OVERVIEW OF COGENERATION AT LSU

A Thesis

Submitted to the Graduate Faculty of the
Louisiana State University and
Agricultural and Mechanical College
in partial fulfillment of the
requirements for the degree of
Master of Science in Chemical Engineering

in

The Department of Chemical Engineering

by
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B.S., Louisiana State University, 2004
August 2006

ACKNOWLEDGEMENTS

First of all, I would like to thank Dr. Knopf for his help and guidance throughout the project. I feel that I have learned a great deal about both cogeneration and large scale utility systems with his assistance. I would like to thank both Dr. Pike and Dr. Corripio for serving as members of my examining committee.

Second, I would like to thank everyone involved with LSU Energy Services for access to the LSU utilities system and for assistance in learning about the system. In particular, I would like to thank Blake Hebert, Peter Davidson, Tony Cupit, the maintenance engineers from Bernhard Mechanical, and all the operators who assisted me.

Finally, I would like to thank everyone from the LSU Department of Chemical Engineering. In my six years here as an undergraduate and graduate student, I feel that I have gained a great deal of knowledge, and I have enjoyed my time here.

TABLE OF CONTENTS

ABSTRACT

Cogeneration (or Combined Heat and Power) continues to gain importance in power production because of its high efficiency, environmental friendliness, and flexibility. Louisiana State University (LSU) recently began operation of a new 20 MW cogeneration system. This new facility can serve as a useful learning tool for chemical and mechanical engineering students throughout their education at LSU. The goal of this project is to develop educational modules utilizing the cogeneration system which have industrial significance. Educational modules will include: a comparison of ideal gas versus real gas thermodynamics for a cogeneration optimization problem, a cogeneration data reconciliation problem, and a system level energy management optimization problem. The modules will be solved using Microsoft Excel as a solution platform to help promote wide spread use. The energy management strategy accounts for seasonal and time of day operating strategies. The optimal operating strategy is compared to current operating strategies to determine the most economical and most efficient methods of operating the LSU utility system. The new operating strategies can offer significant potential savings.

CHAPTER 1
INTRODUCTION

1.1 Definition of Cogeneration

Cogeneration (also known as Combined Heat and Power, or CHP) is the simultaneous production of heat and electrical power. Cogeneration is typically used for large towns, universities, hospitals, hotels, prisons, oil refineries, chemical plants, paper mills, wastewater treatment plants, enhanced oil recovery wells, and numerous other industrial plants with significant heating needs (EDUCOGEN, 2001). Cogeneration has also been adapted on a smaller scale to individual homes or businesses (called micro cogeneration) (EDUCOGEN, 2001).

Because cogeneration is simply combined heat and power production, it is extremely flexible. There are many variations of CHP. Power production options include steam turbines, gas turbines, reciprocating engines, stirling engines, fuel cells, and micro-turbines. Heat recovery typically consists of a waste heat recovery boiler which uses the exhaust gas of power production to heat another fluid, usually water. Heat recovery boilers usually are composed of one, two, or three sections: an economizer (to preheat the water), an evaporator (to vaporize the water), and a superheater (to superheat the steam). The end use of the hot water/steam determines which of the three sections of the heat recovery boilers are needed. Heat recovery boilers can also have supplemental firing in which additional fuel is burned to increase the temperature of the exhaust gas in order to create additional hot water/steam.

There are two types of cogeneration plants. One type of cogeneration plant is called bottoming cycle cogeneration. It generates heat first and electricity second. These plants exist only in heavy industries such as glass or metals manufacturing where very high temperature furnaces are used.

The most common type of cogeneration plant is called topping cycle cogeneration and produces electricity first and heat second. Typical configurations for topping cycle cogeneration plants are (EDUCOGEN, 2001):

(1) A gas turbine or diesel engine producing electrical or mechanical power followed by a heat recovery boiler to create steam to drive a secondary steam turbine. This is called a combined-cycle topping system. Combined cycle is useful for maximizing power production when no process steam or hot water is needed.

(2) The second type of system burns fuel (any type) to produce high-pressure steam that then passes through a steam turbine to produce power while the exhaust provides low-pressure process steam. This is a steam-turbine topping system and is useful when a fuel source is readily available at low cost and only low-pressure process steam is needed.

(3) A third type employs hot water from an engine jacket cooling system flowing to a heat recovery boiler, where it is converted to process steam and hot water for space heating. This type is useful for many engines which require significant cooling because a high temperature cooling water stream is available to further heat into process steam.

(4) The fourth type is a gas-turbine topping system. A natural gas turbine drives a generator. The exhaust gas goes to a heat recovery boiler that makes process hot water or steam. This type is useful for producing large amounts of both power and steam and is the type here at LSU.

1.2 Importance of Cogeneration

Cogeneration is important for numerous reasons. The first is that capturing the waste heat from power generation can result in an increase in efficiency from below 50 % for conventional power generation to 70 - 90 % for cogeneration. This offers significant potential savings in energy costs. Additional electricity generated can also be sold back to the grid in a deregulated electricity market, opening up more opportunities for energy savings (EDUCOGEN, 2001).

Cogeneration also provides a stable supply of electricity and process steam which is only dependent upon the availability of the fuel used in the process. This is very important for areas where the local electric service is unreliable and/or unable to produce enough electricity. For example, the 500,000 barrel per day Hovensa oil refinery in St. Croix produces all of its own electricity and steam primarily through cogeneration (Corripio, 2005).

Cogeneration is also more environmentally friendly than traditional fossil fuel power plants. First, CHP is more efficient, reducing total fossil fuel consumption and thereby reducing emissions to the atmosphere. Second, natural gas (a clean burning fossil fuel) is often used in cogeneration with steam injection to minimize emissions. For a typical gas turbine topping-cycle cogeneration plant, typical CO_2 emissions reductions are 356 g/kW-hr, typical NO_x reductions are 2.9 g/kW-hr, and typical SO_2 reductions are 23.2 g/kW-hr as compared to a traditional fossil fuel plant (EDUCOGEN, 2001).

Cogeneration is especially important in Europe where it accounts for over 10 % of power production across the European Union with the potential to reach 30 % of the European Union’s power production. CHP currently accounts for over 40 % of power production in the Netherlands, Denmark, and Finland. It is especially important in those three countries because of “district heating.” Local cogeneration plants produce electricity to serve the area while the steam is distributed through steam pipes to heat local housing and businesses. District heating is also used on numerous university campuses and is part of the reason why cogeneration is very popular among universities (EDUCOGEN, 2001).

Here in the Unites States, the Department of Energy set a goal of doubling cogeneration capacity to 92 GW (gigawatts) by 2010. At the end of 2005, there were 2,960 sites with over 82 GW of capacity (6th Annual World CHP Decentralized Energy Conference and Workshop, 2005). While the majority of new sites have been commercial applications, the vast majority of new capacity has been from extremely large industrial applications. However, cogeneration faces new challenges in the United States because of natural gas volatility, electricity market restructuring, and grid vulnerabilities. (6th Annual World CHP Decentralized Energy Conference and Workshop, 2005).

1.3 Literature Review

Gas turbine analysis including material, energy, and entropy balances as well as detailed design equations can be found in Bathie (1996). Individual units including compressors, turbines, and combustion chambers are examined first before proceeding to overall gas turbine problems. Numerous problems were solved using both ideal gas and real gas models.

Heat recovery steam generator (HRSG) design and operation is the key to the increased efficiency of cogeneration as compared to traditional power generation. Various works by Ganapathy (1991, 1993, and 1996) were consulted as well as Karthikeyan et al. (1998). HRSG modeling and simulation were studied including unfired and fired modes. One very important concept is the selection of temperature profiles in HRSG, especially the pinch and approach temperatures.

The next step is the combining of gas turbines and HRSG into a cogeneration system. Kim et al. (1994) examined the off-design performance of a gas turbine cogeneration facility. The gas turbine process was modeled using performance maps for compressors and turbines. HRSG performance is examined by modeling of the heat transfer process. The study focused on tracking important operating parameters as the load on the turbine changed. Ahner (1988) modeled and solved several cases for an industrial cogeneration plant. The heat rate and other important parameters of the system were examined for various power generation conditions and process heat requirements.

1.4 Cogeneration at LSU

The LSU campus has two cogeneration systems. The first cogeneration system was installed in 1993. It consists of a 3.7 MW aeroderivative gas turbine (Allison brand) and an accompanying HRSG (called Boiler 7). The shaft of the Allison turbine drives a refrigeration cycle to produce chilled water. The chilled water and steam that are produced are used for campus needs.

In early 2005, LSU brought on-line a new 20 MW cogeneration facility. The system is composed of an aeroderivative gas turbine (GE LM-2000) connected to a generator and a HRSG (called Boiler 8) composed of an evaporator and economizer. The power and steam produced are used for campus needs. The installed cost of this system was over $20 million.

1.5 Description of Thesis

The first goal of this thesis is to develop educational modules for the National Science Foundation (NSF) grant entitled “CCLI: Integrating a Cogeneration Facility into Engineering Education” recently received by the LSU Chemical and Mechanical Engineering Departments. The NSF grant aims to create and implement educational modules in which students solve industrial problems with real-time data from the LSU cogeneration system. Sophomores would be exposed to real-time material and energy balances for process equipment. Juniors would be exposed to thermodynamics and heat transfer problems. Seniors would be exposed to more complex problems such as energy management optimization, online monitoring of emissions, and process control. This thesis will focus on creating and implementing educational modules including a comparison of ideal gas versus real gas thermodynamics for a cogeneration optimization problem, a cogeneration data reconciliation problem, and a system level energy management optimization problem. These modules will also be submitted for publication in journals dealing with the fields of chemical and mechanical engineering.

A second goal of this research is to examine more advanced operations management for the LSU utility system in hopes of improving the overall understanding of all processes. Optimal seasonal and time of day operating strategies will be compared to current operating strategies to determine the most efficient and most economical methods of operating the LSU utility system.

This project is heavily reliant upon obtaining excellent physical and thermodynamic properties for modeling plant data. Significant effort was made in developing a robust physical properties package for combustion and thermodynamic calculations called Physical Properties for Combustion Studies or PPCS (2000-2006). This package has been developed by D. Ozyurt, S. Stafford, J. Punuru, and F. Carl Knopf at LSU. PPCS is based on modifications to Reynolds (1991). Refrigerant properties for R-134a were added to the package and are based on data and correlations from DuPont (2005). The physical properties package was written in C language and assembled as a dynamic link library to allow linking with Microsoft Excel. All physical properties can be obtained in Excel by using user defined functions.

Chapter 2 of the thesis presents the first module. The problem is a well known cogeneration optimization problem that utilizes ideal gas and constant heat capacity assumptions (Valero, 1994). The focus will be on comparing the original solution to a real gas solution based on PPCS.

Chapter 3 presents the second module which is a problem of data reconciliation for the LSU GE Turbine Cogeneration system. Actual plant data and PPCS are used to perform the data reconciliation.

Chapter 4 presents the third module for solving the energy management optimization problem at LSU. It incorporates the cogeneration system with other equipment at LSU. The goal is to compare current operating strategies to optimal operating strategies and to develop seasonal and time of day operating strategies.

Chapter 5 presents the conclusions that were reached from the three educational modules. It also presents recommendations to aid in further implementing the goals of the NSF grant.

CHAPTER 2
CGAM PROBLEM: CONVENTIONAL VS. REAL GAS SOLUTION

2.1 Background

The CGAM problem is an economic optimization of a simple cogeneration system which involves physical, thermodynamic, and economic models. It assumes ideal gas behavior and constant heat capacities. This problem was introduced in a special session at the International Symposium on "Efficiency, Costs, Optimization, and Simulation of Energy Systems (ECOS '92)" held in Zaragoza, Spain from June 15-18, 1992. The conventional solution to the CGAM problem was later published in *Energy Journal* (Valero et al., 1994). The CGAM problem was later revisited by several of the original authors (and others) using other approaches. Frangopoulos (1994) focused on a thermoeconomic approach. Tsatsaronis and Pisa (1994), Alvarado and Gherardelli (1994), and Hua et al. (1997) used exergoeconomic approaches.

2.2 Conventional CGAM Problem

2.2.1 Conventional CGAM Problem Description

The CGAM Problem designs a cogeneration plant which delivers 30 MW (102.3643 MMBTU/hr) of electricity and 14 kg/s (30.865 lb/s) of saturated steam at 20 bar (290.08 psia). The structure of the cogeneration plant is shown in Figure 2-1. The installation consists of an air compressor (AC), air preheater (APH), combustion chamber (CC), gas turbine (GT), and HRSG. The air preheater uses thermal energy from the combustion gas leaving the turbine to heat the air entering the combustion chamber. The HRSG is composed of an economizer (EC) section where the feed water is heated and an evaporator (EV) section where the heated water is vaporized into steam. The reference conditions are defined as T_0 = 77°F and P_0 = 14.69 psia. The fuel for the combustion chamber is natural gas with a lower heating value (LHV) = 21,496 BTU/lb.

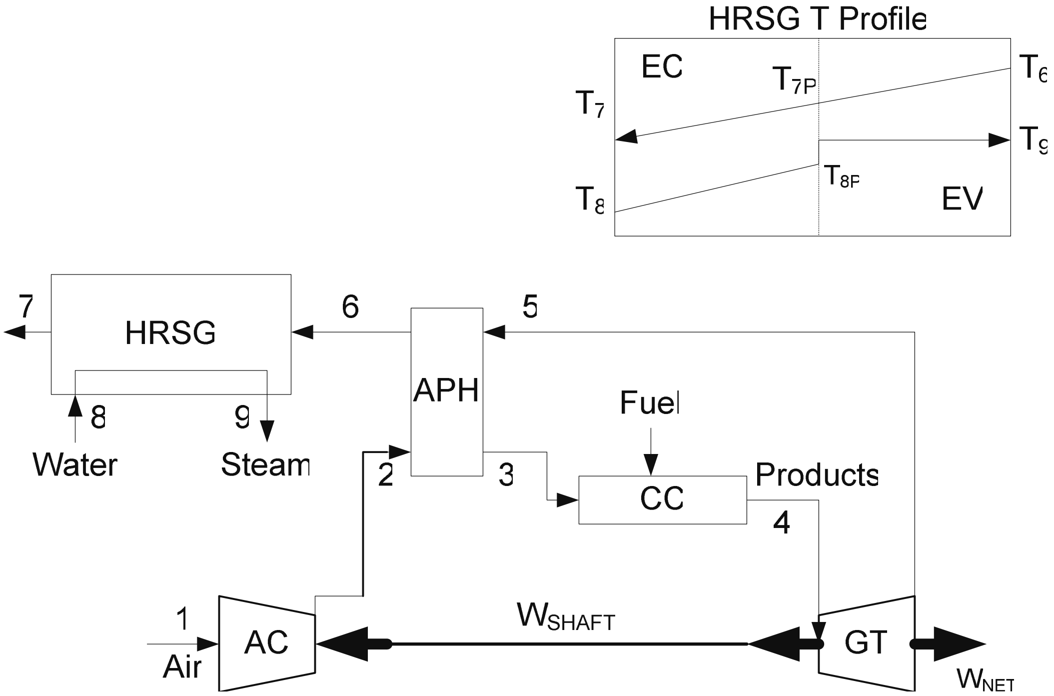


Figure 2-1: CGAM Cogeneration Flow Diagram

The equations that describe the behavior of the system (physical model), the equations of state used to calculate the thermodynamic properties (thermodynamic model), and the equations for calculating the capital costs of the components (economic model) are considered. The decision variables selected for the optimization are the pressure ratio (P_2/P_1), the isentropic efficiencies of the air compressor (η_{AC}) and the gas turbine (η_{GT}) and the temperatures of the air at the air preheater exit (T_3) and of the combustion gas at the gas turbine inlet (T_4). The models are formulated as a function of these decision variables.

A few assumptions are made to simplify the model: (i) The air and combustion gases behave as ideal gases with constant specific heats, (ii) The natural gas fuel is assumed to be all methane (CH_4), (iii) All components, except the combustion chamber, are adiabatic. Pressure losses for the air and gas flows in the combustion chamber, air preheater, and HRSG are given.

2.2.2 Conventional CGAM Physical Model

The conventional CGAM problem (Valero et al., 1994) presents the following equations for the physical model. They also can be found in any standard chemical or mechanical engineering thermodynamics textbook. Mass and energy balances for each component of the plant include:

Air Compressor (AC)

$$T_2 = T_1 \left\{ 1 + \frac{1}{\eta_{AC}} \left[\left(\frac{P_2}{P_1} \right)^{\frac{\gamma_a - 1}{\gamma_a}} - 1 \right] \right\}$$

$$\dot{W}_{AC} = \dot{m}_a c_{P,a} \left(T_2 - T_1 \right)$$

where T_1 is the ambient air temperature (77°F); P_1 is the ambient air pressure (14.69 psia); T_2 is the air temperature leaving the AC; η_{AC} is the isentropic efficiency of the AC; γ_a is the specific heat ratio of the air (1.4); $\dot{W}_{AC}$ is the work of the AC; $\dot{m}_a$ is the mass flow rate of air; and $c_{P,a}$ is the heat capacity of air (0.24 BTU/lb-R).

Air Preheater (APH)

$$\dot{m}_a c_{P,a} \left(T_3 - T_2 \right) = \dot{m}_g c_{P,g} \left(T_5 - T_6 \right)$$

$$P_3 = P_2 \left(1 - \Delta P_{a,APH} \right)$$

$$P_6 = P_5 \left(1 - \Delta P_{g,APH} \right)$$

where $\dot{m}_g$ is the mass flow rate of combustion gas; $c_{P,g}$ is the heat capacity of the combustion gas (0.28 BTU/lb-R); T_3 is the temperature of the air leaving the APH; T_5 is the temperature of the combustion gas leaving the GT; T_6 is the temperature of the combustion gas leaving the APH; P_3 is the pressure of the air leaving the APH; $\Delta P_{a,APH}$ is the percentage pressure drop of the air side in the APH (5 %); P_5 is the pressure of the combustion gas leaving the GT; P_6 is the pressure of the combustion gas leaving the APH; and $\Delta P_{g,APH}$ is the percentage pressure drop of the combustion gas side of the APH (3 %).

Combustion Chamber (CC)

$$\dot{m}_g = \dot{m}_a + \dot{m}_f$$

$$\dot{m}_a h_3 + \dot{m}_f LHV = \dot{m}_g h_4 + \dot{Q}_{l,CC}$$

$$h_3 = c_{P,a}(T_3 - T_0)$$

$$h_4 = c_{P,g}(T_4 - T_0)$$

$$\dot{Q}_{l,CC} = \dot{m}_f LHV(1 - \eta_{CC})$$

$$P_4 = P_3(1 - \Delta P_{CC})$$

where $\dot{m}_f$ is the mass flow rate of fuel; T_4 is the temperature of the combustion gas leaving the CC; $\dot{Q}_{l,CC}$ is the heat loss in the CC; η_{CC} is the combustion thermal efficiency (0.98); P_4 is the pressure leaving the CC; and ΔP_{CC} is the percentage pressure drop in the CC (5 %).

Gas Turbine (GT)

$$T_5 = T_4\left\{1 - \eta_{GT}\left[1 - \left(\frac{P_4}{P_5}\right)^{\frac{1-\gamma_g}{\gamma_g}}\right]\right\}$$

$$\dot{W}_{GT} = \dot{m}_g c_{P,g}(T_4 - T_5)$$

$$\dot{W}_{net} = \dot{W}_{GT} - \dot{W}_{AC}$$

where η_{GT} is the isentropic efficiency of the GT; γ_g is the specific heat ratio of the combustion gas (1.33); $\dot{W}_{GT}$ is the work of the GT; and $\dot{W}_{net}$ is the net work of the system (102.3643 MMBTU/hr).

Heat Recovery Steam Generator (HRSG)

$$T_{8P} = T_9 - \Delta T_A$$

$$\Delta T_P = T_{7P} - T_9 > 0$$

$$\dot{m}_g c_{P,g}\left(T_6 - T_{7P}\right) = \dot{m}_s\left(h_9 - h_{8P}\right)$$

$$T_7 = T_6 - \dot{m}_s\left(h_9 - h_8\right) / \dot{m}_g c_{P,g}$$

$$P_0 = P_6\left(1 - \Delta P_{HRSG}\right)$$

where T_{8P} is the water temperature entering the EV; T_9 is the saturated steam temperature (414.3°F); ΔT_A is the minimum approach temperature difference (27°F); $\dot{m}_s$ is the steam flow rate (30.865 lb/s); $(h_9 - h_{8P})$ is the EV water/steam side enthalpy difference (840.93 BTU/lb); ΔT_P is the minimum temperature difference at the pinch; T_{7P} is the combustion gas temperature leaving the EV; $(h_9 - h_8)$ is the total HRSG water/steam side enthalpy difference (1154.9 BTU/lb); and ΔP_{HRSG} is the percentage pressure drop of the combustion gas in the HRSG (5 %).

2.2.3 Conventional CGAM Thermodynamic Model

The conventional CGAM problem (Valero et al., 1994) presents the following thermodynamic model which is based on standard assumptions for many engineering problems.

Reference Environment

Air (relative humidity = 60 %) with the mole fractions $x_{O2} = 0.2059$, $x_{N2} = 0.7748$, $x_{CO2} = 0.0003$, and $x_{H2O} = 0.019$ at $T_0 = 77°F$ and $P_0 = 14.69$ psia.

Combustion Reaction (molar basis)

The fuel is pure methane. Complete combustion is assumed in the combustion chamber according to the following reaction with methane as the limiting reactant

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$$

The nitrogen and carbon dioxide in the incoming air are inert. The molecular weights of methane and air are M_{CH4} = 16.043 g/mol and M_a = 28.648 g/mol.

2.2.4 Conventional CGAM Economic Model

The conventional CGAM problem (Valero et al., 1994) presents the following economic model that is based on standard engineering costing equations.

Equipment Cost Rate

When evaluating the costs of a plant, it is necessary to consider the annual cost of fuel and the annual cost associated with owning and operating each plant component. The expressions for obtaining the purchase costs of the components (Z) are presented in Tables 2-1 and 2-2. Based on these costs, the general equation for the cost rate ($\dot{Z}_i$ in \$/s) associated with capital investment and the maintenance costs for the ith component is

$$\dot{Z}_i = Z_i CRF \varphi / (N * 3600)$$

where Z_i is the purchase cost of the ith component (\$), CRF is the annual capital recovery factor (CRF = 18.2 %), N represents the number of hours of plant operation per year (N = 8000 hr), and φ is the maintenance factor (φ = 1.06).

Fuel Cost Rate

The cost rate associated with fuel is obtained from

$$\dot{C}_f = c_f \dot{m}_f LHV$$

where the fuel cost per energy unit (on an LHV basis) is c_f = 0.00422 \$/BTU.

Total Cost Rate

The total cost of operation for the installation is obtained from

$$\dot{C}_T = c_f \dot{m}_f LHV + \sum_{i=1}^{5} \dot{Z}_i$$

Table 2-1: Equations to Calculate Equipment Purchase Costs

Compressor	$Z_{AC} = \left(\frac{C_{11}\dot{m}_a}{C_{12} - \eta_{AC}}\right)\left(\frac{P_2}{P_1}\right)\ln\left(\frac{P_2}{P_1}\right)$
Combustion Chamber	$Z_{CC} = \left(\frac{C_{21}\dot{m}_a}{C_{22} - \frac{P_4}{P_3}}\right)\left(1 + EXP\left(C_{23}T_4 - C_{24}\right)\right)$
Gas Turbine	$Z_{GT} = \left(\frac{C_{31}\dot{m}_g}{C_{32} - \eta_{GT}}\right)\ln\left(\frac{P_4}{P_5}\right)\left(1 + EXP\left(C_{33}T_4 - C_{34}\right)\right)$
Air Preheater	$Z_{APH} = C_{41}\left(\frac{\dot{m}_g\left(h_5 - h_6\right)}{U\Delta T_{LM,APH}}\right)^{0.6}$ $\Delta T_{LM,APH} = \frac{\left(T_5 - T_3\right) - \left(T_6 - T_2\right)}{\ln\left(\frac{T_5 - T_3}{T_6 - T_2}\right)}$
HRSG	$Z_{HRSG} = C_{51}\left[\left(\frac{\dot{Q}_{EC}}{\Delta T_{LM,EC}}\right)^{0.8} + \left(\frac{\dot{Q}_{EV}}{\Delta T_{LM,EV}}\right)^{0.8}\right] + C_{52}\dot{m}_s + C_{53}\dot{m}_g^{1.2}$ $\Delta T_{LM,EC} = \frac{\left(T_7 - T_8\right) - \left(T_{7P} - T_{8P}\right)}{\ln\left(\frac{T_7 - T_8}{T_{7P} - T_{8P}}\right)}$ $\Delta T_{LM,EV} = \frac{\left(T_6 - T_9\right) - \left(T_{7P} - T_{8P}\right)}{\ln\left(\frac{T_6 - T_9}{T_{7P} - T_{8P}}\right)}$

Table 2-2: Constants Used in Equipment Purchase Cost Equations

Compressor	$C_{11} = 17.917$ \$/(lb/s) $C_{12} = 0.9$
Combustion Chamber	$C_{21} = 11.612$ \$/(lb/s) $C_{22} = 0.995$ $C_{23} = 0.01$ 1/R $C_{24} = 26.4$
Gas Turbine	$C_{31} = 120.792$ \$/(lb/s) $C_{32} = 0.92$ $C_{33} = 0.02$ 1/R $C_{34} = 54.4$
Air Preheater	$C_{41} = 2290$ \$/m$^{1.2}$ $U = 0.009478$ BTU/(s*R*m^2)
HRSG	$C_{51} = 6097.211$ \$/(BTU/(s*R)$^{0.8}$) $C_{52} = 5361.462$ \$/(lb/s) $C_{53} = 254.815$ \$/(lb/s)$^{1.2}$

where $\dot{C}_T$ is the total cost rate of fuel and equipment ($/s) and $\dot{Z}_i$ is the cost rate ($/s) of the ith equipment item (i = AC, APH, CC, GT, and HRSG).

2.2.5 Conventional CGAM Objective Function

The conventional CGAM problem (Valero et al., 1994) presents the following objective function. The physical and cost models of the CGAM system have five degrees of freedom represented by the decision variables chosen (P_2/P_1, η_{AC}, η_{GT}, T_3, and T_4). The optimization problem consists of minimizing the total operating costs of the cogeneration plant assuming a fixed rate of electricity and steam production. Thus, the optimization problem can be expressed as the minimization of the objective function F, which is equal to C_T, i.e. of

$$F = c_f \dot{m}_f LHV + \dot{Z}_{AC} + \dot{Z}_{APH} + \dot{Z}_{CC} + \dot{Z}_{GT} + \dot{Z}_{HRSG}$$

subject to the constraints imposed by the physical, thermodynamic, and cost models of the installation. The conventional CGAM solution will be presented later.

2.2.6 Conventional CGAM Educational Module

An educational module was created for the conventional CGAM problem and is shown in Appendix A. The module was solved by senior level chemical engineering students as a homework project in the senior-level Process Economics and Optimization course. The students also completed an evaluation of the module with the results in Appendix A. For example, nearly all students agreed that this problem promoted understanding of cogeneration and optimization.

2.3 Real Gas CGAM Problem

2.3.1 Real Gas CGAM Problem Background

The PPCS package is used to reexamine the CGAM problem. Since the PPCS package is based on real gas behavior, the ideal gas and constant heat capacity assumptions are removed. The real gas CGAM Problem was first solved by Bustami (2001).

2.3.2 Real Gas CGAM Physical Model

The energy balances for the air compressor and gas turbine now involve enthalpy and entropy calculations. The other energy balances all involve enthalpy calculations. The energy balance solution procedure is shown from Bustami (2001). The mass balances, pressure drop relations, and approach and pinch temperature relations remain the same as the conventional CGAM problem.

Air Compressor (AC)

Find h_1 and s_1 from T_1. Set $s_1 = s_{2,isen}$.

Find $T_{2,isen}$ from $s_{2,isen}$.

Find $h_{2,isen}$ from $T_{2,isen}$. Find h_2 from $h_2 = h_1 + \frac{h_{2isen} - h_1}{\eta_{AC}}$.

Find T_2 from h_2.

$$\dot{W}_{AC} = \dot{m}_a(h_2 - h_1)$$

where $s_{2,isen}$ is the isentropic entropy leaving the AC, $T_{2,isen}$ is the isentropic temperature leaving the AC, and $h_{2,isen}$ is the isentropic enthalpy leaving the AC.

