A Methodology for Assessing MIT's Energy Use and Greenhouse Gas Emissions

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ABSTRACT

This MIT campus emission assessment has been written in response to the City of Cambridge Climate Protection Plan, which calls for a 20% decrease in greenhouse gas emissions from 1990 levels by the year 2010. This greenhouse gas inventory includes all emissions of carbon dioxide, methane, and nitrous oxide due to utility use from fiscal years 1990 to 2003, as well as estimates of transportation and solid waste emissions. It accounts for utilities purchased and utilities produced from the MIT Cogeneration Power Plant. A methodology has been developed to allocate MIT utility plant emissions based on produced electricity, steam, and chilled water. This allows facilities to develop programs that will directly impact the source of highest emissions. In addition, the assessment includes carbon dioxide emissions due to the MIT commuting population from fiscal years 1999 to 2003, and accounts for equivalent carbon dioxide emissions from campus solid waste incineration from fiscal years 2000 to 2003. The 20% reduction target from 1990 emission levels sets a cap on campus emissions of 161,150 equivalent metric tons of carbon dioxide per year. At current levels, a 22% decrease in emissions would be required to achieve this target. Emissions released from utility use account for 90% of the campus emissions, with 9.5% attributed to commuters, and 0.5% due to campus solid waste. Therefore, reducing the amount of emissions caused by utility production and purchasing would have the largest effect on reducing the total campus greenhouse gas emission rate.

A thermodynamic availability flow analysis has also been conducted on the gas turbine and heat recovery steam generator system of the MIT cogeneration power plant. Availability losses within the system were targeted, and therefore appropriate actions can be made to decrease losses and increase component and plant efficiencies. As production efficiencies are maximized, fuel use, and thus emissions are minimized. From fiscal years 1998 to 2003, the gas turbine efficiency, based on the higher heating value, remained approximately constant at 24%. The heat recovery steam generator effectiveness has decreased 11% from 42% to 37%. It has been shown that the decrease in the heat recovery steam generator's performance can be attributed to fouling effects on the heat transfer surfaces between the hot exhaust gases and the water stream.

An accurate inventory of MIT's greenhouse gas emissions is a necessary first step in reducing campus emissions. This assessment targets emissions generated by the utility, transportation, and solid waste sectors, and identifies areas with the greatest potential for reducing campus emissions. This inventory will also continue to allow MIT to evaluate its greenhouse gas emission trends and establish goals that will contribute to the emission reduction target set by the city of Cambridge.

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Chapter 1 Introduction

1.1 Motivation

In November of 2002 an environmental commitment made, by the city of Cambridge to reduce the city's greenhouse gas (GHG) emissions, called the City of Cambridge Climate Protection Plan was released. This document included the city's first GHG emission inventory results for the years 1990 and 1997. It also demonstrated the city's commitment to follow the emission standards set forth by the Kyoto Protocol, which calls for a 20% reduction in 1990 GHG emissions by the year 2010 [1]. This plan outlines specific areas of environmental concern, such as energy, transportation, land use, and waste management, along with specific strategies within each area that may be taken to achieve this goal. The city proposes actions needed to be taken by specific metropolitan sectors; city government, business community, institutions, and residents, realizing that commitment and dedication from all sectors is needed to achieve the city of Cambridge's environmental goal.

1.2 Steps Taken By MIT

As an institution as well as a member of the city of Cambridge community, MIT has always been concerned with its environmental footprint. MIT is involved in a variety of environmental activities ranging from research and curricula, campus environmental initiatives, and environmental, health, and safety (EHS) services. MIT has a campus wide recycling program, incentives to encourage use of public transportation, as well as a green building task force. In response to the recent request by the city of Cambridge, MIT has also begun additional steps towards reducing its own GHG emissions. The fundamental first step in this process is the survey of its own GHG emissions.

This study is the first campus emission inventory. It includes annual emissions of carbon dioxide, methane, and nitrous oxide due to utility use from 1990 to 2003. The emission assessment accounts for purchased utilities as well as utilities produced at the MIT Cogeneration Power Plant, which has been in operation since 1996. Emissions results from a variety of universities illustrate that emissions due to utility use typically account for 80-90% of total GHG emissions and therefore a detailed analysis was done to correctly account for all utility related emissions. Utility emission results are presented in multiple ways to provide useful insight into the behavior of emission trends and to also aid in developing useful strategies to lower emissions. A detailed thermodynamic analysis has also been performed on individual portions of the MIT plant to locate losses within the system so that action can be taken to minimize inefficiencies, thus ultimately lowering fuel use and emissions.

This emission inventory is also inclusive of emissions due to transportation and campus solid waste. The transportation section incorporates commuters with; campus parking permits, bus pass, T-pass, combo bus/T passes, and commuter rail passes. It also includes the MIT campus fleet mainly consisting of vehicles operated by facilities, the transportation office, and MIT police. When analyzing GHG emissions due to commuter transportation only carbon dioxide emissions are considered.

Emissions due to campus solid waste disposal are also considered within this campus emission inventory. MIT utilizes a variety of solid waste techniques such as composting all yard waste, recycling, and waste to energy incineration of all municipal solid waste. Only net metric tons of CO_2 equivalents due to waste incineration are included in the scope of the solid waste sector.

MIT is now one of many institutions in the Northeast that have conducted a campus greenhouse gas inventory. Schools such as Harvard, Tuffs, and University of New Hampshire have also calculated their campus' emission rates and have begun projects that demonstrate their commitment to their reduction goals [2]. MIT is currently working towards its goal and by conducting this campus GHG inventory has initiated the first steps towards achieving this environmental target.

1.3 Background – Climate Change Science

1.3.1 Greenhouse Effect

The greenhouse effect is a naturally occurring process that aids in the heating of the Earth to an average temperature of 60^oF (15^oC). It is this phenomenon that is necessary for life to flourish and without it Earth would be a very frigid and inhospitable place.

