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A Methodology to Perform a Combined Heating and Power System Assessment and Feasibility Study for an Industrial Manufacturing Facility

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A METHODOLOGY TO PERFORM A COMBINED HEATING AND POWER SYSTEM ASSESSMENT AND FEASIBILITY STUDY FOR AN INDUSTRIAL MANUFACTURING FACILITY

By

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A METHODOLOGY TO PERFORM A COMBINED HEATING AND POWER SYSTEM ASSESSMENT AND FEASIBILITY STUDY FOR AN INDUSTRIAL MANUFACTURING FACILITY

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The main objective of this study is to develop a methodology which can be used to assess the economic potential for combined heat and power (CHP) systems to be employed in an effort to offset a portion or all of the conventionally supplied power and thermal energy at industrial manufacturing facilities. A methodology is developed which determines the economic considerations of proposed industrial CHP projects once the system configuration is specified. This methodology is then applied to a number of different industrial facilities in a parametric analysis in order to demonstrate how it can be used to assess the potential for success for CHP at industrial sites for a wide range of manufacturing processes. Many of the methodology inputs, such as facility operational hours, facility thermal load, etc. are then varied in order to determine how they affect the economic considerations of the corresponding project. Conclusions are subsequently made as to how each of these parameters can be indicative of project success before employing the methodology. This study focuses on industrial sites in the Southeast U.S., which historically have relatively low utility usage rates. The Southeast U.S. also lacks adequate policy applicable to CHP systems, such as net metering and interconnection

standards rules, when compared to the rest of the country. It is for this reason that the methodology developed in this research assumes that a base load CHP system is the most economically viable CHP option and the current status of policy applicable to CHP at industrial facilities located in the Southeast U.S. is also investigated. The results of the parametric analysis are modified to determine if improved economics can be attained if the associated facilities engage in net metering programs. As a result, suggested net metering rates that can positively affect the economic considerations of industrial CHP projects in the Southeast U.S. are realized. Finally, a simple tool based on the methodology presented in this research was developed and can be used to calculate the project economics of an industrial facility CHP system.

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NOMENCLATURE

Cap_{sys}	Electrical capacity of CHP system
CDE_{CHP}	Carbon dioxide emissions from facility operation using CHP system to supply a portion of the electrical and thermal loads
CDE_{conv}	Carbon dioxide emissions from facility operation using conventionally supplied electricity and fuel
CDE_{red}	Reduction in carbon dioxide emissions associated with installation of the proposed CHP system
$Cost_f$	Cost of fuel that must be supplied to CHP system
$Cost_{op}$	Total CHP system annual operational cost
CR	Cost per electrical capacity of proposed CHP system
CS_{ele}	Annual electrical usage cost savings resulting from operation of CHP system
CS_{st}	Cost savings associated with offsetting a portion of the thermal load using the CHP system
CS_{tot}	Total annual cost savings associated with proposed CHP project
E_{grid}	Electricity supplied by the local utility provider
E_m	Total annual facility electrical usage
ECF_{CDE}	Carbon dioxide emissions conversion factor for electricity

ECF_{NOE}	NO_x emissions conversion factor for electricity
ECF_{SDE}	Sulfur dioxide emissions conversion factor for electricity
ES_{st}	Thermal energy savings resulting from operation of CHP system
F_{CHP}	CHP system fuel feed rate converted to kWh/yr
F_{grid}	Fuel supplied by the local utility provider
F_m	Total annual facility fuel usage converted to kWh/yr
FCF_{CDE}	Carbon dioxide emissions conversion factor for fuel
FCF_{NOE}	NO_x emissions conversion factor for fuel
FCF_{SDE}	Sulfur dioxide emissions conversion factor for fuel
$fuel_{avail}$	Waste fuel made available for sale due to operation of the CHP system
$fuel_{cons}$	Annual facility waste that could possibly be utilized as CHP fuel
$fuel_{FR}$	Proposed CHP system fuel feed rate
Hr	Annual operating hours of facility for which CHP feasibility study is being conducted
IC	Installed cost of proposed CHP system
IRR	Internal rate of return
K_1	Conversion constant, [(29.9 Boiler-hp)/(1,000 lb/hr steam)]
K_2	Conversion constant, [(33,479 BTU/hr)/(Boiler-hp)]
K_3	Conversion constant, [(MMBTU)/(10^6 BTU)]
LF	Load factor of CHP system (percentage of facility operating hours that system will be available)
Ld_e	Facility electrical load of which a portion is to be offset by the CHP system

Ld_{th}	Facility thermal or steam load of which a portion is to be offset by CHP system
$lost_{rev}$	Loss in revenue associated with utilization of a sold waste stream as a CHP fuel source
NOE_{CHP}	NO_x emissions from facility operation using CHP system to supply a portion of the electrical and thermal loads
NOE_{conv}	NO_x emissions from facility operation using conventionally supplied electricity and fuel
NOE_{red}	Reduction in NO_x emissions associated with installation of the proposed CHP system
NPV	Net present value
$O\&M$	CHP system operational and maintenance fee estimate
PHR	Power to heat ratio
$Prod$	Proposed CHP system annual electrical production
Rev_{gen}	Revenue generated by sale of available waste fuel from CHP system operation
SDE_{CHP}	Sulfur dioxide emissions from facility operation using CHP system to supply a portion of the electrical and thermal loads
SDE_{conv}	Sulfur dioxide emissions from facility operation using conventionally supplied electricity and fuel
SDE_{red}	Reduction in sulfur dioxide emissions associated with installation of the proposed CHP system
SR	Sale rate of waste stream to be utilized as a CHP system fuel source

UR_{CHP}	Usage rate of electricity generated by CHP system
UR_{conv}	Usage rate of electricity purchased from local utility supplier
UR_{th}	Usage rate of conventional fuel utilized to supply the facility's thermal loads

Abbreviations

CHP	Combined heating and power
CO_2	Carbon dioxide
DOE	Department of Energy
EPA	Environmental Protection Agency
FEL	Follow electric load
FTL	Follow thermal load
NO_x	Nitrogen x-oxide
O&M	Operation and maintenance
SO_2	Sulfur dioxide
SSAT	Steam System Assessment Tool
SSTS	Steam System Tool Suite

Greek

η_{boiler}	Efficiency of existing boiler(s) used to supply the facility's thermal load

Subscripts

cap	Capacity
CDE	Carbon dioxide emissions
CHP	Combined heating and power
conv	Conventional

ele	Electrical
f	Fuel
FR	Feed Rate
grid	Local utility supplier (local utility grid)
m	Annual usage
NOE	NO_x emissions
op	Operation
red	Reduction
SDE	Sulfur dioxide emissions
st	Steam
sys	System
th	Thermal
tot	Total

CHAPTER I

INTRODUCTION

Combined heat and power (CHP) systems have the potential to significantly impact an industrial manufacturing facility's annual energy consumption and associated annual energy fees as well as reduce the facility's greenhouse gas emissions due to the potential for increased operating efficiencies. Production of power at a central power plant results in the loss of thermal energy in the form of exhausted heat. Figure 1.1 provides an estimate of the amount of fuel energy that is lost in the power production process. If CHP is installed, a substantial amount of this energy could be recovered and used to offset thermal loads.

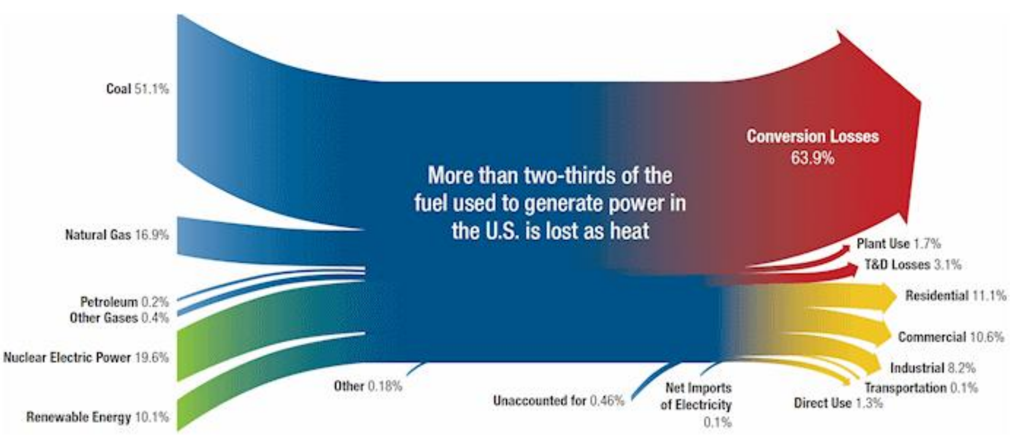


Figure 1.1 Unrecovered Thermal Energy from Conventional Power Generation [Shipley *et al*., 2008]

If the infrastructure were in place to recover this exhausted heat, the operating efficiency of the power production process would be greatly improved. However, in order for a facility to make use of any waste heat recovered, the source of this thermal energy must be in close proximity to the facility's location. Figures 1.2 and 1.3 illustrate how increased levels of efficiency and increased emissions reductions can be obtained by operation of a CHP system in lieu of conventional heat and power supply. In addition, a CHP system can also provide an added level of energy independence which can provide an industrial manufacturing facility with robust capabilities to counter fluctuations in grid supplied power. It is for these reasons that CHP should be considered for any industrial manufacturing facility that has relatively large electrical and process heating loads.

Many industrial manufacturing facilities make use of steam systems to supply their thermal loads. For these sites, CHP can be installed if a relatively simple modification is made to the steam system, shown in Figure 1.4. In order to determine which CHP system configuration is preferred, a number of parameters which include but are not limited to a comparison of energy consumed by electrical and process heating equipment, energy policy and incentives status, etc. will dictate whether a topping or bottoming cycle CHP system will best suit the facility in question's application. Topping cycles describe CHP systems that generate electricity by a prime mover as the primary function and then recover thermal energy from the waste heat given off by the electrical production process. Bottoming cycles are those in which thermal energy is produced first, often by a large boiler, and then any excess thermal energy is recovered in the form of steam and utilized to power a steam turbine generator set.

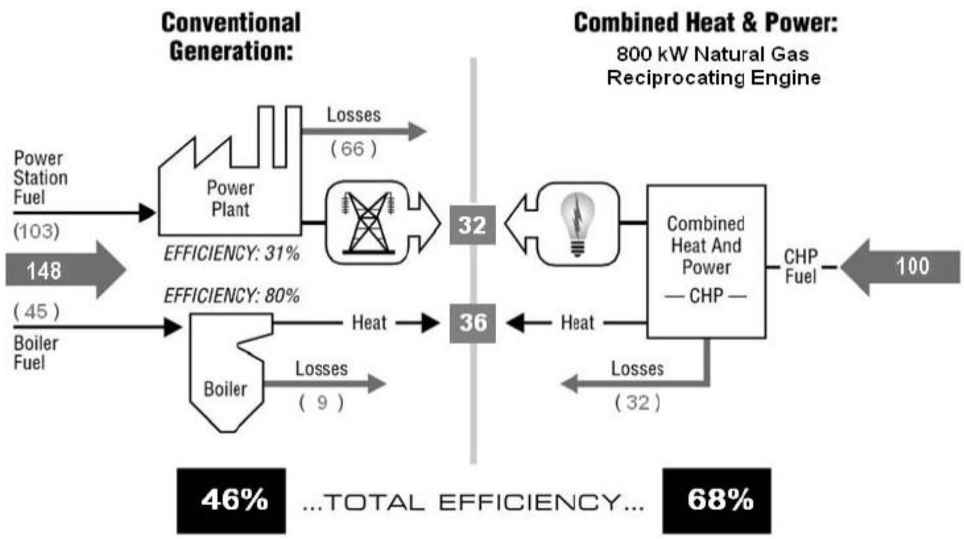


Figure 1.2 Conventional vs. Combined Heat and Power Efficiency Comparison

Source: Midwest Clean Energy Application Center,
www.midwestcleanenergy.org/Archive/pdfs/091105_Cuttica_Modules1and2.pdf

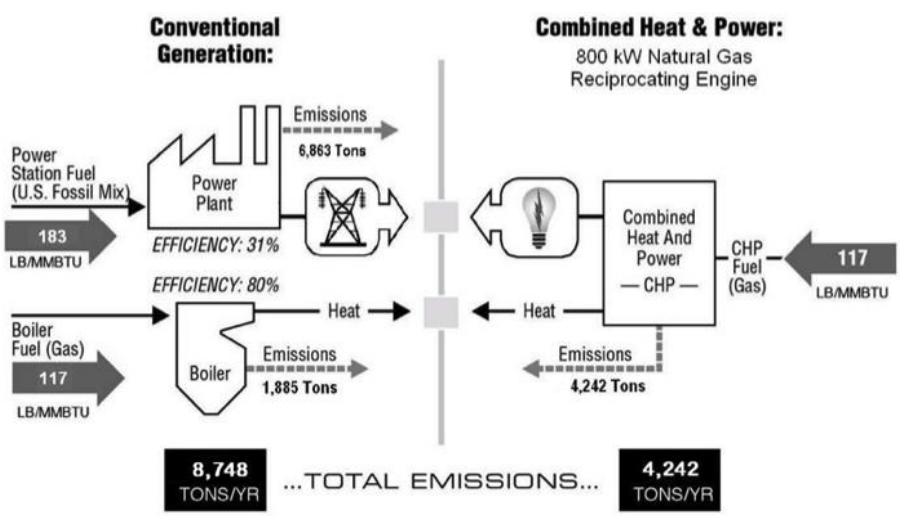


Figure 1.3 Conventional vs. Combined Heat and Power Emissions Comparison

Source: Midwest Clean Energy Application Center,
www.midwestcleanenergy.org/Archive/pdfs/091105_Cuttica_Modules1and2.pdf

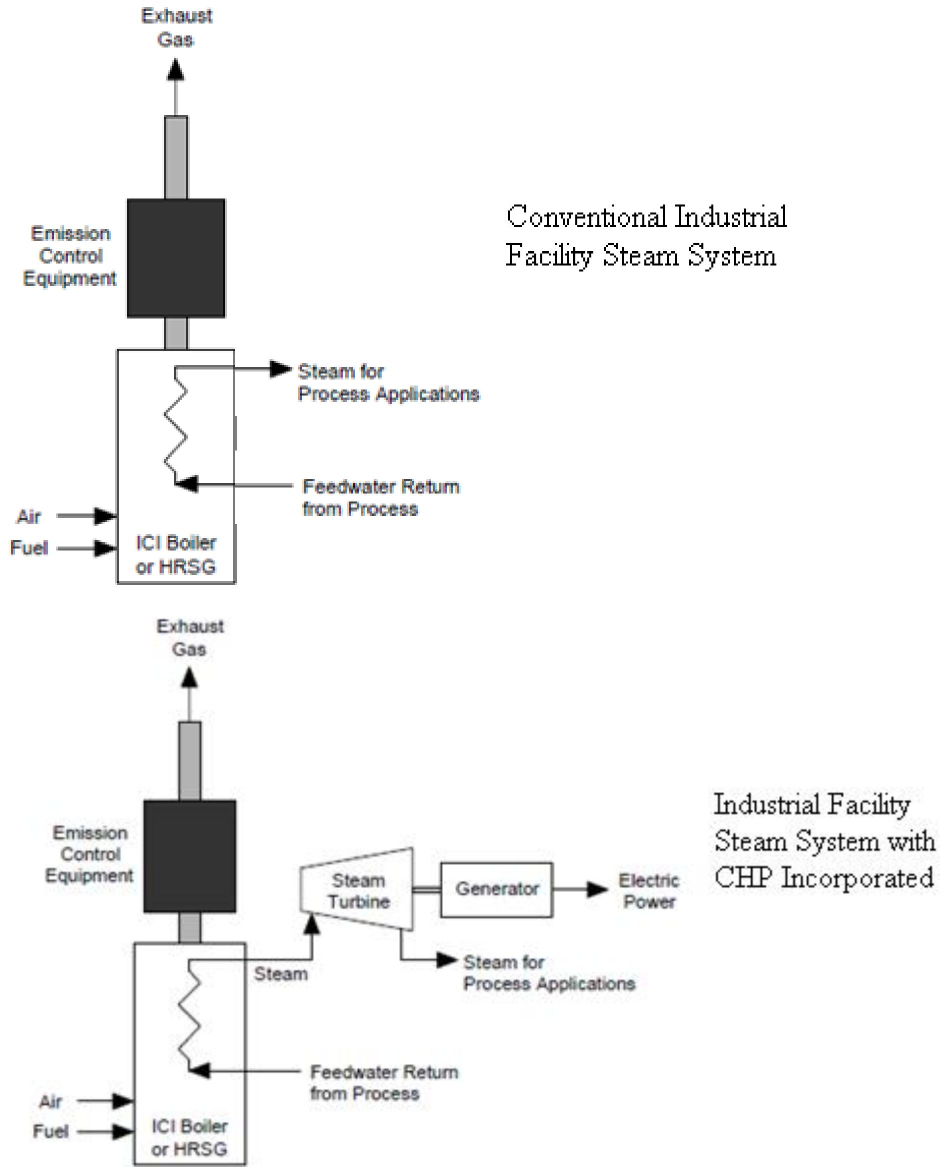


Figure 1.4 Industrial Facility Steam System CHP Retrofit

1.1 Literature Review

Sayane and Shokrollahi [2004], Zogg *et al.* [2005], Al-Sulaiman *et al.* [2010], and Ghaebi *et al.* [2010] have shown that the configuration of the CHP system will also depend on individual component efficiencies and the system operating strategy. However, it is the author's experience that the base electric load of the facility is typically the primary parameter which dictates the configuration of a CHP system at manufacturing sites in the Southeast U.S., and topping cycle CHP systems are the preferred method of offsetting the facility's base electric load. The operational strategy is of significance when attempting to determine the economic feasibility of a CHP system. CHP systems can be configured to run under several different operational strategies, such as: following electric load (FEL), following thermal load (FTL), hybrid FEL-FTL, and base-load operation.

When the CHP system is configured to operate on a FEL strategy, the prime mover will generate electricity to satisfy the instantaneous electrical load of the facility and heat is recovered from the exhaust of the electrical generation process. When the CHP system operates on a FTL strategy, the prime mover will generate the heat necessary to supply the instantaneous thermal load of the facility and any heat exhausted is recovered and used to generate electricity as a by-product. These two operational strategies have been widely investigated by such authors as Cardona *et al.* [2006], Mago *et al.* [2009a], Mago *et al.* [2009b], Jalalzadeh-Azar [2004], Hueffed and Mago [2010], among others. Another engine operation strategy is hybrid FEL-FTL in which the power generation unit is controlled in a manner that results in following the optimal operation as measured by a performance index based on cost, emissions, or primary energy consumption. Hueffed and Mago [2010], Cho *et al.* [2008], and Kong *et al.* [2005] have performed investigations on this type of operation. Finally, since a base-loaded CHP system configuration satisfies a fraction of the facility's electric load, most of heat that can be recovered is utilized in this type of operational scheme, often resulting in a high CHP system efficiency [Mago and Luck, Accepted].