Combustion Chamber (CC)

Find h_3 and h_4 from T_3 and T_4.

$$\dot{m}_a h_3 + \dot{m}_f LHV = \dot{m}_g h_4 + \dot{Q}_{l,CC}$$

$$\dot{Q}_{l,CC} = \dot{m}_f LHV(1 - \eta_{CC})$$

Air Preheater (APH)

$$\dot{m}_a(h_3 - h_2) = \dot{m}_g(h_5 - h_6).$$

Gas Turbine (GT)

Find h_4 and s_4 from T_4. Set $s_4 = s_{5,isen}$.

Find $T_{5,isen}$ from $s_{5,isen}$.

Find $h_{5,isen}$ from $T_{5,isen}$. Find h_5 from $h_5 = h_4 - \eta_{GT}\left(h_4 - h_{5,isen}\right)$.

Find T_5 from h_5.

$$\dot{W}_{GT} = \dot{m}_g\left(h_4 - h_5\right)$$

$$\dot{W}_{net} = \dot{W}_{GT} - \dot{W}_{AC}$$

where $s_{5,isen}$ is the isentropic entropy leaving the GT, $T_{5,isen}$ is the isentropic temperature leaving the GT, and $h_{5,isen}$ is the isentropic enthalpy leaving the GT.

Heat Recovery Steam Generator (HRSG)

Find h_{7P}, h_8, h_{8P}, and h_9 from T_{7P}, T_8, T_{8P}, and T_9.

Find h_6 from $\dot{m}_g\left(h_6 - h_{7P}\right) = \dot{m}_s\left(h_9 - h_{8P}\right)$.

Find T_6 from h_6.

Find h_7 from $\dot{m}_s\left(h_{8P} - h_8\right) = \dot{m}_g\left(h_{7P} - h_7\right)$.

Find T_7 from h_7.

2.3.3 Real Gas CGAM Thermodynamic and Economic Model

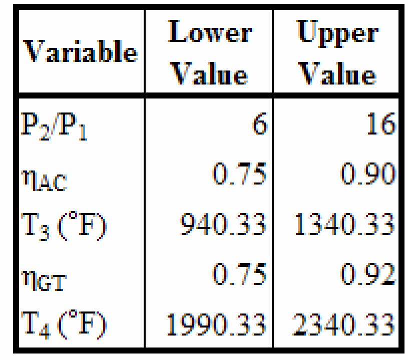
The PPCS package was used to solve all thermodynamic and combustion calculations. The reference environment and combustion reaction remain the same as the conventional CGAM problem. The economic model remains the same as the conventional CGAM problem.

2.3.4 Real Gas CGAM Objective Function and Results

The objective function also remained the same as the conventional CGAM problem.

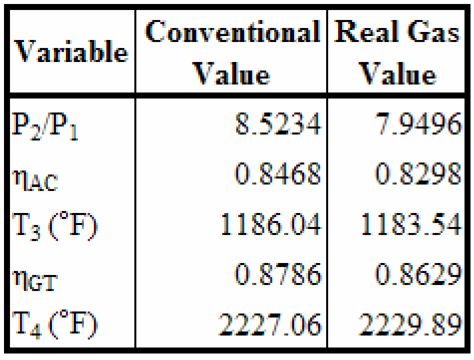
Table 2-3 shows the constraints that were placed on the decision variables by Bustami (2001) to aid the solution process. Tables 2-4, 2-5, 2-6, and 2-7 present the optimum solutions for both problems, obtained directly from Valero et al. (1994) and Bustami (2001). One

Table 2-3: Constraints on Decision Variables



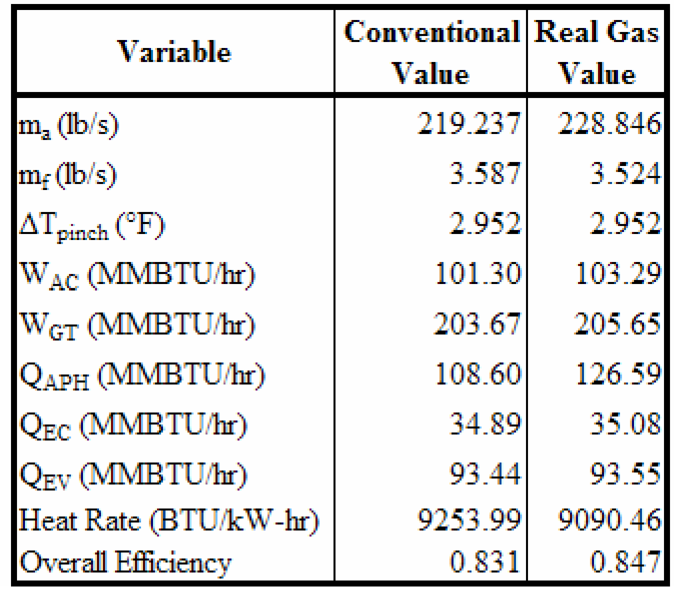
Variable	Lower Value	Upper Value
P_2/P_1	6	16
η_{AC}	0.75	0.90
T_3 (°F)	940.33	1340.33
η_{GT}	0.75	0.92
T_4 (°F)	1990.33	2340.33

Table 2-4: Optimum Values of Decision Variables



Variable	Conventional Value	Real Gas Value
P_2/P_1	8.5234	7.9496
η_{AC}	0.8468	0.8298
T_3 (°F)	1186.04	1183.54
η_{GT}	0.8786	0.8629
T_4 (°F)	2227.06	2229.89

Table 2-5: Selected Thermodynamic Variables



Variable	Conventional Value	Real Gas Value
m_a (lb/s)	219.237	228.846
m_f (lb/s)	3.587	3.524
ΔT_{pinch} (°F)	2.952	2.952
W_{AC} (MMBTU/hr)	101.30	103.29
W_{GT} (MMBTU/hr)	203.67	205.65
Q_{APH} (MMBTU/hr)	108.60	126.59
Q_{EC} (MMBTU/hr)	34.89	35.08
Q_{EV} (MMBTU/hr)	93.44	93.55
Heat Rate (BTU/kW-hr)	9253.99	9090.46
Overall Efficiency	0.831	0.847

potential problem is that the physical model only requires the minimum pinch temperature difference to be positive. The resulting pinch temperature is only 2.95 °F, while a more realistic pinch temperature would be 10-30 °F (Ganapathy, 1991).

As shown in Figure 2-7, the total cost rate for the real gas CGAM problem was significantly lower than the total cost rate for the conventional CGAM problem. The difference was over \$0.012/s (\$350,000 per year). This was accomplished primarily by a lower fuel cost rate and lower equipment costs for the air compressor and turbine.

Table 2-6: Optimal Temperatures and Pressures

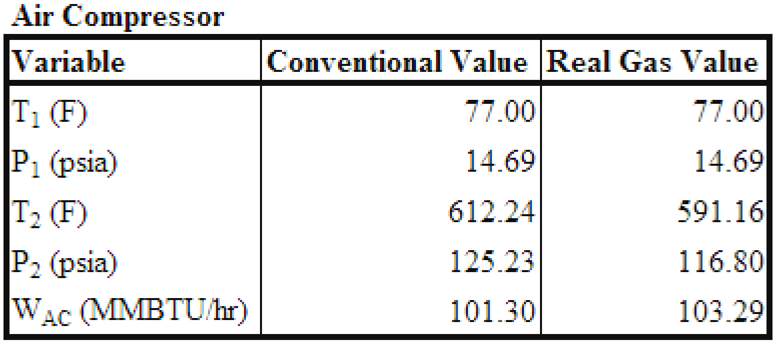
Flow	Component	Conventional T (°F)	Real Gas T (°F)	Conventional P (psia)	Real Gas P (psia)
1	Air	77.00	77.00	14.69	14.69
2	Air	612.24	591.16	125.23	116.80
3	Air	1186.04	1183.54	118.97	110.96
4	Products	2227.06	2229.89	113.02	105.41
5	Products	1318.50	1394.56	15.94	15.94
6	Products	834.04	846.96	15.47	15.47
7P	Products	417.22	417.25	15.08	15.08
7	Products	261.59	250.66	14.69	14.69
8	Water	77.00	77.00	290.08	290.08
8P	Water	387.27	387.30	290.08	290.08
9	Steam	414.27	414.30	290.08	290.08

Table 2-7: Optimal Cost Values

Variable	Conventional Value	Real Gas Value
Total Cost Rate ($/s)	0.3605	0.3486
Fuel Cost Rate ($/s)	0.3254	0.3197
Investment Cost Rate ($/s)	0.0351	0.0289
Cost of AC ($)	1348535	962726
Cost of CC ($)	146842	155984
Cost of APH ($)	828362	761026
Cost of GT ($)	1928709	1434279
Cost of HRSG ($)	983541	995975

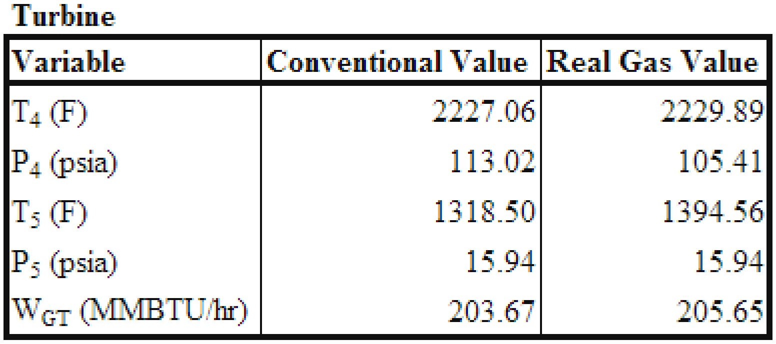
The PPCS package is especially important for modeling the air compressor and gas turbine because the ideal gas energy balances for those two units did a poor job of modeling the actual process. Table 2-8 summarizes the air compressor and turbine performance for both cases and shows the large differences in performance (especially exit temperature). These numbers were directly obtained from Valero et al. (1994) and Bustami (2001).

Table 2-8: Air Compressor and Turbine



Air Compressor

Variable	Conventional Value	Real Gas Value
T_1 (F)	77.00	77.00
P_1 (psia)	14.69	14.69
T_2 (F)	612.24	591.16
P_2 (psia)	125.23	116.80
W_{AC} (MMBTU/hr)	101.30	103.29



Turbine

Variable	Conventional Value	Real Gas Value
T_4 (F)	2227.06	2229.89
P_4 (psia)	113.02	105.41
T_5 (F)	1318.50	1394.56
P_5 (psia)	15.94	15.94
W_{GT} (MMBTU/hr)	203.67	205.65

2.4 Modified Real Gas CGAM Problem

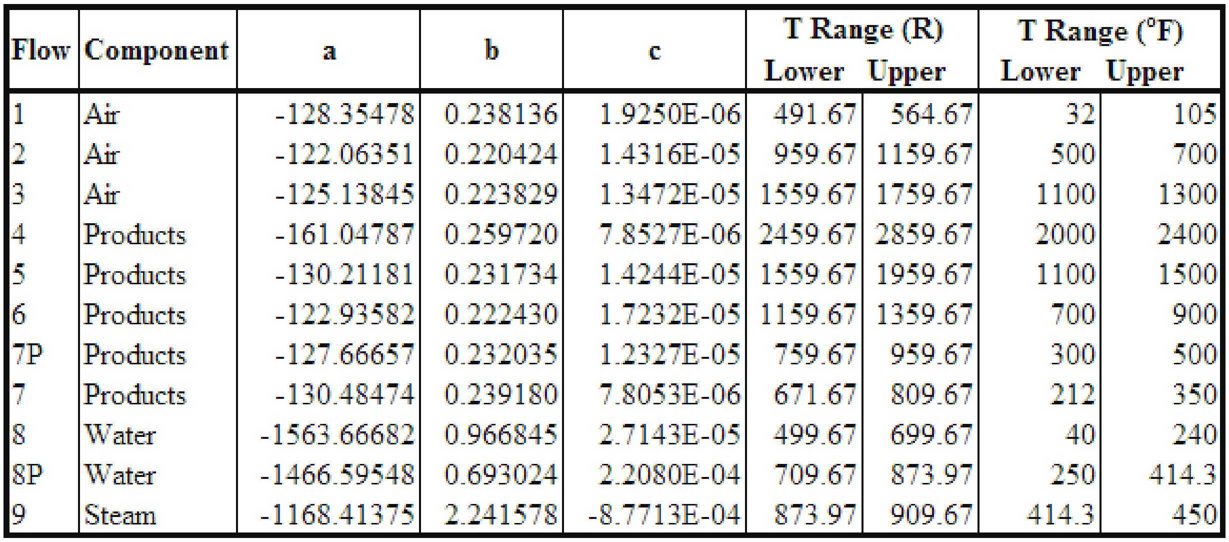
2.4.1 Modified Real Gas CGAM Problem Background

Remember that the goal of this chapter is to develop a module for students to compare the conventional CGAM problem to the real gas solution. The real gas CGAM problem has been solved using the PPCS package by Bustami (2001). However, a quicker and more student friendly approach to solving the module is desired.

To make this educational module more student friendly, the PPCS functions were fitted to three term polynomials by polynomial regression. Enthalpy and entropy functions were regressed for air, combustion products, water, and steam over fixed temperature ranges (the functions are nearly independent of pressure). The polynomial functions matched excellently with PPCS functions as all regressions resulted in $R^2 = 1$.

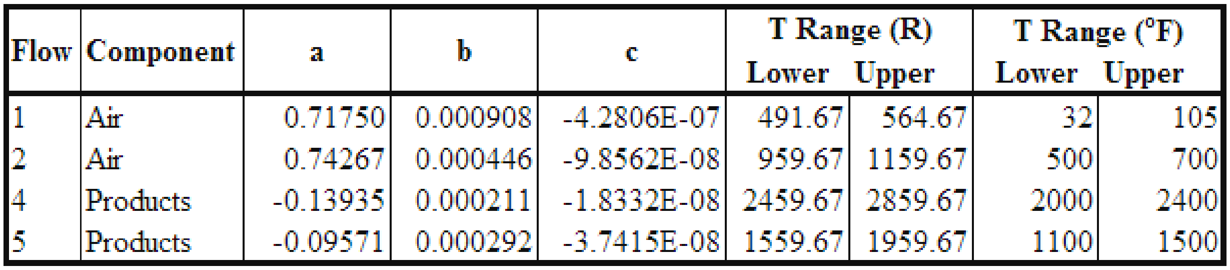
Table 2-9 shows the results of the polynomial regressions for the enthalpy functions, and Table 2-10 shows the results of the polynomial regression for the entropy functions. The temperature must be in Rankine for both functions. Note that the enthalpy functions already have the reference enthalpy subtracted out. For example, $h_{1air}(77°F) = -128.35478 + 0.238136*(77+459.67) + 1.925e\text{-}6*(77+459.67)^2 = 0$.

Table 2-9: Enthalpy Coefficients
$h = a + bT + cT^2$ (BTU/lb)



Flow	Component	a	b	c	T Range (R)		T Range (°F)	
					Lower	Upper	Lower	Upper
1	Air	-128.35478	0.238136	1.9250E-06	491.67	564.67	32	105
2	Air	-122.06351	0.220424	1.4316E-05	959.67	1159.67	500	700
3	Air	-125.13845	0.223829	1.3472E-05	1559.67	1759.67	1100	1300
4	Products	-161.04787	0.259720	7.8527E-06	2459.67	2859.67	2000	2400
5	Products	-130.21181	0.231734	1.4244E-05	1559.67	1959.67	1100	1500
6	Products	-122.93582	0.222430	1.7232E-05	1159.67	1359.67	700	900
7P	Products	-127.66657	0.232035	1.2327E-05	759.67	959.67	300	500
7	Products	-130.48474	0.239180	7.8053E-06	671.67	809.67	212	350
8	Water	-1563.66682	0.966845	2.7143E-05	499.67	699.67	40	240
8P	Water	-1466.59548	0.693024	2.2080E-04	709.67	873.97	250	414.3
9	Steam	-1168.41375	2.241578	-8.7713E-04	873.97	909.67	414.3	450

Table 2-10: Entropy Coefficients
$s = a + bT + cT^2$ (BTU/lb-R)



Flow	Component	a	b	c	T Range (R)		T Range (°F)	
					Lower	Upper	Lower	Upper
1	Air	0.71750	0.000908	-4.2806E-07	491.67	564.67	32	105
2	Air	0.74267	0.000446	-9.8562E-08	959.67	1159.67	500	700
4	Products	-0.13935	0.000211	-1.8332E-08	2459.67	2859.67	2000	2400
5	Products	-0.09571	0.000292	-3.7415E-08	1559.67	1959.67	1100	1500

The functions are valid only for the temperature range given. The combustion products functions are only valid for methane fuel and for a range of excess air ratio from 3.5 to 4. Excess air ratio is defined as moles air / stoichiometric moles air. The optimal value in the problem for the excess air ratio is 3.77.

Next, the polynomial functions were used to solve the real gas CGAM problem that was solved by Bustami in Section 2.3. The polynomial functions and the PPCS package provided an identical solution for the real gas CGAM problem.

2.4.2 Modified Real Gas CGAM Educational Module

Students will first solve this module using the polynomial functions. This will condense the problem into a more manageable form for students. Next, students will solve the problem using the full PPCS package. Students will become familiar with the complexity of the full PPCS package and solve the problem without any of the restrictions that were placed on the polynomial functions. This modified real gas CGAM educational module provides an excellent learning tool for students by solving a straightforward industrial model with robust thermodynamic physical properties. It will be tested in Fall 2006 in the senior-level chemical engineering course Process Economics and Optimization.

CHAPTER 3
LSU COGENERATION SYSTEM DATA RECONCILIATION

3.1 Background and Literature Review

This educational module aims to teach data reconciliation fundamentals to students using real data from the LSU GE turbine cogeneration system. Students will appreciate that all plant data are subject to errors. The data must be reconciled before further use and gross errors, if present, must be removed.

Romagnoli and Sanchez (2000) discuss data redundancy, classification of variables, decomposition, and measurement variances for data processing and reconciliation. They also examine methods for data reconciliation, gross error detection, and parameter estimation. Pike (2005) first focuses on industrial applications of on-line optimization. Next, the key elements of on-line optimization are described in detail including data reconciliation, gross error detection, parameter estimation, economic models, plant models, and optimization algorithms. Other concepts such as observability, redundancy, execution frequency, and steady-state detection are discussed.

Ozyurt and Pike (2004) focus on simultaneous data reconciliation and gross error detection for chemical processes. Numerous different objective functions are described and analyzed in detail, and data reconciliation and gross error detection are successfully performed for several industrial problems. Lee et al. (1998) propose a methodology for on-line data reconciliation and optimization to minimize the energy cost of a utility plant while satisfying changing demands. The problem is based on open form representation and hierarchical decomposition where a system is decomposed into a set of subsystems.

The module developed here will use simultaneous data reconciliation and parameter estimation to reconcile the plant data. There is one parameter in the cogeneration model (the heat loss in the combustion chamber) which must be considered as a variable along with all of the measured process variables. A non-weighted least squares objective function was selected because it would be straightforward for students while still producing accurate results. By assuming normal probability distribution functions for measured variables, gross errors will only be present if the standard error of any variable is greater than 2.16 (Ozyurt and Pike, 2004). The plant material and energy balances will serve as constraints for the data reconciliation.

3.2 LSU GE Turbine Cogeneration System

Information about the LSU GE turbine cogeneration system was gathered from many sources including the LSU Cogeneration Basic Operator's Course (2004), Louisiana State University Co-Gen Project Field Performance Test Report (2005), numerous conversations with the cogeneration maintenance engineers, operators, and supervisors at LSU (2005-2006), and collection of actual plant data and operating conditions. Figure 3-1 shows the LSU GE Turbine Cogeneration system. There are several steps in the process:

- Ambient air (0) is cooled in the Air Cooler using chilled water as the cold fluid.
- The cooled air (1) is then sent to the Compressor to increase its pressure, requiring a significant amount of work.
- Natural gas is burned with the compressed air (2) in the Combustion Chamber.
- The combustion products (3) are sent through the Compressor Turbine. The shaft of this turbine is connected to the Compressor, meaning all work done by the Compressor Turbine is used to power the Compressor.

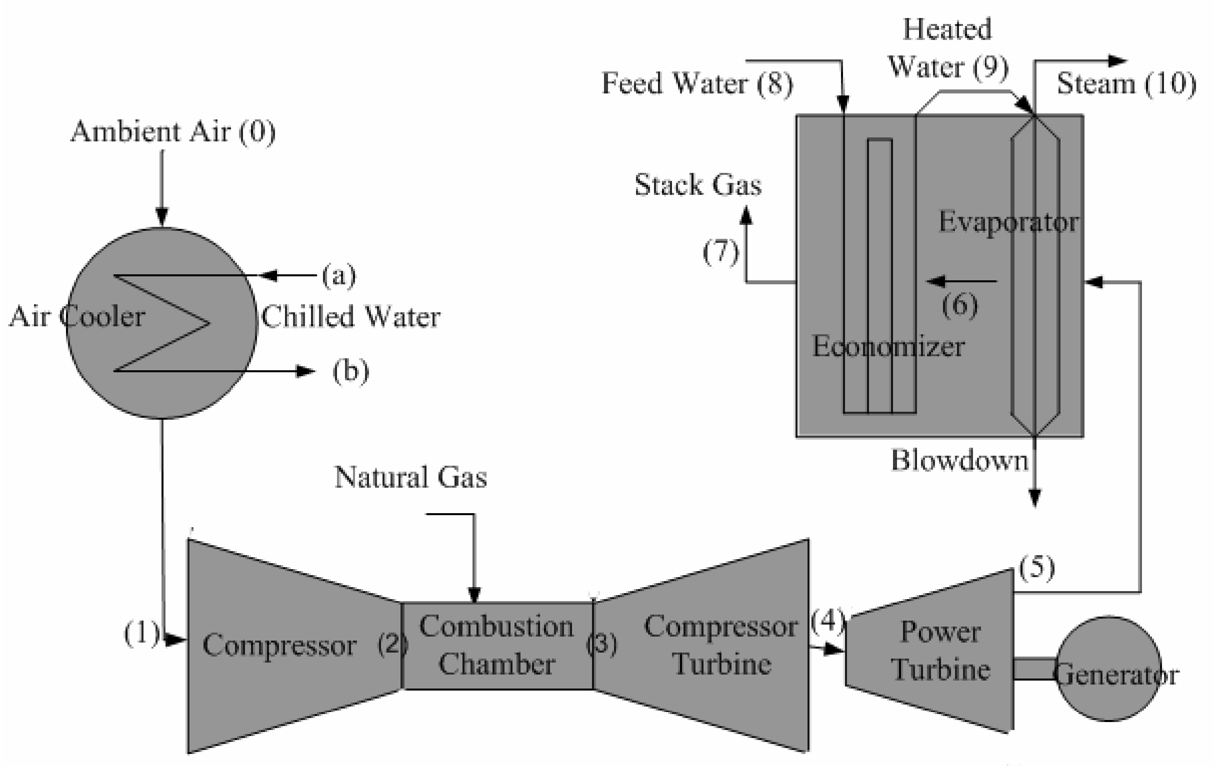


Figure 3-1: LSU Cogeneration System Flow Diagram

- The combustion products exiting the Compressor Turbine (4) then expand to nearly atmospheric pressure in the Power Turbine. The shaft of this turbine is connected to a generator which produces electricity.
- The combustion products exiting the Power Turbine (5) are now sent through two heat exchangers to recover heat before being vented to the atmosphere. The first heat exchanger is the Evaporator. The combustion products (5) transfer heat to vaporize heated water (9) into steam (10). Some of the heated water from the economizer is not vaporized in the Evaporator and exits as blowdown at the heated water conditions.
- The second heat exchanger is the Economizer. The combustion products leaving the Evaporator (6) heat the feed water (8) before the water is sent to the Evaporator. The combustion gas exits the Economizer as stack gas (7).

3.3 Data Reconciliation Problem

3.3.1 Introduction

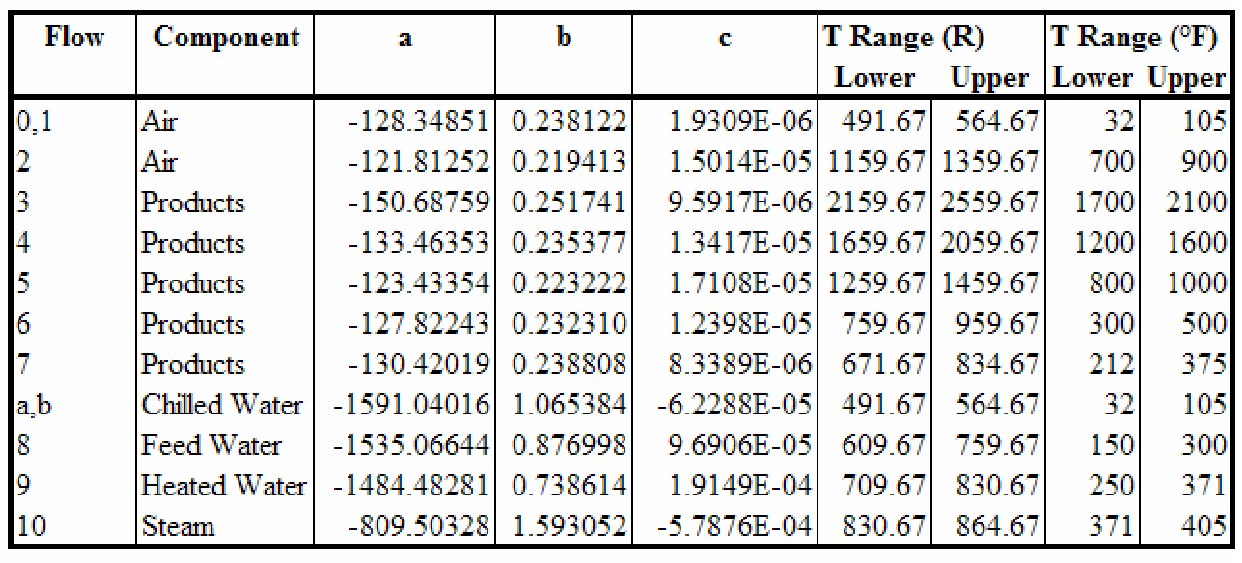
This problem makes a few assumptions to simplify the calculation procedure: (a) steady state, (b) the air is completely dry (no humidity), (c) adiabatic heat exchangers with no pressure drops, (d) complete combustion (reaction goes to completion) in Combustion Chamber with natural gas as limiting reactant, (e) some heat loss in the Combustion Chamber (Q_{loss}), and (g) no water injections in combustion chamber.

The PPCS was first used to solve this problem. To make the problem more student friendly, the PPCS functions were fitted to three term polynomials using polynomial regression. Enthalpy and entropy functions were regressed for air, combustion products, water, and steam over fixed temperature ranges (the functions are nearly independent of pressure). The polynomial functions matched excellently with the PPCS as all regressions resulted in $R^2 = 1$. The polynomial functions and the PPCS provided identical solutions for the data reconciliation problem.

Table 3-1 shows the results of the polynomial regression for the enthalpy functions. Table 3-2 shows the results of the polynomial regression for the entropy functions. Once again, the temperature must be in Rankine for these functions. The reference enthalpy has been subtracted out of the enthalpy functions. For example, $h_{1air}(77°F) = -128.34851 + 0.238122*(77+459.67) + 1.9309e\text{-}6*(77+459.67)^2 = 0$. These functions are valid only for the temperature range given. The combustion products functions are only valid for the natural gas fuel given in Table 3-3 and for a range of excess air ratios from 3.5 to 4. Excess air ratio is defined as moles air / stoichiometric moles air. The excess air ratio for this problem was 3.67.