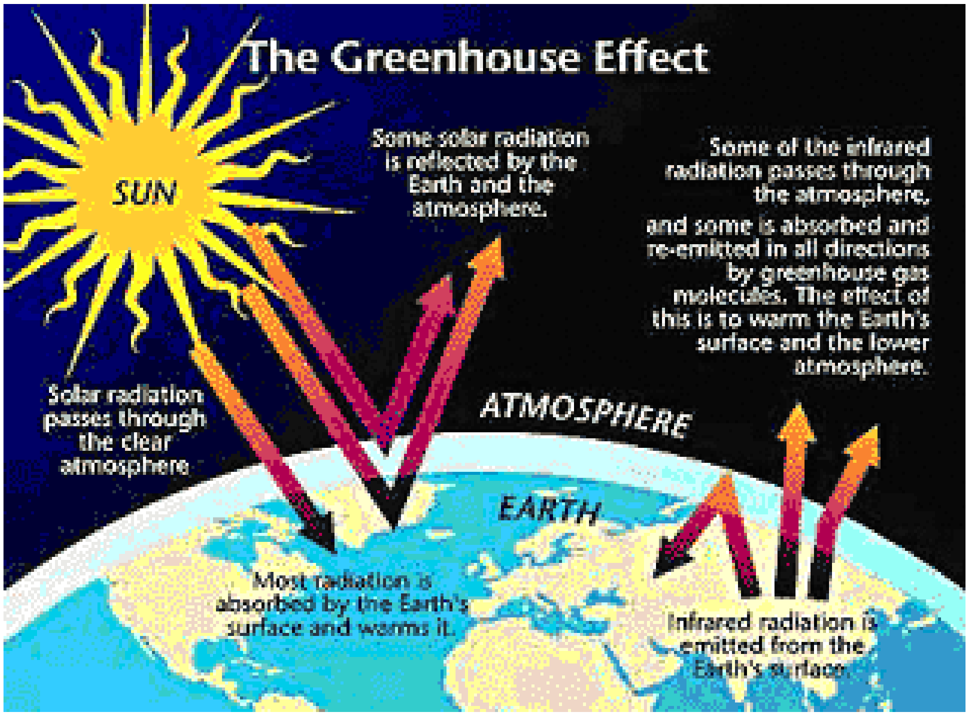

Figure 1-1: Greenhouse Effect [3]

The greenhouse effect begins as shortwave solar radiation from the sun, which can pass through a clear atmosphere relatively unimpeded, enters into the Earth's atmosphere. The presence of clouds and atmospheric particles allow for a portion of this radiation to be absorbed as well as reflected back to space. A majority of the solar radiation that reaches the Earth's surface is absorbed while a small percent is reflected back into the atmosphere. The energy absorbed by the Earth's surface is used for heating the Earth's surface, plant photosynthesis, evaporation of water, and melting of ice caps. Heating of the ground causes the Earth's surface to become a radiator for infrared or longwave radiation generally directed toward space [3]. Gases within the Earth's atmosphere called greenhouse gases absorb most of this energy then re-emit it back to the Earth's surface where the process continues indefinitely until a portion of infrared radiation is absorbed. The end result is a net increase in energy absorbed by the Earth's atmosphere and ground surface. It is this process and end result that creates the phenomenon known as the greenhouse effect.

1.3.2 Greenhouse gases

Naturally occurring atmospheric greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Other very powerful greenhouse gases that are not naturally occurring in the atmosphere include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6), which are generated and used in a variety of industrial processes and devices. Though a majority of the Earth's atmosphere is comprised of oxygen and nitrogen these gases are not considered to contribute to global warming because they are transparent to both the radiation incoming from the sun and the radiation outgoing from the Earth [4]. Additional amounts of the naturally occurring greenhouse gases are released into the atmosphere due to the combustion of fossil fuels as well as other human activities such as deforestation and population growth.

Carbon dioxide is a combustion byproduct of any hydrocarbon fuel (oil, natural gas, coal) that is used for electricity production, transportation, heating and many industrial applications. Carbon dioxide is also released when solid waste, wood, and wood particles are burned. Methane is a byproduct of animal waste, termites, landfills, and oil, coal and natural gas extraction. Methane is released from solid waste landfills during the decomposition of organic waste, and is also released into the atmosphere during gas and oil drilling. Nitrous oxide is released into the atmosphere during the combustion of any fossil fuel, deforestation, biomass burning, and through soil fertilization. While the emission of GHG's is a global problem, in 1997 the United States was responsible for one-fifth of the total global greenhouse gas emissions [3]. The combustion of fossil fuels accounts for 98% of US carbon dioxide emissions, 24% of methane emissions, and 18% of nitrous oxide emissions.

1.3.3 Effects of Global Warming

Increasing atmospheric concentrations of greenhouse gases can affect climate change around the world by increasing the heat absorbing capability of the Earth's atmosphere, which results in what is known as global warming. Therefore, a trend has been seen that correlates the increase in GHG emissions with the increase the global mean temperature. Since the industrial revolution "atmospheric concentrations of carbon dioxide have increased nearly 30%, methane concentrations have more than doubled, and nitrous oxide concentrations have risen by approximately 15%."[3]

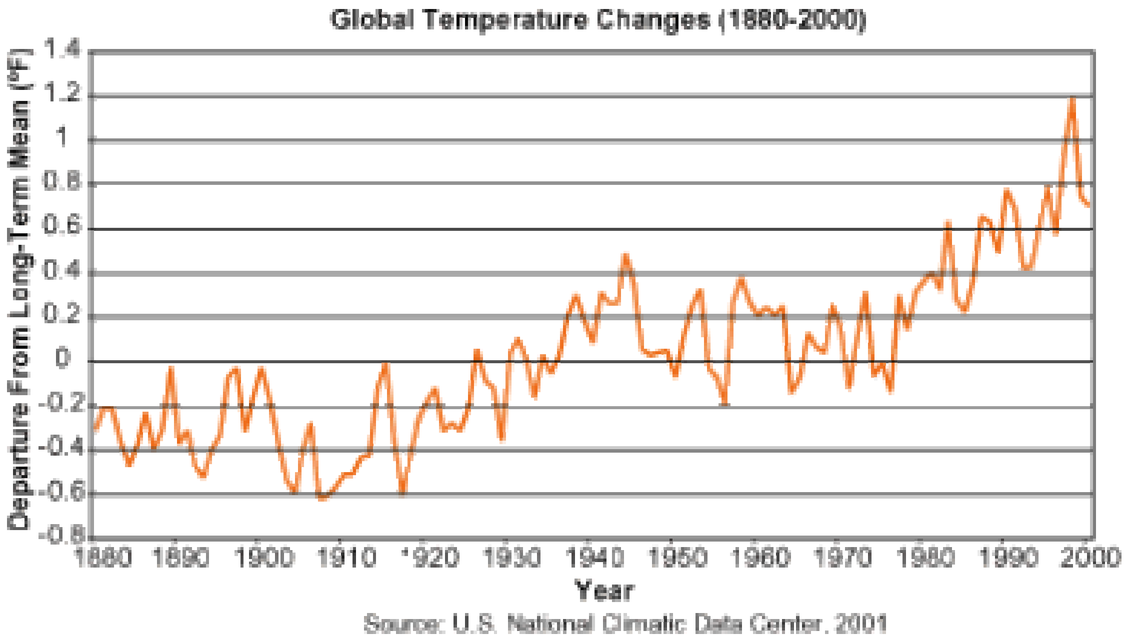

Figure 1-2: Global Temperature Change (1880-2000)

The global mean temperature has risen 0.5-1.0°F since the late 19th century. Scientists estimate that the "average global surface temperature could rise 1-4.5°F (0.6°-2.5°C) in the next fifty years and 2.2°-10°F (1.4°-5.8°C) in the next century", if the current emission trends remain unchanged [3]. Along with increased surface temperature, there are reported decreases in Artic ice glaciers as well decreased snowcaps in the Northern hemisphere. Globally, sea level has risen 4-8 inches over the past century [3]. It is these effects that the scientific community believes are caused by the increase in atmospheric GHG

1.4 Scope – System Boundary

This MIT greenhouse gas inventory includes direct GHG emissions from three main pollution areas; utility use, the campus commuting community, and campus solid waste. Along with an emissions inventory, an analysis of the MIT power plant has also been conducted to assess the plant's performance over an 8-year operating period, from fiscal year 1998 to 2003.

