Cogeneration: Energy savings for industry and utilities.

Clayton Wayne Burns

Follow this and additional works at: http://preserve.lehigh.edu/etd
Part of the Electrical and Computer Engineering Commons

Recommended Citation

This Thesis is brought to you for free and open access by Lehigh Preserve. It has been accepted for inclusion in Theses and Dissertations by an authorized administrator of Lehigh Preserve. For more information, please contact preserve@lehigh.edu.
COGENERATION: ENERGY SAVINGS
FOR INDUSTRY AND UTILITIES

by
Clayton Wayne Burns

A Thesis
Presented to the Graduate Committee
of Lehigh University
in Candidacy for the Degree of
Master of Science

in
Electrical Engineering

Lehigh University
1981
This thesis is accepted and approved in partial fulfillment of the requirements for the degree of Master of Science.

Dec. 10, 1981
(date)

______________________________
Professor in Charge

______________________________
Chairman of Department
# TABLE OF CONTENTS

I. Abstract .......................................................... Page 1

II. Introduction and Historical Overview ....................... Page 3

III. Cogeneration Systems ........................................... Page 11

IV. Cost Analysis ..................................................... Page 28

V. Conclusion ........................................................ Page 34

VI. List of References ............................................... Page 36

VII. Bibliography ...................................................... Page 38

VIII. Vita .............................................................. Page 42
LIST OF FIGURES

Figure 1: Steam Turbine Cycle Page 12

Figure 2: Simplified Gas Turbine Page 12

Figure 3: Gas Turbine with Heat Recovery Page 15
Boiler

Figure 4: Gas Turbine with Refired Heat Page 16
Recovery Boiler

Figure 5: Unfolded Temperature Enthalpy Page 19
Diagram - Steam Cycle

Figure 6: Unfolded Temperature Enthalpy Page 21
Diagram - Combined Cycle

Figure 7: Combined Cycle Gas Turbine Page 25
and Low Temperature Refrigerant
Turbine

Figure 8: Economic Evaluation Chart Page 33
I. ABSTRACT

Total Energy or Cogeneration Systems, as they are commonly referred to today, are among the most effective methods of extracting energy from fuel. These systems concurrently satisfy both electrical and thermal requirements by utilizing a gas turbine as a prime mover and making use of exhaust heat that would normally be lost. A properly designed cogeneration system is more efficient in its use of fuel than any separate electric or heat producing facility.

The concept of cogeneration has been known for decades. It has not been put into widespread application due to economic considerations of installation and the low cost of energy. However, in recent years energy costs have increased dramatically and cogeneration techniques have proven to be advantageous. The cost of installation or retrofitting to existing facilities is offset by the savings of fuel used, providing a favorable payback. This payback when combined with new federal tax incentives for cogeneration facilities is making the installation of cogeneration equipment more desirable for both utilities and industry.

This paper examines the development of cogeneration from economic and design viewpoints. An energy balance is set up to compare and contrast a conventional steam cycle generating system
with a cogeneration system to show where efficiency advantages are achieved. Finally, a typical industrial application is analyzed to determine whether cogeneration is a cost efficient energy management technique.
II. INTRODUCTION AND HISTORICAL OVERVIEW

In the early 1900's, a strategy was developed whereby energy users could generate and use energy in both electrical and thermal form concurrently. Heat normally lost from electrical power generation processes was found to be sufficient to provide heat for boiler feedwater heating, space heating, and other process heating. Considerable savings could be realized from this practice. The fuel savings due to the heat provided by generation processes is credited against the cost of producing electricity. For certain applications, the resultant cost of producing electrical power may be considerably below the price of purchasing it from a utility. The fact that this type of system would pay for itself coupled with short payback periods provides industry and utilities with incentives for considering it.

The term used for the efficient production and usage of heat energy and electrical power was "Total Energy Systems." The early systems were used mainly by the utilities. An example of an early total energy system is the 1949 installation of a small gas turbine at the Oklahoma Gas and Electric Belle Island Station (1)*. In this system, the gas turbine was the prime mover for a small electrical generator (small by utility standards). Exhaust heat from the turbine was used to heat the feedwater for a boiler of a steam powered generating unit. As a result, plant capacity increased and efficiency improved.