Table 3-1: Enthalpy Coefficients

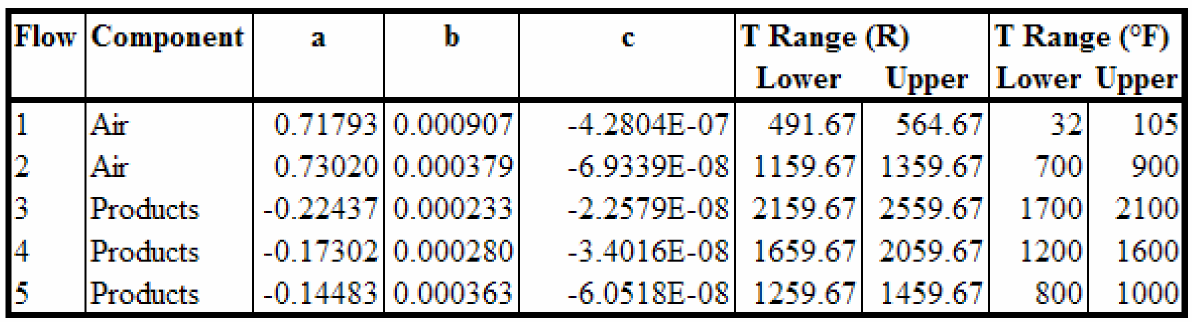
$h = a + bT + cT^2$ (BTU/lb)



Flow	Component	a	b	c	T Range (R)		T Range (°F)	
					Lower	Upper	Lower	Upper
0,1	Air	-128.34851	0.238122	1.9309E-06	491.67	564.67	32	105
2	Air	-121.81252	0.219413	1.5014E-05	1159.67	1359.67	700	900
3	Products	-150.68759	0.251741	9.5917E-06	2159.67	2559.67	1700	2100
4	Products	-133.46353	0.235377	1.3417E-05	1659.67	2059.67	1200	1600
5	Products	-123.43354	0.223222	1.7108E-05	1259.67	1459.67	800	1000
6	Products	-127.82243	0.232310	1.2398E-05	759.67	959.67	300	500
7	Products	-130.42019	0.238808	8.3389E-06	671.67	834.67	212	375
a,b	Chilled Water	-1591.04016	1.065384	-6.2288E-05	491.67	564.67	32	105
8	Feed Water	-1535.06644	0.876998	9.6906E-05	609.67	759.67	150	300
9	Heated Water	-1484.48281	0.738614	1.9149E-04	709.67	830.67	250	371
10	Steam	-809.50328	1.593052	-5.7876E-04	830.67	864.67	371	405

Table 3-2: Entropy Coefficients

$S = a + bT + cT^2$ (BTU/lb-R)



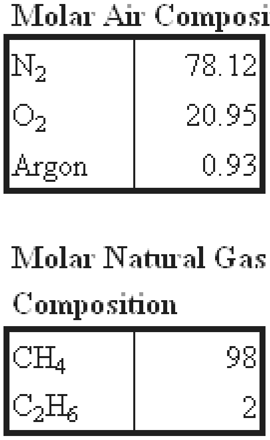
Flow	Component	a	b	c	T Range (R)		T Range (°F)	
					Lower	Upper	Lower	Upper
1	Air	0.71793	0.000907	-4.2804E-07	491.67	564.67	32	105
2	Air	0.73020	0.000379	-6.9339E-08	1159.67	1359.67	700	900
3	Products	-0.22437	0.000233	-2.2579E-08	2159.67	2559.67	1700	2100
4	Products	-0.17302	0.000280	-3.4016E-08	1659.67	2059.67	1200	1600
5	Products	-0.14483	0.000363	-6.0518E-08	1259.67	1459.67	800	1000

3.3.2 Problem Assignment

Part 1

- Write out the mass balances for the Combustion Chamber and Evaporator.
- Write out the energy balances for each process unit. Include the formulas to solve for the isentropic efficiencies of the compressor, compressor turbine, and power turbine as well as the thermal efficiency of the combustion chamber.

Table 3-3: Molar Air and Natural Gas Compositions



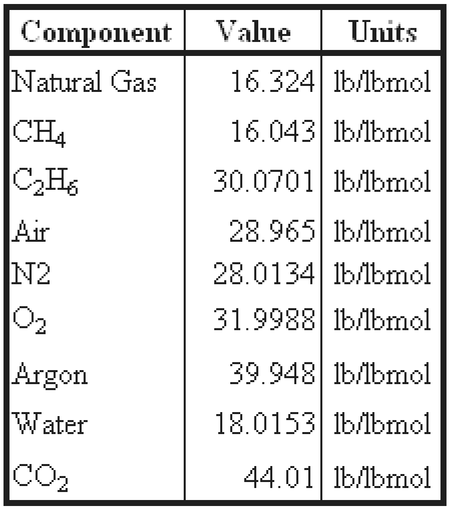
Molar Air Composition

N_2	78.12
O_2	20.95
Argon	0.93

Molar Natural Gas Composition

CH_4	98
C_2H_6	2

Table 3-4: Molecular Weights



Component	Value	Units
Natural Gas	16.324	lb/lbmol
CH_4	16.043	lb/lbmol
C_2H_6	30.0701	lb/lbmol
Air	28.965	lb/lbmol
N2	28.0134	lb/lbmol
O_2	31.9988	lb/lbmol
Argon	39.948	lb/lbmol
Water	18.0153	lb/lbmol
CO_2	44.01	lb/lbmol

- Perform the data reconciliation with the measured variables and standard deviations provided in Table 3-5. Use the mass and energy balances as constraints.

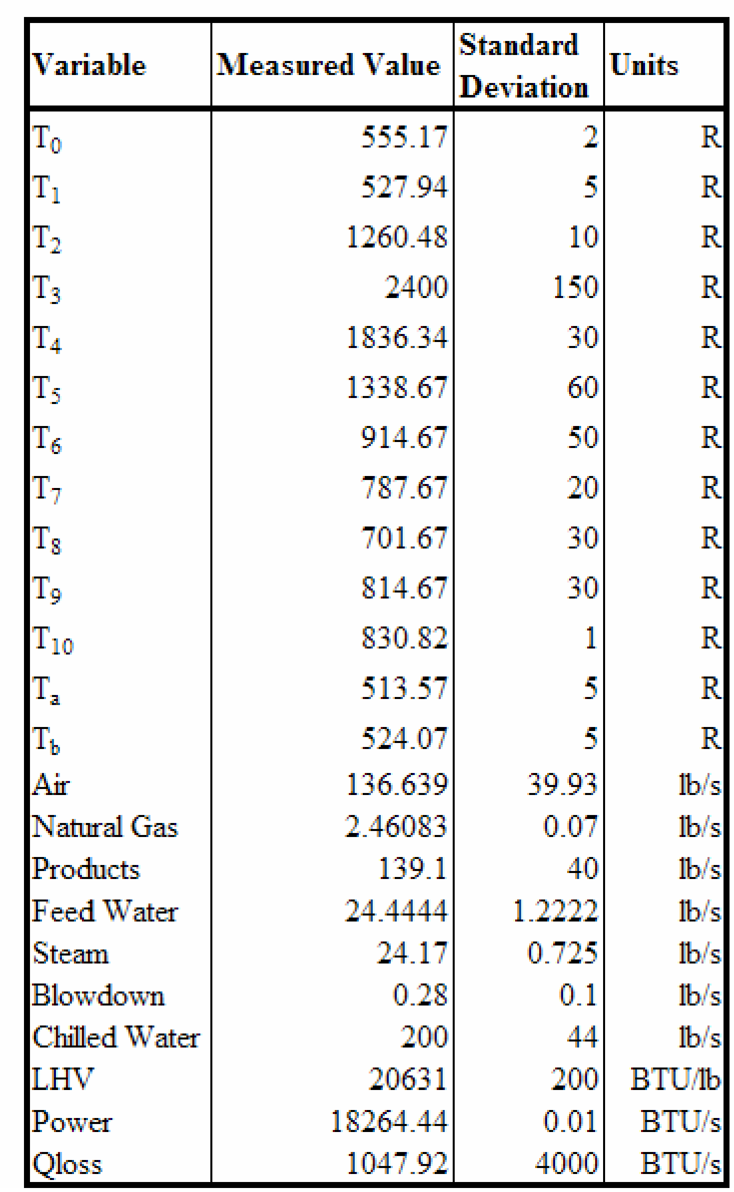
Part 2

- Calculate the mole and mass balance for the individual species in the combustion reaction. The general combustion reaction is $C_xH_y + (x + y/4)\ O_2 \rightarrow x\ CO_2 + y/2\ H_2O$.

Part 3

- Find the isentropic efficiencies for the compressor (η_{comp}), compressor turbine (η_{compt}), and power turbine (η_{powert}). Find the combustion thermal efficiency (η_{cc}). Determine the amount of heat transferred in the air cooler (Q_{cooler}), evaporator (Q_{evap}), and economizer (Q_{eco}). Find the amount of work used by the compressor (W_{comp}). Calculate the overall heat transfer coefficient (U) for both the Evaporator and Economizer given that $A_{evap} = 56248\ ft^2$ and $A_{eco} = 25565\ ft^2$. Find the approach and pinch temperatures. Finally, determine the heat rate (HR) and overall efficiency for the process ($\eta_{process}$).

Table 3-5: Measured Variables and Standard Deviations



Variable	Measured Value	Standard Deviation	Units
T_0	555.17	2	R
T_1	527.94	5	R
T_2	1260.48	10	R
T_3	2400	150	R
T_4	1836.34	30	R
T_5	1338.67	60	R
T_6	914.67	50	R
T_7	787.67	20	R
T_8	701.67	30	R
T_9	814.67	30	R
T_{10}	830.82	1	R
T_a	513.57	5	R
T_b	524.07	5	R
Air	136.639	39.93	lb/s
Natural Gas	2.46083	0.07	lb/s
Products	139.1	40	lb/s
Feed Water	24.4444	1.2222	lb/s
Steam	24.17	0.725	lb/s
Blowdown	0.28	0.1	lb/s
Chilled Water	200	44	lb/s
LHV	20631	200	BTU/lb
Power	18264.44	0.01	BTU/s
Qloss	1047.92	4000	BTU/s

3.3.3 Mass and Energy Balances for Cogeneration

The mass and energy balances for the cogeneration system are listed below.

Combustion Chamber MB: Air + Natural Gas = Products

Evaporator MB: Feed Water = Steam + Blowdown

Air Cooler EB: $\text{Air}*(h_0 - h_1) = \text{Chilled Water}*(h_b - h_a) = Q_{cooler}$

Compressor/Compressor Turbine EB: $\text{Air}*(h_2 - h_1) = \text{Products}*(h_3 - h_4) = W_{comp}$

Combustion Chamber EB: Air*h_2 + Natural Gas*LHV = Products*h_3 + Q_{loss}

Power Turbine EB: Products*($h_4 - h_5$) = Power

Evaporator EB: Products*($h_5 - h_6$) = Steam*($h_{10} - h_9$) = Q_{evap}

Economizer EB: Products*($h_6 - h_7$) = Feed Water*($h_9 - h_8$) = Q_{eco}

Compressor Isentropic Efficiency: Set $s_{2isen} = s_1$. Find T_{2isen} from s_{2isen}.

Find h_{2isen} from T_{2isen}. $\eta_{comp} = \dfrac{h_{2isen} - h_1}{h_2 - h_1}$

Compressor Turbine Isentropic Efficiency: Set $s_{4isen} = s_3$. Find T_{4isen} from s_{4isen}.

Find h_{4isen} from T_{4isen}. $\eta_{compt} = \dfrac{h_3 - h_4}{h_3 - h_{4isen}}$

Power Turbine Isentropic Efficiency: Set $s_{5isen} = s_4$. Find T_{5isen} from s_{5isen}.

Find h_{5isen} from T_{5isen}. $\eta_{powert} = \dfrac{h_4 - h_5}{h_4 - h_{5isen}}$

Combustion Chamber Thermal Efficiency: $\eta_{cc} = 1 - \dfrac{Q_{loss}}{NaturalGas * LHV}$

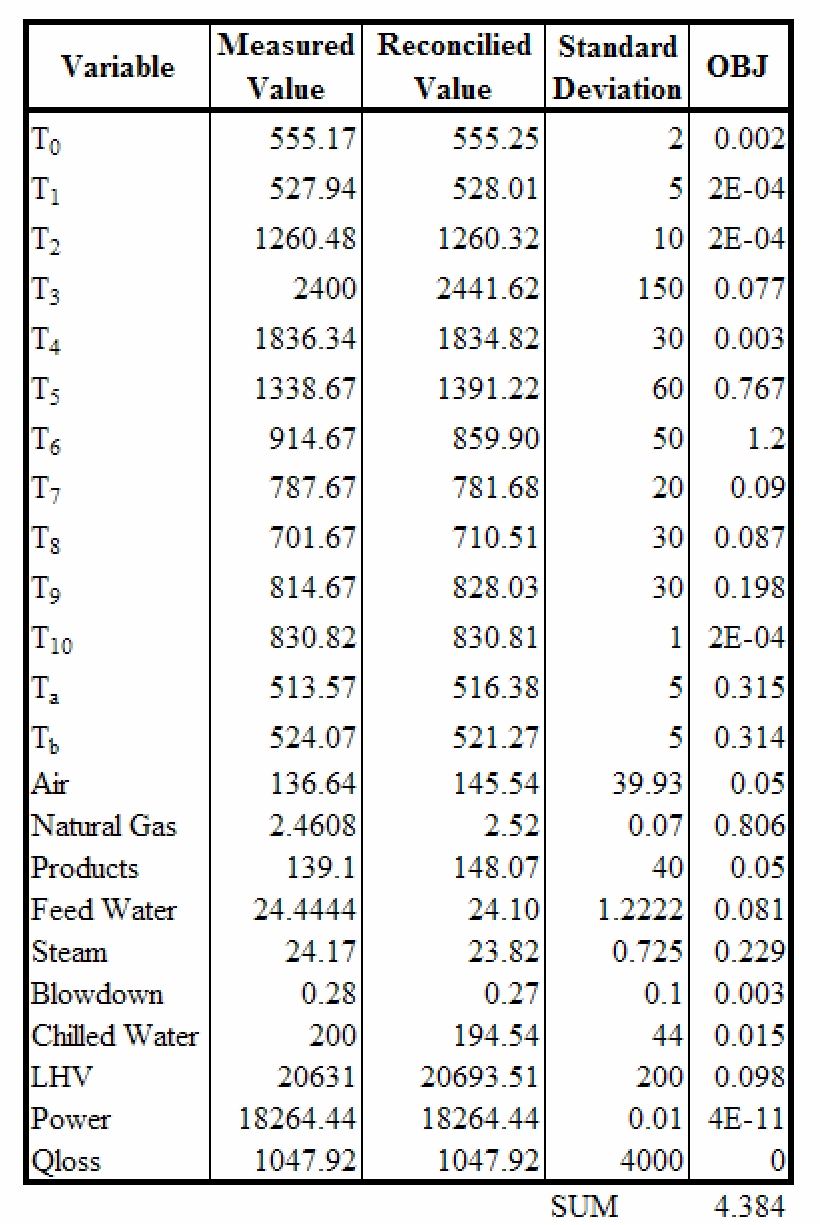
3.3.4 Data Reconciliation Solution

Table 3-6 shows the results of the data reconciliation using Microsoft Excel Solver. The objective function for each variable is ((Measured – Reconciled) / Standard Deviation)^2. Data reconciliation minimized the sum of these individual objective functions while satisfying the mass and energy balances. No gross errors (individual objective function greater than 2.16) were detected.

3.3.5 Combustion Mass and Mole Balance

Table 3-7 shows the results of the combustion mass and mole balances. The combustion mass balance did not close perfectly but was within 0.06 %. This is due to the slight inaccuracies

Table 3-6: Results of Data Reconciliation



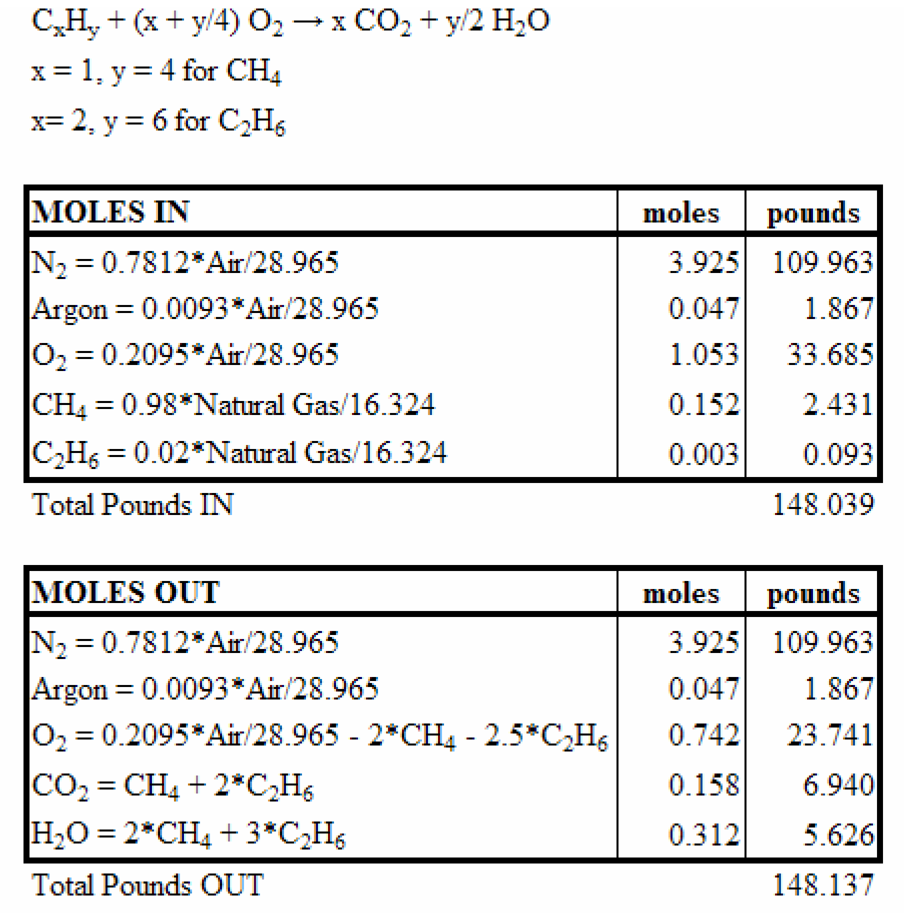
Variable	Measured Value	Reconciled Value	Standard Deviation	OBJ
T_0	555.17	555.25	2	0.002
T_1	527.94	528.01	5	2E-04
T_2	1260.48	1260.32	10	2E-04
T_3	2400	2441.62	150	0.077
T_4	1836.34	1834.82	30	0.003
T_5	1338.67	1391.22	60	0.767
T_6	914.67	859.90	50	1.2
T_7	787.67	781.68	20	0.09
T_8	701.67	710.51	30	0.087
T_9	814.67	828.03	30	0.198
T_{10}	830.82	830.81	1	2E-04
T_a	513.57	516.38	5	0.315
T_b	524.07	521.27	5	0.314
Air	136.64	145.54	39.93	0.05
Natural Gas	2.4608	2.52	0.07	0.806
Products	139.1	148.07	40	0.05
Feed Water	24.4444	24.10	1.2222	0.081
Steam	24.17	23.82	0.725	0.229
Blowdown	0.28	0.27	0.1	0.003
Chilled Water	200	194.54	44	0.015
LHV	20631	20693.51	200	0.098
Power	18264.44	18264.44	0.01	4E-11
Qloss	1047.92	1047.92	4000	0
			SUM	4.384

in the molecular weights used for converted the molar flows to mass flows.

3.3.6 Key Parameters

Table 3-8 shows the results of the key parameters calculations from assignment part 3. The two most important cogeneration parameters are the heat rate (9756.4 BTU/kW-hr) and the overall efficiency (80 %).

Table 3-7: Combustion Mass and Mole Balance



$C_xH_y + (x + y/4)\ O_2 \rightarrow x\ CO_2 + y/2\ H_2O$

$x = 1,\ y = 4$ for CH_4

$x = 2,\ y = 6$ for C_2H_6

MOLES IN	**moles**	**pounds**
$N_2 = 0.7812*Air/28.965$	3.925	109.963
$Argon = 0.0093*Air/28.965$	0.047	1.867
$O_2 = 0.2095*Air/28.965$	1.053	33.685
$CH_4 = 0.98*Natural\ Gas/16.324$	0.152	2.431
$C_2H_6 = 0.02*Natural\ Gas/16.324$	0.003	0.093

Total Pounds IN 148.039

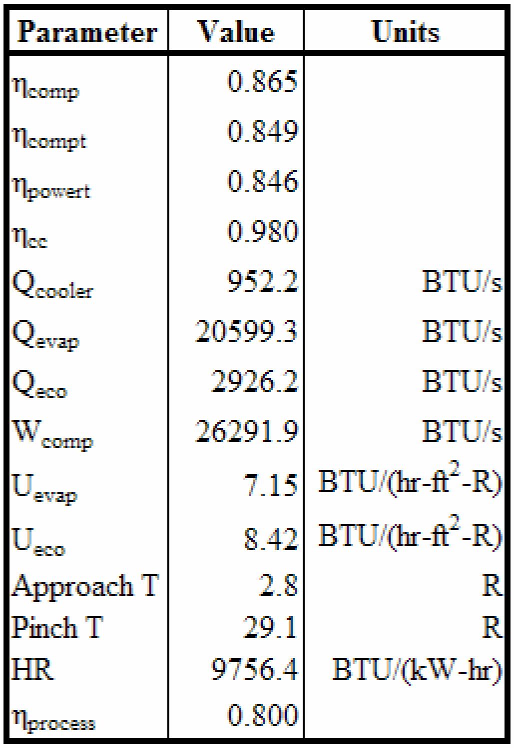
MOLES OUT	**moles**	**pounds**
$N_2 = 0.7812*Air/28.965$	3.925	109.963
$Argon = 0.0093*Air/28.965$	0.047	1.867
$O_2 = 0.2095*Air/28.965 - 2*CH_4 - 2.5*C_2H_6$	0.742	23.741
$CO_2 = CH_4 + 2*C_2H_6$	0.158	6.940
$H_2O = 2*CH_4 + 3*C_2H_6$	0.312	5.626

Total Pounds OUT 148.137

3.4 Data Reconciliation Educational Module

Students will first solve this module using the polynomial functions. This will condense the problem into a more manageable form for students. Next, students will solve the problem using the full PPCS package without any of the restrictions that were placed on the polynomial functions. This educational module provides an excellent learning tool for students by solving a basic data reconciliation problem. Gross errors are not a concern for this problem. This problem has already been solved using the polynomial functions by senior level students in the chemical engineering course Process Economics and Optimization. The students completed an evaluation

Table 3-8: Key Parameters, Heat Transfer, and Work



Parameter	Value	Units
η_{comp}	0.865	
η_{compt}	0.849	
η_{powert}	0.846	
η_{cc}	0.980	
Q_{cooler}	952.2	BTU/s
Q_{evap}	20599.3	BTU/s
Q_{eco}	2926.2	BTU/s
W_{comp}	26291.9	BTU/s
U_{evap}	7.15	BTU/(hr-ft^2-R)
U_{eco}	8.42	BTU/(hr-ft^2-R)
Approach T	2.8	R
Pinch T	29.1	R
HR	9756.4	BTU/(kW-hr)
$\eta_{process}$	0.800	

of the module with the results in Appendix B. For example, nearly all students would recommend this problem to others interested in data reconciliation. This educational module can also be used as part of a plant on-line optimization.

CHAPTER 4
LSU ENERGY MANAGEMENT OPTIMIZATION

4.1 Background

This module aims to solve an energy management optimization problem for the LSU utility system. Figure 4-1 shows the layers of control and operation for the LSU utility system which will play a key role in this module. The first layer is the computer control system that monitors thousands of data points several times per second. The second layer is the supervisory level which consists of the actions of operators and supervisors. It is on the time scale of several minutes up to an hour. The third layer is time of day operations which consists of an early morning, daytime, and evening operating period each day. The final layer is a seasonal operating strategy. This module will focus on further developing the two outer layers of this diagram.

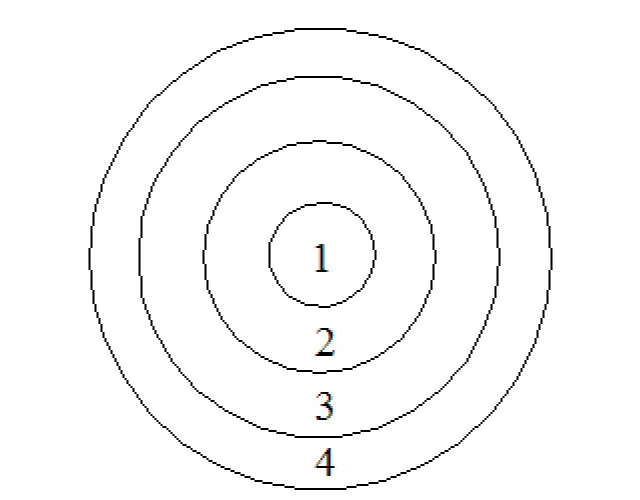


Figure 4-1: Layers of Control and Operation

First, a program will be created to find the most economical method of operating the LSU utility system for any given set of operating conditions. The module will then be used to determine both time of day and seasonal operating strategies for the LSU utility system. This study focuses on minimizing operating costs which include the costs of purchasing natural gas and electricity. Maintenance, personnel, and capital costs are not included in this study.

4.2 Literature Review

Numerous sources are available to gain more knowledge about optimization of cogeneration and utility systems. Some focus on advanced control techniques to improve a combined-cycle cogeneration system (Kaya and Keyes, 1992). However, this study focuses on a time frame of seconds, which is not appropriate for the given problem. Other sources focused on advanced modeling algorithms to optimize performance (Manolas et al., 1997, Wilkendorf et al., 1998). Wilkendorf et al. created an algorithm to minimize the annual capital and operating cost for a utility system. However, this study was concerned with synthesis of optimal utility systems and was only applicable for constant energy demands throughout the year. Manolas et al. created a genetic algorithm to maximize power output of a combined-cycle cogeneration system. However, this method was very complex and required significant computational effort.

Two studies of the cogeneration facility and utility system at Texas A&M University were also reviewed (Athar et al., 1993, Deng et al., 2003). Deng et al. analyzed the effects of several potential upgrades to the utility system. The effects of a turbulent utility market were studied for each alternative. Athar et al. developed a program to minimize operating costs for the entire system by modeling the performance of each piece of equipment. Current pricing information is used in the optimization.

The next three articles model equipment performance along with the use of current demands and equipment restrictions in a manner similar to Athar et al. They also incorporate methods of scheduling and planning. Ito and Yokoyama (1995) created a program to use current economics to advise industrial cogeneration operators in rational operation of the system. The model predicts seasonal operating strategies for the system. Lal and Ma (1998) used multi-time interval scheduling to minimize operations costs for a complex cogeneration and utility system. Varying loads and prices are used to determine optimal operation for each time interval. Iyer and Grossman (1997) used multi-period planning to optimize selection and operation of numerous units in a utility system. Optimal operation was selected for each period based on varying demands for utilities. These three articles will be used to develop a similar method for modeling and optimization of the LSU utility system.

4.3 Natural Gas and Electricity Pricing

LSU buys its natural gas from the Pontchartrain Natural Gas Pipeline. The purchased cost for natural gas is directly tied to the New York Mercantile Exchange (NYMEX) Henry Hub price of natural gas. The price that LSU pays is 1.07*(NYMEX + 0.18) in \$/MMBTU. The NYMEX Henry Hub price fluctuates greatly and is typically highest during the winter (when demand is highest) or during supply shortages (such as after hurricanes). In the past year, the price has fluctuated from \$6 to \$15 per MMBTU. At full capacity, the GE turbine typically consumes about 220 MMBTU per hour, resulting in a typical natural gas bill between \$1300 and \$3300 per hour.

LSU also can buy electricity from Entergy. First, it is important to note that there is no peak and off-peak pricing: the rate per kW-hr is constant throughout each month. The electricity price is composed of two parts. The first is the base rate. The electricity contract gives the base rate as \$0.01472 per kW-hr. This rate is subject to Louisiana Public Service Commission ordered rate decreases and adjustments and is currently \$0.0111 per kW-hr. The second part of the electricity price is the fuel adjustment. It changes monthly with Entergy's cost of providing electricity. Entergy provides electricity primarily through natural gas power plants but also from coal, nuclear, and hydroelectric power plants as well as purchased electricity from other power providers. The fuel adjustment depends upon all of these factors. The fuel adjustment has ranged from about \$0.03 to \$0.08 per kW-hr over the past year and is clearly the most significant part of the electricity price. The total LSU electricity cost can range from \$400 to \$900 per hour for 10 MW of electricity.

4.4 LSU Energy System

The first part of the LSU energy system is the cogeneration system described in Chapter 3. The GE turbine is capable of producing 20 MW of electricity and the HRSG (Boiler 8) is capable of producing 88,000 lb/hr of steam (all campus steam is typically produced at 150 psig). Boiler 8 has supplemental firing capabilities which can add another 62,000 lb/hr of steam.

