9-19-2014

Optimizing operation of a campus energy system for economic and environmental considerations

John Imperatore III

OPTIMIZING OPERATION OF A CAMPUS ENERGY SYSTEM FOR ECONOMIC AND ENVIRONMENTAL CONSIDERATIONS

by
John Imperatore III

A Thesis

Submitted to the
Department of Environmental Engineering
College of Engineering
In partial fulfillment of the requirement
For the degree of
Master of Science in Engineering
at
Rowan University
August 24, 2014

Thesis Chair: William T. Riddell, Ph.D.

Dedication

I would like to dedicate this manuscript to my spouse Lisa Ann Imperatore, and children Alyssa, Tara, Christopher, and Tommy for their love and support each step of the way throughout this process. I would also like to dedicate this manuscript to my mother MaryAnn Hartman and husband Robert Hartman for their encouragement, love, and support, with special recognition to my mother for her endless ambition, inspiration, and pride throughout my life.

Acknowledgments

I would like to express my appreciation to Professor William T. Riddell for his unrelenting patience, many hours of tireless guidance, and continuous encouragement throughout this research.

Abstract

John Imperatore III
OPTIMIZING OPERATION OF A CAMPUS ENERGY SYSTEM FOR ECONOMIC AND ENVIRONMENTAL CONSIDERATIONS
2013/14
William T. Riddell, Ph.D.
Master of Science in Engineering

The objective of this thesis is to determine effective costs of campus utilities, optimal operation of energy conversion and production subsystems through minimization of economic and environmental costs, and to evaluate how changing electrical grid costs and sources will affect future optimal operations at a campus. Characteristic days were developed to typify campus activities and their impact on energy consumption. At current grid electricity and natural gas prices, utilization of a cogeneration unit, a form of combined heat and power plant, is less expensive than purchasing equivalent amounts of electric and gas to produce steam, as long as there is sufficient campus demand for the electricity and steam produced. Carbon dioxide emissions during cogeneration unit operation was nearly the same as purchasing equivalent amounts of electric and gas to produce steam. Simulation of economic and environmental performance of the cogeneration plant, found minor differences between least expensive and greenest operations. Analyses suggested that grid emissions will not become clean enough to merit decommissioning of cogeneration plant early. Operation of the cogeneration plant is favorable for economical and environmental considerations.

Table of Contents

Abstract	v
List of Figures	ix
List of Tables	xi
Chapter 1: Introduction and Scope	1
Chapter 2: Literature Review	5
Chapter 3: Analysis of Campus Utilities Economic and Environmental Cost	13
3.1 Overview of Campus Energy System, Circa 2007	13
3.2 Description of Overall Energy Delivery System to Campus	14
3.3 Primary Level Utilities	16
3.4 Plant Description and Primary Plant Level Equipment	17
3.5 Secondary Plant Level Equipment	21
3.6 Available Utilities	22
3.7 Campus Energy Usage	24
3.8 Energy Stream Reference Indices	26
3.9 Purchased Electricity Streams	29
3.9.1 Energy Distribution, Quantification, and Analysis	31
3.9.2 CO2 Emissions Distribution and Quantification	35
3.9.3 CO2 Quantities per Unit of Host Energy	38
3.9.3 Campus Infrastructure Changes – Circa 2009	45

Table of Contents

Chapter 4: Period of Study and Campus Energy Systems 47

4.1 Period of Study 47

4.2 Sources of Data 48

4.3 Campus Energy Systems 50

4.4 Campus Energy Consumption and Demand 55

Chapter 5: Optimization Approach and Analysis 61

5.1 Developing Characteristic Days 61

5.2 Establishing Parameters 70

5.2.1 Efficiencies of Units 70

5.2.2 Cost and Emissions for Natural Gas and Electricity 73

5.2.3 Algorithm for Analysis 80

Chapter 6: Optimized Operations 86

Chapter 7: Results and Discussion 96

7.1 Point in Time Analysis -- Economics 96

7.2 Economic Break-Even Point 100

7.3 Point in Time Analysis – Environmental Impacts 103

7.4 Environmental Break-Even Point 106

7.5 Simulations based on Characteristic Days 109

7.6 Sensitivity Analysis 114

Table of Contents

7.7 Reliability and Emergency Preparedness	125
Chapter 8: Summary and Conclusions	127
List of References	136
Appendix A: Computer Programming Code	138
Appendix B: Primary Plant Equipment Specifications	148

List of Figures

Figure	Page
Figure 3.1 Overall Central Heat and Power Plant Schematic – Circa 2007	15
Figure 3.2 Overall Campus Energy Flow Schematic	16
Figure 3.3 Identification of all Energy Streams	29
Figure 3.4 Electricity purchased by Rowan University by Energy Source	31
Figure 3.5 Supply and Demand Energy Accounting – FY07	32
Figure 3.6 Quantification of CO_2 Emissions	37
Figure 3.7 CO_2 Emissions Quantities per Unit	39
Figure 4.1 Schematic of Typical Cogeneration Unit	51
Figure 4.2 Schematic of Water-tube Boiler Economizer	55
Figure 4.3 Campus Electric Demand, kW versus Hour	56
Figure 4.4 Campus Electric Load Duration Curve	58
Figure 4.5 Campus Steam Demand	57
Figure 4.6 Campus Steam Load Duration Curve	58
Figure 5.1 Generalized Flowchart for Optimization Program	81
Figure 6.1 Campus Electric Load Duration Curve	88
Figure 6.2 Campus Electric Load Duration Curve with Stacked Energy Sources	89

List of Figures

Figure	Page
Figure 6.3 Campus Electric Load Duration Curve	90
Figure 6.4 Campus Steam Load Duration Curve	91
Figure 7.1 Decision Matrix for Plant Operation	109
Figure 7.2 Annual Cost Differences for Optimal Operation	114
Figure 7.3 Cost Differences – Overall Transition Areas	116
Figure 7.4 Cost Differences – First Transition Area	117
Figure 7.5 Cost Differences – Second Transition Area	118
Figure 7.6 Differences in annual CO_2 emissions between	119
Figure 7.7 Annual CO_2 Emissions Differences	120
Figure 7.8 Cost per Pound of CO_2 Emissions	121
Figure 7.9 Interagency Working Group Comparison	122
Figure 7.10 CO_2 Emissions Cost – – First Transition Area	123
Figure 7.11 CO_2 Emissions Cost – Second Transition	124
Area Figure 8.1 Historical and Projected Electricity Costs	134

List of Tables

Table	Page
Table 2.1 Social Cost of CO_2	6
Table 3.1 Determination of CO_2 emissions coefficients – Cogeneration Unit	42
Table 3.2 Determination of CO_2 emissions coefficients – Overall Plant	44
Table 4.1 Excerpt of Plant Steam and Electricity Production Data	49
Table 4.2 Excerpt of Quarter-Hour Interval Data	50
Table 4.3 Capacities of Cogeneration Units and Boilers	55
Table 4.4 Comparison of Plant Input Energies for FY2006	59
Table 4.5 Conversions of Plant Output Energies	60
Table 4.6 Preliminary Determinations of CO_2 Emissions Coefficients	60
Table 4.7 Final Determinations of CO_2 Emissions Coefficients	60
Table 5.1 Excerpt of Table Showing Campus Steam and Electricity Production	63
Table 5.2 Academic Characteristic Days	64
Table 5.3 Excerpt of table Showing Assigned Academic Characteristic Days	65
Table 5.4 Table of Energy Characteristic Days	67
Table 5.5 Energy Characteristic Day Model	68
Table 5.6 Simulation of Characteristic Day Model	69

List of Tables

Table	Page
Table 5.7 Coefficients – Quantities of Electricity and Steam	71
Table 5.8 Economic and Environmental Coefficients	80
Table 7.1 Summary of CO_2 Emissions and Costs	103
Table 7.2 Cost and CO_2 Emission values -- Economic	111
Table 7.3 Cost and CO_2 Emission values -- Environmental	112
Table 7.4 Optimized Economic and Environmental Costs	113
Table 8.1 Campus Electricity and Steam Usages	127
Table 8.2 Purchased Utilities and CO_2 Emissions	128
Table 8.3 Potential Reconfiguration of Characteristic Days	130

Chapter 1

Introduction and Scope

This thesis focuses on energy purchasing, conversion, and production systems situated at Rowan University, a public university located in Glassboro, New Jersey. Rowan University has a complex utility (energy) system, consisting of two cogeneration units, three boilers, and three chillers that are fueled by, and supplemented with, electrical grid, natural gas, and other utility purchases. As part the overall campus energy system, in this thesis, we refer to the cogeneration units and boilers as subsystems. A cogeneration system is a form of combined heat and power energy generation. Using the term cogeneration in a campus energy system context refers to equipment utilizing combustion of natural gas or fuel oil to produce thermal energy and electrical energy simultaneously. The objective of this thesis is to determine effective costs of campus utilities, the optimal operation of energy conversion and production subsystems through minimization of economic and environmental costs, and to evaluate how changing electrical grid costs and sources will affect future optimal operations.

The optimization of electric and thermal energy generation systems is a topic of increasing importance given recent attention placed by society on economic and environmental costs of energy use. Specifically, energies in this context refer to electricity, steam, and chilled water as utilities used in industrial, commercial and residential facilities. In general, thermal and electrical energy generation and distribution systems are complex in that multiple types and numbers of energy producing and conversion equipment are integrated into networks of devices that must work in harmony to achieve a common objective. Traditionally, the objective has been to maximize economic performance. Given finite fossil fuel resources and growing concerns with environmental impact, there has been increased emphasis on other objectives in addition to economic. This shift in thinking has led to the emergence of minimized environmental impact as a potential additional objective. A new challenge has emerged as a result: To balance both economic costs and environmental impact. In this context, optimization refers to the minimization of either economic or environmental costs, quantified by dollars or carbon emissions, respectively. The minimization of environmental costs in this thesis refers to the minimization of carbon dioxide (CO_2) emissions from generating electricity. It is well known that the emission of CO_2 from fossil fuel-burning power plants is not the only contributor to air pollution. Other contributors to air pollution from fossil fuels include carbon monoxide, nitrous oxide, sulfur dioxide, and volatile organic compounds (VOCs). Coal-fired power plants emit sulfur dioxide. Hydraulic fracturing (fracking) is a current well drilling technology that raises concerns about contamination of ground water supplies. In the case of nuclear power generation, radioactive solid waste is an additional concern. This thesis focuses on CO_2 emissions and costs associated with operation of Rowan University's campus energy system.

Chapter 1 introduces the topic of this thesis in a broad sense, and summarizes the scope of this study. Chapter 2 discusses results of previous efforts reported in the literature that are related to topics associated with this study.

Chapter 3 presents an overview of the Rowan University energy system, including a high level analysis of carbon dioxide (CO_2) emissions of the Rowan University campus during the year 2007, when this research was initiated. The high level analysis presents a review of major energy streams at Rowan University including utilities purchased, thermal and electrical energies produced, and utilization of energy on campus. Purchased utilities include electricity and natural gas delivered to Rowan University by outside utility providers. Produced thermal and electrical energies include steam and electricity generated and distributed by Rowan University. Chapter III also examines the environmental performance of Rowan University through an assessment of CO_2 emissions. The energy systems reviewed in this chapter include raw fossil and renewable utilities, electrical and thermal utilities generated on-site, and the consumption of utilities at end use levels.

Chapter 4 discusses the Rowan University campus energy system in 2009 following the implementation of two new cogeneration subsystems and decommissioning the previous cogeneration subsystem. In addition, an analysis of on-campus energy production and energy usage is presented for the study period. Sources of data utilized in this thesis are identified and critical parameters for modeling are established. An updated description of campus energy equipment is presented in this chapter.

Chapter 5 presents an approach for analytical optimization of operation of the energy system. A concept that characterizes energy demand through a full year of seasonal weather changes and a full range of campus activities is developed and presented. Parameters established for optimization analysis are discussed in this chapter. In addition, an algorithm developed for optimization is presented in this chapter.

Results from the analyses are presented in Chapter 6.

Chapter 7 presents results and discussion. In addition, Chapter VII includes a sensitivity analysis of the mathematical model developed in this thesis.

Finally, summary and conclusions can be found in Section 8. This section summarizes the key areas of focus defined in this report and identifies conclusions resulting from this study.

Chapter 2

Literature Review

This thesis discusses the optimization of a campus-based energy system comprised of two cogeneration subsystems, three steam boilers, and a chiller plant. Cogeneration systems are utilized in a variety of commercial applications involving the availability of natural gas and year-round thermal and electrical energy demands.

This chapter summarizes research that has been reported in the literature regarding the optimization of electric and thermal energy generating systems. Specifically, energy in this context refers to electricity and heat utilized in an application serving commercial and residential facilities. In this application, heat also is utilized to provide cooling through the use of steam-based absorption cooling technologies. Optimization of electric and thermal energy generating systems can take a variety of forms. This includes optimizing the performance of a single generating unit. Optimization can also refer to maximizing the overall utilization of multiple components within a large system. Optimization of energy systems in this thesis refers to assessing the performance of multiple components of an energy system from a macro approach. The macro approach refers to maximizing the performance of two cogeneration units with consideration given to the performance of three boilers and assessment of campus electric and thermal demand. This focus differs from routine tuning procedures utilized in starting up and commissioning individual equipment. This includes setup and adjustment of parameters for controllers and process pressures and temperatures, associated with micro-optimization.

The Interagency Working Group on Social Cost of Carbon[1] presented a paper that estimates the social cost of carbon. The purpose of the study was to allow agencies to incorporate the social benefits of reducing carbon dioxide emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The social cost of carbon is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change. The study updates prior efforts to monetize carbon emissions and provides tables that economically quantify the social cost of carbon in dollars per metric ton of carbon dioxide. Shown in Table 2.1 below is a social cost of carbon table that includes cost projections for years 2010 through 2050. As shown, the social cost of carbon values are presented in four different discount rate values ranging from 2.5 percent to 5.0%.

Table 2.1 – Social Cost of CO_2, in 2007 dollars per metric ton of CO_2 (adopted from reference 1)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

Linear Programming has been widely used for micro energy system optimization. Linear Programming refers to the modeling of complex systems using mathematical relationships in canonical form. Such relationships are constructed around specific objectives to be achieved as well as requirements built into the problem. Typically, linear programming problems consist of an objective function to be minimized or maximized and constraint equations. The overall objective is to determine the best outcome or set of outcomes. For example, Hori, et al[2], optimized the economic operation of a gas turbine cogeneration plant. A mathematical relationship based on the standard annual cost method defined the economics of the plant. This relationship formed the objective function which was minimized. All other formulations involved system constraints serving as the conditions of the problem. Mixed-integer linear programming was used to determine the optimal combination of equipment in the plant.

Acuri, et al.,[3], also utilized Linear Programming to optimize the operation of a trigeneration system at a hospital complex. Trigeneration is the simultaneous production of heating, cooling, and electricity in one process. The goal of the optimization was to maximize short and long term investment returns for the trigeneration system. Constraints were developed after decision variables were established. Binary variables were used to describe the on/off state of the devices. Once formulated, the mathematical model was solved using a popular mathematical software program known as LINGO. As a result, a description of an optimal plant configuration was achieved.

Another approach to optimizing energy systems, Derivation-Based Systems Modeling, incorporates the use of graphical and mathematical representations for systems analysis. For system representation, a function model, also called an activity model or process model, is developed and serves as a graphical representation of a function within a defined scope. The purposes of the function model are to describe the functions and processes, assist with discovery of information needs, help identify opportunities, and establish a basis for determining system performance as defined by management policy or objectives. For example, a cogeneration plant located in Zagreb, Croatia was optimized based on economics[4]. In this case, each energy generating and conversion device was modeled with respect to energy efficiency, energy recovery and performance. Each component model was solved according to its boundary conditions and input data. An iterative technique was used due to the nonlinear nature of several of the components. A mathematical representation was written in MS Excel Visual Basic language and solved for system optimization based on economics.

Another example of Derivation-Based Systems Modeling for energy system optimization was identified in a paper that discussed systems comprised of multiple energy carriers[5]. Geidl and Anderson take an approach that is based on the concept of 'energy hubs'. The perspective of energy hubs enables analysis of couplings and interactions between the different infrastructures. A generalized modeling and optimization framework for energy systems, involving multiple energy carriers, was developed. In cases where the objective function is concave and/or the constraints are nonlinear, numerical methods can be used, but it cannot be ensured that the global optimum solution is achieved. Similar to the standard approach for electricity systems, this method incorporates a general dispatch rule for linear energy hubs and is derived and related to the marginal cost of energy carriers.

Another approach to optimizing energy systems involves an overall improvement design concept. Giannantoni et al.[6] present a broad iterative procedure that expands the overall design concept to include economic and environmental considerations in addition to a typical engineering approach that focuses on design of existing energy conversion systems. The concept is based on 1.) a traditional engineering approach that focuses on energy conversions and 2.) the integration of environmental and economic assessment procedures to influence an already existing design. The procedure is presented as a concept that incorporates environmental and economic evaluations as feedback loops to the iterative design process. As opposed to traditional optimization methods that use complex algorithms and/or multi-objective functions, the methodology used here consists of a progressive step-by-step improvement of a preliminary solution, which can be modified according to the results of selected groups of indicators.

We now take a look at macro approaches to energy system optimization. Gamous, et al.[7] proposed a method for evaluating the economic feasibility of microturbine cogeneration systems in typical hotel settings. The method proposed involved developing and examining mathematical relationships between the optimal number of microturbine cogeneration units and the maximum energy demands under various conditions. Based on a linear programming approach, electrical generating efficiency and capital unit cost parameters were established, to understand their influence on the economic feasibility of the overall system. Relationships between optimal number of microturbine cogeneration units and the maximum energy demands were illustrated under various scenarios by this study.

Casisi, et al.[8] presented an optimization model of a distributed cogeneration system with a district heating network in an urban environment. The overall plant under review consisted of multiple natural gas-fired micro-turbines installed in six public buildings, each with a single natural gas-fired boiler, located in Pordenone, Italy. A centralized cogeneration unit is comprised of a natural gas-fired internal combustion engine coupled to an electric generator. Electricity demand not met by the generator is supplemented by grid purchases. An objective function was selected to provide an economic optimization of annual total costs, consisting of owning, operating, and maintaining the system. A mixed integer linear program was formulated and solved by commercial software working on the basis of the classical Branch and Bound algorithm approach[9] to finding optimal solutions for optimization problems. The optimization model allowed the optimal lay-out and operation of a cogeneration system to be obtained, taking into consideration technological options, year-round varying ambient conditions, fuel rates, and grid electricity rates.

Gimelli, et al.[10] presented an optimal configuration of a cogeneration system in a hospital setting, using a multi-objective approach. The study was focused at S. Paolo Hospital in Naples, Italy and was structured around goals to optimize the system through minimization of energy and economics. The study presented analyses of cogeneration applications with natural gas-fired reciprocating internal combustion engines with capacity ranges on the order of three-to-five megawatts of power. Electric and thermal loads were studied and energy characteristic weeks, broken down on daily bases, over three seasons emerged. Ten scenarios with varying combinations of cogeneration equipment type and size were evaluated using the multi-objective approach. A solution to utilize three natural gas reciprocating engines with generators in the size range of 225-240 kilowatts provided significant energy savings. It was found that this configuration produced a reasonable compromise of operational flexibility, plant simplicity, and reliability.

Yilmaz[11] presents optimization of cogeneration systems based on performance criteria that differs from traditional criteria. In this study, a reversible Carnot cycle, modified for cogeneration, with external irreversibilities, is analyzed with the aid of numerical analysis. A goal of this study was to develop better performance criteria for actual cogeneration plants. This analysis incorporates exergenic performance criteria, consistent with thermodynamic and energetic studies. One of the alternative performance criteria utilized by Yilmaz is artificial thermal efficiency. The artificial thermal efficiency plays an important role in that this study assumes a cogeneration plant configured with a steam extraction turbine. It was found that when R, a power to process heat ratio, is equal to one, R becomes a critical value. By varying the source side and consuming side temperatures, energy utilization factor and exergy efficiency values also change and affect performance.

This thesis also included research and review of literature that focused on modeling of energy demand. Ortiga, et al.[12] proposed a method for the selection of typical days of hourly energy demand for one year in a building. The selection of typical days enabled a reduction in the number of data points associated with 365 days a year. The typical days were characteristic of days that could be grouped for data simplification, yet repeatable to the extent that reasonable accuracy was preserved. In addition, an analysis of the influence of the results on an optimization model for a trigeneration system was prepared. The authors utilized a graphical method to accomplish these objectives. Specifically, cumulative energy demand curves were produced for select heating and cooling days that were repeatable. The cumulative energy demand curves had to be as close as possible to a cumulative energy demand curve for the entire year in review. The results were tested in previously-developed economic optimization programs. It was determined that this method worked well, provided that several of the selected days are tested so that a correct representation of a whole year can be verified.

Chapter 3

Analysis of Average Campus Utilities Economic and Environmental Cost

This chapter presents an overview of the Rowan University campus energy system in the fiscal year 2007. The environmental impact of all delivered utilities to campus buildings, including dormitories and apartments, fed from a central heat and power cogeneration plant during university business year FY07 is analyzed. Quantities of CO_2 emissions for each utility, ranging from raw to delivered utilities, were determined. This chapter also includes an assessment of the original cogeneration plant in terms of the environmental impact of the energy conversion processes for all equipment that was operational during business year FY07. The energy-related carbon footprint of the campus, its students including residential, and staff is determined in this chapter. Energy quantities associated with all purchased and produced utilities for FY07 are presented in this study. All energy quantities are converted to their equivalent CO_2 emission levels appropriate conversion factors. The results are displayed on campus energy stream flow diagrams developed for this purpose.

3.1 Overview of Campus Energy System, Circa 2007

Founded in 1923 and known at the time as a two-year teaching school called "Glassboro Normal School," Rowan University has experienced significant growth over time and as of July 31, 2013, serves a student population of 13,349, a third of which reside on campus[13]. Faculty and staff comprise 2,057 of the total community population of 15,406. The campus community is mainly situated on a developed parcel of land traversing an area of 203 acres. Approximately 2.5 million gross square feet of space is made up by 72 buildings, primarily comprised of academic, administrative, and residential facilities.

In 2007, Rowan University served a student population of 10,091, a third of which resided on campus[14]. Rowan University utilized a fiscal-year system as a basis for business and financial accounting systems coincident to the State of New Jersey. Within these systems, fiscal years run from July 1 to June 30. Specifically, the period of study in this chapter commences on July 1, 2006 and runs through June 30, 2007. This period is referred to as Fiscal Year 2007 and is referred to throughout this chapter as FY07.

3.2 Description of Overall Energy Delivery System to Campus

A schematic diagram of the central heat and power plant, with its relationship to the campus, is depicted below in Figure 3.1. As shown, in FY07, the original cogeneration plant was a single 1.5 MW cogeneration unit. Further, the cogeneration unit was part of an overall energy delivery system that included purchased electric, natural gas, fuel oil, and water utilities, three steam boilers, a steam-driven centrifugal chiller, and two electrically-driven centrifugal chillers. As shown, energies delivered to campus buildings were in the form of steam, electricity, and chilled water. Note this is a graphical representation of the general arrangement of the circa 2007 central heat and power plant with relative equipment sizing shown, to acquaint the reader with a general understanding of the overall concept and function. A detailed description follows.

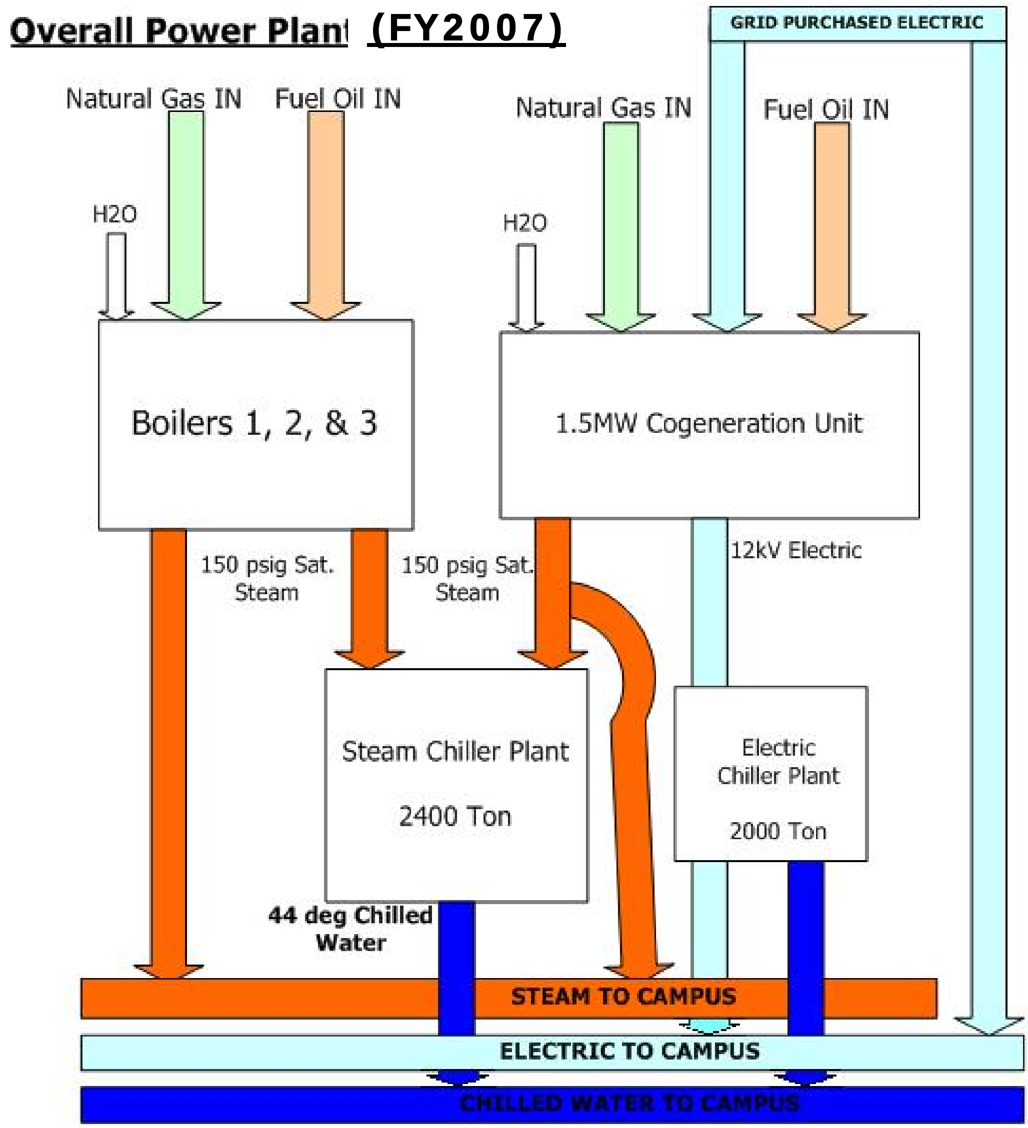

Figure 3.1 – Overall Central Heat and Power Plant Schematic Diagram – Circa 2007

The combination of natural resources, purchased energy, produced energy, coupled with distribution and usage, formed a complete system of energy delivery and consumption for the Rowan University campus. This system has been classified into five categories: Primary Level Utilities, Primary Plant Level, Secondary Plant Level, Available Utility, and Campus Use. Refer to Figure 3.2 below for detailed descriptions of these classifications.

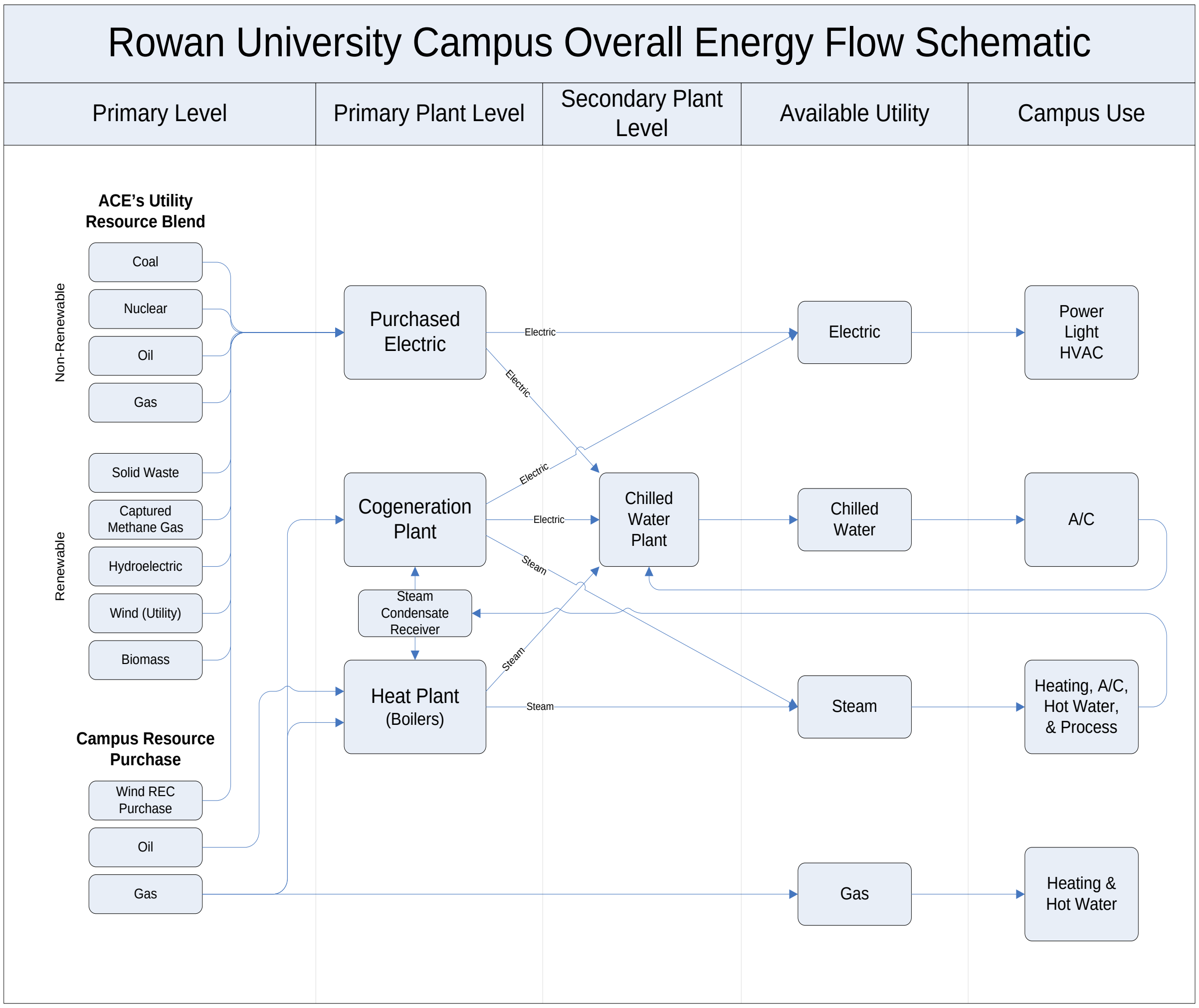

Figure 3.2 – Overall Campus Energy Flow Schematic

3.3 Primary Level Utilities

The term "primary level utilities" used in this study refers to the raw resources utilized in the generation and delivery of utilities purchased by the university. With respect to purchased electricity, a breakdown of the individual components that make up fossil and renewable generated sources and technologies has been obtained from Atlantic City Electric, the local electrical service provider. Regarding fossil fuels, Rowan University purchased electricity generated from a mixture of sources including coal, nuclear, natural gas, and oil. On the renewable portion of the mixture, technologies included solar energy, solid waste, captured methane gas, hydroelectric, wood and other biomass, and wind. In addition, the university purchased wind renewable energy certificates (w-recs) directly from a third party alternative energy generator.

Natural gas was directly purchased from Amerada Hess, a third party supplier, and delivered by South Jersey Gas, a local transportation natural gas utility. Fuel oil was purchased directly from Riggins, a local petroleum supplier.

3.4 Plant Description and Primary Plant Level Equipment

Primary plant level on-site energy generation refers to electric and heat energy generated on-site for distribution and usage by the campus. The “primary” portion of the central power plant was configured with three boilers and one combined heat and power generation unit. In 2007, a process to replace the existing 1.5 MW cogeneration unit with a 4.7 MW combined dual turbine cogeneration plant was initiated.

