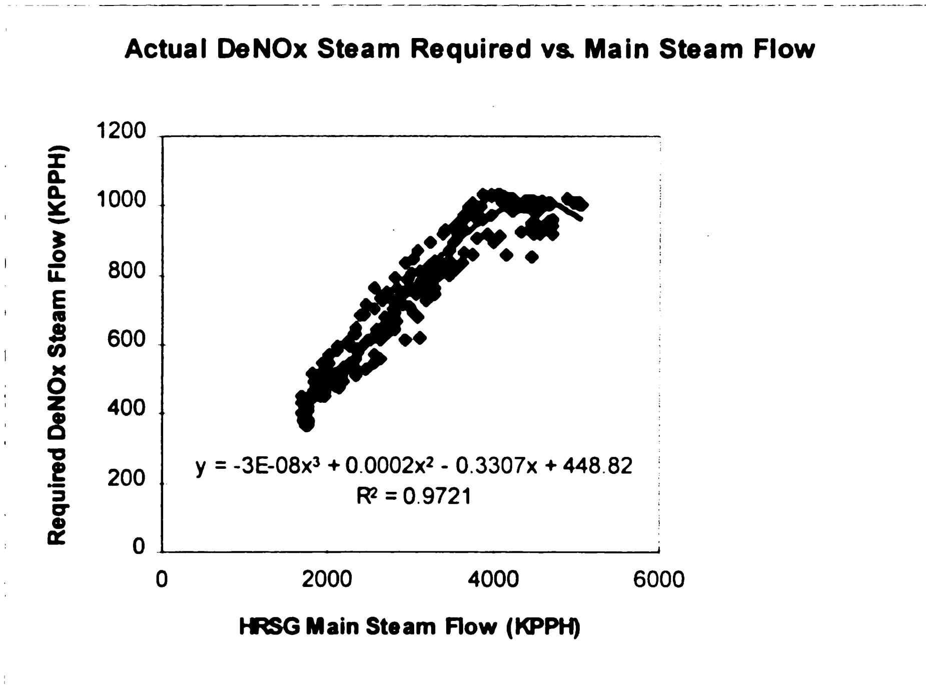

Figure 3-9: Required DeNOx Header Mass Flow Actual Data and Curve Fit

Using the above equations the required device parameter may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.6 Device #6 DeNOx Feedwater Pump Model

The device parameter required for modeling the deNOx (LP HRSG Boiler) feedwater pump is the discharge pressure. The deNOx header pressure is given below in Figure 3-10 as a linear function of the HRSG main steam flow rate.

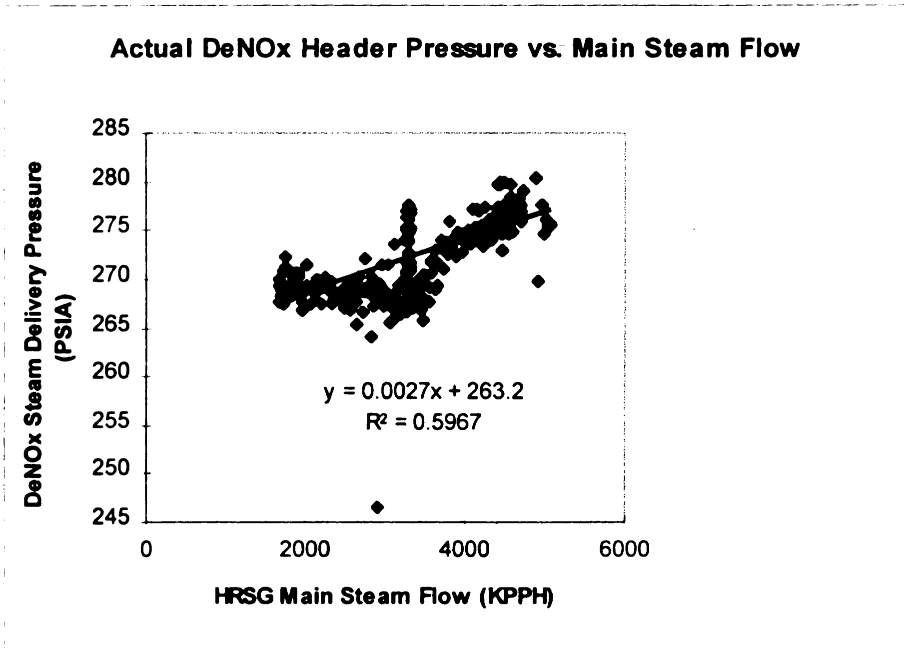

Figure 3-10: DeNOx Header Pressure Actual Data and Curve Fit

Using the above equation the required device parameter may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.7 Device #7 Main Boiler Feedwater Pump Model

Similar to the deNOx boiler feedwater pump, the device parameter required for modeling the Main Boiler (HP HRSG Boiler) feedwater pump is the discharge pressure. The main steam header pressure is given below in Figure 3-11 as a 6th order function of the HRSG main steam flow rate. The equation is six order to closely approximate the lower bound main steam constant pressure condition of approximately 475 PSIA for HRSG main steam outlet flows less than 3000 KPPH.

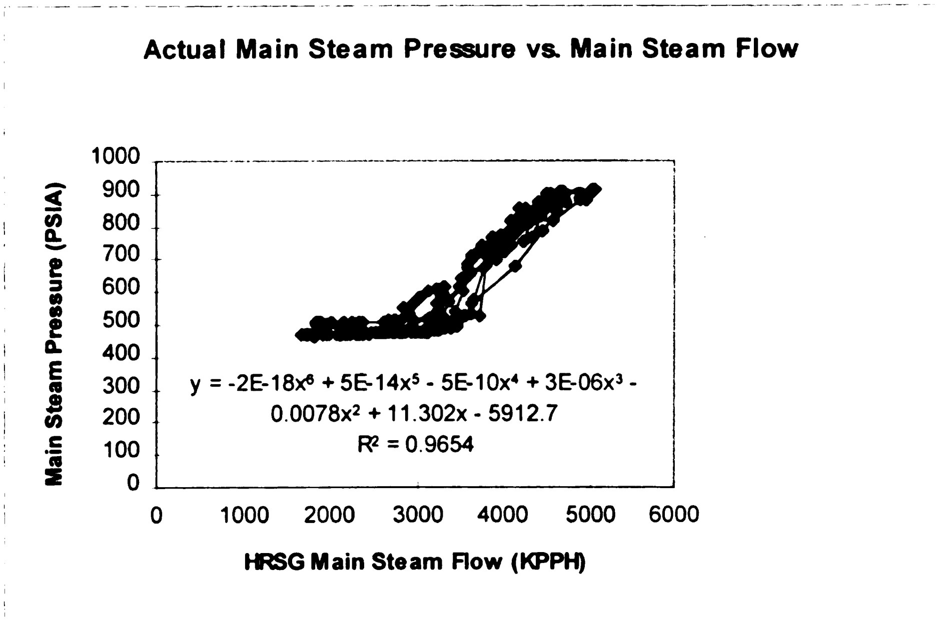

Figure 3-11: HRSG Main Steam Pressure Actual Data and Curve Fit

Using the above equation the required device parameter may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.8 Device #8 DeNOx BFW Pump to HRSG and Process Desuperheater Junction

The device parameters required for the modeling the junction connecting the deNOx boiler feedwater pump, the HRSG low pressure boiler, and the process steam desuperheater are the inlet and outlet flows to each connection. These values are simply obtained algebraically as follows by performing a mass balance about the junction using previously obtained values.

$$\dot{m}_{\text{DeNOx BFW Pump}} = \dot{m}_{\text{DeNOx HRSG}} + \dot{m}_{\text{Process Desuperheater}}$$

where

$$\dot{m}_{\text{Process Desuperheater}} = 0.02 * \dot{m}_{\text{Process Required}}$$

and $\dot{m}_{DeNOx\ HRSG}$ was found previously using curve fitting techniques. Note that the required saturated liquid mass flow rate to the process desuperheater is 2% of the total required mass flow required. This is an arbitrary value to reduce the process steam temperature prior to transport to the customer however ensuring that the provided process steam remains at least +10°F superheat. Using the above equations the required device parameter may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.9 Device #9 Main BFW Pump to HRSG and Main Steam Desuperheater Junction

Similar to the previous junction model, the device parameters required for the modeling the junction connecting the main boiler feedwater pump, the HRSG high pressure boiler, and the main steam desuperheater are the inlet and outlet flows to each connection. Again these values are obtained algebraically as follows by performing a mass balance about the junction using previously obtained values.

$$\dot{m}_{Main\ BFW\ Pump} = \dot{m}_{Main\ HRSG} + \dot{m}_{Main\ Header\ Desuperheater}$$

where

$$\dot{m}_{Main\ Header\ Desuperheater} = 1000 * (0.017 * \dot{m}_{Main\ After\ BP\ Turbine} - 54.9)$$

and $\dot{m}_{Main\ HRSG}$ is given as a user input parameter based on GT operating configuration. Note that the equation for the required mass flow rate of saturated liquid to the main header desuperheater is a function of the main steam mass flow rate after steam is diverted to the BP steam turbine. This equation is a given operating equation used to control the main steam temperature. The main steam mass flow after the BP turbine value is calculated as

$$\dot{m}_{\text{Main After BP Turbine}} = \dot{m}_{\text{Main HRSG}} - \dot{m}_{\text{HRSG HP Blowdownr}} - \dot{m}_{\text{BP Turbine}}$$

Using the above equations the required device parameter may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.10 Device #10 Combine HRSG Boiler Model

The device parameters required for modeling the combined HRSG boiler model are the main boiler (high pressure) exit temperature and the deNOx boiler (low pressure) exit temperature. The main steam header temperature equation is given below in Figure 3-12 as a linear function of the HRSG main steam flow rate. The deNOx boiler exit temperature is a user specified input parameter and is assumed to remain constant for various load conditions (main steam mass flow rates). During the four day period when system data was collected this value remained approximately at 464°F, and this value was chosen for our model and analysis.

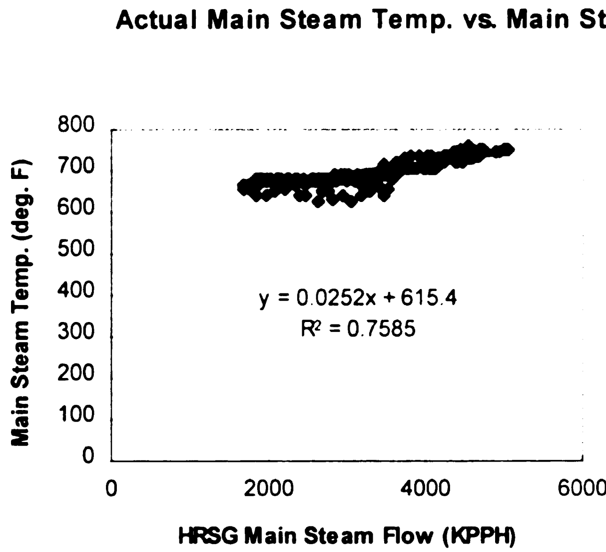

Figure 3-12: HRSG Main Steam Exit Temp. Actual Data and Curve Fit

3.4.11 Device #11 Main Steam Blowdown Junction

The device parameters required for the modeling the HRSG main steam blowdown junction are the HRSG main steam mass flow rate and the high pressure blowdown mass flow rate. Both of these values are simply obtained algebraically as follows

$$\dot{m}_{HRSGHPBlowdown} = 0.005 * \dot{m}_{Main\ HRSG}$$

where the $\dot{m}_{Main\ HRSG}$ the user specified value depending upon GT operation configuration. Note that only 0.5% of the main steam is blowdown. This quantity was determined by plant personnel through the analysis of historical data to be the appropriate mass flow to maintain proper chemical control of the superheated steam and saturated liquid condensate. Using the above equation and user specified value the required device parameters may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.12 Device #12 DeNOx Steam Blowdown Junction

The device parameters required for the modeling the HRSG deNOx steam blowdown junction are the HRSG deNOx steam mass flow rate and the low pressure blowdown mass flow rate. Both of these values are simply obtained algebraically as follows

$$\dot{m}_{\text{HRSG HP Blowdown}} = 0.005 * \dot{m}_{\text{DeNOx HRSG}}$$

where the $\dot{m}_{\text{DeNOX HRSG}}$ is a previously calculated value. Again note, that only 0.5% of the deNOx steam is blowdown. This quantity was determined by plant personnel through the analysis of historical data to be the appropriate mass flow to maintain proper chemical control of the superheated steam and saturated liquid condensate. Using the above equation and user specified value the required device parameters may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.13 Device #13 Junction from Main Steam Header to BP Steam Turbine

No device parameters are required to be input for the modeling the junction connecting the main steam header to the BP steam turbine. RANKINE 3.0 performs the necessary thermodynamic analysis of the connecting nodes to ensure continuity about this device. Therefore nothing further needs to be input into the RANKINE 3.0 input data file.

3.4.14 Device #14 BP Steam Turbine

The device parameters required for the modeling of the BP Steam Turbine is the BP turbine mass flow rate and the BP turbine exhaust pressure. The BP turbine inlet mass flow is a user input parameter and the exhaust pressure is the previously calculated

deNOx steam header (delivery) pressure. Each of these values are then input into the RANKINE 3.0 input data file. From actual collected data it is shown that the adiabatic efficiency of each stage was found to be statistically constant and as follows in Appendix C. The resultant stage adiabatic efficiency is 78%.

3.4.15 Device #15 Main Steam Desuperheater

The device input parameter required for the modeling of the main steam desuperheater in the previously calculated feedwater mass flow rate derived in the description of device #9. Similarly this mass flow rate is input into the RANKINE 3.0 input data file.

3.4.16 Device #16 Main Steam to DeNOx and Process Letdown

The device parameters required for the modeling the deNOx and process steam letdown junction are the deNOx steam letdown mass flow rate and process steam letdown mass flow rate. The deNOx steam letdown mass flow rate is a user input value and the process steam letdown value was previous obtained algebraically as follows

$$\dot{m}_{\text{Process Letdown}} = \dot{m}_{\text{Process Required}} - \dot{m}_{\text{Process HP Extraction}}$$

The above device parameters are then input into the RANKINE 3.0 input data file.

3.4.17 Device #17 & #18 Steam Letdown Throttling Processes

The device parameters required for the modeling the deNOx steam and process steam throttling process are the main steam header to deNOx steam header and the main steam header to process steam header pressure differences respectively. The deNOx throttling process pressure difference value is calculated as

$$\Delta P_{DeNOx\ Throttling} = P_{Main\ Header} - P_{DeNOx\ Header}$$

and similarly the process steam throttling process pressure difference value is calculated as

$$\Delta P_{Process\ Throttling} = P_{Main\ Header} - P_{Process\ Header}$$

Using the above equations the required device parameters may be easily calculated and input into the RANKINE 3.0 input data file.

3.4.18 Device #19 & #23 HP Extraction to DeNOx/Process Header Pressure

Similar to the previous derivation the device parameters required for the modeling the HP deNOx steam and HP process steam throttling processes are HP deNOx steam extraction to deNOx steam header and the HP process steam extraction to process steam header pressure differences respectively. The HP deNOx throttling process pressure difference value is calculated as

$$\Delta P_{HP\ DeNOx\ Throttling} = P_{HP\ DeNOx\ Extraction} - P_{DeNOx\ Header}$$

and similarly the HP process steam throttling process pressure difference value is calculated as

$$\Delta P_{HP\ Process\ Throttling} = P_{HP\ Process\ Extraction} - P_{Process\ Header}$$

Using the above equations the required device parameters may be calculated and input into the RANKINE 3.0 input data file.

3.4.19 Device #20-22 & #24 Mixing of DeNOx/Process Letdown and Extraction Flows

No device parameters are required to be input for the modeling the open feed water heater mixing chamber models connecting the various deNOx and process steam supply devices. RANKINE 3.0 performs the necessary thermodynamic analysis of the connecting nodes to ensure continuity about these devices. Therefore nothing further needs to be input into the RANKINE 3.0 input data file.