1.4.1 Utility Scope

The analysis of MIT's utility GHG emissions includes the emission of carbon dioxide, methane, and nitrous oxide. It includes all emissions due to purchased and produced utilities from 1990 to 2003. To determine the amount of emissions attributed to purchased utilities, transmission and distribution losses as well as the northeast energy source portfolios are included to account for actual emissions at the regional electric production plant. All utility information is obtained from MIT facilities and from MIT's central plants' database called PI. This analysis does not include indirect emissions due to the collection and transportation of fuel.

1.4.2 Transportation Scope

The transportation scope of this analysis includes estimates of carbon dioxide emissions due to commuters to and from the campus using parking permits and T/bus passes from 1999 to 2003. An average MIT commuter distance is determined from a 2002 Transportation and Parking Survey. The survey includes 80% of parking permit holders and contains residential information that is used to determine an average trip length per person. Information regarding number of bus, subway, and combo passes sold along with the average MIT commuter distance is also used to determine MIT's approximate carbon dioxide emissions due to public transportation use. Needed transportation constants, such as fuel energy content, energy per mile and CO_2 emissions per amount of fuel burned, are obtained from the *U.S. Department of Energy Transportation Energy Data Book Edition 21*. Emissions due to vehicles from various departments within the MIT fleet are also included.

1.4.3 Solid Waste Scope

MIT is an institution that promotes recycling and conservation to minimize campus waste. Currently MIT recycles 22% of its solid waste and composts all of its landscaping/yard waste. The MIT greenhouse gas inventory includes all campus solid waste that is not composted or recycled. MIT's solid waste is collected and transported to a waste-to-energy (WTE) plant where it is incinerated to produce electricity. Burning solid waste to generate electricity displaces additional burning of fossil fuels, and thus emissions, that otherwise would have been emitted to produce the same amount of electricity. Therefore, these avoided GHG emissions are subtracted from the GHG emissions associated with the combustion of the solid waste to produce a net GHG emission rate due to MIT's solid waste. Data regarding waste disposal and recycling trends is obtained from the Office of Environmental, Health, and Safety.

1.4.4 Plant Performance Scope

A thermodynamic available energy flow analysis has also been conducted on the gas turbine and heat recovery steam generator system. Availability losses within the system are identified so that appropriate actions can be made to decrease losses and therefore increase production efficiencies. As production efficiencies are maximized, fuel use, thus emissions are minimized.

1.5 Topics To Be Covered

Analyzing a systems GHG emissions and utility plant performance takes the cooperation of multiple departments for the needed information as well as an understanding of thermodynamic principles and their applications. In the following chapters, applicable thermodynamic theory, emission calculations, and emission separation methodologies, are discussed. Discussion of utility emissions are emphasized as these account for over 85% of the total campus emissions and, therefore, improvement in this sector would have the greatest benefits to lower campus emissions. The transportation and solid waste sector emissions discussions are based on approximate methodologies on a shorter time scale, as accurate data in these sectors is only available for recent years. A detailed thermodynamic analysis of both the plant energy use and availability streams will also be used to show plant performance trends and areas where improvements can be made.

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Chapter 2 Utility Greenhouse Gas Emissions

The MIT cogeneration power plant produces steam, electricity, and chilled water for over one hundred MIT buildings. Though the plant provides approximately 80% of the total annual campus electricity demand, additional electricity is purchased when the campus demand exceeds the plants capacity. Therefore, MIT is responsible for utility emissions due to the combustion of hydrocarbon fuels by the MIT plant, and due to the energy utilized for electricity the campus purchases. The following sections will discuss the approach and assumptions made to determine the amount of GHG's emitted due to the campus utility use, along with a methodology for apportioning the amount of GHG's emitted to utility product produced for a cogeneration plant. The latter allows facilities to target campus projects that can have the greatest effect on the amount of GHG's the campus emits, thus enabling the campus to work towards the 20% City of Cambridge's Climate Protection emission reduction goal.

2.1 Greenhouse Gas Emissions Calculation Background

The amount of GHG's emitted due to the combustion of hydrocarbon fuels is dependent upon the MIT plants fuel type and amount. The MIT plant generates electricity, steam, and chilled water by burning hydrocarbon fuels consisting of natural gas and both No. 6 and No. 2 oil. Natural gas consists mainly of methane (generally over 85%) and varying amounts of ethane, propane, and butane. Due to composition variations, the higher heating value for natural gas varies from 950 to 1,050 BTU/scf or by 10%. No. 6 oil is generally referred to as a residual oil, while No. 2 is known as distillate oil. Distillate oils are more volatile and less viscous than residual oils. Emissions from hydrocarbon fuels are dependent on the grade and composition of the fuel being burned. Carbon dioxide, methane, and nitrous oxide are all greenhouse gases that are produced during the combustion of a hydrocarbon fuel. Independent of the combustion configuration, nearly 99% of all fuel carbon is converted into CO_2 during the combustion process[5]. Methane and nitrous oxide emissions vary with fuel type and firing configuration. They also vary according to combustion temperatures and with the amount of air used during combustion. Because emission levels vary depending on a wide range of variables, industry wide emission factors have been developed to provide a means for calculating source specific emission levels.

2.1.1 AP-42 Emission Factors

Emission factors (EF) are a representative value that attempts to relate the quantity of a pollutant released into the atmosphere with an activity associated with the release of that pollutant. They are based upon emission testing performed at similar facilities and therefore, are averages of available industry-wide data. Table 2-1 lists the emission factors for various fuels for stationary combustion sources and combustion in electric utility plants [5].

GHG Emission Factors (g Pollutant/MMBTU)				
	Methane	**Nitrous Oxide**	**Methane**	**Nitrous Oxide**
	Stationary Sources		**Electric Utilities**	
Fuel	Factor		Factor	
No 2 Oil	0.7	0.357	0.91	0.36
No 6 Oil	0.7	0.357	0.91	0.36
Natural Gas	1.1	1.1	1.1	1.1
Coal	0.75	0.298	0.75	0.298
Propane	1.08	4.86	-	-

Table 2-1

While experimental data is needed to determine the emission factors for methane, nitrous oxide and other gas, the emission factor for carbon dioxide is generally more well known. For a stoichiometric or lean combustion process, approximately 99% of the carbon content in the fuel is converted to carbon dioxide. Table 2-2 lists the carbon emission factors for a variety of fuels.

Carbon Emission Factors (Metric Tons C/MMBTU)	
Fuel	Factor
No. 2 Oil	0.0225
No. 6 Oil	0.0225
Natural Gas	0.01633
Coal	0.0265
Propane	0.01951

Table 2-2

While an emission factor allows one to calculate the amount of pollutant created due to combustion, a pollutants global warming potential represents a pollutants ability to enhance the greenhouse effect.