Base load CHP systems are often the best option for industrial manufacturing facilities as they can often be integrated into the existing operational structure with relative ease and are typically the most economically viable alternative. When considering a base-load CHP system for an industrial manufacturing facility, a number of different parameters must be examined and addressed before one can determine its estimated economic viability and potential for success. The most widely accepted parameter that is used to estimate the feasibility of any proposed CHP project is known as spark spread, which is essentially the difference in the cost of utility supplied electricity and the fuel cost associated with production of electricity on site. A spark spread of \$12/MMBtu (\$0.041/kWh) is typically considered to be the threshold that is representative of an economically attractive CHP project, meaning that projects that exhibit spark spreads in excess of \$12/MMBtu (\$0.041/kWh) will have a good potential for low payback periods and overall economic success [Cuttica and Haefke, 2009].

Graves *et al.* [2008] developed a more sophisticated method that incorporates generator heat rate, thermal recovery efficiency, equipment cost, and acceptable payback period, allowing for a more accurate indication of CHP viability. In a similar manner, Smith *et al.* [2011] developed a detailed model, based on the spark spread, which compares the electrical energy and heat energy produced by a CHP system against equivalent amounts of energy produced by a traditional, or separate heating and power (SHP), system. In addition, they introduced an expression for the spark spread based on the cost of the fuel and some of the CHP system efficiencies as well as an expression for the payback period for a given capital cost and spark spread. However, for industrial manufacturing facilities, in addition to the spark spread, there are other factors that must be considered when analyzing the economic feasibility of a CHP system, such as the type of prime mover, the fuel availability and cost, and operational hours, among others.

Another key factor that can significantly affect the configuration of a CHP system at an industrial manufacturing facility is the status of net metering and interconnection standards policy and incentives available in the region where the facility is located. If an industrial site is able to engage in a net metering program, it may be advantageous for the facility to size a CHP system such that it meets their thermal load with intentions of selling any resulting excess electrical generation back to the local utility provider. On the other hand, if no favorable net metering incentives or policy are available, which is the case for many states in the Southeast U.S. it is typically not advantageous for the facility in question to produce more power than can be consumed on site. For these cases, CHP systems that are sized to closely match the base electric load of the facility are often the most viable alternatives to conventionally supplied power. Suggested modifications to net metering rates, sometimes referred to as utility avoided cost of production rates, are investigated in the parametric analysis presented in the following chapters and an overview of net metering and how it can be applied to CHP systems at industrial manufacturing facilities in the Southeast U.S. is also investigated.

Typical prime movers for CHP systems that are used in manufacturing facilities include, but are not limited to: steam turbines, combustion turbines, and internal combustion engines. Reciprocating engine and fuel cell CHP systems are other options that could possibly be considered for industrial manufacturing facilities. However, these technologies are often expensive and have somewhat limited operating ranges. Micro-turbines are a good choice for smaller commercial and residential buildings, but in general they do not have the capacity to offset an adequate amount of an industrial manufacturing facility's base electrical load. Ellis and Gunes [2002] presented a comparison of different generating system characteristics, which addressed the use of fuel cells. Steam turbines are frequently employed due to their fuel flexibility as well as their ability to provide an extensively wide range of process steam supply flow rates when compared to combustion turbines. For example, combustion turbine CHP units are typically rated to supply a certain amount of steam, with multiple increased steam flow rate options available if duct burners are employed. Steam turbines, on the other hand, allow for multiple variations in process steam flow rates [Zimmer, 2008]. Thus, the desired process steam flow rate can be attained by a number of different methods, such as utilization of extraction steam turbines instead of backpressure steam turbines or by optimization of the backpressure turbine boiler system, which can be easily modeled by making use of the U.S. Department of Energy's Steam System Assessment Tool (SSAT) [U.S. DOE, 2010] or any other appropriate turbine modeling software.

In contrast, combustion turbines are often more easily integrated into an industrial facility's operating scheme. Also, as will be seen in one of the cases presented in the parametric analysis section of this research, a combustion turbine CHP system can often allow for positive electrical cost savings, which is seldom the case for steam turbine CHP systems. In addition, the use of renewable fuels is on the rise due to the price surge and volatility of traditional fuels, as well as a general desire to decrease on site emissions and use more environmentally friendly fuel sources. For example, biomass, such as waste materials from agricultural or industrial processes, is often available at or close to the CHP site and sometimes is obtained free of charge. Thus biomass can be a cost effective CHP fuel source when it is utilized to generate heat and power for a manufacturing facility [Resource Dynamics Corp., 2004]. Figures 1.5-1.7 display schematics of typical backpressure turbine, extraction turbine, and combustion turbine CHP systems.

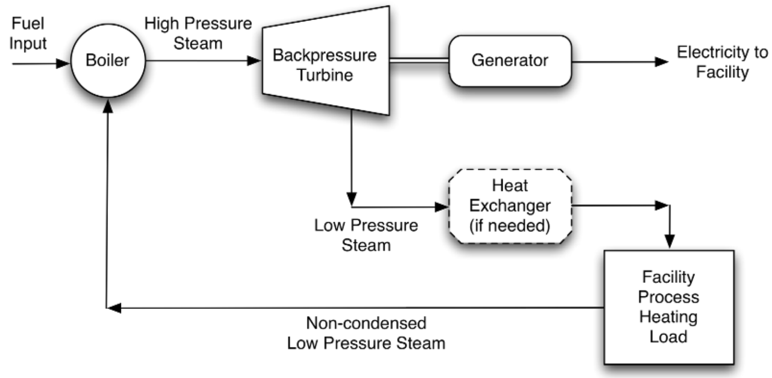


Figure 1.5 Schematic of Typical Backpressure Turbine CHP System

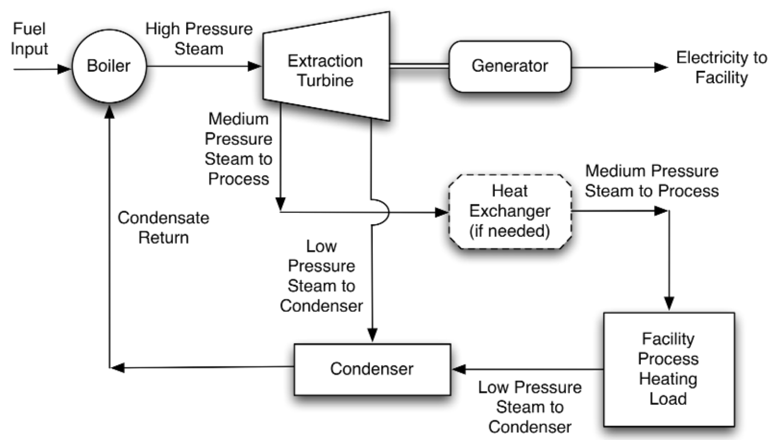


Figure 1.6 Schematic of Typical Extraction Turbine CHP System

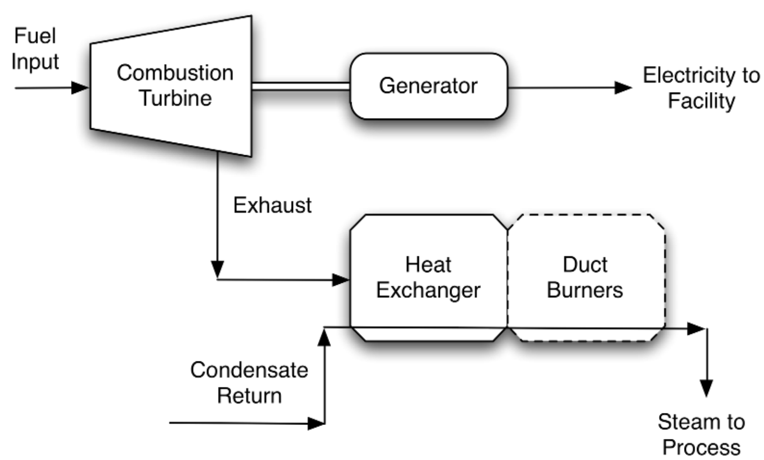


Figure 1.7 Schematic of Typical Combustion Turbine CHP System

Several researchers who have extensively investigated modeling of CHP systems for commercial buildings are Zogg *et al.* [2005], Al-Sulaiman *et al.* [2010], Ghaebi *et al.* [2010], Cardona *et al.* [2006], Mago *et al.* [2009a], Mago *et al.* [2009b], Jalalzadeh-Azar [2004], Hueffed and Mago [2010], and Cho *et al.* [2008]. However, very little research has been performed on CHP for the industrial sector and few methodologies have been developed to evaluate the performance of these types of systems at industrial manufacturing facilities [Wheeley *et al.*, 2011]. Therefore, this investigation presents a detailed model which can be used to evaluate the economic performance of a CHP system at an industrial manufacturing facility which is located in a region that historically has no advantageous net metering policy or incentives.

In general, there are a number of parameters that play a vital role in the outcome of the economic analysis of a CHP system. Therefore, these factors can often be used to gauge the economic attractiveness of any such CHP system. However, since each of these parameters can vary greatly from one facility to the next, a parametric analysis of a number of different industrial manufacturing facilities has been performed using the model developed in this research in an effort to illustrate not only how each of these factors can provide insight to economic considerations of any such CHP system but also how the model accounts for variations in many of these indicating parameters. The factors which are investigated in the parametric analysis are the annual operating hours of the facility during which both electricity and process heat are required (equivalent to the annual operating hours of the CHP system), the usage rate of conventionally supplied electricity, the average hourly thermal load of the facility, and finally the CHP system fuel type and its associated fuel cost.

Another important aspect of CHP systems is their potential to reduce emissions. Several researchers have evaluated and analyzed the benefits of CHP systems in terms of reduction of pollutants for different applications. Some of them include: Mago and Luck [accepted], Möllersten *et al*. [2003a], Wahlund *et al.* [2004], Möllersten *et al*. [2003b], Chicco and Mancarella [2008], and Mancarella and Chicco [2008], among others. In general, all of them reported that CHP systems have the ability to reduce greenhouse gas emissions with a strong emphasis on carbon dioxide emissions reductions. It is for this reason that the methodology developed in the following chapters incorporates equations which can be used to determine the reduction of CO_2, SO_2, and NO_x emissions associated with operation of a CHP system at an industrial manufacturing facility. A comparison of the emissions reductions associated with multiple CHP projects proposed at industrial manufacturing facilities is also included in the parametric analysis chapter.

1.2 Objectives

The main goal of this study is to develop a methodology which can be used to assess the economic viability of a CHP system at an industrial manufacturing facility. The methodology is then applied to multiple different industrial sites in order to demonstrate its robustness in handling varying manufacturing processes and schemes as well as to investigate parameters indicative of economic success for CHP systems at industrial locations. To achieve this objective, the following milestones had to be accomplished:

1. Perform a literature review of existing or proposed CHP systems at industrial manufacturing facilities as well as descriptions of available industrial CHP

technology and typical operating schemes, etc. This information is presented in the current chapter.

2. Develop a methodology which can be used to assess the economic viability of a CHP system for an industrial manufacturing facility. This methodology, which also determines any greenhouse gas equivalent emissions reductions that would be realized if the proposed CHP system were to be installed, is presented in Chapter 2.
3. Perform a parametric analysis of the economic viability of CHP systems at multiple industrial manufacturing facilities using the methodology developed in Chapter 2. The results from this milestone are presented in Chapter 3. This analysis is then used to identify factors that are indicative of CHP project success or failure. Many of these factors are then further investigated in an effort to determine how variations in these parameters will affect associated CHP project economic considerations.
4. Asses the current status of policy and incentives that have the potential to improve the installation rate of CHP at industrial manufacturing facilities in the Southeast U.S., particularly in the state of Mississippi. This information is presented in Chapter 4. Information from the parametric analysis completed in Chapter 3 is called upon in this chapter in order to suggest improvements to the current CHP policy and incentives status as well as new incentives that should be considered in order to allow for increased penetration of CHP in the industrial sector and thus an improved overall CHP implementation rate.

5. Develop a simple tool, based on the methodology developed in Chapter 2, that can be used by engineers and designers to study the feasibility of CHP systems for industrial manufacturing facilities.

CHAPTER II

A METHODOLOGY TO PERFORM A COMBINED HEAT AND POWER SYSTEM FEASIBILITY STUDY FOR INDUSTRIAL MANUFACTURING FACILITIES

2.1 Introduction

This chapter presents a methodology to perform a base load CHP system assessment and feasibility study for industrial manufacturing facilities as well as to determine emissions reductions that may result from utilization CHP. While extensive research has been completed and multiple simulations have been performed to develop numerous methodologies which estimate the economic success of CHP at commercial and residential sites, very few attempts have been made to develop methodologies which can be employed at industrial facilities. Therefore, it follows that there is a need in the CHP related literature for an analysis method that is explicit and yet general enough to determine the economic viability and potential for success of CHP systems at industrial sites.

In order to determine the best and most viable option for any industrial facility in question, the methodology developed in this chapter can be used to size different systems which utilize diverse technologies and fuel sources, perform an economic analysis of each proposed option, and then compare the benefits and setbacks of each type of CHP system considered. The economic analysis will provide a broad insight as to which proposed system will show the best payback if installed. In addition to the economic analysis, the proposed methodology can be used to determine the potential reduction of emissions associated with utilization of each type of CHP system analyzed. Examples presented in the following chapter describe in detail the application of this methodology.

As will be realized in the examples presented in the following chapters, topping cycle CHP systems are typically the best alternative to conventional heat and power supply at industrial manufacturing facilities which are located in the Southeast U.S. This is typically the case due to the fact that on average the Southeast U.S. lacks favorable net metering and interconnection standards policy and thus electrical production that exceeds the consumption of the facility considered is undesirable in these locations. Therefore, the methodology developed in the following analysis allows for selection of the CHP prime mover based on its capability to supply the facility's base electric load. Any resulting waste heat that can be recovered from the electrical generation process is then utilized to offset either a portion of or the facility's entire process heating load.

2.2 Industrial Facility CHP Feasibility Study Methodology

2.2.1 Preliminary Data Collection and Screening

First and foremost, an industrial manufacturing facility that has a history of relatively high electrical and thermal loads is a prerequisite for preparation of a CHP feasibility study. For most viable and economically attractive topping cycle CHP applications, the resulting process heating energy savings associated with the project offsets the majority of the installation and operational costs, which must both be countered if net positive financial gains are to be obtained. It follows that if a large portion of the waste heat produced by a proposed CHP system cannot be utilized to offset all or a portion of the facility's heating load then the project under consideration will not be economically feasible.

2.2.2 Site Assessment

Once an acceptable site has been identified, the next step in the process is to schedule an on-site visit and a tour of the facility with company representatives who are familiar with the electrical and thermal requirements of the equipment and processes. It is often useful to submit a brief questionnaire to the facility personnel in order to obtain preliminary information concerning equipment that is used to supply the facility's thermal loads. Any information that can be obtained which describes the facilities large process equipment prior to the site visit allows for a more organized and efficient assessment. It is also helpful to have information regarding the facility's electrical usage and demand load history prior to the on-site visit. It is good practice to obtain usage and billing history for at least 12-24 months prior to the date of the site visit so that the data obtained will be representative of the average operating loads of the facility and to ensure that unusual operating circumstances such as plant trips or periods of unusual loads will not skew the determined average facility base electrical load. Once this information is obtained, the power to heat ratio for the facility can be determined. The power to heat ratio is defined as:

$$PHR = \left(\frac{Ld_e}{Ld_{th}}\right) \tag{2.1}$$

where Ld_e is the electrical base load and Ld_{th} is the thermal or process heating load. The PHR will provide a broad indication as to the potential viability of a CHP project. The use of the power to heat ratio to determine the potential for a CHP system is discussed in further detail in the examples presented in the following chapters.

2.2.3 System Sizing

After the electrical usage and demand history for the facility is obtained, electrical generation equipment can be sized to meet all or a portion of the facility's base electric load. For a first order analysis, monthly demand data is a good indicating factor of the average base electrical load and may be used to estimate the desired capacity of the electrical generation equipment for a proposed CHP system. Therefore, the prime movers to be considered for a CHP application will need to have a capacity approximately equal to or as close as can be achieved to that of the facility's base electrical load.

$$Cap_{sys} = Ld_e \tag{2.2}$$

If a CHP system which is sized based on information determined from monthly demand data shows an above marginal payback and internal rate of return, the analysis may be repeated using more precise demand data (i.e. 15/30 minute demand interval data history) if desired in order to more accurately predict the overall project payback period. Therefore, it is recommended that the size of the electrical generation equipment be chosen so it matches the estimated base demand load as closely as possible. Assuming net metering is not an option, this will ensure that the electricity produced at any given time while the CHP system is operating will be entirely consumed by the facility.

2.2.4 System Selection

In order to select the best base load CHP system option, many electrical generation unit technologies, such as a combustion turbine, microturbine, steam turbine generator set, etc., must be considered and compared. The amount of waste heat that can be recovered from the electrical generation process varies depending on the type of prime mover and the results of the economic analysis for each alternative is thus the governing factor that determines which option should be pursued. The U.S. Department of Energy's Industrial Technologies Program offers a wide range of software tools that can be utilized to identify potential energy savings projects for industrial manufacturing facilities. One of these software programs is the Steam System Tool Suite (SSTS), which contains the Steam System Assessment Tool (SSAT) [U.S. DOE, 2010]. This tool is useful in identifying how much waste heat can be recovered from typical electrical generation processes, such as operation of a steam turbine generator set. In this case, heat in the form of steam extracted from the desired stage in the steam turbine may be supplied to the facility's process steam header, thus offsetting some of the steam load that must otherwise be supplied by a boiler. The SSAT program not only calculates the available waste heat that can be recovered by a steam turbine CHP system but it also determines the fuel input, for a number of different specified fuel sources, that corresponds to the desired electrical output.

In some applications combustion turbines are a good alternative to steam turbine generator sets. Combustion turbines can typically be equipped with duct burners that increase the exhaust temperature and, hence, increase the available mass flow rate of steam used by a facility. In these cases and depending on the number of duct burners employed, the fuel inputs can be obtained from the equipment manufacturers. Information regarding the exhaust temperature as well as the flow rate of steam produced by the combustion turbine exhaust can be also acquired from the equipment manufacturer.

2.2.5 Economic Considerations

After the size of the electrical generation equipment has been estimated and the amount of recoverable waste heat for each alternative is determined, a project comparison and cost analysis must be performed. The facility's average electrical usage cost ($/kWh) is determined from the usage and billing histories. While blended utility rates are often used for estimation of a CHP project payback, only electrical usage rates are considered in the current methodology. It is assumed that, on average, the CHP system will experience periods of downtime at least once a month that exceed the time intervals during which readings are taken by the electrical utility provider. During this interim time period, all of the facility's power is assumed to be supplied by the electrical grid. As a result, the electrical demand will be set for the entire month due to the readings taken during this window when the CHP system is not operating and all of the power needed by the facility is supplied by the local utility provider.