3.4.20 Device #26 Process Steam Desuperheater

The device input parameter required for the modeling of the process steam desuperheater is the user input customer required process steam mass flow rate. Similarly this mass flow rate is input into the RANKINE 3.0 input data file.

3.4.21 Device #25, #27, & #28 Misc. Pressure Losses and Throttling Processes

Similar to the previous derivation of throttling processes, the device parameters required for the modeling of the process desuperheater feedwater thottling process, moisture separator condensate throttling process ,and HRSG main steam to HP turbine inlet pressure losses are deNOx steam header to process steam header pressure difference, moisture separator exit to condenser pressure difference, and the HRSG main steam to HP inlet pressure difference respectively. The process desuperheater feedwater throttling process pressure difference value is calculated as

$$\Delta P_{\text{Process FW Throttling}} = P_{\text{DeNOx Header}} - P_{\text{Process Header}}$$

and similarly the moisture separator condensate throttling process pressure difference value is calculated as

$$\Delta P_{\text{Moisture Separator Thottling}} = P_{\text{Moisture Separator Exit}} - P_{\text{Condenser}}$$

and finally the and HRSG main steam to HP turbine inlet pressure losses is modeled as a SIMPLE PIPE pressure loss as

$$\Delta P_{\text{Main Header Losses}} = P_{\text{Main HRSG}} - P_{\text{HP Inlet}}$$

Using the above equations the required device parameters may be calculated and input into the RANKINE 3.0 input data file.

3.5 Pre-Processing Worksheet Summary

With all the device parameters now algebraically defined as functions of the user input parameters this information may be incorporated into an Excel 5.0 spreadsheet. An example of the pre-processing worksheet is shown in Appendix A. The spreadsheet prompts the user to enter the eight following key input parameters: HRSG main steam flow, process steam mass flow required, process steam required delivery pressure, HRSG deNOx steam temperature, condenser exit temperature, process steam extracted via the HP steam turbine, deNOx steam extracted via the BP steam turbine, and the deNOx steam extracted via the main steam header deNOx letdown. With this information along with the above performance equations derived from actual operating data the remaining required RANKINE 3.0 input parameters are calculated for input into the RANKINE 3.0 input file.

3.6 RANKINE 3.0 Input/Output Files

Given in Appendix A is the constructed RANKINE 3.0 input file and Excel 5.0 spreadsheet used to pre-process the required operating parameters, as discussed and developed in section 3.3 and 3.4, that is used to traverse the above system layout device by device, analyzing the working fluid as it passes through each device. The subsequent analysis performed by RANKINE 3.0 provides additional fluid properties at each node resulting in the completed output table file. An example of this file is given in Appendix A. With this completed table, the system information (such as thermal efficiency and work produced) is calculated.

Chapter 4 Model Verification

4.0 Outline of Model Verification Procedure

The following procedure was used to verify the developed facility model.

1. Determine a number of test cases that adequately represent actual facility operating conditions.

2. Determine various key 'nodes' in the process and energy outputs (e.g. unit 1 STG megawatts produced) and collect historical mass flow rate, temperature, pressure, and MW data to compare with the model results.

3. Calculate the enthalpy at each of the above nodes given the temperature and pressure using appropriate steam tables.

4. For each test case use the above facility model to model each of the various operating conditions.

5. Obtain an output file from the model and extract the node and energy output data, as determined above, to compare with the actual operating data.

6. Tabulate the collected historical and resulting model node and energy output data by calculating a percent error, defined as

$$\text{Percent Error} = \left(\frac{\text{Node Value}_{\text{Model}} - \text{Node Value}_{\text{Actual}}}{\text{Node Value}_{\text{Actual}}} \right) \times 100\%$$

7. Given the model assumptions, the model will be considered to have successfully modeled the various test case operating conditions if the resulting percent error is five percent or less.

8. Given the model assumptions, the model will be considered to have marginally modeled the various test case operating conditions if the resulting percent error is between five and fifteen percent.

9. Given the model assumptions, the model will be considered to have unsuccessfully modeled the various test case operating conditions if the resulting percent error is greater than fifteen percent.

4.1 Model Application Using RANKINE 3.0 and Excel 5.0

Eight actual operating test cases along with the initial feasibility heat balance calculated April 28, 1998 by the Fluor Engineering Corporation were chosen to be modeled using the RANKINE 3.0 and Excel 5.0 tools for model verification. Each test case was chosen to represent a particular load/configuration condition as classified below in Table 4-1. The heat balance case was chosen to provide a basis for model development and for model comparison, however since the introduction of the back pressure steam turbine and more efficient blading of the unit one low pressure steam turbine, variances between the heat balance and the model are expected.

Each test case is summarized below in Table 4-1.

Table 4-1: Model Verification Test Case Summary

Case Number	***Description***
Case No. 1 - Heat Balance 4/28/88	Expected operating conditions obtained from heat balance performed by Fluor Engineering Corp. 1988
Case No. 2 - Max. Load Fired	12 GTs in operation with duct firing in 6 HRSGs
Case No. 3- Max. Load Fired	12 GTs in operation with duct firing in 3 HRSGs
Case No. 4 - Max Load Unfired	12 GTs in operation with no duct firing in any HRSG
Case No. 5 - Partial Load - Ramp Up	8-10 GTs in operation during 4 hour "ramp up" period
Case No. 6 - Partial Load - Transient	8-12 GTs in operation, none at full load, bringing GT up to load while turning others off
Case No. 7 - Partial Load - Ramp Down	10 -8 GTs in operation during 4 hour "ramp down" period
Case No. 8 - Min. Load	5 GTs in operation with no duct firing
Case No. 9 - Min. Load	5 GTs in operation with no duct firing

For each test case it was determined that the key nodes of interest would be those associated the heat recovery steam generator, the high pressure steam turbine, the low pressure steam turbine, the back pressure steam turbine, the required deNOx control steam to be delivered to the gas turbines, and the required process steam to be delivered to the customer, since they provide the base heat input, and work and heat output of the simplified steam model. Thus, the previous device fluid state values were collected from facility historical data and the following parameters were entered into the Excel 5.0 pre-processing worksheet for each test case: main steam flow exiting the HRSG, customer process steam mass flow required, customer process steam delivery pressure, deNOx steam temperature exiting HRSG, condenser condensate exit temperature, customer process steam mass flow extracted from the HP steam turbine, deNOx control steam mass flow extracted from the main steam head via the BP steam turbine, and deNOx control steam mass flow extracted from the main steam header via deNOx steam letdown. The Excel 5.0 worksheet checks to make sure all data entered is valid (e.g. perform conservation of mass check, and verify that temperature/pressure values do not exceed design constraints) and calculated all of the required data to be input into the RANKINE 3.0 input data file. The resulting data was then entered into a RANKINE 3.0 input data file device by device for each test condition and the RANKINE 3.0 software was subsequently run, to generate the desired output file. The input and output files for each test case are compiled and compared with the actual data obtained from the facility. The mass flow rate, pressure, temperature, and enthalpy were then extracted from the RANKINE 3.0 output data file for the following nodes for comparison with the actual recorded values: node 1 (HRSG main steam exit), node 16 (HRSG deNOx steam exit), node 1 (HP steam turbine inlet), node 2 (HP steam turbine deNOx steam extraction), node 3 (HP steam turbine customer process steam extraction), node 4 (HP steam turbine exhaust), node 5 (LP steam turbine inlet), node 22 (BP steam turbine inlet), node 24 (BP steam turbine exhaust), node 32 (required deNOx controls steam delivery to GTs), and node 36 (required process steam delivery to customer). In addition to the above the following energy outputs of the actual and modeled steam system were recorded from historical data and resulting model output files: megawatts produced by the back pressure steam turbine, megawatts produced by the unit one steam turbine generator (addition of HP and LP megawatts produced), and the net gas turbine megawatts produced (actual historical data only). This comparison data was then tabulated and a resultant percent error calculated for each of the above stated nodes for comparison/verification purposes.

4.2 Comparison of Model to Actual Operating Data

The comparison data compiled in Appendix B is then used to determine if the developed model can successfully simulate the actual facility steam cycle. The actual and modeled mass flow rate, pressure, temperature, and enthalpy values are tabulated for each test case and node location.

4.2.1 Test Case No. 1 - Heat Balance 4/28/88

This case modeled the steam system of the expected heat balance of the facility calculated April 28, 1988 when the facility was being evaluated if conversion from a nuclear power plant to a combine cycle cogeneration facility would be feasible. This heat balance provided insight into the initial model development, however due to the numerous changes to the facility (e.g. addition of the BP steam turbine, reduced deNOx control steam requirements, etc.) this heat balance is no longer valid. Therefore, it was decided to model this case to determine the validity of the past heat balance and to provide an initial glimpse of how well the developed facility model simulated the facility. From Table B-1, Case No. 1, it is shown that the model does a successful job in predicting the

electrical output and enthalpy values at each node, with percent error values less than five percent. However, the model does a marginal, or unsuccessful job in predicting a number of the temperature and pressure values, with percent error values greater than five percent. As stated earlier this margin of error was to be expected since the initial facility heat balance was developed from expected operating conditions, assumed adiabatic efficiencies, etc. that differ from the current facility operating characteristics. Therefore with the accuracy obtained from the enthalpy predications and subsequent unit one steam turbine generator output, the model is considered to provide an appropriate representation of the facility to continue with the test case analysis.

4.2.2 Test Cases No. 2 thru 4 - Max. Load with and without Duct Firing

For these three test cases all twelve gas turbines were in steady state operation, where the variance in the main steam flow from the HRSG is directly attributed to the duct firing configuration of each HRSG. Comparing the data tabulated in Table B-1, it is easily determined that the developed model successfully represents the facility electrical output and enthalpy values at each node, with percent error values less than five percent. Note, the error in the mass flow values of the required process steam to be supplied to the customer is greater than fifteen percent. This is a user error made by the author by not modifying the input file as required from the collected historical data and was perpetuated for the remaining test cases. Since this a user input error, and its effects do not adversely effect the remaining values this error is ignored. It is noted, however, that most temperature and pressure values are marginally predicted by the model as defined in section 4.0. This variance can best be explained by the experimental error and inherent variation of the measurement devices used to collect the state data at each node and the curve fitting error and assumptions used in developing the model. It is important to note that even though the model marginally predicts the states at the selected nodes the resulting enthalpy values are still accurate to less than five percent, and therefore the error in the predicted temperature and pressure values is shown to have little effect on the enthalpy values. Hence the developed model was determined to provide a successful representation of the facility for these operating conditions.

4.2.3 Test Cases No. 5 thru 7 - Partial/Transient Load Conditions

Three transient operating conditions were modeled in test cases five through seven. These models were used to evaluate the developed model under intermediate load conditions where the number of gas turbines in operation were between five and twelve. For each partial/transient load case data was collected for a period of four hours. This data was then averaged and used for the various state data for each node. For case number five the data collected during the four hour period was during a "ramp up" period where the number of gas turbines in use was increased from 8 to 12 in order to meet customer electricity demands. Similarly for case number seven the data collected during the four hour period was during a "ramp down" period where the number of gas turbines in use was decreased from 12 to 8 in response to decrease customer demand. Data collected during the four hour period for case number six was during a transition period where four of the eight gas turbines in operation where shut down for preventative maintenance and replaced by four gas turbines that were previously not in operation. Thus during this period all twelve gas turbines were in operation however, all of which were not at maximum rated load during the transition. Comparing the data tabulated in Table B-1 for these cases, it is determined that the developed model successfully represents the facility unit one steam turbine electrical output and enthalpy values at each node, with percent error values less than five percent. Note, the error in the back pressure steam turbine electrical production is much greater than fifteen percent. This is primarily due to the mis-calculation of the inlet pressure, or main steam header pressure. Recall that the transient temperature and pressure values collected during their respective four hour time period where averaged over time irrespective of the main steam mass flow rate from the HRSG. Whereas the model assumes steady state operation and uses the main steam mass flow as the primary independent variable to calculate the modeled temperatures and pressures. Therefore it is noted, that a number of temperature and pressure values are unsuccessfully predicted by the model as defined in section 4.0. This variance can best be explained by the experimental error in trying to represent each four hour period by simply choosing a single time averaged data point. The appropriate method to evaluate these transient operating conditions would be to increase the collection intervals such that the transient behavior may be modeled via a number of individual steady state conditions, rather than by the method described above. It is important to note that even though the model unsuccessfully or marginally predicted a number of the states at the selected nodes the resulting enthalpy values are still accurate to less than five percent, and therefore the error in the predicted temperature and pressure values has little effect on the enthalpy values. Hence the developed model was determined to provide a marginal representation of the facility during these transient operating conditions. Where the primary error lies in the time averaged historical actual data used for the model comparison.

4.2.4 Test Cases No. 8 and 9 - Min. Load without Duct Firing

Similar for the maximum load operating conditions in section 4.2.2 these last two test cases model five gas turbines in operation at steady state during a four hour period, where the difference in the main steam flow from the HRSG is 4% from case 8 to case 9. Again comparing the data tabulated in Table B-1, it is shown that the developed model successfully represents the facility electrical output and enthalpy values at each node, with percent error values less than five percent. Once again, most temperature and pressure values are marginally predicted by the model as defined in section 4.0. This variance is explained by the experimental error and inherent variation of the measurement devices used to collect the state data at each node and the curve fitting error and assumptions used in developing the model. It is important to note that even though the model marginally predicts the states at the selected nodes the resulting enthalpy values are still accurate to less than five percent, and therefore the error in the predicted temperature and pressure values is shown to have little effect on the enthalpy values. Hence the developed model was determined to provide a successful representation of the facility for these operating conditions.

4.3 Overall Model Evaluation

From the previous case comparisons of actual data to the resultant model data for the various facility operating conditions it is concluded that the developed model can successfully model the facility under steady state operating conditions. In order to perform an accurate transient study the time interval between data points must be reduced such that the transient process may be successfully represented as a series of steady state snapshots in time. Though the model was shown to marginally represent the thermodynamic states at the desired node locations for the reasons stated above, the model did however closely model the enthalpy values at each node location. We are primarily interested in the system performance and resulting electrical output values for the various load conditions and system configurations of the facility. Therefore, the accuracy of the modeled enthalpy values is paramount, considering the resultant performance and output values are functions of the enthalpy at each node. Thus, due to the highly accurate representation of the enthalpy values for the test cases discussed above the model may be considered to successfully model the described combine cycle cogeneration facility.

Chapter 5 Facility Evaluation

5.0 Evaluation Overview

Following is a brief facility evaluation using the developed model to illustrate its use for process optimization. The developed model may be used to efficiently perform both a first (heat balance) and second law analysis of the facility for numerous operating configurations. This information is then used to determine a process optimization in regards to auxiliary and emission control steam production, electrical power production, and process steam sold to the customer. Evaluation was begun by selecting a suitable base case from which the mass flow rates to the various devices used to provide process and deNOx control steam are varied in order to investigate the optimum operating configuration of the system. The case chosen is given as the MCVOP1.DAT file in Appendix E. This case represents the typical operating conditions of the plant at full load where eleven gas turbine generators are in operation with approximately 3 units utilizing duct firing. From this base configuration the steam mass flow rates were varied from one device to another to investigate the resultant effect on system performance. For example, for the first case, 25 percent of the base mass flow from the process steam main header letdown was diverted to/from the high pressure steam turbine extraction. Therefore, rather than obtaining the required customer process steam via the main steam header letdown, 25 percent of the mass flow was diverted from the process letdown and provided to the HP steam turbine where it was extracted from the high pressure steam turbine, and vice versa. Similarly, for the remaining cases the various deNOx control steam mass flow rates were diverted from one device to another to investigate the optimum configuration to obtain the required deNOx control steam. Each case is run using the developed model and the following performance values were calculated by the RANKINE 3.0 software for analysis: net megawatts produced, system heat rate, carnot cycle efficiency, 1st law efficiency, 2nd law efficiency, and 2nd law effectiveness. The performance values are then analyzed to determine the optimum system configuration for the given operating condition. The summary of this analysis is provided in Appendix D.

