Methodology to Perform a Combined Heating and Power System Feasibility Study for Industrial Manufacturing Facilities

Chad Wheeley, Pedro J. Mago, Rogelio Luck

ABSTRACT

This article considers combined heating and power (CHP) systems based on topping cycles, in which electricity is generated by a prime mover and heat is then recovered from the exhaust and utilized to offset all or a portion of the facility's process and/or space heating requirements. The article 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 of such a system. In order to determine the best and most viable option for the facility in question, the proposed methodology 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 the CHP system. Examples are presented to describe in detail the application of this methodology.

Key Words: CHP systems, CHP feasibility study, emissions reduction, CHP for industrial manufacturing facilities.

INTRODUCTION

CHP systems should be considered for any industrial manufacturing facility that has relatively large electrical and process heating loads because these systems have the potential to significantly impact a facility's annual energy fees and can often result in a substantial reduction in greenhouse gas emissions. A CHP system also provides an added level of energy independence resulting in robustness to fluctuations in grid supplied power. For any industrial facility under consideration, the comparison of energy consumed by electrical equipment and process or space heating equipment, as well as the status of energy policies in the state in which the facility resides, will dictate whether a topping or bottoming cycle CHP configuration will best suit their application. The configuration of the CHP system will depend on individual component efficiencies and the system operating strategy [1-4]. For instance, in the authors' experience, for the majority of industrial manufacturing sites in the Southeast, it is usually preferred to size systems using electrical base loads and use a topping cycle CHP application. A key factor that needs to be considered when determining whether to use a topping or bottoming cycle CHP system is the status of net-metering and interconnection standards policy as well as any other incentives friendly to net-metering in place in the state in which the facility resides. If a facility is able to engage in a net-metering program, it may be advantageous for the facility to size a CHP system to meet the thermal loads and sell any excess power back to the local utility provider. On the other hand, if there are not any net-metering or interconnection standards policy in place, which is the case for many states in the Southeast, it is usually not advantageous for the facility to produce more power than can be consumed on-site, and a CHP system sized to provide the electrical base load may be a viable, relatively easy to implement alternative to reduce costs as well as emissions.

As previously mentioned, the operational strategy is very important to determine the feasibility of a CHP system. CHP systems can be configured to run under several operation strategies such as: following electric load (FEL), following thermal load (FTL), hybrid FEL-FTL, and base-loaded operation. When the CHP system is configured to operate on a FEL strategy, the prime mover will generate electricity to satisfy the electrical load of the facility and produce exhaust heat as a by-product. When the CHP system operates on a FTL strategy, the prime mover will generate the heat necessary to satisfy the thermal load of the building and electrical generation is a by-product of heat production. These two operational strategies have been widely investigated by several authors such as: Cardona et al. [5], Mago et al. [6-7], Jalalzadeh-Azar [8], Hueffed and Mago [9], among others. Another engine operation strategy is a 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 [9], Cho et al. [10], and Kong et al. [11] 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 the heat recovered is used resulting in high CHP system efficiencies [12].

An 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 et al. [13], Möllersten et al. [14], Wahlund et al. [15], Möllersten et al. [16], and Chicco and Mancarella [17], Mancarella and Chicco [18], among others. In general, all of them reported that CHP systems have the ability to reduce emissions, especially, carbon dioxide emissions.

This article presents a methodology to perform a CHP feasibility study for an industrial manufacturing facility in a location that does not have advantageous net-metering policy in place. For facilities in these regions, a topping cycle CHP system for on-site energy generation is typically recommended as the most viable option. The proposed prime mover is chosen based on its ability to meet the electrical base load of the facility. Any waste heat that can be recovered from the generation of electricity is used to offset all or a portion of the facility's process or space heating loads. A methodology to determine the emissions reduction of CO_2, SO_2, and NO_x, associated with installation of a CHP system is also presented. Two examples of CHP feasibility studies are presented to illustrate the use of the proposed methodology. The first example details an industrial manufacturing facility where a proposed CHP system showed substantial cost and energy savings as a result of the relatively large electrical and process heating loads of the facility. The second example shows the analysis for an industrial manufacturing facility with a relatively large electrical base load but a relatively small process heating load. As a result, the analysis showed negative project paybacks for the CHP system configurations analyzed for this latter facility. For each case, the reduction in CO_2, SO_2, and NO_x emissions are calculated using the methodology presented. The facilities used in the two examples are located in a state that had no effective net-metering or interconnection standards policy in place, and thus topping cycle CHP systems were analyzed in both instances.