Second is a smaller cogeneration system. This system is composed of an Allison gas turbine rated at 5000 hp (3728 kW). The shaft of this turbine powers a chiller that can produce up to 6400 tons of chilled water. A HRSG (called Boiler 7) recovers heat leaving the gas turbine and can produce about 25,000 lb/hr of steam. Boiler 7 is capable of supplemental firing that can add another 75,000 lb/hr of steam.

Third are two stand alone boilers. Boiler 4 is a forced draft natural gas boiler capable of producing 100,000 lb/hr of steam. Boiler 6 is very inefficient and is only used for an emergency situation. Boiler 6 will not be involved in this study.

Next are 3 York centrifugal steam-driven chillers (Chillers 8, 9, and 10). Each chiller is rated at 2060 tons with R-134a as the refrigerant. Each chiller operates by using condensing steam to drive a turbine that powers a refrigeration cycle. Note that the steam from Boiler 4 or Boiler 8 must be used to power these chillers. The steam from Boiler 7 cannot power these chillers.

Finally, there are 6 centrifugal electric-driven chillers (Chillers 1-5 and 7). All chillers are rated below 2000 tons with a total combined capacity of 9400 tons. These chillers can be powered by generated or purchased electricity.

To summarize, produced electricity and purchased electricity are used to supply the campus electricity demand and to power the electric-driven chillers. Steam produced by Boiler 4, 7, and 8 can be used for the campus steam demand and steam produced by Boiler 4 and 8 can power the steam-driven chillers. Chilled water is produced by the steam-driven chillers, electric-driven chillers, and the Allison chiller, and chilled water is used for the campus chilled water demand and the cogeneration air cooler.

Figure 4-2 shows the overall LSU utility system. Note that the condensate return and chilled water return loops are not shown on the diagram. Also note that cooling water is used in the refrigeration cycles for Chillers 8, 9, and 10 and the Allison Chiller, but is not shown on the diagram. Figure 4-3 gives a summary of the production and uses of electricity, steam, and chilled water.

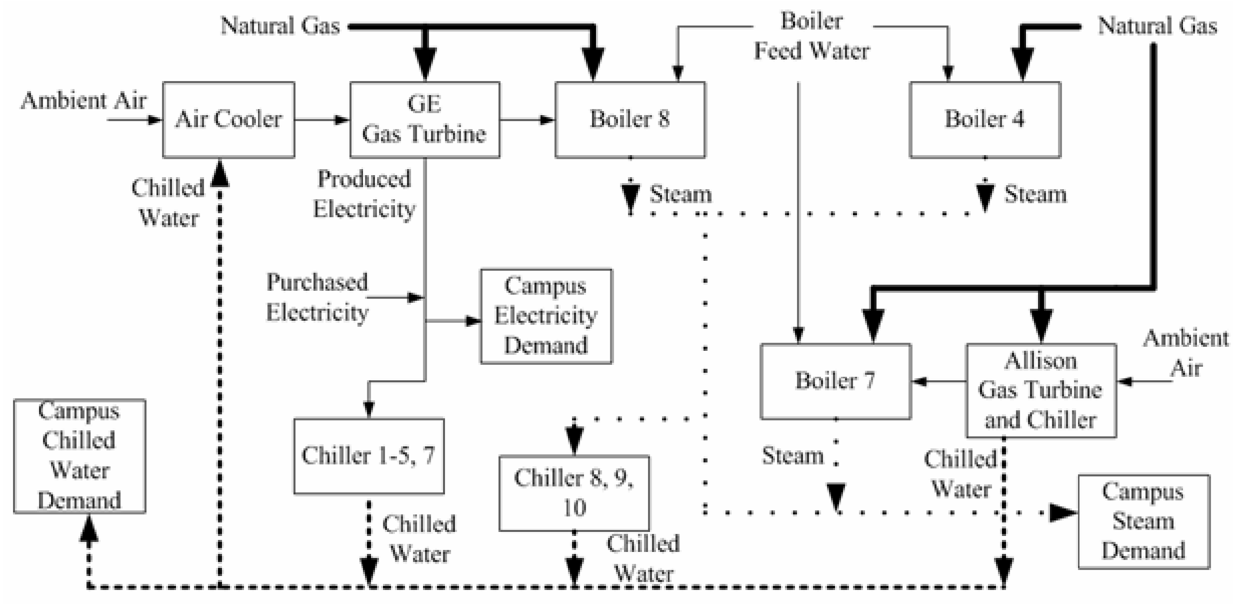
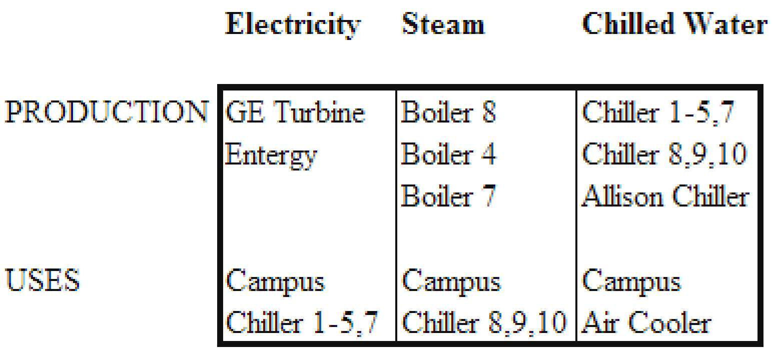


Figure 4-2: LSU Utility System



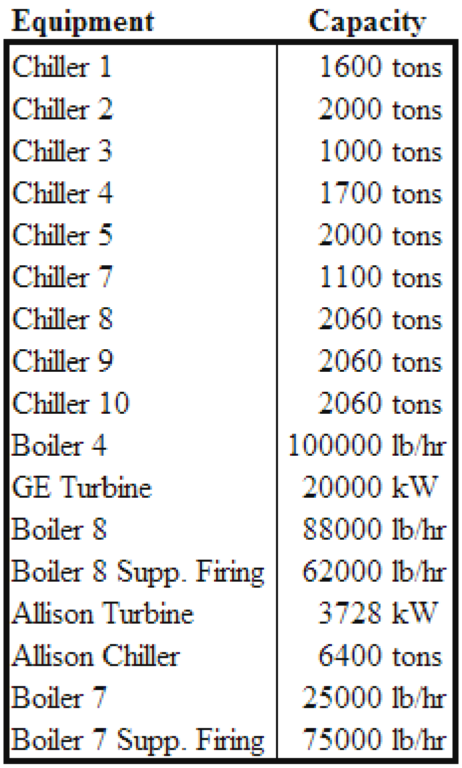
	Electricity	Steam	Chilled Water
PRODUCTION	GE Turbine Entergy	Boiler 8 Boiler 4 Boiler 7	Chiller 1-5,7 Chiller 8,9,10 Allison Chiller
USES	Campus Chiller 1-5,7	Campus Chiller 8,9,10	Campus Air Cooler

Figure 4-3: Utility Production and Uses

4.5 General Method for Finding Optimal Operating Strategy

The first step in developing a general method to find the optimal operating strategy was to learn as much as possible about each piece of equipment. First, the capacity and typical use of each piece of equipment was studied. Table 4-1 shows the capacity of each piece of equipment.

Table 4-1: Equipment Capacity



Equipment	Capacity
Chiller 1	1600 tons
Chiller 2	2000 tons
Chiller 3	1000 tons
Chiller 4	1700 tons
Chiller 5	2000 tons
Chiller 7	1100 tons
Chiller 8	2060 tons
Chiller 9	2060 tons
Chiller 10	2060 tons
Boiler 4	100000 lb/hr
GE Turbine	20000 kW
Boiler 8	88000 lb/hr
Boiler 8 Supp. Firing	62000 lb/hr
Allison Turbine	3728 kW
Allison Chiller	6400 tons
Boiler 7	25000 lb/hr
Boiler 7 Supp. Firing	75000 lb/hr

Next, an extensive study was done to determine the operating performance (closely related to efficiency) of each piece of equipment and what variables affected this performance. Data was collected over the past year from the LSU utility control room for each piece of equipment (shown in Appendix C). Data used to measure the performance (and efficiency) of each piece of equipment is shown in Appendix C. Performance was nearly constant for electric-driven chillers, steam-driven chillers, Boiler 4, and supplemental firing of Boiler 8 and Boiler 7. The GE turbine cogeneration system performance varies as a function of the natural gas used. The Allison turbine cogeneration system performance varies as a function of both ambient air temperature and the amount of natural gas used. Note that the GE turbine air cooler keeps the inlet air temperature nearly constant and thus the ambient air temperature does not affect performance of the GE turbine cogeneration system. The Allison cogeneration system does not have an air cooler and the ambient air temperature greatly affects performance.

Next, a Microsoft Excel mixed integer nonlinear programming problem was developed to determine the optimal operating strategy. Each piece of equipment is treated as a binary variable to determine whether it should be on or off. Equipment which is currently unavailable (due to maintenance or other issues) can be forced into the off position in the program. Inputs for the program include the natural gas price, fuel adjustment, campus electricity demand, campus steam demand, campus chilled water demand, and ambient air temperature. After the variables are input, Solver minimizes the sum of the natural gas cost and purchased electricity cost while satisfying three main constraints as well as several other constraints. The three main constraints are 1) total electricity produced and purchased equals total electricity consumed, 2) total steam produced equals total steam consumed, and 3) total chilled water produced equals total chilled water consumed. Other constraints include that all equipment which is turned on must operate between 50% and 100% of capacity. The 50% of capacity minimum was selected as a realistic minimum load for industrial equipment. The Excel optimal operating strategy program is shown in Appendix C.

4.6 Seasonal LSU Campus Demands

The first step in determining an operating strategy for the cogeneration and utility system is to determine the campus demands for electricity, steam, and chilled water. An initial study of the LSU utility system was done by ESI Engineering Services (1997) to estimate these demands. Based on this research, the energy demands were divided into three seasons. The winter season lasts from December to February, the spring/fall season consists of March, April, and November, and the summer season lasts from May to October. Figure 4-4 gives the average monthly temperatures in Baton Rouge, LA (from the Weather Channel).

Figure 4-4: Average Temperatures in Baton Rouge, LA

The energy demands were also divided into a weekday period and a weekend period within each season. This is because of the significant differences in energy usage between weekdays and weekends. The end result is then a total of six possible groups: 1) winter weekday, 2) winter weekend, 3) spring/fall weekday, 4) spring/fall weekend, 5) summer weekday, and 6) summer weekend.

Electricity Demand

Figure 4-5 gives the campus electric demand plotted versus time of day. Here the campus electric demand does not include electricity used to power electric-driven chillers. This gives the true campus electric demand independent of any energy used in utility equipment operation. Here we combined the winter season and the spring/fall season as demands are similar, resulting in four total groups for electric demand: 1) summer weekday, 2) summer weekend, 3) winter, spring/fall weekday, and 4) winter, spring/fall weekend.

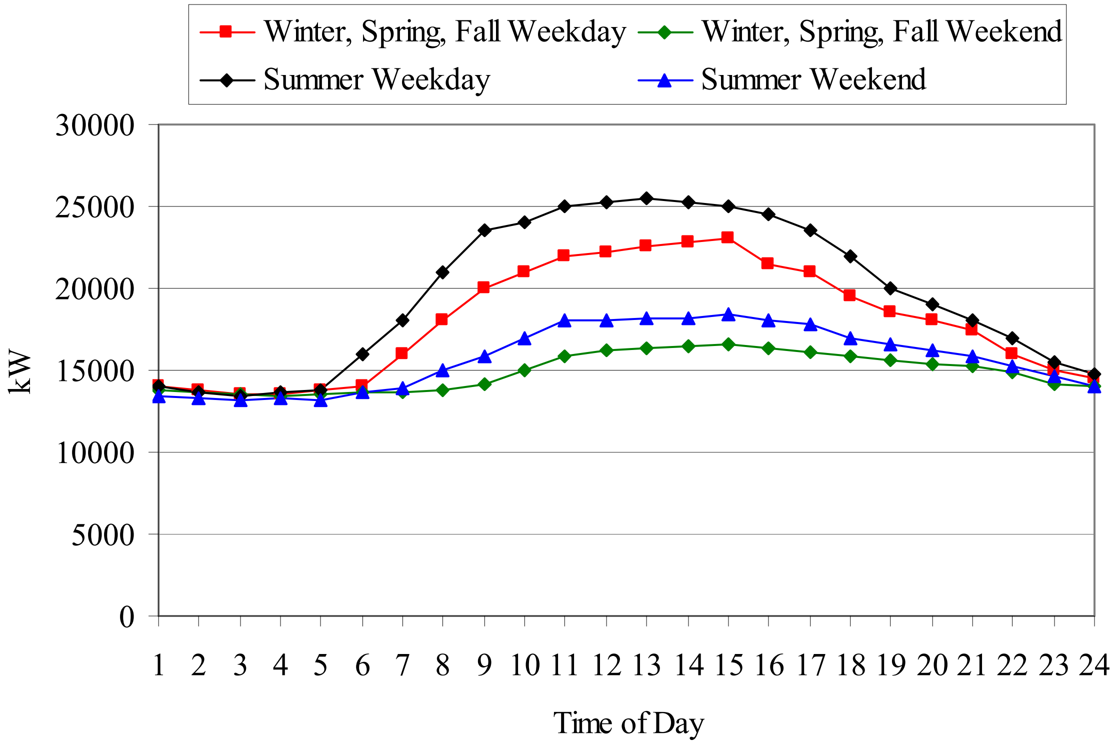


Figure 4-5: Campus Electricity Demand

Steam Demand

Figure 4-6 gives the campus steam demand plotted versus time of day. This steam demand does not include any steam used by the steam-driven chillers. This gives the true campus steam demand, independent of steam used in utility equipment operation. For the steam demand, there were no significant differences between weekdays and weekends. Once again seasons were grouped because of similar demands. The two resulting groups were 1) winter and 2) spring/fall and summer.

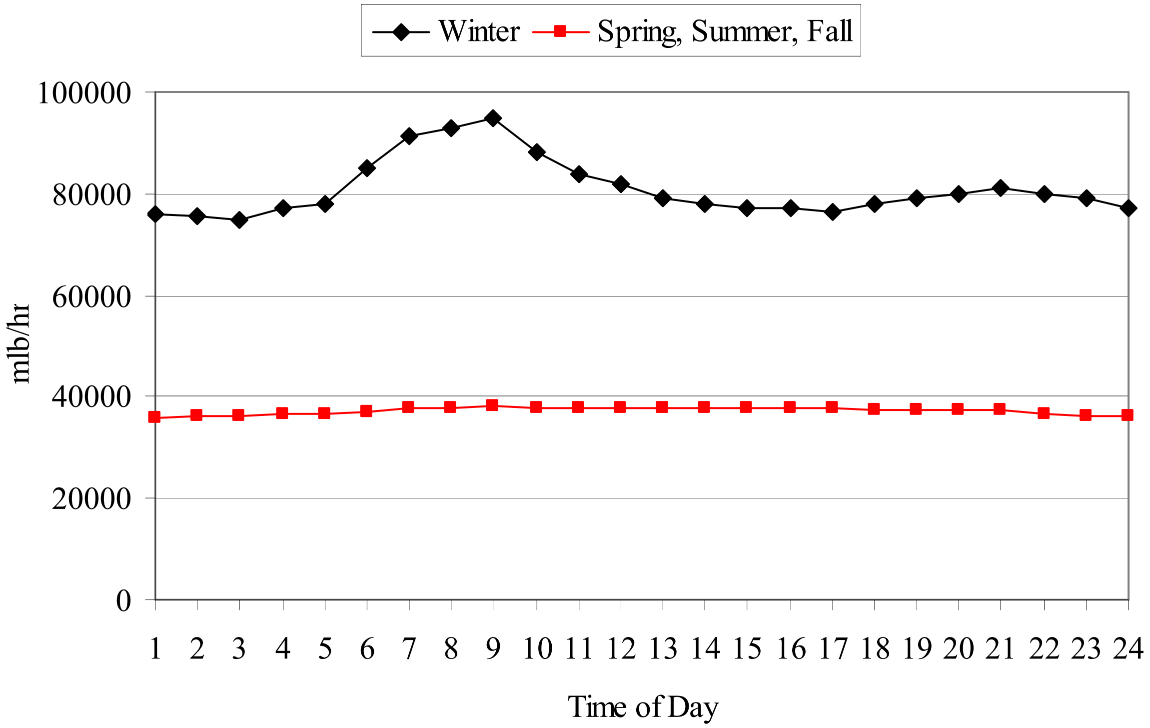


Figure 4-6: Campus Steam Demand

Chilled Water Demand

Figure 4-7 gives the campus chilled water demand plotted versus time of day. Here the campus chilled water demand does not include any chilled water used in the air cooler of the GE turbine cogeneration system. This once again gives true campus chilled water demand, independent of any chilled water used in utility equipment operation. For chilled water, the winter season and the spring/fall season were combined because of similar demands, resulting in four total groups for chilled water demand: 1) summer weekday, 2) summer weekend, 3) winter, spring/fall weekday, and 4) winter, spring/fall weekend.

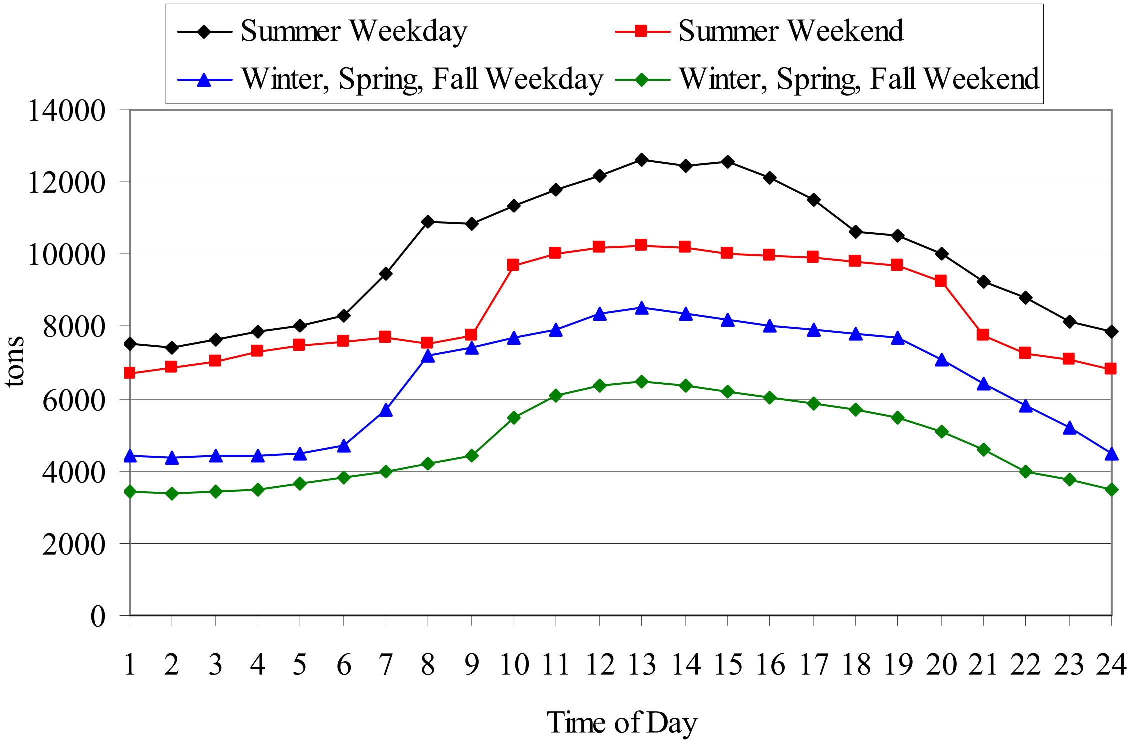


Figure 4-7: Campus Chilled Water Demand

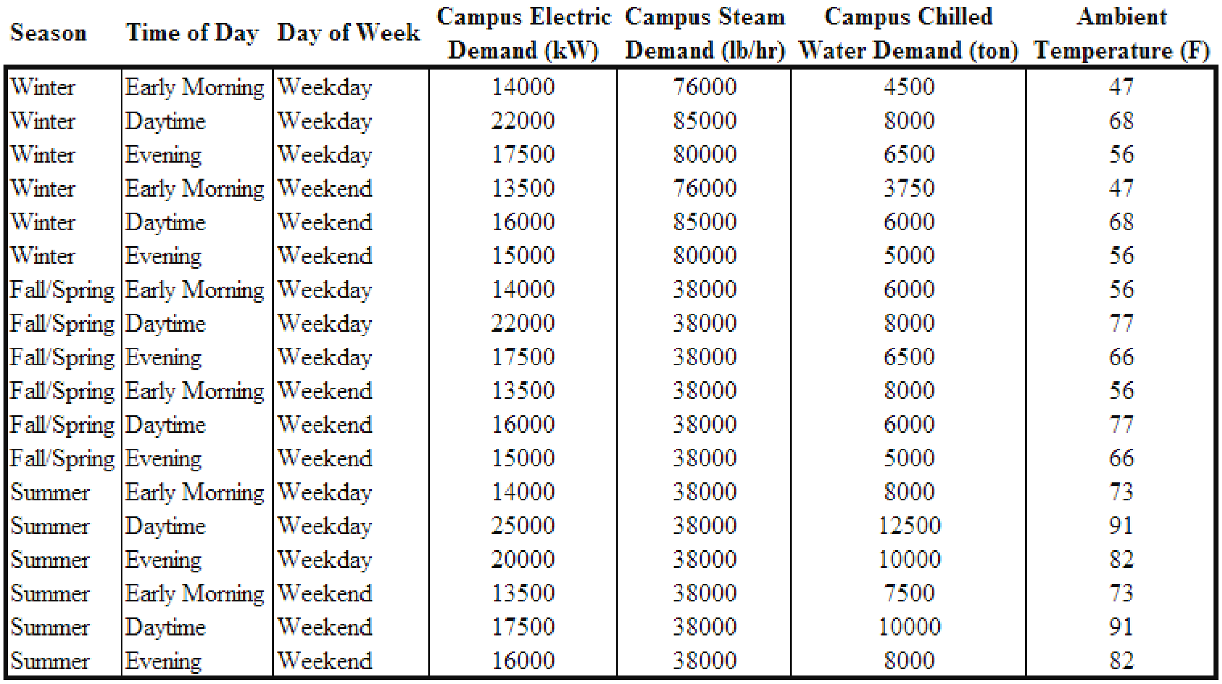
Time of Day

From observing the demand curves, it is evident that each day can be divided into three sections: daytime period from 8 AM to 5 PM (8 to 17), evening period from 5 PM to midnight (17 to 24), and early morning period from midnight to 8 AM (24 to 8). Combining the three daily sections with the six possible groups for overall energy usage mentioned earlier results in 18 possible overall operating periods.

4.7 Seasonal Operating Strategies

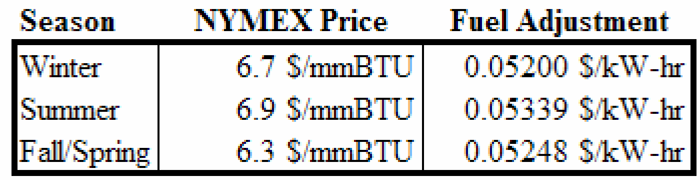
As described above, 18 operating periods were created based on seasonal and daily campus demands for electricity, steam, and chilled water. The campus demands and ambient air temperature for each of the 18 operating periods are shown in Table 4-2. The average NYMEX natural gas price and fuel adjustment for each season are shown in Table 4-3. The pricing information was obtained from historical pricing information from the past two years. These demands and pricing information are used in the program to find the 18 optimal operating strategies.

Table 4-2: Campus Demands for 18 Operating Periods



Season	Time of Day	Day of Week	Campus Electric Demand (kW)	Campus Steam Demand (lb/hr)	Campus Chilled Water Demand (ton)	Ambient Temperature (F)
Winter	Early Morning	Weekday	14000	76000	4500	47
Winter	Daytime	Weekday	22000	85000	8000	68
Winter	Evening	Weekday	17500	80000	6500	56
Winter	Early Morning	Weekend	13500	76000	3750	47
Winter	Daytime	Weekend	16000	85000	6000	68
Winter	Evening	Weekend	15000	80000	5000	56
Fall/Spring	Early Morning	Weekday	14000	38000	6000	56
Fall/Spring	Daytime	Weekday	22000	38000	8000	77
Fall/Spring	Evening	Weekday	17500	38000	6500	66
Fall/Spring	Early Morning	Weekend	13500	38000	8000	56
Fall/Spring	Daytime	Weekend	16000	38000	6000	77
Fall/Spring	Evening	Weekend	15000	38000	5000	66
Summer	Early Morning	Weekday	14000	38000	8000	73
Summer	Daytime	Weekday	25000	38000	12500	91
Summer	Evening	Weekday	20000	38000	10000	82
Summer	Early Morning	Weekend	13500	38000	7500	73
Summer	Daytime	Weekend	17500	38000	10000	91
Summer	Evening	Weekend	16000	38000	8000	82

Table 4-3: Seasonal NYMEX Price and Fuel Adjustment



Season	NYMEX Price	Fuel Adjustment
Winter	6.7 $/mmBTU	0.05200 $/kW-hr
Summer	6.9 $/mmBTU	0.05339 $/kW-hr
Fall/Spring	6.3 $/mmBTU	0.05248 $/kW-hr

Winter

The results for the winter operating period are shown in Table 4-4. The program recommends running the Allison turbine cogeneration system near full capacity throughout the

Table 4-4: Winter Operating Period Results

Parameter	**Early Morning Weekday**	**Daytime Weekday**	**Evening Weekday**	**Early Morning Weekend**	**Daytime Weekend**	**Evening Weekend**
Operating Cost ($/hr)	1630.12	2074.50	1707.66	1517.14	1637.60	1684.63
GE Turbine NG (MMBTU/hr)	0	221	211	0	200	0
Allison Turbine NG (MMBTU/hr)	21	25	21	20	23	32
Boiler 4 NG (MMBTU/hr)	79	0	0	67	0	67
Electricity Purchased (kW)	14000	4142	0	13847	3	15000
Electricity Produced (kW)	0	19514	18401	0	17206	0
Campus Electricity Demand (kW)	14000	22000	17500	13500	16000	15000
Electric Chiller Electricity (kW)	0	1656	901	347	1210	0
Boiler 8 Steam Produced (lb/hr)	0	87136	81861	0	76776	0
Boiler 8 Supp. Steam (lb/hr)	0	0	0	0	0	0
Boiler 7 Steam Produced (lb/hr)	19610	20306	19241	18970	19568	22594
Boiler 7 Supp. Steam (lb/hr)	0	0	0	0	0	0
Boiler 4 Steam Produced (lb/hr)	67611	0	0	57030	0	57407
Campus Steam Demand (lb/hr)	76000	85000	80000	76000	85000	80000
Steam Chiller Steam Usage (lb/hr)	11221	22442	21102	0	11344	0
Electric Chiller CHW (tons)	0	2656	1420	550	1962	0
Steam Chiller CHW (tons)	1030	2060	1937	0	1041	0
Allison CHW (tons)	3470	3517	3200	3200	3200	5000
Campus CHW Demand (tons)	4500	8000	6500	3750	6000	5000
Air Cooler CHW (tons)	0	234	57	0	203	0

winter. This aids in meeting the large winter campus steam demand and also produces the majority of the needed chilled water simultaneously. During both daytime periods and on weekday evenings, the program recommends running the GE turbine cogeneration system near full capacity. The GE turbine cogeneration system produces nearly all the needed electricity as well as steam above the campus steam demand that can be sent to the steam-driven chillers. On both early morning periods and on weekend evenings (periods of lower electricity and steam demand), the program recommends shutting down the GE turbine cogeneration system. For these periods, all of the electricity should be purchased, and Boiler 4 should be used to meet the rest of the steam demand. Throughout the winter, the electric-driven chillers are used only to supplement the Allison chiller and steam-driven chillers.

Fall/Spring

The results for the fall/spring operating period are shown in Table 4-5. The program recommends running the GE turbine cogeneration system for all of the periods to provide the majority of needed electricity. Any steam beyond the campus demand is sent to the steam-driven chillers to produce chilled water. The Allison turbine cogeneration system and Boiler 4 are not recommended for use. For weekday daytime and weekday evenings, the GE turbine cogeneration system should be run at capacity. For all weekend periods and the early morning weekday, the GE turbine cogeneration system should be run below capacity. Throughout the fall/spring period, the electric-driven chillers are used to supplement the steam-driven chillers.