5.1 Facility Operating Configuration Variation

5.1.1 Case #1: Process Steam from Main Steam Letdown to HP Turbine Extraction

For this case, 25% (110 KPPH) of the base process steam obtained from the main steam letdown throttling process was diverted, expanded, and extracted through the high pressure steam turbine. Similarly, 23% (99 KPPH) of the base process steam obtained from the high pressure steam turbine extraction was diverted and throttled through the main steam header letdown valve. Each case was simulated using the developed model and their subsequent RANKINE 3.0 output files were compiled. The summary of the resultant system performance values for each condition is given in Table D-1. From the information presented in Table D-1, it is shown that for each 110 KPPH incremental diversion of process steam from the main steam header letdown through the high pressure steam turbine extraction, approximately an additional 1.2% increase in net megawatt production (5 MW), 1st law efficiency, and 2nd law effectiveness are realized. This result is due to the additional 4.0% (5 MW) increase in gross megawatt production from the high pressure steam turbine per each 110 KPPH incremental diversion of process steam. Therefore, in order to optimize net megawatt production and the above performance measurements it makes sense to extract customer process steam through the high pressure steam turbine. Through expansion additional energy may be extracted from the working fluid rather than through process steam letdown throttling valves (a purely irreversible process) to obtain the desired pressure reduction from the main steam header to the customer required delivery pressure.

5.1.2 Case #2: DeNOx Steam from BP Steam Turbine to HP Turbine Extraction

For this case, 25% (117 KPPH) of the base deNOx control steam obtained from the back pressure steam turbine was diverted, expanded, and extracted through the high pressure steam turbine. Similarly, 50% (234 KPPH) of the base deNOx control steam obtained from the back pressure steam turbine was diverted, expanded, and extracted through the high pressure steam turbine. Each case was simulated using the developed model and their subsequent RANKINE 3.0 output files were compiled. The summary of the resultant system performance values for each condition is given in Table D-1. From the information presented in Table D-1, it is shown that for each 117 KPPH incremental diversion of deNOx control steam from the back pressure steam turbine to the high pressure steam turbine extraction, only a 0.33% increase in net megawatt production (~1.5 MW) is realized. The 1st law efficiency and 2nd law effectiveness, however, exhibit unique behavior. Note, from Table D-1 as 117 KPPH of deNOx control steam is diverted from the back pressure steam turbine to the high pressure steam turbine extraction, both the 1st law efficiency and the 2nd law effectiveness increase by 1.5% as compared to the base case. Next, as 234 KPPH of deNOx control steam is diverted as stated above, both the 1st law efficiency and the 2nd law effectiveness only increase by 0.67% as compared to the base case. Since the performance values obtained for the 117 KPPH condition are greater than that of the 234 KPPH condition that suggests there is a local mass flow rate value that will yield an optimum 1st law efficiency and 2nd law effectiveness value. Determination of this value is suggested to the reader as an extension to this analysis. It is not found here due to the negligible effects diversion of the deNOx control steam from the BP steam turbine to the HP steam turbine extraction has on the net megawatt production. Recall from table D-1, for each 117 KPPH incremental diversion of deNOx control steam a 0.33% increase in megawatt production is realized. The model has been successfully verified to be accurate to within 5% in predicting actual net megawatt production in the previous chapter, thus the predicted 0.33% net increase in net megawatt production may or may not be realized by the actual facility due to model assumption error and actual process variation. Therefore, it is concluded that there is no optimum selection in obtaining deNOx control steam through the back pressure steam turbine or the high pressure steam turbine in terms of net megawatt production. Either device is well suited to provide the desired pressure reduction from the main steam header to the required deNOx control steam delivery pressure.

5.1.3 Case #3: DeNOx Steam from BP Steam Turbine to Main Steam Letdown

For this case, 25% (117 KPPH) of the base deNOx control steam obtained from the back pressure steam turbine was diverted and throttled through the main steam header letdown valve. Similarly, 50% (234 KPPH) of the base deNOx control steam obtained from the back pressure steam turbine was diverted and throttled through the main steam header letdown valve. Each case was simulated using the developed model and their subsequent RANKINE 3.0 output files were compiled. The summary of the resultant system performance values for each condition is given in Table D-1. From the information presented in Table D-1, it is shown that for each 117 KPPH incremental diversion of deNOx control steam from the back pressure steam turbine to the main steam header deNOx letdown, approximately a 0.8% decrease in net megawatt production (3.5 MW), 1st law efficiency, and 2nd law effectiveness are realized. This result is due to the 25% (3.5 MW) decrease in gross megawatt production per each 117 KPPH incremental diversion of deNOx control steam from the back pressure steam turbine to the main steam letdown. Therefore, in order to optimize net megawatt production and the above performance measurements it makes sense to extract deNOx control steam through the back pressure steam turbine, rather than through main header letdown. Through expansion additional energy may be extracted from the working fluid rather than through deNOx control steam letdown throttling valves to obtain the desired pressure reduction from the main steam header to the customer required delivery pressure.

5.1.4 Case #4: DeNOx Steam from Main Steam Letdown to HP Turbine Extraction

For this case, 50% (39 KPPH) of the base process steam obtained from the main steam deNOx letdown throttling process was diverted, expanded, and extracted through the high pressure steam turbine. Similarly, 100% (77 KPPH) of the base process steam obtained from the main steam deNOx letdown throttling process was diverted, expanded, and extracted through the high pressure steam turbine. Each case was simulated using the developed model and their subsequent RANKINE 3.0 output files were compiled. The summary of the resultant system performance values for each condition is given in Table D-1. From the information presented in Table D-1, it is shown that for each 39 KPPH incremental diversion of deNOx control steam from the main steam header letdown through the high pressure steam turbine extraction, approximately an additional 0.35% increase in net megawatt production (1.6 MW), 1st law efficiency, and 2nd law effectiveness are realized. This result is due to the additional 1.2% (1.6 MW) increase in gross megawatt production from the high pressure steam turbine per each 39 KPPH incremental diversion of deNOx control steam. Therefore, in order to optimize net megawatt production and the above performance measurements it makes sense to extract deNOx control steam through the high pressure steam turbine. Similarly to case one, through expansion additional energy may be extracted from the working fluid rather than through deNOx steam letdown throttling valves (a purely irreversible process) to obtain the desired pressure reduction from the main steam header to the required deNOx control steam delivery pressure to the gas turbine combustor.

5.2 Optimum Operating Configuration

From the evaluation performed above, and the supporting data in Table D-1, it is determined that the optimum operating configuration of the modeled steam system would be to close both deNOx and process steam letdown valves (0 KPPH mass flow) from the main steam header and obtain all required deNOx control and customer process steam via the extraction of either the back pressure or high pressure steam turbines. This allows for the extraction of the available energy from the deNOx and process steam letdown throttling processes via the expansion of the diverted steam to either the back pressure or high pressure steam turbines.

As stated in section 2.2.1, the back pressure steam turbine was installed to provide a more reliable means of extracting deNOx control steam without being constrained to deNOx letdown and to increase overall electrical production capacity. It is suggested to the reader to review section 2.2.1 as necessary to understand the advantages and disadvantages of the use of the back pressure steam turbine within the steam system. From the above evaluation and Table D-1, it is shown that approximately an additional 10 megawatts of electricity may be obtained if proper deNOx steam extraction control can be implemented to the high pressure steam turbine. It is important to note that effective control of the HP steam turbine deNOx extraction pressures will yield an increase in actual plant capacity (~10 MW) by greatly reducing the use of the inefficient letdown extractions from the main steam header to obtain required deNOx control and customer process steam. Therefore, it is suggested that the implementation of globe type valves (or equivalent) similar to those that were installed to control process steam extraction pressures from the high pressure steam turbine be investigated as to being an effective solution, such that the letdown throttling processes be used only in extenuating circumstances.

Chapter 6 Conclusions and Recommendations

6.0 Conclusions

The following conclusions are supported by this analysis:

- The RANKINE 3.0 software permits the steam system modeling of an actual combined-cycle cogeneration facility through the use of an Excel 5.0 pre-processing worksheet.

- The developed steam system model permits various operating configurations to be studied and provide results which are consistent with actual operating data.

- At base load, all required deNOx control and customer process steam should be obtained via the back pressure steam turbine or high pressure steam turbine extraction to attain optimum electrical energy production.

- Facility electrical production capacity and thermal efficiency may be improved if enhanced control valves are implemented to improve deNOx steam extraction from the high pressure steam turbine.

- The developed model can not determine which device, the back pressure or the high pressure steam turbine, is better suited to provide the desired pressure reduction from the main steam header to the required deNOx control steam delivery pressure.

6.1 Recommendations

The following recommendations are suggested by the author:

- Integrate the pre-processing Excel 5.0 worksheet (or equivalent) into the RANKINE 3.0 input file format.
- Perform a transient analysis of the facility and compare with obtained data during load dispatch (ramp up/down) to confirm robustness of the developed model under such conditions.
- Investigate the effects of varying adiabatic stage efficiencies in the high pressure steam turbine when subject to low main steam mass flow conditions.
- Determine the optimum local high pressure steam turbine deNOx extraction and back pressure steam turbine mass flow rate values that will yield an optimum 1st law efficiency and 2nd law effectiveness value and note its effects on net electrical megawatt production

Appendix A:

Excel 5.0 Pre-Processing Worksheet, & RANKINE 3.0 Input/Output File Examples

RANKINE 3.0: Pre-Processing Worksheet INPUT File Calculator

File Name: MCVF**.DAT

Date 10/6/98

Author Brian J Vokal

User Input Operating Conditions

Description	Value	Resulting % of Required	Max. Allowed %
HRSG Main Steam Flow	4511 KPPH		
Process Steam Req'd (Flow)	538 KPPH		
Process Steam Req'd (Press.)	190 PSIA		
DeNOx Steam Delivery Temp.	464 DEG. F		
Condenser Exit Temp.	97.5 DEG. F		
Process Steam Process Letdown	99 KPPH	18 %	100 %
Process Steam Thru HP	439 KPPH	82 %	100 %
DeNOx Steam thru BP Turbine	468 KPPH	45 %	46 %
DeNOx Steam thru DeNOx Letdown	5 KPPH	0 %	54 %
DeNOx Steam thru HP Turbine	82 KPPH	8 %	8 %
DeNOx Steam thru HRSG	475 KPPH	46 %	46 %

Input Values Are Valid

Operating Conditions Derived from Actual Data Obtained 8/21 - 8/24, 1998

	To = 75 deg F		
Description	Flow (lb/hr)	Temp (F)	Press (PSIA)
HRSG Steam Flow	4511000	729	910
HRSG DeNOx Steam	474552	464	275
H2O Injection to Main Steam	13831	97.5	910
HP Inlet Conditions	3952831	701	856
HP DeNOx Extraction	82448	-	355
HP Process Extraction	439000	-	290
HP Exit Conditions	3431383	-	207
LP Inlet Conditions	-	-	196
Condenser Exit Conditions	-	97.5	1.0
DeNOx Steam Req'd	1030000	464	275

Device #1: Simple Turbine (HP Steam Turbine Model)

Input Required: HP Turbine Inlet Conditions

Inlet Pressure	856 PSIA
Inlet Mass Flow	3952831 lbm/hr

Input Required: Flow & Extraction Conditions

Ex. #1 Pressure (DeNOx)	355 PSIA
Ex. #1 Mass Flow (DeNOx)	82448 lbm/hr
Ex. #2 Pressure (Process)	290 PSIA
Ex. #2 Mass Flow (Process)	430220 lbm/hr
Ex. #3 Pressure (Outlet)	207 PSIA
Stage #1 Isentropic Efficiency	78 %
Stage #2 Isentropic Efficiency	100 %
Stage #3 Isentropic Efficiency	91 %

Device #2: Simple Moisture Separator (CIV/Moisture Separator Model)

Input Required: Outlet/Condenser Pressure

Separator Pressure Loss	11 PSIA

Device #3: Simple Turbine (LP Steam Turbine Model)

Input Required: Outlet/Condenser Pressure

Ex. #1 Pressure (Outlet)	1 PSIA

Device #4: Simple Condenser (Condenser/Hotwell)

Input Required: Outlet water temperature

Exit Temperature	97.5 deg F

Device #5: Simple Junction (Makeup to Feedwater Pumps)

Input Required:Makeup and DeNOx Mass Flow

Inlet #1 Mass Flow (From Condenser)	3431383 lb/hr
Inlet #2 Mass Flow (Makeup)	1568000 lb/hr

Device #6: Simple Pump (DeNOx BFW Pump)

Input Required: DeNOx Header Pressure

Discharge Pressure	275 PSIA

Device #7: Simple Pump (Main BFW Pump)

Input Required: Main Steam Header Pressure

Discharge Pressure	910 PSIA

Device #8: Simple Junction (DeNOx BFW Pump to HRSG & Process DeSuperheater)

Input Required: Various Flow Rates

Inlet #1: Main DeNOx Boiler Flow	485312 lbm/hr
Exit #1: DeNOx to HRSG	474552 lbm/hr
Exit #2: Flow to Process Desuperheater	10760 lbm/hr

Device #9: Simple Junction (Main BFW Pump to HRSG & Main DeSuperheater)

Input Required: Various Flow Rates

Inlet #1: Main Boiler Flow	4524831 lbm/hr
Exit #1: Main to HRSG	4511000 lbm/hr
Exit #2: Flow to Main Desuperheater	13831 lbm/hr

Device #10: Simple Boiler (HRSG Model)

Input Required: Main Steam Temperature

Boiler Exit Temperature	729 deg. F

Input Required: DeNOx Steam Temperature

Boiler Reheat Leg #1 Exit Temperature	464 deg. F

Device #11: Simple Junction (Main to HP Blowdown)

Input Required: Mass Flow

Inlet #1 Mass Flow	4511000 lbm/hr
Exit #2 Mass Flow	22555 lbm/hr

Device #12: Simple Junction (DeNOx to LP Blowdown)

Input Required: Mass Flow

Inlet #1 Mass Flow	474552 lbm/hr
Exit #2 Mass Flow	2373 lbm/hr

Device #13: Simple Junction (Main to BP Steam Turbine)

Input Required: None

Device #14: Simple Turbine (BP Steam Turbine Model)

Input Required: Mass Flow & DeNOx Pressure

Inlet Mass Flow	468000 lbm/hr
Extraction #1 Pressure	275 PSIA

Device #15: Simple OFW Heater (Main Steam DeSuperheater Model)

Input Required: Mass Flow

Feed Water Inlet Mass Flow	13831 lbm/hr

Device #16: Simple Junction (Main to DeNOx & Process)

Input Required: Mass Flow

Exit #2 Mass Flow (DeNOx)	5000 lbm/hr
Exit #3 Mass Flow (Process)	97020 lbm/hr

Device #17: Simple Pipe (Throttling - DeNOx)

Input Required: Pipe Pressure Loss

Pipe Pressure Loss	635 PSIA

Device #18: Simple Pipe (Throttling - Process)

Input Required: Pipe Pressure Loss

Pipe Pressure Loss	720 PSIA

Device #19: Simple Pipe (Throttling - HP to DeNOx)

Input Required: Pipe Pressure Loss

Pipe Pressure Loss	79 PSIA

Device #20: Simple OFW Heater (DeNOx Mixing)

Input Required: None

Device #21: Simple OFW Heater (DeNOx Mixing)

Input Required: None

Device #22: Simple OFW Heater (DeNOx Mixing)