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
$fuel_{FR}$	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
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
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
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

INDUSTRIAL FACILITY CHP FEASIBILITY STUDY METHODOLOGY

Preliminary Data Collection and Screening

An industrial manufacturing facility that has a history of relatively high electrical and thermal loads is needed for the CHP feasibility study. For most viable topping cycle CHP applications, the resulting process heating energy savings associated with the proposed project help offset the cost of CHP installation and operation resulting in a net positive financial gain. 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 is not economically feasible.

Site Assessment

Once an acceptable site has been identified, i.e. a facility with a significant CHP load, 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 regarding equipment that is used to supply the facility's thermal loads. Any information that can be obtained regarding 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. This information can usually be obtained from the plant's local utility providers. A utility bills release authorization is typically the only documentation required to obtain the usage and billing history for the facility in question. Once this information is obtained, the power to heat ratio for the facility can be determined. The power to heat ratio is defined as:

$$PHR = \left(\frac{Ld_e}{Ld_{th}} \right) \tag{1}$$

where LD_e is the electrical base load and LD_{th} is the thermal or process heating base 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 two examples presented in this article.

System Sizing

Once the electrical usage and demand history for the facility is obtained, electrical generation equipment can be sized to meet the facility's loads. For a first order analysis, monthly demand data is a good indicating factor of the average base electrical load and may be used to somewhat accurately size 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 that of the facility base electrical load.

$$Cap_{sys} = Ld_e \tag{2}$$

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 closely matches the estimated base demand load. Assuming net metering is not an option, this will ensure that the electricity produced at a given time during the operation of the CHP system is consumed by the facility.

System Selection

In order to select the best alternative for a base load CHP system, many electrical generation unit options, 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. The resulting economic analysis of each alternative is the deciding factor on which option should be pursued. The U.S. Department of Energy's Industrial Technology Program offers a wide range of software tools that can be utilized to identify potential energy savings projects at industrial manufacturing facilities. One of these software programs is the Steam System Tool Suite (SSTS), which contains the Steam System Assessment Tool (SSAT) [19]. 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 determined from the equipment manufacturer.

Economic Considerations

Once the electrical generation equipment has been sized and the amount of recovered waste heat for each alternative is determined, a project comparison and cost analysis is 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 system 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 window of time, 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 window when the CHP system is not operating and all of the power needed by the facility has to be supplied by the local utility provider.

To perform an economic analysis, first determine the installed cost (*IC*) of the desired CHP system using a *linear* cost rating CR ($/kW). Such a constant $/kW rating assumes economies of scale are negligible within the range of CHP system sizes explored for the facility. Such cost is obtained either directly from the manufacturer or from the EPA CHP Catalog [20]:

$$IC = (CR * (Cap_{sys}) \qquad (3)$$

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

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

$$Prod = (Cap_{sys}) * (Hr) * (LF) \tag{4}$$

The load factor is equivalent to the fraction of the nominal system capacity which will be utilized in the average during the annual operating hours. This number varies according to the size and type of system considered, CHP load profile, and other information provided by the facility; it typically ranges between 75-90%. The value calculated using Eq. (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)* cost per system capacity, taken to be $0.008/kWh in this article, which is a typical value that includes turbine and boiler maintenance fee,

$$O\&M = (Prod) * \left(0.008 * \frac{\$}{kWh}\right) \tag{5}$$

Next, the cost of operating the proposed CHP system is determined. The annual operational cost of the proposed system ($Cost_{op)}$ is the sum of the annual fuel cost and the annual *O&M* cost

$$Cost_{op} = (fuel_{FR}) * (cost_f) * (Hr) * (LF) + (O\&M) \tag{6}$$

where the fuel feed rate, $fuel_{FR}$ can be obtained directly from the manufacturer or can be estimated using the DoE SSAT software.