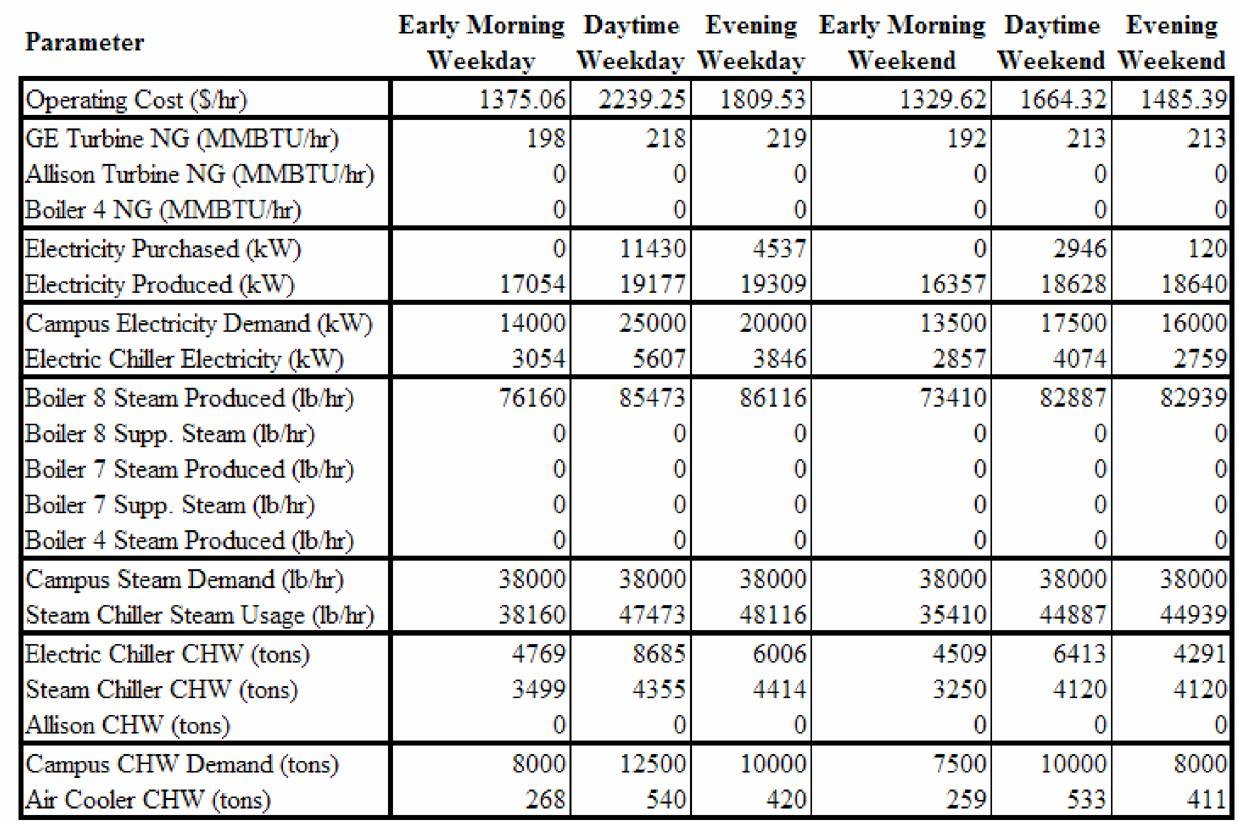
Table 4-5: Fall/Spring Operating Period Results

Parameter	**Early Morning Weekday**	**Daytime Weekday**	**Evening Weekday**	**Early Morning Weekend**	**Daytime Weekend**	**Evening Weekend**
Operating Cost ($/hr)	1361.81	1994.09	1641.45	1303.47	1553.58	1460.09
GE Turbine NG (MMBTU/hr)	180	220	217	168	198	163
Allison Turbine NG (MMBTU/hr)	0	0	0	0	0	0
Boiler 4 NG (MMBTU/hr)	0	0	0	0	0	0
Electricity Purchased (kW)	0	5071	0	467	878	3481
Electricity Produced (kW)	15090	19382	19019	13874	16978	13362
Campus Electricity Demand (kW)	14000	22000	17500	13500	16000	15000
Electric Chiller Electricity (kW)	1090	2453	1519	841	1856	1843
Boiler 8 Steam Produced (lb/hr)	68623	86477	84714	64147	75855	62259
Boiler 8 Supp. Steam (lb/hr)	0	0	0	0	0	0
Boiler 7 Steam Produced (lb/hr)	0	0	0	0	0	0
Boiler 7 Supp. Steam (lb/hr)	0	0	0	0	0	0
Boiler 4 Steam Produced (lb/hr)	0	0	0	0	0	0
Campus Steam Demand (lb/hr)	38000	38000	38000	38000	38000	38000
Steam Chiller Steam Usage (lb/hr)	30623	48477	46714	26147	37855	24259
Electric Chiller CHW (tons)	1701	3906	2415	1350	2850	2900
Steam Chiller CHW (tons)	2811	4447	4285	2400	3471	2224
Allison CHW (tons)	0	0	0	0	0	0
Campus CHW Demand (tons)	4500	8000	6500	3750	6000	5000
Air Cooler CHW (tons)	12	354	200	0	321	124

Summer

The results for the summer operating period are shown in Table 4-6. The program recommends running the GE turbine cogeneration system for all of the periods to produce the majority of the needed electricity. Any steam beyond the campus demand is sent to the steam-driven chillers to produce chilled water. The Allison turbine cogeneration system and Boiler 4 are not recommended for use. For weekday daytime and weekday evenings, the GE turbine cogeneration system should be run at capacity. For all weekend periods and the early morning weekday, the GE turbine cogeneration system should be run below capacity. Throughout the summer period, the electric-driven chillers will produce the majority of the chilled water.

Table 4-6: Summer Operating Period Results



Parameter	Early Morning Weekday	Daytime Weekday	Evening Weekday	Early Morning Weekend	Daytime Weekend	Evening Weekend
Operating Cost ($/hr)	1375.06	2239.25	1809.53	1329.62	1664.32	1485.39
GE Turbine NG (MMBTU/hr)	198	218	219	192	213	213
Allison Turbine NG (MMBTU/hr)	0	0	0	0	0	0
Boiler 4 NG (MMBTU/hr)	0	0	0	0	0	0
Electricity Purchased (kW)	0	11430	4537	0	2946	120
Electricity Produced (kW)	17054	19177	19309	16357	18628	18640
Campus Electricity Demand (kW)	14000	25000	20000	13500	17500	16000
Electric Chiller Electricity (kW)	3054	5607	3846	2857	4074	2759
Boiler 8 Steam Produced (lb/hr)	76160	85473	86116	73410	82887	82939
Boiler 8 Supp. Steam (lb/hr)	0	0	0	0	0	0
Boiler 7 Steam Produced (lb/hr)	0	0	0	0	0	0
Boiler 7 Supp. Steam (lb/hr)	0	0	0	0	0	0
Boiler 4 Steam Produced (lb/hr)	0	0	0	0	0	0
Campus Steam Demand (lb/hr)	38000	38000	38000	38000	38000	38000
Steam Chiller Steam Usage (lb/hr)	38160	47473	48116	35410	44887	44939
Electric Chiller CHW (tons)	4769	8685	6006	4509	6413	4291
Steam Chiller CHW (tons)	3499	4355	4414	3250	4120	4120
Allison CHW (tons)	0	0	0	0	0	0
Campus CHW Demand (tons)	8000	12500	10000	7500	10000	8000
Air Cooler CHW (tons)	268	540	420	259	533	411

4.8 Comparison with Daily Operations Data

The next step is to compare the optimal daily operating strategies with actual operating strategies. This involves examining current campus electricity, steam, and chilled water demands along with current natural gas and electricity prices to determine optimal operations. The campus electricity, steam, and chilled water demands are easily obtained from the LSU campus control room. The NYMEX natural gas price is available daily.

However, the fuel adjustment portion of the electricity price presents a difficulty. It changes monthly and is not known until the monthly electric bill is received the next month. For example, the fuel adjustment charged for January would not be known until the January electric bill is received some time in February. This presents significant difficulties in economic planning. Thus, it was necessary to develop a method to predict the fuel adjustment cost.

The NYMEX natural gas price is the primary factor in determining the fuel adjustment, so it will be used to predict the fuel adjustment. Dr. David Dismukes of the LSU Center for Energy Studies (2006) was consulted. He stated that the fuel adjustment is based on the cost of producing electricity from two months ago. Figure 4-8 shows the average monthly NYMEX natural gas price and the fuel adjustment corresponding to that month's fuel costs. Figure 4-9 shows a linear fit between the average monthly NYMEX natural gas price and the fuel adjustment corresponding to that month's fuel costs. With this linear fit, the current fuel adjustment can be closely estimated from previous natural gas prices.

Several data sets from the past year were compared with the optimal results from the program. Figure 4-7 gives the results of these comparisons. Note that the costs based on predicted fuel adjustment are reported first in the table, and the costs based on actual fuel adjustment are reported later in the table. The predicted and actual savings are pretty close for

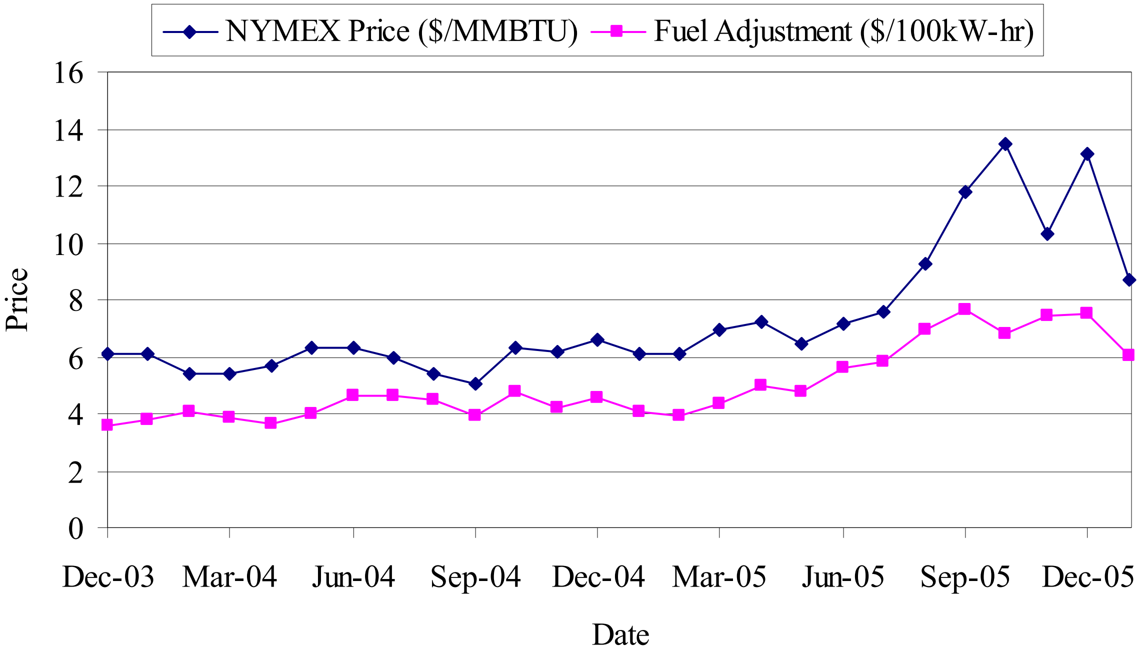


Figure 4-8: NYMEX Natural Gas Price and Fuel Adjustment

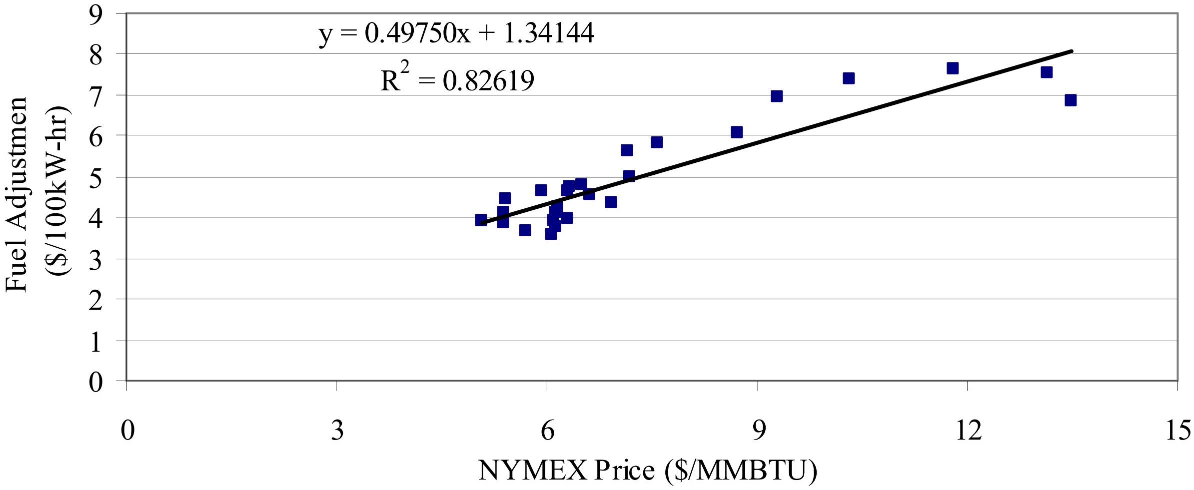


Figure 4-9: Linear Fit

the data sets, showing that the method developed to predict the fuel adjustment was successful. The program shows that operational savings can be achieved for each data set with an average savings above $50 per hour. Even a modest savings such as this could result in operational cost savings of over $500,000 per year.

Table 4-7: Actual and Optimal Operations for Collected Data

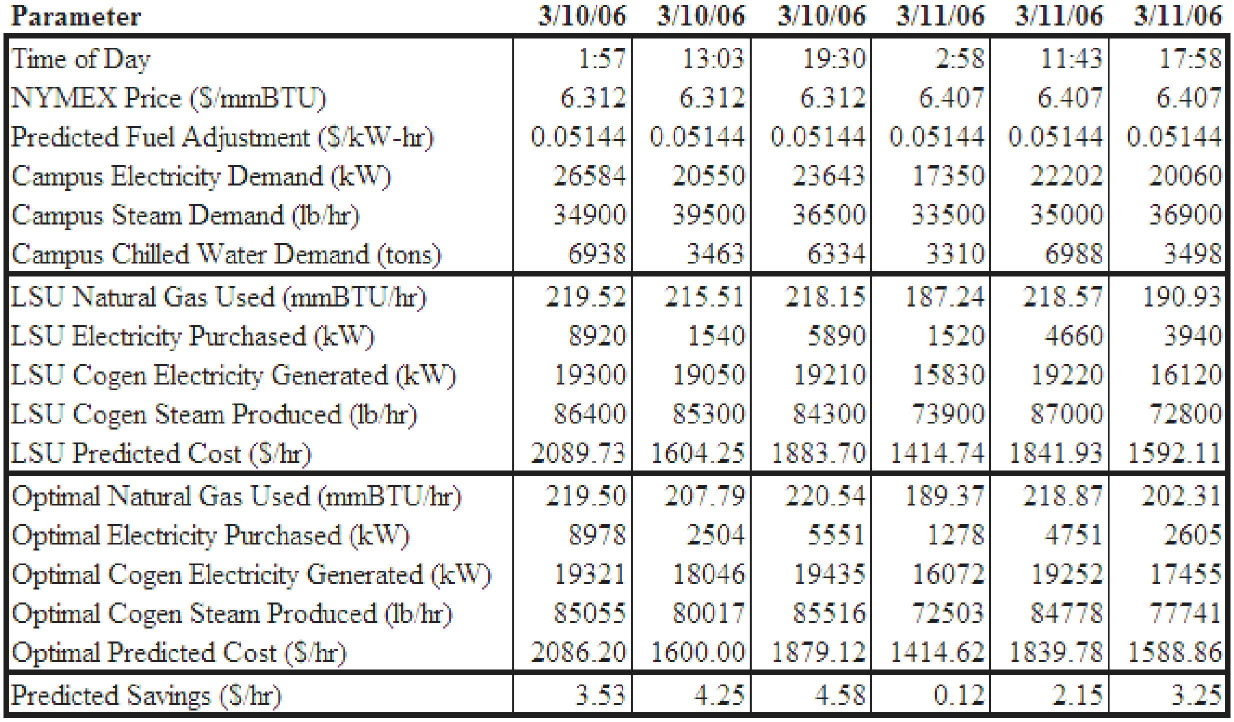
Parameter	3/31/05	5/16/05	6/24/05	8/19/05	1/18/06	2/23/06	3/19/06
NYMEX Price ($/mmBTU)	7.58	6.95	7.48	9.93	9.41	6.47	7.05
Predicted Fuel Adjustment ($/kW-hr)	0.04382	0.04924	0.04569	0.05118	0.07887	0.05682	0.05144
Actual Fuel Adjustment	0.03934	0.04967	0.04785	0.05173	0.07536	0.06046	NA
Campus Electricity Demand (kW)	26152	26292	25645	24307	23735	23519	20060
Campus Steam Demand (lb/hr)	41528	35198	34904	39597	40731	49200	36900
Campus Chilled Water Demand (tons)	6631	8463	9623	12567	3526	1442	3498
LSU Natural Gas Used (mmBTU/hr)	219.6	220.3	220	219.7	128.7	130.38	190.93
LSU Electricity Purchased (kW)	9099	9899	9940	11035	15500	14620	4567
LSU Cogen Electricity Generated (kW)	19101	19381	19360	19270	10110	99600	16120
LSU Cogen Steam Produced (lb/hr)	83159	85241	87676	86715	48903	52900	72800
LSU Predicted Cost ($/hr)	2323.13	2277.96	2367.68	3063.91	2715.15	2070.73	1763.29
LSU Actual Cost ($/hr)	2282.34	2282.25	2389.13	3069.98	2660.76	2123.90	NA
Optimal Natural Gas Used (mmBTU/hr)	138.53	219.33	139.33	208.94	210.76	178.09	128.91
Optimal Electricity Purchased (kW)	18919	9748	20036	12238	5367	8631	11637
Optimal Cogen Electricity Generated (kW)	10916	19302	10995	18171	18368	14888	10000
Optimal Cogen Steam Produced (lb/hr)	52749	84978	53060	80502	81271	68061	49004
Optimal Predicted Cost ($/hr)	2189.33	2261.41	2279.85	3022.41	2645.53	2058.36	1725.44
Optimal Actual Cost ($/hr)	2104.50	2265.63	2323.08	3029.14	2626.70	2089.75	NA
Predicted Savings ($/hr)	133.80	16.55	87.83	41.50	69.62	12.37	37.85
Actual Savings ($/hr)	177.84	16.62	66.05	40.84	34.06	34.15	NA

Next, a comprehensive study of operations was done for a two-day period (Friday 3/10/06 and Saturday 3/11/06). Several data sets were collected for each day and compared to the optimal operations strategy from the program. The actual fuel adjustment for March is not yet known, so the predicted fuel adjustment is used in the calculations. The results are shown in Figure 4-8 and show that the system was operated very economically for that period.

4.9 Energy Management Optimization Educational Module

This module first created a general mixed integer nonlinear programming problem to successfully model and optimize the LSU utility system. Next, campus energy demands were divided by time of day and season and recommended operating strategies were developed for each of the operating periods. Finally, these recommended strategies were compared to operating strategies at LSU to determine the potential savings that can be realized.

Table 4-8: Study of March 10 and March 11 Operations



Parameter	3/10/06	3/10/06	3/10/06	3/11/06	3/11/06	3/11/06
Time of Day	1:57	13:03	19:30	2:58	11:43	17:58
NYMEX Price ($/mmBTU)	6.312	6.312	6.312	6.407	6.407	6.407
Predicted Fuel Adjustment ($/kW-hr)	0.05144	0.05144	0.05144	0.05144	0.05144	0.05144
Campus Electricity Demand (kW)	26584	20550	23643	17350	22202	20060
Campus Steam Demand (lb/hr)	34900	39500	36500	33500	35000	36900
Campus Chilled Water Demand (tons)	6938	3463	6334	3310	6988	3498
LSU Natural Gas Used (mmBTU/hr)	219.52	215.51	218.15	187.24	218.57	190.93
LSU Electricity Purchased (kW)	8920	1540	5890	1520	4660	3940
LSU Cogen Electricity Generated (kW)	19300	19050	19210	15830	19220	16120
LSU Cogen Steam Produced (lb/hr)	86400	85300	84300	73900	87000	72800
LSU Predicted Cost ($/hr)	2089.73	1604.25	1883.70	1414.74	1841.93	1592.11
Optimal Natural Gas Used (mmBTU/hr)	219.50	207.79	220.54	189.37	218.87	202.31
Optimal Electricity Purchased (kW)	8978	2504	5551	1278	4751	2605
Optimal Cogen Electricity Generated (kW)	19321	18046	19435	16072	19252	17455
Optimal Cogen Steam Produced (lb/hr)	85055	80017	85516	72503	84778	77741
Optimal Predicted Cost ($/hr)	2086.20	1600.00	1879.12	1414.62	1839.78	1588.86
Predicted Savings ($/hr)	3.53	4.25	4.58	0.12	2.15	3.25

This module will be tested in Fall 2006 in the senior-level chemical engineering course Process Economics and Optimization. Students were surveyed to give their initial impressions of this problem based on a description of the problem. The results are shown in Appendix D. This educational module was also reviewed by supervisors from LSU Utility Services with good agreement between their current operating strategies and the program. LSU Utility Services has reevaluated their operating strategies in the past year to become more economical. This is shown in the program results. Large savings were typically available in 2005, while current operations are very close to the program recommendations. LSU Utility Services feels that this model will aid in operations planning because of its ease of use and accuracy.

CHAPTER 5
CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The first goal of this project was to provide three educational modules for use by undergraduate students. These modules enhance basic concepts and understanding of cogeneration systems. The CGAM educational module provides an excellent learning tool for students by solving a straightforward industrial model. It shows the importance of using the real gas physical property package for obtaining an accurate solution, and it shows that an ideal gas, constant heat capacity model should be limited to quick estimations for most industrial units.

The data reconciliation educational module provides a learning tool for students by solving a basic data reconciliation problem. Combined data reconciliation and parameter estimation is used with a least squares objective function. This problem has been solved by senior level students in the chemical engineering course Process Economics and Optimization.

The energy management optimization module has been used to compare current operating strategies to optimal operating strategies and also to find optimal operating strategies for the 18 operating periods. Students will be exposed to numerous types of industrial equipment and learn about the performance and efficiencies of each. This module may be used by LSU in the future to operate the utility system more economically.

5.2 Recommendations

The first recommendation involves modifications to the GE turbine cogeneration system. A flow meter / thermocouple should be added to better measure the exhaust gas flow rate. An ideal location would be in the stack before the exhaust gas is exited to the atmosphere. This could be installed relatively easily and at a low cost.

Another modification to the cogeneration system would be involved with obtaining and accessing data. First, manual gauges located on the HRSG (measuring T_5, T_6, T_7, T_8, P_8, and T_9) should be connected to the plant distributed control system. Second, a data historian should be installed to collect and store all plant data. This would allow anytime online access to the data and would be a significant improvement over the current method of obtaining data from the control room and manual gauges.

A final recommendation involves the possibility of adding absorptive chillers to the LSU system. Absorptive chillers use waste heat to produce chilled water. This could be implemented by recovering additional heat from the product gas before it exits to the atmosphere. Significant amounts of waste heat could be recovered with the possibility of significant energy savings. Additional studies should be done to determine the feasibility of this idea. More information about absorptive chillers is given by Bruno (1999) and from the absorptive refrigeration section of Lineau (1998).

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APPENDIX A
CGAM EDUCATIONAL MODULE

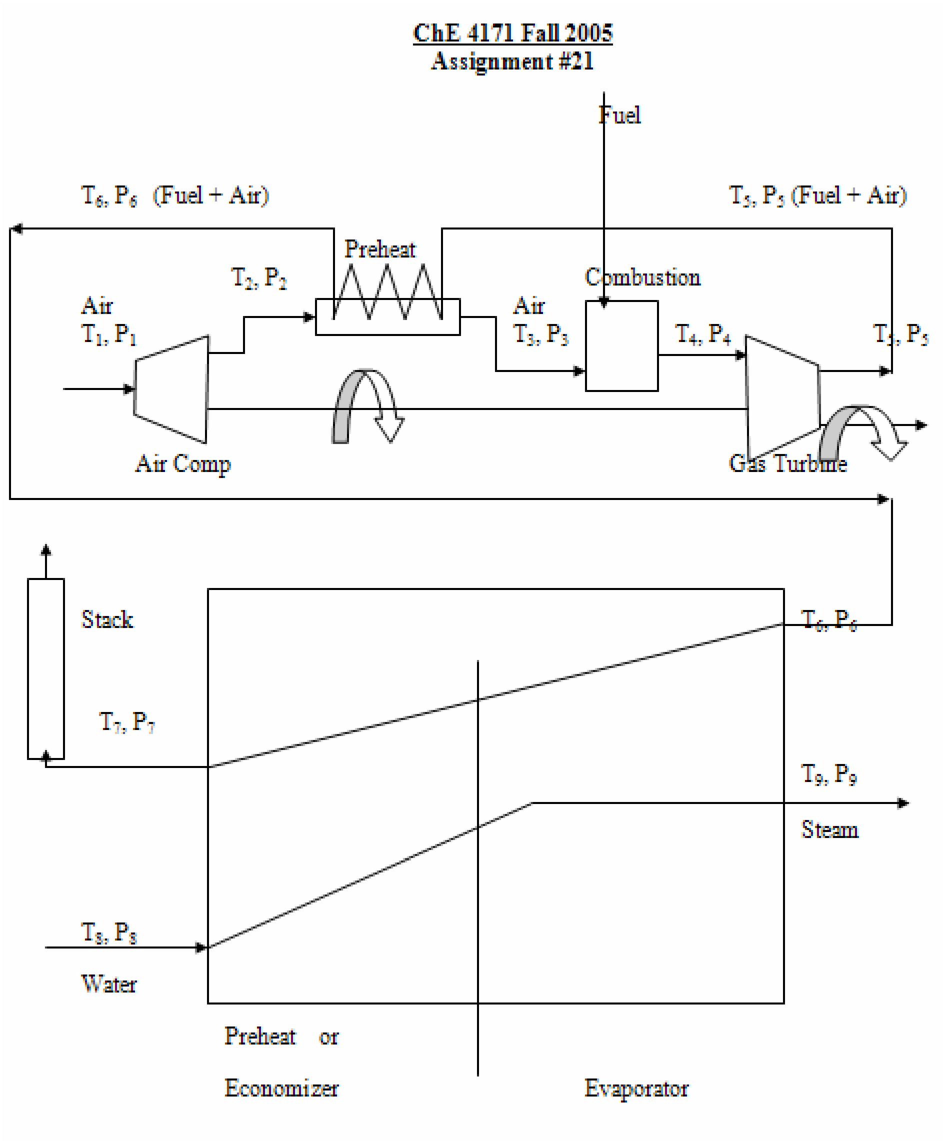
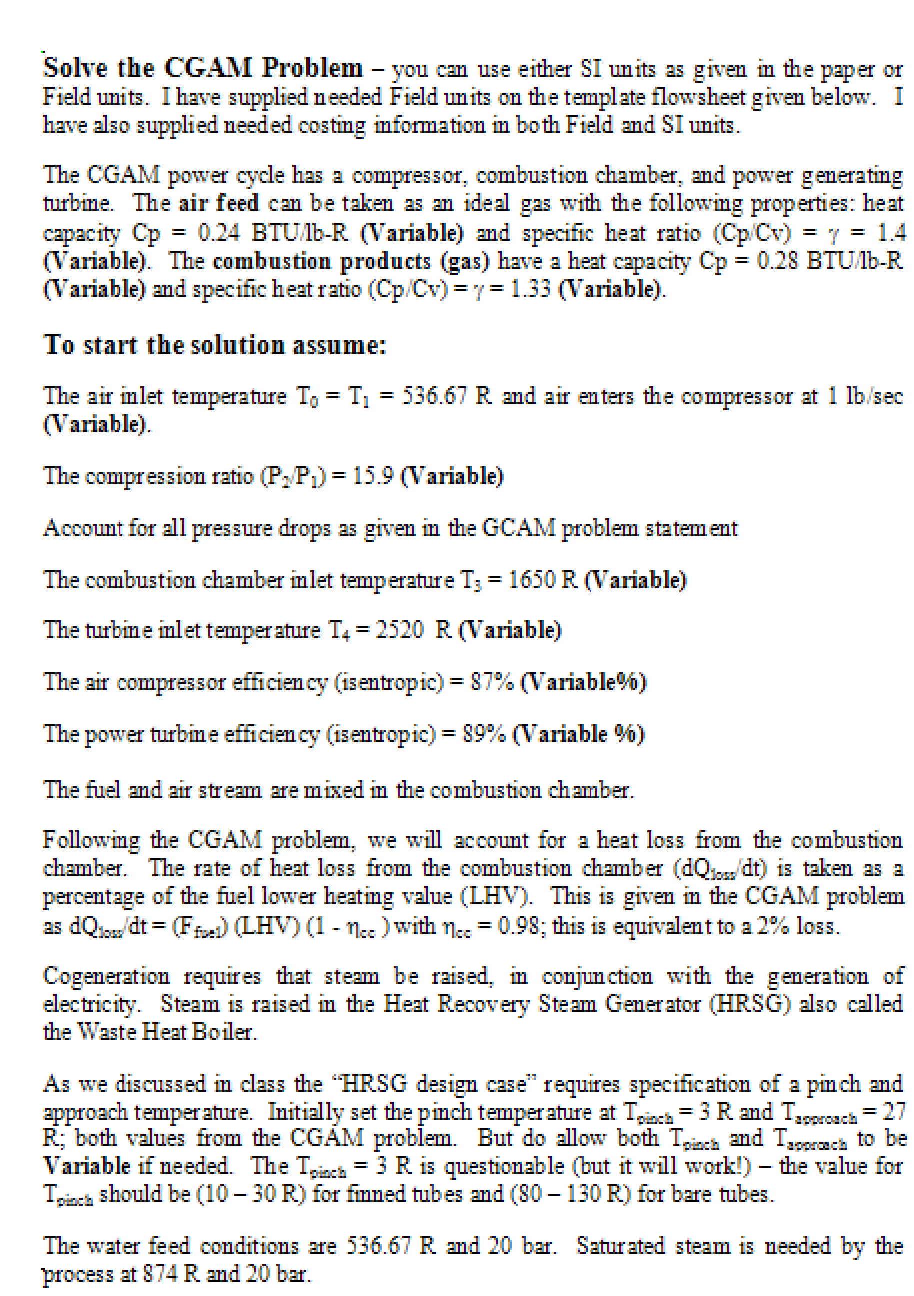


Figure A-1: Problem Assignment Page 1



Solve the CGAM Problem – you can use either SI units as given in the paper or Field units. I have supplied needed Field units on the template flowsheet given below. I have also supplied needed costing information in both Field and SI units.