To perform an economic analysis, first determine the installed cost (IC) of the desired CHP system using an equipment cost rating ($/kW) which is obtained either directly from the manufacturer or from the EPA CHP Catalog [U.S. EPA, 2008]:

$$IC = (CR) * (Cap_{sys}) \tag{2.3}$$

where CR is the cost per electrical capacity of proposed CHP system.

Next it is necessary to determine the annual electrical generation ($Prod$) that the proposed system is capable of producing, based on the system capacity, annual operating hours (Hr), and CHP system load factor (LF).

$$Prod = (Cap_{sys}) * (Hr) * (LF) \tag{2.4}$$

The load factor is a number that can be varied and adjusted based on the type of system considered and other information provided by the facility; anywhere in the range of 75-90% is usually an acceptable value. The value calculated using Equation (2.4) represents how much electricity the proposed CHP system is capable of producing annually when system downtimes are considered. If this value exceeds the facility's annual electrical consumption, then the annual electrical usage of the facility should be substituted in place of the calculated production value.

Operation and maintenance costs also need to be considered. The combined value of these costs is estimated using the annual production of the proposed system and a CHP system operational and maintenance fee estimate $(O\&M)$ per system capacity, taken to be \$0.008/kW in this analysis. This value is typical for maintenance of systems that include turbines and boilers.

$$O\&M = (Prod) * (0.008 * \frac{\$}{kW}) \tag{2.5}$$

Next, the cost of operating the proposed CHP system is determined. The annual operational cost of the proposed system $\left(Cost_{op}\right)$ is the sum of the annual fuel cost, annual *O&M* cost, and any resulting loss in revenue

$$Cost_{op} = (fuel_{FR}) * \left(cost_f\right) * (Hr) * (LF) + \ (O\&M) + lost_{rev} \tag{2.6}$$

where the fuel feed rate, $fuel_{FR}$, can be obtained directly from the manufacturer or can be estimated using the DOE SSAT software and $lost_{rev}$ is any lost revenue that may result due to operation of the CHP system. For example, if the proposed CHP system utilizes a waste stream produced on site, such as wood waste, as a potential fuel source, there may be a loss in revenue experienced by the facility if they received payment for the waste. The loss in revenue can be calculated as

$$lost_{rev} = (fuel_{cons}) * (SR) \tag{2.7}$$

where $fuel_{cons}$ is the annual CHP unit waste fuel consumption and SR is the sale rate, or the rate at which the waste to be used as a CHP fuel source was sold by the facility. If there is no loss in revenue, which is often the case, then $lost_{rev}$ should be set to \$0.00.

Once the CHP system annual production and annual operating cost values have been determined, the usage rate of electricity produced by the CHP system (UR_{CHP}) can be calculated as

$$UR_{CHP} = \left[\frac{Cost_{op}}{Prod}\right] \tag{2.8}$$

The annual electrical cost savings (CS_{ele}) is then

$$CS_{ele} = (Prod) * (UR_{conv} - UR_{CHP}) \tag{2.9}$$

where UR_{conv} is the usage rate of electricity purchased from local utility supplier.

After determining the annual electrical cost savings, the cost savings associated with recovering waste heat to offset the facility's process heating loads, which is usually in the form of process steam, must be calculated. The steam production rate of the CHP system (ES_{st}) can either be specified by the equipment manufacturer or can be determined from the model created by the DOE SSAT software as follows

$$ES_{st} = (Ld_{st}) * (K_1) * (K_2) * (K_3) * (Hr) * (LF) \tag{2.10}$$

where K_1, K_2, and K_3 are conversion constants.

The cost savings associated with offsetting the process heating load is equal to the thermal energy savings (steam in this case) multiplied by the usage rate (\$/MMBtu) of the fuel source, typically natural gas, that is used to generate thermal energy for the process heating load. It is important to note here that if the process heating load to be offset is supplied by a boiler, then the efficiency of the boiler (η_{boiler}) must also be included in the associated cost savings calculation as shown below.

$$CS_{st} = \left[\frac{ES_{st}}{\eta_{boiler}}\right] * UR_{th} \tag{2.11}$$

Now that the cost savings values associated with the production of electricity and the recovery of waste heat from the proposed CHP system have been estimated, the total annual cost savings of the proposed project (CS_{tot}) can be expressed as

$$CS_{tot} = CS_{ele} + CS_{st} + Rev_{gen} \tag{2.12}$$

where Rev_{gen} accounts for any additional revenue that might be generated due to the sale of a waste fuel source that is now unused as a result of CHP system operation. For instance, if an industrial facility utilizes a waste stream as a fuel source, such as wood waste, in order to generate process heat, the CHP system could offset some of the process heat load. As a result, the now unused portion of the waste fuel could then be sold by the facility, generating additional revenue, which is calculated as

$$Rev_{gen} = (fuel_{avail}) * (SR) \tag{2.13}$$

where $fuel_{avail}$ is the waste fuel that is made available for sale due to operation of the CHP system. However, it is important to note that this is not the typical case and often Rev_{gen} is set to \$0.00.

With the value obtained in Equation (2.12) along with the implementation cost, the project simple payback, internal rate of return, and net present worth can then be determined. The project simple payback (SP) is the time period, in years, that it will take for the annual cost savings to repay the funds used for implementation of the project and it can be calculated as

$$SP = [\frac{IC}{CS_{tot}}] \tag{2.14}$$

The project net present value (NPV) can be determined from the implementation cost and annual cost savings values. First, the interest rate that the facility could receive if the capital used to fund the project were invested differently must be known. The example equation below assumes that the facility in question could receive a 15% interest rate if it invested its capital rather than using it to fund the CHP project.

$$NPV = -IC + \sum_{n=1}^{9} CS_{tot}/(1+0.15)^n \tag{2.15}$$

Assuming a 10-year project life cycle, the internal rate of return (IRR) can be determined from Equation (2.16) below.

$$-IC + \sum_{n=1}^{9} CS_{tot}/(1+IRR)^n = 0 \tag{2.16}$$

2.2.6 Emission Reduction Calculations

In order to determine the carbon emissions reductions associated with the installation and utilization of a proposed CHP system, it is necessary to determine the current carbon emissions resulting from operation of an industrial manufacturing facility which utilizes grid supplied electricity and fuel supplied by the local natural gas utility provider. The grid supplied electricity can be taken to be equal to the electric load of the facility (note that this value will be in excess of the facility base electric load). This value can be determined by obtaining the total electrical usage (kWh) of the facility on an annual basis, E_m. The total amount of fuel, typically natural gas, that the facility consumes annually, F_m., must also be determined. Each of these total annual usage values can be easily obtained from the facility's utility billing history.

The carbon dioxide emissions associated with operating the facility using utility supplied electricity and natural gas, CDE_{conv}, can be estimated using carbon dioxide emissions conversion factors as follows

$$CDE_{conv} = E_m * ECF_{CDE} + F_m * FCF_{CDE} \tag{2.17}$$

where ECF_{CDE} is the carbon dioxide emissions conversion factor for electricity and FCF_{CDE} is the carbon dioxide emissions conversion factor for fuel. The emissions conversion factors depend on geographical location and the fuel mix used by the utility supplier to generate electricity.

The emissions associated with operation of the facility using a CHP system are obtained below. In a base load CHP system, some of the facility's electrical load will be provided by the CHP unit and the rest is imported from the local utility provider, i.e., the grid. The portion of the total annual electrical usage supplied by the grid, E_{grid} is determined as follows.

$$E_{grid} = E_m - Ld_e * Hr \tag{2.18}$$

Similarly, only a portion of the facility's process heating load may be offset by waste heat recovered by the CHP system. The remaining portion, F_{grid}, of the annual fuel usage is imported from the local utility. The fuel used by the CHP system, F_{CHP}, can be determined, depending on the type of prime mover chosen, either from technical information from the equipment supplier or by making use of the DOE SSAT software. The annual carbon emissions associated with operation of the facility using the CHP system to supply a portion of the electrical and thermal loads, CDE_{CHP}, can be expressed as

$$CDE_{CHP} = E_{grid} * ECF_{CDE} + \left(F_{CHP} + F_{grid}\right) * FCF_{CDE} \tag{2.19}$$

The emission conversion factor for the particular type of fuel used in the CHP prime mover in Equation (2.19) is assumed to be same as the fuel emission conversion factor for heat supplied by conventional means, such as use of a commercial boiler, for example. The total annual carbon emissions reductions associated with utilization of the CHP system, CDE_{red}, is then

$$CDE_{red} = CDE_{conv} - CDE_{CHP} \tag{2.20}$$

The same methodology can be applied to determine the reduction of SO_2 and NO_x emissions by using Equations (2.17), (2.19), and (2.20) and changing the carbon dioxide emissions conversion factors by the SO_2 and NO_x emission conversion factors for electricity and natural gas, respectively. Table 2.1 presents a step-by-step process which can be followed to use the methodology presented in this chapter to perform a CHP analysis and feasibility study at an industrial manufacturing facility.

Table 2.1 Step-by-Step Use of CHP Feasibility Study Methodology

Step	Description	Parameters	Equation(s)
1	Determine system capacity from facility base electric load	Cap_{sys}, Ld_e	2.2
2	Using cost rating corresponding to type of CHP unit and system capacity to calculate system installation cost	IC, CR, Cap_{sys}	2.3
3	Calculate CHP system annual production from system capacity, system availability factor, and annual facility operating hours	$Prod$, Cap_{sys}, Hr, LF	2.4
4	Determine system operation and maintenance cost	$O\&M$, $Prod$	2.5
5	Calculate CHP system annual operation cost	$Cost_{op}$, $fuel_{FR}$, $cost_f$, Hr, LF, $O\&M$, $lost_{rev}$, $fuel_{cons}$, SR	2.6, 2.7
6	Determine CHP electrical usage rate	UR_{CHP}, $Cost_{op}$, $Prod$	2.8
7	Calculate electrical cost savings using CHP and conventional electrical usage rates	CS_{ele}, $Prod$, UR_{CHP}, UR_{conv}	2.9
8	Determine thermal energy savings available due to amount of thermal load to be offset by the CHP system	ES_{st}, Ld_{st}, Hr, LF	2.10
9	Calculate thermal energy cost savings	CS_{st}, ES_{st}, η_{boiler}, Ur_{th}	2.11, 2.13
10	Determine total project cost savings from electrical cost savings, thermal cost savings, and any additional revenue generated	CS_{tot}, CS_{ele}, CS_{st}, Rev_{gen}, $fuel_{avail}$, SR	2.12
11	Using total project cost savings, determine project simple payback, internal rate of return, and net present value	SP, IRR, NPV, CS_{tot}	2.14, 2.15, 2.16

2.2.7 Methodology Process Flow Chart

Figure 2.1 presents a flow chart which was developed in order to illustrate the step-by-step process of completing an industrial facility CHP feasibility study using the methodology developed in this chapter.

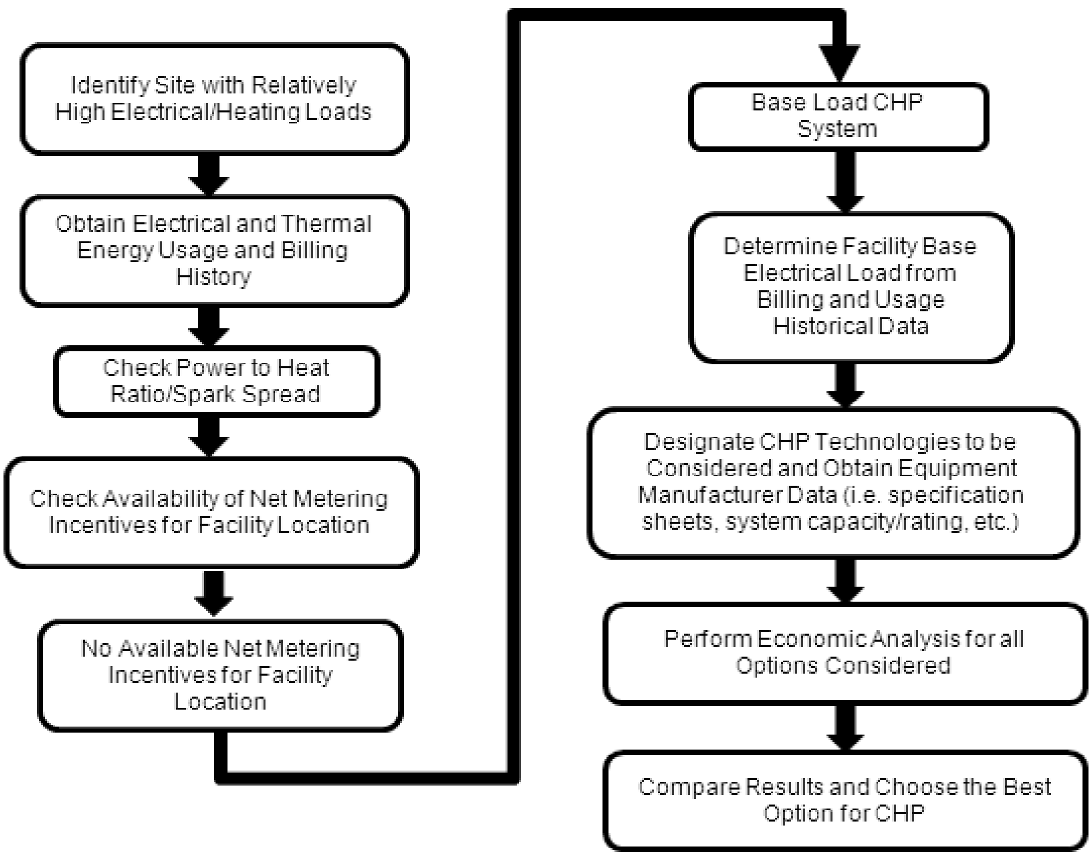


Figure 2.1 Industrial Facility CHP Feasibility Study Methodology Flow Chart

2.3 Conclusion

This chapter presented a methodology to perform a base load CHP feasibility study for an industrial manufacturing facility. There are many factors that must be considered when determining which type of system configuration should be considered when conducting a CHP system feasibility study. As will be examined in the following chapters, the existence of any net-metering or interconnection standards policy, as well as the relative cost of electrical and thermal energy from conventional utility providers can be used to determine whether a topping or bottoming cycle CHP system will prove to be the best option. Experience has shown that if the cost of electricity is relatively low and no net-metering policy is available for a specific facility, then a topping cycle CHP system sized to fit the base electric load of the facility will reveal the best project economics. For a base load CHP system to be economically attractive, the facility for which the system is being considered must have a substantial process heating load and it is often preferable to perform the analysis for a facility that has a thermal load that well matches the waste heat energy that can be recovered from the CHP system electrical generation process. A facility with a high thermal load will also have a better chance of having a low power to heat ratio as well. Therefore, the power to heat ratio provides a good indicating factor as to whether or not a base load CHP system will prove to be a viable option for an industrial manufacturing facility. These concepts will be further investigated in the next chapter.

The methodology presented in this chapter can also be used to determine the reduction in CO_2, SO_2, and NO_x emissions associated with installation of a proposed CHP system. A number of factors must be considered when determining the reduction in emissions resulting from the installation of a CHP system. It is also important to note that depending on certain system parameters, such as variations in on site fuel consumption due to the installation of a CHP system, the emissions might actually be increased.

CHAPTER III

PARAMETRIC ANALYSIS OF CHP AT INDUSTRIAL MANUFACTURING FACILITIES

3.1 Introduction

In order to demonstrate the use of the methodology developed in Chapter 2 as well as its effectiveness in identifying industrial sites that exhibit a good chance for success for CHP projects, a comparison of multiple CHP feasibility study case studies at industrial sites in the Southeast U.S. are compared and contrasted in this chapter. The economic results for each case study considered in this chapter were thus calculated using the methodology presented in Chapter 2. First, the results of two different CHP feasibility studies are presented in order to illustrate the use of the methodology and how the results obtained are indicative of a project with a good chance for success as well as how they could also indicate that the project under consideration is not economically viable. The CHP feasibility studies considered in this first comparison were completed for a food products rendering facility located in central Mississippi, referred to as Case 1, and a plastic products manufacturing facility located on the Mississippi Gulf Coast, referred to as Case 2.

In order to draw conclusions regarding the potential for success for CHP at an industrial site using several indicative parameters, a second comparison of CHP case studies completed at four different industrial sites is also included in this chapter. The proposed CHP projects considered in this comparison were chosen in order to demonstrate a wide range of facility operational inputs to be used in the methodology. All of the facilities considered in this comparison have a need for both electricity from the local utility provider and thermal energy in the form of process steam. However, each of the facilities considered in this comparison produce different products, have significantly different thermal and electrical loads, have different annual operating hours, and some even have CHP fuel sources available on site. Thus, the facilities considered in this second comparison were chosen based on these variations in order to add robustness to any conclusions made regarding how facility characteristics, such as those mentioned previously, can be utilized to estimate the economic success of industrial CHP.

3.2 Initial CHP Methodology Comparison

In this section, two cases for which CHP systems were proposed for industrial manufacturing facilities are presented to illustrate the use of the methodology developed in Chapter 2. The first case describes a CHP feasibility study that was performed at a food products rendering plant in central Mississippi and the second case details a CHP feasibility study that was performed at a plastic products manufacturing plant on the Gulf Coast (Mississippi). For both locations, the CO_2, SO_2, and NO_x emissions conversion factors for electricity and natural gas are similar and are presented in Table 3.1.

Table 3.1 Regional Carbon Dioxide, Sulfur Dioxide, and Nitrogen x-Oxide Conversion Factors

	Central Mississippi and Gulf Coast
CO_2 Emission Conversion Factor for Electricity (tons/kWh)	0.000748
CO_2 Emission Conversion Factor for Natural Gas (tons/kWh)	0.0002
SO_2 Emission Conversion Factor for Electricity (tons/kWh)	0.00000428
SO_2 Emission Conversion Factor for Natural Gas (tons/kWh)	1.0035E-9
NOx Emission Conversion Factor for Electricity (tons/kWh)	0.000000955
NOx Emission Conversion Factor for Natural Gas (tons/kWh)	1.0704E-9

3.2.1 Description of the Facilities

3.2.1.1 Case 1

The facility in the first case was determined to have an electrical base load of approximately 4.6 MW and a process heating load of 213.8 MMBTU/hr (62,661.2 kW) in the form of 120 psig (827,370.8 Pa) saturated steam. Therefore the power to heat ratio for this facility was 0.074. The facility utilizes natural gas fired boilers which supply steam at a flow rate of 156,200 lb/hr (70,839 kg/hr) in order to meet the process heating load. The facility considered operates for 6,864 production hours per year and has an approximate energy cost of \$0.08258/kWh. Demand savings were not considered as it was assumed that the installed CHP system would have an availability factor of 80% and monthly demand peaks would be set during periods of system downtime. This also helps to ensure that cost savings estimates and overall project payback figures remain conservative.