Two of the three boilers were manufactured by Babcock & Wilcox and were installed in 2005. The two boilers were rated each at 40,000 pounds of steam per hour. The manufacturer-supplied efficiencies of the two boilers were 83% using Natural Gas and 81% using Fuel Oil. Efficiency, in this context, refers to the ratio of energy output divided by energy input. In the case of steam, the energy output is considered to be the increase in specific energy times mass associated with converting condensate returning from campus into steam. The third boiler was installed in 1960 and was de-rated to 26,000 pounds of steam per hour in the 1970s to comply with evolving environmental regulations. The efficiency of this boiler is approximately 75% with natural gas as a fuel. The thermal energy conditions produced by the boilers were 150 pounds per square inch of saturated steam at 366° F. Saturated steam was utilized on campus for heating, air conditioning, domestic hot water, and laboratory process applications. A detailed description of the boilers is presented in chapter 4. In general, the boilers operated in standby and supplemental capacity modes. For example, if the campus steam requirements were being met by the cogeneration unit, the boilers were put in standby mode or in a state of "readiness" for supplemental or emergency demand needs. If the cogeneration unit could not meet the campus steam requirements, the boilers were put into operation in a sequence such that the most efficient boilers were brought on line first. All three boilers could operate either on natural gas or number two fuel oil. With choices of fuel input and instrumentation, plant operators could base their fuel decisions on economy, reliability, energy efficiency, or available fuel supply. In addition, this dual-fuel arrangement also permitted switching to the second fuel whenever the first fuel was curtailed for emergency reasons. This flexibility helped the university hedge sudden fuel cost increases through fuel diversity.

The cogeneration unit produced steam and electricity simultaneously. A detailed description of cogeneration operation is presented in chapter 4. Similar to the three boilers, the cogeneration unit had dual-fuel capability utilizing natural gas or fuel oil. However, during the period chosen in this chapter, only natural gas was utilized by the cogeneration unit. This was due to an ongoing malfunction of the liquid fuel delivery system.

The original cogeneration unit employed a turbine in which a fuel/air mixture was ignited in a combustion chamber resulting in an increase in gas pressure that was expanded against turbine blades. The expansion produced thrust as the resulting chemical energy was converted into mechanical energy in the form of rotary motion produced by the turbine. The turbine was mechanically coupled to an electric generator through a gearbox and electricity was produced by a stator rotating in an excitation field. The gearbox allowed the rotational speed turndown of the turbine from 22,000 revolutions per minute to 1,800 revolutions per minute, so that the three-phase generator could deliver the proper electrical energy characteristics. The electrical output of the generator was a nominal 1.2 MW and delivered a nominal voltage of 4,160 volts.

On the thermal portion of the cogeneration unit, high temperature combusted gases were exhausted from the turbine. The combusted gases were routed from the turbine to the outside of the cogeneration unit and into a two-way bypass valve. During normal operation this valve diverted all gases into a heat recovery steam generator (HRSG). The HRSG is similar to a standard water tube boiler except for the source of heat. Instead of combusting natural gas or oil, high temperature turbine exhaust gases pass over tubes containing water that is converted to steam. As with the boilers, thermal energy delivered by the cogeneration unit was 150 pounds per square inch of saturated steam. In the event that the HRSG needed to be taken out of service while the cogeneration unit remained in service, the position of the two-way bypass was changed to divert all gases to the stack, venting all turbine exhaust gases directly to the atmosphere.

The 1.2 MW cogeneration unit was manufactured by Kawasaki Motors Corporation, was first put in service in 1991, and through the HRSG delivered 9,000 pounds per hour of 150 pounds per square inch saturated steam. In addition, ductburner equipment was installed for emergency heat generation. In the event that the cogeneration unit failed and there was no other source of heat available, the ductburner unit could be put into service. The ductburner was essentially a direct-gas-fired heating unit installed in the ductwork between the turbine and the HRSG unit. During emergencies, this equipment replaced the turbine exhaust to maintain a heat source for the HRSG, and was capable of generating 21,000 pounds of steam per hour on its own. According to plant operators, the ductburner was never placed on line at any given time during FY07.

As the prime mover of the Primary Plant Level, the cogeneration unit fulfilled the lead role in supplying electricity and steam to other parts of the plant and the balance of the campus. In this configuration, electricity was purchased to meet the balance of campus demand not met by the cogeneration unit. The same went for the heat side of the cogeneration unit, as the boilers were operated as required to supplement the steam demand not met by the cogeneration unit. Electricity and steam generated by primary plant level equipment entered the secondary portion of the central heat and power plant.

3.5 Secondary Plant Level Equipment

Secondary Plant Level Equipment refers to equipment that was involved in the on-site production of chilled water for distribution and usage by the campus. The secondary portion of the central power plant was typically referred to as the central chilled water plant and was comprised of three centrifugal chillers. In keeping with the concept of fuel diversity, the chilled water plant was a true hybrid plant. The chilled water plant was powered by a combination of electricity purchased from the utility company, electricity produced by the cogeneration plant, and steam generated from the primary level plant. However, for simplicity, the flow diagrams indicate only electricity coming from the utility company and only steam from the boilers. The chilled water plant was first brought on line in April 2006.

The primary chiller, manufactured by York, was of the centrifugal type and had a refrigeration capacity of 2,400 tons. The driver of the chiller was a steam turbine fed by the cogeneration unit and boilers as required. There were two other chillers rated at 1,000 tons each. They were also of the centrifugal type but were driven by electric motors controlled by variable speed drives. To maximize the economic benefit of the cogeneration plant, the steam-driven chiller was always called upon first whenever campus chilled water requirements dictated that mechanical cooling was necessary. During periods when campus chilled water requirements exceeded the capacity of the steam chiller, the electric chillers were brought on line as necessary for supplemental purposes. There were times when chilled water requirements were marginal and outdoor conditions were favorable, particularly during the fall and spring seasons. During these conditions, water-to-water economizing heat exchangers were utilized to permit free cooling for energy conservation. Throughout the year, the chilled water plant was expected to work in unison with the cogeneration unit and boilers such that the overall economics were maximized through optimal selections of fuel and equipment operation.

3.6 Available Utilities

Available Utilities refers to those utilities delivered to the buildings either from the plant, directly from utility companies, or some combination of both. The available utilities were electricity, steam, chilled water, and natural gas.

In the case of electricity, the vast majority of buildings on campus were fed from the central heat and power plant through an underground electrical distribution system operating at 4,160 volts. This distribution system was sourced by a combination of the cogeneration unit and purchased electric utilities. Buildings not on the electrical distribution system were fed directly by the local electric utility company. Triad, Edgewood Park, Mansion Park, and the Team House are included in this group.

Only a minority of buildings on campus were fed from the chilled water plant through an underground distribution system. The chilled water plant addition was completed in April 2006. This measure marked the first phase of a lengthy project to centralize campus air conditioning. To minimize disruption to the campus, chilled water distribution piping was routed in conjunction with a steam pipe replacement project involving shared trenches. This approach necessitated coordination with prioritized steam line replacements and building chiller failures such that chilled water delivery to buildings would be phased-in over time. During FY07, the central chilled water plant fed the following buildings: Education Hall, Robinson, ESBY Gym, Campbell Library, and portions of the Student Center. The remaining buildings utilized stand-alone building water chillers fed by steam from the central heat and power plant, direct expansion air conditioning, or had no air conditioning at all.

The vast majority of buildings were fed with steam generated by the central heat and power plant. Steam was supplied through underground steam pipes at a pressure of 150 pounds per square inch and pipes that returned steam condensate to the plant. Exceptions to this arrangement included Triad, Edgewood Park, Mansion Park, and the Team House, which were configured with stand-alone natural gas-fired boilers, furnaces, or electric resistance heating.

Natural Gas, as an available utility, was fed to select buildings directly from the local natural gas utility, South Jersey Gas. This included Triad, Edgewood Park, and the Team House. These buildings utilized either dedicated stand-alone boilers or furnaces.

Also there were several gas-fired emergency electric power generators at select buildings. Due to the limited use of this equipment and resulting negligible fuel consumption, these units were omitted from this study.

3.7 Campus Energy Usage

Each available utility had one or more intended uses on campus. This section briefly describes these uses.

As discussed previously, electricity was supplied through utility purchases and/or generated on site at the central heat and power plant. However, the source of electricity did not affect how it was used on campus. In general, campus electricity was utilized for power, lighting, vertical transportation, and heating, ventilation and air conditioning (HVAC) systems. Power included wall, floor, power pole, or outdoor electric receptacles, laboratory power, and any other general power utility source available to building occupants. Lighting included both indoor and outdoor applications. HVAC systems included a vast multitude of equipment including electric chillers, direct expansion air conditioning units, window air conditioners, hot water and chilled water pumps, fans including those used in air handlers, supply, return, makeup, and exhaust. HVAC systems also included automatic temperature control systems and air compressor stations required to operate them.

Chilled water served only air conditioning systems on campus. Whether chilled water was produced at the central heat and power plant and distributed to buildings, or circulated in a building in conjunction with a dedicated chiller in the process of being phased out as an available utility, chilled water was solely dedicated to air conditioning systems.

Steam was widely used on campus in four general applications including heating, air conditioning, hot water, and laboratory processes. Through steam-to-water heat exchangers, steam from the central heat and power plant heated cold water, which was circulated through baseboard radiator heating, in-floor radiant heating, through coils in air handlers, or ductwork to provide comfort heating. Steam was also used as a heat source for several stand-alone absorption chillers utilized for air conditioning. The same was true for the central heating and power plant in that a portion of the steam was diverted to the steam-driven chiller. Steam was also widely used as a thermal source to heat cold water for domestic uses. Similar to comfort heating mentioned above, steam-to-water heat exchangers were utilized to raise the temperature of incoming cold water to a level adequate for domestic uses. Finally, there were a few laboratories on campus where steam served experimental equipment. However, steam usage by laboratory equipment contributed little to overall campus steam demand.

Natural gas serving a few outlying buildings/complexes was provided directly from a local gas company, South Jersey Gas. This included Triad, Team House, and Edgewood Park. For comfort heating, equipment in these buildings employed direct-fired boilers or furnaces. For generation of domestic hot water, direct-fired boilers were used in conjunction with hot water circulation systems at these locations.

3.8 Energy Stream Reference Indices

For purposes of analysis and discussion, a system of notation has been devised for this study. Refer to Figure 3.3 below throughout the description that follows. All energy streams associated with this study have been assigned a two-digit number for reference.

Starting with the Primary Level utilities, each raw source that comprised electricity purchased from Atlantic City Electric, was numbered 01 through 09. Sources 01 through 04 were considered non-renewable utilities while sources 05 through 09 were considered renewable. Source 10 represents sourcing of wind-generated electricity, commonly referred to as w-recs from third-party renewable energy generator, Community Energy. These w-recs allow the offset of CO_2 produced during the generation of the standard grid mix of electricity, but involve no additional electricity being delivered from the grid. However, for the purpose of determining appropriate $C0_2$ emmisions, the w-recs are treated as corresponding directly to purchasing wind-developed electricity. Fuel oil and natural gas utilities have been assigned as streams 11 and 12, respectively. Streams 13 through 17 represent individual utility feeds to equipment within the central heating and power plant and are discussed further below.

Within the primary plant level, stream 13 represents the sum of all raw sources bundled together into all electricity purchased by the university. Stream 14 is the natural gas feed to the cogeneration unit. Stream 15 is the fuel oil feed to boilers 1, 2, and 3. Stream 16 is the natural gas feed to boilers 1, 2, and 3. Stream 17 represents a "plant pass-through" natural gas stream directly serving those buildings that employ direct-fired heating and domestic hot water equipment. Streams 18 and 19 are steam condensate return flows back to the cogeneration and boilers.

At the Secondary Plant Level, several energy streams make up the complex interface between primary and secondary plant equipment. Similar to stream 17, stream 20 represents a "plant pass-through" electricity stream directly serving the available utility electricity to the campus. Stream 21 represents that portion of purchased electricity feeding the chilled water plant. Stream 22 refers to the electricity generated by the cogeneration unit feeding the available electricity to the campus. Stream 23 represents that portion of cogeneration plant electricity produced electricity that feeds the chilled water plant. Stream 24 refers to the steam produced by the cogeneration plant feeding the available steam to the campus. Note that steam produced by the cogeneration plant also serves the chilled water plant. For purposes of energy and CO_2 emissions accounting and balancing, steam and electricity used by the chilled water plant are considered to reflect the campus average that considers all sources of steam and electricity used by the campus. Stream 25 represents the return of all steam condensate from the campus to the plant. Stream 26 refers to that portion of the steam produced by the boilers that serves the chilled water plant. Stream 27 is the balance of the steam produced by the boilers serving the available utility steam to the campus. Stream 28 is a sole chilled water output from the chilled water plant. Stream 29 represents the warmed chilled water that is returned to the chilled water plant for re-chilling since it is a closed-loop system similar to steam.

Moving to the Available Utilities level, Stream 30 is the sum of streams 20 and 22 and represents all electricity used by the campus for power, lighting, HVAC, etc. Stream 31 represents all chilled water that is distributed around campus and delivered to those buildings connected for the sole purpose of air conditioning. Similar to stream 31, stream 32 represents all steam that is distributed around campus and delivered to those buildings connected for purposes of heating, domestic hot water production, and laboratory processes. Stream 33 represents all natural gas directly serving those buildings that employ stand-alone heating and domestic hot water equipment.

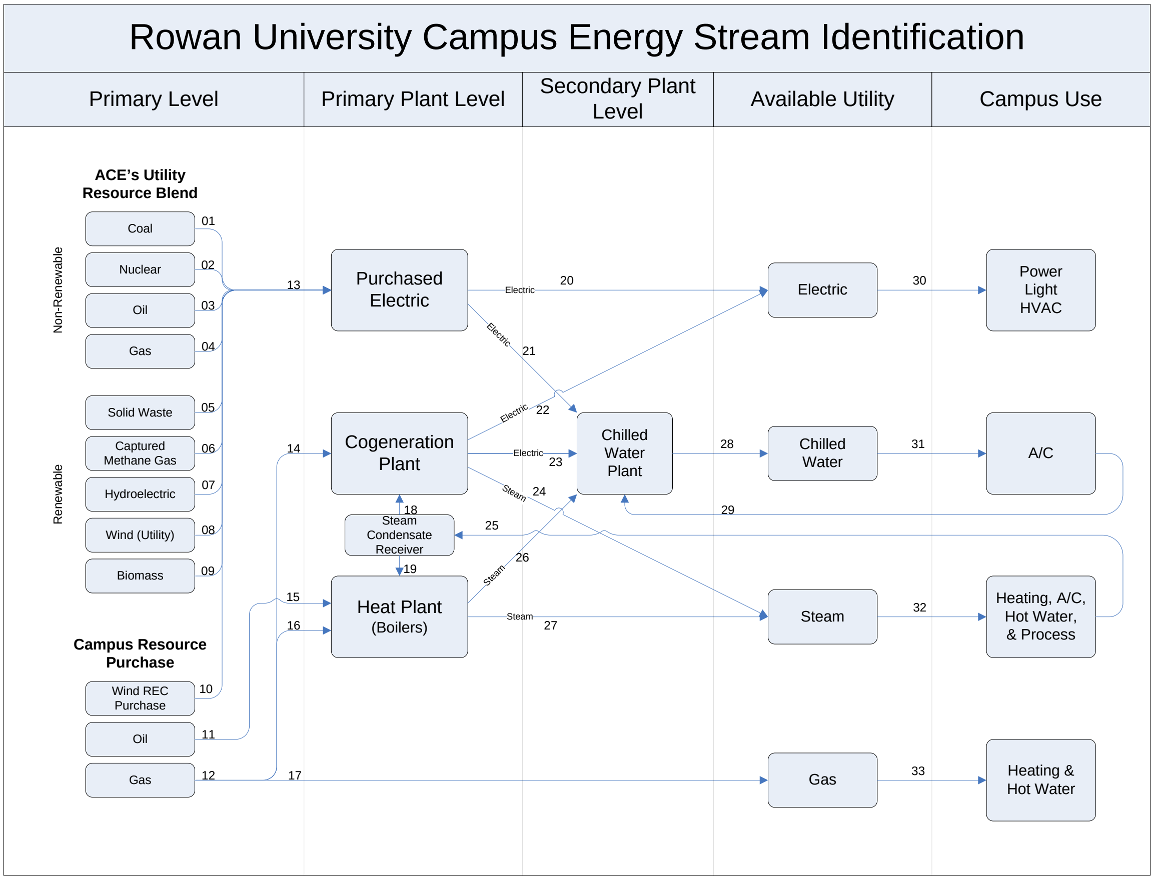

Figure 3.3 – Identification of all Energy Streams for Reference Purposes.

3.9 Purchased Electricity Streams

This section describes and breaks down the components that make up electricity purchased by Rowan. Refer to Figure 3.4 below for detailed descriptions of these components.

In FY2007, Rowan University was supplied with transmission and distribution electrical service from the utility Atlantic City Electric (ACE). According to federal rules and regulations, ACE and other load serving entities are required to issue a statement that describe all energy sources and their respective percentages that make up the resource blend of electricity they supply. The environmental label for July 1, 2006 through June 30, 2007 was obtained from ACE[15] and the results are indicated in Figure 4 below.

Percentages for each energy source type are displayed in color code format to distinguish between renewable from non-renewable energy sources. During FY07, nearly 95% of the electricity supplied by ACE came from non-renewable energy sources. However 43.9% of this energy was generated from nuclear sources, which are considered to emit zero CO_2 plant emissions. ACE's renewable portfolio accounted for the remaining 5.5% balance of the entire resource blend.

To increase the percentage of renewable energy it purchased, Rowan University purchased w-recs. This energy was purchased from a third-party renewable generator, Community Energy. By purchasing 25% energy from wind sources, Rowan University had rebalanced the resource blend to levels that favor CO_2 emissions-free technologies.

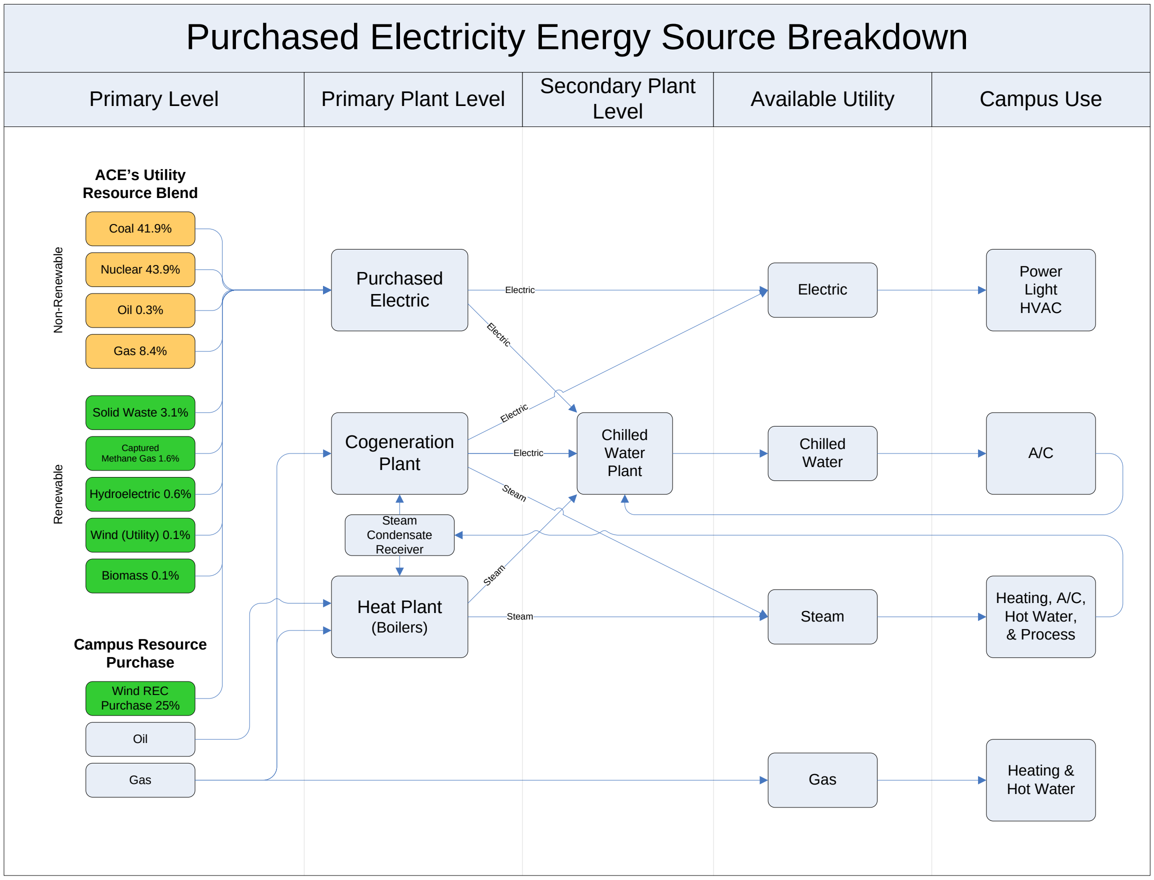

Figure 3.4 – Electricity purchased by Rowan University broken down by Energy Source

3.9.1 Energy Distribution, Quantification, and Analysis

Referring to Figure 3.5 below, all major energy streams for all levels have been identified and quantified on an annualized basis for FY07. For brevity, several of the energy values in Figure 3.5 are positioned inside of the process blocks. In all cases, the value inside of the block represents the energy input to that block. Sources for these data include copies of plant operator's logs, utility bills, and energy accounting calculations.

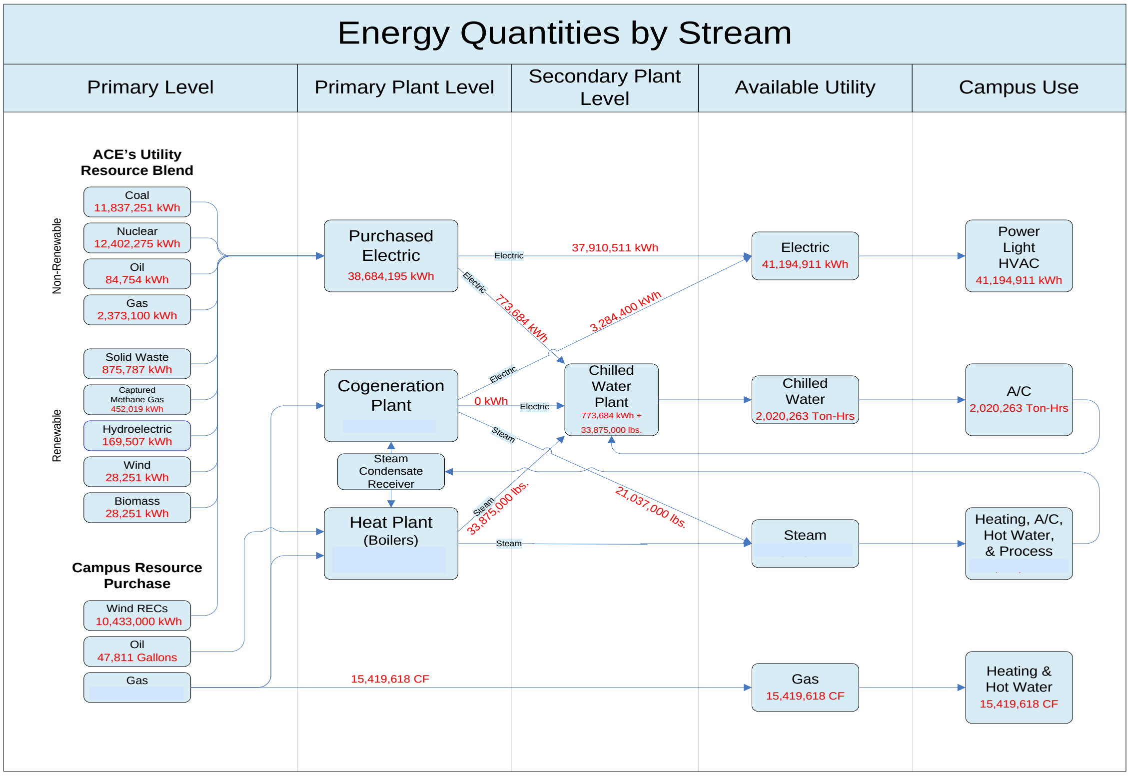

Figure 3.5 –Supply and Demand Energy Accounting for the Rowan University campus – FY07.

Beginning with the primary level, each raw utility resource has an energy value associated with it. These energy values were determined by their relative proportion as defined in Atlantic City Electric's Environmental Label. The non-renewable portion of ACE's blend accounts for nearly 95% of the entire portfolio. Coal and nuclear energy account for the approximately 86% of the electric power purchased by Rowan University from ACE. Energy values are also posted for the renewable portion of ACE's electric service and these values are broken down similarly in Figure 3.5.

In addition to purchasing electricity from ACE, Rowan University purchased wind-generated renewable energy certificates (w-recs) in a separate transaction.

Renewable energy certificates are tradable, non-tangible energy commodities in the United States that represent environmental attributes of the power produced from renewable energy sources and are sold separately from commodity electricity[16]. One rec is equivalent to one megawatt-hour of electricity, which displaces carbon-emitting energy. The environmental attributes of recs can be used to offset the carbon footprint associated with other polluting activities. As a result, purchasing recs is a popular method of reducing greenhouse gas emissions for businesses and governmental organizations. During FY07, Rowan University purchased a total of 38,684,195 kWh from the grid, as well as 10,433,000 kilowatt-hours of w-recs. The electricity purchased from the grid actually came from a portfolio of sources that was representative of the ACE blend. However, for the purpose of accounting for carbon, it was assumed that 10,433,000 kWh were directly obtained from windpower, and the remaining 28,251,195 was reflected the ACE blend. The implications of this are discussed further in Riddell et al.[19]

Values for fuel oil and natural gas for use in the central heat thermal and power plant are indicated under primary level as well. Natural gas is fed to the boilers as well as the cogeneration unit. Fuel oil is also fed to both plants. However, during FY07 no oil was consumed by the cogeneration plant due to an ongoing faulty liquid fuel pump system problem. All of the 47,811 gallons of fuel oil were consumed in the boilers only. The cogeneration plant consumed 60,383,999 cubic feet of natural gas during FY07. The boilers consumed 293,888,283 cubic feet of gas in FY07. Natural gas not used by the cogeneration or heat plants accounted for 15,419,618 cubic feet in FY07 and typically served apartments, e.g., Edgewood Park, using gas direct-fired hot water and heat.

Purchased electricity was split into two streams: 37,910,511 kilowatt-hours (Stream 20) serving the campus as electric available utility, and 773,684 kilowatt-hours serving the chilled water plant (Stream 21). The cogeneration unit produced electricity and steam. In FY07, the cogeneration unit produced 3,284,400 kilowatt-hours while serving the campus, reducing grid purchases. The cogeneration unit produced 21,037,000 pounds of steam for heating, cooling, hot water, and laboratory equipment on campus.

To supplement thermal requirements, the boilers produced 258,704,586 pounds of steam in FY07. 33,875,000 pounds of steam were utilized by the chilled water plant while 224,829,586 pounds were distributed to the campus. Note that in general, the chilled water plant utilized relatively small percentages of electricity and steam utilized by the entire campus. This is because FY07 started in the middle of the first season the chilled water plant was placed online, April 2006. At that time, only three buildings on campus were connected to the plant so electricity use, associated with chilled water production, was low.

As available utilities for multiple campus uses, the four campus consumer energy sources are discussed below. Electricity consumed by the campus in FY07 reached 41,194,911 kilowatt-hours. As Figure 3.5 indicates, this energy is the sum of purchased plus produced electricity and serves power, lighting, and HVAC systems on campus, minus the electricity used by the chilled water plant. The chilled water plant produced 2,020,263 ton-hours of cooling dedicated to air conditioning in FY07 from a combination of electric and thermal sources also shown in Figure 3.5. Steam consumed by the campus reached 245,866,586 pounds and was fed from the cogeneration unit and boilers in FY07. This thermal energy was used for heating, air conditioning, domestic hot water, and laboratory process applications. Finally, 15,419,618 cubic feet of natural gas was supplied throughout campus for non-central heating and power plant applications mostly comprising apartment complexes employing direct fired heating and hot water equipment.

3.9.2 CO_2 Emissions Distribution and Quantification

Figure 3.6 depicts quantities of CO_2 emissions in a manner similar to which Figure 3.5 conveys energy information. All values displayed in Figure 3.6 are in pounds of CO_2. All calculations were based on equations and coefficients appearing in the references found at the end of this thesis.[17]

Starting with the primary level, at 24,266,365 pounds of CO_2, in FY07, coal was by far the most significant contributor to CO_2 emissions within the ACE portfolio. Contributions from oil and gas were 161,880 pounds and 2,040,866 pounds of CO_2 respectively. Note that nuclear, while the largest provider of electricity from ACE, yields zero emissions and this fact greatly helped to balance ACE's blend regarding CO_2

emissions. All renewable energy sources from ACE and other utility companies yield zero CO_2 emissions. This includes captured methane gas. The release of methane gas directly to the atmosphere would result in greater CO_2 emissions than combustion of methane gas.

CO_2 emissions from the combustion of fuel oil for use in the boilers amounted to 1,029,849 pounds, while natural gas contributed 44,362,788 pounds for boilers and the cogeneration unit. All electric purchased in FY07 resulted in the effect of producing 26,469,111 pounds of CO_2. A relatively small portion (529,382 pounds of CO_2) of the electric purchased fed the chilled water plant. The balance (25,939,728 pounds of CO_2) was diverted to electric as an available campus utility. The cogeneration unit with its mix of fossil fuel inputs contributed 7,246,080 pounds of CO_2 in FY07. 2,824,584 pounds of CO_2 were associated with the electrical output of the plant. The remaining 4,421,496 pounds of CO_2 went toward the available steam campus utility.

The boilers contributed 36,296,203 pounds of CO_2 with a mixture of natural gas and fuel oil, with natural gas as fuel the majority of the time. 4,183,706 pounds of CO_2 was associated with usage by the chilled water plant. The remaining 32,112,497 pounds of CO_2 represented the steam used as an available campus utility. The hybrid steam/electric chilled water plant contributed 4,713,088 pounds of CO_2 in FY07 as a result of the blend of steam and electric inputs.

As available utilities for multiple campus usages, the four campus consumer energy sources are discussed below with regard to CO_2 emissions. Electricity, as an available utility, contributed 28,764,312 pounds of CO_2 and represented a blend of purchased and produced energy used for power, lighting, and HVAC systems on campus. The production of chilled water, used exclusively for air conditioning, contributed 4,713,088 pounds of CO_2. The production, distribution, and usage of steam accounted for the emission of 36,533,993 pounds of CO_2 in FY07. Natural gas used for heating and hot water in stand-alone apartment complexes contributed 1,850,354 pounds of CO_2 in FY07.

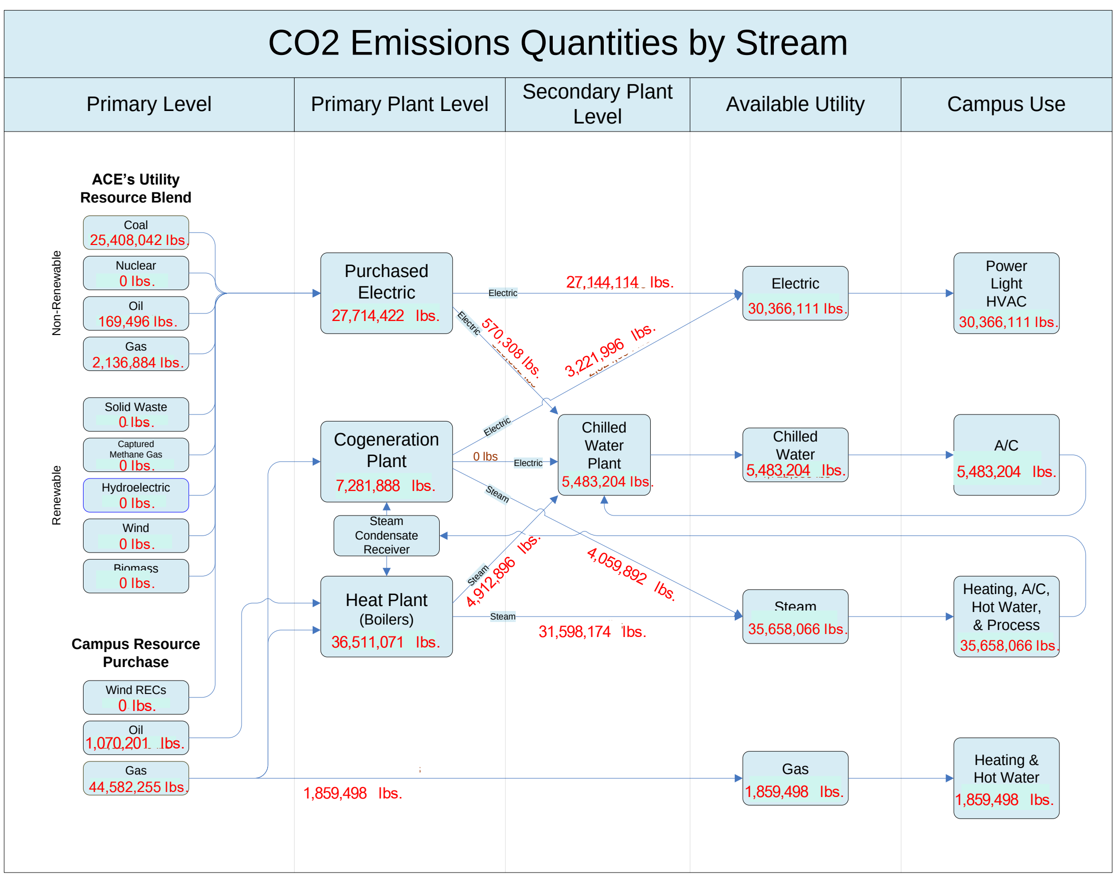

Figure 3.6 – Quantification of CO_2 Emissions throughout the campus energy delivery system cycle.