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

$$UR_{CHP} = \left[\frac{Cost_{op}}{\text{Prod}}\right] \tag{7}$$

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

$$CS_{ele} = (\text{Prod}) * (UR_{conv} - UR_{CHP}) \tag{8}$$

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

$$ES_{st} = (Ld_{st}) * (K_1) * (K_2) * (K_3) * (Hr) * (LF) \qquad (9)$$

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 produce 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.

$$CS_{st} = \left[\frac{ES_{st}}{\eta_{boiler}}\right] * UR_{th} \qquad (10)$$

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

$$CS_{tot} = CS_{ele} + CS_{st} \qquad (11)$$

With the value obtained in Eq. (11) 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

$$SP = \left[\frac{IC}{CS_{tot}}\right] \qquad (12)$$

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.

$$NPV = -IC + \sum_{n=1}^{9} CS_{tot} / (1 + 0.15)^{n} \qquad (13)$$

Assuming a 10-year project life cycle, the internal rate of return (*IRR*) can be determined from Equation (14) below.

$$-IC + \sum_{n=1}^{9} CS_{tot} / (1 + IRR)^{n} = 0 \qquad (14)$$

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 must also be determined, F_m. Each of these total annual usage values can be easily obtained from the facility's utility bills.

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 follow

$$CDE_{conv} = E_m * DCF_{CDE} + F_m * FCF_{CDE} \quad (15)$$

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 to generate the 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.

$$E_{grid} = E_m - Ld_e * Hr \tag{16}$$

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

$$CDE_{CHP} = E_{grid} * ECF_{CDE} + (F_{CHP} + F_{grid}) * FCF_{CDE} \tag{17}$$

The total annual carbon emissions reductions associated with utilization of the CHP system, CDE_{red} is

$$CDE_{red} = CDE_{conv} - CDE_{CHP} \tag{18}$$

The same methodology can be applied to determine the emissions of SO_2 and NO_x using Equations (17) and (18) and changing the carbon dioxide emissions conversion factors by the SO_2 and NO_x emission conversion factors for electricity and natural gas, respectively.

Summary of Methodology

The flowchart depicted in Figure 1 summarizes the methodology presented in this article. Note this methodology is suitable for preliminary feasibility analysis of CHP systems in manufacturing facilities when net metering and/or power sell back are not allowed.