Input Required: None

Device #23: Simple Pipe (Throttling - HP Process Extraction to Required Process Pressure)

Input Required: Pipe Pressure Loss

Pipe Pressure Loss	100 PSIA

Device #24: Simple OFW Heater (Process Mixing)

Input Required: None

Device #25: Simple Pipe (Throttling - DeNOx FW to Dow/Corning Req'd)

Input Required: Pipe Pressure Loss

Pipe Pressure Loss	85 PSIA

Device #26: Simple OFW Heater (Process DeSuperheater Model)

Input Required: Feed Water Mass Flow Rate

Feed Water Exit Mass Flow Rate	538000 lbm/hr

Device #27: Simple Pipe (Throttling - Main to HP Inlet Pressure)

Input Required: Pipe Pressure Loss

Pipe Pressure Loss	54 PSIA

Device #28: Simple Pipe (Throttling - MS/CIV to Condenser Pressure)

Input Required: Pipe Pressure Loss

Pipe Pressure Loss	195 PSIA

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RANKINE 3.0 INPUT FILE

TITLE LINE
 Midland Cogeneration Venture - Steam System Model MCVF01.DAT 10/11/98
 This model is used to incorporate performance curves provided from
 Actual Plant Data obtained from MCV 8/20 - 8/24 1998 (Nox and Process extraction
pressure
 controlled). This will realistically model the facility and allow first
 and second law optimizations to be performed.
END TITLE

NUMBER OF NODES IS 41
HIGH TEMPERATURE RESERVOIR: 750.0 DEG F
LOW TEMPERATURE RESERVOIR: 60.0 DEG F
DEAD STATE TEMPERATURE RESERVOIR: 60.0 DEG F
DEAD STATE PRESSURE: 101 KPA
GENERATOR MECHANICAL LOSS IS 0.0 MW
GENERATOR ELECTRICAL LOSS IS 0.0 MW

COMMENT: HP STEAM TURBINE MODEL
DEVICE #1: SIMPLE TURBINE
 INLET NODE NUMBER IS 1
 EXTRACTION #1 NODE NUMBER IS 2
 EXTRACTION #2 NODE NUMBER IS 3
 EXTRACTION #3 NODE NUMBER IS 4

 COMMENT: INPUT HP TURBINE INLET CONDITIONS
 INLET MASS FLOW RATE IS 3900637 LBM/HR
 INLET PRESSURE IS 845 PSIA

 COMMENT: EXTRACTION #1 TO DENOX STEAM HEADER
 EXTRACTION #1 PRESSURE IS 350.0 PSIA
 EXTRACTION #1 MASS FLOW RATE IS 10000 LBM/HR

 COMMENT: EXTRACTION #2 TO PROCESS STEAM HEADER
 EXTRACTION #2 PRESSURE IS 292 PSIA
 EXTRACTION #2 MASS FLOW RATE IS 9800 LBM/HR

 COMMENT: EXTRACTION #3 TO LP STEAM TURBINE
 EXTRACTION #3 PRESSURE IS 234.0 PSIA
 STAGE GROUP #1 EFFICIENCY IS 78%
 STAGE GROUP #2 EFFICIENCY IS 100%
 STAGE GROUP #3 EFFICIENCY IS 91%
 END DEVICE

```
COMMENT: CIV/MOISTURE SEPARATOR MODEL
DEVICE #2: SIMPLE MOISTURE SEPARATOR
        SEPARATOR INLET NODE NUMBER IS 4
        SEPARATOR VAPOR EXIT NODE NUMBER IS 5
        SEPARATOR CONDENSATE EXIT NODE NUMBER IS 6
        SEPARATOR PRESSURE LOSS IS 10.0 PSIA
        END DEVICE

COMMENT: LP STEAM TURBINE MODEL
DEVICE #3: SIMPLE TURBINE
        INLET NODE NUMBER IS 5
        EXTRACTION #1 NODE NUMBER IS 7
        EXTRACTION #1 PRESSURE IS 1.0 PSIA
        STAGE GROUP #1 EFFICIENCY IS 78%
        END DEVICE

COMMENT: CONDENSER/HOTWELL MODEL
DEVICE #4: SIMPLE CONDENSER
        EXIT NODE NUMBER IS 8
        INLET #1 NODE NUMBER IS 7
COMMENT:INLET #2 NODE NUMBER IS 41
        EXIT TEMPERATURE IS 97.5 DEG F
        END DEVICE

COMMENT: JUNCTION FROM CONDENSER AND MAKEUP TO FEED WATER
PUMPS
DEVICE #5: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 8
        INLET #2 NODE NUMBER IS 9
        EXIT #1 NODE NUMBER IS 10
        EXIT #2 NODE NUMBER IS 11
        COMMENT: INLET #1 IS FLOW FROM CONDENSER/HOTWELL
        INLET #1 MASS FLOW RATE IS 3880637 LBM/HR

        COMMENT: INLET #2 IS MAKEUP WATER FLOW
        INLET #2 MASS FLOW RATE IS 1659000 LBM/HR
        END DEVICE
```

```
COMMENT: DENOX FEED WATER PUMP MODEL
DEVICE #6: SIMPLE PUMP
        SUCTION NODE NUMBER IS 10
        DISCHARGE NODE NUMBER IS 12
        COMMENT: INPUT DENOX HEADER PRESSURE
        DISCHARGE PRESSURE IS 277.0 PSIA
        PUMP EFFICIENCY IS 80 PERCENT
        END DEVICE

COMMENT: BOILER FEED WATER PUMP MODEL
DEVICE #7: SIMPLE PUMP
        SUCTION NODE NUMBER IS 11
        DISCHARGE NODE NUMBER IS 13
        COMMENT: INPUT MAIN STEAM HEADER PRESSURE
        DISCHARGE PRESSURE IS 910.0 PSIA
        PUMP EFFICIENCY IS 80 PERCENT
        END DEVICE

COMMENT: JUNCTION FROM FROM DENOX BFW TO PROCESS
DESUPERHEAT AND HRSG
DEVICE #8: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 12
        EXIT #1 NODE NUMBER IS 14
        EXIT #2 NODE NUMBER IS 35
        COMMENT: INLET #1 IS DENOX BFW FLOW
        INLET #1 MASS FLOW RATE IS 509580 LBM/HR
        COMMENT: EXIT #1 IS FLOW TO HRSG
        EXIT #1 MASS FLOW RATE IS 497000 LBM/HR
        COMMENT: EXIT #2 IS FLOW TO PROCESS DESUPERHEATER
        EXIT #2 MASS FLOW RATE IS 12580 LBM/HR
        END DEVICE

COMMENT: JUNCTION FROM FROM MAIN BFW TO MAIN DESUPERHEAT
AND HRSG
DEVICE #9: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 13
        EXIT #1 NODE NUMBER IS 15
        EXIT #2 NODE NUMBER IS 25
        COMMENT: INLET #1 IS MAIN BFW FLOW
        INLET #1 MASS FLOW RATE IS 5042637 LBM/HR
        COMMENT: EXIT #1 IS FLOW TO HRSG
        EXIT #1 MASS FLOW RATE IS 5020000 LBM/HR
        COMMENT: EXIT #2 IS FLOW TO MAIN DESUPERHEATER
        EXIT #2 MASS FLOW RATE IS 22637 LBM/HR
        END DEVICE
```

COMMENT: SIMPLE COMBINED HRSG BOILER MODEL
DEVICE #10: SIMPLE BOILER
    BOILER INLET NODE NUMBER IS 15
    BOILER EXIT NODE NUMBER IS 17
    BOILER REHEAT LEG #1 INLET NODE NUMBER IS 14
    BOILER REHEAT LEG #1 EXIT NODE NUMBER IS 16
    BOILER PRESSURE LOSS IS 0.0 MPA

    COMMENT: INPUT MAIN STEAM HEADER TEMPERATURE
    BOILER EXIT TEMPERATURE IS 742.0 DEG F

    COMMENT: INPUT DENOX HEADER TEMPERATURE
    BOILER REHEAT LEG #1 EXIT TEMPERATURE IS 460.0 DEG F
    BOILER REHEAT LEG #1 PRESSURE LOSS IS 0.0 PSIA
    END DEVICE

COMMENT: JUNCTION FROM HRSG MAIN STEAM TO HP BLOWDOWN 0.5%
DEVICE #11: SIMPLE JUNCTION
    INLET #1 NODE NUMBER IS 17
    EXIT #1 NODE NUMBER IS 19
    EXIT #2 NODE NUMBER IS 18

    COMMENT: INLET #1 IS MAIN HRSG STEAM FLOW
    INLET #1 MASS FLOW RATE IS 5020000 LBM/HR

    COMMENT: EXIT #2 IS FLOW TO HP BLOWDOWN (0.5%)
    COMMENT: THIS VALUE SHOULD BE 0.5% OF MAIN STEAM MASS
FLOW
    EXIT #2 MASS FLOW RATE IS 25100 LBM/HR
    END DEVICE

COMMENT: JUNCTION FROM HRSG DENOX TO LP BLOWDOWN 0.5%
DEVICE #12: SIMPLE JUNCTION
    INLET #1 NODE NUMBER IS 16
    EXIT #1 NODE NUMBER IS 21
    EXIT #2 NODE NUMBER IS 20

    COMMENT: INLET #1 IS DENOX HRSG STEAM FLOW
    INLET #1 MASS FLOW RATE IS 497000 LBM/HR

    COMMENT: EXIT #2 IS FLOW TO LP BLOWDOWN (0.5%)
    COMMENT: THIS VALUE SHOULD BE 0.5% OF DENOX STEAM MASS
FLOW
    EXIT #2 MASS FLOW RATE IS 2485 LBM/HR
    END DEVICE

COMMENT: JUNCTION FROM MAIN STEAM HEADER TO BP STEAM TURBINE
DEVICE #13: SIMPLE JUNCTION
INLET #1 NODE NUMBER IS 19
EXIT #1 NODE NUMBER IS 23
EXIT #2 NODE NUMBER IS 22
END DEVICE

COMMENT: BP STEAM TURBINE MODEL
DEVICE #14: SIMPLE TURBINE
INLET NODE NUMBER IS 22
EXTRACTION #1 NODE NUMBER IS 24

COMMENT: INPUT MASS FLOW ENTERING BP TURBINE
COMMENT: FOR 0.00 USE 0.1 LBM/HR
INLET MASS FLOW RATE IS 459000 LBM/HR

COMMENT: INPUT DENOX HEADER PRESSURE
EXTRACTION #1 PRESSURE IS 277.0 PSIA
COMMENT: THE EFFICIENCY BELOW WAS CALCULATED FROM PROVIDED DATA
STAGE GROUP #1 EFFICIENCY IS 78%
END DEVICE

COMMENT: MAIN STEAM DESUPERHEATER MODEL
DEVICE #15: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 26
EXTRACTION INLET NODE NUMBER IS 23
FEED WATER INLET NODE NUMBER IS 25
FEED WATER INLET MASS FLOW RATE IS 22637 LBM/HR
FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: JUNCTION FROM MAIN STEAM HEADER TO DENOX AND PROCESS STEAM
DEVICE #16: SIMPLE JUNCTION
INLET #1 NODE NUMBER IS 26
EXIT #1 NODE NUMBER IS 40
EXIT #2 NODE NUMBER IS 27
EXIT #3 NODE NUMBER IS 29

COMMENT: EXIT #2 MASS FLOW IS MAIN HEADER TO DENOX HEADER
COMMENT: FOR 0.00 USE 0.1 LBM/HR
EXIT #2 MASS FLOW RATE IS 64000 LBM/HR

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COMMENT: EXIT #3 MASS FLOW IS MAIN HEADER TO DOW PROCESS STEAM
COMMENT: FOR 0.00 USE 0.1 LBM/HR
EXIT #3 MASS FLOW RATE IS 606620 LBM/HR
END DEVICE

COMMENT: DENOX STEAM LETDOWN FROM MAIN - THOTTLE PROCESS
DEVICE #17: SIMPLE PIPE
INLET NODE NUMBER IS 27
EXIT NODE NUMBER IS 28
COMMENT: INPUT MAIN HEADER TO DENOX PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 633.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: PROCESS STEAM LETDOWN FROM MAIN - THOTTLE PROCESS
DEVICE #18: SIMPLE PIPE
INLET NODE NUMBER IS 29
EXIT NODE NUMBER IS 30
COMMENT: INPUT MAIN HEADER TO DENOX PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 720.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: DENOX STEAM LETDOWN FROM HP TURBINE EXTRACTION #1 - THOTTLE PROCESS
DEVICE #19: SIMPLE PIPE
INLET NODE NUMBER IS 2
EXIT NODE NUMBER IS 31
COMMENT: INPUT HP EXTRACTION #1 TO DENOX PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 73 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: DEVICES #20-#22 MODEL THE MIXING OF DENOX EXTRACTION FLOWS
COMMENT: FROM BP TURBINE, MAIN STEAM EXTRACTION, HP EXTRACTION, & HRSG
DEVICE #20: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 38
EXTRACTION INLET NODE NUMBER IS 31
FEED WATER INLET NODE NUMBER IS 28
COMMENT: NODE 31 IS FLOW FROM HP TURBINE
COMMENT: NODE 28 IS FLOW MAIN STEAM

FEED WATER EXIT IS NOT SATURATED
END DEVICE

DEVICE #21: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 39
EXTRACTION INLET NODE NUMBER IS 38
FEED WATER INLET NODE NUMBER IS 24
COMMENT: NODE 24 IS FLOW FROM BP TURBINE
FEED WATER EXIT IS NOT SATURATED
END DEVICE
DEVICE #22: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 32
EXTRACTION INLET NODE NUMBER IS 39
FEED WATER INLET NODE NUMBER IS 21
COMMENT: NODE 21 IS FLOW FROM HRSG
COMMENT: FEED WATER EXIT (NODE 32) IS FLOW TO GT DENOX INJECT.
FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: HP PROCESS EXTRACTION TO PROCESS PRESSURE FOR PROCESS STEAM - THOTTLE PROCESS
DEVICE #23: SIMPLE PIPE
INLET NODE NUMBER IS 3
EXIT NODE NUMBER IS 34
COMMENT: INPUT PROCESS TO HP TURBINE EXTRACTION #2 PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 102.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: DEVICE #23 MODELS THE MIXING OF PROCESS EXTRACTION FLOWS
DEVICE #24: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 33
EXTRACTION INLET NODE NUMBER IS 34
FEED WATER INLET NODE NUMBER IS 30
COMMENT: NODE 3 IS FLOW FROM HP TURBINE
COMMENT: NODE 30 IS FLOW MAIN STEAM
FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: DENOX FEEDWATER THROTTLED TO DESIRED PRESSURE - THOTTLE PROCESS
DEVICE #25: SIMPLE PIPE

INLET NODE NUMBER IS 35
EXIT NODE NUMBER IS 37
COMMENT: INPUT DENOX PRESSURE TO DOW/CORNING PROCESS
COMMENT: DESIRED PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 87.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: PROCESS STEAM DESUPERHEATER MODEL
DEVICE #26: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 36
EXTRACTION INLET NODE NUMBER IS 33
FEED WATER INLET NODE NUMBER IS 37

COMMENT: INPUT PROCESS STEAM MASS FLOW REQUIRED
FEED WATER EXIT MASS FLOW RATE IS 629000 LBM/HR
FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: SIMPLE PIPE TO MODEL MAIN STEAM PIPING PRESSURE LOSS
DEVICE #27: SIMPLE PIPE
INLET NODE NUMBER IS 40
EXIT NODE NUMBER IS 1
COMMENT: INPUT MAIN STEAM TO HP TURBINE INLET PRESS. DIFF.
PIPE PRESSURE LOSS IS 65.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: SIMPLE PIPE TO MODEL MS/CIV TO CONDENSER PRESSURE DIFF.
DEVICE #28: SIMPLE PIPE
INLET NODE NUMBER IS 6
EXIT NODE NUMBER IS 41
COMMENT: INPUT HP EXIT MINUS MS/CIV TO CONDENSER PRESS. DIFF.
PIPE PRESSURE LOSS IS 222 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

RANKINE 3.0 OUTPUT FILE

RANKINE 3.0: A steam power plant computer simulation

W.A. Thelen, C.W. Somerton

********************************** TITLE **********************************

Midland Cogeneration Venture - Steam System Model MCVF01.DAT 10/11/98
This model is used to incorporate performance curves provided from
Actual Plant Data obtained from MCV 8/20 - 8/24 1998 (Nox and Process extracti
controlled). This will realistically model the facility and allow first and
second law optimizations to be performed.