3.9.3 CO_2 Quantities per Unit of Host Energy

To assess the impact of CO_2 emissions of the campus energy delivery system at Rowan University, it is necessary to establish a system of ratios. In a system of ratios, one could readily navigate complex energy systems and work with individual systems and components to gain insight and come up with ways to reduce specific CO_2 emissions.

Figure 3.7 displays such ratios for all energy streams defined in this chapter. CO_2 emissions levels were divided by the associated energy quantities at every point. This also will enable future comparisons with similar systems.

Using government published CO_2 – Fuel ratios[i], as shown in Figure 3.7, Coal emits 2.47 pounds of CO_2 per pound consumed. Again, nuclear energy is considered to emit zero CO_2 emissions. Fuel oil emits 21.54 pounds of CO_2 per gallon. Natural Gas emits 0.12 pounds of CO_2 per cubic foot. The remaining sources from ACE are renewable and emit zero CO_2 emissions. As shown, the same ratios are used for the direct natural gas and oil purchases for the boilers and cogeneration unit.

All of these ratios carry over into the primary plant level, totalized and/or combined, to show the blended ratios that result at the plant machinery level. The generation of the electricity purchased emitted 0.684 pounds of CO_2 per kWh. This value includes wind renewable energy certificate purchases. The contribution of the cogeneration unit was 0.12 pounds CO_2 per cubic foot of natural gas. Note the resemblance the cogeneration unit has to natural gas. This is due to the equipment running solely on natural gas during FY07. Similarly, energy inputs to the boilers contributed 0.12 pounds of CO_2 per cubic foot of natural gas and 21.54 pounds CO_2 per gallon of fuel oil. An accounting of CO_2 for each point and stream is shown in Figure 3.7. Electricity and steam energy inputs to the chilled water plant account for 0.684 pounds CO_2 per kWh and 0.1235 pounds CO_2 per pound of steam. Now that all streams have been quantified and accounted for, one can review the CO_2 / energy ratios resulting from the blending that occurred as energy was diverted through the plant and campus.

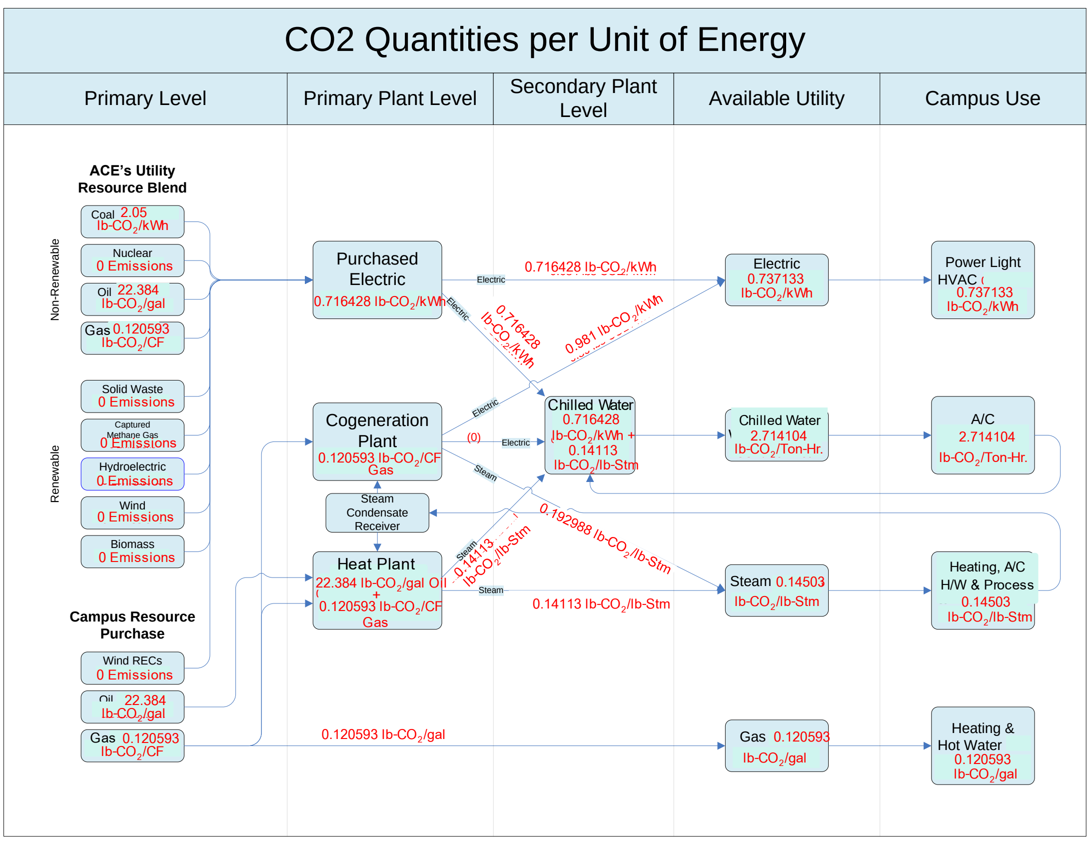

Figure 3.7 –CO_2 Emissions Quantities per Unit of Host Energy.

We now extend the above analysis and recalculate CO_2 emissions coefficients for steam and electricity produced by the cogeneration unit based on fractioning of the total energy produced by the cogeneration unit. Referring to Table 3.1 below, during FY2007, 60,383,999 cubic feet of natural gas were consumed by the cogeneration unit. No fuel oil was consumed by the cogeneration unit. Multiplying the consumed natural gas by the CO_2 emissions coefficient of 0.1200 pounds of CO_2 per cubic foot of natural gas resulted in 7,246,080 pounds of CO_2 emissions on the input side of the cogeneration plant. On the output side of the cogeneration unit, 3,284,400 kilowatts of electricity were produced and 21,037,000 pounds of steam were produced. To combine the two output energy quantities, standard energy conversion factors were used. Multiplying 3,284,400 kilowatts of electricity by 3,412.142 BTUs per kilowatt hour, we find 11,206,839,185 BTUs of output energy was produced in electricity alone. In a similar manner, multiplying 21,037,000 pounds of steam by 1,196.230 BTUs per pound of steam, we find 25,165,090,510 BTUs of output energy was produced in steam alone. Combining the two output energies, we find a total of 36,371,929,695 BTUs were produced by the cogeneration unit in FY07.

A preliminary CO_2 emissions coefficient for steam was then calculated by first assuming the electricity produced by the cogeneration unit was the same as the grid, 0.9810 pounds of CO_2 emissions per kilowatt hour. Multiplying 3,284,400 kilowatts of electricity by 0.9810 pounds of CO_2 emissions per kilowatt hour, we find a preliminary value of 3,221,996 pounds of CO_2 emissions, associated with electricity produced by the cogeneration unit. To balance CO_2 emissions on the input and output sides of the cogeneration unit, accounting must take into consideration that emissions on both sides are equal. To calculate CO_2 emissions associated with steam, we must subtract 3,221,996 pounds of CO_2 emissions from 7,246,080 pounds of CO_2 emissions, attributing 4,024,083 pounds of CO_2 emissions to steam. To calculate a preliminary steam CO_2 emissions coefficient, we divide 4,024,083 pounds of CO_2 emissions by the amount of steam produced by the cogeneration unit, or 21,037,000 pounds. This calculation yields a result of 0.1913 pounds of CO_2 emissions per pound of steam as a preliminary CO_2 emissions coefficient for steam produced by the cogeneration unit. We will refer to the above extended analysis as Method 1.

A second approach (Method 2) used to determine the CO_2 emissions coefficient for steam produced by the cogeneration unit was to consider the fraction of total CO_2 emissions was attributed based on the energy ratio of steam energy over total energy. Recalling that 25,165,090,510 BTUs of steam output energy was produced out of a total of 36,371,929,695 BTUs produced by the cogeneration unit, through division, we find a fraction value of 0.69188. Multiplying this fraction by the total output CO_2 emissions of 7,246,080 pounds, we find that 5,013,434 pounds of CO_2 emissions were attributed to steam produced by the cogeneration unit in FY07. Through division of CO_2 emissions attributed to steam by the amount of steam produced, or 21,037,000 pounds, we find the final CO_2 emissions coefficient for steam produced by the cogeneration unit as 0.23832 pounds of CO_2 emissions per pound of steam produced by the cogeneration unit. Using a similar approach for electricity produced by the cogeneration unit, we find a final CO_2 emissions coefficient for electricity of 0.67977.

Table 3.1 – Determination of CO_2 emissions coefficients for steam and electricity produced by cogeneration unit

FY 2006/2007 Cogeneration Unit Input Energy			
Fuel	Amount of Fuel in Gallons of Oil or Cubic Feet of Natural Gas	CO_2 Emissions Coefficient	CO_2 Emissions, Pounds of CO_2
Oil	-	21.5400	-
Natural Gas	60,383,999	0.1200	7,246,080
Total			7,246,080
FY 2006/2007 Cogeneration Unit Output Energy			
Energy Produced	Amount of Energy Produced in kWh of Electricity or Pounds of Steam	Energy Conversion Coefficient in BTUs per Energy Unit	Total Energy in BTUs
Electricity	3,284,400	3,412.142	11,206,839,185
Steam	21,037,000	1,196.230	25,165,090,510
Total			36,371,929,695
FY 2006/2007 Cogeneration Unit CO_2 Emissions			
Energy Produced	Amount of Energy Produced in kWh of Electricity or Pounds of Steam	Preliminary CO_2 Emissions Coefficients	Total CO_2 Emissions in Pounds
Electricity	3,284,400	0.9810	3,221,996
Steam	21,037,000	0.1913	4,024,083
Total			7,246,080
Energy Produced	Amount of Energy Produced in kWh of Electricity or Pounds of Steam	Final CO2 Emissions Coefficients	Total CO_2 Emissions in Pounds
Electricity	3,284,400	0.67977	2,232,646
Steam	21,037,000	0.23832	5,013,434
Total			7,246,080

The above analysis was extended further in the determination of CO_2 emissions coefficients for the four primary utilities distributed to the campus. Calculations of the CO_2 emissions coefficients followed a similar format as the calculations for steam and electricity produced by the cogeneration unit. Referring to Table 3.2 below, final CO_2 emissions coefficients are summarized at the bottom of the table. In summary, for every kilowatt-hour of electricity consumed by the campus for purposes of power, lighting, and HVAC, 0.7371 pounds of CO_2 were emitted. For every cubic foot of natural gas consumed by the campus for the purpose of direct-fired heating and hot water, 0.120593 pounds of CO_2 were emitted[19]. Similarly, for every pound of steam consumed by the campus for the purpose of heating, domestic water, HVAC systems, and processes, 0.14503 pounds of CO_2 were emitted. For every ton-hour of chilled water consumed by the campus for purposes of air conditioning, 2.7141 pounds of CO_2 were emitted.

Table 3.2 -- Determination of CO_2 emissions coefficients for steam and electricity utilized by campus

FY 2006/2007 Plant Input Energy			
Fuel	Amount of Energy Consumed	Pounds of CO2 Emissions Per Energy Unit	Total CO2 Emissions, Pounds of CO2
Total Grid Electricity, kWh	38,684,195	0.981	37,949,195
Wind Rec Electricity, kWh	10,433,000	0.000	-
Grid Adjusted for Wind Recs, kWh	28,251,195	0.981	27,714,422
Natural Gas, Cubic Feet	369,689,900	0.120593	44,582,014
Oil, Gallons	47,811	22.384	1,070,201
Total Adjusted Grid, Natural Gas, & Oil			73,366,638
FY 2006/2007 Plant Output Energy			
Utility Available to Campus	Amount of Available Utility	Energy Conversion Coefficient in BTUs per Energy Unit	Total Energy in BTUs
Electricity, kWh	41,194,911	3,412.142	140,562,886,009
Natural Gas, Cubic Feet	15,419,618	1,027	15,835,947,686
Steam, Pounds	245,866,586	1,196.230	294,112,986,171
Chilled Water, Ton-hours	2,020,263	12,000	24,243,156,000
Total			474,754,975,866
FY 2006/2007 Preliminary CO_2 Emissions Coefficients			
Utility Available to Campus	Amount of Available Utility	Pounds of CO2 Emissions Per Energy Unit	Total CO2 Emissions, Pounds of CO2
Electricity, kWh	41,194,911	0.69825	28,764,347
Natural Gas, Cubic Feet	15,419,618	0.120593	1,859,498
Steam, Pounds	245,866,586	0.1547	38,029,742
Chilled Water, Ton-hours	2,020,263	2.3330	4,713,274
Total			73,366,861
FY 2006/2007 Final CO_2 Emissions Coefficients			
Utility Available to Campus	Amount of Available Utility	Pounds of CO2 Emissions Per Energy Unit	Total CO2 Emissions, Pounds of CO2
Electricity, kWh	41,194,911	0.7371	30,366,128
Natural Gas, Cubic Feet	15,419,618	0.120593	1,859,498
Steam, Pounds	245,866,586	0.14503	35,658,031
Chilled Water, Ton-hours	2,020,263	2.7141	5,483,204
Total			73,366,861

In FY07, electricity costs were $5,092,378 with 18,245,668 pounds of associated CO_2 emissions. Steam costs were $3,395,481 with 48,899,967 pounds of associated CO_2 emissions. Reflecting the period of FY07, the information assembled in this analysis can be utilized as baseline data for comparison in future related studies.

3.9.3 Campus Infrastructure Changes – Circa 2009

Between FY07 and 2009, significant changes to the campus infrastructure took place, while this study continued. The single 1.5 MW cogeneration unit was replaced with a plant that incorporated two cogeneration units totaling 4.7 MW of electrical output capacity. The new cogeneration plant is described in detail later in this paper, providing the main topic for analysis and discussion in this thesis. In addition, in early 2009, a new substation was brought online, reducing the number of high tension electric (primary) utility services from three to one and enabling Rowan University to purchase electricity directly from a single transmission line. By consolidating the primary electric utility services, Rowan University assumed a better position for future elimination of costly lower tension electric (secondary) utility services by connecting them into the campus electrical distribution system. The new substation transforms electricity at voltages from 69 kilovolts to 12.47 kilovolts. The substation is rated for a maximum capacity of 20 megavolt-amperes. Electricity at 12.47 kilovolts is distributed to campus buildings, some of which are in the process of being converted from an aged 4.16 kilovolt electrical distribution system that is being phased out. By owning, operating, and maintaining the 69/12.47 kilovolt substation and all other distribution equipment, Rowan University avoids payment of distribution charges to their local electricity provider, Atlantic City Electric, and purchases transmission-level electricity directly from the grid. Therefore, grid electricity is currently limited to 20 megavolt-amperes, the rating of Rowan University's substation. In addition, consolidation of the primary utility service from three to one provided a more streamlined approach in the monitoring of campuswide electrical demand via interval data. A discussion of interval data will follow in the next chapter of this thesis. The connection of electrical loads, associated with adding buildings to the campus electrical distribution system, increased the amount of campus electric demand on the new lightly-loaded substation.

Chapter 4

Period of Study and Campus Energy Systems, Production, and Usage

In this chapter, we discuss the sources of data utilized in this thesis. In addition, the time period studied for this thesis is primarily based is discussed. Further, an updated description of campus energy equipment and an analysis of on-campus energy production and energy usage are presented for the new study period.

4.1 Period of Study

As a reliable provider of electrical and thermal energy to the campus, the cogeneration plant is expected to operate year-round, 24 hours a day. However, turbine maintenance requirements involve approximately one week of downtime per year. A dual unit arrangement provides a means to shut down one unit at a time for maintenance, thereby permitting continued supply of electrical and thermal energy to the campus. Utility infrastructure changes made between 2005 and 2009 resulted in a period of transition in which purchased and produced energy varied significantly. In the early part of year 2009, the cogeneration plant was in a period of equipment commissioning and regulatory environmental compliance testing. During the summer of 2009, commissioning and testing was completed and final air permitting was approved by the New Jersey Department of Environmental Protection. On September 1, 2009, plant operators began logging data for cogeneration units 1 and 2 separately, providing a starting point for tracking the performance of each unit. Given the timing of permit, the runtime of each cogeneration turbine, and availability of complete cogeneration plant operational data, the period September 1, 2009 through August 31, 2010 was selected to establish the utility demand to study optimization of the cogeneration plant. This period provided data for the first year of significant runtime for both cogeneration turbines and followed commissioning and complete monitoring. In addition, this period encompassed academic year 2009 - 2010 and five summer sessions that took place in the summer season of 2010.

4.2 Sources of Data

Plant steam and electricity production data, and grid purchase data from Atlantic City Electric were gathered and reviewed. Daily totals for plant steam and electricity production for the boilers and cogeneration units was made available in a spreadsheet format, an excerpt of which is shown in Table 4.1. In addition, quarter-hour and hourly grid purchase data was made available in interval format through Energy Profiler Online, an online data download service provided by Atlantic City Electric. An excerpt of interval data is shown below in Table 4.2. To merge the hourly grid purchase data with the daily plant data, plant data was converted into hourly format by dividing daily values by 24, posting equal hourly values across each day, and adding the values with corresponding hourly interval data.

Table 4.1 Excerpt of Plant Steam and Electricity Production Data for September 2009

SEPT2009	BLR1 STM	HRS	BLR2 STM	HRS	BLR3 STM	HRS	HP STM
1	0	0	0	0	315000	24	315000
2	0	0	417000	22	58000	2	475000
3	0	0	438000	24	0	0	438000
¦	¦	¦	¦	¦	¦	¦	¦
29	0	0	424000	24	0	0	424000
30	0	0	410000	24	1000	0	411000
31							0
Totals	0	0	1689000	94	374000	26	2063000

SEPT2009	GH HP GAS	SAT20 STM	HRS	CENT40 STM	HRS	CGTOL STM
1	370000	0	0	430000	24	430000
2	540000	0	0	407000	24	407000
3	520000	0	0	398000	24	398000
¦	¦	¦	¦	¦	¦	¦
29	490000	0	0	398000	24	398000
30	480000	0	0	412000	24	412000
31						0
Totals	2400000	0	0	2045000	120	2045000

SEPT2009	TKWHR20	TKWHR40	BLR1 GAS	HRS	BLR2 GAS	HRS	BLR3 GAS
1	0	77394	0	0	557	0	381043
2	0	73561	0	0	513305	22	70740
3	0	71772	0	0	570183	24	0
¦	¦	¦	¦	¦	¦	¦	¦
29	0	71611	0	0	509949	24	1907
30	0	73763	0	0	498943	24	4496
31							
Totals	0	368101	0	0	2092937	94	458186

SEPT2009	HRS	SAT20 GAS	HRS	CENT40 GAS	HRS
1	24	0	0	1070000	24
2	2	0	0	1039000	24
3	0	0	0	1017000	24
¦	¦	¦	¦	¦	¦
29	0	0	0	1004000	24
30	0	0	0	1037000	24
31					
Totals	26	0	0	5167000	120

Table 4.2 Excerpt of Quarter-Hour Interval Data from Atlantic City Electric

Customer Name	ROWAN COLLEGE/NJ		
Account Number	93586591393		
Meter Number	105736853F		
Service Address1	GIRARD & WHITNEY		
Service Address2			
CityStateZip	GLASSBORO	NJ	8028
DATE	TIME	kWh	kVARh
90109	15	712.8	345.6
90109	30	678.24	345.6
90109	45	658.8	345.6
90109	100	652.32	343.44
90109	115	650.16	345.6
90109	130	641.52	343.44
90109	145	641.52	343.44
90109	200	639.36	345.6

4.3 Campus Energy Systems

Figure 4.1 is a schematic of a cogeneration system consisting of a combustion turbine, heat recovery steam generator, gearbox, and a generator. Air enters the inlet portion of the compressor section of the combustion turbine. Configured as a conical shape, the volume of the inlet portion of the compressor section is large relative to the outlet section of the compressor. Propelled by turbine blades attached to a rotating shaft, air is compressed as it moves along the compressor section to regions of reduced volume. At maximum compression, the air exits the compressor section and enters the combustion chamber where fuel is introduced and mixed with the compressed air at ratios that support combustion aided by a spark igniter. The fuel-air mixture is ignited, resulting in elevated pressure of the combusted mixture (exhaust gases). Under high pressure, the exhaust gases exit the combustion chamber and enter the expansion section of the combustion turbine. In the expansion section, exhaust gases exert forces onto turbine blades resulting in rotation of the shaft. The expansion section is conical in shape, but is inverted, relative to the compressor section. This configuration maximizes the work done on the turbine blades by the exhaust gases by providing increased turbine blade area as gases pass through the expansion section. Exhaust gases exiting the expansion section enter a heat recovery steam generator where heat is transferred to water. The heat recovery steam generator (HSRG) is a plate frame heat exchanger where a mixture of water and cooled steam condensate returning from the campus, flows through tubes surrounded by a flow of exhaust gases. As the water/condensate mixture is heated by the exhaust gases, steam is produced for campus use. The combustion turbine shaft is coupled to a gearbox to reduce the shaft speed to levels suitable for use with a generator. Rated for speeds of 15,000 to 22,300 revolutions per minute, the combustion turbine requires a gearbox, to reduce shaft speed to 1,800 revolutions per minute, for three-phase electric power generation. The gearbox is coupled to the generator, where mechanical power is converted to electric power, to be distributed for campus use.

The Rowan University cogeneration system combustion turbines operate at constant volumetric flow rates. However, the combustion turbines operate at varied efficiencies as a function of inlet air conditions. Turbine inlet air flow is limited to fixed volumetric rates regardless of ambient air conditions. As ambient air temperature is increased, there is a corresponding reduction in air density. With a constant volumetric flow rate, mass flow rate is reduced when temperature is increased. Therefore, for a given mass flow rate, turbine output is reduced as air temperature increases. Turbine efficiency is reduced as air temperature is increased since compression of warmer air requires more power.

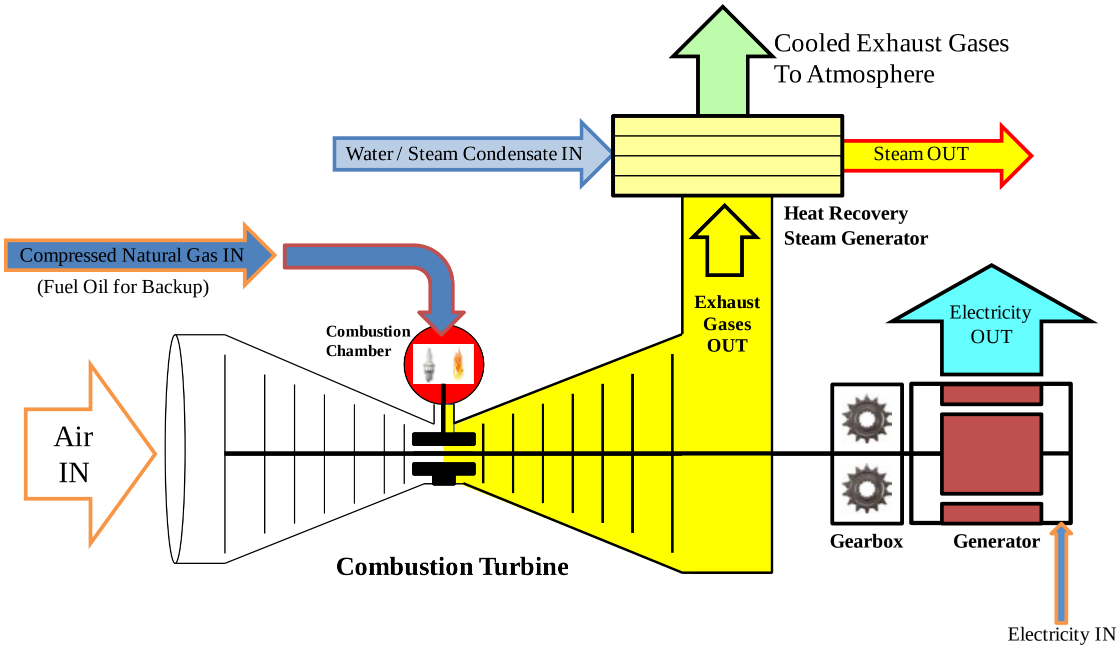

Figure 4.1: Schematic of Typical Cogeneration Unit at Rowan University

Cogeneration Unit 1 has been rated a nominal electrical output of 1,210 kilowatts by its manufacturer, Solar Turbines, Inc. During the study period, Rowan University plant operators logged 130 days of 24-hour operation using natural gas as a fuel. Daily electrical outputs ranging from 20,215 to 32,567 kilowatt-hours were recorded during this period. By dividing the minimum and maximum consumption daily values by 24 hours, the average electrical power output for these days range from 842 to 1,357 kilowatts. For purposes of this study, Cogeneration Unit 1 has been assigned an upper limit electrical capacity of 1,357 kilowatts.

The manufacturer also published a thermal output range of 14,000 to 15,000 BTUs per kilowatt-hour for Cogeneration Unit 1. The manufacturer of the HRSG, Rentech Boiler Systems, Inc., published a nameplate rating of 8,300 pounds of steam per hour. During the study period, with natural gas as a fuel, 209,370 pounds of steam were produced on the peak day of production for the year. By dividing the peak steam production day value by 24 hours, we can approximate the peak thermal output range as 8,724 pounds of steam per hour. For purposes of this study, the upper limit of thermal capacity of 8,724 pounds of steam per hour will be utilized for Cogeneration Unit 1.

Similarly, Cogeneration Unit 2 has been rated a nominal electrical output of 3,515 kilowatts by Solar Turbines, Inc. During the study period, Rowan University plant operators logged 250 days of 24-hour operation using natural gas as a fuel. An electrical output ranging from 65,782 to 92,814 kilowatt-hours of daily production was recorded during this period. This results in an average electrical output range from 2,741 to 3,867 kilowatts. For purposes of this study, Cogeneration Unit 2 has been assigned an upper limit electrical capacity of 3,867 kilowatts.

The manufacturer also published a thermal output range between 12,000 and 14,500 BTUs per kilowatt-hour. Rentech Boiler Systems, Inc., published a nameplate rating of 19,550 pounds of steam per hour for the HRSG associated with Cogeneration Unit 2. During the study period, with natural gas as a fuel, 486,240 pounds of steam were produced on the peak day of production for the year. By dividing the peak steam production day value by 24 hours, we can approximate the peak thermal output range as 20,260 pounds of steam per hour. For purposes of this study, the upper limit of thermal capacity of 20,260 pounds of steam per hour will be utilized for Cogeneration Unit 2.

Referring to Figure 4.2, Boiler 1 has been rated a nominal thermal output of 26,000 pounds of steam per hour by its manufacturer, Superior Combustion Industries, Inc. Original to the plant, Boiler 1 does not incorporate a stack gas economizer to preheat boiler feedwater, as with Boilers 2 and 3. Plant operators indicated that Boilers 1, 2, and 3 are operated as required to supplement the campus steam demand not met by the cogeneration units. Data recorded during the study period are indicative of a wide range of production values, including periods when the boilers were consistently operated at less than 50 percent of their capacities. For purposes of this study, the manufacturer-specified upper limits of thermal capacity of 26,000 pounds of steam per hour for Boiler 1 and 40,000 pounds of steam per hour, for Boilers 2 and 3 will be utilized. A summary of capacities for the cogeneration units and boilers can be found in Table 4.3 below.

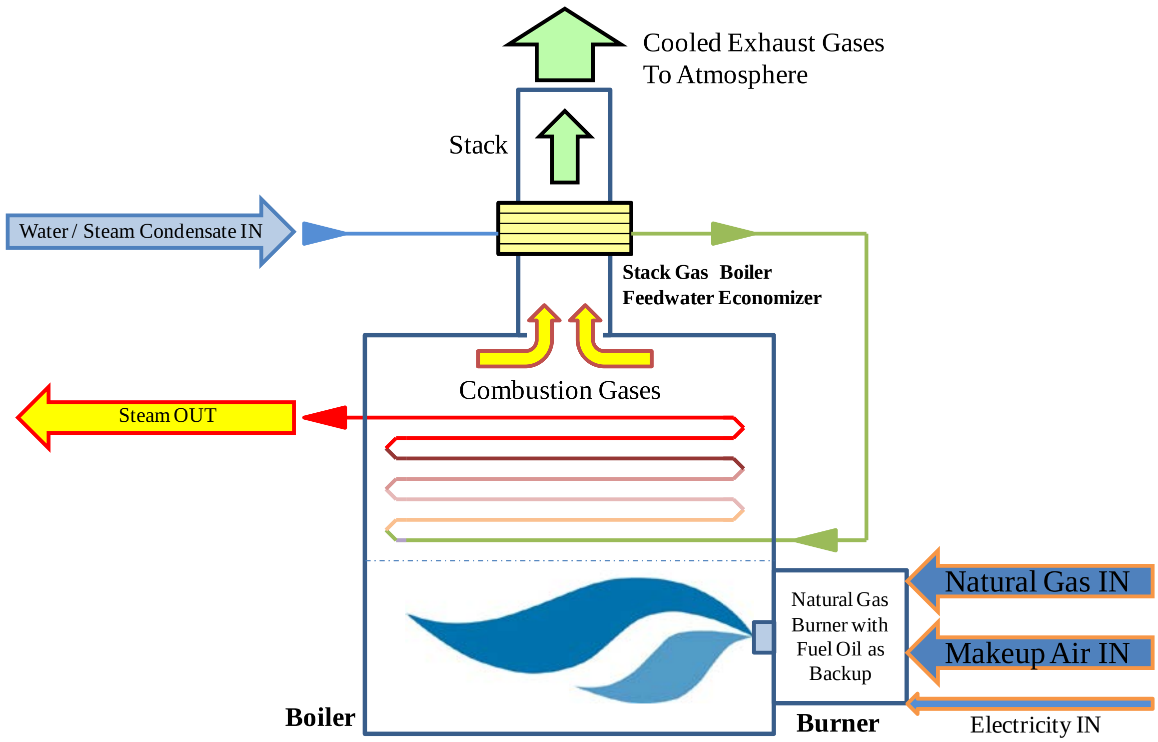

Figure 4.2: Schematic of Water-tube Boiler with Stack Gas Economizer (Boilers 2 and 3)

Table 4.3 – Capacities of Cogeneration Units and Boilers

Equipment	Steam Capacity (lbs./Hr)	Electrical Capacity (kW)
Boiler 1	26,000	0
Boiler 2	40,000	0
Boiler 3	40,000	0
Cogeneration Unit 1	8,724	1,357
Cogeneration Unit 2	20,260	3,867

4.4 Campus Energy Consumption and Demand

Grid purchase data was downloaded to a spreadsheet. The hourly data was totaled to provide grid purchases on a daily basis in a format similar to the plant steam and electricity production data. Daily produced electricity and purchased electricity was combined to determine campus daily electrical consumption. In a similar fashion, steam data for the three boilers and two cogeneration units were combined on a spreadsheet to determine campus daily steam consumption.

Figure 4.3 is a plot of chronological campus electric demand in kilowatts for every hour of the study period. Note that this plot incorporates hourly grid interval data merged with daily cogeneration data that has been distributed on an hourly basis. As shown, peak demand values approached an order-of-magnitude of 10,000 kilowatts. Conversely, a low demand value of 302 kilowatts was recorded. The average electric demand was 5,762 kilowatts.

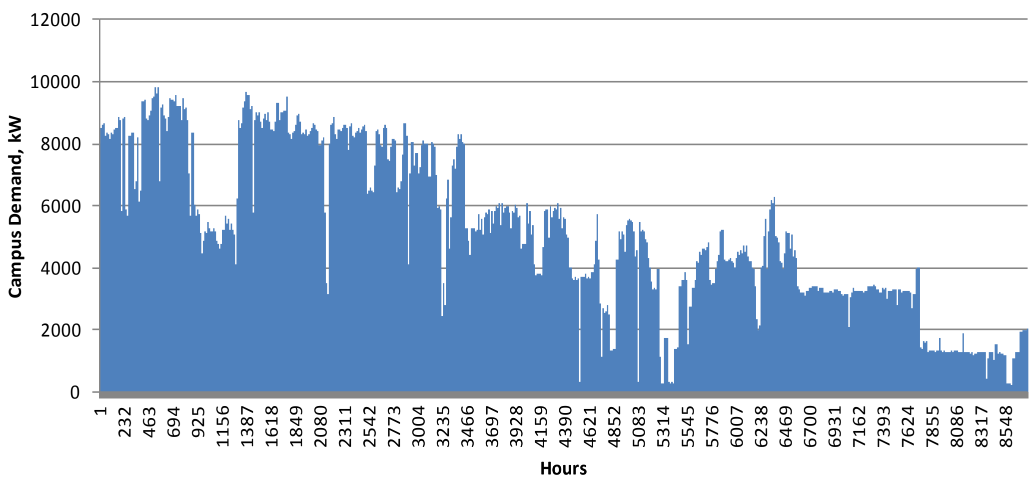

Figure 4.3 -- Campus Electric Demand, kW versus hour September 1, 2009 through August 31, 2010

Figure 4.4 is an electric load duration curve with the same hourly data shown in Figure 4.3. An electric load duration curve is generated by rearranging all interval data such that demand values are in the order from highest to lowest. This type of plot illustrates the relationship between generating capacity requirements and capacity utilization. Load duration curves can assist in determining load dispatching, system planning, and reliability assessment. The area under the load duration curve represents the total electrical energy demanded by the system in kilowatt-hours.