The CGAM power cycle has a compressor, combustion chamber, and power generating turbine. The **air feed** can be taken as an ideal gas with the following properties: heat capacity Cp = 0.24 BTU/lb-R **(Variable)** and specific heat ratio (Cp/Cv) = γ = 1.4 **(Variable)**. The **combustion products (gas)** have a heat capacity Cp = 0.28 BTU/lb-R **(Variable)** and specific heat ratio (Cp/Cv) = γ = 1.33 **(Variable)**.

To start the solution assume:

The air inlet temperature $T_0 = T_1$ = 536.67 R and air enters the compressor at 1 lb/sec **(Variable)**.

The compression ratio (P_2/P_1) = 15.9 **(Variable)**

Account for all pressure drops as given in the GCAM problem statement

The combustion chamber inlet temperature T_3 = 1650 R **(Variable)**

The turbine inlet temperature T_4 = 2520 R **(Variable)**

The air compressor efficiency (isentropic) = 87% **(Variable%)**

The power turbine efficiency (isentropic) = 89% **(Variable %)**

The fuel and air stream are mixed in the combustion chamber.

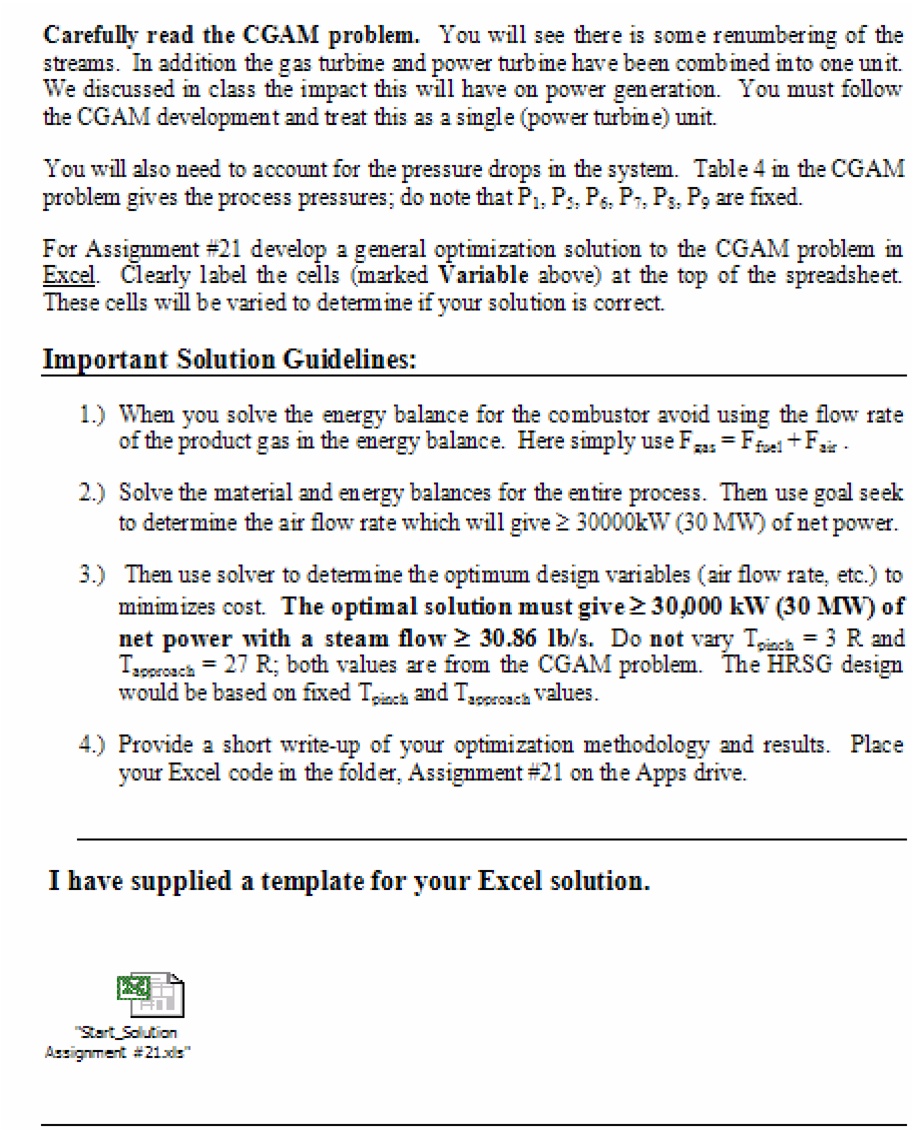
Following the CGAM problem, we will account for a heat loss from the combustion chamber. The rate of heat loss from the combustion chamber (dQ_{loss}/dt) is taken as a percentage of the fuel lower heating value (LHV). This is given in the CGAM problem as $dQ_{loss}/dt = (F_{fuel})$ (LHV) $(1 - \eta_{cc})$ with $\eta_{cc} = 0.98$; this is equivalent to a 2% loss.

Cogeneration requires that steam be raised, in conjunction with the generation of electricity. Steam is raised in the Heat Recovery Steam Generator (HRSG) also called the Waste Heat Boiler.

As we discussed in class the "HRSG design case" requires specification of a pinch and approach temperature. Initially set the pinch temperature at T_{pinch} = 3 R and $T_{approach}$ = 27 R; both values from the CGAM problem. But do allow both T_{pinch} and $T_{approach}$ to be **Variable** if needed. The T_{pinch} = 3 R is questionable (but it will work!) – the value for T_{pinch} should be (10 – 30 R) for finned tubes and (80 – 130 R) for bare tubes.

The water feed conditions are 536.67 R and 20 bar. Saturated steam is needed by the process at 874 R and 20 bar.

Figure A-2: Problem Assignment Page 2



Carefully read the CGAM problem. You will see there is some renumbering of the streams. In addition the gas turbine and power turbine have been combined into one unit. We discussed in class the impact this will have on power generation. You must follow the CGAM development and treat this as a single (power turbine) unit.

You will also need to account for the pressure drops in the system. Table 4 in the CGAM problem gives the process pressures; do note that P_1, P_5, P_6, P_7, P_8, P_9 are fixed.

For Assignment #21 develop a general optimization solution to the CGAM problem in Excel. Clearly label the cells (marked **Variable** above) at the top of the spreadsheet. These cells will be varied to determine if your solution is correct.

Important Solution Guidelines:

1.) When you solve the energy balance for the combustor avoid using the flow rate of the product gas in the energy balance. Here simply use $F_{gas} = F_{fuel} + F_{air}$.

2.) Solve the material and energy balances for the entire process. Then use goal seek to determine the air flow rate which will give ≥ 30000kW (30 MW) of net power.

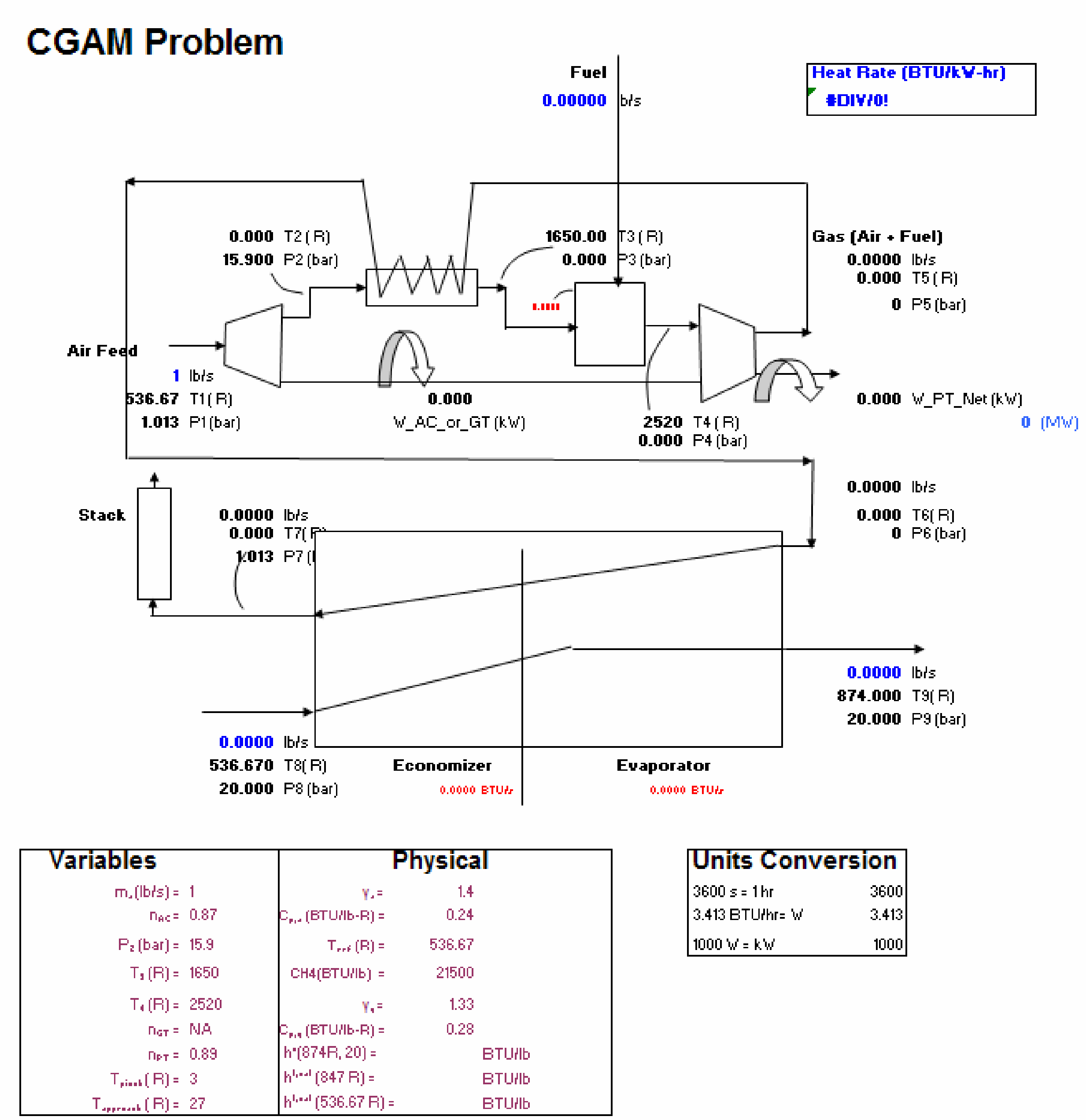
3.) Then use solver to determine the optimum design variables (air flow rate, etc.) to minimizes cost. **The optimal solution must give ≥ 30,000 kW (30 MW) of net power with a steam flow ≥ 30.86 lb/s.** Do **not** vary T_{pinch} = 3 R and $T_{approach}$ = 27 R; both values are from the CGAM problem. The HRSG design would be based on fixed T_{pinch} and $T_{approach}$ values.

4.) Provide a short write-up of your optimization methodology and results. Place your Excel code in the folder, Assignment #21 on the Apps drive.

I have supplied a template for your Excel solution.

"Start_Solution Assignment #21.xls"

Figure A-3: Problem Assignment Page 3

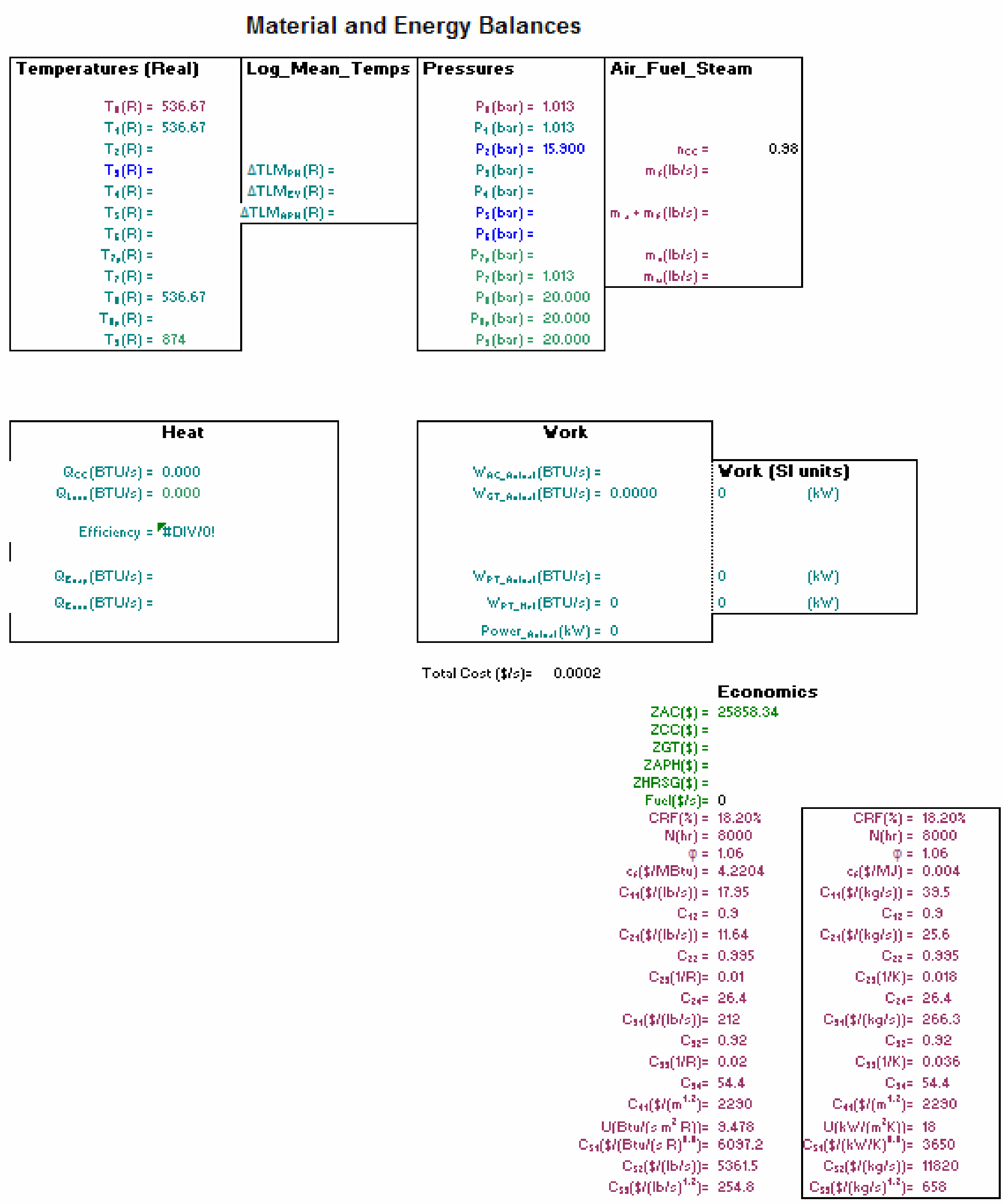


Variables	
m_a (lb/s) =	1
η_{AC} =	0.87
P_2 (bar) =	15.9
T_3 (R) =	1650
T_4 (R) =	2520
η_{GT} =	NA
η_{PT} =	0.89
T_{pinch} (R) =	3
$T_{approach}$ (R) =	27

Physical		
γ_a =	1.4	
$C_{p,a}$ (BTU/lb-R) =	0.24	
T_{ref} (R) =	536.67	
CH4(BTU/lb) =	21500	
γ_g =	1.33	
$C_{p,g}$ (BTU/lb-R) =	0.28	
h°(874R, 20) =		BTU/lb
h^{liq} (847 R) =		BTU/lb
h^{liq} (536.67 R) =		BTU/lb

Units Conversion	
3600 s = 1 hr	3600
3.413 BTU/hr= W	3.413
1000 W = kW	1000

Figure A-4: Template Page 1



Material and Energy Balances

Temperatures (Real)

$T_0(R)$ = 536.67
$T_1(R)$ = 536.67
$T_2(R)$ =
$T_3(R)$ =
$T_4(R)$ =
$T_5(R)$ =
$T_6(R)$ =
$T_{7p}(R)$ =
$T_7(R)$ =
$T_8(R)$ = 536.67
$T_{8p}(R)$ =
$T_9(R)$ = 874

Log_Mean_Temps

$\Delta TLM_{PH}(R)$ =
$\Delta TLM_{EV}(R)$ =
$\Delta TLM_{APH}(R)$ =

Pressures

P_0(bar) = 1.013
P_1(bar) = 1.013
P_2(bar) = 15.900
P_3(bar) =
P_4(bar) =
P_5(bar) =
P_6(bar) =
P_{7p}(bar) =
P_7(bar) = 1.013
P_8(bar) = 20.000
P_{8p}(bar) = 20.000
P_9(bar) = 20.000

Air_Fuel_Steam

η_{cc} = 0.98
m_f(lb/s) =
$m_a + m_f$(lb/s) =
m_a(lb/s) =
m_w(lb/s) =

Heat

Q_{cc}(BTU/s) = 0.000
Q_{Loss}(BTU/s) = 0.000
Efficiency = #DIV/0!
Q_{Evap}(BTU/s) =
Q_{Econ}(BTU/s) =

Work

W_{AC_Actual}(BTU/s) =
W_{GT_Actual}(BTU/s) = 0.0000
W_{PT_Actual}(BTU/s) =
W_{PT_Net}(BTU/s) = 0
$Power_{Actual}$(kW) = 0

Work (SI units)

0 (kW)
0 (kW)
0 (kW)

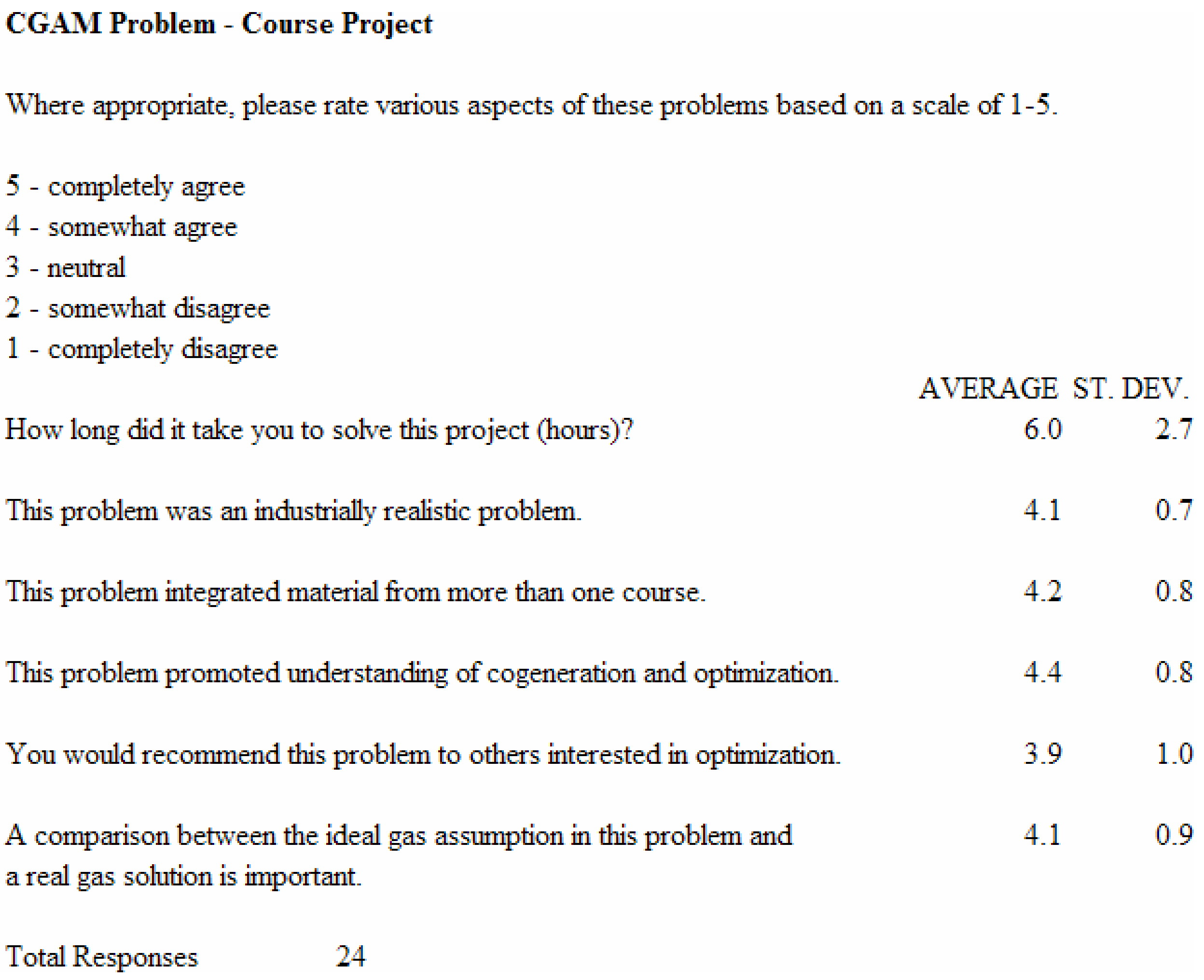
Total Cost ($/s)= 0.0002

Economics

ZAC($) = 25858.34
ZCC($) =
ZGT($) =
ZAPH($) =
ZHRSG($) =
Fuel($/s)= 0
CRF(%) = 18.20%
N(hr) = 8000
φ = 1.06
c_f($/MBtu) = 4.2204
C_{11}($/(lb/s)) = 17.35
C_{12} = 0.9
C_{21}($/(lb/s)) = 11.64
C_{22} = 0.995
C_{23}(1/R)= 0.01
C_{24}= 26.4
C_{31}($/(lb/s))= 212
C_{32}= 0.92
C_{33}(1/R)= 0.02
C_{34}= 54.4
C_{41}($/(m$^{1.2}$)= 2290
U(Btu/(s m^2 R))= 3.478
C_{51}($/(Btu/(s R)$^{0.8}$)= 6097.2
C_{52}($/(lb/s))= 5361.5
C_{53}($/(lb/s)$^{1.2}$)= 254.8

CRF(%) = 18.20%
N(hr) = 8000
φ = 1.06
c_f($/MJ) = 0.004
C_{11}($/(kg/s)) = 39.5
C_{12} = 0.9
C_{21}($/(kg/s)) = 25.6
C_{22} = 0.995
C_{23}(1/K)= 0.018
C_{24}= 26.4
C_{31}($/(kg/s))= 266.3
C_{32}= 0.92
C_{33}(1/K)= 0.036
C_{34}= 54.4
C_{41}($/(m$^{1.2}$)= 2290
U(kW/(m^{2}K))= 18
C_{51}($/(kW/K)$^{0.8}$)= 3650
C_{52}($/(kg/s))= 11820
C_{53}($/(kg/s)$^{1.2}$)= 658

Figure A-5: Template Page 2



CGAM Problem - Course Project

Where appropriate, please rate various aspects of these problems based on a scale of 1-5.

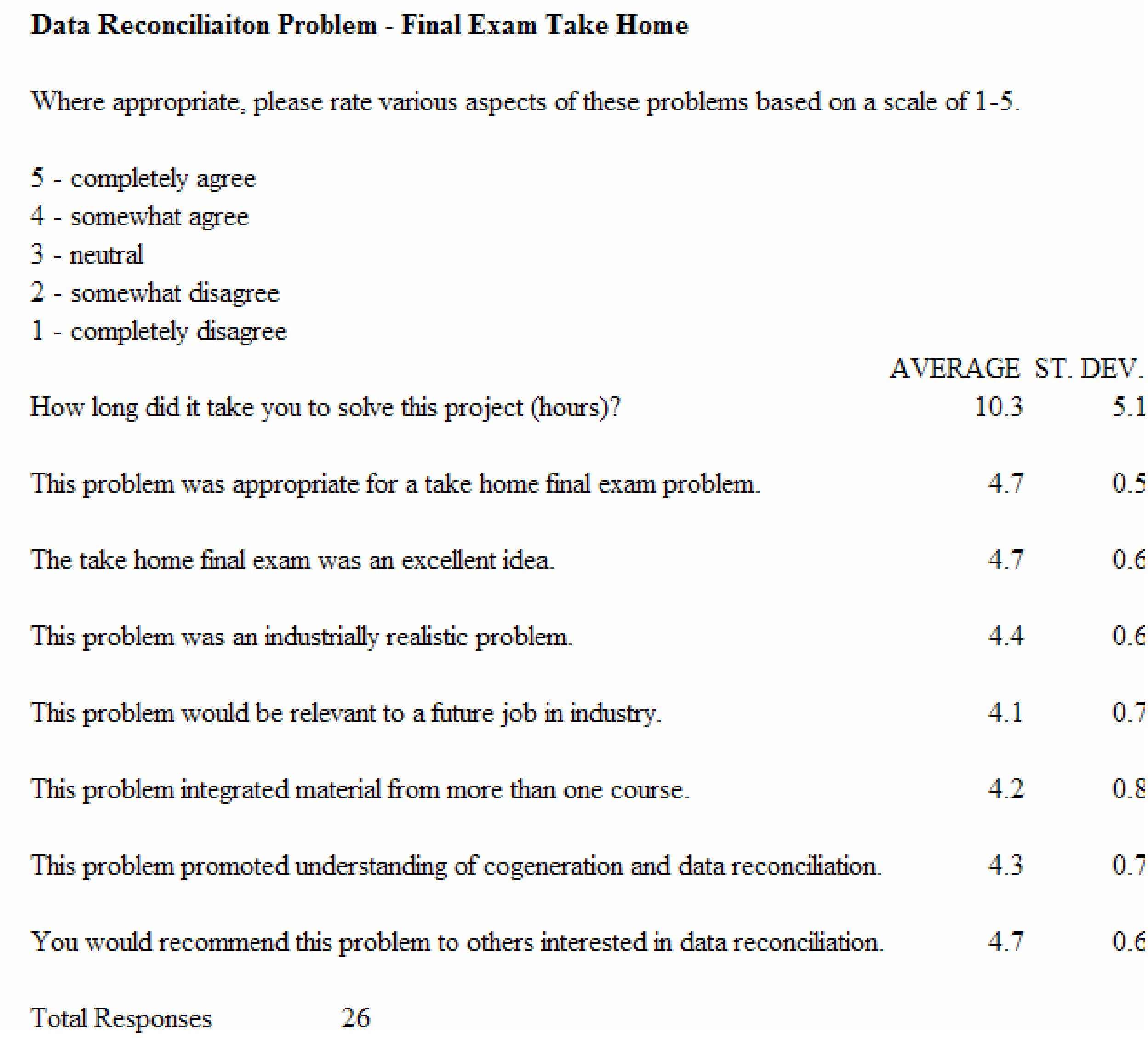
5 - completely agree
4 - somewhat agree
3 - neutral
2 - somewhat disagree
1 - completely disagree

	AVERAGE	ST. DEV.
How long did it take you to solve this project (hours)?	6.0	2.7
This problem was an industrially realistic problem.	4.1	0.7
This problem integrated material from more than one course.	4.2	0.8
This problem promoted understanding of cogeneration and optimization.	4.4	0.8
You would recommend this problem to others interested in optimization.	3.9	1.0
A comparison between the ideal gas assumption in this problem and a real gas solution is important.	4.1	0.9

Total Responses	24

Figure A-6: Evaluation Responses

APPENDIX B
DATA RECONCILIATION EDUCATIONAL MODULE



Data Reconciliaiton Problem - Final Exam Take Home

Where appropriate, please rate various aspects of these problems based on a scale of 1-5.