********************************* NODE DATA *************************

NODE	T(C)	P(MPa)	L	Q	S(KJ/KG/K)	H(KJ/KG)	V(M^3/KG)	M(KG/S)	A
1	385.34	5.8261	3	*****	6.5038	3144.31	.04748	491.4803	1267.89
2	283.48	2.4132	3	*****	6.5929	2971.53	.09893	1.2600	1069.39
3	260.70	2.0133	3	*****	6.5929	2929.15	.11383	1.2348	1027.01
4	235.94	1.6134	3	*****	6.6017	2884.12	.13572	488.9854	979.45
5	234.64	1.5444	3	*****	6.6205	2884.12	.14180	488.9854	974.02
6	199.67	1.5444	4	*****	2.3258	850.58	.00116	.0000	180.36
7	38.75	.0069	2	.861	7.2059	2236.70	17.9199	488.960	157.59
8	36.39	.0069	1	*****	.5236	152.41	.00101	488.960	2.52
9	36.39	.0069	1	*****	.5236	152.41	.00101	209.0340	2.52
10	36.39	.0069	1	*****	.5236	152.41	.00101	64.2071	2.52
11	36.39	.0069	1	*****	.5236	152.41	.00101	635.3723	2.52
12	36.66	1.9098	1	*****	.5254	155.26	.00101	64.2071	4.84
13	37.28	6.2742	1	*****	.5296	161.76	.00101	635.3723	10.13
14	36.66	1.9098	1	*****	.5254	155.26	.00101	62.6220	4.84
15	37.28	6.2742	1	*****	.5296	161.76	.00101	632.5200	10.13
16	237.78	1.9098	3	*****	6.5111	2874.67	.11346	62.6220	996.15
17	394.44	6.2742	3	*****	6.4952	3159.19	.04460	632.5200	1285.27
18	394.44	6.2742	3	*****	6.4952	3159.19	.04460	3.1626	1285.27
19	394.44	6.2742	3	*****	6.4952	3159.19	.04460	629.3574	1285.27
20	237.78	1.9098	3	*****	6.5111	2874.67	.11346	.3131	996.15
21	237.78	1.9098	3	*****	6.5111	2874.67	.11346	62.3089	996.15
22	394.44	6.2742	3	*****	6.4952	3159.19	.04460	57.8340	1285.27
23	394.44	6.2742	3	*****	6.4952	3159.19	.04460	571.5234	1285.27
24	259.79	1.9098	3	*****	6.6189	2930.94	.12024	57.8340	1021.29
25	37.28	6.2742	1	*****	.5296	161.76	.00101	2.8523	10.13
26	388.77	6.2742	3	*****	6.4728	3144.31	.04405	574.3757	1276.84
27	388.77	6.2742	3	*****	6.4728	3144.31	.04405	8.0640	1276.84
28	352.40	1.9098	3	*****	6.9886	3144.31	.14606	8.0640	1127.92
29	388.77	6.2742	3	*****	6.4728	3144.31	.04405	76.4341	1276.84
30	346.83	1.3100	3	*****	7.1576	3144.31	.21326	76.4341	1079.13
31	276.50	1.9098	3	*****	6.6939	2971.53	.12515	1.2600	1040.22
32	254.41	1.9098	3	*****	6.5937	2917.54	.11862	129.4669	1015.18
33	345.24	1.3100	3	*****	7.1521	3140.89	.21266	77.6689	1077.31
34	249.21	1.3100	3	*****	6.7796	2929.15	.17519	1.2348	973.11
35	36.66	1.9098	1	*****	.5254	155.26	00101	1.5851	4.84

36	317.54	1.3100	3	*****	7.0533	3081.17	.20214	79.2540	1046.12
37	36.79	1.3100	1	*****	.5277	155.26	.00101	1.5851	4.17
38	341.85	1.9098	3	*****	6.9510	3120.96	.14325	9.3240	1115.44
39	270.58	1.9098	3	*****	6.6680	2957.32	.12343	67.1580	1033.52
40	388.77	6.2742	3	*****	6.4728	3144.31	.04405	489.8775	1276.84
41	52.27	.0138	2	.266	2.6741	850.58	2.88348	0.0000	0.00

******************************* SYSTEM DATA *******************************

TOTAL MASS FLOW RATE EXITING SYSTEM:	211.1966 KG/SEC
TOTAL MASS FLOW RATE ENTERING SYSTEM:	209.0340 KG/SEC
TOTAL ENTHALPY FLOW RATE EXITING SYSTEM:	631961.4000 KW
TOTAL ENTHALPY FLOW RATE ENTERING SYSTEM:	31858.8800 KW
TOTAL HEAT AND WORK ENTERING SYSTEM:	595728.4000 KW
BOILER HEAT (DEVICE # 10):	2066230.0000 KW
TOTAL BOILER HEAT:	2066230.0000 KW
TOTAL HEAT LOAD HEAT:	.0000 KW
CONDENSER HEAT (DEVICE # 4):	-1019134.0000 KW
TOTAL PIPE ENERGY LOSSES:	.0000 KW
TURBINE WORK (DEVICE # 1):	127708.3000 KW
TURBINE WORK (DEVICE # 3):	316582.4000 KW
TURBINE WORK (DEVICE # 14):	13200.4000 KW
NET WORK TO GENERATORS:	457491.1000 KW
PUMP WORK (DEVICE # 6):	-183.0944 KW
PUMP WORK (DEVICE # 7):	-5940.6380 KW
TOTAL PUMP WORK:	-6123.7320 KW
GENERATOR MECHANICAL LOSSES:	.0000 KW
GENERATOR ELECTRICAL LOSSES:	.0000 KW
NET ELECTRICAL POWER:	451367.3000 KW

SYSTEM HEAT RATE:	15619.1500 BTU/KW*HR
CARNOT CYCLE EFFICIENCY:	57.0404 PERCENT
1ST LAW EFFICIENCY:	21.8450 PERCENT
2ND LAW EFFICIENCY:	57.0528 PERCENT
2ND LAW EFFECTIVENESS:	38.2974 PERCENT

Appendix B:

Steam System Model Verification Summary

Table B-1: Steam System Model Verification Summary

		Case No. 1 (Heat Balance 4/28/88)			Case No. 2 (Max. Load Fired)			Case No. 3 (Max. Load Fired)			Case No. 4 (Max. Load - Unfired)			Case No. 5 (Partial Load - Ramp Up)		
Description		Actual	Model	% Error	Actual	Model	% Error	Actual	Model	% Error	Actual	Model	% Error	Actual	Model	% Error
Main HRSG [node 17]	Flow (KG/S)	510.2	510.1	-0.02%	632.5	632.5	0.00%	568.4	568.4	0.00%	527.3	527.3	0.00%	431.2	431.2	0.00%
	Pressure (MPa)	6.3777	6.0467	-5.19%	6.2248	6.2742	0.79%	6.0348	6.2742	3.97%	5.5545	6.2397	12.34%	3.8462	5.1366	33.55%
	Temperature (DEG C)	376.1	380.6	1.20%	399	394.4	-1.15%	397	387.2	-2.47%	382	382.8	0.21%	363	372.2	2.53%
	Enthalpy (KJ/KG)	3104.4	3127.2	0.73%	3171.5	3159.2	-0.39%	3167.8	3140.2	-0.87%	3138.9	3129.1	-0.31%	3127.1	3124.6	-0.08%
HRSG DeNOx [node 16]	Flow (KG/S)	75.1	52.7	-29.83%	59.6	62.6	5.03%	59.3	59.8	0.84%	58	54.8	-5.52%	36	43.2	20.00%
	Pressure (MPa)	1.7513	1.8892	7.87%	1.8968	1.9098	0.69%	1.9028	1.8961	-0.35%	1.893	1.8892	-0.20%	1.8596	1.8754	0.85%
	Temperature (DEG C)	240	240	0.00%	238	237.8	-0.08%	238	237.8	-0.08%	238	237.8	-0.08%	238	237.8	-0.08%
	Enthalpy (KJ/KG)	2887.5	2881.5	-0.21%	2874.9	2874.7	-0.01%	2874.9	2875.3	0.01%	2874.9	2875.7	0.03%	2877.3	2876.3	-0.03%
HP Inlet [node 1]	Flow (KG/S)	508.3	511.9	0.71%	520	491.5	-5.48%	502.2	476.3	-5.16%	461.7	439.9	-4.72%	304.7	293.1	-3.81%
	Pressure (MPa)	6.2053	6.0467	-2.56%	6.1633	5.8261	-5.47%	5.9747	5.6537	-5.37%	5.4994	5.24	-4.72%	3.8254	3.5508	-7.18%
	Temperature (DEG C)	371.1	376.7	1.51%	373	385.3	3.30%	371	378.5	2.02%	371	372	0.27%	366	358.7	-1.99%
	Enthalpy (KJ/KG)	3094.8	3117	0.72%	3100.6	3144.3	1.41%	3100.6	3130	0.95%	3112.2	3121.9	0.31%	3137.8	3124.6	-0.42%
HP DeNOx Ex. [node 2]	Flow (KG/S)	74.4	66.3	-10.89%	1.26	1.26	0.00%	0.06	0.05	-16.67%	1.25	1.25	0.00%	0.1	0.1	0.00%
	Pressure (MPa)	2.0891	2.5097	20.13%	2.764	2.4132	-12.69%	2.4743	2.3373	-5.54%	2.2552	2.1649	-4.00%	1.5585	1.4479	-7.10%
	Temperature (DEG C)	240	275.7	14.88%	280	283.5	1.25%	270	277.4	2.74%	269	272.1	1.15%	269	261	-2.97%
	Enthalpy (KJ/KG)	2876.3	2948.5	2.51%	2947	2971.5	0.83%	2933.1	2958.9	0.88%	2940.1	2951.8	0.40%	2965.7	2951.41	-0.48%
HP Process Ex. [node 3]	Flow (KG/S)	77.7	77.6	-0.13%	1.2	1.24	3.33%	55.3	54.2	-1.99%	57.3	56.2	-1.92%	17.5	0.124	-99.29%
	Pressure (MPa)	1.6347	1.834	12.19%	2.3546	2.0133	-14.50%	2.0177	1.9581	-2.95%	1.83	1.8064	-1.29%	1.295	1.2204	-5.76%
	Temperature (DEG C)	214.3	237.6	10.87%	260	260.7	0.27%	244	255.4	4.67%	240	249.8	4.08%	244	240	-1.64%
	Enthalpy (KJ/KG)	2826.6	2877.9	1.81%	2909.8	2929.2	0.67%	2886.6	2918	1.09%	2884.2	2910.2	0.90%	2916.8	2912.1	-0.16%
HP Exit [node 4]	Flow (KG/S)	354.4	367.9	3.81%	505	489	-3.17%	434.7	422	-2.92%	393.3	382.4	-2.77%	280.2	292.9	4.53%
	Pressure (MPa)	1.0239	1.2066	17.84%	1.6407	1.6134	-1.66%	1.4083	1.3858	-1.60%	1.2759	1.2548	-1.65%	0.8974	0.9653	7.57%
	Temperature (DEG C)	180.9	194.1	7.30%	217	235.9	8.71%	204	217.7	6.72%	203	210.6	3.74%	208	215.1	3.41%
	Enthalpy (KJ/KG)	2740.5	2798.8	2.13%	2834.2	2884.12	1.76%	2812.1	2849.4	1.33%	2819.1	2838.7	0.70%	2851.7	2865.2	0.47%
LP Inlet [node 5]	Flow (KG/S)	348	367.9	5.72%	505	489	-3.17%	434.7	422	-2.92%	393.3	382.4	-2.77%	280.2	292.9	4.53%
	Pressure (MPa)	0.9563	1.1307	18.24%	1.5865	1.5444	-2.65%	1.3593	1.31	-3.63%	1.2293	1.179	-4.09%	0.8544	0.8894	4.10%
	Temperature (DEG C)	178.3	192.1	7.74%	217	234.6	8.11%	204	216	5.88%	203	208.8	2.86%	208	213.4	2.60%
	Enthalpy (KJ/KG)	2776.8	2798.8	0.79%	2837.7	2884.12	1.64%	2816.8	2849.4	1.16%	2821.4	2838.7	0.61%	2854	2865.2	0.39%
BP Inlet [node 22]	Flow (KG/S)	0	0	#DIV/0!	57.8	57.8	0.00%	59	59	0.00%	53	53	0.00%	31.6	31.6	0.00%
	Pressure (MPa)	6.3777	6.0467	-5.19%	6.2248	6.2742	0.79%	6.0348	6.2742	3.97%	5.5545	6.2397	12.34%	3.8462	5.1366	33.55%
	Temperature (DEG C)	376.1	380.6	1.20%	373	394.4	5.74%	371	387.2	4.37%	371	382.8	3.18%	367	372	1.36%
	Enthalpy (KJ/KG)	3104.4	3127.24	0.74%	3172.7	3159.2	-0.43%	3168	3140.2	-0.88%	3140.1	3129.1	-0.35%	3126.1	3124.6	-0.05%
BP Exit [node24]	Flow (KG/S)	0	0	#DIV/0!	57.8	57.8	0.00%	59	59	0.00%	53	53	0.00%	31.6	31.6	0.00%
	Pressure (MPa)	1.7513	1.8892	7.87%	1.8968	1.9098	0.69%	1.9028	1.8961	-0.35%	1.893	1.8892	-0.20%	1.8596	1.8754	0.85%
	Temperature (DEG C)	240	250.7	4.46%	264	259.8	-1.59%	264	252.9	-4.20%	260	249.3	-4.12%	286	260	-9.09%
	Enthalpy (KJ/KG)	2887.5	2909.2	0.75%	2940.1	2931	-0.31%	2942.4	2914.3	-0.96%	2930.8	2905.6	-0.86%	2991.2	2932.8	-1.95%
Required DeNOX [node 32]	Flow (KG/S)	150.8	118.8	-21.22%	126.9	129.5	2.05%	125.3	129.5	3.35%	127.7	122.5	-4.07%	109.1	102.1	-6.42%
	Pressure (MPa)	1.7513	1.8892	7.87%	1.8968	1.9098	0.69%	1.9028	1.8961	-0.35%	1.893	1.8892	-0.20%	1.8596	1.8754	0.85%
Required Process [node 36]	Flow (KG/S)	79.3	79.2	-0.13%	67.8	79.2	16.81%	67.8	79.3	16.96%	66.5	79.3	19.25%	72.8	79.3	8.93%
	Pressure (MPa)	1.3079	1.31	0.16%	1.31	1.31	0.00%	1.31	1.31	0.00%	1.31	1.31	0.00%	1.31	1.31	0.00%
BP Turbine	MW Produced (MW)	0	0	0.00%	13.44	13.2	-1.79%	13.3	13.3	0.00%	11.13	11.7	5.12%	4.28	6.07	41.82%
Combine HP & LP	MW Produced (MW)	355.2	364.2	2.53%	430	444.3	3.33%	392	391.5	-0.13%	359	352.1	-1.92%	248	246.8	-0.48%
Total HP, LP, & BP	MW Produced (MW)	355.2	364.2	2.53%	444	457.5	3.04%	405	404.9	-0.02%	370	364	-1.62%	253	252.9	-0.04%
Total GT	MW Produced (MW)	1046	1046.0	0.00%	947	947.0	0.00%	928	928	0.00%	963	963	0.00%	775	775	0.00%
Total (All)	MW Produced (MW)	1401	1410.0	0.63%	1391	1404.5	0.97%	1333	1333	0.00%	1333	1327	-0.45%	1028	1028	0.00%