*Numbers in parenthesis correspond to entries in the list of references.
Another design, built for the City of Monroe, Louisiana, is identified as one of the first complete total energy systems (2). It began with the installation of a gas turbine peaking unit in 1959. A steam turbine unit was to be installed at a later date when electrical demand warranted. The total system was designed with the gas and steam cycles operating together to extract the maximum amount of energy possible. Exhaust from the gas turbine would be used as preheated combustion air for the boiler of the steam turbine. When operating as a total energy system, the efficiency would be good enough to provide base load for the power system.

Total energy systems were not only for utilities. Industrial plants recognized the savings that could be provided when these systems were used in applications with both thermal and electrical requirements. Many total energy configurations seemed feasible. Of the different applications attempted over the years, some proved to be worthwhile and others were found to be uneconomical. Most commonly, industrial applications with higher annual utilization proved to be more feasible than commercial applications.

Profitability of early systems depended primarily upon design. Some systems were designed using ideal conditions which, in practice, worked out poorly. This was common especially among commercial applications. Better designs were developed when a constant ratio of electrical demand to heat demand was obtained (3).
Almost all early systems were designed as independent systems and electrical demand was the primary design criteria. The system had to be sized such that the entire electrical load was met. This type of design did not take heat demand into account. As with any system, a certain quantity of heat would be exhausted, and a use for it had to be found. Thus, there usually was either an excess or an insufficient amount of heat for the assigned process. In both cases, efficiency suffered. Of primary concern was the amount of heat energy which was exhausted and lost. The case of insufficient heat for an assigned process could be solved by using supplemental refiring techniques.

Another problem with designs using electrical demand as the primary criterion is that electrical machines must be rated for peak loading with extra capacity to handle periods when other units are out of service. This increases initial costs and lengthens payback periods by mandating industry to spend more for equipment redundancy.

As total energy systems were used more widely and problems with initial costs and efficiencies were uncovered, new design data was used. By retaining an interface to the utility, total energy systems could be designed with heat demand in mind. Using the paralleled generation of industry and utility, more commonly termed cogeneration, the system may achieve higher efficiencies provided exhausted heat is used. For this venture, industrial
in-house generation would handle base loading of the industry, and the utility tie line would provide for excess load variations and any additional base load required by new installations.

Cogeneration not only achieves higher efficiencies for the industrial system but can be of benefit for the utilities and their source responsibilities as well. As the cost of energy increases and more stringent federal regulations are imposed on utilities, the capital cost of new generation grows exponentially. In recent years, growth of electrical demand has been unpredictable. Combining these uncertainties with the long lead time to build new generating plants, the utilities now recognize that power sources brought on line by industries can be beneficial.

From an industrial point of view, the utility that provides reserve power is supplying more than power only. The utility is supplying a service whereby the industrial plant would not need to spend extra money on backup generating units which may have been necessary for continuous operations. The utility also absorbs swings in the industrial loading allowing the industry's cogeneration unit to run at peak efficiency.

By providing this service to industries, the utility could avoid costly expenditures for new generation. By encouraging industrial cogeneration and providing reserve power for many small
units, the reserve required would be much lower than for one or two large utility owned units with equal total rating. Of the many small industrial generating plants, very few would be on forced outage at any one time. When one or two of the units were out of service, the relatively low power loss could easily be absorbed by the utility. However, if a large utility unit went off line, reserve required to make up the power loss would be considerable and costly. The use of cogeneration techniques for industries will benefit industry by increasing plant power producing efficiency and also benefit utilities by removing uncertainty in systems planning and reducing the amount of spinning reserve required.