For the facility considered in Case 1, four different CHP configurations, including a condensing steam turbine system, a backpressure steam turbine system, an extraction steam turbine system, and a combustion turbine system were all considered and the economic viability of each configuration was determined. The combustion turbine configuration also considered multiple options in which no duct burner was employed and either small or large duct burners were also in use. A comparison of the economic analyses for each configuration showed that a backpressure steam turbine CHP system capable of supplying an electrical demand load of approximately 3.4 MW and steam at a flow rate that meets the facility's needs when the system is online provided the best alternative. Typical green wood was chosen for the fuel source for each of the steam turbine options and natural gas was used as the fuel source for the combustion turbine option. Fuel costs were obtained from the natural gas utility billing information or were estimated from the DOE SSAT software. A 10% Investment Tax Credit was used for all of the CHP options considered. The results of the cost analysis for each different CHP configuration are shown in Table 3.2. In Table 3.2, a negative internal rate of return indicates that the proposed option will not reach full payback during a 10 year life cycle (assuming implementation is the cost in the first year and cost savings take place over the next nine years) and a negative net present value indicates that it would be more advantageous to invest the capital in other areas rather than to use it to fund the project.

Table 3.2 Case 1 Cost Analysis Results for Each CHP Configuration

Option	Implementation Cost ($)	Simple Payback (yr)	Internal Rate of Return	Net Present Value ($)	Power Generated (MW)	Steam Production Rate (lb/hr)
Condensing Turbine	12.01 M	11.7	-4.87%	-7.09 M	4.6	-
Extraction Steam Turbine	21.03 M	7.3	4.45%	-7.25 M	4.674	156,200
Backpressure Steam Turbine	9.04 M	3.7	22.86%	2.65 M	3.463	156,200
Combustion Turbine (w/o DB)	7.45 M	5.0	13.68%	-0.35 M	4.6	25,300
Combustion Turbine (w/ small DB)	7.66 M	4.8	14.63%	-0.10 M	4.6	53,000
Combustion Turbine (w/ large DB)	8.09 M	4.5	16.53%	0.44 M	4.6	112,400

In order to determine the internal rate of return as well as the net present value for each of the options considered, it was assumed that the facility in question could receive an interest rate of 15% if it invested the equivalent amount of capital in an alternative project or venture. This assumption also helps to ensure that any cost savings estimates and figures remain conservative. For this case the estimated implementation costs were obtained from equipment manufacturers. From the cost comparison of the different CHP configurations, it can be seen that the backpressure turbine option provided the best cost savings and payback for the facility in question. A more detailed representation of the cost analysis for the backpressure turbine for Case 1 is presented in Table 3.3. As mentioned before, an operation and maintenance fee of $0.008/kWh was used to account for any equipment failure or replacement needs for the proposed CHP system. The resulting simple payback for the backpressure turbine recommended for the facility considered in Case 1 is 3.7 years with an internal rate of return of 22.86%.

Table 3.3 Cost Analysis Results for the Backpressure Turbine for Case 1

Revenue Stream	**Value**
Installation Cost	-$10,042,700
Investment Tax Credit (Grant)	$1,004,270
Total Investment	-$9,038,430
Annual O&M Fees	-$152,128
Annual Cost Savings	$2,450,421
Simple Payback (yr)	3.7
Internal Rate of Return	22.86%
Net Present Value	$2,653,961
Fuel Source	**Cost ($/ton)**
Typical Green Wood (50% moisture content)	$21.00

The resulting emissions reductions estimates for Case 1 are included in Table 3.4. It is important to mention here that all the prime movers analyzed for CHP resulted in a reduction in emissions when compared to conventional heat and power supply. It can be observed that the extraction turbine is the prime mover that provides the highest emissions reduction while the combustion turbine (w/o duct burner) is the one that provides the lowest reduction.

Table 3.4 Case 1 Emissions Reduction Estimates

Annual Emissions	Emissions Reductions					
	Condens. Turbine	Extract. Turbine	Backpress. Turbine	Comb. Turbine (w/o duct burner)	Comb. Turbine (w/ small duct burner)	Comb. Turbine (w/ large duct burner)
CO_2 (tons/year)	18,893	78,407	73,433	11,393	12,591	15,152
SO_2 (tons/year)	108.11	110.14	81.68	108.07	108.08	108.09
NO_x (tons/year)	24.12	24.83	18.48	24.08	24.09	24.10

3.2.1.2 Case 2

The facility in the second case was determined to have an electrical base load of approximately 15.0 MW and a process heating load of 29.8 MMBTU/hr (8,733.9 kW) in the form of 300 psig (2,068,427.1 Pa) saturated steam. Therefore the power to heat ratio for this facility was found to be 1.717. The facility considered in Case 2 utilizes natural gas fired boilers in order to supply steam at flow rates ranging from approximately 15,000 lb/hr to 22,000 lb/hr (6,803 kg/hr to 9,977 kg/hr). Therefore, the steam load was taken to be 22,000 lb/hr (9,977 kg/hr) in order to ensure conservative results. The facility considered in the second case operates for 8,760 production hours per year and has an approximate energy cost of $0.07328/kWh. Similar to Case 1, demand savings were not considered for Case 2 either as the CHP system in this case was also assumed to have an availability of 80%.

For the facility considered in Case 2, two different CHP system configurations were analyzed for the facility. The first option consisted of an extraction steam turbine option which utilized steam from a natural gas fired boiler and the second option considered the use of multiple small combustion turbines to be fueled by natural gas. The economic analysis for each CHP system configuration showed that both options resulted in negative annual cost savings, or in other words it was determined to be more expensive to operate either option even when the savings associated with recovering thermal energy were considered. Of the two options, the extraction steam turbine CHP configuration proved to be less expensive, and the associated economic analysis figures for that option are presented in the Table 3.5.

Table 3.5 Case 2 Extraction Turbine Option Cost Analysis Results

Revenue Stream	**Value**
Installation Cost	-$16,997,200
Investment Tax Credit (Grant)	$1,699,720
Total Investment	-$15,297,480
Annual O&M Fees	-$693,040
Annual Cost Savings*	-$1,693,936
Simple Payback (yr)	N/A
Internal Rate of Return	N/A
Net Present Value	N/A
Fuel Source	**Cost ($/MMBTU)**
Natural Gas (purchased on spot market, average value)	$4.510

This option showed a negative annual cost savings and thus the simple payback associated with an extraction turbine CHP system for the facility analyzed in Case 2 was not applicable as the project would never result in a positive payback based on the facility's current electrical and natural gas usage rates. Even when the 10% Investment Tax Credit was used to offset a portion of the implementation cost in the economic analysis, the results remained unchanged. Similar to Case 1, an operational and maintenance cost of $0.008/kWh was also used in the economic analysis prepared for Case 2. Table 3.6 presents the emissions reductions estimates for Case 2.

Table 3.6 Case 2 Emissions Reduction Estimates

Annual Emissions	Emissions Reductions Extraction Turbine
CO_2 (tons/year)	-22,830
SO_2 (tons/year)	359.48
NO_x (tons/year)	79.85

In Table 3.6, a negative value indicates that the CHP system produces more emissions than conventional power and thermal energy production methods. Therefore, the CHP system considered for Case 2 would actually result in an increase in carbon dioxide emissions if it were to be installed. This is a direct result of the additional natural gas fuel that must be supplied to the facility's boilers to produce the steam flow rate required by the CHP system. Had the facility elected to consider retro-fitting the boilers to utilize wood waste as a fuel, then there would have most likely been a substantial reduction in the carbon dioxide emissions associated with the installation of the proposed CHP system. This is due to the fact that wood waste is considered to be a "carbon neutral" fuel source, which means that in order for wood fuel to be a sustainable source, the amount of trees that must be planted is equal to a one-to-one ratio of that which is consumed. Also, it is assumed that the newly planted trees will absorb the carbon emissions associated with the use of the wood waste as fuel.

3.2.2 Comparison of Cases 1 and 2

The economic analyses completed for each case leads to the conclusion that a relatively high process heating load is a necessary component for a topping cycle CHP system to be economically viable at an industrial manufacturing facility located in the Southeast U.S.. This is presumably due to the relatively low cost of electrical usage in this region. In both cases, the cost savings associated with the on-site production of electricity only was negative. In the first case, the cost savings associated with offsetting the process heating load with thermal energy recovered from the CHP system exhaust was substantial enough to counter its associated negative electrical cost savings, which ensured that the overall project cost savings was economically attractive. However, the facility considered in Case 2 had a relatively low process heating load. As a result, even when the savings associated with offsetting some of that load with thermal energy recovered from the CHP system was considered the negative threshold was not crossed and the overall project cost savings was negative. As mentioned previously, both facilities are located in a state that did not have any net-metering or interconnection standards policy currently in place. This is important to point out especially for Case 1 since producing more electricity than required in an attempt to offset all of the facility's process heating loads could have resulted in better economics for any of the options considered if incentives were available.

3.3 Comparison of Economic Performance and Indicative Parameters for Four Industrial Facility CHP Feasibility Studies

In this section, the results of four industrial facility CHP feasibility studies are presented and compared/contrasted in order to formulate conclusions regarding how specific operating characteristics of an industrial facility may be used to estimate the potential viability of CHP at manufacturing plants. The four cases considered in this section are labeled cases A, B, C, and D. Case A considers the same CHP case study labeled as Case 1 in the previous section, Case B considers a CHP case study that was prepared for a lumber facility located in central Mississippi, Case C considers the same case study that was designated Case 2 in the previous section, and Case D analyzes a CHP case study that was prepared for a chemical manufacturing plant also located on the Mississippi Gulf Coast. Cases A-C all analyze backpressure turbine CHP systems and Case D considers a combustion turbine CHP configuration. The comparative analysis of each of these cases analyzes the difference in annual facility operational hours during which both electricity and process heat are required, conventional electrical usage rate that each facility is subjected to, average hourly thermal load of each facility, and the CHP system fuel type and associated fuel cost for the particular type of CHP unit proposed at each facility. The results of this analysis then provides insight as to the economic viability of CHP at industrial sites based on each of these parameters.

3.3.1 Description of the Facilities

3.3.1.1 Case A

The first case considered analyzes the backpressure steam turbine CHP system proposed for the food products rendering plant previously introduced. The facility considered in Case A operates for 6,864 productions hours per year during which both electricity and process heat are required. The most economical CHP option considered for the facility was a backpressure steam turbine CHP unit fueled by biomass. The PGU was selected to supply all the steam required by the facility (156,200 lb/h) and the corresponding electrical capacity was found to be 3.46 MW.

3.3.1.2 Case B

Case B analyzes a backpressure steam turbine CHP system proposed for a lumber facility located in northern Mississippi. The facility considered in this case operates for

2,750 production hours per year during which both electricity and process heat are required. The most economical CHP option considered for this facility was a backpressure steam turbine CHP unit, which was sized using the SSAT software [U.S. DOE, 2010] and knowledge of the facility's average base electric load (3,200 MW). However, for this case, the facility generated a large amount of wood waste on-site and sold it to local biomass suppliers in order to generate additional revenue. The most economical CHP system for the facility required that a large portion of this wood waste no longer be sold but rather be utilized as fuel for the CHP unit. Therefore, there is a loss in revenue associated with this case. The facility considered also used a large portion of another waste stream, planer wood shavings, as a fuel source for wood fired boilers which supplied process heat in the form of steam to the wood drying kilns. The CHP system considered provided the facility with the capability to offset a portion of this steam. As a result, a portion of the wood fuel that was supplied to the existing boilers was no longer used and could then be sold to the same local biomass fuel suppliers, resulting in an additional generated revenue source.

3.3.1.3 Case C

Case C analyzes an extraction steam turbine CHP system that was proposed for a plastic products manufacturing facility located on the Mississippi Gulf Coast. For this case, a natural gas fueled boiler/steam turbine CHP unit which was sized using the SSAT software [U.S. DOE, 2010] and the facility's annual base electric load was considered. The facility analyzed in this case operates for 7,008 hours during the year.

3.3.1.4 Case D

As mentioned before, to establish a contrast between steam turbines and combustion turbines in CHP applications, another case that utilizes a combustion turbine is included in this chapter. Case 4 presents a CHP system which was proposed for a chemical manufacturing facility on the Mississippi Gulf Coast. The most economical option considered for this facility was a 5.7 MW combustion turbine CHP system. The facility's annual base electric load was the parameter used to select combustion turbines that could supply an adequate amount of electricity as well as process heat. Based on the facility's needs, three different sizes of combustion turbines were considered and analyzed using equipment specifications provided by the combustion turbine manufacturer and the most economically viable option was chosen. The facility considered in Case 4 operates for 8,760 production hours annually. The *O&M* cost for this case was zero since a combustion turbine CHP unit was utilized and the equipment manufacturer provided a system warranty which covered maintenance fees.

3.3.2 Comparison of Economic Analyses Results for Cases A-D

The methodology was applied to each of the four cases and the results obtained for all of the significant parameters are presented in Tables 3.7 and 3.8. From Table 3.8, it can be observed that Case A exhibits a favorable CHP system economic performance. The values included in Table 3.8 were obtained using the step-by-step process presented in Table 2.1. The facility considered in Case A has a very large process heating load and a low PHR (0.074). In addition, it also has a relatively large amount of annual operating hours (≈ 78% of the time during a year), which allowed for longer CHP system operation. The annual electrical consumption which was to be offset by the CHP system considered for this case was somewhat large and the associated CHP electrical production rate was relatively high. Therefore, the cost of producing only electricity from the CHP system was more expensive than purchasing conventional electricity from the grid. However, the thermal load which was to be offset by the CHP system for this case was also relatively high, resulting in high thermal energy cost savings. This large thermal energy cost savings was therefore capable of adequately countering the increased electrical cost due to operation of the CHP unit, and the result was an economically attractive project. Therefore, this case illustrates how a low PHR combined with large amount of annual operating hours yields good annual cost savings and therefore a good payback period.

Table 3.7 Energy Load and Operational Data for Cases A-D

Facility	Base Electric Load (kW)	Thermal Load (MMBtu/hr)	Power to Heat Ratio	Annual Operating Hours (hr/yr)
Case A	4,600	213.8	0.074	6,864
Case B	3,200	27.3	0.401	2,750
Case C	15,000	29.8	1.717	7,008
Case D	10,000	18.5	1.842	8,760

Table 3.8 Methodology Results for Cases A-D

Methodology	**Case A**	**Case B**	**Case C**	**Case D**
Cap_{sys} [MW]	3.463	0.63	15.45	5.7
CR [$/kW]	2,900	2,900	1,100	1,313
IC [$]	10,042,700	2,661,820	16,997,200	7,484,100
HR [hr]	6,864	2,750	7,008	8,760
LF	0.8	0.8	0.8	0.8
Prod [kWh/yr]	19,016,025	1,386,000	86,630,092	39,945,600
O&M [$/yr]	152,128	11,088	693,040	0
$lost_{rev}$ [$/yr]	-	118,800	-	-
$cost_f$	$21.00/ton	$0.00/ton	$4.510/MMBtu	$4.421/MMBtu
$fuel_{FR}$	25.8 tons/hr	4.5 tons/hr	312.7 MMBtu/hr	61.0 MMBtu/hr
$Cost_{op}$ [$/yr]	3,127,260	129,888	8,599,617	1,889,924
UR_{CHP} [$/kWh]	0.16445	0.09371	0.09927	0.047312
UR_{conv} [$/kWh]	0.0825888	0.05497	0.0732886	0.061793
CS_{ele} [$/yr]	-1,556,674	-53,693	-2,250,771	578,434
Ld_{st} [lb/hr]	156,200	27,222	22,000	18,500
ES_{st} [MMBtu/yr]	858,602	59,949	123,467	129,780
CS_{st} [$/yr]	4,007,096	106,531	556,835	675,011
Rev_{gen}[$/yr]	0	97,092	0	0
CS_{tot} [$/yr]	2,450,421	149,929	-1,693,935	1,253,445
lc-year [yr]	10	10	10	10
ITC%	10%	10%	10%	10%
SP [yr]	3.69	15.98	N/A	5.37
IRR	23.94%	N/A	N/A	13.24%
NPV [$]	3,259,668	-1,643,176	N/A	-444,937

Case C on the other hand had a somewhat large electrical base load but a relatively small process heating load, which yielded a high PHR (1.717). Table 3.8 illustrates that even though the annual facility operational hours during which the CHP system was to be utilized were high for this case (≈ 80% of the time during a year), there were no cost savings and therefore the use of a CHP system was not economically feasible. This was mostly due to the combination of the high electrical usage and low thermal usage which were to be offset by the CHP unit. As a result, the low thermal energy cost savings were incapable of countering the increase in electrical cost from the CHP system. Case C supports the conclusion that a high PHR is indicative of a CHP system that is not economically feasible for a particular facility even if the system could be utilized for a high amount of annual operating hours and the installed cost rating ($/kW) is relatively low.

Case B differed from all of the other cases considered in that the fuel needed to operate the proposed CHP system was generated on site as a waste stream. However, this waste fuel was sold by the facility to local biomass fuel suppliers, so any amount that was to be utilized as a CHP system fuel source resulted in a loss in revenue for the facility. Even though the thermal load for this case was relatively small, the facility yielded a low PHR (0.041). However, the thermal energy cost savings was still adequate to counter the associated electrical cost increase from use of the CHP system considered. On the other hand, the annual facility operating hours during which both process heat and electricity were needed were very low. The proposed CHP unit only operated 2,750 hours annually (31% of the time), which significantly decreased its capability to provide favorable overall project cost savings. The low operating hours of the proposed CHP unit along with the associated revenue loss related to utilization of the waste fuel ultimately resulted in poor economic performance and a relatively long project payback period for this case.

In general, for the cases that employed steam turbines (A, B, and C), the electricity production from the CHP system was more expensive than the electricity produced using conventional means. However, if the thermal load which was to be offset by the CHP system is relatively high, the thermal energy cost savings can counter the increase of the electrical cost due to operation of the CHP unit, resulting in an economically attractive project. On the other hand, if the thermal load to be offset by the CHP unit is small, the thermal energy cost savings will be low and will most likely result in poor or negative overall cost savings.

3.3.3 Comparison of Steam Turbine and Combustion Turbine Prime Movers for Industrial CHP

Case D analyzed a CHP system for a chemical manufacturing plant that had an average base electrical load but a relatively small process heating load, which in turn yielded a high PHR (1.842). However, rather than analyzing a steam turbine, a combustion turbine CHP system was considered. The facility considered in this case operated for 8,760 hours per year (non-stop) and the resulting CHP electrical production rate was lower than the conventional electrical purchase rate, meaning that there were positive electrical cost savings resulting from use of the CHP unit, which is seldom the case for a steam turbine CHP system. The resulting annual electrical cost savings was still somewhat low. The corresponding thermal energy cost savings was also relatively low due to the facility's low process heating load which was to be offset by the CHP system.