Appendix C:

HP, LP, and BP Steam Turbine Adiabatic Efficiency Calculations and

Actual Operating Data

8/20 - 8/24 1998

HP Turbine Analysis

Case #	HP Inlet	DeNOx Extract		Process Extract		HP Exit		Stage 1	Stage 2	Stage 3
	h1	ha	hs	ha	hs	ha	hs			
1	1333	1267	1249	1251	1251	1219	1219	79%	100%	100%
2	1333	1261	1241	1241	1241	1209	1209	78%	100%	100%
3	1338	1264	1243	1240	1240	1212	1207	78%	100%	85%
4	1349	1275	1252	1254	1254	1226	1219	76%	100%	80%
5	1347	1272	1253	1253	1253	1229	1227	80%	100%	92%
								78%	100%	91%

BP Turbine Analysis

Case #	BP Inlet	BP Exit		Eff.	MW Produced		Resultant Flow
	h1	ha	hs	%	MW	Btu/hr	lbm/hr
1	1364	1264	1237	79%	13.44	45860373	458604
2	1362	1265	1238	78%	13.30	45382661	467862
3	1350	1260	1236	79%	11.13	37978121	421979
4	1344	1286	1266	74%	4.28	14604345	251799
5	1342	1285	1262	71%	4.71	16071604	281958
6	1345	1298	1277	69%	2.90	9895467	210542
7	1343	1302	1283	68%	2.08	7097439	173108
8	1338	1297	1279	69%	2.09	7131561	173941
9	1342	1299	1279	68%	2.34	7984618	185689

LP Turbine Analysis

Case #1 (MCV 4/13/88)

	Actual Temp. (F)	P (psia)	H (Btu/lb)	m (lb/hr)	s (Btu/lb-R)	Adiabatic Temp. (F)	P (psia)	H (Btu/lb)	m (lb/hr)	s (Btu/lb-R)
Inlet	356.0	139.7	1193.4	2743000	1.5789	356	139.7	1193.4	2743000	1.5789
Outlet	94.8	0.8	973.8	2743000	1.7632	94.7	0.8	871.61	2743000	1.5789

Case #2 (MCV Actual 5/4/98)

	Actual Temp. (F)	P (psia)	H (Btu/lb)	m (lb/hr)	s (Btu/lb-R)	Adiabatic Temp. (F)	P (psia)	H (Btu/lb)	m (lb/hr)	s (Btu/lb-R)
Inlet	421.0	171.0	1225.3	3108000	1.5839	356	171.0	1225.3	3108000	1.5839
Outlet	98.0	0.9	979.8	3108000	1.9861	98.5	0.9	879.83	3108000	1.5839

Case #3 (MCV 4/28/88)

	Actual Temp. (F)	P (psia)	H (Btu/lb)	m (lb/hr)	s (Btu/lb-R)	Adiabatic Temp. (F)	P (psia)	H (Btu/lb)	m (lb/hr)	s (Btu/lb-R)
Inlet	353.0	171.0	1193.8	2761930	1.5773	353	171.0	1225.3	2761930	1.5773
Outlet	98.5	0.9	958.7	2761930	1.7252	98.5	0.9	876.2	2761930	1.5773

Stage Efficiency Calculations
n = (h1-h2a)/(h1-h2s)

	Case #1 (MCV 4/13/88)	MW Generated
Stage 1	0.682433	176.5352 MW
	Case #2 (MCV Actual 5/4/98)	MW Generated
Stage 1	0.710539	223.5901 MW
	Case #3 (MCV 4/28/88)	331 Actual MW
Stage 1	0.740239	

MCV Actual Operating Condition Data (9 Test Data Points)

			Main Steam HRSG Conditions							
			Combine GT Boiler Steam Flow		Inlet Temp to BP		Main Steam Pressure (Power Block)		Main Steam Enthalpy	
Time			TOTMNSF		TI15204		PT99056		-------	
End	Begin	Date	KPPH	KG/S	DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG
10:44:38	9:04:38	8/24/98	5020	632.5	751	399	903	6.2248	1363.5	3171.5
19:44:38	13:04:38	8/23/98	4511	568.4	746	397	875	6.0348	1361.9	3167.8
7:34:38	2:24:38	8/24/98	4185	527.3	720	382	806	5.5545	1349.5	3138.9
0:54:38	9:54:38	8/21/98	3422	431.2	685	363	558	3.8462	1344.4	3127.1
21:54:38	6:54:38	8/20/98	3283	413.6	683	362	573	3.9502	1342.2	3122.0
Various	Various	Various	2220	279.7	671	355	477	3.2882		0.0
7:54:38	0:14:38	8/21/98	1878	236.6	681	361	503	3.4669	1345.6	3129.9
5:44:38	2:54:38	8/22/98	1823	229.7	673	356	467	3.2229	1343.4	3124.7
7:54:38	1:44:38	8/23/98	1747	220.1	664	351	468	3.2263	1338.4	3113.1

MCV Actual Operating Condition Data (9 Test Data Points)

DeNOx HRSG Conditions							
Total Denox Steam From HRSG's		DeNox Temp from HRSG		DeNOx Delivery Pressure		DeNOx Steam Enthalpy	
OTDNXSF		-------		PI151001		-------	
KPPH	KG/S	DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG
473	59.6	460	238	275	1.8968	1236	2874.9
471	59.3	460	238	276	1.9028	1236	2874.9
460	58.0	460	238	275	1.8930	1236	2874.9
286	36.0	460	238	270	1.8596	1237	2877.3
299	37.6	460	238	272	1.8755		0.0
194	24.5	460	238	269	1.8530	1237	2877.3
164	20.6	460	238	270	1.8642	1237	2877.3
178	22.5	460	238	269	1.8529	1237	2877.3
170	21.4	460	238	269	1.8535	1237	2877.3

MCV Actual Operating Condition Data (9 Test Data Points)

HP Inlet Conditions							
Flow Into Unit #1		Main Steam Temperature After H2O		HP Inlet Pressure		HP Inlet Enthalpy	
TG1FLOW		TT0E120X		PI15205		-------	
KPPH	KG/S	DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG
4127	520.0	703	373	894	6.1633	1333.0	3100.6
3985	502.2	700	371	867	5.9747	1333.0	3100.6
3664	461.7	700	371	798	5.4994	1338.0	3112.2
2419	304.7	692	366	555	3.8254	1349.0	3137.8
2596	327.1	690	365	570	3.9273		0.0
1102	138.9	679	359	475	3.2754	1347.0	3133.1
670	84.4	681	361	500	3.4491	1346.0	3130.8
717	90.3	672	356	465	3.2091	1343.0	3123.8
783	98.6	672	355	466	3.2153	1343.0	3123.8

MCV Actual Operating Condition Data (9 Test Data Points)

HP DeNOx Extraction Conditions									
DeNOx Extraction Flow		Average Denox Extract Temp		Average DeNox Extraction Pressure		DeNOx Extract Enthalpy		Calc. Flow After DeNox Extract	
FT1G017A		-------		-------		-------		-------	
KPPH	KG/S	DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG	KPPH	KG/S
107	13.4	535	280	401	2.7640	1267	2947.0	4020	506.5
97	12.2	518	270	359	2.4743	1261	2933.1	3889	490.0
88	11.1	517	269	327	2.2552	1264	2940.1	3576	450.6
56	7.1	516	269	226	1.5585	1275	2965.7	2362	297.7
60	7.6	514	268	238	1.6439		0.0	2536	319.6
20	2.5	489	254	102	0.7017	1272	2958.7	1082	136.3
49	6.2	473	245	58	0.4016	1270	2954.0	621	78.2
46	5.8	475	246	63	0.4344	1270	2954.0	670	84.5
50	6.3	473	245	69	0.4780	1269	2951.7	732	92.3

MCV Actual Operating Condition Data (9 Test Data Points)

HP Process Ex. Conditions									
Total Process Extraction Flow (A+B)		Average Process Extract Temp		Average Process Extraction Pressure		Process Extract Enthalpy		Calc. HP Turbine Exit Flow	
-------		-------		-------		-------		-------	
KPPH	KG/S	DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG	KPPH	KG/S
12	1.5	499	260	342	2.3546	1251	2909.8	4008	505.0
439	55.3	471	244	293	2.0177	1241	2886.6	3450	434.7
455	57.3	464	240	265	1.8300	1240	2884.2	3121	393.3
139	17.5	471	244	188	1.2950	1254	2916.8	2224	280.2
395	49.8	471	244	197	1.3596		0.0	2141	269.8
2	0.2	436	224	85	0.5853	1253	2914.5	1081	136.2
1	0.1	420	216	47	0.3236	1245	2895.9	620	78.1
3	0.3	423	217	51	0.3523	1246	2898.2	668	84.1
0	0.0	412	211	57	0.3904	1240	2884.2	732	92.3

MCV Actual Operating Condition Data (9 Test Data Points)

HP Exit Conditions						LP Operating Conditions					
HP Exhaust Temp.		Average HP Turbine Exhaust Pressure		HP Exit Enthalpy		LP Inlet Pressure		~ LP Inlet Temp.		LP Inlet Enthalpy	
TT1E073B		-------		-------		PT1E070		TT1E073B		-------	
DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG	PSIG	MPa	DEG F	DEG C	BTU/LBM	KJ/KG
423	217	238	1.6407	1219	2834.2	230	1.5865	423	217	1220	2837.7
399	204	204	1.4083	1209	2812.1	197	1.3593	399	204	1211	2816.8
397	203	185	1.2759	1212	2819.1	178	1.2293	397	203	1213	2821.4
406	208	130	0.8974	1226	2851.7	124	0.8544	406	208	1227	2854.0
417	214	150	1.0363		0.0	118	0.8108	417	214		0.0
388	198	59	0.4049	1229	2858.7	52	0.3591	388	198	1234	2870.3
373	190	31	0.2142	1225	2849.4	26	0.1826	373	190	1225	2849.4
373	189	34	0.2345	1224	2847.0	29	0.2031	373	189	1224	2847.0
371	188	38	0.2614	1223	2844.7	33	0.2297	371	188	1223	2844.7

MCV Actual Operating Condition Data (9 Test Data Points)

Condenser Operating Conditions						DeNOx Steam Required						
Cond. Pressure		Cond. Exit Temp		Cond. Exit Enthalpy		GT #3 DeNOx	GT #4 DeNOx	GT #5 DeNOx	GT #6 DeNOx	GT #7 DeNOx	GT #8 DeNOx	GT #9 DeNOx
PT1H029		-------		-------		FI03205	FI04205	FI05205	FI06205	FI07205	FI08205	FI09205
PSIG	MPa	DEG F	DEG C	BTU/LBM	KJ/KG	KPPH	KPPH	KPPH	KPPH	KPPH	KPPH	KPPH
1.20	0.0082	98	36	65.6	152.5	89	96	84	90	97	97	91
1.12	0.0077	98	36	65.6	152.5	88	94	85	89	95	95	90
1.14	0.0078	98	36	65.6	152.5	90	97	87	91	97	97	92
1.04	0.0072	98	36	65.6	152.5	91	70	92	52	96	96	93
0.92	0.0063	98	36	65.6	152.5	10	85	82	89	89	89	89
0.84	0.0058	98	36	65.6	152.5	63	47	74	54	51	41	77
0.75	0.0052	98	36	65.6	152.5	0	8	88	0	88	88	88
0.77	0.0053	98	36	65.6	152.5	87	11	87	87	12	0	87
0.81	0.0056	98	36	65.6	152.5	86	3	1	85	10	0	15

GT #10 DeNOx	GT #11 DeNOx	GT #12 DeNOx	GT #13 DeNOx	GT #14 DeNOx
FI10205	FI11205	FI12205	FI13205	FI14205
KPPH	KPPH	KPPH	KPPH	KPPH
91	92	0	91	89
90	91	0	90	88
90	93	0	92	90
90	52	0	58	77
90	13	0	89	89
49	30	0	60	10
89	10	0	12	0
0	0	0	87	0
11	86	0	85	0

MCV Actual Operating Condition Data (9 Test Data Points)

DeNOx Steam Required				Process Steam Required					
Required DeNOx Steam Flow		Required DeNOx Delivery Pressure		Dow Process Steam	Corning Process Steam	Total Process Steam		~Process Delivery Pressure	
-------		PI151001		FT0G100X	FTDG200	-------		-------	
KPPH	KG/S	PSIG	MPa	KPPH	KPPH	KPPH	KG/S	PSIG	MPa
1007	126.9	275	1.8968	448	90	538	67.8	190	1.3100
994	125.3	276	1.9028	441	97	538	67.8	190	1.3100
1014	127.7	275	1.8930	435	93	528	66.5	190	1.3100
866	109.1	270	1.8596	475	103	577	72.8	190	1.3100
815	102.7	272	1.8755	470	103	573	72.2	190	1.3100
557	70.2	269	1.8530	469	102	572	72.0	190	1.3100
472	59.4	270	1.8642	487	103	590	74.4	190	1.3100
459	57.8	269	1.8529	455	103	558	70.3	190	1.3100
382	48.1	269	1.8535	464	100	564	71.1	190	1.3100

MCV Actual Operating Condition Data (9 Test Data Points)

BP Turbine Operating Conditions												
Main Steam Temp.		Main Steam Pressure (Power Block)		Inlet Enthalpy		Unit 15 Exhaust Temp		DeNOx Delivery Pressure		Exit Enthalpy		BP Turbine Flow
TT0E120X		PT99056		-------		TI15203		PI151001		-------		-------
DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG	DEG F	DEG C	PSIG	MPa	BTU/LBM	KJ/KG	KPPH
703	373	903	6.2248	1364	3172.7	507	264	275	1.8968	1264	2940.1	459
700	371	875	6.0348	1362	3168.0	508	264	276	1.9028	1265	2942.4	468
700	371	806	5.5545	1350	3140.1	500	260	275	1.8930	1260	2930.8	421
692	367	558	3.8462	1344	3126.1	546	286	270	1.8596	1286	2991.2	251
690	366	573	3.9502	1342	3121.5	543	284	272	1.8755	1299	3021.5	186
679	360	477	3.2882	1342	3121.5	567	297	269	1.8530	1285	2988.9	281
681	361	503	3.4669	1345	3128.5	566	297	270	1.8642	1298	3019.1	211
672	355	467	3.2229	1343	3123.8	572	300	269	1.8529	1302	3028.5	173
671	355	468	3.2263	1338	3112.2	564	296	269	1.8535	1297	3016.8	174

MCV Actual Operating Condition Data (9 Test Data Points)

	GT & HP MW Produced and Totals									
	Unit 15 MW Produced	Total GT Turbine MW Produced	Total GT MW Produced (sum)	GT MW Produced % Error	Combine HP & LP MW Produced	Total Unit#1 & BP MW Produced	Total MW Produced (ALL)		No. GT's Fired	
	JI15200	TGTOTM	-------	-------	JT1Y0027	-------	-------		-------	
KG/S	MW	MW	MW	%	MW	MW	MW		No.	
57.8	13.44	947	951	0.46%	430	444	1395		12	
59.0	13.30	928	928	0.00%	392	405	1333		12	
53.0	11.13	963	962	-0.10%	359	370	1332		12	
31.6	4.28	775	782	0.65%	248	253	1035		12	Transient
23.4	4.71	753	750	-0.44%	241	246	996		10	Transient
35.4	2.34	470	473	-0.39%	110	112	585		?	Transient
26.6	2.90	375	377	0.47%	64	67	444		5	
21.8	2.08	367	370	0.86%	69	71	442		5	
21.9	2.09	361	363	0.38%	75	77	441		5	