2.1.2 Global Warming Potentials

The intensity of a gas' ability to trap radiation and contribute to the greenhouse effect varies depending on the greenhouse gases in question. The concept of a global warming potential (GWP) has been developed to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to CO_2. Therefore as a reference gas, CO_2 has a GWP equal to one [3]. Technically the GWP is defined as the ratio of the time integrated radiative forcing from the instantaneous release of 1 kg of a trace substance relative to that of 1 kg of reference gas [6]. Table 2-3 provides a list of GWP values that are used to determine the amount of equivalent carbon dioxide emitted during a combustion process due to the release of other GHG's [7].

Global Warming Potential (GWP) (MTCD/kg Pollutant)	
Carbon Dioxide	1
Methane	21
Nitrous Oxide	310
HFC-23	11,700
HFC-32	2,800

Table 2-3

2.2 Greenhouse Gas Calculation Methodology

2.2.1 Emission Calculations For Hydrocarbon Fuels

The amount of GHG's emitted due to the combustion of a hydrocarbon fuel is directly proportional to the amount of fuel burned. The needed parameters to calculate the amount of CO_2 and CO_2 equivalents due to CH_4 and N_2O include:

1. Amount and type of fuel burned
2. The fuels' heating value (either HHV or LHV)
3. The EF and GWP's for CH_4 and N_2O to determine the equivalent amount of CO_2

The following are steps needed to determine the amount of CO_2 emissions due to burning a hydrocarbon fuel:

Step 1: Determine the amount of chemical energy consumed during the combustion process

$$Energy\ Consumption = Amount\ Fuel \times HHV \qquad \text{Eq. 2-1}$$

Step 2: Determine the amount of carbon in the fuel that is converted to CO_2

$$Carbon\ \ Content = Energy\ Consumption \times Emission\ Factor \qquad \text{Eq. 2-2}$$

$$Metric\ Tons\ of\ CO_2 = Metric\ Tons\ C \times \underbrace{\frac{44\ Metric\ Tons\ CO_2}{12\ Metric\ Tons\ C}}_{Conversion} \qquad \text{Eq. 2-3}$$

Step 3: Determine the amount of CO_2 equivalents due to the production of any other GHG, using methane as an example

$$CH_4\ Produced = Energy\ Consumption \times CH_4\ Emission\ Factor \qquad \text{Eq. 2-4}$$

$$Metric\ Tons\ of\ CO_2\ Equivalents\ due\ to\ CH_4 = CH_4\ Produced \times GWP \qquad \text{Eq. 2-5}$$

A complete example calculation for fiscal year 2000 can be found in Appendix A

2.2.2 Purchased Electricity

MIT's purchases electricity from NSTAR when the campus' electricity demand exceeds the cogeneration plant's capacity. MIT has two busses, 13A and 13B, that are the main feeders for the campuses electrical power. These busses are responsible for converting purchased power to 2.4 kV that is then distributed to the campus. The amount of GHG emissions due to this additional electricity use is also included within the system boundary. To properly calculate the amount of GHG's associated with purchased electricity one needs to work backwards from the known purchased electricity amount to the actual amount of energy that was consumed at the regional power plant where the purchased amount of electricity is produced. The first step in doing this is to determine how much electricity is first produced at the regional power plant before transmitted to MIT. To provide a given amount of electricity, power plants have to produce larger amounts of electricity than is actually delivered due to distribution and transmission losses. The New England power grid network, distribution and transmission losses are approximately 8%. GHG emissions also depend on the type of fuel or power generating technique used to produce a given amount of electricity. Power plants use a variety of sources to produce electricity and therefore, knowing the energy source portfolio for ones regional power plants is necessary. New England energy portfolio, in order of decreasing use, consists of coal, natural gas, distillate oil, nuclear power, renewable energy, and hydroelectric. These sources vary due to availability and price. To determine the needed energy portfolio the average annual

Massachusetts's electricity energy portfolio from 1990-2003 is used [8]. Along with knowing how electricity is produced it is also necessary to know the efficiency of production by each energy source. This will allow one to calculate the total energy consumed at the power plant by energy source to produce a given amount of electricity. Table 2-4, first provides an example of the average annual Massachusetts energy source portfolio and second, includes a list of average efficiency's for power production based on energy source [8].

% Source of Electricity Production		**Efficiency of Power Production (%)**
Fuel		
Coal	28.8%	34.0%
Natural Gas	27.6%	41.2%
Distillate Oil (1 - 4)	22.6%	34.2%
Residual Oil (5 - 6)	0.0%	34.2%
Hydroelectric	0.9%	35.0%
Nuclear	14.2%	34.0%
Renewable	5.9%	35.0%

2000 energy source and efficiency of power production
www.transportation.anl.gov:80/ttrdc/greet/index.html

Table 2-4

Once the total energy consumed by a source is known an appropriate emission factor can then be used to calculate the amount of GHG's emitted. As emission factors are based upon average experimental data they therefore are dependent upon type of industry and combustion process. Table 2-5 lists the EF for the three GHG's considered in this analysis based on the electric industry utility data.

GHG Emission Factors for Electric Utilities			
Fuel	**Carbon Emission Factors (Metric Tons C /MMBTU)**	**Methane Emission Factors (g/MMBTU)**	**Nitrous Oxide Emission Factors (g/MMBTU)**
Coal	0.027	0.75	0.298
Natural Gas	0.01633	1.1	1.1
Distillate Oil (1 - 4)	0.0225	0.91	0.36
Residual Oil (5 - 6)	0.0225	0.91	0.36
Hydroelectric	0	0	0
Nuclear	0	0	0
Renewable	0	0	0

Table 2-5

The following steps are needed to calculate the amount of CO_2 and CO_2 equivalents emitted due to purchasing electricity:

Step 1. Determine the amount of electricity produced at the central power plant.

$$Electricity\ Produced\ at\ Power Plant = \frac{Electricty Purchased}{1 - \%losses} \quad \text{Eq. 2-6}$$

$$Produced\ Energy_{Elec} = Electricity\ Produced\ at\ Power\ Plant \times \frac{3413\ BTU}{1\ kW\text{ - }hr} \quad \text{Eq. 2-7}$$

Step 2. Attribute the amount of electricity produced to electricity generating source (coal, oil, hydro, ect.)

$$Produced\ Elect by\ Source = Total Produced\ Electricity \times \%Elect. Production\ Source \quad \text{Eq. 2-8}$$

Step 3. Determine the amount of energy consumed by a source to produce a given amount of electricity. This takes into account the efficiency of power production by a specific sector (i.e. burning natural gas or hydroelectric)

$$Plant\ Energy\ Consumption_{source} = \frac{\Pr oduced\ Elect.by\ Source}{Efficiency\ of\ Source} \quad \text{Eq. 2-9}$$

One now has the total amount of energy needed to produce a given amount of electricity purchased separated by type of energy production source.

Step 4. Aside – The sum of all the $plant\ \ energy\ \ consumption_{source}$ gives the total amount of energy the power plant consumed to produce a the given amount of electricity purchased

$$Total\ Plant\ Energy\ Consumption = \sum Plant\ Energy\ Consumption_{source} \quad \text{Eq. 2-10}$$

Step 5. Determine the amount of carbon emitted by each source

$$Carbon\,Content_{source} = Plant\,Energy\,Consumption_{source} \times EF_{source}$$
$$Total\,Carbon\,Content = \sum Carbon\,Content_{source} \quad \text{Eq. 2-11}$$

Once the energy consumption by source and the total carbon content are known, the next step would be to determine the total amount of CO_2 and CO_2 equivalents emitted due to methane and nitrous oxide. This can be done by using equations 2-3 through 2-5. An example of this for fiscal year 2000 can be found in appendix A.