However, much of the equipment needed for the CHP project was already installed or could easily be retrofitted and much of this equipment was not being utilized to its full potential. As a result, the CHP system installation cost was very low. Therefore the use of a CHP system for this case exhibited good economic considerations in spite of the fact that the annual cost savings were lower for this case than for many of the other cases considered. It is important to highlight that Case D is the only case in which the cost of the electricity produced by the CHP system is lower than the conventional cost of utility supplied electricity. However, when using a combustion turbine, it is also important to note that the ability to significantly vary the CHP system steam supply rate will be greatly decreased. For instance, the steam supply rate for a steam turbine CHP system can be relatively easily increased or decreased over a wide range by modifying the boiler fuel input and boiler steam flow rate.

Typically, combustion turbine CHP systems are rated to recover a certain amount of heat from the exhaust and utilize that heat source for process steam production. If additional steam is required by the facility, then the combustion turbine CHP system can often be equipped with a duct burner, which requires additional fuel input in order to produce excess steam. However, duct burners that are incorporated into the combustion turbine CHP system are usually only available in two or three sizes, thus limiting the options for increasing process steam flow rates. The reduced capability to modify the CHP process steam flow rate is an important aspect that must be thoroughly addressed when considering a combustion turbine CHP application. It is often the case that a facility could generate electricity at a rate lower than the conventional utility electrical cost if they utilize a combustion turbine as the prime mover for a CHP system they are considering. However, the thermal energy cost savings might be substantially less than the thermal energy cost savings associated with a steam turbine CHP system due to the steam supply flow rate restrictions corresponding to the combustion turbine. Therefore, combustion turbines may not always be the most economically attractive option. For instance, in many cases, the increased thermal energy cost savings resulting from utilizing a steam turbine CHP application could outweigh the electrical cost savings benefits of a combustion turbine.

Another aspect that influences the economic performance of a CHP system is the annual operating hours. In general, it is apparent that longer system operational hours result in better the economics which correspond to the use of CHP systems. From the results presented in Table 3.8, it can be concluded that some of the key parameters to be considered during a CHP project economic analysis are the PHR (electric and thermal loads), the annual operating hours, the electric utility rates, and of course the cost and availability of the fuel to be used to operate the CHP system. For this reason the following section evaluates how varying some of these parameters will affect the economic performance of CHP systems.

3.3.4 Parametric Analysis of Key Parameters from Cases A-D

This section presents the effect of several parameters on the economic performance of CHP systems for the cases evaluated previously. These parameters include: annual facility operating hours, electric utility usage rates, the facility electrical and thermal load (represented by the PHR), and the fuel to be used to operate the CHP system.

3.3.4.1 Annual Facility Operating Hours

CHP systems are often good alternatives for industrial manufacturing facilities that require both electrical power and process heat. However, these projects will not result in good economics if the CHP units are operated during times when only electricity or only process heat are required by the facility in question. Therefore, the annual facility operating hours during which both electricity and process heating are required is an important parameter that has a significant impact on the economic success of a CHP project. To assess the effect of the operating hours on CHP economic performance, the facilities were evaluated using 8760 hr, 6570 hr, 4380 hr, and 2190 hr, while all of the other independent parameters, such as their corresponding base electric loads, thermal loads, etc. are held constant.

Figure 3.1 shows the effect of the operational hours on the CHP system economic performance for all the evaluated cases. Figure 3.1(a) illustrates that for Cases A, B, and D increasing the hours of operation increases the annual cost savings obtained from the CHP system. This is due to the fact that larger portions of the facilities electrical and thermal energy usages are offset by their respective CHP systems as the CHP operating hours are increased. While this does mean that in some cases the CHP electrical energy cost will be higher, the associated thermal energy cost savings will also be higher, which provides a better potential for improved overall project economics. However, for Case C, increasing the CHP operational hours represents a decrease in the already poor economic performance. For this case, the electrical cost resulting from operation of the CHP system is higher than the conventional system electrical cost.

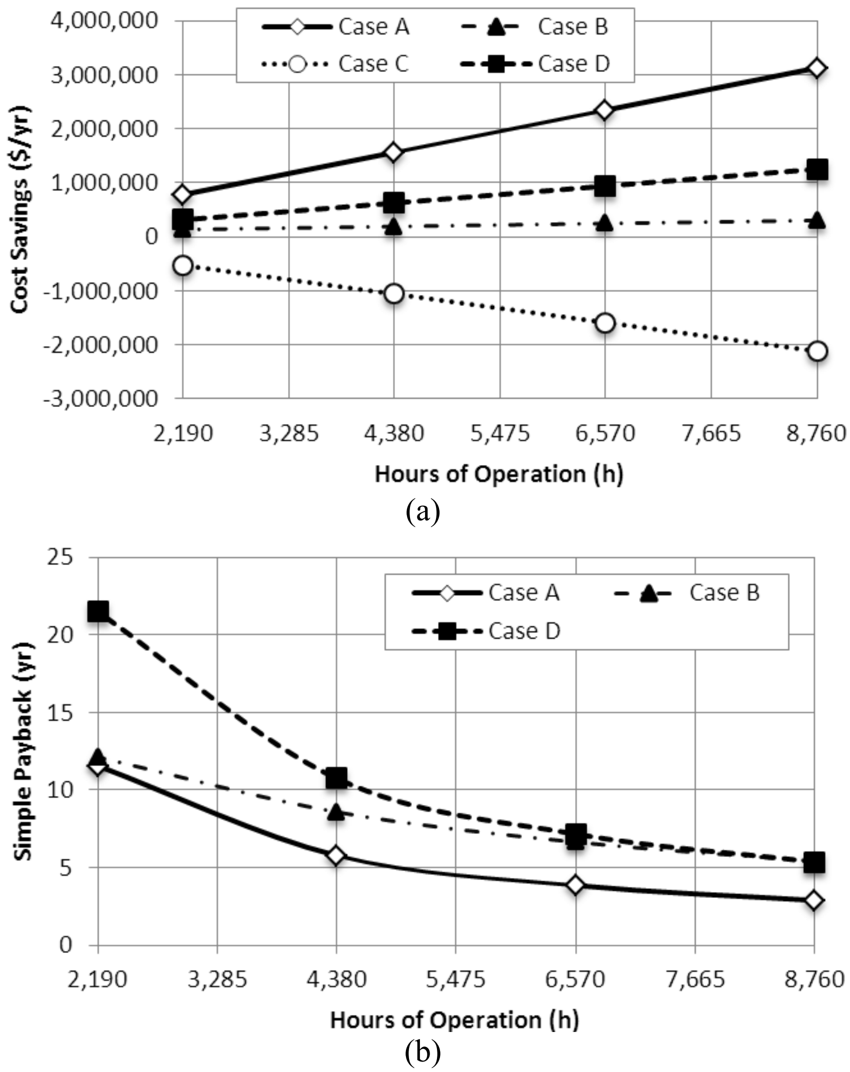
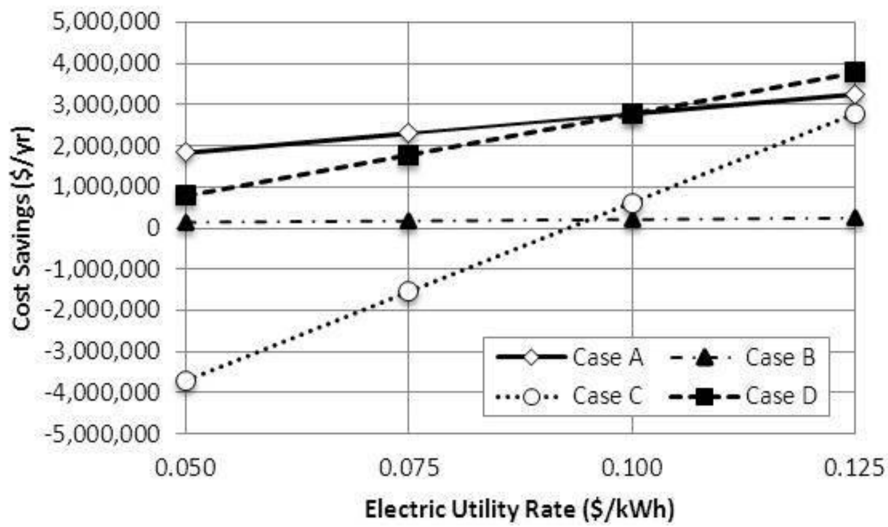


Figure 3.1 Effect of Annual Operating Hours on Cost Savings and Simple Payback

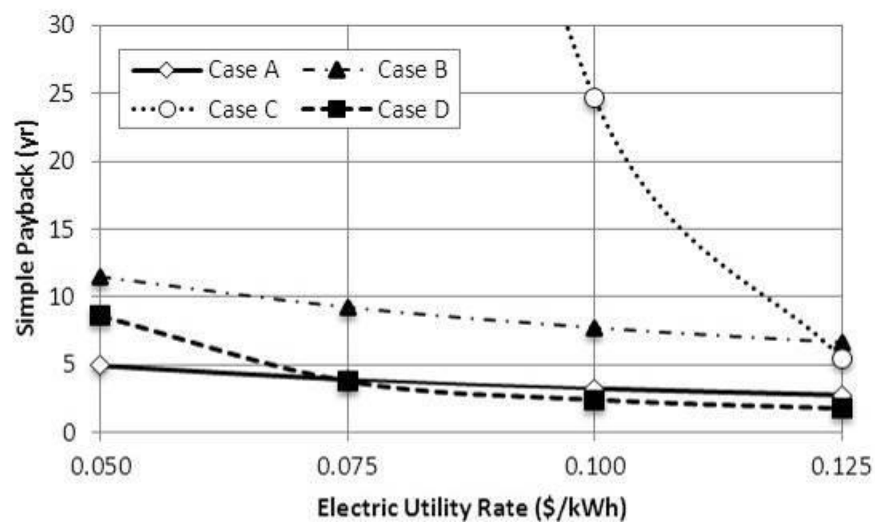
Also, Case C requires a relatively low steam flow rate to offset all of the process heating requirements. Therefore, the annual thermal energy cost savings are far too low to offset the negative electrical savings when the normal facility operating hours (7,008 hr/yr) are used in the economic analysis. Even when the facility operating hours are increased to a maximum (8,760 hr/yr), the total CHP system project cost savings remains negative for Case C. Figure 3.1(b) illustrates the simple payback for different operating hours for the evaluated facilities. The results presented in this Figure 3.1(b) agree with the results obtained previously, which are presented in Figure 3.1(a), since it is the case that greater annual savings yield lower payback periods. The payback time period was not applicable for Case C since the CHP system considered exhibited no net positive annual cost savings.

3.3.4.2 Facility Electric Utility Rate

Another important parameter that strongly affects the economic performance of a CHP system is the facility's local electric utility rate for purchase of conventionally supplied electricity. To evaluate the effect of the facility electric utility rate on the CHP systems' economic performance, the facilities considered in Cases A-D were evaluated using assumed electric utility rates of $0.050/kWh, $0.075/kWh, $0.100/kWh, and $0.125/kWh, while all of the other independent parameters, such as the base electric load, thermal load, operating hours, etc. are held constant. Figure 3.2(a) illustrates the concept that higher electric utility rates result in higher annual cost savings associated with operation of a CHP system. Favorable economics are obtained for Case C as the electric utility rate is increased above $0.095/kWh.



(a)



(b)

Figure 3.2 Effect of Electric Utility Rates on Annual Cost Savings and Simple Payback

Figure 3.2(b) shows that the payback for Cases A, B and D decreases as the electric utility rate is increased, which is the expected result. However, for Case C, payback values only become applicable after the $0.095 electric utility rate threshold is exceeded. Even though there are some cost savings associated with the CHP system considered for Case C after the $0.095 electric utility rate threshold was exceeded, the corresponding payback timeframe is still extremely high. This is why it is significantly important to analyze both the cost savings and the payback period when considering implementation of a CHP system. Therefore, it is apparent that the electric utility rate has a strong influence on the economic feasibility of a CHP system.

3.3.4.3 Facility Thermal Load

The thermal load of facilities for which CHP systems are proposed is another important parameter that has a significant impact on the economic success of a CHP project. This can also be evaluated as the effect of the PHR on the economic performance of the CHP system. To estimate how the facility's thermal load influences the economic performance of a CHP system, the thermal loads of each of the facilities considered in Cases A-D were decreased by 25% and 50% and also increased by 25%, while all of the other independent parameters, such as the base electric load, operating hours, etc., were held constant. Figure 3.3 shows the effects of varying the thermal load on the annual cost savings and the payback period. Figure 3.3(a) illustrates that for Cases A, B, and D, higher thermal loads, or in other terms smaller PHRs, will result in greater cost savings associated with operation of the associated CHP systems.

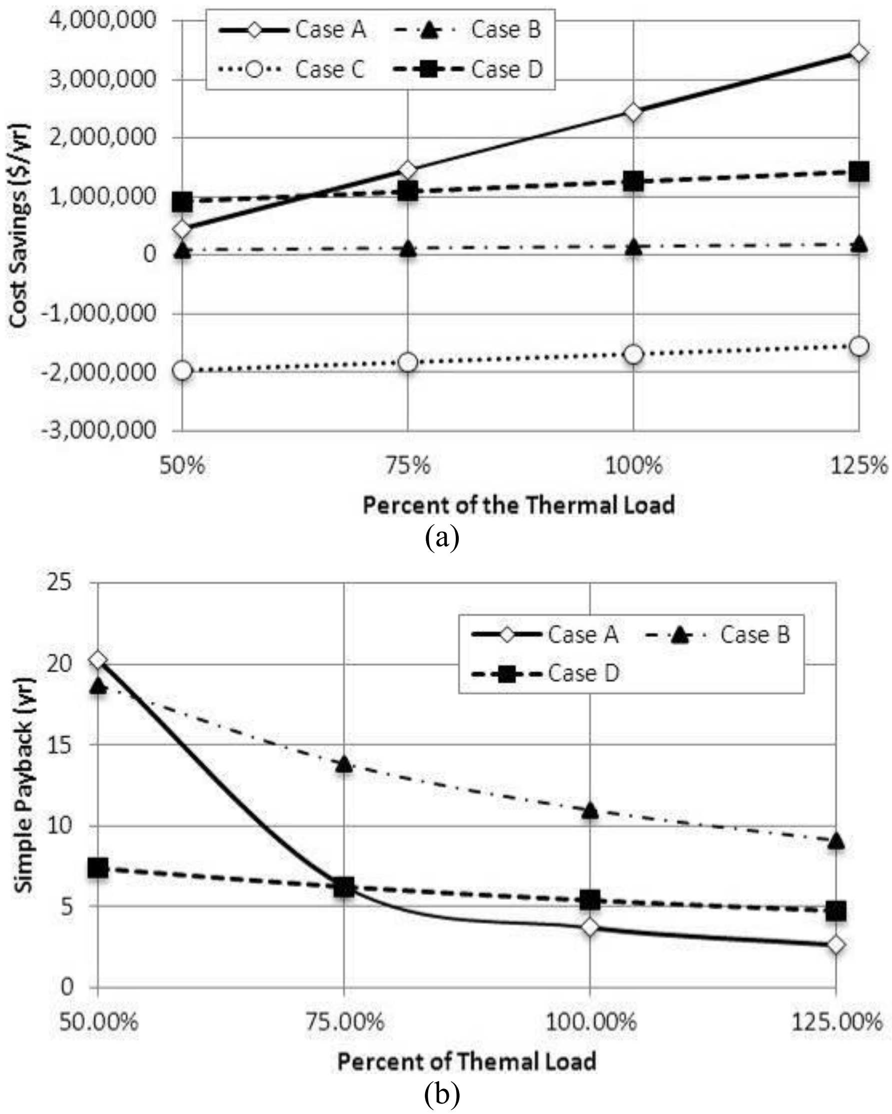


Figure 3.3 Effect of Facility Thermal Load on Annual Cost Savings and Simple Payback

However, the thermal load would have to be increased to an unrealistic value in order to obtain positive cost savings for Case C due to its extremely poor original total cost savings. This can be realized by examining the trend for Case C in Figure 3.3(a). As the thermal load is varied from 50% to 125%, there are minimal changes in the cost savings associated with the CHP project considered for Case C and it is also apparent that the thermal load would have to be increased greatly before positive project cost savings would be obtained.

3.3.4.4 Fuel Selection and Cost

The fuel selection, cost, and availability of the fuel to be used to operate the CHP unit are very important factors to consider when determining the economic performance of any such system. Figure 3.4 provides an indication as to which types of fuels are typically used in industrial facility CHP systems in the U.S. Therefore, it is apparent that the majority of the existing industrial site CHP plants are fueled by natural gas. Also, most steam turbines utilize natural gas fired boilers and combustion turbines typically have natural gas inputs.

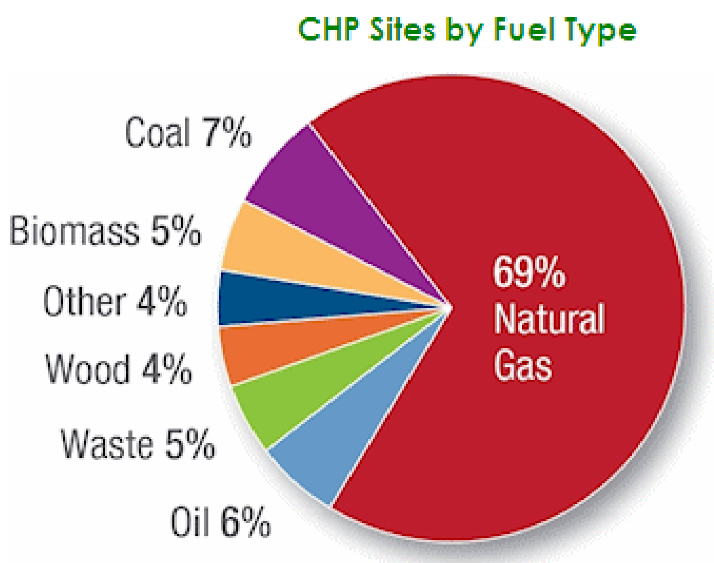


Figure 3.4 Fuel Types for Industrial CHP.

Source: http://www.midwestcleanenergycenter.org/cleanenergy/chp/fuels.aspx

Figure 3.5 shows the annual cost savings as well as the payback period for different CHP fuels used for the facility evaluated in Case A.