APPLICATIONS

Two cases in which analysis was performed on the potential

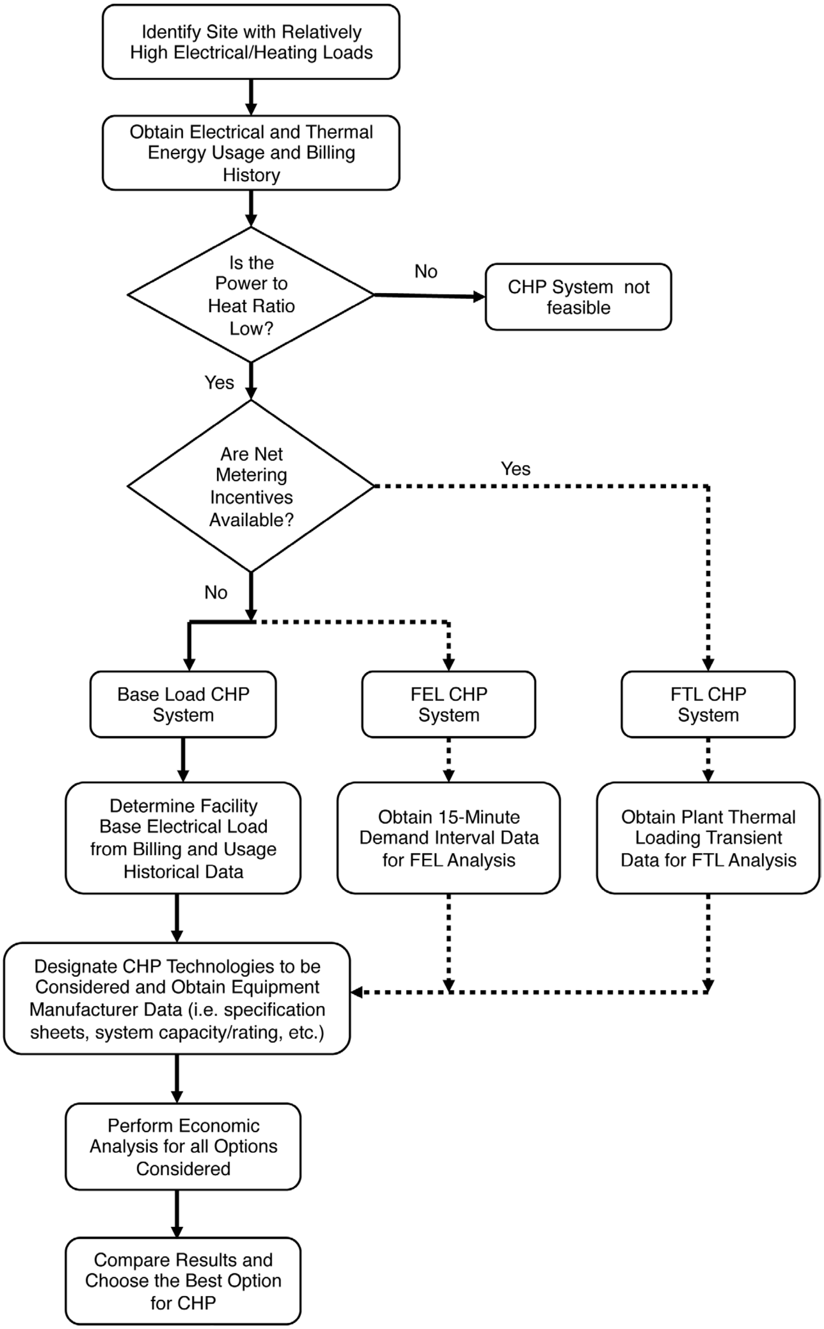

Figure 1. Flow chart of the methodology presented in this article.

economic viability of a proposed CHP system for an industrial manufacturing facility are employed to illustrate the use of the methodology presented in Section 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 presented in Table 1.

Table 1. Regional Carbon Dioxide, Sulfur Dioxide, and Nitrogen x-Oxide Emissions Conversion Factors for the two locations evaluated in this article [21]

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

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 capable of supplying steam at a flow rate that meets the facility's needs when the system is online provided the best alternative for the facility considered in Case 1. 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 2. In this table, 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 (assuming a 15% interest rate could be obtained by investing the capital) rather than to use it to fund the project.

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 account. 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

Table 2. Results of the cost analysis for each different CHP configuration for Case 1.

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

turbine option provided the best cost savings and payback for the facility in question for Case 1. A more detailed representation of the cost analysis for the backpressure turbine for Case 1 is presented in the Table 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%.

The methodology presented in Section 2.6 was used to determine the reduction in CO_2, SO_2, and NO_x emissions for each of the options considered for Case 1. The resulting emissions reductions estimates are included in Table 4. It is important to mention here that all the prime movers analyzed for CHP result in a reduction in emissions compared to the conventional case. 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.

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 1.717. The facility utilizes natural gas fired boilers in order to supply

Table 3. Cost analysis for the backpressure turbine for Case 1.

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

Table 4. Emissions reductions estimate results for Case 1.

	Emissions Reductions					
Annual Emissions	Condensing Turbine	Extraction Turbine	Backpressure Turbine	Combustion Turbine (w/o duct burner)	Combustion Turbine (w/ small duct burner)	Combustion 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

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 for the facility in Case 2 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 as well 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

Table 5. Cost analysis for the extraction steam turbine CHP configuration.

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

options resulted in negative annual cost savings, or in other words it is 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 5. 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. 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 6 presents the emissions reductions estimates for Case 2. In Table 2, a negative value means that the CHP system produces more emissions than conventional power and thermal energy production methods. Therefore, the CHP system considered for Case 2 actually results 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

Table 6. Emissions reductions estimate results for Case 2.

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

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, or in essence 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 and the newly planted trees will absorb the carbon emissions associated with the use of the wood waste as fuel.

Comparison of Both Cases

The economic analyses completed for each case lead 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, most likely 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 and ensure that the overall project cost savings was economically attractive. However, the facility considered in Case 2 had a relatively low process heating load so 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 resulted in a negative cost savings. 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 to sell that additional power back to the local utility were available.