In the early 1970's, energy consumption and efficiency became of vital importance to companies that made use of energy from fossil fuels. Industries had thermal requirements which had to be satisfied by burning quantities of fuel. When costs increased tremendously, methods of increasing energy efficiency were welcomed. By using a combined cycle cogeneration system, unit net heat rates (see cost analysis section of this paper) may often be 50% less than the heat rate corresponding to a utility generator to generate the same amount of power (3). The heat rate is a measure of how efficiently a system converts fuel into electrical energy. By generating more efficiently than the utility, energy and money could be saved. Many industries have high thermal requirements
and high utilization and would profit by using some type of cogeneration system.

Recently the Federal Government has recognized the fact that energy may be saved using cogeneration techniques and has provided industry with financial incentives that make the installation or changeover more appealing and easily realized. The following quote illustrates the stand that the Federal Government has taken to promote industrial energy efficiency (3).

"In his national energy policy presented to Congress on April 20, 1977, President Carter requested legislation to promote electric cogeneration systems to conserve fuel."

"The following quotations from the Administration's program statement indicate what changes were requested and how they would affect a potential cogeneration application.

'A tax credit of 10 percent, in addition to the current 10 percent tax credit, would be provided for the purchase of cogeneration equipment...'

"If these tax credits are applicable to your facilities, the effective cost of the system is reduced by 20 percent from the quoted costs.

'Industries using cogeneration would be entitled to intertie with utility transmission facilities to sell surplus power and buy back-up power at fair prices.

'The Federal Power Commission would be required to establish procedures to ensure fair rates for both sale of power by cogenerators and for purchase of back-up power.'"
"The installed cost of the system will be lower than an isolated system since no low annual usage peaking generation capacity or standby generation equipment needs to be included. This capacity can be furnished by the utility. The annual utilization of the cogeneration system can be maximized and the payback improved. The system also can be operated to meet process heat requirements to optimize the system's efficiency at partial heat load conditions. This provision also opens the possibility that a system which generates more power than the site can use would be assured of the opportunity to sell the excess power at a fair rate.

'An exemption from Federal and State public utility regulations would be available to industrial cogenerators.'

"This provision would allow the owner of a cogeneration system to sell excess power to the utility without being subject to governmental regulations.

'...prohibit industry and utilities from burning natural gas or petroleum in new boilers with only limited environmental and economic exception; industry could also be prohibited from burning gas or petroleum in facilities other than boilers by regulations applicable to types of installations or on a case-by-case basis.

'...Those industries which invest in (cogeneration) equipment could be exempted from the requirement to convert from oil and gas in cases where an exemption is necessary to stimulate cogeneration.'

"With this proposed limitation on oil and gas, the industrial user could be faced with the alternative of using either cogeneration or coal. By selecting cogeneration, the user will be able to avoid conversion to coal with all its attendant pollution control and solid fuel handling problems to meet their process heat requirements."
The incentives that were outlined in this energy policy presentation would greatly aid industry in their development of cost efficient cogeneration systems. It is clear that cogeneration is a viable means of saving energy and if applied on a large scale could make a definite impact on the future energy outlook.
III. COGENERATION SYSTEMS

The steam turbine and gas turbine are both standard methods for providing mechanical energy for electrical power generation. These two methods have been used independently of each other with satisfactory efficiencies and outputs. However, it has been shown that if the two cycles are combined correctly, the resulting efficiency is better than either one of the cycles operating alone. The combination will be discussed in more detail later, but first an understanding of each individual system should be acquired.

A conventional steam plant is shown in Figure 1. A forced draft fan provides combustion air. This air is usually preheated in an air to air heat exchanger that extracts heat from high temperature boiler flue gas exhaust. The fuel is mixed with the air, ignited, and burned (combusted) in the furnace area of the boiler, thereby releasing heat. This heat is absorbed by water circulated through tubing configurations that enclose and contain the combustion processes to produce steam. Saturated steam is produced in a series of tubes called the evaporator. Higher temperature steam is produced in the boiler's superheater section. Steam exits the boiler and is piped to the steam turbine. The energy potential of the steam supply at the turbine inlet is converted to provide the rotational force through heat expansion of the steam as it passes through the
Figure 1  Steam Turbine Cycle

Figure 2  Simplified Gas Turbine
turbine stages. After the expansion is complete, the steam, at low pressure, passes through a condenser where it is returned to its liquid state for return to the boiler as feedwater to begin the cycle again. Heat extracted by the condensing medium is generally not fully utilized and is lost, although some reclaimed benefit can be obtained by preheating make-up water and boiler feedwater or specific process and space heating needs.