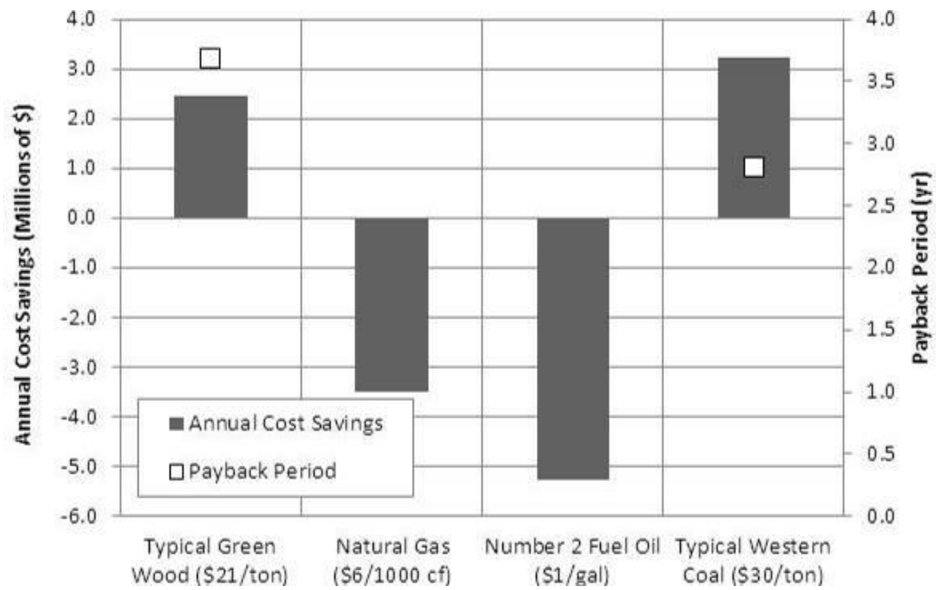


Figure 3.5 Effect of CHP Fuel Type on Annual Cost Savings and Simple Payback for Case A

The fuels used in this case are: typical green wood, natural gas, number 2 fuel oil, and typical western coal. In addition, the costs of the evaluated fuels, which are obtained from the SSAT software estimates, are presented in Figure 3.4 [U.S. DOE, 2010]. The fuel energy required in the boiler to satisfy the steam requirements of the evaluated facility is about 271 MMBtu/hr. Therefore, the amount of fuel needed will depend on the specific fuel's heating value. Figure 3.4 illustrates that using typical green wood and typical western coal provide annual cost savings and paybacks on the order of $2.4M and 3.69 yr and $3.2M and 2.81 yr, respectively. On the other hand, natural gas and number 2 fuel oil both provide negative cost savings, or annual costs which exceed their respective conventional costs. The results presented in this figure show how important the fuel selection is in relation to the economic performance of a CHP system. However, it is also important to keep in mind that the fuel selection is often driven by the availability of the particular type of fuel at the desired location and that the region where the facility is located will impact the cost of the fuel as well.

3.4 Conclusion

The methodology developed in the previous chapter allowed for analysis of multiple parameters that are indicative of favorable economic performance for CHP and also accounted for any variations encountered due to differing availability of resources, energy requirements, or operating schemes of the facility considered. The effects that variations in many of these indicative factors, such as annual facility operational hours during which both process heat and electricity were needed, facility average hourly thermal load, the cost of utility supplied electricity, and the CHP fuel type and associated fuel cost, have on the outcome of the economic analysis were also examined.

Initially, CHP case studies completed using the methodology previously developed at facilities located in the Southeast U.S. were compared in order to make conclusions on their potential for success based on the corresponding facility energy usage history. From the two cases analyzed, it was observed that electrical energy cost savings due to CHP were most often negative, and therefore must be countered by thermal energy cost savings due to CHP in most cases. This led to the conclusion that high thermal loads which can be offset by the proposed CHP system are a must for project success for base electric load CHP systems which are to be installed at manufacturing plants in the Southeast U.S. Therefore, a low PHR indicates a good chance for project success for base load CHP systems at industrial facilities in the Southeast U.S.

Next, four cases studies were analyzed in order to determine how each of the factors mentioned previously affect the economic considerations of installing a CHP system. In general it was observed that CHP systems that had high annual operational hours resulted in favorable economics and facilities that required less process heat exhibited poor economics when compared to the other cases. Also, it was observed that CHP economics could possibly be improved if a facility was able to utilize a waste stream produced on site as a fuel source for the CHP system. However, variations in the other parameters can negatively counter any of these available benefits and therefore all of the indicating factors must be thoroughly analyzed when conducting a CHP feasibility study.

In general, the project payback timeline was decreased and both the internal rate of return and net present value were increased as (1) the operational hours during which both process heat and electricity were required by the facility were increased, (2) the average hourly thermal load of the facility was increased, and (3) the cost of utility supplied electricity was increased. The type of fuel to be used in the CHP unit had a significant impact on the economic performance of the system. From the case considered, it was observed that some of the evaluated fuels provided favorable economic analysis results while other fuels resulted in negative annual cost savings. Therefore, in order to add robustness to any CHP feasibility study, it is apparent that multiple fuel types should be considered when determining the system economic performance.

In short, in order to have the best chance to achieve overall project success for a CHP unit that is proposed for an industrial manufacturing plant in the Southeast U.S., the following parameters are desirable; (1) the facility should exhibit a relatively low PHR, indicating that the facility's average hourly thermal load is somewhat large, (2) the annual operating hours during which both electricity and process heat are required by the facility should be relatively high, (3) the cost of conventionally supplied electricity should be relatively high, indicating that the spark spread is also relatively high.

Therefore, when analyzing multiple different proposed CHP projects, these factors can be used to determine which project under consideration has the best chance for success.

CHAPTER IV

STATE AND FEDERAL COMBINED HEAT AND POWER POLICY AND INCENTIVES APPLICABLE TO THE SOUTHEAST U.S.

4.1 Introduction

This chapter focuses on the current market for CHP friendly policy and incentives as well as the availability of any potential net metering options which could be applied to CHP systems at industrial manufacturing facilities in the Southeastern U.S. Net metering is a program under which the customers of a utility provider may generate their own electricity on site and then either use that electricity to offset a portion of their consumption or supply it directly to the utility provider [Varnado *et al.* 2009]. Historically, the Southern states have experienced relatively low electrical utility usage rates as well as somewhat low natural gas rates. Consequentially, it is fairly challenging to identify CHP projects that have a good probability for success at industrial manufacturing facilities in this region. This is by far the most difficult hurdle that must be overcome when attempting to increase the implementation rate of CHP systems in the Southeast U.S. For instance, if a manufacturing facility is considering installing a CHP system to offset a portion or all of their electrical and thermal usage, then the combined cost of production of electrical and thermal energy on site must be lower than the corresponding purchase rates of conventionally supplied electrical and thermal energy, and this outcome is difficult to achieve without the assistance of policy or incentives that aim to make CHP technology a viable alternative to conventional power supply. Net metering is an option that has gained notoriety and therefore should be considered when exploring economic considerations of potential CHP systems. Net metering rules and legislation have not been enacted in many states in the Southeast U.S. Also, most of the rules that have been put in place in other states often do not substantially improve CHP project economics. The status of net metering and interconnection standards rules in the Southeastern U.S. states as well as any suggestions to improve the status of these types of incentives is explored in this chapter. In addition, an example which illustrates how net metering can help improve the economic feasibility of a CHP project is also presented.

4.2 Existing Policy and Incentives Applicable to CHP Systems

The calculation methodology presented in the previous chapters incorporates all of the CHP unit operational costs into the on-site electrical production rate, and thus the thermal energy produced on-site is essentially free of charge. This typically results in a negative electrical cost savings, as the on-site electrical production rate is usually much higher than the usage rate of conventionally supplied electricity. For projects that exhibit favorable economics, the thermal energy cost savings typically accounts for this issue. However, due to the relatively low cost of utility supplied electricity in the Southeast, the difference between the cost of utility supplied electricity and electricity produced on-site remains large, which in turn makes it increasingly difficult for any potential thermal energy cost savings to counter the increased electrical costs from the operation of CHP systems. This outcome often results in negative perceptions of CHP technology and consequentially a low CHP system implementation rate at industrial manufacturing facilities in the Southeast U.S. While conventional utility rates are constantly increasing, it is often the case that unreasonably high usage rates must be approached before many

CHP projects would show favorable economics. Therefore, it is apparent that alternate methods must be available to offset poor project economics if CHP is to be a viable option at a large number of the manufacturing plants in the Southeast U.S.

Many programs and incentives are available, either federally or from local utility suppliers, that can positively affect the economics and thus the overall outcome of CHP projects in the Southeast [DSIRE, 2011]. However, these incentives often have multiple requirements, such as a maximum CHP unit electrical generation capacity, a list of eligible system fuel sources, etc, that must be met in order for a facility to obtain the incentive, which is typically in the form of a reduced conventional usage rate or an increased excess generation sale rate. Other incentive options that are often available are tax credits, which are usually applied in the facility's following tax year and are often awarded as a percentage of the installed cost of the system. Some of these alternatives are presented below.

4.2.1 The Business Energy Investment Tax Credit (ITC)

The Business Energy ITC is available federally for a commercial or industrial CHP system and allows the facility to receive a tax credit in the amount of 10% of the installed cost of the system in the following tax year [DSIRE, 2011]. However, a number of strict requirements must be met and the system capacity must be below 50 MW in order for the CHP unit to be eligible.

4.2.2 The Renewable Energy Production Tax Credit (PTC)

Under the Renewable Energy PTC, power generated on site by a qualifying source such as biomass, landfill gas, etc. in the case of industrial CHP, a facility will receive a tax credit, per kWh, for the electricity they produce and supply to the grid

[DSIRE, 2011]. However, there are multiple qualifying parameters that must be attained before this option can be taken advantage of as well. Also, many states throughout the Southeast have implemented renewable portfolio standards, which require power generators within the state to produce an increased amount of electricity from renewable sources. Thus, in these states it is often advantageous for a utility supplier to purchase power generated on site at an industrial manufacturing facility if that power is generated using renewable fuels.

4.2.3 Low-Interest Loans

Alternative options that are often available to aid in funding CHP projects at industrial manufacturing facilities are low interest loans. For instance, many states in the Southeast U.S. have made loans available through their respective state energy offices, mostly in response to funding received through the American Recovery and Reinvestment Act (ARRA), which allow industrial manufacturing facilities to borrow capital to fund CHP projects at interest rates well below the market average. These loans typically have an interest rate at a set amount below the prime rate and have a fixed repayment term as well as a minimum and maximum borrowed amount. For a facility to qualify for a low-interest energy loan, usually they must demonstrate that the loan is to fund a project that will either increase the energy efficiency of the facility or will decrease the facility's energy consumption. Thus, obtaining a low-interest energy loan is an additional option that industrial manufacturing facilities can pursue in order to aid in funding and implementing a CHP system.

4.2.4 Carbon Emissions Credits

A carbon emissions credit, often referred to simply as a carbon credit, which is essentially the right to emit one ton of carbon dioxide or any other greenhouse gas with the equivalent of one ton of carbon dioxide, is another topic that has gained notoriety as of late. It has been proposed that a maximum carbon dioxide or carbon equivalent emissions limit will be set and any facility that exceeds this limit will need to purchase carbon credits from another entity [Levin *et al.*, 2011]. Also, facilities may have excess carbon credits if their emissions are below the maximum limit, and they will then be given the opportunity to sell those excess credits to other facilities that exceed the limit. This concept of "cap-and-trade" for carbon emissions credits has been highly debated over the past few years and as a result no definite conclusion that satisfies both sides of the argument has been reached. However, even though it has yet to be determined whether or not facilities that emit greenhouse gases will be required to obtain carbon credits, many organizations and manufacturing facilities have already made attempts to decrease their greenhouse gas emissions and thus increase their associated carbon credits in anticipation of carbon emissions legislation. Foregoing both sides of the carbon cap-and-trade argument, one thing that can be said for certain is that any potential carbon credit legislation will positively affect the implementation rate of CHP systems as these systems have the potential to greatly reduce on site emissions.

The items mentioned in this section are simply a few examples which are intended to demonstrate that there are many options which are readily available in order for industrial manufacturing facilities to gain assistance to support and fund CHP projects. However, despite all of these monetary incentives, the CHP installation rate remains relatively low in the Southeast U.S. Therefore, it is apparent that significant improvements must be made to any available incentives or stricter requirements must be placed on allowable emissions if CHP is to ever reach adequate market penetration in this region.

4.3 Net Metering and Interconnection Standards Effects on CHP

Many states have also enacted net metering and interconnection standards rules, which govern the methods by which electricity generated on site may be supplied to the grid as well as the rates at which utility companies must purchase that electricity. The Public Utility Regulatory Policies Act (PURPA), passed in 1978, which was intended to encourage electrical generation by renewable sources, required all electric utilities to purchase power from other more efficient energy generators so long as the purchase rate imposed on the utility does not exceed the "utility avoided cost of production," or the utility's base line cost of production of electricity [Pierce, 1995]. Figure 4.1 presents an overview of net metering policies and programs on a state-by-state basis. Therefore, it is apparent from Figure 4.1 that, when compared to other regions, the Southeast U.S. lacks adequate net metering programs and incentives. In addition, Mississippi is one of the four states in the country that has no net metering policy in place.

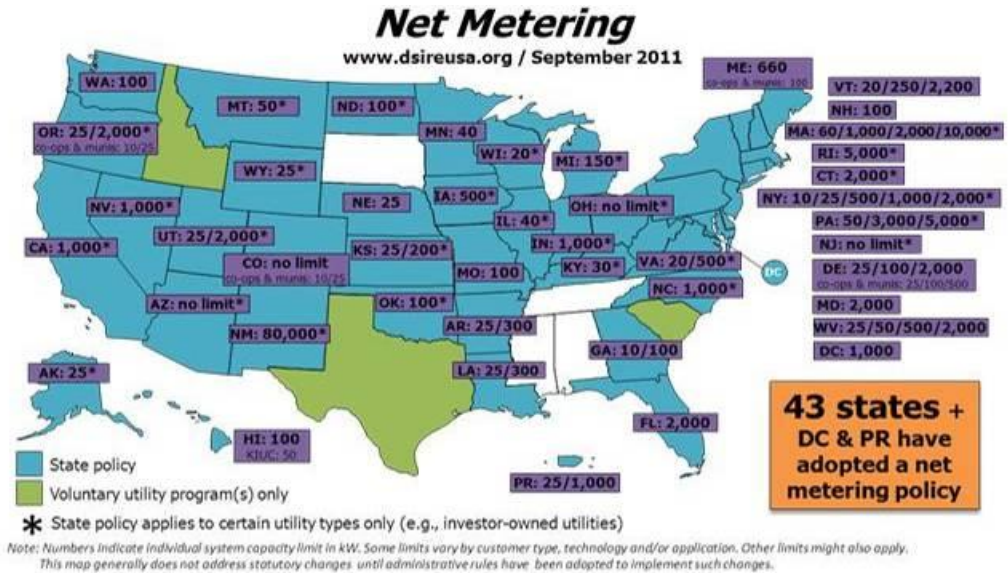


Figure 4.1 Net Metering Policies and Programs on a State-by-State Basis

Source: Database of State Incentives for Renewables and Electricity, www.dsireusa.org

The avoided costs of producing electricity corresponding to a major power utility provider in Mississippi for 2010 through 2012 are listed in Table 4.1. The average electrical usage rate that the utility provider represented in Table 4.1 charged its customers for 2010 through mid 2011 was approximately \$0.0883/kWh. Therefore, it is observed that any facility that attempts to produce power on site for the sole purpose of selling that power back to the utility mentioned above is at a disadvantage from the beginning as the utility avoided costs are all lower than the average utility usage rates imposed on industrial sites. As previously mentioned, it is relatively difficult for an industrial manufacturing facility to generate power on site at a lower cost than the associated cost of utility supplied electricity. Therefore, if an industrial manufacturing facility located in the service area of the utility provider described in Table 4.1 attempted to generate on site power that exceeded their demand, then it can be observed that the utility in question would have purchased that excess electricity at an average rate of approximately 50% of the rate at which the utility sold electricity for the simultaneous time period.

Table 4.1 Mississippi Utility Avoided Cost of Producing Electricity

Large Utility Provider in Mississippi - Avoided Costs		
Year	**Peak (12:00 PM - 8:00 PM) [$/kWh]**	**Off-Peak [$/kWh**
2010	0.0523	0.0400
2011	0.0579	0.0420
2012	0.0622	0.0469

4.3.1 Net Metering Benefits Example

To illustrate the benefits of net metering on CHP system economic considerations, the animal foods rendering facility mentioned in the previous chapters was used. A combustion turbine CHP option considered for this facility was found to have an annual cost savings of $1,788,118, with an associated project payback period of 4.5 years, an internal rate of return of 16.5%, and a net present value of $443,765. However, this option could only provide approximately 72% of the facility's process heating load due to the fact that the CHP unit was chosen such that its electrical generating capacity did not exceed the demand of the facility. If favorable net metering options were available, the CHP unit size could have been chosen in order to supply the facility's total process heating load and any resulting excess electricity could then be sold back to the local utility at an economically attractive rate.

Therefore, to illustrate the benefits of net meeting, a combustion turbine CHP unit that can supply the facility's entire process heating load but in turn exceeds the electrical demand of the facility is considered in Table 4.2. This analysis thus demonstrates how increasing the utility's avoided cost of production, or the rate at which the utility purchases the excess electricity produced by the facility, affects economic considerations.

The combustion turbine for the original case was sized to match the facility's base electrical load, and thus it had a capacity of 4.6 MW. However, the combustion turbine for the net metered case was sized such that it matched the facility's thermal load. This resulted in a combustion turbine electrical generating capacity of 7.5 MW. When the corresponding annual operating hours of the facility was applied to both cases, the annual electrical production was calculated for each case. As a result, the excess electrical capacity for the net metered case was determined to be approximately 2.63 MW. It is important to note that the excess capacity is not simply the difference between the electrical generation capacities for each case due to the fact that the actual annual electrical consumption is seldom equal to the base electric load multiplied by the annual facility operating hours. This excess electrical capacity was then assumed to generate excess electricity (kWh) based on the facility's annual operating hours. For this analysis, it was also assumed that the utility provider purchased all of this excess electricity at their associated avoided cost of production.

At the time the initial CHP feasibility analysis was conducted for this facility, the electrical usage rate was determined to be \$0.0825888/kWh. Therefore, this is taken to be the facility's electrical usage rate for all of the cases considered in Table 4.2. The average utility avoided cost was determined to be \$0.04641/kWh from information provided in Table 4.1. This value was then taken to be the base utility avoided cost for the analysis presented in Table 4.2. The results show that when the actual utility avoided cost of production is applied to any excess electrical generation, the payback period is above 5 years and the project net present value is negative. If the utility avoided cost is increased by approximately 40%, the project net present value becomes positive. Also, if the utility avoided cost is increased by a factor of 5, the project payback period approaches 2 years and the project net present value exceeds the CHP system installation cost.