CONCLUSION

This article presented a methodology to perform a CHP feasibility study for an industrial manufacturing facility for which a base load CHP system would most likely be the preferred alternative. There are many factors that must be considered when determining which type of CHP system configuration should be considered for a CHP feasibility study. 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. Results showed that if the cost of electricity was relatively low and no net-metering policy was available for a specific facility, then a topping cycle CHP system sized to fit the base electric load of the facility would most likely show the best project economics. For a base load CHP system to be economically attractive, the facility for which the system is being considered will most likely need to 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 waste heat energy that can be recovered from the electrical generation process used to supply the base electrical load. 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.

This article also presented a methodology that can 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 carbon dioxide emissions resulting from the installation of a CHP system. It is also important to note, that depending on certain system parameters, such as the variation of fuel consumption due to the installation of a CHP system, carbon dioxide or other emissions might actually be increased.

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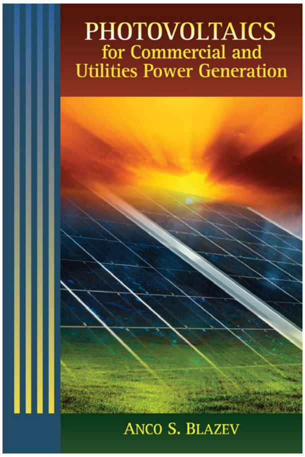

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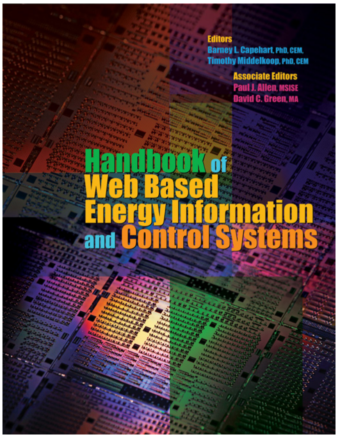

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ABOUT THE AUTHORS

Chad Wheeley is a Research Associate with the Mechanical Engineering Department at Mississippi State University where he serves as a research engineer for the DoE Southeast Clean Energy Application Center, the Southeastern Center for Industrial Energy Intensity Reduction, and the MSU Micro-CHP and Bio-Fuel Center. He also works with the MSU Industrial Assessment Center. Mr. Wheeley received a B.S.M.E. from MSU in August of 2006 and an M.S.M.E. from MSU in December of 2007. Prior to returning to MSU in March of 2009, Mr. Wheeley worked as a Mechanical Design Engineer for the Tennessee Valley Authority's Sequoyah Nuclear Plant in Soddy-Daisy, TN. Mr. Wheeley is a DOE Qualified Specialist in process heating systems, pumping systems, compressed air systems, and steam systems and is also an E.I.T. He can be contacted via email at *wheeley@me.msstate.edu*.

Pedro Mago is an Associate Professor of Mechanical Engineering at Mississippi State University where holds a Tennessee Valley Authority Professorship in Energy Systems and The Environment. He received his Master and PhD degrees from the University of Florida. His research has been on sustainable energy systems and he is currently focused on combined heat and power (CHP) systems, building energy simulation, and waste heat recovery technologies. He has been principal investigator and co-principal investigator on several projects funded by the US Department of Energy and private industry in energy utilization and efficiency. Currently, he serves as Director of the Micro-CHP and Bio-Fuel Center at Mississippi State University and Co-Director of the US DoE Southeast Clean Energy Application Center. He has published over 100 journal articles, conference papers, and technical reports. He can be contacted via email at *mago@me.msstate.edu*.

Rogelio Luck received the B.S. degree from Texas Tech University in 1984, and the M.S. and Ph.D. degrees from Penn State Univ., University Park, in 1987 and 1989, respectively, all in Mechanical Engineering. In 1989 he joined the faculty at the Mechanical Engineering Dept. at Mississippi State University. His current research interest is in the area of simulation, optimization and control of building cooling heating and power. He has published in the areas of building cooling heating and power, uncertainty analysis, inverse heat transfer, radiation heat transfer, applied math, theoretical and applied control systems, piezoelectric sensors, electrical power system generation and distribution, and redundant measurement systems. He can be contacted via email at luck@me.msstate.edu.