A gas turbine cycle is completely different except for the fact that it makes use of expanding gases. Figure 2 shows a simplified gas turbine. Air is drawn in and compressed in the compressor section. It then flows to the combuster where fuel is injected into the air stream. The mixture is ignited and the high energy hot gases flow into the turbine section. The gases are allowed to expand and the thermal energy is transferred into a rotational force. Due to the high rotational speeds developed by the gas turbine, it must be geared down to drive an electric generator. Once expanded, the spent gases exit the turbine and are exhausted. The lower the exhaust temperatures, the more efficient the gas turbine. However, most often the exhaust temperatures are in the 700° to 900°F range and this heat energy is being lost when the exhaust is discharged directly to atmosphere. Temperatures of the gas turbine exhaust vary with the fuel-air ratio which is predicated upon electrical demand.
When a gas turbine and steam cycle are combined, heat that is exhausted or otherwise lost may be partially recovered. Figure 3 illustrates a gas turbine followed by a steam turbine. The gas turbine cycle is unchanged except that the exhaust now flows into a heat recovery boiler instead of being exhausted to the atmosphere. This exhaust may be used in a number of ways in the heat recovery boiler. The first method makes use of the waste gas as the direct heating energy for the boiler. For this case the amount of steam produced for the steam turbine would be a function of the gas turbine exhaust temperature. Temperature of the gas turbine exhaust gases are controlled by the fuel-air ratio, as mentioned previously, and depending upon electrical loading, this ratio may be adjusted for more or less power output from both turbines. The steam turbine output follows that of the gas turbine.

The second method of gas turbine exhaust usage is refiring in the boiler. Figure 4 shows a simple schematic. Most gas turbines are operated using three to four times the amount of air required for combustion. Thus, the exhaust stream still has a high content of oxygen and may be used as preheated combustion air for the boiler. This is the most efficient usage of gas turbine exhaust because all of the heat is utilized. As the exhaust enters the boiler, fuel is mixed with it and ignited. The amount of fuel added corresponds to the loading on the steam
Figure 3  Gas Turbine With Heat Recovery Boiler
Figure 4  Gas Turbine With Refired Heat Recovery Boiler
turbine. For greater loads more steam is needed and more fuel would be used within the constraints of the exhaust properties. If the exhaust stream is not sufficient to provide the combustion air needed, supplemental outside air may be introduced and blended with the exhaust stream prior to boiler entry. Using refiring techniques, the steam turbine cycle is independent of the gas turbine operation. The gas turbine generator may be run fully loaded at all times to maximize efficiency and maintain constant exhaust flow and temperature. The steam turbine generator would have to be loaded enough to make use of all of the gas turbine exhaust heat but would be capable of extra loading, with added fuel, to handle swings. Optimally, the two units would be loaded and provide power for electrical base loading of an industrial plant or utility.

Other advantages of refiring over a boiler heated only by gas turbine exhaust is its flexibility during forced outaged and maintenance periods. For the case of a heat recovery boiler heated only by turbine exhaust, the boiler and steam turbine would be shutdown whenever the gas turbine was out of service. However, the gas turbine could be operated when the steam turbine was shutdown provided a proper exhaust bypass was installed. For a refired boiler, either gas or steam systems could be operated independently. Efficiency would suffer but
MICROFILM CORRECTION GUIDE (M-5)

CORRECTION

The preceding document has been re-photographed to assure legibility and its image appears immediately hereafter.
turbine. For greater loads more steam is needed and more fuel would be used within the constraints of the exhaust properties. If the exhaust stream is not sufficient to provide the combustion air needed, supplemental outside air may be introduced and blended with the exhaust stream prior to boiler entry. Using refiring techniques, the steam turbine cycle is independent of the gas turbine operation. The gas turbine generator may be run fully loaded at all times to maximize efficiency and maintain constant exhaust flow and temperature. The steam turbine generator would have to be loaded enough to make use of all of the gas turbine exhaust heat but would be capable of extra loading, with added fuel, to handle swings. Optimally, the two units would be loaded and provide power for electrical base loading of an industrial plant or utility.