Table 4.2 Effects of Increasing Utility Avoided Cost (Re-Purchase Rate) on CHP Project Economics

Avoided Cost Percentage Case	Annual Cost Savings ($/yr)	Simple Payback (yrs)	IRR (%)	NPV ($)
Actual	$2,298,464	5.29	12.21%	($1,182,684)
125%	$2,466,019	4.93	14.11%	($383,185)
150%	$2,633,572.76	4.61	15.96%	$416,313
175%	$2,801,126.93	4.34	17.76%	$1,215,812
200%	$2,968,681.09	4.09	19.53%	$2,015,311
300%	$3,638,897.75	3.34	26.28%	$5,213,306
400%	$4,309,114.40	2.82	32.68%	$8,411,301
500%	$4,979,331.06	2.44	38.85%	$11,609,296
600%	$5,649,547.71	2.15	44.84%	$14,807,291

It is also important to note that the original combustion turbine option considered in which no excess electricity was generated resulted in emissions reductions of 17.65 tons/yr of NO_x, 59.56 tons/yr of SO_2, 17,521 tons/yr of CO_2, and 4,332 metric tons/yr of carbon [EPA, 2010]. When the combustion turbine CHP unit was sized to meet the facility's entire process heating load, which resulted in excess electrical generation, the emissions reductions were determined to be 51.22 tons/yr of NO_x, 97.11 tons/yr of SO_2, 29,539 tons/yr of CO_2, and 7,304 metric tons/yr of carbon [EPA, 2010]. Therefore it seems as though it is highly beneficial to generate more on site electricity from an emissions point of view. Figure 4.2 displays the effects that the net metered CHP option has on emissions reductions for each of the greenhouse gas emission sources considered. It is apparent from the figure that the net metered CHP option allows for substantial increases in greenhouse gas emissions reductions for all greenhouse gas sources when compared to the base line CHP option, or the option that does not take advantage of net metering.

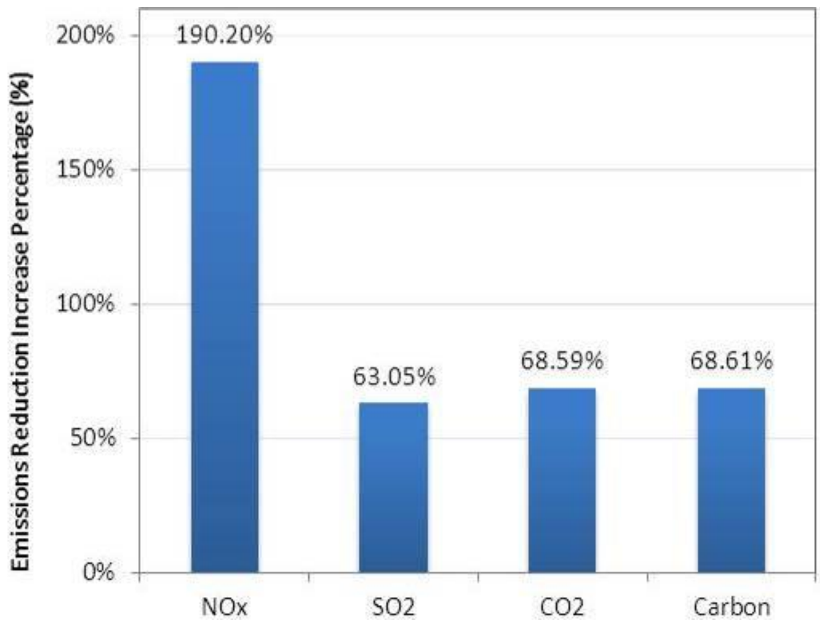


Figure 4.2 Base Line and Net Metered CHP Options Greenhouse Gas Emissions Comparison

From the results presented in Table 4.2, it is apparent that additional incentives which supplement the utility's avoided cost of production or increased utility re-purchase (i.e. equivalent of avoided cost) rates are necessary in order for it to be economically viable for an industrial manufacturing facility to generate power in excess of their on-site requirements for the sole purpose of selling that excess back to the local utility provider. Some large utility providers in the Southeast U.S. have already initiated programs that supplement their avoided costs. However, these actions are not in response to any regulations or requirements that were imposed on the utility providers and as a result most of these utility incentives are relatively unsubstantial unless the facility in question plans to generate power using renewable sources such as wind, solar, etc. Individual states have all authority when it comes to implementation of PURPA legislation, and therefore states that had limited resources for production of electricity using renewable fuels have not experience much activity to date. Many states that have made positive strides in response to PURPA legislation have yet to impose purchase rates on utilities that exceed their avoided costs. As a result, it is still a challenge to identify an economically attractive CHP project even when any implications resulting from PURPA legislation are considered [Wooster *et al.*, 1984].

Net metering is in most cases a practical option for the sale of electricity which is generated on site that has recently gained a great deal of attention. Under net metering agreements, a facility generates a certain amount of electricity on site and often still requires a substantial portion of their electrical load to be supplied by the grid. Typically, the "net" difference, or the difference between the facility's total electrical usage that is supplied by the electrical utility and the electricity that they produce on site, is the usage which they are charged. Thus the facility's electrical system is situated such that electricity can either "flow into" the complex when their electrical demand is high or "flow out" of the complex when their operation is off peak. Thus the "in flow" of electricity minus the "out flow" of electricity is the usage for which the facility is charged by the utility supplier. Typically, there are additional service and interconnection fees that are associated with a net meter that must also be accounted for when considering this as an option. Under the Energy Policy Act of 2005, all electrical utilities are required to make available upon request net metering services to any electric consumer that the utility serves [Varnado *et al.*, 2009]. However, net metering rates vary significantly based on location, utility provider, electrical generation fuel, etc. and are often not substantial enough to make net metering projects an economically viable option.

Feed-in tariffs can also be utilized to positively affect the economic considerations of a CHP unit at an industrial manufacturing facility. If electricity is generated on site using a renewable fuel source, then feed-in tariffs often allow a facility to obtain a long term purchase contract in order to ensure the power generated on site will be purchased at a premium rate for an extended period of time [Rickerson *et al.*, 2007]. Many of the incentives that are potentially available through the facility's local electric utility supplier typically require that all of the electricity generated on-site be sold directly to the utility rather than be used to offset the on-site electrical usage [Carley, 2009]. However, as previously mentioned, if renewable portfolio standards or feed-in tariffs are already in place, then an electric utility will purchase power generated on site at a premium depending on the fuel source utilized [Kydes, 2007].

4.4 Conclusions

Numerous case studies of CHP systems at industrial manufacturing facilities in the Southeast U.S. have been prepared which incorporate any and all appropriate CHP incentives. However, even when these additional factors are included, it is still rather difficult to identify a CHP project at an industrial site that shows favorable economic considerations. Therefore, it is apparent that substantial ground must be covered and the status of policy and incentives friendly to CHP systems at industrial manufacturing facilities must be significantly improved in order for the capacity of installed CHP systems to be increased in the Southeast U.S. In order to support this conclusion, a sensitivity analysis of CHP policies and incentives was applied to a case study of an industrial manufacturing facility CHP system that was not economically feasible in order to determine what policy and incentive improvements were needed to improve the project's economic considerations.

CHAPTER V

INDUSTRIAL FACILITY CHP FEASIBILITY CALCULATOR TOOL

5.1 Introduction

The methodology developed in Chapter 2 provides all of the equations and inputs needed to conduct a base load CHP feasibility study at an industrial manufacturing facility. However, the process becomes somewhat tedious if one is to perform the calculations by hand or if they attempt to create their own calculation software. Therefore, a tool that is capable of determining the economic feasibility of an industrial facility CHP system using the methodology developed in Chapter 2 was created and is presented in Figure 5.1. This user friendly tool was developed in Microsoft Excel, and is simple to use as only minimal knowledge of the methodology is needed. The tool requires the same inputs used in the methodology equations and determines all of the important feasibility study results, such as total project cost savings, simple payback, internal rate of return, and net present value. The advantage of using the developed tool is that users can quickly study how varying many of the tool inputs, such as system operating hours, thermal load to be offset, etc. affects the outcome of the economic analysis for an industrial facility CHP project.

5.2 Description of the tool

5.2.1 Data Input

The green highlighted section represents the area where all of the inputs are entered into the calculator tool by the user. A screen capture of this section is presented in Fig. 5.2. These inputs include: installed cost, operation hours, load factor, fuel and electricity prices, etc. In this section, users can select the type of prime mover, such as a backpressure turbine or combustion turbine, for the system they wish to analyze. In addition, users can also specify the type of fuel to be used by the prime mover. Therefore, this section allows the user to modify project parameters that affect the simulation and results if they wish to perform a sensitivity analysis.

5.2.2 Calculations

The blue highlighted section contains all of the values calculated by the methodology and is presented in Figure 5.3. In this section, users can clearly see if any cost savings realized due to CHP implementation are a result of electrical consumption offset by the CHP system or the facility thermal load that is offset by the CHP system. It is important to note here that a negative result for the electrical cost savings may not always indicate the project is not economically viable as this is typically countered by thermal energy savings for many CHP systems. However, if a negative result is obtained for the total project cost savings, then the CHP system will have no chance for success.

5.2.3 Economic Analysis

The red highlighted section (Figure 5.4) allows the user to specify whether or not the facility is able to take advantage of the Investment Tax Credit (ITC). This will quickly compare the advantages that the ITC has on implementation of the CHP system.

5.2.4 Main Results

A screen shot of the main results section is presented in Figure 5.5. The orange highlighted section presents the CHP project economic analysis results, which include: CHP annual cost savings, project payback period, internal rate of return, and net present value both with and without consideration of the Investment Tax Credit. This section of the tool displays a comparison of the electrical, thermal, and total cost savings and also includes a comparison of project net present value and simple payback again both with and without the Investment Tax Credit considered.

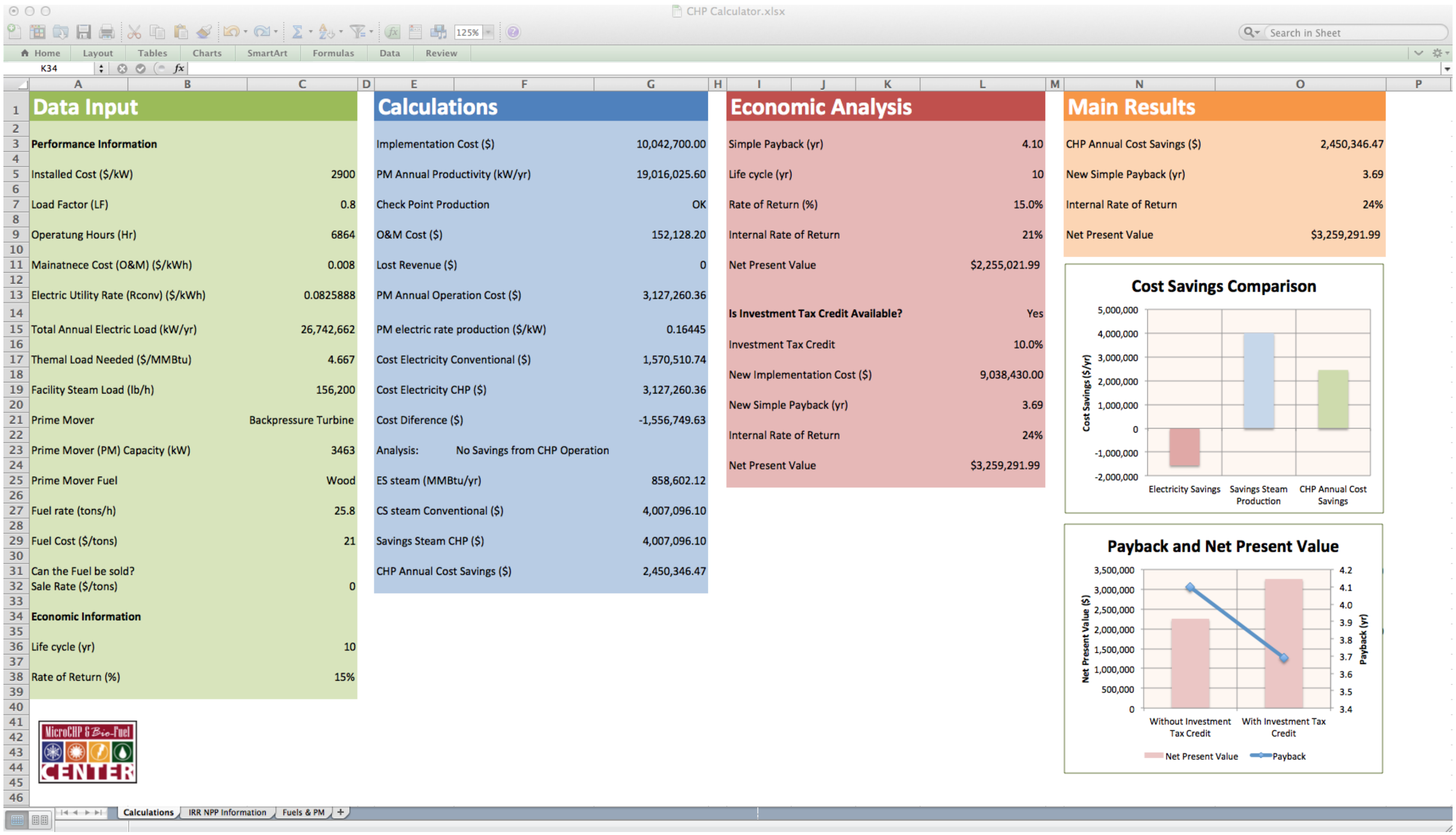
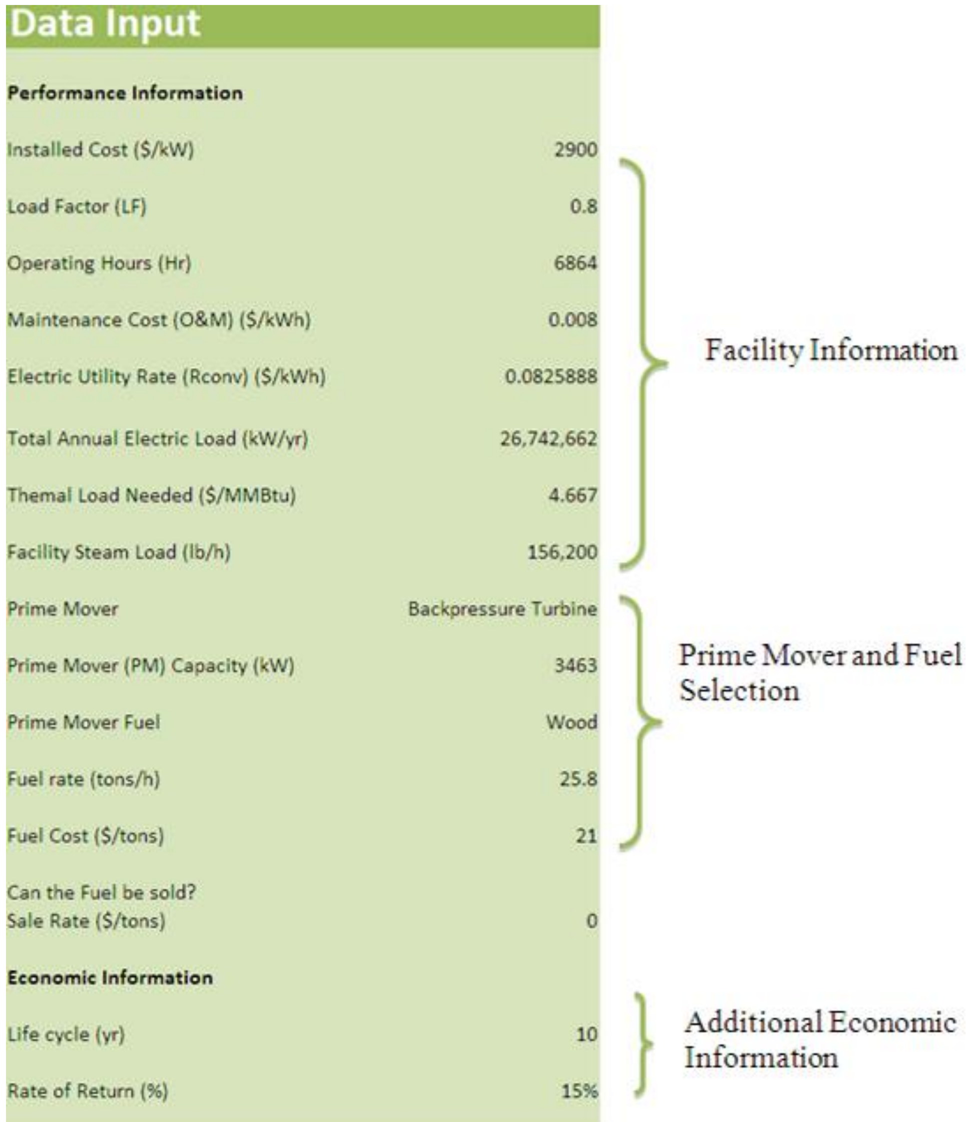
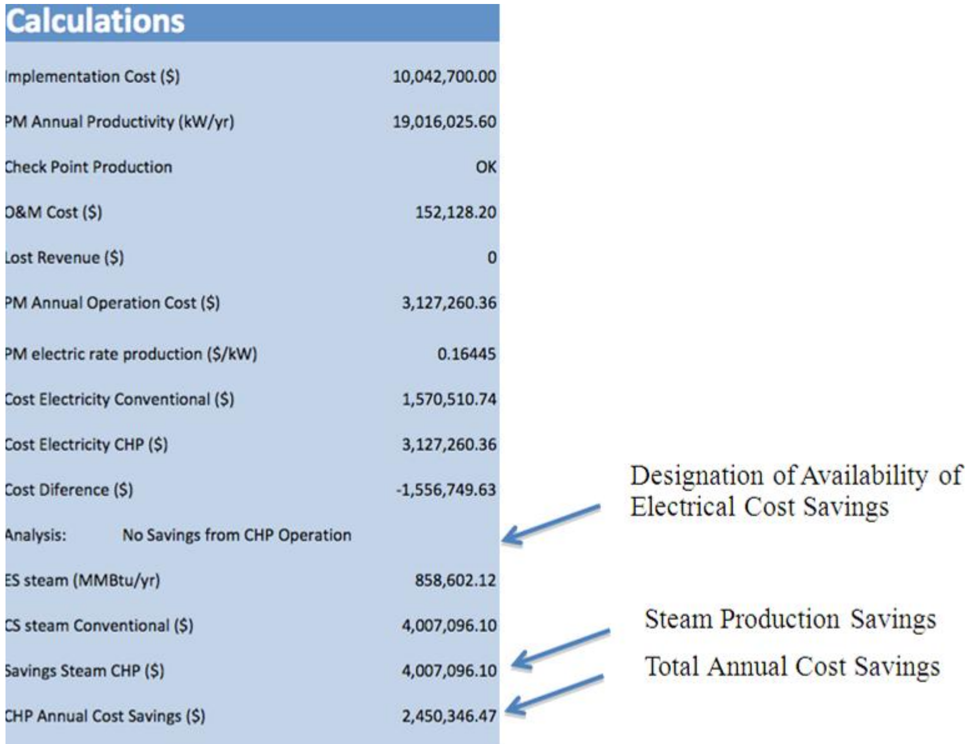