2.3 Separation of Plant Emissions by Utility Product

The amount of emissions emitted by the MIT power plant can also be apportioned by produced utility products; electricity, steam, and chilled water to enable facilities to target projects on campus that can most greatly affect fuel use and thus campus emissions. In a typical power plant this would be a simple task as the fuel input directly produces one utility product. But in a cogeneration plant, one fuel input can produce multiple utility products. For example, if natural gas is burned in the combustion turbine it is initially used to produce electricity and then the remaining thermal energy is used to produce steam. That steam is then divided to either run steam driven chillers for chilled water production or sent out for campus use. The question then arises, which utility product is responsible for the emission of a given amount of GHG's? Therefore, a methodology was developed to apportion the appropriate amount of emissions to each utility product produced. This approach bases emission apportioning on energy use. A detailed thermodynamic analysis of the MIT power plant provides the necessary information to accomplish this from fiscal year 1998 to 2003. Component energy losses are apportioned according to the percentage of energy used per stream. Once energy streams throughout the system are determined, emissions from each fuel source are allocated according to each streams energy percentage from its origin. To determine the energy flows for any plant schematic the thermodynamic principle is applied;

"All systems whether man made or naturally occurring in nature follow a common principle that energy is neither created nor destroyed but rather converted from one energy form to another [9]."

For an open system with steady-state flow through a control volume (CV) the first law of thermodynamics takes the form,

$$\dot{Q} - \dot{W}_{Shaft} = \sum_{out} \dot{m}_e (h + \frac{V^2}{2} + gz)_e - \sum_{in} \dot{m}_i (h + \frac{V^2}{2} + gz)_i \quad \text{Eq. 2-12}$$

The equation 2-12 is applied to determine the energy flows across any system or component boundary. The following section describes the MIT cogeneration power plant schematic, major components, and governing equations that enable one to determine each streams energy flow and system efficiencies.

2.3.1 MIT Cogeneration Power Plant

MIT's cogeneration power plant began producing electricity, steam, and chilled water for the campus in July 1995. A general definition of a cogeneration plant, also known as a combined heat and power plant (CHP), is a plant that simultaneously generates two different forms of useful energy, mechanical and thermal, from a single primary energy source. MIT's cogeneration plant utilizes the waste heat in the turbine exhaust gas to produce a majority of the campus steam. The efficiency of a CHP plant can be expressed in several ways creating the possibility for misleading or faulty comparisons. The Environmental Protection Agency (EPA) has therefore defined the efficiency of a CHP plant to equal "the sum of the net electrical output and the net useful thermal output of the CHP system divided by the fuel consumed by the CHP plant"[10]. Compared to conventional power plants a cogeneration plant can increase the overall plant efficiency to over 70%.

The major components of the MIT plant currently include:

- 20 MW Gas Turbine (GT)
- Heat Recovery Steam Generator (HRSG)
- 3 Boilers
- 6 Steam and 3 Electric Driven Chillers

Below is a schematic of the power plant:

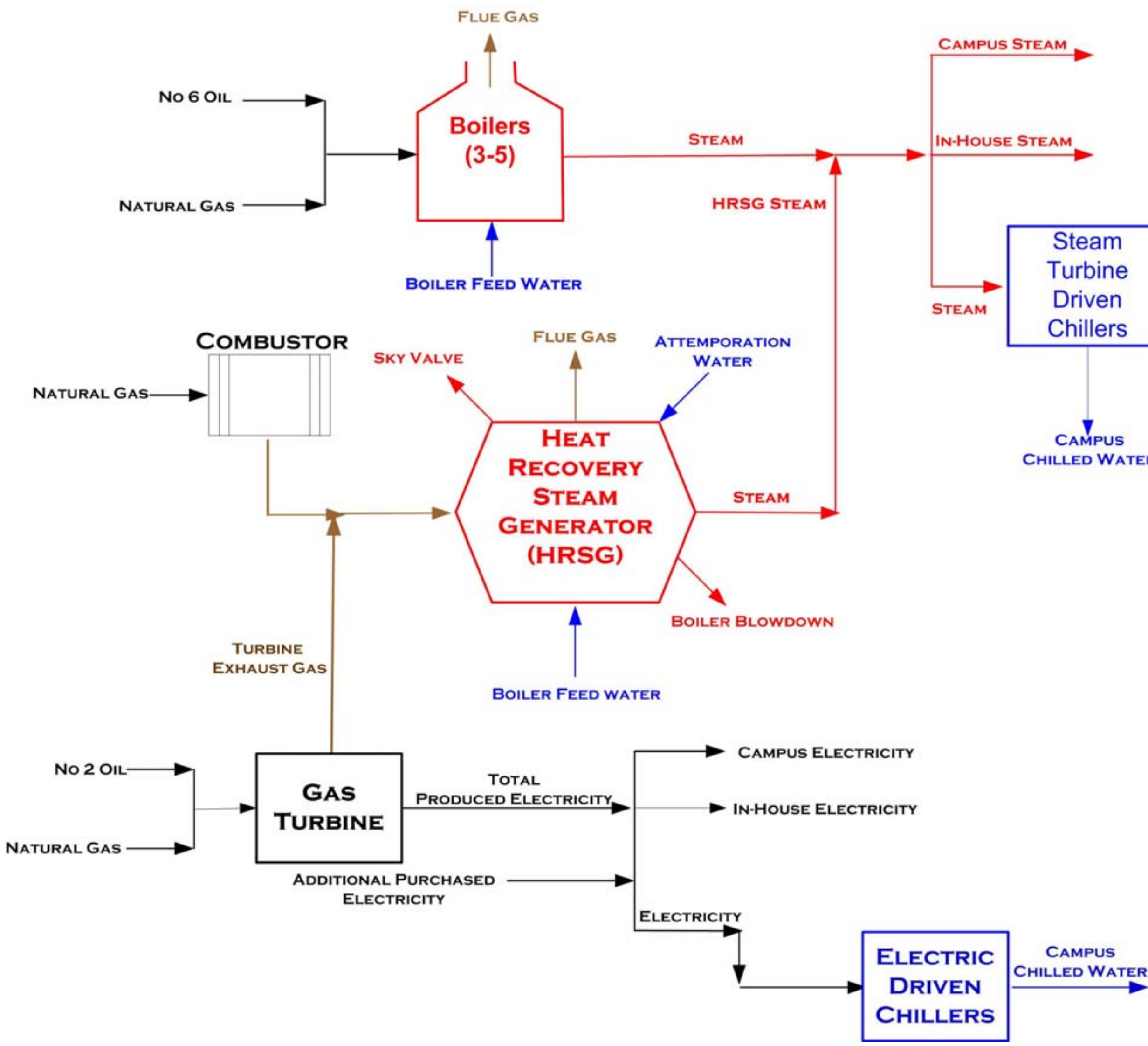

Figure 2-1: MIT Cogeneration Plant Schematic

Fuel use and output parameters are known and used to determine all other unknowns. In addition, the availability analysis performed only considered the combined system of the combustion turbine and heat recovery steam generator. The following sections will discuss the major component performance specifications and governing thermodynamic equations.