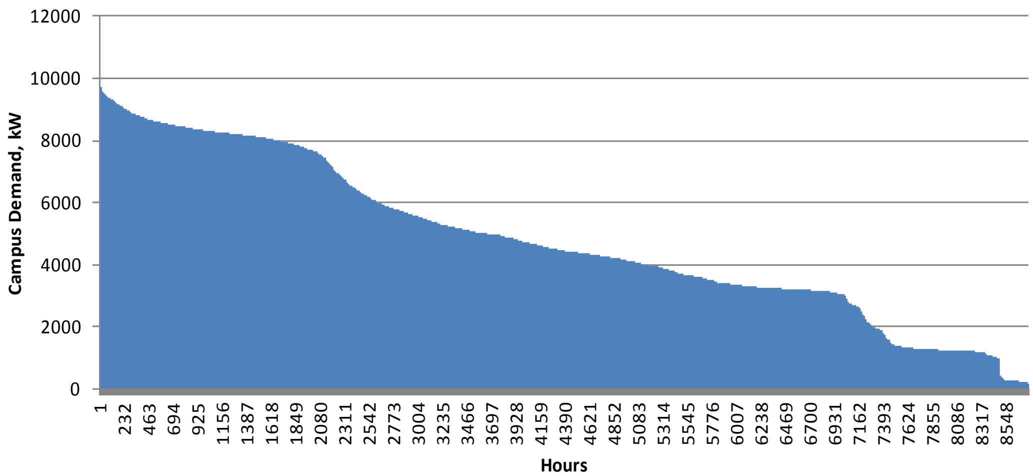

Figure 4.4 -- Campus Electric Load Duration Curve September 1, 2009 through August 31, 2010

Figure 4.5 is a plot of campus steam demand in pounds for every hour of the study period. The peak steam demand value was 53,439 pounds per hour. Conversely, a low demand value of 4,788 pounds was recorded by plant operators. The average steam demand was 36,943 pounds per hour.

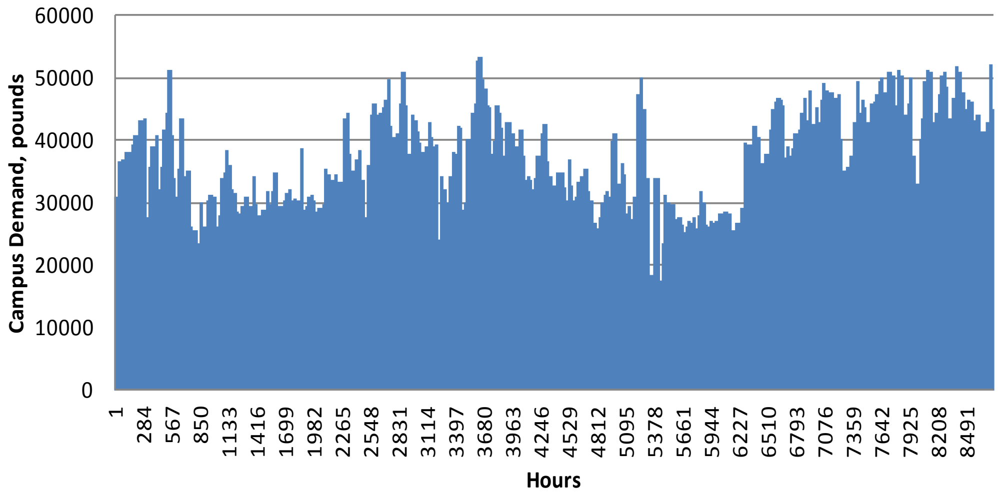

Figure 4.5 -- Campus Steam Demand, pounds of steam per hour versus hour September 1, 2009 through August 31, 2010

Figure 4.6 is a steam load duration curve with the same hourly data shown in Figure 4.5. Similar to an electric load duration curve, a steam load duration curve is generated by rearranging all interval data such that demand values are in the order from highest to lowest. Again, this type of plot illustrates the relationship between generating capacity requirements and capacity utilization. The area under the load duration curve represents the total heat energy demanded by the system in Steam pound-hours.

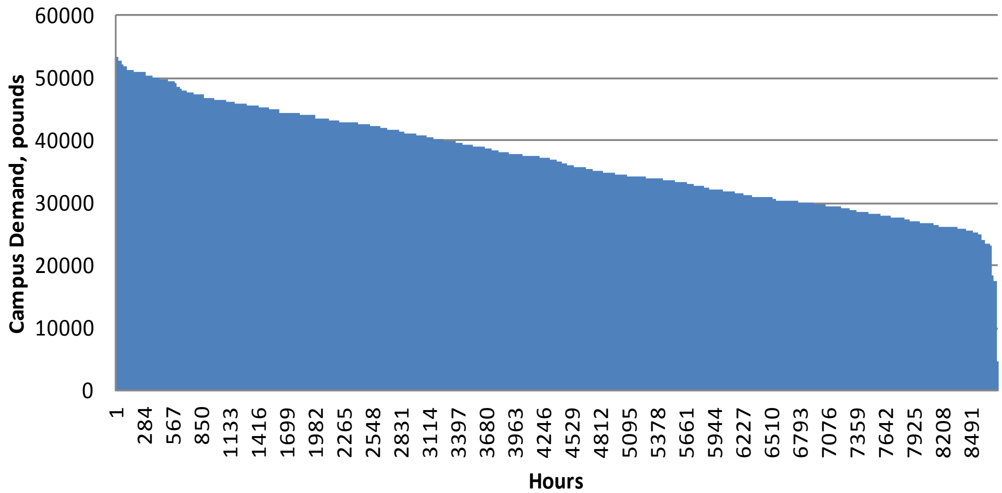

Figure 4.6 -- Campus Steam Load Duration Curve, September 1, 2009 through August 31, 2010

Tables 4.4 through 4.7 below show results of analyses for determination of CO_2 emissions coefficients for steam and electricity utilized by campus during the study period, September 1, 2009 through August 31, 2010. The results were determined the same way as described in Chapter 3 for FY07 data. The results of the analysis for FY07 data are repeated in Tables 4.4 through 4.7 for comparison.

Table 4.4 – Comparison of Plant Input Energies and CO_2 Emissions for FY2006/2007 and AY2009/2010 for CO_2 Emissions Coefficient Determination.

	FY 2006/2007 Plant Input Energy			AY 2009/2010 Plant Input Energy		
Fuel	Amount of Energy Consumed	Pounds of CO_2 Emissions Per Energy Unit	Total CO_2 Emissions, Pounds of CO_2	Amount of Energy Consumed	Pounds of CO_2 Emissions Per Energy Unit	Total CO_2 Emissions, Pounds of CO_2
Grid Electricity, kWh	38,684,195	0.981	37,949,195	26,028,266	0.981	25,533,729
Wind Rec Electricity, kWh	10,433,000	0.000	-	14,705,000	0.000	-
Grid Adjusted for w-recs, kWh	28,251,195	0.981	27,714,422	11,323,266	0.981	11,108,124
Natural Gas, Cubic Feet	369,689,900	0.120593	44,582,014	550,898,289	0.120593	66,434,477
Oil, Gallons	47,811	22.384	1,070,201	76,509	22.384	1,712,577
Total			73,366,638			79,255,179

Table 4.5 – Conversions of Plant Output Energies into Common Energy Units for Comparison of FY2006/2007 and AY2009/2010.

	FY 2006/2007 Plant Output Energy			AY 2009/2010 Plant Output Energy		
Utility Available to Campus	Amount of Available Utility	Energy Conversion Coefficient in BTUs per Energy Unit	Total Energy in BTUs	Amount of Available Utility	Energy Conversion Coefficient in BTUs per Energy Unit	Total Energy in BTUs
Electricity, kWh	41,194,911	3,412.142	140,562,886,009	50,383,290	3,412.142	171,914,939,907
Natural Gas, Cubic Feet	15,419,618	1,027	15,835,947,686	23,129,427	1,027	23,753,921,529
Steam, Pounds	245,866,586	1,196.230	294,112,986,171	319,963,943	1,196.230	382,750,467,535
Chilled Water, Ton-hours	2,020,263	12,000	24,243,156,000	3,030,395	12,000	36,364,734,000
Total			474,754,975,866			614,784,062,971

Table 4.6 – Preliminary Determinations of CO2 Emissions Coefficients for FY2006/2007 and AY2009/2010.

	FY 2006/2007 Preliminary CO_2 Emissions Coefficients			AY 2009/2010 Preliminary CO2 Emissions Coefficients		
Utility Available to Campus	Amount of Available Utility	Pounds of CO_2 Emissions Per Energy Unit	Total CO_2 Emissions, Pounds of CO_2	Amount of Available Utility	Pounds of CO_2 Emissions Per Energy Unit	Total CO_2 Emissions, Pounds of CO_2
Electricity, kWh	41,194,911	0.69825	28,764,347	50,383,290	0.9810	49,426,007
Natural Gas, Cubic Feet	15,419,618	0.120593	1,859,498	23,129,427	0.120593	2,789,247
Steam, Pounds	245,866,586	0.1547	38,029,742	319,963,943	0.0624	19,970,014
Chilled Water, Ton-hours	2,020,263	2.3330	4,713,274	3,030,395	2.3330	7,069,910
Total			73,366,861			79,255,179

Table 4.7 – Final Determinations of CO_2 Emissions Coefficients for FY2006/2007 and AY2009/2010.

	FY 2006/2007 Final CO_2 Emissions Coefficients			AY 2009/2010 Final CO_2 Emissions Coefficients		
Utility Available to Campus	Amount of Available Utility	Pounds of CO_2 Emissions Per Energy Unit	Total CO_2 Emissions, Pounds of CO_2	Amount of Available Utility	Pounds of CO_2 Emissions Per Energy Unit	Total CO_2 Emissions, Pounds of CO_2
Electricity, kWh	41,194,911	0.73713	30,366,128	50,383,290	0.4922	24,798,470
Natural Gas, Cubic Feet	15,419,618	0.120593	1,859,498	23,129,427	0.120593	2,789,247
Steam, Pounds	245,866,586	0.14503	35,658,031	319,963,943	0.1394	44,597,551
Chilled Water, Ton-hours	2,020,263	2.7141	5,483,204	3,030,395	2.3330	7,069,910
Total			73,366,861			79,255,179

Chapter 5

Optimization Approach and Analysis

This chapter presents an overall approach and analyses for optimization of campus energy system operation. Insight into demands placed on energy systems is presented in this chapter. Energy demands must be related to campus activities. Energy usage patterns evolve. As a result, a system establishing groups of days to simplify datasets has been devised. A concept of characterization of modeled energy days will be developed and presented. Parameters established for optimization analysis will be discussed in this chapter. Finally, an algorithm developed for optimization will be presented.

5.1 Developing Characteristic Days

To consider optimization of the cogeneration plant, it is necessary to establish an understanding of the energy demands placed on the plant. Energy demands on the plant are primarily functions of seasonal weather activities, as well as, campus activities. As such, characterization of energy demand through a full year of seasonal weather changes and a full range of campus activities must be developed. This chapter presents a model that characterizes energy demand over a one-year period. The purpose of this chapter is to illustrate the development of this characterization and provide a model for potential use in future studies.

During the period September 1, 2009 through August 31, 2010 (the study period), utility infrastructure and campus square footage remained constant. This consistency permitted a look at the newly developed energy relationship between the cogeneration plant and campus. As the cogeneration plant was placed into priority operation, energy production and usage profiles emerged. It was necessary to develop a model that characterized campus energy demand through a full year of seasonal weather changes and a full range of campus activities to consider optimization of the new plant.

Plant steam and electricity production data, and grid purchase data from Atlantic City Electric were gathered and reviewed. Quarter-hour interval data from Atlantic City Electric was totalized to provide grid purchases on a daily basis in a format similar to the plant steam and electricity production data. Daily produced electricity and purchased electricity was combined to determine campus daily electrical consumption. In a similar fashion, steam data for the three boilers and two cogeneration units were combined on a single spreadsheet to determine campus daily steam consumption. Table 5.1 is an excerpt of a table that shows campus steam and electrical demand for the first and last five days of the study period.

Table 5.1 -- Excerpt of table showing campus steam and electrical consumption for first and last five days of study period.

		Total Load	Total Load
		Steam, Pounds	Electricity, kWh
Day #	**Date**	**Campus**	**Campus**
1	Tuesday, September 01, 2009	745,000	198,229
2	Wednesday, September 02, 2009	882,000	198,858
3	Thursday, September 03, 2009	836,000	193,993
4	Friday, September 04, 2009	885,000	190,124
5	Saturday, September 05, 2009	913,000	196,542
⋮	⋮	⋮	⋮
361	Friday, August 27, 2010	997,440	29,844
362	Saturday, August 28, 2010	954,646	30,095
363	Sunday, August 29, 2010	1,029,554	28,957
364	Monday, August 30, 2010	1,253,171	29,728
365	Tuesday, August 31, 2010	1,079,942	29,556
	TOTAL CAMPUS LOAD	**338,140,224**	**49,513,257**
		Steam, Lbs.	**Electricity, kWh**

Review of the complete table referenced in Figure 5.1 indicated a diverse range of campus steam and electricity consumption throughout the study period. Review of the steam and electricity demand ranges was conducted to characterize the diversities. Academic calendars, published by the university, were obtained and are attached to this thesis.[20] The academic calendar provided all university holidays, semester beginning and end dates for fall, spring, and all five summer sessions, and finals weeks for the study period. Summer sessions consist of 3, 5, and 8 week semesters completed within a three-month period. To complete the five summer sessions in three months, it is necessary to overlap several of the sessions. Accordingly, campus occupancy varies during the summer season. In addition, information from Rowan University's Human Resources website indicated that during the summer season, the university switches from a five-day work schedule to a four-day work schedule, based on a Monday through Thursday workweek. Given the complexity of the academic calendar, it was necessary to first define blocks of representative days we will call academic characteristic days.

An academic characteristic day represents a group of days that are similar to each other, with respect to types of activities on campus. For example, during the study period, there were 76 fall semester weekdays observed in the academic calendar for the study period. During the 76 fall semester weekdays, it was assumed that campus occupancy was constant. This assumption permitted the 76 days to be grouped and represented by an academic calendar day we will call a Fall Semester Weekday. Table 5.2 below is a listing of twelve academic characteristic days developed from review of the academic calendar.

<u>Table 5.2 -- Academic Characteristic Days</u>

Fall Semester Weekday
Fall Semester Weekend Day
Spring Semester Weekday
Spring Semester Weekend Day
Summer Session Weekday
Summer Session Weekend Day
Non-Semester Weekday
Non-Semester Weekend Day
University Holiday – Single Day
University Holiday – Break
Spring Break
Residential Student Move-in Day

Each day of the study period was assigned one of the academic characteristic days from Table 5.2. A new table, Table 5.3, was generated by adding steam and electricity demand columns to Table 5.1. This permitted a review campus steam and electricity consumption by academic characteristic day. Table 5.3 is an excerpt of a table that shows campus steam and electrical consumption with academic characteristic days for the first and last five days of the study period.

Table 5.3 -- Excerpt of table showing assigned academic characteristic days for first and last five days of study period.

		Total Load	Total Load
	Assigned	Steam, Pounds	Electricity, kWh
Date	Academic Characteristic Day	Campus	Campus
Tuesday, September 01, 2009	Fall Semester Weekday	745,000	198,229
Wednesday, September 02, 2009	Fall Semester Weekday	882,000	198,858
Thursday, September 03, 2009	Fall Semester Weekday	836,000	193,993
Friday, September 04, 2009	Fall Semester Weekday	885,000	190,124
Saturday, September 05, 2009	Fall Semester Weekend Day	913,000	196,542
⋮	⋮	⋮	⋮
Friday, August 27, 2010	Residential Student Move-in	997,440	29,844
Saturday, August 28, 2010	Residential Student Move-in	954,646	30,095
Sunday, August 29, 2010	Residential Student Move-in	1,029,554	28,957
Monday, August 30, 2010	Residential Student Move-in	1,253,171	29,728
Tuesday, August 31, 2010	Residential Student Move-in	1,079,942	29,556
	TOTAL CAMPUS LOAD	**338,140,224**	**49,513,257**
		Steam, Lbs.	**Electricity, kWh**

A review of assigned academic characteristic days indicated instances when campus steam and electricity consumption continued to vary within diverse ranges. For example, university holidays occurred during all four seasons requiring various modes of campus heating, ventilation, and air conditioning (HVAC) equipment operation. To characterize campus steam and electricity demand throughout the study period in a more precise manner, it was necessary to incorporate the effect of seasonal weather changes as they related to operation of campus HVAC equipment. To incorporate seasonal weather changes, we now define a more developed representative day we will call an Energy Characteristic Day.

Similar to the concept of the academic characteristic day, an energy characteristic day represents a group of days that are similar to each other, with respect to campus energy usage, in addition to campus activities. For example, during the study period, there were nine single university holidays, not counting multiple day university holiday break periods. Of the nine single university holidays, three holidays occurred when air conditioning (cooling) equipment was operating. Four of the nine holidays occurred when heating equipment was operating. Further, two of the nine holidays occurred during the fall and spring seasons, when operations of campus heating and cooling systems were in states of transition. By assigning each single university holiday into one of three categories, cooling, heating, and mixed-mode, the nine holidays were grouped and represented by three distinct energy characteristic days. During each energy characteristic day, campus energy usage profiles were verified as comparable, with the assumption that campus occupancy was consistent. This permitted each academic characteristic day to be mapped into an energy characteristic day. Variations in energy consumption and campus activities resulted in the development of sixteen energy characteristic days. Note that fall, spring, and summer semester energy characteristic days were not associated with cooling, heating, or mixed modes. A review of steam and electricity usages on semester days indicated minimal variation, such that adding HVAC operating mode days was not merited. Table 5.4 below is a listing of the sixteen energy characteristic days developed as part of this study. The purpose of establishing these characteristic days was to establish a limited number of days with which to characterize the complete year of energy demands. This list represents a workable number of days.

However, it is likely that careful analysis could reduce the number of characteristic days required to model the year.

Table 5.4 – Table of Energy Characteristic Days

Fall Semester Weekday
Fall Semester Weekend Day
Spring Semester Weekday
Spring Semester Weekend Day
Spring Break Day
Summer Session/Four-Day Weekday
Summer Session/Four-Day Weekend Day
Non-Semester Weekday – Cooling Mode
Non-Semester Weekday – Heating Mode
Non-Semester Weekend Day – Cooling Mode
Non-Semester Weekend Day – Heating Mode
University Holiday – Cooling Mode
University Holiday – Heating Mode
University Holiday – Mixed Mode
Christmas/New Years Break Day
Low Occupancy / Moderate Cooling

Each day of the study period was assigned one of the energy characteristic days from Table 5.4 based on energy usage and campus activity. Steam and electricity demand for individual days, assigned to energy characteristic days, were summed and divided by the number of individual days, to calculate daily consumption totals for each energy characteristic day. The energy characteristic days were summed and compared to actual data from the plant. Table 5.5 summarizes campus steam and electrical consumption with energy characteristic days.

Table 5.5 -- Energy characteristic day model with campus steam and electrical consumption.

Energy Characteristic Day	# Days	Average lbs Steam/day	Total Steam, lbs	Average kWh Elec/day	Total Electric, kWh
Christmas/New Years Break Day	10	1,103,660	11,036,600	153,226	1,532,262
Fall Semester Weekday	76	842,000	63,992,000	200,431	15,232,780
Fall Semester Weekend Day	28	748,390	20,954,920	118,224	3,310,269
Non-Semester Weekday - Cooling Mode	5	1,141,480	5,707,400	121,690	608,449
Non-Semester Weekday - Heating Mode	15	937,410	14,061,150	139,336	2,090,042
Non-Semester Weekend Day - Cooling Mode	3	954,646	2,863,938	97,679	293,037
Non-Semester Weekend Day - Heating Mode	5	1,030,970	5,154,850	178,677	893,386
Spring Break Day	4	730,618	2,922,472	97,467	389,870
Spring Semester Weekday	74	837,534	61,977,516	124,237	9,193,526
Spring Semester Weekend Day	28	821,030	22,988,840	92,075	2,578,103
Summer Session/Four-Day Weekday	35	1,188,980	41,614,300	126,855	4,439,940
Summer Session/Four-Day Weekend Day	27	1,028,642	27,773,334	108,066	2,917,788
University Holiday - Cooling Mode	3	1,001,582	3,004,746	113,193	339,580
University Holiday - Heating Mode	4	849,000	3,396,000	186,812	747,247
University Holiday - Mixed Mode	2	762,000	1,524,000	195,516	391,031
Low Occupancy / Moderate Cooling	46	1,068,873	49,168,158	99,042	4,555,947
Averaged campus demand from char.days	**365**		**338,140,224**		**49,513,257**

Referring to Table 5.5, each energy characteristic day defined was assigned a group of individual days that occurred during the study period. The number of days varied by energy characteristic day as shown in column two. The "Average Lbs. Steam/Day" column represents daily averages of steam derived by averaging individual days within each characteristic day group. The "Total Lbs. Steam" column represents multiplication of columns two and three, providing daily steam demands, associated with each energy characteristic day. In a similar fashion, The "Average kWh Elec/Day" column was multiplied by the "# Days" column to provide daily electricity consumptions, associated with each energy characteristic day. The last row of Table 5.5 provides a summation of the number of days modeled throughout the study as a check. In addition, summations of modeled campus steam and electricity usage throughout the study period are shown in the last row of the table. The above model estimates steam consumption during the study period as 323,820,717 pounds of steam. Similarly, the model estimates electricity consumption during the study period as 49,513,257 kilowatt hours.

To assess the accuracy of the energy characteristic day model, actual energy data for individual days assigned to energy characteristic days, was entered into the energy characteristic day model and calculations were made. Results are shown in Table 5.6 below.

Table 5.6 -- Simulation of characteristic day model with actual campus steam and electricity.

Characteristic Day	Example Day	# Days	Steam lbs/day	Steam lbs	Electric kWh/day	Total Electric kWh
Christmas/New Years Break Day	12/28/09	10	1,103,660	11,036,600	153,226	1,532,262
Fall Semester Weekday	12/08/09	76	842,000	63,992,000	200,431	15,232,780
Fall Semester Weekend Day	10/10/09	28	748,390	20,954,920	118,224	3,310,269
Non-Semester Weekday - Cooling Mode	08/19/10	5	1,141,480	5,707,400	121,690	608,449
Non-Semester Weekday - Heating Mode	01/11/10	15	937,410	14,061,150	139,336	2,090,042
Non-Semester Weekend Day - Cooling Mode	08/28/10	3	954,646	2,863,938	97,679	293,037
Non-Semester Weekend Day - Heating Mode	01/09/10	5	1,030,970	5,154,850	178,677	893,386
Spring Break Day	03/17/10	4	730,618	2,922,472	97,467	389,870
Spring Semester Weekday	03/03/10	74	837,534	61,977,516	124,237	9,193,526
Spring Semester Weekend Day	03/13/10	28	821,030	22,988,840	92,075	2,578,103
Summer Session/Four-Day Weekday	07/06/10	35	1,188,980	41,614,300	126,855	4,439,940
Summer Session/Four-Day Weekend Day	07/10/10	27	1,028,642	27,773,334	108,066	2,917,788
University Holiday - Cooling Mode	05/31/10	3	1,001,582	3,004,746	113,193	339,580
University Holiday - Heating Mode	11/27/09	4	849,000	3,396,000	186,812	747,247
University Holiday - Mixed Mode	11/03/09	2	762,000	1,524,000	195,516	391,031
Low Occupancy / Moderate Cooling	08/08/10	46	1,068,873	49,168,158	99,042	4,555,947
Averaged campus demand from char.days		**365**		**338,140,224**		**49,513,257**
Modeled campus demand: Characteristic days		**365**		**338,140,224**		**49,513,257**
Actual campus demand 9/1/09 - 8/31/10				**323,820,717**		**50,383,290**
Difference, Energy Units				**14,319,507**		**870,033**
Percent Difference				**4%**		**2%**

As shown, total modeled campus steam demand for the study period was 338,140,224 pounds of steam. Actual steam demand recorded by plant operators during the study period was 323,820,717 pounds of steam. This equates to a difference of 14,319,507 pounds or 4%. In a similar fashion, total modeled campus electricity demand for the study period was 49,513,257 kilowatt hours. Actual electricity demand recorded by Atlantic City Electric was 50,383,290 kilowatt hours. This equates to a difference of 870,033 kilowatt hours or 2%. Differences of 4% and 2% are within a reasonable degree of engineering certainty. In addition, electricity and steam load duration curves were similar to characteristic day plots. It can be concluded that the above energy characteristic day model has sufficient accuracy for utilization within the overall optimization study.

5.2 Establishing Parameters

To characterize the performance of the cogeneration units and boilers, parameters must be developed to allow operation of the system to be optimized. The purpose of this chapter is to develop the parameters needed for the system model. A series of coefficients that characterize performance of the cogeneration units and boilers over the study period are presented. The parameters required are capacities of equipment, output per unit of natural gas fuel, cost of operation, carbon dioxide emissions per unit of natural gas fuel, and electricity purchased from the grid.

5.2.1 Efficiencies of Units

Given that the cogeneration plant and boilers utilize fossil fuels for energy input, it is important to quantify how efficient natural resources are being utilized during the production of electrical and thermal energies for campus usage. In this sense, we define efficiency as a ratio of input energy to the plant, divided by output energy produced by the plant and distributed to the campus. Review of plant records indicates that Boiler 1 utilized 16,345,804 cubic feet of natural gas during the study period. During this period when natural gas was selected as fuel, Boiler 1 produced 13,307,779 pounds of steam. This resulted in an energy input/out ratio of 1.228 cubic feet of natural gas per pound of steam. By inverting this ratio and representing it as a coefficient, it can be concluded that for every cubic foot of natural gas input, 0.814 pounds of steam are produced by Boiler 1. In a similar manner, coefficients for Boilers 2 and 3 were developed and are summarized in Table 5.7.

In the case of Cogeneration Units 1 and 2, quantities of steam and electricity energies, produced when natural gas was selected as fuel during the study period, were incorporated in the development of coefficients. Separate coefficients for steam and electricity were developed given the dual output nature of the cogeneration units. A summary of energy input/output coefficients for Boilers 1, 2, and 3 and Cogeneration Units 1 and 2 are presented in Table 5.7 below.

Table 5.7 -- Coefficients – Quantities of electricity and steam produced during one-year study period

Energy System	Natural Gas Consumed in cubic feet (CF)	Electricity Produced in kilowatt-hours (kWh)	Electricity Produced in kilowatt-hours per cubic foot of natural gas consumed (kWh/CF-gas)	Steam Produced in pounds (lbs.)	Steam Produced in pounds per cubic foot of natural gas consumed (lbs./CF-gas)
Boiler 1	16,345,804	-	-	13,307,779	0.814
Boiler 2	106,659,761	-	-	89,204,002	0.836
Boiler 3	69,569,439	-	-	59,275,051	0.852
Cogeneration Unit 1	66,312,732	3,952,599	0.0596	28,090,048	0.424
Cogeneration Unit 2	292,010,553	20,402,425	0.0699	121,057,073	0.415

Cogeneration unit 1 utilized 66,312,732 cubic feet of natural gas during the study period when natural gas was selected as a fuel. During this period, the generator component of cogeneration unit 1 produced 3,952,599 kilowatt-hours of electricity. This resulted in an overall gas-to-electrical energy conversion ratio of 16.777 cubic feet of natural gas per kilowatt-hour of electricity. Expressing this ratio in terms of a unit of natural gas, for every cubic foot of natural gas input, 0.0596 kilowatt-hours of electricity were produced. Also during the study period, the HSRG component of Cogeneration unit 1 produced 28,090,048 pounds of steam. This resulted in an overall gas-to-thermal energy conversion ratio of 2.361 cubic feet of natural gas per pound of steam. Expressing this ratio in terms of a unit of natural gas, for every cubic foot of natural gas input, 0.424 pounds of steam were produced. We can represent the overall energy balance of Cogeneration Unit 1 with the following relationships:

$E_{cgi} = E_{cge} + E_{cgh} - \text{Losses}$

Where E_{cgi} = Natural Gas Input Fuel Consumed, in cubic feet

E_{cge} = Electrical Output Energy Produced, in kilowatt-hours

E_{cgh} = Thermal Output Energy Produced, pounds of steam

1 cubic foot of natural gas $\Rightarrow$ 0.0596 kilowatt-hours + 0.424 pounds of steam

Cogeneration unit 2 utilized 292,010,553 cubic feet of natural gas during the study period when natural gas was selected as a fuel. During this period, the generator component of cogeneration unit 2 produced 20,402,425 kilowatt-hours of electricity. This resulted in an overall gas-to-electrical energy conversion ratio of 14.313 cubic feet of natural gas per kilowatt-hour of electricity. Expressing this ratio in terms of a unit of natural gas, for every cubic foot of natural gas input, 0.0699 kilowatt-hours of electricity were produced. Also during the study period, the HSRG component of Cogeneration unit 2 produced 121,257,073 pounds of steam. This resulted in an overall gas-to-thermal energy conversion ratio of 2.408 cubic feet of natural gas per pound of steam. Expressing this ratio in terms of a unit of natural gas, for every cubic foot of natural gas input, 0.415 pounds of steam were produced. Similar to Cogeneration Unit 1, we can represent the overall energy balance with the following mathematical relationship for Cogeneration Unit 2:

1 cubic foot of natural gas $\Rightarrow$ 0.0699 kilowatt-hours + 0.415 pounds of steam

A summary of energy input/output coefficients for Cogeneration Units 1 and 2 are presented in Table 5.7.

5.2.2 Cost and Emissions for Natural Gas and Electricity from the Grid

To characterize the economics associated with optimization of the cogeneration plant, parameters must be developed to allow economic performance to be optimized. In general, natural gas is purchased by Rowan University for a variety of commercial and residential applications including the cogeneration plant, boilers, heating and domestic water production equipment, emergency power generators, and laboratory equipment at various locations on campus. Each service is metered and designated by an account issued by Rowan University's local natural gas utility, South Jersey Gas, for billing and account management purposes. With a multitude of diverse natural gas services on campus, natural gas costs vary widely by location, gas volume, usage type, and rate structure. Consistent with the scope of this study, natural gas specifically purchased for the cogeneration units and boilers is presented solely in this paper.

The purchase cost of commercial natural gas for the cogeneration units and boilers at Rowan University can be broken down into three primary components, local transportation, regional transportation, and commodity. The local transportation component involves providing, maintaining, and operating equipment associated with local transportation and delivery of natural gas from a provider to the cogeneration units and boilers. Provided by South Jersey Gas, the local transportation component has defined utility rate structures known as utility rate tariffs. There are separate tariffs for the cogeneration units and boilers. The tariffs change over time and are regulated by the New Jersey Board of Public Utilities. According to the New Jersey State Department of the Treasury, natural gas sales and use tax exemptions are provided to cogenerating facilities in New Jersey. As such, Rowan University is exempt from paying sales tax on the natural gas commodity and both transportation components for natural gas serving the cogeneration units. However, Rowan University is not exempt from paying sales tax for natural gas serving the boilers, since boiler operations are not applicable under the cogeneration unit incentives.

The regional transportation component involves providing, maintaining, and operating equipment associated with the transportation of natural gas from wellheads through interstate pipelines for delivery to a provider. Unlike the local transportation component, the regional transportation component is not regulated. The regional transportation component is included with commodity billing. Again, Rowan University is exempt from paying sales tax for natural gas serving the cogeneration units, but not for the boilers.

The commodity purchasing component strictly involves the sale of natural gas on unregulated bases. Commodity rates are set on a daily basis through futures contracts established by trading futures on the New York Mercantile Exchange (NYMEX). Monthly volumes of natural gas are estimated and purchased in advance of actual usage months at rates established by the date of sale. When volumes of natural gas are purchased in excess of actual usage, remarketing of unused natural gas takes place on a monthly basis. During remarketing, it is not unusual to sell unused natural gas at a rate significantly less than commodity rates.

Rowan University utilizes a complex natural gas procurement strategy that involves hedging futures contracts in conjunction with decision-making by a committee referred to as the Energy Review Panel[21]. Through frequent monitoring of online real time pricing, historical and current data are analyzed and lock-in rate and gas allocation models are developed for decision-making by the Energy Review Panel. The overarching goal in this process is to provide utility budgetary control in a deregulated market. Rowan University also applies the same process to purchase electricity, a utility that is structured quite similar to natural gas.