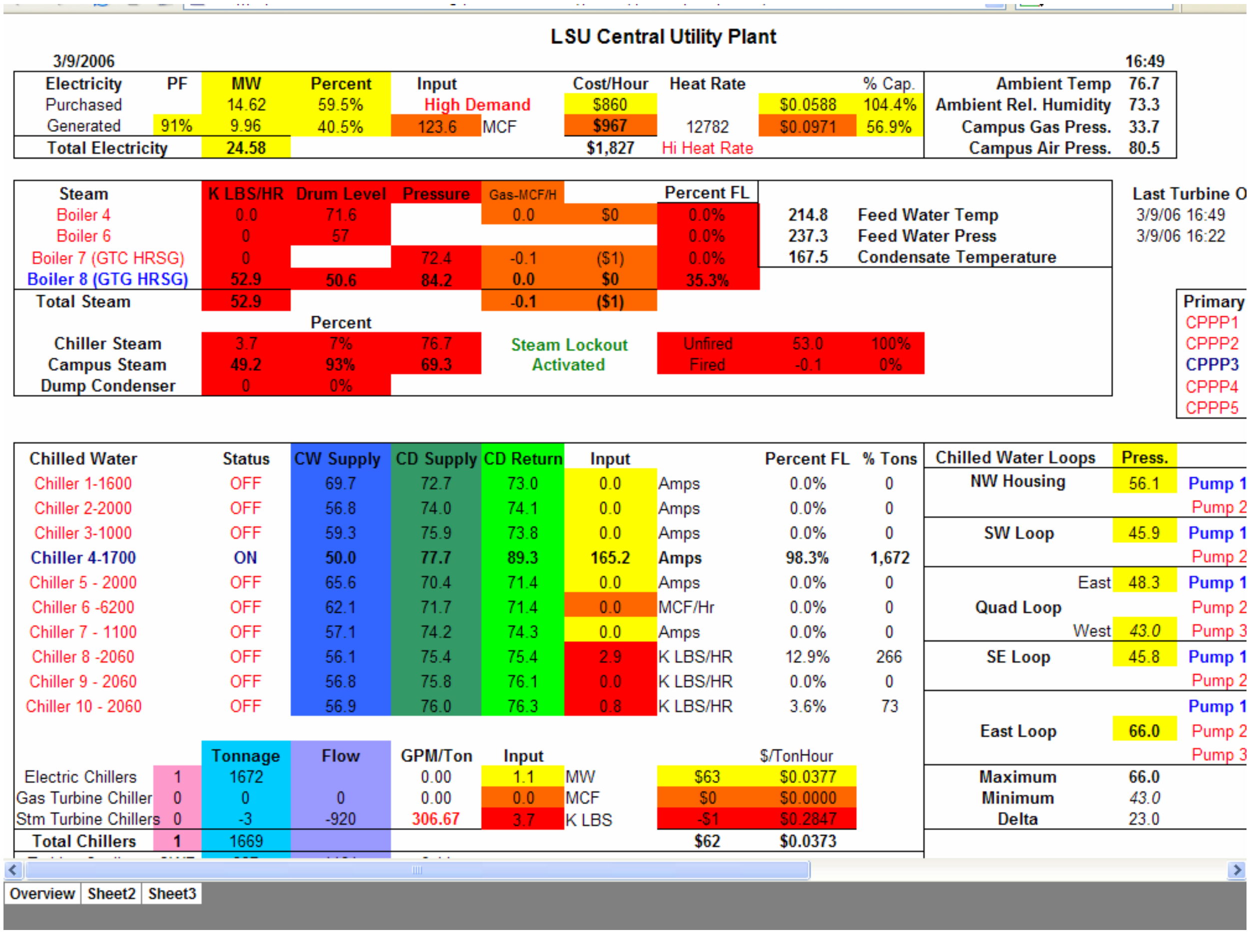
5 - completely agree
4 - somewhat agree
3 - neutral
2 - somewhat disagree
1 - completely disagree

	AVERAGE	ST. DEV.
How long did it take you to solve this project (hours)?	10.3	5.1
This problem was appropriate for a take home final exam problem.	4.7	0.5
The take home final exam was an excellent idea.	4.7	0.6
This problem was an industrially realistic problem.	4.4	0.6
This problem would be relevant to a future job in industry.	4.1	0.7
This problem integrated material from more than one course.	4.2	0.8
This problem promoted understanding of cogeneration and data reconciliation.	4.3	0.7
You would recommend this problem to others interested in data reconciliation.	4.7	0.6

Total Responses 26

Figure B-1: Evaluation Responses

APPENDIX C
EQUIPMENT PERFORMANCE



LSU Central Utility Plant

3/9/2006 16:49

Electricity	PF	MW	Percent	Input		Cost/Hour	Heat Rate		% Cap.
Purchased		14.62	59.5%	High Demand		$860		$0.0588	104.4%
Generated	91%	9.96	40.5%	123.6	MCF	$967	12782	$0.0971	56.9%
Total Electricity		24.58				$1,827	Hi Heat Rate		

Ambient Temp	76.7
Ambient Rel. Humidity	73.3
Campus Gas Press.	33.7
Campus Air Press.	80.5

Steam	K LBS/HR	Drum Level	Pressure	Gas-MCF/H		Percent FL
Boiler 4	0.0	71.6		0.0	$0	0.0%
Boiler 6	0	57				0.0%
Boiler 7 (GTC HRSG)	0		72.4	-0.1	($1)	0.0%
Boiler 8 (GTG HRSG)	52.9	50.6	84.2	0.0	$0	35.3%
Total Steam	52.9			-0.1	($1)	

214.8	Feed Water Temp
237.3	Feed Water Press
167.5	Condensate Temperature

Last Turbine O
3/9/06 16:49
3/9/06 16:22

		Percent					
Chiller Steam	3.7	7%	76.7	Steam Lockout	Unfired	53.0	100%
Campus Steam	49.2	93%	69.3	Activated	Fired	-0.1	0%
Dump Condenser	0	0%					

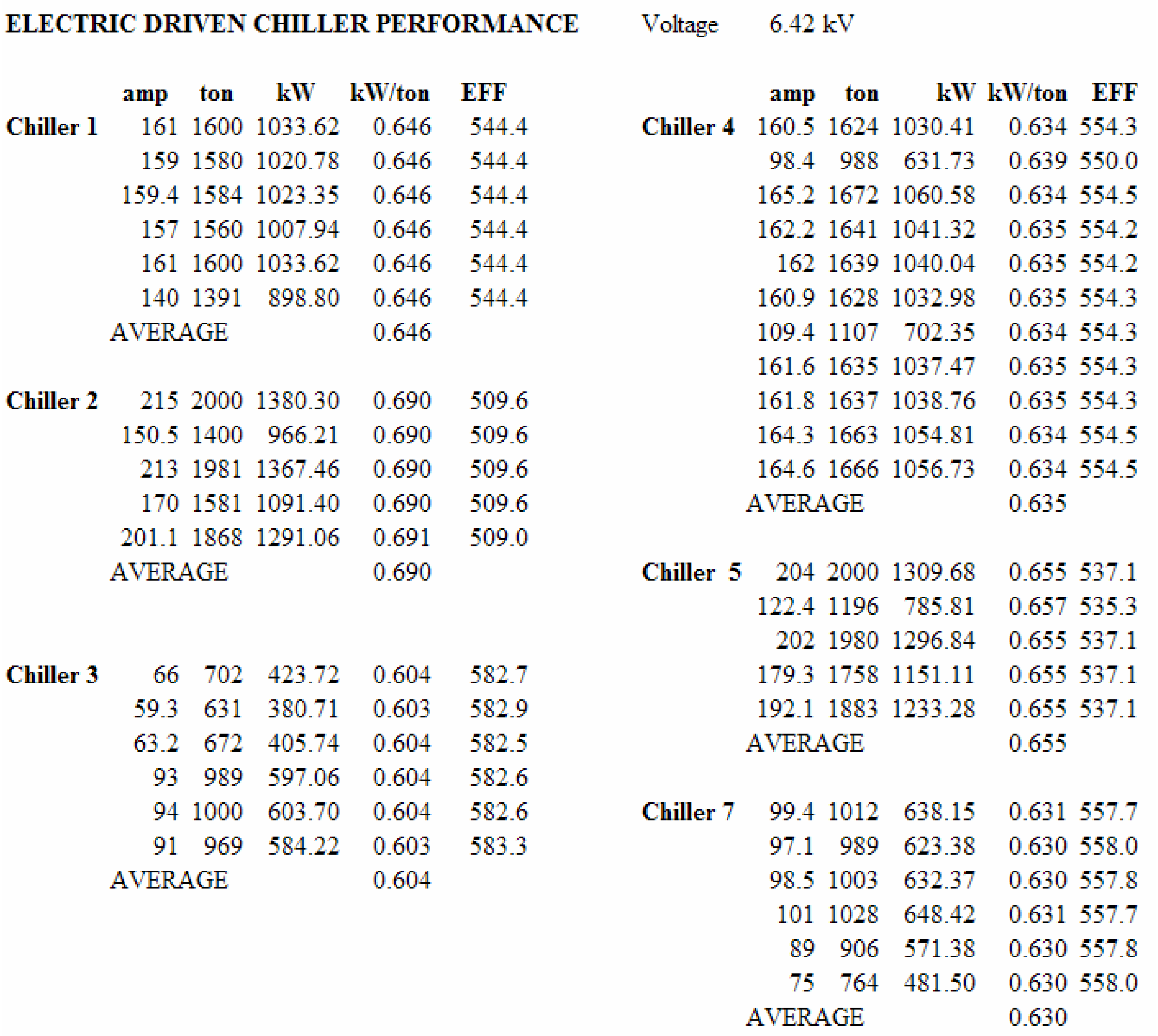
Primary
CPPP1
CPPP2
CPPP3
CPPP4
CPPP5

Chilled Water	Status	CW Supply	CD Supply	CD Return	Input		Percent FL	% Tons
Chiller 1-1600	OFF	69.7	72.7	73.0	0.0	Amps	0.0%	0
Chiller 2-2000	OFF	56.8	74.0	74.1	0.0	Amps	0.0%	0
Chiller 3-1000	OFF	59.3	75.9	73.8	0.0	Amps	0.0%	0
Chiller 4-1700	ON	50.0	77.7	89.3	165.2	Amps	98.3%	1,672
Chiller 5 - 2000	OFF	65.6	70.4	71.4	0.0	Amps	0.0%	0
Chiller 6 -6200	OFF	62.1	71.7	71.4	0.0	MCF/Hr	0.0%	0
Chiller 7 - 1100	OFF	57.1	74.2	74.3	0.0	Amps	0.0%	0
Chiller 8 -2060	OFF	56.1	75.4	75.4	2.9	K LBS/HR	12.9%	266
Chiller 9 - 2060	OFF	56.8	75.8	76.1	0.0	K LBS/HR	0.0%	0
Chiller 10 - 2060	OFF	56.9	76.0	76.3	0.8	K LBS/HR	3.6%	73

		Tonnage	Flow	GPM/Ton	Input			$/TonHour
Electric Chillers	1	1672		0.00	1.1	MW	$63	$0.0377
Gas Turbine Chiller	0	0	0	0.00	0.0	MCF	$0	$0.0000
Stm Turbine Chillers	0	-3	-920	306.67	3.7	K LBS	-$1	$0.2847
Total Chillers	1	1669					$62	$0.0373

Chilled Water Loops		Press.	
NW Housing		56.1	Pump 1
			Pump 2
SW Loop		45.9	Pump 1
			Pump 2
	East	48.3	Pump 1
Quad Loop			Pump 2
	West	43.0	Pump 3
SE Loop		45.8	Pump 1
			Pump 2
			Pump 1
East Loop		66.0	Pump 2
			Pump 3
Maximum		66.0	
Minimum		43.0	
Delta		23.0	

Figure C-1: Data Collection Screen

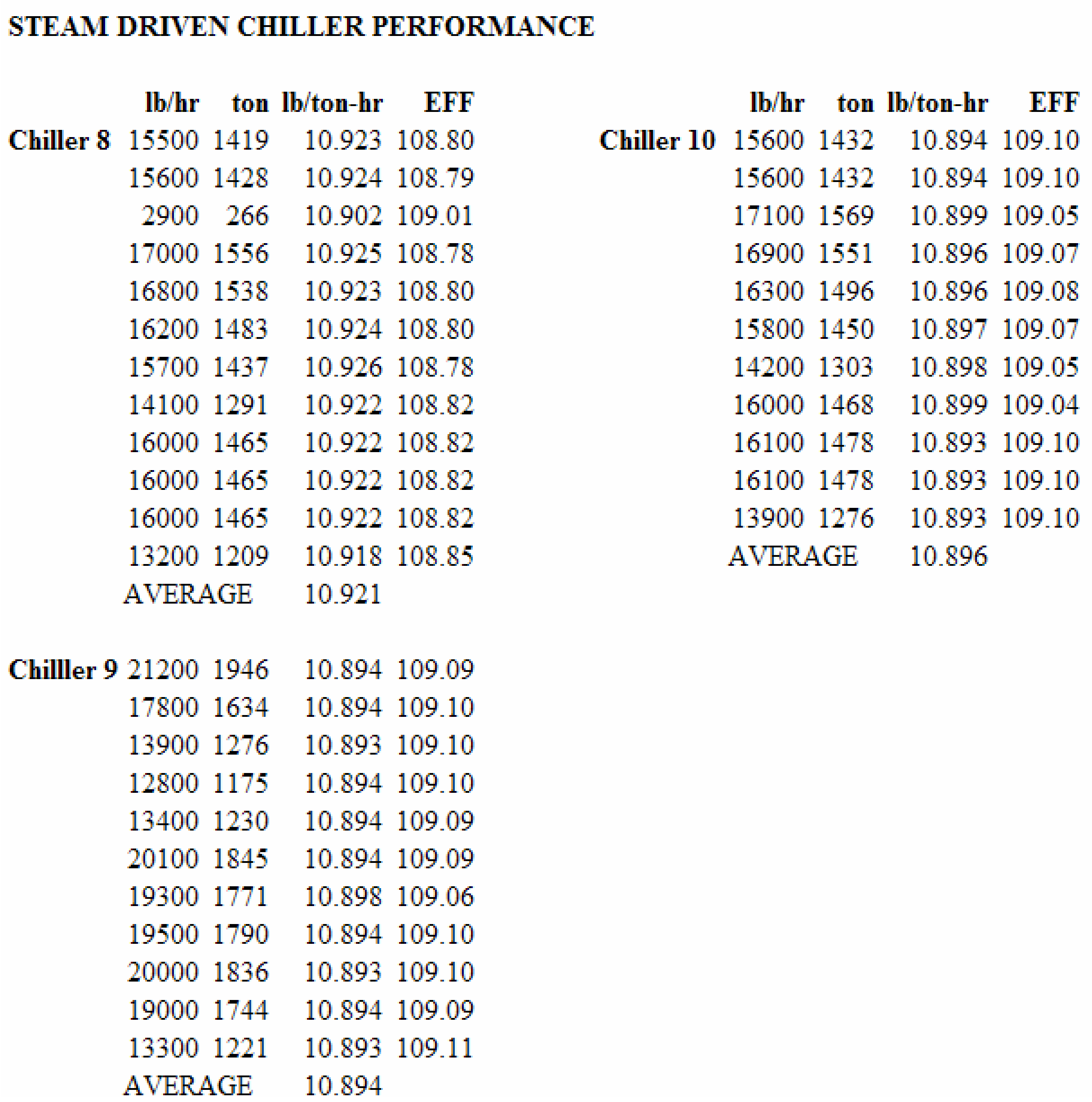


ELECTRIC DRIVEN CHILLER PERFORMANCE Voltage 6.42 kV

	amp	ton	kW	kW/ton	EFF
Chiller 1	161	1600	1033.62	0.646	544.4
	159	1580	1020.78	0.646	544.4
	159.4	1584	1023.35	0.646	544.4
	157	1560	1007.94	0.646	544.4
	161	1600	1033.62	0.646	544.4
	140	1391	898.80	0.646	544.4
	AVERAGE			0.646	
Chiller 2	215	2000	1380.30	0.690	509.6
	150.5	1400	966.21	0.690	509.6
	213	1981	1367.46	0.690	509.6
	170	1581	1091.40	0.690	509.6
	201.1	1868	1291.06	0.691	509.0
	AVERAGE			0.690	
Chiller 3	66	702	423.72	0.604	582.7
	59.3	631	380.71	0.603	582.9
	63.2	672	405.74	0.604	582.5
	93	989	597.06	0.604	582.6
	94	1000	603.70	0.604	582.6
	91	969	584.22	0.603	583.3
	AVERAGE			0.604	

	amp	ton	kW	kW/ton	EFF
Chiller 4	160.5	1624	1030.41	0.634	554.3
	98.4	988	631.73	0.639	550.0
	165.2	1672	1060.58	0.634	554.5
	162.2	1641	1041.32	0.635	554.2
	162	1639	1040.04	0.635	554.2
	160.9	1628	1032.98	0.635	554.3
	109.4	1107	702.35	0.634	554.3
	161.6	1635	1037.47	0.635	554.3
	161.8	1637	1038.76	0.635	554.3
	164.3	1663	1054.81	0.634	554.5
	164.6	1666	1056.73	0.634	554.5
	AVERAGE			0.635	
Chiller 5	204	2000	1309.68	0.655	537.1
	122.4	1196	785.81	0.657	535.3
	202	1980	1296.84	0.655	537.1
	179.3	1758	1151.11	0.655	537.1
	192.1	1883	1233.28	0.655	537.1
	AVERAGE			0.655	
Chiller 7	99.4	1012	638.15	0.631	557.7
	97.1	989	623.38	0.630	558.0
	98.5	1003	632.37	0.630	557.8
	101	1028	648.42	0.631	557.7
	89	906	571.38	0.630	557.8
	75	764	481.50	0.630	558.0
	AVERAGE			0.630	

Figure C-2: Electric Driven Chiller Performance

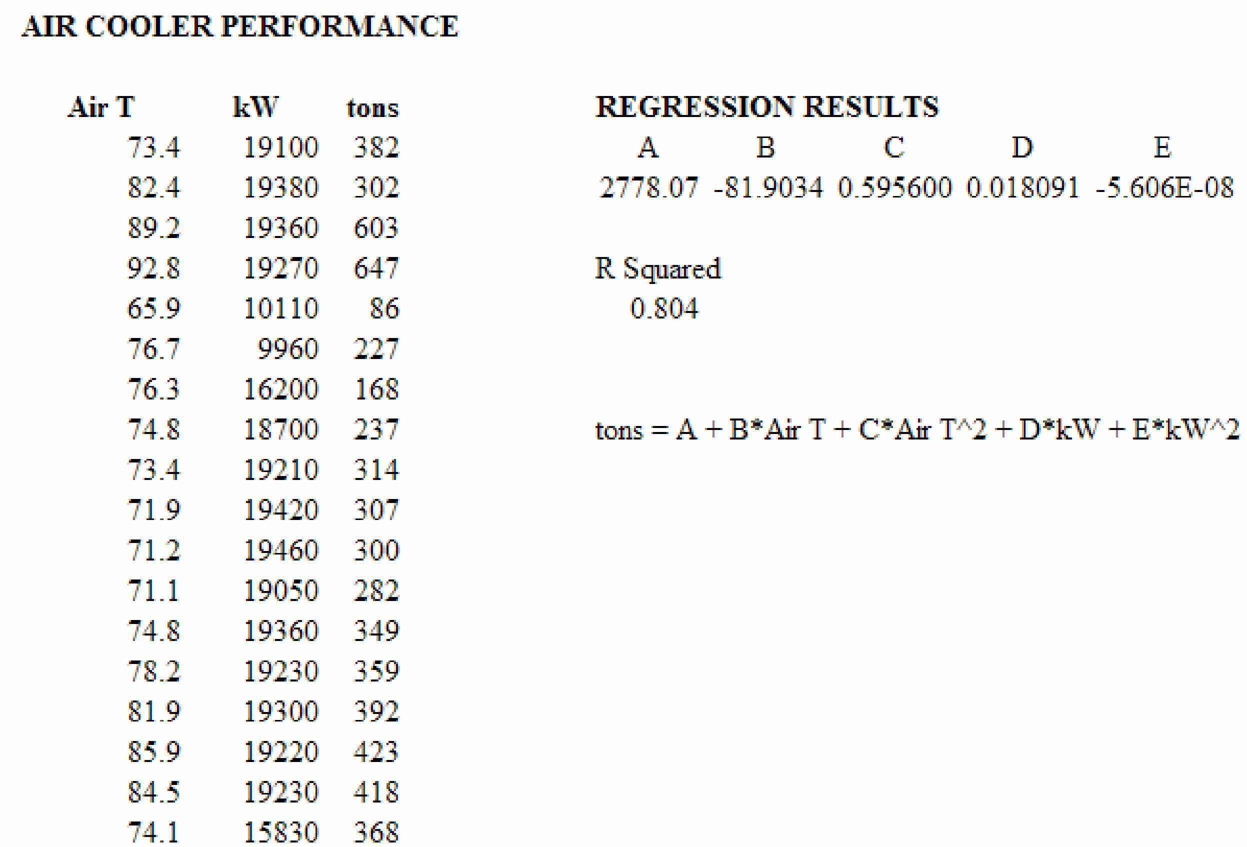


STEAM DRIVEN CHILLER PERFORMANCE

	lb/hr	ton	lb/ton-hr	EFF
Chiller 8	15500	1419	10.923	108.80
	15600	1428	10.924	108.79
	2900	266	10.902	109.01
	17000	1556	10.925	108.78
	16800	1538	10.923	108.80
	16200	1483	10.924	108.80
	15700	1437	10.926	108.78
	14100	1291	10.922	108.82
	16000	1465	10.922	108.82
	16000	1465	10.922	108.82
	16000	1465	10.922	108.82
	13200	1209	10.918	108.85
	AVERAGE		10.921	
Chillller 9	21200	1946	10.894	109.09
	17800	1634	10.894	109.10
	13900	1276	10.893	109.10
	12800	1175	10.894	109.10
	13400	1230	10.894	109.09
	20100	1845	10.894	109.09
	19300	1771	10.898	109.06
	19500	1790	10.894	109.10
	20000	1836	10.893	109.10
	19000	1744	10.894	109.09
	13300	1221	10.893	109.11
	AVERAGE		10.894	

	lb/hr	ton	lb/ton-hr	EFF
Chiller 10	15600	1432	10.894	109.10
	15600	1432	10.894	109.10
	17100	1569	10.899	109.05
	16900	1551	10.896	109.07
	16300	1496	10.896	109.08
	15800	1450	10.897	109.07
	14200	1303	10.898	109.05
	16000	1468	10.899	109.04
	16100	1478	10.893	109.10
	16100	1478	10.893	109.10
	13900	1276	10.893	109.10
	AVERAGE		10.896	

Figure C-3: Steam Driven Chiller Performance



AIR COOLER PERFORMANCE

Air T	kW	tons
73.4	19100	382
82.4	19380	302
89.2	19360	603
92.8	19270	647
65.9	10110	86
76.7	9960	227
76.3	16200	168
74.8	18700	237
73.4	19210	314
71.9	19420	307
71.2	19460	300
71.1	19050	282
74.8	19360	349
78.2	19230	359
81.9	19300	392
85.9	19220	423
84.5	19230	418
74.1	15830	368

REGRESSION RESULTS

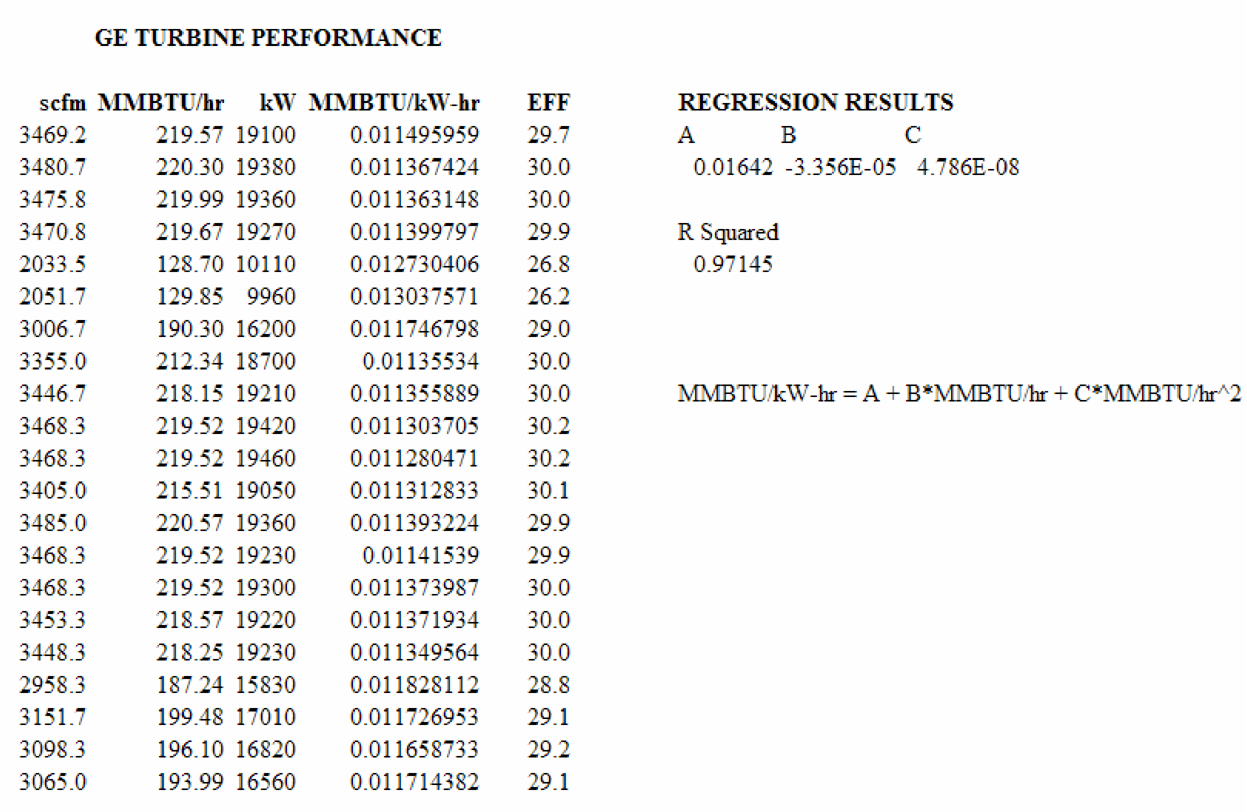
A	B	C	D	E
2778.07	-81.9034	0.595600	0.018091	-5.606E-08