Other advantages of refiring over a boiler heated only by gas turbine exhaust is its flexibility during forced outaged and maintenance periods. For the case of a heat recovery boiler heated only by turbine exhaust, the boiler and steam turbine would be shutdown whenever the gas turbine was out of service. However, the gas turbine could be operated when the steam turbine was shutdown provided a proper exhaust bypass was installed. For a refired boiler, either gas or steam systems could be operated independently. Efficiency would suffer but
the individual units would be available to provide power while one or the other was on forced outage.

A simple energy balance may be used to show the increased efficiency possible with a combined cycle over the straight steam cycle (4). The process for the steam cycle of Figure 1 is shown in Figure 5. Each point on the graph represents a certain temperature, enthalpy state which the combustion air and fuel takes on. Point 0 represents the initial states of the working fluid. As it takes on heat, the temperature and enthalpy change accordingly. States 0 to 1 represents the heat taken on by the combustion air ($Q_0$). States 1 to 2 is the heat produced due to the combustion of the fuel in the boiler ($n_H H_S$ where $n_H$ is the efficiency of combustion process; heat lost due to radiation, unburnt fuel, etc., is taken into account by this term). Points 2 to 3 represents the heat that is transferred from the hot boiler gases to the steam ($V_S$). States 3 to 4 is the heat absorbed by the air heater ($Q_S$; this amount of heat is equal to the amount of heat taken on by the incoming combustion air) and finally Path 4 to 0 represents the heat that is lost and exhausted to the atmosphere ($Z_S$). The following energy balance may be written.

\[ Q_S + n_H H_S - V_S - Q_S - Z_S = 0 \quad \text{Eq.1} \]
Figure 5  Unfolded Temperature Enthalpy Diagram - Steam Cycle (4)
The energy equation illustrates that the heat into the system equals the heat given up by the system (positive terms indicate heat entering and negative terms signify heat exiting the system). Since the heat absorbed by the incoming combustion air equals the amount of heat given up to the air heater, the heat balance equation may be solved for $V_S$, the heat absorbed by the steam.

$$V_S = n_H H_S - Z_S \quad \text{Eq. 2}$$

An output power equation can be written as,

$$P_S = n_{TH} V_S - P_{S AUX} \quad \text{Eq. 3}$$

where $n_{TH}$ is the thermal efficiency of the steam turbine and $P_{S AUX}$ is the power consumed by the auxiliaries.

The combined cycle heat balance diagram is somewhat more complicated. Figure 6 is the unfolded temperature, enthalpy diagram which illustrates the processes for Figure 4. Path 0 to 1 represents the compression of the inlet air into the gas turbine ($C_C$). Path 1 to 2 is the heat absorbed by the inlet air from the boiler air heater ($Q$). Points 2 to 3 shows the combustion process in the gas turbine ($n_H H_E$). States 3 to 4 is the power producing hot gas expansion in the gas turbine ($E_C$). Path 4 to 5 represents the combustion of gas turbine exhaust and more fuel in the boiler ($n_H H_B$), 5 to 6 is the heat input into the steam circuit ($V_C$), 6 to 7 is the heat absorbed by the air heater ($Q$), 7 to 8 is a
Figure 6  Unfolded Temperature Enthalpy Diagram - Combined Cycle (4)
heat recovery stage (R), and finally Path 8 to 0 is the heat
exhausted to the atmosphere ($Z_c$).