Local transportation, regional transportation, and commodity natural gas is purchased by Rowan University in units of heat energy known as therms, which represents 100,000 BTU of energy. Therms are quantities of natural gas based on volumetric flow and adjusted for variations in the heat energy contents of the delivered natural gas. A conversion factor, known as a therm factor, varies and is reported on monthly natural gas bills. The therm factor converts volume (cubic feet) to thermal energy content (therms). Utility-owned natural gas meters are read by South Jersey Gas and measure gas volumes in cubic feet. Cogeneration and heat plant operators also monitor and record daily volumetric natural gas consumption in units of cubic feet separately, for cogeneration units 1 and 2, and boilers 1, 2, and 3. To conduct energy analyses, comparison of plant data with utility bill information requires an application of monthly therm factors to plant volumetric flow readings for consistency in units and accuracy in analysis.

Variations in heat energy content of delivered natural gas results in performance and efficiency variations in the cogeneration units and boilers. With less heat energy content in the fuel, additional natural gas volume is required to achieve the same output as fuel with higher content, resulting in additional purchases and increased costs. As discussed above, therm factors take the varying heat energy content of delivered natural gas into account.

Given the complexities of energy and economic analyses and efforts required to address multiple rate structures, futures contracts, tariffs, taxation, decision-making for purchases, remarketing, conversions, and energy content variation, it is beyond the scope of this research to conduct a high level energy and cost accounting review of all plant and utility bill records for the cogeneration units and boilers during the review period. Further, purchasing strategies evolve over time in response to changes in regulatory, statutory, and market conditions. Given that this paper is intended to create a model for future studies, it is reasonable to incorporate historical energy cost data published by the United States Energy Information Administration (EIA). Further, the EIA publishes natural gas prices in terms of cubic feet which, is consistent with units utilized in Rowan University plant records.

The EIA provides historical monthly natural gas prices for a variety of United States consumers. Historical monthly natural gas prices for New Jersey commercial consumers, during months of the review period, September 2009 through August 2010, were researched and downloaded from the EIA website. It was confirmed through EIA representatives, that the published prices incorporated local transportation, regional transportation, and commodity pricing. The published prices varied on a seasonal basis. Natural gas prices for all 12 months of the study period were averaged to establish a single rate that could be applied throughout the study period for purposes of this paper. The average natural gas price was $9.5242 per thousand cubic feet, and was used as an economic coefficient for natural gas in this paper. Seasonally varying values were within 7% of the economic coefficient.

Similarly, the EIA provides historical monthly electricity prices for a variety of United States consumers. Historical monthly electricity prices for New Jersey commercial consumers, during months of the review period, September 2009 through August 2010, were researched and downloaded from the EIA website. As with the case of natural gas, it was confirmed through EIA representatives that the published prices included local distribution, regional transmission, and generation pricing. Electricity prices for all 12 months of the study period were averaged to a single rate and applied throughout the study period for purposes of this paper. The average electricity price was $0.1372 per kilowatt-hour, which was used as the coefficient for electricity in this paper.

To quantify the environmental impact associated with optimization of the cogeneration plant, we must establish parameters that address environmental performance of the cogeneration plant. For purposes of this paper, environmental performance of the cogeneration plant is presented as a function of carbon dioxide (CO_2) emissions. CO_2 emissions, in the context of the cogeneration plant, come from two primary sources, grid electricity and natural gas.

Electricity purchased from Atlantic City Electric is produced by multiple generating plants that produce electricity in various ways. Resources utilized by the generating plants are categorized as renewable and non-renewable by ACE. In general, renewable resources are considered to be free of CO_2 emissions, while non-renewal resources are associated with CO_2 emissions. On an annual basis, ACE publishes a listing of generating resources and their percentage contribution to the total electricity they provide. In addition, Rowan University purchases wind renewable energy certificates (w-recs), adding to the complexity of establishing a parameter for CO_2 associated with electricity purchased from the grid.

A high level analysis of CO_2 quantification for grid electricity purchased by Rowan University was incorporated in a paper, "Assessing carbon dioxide emissions from energy at a university," published in 2008[22]. This publication was based on Rowan University energy data from 2006 and 2007. A review of ACE's mixture of generating resources and associated percentage contributions from 2007 through 2010 indicates that minimal changes had taken place. In addition, w-rec purchases were relatively constant during the same period. Therefore, it is reasonable to incorporate CO_2 emissions for grid electricity from the high level analysis presented in the 2008 paper into this analysis. A value of 0.981 pounds of CO_2 emitted per kilowatt-hour of electricity generated from the grid, is an appropriate coefficient for utilization in this paper.

In the case of natural gas utilized by the cogeneration plant, an analysis of CO_2 emissions was also presented in the 2008 paper mentioned in the paragraph above. The paper used a value of 120.593 pounds of CO_2 emitted per 1,000 cubic feet of natural gas as obtained from the EIA[23]. A summary of economic and environmental coefficients for boilers 1, 2, and 3, and Cogeneration Units 1 and 2 are presented in Table 5.8 below.

Table 5.8 -- Economic and Environmental Coefficients for Grid Electricity and Natural Gas Utilities

Coefficient Description	**Coefficient**	**Units**
Grid Electricity Cost	0.1372	\$/kW-hr
Natural Gas Cost	9.5242	\$/1000 ft^3
Grid Electricity CO_2 Emissions	0.981	lb CO_2/kW-hr
Natural Gas CO_2 Emissions	120.593	lb CO_2/1000 ft^3

5.2.3 Algorithm for Analysis

Optimized operation requires numerical analyses that process multiple instructions over wide ranges of data, subject to multiple boundary conditions. To develop programming instructions for the evaluation of operating data and equipment contributions, a generalized flowchart was prepared and is shown in Figure 5.1. As shown, two criteria groups establish program boundary conditions that are consistent with objectives of this study. Criteria groups include minimization of operational costs and minimization of carbon dioxide emissions. A comparator determines whether data meets the established criteria. Data that does not meet the program criteria ceases to be processed further, reaching the end point of the program. Data that meets program criteria is further processed with calculations and routed back through the program and compared with criteria again. The process continues to repeat until all feasible solutions are identified.

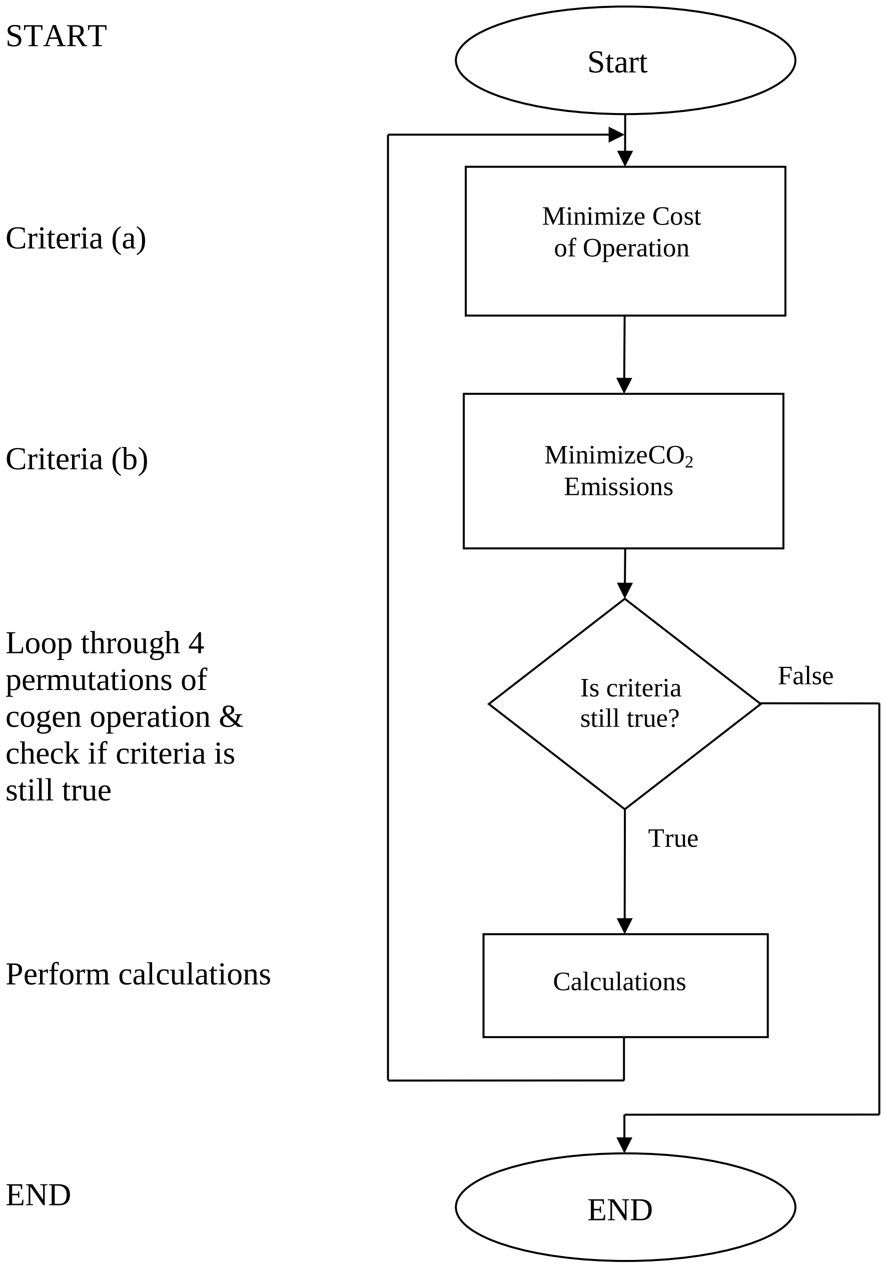

Figure 5.1 Generalized Flowchart for Optimization Program

To determine optimal operation of the cogeneration plant, parameters developed in Chapter 5 were combined with operational data and a set of repetitive instructions, to evaluate the data over wide ranges. Numerical programming was chosen in conjunction with matrix linear algebra. Vectors were defined to characterize contributions of primary plant equipment in various operational configurations, over equipment operating ranges.

A general format for vector representation is as follows:

V = [CG1, CG2, BO1, BO2, BO3, GRI]

Where, CG1 = Cogeneration Unit 1 (1.2 MW unit)
CG2 = Cogeneration Unit 2 (3.5 MW unit)
BO1 = Boiler 1 (26,000 pounds/hour)
BO2 = Boiler 2 (40,000 pounds per hour)
BO3 = Boiler 3 (40,000 pounds per hour)
GRI = Grid Purchases (KW)

The vectors defined below, were developed to numerically characterize plant equipment operation in various configurations as follows:

Equipment Operation Vector, EQUIPOP

EQUIPOP is an array that represents operational states of plant energy production equipment including electricity supplied from the grid. The array is represented as a vector that characterizes all permutations of the general vector format shown above, with respect to equipment operational states. To represent "ON" and "OFF" states of equipment operation, a numerical system of zeroes and ones is utilized. If a particular piece of equipment is in a shutdown state, this state is represented with a zero. Conversely, if the equipment is in an operating state, this state is represented with a one. For example, EQUIPOP = [0, 1, 0, 1, 0, 1] represents a state of equipment operation as follows:

Cogeneration Unit 1 is shut down,	[0]
Cogeneration Unit 2 is operating at full capacity,	[1]
Boiler 1 is shut down,	[0]
Boiler 2 is operating at full capacity,	[1]
Boiler 3 is shut down,	[0]
Grid is supplying 1 kW of electrical energy,	[1]

<u>Electrical Production Vector, ELECPROD</u>

ELECPROD is an array that represents electrical power in kilowatts solely produced by the various plants at capacity. ELECPROD = [1,200, 3,500, 0, 0, 0, 0] represents the following states of electrical energy production by the various aspects of the campus plant:

Cogeneration Unit 1 produces 1,200 kilowatts of electrical power,	[1,200]
Cogeneration Unit 2 is produces 3,500 kilowatts of electrical power,	[3,500]
Boiler 1 does not produce electrical power,	[0]
Boiler 2 does not produce electrical power,	[0]
Boiler 3 does not produce electrical power,	[0]
Grid is not supplying electrical power,	[0]

<u>Steam Generation Vector, STEAMPROD</u>:

STEAMPROD is an array that represents steam produced by the cogeneration and boiler plants at capacity. Cogeneration units 1 and 2 are equipped with heat recovery steam generators, one each, to utilize turbine exhaust heat for conversion of water into steam. STEAMPROD = [8724, 20260, 26000, 40000, 40000, 0] represents the following states of thermal energy production by the campus energy system at full capacity:

Cogeneration Unit 1 produces 8,724 pounds of steam per hour at capacity,	[8724]
Cogeneration Unit 2 produces 20,260 pounds of steam per hour at capactity,	[20260]
Boiler 1 produces 26,000 pounds of steam per hour at capacity,	[26000]
Boiler 2 produces 40,000 pounds of steam per hour at capacity,	[40000]
Boiler 3produces 40,000 pounds of steam per hour at capacity,	[40000]
Grid does not supply steam,	[0]

Natural Gas Usage Vector, GASUSE:

GASUSE is an array that represents natural gas consumed by the cogeneration and boiler plants at capacity. The array is represented as a vector that characterizes all permutations of natural gas usage. Values in the array are expressed in units of 1,000 cubic feet of natural gas per hour (MCF/hour). GASUSE = [20.575, 48.819, 31.941, 47.847, 46.948, 0] represents the following states of natural gas consumed by the campus energy system at full capacity:

Cogeneration Unit 1 consumes 20.575 MCF/hour of gas,	[20.575]
Cogeneration Unit 2 consumes 48.819MCF/hour of gas,	[48.819]
Boiler 1 consumes 31.941MCF/hour of natural gas,	[31.941]
Boiler 2 consumes 47.847MCF/hour of natural gas,	[47.847]
Boiler 3 consumes 46.948MCF/hour of natural gas,	[46.948]
Grid does not consume natural gas,	[0]

Grid Electricity Usage Vector, GRIDUSE:

GRIDUSE is an array that represents electricity supplied by the grid. The array is represented as a vector that characterizes all permutations of electricity supplied by the grid. Values in the array are expressed in units of kilowatts. For example, GRIDUSE = [0, 0, 0, 0, 0, 1] represents the following states of electricity supplied by the grid:

Cogeneration Unit 1 supplies electricity to the campus only,	[0]
Cogeneration Unit 2 supplies electricity to the campus only,	[0]
Boiler 1 supplies steam to the campus only,	[0]
Boiler 2 supplies steam to the campus only,	[0]
Boiler 3 supplies steam to the campus only,	[0]
1 kilowatt of electricity is being supplied by the grid,	[1]

Development of the optimization algorithm incorporated the use of the vectors described above, a series of data files representing steam and electricity demand for each characteristic day, and a set of code programming instructions based on the objectives of this thesis. The program was run with MATLAB software with input files created by merging utility interval data with plant operating records. The complete code used for these analyses can be found in Appendix I.

Chapter 6

Optimized Operations

In this chapter, we discuss optimized operations of the cogeneration plants and boilers. This includes how optimization is defined within the context of this paper. A review of operating hours and utilization analysis of each cogeneration and boiler unit is presented. Equipment operating constraints are presented. Finally, a description of optimized operations, as defined by this paper, is presented.

In general, optimization goals for energy production and conversion facilities are driven by strategies developed by ownership and management. Historically, such goals and strategies have often been driven by maximizing revenues and minimizing expenses. This approach often takes the form of negotiating energy contracts to minimize utility costs, minimizing labor, minimizing production and conversion equipment downtime, minimizing waste, and maximizing plant equipment efficiency and output. This chapter focuses on optimizing the operation of cogeneration and boiler plant equipment based on the two goals set forth in this paper, economics of natural resources, and the environment.

Figure 6.1 is an electric load duration curve developed with data from the study period. Electrical capacity limit lines for utility and cogeneration plant equipment have been superimposed onto the load duration curve. The limit line for the utility (grid) is shown coincident with a campus peak demand that approached 10,000 kilowatts during the study period. This representation is intended to illustrate plant equipment electrical capacities, relative to campus demand. Typically, the grid represents an abundant supply of electricity that is limited by the capacities of generation, transmission, and distribution equipment owned by local electricity providers.

Base load hours of operation for each cogeneration unit are shown in Figure 6.1 and indicated by vertical red lines that intersect with horizontal red capacity limit lines superimposed onto the load duration curve. Of a possible 8,760 hours of operation per year, there exists sufficient campus electrical demand to operate only cogeneration unit 1 for 8,300 hours. This represents approximately 95 percent or 346 days of the study period. In a similar manner, throughout the study period, there exists sufficient electrical demand to operate only cogeneration unit 2 for 6,061 hours. This represents approximately 69 percent or 253 days of the study period. Again, we show that the grid is available to provide electricity in excess of levels produced by the cogeneration units when operated individually, in combination, or in the case neither unit is operating. A discussion of combined operation of cogeneration units 1 and 2 follows this paragraph.

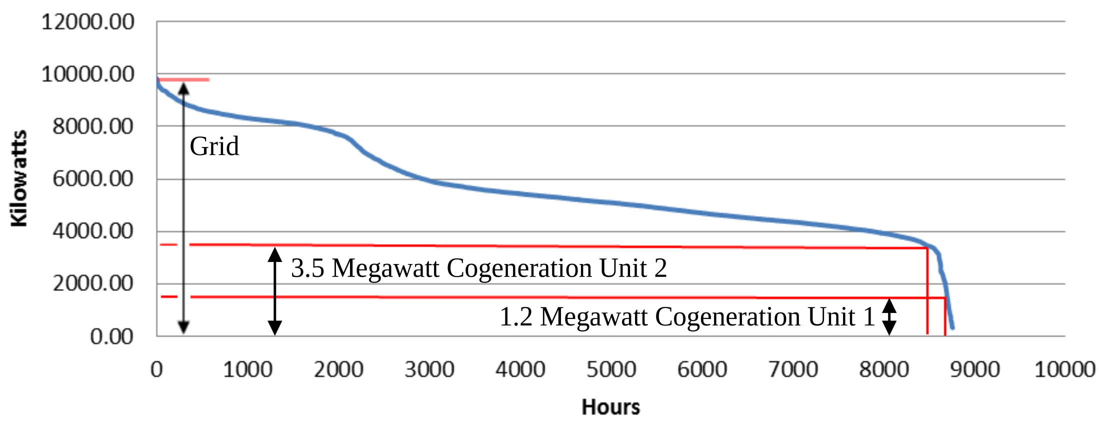

Figure 6.1 -- Campus electric load duration curve during study period with utility and cogeneration plant equipment capacity limit lines superimposed. Shown as peak campus electrical demand, actual grid capacity is 20 megavolt-amperes, limited by 69/12.47 kilovolt substation owned, operated, and maintained by Rowan University.

Figure 6.2 is a variation of Figure 6.1 with electrical capacity limit lines in a stacked configuration. As shown, cogeneration unit 1 is designated as the base load unit and first placed into operation to supply a base electrical load that exists for 95 percent of the study period. When campus electrical load reaches a level greater that 1.2 megawatts, cogeneration unit 2 is placed into operation. Combined operation of cogeneration units 1and 2 provide a supply of electricity limited to 4.7 megawatts to an electrical load with a duration of 3,940 hours or 45 percent of the study period. Again, the grid is available to provide electricity in excess of levels produced by the cogeneration units, individually, in combination, or in the case neither unit is operating.

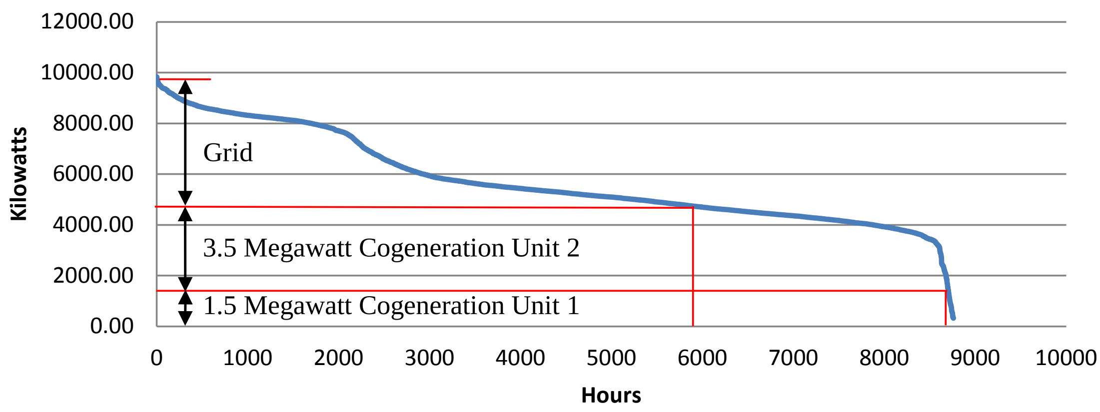

Figure 6.2 -- Campus electric load duration curve during study period with stacked utility and cogeneration plant equipment electrical capacity limit lines superimposed.

Figure 6.3 is a variation of Figure 6.2 with the order of cogeneration unit operation reversed. As shown, cogeneration unit 2 is designated as the base load unit and first placed into operation to supply a base electrical load that exists for 5,800 hours or 66 percent of the study period. When campus electrical load reaches a level greater that 3.5 megawatts, cogeneration unit 1 is placed into operation. Combined operation of cogeneration units 1and 2 provide a supply of electricity to 4.7 megawatts to an electrical load with a duration of 3,940 hours or 45 percent of the study period. Again, the grid is available to provide electricity in excess of levels produced by the cogeneration units, individually, in combination, or in the case neither unit is operating. Plant records indicated that during the study period, cogeneration unit 1 operated 3,617 hours and cogeneration unit 2 operated 6,574 hours. These hours of operation are of an order of magnitude that is reasonable compared to the configuration presented in Figure 6.3. This is indication that the Figure 6.3 represents the sequence of operation likely implemented during the study period.

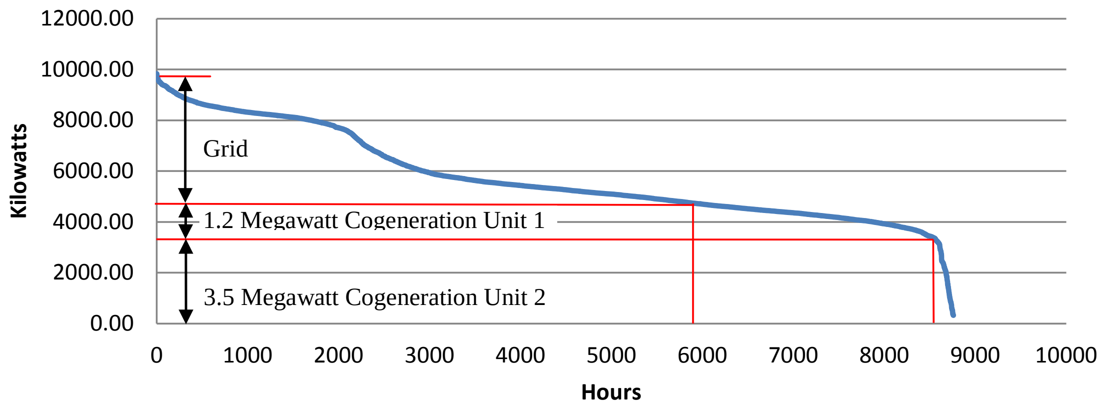

Figure 6.3 -- Campus electric load duration curve during study period with stacked utility and cogeneration plant equipment electrical capacity limit lines superimposed.

Figure 6.4 is a steam load duration curve developed with data from the study period. Steam capacity limit lines for cogeneration plant and boiler equipment have been superimposed onto the load duration curve. Again, base load hours of operation for each cogeneration unit and boiler are indicated by vertical red lines that intersect with horizontal red capacity limit lines and the load duration curve. By observation, neither cogeneration units 1 or 2 alone have sufficient capacities to meet the required base campus steam load. In combination, cogeneration units 1 and 2 can meet the required base campus steam load. Also by observation, boiler 1 can meet the required base campus steam load. Boilers 2 and 3 have individual capacities equivalent to 75% of the peak steam demand of 53,439 pounds per hour reached during the study period. By summation of steam capacities of the cogeneration units and boilers, the combined steam capacity is 134,984 pounds of steam per hour. The combined steam capacity of the cogeneration units and boilers is greater than 2.5 times the peak steam demand reached during the study period. The purpose of this redundancy is to achieve equipment reliability. Unlike having the flexibility of purchasing electricity from by the grid, the cogeneration units and boilers are energy conversion devices. There is no district steam or other steam utility source in the vicinity of the Rowan University campus. This configuration of equipment with varying capacities provides multiple choices for flexible equipment operation, to meet diverse campus steam demand conditions in a reliable manner.

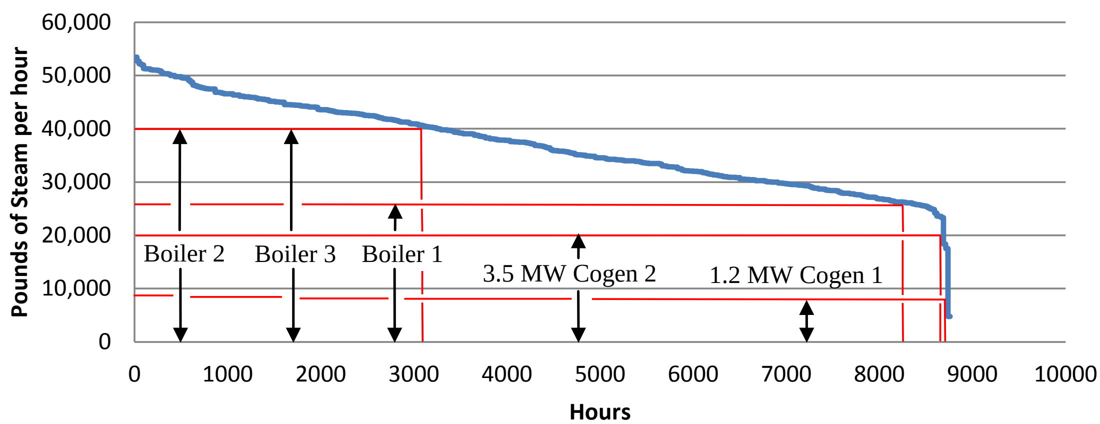

Figure 6.4 -- Campus steam load duration curve during study period with boiler and cogeneration plant equipment steam capacity limit lines superimposed. Steam is in units of pounds.

To meet campus steam demand requirements, the boilers can be started from cold or adjusted for increased output while already in hot standby mode. Recalling that the boilers at Rowan University are water-tube boilers, boiler feedwater flows through a series of tubes, the outside surfaces of which are heated by combustion gases that flow around the tubes as the gases pass through the boilers. The tubes are manufactured from copper. Other metallic boiler components are manufactured from various grades of steel used for casings, drums, shells, tube sheets, inlet and outlet pipe connections, burner components, stack components, and fasteners. Material properties such as thermal conductivity and thermal expansion vary among dissimilar metallic materials. In an assembly comprised of dissimilar metals such as a boiler, care must be taken to avoid rapid temperature transitions as dissimilar metals will expand or contract at different rates. Uneven expansion and contraction of dissimilar results in stresses associated with components that interfere with each other. Such stresses can cause material failures such as cracking and leaks.

The flame temperature of combustion for a mixture of natural gas and air is 1950°C. Ambient room temperature within the boiler plant is an average 25°C. When the boilers have been shut down for an extended period, materials within the boilers are at room temperature. During boiler start-up, boiler materials, combustion chamber and stack components, and feedwater in tubes in the vicinity of the burner and flame are heated from 25°C to temperatures approaching 1950°C, a difference of 1925°C. The boiler shells are insulated from the combustion chamber with refractory materials and as a result, sustain reduced temperature differentials during boiler start-up. If the burner firing rate is set to minimum during a cold start-up, the distribution of heat to surfaces within the boiler will be gradual and controlled, allowing for reduced thermal stresses, resulting in a less incidence of material failures. Referred to as the warm-up phase of boiler start-up, operating the boiler at minimum firing rate is a period during which the boiler cannot achieve consistent steam production at rated levels. Therefore, during warm-up, the boiler cannot be relied on to meet increased campus steam demand requirements.

Another factor in the warm-up phase of boiler start-up is phase change of the boiler feedwater. Boilers at Rowan University generate steam. Unlike their hot water boiler counterparts that increase boiler return water temperature only, steam boilers must convert feedwater into steam, in addition to increasing feedwater temperature. To change feedwater to steam, heat energy must be added to the feedwater at a rate equal to, or greater than, the latent heat of vaporization for water, 970.4 BTUs per pound. Increased heat energy requirements for conversion from water to steam result in longer boiler warm-up and start-up periods.

From cold starts, warm-up periods for the three boilers at Rowan University generally take two-to-three hours. After this period, the boilers can be placed online, operate in normal steam production mode, and respond to varying campus steam demand requirements.

Hot standby mode refers to maintaining heat in the boilers by continuous low-level firing, in conjunction with periodic increased firing for short durations. Operating boilers in hot standby mode requires fuel that does not directly contribute to steam production. However, this fuel penalty provides steam production readiness and reliability in response to varied campus steam demands. Boiler 1, the oldest of the three boilers and built in 1960, requires continuous low-level firing and increased incremental firing once or twice on a manual basis each 8-hour shift to maintain hot standby mode. Boilers 2 and 3 were built in 2004 and are equipped with mud drum heaters. The mud drum heaters automatically maintain 75 pounds per square inch of steam pressure in the boiler tubes for warm standby mode. For hot standby mode, the mud drum heaters in boilers 2 and 3 increase pressure in the boiler tubes to 135 pounds per square inch once per 8-hour shift. Automated mud drum heater operation reduces standby fuel usage and cost penalties. Once in hot standby mode, boilers 1, 2, and 3 require 20-30 minutes to be placed online, operate in normal steam production mode, and respond to varying campus steam demand requirements. As a result of these operational considerations, the simulation assumes all boilers operate at least five percent capacity all the time.

The heat recovery steam generators (HRSGs) for cogeneration units 1 and 2 use no fuel and therefore are not considered fired. Rather, the HRSGs utilize combustion gases exhausted from the turbine components of cogeneration units 1 and 2. While the gas turbine generator sets can be brought online rapidly from a cold start, the HRSGs require warm up before they generate adequate steam. Similar to the boilers, HRSG feedwater flows through a series of tubes, the outside surfaces of which are heated by combustion gases that flow around the tubes as the gases pass through the HRSGs. HRSG materials of construction include copper and various grades of steel. With similarities in terms of materials of construction and methods of heat transfer, the HRSGs have similar problems as the boilers, requiring consideration for the rapidity at which they are brought on line.

Since there is no burner or fire to regulate, the HRSGs are unfired shell and tube heat exchangers that do not have formal warm-up controls like the boilers. Manufactured in 2006 and rated at 8,300 pounds per hour and 19,550 pounds per hour, the HRSGs are physically smaller and rated for considerably less steam output than the boilers. The HRSGs have smaller components that can better sustain rapid variations in thermal activity. From a cold start, the HRSGs can be placed online, operate in normal steam production mode, and respond to varying campus steam demand requirements within two hours. However, the electricity generation components of the cogeneration units can be brought on line faster. From a cold start, the turbogenerator components of the cogeneration units can be placed on line and operate in normal production mode within one hour.

Chapter 7

Results and Discussion

This chapter presents results and discussion of point-in-time and break-even analyses based on economic and environmental conditions, characteristic day simulations, and sensitivity analyses of the mathematical model developed in this thesis. One goal of this chapter is to provide an increased understanding of the relationships between input and output variables of the model. Relationships between operation of the cogeneration plant and variations of electricity purchased from the grid will be presented and discussed. Conditions will be identified that recommend alternate cogeneration unit operating scenarios based on costs and CO_2 emissions. The role of the cogeneration plant for reliability and emergency preparedness will be discussed.

7.1 Point in Time Analysis -- Economics

In review of cogeneration plant operational choices, we now take a look at economic considerations through point-in-time calculations. Let's assume cogeneration unit 1 is operating at full capacity. Recall that at full capacity, cogeneration unit 1 produces 1,357 kilowatts of electricity and 8,724 pounds of steam per hour. Coefficients presented in Table 5.7 indicate that for every cubic foot of natural gas consumed by cogeneration unit 1, 0.0596 kilowatt-hours of electricity are produced. We calculate the one-hour natural gas consumptive requirement as follows:

$$1{,}357 \frac{kWh}{hour} \times \frac{1\ CF\ Gas}{0.0596\ kWh} = 22{,}768.46 \text{ CF Gas per hour}$$

Recall from Table 5.8 that the cost of natural gas during the study period is $9.5242 per 1,000 cubic feet. We calculate the one-hour natural gas purchase cost for cogeneration unit 1 as follows:

$$22{,}768.46\ \frac{CF\ Gas}{hour} \times \frac{\$9.5242}{1{,}000\ CF\ Gas} = \$216.85\ per\ hour$$

Replacing the energy production of cogeneration unit 1 requires that an amount of electricity and steam equivalent to the amount that would have been produced by cogeneration unit 1, be purchased from the grid, and produced by the campus boilers, respectively. Recall from Table 5.8 that the cost of electricity from the grid during the study period is $0.1372 per kilowatt hour. We calculate the cost of the electricity purchased from the grid as follows:

$$1{,}357\ \frac{kWh}{hour} \times \frac{\$0.1372}{kWh} = \$186.18\ per\ hour$$

Boiler 2 was selected for operation due to its high efficiency rating relative to boiler 1. We first calculate how much natural gas is required for boiler 2 to produce 8,724 pounds of steam. From Table 5.7, boiler 2 produces 0.836 pounds of steam for every cubic foot of natural gas. We calculate how much natural gas is required for boiler 2 to produce 8,724 pounds of steam as follows:

$$8{,}724\ \frac{lbs\ Steam}{hour} \times \frac{1\ CF\ Gas}{lb\ Steam} = 10{,}435.40\ Cubic\ feet\ of\ gas\ per\ hour$$

$$10{,}435.40\ \frac{CF\ Gas}{hour} \times \frac{\$9.5242}{1{,}000\ CF\ Gas} = \$99.39\ per\ hour$$

Adding the cost of purchasing electricity from the grid to the cost of purchasing natural gas to produce steam in boiler 2, we calculate the hourly cost of shutting down cogeneration unit 1 as follows:

$$\frac{\$186.18}{hour} + \frac{\$99.39}{hour} = \$285.57\ per\ hour$$

Recall the cost of operating cogeneration unit 1 at full capacity is $216.85 per hour. This amount is $68.72 per hour less expensive that purchasing electricity from the grid and operating boiler 2 to supplement the steam that would have been produced by cogeneration unit 1. From this calculation, it can be concluded that, under current cost and emissions, operating cogeneration unit 1 is more economical than purchasing electricity from the grid as long as there is sufficient demand for the electricity and steam produced by cogeneration unit 1.