Combustion Turbine

The MIT plant operates a ABB GT10A Combustion Turbine Generator set that has an output of 21 MW. The rated electrical heat rate is 11,400 BTU/kWh based on the fuels lower heating value (30% efficiency), a maximum exhaust gas temperature of approximately 1050^{o}F (834 K), and the exhaust flow is approximately 648,000 lb_m/hr. It also has an AC generator and gear efficiency of 98%. It utilizes a premixed, swirling combustion flow to generate low NO_x emission levels. Water injection into the combustion zone is also used to cool the flame temperature to approximately 2300 ^oF (1530 K) which also helps in the reduction of NO_x levels. This combustion turbine operates on both natural gas and No. 2 oil. It generates approximately 80% of the campus' yearly electricity use; when additional electricity is needed it is purchased and distributed by NSTAR and Cambridge Electric respectively. The approximate air-fuel ratio is 0.295 and 0.289 depending on the burning of No. 2 oil or natural gas respectively. Below is a schematic of a combustion turbine and its T-s diagram:

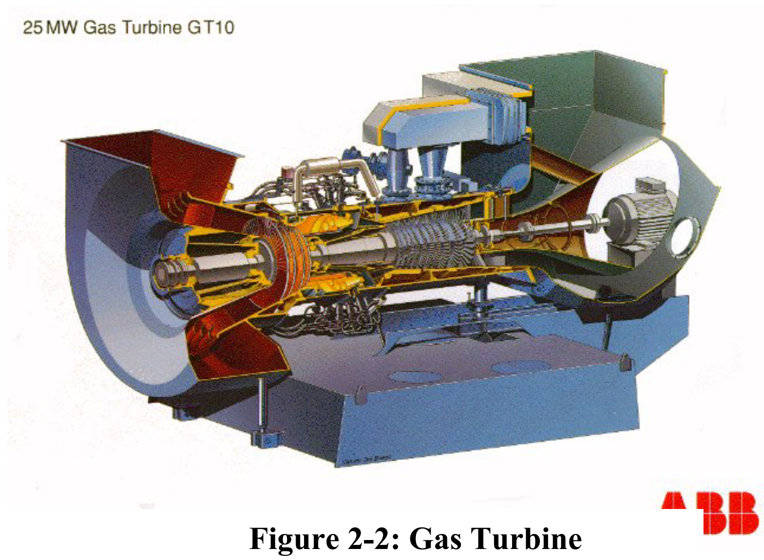

Figure 2-2: Gas Turbine

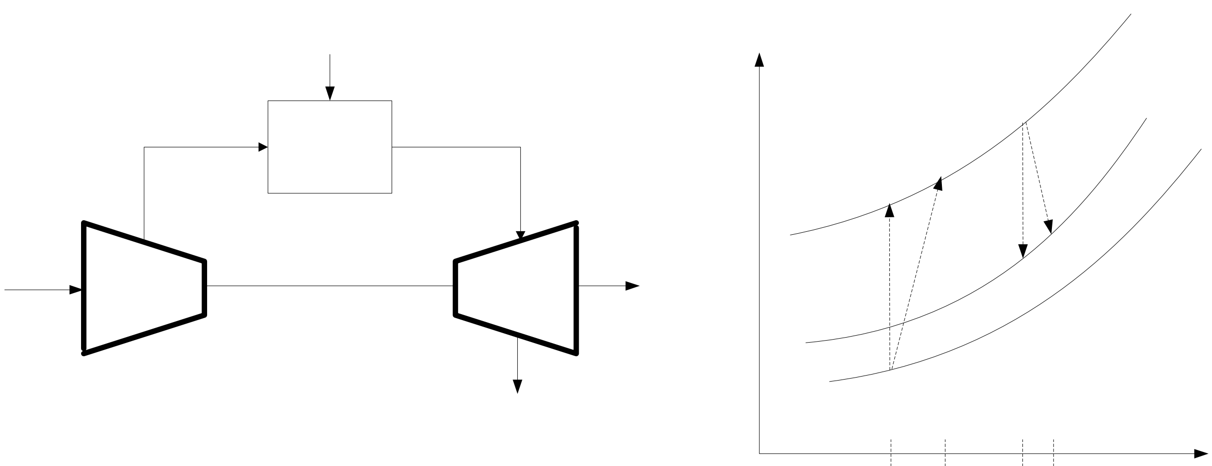

Figure 2-3: Gas Turbine and T-s Diagram

The following are equations needed to evaluate the performance of the combustion turbine divided by components:

Compressor

Assumptions: negligible kinetic energy changes and heat transfer

$$\dot{W}_C = \dot{m}(h_{out} - h_{in}) = \dot{m}_{air} c_{p_{air}} (T_{out} - T_{in})$$ Eq. 2-13

$$\eta_C = \frac{\dot{W}_{ideal}}{\dot{W}_{actual}} = \frac{T_{2s} - T_1}{T_2 - T_1} = \frac{\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1}{\left(\frac{T_2}{T_1}\right) - 1}$$ Eq. 2-14

Combustor

Assumptions: negligible kinetic energy changes, constant pressure device, adiabatic combustion, and constant mass flow rate.

$$\dot{Q}_{in} = \dot{m}_{fuel}(h_{out} - h_{in})$$
$$\dot{Q}_{in} = \dot{m}_{fuel} \times Fuel\ Higher\ Heating\ Value$$ Eq. 2-15

The quantity of heat generated by complete combustion of a unit of specific fuel is termed the heating value, heat of combustion, or caloric value of that fuel. It can be determined by measuring the heat released during combustion of a known quantity of the fuel in a calorimeter. Burning fuel produces both CO_2 and H_2O, and depending on the state that water is in, vapor or liquid, the lower and higher heating value is used. The higher heating value (HHV) includes the latent heat of vaporization and is determined when water vapor in the fuel combustion is condensed. If the water is in the gaseous form then the lower heating value (LHV) is used, and the latent heat of vaporization is not included. The two values are related by the following equation which includes the ratio of the mass fraction of water in the combustion products and the total mass of the fuel burned [11],

$$Q_{HHV} = Q_{LHV} + \frac{m_{H2O}}{m_{Fuel}} h_{fg\ H2O}$$ Eq. 2-16

In the United States the convention is to use the higher value. Deciding which heating value to use is arbitrary and the only warning is the need to be consistent throughout the calculation. For this analysis the HHV is used to stay consistent with MIT plant engineers and facilities. A list of HHV and LHV for a variety of fuels can be found in appendix B.