Figure 5.1 Industrial Facility CHP Feasibility Calculator Tool



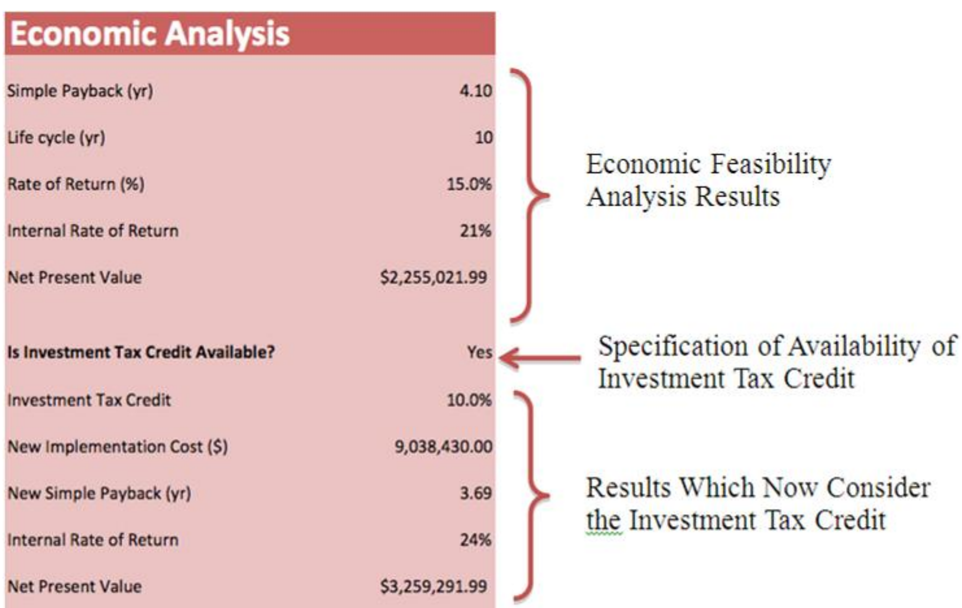
Data Input	
Performance Information	
Installed Cost ($/kW)	2900
Load Factor (LF)	0.8
Operating Hours (Hr)	6864
Maintenance Cost (O&M) ($/kWh)	0.008
Electric Utility Rate (Rconv) ($/kWh)	0.0825888
Total Annual Electric Load (kW/yr)	26,742,662
Themal Load Needed ($/MMBtu)	4.667
Facility Steam Load (lb/h)	156,200
Prime Mover	Backpressure Turbine
Prime Mover (PM) Capacity (kW)	3463
Prime Mover Fuel	Wood
Fuel rate (tons/h)	25.8
Fuel Cost ($/tons)	21
Can the Fuel be sold? Sale Rate ($/tons)	0
Economic Information	
Life cycle (yr)	10
Rate of Return (%)	15%

Figure 5.2 Tool Data Input Screen



Calculations	
Implementation Cost ($)	10,042,700.00
PM Annual Productivity (kW/yr)	19,016,025.60
Check Point Production	OK
O&M Cost ($)	152,128.20
Lost Revenue ($)	0
PM Annual Operation Cost ($)	3,127,260.36
PM electric rate production ($/kW)	0.16445
Cost Electricity Conventional ($)	1,570,510.74
Cost Electricity CHP ($)	3,127,260.36
Cost Diference ($)	-1,556,749.63
Analysis: No Savings from CHP Operation	
ES steam (MMBtu/yr)	858,602.12
CS steam Conventional ($)	4,007,096.10
Savings Steam CHP ($)	4,007,096.10
CHP Annual Cost Savings ($)	2,450,346.47

Figure 5.3 Tool Calculations Screen



Economic Analysis	
Simple Payback (yr)	4.10
Life cycle (yr)	10
Rate of Return (%)	15.0%
Internal Rate of Return	21%
Net Present Value	$2,255,021.99
Is Investment Tax Credit Available?	Yes
Investment Tax Credit	10.0%
New Implementation Cost ($)	9,038,430.00
New Simple Payback (yr)	3.69
Internal Rate of Return	24%
Net Present Value	$3,259,291.99

Figure 5.4 Tool Economic Analysis Screen

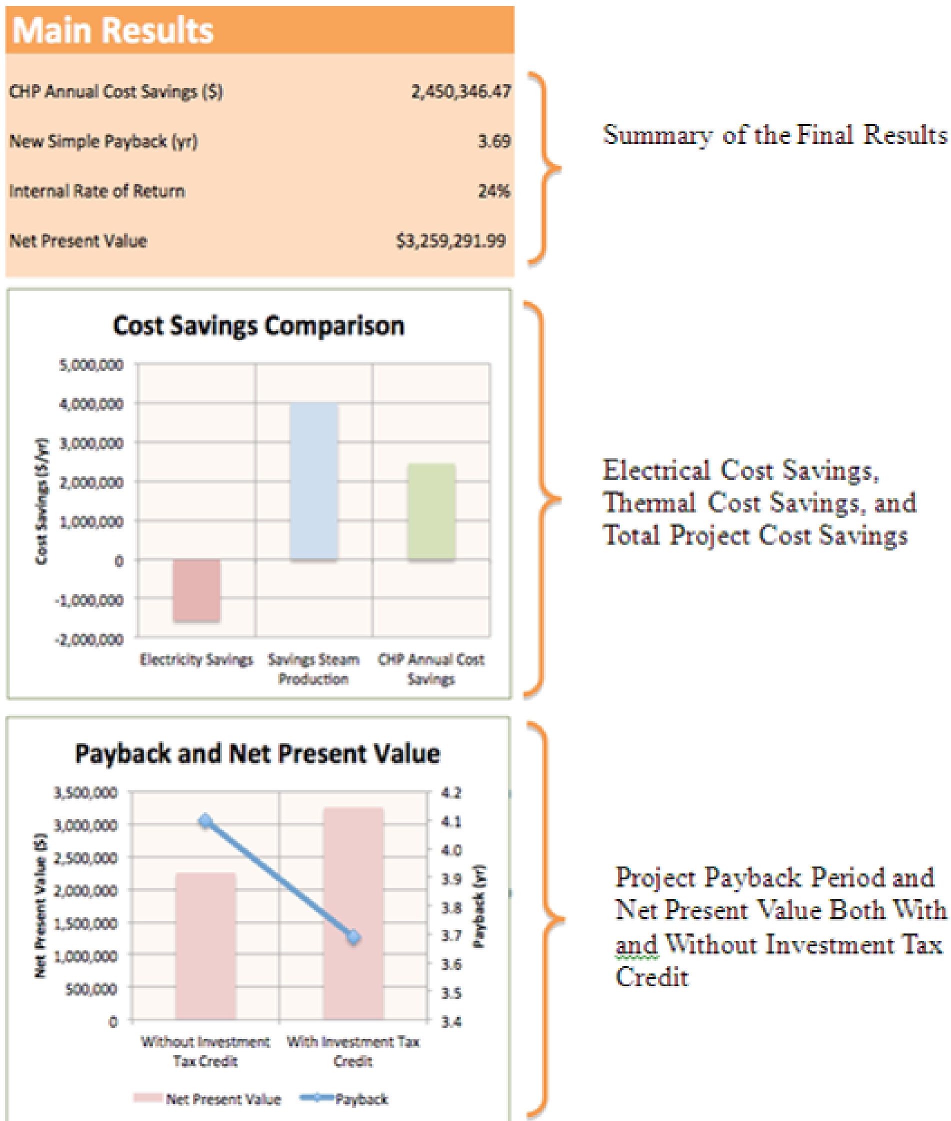


Figure 5.5 Tool Main Results Screen

5.3 Conclusion

This Chapter presented a tool based on the methodology developed in Chapter 2. The tool was developed in Microsoft Excel and allows users to quickly determine the economic feasibility of implementing a CHP system at an industrial manufacturing facility. The tool is very user friendly and does not require an extensive knowledge of the methodology employed as only a few inputs are necessary. In addition, users can easily modify a number of the input parameters and quickly assess how those modifications affect the overall economic considerations and performance of the CHP system.

CHAPTER VI

CONCLUSION

This study initially investigated the need for a process which could be used to determine the economic practicality of CHP systems at industrial manufacturing facilities. After the literature review was completed, it was apparent that there was an obvious need for a methodology which could be employed to estimate the economic potential for a CHP system at a wide range of industrial sites. As a result, this research developed a methodology which performs an economic analysis and feasibility study of a base load CHP system which is being considered for an industrial manufacturing plant. Many factors had to be taken into consideration when preparing the methodology developed in this research, which included but were not limited to the relative cost of electricity and thermal energy from conventional utility suppliers, the annual operating hours of the facility, the facility's thermal load, and the existence of any favorable net metering or interconnection standards policies or incentives. Many of these factors also provide insight as to which type of CHP configuration, such as a topping or bottoming cycle, will best suit the facility's application and also whether a steam turbine or combustion turbine should be chosen as the prime mover for the system.

The methodology developed in this study was then applied to a number of different industrial manufacturing facilities in order to display its capabilities in accounting for a variety of different manufacturing processes and facility energy requirements. The methodology is also capable of accounting for differing availability of resources as well as diverse facility operating schemes. The methodology was then applied to multiple CHP feasibility case studies for manufacturing plants located in the Southeast U.S. Many of the indicative parameters were then varied for each of these facilities and conclusions were made as to how variations in these parameters could either benefit or damage the economic considerations of a CHP project under consideration. The effects that variations in the annual facility operating hours during which both process heat and electricity were needed, the facility average hourly thermal load, the cost of utility supplied electricity, and the CHP fuel type and associated fuel cost all had on the outcome of the economic analysis calculated by the methodology were investigated.

From the cases analyzed, it was observed that the electrical energy cost savings due to implementation of CHP were most often negative and thus needed to be countered by any CHP thermal energy cost savings if the project was to be economically viable. As a result, this led to the conclusion that high facility thermal loads which can in turn be offset by the proposed CHP system are a must for project success of an industrial plant CHP project. Therefore, low PHR values are favorable when considering the installation of a CHP system. Also, it was observed that CHP systems which had high annual operational hours displayed favorable economics and that if a facility could utilize a waste stream generated on site as a fuel source for CHP, then project economics could potentially be improved as well. However, it is also important to note that in some instances this could result in a loss in revenue if the associated waste stream in some way generated funds for the facility. For example, it is often the case that biomass fuel suppliers will actually purchase wood waste from a facility that generates a large amount.

Based on the parametric analysis and the comparison of variations in many of the indicative parameters, it was found that the project simple payback, internal rate of return, and net present value were all positively affected as (1) the CHP operational hours were increased, (2) the average hourly thermal load of the facility was increased, and (3) the cost of utility supplied electricity was raised. It was also observed that the type of fuel to be used in the CHP system could also significantly affect the project economic considerations. However, it quickly became apparent that while certain fuel types could result in favorable economics for a specific facility, they could just as easily result in negative cost savings for another facility. For this reason it is suggested that multiple fuel types be investigated and compared when considering an industrial site CHP system.

In general, it is concluded that for a CHP system to have the best chance for economic success, the following parameters are desirable; (1) the facility should have a low PHR, (2) the annual CHP operational hours should be maximized, and (3) the spark spread should be substantial. Any favorable CHP policy or incentives which can be taken advantage of also aid in the economic success of a CHP project at an industrial site. However, it is important to note that project success of a CHP system at an industrial facility in the Southeast U.S. is often difficult to achieve even when many of the available incentives are considered. As a result, it was concluded that substantial ground still needs to be covered if CHP is to become a mainstay in the industrial sector. In order to support this claim, a sensitivity analysis of available policies and incentives friendly to CHP was applied to one of the case studies from the parametric analysis chapter. The case study did not originally display favorable economics and the assistance provided by available incentives was incrementally increased until the negative economic considerations of the project were reversed.

In addition, a user friendly tool based on the methodology developed in this research was produced. This tool allows users to enter minimal basic inputs and then quickly assess the feasibility of implementation of CHP systems at industrial manufacturing facilities. Also, users can quickly determine how a number of different parameters will affect the overall economic performance of industrial site CHP systems. The results generated by the tool developed in this research, along with the EPA emissions calculator tool, can be used by representatives at any respective industrial manufacturing plant in order to determine whether or not CHP is a better economical and environmental option than conventional heat and power supply.

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APPENDIX A

SCREEN CAPTURES OF SOFTWARE TOOLS USED FOR COMBINED HEAT AND POWER METHODOLOGY ANALYSIS

A.1 U.S. DOE Steam System Assessment Tool Software

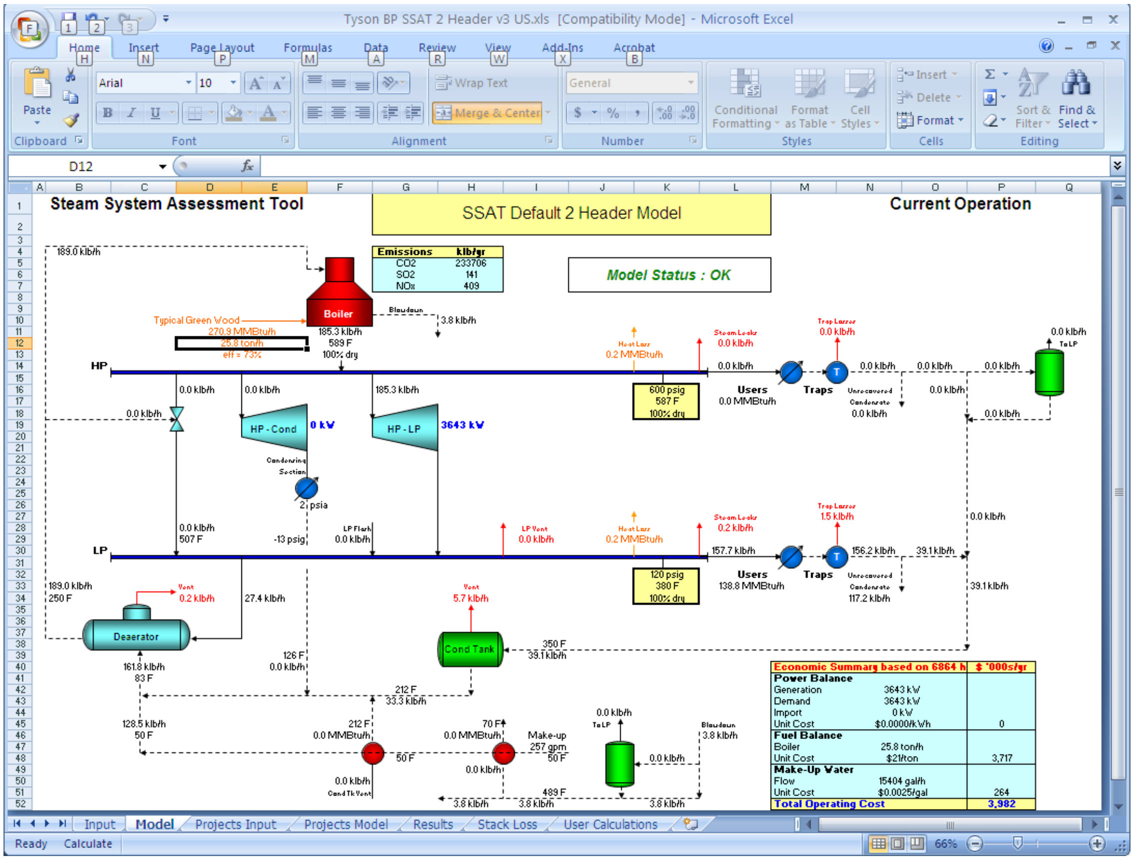

Figure A.1 U.S. DOE Steam System Assessment Tool Results Example

A.2 U.S. EPA Emissions Calculator Tool Software

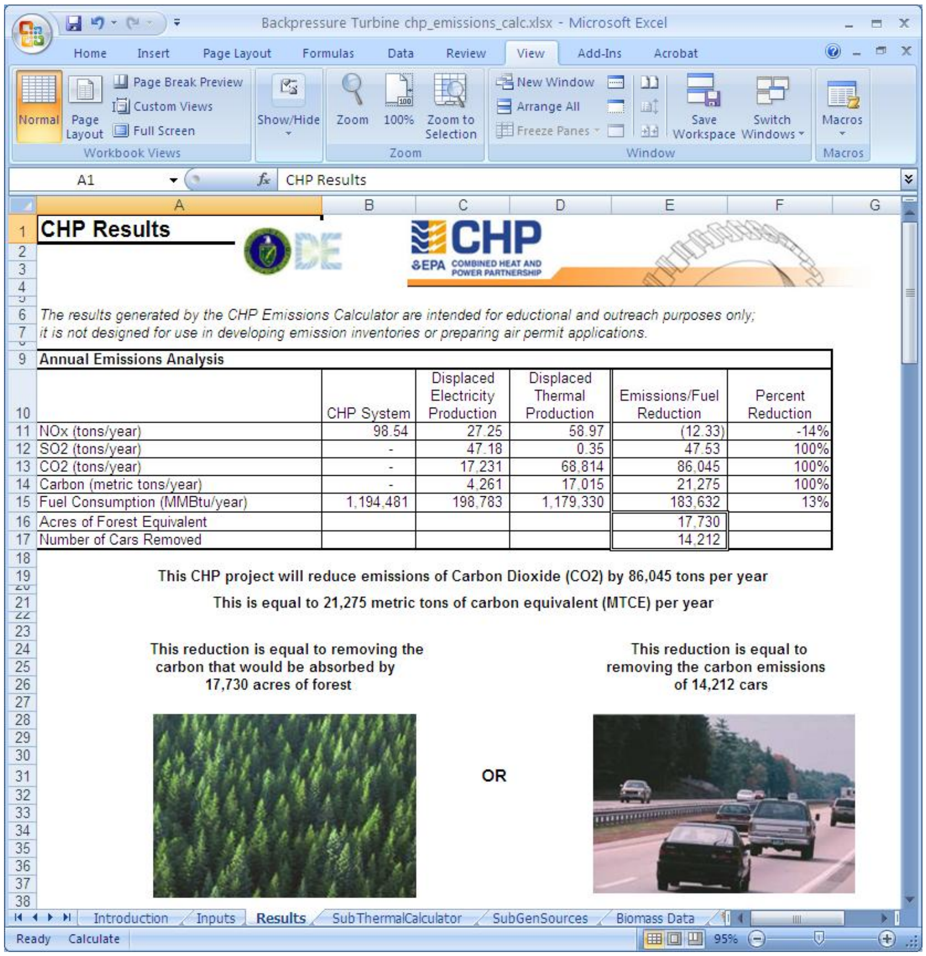

Figure A.2 U.S. EPA Emissions Calculator Tool Results Example