R Squared

0.804

tons = A + B*Air T + C*Air T^2 + D*kW + E*kW^2

Figure C-4: Air Cooler Performance



GE TURBINE PERFORMANCE

scfm	MMBTU/hr	kW	MMBTU/kW-hr	EFF
3469.2	219.57	19100	0.011495959	29.7
3480.7	220.30	19380	0.011367424	30.0
3475.8	219.99	19360	0.011363148	30.0
3470.8	219.67	19270	0.011399797	29.9
2033.5	128.70	10110	0.012730406	26.8
2051.7	129.85	9960	0.013037571	26.2
3006.7	190.30	16200	0.011746798	29.0
3355.0	212.34	18700	0.01135534	30.0
3446.7	218.15	19210	0.011355889	30.0
3468.3	219.52	19420	0.011303705	30.2
3468.3	219.52	19460	0.011280471	30.2
3405.0	215.51	19050	0.011312833	30.1
3485.0	220.57	19360	0.011393224	29.9
3468.3	219.52	19230	0.01141539	29.9
3468.3	219.52	19300	0.011373987	30.0
3453.3	218.57	19220	0.011371934	30.0
3448.3	218.25	19230	0.011349564	30.0
2958.3	187.24	15830	0.011828112	28.8
3151.7	199.48	17010	0.011726953	29.1
3098.3	196.10	16820	0.011658733	29.2
3065.0	193.99	16560	0.011714382	29.1

REGRESSION RESULTS

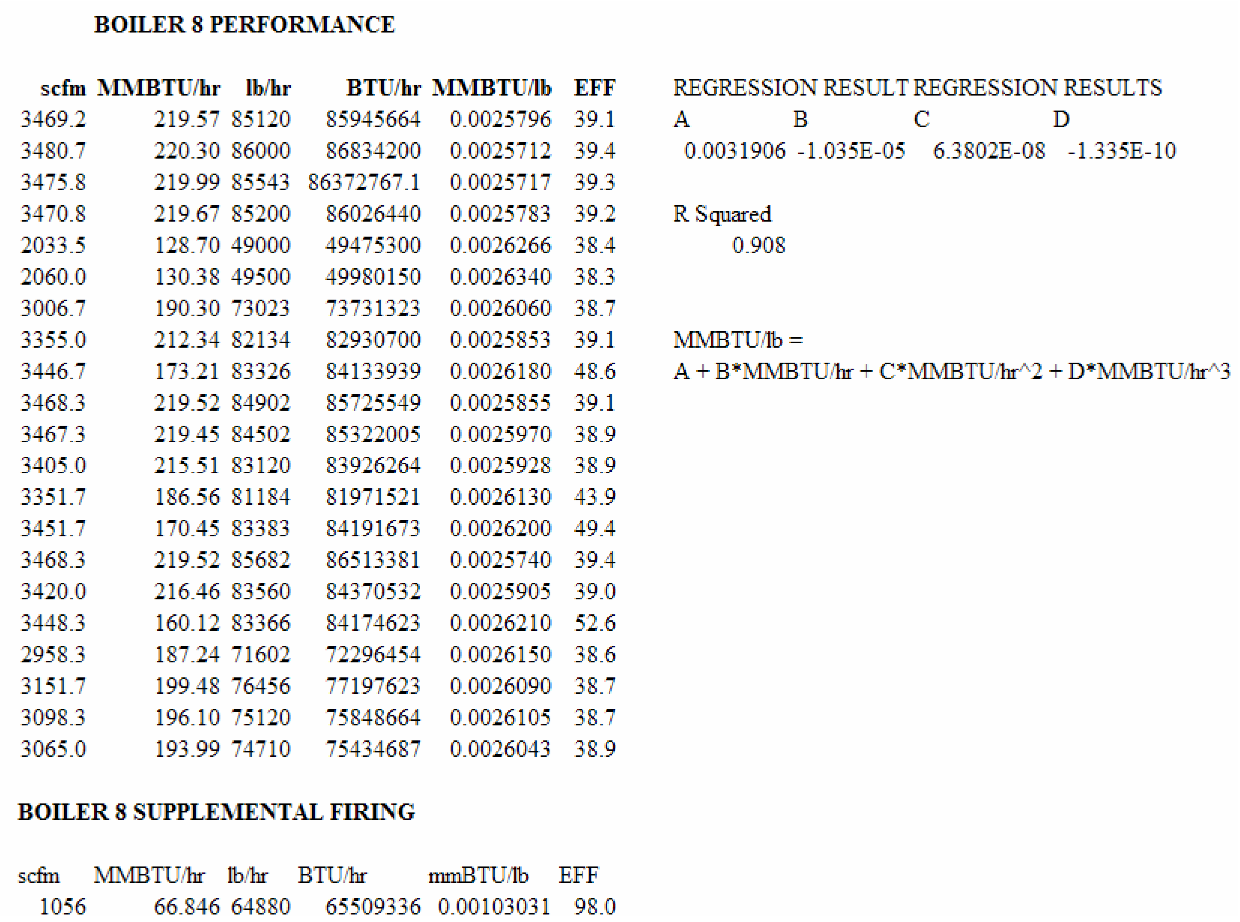
A	B	C
0.01642	-3.356E-05	4.786E-08

R Squared

0.97145

MMBTU/kW-hr = A + B*MMBTU/hr + C*MMBTU/hr^2

Figure C-5: GE Turbine Performance



BOILER 8 PERFORMANCE

scfm	MMBTU/hr	lb/hr	BTU/hr	MMBTU/lb	EFF
3469.2	219.57	85120	85945664	0.0025796	39.1
3480.7	220.30	86000	86834200	0.0025712	39.4
3475.8	219.99	85543	86372767.1	0.0025717	39.3
3470.8	219.67	85200	86026440	0.0025783	39.2
2033.5	128.70	49000	49475300	0.0026266	38.4
2060.0	130.38	49500	49980150	0.0026340	38.3
3006.7	190.30	73023	73731323	0.0026060	38.7
3355.0	212.34	82134	82930700	0.0025853	39.1
3446.7	173.21	83326	84133939	0.0026180	48.6
3468.3	219.52	84902	85725549	0.0025855	39.1
3467.3	219.45	84502	85322005	0.0025970	38.9
3405.0	215.51	83120	83926264	0.0025928	38.9
3351.7	186.56	81184	81971521	0.0026130	43.9
3451.7	170.45	83383	84191673	0.0026200	49.4
3468.3	219.52	85682	86513381	0.0025740	39.4
3420.0	216.46	83560	84370532	0.0025905	39.0
3448.3	160.12	83366	84174623	0.0026210	52.6
2958.3	187.24	71602	72296454	0.0026150	38.6
3151.7	199.48	76456	77197623	0.0026090	38.7
3098.3	196.10	75120	75848664	0.0026105	38.7
3065.0	193.99	74710	75434687	0.0026043	38.9

REGRESSION RESULT REGRESSION RESULTS

A	B	C	D
0.0031906	-1.035E-05	6.3802E-08	-1.335E-10

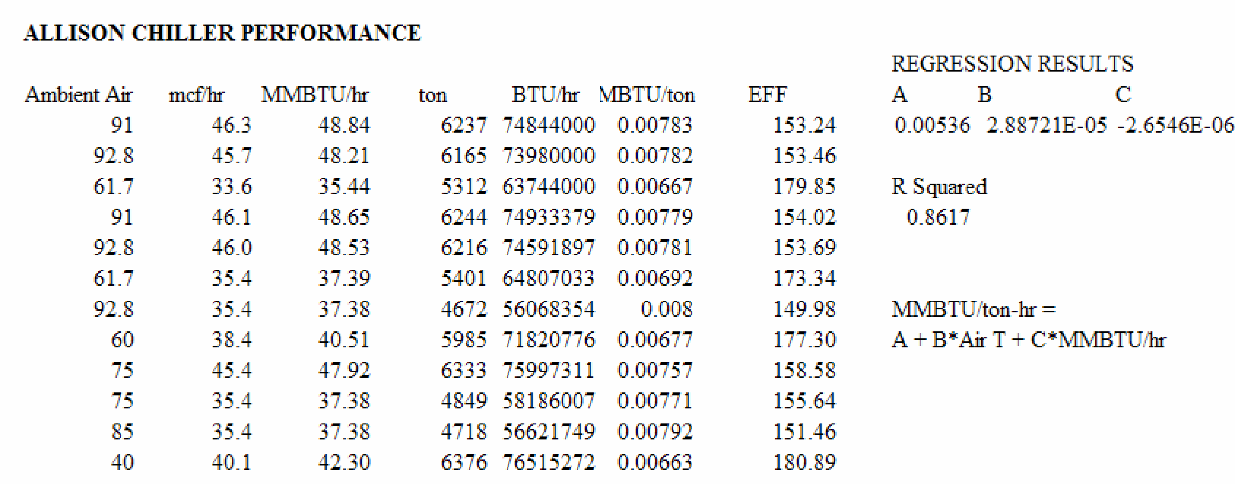
R Squared
0.908

MMBTU/lb =
A + B*MMBTU/hr + C*MMBTU/hr^2 + D*MMBTU/hr^3

BOILER 8 SUPPLEMENTAL FIRING

scfm	MMBTU/hr	lb/hr	BTU/hr	mmBTU/lb	EFF
1056	66.846	64880	65509336	0.00103031	98.0

Figure C-6: Boiler 8 Performance



ALLISON CHILLER PERFORMANCE

Ambient Air	mcf/hr	MMBTU/hr	ton	BTU/hr	MBTU/ton	EFF
91	46.3	48.84	6237	74844000	0.00783	153.24
92.8	45.7	48.21	6165	73980000	0.00782	153.46
61.7	33.6	35.44	5312	63744000	0.00667	179.85
91	46.1	48.65	6244	74933379	0.00779	154.02
92.8	46.0	48.53	6216	74591897	0.00781	153.69
61.7	35.4	37.39	5401	64807033	0.00692	173.34
92.8	35.4	37.38	4672	56068354	0.008	149.98
60	38.4	40.51	5985	71820776	0.00677	177.30
75	45.4	47.92	6333	75997311	0.00757	158.58
75	35.4	37.38	4849	58186007	0.00771	155.64
85	35.4	37.38	4718	56621749	0.00792	151.46
40	40.1	42.30	6376	76515272	0.00663	180.89

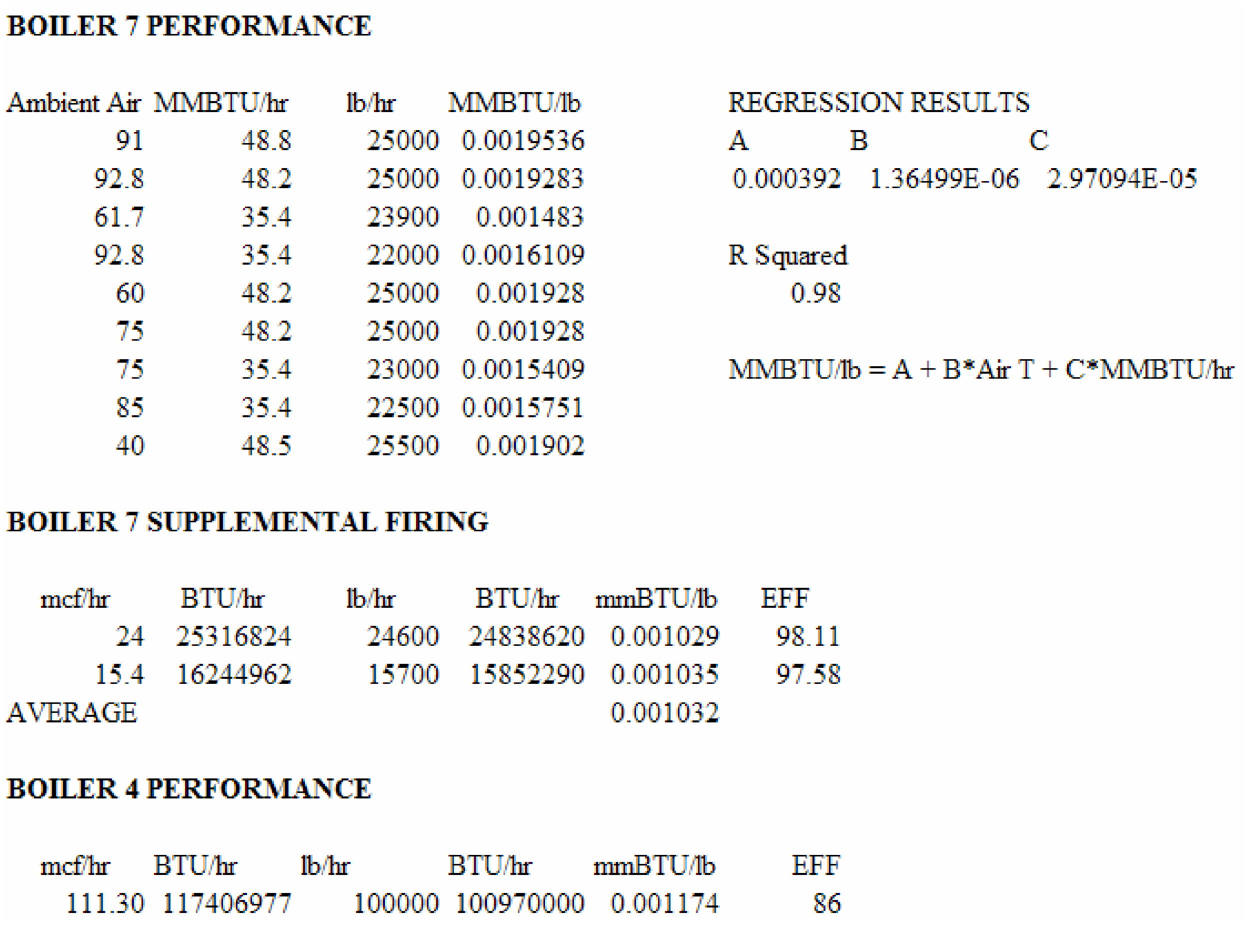
REGRESSION RESULTS

A	B	C
0.00536	2.88721E-05	-2.6546E-06

R Squared
0.8617

MMBTU/ton-hr =
A + B*Air T + C*MMBTU/hr

Figure C-7: Allison Chiller Performance



BOILER 7 PERFORMANCE

Ambient Air	MMBTU/hr	lb/hr	MMBTU/lb
91	48.8	25000	0.0019536
92.8	48.2	25000	0.0019283
61.7	35.4	23900	0.001483
92.8	35.4	22000	0.0016109
60	48.2	25000	0.001928
75	48.2	25000	0.001928
75	35.4	23000	0.0015409
85	35.4	22500	0.0015751
40	48.5	25500	0.001902

REGRESSION RESULTS

A	B	C
0.000392	1.36499E-06	2.97094E-05

R Squared
0.98

MMBTU/lb = A + B*Air T + C*MMBTU/hr

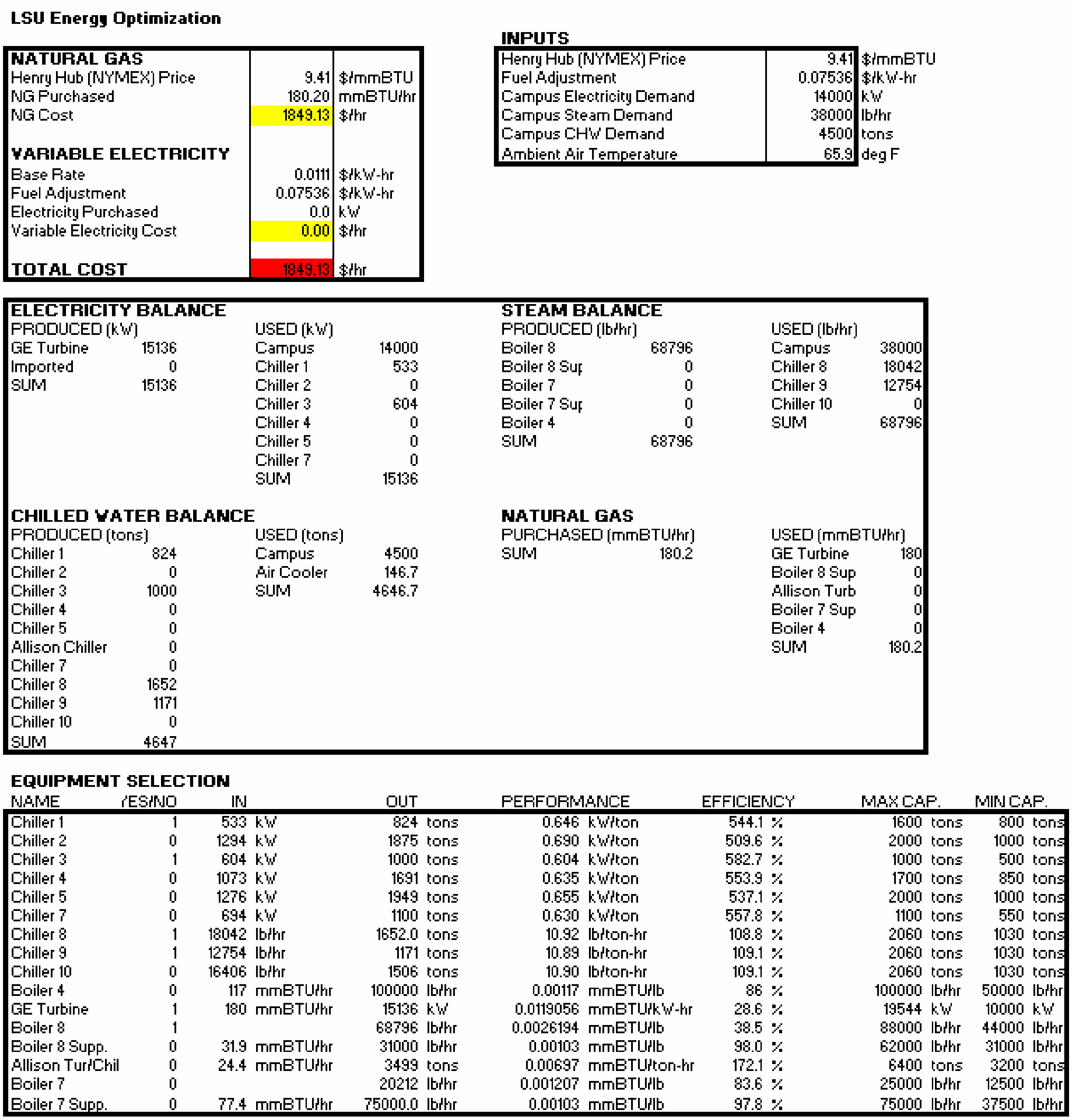
BOILER 7 SUPPLEMENTAL FIRING

	mcf/hr	BTU/hr	lb/hr	BTU/hr	mmBTU/lb	EFF
	24	25316824	24600	24838620	0.001029	98.11
	15.4	16244962	15700	15852290	0.001035	97.58
AVERAGE					0.001032	

BOILER 4 PERFORMANCE

mcf/hr	BTU/hr	lb/hr	BTU/hr	mmBTU/lb	EFF
111.30	117406977	100000	100970000	0.001174	86

Figure C-8: Boiler 7 and Boiler 4 Performance



LSU Energy Optimization

NATURAL GAS		
Henry Hub (NYMEX) Price	9.41	$/mmBTU
NG Purchased	180.20	mmBTU/hr
NG Cost	1849.13	$/hr
VARIABLE ELECTRICITY		
Base Rate	0.0111	$/kW-hr
Fuel Adjustment	0.07536	$/kW-hr
Electricity Purchased	0.0	kW
Variable Electricity Cost	0.00	$/hr
TOTAL COST	1849.13	$/hr

INPUTS

Henry Hub (NYMEX) Price	9.41	$/mmBTU
Fuel Adjustment	0.07536	$/kW-hr
Campus Electricity Demand	14000	kW
Campus Steam Demand	38000	lb/hr
Campus CHW Demand	4500	tons
Ambient Air Temperature	65.9	deg F

ELECTRICITY BALANCE

PRODUCED (kW)		USED (kW)	
GE Turbine	15136	Campus	14000
Imported	0	Chiller 1	533
SUM	15136	Chiller 2	0
		Chiller 3	604
		Chiller 4	0
		Chiller 5	0
		Chiller 7	0
		SUM	15136

STEAM BALANCE

PRODUCED (lb/hr)		USED (lb/hr)	
Boiler 8	68796	Campus	38000
Boiler 8 Sup	0	Chiller 8	18042
Boiler 7	0	Chiller 9	12754
Boiler 7 Sup	0	Chiller 10	0
Boiler 4	0	SUM	68796
SUM	68796		

CHILLED WATER BALANCE

PRODUCED (tons)		USED (tons)	
Chiller 1	824	Campus	4500
Chiller 2	0	Air Cooler	146.7
Chiller 3	1000	SUM	4646.7
Chiller 4	0		
Chiller 5	0		
Allison Chiller	0		
Chiller 7	0		
Chiller 8	1652		
Chiller 9	1171		
Chiller 10	0		
SUM	4647		

NATURAL GAS

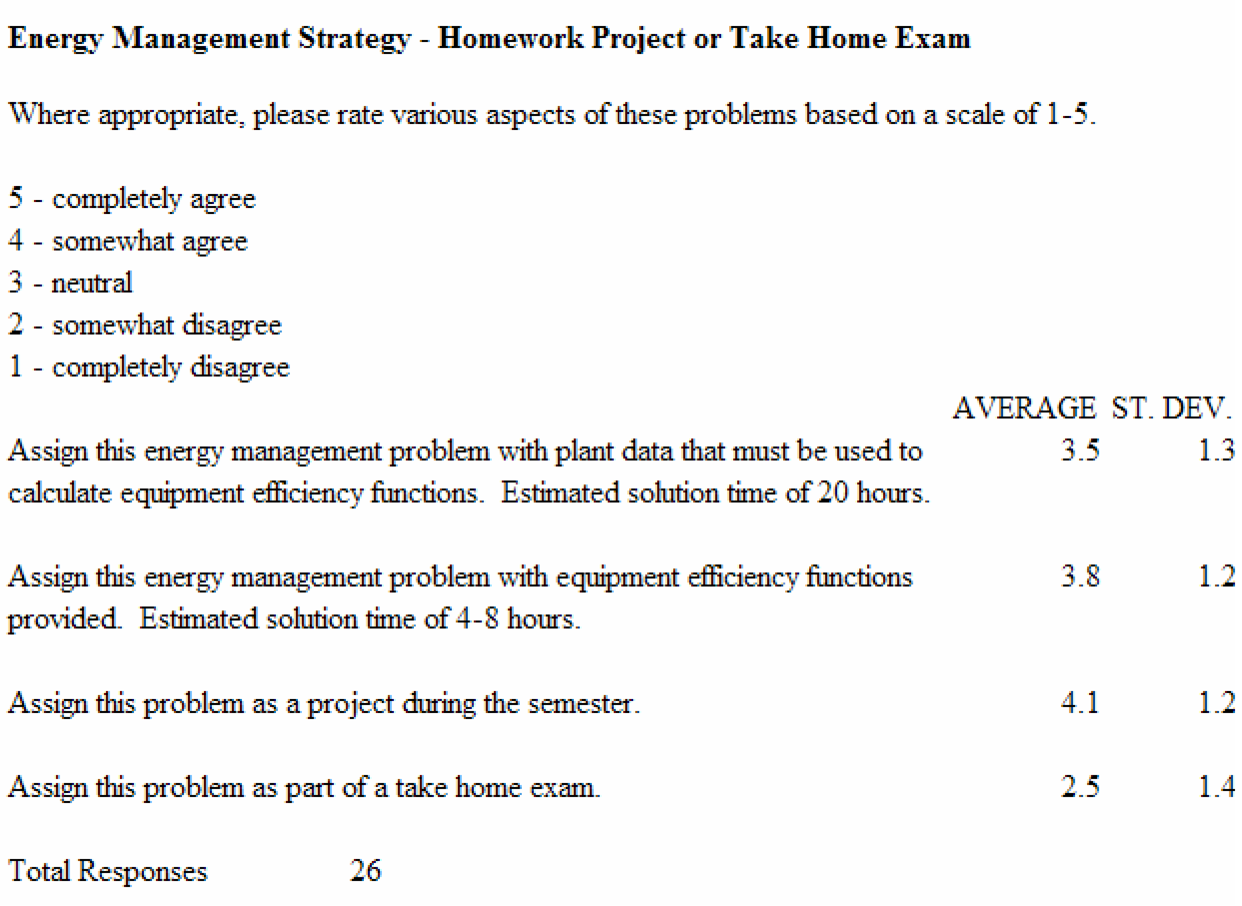
PURCHASED (mmBTU/hr)		USED (mmBTU/hr)	
SUM	180.2	GE Turbine	180
		Boiler 8 Sup	0
		Allison Turb	0
		Boiler 7 Sup	0
		Boiler 4	0
		SUM	180.2

EQUIPMENT SELECTION

NAME	YES/NO	IN		OUT		PERFORMANCE		EFFICIENCY		MAX CAP.		MIN CAP.	
Chiller 1	1	533	kW	824	tons	0.646	kW/ton	544.1	%	1600	tons	800	tons
Chiller 2	0	1294	kW	1875	tons	0.690	kW/ton	509.6	%	2000	tons	1000	tons
Chiller 3	1	604	kW	1000	tons	0.604	kW/ton	582.7	%	1000	tons	500	tons
Chiller 4	0	1073	kW	1691	tons	0.635	kW/ton	553.9	%	1700	tons	850	tons
Chiller 5	0	1276	kW	1949	tons	0.655	kW/ton	537.1	%	2000	tons	1000	tons
Chiller 7	0	694	kW	1100	tons	0.630	kW/ton	557.8	%	1100	tons	550	tons
Chiller 8	1	18042	lb/hr	1652.0	tons	10.92	lb/ton-hr	108.8	%	2060	tons	1030	tons
Chiller 9	1	12754	lb/hr	1171	tons	10.89	lb/ton-hr	109.1	%	2060	tons	1030	tons
Chiller 10	0	16406	lb/hr	1506	tons	10.90	lb/ton-hr	109.1	%	2060	tons	1030	tons
Boiler 4	0	117	mmBTU/hr	100000	lb/hr	0.00117	mmBTU/lb	86	%	100000	lb/hr	50000	lb/hr
GE Turbine	1	180	mmBTU/hr	15136	kW	0.0119056	mmBTU/kW-hr	28.6	%	19544	kW	10000	kW
Boiler 8	1			68796	lb/hr	0.0026194	mmBTU/lb	38.5	%	88000	lb/hr	44000	lb/hr
Boiler 8 Supp.	0	31.9	mmBTU/hr	31000	lb/hr	0.00103	mmBTU/lb	98.0	%	62000	lb/hr	31000	lb/hr
Allison Tur/Chil	0	24.4	mmBTU/hr	3499	tons	0.00697	mmBTU/ton-hr	172.1	%	6400	tons	3200	tons
Boiler 7	0			20212	lb/hr	0.001207	mmBTU/lb	83.6	%	25000	lb/hr	12500	lb/hr
Boiler 7 Supp.	0	77.4	mmBTU/hr	75000.0	lb/hr	0.00103	mmBTU/lb	97.8	%	75000	lb/hr	37500	lb/hr

Figure C-9: Optimal Operating Strategy Program

APPENDIX D
ENERGY MANAGEMENT EDUCATIONAL MODULE



Energy Management Strategy - Homework Project or Take Home Exam

Where appropriate, please rate various aspects of these problems based on a scale of 1-5.

5 - completely agree
4 - somewhat agree
3 - neutral
2 - somewhat disagree
1 - completely disagree

	AVERAGE	ST. DEV.
Assign this energy management problem with plant data that must be used to calculate equipment efficiency functions. Estimated solution time of 20 hours.	3.5	1.3
Assign this energy management problem with equipment efficiency functions provided. Estimated solution time of 4-8 hours.	3.8	1.2
Assign this problem as a project during the semester.	4.1	1.2
Assign this problem as part of a take home exam.	2.5	1.4

Total Responses 26

Figure D-1: Evaluation Results

VITA

Robert A. Buckley Jr. was born in New Orleans, Louisiana in 1982. He graduated from Holy Cross High School in New Orleans, Louisiana, in May 2000 and enrolled at Louisiana State University in August 2000. He graduated from Louisiana State University in May 2004 with degree of Bachelor of Science in Chemical Engineering. Upon graduation, he decided to pursue the degree of Master of Science in Chemical Engineering at Louisiana State University. He will graduate in 2006 and begin working for ExxonMobil in Baton Rouge after graduation.