Turbine

Assumptions: neglect kinetic energy changes and heat transfer losses

$$\dot{W}_T = \dot{m}(h_{in} - h_{out}) = \dot{m}c_{p_{EG}}(T_{in} - T_{out}) \qquad \text{Eq. 2-17}$$

$$\eta_T = \frac{\dot{W}_{actual}}{\dot{W}_{ideal}} = \frac{T_3 - T_4}{T_3 - T_{4s}} = \frac{1 - \left(\frac{T_4}{T_3}\right)}{1 - \left(\frac{P_4}{P_3}\right)^{\frac{\gamma-1}{\gamma}}} \qquad \text{Eq. 2-18}$$

Combustion Turbine

Assumptions: assume constant mass flow rate and neglect heat transfer losses

$$\dot{W}_{Elec\,Out} = \dot{m}(h_3 - h_4) - \dot{m}(h_2 - h_1) = \dot{m}c_{P,EG}(T_3 - T_4) - \dot{m}c_{P,AIR}(T_2 - T_1)$$

$$\eta_T = \frac{\dot{W}_{Elec\,Out}}{\dot{Q}_{in}} = \frac{\dot{W}_T - \dot{W}_C}{\dot{Q}_{in}} = \frac{\dot{m}c_{P,EG}(T_3 - T_4) - \dot{m}c_{P,AIR}(T_2 - T_1)}{Amt.Fuel \times Higher\ Heating\ Value} \qquad \text{Eq. 2-19}$$

Heat Recovery Steam Generator

A heat recovery steam generator (HRSG) is also referred to as a waste heat recovery boiler (WHRB) or a turbine exhaust gas boiler (TEG). A HRSG utilizes thermal energy in the combustion turbine exhaust gas to generate steam. The HRSG is a key element in a combined cycle plant affecting the initial costs, operating costs and overall plant efficiency. A HRSG can be unfired, meaning it uses only the sensible heat from the turbine exhaust gas, or it can also utilize supplemental fuel firing to add thermal energy to the exhaust gas. This increases the exhaust gas temperature and therefore decreases the amount of heat transfer surface needed. The MIT heat recovery steam generator only burns natural gas if supplemental firing is necessary. High temperature turbine exhaust gas enters into the HRSG and passes over a series of fined pipes with flowing water/steam. The exhaust gas flow is driven by a natural pressure-drop across the HRSG. At a 100% load with supplemental natural gas firing the HRSG was designed to produce 167,950l bs/hr of steam and be 83% efficient.

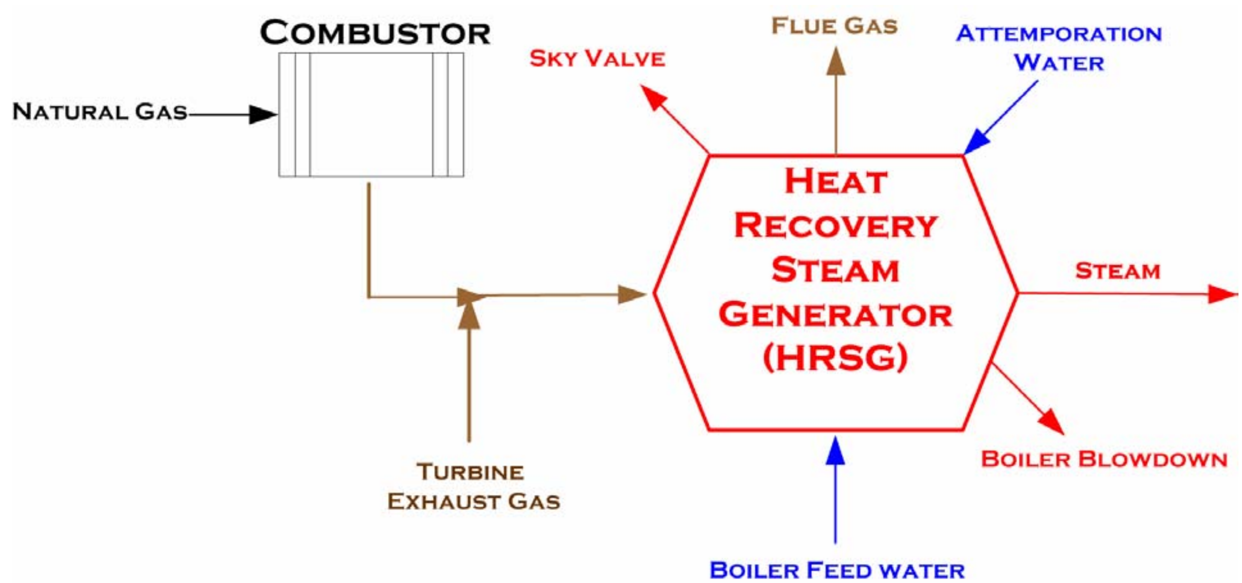

Figure 2-4: Gas Turbine and HRSG Schematic

Figure 2-4 is a schematic for the HRSG in the MIT cogeneration plant. The sky valve is used to vent steam during testing. Attemporation water is water added to the superheated steam to decrease its temperature. This is mainly necessary to keep the mechanical integrity of the steam driven chillers turbine blades. As water is continuously used to produce steam in a closed loop system water impurities begin to increase. Boiler blowdown is used to expel recirculated water and therefore decrease impurities in the steam produced. The rate at which this occurs depends on the quality of water used. MIT's boiler blowdown rate varies from 2%-5% which allows for 50-20 cycles of water use before dumping. In addition, there is approximately 20% make up water needed to account for the amount lost to the atmosphere during campus circulation.

The following energy balance was applied to the HRSG:

$$\dot{H}_{EG} + \dot{H}_{NG} + \dot{H}_{BW} + \dot{H}_{AW} = \dot{H}_{Steam} + \dot{H}_{Flue\,Gas} + \dot{H}_{SV} + \dot{H}_{BB}$$

$$\dot{m}_{EG} c_{p,EG}(T_{EG} - T_{ref}) + \dot{m}_{NG} HHV_{NG} + \dot{m}_{H2O} h_{T,BW} + \dot{m}_{H2O} h_{T,AW} = \qquad \text{Eq. 2-20}$$

$$\dot{m}_{Steam} h_{T,Steam} + \dot{m}_{FG} c_{p,FG}(T_{FG} - T_{ref}) + \dot{m}_{SV} h_{T,SV} + \dot{m}_{BB} h_{T,BB}$$

Equation 2-16 still needs to be applied to account for the latent heat of vaporization in the turbine exhaust if the higher heating value is used.