The energy balance can be written as follows:
\[ C + Q + n_H H_G - E + n_H H_B - V_C - Q - R_C - Z_C = 0 \]  
Eq. 4
Solved for $V_C$, the heat absorbed by the steam, yields:
\[ V_C = n_H (H_G + H_B) - Z_C - (E - C) - R \]  
Eq. 5
The power from this combined cycle system can be written as,
\[ P = n_{EL} (E - C) + n_{TH} V_C + n_R R - P_{AUX} \]  
Eq. 6
where $n_{EL}$ is the efficiency of the gas turbine generator set and
$n_R$ is the efficiency at which the waste heat is recovered.

To compare the two systems, the following assumptions will
be made (1).

1. The pressure and temperature of the live steam and the
temperature of the vacuum and feed water systems are
equal in both cases.
2. The thermal efficiencies of the steam turbines are equal
in both cases.
3. The fuel input for both systems is the same. Therefore,
\[ H_G + H_B = H_S \]
4. The exhaust gas losses are equal. Therefore,
\[ Z_S = Z_C \]
5. The auxiliary power consumed by the fans in the steam only system is set equal to the reduction of power output of the gas turbine. The reduced gas turbine output is due to its operation into a higher backpressure than if it was exhausted directly into atmosphere.

6. The airflow through both systems is constant and equal. From the previous assumptions, energy relations may be written as:

\[ V_c = n_H S - Z - (E - C) - R \] Eq. 7

Combining Equation 7 with Equation 2,

\[ V_c = V_s - (E - C) - R \] Eq. 8

The power equation (From Equation 6) may be written as:

\[ P = n_{EL}(E - C) + n_{TH} [V_s - (E - C) - R] + n_R R - P_{AUX} \] Eq. 9

and the net increase in output of the combined system over the steam only system is

\[ P_C - P_S = (n_{EL} - n_{TH})(E - C) - (n_{TH} - n_R) R \] Eq. 10

Equation 10 illustrates that a greater output margin can be realized by selecting a gas turbine generator set that has low compression losses with good expansion characteristics. Also, optimum generating efficiency is imperative. A good recuperation efficiency is essential to force the second term to zero. Normally the recuperation efficiency is not nearly as good as the thermal efficiency so the recuperative section requires special attention.
With the selection of proper equipment, substantial power output gains may be realized using combined cycle systems.

Combined cycle systems are not restricted for use only with gas turbine and steam cycles. Many industries today have thermal requirements that could be met more efficiently through the use of combined cycle techniques. Industries with thermal requirements or process steam requirements can make use of combined cycles with heat recovery. A gas turbine can be used as a prime mover for a base loaded generator. The turbine exhaust may be passed directly into an oven for heating or drying. Once again, it may be supplemented by the addition of fuel and fired for higher temperatures. For drying oven application, the exhaust can be used without any type of processing provided the temperature is high enough. Gas turbine exhaust inherently is clean and dry.

For heating requirements, a low pressure heat recovery steam generator would be used in the exhaust stream. The steam could be used for building heating, steam powered drives, steam control, or any other low pressure steam requirement.

A more recent combined cycle combination utilizes a gas turbine with a refrigeration cycle. This combination is schematically shown in Figure 7. The gas turbine in this application operates as previously described. The refrigeration cycle uses Freon 11, 12, 21, or 114 as a working fluid.
Figure 7  Combined Cycle Gas Turbine and Low Temperature Refrigerant Turbine (5)
illustrated in the figure, the Freon follows a path similar to water in a steam cycle. It takes on heat in the intercooler and waste heat exchanger, is expanded to provide power in the refrigerant turbine and is condensed and pumped back through the cycle. The difference between the steam cycle and refrigerant cycle is the temperature constraints in which they work. The temperature limit for most of the refrigerants suitable for this combined cycle is around 400°F (5). Above these temperatures, gas decomposition takes place. However, higher working temperatures are not needed due to the good heat absorption qualities of the gas at lower temperatures. As a result of these heat absorption properties of the gas, high efficiencies may be achieved in the heat recovery stages.