By preparing similar calculations to cogeneration unit 2, we find the following:

$$3{,}867\ \frac{kWh}{hour} \times \frac{1\ CF}{0.0699\ kWh} = 55{,}321.89 \text{ cubic feet of gas per hour}$$

$$55{,}321.89\ \frac{CF\ Gas}{hour} \times \frac{\$9.5242}{1{,}000\ CF\ Gas} = \$526.89\ per\ hour$$

$$3{,}867\ \frac{kWh}{hour} \times \frac{\$0.1372}{kWh} = \$530.55\ per\ hour$$

$$20{,}260\ \frac{lbs\ Steam}{hour} \times \frac{1\ CF\ Gas}{0.836\ lb\ Steam} = 24{,}234.45\ cubic\ feet\ of\ gas\ per\ hour$$

$$24{,}234.45\ \frac{CF\ Gas}{hour} \times \frac{\$9.5242}{1{,}000\ CF\ Gas} = \$230.81\ per\ hour$$

Adding the cost of purchasing electricity from the grid to the cost of purchasing natural gas to produce steam in boiler 2, we calculate the hourly cost of shutting down cogeneration unit 2 as follows:

$$\frac{\$530.55}{hour} + \frac{\$230.81}{hour} = \$761.36\ per\ hour$$

The cost of operating cogeneration unit 2 at full capacity is \$526.89 per hour. This amount is \$234.47 per hour less expensive that purchasing the equivalent amount of electricity from the grid and operating boiler 2 to supplement the steam that would have been produced by cogeneration unit 2. From this calculation, it can be concluded that operating cogeneration unit 2 is more economical than purchasing from the grid.

We now review economic operating scenarios representing simultaneous operation of both cogeneration units at full capacity. Recall that cogeneration units 1 and 2 have respective operating costs of \$216.85 per hour and \$526.89 per hour. By adding these values, we obtain a single value of \$743.74 per hour for combined cogeneration unit operation. In a similar manner, we combine grid and boiler hourly costs for the scenario involving shutdown of both cogeneration units. We sum the values $285.57 per hour (cogeneration unit 1 off) and $761.36 per hour (cogeneration unit 2 off) for a total value of $1,046.93 per hour representing a combined unit shutdown. Comparing hourly operating costs associated with simultaneous cogeneration operation and simultaneous shutdown resulted in a difference of $303.19 per hour. As in the cases of individual operation of cogeneration units 1 and 2 at full capacity, purchasing electricity from the grid and operating boiler 2 is more expensive than simultaneous operation of both cogeneration units at full capacity by $303.19 per hour. It can also be concluded that cogeneration units 1 and 2 operated in any combination is less expensive that purchasing electricity from the grid and producing steam from campus boilers, as long as there is sufficient demand for the electricity and steam produced.

7.2 Economic Break-Even Point

From the above, we observe that purchasing electricity from the grid and operating the boilers is more expensive than all possible combinations of cogeneration unit operation, as long as there is sufficient demand for both the electricity and steam produced by the cogeneration units. We now determine the economical break-even point between cogeneration unit operation and grid purchases. To determine the economical break-even point, we set the cost of electricity (in $/kWh) as the variable, and assume full cogeneration unit production. We then solve for the cost of electricity that makes the two cases equivalent. The cost of running both cogeneration units, C_c for one hour is found by

$$Cc = \left(1{,}357\ kWh \times \frac{1\ CF\ Gas}{0.0596\ kWh} \times \frac{\$9.5242}{1{,}000\ CF\ Gas}\right) + \left(3{,}867\ kWh \times \frac{1\ CF\ Gas}{0.0699\ kWh} \times \frac{\$9.5242}{1{,}000\ CF\ Gas}\right) = \$743.74$$

Combined, the two cogeneration units produce 5,224 kWh and 28,984 lb steam per hour. The hourly cost of grid purchases and operating the boilers to replace production from both cogeneration units, C_{g+b} can be found by

$$C_{g+b} = \left(5{,}224\ kWh \times Cg\,\frac{\$}{kWh}\right) + \left(28{,}984\ lb\ Steam \times \frac{1\ CF\ Gas}{0.836\ lb\ Steam} \times \frac{\$9.5242}{1{,}000\ CF\ Gas}\right) = 5{,}224\ C_g\,\frac{\$-kWh}{kWh} + \$330.20$$

Where Cg is the cost of purchasing electricity from the grid in \$/kWh.

Using parameters previously developed in this thesis: \$9.5242 per cubic foot for natural gas, 0.836 pounds of steam produced per cubic foot of natural gas consumed by boiler 2, 0.0596 kilowatt hours produced per cubic foot of natural gas consumed by cogeneration unit 1, and 0.0699 kilowatt hours produced per cubic foot of natural gas consumed by cogeneration unit 2.

At the economic break-even point, $C_c = C_{g+b}$

$$\$743.74 = 5{,}224\ C_g \frac{\$-kWh}{kWh} + \$330.20$$

Solving for C_g, the economic break-even point for production versus purchasing is:

C_g = \$0.07916 per kilowatt hour

Applying the same methodology to individual operating cases of cogeneration units 1 and 2, below are the following economic break-even points for production versus purchasing.

C_{Cogen1} = \$0.0866 per kilowatt hour

C_{Cogen2} = \$0.0766 per kilowatt hour

Table 7.1 includes a summary of hourly costs for operating scenarios of the cogeneration units at full capacity. The economic break-even points developed above are also listed in Table 7.1.

Table 7.1 – Summary of CO_2 emissions, costs, and break-even points for operating scenarios of cogeneration units at full capacity.

Operating Scenario	Operating Cost, $/hr	CO_2 Emissions, lbs/hr
Operate Cogeneration Unit 1	216.85	2,745.72
Replace Cogen Unit 1 with Grid and Boilers	285.57	2,589.66
Operate Cogeneration Unit 2	526.89	6,671.43
Replace Cogen Unit 2 with Grid and Boilers	761.36	6,716.04
Operate Cogeneration Units 1 and 2	743.74	9,417.15
Replace Cogen Units 1 and 2 with Grid and Boilers	1046.93	9,305.70
Cogeneration Operating Break-even Points	Economic, $/kWh	Environmental, lb CO_2/kWh
Operate Cogeneration Unit 1	0.0866	1.096
Operate Cogeneration Unit 2	0.0766	0.9695
Operate Cogeneration Units 1 and 2	0.0792	1.0023

7.3 Point in Time Analysis – Environmental Impacts

We now quantify the environmental impacts of operating the cogeneration units in terms of CO_2 emissions. Again, we assume cogeneration unit 1 is operating at full capacity, which produces 1,357 kilowatts of electricity and 8,724 pounds of steam per hour. The one-hour natural gas consumptive requirement was determined to be 22,768.46 cubic feet of gas per hour above. From Table 5.8, the environmental coefficient for natural gas is 120.593 pounds of CO_2 per 1,000 cubic feet. We therefore calculate hourly CO_2 emissions associated with operating cogeneration unit 1 as follows:

$$\frac{22{,}768.46\ CF\ Gas}{hour} \times \frac{120.593\ lb\ CO2}{1{,}000\ CF\ Gas} = 2{,}745.72 \text{ pounds of } CO_2 \text{ per hour}$$

Again, shutting down cogeneration unit 1 requires purchasing electricity from the grid and operating boiler 2 to supplement steam production. From Table 5.8, the environmental coefficient for grid electricity is 0.981 pound of CO_2 per kilowatt hour.

We calculate the hourly CO_2 emissions associated with purchasing electricity from the grid as follows:

$$\frac{1{,}357\ kWh}{hour} \times \frac{0.981\ lb\ CO2}{kWh} = 1{,}331.22 \text{ pounds of } CO_2 \text{ per hour}$$

It was determined above that operating boiler 2 to supplement steam produced by cogeneration unit 1 results in consumption of 10,435.40 CF gas per hour. Again using the environmental coefficient for natural gas, we calculate the hourly CO_2 emissions associated with operating boiler 2 instead of cogeneration unit 1 as follows:

$$\frac{10{,}435.40\ CF\ Gas}{hour} \times \frac{120.593\ lb\ CO2}{1{,}000\ CF\ Gas} = 1{,}258.44 \text{ pounds of } CO_2 \text{ per hour}$$

Purchasing electricity from the grid and operating boiler 2 results in the following hourly CO_2 emissions:

$$\frac{1{,}331.22\ lb\ CO2}{hour} + \frac{1{,}258.44\ lb\ CO2}{hour} = 2{,}589.66 \text{ pounds of } CO_2 \text{ per hour}$$

Recall that operating cogeneration unit 1 resulted in CO_2 emissions of 2,745.72 pounds of CO_2 per hour. This value is 156.06 pounds of CO_2 per hour greater than purchasing electricity from the grid and supplementing the steam with boiler 2. From the above, it can be concluded that purchasing electricity from the grid and operating boiler 2 is slightly cleaner than operating cogeneration unit 1 at full capacity. The percentage difference between the two scenarios is 5.7 percent.

By preparing similar calculations to cogeneration unit 2, we find the following:

$$\frac{55{,}321.89\ CF\ Gas}{hour} \times \frac{120.593\ lb\ CO2}{1{,}000\ CF\ Gas} = 6{,}671.43 \text{ pounds of } CO_2 \text{ per hour}$$

$$\frac{3{,}867\ kWh}{hour} \times \frac{0.981\ lb\ CO2}{kWh} = 3{,}793.53 \text{ pounds of } CO_2 \text{ per hour}$$

$$\frac{24{,}234.45\ CF\ Gas}{hour} \times \frac{120.593\ lb\ CO2}{1{,}000\ CF\ Gas} = 2{,}922.51 \text{ pounds of } CO_2 \text{ per hour}$$

$$\frac{3{,}793.53\ lb\ CO2}{hour} + \frac{2{,}922.51\ lb\ CO2}{hour} = 6{,}716.04 \text{ pounds of } CO_2 \text{ per hour}$$

Operating cogeneration unit 2 results in CO_2 emissions of 6,671.43 pounds of CO_2 per hour. Shutting down cogeneration unit 2, purchasing electricity from the grid, and supplementing the steam with boiler 2, results in CO_2 emissions of 6,716.04 pounds of CO_2 per hour. This is a difference of 44.61 pounds of CO_2 per hour and indicates that at full capacity, operating cogeneration unit 2 is slightly cleaner than purchasing electricity from the grid. The percentage difference between the two scenarios is 0.67%.

Given there are slight, yet mixed CO_2 emission variations for individual cogeneration unit operation, we must look at operating scenarios representing simultaneous operation. Recall that cogeneration units 1 and 2 have respective hourly CO_2 emissions values of 2,745.72 pounds of CO_2 per hour and of 6,671.43 pounds of CO_2 per hour. By adding these values, we obtain a single value of 9,417.15 pounds of CO_2 per hour for combined cogeneration unit operation. In a similar manner, we combine grid and boiler emissions values for the scenario involving shutdown of both cogeneration units. We add the values 2,589.66 pounds of CO_2 per hour (cogeneration unit 1 off) and 6,716.04 lb pounds of CO_2 per hour (cogeneration unit 2 off) for a total value of 9,305.70 pounds of CO_2 per hour representing a combined unit shutdown. Comparing CO_2 emissions associated with simultaneous cogeneration operation and simultaneous shutdown resulted in a difference of 111.45 pounds of CO_2 per hour. As in the case of individual operation of cogeneration unit 1 at full capacity, purchasing electricity from the grid and operating boiler 2 is slightly cleaner than operating both cogeneration units at full capacity. The percentage difference between the two scenarios is 1.2 percent.

7.4 Environmental Break-Even Point

We now determine the environmental break-even point between cogeneration unit operation and grid purchases. To determine the environmental break-even point, we set the grid emissions coefficient (in lb CO_2/kWh) as the variable, and assume full cogeneration unit production. It can be assumed that CO_2 emissions associated with the combustion of natural gas is unlikely to change. We then solve for the grid emissions coefficient that makes the two cases equivalent.

Let G_c = CO_2 emissions of operating both cogeneration units at full capacity for one hour.

Let G_{g+b} = CO_2 emissions of purchasing grid electricity and operating the boilers for one hour.

Let A = Hourly CO_2 emissions of electricity purchased from the grid as a variable in pounds of CO_2 per kilowatt hour.

We recall that the combined steam output of cogeneration units 1 and 2 is 28,984 pounds of steam per hour. The combined electrical output of cogeneration units 1 and 2 is 5,224 kilowatts. Recalling the following parameters previously developed in this thesis: 0.981 pounds of CO_2 per kilowatt hour for electricity purchased from the grid, pounds of CO_2 per 1,000 cubic foot for natural gas, 0.836 pounds of steam produced per cubic foot of natural gas consumed by boiler 2, 0.0596 kilowatt hours produced per cubic foot of natural gas consumed by cogeneration unit 1, and 0.0699 kilowatt hours produced per cubic foot of natural gas consumed by cogeneration unit 2. The CO_2 emissions associated with operating both cogeneration units at full capacity for one hour is found by

$$G_c = \left(1{,}357\ kWh \times \frac{1\ CF\ Gas}{0.0596\ kWH} \times \frac{120.593\ lb\ CO2}{1{,}000\ CF\ Gas}\right) + (3{,}867\ kWh \times \frac{1\ CF\ Gas}{0.0699\ kWh} \times \frac{120.593\ lb\ CO2}{1{,}000\ CF\ Gas}) = 9{,}417.15 \text{ pounds of } CO_2$$

The CO_2 emissions associated with grid purchases and operating the boilers at full capacity for one hour is found by

$$G_{g+b} = \left(5{,}224\ kWh \times \frac{A\ lb\ CO2}{kWh}\right) + \left(28{,}984\ lb\ Steam \times \frac{1CFGas}{0.836\ lb\ Steam} \times \frac{120.593\ lb\ CO2}{1{,}000\ CF\ Gas}\right) = \frac{5{,}224\ A\ kWh}{lb\ CO2} + 4{,}180.94\ \text{ lb } CO_2$$

However, $G_c = G_{g+b}$

$$9{,}417.15 \text{ lb } CO_2 = \frac{5{,}224\ A\ kWh\ lb\ CO2}{kWh} + 4{,}180.94\ lb\ CO2$$

Solving for A, the environmental break-even point for production versus purchasing is given by:

A = 1.0023 pounds of CO_2 per kilowatt hour

Applying the same methodology to individual operating cases of cogeneration units 1 and 2, below are the following economic break-even points for production versus purchasing.

A_{Cogen1} = 1.0960 pounds of CO_2 per kilowatt hour

A_{Cogen2} = 0.9695 pounds of CO_2 per kilowatt hour

Table 7.1 is a summary of hourly CO_2 emissions and costs for operating scenarios of the cogeneration units at full capacity. Economic and environmental break-even points developed above are also listed in Table 7.1.

Figure 7.1 is a decision matrix for operating the cogeneration plant under varying grid economic and environmental conditions. The y-axis represents the cost of grid electricity in dollars per kilowatt hour of grid electricity. The red horizontal line represents the economic break-even point of $0.07916/kWh, developed above. Below this break-even point are left and right quadrants that represent less expensive operational scenarios. The x-axis represents grid CO_2 emissions in pounds of CO_2 per kilowatt hour of grid electricity. The red vertical line represents the environmental break-even point of 1.0023 lb-CO_2/kWh, developed above. To the left of this break-even point are upper and lower quadrants that represent cleaner operational scenarios. The quadrants identify scenarios of operating the cogeneration unit versus operating the boilers and purchasing electricity from the grid. Each quadrant is labeled such that operating decisions can be made as grid electricity changes over time in both cost and CO_2 emissions. As a reference, current grid cost and CO_2 emissions conditions are denoted as a point in Figure 7.1.

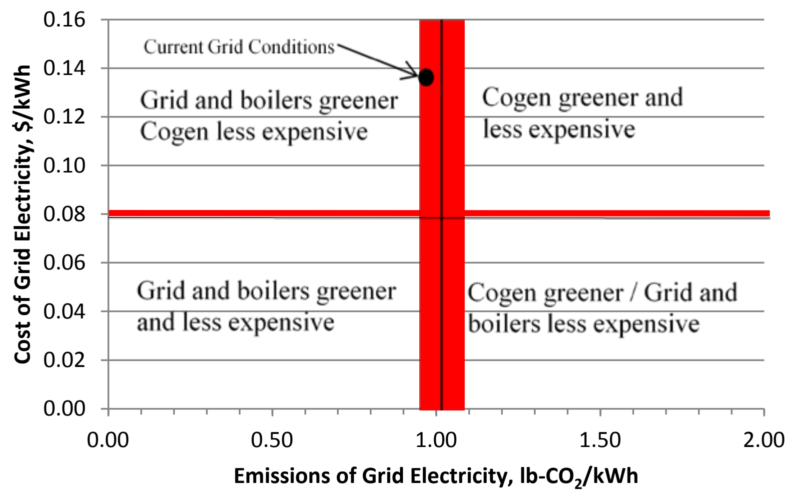

Figure 7.1 – Decision matrix for cogeneration plant operation versus grid purchases and boiler operation as functions of grid electricity costs and emissions.

7.5 Simulations based on Characteristic Days

Tables 7.2 and 7.3 below contain optimized cost and CO_2 emission values for energy characteristic days. The values were generated through simulations by the algorithm presented in this thesis. The algorithm processed input files that included actual plant data from example days that corresponded with the energy characteristic days shown.

The first simulation determined the most economical mode of cogeneration plant operation for each energy characteristic day. As shown in Table 7.2, energy characteristic days are listed along with their respective number of days they occurred during the study period. The number of days column is followed by two columns that indicate the number of hours per day each cogeneration unit should be operated to achieve optimal economic operation. As shown, cogeneration unit 2 operates 24 hours per day throughout the study period. Cogeneration unit 1 does not operate continuously throughout the study period to achieve optimal economic operation. This is due to varying campus electrical demand that, at times, is below the combined electrical output of cogeneration units 1 and 2. In addition, cogeneration unit 1 is less efficient than cogeneration unit 2 in that less electricity is produced by cogeneration unit 1 per cubic foot of natural gas consumed, relative to cogeneration unit 2. The last two columns of Table 7.2 show cost and CO_2 emissions information corresponding to each energy characteristic day for optimal economic operation. The cost and CO_2 emissions information is displayed on daily bases for each energy characteristic day in dollars per day and pounds of CO_2 per day, respectively.

Table 7.2 – Daily cost and CO_2 emission values for economically optimized cogeneration plant operation from simulation based on characteristic days

Characteristic Day	# Days	Cogen Unit 1 Operation Hours/day	Cogen Unit 2 Operation Hours/day	Least Expensive Daily Cost $/day	Least Expensive Daily Emissions lbs-CO_2 /day
Christmas/New Years Break Day	10	24.00	24.00	$ 24,301	286,635
Fall Semester Weekday	76	24.00	24.00	$ 27,825	295,553
Fall Semester Weekend Day	28	16.25	24.00	$ 17,056	211,705
Non-Semester Weekday - Cooling Mode	5	18.50	24.00	$ 21,182	263,729
Non-Semester Weekday - Heating Mode	15	24.00	24.00	$ 20,519	249,252
Non-Semester Weekend Day - Cooling Mode	3	0.00	24.00	$ 17,250	214,188
Non-Semester Weekend Day - Heating Mode	5	24.00	24.00	$ 26,973	301,215
Spring Break Day	4	0.00	24.00	$ 15,044	184,342
Spring Semester Weekday	74	24.00	24.00	$ 17,699	222,875
Spring Semester Weekend Day	28	0.00	24.00	$ 15,070	190,153
Summer Session/Four-Day Weekday	35	18.00	24.00	$ 22,325	274,587
Summer Session/Four-Day Weekend Day	27	9.50	24.00	$ 19,182	237,573
University Holiday - Cooling Mode	3	16.75	24.00	$ 19,145	239,525
University Holiday - Heating Mode	4	24.00	24.00	$ 26,035	283,192
University Holiday - Mixed Mode	2	24.00	24.00	$ 26,934	287,990
Low Occupancy / Moderate Cooling	46	0.00	24.00	$ 18,691	231,463

The second simulation determined the best environmental mode of cogeneration plant operation for each energy characteristic day, based on minimizing CO_2 emissions. Formatted similar to Table 7.2, Table 7.3 identifies cost and CO_2 emissions information corresponding to each energy characteristic day for optimal environmental operation of the cogeneration plant. Again, we see that Cogeneration unit 1 does not operate continuously throughout the study period. This is attributed to campus electrical demand that, at times, is below the level required to both cogeneration units.

Table 7.3 – Daily cost and CO_2 emission values for environmentally optimized cogeneration plant operation from simulation based on energy characteristic days

Energy Characteristic Day	# Days	Cogen Unit 1 Operation Hours/day	Cogen Unit 2 Operation Hours/day	Greenest Day Cost $/day	Greenest Day Emissions lbs-CO_2 /day
Christmas/New Years Break Day	10	24.00	24.00	$ 24,301	286,635
Fall Semester Weekday	76	24.00	24.00	$ 27,825	295,553
Fall Semester Weekend Day	28	0.00	24.00	$ 17,618	203,850
Non-Semester Weekday - Cooling Mode	5	13.00	24.00	$ 21,379	262,183
Non-Semester Weekday - Heating Mode	15	24.00	24.00	$ 20,519	249,252
Non-Semester Weekend Day - Cooling Mode	3	0.00	24.00	$ 17,256	214,093
Non-Semester Weekend Day - Heating Mode	5	24.00	24.00	$ 26,973	301,215
Spring Break Day	4	0.75	24.00	$ 15,121	184,319
Spring Semester Weekday	74	15.50	24.00	$ 18,099	221,169
Spring Semester Weekend Day	28	0.00	24.00	$ 15,070	190,153
Summer Session/Four-Day Weekday	35	15.00	24.00	$ 22,446	273,843
Summer Session/Four-Day Weekend Day	27	0.00	24.00	$ 19,387	233,932
University Holiday - Cooling Mode	3	0.00	24.00	$ 19,785	235,095
University Holiday - Heating Mode	4	24.00	24.00	$ 26,035	283,192
University Holiday - Mixed Mode	2	0.00	24.00	$ 28,376	281,619
Low Occupancy / Moderate Cooling	46	0.00	24.00	$ 18,691	231,463

Differences between the economic and environmental simulations are summarized on yearly bases below in Table 7.4. As shown, for optimal economical operation of the cogeneration plant, cogeneration unit 1 operates for 5,948 hours while cogeneration unit 2 operates continuously throughout the year. Grid purchases for the year amount to 8,117,040 kilowatt-hours. CO_2 emissions and costs for one year were 90,116,221 pounds of CO_2 and $7,601,968, respectively. This equates to $0.0843 per pound of CO_2 emissions. For optimal environmental operation, cogeneration unit 1 operates for 4,380 hours, which is 1,568 hours or 65 days less than optimal economical operation. As with optimal economic operation, cogeneration unit 2 operates continuously throughout the year. Grid purchases for the year amount to 9,809,645 kilowatt-hours. This amount of electricity is 1,692,605 kilowatt-hours more than the optimal economic scenario to make up for less electricity produced by cogeneration unit 1 operating for fewer hours. For optimal environmental operation, 89,611,551 pounds of

CO_2 are emitted. This is 504,670 pounds or 229 metric tons of CO_2 less than the optimal economic scenario. It costs $7,663,189 to operate the cogeneration plant optimally for minimized CO_2 emissions. This amount is $61,221 more than the cost to operate the cogeneration plant in the optimal economic scenario.

At $0.0855 per pound of CO_2 emissions for optimal environmental operation, a cost difference of only $0.0012 per pound of CO_2 emissions exists between optimally economic and optimally environmental operating scenarios. As a point of comparison, in 2009, Rowan University purchased New Jersey wind renewable energy certificates at a price of $0.0235 per kilowatt hour. Dividing this value by the grid emissions coefficient 0.981 pounds of CO_2 emissions per kilowatt hour, one finds that purchasing New Jersey wind renewable energy certificates results in avoiding CO_2 emissions at a cost of $0.0239 per pound of CO_2 emissions. This finding suggests and recommends that purchasing wind renewable energy certificates is more effective in reducing CO_2 emissions than switching the operation of the cogeneration plant from optimally economic to optimally environmental.

Table 7.4 – Summary of optimized economic and environmental operating scenarios of the cogeneration plant based on one year of operation.

	Cogen 1 Hours	Cogen 2 Hours	CO_2 Emissions, lbs	Cost, $
Least Expensive Operation	5,948	8,760	90,116,224	$ 7,601,974
Greenest Operation	4,380	8,760	89,611,626	$ 7,663,208
	Grid Purchases, kWh	Cogen Electricity, kWh	Boiler Steam, lbs	Cogen Steam, lbs
Least Expensive Operation	8,117,040	41,947,713	110,296,142	229,376,676
Greenest Operation	9,809,645	39,806,979	122,512,255	215,627,940

7.6 Sensitivity Analysis

Figure 7.2 is a graph showing differences in annual costs between optimally economic and optimally environmental operation of the cogeneration plant. Differences in costs are indicated on the y-axis. Graduated in pounds of CO_2 per kilowatt-hour, the x-axis is scaled in units of CO_2 emissions of electricity purchased from the grid. Ranging from 0.000 to 1.600, the CO_2 emissions axis represents a set of values encompassing the value of 0.981 pounds of CO_2 emitted per kilowatt-hour of electricity selected for use in this thesis for the study period. The CO_2 emissions axis also encompasses values utilized during 14 trials of this sensitivity analysis. A series of curves on the graph illustrates iterations of grid electricity cost trials in units of dollars per kilowatt-hour. A range of \$0.05 per kilowatt-hour to \$0.30 per kilowatt-hour was selected for this illustration. This range encompassed 6 trials of this sensitivity analysis including the electricity price of \$0.1372 per kilowatt-hour, selected as an average price in this thesis for the study period.

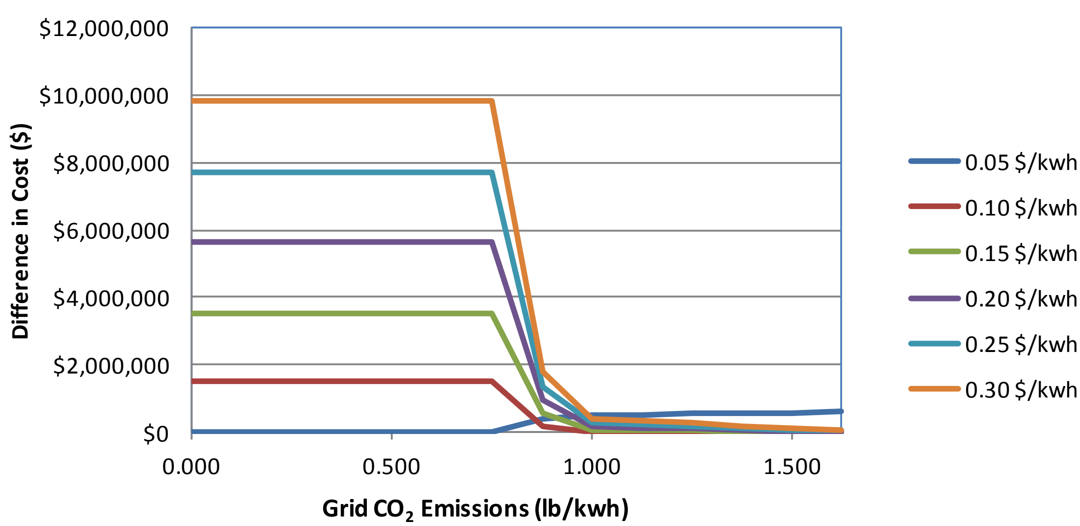

Figure 7.2 – Differences in annual costs between optimal economic and optimal environmental operations over ranges of grid emissions and grid electricity purchase prices.

As shown in Figure 7.2, in five of six grid electricity price trials, annual cost differences were pronounced and flat for smaller grid CO_2 emissions values. For example, purchasing grid electricity at \$0.20 per kilowatt-hour with a CO_2 emissions value of 0.500 pounds per kilowatt-hour will result in an annual cost difference of \$5,624,549. This is indication that for lower grid CO_2 emissions values, cost differences between economically and environmentally optimal cogeneration plant operation were significant. At a grid electricity price of \$0.30 per kilowatt-hour, an average cost difference of \$9,820,653 resulted between economically and environmentally optimal cogeneration plant operation. As the grid becomes cleaner, annual cost differences become reduced, with an initial steep decrease at 0.8 pounds of CO_2 per kilowatt-hour to significant convergence at 1 pound of CO_2 per kilowatt-hour. At a grid electricity price of \$0.05 per kilowatt-hour, there was no difference in annual cost between economically and environmentally optimal cogeneration plant operation.

Figure 7.3 below provides insight into two areas of transition of the curves shown in Figure 7.2. In Figures 7.3, 7.4, and 7.5, 448 trials of CO_2 emissions per kilowatt-hour values were executed through the program code. This provided more data points and better-defined curves for analyses of transitional areas. As shown, at 0.777 pounds of CO_2 emissions per kilowatt-hour, a steep drop in annual cost differences was observed between optimal economic and optimal environmental operations for all grid electricity prices, with the exception of \$0.05 per kilowatt-hour. Between 0.777 and 0.910 pounds of CO_2 emissions per kilowatt-hour, cost differences were relatively flat. At 0.910

pounds of CO_2 emissions per kilowatt-hour, a second steep decrease was observed, followed by a region of relatively unchanging cost differences.

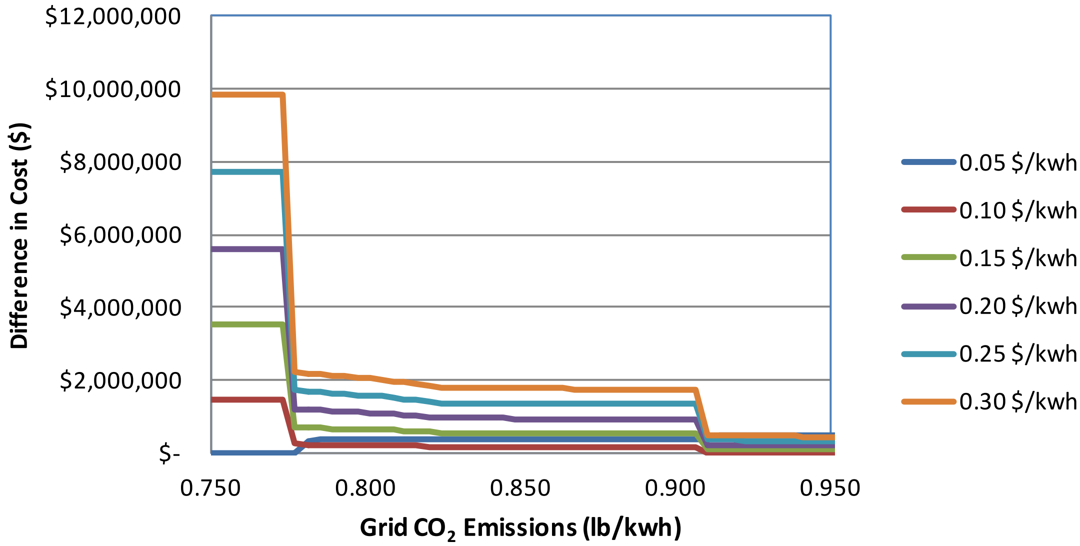

Figure 7.3 – Differences in annual costs between optimal economic and optimal environmental operations for transitional areas of the curves in Figure 7.1.

To gain further insight into transitional areas of the curves, Figure 7.3 shows annual cost difference curves for grid CO_2 emissions between 0.771 and 0.785 pounds per kilowatt-hour. Figure 7.3 is a detailed view of the first transition region. As shown, the first transition region consists of decreasing annual cost differences between optimal economic and environmental operations over a range of grid electricity costs. Slopes of the curves in the first transition region vary with grid electricity costs. This is indicative of convergence from larger to smaller cost differences as grid electricity costs rise and CO_2 emissions increase. At a grid electricity price of $0.05 per kilowatt-hour, there was no difference in annual cost until grid electricity CO_2 emissions reached 0.777 pounds per kilowatt-hour. Beyond this level, annual cost differences rose minimally, crossing the $0.10 per kilowatt-hour curve at 0.78 pounds of grid CO_2 emissions per hour.