MCV Actual Operating Condition Data (9 Test Data Points)

DeNOx Extraction Valve Position	Process Valve Pos. A	Process Valve Pos. B	Process Valve Pos. C	DeNOx Letdown Valve Pos.	Process Letdown Valve Pos. A	Process Letdown Valve Pos. B	MSR Temp.	GT #3 MW	GT #4 MW	GT #5 MW	GT #6 MW	GT #7 MW
PC99055C	XY0G109A	XY0G109B	XY0G109C	PC99056B	XY0G110A	XY0G110B	TT1E073A	JI03200	JI04200	JI05200	JI06200	JI07200
PERCENT	PERCENT	PERCENT	PERCENT	PERCENT	PERCENT	PERCENT	DEG F	MW	MW	MW	MW	MW
0	0	0	5	30	6	8	424	77	87	69	79	88
0	0	0	41	24	0	0	399	75	85	71	77	86
0	0	0	53	28	0	0	398	78	88	73	79	89
0	35	42	42	43	12	15	406	80	58	81	46	86
0	42	42	42	38	5	6	418	0	73	70	77	77
0	41	41	41	32	16	21	387	52	38	64	46	39
0	45	45	45	24	15	20	373	0	2	75	0	75
0	39	39	39	26	16	21	372	74	1	74	74	0
0	38	38	38	7	16	21	371	71	0	0	71	0

MCV Actual Operating Condition Data (9 Test Data Points)

GT #8 MW	GT #9 MW	GT #10 MW	GT #11 MW	GT #12 MW	GT #13 MW	GT #14 MW
JI08200	JI09200	JI10200	JI11200	JI12200	JI13200	JI14200
MW	MW	MW	MW	MW	MW	MW
88	80	76	81	69	80	77
86	77	74	79	67	78	74
89	80	77	82	69	81	77
87	82	77	39	40	46	61
77	77	77	1	70	77	77
34	65	41	21	22	46	5
75	75	75	0	0	0	0
0	74	0	0	0	74	0
0	0	6	71	71	71	0

Appendix D:

Facility Evaluation Summary Used for Optimization

Table D-1: Steam System Model Facility Evalutation Summary

Description		Case No. 1 Vary Process Steam from Letdown to HP					Case No. 2 Vary DeNOx Steam from BP to HP				
		Base	-25% (-110KPPH)	% Change	+23% (+99KPPH)	% Change	Base	-25% (-117KPPH)	% Change	-50% (-234KPPH)	% Change
HRSG Boiler	Total Boiler Heat (kW)	1855910	1855910	0.00%	1855910	0.00%	1855910	1855910	0.00%	1855910	0.00%
Device No. 10	Irreversibility (kW)	653053	653053	0.00%	653053	0.00%	653053	653053	0.00%	653053	0.00%
BP Turbine	Turbine Work (kW)	13322	13322	0.00%	13322	0.00%	13322	9991	-25.00%	6661	-50.00%
Device No. 14	Irreversibility (kW)	2112	2112	0.00%	2112	0.00%	2112	1584	-25.00%	1056	-50.00%
HP Turbine	Turbine Work (kW)	132895	127612	-3.98%	137548	3.50%	132895	138268	4.04%	143671	8.11%
Device No. 1	Irreversibility (kW)	14207	13755	-3.18%	14630	2.98%	14207	14591	2.70%	14911	4.96%
LP Turbine	Turbine Work (kW)	270278	270765	0.18%	269862	-0.15%	270278	269592	-0.25%	268921	-0.50%
Device No. 3	Irreversibility (kW)	70557	70684	0.18%	70448	-0.15%	70557	70378	-0.25%	70202	-0.50%
BFW Pumps	Total Pump Work (kW)	5504	5504	0.00%	5504	0.00%	5504	5506	0.04%	5508	0.07%
Device No. 6 & 7	Irreversibility (kW)	1028	1028	0.00%	1028	0.00%	1028	1028	0.00%	1029	0.10%
Process Steam	Flow (KG/S)	67.8	67.8	0.00%	67.8	0.00%	67.8	67.8	0.00%	67.8	0.00%
Node No. 36	Enthalpy Supplied (KJ/kg)	2900	2943	1.48%	2863	-1.28%	2900	2895	-0.17%	2889	-0.38%
	Enthalpy Returned (KJ/kg)	152	152	0.00%	152	0.00%	152	152	0.00%	152	0.00%
	Net Heat Provided (kW)	186314	189230	1.56%	183806	-1.35%	186314	185975	-0.18%	185569	-0.40%
DeNOx Control Steam	Flow (KG/S)	130	130	0.00%	130	0.00%	130	130	0.00%	130	0.00%
Node No. 32	Enthalpy (KJ/kg)	2917	2917	0.00%	2917	0.00%	2917	2922	0.17%	2945	0.96%
	Enthalpy Rate (kW)	379210	379210	0.00%	379210	0.00%	379210	379860	0.17%	382850	0.96%
Net MW Produced (MW)		411	406	-1.17%	415	1.03%	411	412	0.33%	414	0.67%
System Heat Rate		15408	15590	1.18%	15250	-1.03%	15408	15180	-1.48%	15305	-0.67%
Carnot Cycle Eff.		57.0404	57.0404	0.00%	57.0404	0.00%	57.0404	57.0404	0.00%	57.0404	0.00%
1st Law Eff.		22.1449	21.8865	-1.17%	22.3733	1.03%	22.1449	22.4763	1.50%	22.2933	0.67%
2nd Law Eff.		57.9353	57.6053	-0.57%	58.2310	0.51%	57.9353	58.3372	0.69%	58.2159	0.48%
2nd Law Effectiveness		38.8233	38.3702	-1.17%	39.2236	1.03%	38.8233	39.4042	1.50%	39.0834	0.67%
Cogeneration Utilization Factor		32.1840	32.0826	-0.31%	32.2771	0.29%	32.1840	32.2387	0.17%	32.2922	0.34%

Table D-1 Con't: Steam System Model Facility Evalutation Summary

		Case No. 3 Vary DeNOx Steam from BP to Letdown					Case No. 4 Vary DeNOx Steam from Letdown to HP				
Description		Base	-25% (-117KPPH)	% Change	-50% (-234KPPH)	% Change	Base	-50% (-39KPPH)	% Change	-100% (-77KPPH)	% Change
HRSG Boiler	Total Boiler Heat (kW)	1855910	1855910	0.00%	1855910	0.00%	1855910	1855910	0.00%	1855910	0.00%
Device No. 10	Irreversibility (kW)	653053	653053	0.00%	653053	0.00%	653053	653053	0.00%	653053	0.00%
BP Turbine	Turbine Work (kW)	13322	9991	-25.00%	6661	-50.00%	13322	13322	0.00%	13322	0.00%
Device No. 14	Irreversibility (kW)	2112	1584	-25.00%	1056	-50.00%	2112	2112	0.00%	2112	0.00%
HP Turbine	Turbine Work (kW)	132895	132858	-0.03%	132809	-0.06%	132895	134464	1.18%	136303	2.56%
Device No. 1	Irreversibility (kW)	14207	14246	0.27%	14249	0.30%	14207	14451	1.72%	14544	2.37%
LP Turbine	Turbine Work (kW)	270278	270313	0.01%	270369	0.03%	270278	270090	-0.07%	269840	-0.16%
Device No. 3	Irreversibility (kW)	70557	70566	0.01%	70580	0.03%	70557	70508	-0.07%	70442	-0.16%
BFW Pumps	Total Pump Work (kW)	5504	5506	0.04%	5508	0.07%	5504	5504	0.00%	5504	0.00%
Device No. 6 & 7	Irreversibility (kW)	1028	1028	0.00%	1029	0.10%	1028	1028	0.00%	1028	0.00%
Process Steam	Flow (KG/S)	67.8	67.8	0.00%	67.8	0.00%	67.8	67.8	0.00%	67.8	0.00%
Node No. 36	Enthalpy Supplied (KJ/kg)	2900	2899	-0.03%	2899	-0.03%	2900	2899	-0.03%	2897	-0.10%
	Enthalpy Returned (KJ/kg)	152	152	0.00%	152	0.00%	152	152	0.00%	152	0.00%
	Net Heat Provided (kW)	186314	186247	-0.04%	186247	-0.04%	186314	186247	-0.04%	186111	-0.11%
DeNOx Control Steam	Flow (KG/S)	130	130	0.00%	130	0.00%	130	130	0.00%	130	0.00%
Node No. 32	Enthalpy (KJ/kg)	2917	2941	0.82%	2965	1.65%	2917	2910	-0.24%	2904	-0.45%
	Enthalpy Rate (kW)	379210	382330	0.82%	385450	1.65%	379210	378300	-0.24%	377520	-0.45%
Net MW Produced (MW)		411	408	-0.81%	404	-1.62%	411	412	0.34%	414	0.72%
System Heat Rate		15408	15534	0.82%	15661	1.64%	15408	15356	-0.34%	15297	-0.72%
Carnot Cycle Eff.		57.0404	57.0404	0.00%	57.0404	0.00%	57.0404	57.0404	0.00%	57.0404	0.00%
1st Law Eff.		22.1449	21.9653	-0.81%	21.7860	-1.62%	22.1449	22.2194	0.34%	22.3050	0.72%
2nd Law Eff.		57.9353	57.7561	-0.31%	57.5782	-0.62%	57.9353	58.0268	0.16%	58.1361	0.35%
2nd Law Effectiveness		38.8233	38.5083	-0.81%	38.1941	-1.62%	38.8233	38.9537	0.34%	39.1039	0.72%
Cogeneration Utilization Factor		32.1840	32.0006	-0.57%	31.8215	-1.13%	32.1840	32.2547	0.22%	32.3330	0.46%

Appendix E:

Base Facility Evaluation Model

RANKINE 3.0 Input/Output Files

Base Facility Evaluation Model INPUT File

```
TITLE LINE
 Midland Cogeneration Venture - Steam System Model MCVOP1.DAT 10/11/98
 This model is used to incorporate performance curves provided from
 Actual Plant Data obtained from MCV 8/20 - 8/24 1998 (Nox and Process extraction pressure
 controlled). This will realistically model the facility and allow first
 and second law optimizations to be performed.
END TITLE


NUMBER OF NODES IS 41
HIGH TEMPERATURE RESERVOIR: 750.0 DEG F
LOW TEMPERATURE RESERVOIR: 60.0 DEG F
DEAD STATE TEMPERATURE RESERVOIR: 60.0 DEG F
DEAD STATE PRESSURE: 101 KPA
GENERATOR MECHANICAL LOSS IS 0.0 MW
GENERATOR ELECTRICAL LOSS IS 0.0 MW

COMMENT: HP STEAM TURBINE MODEL
DEVICE #1: SIMPLE TURBINE
        INLET NODE NUMBER IS 1
        EXTRACTION #1 NODE NUMBER IS 2
        EXTRACTION #2 NODE NUMBER IS 3
        EXTRACTION #3 NODE NUMBER IS 4

        COMMENT: INPUT HP TURBINE INLET CONDITIONS
        INLET MASS FLOW RATE IS 3875831 LBM/HR
        INLET PRESSURE IS 840 PSIA

        COMMENT: EXTRACTION #1 TO DENOX STEAM HEADER
        EXTRACTION #1 PRESSURE IS 348.0 PSIA
        EXTRACTION #1 MASS FLOW RATE IS 5448 LBM/HR

        COMMENT: EXTRACTION #2 TO PROCESS STEAM HEADER
        EXTRACTION #2 PRESSURE IS 290 PSIA
        EXTRACTION #2 MASS FLOW RATE IS 430220 LBM/HR

        COMMENT: EXTRACTION #3 TO LP STEAM TURBINE
        EXTRACTION #3 PRESSURE IS 207.0 PSIA
        STAGE GROUP #1 EFFICIENCY IS 78%
        STAGE GROUP #2 EFFICIENCY IS 100%
        STAGE GROUP #3 EFFICIENCY IS 91%
        END DEVICE

COMMENT: CIV/MOISTURE SEPARATOR MODEL
DEVICE #2: SIMPLE MOISTURE SEPARATOR
        SEPARATOR INLET NODE NUMBER IS 4
        SEPARATOR VAPOR EXIT NODE NUMBER IS 5
        SEPARATOR CONDENSATE EXIT NODE NUMBER IS 6
        SEPARATOR PRESSURE LOSS IS 11.0 PSIA
        END DEVICE
```

```
COMMENT: LP STEAM TURBINE MODEL
DEVICE #3: SIMPLE TURBINE
        INLET NODE NUMBER IS 5
        EXTRACTION #1 NODE NUMBER IS 7
        EXTRACTION #1 PRESSURE IS 1.0 PSIA
        STAGE GROUP #1 EFFICIENCY IS 78%
        END DEVICE

COMMENT: CONDENSER/HOTWELL MODEL
DEVICE #4: SIMPLE CONDENSER
        EXIT NODE NUMBER IS 8
        INLET #1 NODE NUMBER IS 7
COMMENT:INLET #2 NODE NUMBER IS 41
        EXIT TEMPERATURE IS 97.5 DEG F
        END DEVICE

COMMENT: JUNCTION FROM CONDENSER AND MAKEUP TO FEED WATER PUMPS
DEVICE #5: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 8
        INLET #2 NODE NUMBER IS 9
        EXIT #1 NODE NUMBER IS 10
        EXIT #2 NODE NUMBER IS 11
        COMMENT: INLET #1 IS FLOW FROM CONDENSER/HOTWELL
        INLET #1 MASS FLOW RATE IS 3431383 LBM/HR

        COMMENT: INLET #2 IS MAKEUP WATER FLOW
        INLET #2 MASS FLOW RATE IS 1568000 LBM/HR
        END DEVICE

COMMENT: DENOX FEED WATER PUMP MODEL
DEVICE #6: SIMPLE PUMP
        SUCTION NODE NUMBER IS 10
        DISCHARGE NODE NUMBER IS 12
        COMMENT: INPUT DENOX HEADER PRESSURE
        DISCHARGE PRESSURE IS 275.0 PSIA
        PUMP EFFICIENCY IS 80 PERCENT
        END DEVICE

COMMENT: BOILER FEED WATER PUMP MODEL
DEVICE #7: SIMPLE PUMP
        SUCTION NODE NUMBER IS 11
        DISCHARGE NODE NUMBER IS 13
        COMMENT: INPUT MAIN STEAM HEADER PRESSURE
        DISCHARGE PRESSURE IS 910.0 PSIA
        PUMP EFFICIENCY IS 80 PERCENT
        END DEVICE

COMMENT: JUNCTION FROM FROM DENOX BFW TO PROCESS DESUPERHEAT AND HRSG
DEVICE #8: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 12
        EXIT #1 NODE NUMBER IS 14
        EXIT #2 NODE NUMBER IS 35
        COMMENT: INLET #1 IS DENOX BFW FLOW
        INLET #1 MASS FLOW RATE IS 485312 LBM/HR
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        COMMENT: EXIT #1 IS FLOW TO HRSG
        EXIT #1 MASS FLOW RATE IS 474552 LBM/HR
        COMMENT: EXIT #2 IS FLOW TO PROCESS DESUPERHEATER
        EXIT #2 MASS FLOW RATE IS 10760 LBM/HR
        END DEVICE

COMMENT: JUNCTION FROM FROM MAIN BFW TO MAIN DESUPERHEAT AND HRSG
DEVICE #9: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 13
        EXIT #1 NODE NUMBER IS 15
        EXIT #2 NODE NUMBER IS 25
        COMMENT: INLET #1 IS MAIN BFW FLOW
        INLET #1 MASS FLOW RATE IS 4524831 LBM/HR
        COMMENT: EXIT #1 IS FLOW TO HRSG
        EXIT #1 MASS FLOW RATE IS 4511000 LBM/HR
        COMMENT: EXIT #2 IS FLOW TO MAIN DESUPERHEATER
        EXIT #2 MASS FLOW RATE IS 13831 LBM/HR
        END DEVICE

COMMENT: SIMPLE COMBINED HRSG BOILER MODEL
DEVICE #10: SIMPLE BOILER
        BOILER INLET NODE NUMBER IS 15
        BOILER EXIT NODE NUMBER IS 17
        BOILER REHEAT LEG #1 INLET NODE NUMBER IS 14
        BOILER REHEAT LEG #1 EXIT NODE NUMBER IS 16
        BOILER PRESSURE LOSS IS 0.0 MPA

        COMMENT: INPUT MAIN STEAM HEADER TEMPERATURE
        BOILER EXIT TEMPERATURE IS 729.0 DEG F

        COMMENT: INPUT DENOX HEADER TEMPERATURE
        BOILER REHEAT LEG #1 EXIT TEMPERATURE IS 464.0 DEG F
        BOILER REHEAT LEG #1 PRESSURE LOSS IS 0.0 PSIA
        END DEVICE

COMMENT: JUNCTION FROM HRSG MAIN STEAM TO HP BLOWDOWN 0.5%
DEVICE #11: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 17
        EXIT #1 NODE NUMBER IS 19
        EXIT #2 NODE NUMBER IS 18

        COMMENT: INLET #1 IS MAIN HRSG STEAM FLOW
        INLET #1 MASS FLOW RATE IS 4511000 LBM/HR

        COMMENT: EXIT #2 IS FLOW TO HP BLOWDOWN (0.5%)
        COMMENT: THIS VALUE SHOULD BE 0.5% OF MAIN STEAM MASS FLOW
        EXIT #2 MASS FLOW RATE IS 22555 LBM/HR
        END DEVICE

COMMENT: JUNCTION FROM HRSG DENOX TO LP BLOWDOWN 0.5%
DEVICE #12: SIMPLE JUNCTION
        INLET #1 NODE NUMBER IS 16
        EXIT #1 NODE NUMBER IS 21
        EXIT #2 NODE NUMBER IS 20
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COMMENT: INLET #1 IS DENOX HRSG STEAM FLOW
INLET #1 MASS FLOW RATE IS 474552 LBM/HR

COMMENT: EXIT #2 IS FLOW TO LP BLOWDOWN (0.5%)
COMMENT: THIS VALUE SHOULD BE 0.5% OF DENOX STEAM MASS FLOW
EXIT #2 MASS FLOW RATE IS 2373 LBM/HR
END DEVICE

COMMENT: JUNCTION FROM MAIN STEAM HEADER TO BP STEAM TURBINE
DEVICE #13: SIMPLE JUNCTION
INLET #1 NODE NUMBER IS 19
EXIT #1 NODE NUMBER IS 23
EXIT #2 NODE NUMBER IS 22
END DEVICE

COMMENT: BP STEAM TURBINE MODEL
DEVICE #14: SIMPLE TURBINE
INLET NODE NUMBER IS 22
EXTRACTION #1 NODE NUMBER IS 24

COMMENT: INPUT MASS FLOW ENTERING BP TURBINE
COMMENT: FOR 0.00 USE 0.1 LBM/HR
INLET MASS FLOW RATE IS 468000 LBM/HR

COMMENT: INPUT DENOX HEADER PRESSURE
EXTRACTION #1 PRESSURE IS 275.0 PSIA
COMMENT: THE EFFICIENCY BELOW WAS CALCULATED FROM PROVIDED DATA
STAGE GROUP #1 EFFICIENCY IS 78%
END DEVICE

COMMENT: MAIN STEAM DESUPERHEATER MODEL
DEVICE #15: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 26
EXTRACTION INLET NODE NUMBER IS 23
FEED WATER INLET NODE NUMBER IS 25
FEED WATER INLET MASS FLOW RATE IS 13831 LBM/HR
FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: JUNCTION FROM MAIN STEAM HEADER TO DENOX AND PROCESS STEAM
DEVICE #16: SIMPLE JUNCTION
INLET #1 NODE NUMBER IS 26
EXIT #1 NODE NUMBER IS 40
EXIT #2 NODE NUMBER IS 27
EXIT #3 NODE NUMBER IS 29

COMMENT: EXIT #2 MASS FLOW IS MAIN HEADER TO DENOX HEADER
COMMENT: FOR 0.00 USE 0.1 LBM/HR
EXIT #2 MASS FLOW RATE IS 82000 LBM/HR

COMMENT: EXIT #3 MASS FLOW IS MAIN HEADER TO DOW PROCESS STEAM
COMMENT: FOR 0.00 USE 0.1 LBM/HR

EXIT #3 MASS FLOW RATE IS 97020 LBM/HR
END DEVICE

COMMENT: DENOX STEAM LETDOWN FROM MAIN - THOTTLE PROCESS
DEVICE #17: SIMPLE PIPE
INLET NODE NUMBER IS 27
EXIT NODE NUMBER IS 28
COMMENT: INPUT MAIN HEADER TO DENOX PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 635.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: PROCESS STEAM LETDOWN FROM MAIN - THOTTLE PROCESS
DEVICE #18: SIMPLE PIPE
INLET NODE NUMBER IS 29
EXIT NODE NUMBER IS 30
COMMENT: INPUT MAIN HEADER TO DENOX PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 720.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: DENOX STEAM LETDOWN FROM HP TURBINE EXTRACTION #1 - THOTTLE PROCESS
DEVICE #19: SIMPLE PIPE
INLET NODE NUMBER IS 2
EXIT NODE NUMBER IS 31
COMMENT: INPUT HP EXTRACTION #1 TO DENOX PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 72 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: DEVICES #20-#22 MODEL THE MIXING OF DENOX EXTRACTION FLOWS
COMMENT: FROM BP TURBINE, MAIN STEAM EXTRACTION, HP EXTRACTION, & HRSG
DEVICE #20: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 38
EXTRACTION INLET NODE NUMBER IS 31
FEED WATER INLET NODE NUMBER IS 28
COMMENT: NODE 31 IS FLOW FROM HP TURBINE
COMMENT: NODE 28 IS FLOW MAIN STEAM
FEED WATER EXIT IS NOT SATURATED
END DEVICE
DEVICE #21: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 39
EXTRACTION INLET NODE NUMBER IS 38
FEED WATER INLET NODE NUMBER IS 24
COMMENT: NODE 24 IS FLOW FROM BP TURBINE
FEED WATER EXIT IS NOT SATURATED
END DEVICE
DEVICE #22: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 32
EXTRACTION INLET NODE NUMBER IS 39
FEED WATER INLET NODE NUMBER IS 21
COMMENT: NODE 21 IS FLOW FROM HRSG
COMMENT: FEED WATER EXIT (NODE 32) IS FLOW TO GT DENOX INJECT.

FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: HP PROCESS EXTRACTION TO PROCESS PRESSURE FOR PROCESS STEAM - THOTTLE PROCESS
DEVICE #23: SIMPLE PIPE
INLET NODE NUMBER IS 3
EXIT NODE NUMBER IS 34
COMMENT: INPUT PROCESS TO HP TURBINE EXTRACTION #2 PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 100.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: DEVICE #23 MODELS THE MIXING OF PROCESS EXTRACTION FLOWS
DEVICE #24: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 33
EXTRACTION INLET NODE NUMBER IS 34
FEED WATER INLET NODE NUMBER IS 30
COMMENT: NODE 3 IS FLOW FROM HP TURBINE
COMMENT: NODE 30 IS FLOW MAIN STEAM
FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: DENOX FEEDWATER THROTTLED TO DESIRED PRESSURE - THOTTLE PROCESS
DEVICE #25: SIMPLE PIPE
INLET NODE NUMBER IS 35
EXIT NODE NUMBER IS 37
COMMENT: INPUT DENOX PRESSURE TO DOW/CORNING PROCESS
COMMENT: DESIRED PRESSURE DIFFERENCE
PIPE PRESSURE LOSS IS 85.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

COMMENT: PROCESS STEAM DESUPERHEATER MODEL
DEVICE #26: SIMPLE OFW HEATER
FEED WATER EXIT NODE NUMBER IS 36
EXTRACTION INLET NODE NUMBER IS 33
FEED WATER INLET NODE NUMBER IS 37

COMMENT: INPUT PROCESS STEAM MASS FLOW REQUIRED
FEED WATER EXIT MASS FLOW RATE IS 538000 LBM/HR
FEED WATER EXIT IS NOT SATURATED
END DEVICE

COMMENT: SIMPLE PIPE TO MODEL MAIN STEAM PIPING PRESSURE LOSS
DEVICE #27: SIMPLE PIPE
INLET NODE NUMBER IS 40
EXIT NODE NUMBER IS 1
COMMENT: INPUT MAIN STEAM TO HP TURBINE INLET PRESS. DIFF.
PIPE PRESSURE LOSS IS 70.0 PSIA
PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
END DEVICE

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COMMENT: SIMPLE PIPE TO MODEL MS/CIV TO CONDENSER PRESSURE DIFF.
DEVICE #28: SIMPLE PIPE
        INLET NODE NUMBER IS 6
        EXIT NODE NUMBER IS 41
        COMMENT: INPUT HP EXIT MINUS MS/CIV TO CONDENSER PRESS. DIFF.
        PIPE PRESSURE LOSS IS 195 PSIA
        PIPE ENTHALPY LOSS IS 0.0 BTU/LBM
        END DEVICE
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Base Facility Evaluation Model OUTPUT File

RANKINE 3.0: A steam power plant computer simulation

W.A. Thelen, C.W. Somerton

*********************************** TITLE ***********************************

Midland Cogeneration Venture - Steam System Model MCVOP1.DAT 10/11/98
This model is used to incorporate performance curves provided from
Actual Plant Data obtained from MCV 8/20 - 8/24 1998 (Nox and Process extraction controlled).
This will realistically model the facility and allow first and second law optimizations to be performed.

******************************** NODE DATA ********************************

NODE	T(C)	P(MPa)	L	Q	S(KJ/KG/K)	H(KJ/KG)	V(M^3/KG)	M(KG/S)	A(KJ/KG)
1	379.59	5.7916	3	*****	6.4845	3130.01	.04720	488.3547	1259.17
2	278.42	2.3994	3	*****	6.5733	2959.31	.09833	.6864	1062.82
3	255.73	1.9995	3	*****	6.5733	2917.17	.11324	54.2077	1020.69
4	218.92	1.4272	3	*****	6.5868	2850.31	.14802	433.4605	949.93
5	217.30	1.3514	3	*****	6.6103	2850.31	.15634	433.4605	943.16
6	193.39	1.3514	4	*****	2.2663	822.34	.00115	.0000	169.32
7	38.75	.0069	2	.857	7.1741	2226.77	17.83418	432.3542	156.85
8	36.39	.0069	1	*****	.5236	152.41	.00101	432.3542	2.52
9	36.39	.0069	1	*****	.5236	152.41	.00101	197.5680	2.52
10	36.39	.0069	1	*****	.5236	152.41	.00101	61.1493	2.52
11	36.39	.0069	1	*****	.5236	152.41	.00101	570.1287	2.52
12	36.66	1.8961	1	*****	.5254	155.24	.00101	61.1493	4.83
13	37.28	6.2742	1	*****	.5296	161.76	.00101	570.1287	10.13
14	36.66	1.8961	1	*****	.5254	155.24	.00101	59.7936	4.83
15	37.28	6.2742	1	*****	.5296	161.76	.00101	568.3860	10.13
16	240.00	1.8961	3	*****	6.5269	2881.19	.11508	59.7936	998.11
17	387.22	6.2742	3	*****	6.4666	3140.22	.04390	568.3860	1274.54
18	387.22	6.2742	3	*****	6.4666	3140.22	.04390	2.8419	1274.54
19	387.22	6.2742	3	*****	6.4666	3140.22	.04390	565.5441	1274.54
20	240.00	1.8961	3	*****	6.5269	2881.19	.11508	.2990	998.11
21	240.00	1.8961	3	*****	6.5269	2881.19	.11508	59.4946	998.11
22	387.22	6.2742	3	*****	6.4666	3140.22	.04390	58.9680	1274.54
23	387.22	6.2742	3	*****	6.4666	3140.22	.04390	506.576	1274.54
24	252.90	1.8961	3	*****	6.5907	2914.32	.11909	58.9680	1012.83
25	37.28	6.2742	1	*****	.5296	161.76	.00101	1.7427	10.13
26	383.38	6.2742	3	*****	6.4511	3130.01	.04353	508.3188	1268.81
27	383.38	6.2742	3	*****	6.4511	3130.01	.04353	10.3320	1268.81
28	345.87	1.9029	3	*****	6.9673	3130.01	.14486	10.3320	1119.80
29	383.38	6.2742	3	*****	6.4511	3130.01	.04353	12.2245	1268.81
30	340.18	1.3100	3	*****	7.1344	3130.01	.21075	12.2245	1071.53
31	271.31	1.9029	3	*****	6.6732	2959.31	.12412	.6864	1034.00
32	253.79	1.8961	3	*****	6.5949	2916.55	.11936	129.481	1013.83
33	261.06	1.3100	3	*****	6.8311	2956.34	.18002	66.4322	985.44
34	244.06	1.3100	3	*****	6.7566	2917.17	.17307	54.2077	967.78
35	36.66	1.8961	1	*****	.5254	155.24	.00101	1.3558	4.83
36	236.91	1.3100	3	*****	6.7238	2900.32	.17009	67.7880	960.40

37	36.79	1.3100	1	*****	.5277	155.24	.00101	1.3558	4.17
38	341.01	1.8961	3	*****	6.9516	3119.38	.14410	11.0184	1113.67
39	265.95	1.8961	3	*****	6.6513	2946.60	.12302	69.9865	1027.61
40	383.38	6.2742	3	*****	6.4511	3130.01	.04353	485.7623	1268.81
41	38.75	.0069	2	.274	2.6717	822.34	5.70347	.0000	0.000

******************************* SYSTEM DATA ****************************

TOTAL MASS FLOW RATE EXITING SYSTEM: 199.4099 KG/SEC
TOTAL MASS FLOW RATE ENTERING SYSTEM: 197.5680 KG/SEC
TOTAL ENTHALPY FLOW RATE EXITING SYSTEM: 583207.7000 KW
TOTAL ENTHALPY FLOW RATE ENTERING SYSTEM: 30111.3400 KW
TOTAL HEAT AND WORK ENTERING SYSTEM: 548061.1000 KW

BOILER HEAT (DEVICE # 10): 1855910.0000 KW
TOTAL BOILER HEAT: 1855910.0000 KW
TOTAL HEAT LOAD HEAT: .0000 KW
CONDENSER HEAT (DEVICE # 4): -896859.2000 KW
TOTAL PIPE ENERGY LOSSES: .0000 KW

TURBINE WORK (DEVICE # 1): 132894.8000 KW
TURBINE WORK (DEVICE # 3): 270278.0000 KW
TURBINE WORK (DEVICE # 14): 13321.0800 KW
NET WORK TO GENERATORS: 416493.9000 KW

PUMP WORK (DEVICE # 6): -173.1171 KW
PUMP WORK (DEVICE # 7): -5330.6200 KW
TOTAL PUMP WORK: -5503.7370 KW
GENERATOR MECHANICAL LOSSES: .0000 KW
GENERATOR ELECTRICAL LOSSES: .0000 KW
NET ELECTRICAL POWER: 410990.1000 KW

SYSTEM HEAT RATE:	15407.5900 BTU/KW*HR
CARNOT CYCLE EFFICIENCY:	57.0404 PERCENT
1ST LAW EFFICIENCY:	22.1449 PERCENT
2ND LAW EFFICIENCY:	57.9353 PERCENT
2ND LAW EFFECTIVENESS:	38.8233 PERCENT

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