In this type of combined cycle, the two distinct cycles do not share the same temperature ranges. The gas turbine limits are approximately 800 to 1500°F, temperatures in the regenerator range from 400 to 800°F and refrigerant limits are 100 to 400°F. The heat recovery works as follows. The high temperature combustion exhaust flows out of the gas turbine. It flows to the regenerator where heat is transferred to the turbine inlet air. The turbine inlet air is heated from compression, so there is a limit to the amount of heat that should be transferred from the exhaust gases. The exhaust flows out of the regenerator. It still is at an elevated temperature and has substantial heat
recovery potential. As it passes through the waste heat exchanger the Freon absorbs the last amount of heat in the exhaust stream. Due to its inherent properties, the Freon is able to efficiently extract a very high percentage of the remaining heat.

Once the heat is transferred to the Freon, the now high energy Freon starts its cycle. It is expanded in the refrigerant turbine to produce mechanical energy, condensed and reheated to start the cycle over again.

Due to the temperature ranges that various parts of this combined cycle operate in, very high efficiencies may be realized. Even when applied to small units that are applicable to industrial or commercial requirements, the gas turbine/refrigerant turbine combined cycle may yield efficiencies far superior to single units.
IV. COST ANALYSIS

Cogeneration systems have proven to be quite energy efficient. However, any system that is to attain wide usage in large industry must also be cost efficient. The recovery of capital investment in three to five years is essential. Therefore, any new equipment must show such a return on paper before being considered.

The rate at which capital investment may be recovered on cogeneration equipment can be determined by considering four primary and two secondary variables (6). The primary variables are: (Costs based on 1980 energy prices)

1. Utility Electric Rate ($/kwh) - This is the composite rate which includes energy charge, demand charge, taxes and any other charge that is applicable. This rate may be a function of a rate structure which is controlled by the utility.

2. Annual Utilization (%) - This is the percentage of the year that the system is in full operation. It is calculated as,

\[
\text{Annual Utilization} = \frac{\text{Annual Hours of Operation}}{8760 \text{ hours/year}}
\]

As with most investments, return increases with increased utilization. As indicated previously, maximum efficiency occurs with the generator fully loaded. Optimum operation would therefore call for full load operation for as many hours of the year as possible.
3. Fuel Cost ($/million Btu) - Cost of generated electricity is a direct function of fuel costs. Fuel costs in dollars per million Btu may be calculated for various fuels.

Number 2 Fuel Oil:

Heating Value = 130,000 Btu/gal.

Fuel Cost = $1.20/gal.

Fuel Cost ($/mm Btu) = \frac{1,000,000}{130,000} (1.2) = \$9.23/\text{mm Btu}

Natural Gas:

Price = \$4.50 \text{/1000 CFM}

Heat Content = 1000 Btu/CFM

Fuel Cost ($/mm Btu) = \frac{4.50}{(1000)(1000)} = \$4.50/\text{mm Btu}

4. Installed Cost of Cogeneration System ($/kw) - Precise costs of installation will vary due to site conditions, labor costs and geographical locations. Average values are usually used for preliminary estimates.

The secondary variables for calculating payback are listed below:

1. Net Fuel Rate (NFR) for Generated Electricity (Btu/kwh) - NFR is defined as the incremental fuel required to generate electricity credited by the fuel value of the heat recovered from the exhaust. The Btu value of the usable exhaust heat is subtracted from the
total amount of fuel burned by the turbine and then
adjusted by the generator output. All losses in the
heat recovery equipment must be accounted for.

\[ NFR = \frac{(\text{Turbine Fuel}) - (\text{Fuel Value of Heat Recovered})}{\text{Generator Output}} \]

Net fuel rates vary depending upon methods used for heat
recovery and generator loading. Typical values for some
of the modern units range from 4000 to 6000 Btu/kwh.
These values compare favorably to utility net fuel rates.

2. Maintenance Costs - Maintenance is always required on any
industrial installation. It is primarily a function of
normal operating procedures. Increased maintenance costs
would correspond to operating procedures calling for
frequent system start up and shutdown. Maintenance costs
would decrease with greater utilization and would be
lowest for continuous operation. Typically these costs
are about $0.0018/kw.