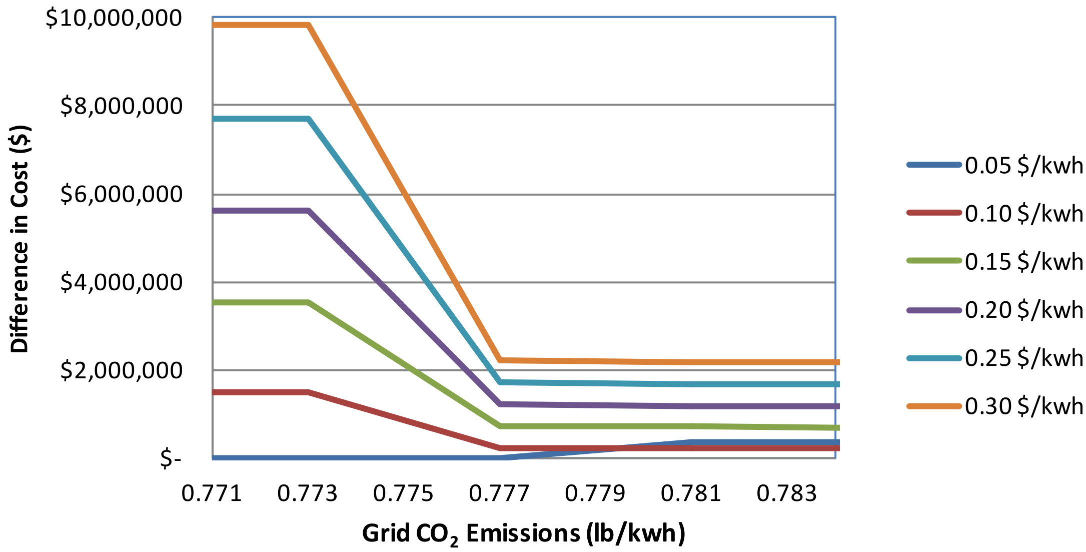

Figure 7.4 – Differences in annual costs between optimal economic and optimal environmental operations at first transitional area.

Figure 7.5 below shows the second transitional area of the annual cost difference curves. At decreased annual cost differences in the range of $250,000 to $1,800,000, this transition region represents sharp decreases at 0.91 pounds of CO_2 emissions of grid electricity. Also at 0.91 pounds of CO_2 emissions of grid electricity, the annual cost difference between optimal economic and environmental operations increases from $380,000 to $500,000 for grid electricity at $0.05 per kilowatt-hour. As grid CO_2 emissions increase beyond this point, annual cost differences for $0.05 per kilowatt-hour electricity level off, as with the other curves. Before and after the second transition, the curves are relatively flat, indicative of cost differences that are minimal between optimal economic and environmental operations.

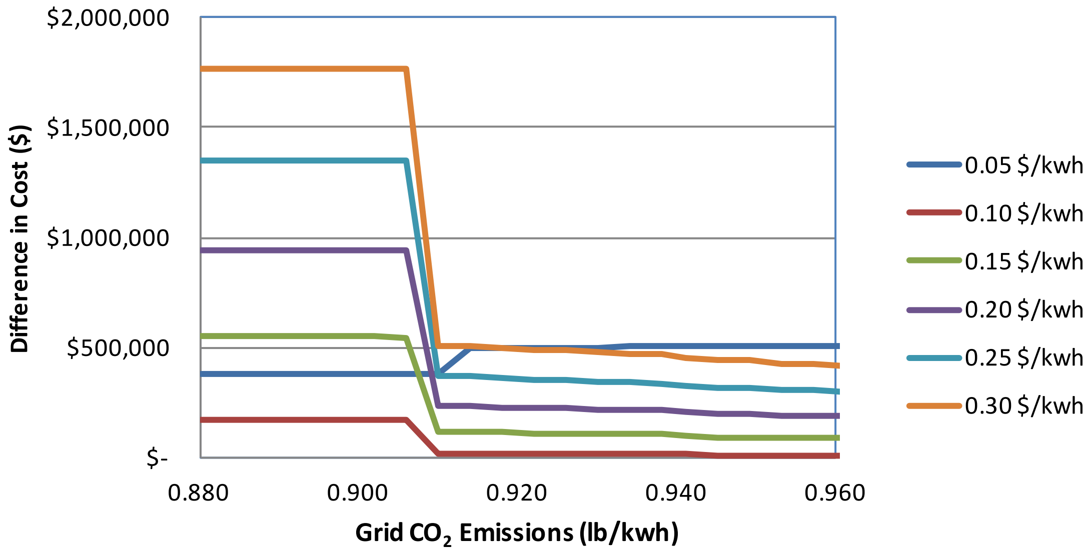

Figure 7.5 – Differences in annual costs between optimal economic and optimal environmental operations at second transitional area.

The differences in annual CO_2 emissions between optimal economic and optimal environmental operation of the campus energy system are plotted in Figure 7.6. The graph displays six trials of grid electricity costs in a plot of grid CO_2 emissions versus a difference in CO_2 emissions between optimal economic and optimal environmental operation of the cogeneration plant. The graph depicts two relatively linear regions, connected by a transition region. Low values of CO_2 emissions along the x-axis indicate grid electricity that is cleaner. As shown, when the grid is clean, differences in CO_2 emissions associated with economically and environmentally optimal cogeneration plant operation are pronounced. As an example, at a grid electricity price of $0.10 per kilowatt-hour, and a zero value for grid CO_2 emissions, the difference in CO_2 emissions between economically and environmentally optimal cogeneration plant operation is 32,486,200 pounds, or 14,735 metric tons. By changing the grid electricity price to $0.30 per kilowatt-hour, and keeping the grid CO_2 emissions at zero pounds per kilowatt-hour, a difference in CO_2 emissions between economically and environmentally optimal cogeneration plant operation of 35,480,852 pounds is realized, a difference of 2,994,652 pounds, or 1,358 metric tons. As the grid becomes less clean, differences in CO_2 emissions between economically and environmentally optimal cogeneration plant operation become rapidly reduced in a linear fashion between zero and 0.8 pounds of CO_2/kWh. Beyond 0.8 pounds of CO_2/kWh, differences in CO_s emissions reduce gradually and asymptotically to zero as grid emissions approach 2 pounds of CO_2/kWh and beyond.

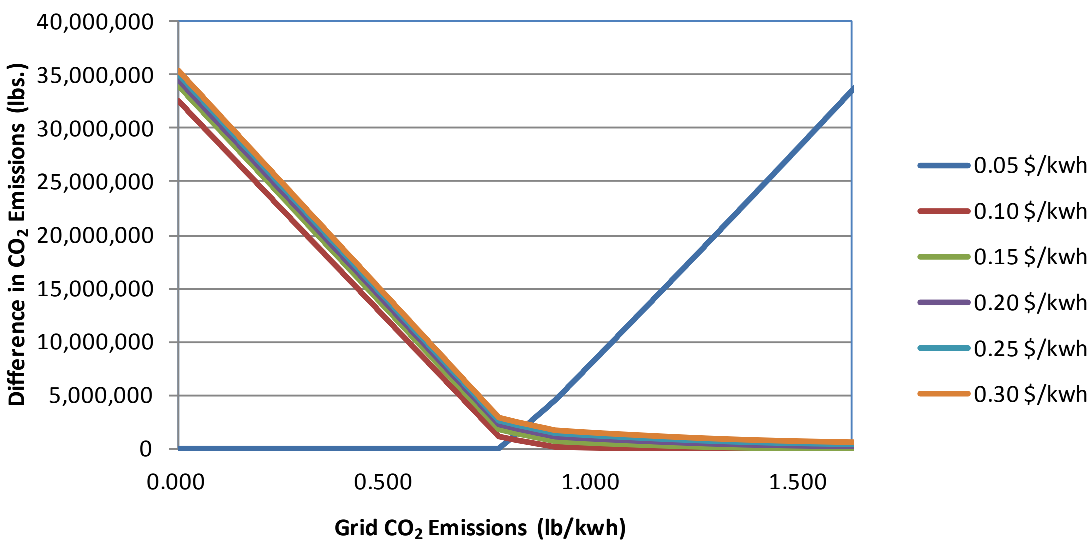

Figure 7.6 – Differences in annual CO_2 emissions between optimal economic and optimal environmental operation over ranges of grid emissions and electricity purchase prices.

To gain further insight into transition area of the curves, Figure 7.7 shows annual CO_2 emissions difference curves for grid CO_2 emissions between 0.650 and 1.000 pounds per kilowatt-hour. As shown, in the transition region, the curves remain parallel and trend in a similar fashion, with the exception of the grid electricity price of $0.05 per kilowatt-hour. When the grid is very clean and least expensive, there is no difference in CO_2 emissions between optimal economic and optimal environmental campus energy systems operations. Holding the grid electricity price of $0.05 per kilowatt-hour, as the grid becomes less clean, linear increases in CO_2 emissions between optimal economic and optimal environmental campus energy systems operations become more pronounced. For grid electricity is $0.10 and above, differences in CO_2 emissions between optimal economic and optimal environmental campus energy systems operations vary little through the full range of zero to 1.7 pounds of CO_2 emissions of grid electricity.

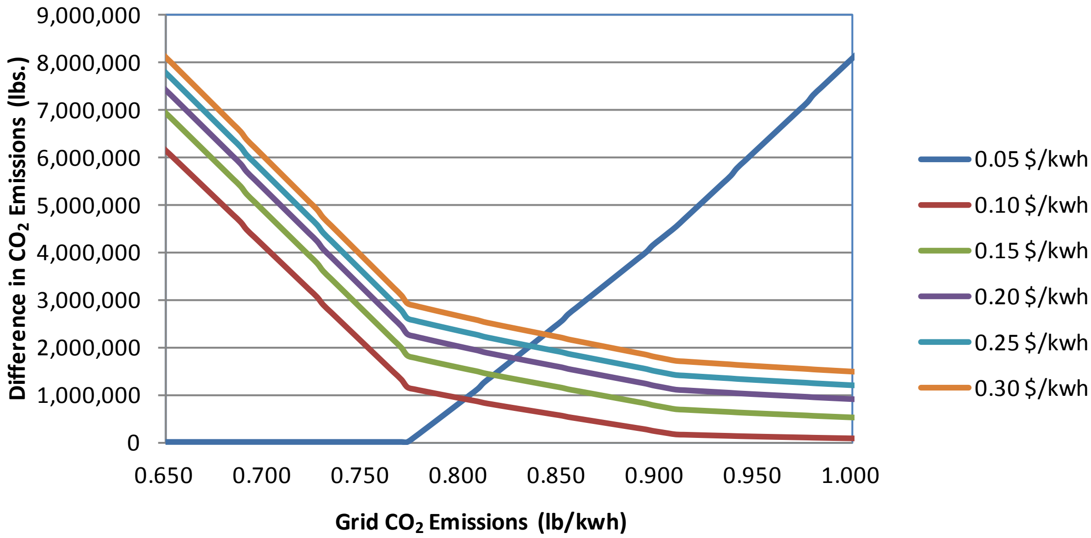

Figure 7.7 – Differences in annual CO_2 emissions between optimal economic and optimal environmental operation at the transition region.

Figure 7.8 below is a plot showing the cost of CO_2 emissions per pound over ranges of grid CO_2 emissions and grid electricity purchase prices. At grid CO_2 emissions levels of 0.5 pounds per kilowatt-hour or less, and for the entire range of grid electricity purchase prices evaluated, the cost of CO_2 was at or below $0.68 per pound. As the grid became less clean, the cost of CO_2 per pound curves diverged reaching peaks that appeared to be coincident. A peak of $3.34 per pound of CO_2 emissions was reached for a trial grid electricity price of \$0.30 per kilowatt-hour. As the grid became less clean beyond the \$3.34 per pound of CO_2 emissions peak, there was a steep decrease in cost per pound of CO_2 followed by small increases and a second steep decrease. Two transition areas were identified for further examination.

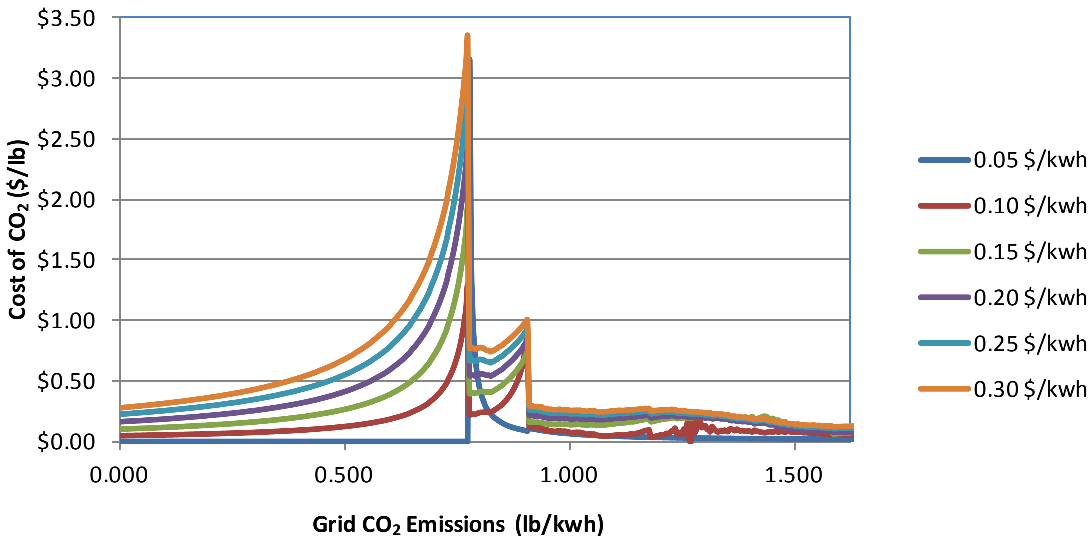

Figure 7.8 – Cost per pound of CO_2 emissions over ranges of grid emissions and electricity purchase prices.

To get a sense of the cost per pound of CO_2 emissions of optimal operation of the campus energy system, Figure 7.9is similar to Figure 7.8, with the exception of the y-axis, which is graduated over a much smaller range. As shown, the y-axis ranges from zero to \$0.20 per pound of CO_2 emissions, a fraction of the corresponding range in Figure 7.8. This illustration is a comparison of optimal campus energy system operation with purchasing renewable energy certificates and a projection of the social cost of carbon from the Interagency Working Group on the Social Cost of Carbon.[1] The top horizontal thick black line represents the 2014 year-to-date average New Jersey solar renewable energy certificate (SREC) price. An average SREC price of \$165.00 per megawatt-hour was obtained from SREC Trade, Inc.[24] This price was converted into kilowatt-hour units and converted to pounds of CO_2 emissions through division by the grid emissions coefficient of 0.981 pounds per kilowatt-hour. The horizontal thick black line at $0.0585 per pound of CO_2 emissions represents the projected social cost of carbon for 2020 from the Interagency Working Group on the Social Cost of Carbon. The horizontal thick black line at $0.0239 per pound of CO_2 emissions represents the contracted price Rowan University paid for New Jersey wind renewable energy certificates (WRECs) in 2009. As shown, purchasing renewable energy certificates is more cost effective than decommissioning cogeneration units 1 and 2.

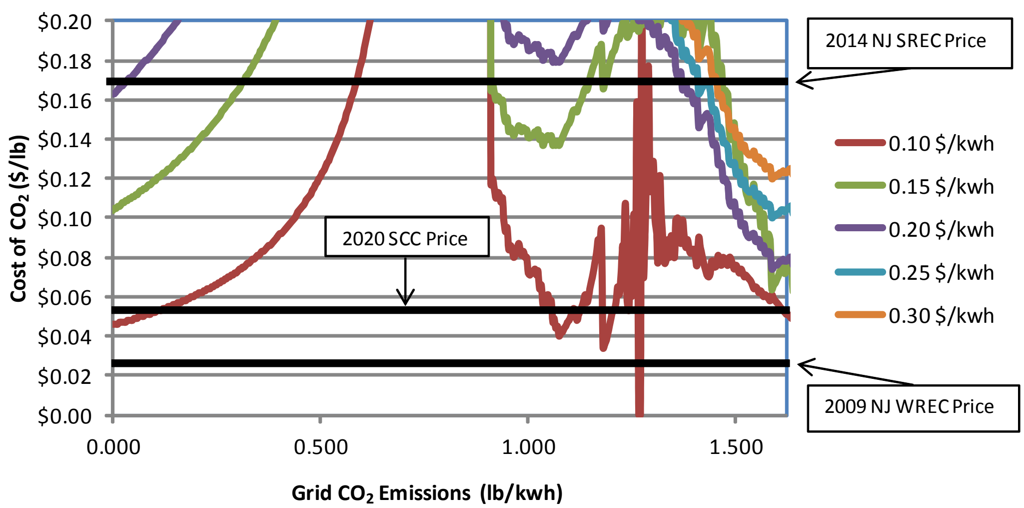

Figure 7.9 – Comparison of cost per pound of CO_2 emissions with renewable energy certificate prices and projected social cost of carbon by the Interagency Working Group on the social cost of carbon.

Figure 7.10 below is a representation of the first transition region shown in Figure 7.8. At a grid emissions level of 0.785 pounds per kilowatt-hour, peak CO_2 per pound costs were identified for grid electricity costs of $0.10 per kilowatt-hour or greater. The first transition consisted of a steep linear decrease in CO_2 per pound costs over a range of

0.773 to 0.777 pound per kilowatt-hour. At a grid emissions level of 0.777 pounds per kilowatt-hour and beyond, the cost of CO_2 curves remained flat for the selected range of grid costs and CO_2 emissions with the exception of a grid electricity cost of $0.05 per kilowatt-hour. At $0.05 per kilowatt-hour, CO_2 costs per pound increased in an inverse manner, relative to the other curves, through the transition region. Beyond the peak at 0.777 pounds of CO_2 emissions per kilowatt-hour, the cost of CO_2 per pound decreased in a non-linear manner for grid electricity costing $0.05 per kilowatt-hour.

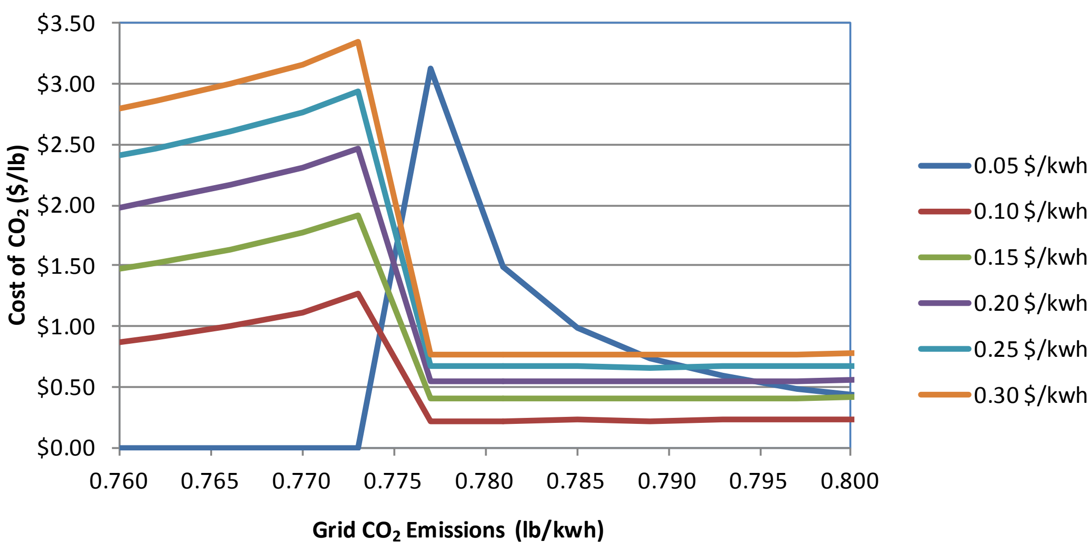

Figure 7.10 – Cost per pound of CO_2 emissions over the range of grid emissions for the first transition region.

The second transition region is shown in Figure 7.11. The second transition region involved smaller changes in costs of CO_2 per pound. As a result, the scale for the y-axis was reduced for improved observation of data trends. Curves associated with grid electricity costs of $0.10 per kilowatt-hour or greater decreased non-linearly from 0.800 to 0.824 pounds of CO_2 emissions per kilowatt-hour. CO_2 costs per pound then increased in a non-linear manner between 0.824 and 0.910 grid CO_2 emissions per kilowatt-hour. From 0.800 to 0.910 pounds of CO_2 emissions per kilowatt-hour, CO_2

costs per pound associated with \$0.05 per kilowatt-hour grid electricity costs decreased in a non-linear manner. At grid emissions values of 0.910 pounds per kilowatt-hour or greater, all CO_2 cost per pound curves decreased gradually and were at or below \$0.295 per pound of CO_2 emissions.

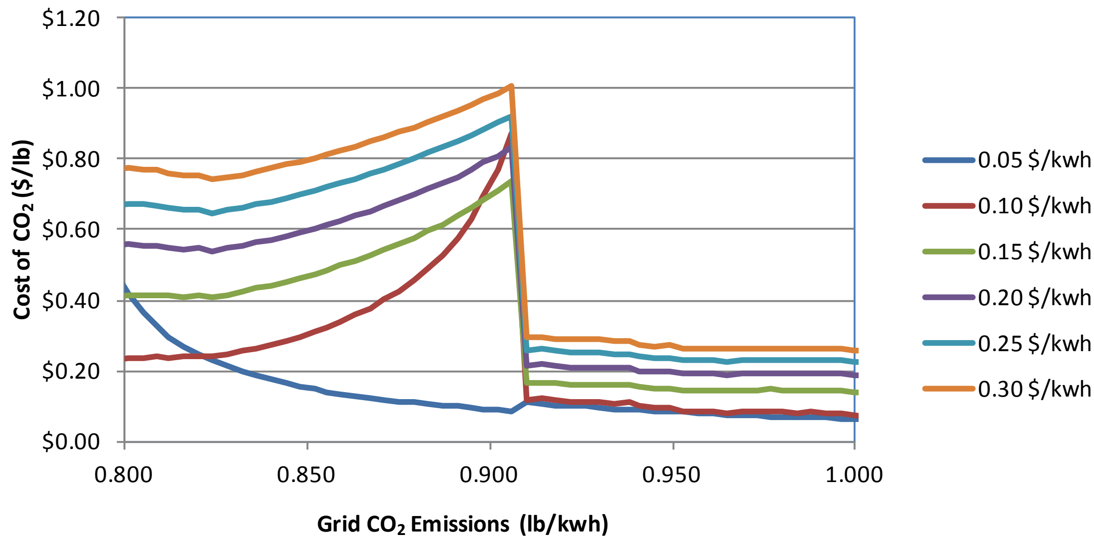

Figure 7.11 – Cost per pound of CO_2 emissions over the range of grid emissions for the second transition region.

It should be noted that in general, the grid changes in cost of operation and CO_2 emissions through a typical day. As demand changes, utilities respond by starting up or shutting down generation equipment. For example, in the middle of a typical summer day, peak-shaving generation equipment will be brought online by regional transmission operators to meet rapid changes in demand. Peak-shaving generation equipment includes gas-fired reciprocating generators because of their rapid start capabilities. However, reciprocating generators are typically less efficient then their turbine counterparts. In addition, reciprocating turbines emit higher rates of CO_2 emissions. Starting up and shutting down various generation equipment results in marginal cost differences and CO_2 emissions grid throughout the day. As a sizeable community of energy users, Rowan

University represents a significant load to add to, or remove from, the grid, as opposed to residences. As such, it is important that campus energy systems operations decisions be made with simultaneous and real time knowledge of economic and environmental considerations.

7.7 Reliability and Emergency Preparedness

Beyond economic and environmental performance, the cogeneration plant provides a level of electrical and thermal reliability to the Rowan University campus. Should there be a disruption of the electric utility to the campus, the cogeneration plant can provide approximately 4.7 megawatts of electricity to the campus. Although the campus electrical demand can double at peak usage times, the cogeneration plant can provide the required demand to meet critical campus electrical loads during emergencies. This includes loads associated with emergency lighting, alarm systems, fire protection systems, and other critical building systems, critical boiler plant loads, elevators, health care facilities, and communications systems. Should the need arise, a black-start emergency generator at the cogeneration plant is capable of providing electricity for starter motors and excitation windings for both cogeneration units when power to the campus has been disrupted. During such circumstances, campus electricians would open circuit breakers at buildings, implementing selective load reduction strategies. This action would ensure that the cogeneration plant provides only power for critical campus loads and that the load capability of the cogeneration plant is not exceeded.

In 2011, Rowan University was activated as a regional evacuation center during hurricane Irene. In this role, Rowan University became a temporary residence for evacuees. As it is possible to again fulfill this role similarly for future emergency events, providing space with lighting, heat, medical services, food and water for mass gatherings, Rowan University can utilize the cogeneration plant to provide electricity and heat as described above.

Chapter 8

Summary and Conclusions

This section provides a summary and conclusions developed in this thesis. As stated at the beginning of this thesis, the objective of this thesis was to determine the optimal operation of energy conversion and production subsystems through minimization of economic and environmental costs and to evaluate how changing electrical grid costs and sources will affect future optimal operations. This thesis has accomplished these objectives. There are five major conclusions we can make from the efforts that went into the development of this thesis. Detailed below, the conclusions include a comparison of year 2007 and 2009, the development of energy characteristic days, daily consumption that is not unusual, minor differences between least expensive and greenest cogeneration plant operation, addressing future changes in grid quality and cost, and favorability of the cogeneration plant for economics and the environment.

In FY07, the campus used 41,194,911 kilowatt-hours of electricity and 245,866,586 pounds of steam. This includes electricity and steam utilized by the central chiller plant. Table 8.1 below is a comparison years 2007 and 2009. As shown, electricity demand increased from 2007 to 2009. Similarly, steam usage decreased from 2007 to 2009.

Table 8.1 – Comparison of campus electricity and steam usages for years 2007 and 2009

Year	Electricity Usage kWh	Steam Usage lbs.
2007	41,194,911	245,866,586
2009	50,383,290	319,963,943

Table 8.2 below shows purchased utilities and total CO_2 emissions in pounds for years 2007, 2009, and the simulated optimal economic and optimal environmental operational scenarios. As shown, year 2007 was a year involving less fuel oil and natural gas purchases than in 2009. However, grid electricity purchases were higher in 2007 than in 2009. In 2007, Rowan University's first cogeneration plant was in the process of being decommissioned. It would be expected that during this time, less electricity was being generated on campus. Therefore, grid electricity purchases would have had to increase to meet campus demand. CO_2 emissions were less in 2007 than in 2009. With less electricity production on campus and use of smaller grid CO_2 emissions coefficient, CO_2 emissions were lower in 2007 compared to 2009. Purchased utilities and CO_2 emissions values for optimal economic and optimal environmental operations were compared to 2007 and 2009 values, also shown in Table 8.2. As expected, subtle differences were found between the two optimized operations. The results were consistent that for the least expensive operation, more natural gas is purchased, less grid electricity is purchased, and CO_2 emissions were greater than for greenest operation. Conversely, for greenest operation, less natural gas is purchased, more grid electricity is purchased, and CO_2 emissions were less.

Table 8.2 – Purchased utilities and CO_2 emissions for years 2007, 2009, and simulated optimal operations

Year	Fuel Oil, Gal.	Natural Gas, CF	Grid Electricity, kWh	CO_2 Emissions, Pounds
2007 Actual	47,811	369,691,901	38,684,195	73,366,838
2009 Actual	76,509	550,898,289	26,028,266	79,255,179
Least Expensive Operation	-	683,752,641	8,117,040	90,116,224
Greenest Operation	-	666,130,678	9,809,645	89,611,626

It can be concluded that in 2007, a reduction in on-campus electricity production resulted when the first cogeneration unit was decommissioned. As a result, decreases in natural gas purchases, coupled with increases in grid electricity purchases, occurred. In 2007, grid electricity costs were $5,092,378 and natural gas costs were $4,157,332. With increased grid purchases and usage of a lower grid CO_2 emissions coefficient, a value of 73,366,838 pounds of CO_2 emissions was established. Increased on-campus electricity and steam production resulted in higher CO_2 emissions. Marginal differences between optimal economic and optimal environmental operations were found in this analysis.

To characterize daily campus activities and the impact the activities had on campus energy consumption, it was necessary to define blocks of representative academic days that were initially referred to as academic characteristic days. An academic characteristic day represents a group of days that are similar to each other, with respect to types of activities on campus. By studying the academic characteristic days and integrating campus energy usage data into the study, 16 characteristic days were developed. The characteristic days were utilized in a model to simulate and predict economic and environmental performance of the cogeneration plant. Characteristic day values were within 4% of actual campus annual electricity and steam usages. The shapes of hourly and daily energy curves were in agreement, indicating high usages in day and low usages at night. To simplify the analysis further, the number of characteristic days could be reduced as long as the general distribution is reproduced. A recommended reconfiguration of characteristic days is shown in Table 8.3 below.

Table 8.3 – Potential reconfiguration of characteristic days for future studies.

Campus Use	Hot	Mild	Cold
Class in Session	April Weekday	October Weekday	December Weekday
Students on campus no classes	April Weekend	October Weekend	December Weekend
Students off campus	Summer	Spring Break	Winter Break

An alternate method of typifying days would be to prepare degree-day analyses. Although the use of degree-day analyses for calculations is a more traditional approach than developing characteristic days, degree-days too have limitations. For example, heating and cooling requirements for buildings are not always linear with outdoor temperatures.

During review of the energy data provided to this thesis, daily energy consumption for the campus was determined to be not unusual. As this thesis studied the first commissioned year of cogeneration plant operation, this base year represented a new operating paradigm for a system that was configured with two units. However, campus demand did not change, allowing campus behavior to be profiled. These findings provided assistance the development of characteristic days. The period of study in the main topic of this thesis involved weather conditions characterized by a mild winter and hot summer. Ideally, analysis of a second set of data including another year of purchasing, production, and consumption data would serve as further validation of the model. For alternate year data associated with weather conditions that differ from this study, it is anticipated that hours of operation and characteristic days would require adjustments in magnitude. In addition, magnitudes of costs and CO_2 emissions would be expected to differ. However, plant equipment efficiencies would not be expected to change. Further, fundamental changes in overall trends and conclusions would not be expected. In addition, changes in campus size and population would impact the results of similar studies and is beyond the scope of this thesis. It is anticipated that analyses of overall costs and CO_2 emissions between optimally economic and optimally environmental scenarios, conducted in alternate years, would permit comparison, despite weather differences.

Using the analytical model, it was found that purchasing electricity from the grid and operating the boilers is more expensive than simultaneous operation of both cogeneration units at full capacity by the amount of $303.19 per hour, provided there is sufficient campus demand for the electricity and steam produced. The analytical model also determined that, at current grid electricity and natural gas prices, cogeneration units 1 and 2, operated in any combination, is less expensive that purchasing electricity from the grid and producing steam from campus boilers. It can be concluded that, at current grid electricity and natural gas prices, cogeneration unit utilization is less expensive than purchasing equivalent amounts of electric and gas to produce steam, as long as there is sufficient campus demand for the electricity and steam produced.

The analytical model determined that purchasing electricity from the grid and operating the boilers is slightly cleaner than operating cogeneration unit 1 at full capacity by 156.06 pounds of CO_2 per hour. Operating cogeneration unit 2 resulted in 44.61 pounds of CO_2 emissions per hour less than shutting down cogeneration unit 2, purchasing electricity from the grid, and supplementing the steam with the boilers. This difference indicated that, at full capacity, operating cogeneration unit 2 is slightly cleaner than purchasing electricity from the grid. Purchasing electricity from the grid and operating the boilers is slightly cleaner than simultaneous operation of cogeneration units 1 and 2 at full capacity. Cogeneration Unit 1 was slightly less clean than purchasing electricity from the grid and operating the boilers. Cogeneration Unit 2 was cleaner than purchasing electricity from the grid and operating the boilers, with both cogeneration units within a 10% difference. It can be concluded that cogeneration unit utilization was nearly the same for CO_2 emissions as purchasing equivalent amounts of electric and gas to produce steam.

Executing the program code produced more nuanced operating scenarios that kept all three boilers in a continuous state of readiness. In addition, the program code suggested operating cogeneration unit 2 continuously throughout the study period, with cogeneration unit 1 operating with less duration the extent of which, was driven by optimal economical versus optimal environmental operations. The least expensive operation for one year was $7,601,974 with 90,116,224 pounds of CO_2 emissions. The greenest operation was $7,663,208 with 89,611,626 pounds of CO_2 emissions.

Through simulation of economic and environmental performance of the cogeneration plant, differences between the least expensive and greenest optimal operations were found to be minor. By making minor changes in operating protocol and minimal added costs, the cogeneration plant can be operated in such a way that it favors environmental performance by reducing CO_2 emissions.