To illustrate the economic analysis, a specific example will
be used. This example is typical of an application that may be
used by any vertically integrated steel plant. Heating and
treating furnaces have high thermal requirements. They are well
suited to cogeneration techniques because the temperature required
is higher than that of the exhaust gas. For this application, the
exhaust flow from the gas turbine would be used as high temperature
combustion air for furnaces. Extra fuel would be added to the stream and refired to attain the higher temperatures required. One gas turbine could be used to provide exhaust heat for a few separate furnaces. This would allow furnaces to be taken out of service for maintenance without adversely affecting overall efficiency.

At most steel plants coke is used as a fuel for blast furnaces. If the coke making facilities are on site, gas turbine fuel costs may be reduced by using the by-product gas from the coke making process to fire the gas turbine. In this example, it will be assumed that the cogeneration gas turbine will burn a mixture of coke gas (by-product gas) and natural gas.

Proceeding with the example:
Utility Composite Electric Rate = $0.03/kwh
Annual Utilization:

21 shift per week operation
1 day of downtime per quarter

\[
\text{Utilization} = \frac{(7)(24)(52)-4(24)}{8760} = 96\%
\]

Fuel Cost - 50% mixture of coke gas with an energy content of 500 Btu/CFM and natural gas with 1000 Btu/CFM. For this process there is no cost for the coke gas. The cost for natural gas is $4.50/mm Btu. After blending, the resulting fuel cost is $3.00/mm Btu.
Installed Cost = $400/kw for a 7500 kw unit

Recoverable Heat = 55 mm Btu/hr. for furnace operation

Maintenance Cost = $0.0018/kwh

Net Fuel Rate = 4500 Btu/kwh

Cost of Generated Electricity = Fuel Rate x Fuel Cost + Maintenance

\[
\text{Cost} = (4500)(3.00)10^6 + 0.0018
\]

\[
= $0.0153/kwh
\]

Savings = Utility Rate - in-house generating cost

\[
= $0.03 - $0.0153 = $0.0147/kwh
\]

The annual savings from Figure 8 is shown as $126/kw.

Therefore, total yearly savings for the 7500 kw cogeneration unit is almost $1.7 million.

Simple Payback Period = Installed Cost per kw/Annual Savings per kw

\[
= 400/126 = 3.2 \text{ years}
\]

The payback period falls within the allowed three to five years required by industry and so the capital investment could be justified.
Figure 8  Economic Evaluation Chart (6)
V. CONCLUSION

Cogeneration systems are proving to be very efficient means for producing electricity and satisfying heat requirements at the same time. It is to both utility's and industry's benefit to consider wider use of these systems. Not only does cogeneration provide a favorable payback period for capital investment and result in future energy savings continuity, but more importantly increased application would insure extended availability for current energy sources. This would provide additional time for researchers to develop new safe alternative energy sources.

The greatest potential for energy savings is in American industry. Large vertically integrated industries have increasing amounts of outdated, energy inefficient facilities which waste more thermal energy than is used. A properly applied cogeneration system with current state-of-the-art equipment would not only decrease thermal waste but would turn the facility into a more cost efficient operation.

In these days when utilities and industries are making large capital investments on federally mandated pollution control equipment, it would seem that investment consideration for cogeneration systems would be relevant (unlike pollution control systems which require a capital investment with increased operating costs and produce no payback, cogeneration systems provide an energy savings with resultant payback). Instead of being federally mandated,
cogeneration is being promoted with tax incentives. Cogeneration systems are being recognized as efficient users of current sources of energy. With wider usage, such systems could play a major role in the ultimate goal to make the United States energy self-sufficient.
VI. LIST OF REFERENCES


VII. BIBLIOGRAPHY

Articles


VIII. VITA


Following graduation from Lehigh, Mr. Burns entered the employment of Bethlehem Steel Company as an engineer in the Service Division Electrical Department. While working full time, he enrolled in the Bethlehem Steel Educational Assistance Program and continued his education at Lehigh University. He currently works as an electrical engineer in the Engineering and Training Department of the newly formed Control Division.

Mr. Burns resides in Bethlehem, Pennsylvania, with his wife, Susan and fourteen month old daughter, Rochelle.