As the cost and environmental quality of grid electricity has changed since its inception during the industrial age, it will continue to change in the future. The US Energy Information Administration is predicting a reduction in electricity generated by coal and nuclear technologies as plants retire in the next 20 years. As renewable types of energy continue to expand their presences on the grid, environmental profiles of grid electricity will continue to evolve. Technological change in renewable energy is accelerating its growth and impact to reducing CO_2 emissions in ways that cannot be predicted far in advance. At the same time, hydraulic fracturing is accelerating natural gas exploration and production, particularly in the Marcellus shale regions of the United States. By utilizing hydraulic fracturing, production of natural gas has more than quadrupled in the last decade using this technology. As fossil fuel production and renewable power generation facilities continue to expand, possible outcomes of CO_2 emissions profiles include a grid that is cleaner, dirtier, or unchanging. According to the US Energy Information Administration, the CO_2 emissions profile of the grid is not likely to change significantly over the remaining life of the cogeneration plant as shown in Figure 8.1 below.

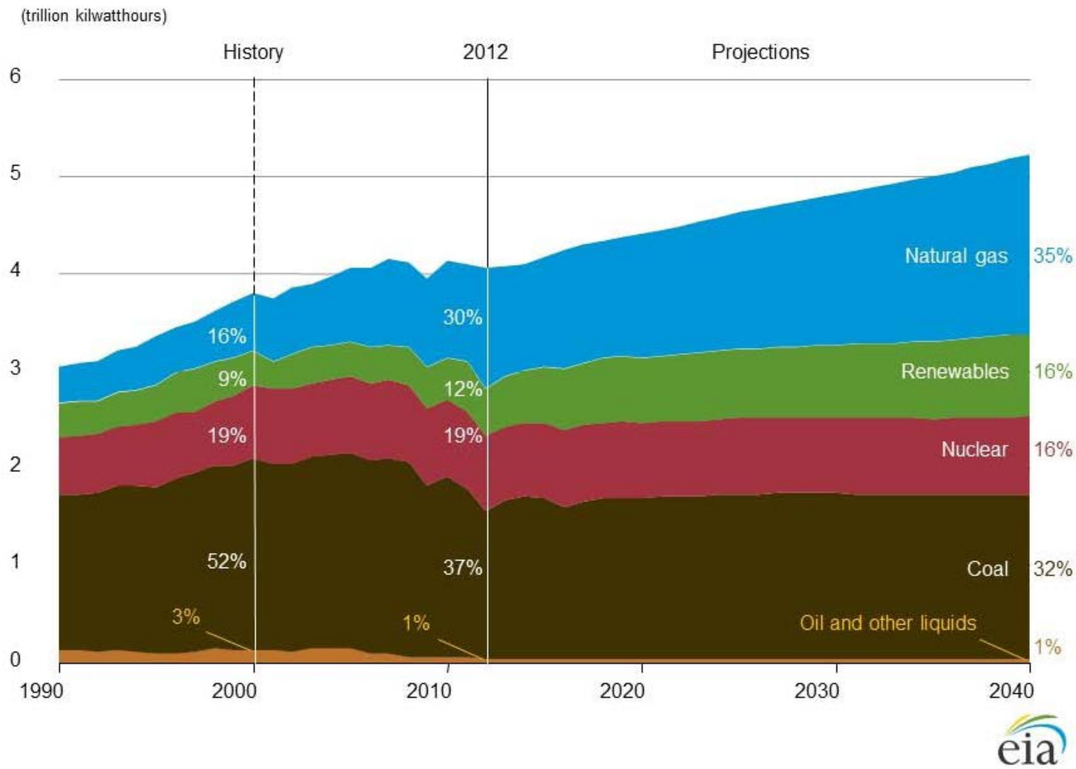

Figure 8.1 – Historical and projected US electricity generation by fuel, 1990 – 2040.

Similarly, costs for grid electricity have evolved over time and will continue to evolve, also at levels that cannot be predicted far in advance. History tells us that over time, grid prices have increased, with smaller decreases over smaller periods. It is likely that the overall upward trend will continue over the remaining life of the cogeneration plant. This thesis provides a means for evaluating the operation of the cogeneration plant as the cost and environmental quality of grid electricity continues to change in the future.

The sensitivity study demonstrated that, for changing grid emissions values and projected future grid costs, over the life cycle of the current cogeneration plant, it is not anticipated that grid emissions will become clean enough to merit decommissioning of cogeneration plant early.

This thesis has identified the relatively small degrees of differences at which the cogeneration plant operates with consideration to economics and the environment. This thesis has also identified new choices for operating cogeneration plant equipment and the economic and environmental impact that come with the new choices. It can be concluded that operation of the cogeneration plant is favorable for both economical and environmental considerations.

References

[1] Interagency Working Group on Social Cost of Carbon, “Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Analysis – Under Executive Order 12866,” United States of America, 2013.

[2] S. Horii, K. Ito, P.S. Pak, Y. Suzuki, “Optimal Planning of Gas Turbine Co-Generation Plants Based on Mixed-Integer Linear Programming,” Dept. Com. Eng., Osaka Electro-Com. Univ., Osaka Prefecture, Japan, 1987.

[3] P. Acuri, G. Florio, P. Fragiacomo, “A mixed integer programming model for optimal design of trigeneration in a hospital complex,” Dept. of Mech. Eng., Univ. of Calabria, Arcavacada di Rende Cosenza, Italy, 2005.

[4] Z. Bogdan, M. Baburic, N. Serman, “Optimization Model for El-To Zagreb Cogeneration Plant,” Dept. of Power Eng., Univ. of Zagreb; Zagreb, Croatia, 2007.

[5] M. Geidl, G. Andersson, “Optimal Power Flow of Multiple Energy Carriers,” Swiss Federal Office of Energy, Mühlestrasse, Ittigen, 2006.

[6] C. Giannantoni, A. Lazzaretto, A. Macor, A. Mirandola, A. Stoppato, S. Tonon, S. Ulgiati, “Multicriteria approach for the improvement of energy systems design,” Dept. of Mech. Eng., University of Padova, Via Venezia, Italy; Dept. of Chem., Univ. of Siena, Via Aldo Moro, Siena, Italy, 2001.

[7] S. Gamou, R. Yokoyama, K. Ito, “Parametric Study on Economic Feasibility of Microturbine Cogeneration Systems by an Optimization Approach,” Dept. of Energy Systems Eng., Osaka Prefecture Univ., Osaka Prefecture, Japan, 2005.

[8] M. Casisi, P. Pinamonti, M. Reini, “Optimal lay-out and operation of combined heat & power (CHP) distributed generation systems,” Dept. of Energy and Turbomachinery, Univ. of Udine; Dept. of Mech. Eng., Univ. of Trieste, Trieste, Italy, 2009.

[9] A. H. Land and A. G. Doig (1960). "An automatic method of solving discrete programming problems,” Econometrica 28 (3), pp. 497–520.

[10] A. Gimelli, M. Muccillo, “Optimization criteria for cogeneration systems: Muli-objective approach and application in a hospital facility,” Dept. of Mech. and Energy Eng., University of Naples Federico II, Naples, Italy, 2012.

[11] T. Yilmaz, “Optimization of cogeneration systems under alternative performance criteria,” Dept. of Naval Architecture, Yildiz Technical University, Istanbul/Istanbul Province, Turkey, 2003.

[12] J. Ortiga, J.C. Bruno, A. Coronas, “Selection of typical days for the characterization of energy demand in cogeneration and trigeneration optimization models for buildings,” Energy Conversion and Management, Vol. 52, No. 4, 2011.

[13] “Rowan Fast Facts 2012-2013” web page; Rowan Univ. Dept. of Media and Public Relations, Glassboro, New Jersey, USA, press release date July 31, 2013.

[14] “Common Data Set 2007-2008,” Rowan Univ. Office of Institutional Effectiveness, Research and Planning, Glassboro, New Jersey, USA, 2009.

[15] Atlantic City Electric, “Environmental Information for the Electricity Product,” Electricity Supplied from July 1, 2006 through June 30, 2007, Atlantic City, New Jersey, USA, 2008.

[16] United States Dept. of Energy website, “Renewable Energy Certificates,” Green Power Markets, Energy Efficiency and Renewable Energy, 2013.

[17] United States Dept. of Energy website, “Updated State-level Greenhouse Gas Coefficients for Electricity Generation,” Energy Information Administration, 2013.

[18] United States Dept. of Energy website, “Carbon Dioxide Emissions Coefficients by Fuel,” Energy Information Administration, 2013.

[19] J. Imperatore, W. Riddell, K. Bhatia, M. Parisi, J. Foote, “Assessing Carbon Dioxide Emissions from Energy Use at a University,” International Journal of Sustainability in Higher Education, 2008.

[20] Rowan University, “Official 2007-2012 Academic Calendar,” Approved Fall 2005- Revised Summer 2009, Glassboro, New Jersey, USA, 2009.

[21] K. Duke, J. Imperatore, Rowan University, “Purchasing of Natural Gas and Electricity Commodities Position Paper” Energy Review Panel, Glassboro, New Jersey, USA, 2006.

[22] J. Imperatore, W. Riddell, K. Bhatia, M. Parisi, J. Foote, “Assessing Carbon Dioxide Emissions from Energy Use at a University International Journal of Sustainability in Higher Education, 2009.

[23] United States Dept. of Energy website, “State Historical Utility Price Tables,” Energy Information Administration, 2008.

[24] SRECTrade, Inc, website. “New Jersey SREC Market Update,” report; January 2014

```
% Opti5_1
%
% version history:
% Opti1: first program accounted for electric use for a given electric demand
% Opti2: added steam generation for given electric and steam demand
%   Opti2_1: calculated steam from co-gen
%   Opti2_2: calculated steam from co-gens and boiler1 and 2
%   Opti2_3: includes error trapping to limit boilers to capacity, and
%           prevent negative grid purchases
%   Opti2_4: calculates the prices in dollars and CO2 for best of the four
%           possibilities for given electric and steam demand
% Opti3:   Looks for optimal use throughout the day.
%   Opti3_1: Reads in demand in 15 minute increments, and outputs optimal use
%   Opti3_2: Updates values for parameters elecprod, steamprod, gasuse, gascost,
%           electriccost, and electricCO2.
%        Opti3_3: Provides error trapping
%        Opti3_4: Calculates daily totals of mincost, greencostofcheapest, costofgreenest,
and mingreencost.
%        Opti3_5: Converts all time-based parameters to quarter-hour bases, consistent
with input file format.
%        Opti3_6: Returns time-based program parameters to hourly bases and corrects
daily totals.
%        Opti3_7: Initializes all totalizing values to zero prior to program loops.
% Opti5: Totals values for the full year.
%   Opti5_1: First cut at looping through 15 characteristic days
% Opti6: Cycles through different costs and CO2 coefficients for electricity
%
%-----------------------------------------------------------------------------------------
% variables
%-----------------------------------------------------------------------------------------
%  system inputs
%
%  vectors refer to [cogen1,cogen2,boiler1,boiler2,boiler3,grid]
%
%  elecprod and steamprod define the production of electricity and steam at capacity
%
elecprod=[1357,3867,0,0,0,1];                    %electrical    capacity    in
kilowatts
steamprod=[8724,20260,26000,40000,40000,0];   %thermal capacity in pounds of
steam per hour
%
%  gasuse defines the use of natural gas to run the cogen and boilers at capacity
%
```

```
gasuse=[20.575,48.819,31.941,47.847,46.948,0];     %gas usage at capacity in MCF/hour
(1,000 x cubic feet of gas per hour)
griduse=[0,0,0,0,0,1];
gascost=9.5242;            %cost in dollars per unit of gas, $/MCF
gasCO2=120.593;            %CO2 emission per unit of gas, lb CO2/MCF of gas
% electriccost       %cost in dollars of electricity per kilowatt hour, $/kW-Hr
% electricCO2        %CO2 emission per kilowatt-hour of electricity, lb CO2/kW-Hr
%
%------------------------------------------------------------------------------------------
% define boiler capacities as their own variables
%
boiler1cap=steamprod(3);
boiler2cap=steamprod(4);
boiler3cap=steamprod(5);
%
%------------------------------------------------------------------------------------------
% Set up characteristic days
%
% day1       Fall Semester Weekday                              (120809)
% day2       Fall Semester Weekend Day                          (101009)
% day3       Spring Semester Weekday                            (030310)
% day4       Spring Semester Weekend Day                        (031310)
% day5       Spring Break Day                                   (031710)
% day6       Summer Session Weekday                             (070610)
% day7       Summer Session Weekend Day                         (071010)
% day8       Non-semester Weekday - Cooling Mode       (081910)
% day9       Non-semester Weekday - Heating Mode       (010910)
% day10      Non-Semester Weekend Day - Cooling Mode (082810)
% day11      Non-Semester Weekend Day - Heating Mode (011110)
% day12 University Holiday - Cooling Mode              (053110)
% day13      University Holdiay - Heating Mode         (112709)
% day14      University Holdiay - Mixed Mode           (110309)
% day15      Christmas/New Years Break                          (122809)
% day16 Low Occupancy/Moderate Cooling          (080810)

Daysperyear=[76,28,74,28,4,35,27,5,5,3,15,3,4,2,10,46];  % # of each characteristic
day/year
%------------------------------------------------------------------------------------------
% Open Input and output files
%------------------------------------------------------------------------------------------
% fday1 = fopen('120809Input.prn','r')
% fday2 = fopen('101009Input.prn','r')
% fday3 = fopen('030310Input.prn','r')
% fday4 = fopen('031310Input.prn','r')
% fday5 = fopen('031710Input.prn','r')
```

```
% fday6 = fopen('070610Input.prn','r')
% fday7 = fopen('071010Input.prn','r')
% fday8 = fopen('081910Input.prn','r')
% fday9 = fopen('010910Input.prn','r')
% fday10 = fopen('082810Input.prn','r')
% fday11 = fopen('011110Input.prn','r')
% fday12 = fopen('053110Input.prn','r')
% fday13 = fopen('112709Input.prn','r')
% fday14 = fopen('110309Input.prn','r')
% fday15 = fopen('122809Input.prn','r')
% fday16 = fopen('080810Input.prn','r')
%
%------------------------------------------------------------------------------------------
fid2 = fopen('C02difference.txt','w')
fid3 = fopen('Costdifference.txt','w')
fid4 = fopen('CostofC02.txt','w')
%
% Write header to fid2
%
fprintf(fid2,"CO2 difference \r\n")
fprintf(fid2," \r\n");
fprintf(fid2,"    Carbon                    Difference in C02 (pounds)                    \r\n");
fprintf(fid2,"   Emissions                                                      \r\n");
fprintf(fid2,"  (lb/kW  hour)                          Cost  of  Electricity  ($/kW  hour)
\r\n");
fprintf(fid2,"              0.05      0.10      0.15      0.20      0.25      0.30      \r\n");

% Write header to fid3
%
fprintf(fid3,"Cost difference \r\n")
fprintf(fid3," \r\n");
fprintf(fid3,"    Carbon                    Difference in Cost ($)                    \r\n");
fprintf(fid3,"   Emissions                                                      \r\n");
fprintf(fid3,"  (lb/kW  hour)                          Cost  of  Electricity  ($/kW  hour)
\r\n");
fprintf(fid3,"              0.05      0.10      0.15      0.20      0.25      0.30      \r\n");
%
% Write header to fid4
%
fprintf(fid4,"Cost of CO2 \r\n")
fprintf(fid4," \r\n");
fprintf(fid4,"    Carbon                    Cost of C02($/lb)                    \r\n");
fprintf(fid4,"   Emissions                                                      \r\n");
fprintf(fid4,"  (lb/kW  hour)                          Cost  of  Electricity  ($/kW  hour)
\r\n");
```

```
fprintf(fid4,"              0.05       0.10       0.15       0.20       0.25       0.30         \r\n");
%
for i = [1:14];
        electricCO2 =(i-1)*0.125
        Results1=[0.0,0.0,0.0,0.0,0.0,0.0];
        Results2=[0.0,0.0,0.0,0.0,0.0,0.0];
        Results3=[0.0,0.0,0.0,0.0,0.0,0.0];
        for j = [1:6];
                electriccost=(j)*0.05
                %------------------------------------------------------------------------------------
-----
                % Totaling variables
                %
                equipop=[0.0,0.0,0.0,0.0,0.0,0.0];                % use of cogen1,2; boilers
1,2,3; grid
                cheapest_day_totalCO2 = 0;          % daily total of CO2 emissions for
cheapest operation
                cheapest_day_cost = 0;                      % daily total of $ for cheapest
operation
                greenest_day_totalCO2 = 0;          % daily total of CO2 emissions for
greenest operation
                greenest_day_cost = 0;                      % daily total of $ for greenest
operation
                cheapest_year_totalCO2 = 0;         % yearly total of CO2 emissions for
cheapest operation
                cheapest_year_cost = 0;                     % yearly total of $ for cheapest
operation
                greenest_year_totalCO2 = 0;         % yearly total of CO2 emissions for
greenest operation
                greenest_year_cost = 0;                     % yearly total of $ for greenest
operation
                greenest_day_op_total=[0.0,0.0,0.0,0.0,0.0,0.0];
                cheapest_day_op_total=[0.0,0.0,0.0,0.0,0.0,0.0];
                dailyelectricdemand = .0;
                dailysteamdemand = 0.0;
                yearlyelectricdemand = 0.0;
                yearlysteamdemand = 0.0;
                greenest_year_op_total=[0.0,0.0,0.0,0.0,0.0,0.0];
                cheapest_year_op_total=[0.0,0.0,0.0,0.0,0.0,0.0];
                %------------------------------------------------------------------------------------
-----
                % Loop through all 16 characteristic days
                %
                for day = [1:16];
                %
```

```
if (day == 1)
        fid1 = fopen('120809Input.prn','r')
end
if (day == 2)
        fid1 = fopen('101009Input.prn','r')
end
if (day == 3)
        fid1 = fopen('030310Input.prn','r')
end
if (day == 4)
        fid1 = fopen('031310Input.prn','r')
end
if (day == 5)
        fid1 = fopen('031710Input.prn','r')
end
if (day == 6)
        fid1  = fopen('070610Input.prn','r')
end
if (day == 7)
        fid1  = fopen('071010Input.prn','r')
end
if (day == 8)
        fid1  = fopen('081910Input.prn','r')
end
if (day == 9)
        fid1  = fopen('010910Input.prn','r')
end
if (day == 10)
        fid1 = fopen('082810Input.prn','r')
end
if (day == 11)
        fid1  = fopen('011110Input.prn','r')
end
if (day == 12)
        fid1  = fopen('053110Input.prn','r')
end
if (day == 13)
        fid1  = fopen('112709Input.prn','r')
end
if (day == 14)
        fid1  = fopen('110309Input.prn','r')
end
if (day == 15)
        fid1  = fopen('122809Input.prn','r')
end
```

```
if (day == 16)
        fid1  = fopen('080810Input.prn','r')
end
%
% Read data in from fid1
% start with 8 lines of text
% assumes 4th line is used as header for output file.
%
foo = fgetl(fid1);
foo = fgetl(fid1);
foo = fgetl(fid1);
foo4 = fgetl(fid1);
foo = fgetl(fid1);
foo = fgetl(fid1);
foo = fgetl(fid1);
foo = fgetl(fid1);
%-------------------------------------------------------------------------------------
% Initialize all daily totalizing values to zero
%
cheapest_day_totalCO2 = 0;        % daily total of CO2 emissions for cheapest operation
cheapest_day_cost = 0;            % daily total of $ for cheapest operation
greenest_day_totalCO2 = 0;        % daily total of CO2 emissions for greenest operation
greenest_day_cost = 0;            % daily total of $ for greenest operation
greenest_day_op_total=[0.0,0.0,0.0,0.0,0.0,0.0];
cheapest_day_op_total=[0.0,0.0,0.0,0.0,0.0,0.0];
dailyelectricdemand = 0.0;
dailysteamdemand = 0.0;
%
%       input datafile is in 15 minute increments
%         => need to loop through 96 time steps to get full day
%
for timestep = [1:96];
        %
        % read one line of 15 minutes of data
        %
        date = fscanf(fid1,'%c',[9]);
        time = fscanf(fid1,'%c',[4]);
        foo = fscanf(fid1,'%f',[4]);
        foo2 = fscanf(fid1,' \r\n');
        electdemand = foo(3);
```

```
steamdemand = foo(4);
dailyelectricdemand = dailyelectricdemand+electdemand*0.25;
dailysteamdemand = dailysteamdemand+steamdemand*0.25;
%
%  loop through 4 permutations of cogens on or off
mincostperhour = 2000000;
mingreencostperhour = 20000000;
for cogen1=[0,1]
    for cogen2=[0,1]
        % start by assuming boilers on low, zero grid purchase
        equipop=[cogen1,cogen2,0.05,0.05,0.05,0];
        %
        % calculate electric and steam deficits for original assumption
        elecgen=dot(equipop,elecprod);
        steamgen=dot(equipop,steamprod);
        electdeficit = electdemand-elecgen;
        steamdeficit = steamdemand-steamgen;
        %
        % update boiler and grid to account for deficits
        equipop(6) = electdeficit;
        equipop(4)=equipop(4)+(steamdeficit/(2.0*boiler2cap));
        equipop(5)=equipop(5)+(steamdeficit/(2.0*boiler3cap));
        %
        % begin error trapping
        if equipop(6) < 0.0;
            equipop(6) = 0;
        end
        if equipop(5) < 0.05
            equipop(5) = 0.05;
        end
        if equipop(4) < 0.05
            equipop(4) = 0.05;
        end
        if equipop(3) < 0.05
            equipop(3) = 0.05;
        end
        if equipop(3) > 1.0;
            equipop(3) = 1.0;
```

```
                    equipop(4) = 1.0;
                    steamdeficit = steamdemand-dot(equipop,steamprod);
                    equipop(3) = equipop(3)+(steamdeficit/boiler1cap);
                    if equipop(3) > 1.0;
                        equipop(3) = 1.0
                        % cannot meet demand, add big cost penalty
                        cost = 1000000;
                        greencost = 1000000;
                    end
                end
                %
                % calculate costs of option
                totalgas = dot(gasuse,equipop);
                totalgrid = dot(griduse,equipop);
                cost = totalgas*gascost+totalgrid*electriccost;
                greencost = totalgas*gasCO2+totalgrid*electricCO2;
                %
                % check to see if this is cheapest or greenest option
                if cost < mincostperhour;       % cheapest option so far
                    mincostperhour = cost;
                    greencostofcheapestperhour = greencost;
                    cheapestop = equipop;
                end
                if greencost < mingreencostperhour;     % greenest option so far
                    mingreencostperhour = greencost;
                    costofgreenestperhour = cost;
                    greenestop=equipop;
                end
            end
        end
    %
    %   add *0.25 times hourly rates to daily totals
    %
        cheapest_day_op_total = cheapest_day_op_total + 0.25*cheapestop;
```

```
                    greenest_day_op_total = greenest_day_op_total + 
0.25*greenestop;

     cheapest_day_cost=cheapest_day_cost+0.25*mincostperhour;

     cheapest_day_totalCO2=cheapest_day_totalCO2+0.25*greencostofcheapestperho
ur;

     greenest_day_totalCO2=greenest_day_totalCO2+0.25*mingreencostperhour;

     greenest_day_cost=greenest_day_cost+0.25*costofgreenestperhour;
               end
               %
               % update yearly totals
               %

     yearlyelectricdemand=yearlyelectricdemand+dailyelectricdemand*Daysperyear(d
ay);

     yearlysteamdemand=yearlysteamdemand+dailysteamdemand*Daysperyear(day);

     cheapest_year_op_total=cheapest_year_op_total+cheapest_day_op_total*Dayspe
ryear(day);

     greenest_year_op_total=greenest_year_op_total+greenest_day_op_total*Daysper
year(day);

     cheapest_year_cost=cheapest_year_cost+cheapest_day_cost*Daysperyear(day);

     cheapest_year_totalCO2=cheapest_year_totalCO2+cheapest_day_totalCO2*Days
peryear(day);

     greenest_year_totalCO2=greenest_year_totalCO2+greenest_day_totalCO2*Days
peryear(day);

     greenest_year_cost=greenest_year_cost+greenest_day_cost*Daysperyear(day);
               %
               fclose(fid1);
          end
          Results1(j)=Results1(j)+cheapest_year_totalCO2-
greenest_year_totalCO2;
          Results2(j)=Results2(j)+greenest_year_cost-cheapest_year_cost;
          Results3(j)=Results3(j)+(greenest_year_cost-
cheapest_year_cost)/(cheapest_year_totalCO2-greenest_year_totalCO2);
     end
```

```
    fprintf(fid2,'  %10.3f    %10.1f    %10.1f    %10.1f    %10.1f    %10.1f    %10.1f
\r\n',electricCO2,
Results1(1),Results1(2),Results1(3),Results1(4),Results1(5),Results1(6));
    fprintf(fid3,'  %10.3f    %10.1f    %10.1f    %10.1f    %10.1f    %10.1f    %10.1f
\r\n',electricCO2,
Results2(1),Results2(2),Results2(3),Results2(4),Results2(5),Results2(6));
    fprintf(fid4,'  %10.3f    %10.3f    %10.3f    %10.3f    %10.3f    %10.3f    %10.3f
\r\n',electricCO2,
Results3(1),Results3(2),Results3(3),Results3(4),Results3(5),Results3(6));
    %
end
fclose(fid2);
fclose(fid3);
```

Appendix: Primary Plant Equipment Data	
I. Cogeneration Turbogenerator Unit # 1	
Nominally Rated Electrical Power Output	1.2 Megawatt
Manufacturer	Solar Turbines, Inc.
Model	Saturn 20
Serial Number	SG05N74
Year Built	2006
Sales Order Number	2-76932
Generator Output	1,210 Kilowatts
Mechanical Drive Output	1,185 Kilowatts
Mechanical Drive Output	1,590 Horsepower
Highest Supply Ratings, VAC/φ/AMP	460/3/102
Highest Supply Ratings, VDC/AMP	30/1.3
Generator, VAC/φ/Hz/kW	4,160/3/60/1,360
II. Cogeneration Turbogenerator Unit # 2	
Nominally Rated Electrical Power Output	3.5 Megawatt
Manufacturer	Solar Turbines, Inc.
Model	Centaur 40
Serial Number	CG05964
Year Built	2006
Sales Order Number	2-76931
Generator Output	3,515 Kilowatts
Mechanical Drive Output	3,500 Kilowatts
Mechanical Drive Output	4,700 Horsepower
Highest Supply Ratings, VAC/φ/AMP	460/3/337
Highest Supply Ratings, VDC/AMP	120/13
Generator, VAC/φ/Hz/kW	12,470/3/60/4,750

III. Heat Recovery Steam Generator # 1	
Equipment integrated with	Cogeneration Turbogenerator Unit # 1
Maximum Design Steam Capacity	8,300 pounds per hour
Manufacturer	Rentech Boiler Systems, Inc.
Purchase Order Number	P6003805
Year Built	2006
Maximum Allowable Working Pressure	250 psig at 500°F; Tubes 700°F
1st Stage MFG Service Number	2005-117
1st Stage Heating Surface Square Feet	7,562
2nd Stage MFG Service Number	2005-116
2nd Stage Heating Surface Square Feet	809
IV. Heat Recovery Steam Generator # 2	
Equipment integrated with	Cogeneration Turbogenerator Unit # 2
Maximum Design Steam Capacity	19,550 pounds per hour
Manufacturer	Rentech Boiler Systems, Inc.
Purchase Order Number	P6003805
Year Built	2006
Maximum Allowable Working Pressure	250 psig at 500°F; Tubes 700°F
1st Stage MFG Service Number	2005-121
1st Stage Heating Surface Square Feet	15,459
2nd Stage MFG Service Number	2005-119
2nd Stage Heating Surface Square Feet	1,803

V. Natural Gas Compressor # 1	(Provides Compressed Natural Gas to Cogeneration Turbogenerator Unit #1)
Location	Outdoor, North Side of Plant
System Configuration	Enclosed Skid-Mounted Compressor Coupled with Pre-Engineered Auxilliary Systems
Manufacturer	Frick
Model/Serial Number	XJF120521G3DDZ
Manufacture Date	2006
Type of Compressor	Rotary Screw
RPM	3,600
Volume Ratio	2.2 - 5.0
Swept Volume at Maximum Speed	296 Feet per minute
Maximum Allowabe Pressure	350 psig
Exchanger Manufacturer	York
Exchanger Serial Number	155053
Driver	Electric Motor
Motor Horsepower	100 Horsepower
VI. Natural Gas Compressor # 2	(Provides Compressed Natural Gas to Cogeneration Turbogenerator Unit #2)
Location	Outdoor, North Side of Plant
System Configuration	Enclosed Skid-Mounted Compressor Coupled with Pre-Engineered Auxilliary Systems
Manufacturer	Frick
Model Number	RWF 11 134H
Serial Number	0494
Manufacture Date	June 12, 2006
Sales Order Number	28401401000
Refrigerant Type	R-50
Driver	Induction Electric Motor
Motor Manufacturer	Siemens
Motor Horsepower	300 Horsepower

VII. Boiler # 1	
Boiler Manufacturer	Superior Combustion Industries, Inc.
Manufacturer Location	Wilkes Barre, PA
Boiler Type	Water Tube
Fuel Type	Dual: Natural Gas and #2 Fuel Oil
H.S.B	2583
National Board Number	2583
Capacity	26,000 pounds of steam per hour
Heat release per cubic foot	53,500
Furnace Volume	654
Year Built	1960
Working Pressure	250 Psig
Heating Surface	3,083
Serial Number	2583 3716
NJ Number	21374
VIII. Boiler # 2	
Boiler Manufacturer	Babcock & Wilcox, a McDermott Company
Manufacturer Location	West Point, Mississippi
Boiler Type	Water Tube
Fuel Type	Dual Fuel: Natural Gas and #2 Fuel Oil
Efficiency Feature	Stack Economizer
National Board Number	25199
B&W Number	201-3403
Boiler MAWP	250 psi at 366° F
Capacity - MDSC	40,000 pounds per hour
Boiler Heating Surface	3,063 square feet
Waterwall Heating Surface	543 square feet
Year Built	2004
Erected by	Frank Lill & Son (Rochester, NY)
Erect Date	January, 2005

IX. Boiler # 3	
Boiler Manufacturer	Babcock & Wilcox, a McDermott Company
Manufacturer Location	West Point, Mississippi
Boiler Type	Water Tube
Fuel Type	Dual Fuel: Natural Gas and #2 Fuel Oil
Efficiency Feature	Stack Economizer
National Board Number	25200
B&W Number	201-3404
Boiler MAWP	250 psi at 366° F
Capacity - MDSC	40,000 pounds per hour
Boiler Heating Surface	3,063 square feet
Waterwall Heating Surface	543 square feet
Year Built	2004
Erected by	Frank Lill & Son (Rochester, NY)
Erect Date	January, 2005
X. Steam Turbine-Driven Centrifugal Chiller	
Nominally Rated Thermal Power Output	2,400 Tons
Chiller Manufacturer	York International Corp.
Chiller Model Number	YSTXFXDJ5-KD2000125-13-1.061-35216C-FS
Compressor Model Number	YDHA-104VDD
Refrigerant Charge, R134a	5,810 pounds
Serial Number	896610
Electric Supply Voltage	460 VAC
Turbine Manufacturer	Tuthill/Murray
Turbine Model Number	KD2000125
Turbine Rated Horsepower	1,994 Horsepower
Supply Steam Pressure	150 psig
Exhaust Steam Pressure	3.85 psig
Steam Condensor Manufacturer	ITT Standard
Steam Condensor Model Number	35216C

XI. Electric Motor-Driven Centrifugal Chiller # 1	
Nominally Rated Thermal Power Output	1,060 tons
Manufacturer	Trane, Inc.
Model Name	CVHF1060
Model Number	CVHF106GA2MOPCW279AE9LCEBC00 00000YA1004CLOW0003A100A
Serial Number	L05D01947
Manufacture Date	October 5, 2005
Sales Order Number	D2U929A
Rated Voltage	480 Volts
Number of Phases	3
Frequency	60 Hertz
Nominal Electric Power	595 Kilowatts
Compressor Motor Voltage	480 Volts
Compressor Motor Rated Amperage	844 Amps
Refrigerant	R-123
Field Charge	2,200 Pounds
High Side Max Working Pressure	15 psig
Low Side Max Working Pressure	15 psig
XII. Electric Motor-Driven Centrifugal Chiller # 2	
Nominally Rated Thermal Power Output	1,060 tons
Manufacturer	Trane, Inc.
Model Name	CVHF1060
Model Number	CVHF106GA2MOPCW279AE9LCEBC00 00000YA1004CLOW0003A100A
Serial Number	L05D01975
Manufacture Date	October 5, 2005
Sales Order Number	D2U929B
Rated Voltage	480 Volts
Number of Phases	3
Frequency	60 Hertz
Nominal Electric Power	595 Kilowatts
Compressor Motor Voltage	480 Volts
Compressor Motor Rated Amperage	844 Amps
Refrigerant	R-123
Field Charge	2,200 Pounds
High Side Max Working Pressure	15 psig
Low Side Max Working Pressure	15 psig