Boilers

MIT has three boilers that burn both No 6 oil and natural gas. These boilers primarily provide any additional steam the campus may need during high demand or in the event that the HRSG is offline. Figure 2-5 is a schematic of the boiler system. A first law energy balance yields the following equation,

$$\dot{H}_{Fuel} + \dot{H}_{BW} = \dot{H}_{Steam} + \dot{H}_{BW} + \dot{H}_{BB} + \dot{H}_{Flue\,Gas} \qquad \text{Eq. 2-21}$$

The energy associated with the fuel is determined by the fuel mass flow rate and higher heating value of the fuel. The sensible energy of the water/steam streams is also

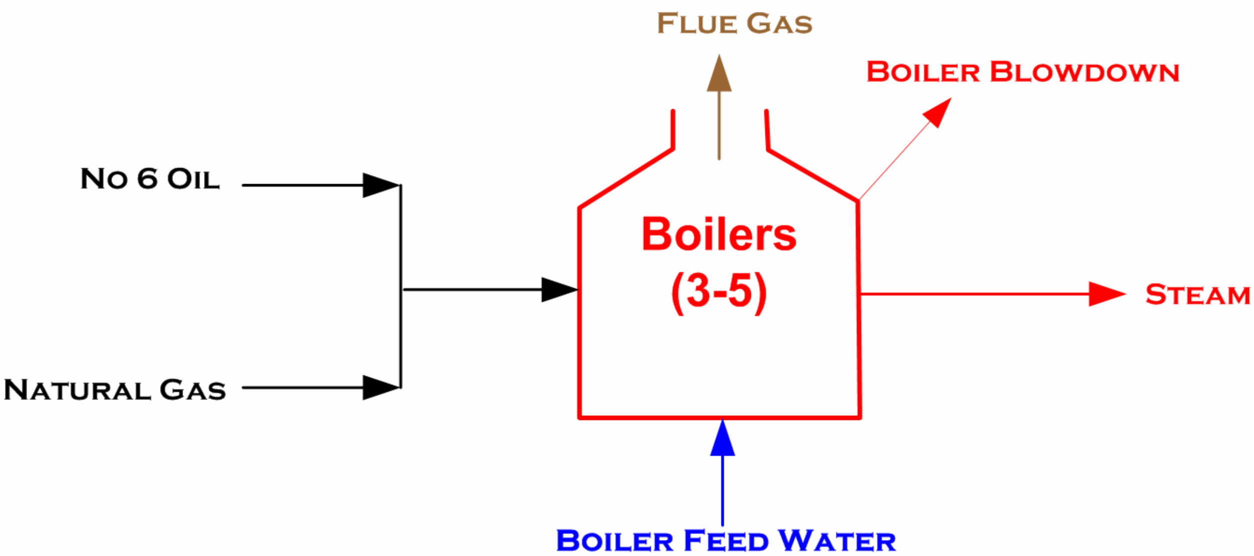

Figure 2-5: Boiler Schematic

calculated by the appropriate mass flow rate and enthalpy at the given streams temperature. The energy in the flue gas is given by the gas mass flow rate, specific heat at the exit temperature, and exit gas temperature. The enthalpy of the flue gas can also be calculated directly from the boiler energy equation 2-21, as it is the only unknown. If the latter is done, one must realize that all system losses are then associated with the flue gas. By applying a GHG calculation methodology and the appropriate thermodynamic theory, the MIT emissions due to campus utility use are then calculated from fiscal year 1990 to 2003.

2.4 Utility Greenhouse Gas Emissions Results and Discussion

Figure 2-6 displays the total amount of CO_2 equivalents due to campus utility use from fiscal year 1990 to 2003. It includes all purchased electricity and produced steam, electricity and chilled water from the MIT cogeneration utility plant. The 20% reduction target set by the city of Cambridge would cap the campus utility emissions at 148,936 metric tons of CO_2 per year, and would therefore, call for a 23% reduction in utility emission rates.

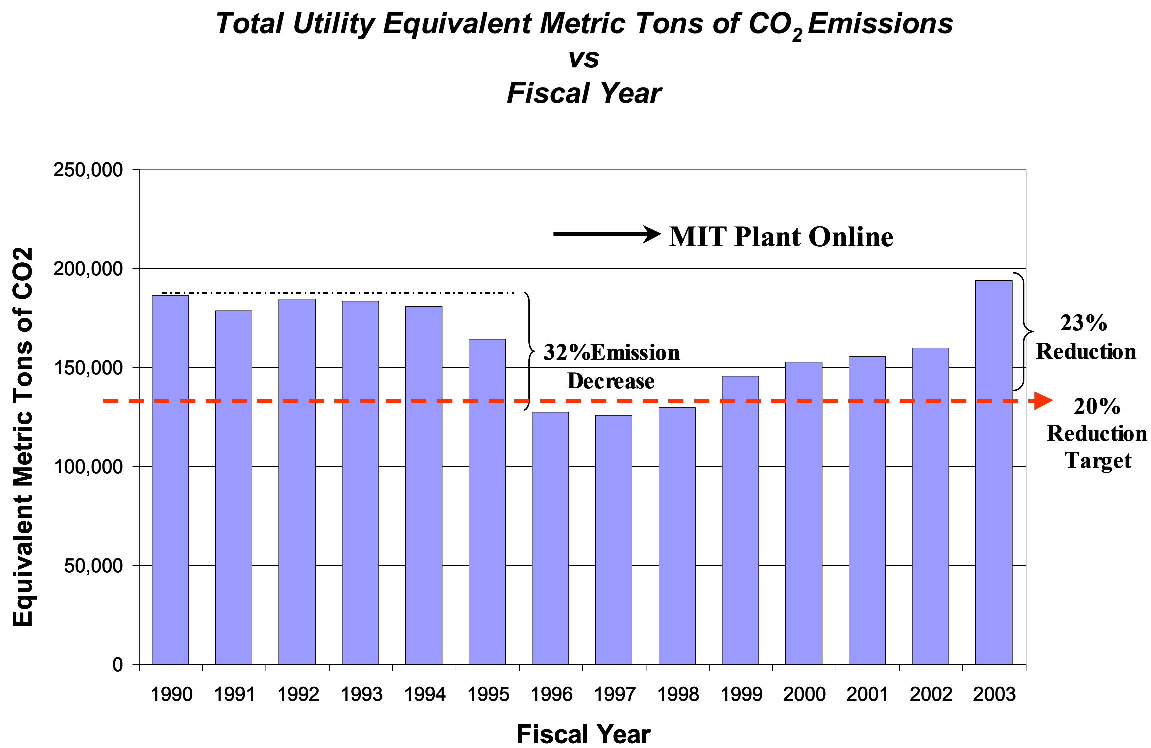

Figure 2-6: Total Utility Equivalent Metric Tons of CO_2 Emissions vs Fiscal Year

The power plant came online in July of 1995 and there was an initial 9% decrease in the utility GHG emission. Once a full year of operation was attained in 1996, a 32% reduction in GHG emissions was seen from 1990 levels and 22% decrease from 1995 levels. This is directly related to the utilization of thermal energy in the gas turbine exhaust gas for the production of steam. It is also related to electricity production on the MIT campus as opposed to purchasing electricity from region electric grids. This eliminates transmission and distribution losses and enables the MIT plant to generate electricity from a cleaner fuel source such as natural gas as opposed to coal and oil. A 12% increase in GHG emissions occurred from fiscal year 1998 to 1999. This is due to a 24% increase in the combustion of oil in the gas turbine and an increase of 5% in purchased electricity. From 2002 to 2003 there was an additional 21% increase in GHG emissions due to the addition of several energy intensive buildings, an increase in purchased electricity, and a decrease in steam production in the HRSG. A closer look at a comparison between 1998 and 2003 levels will be discussed later in this section. Currently MIT is emitting

5% more metric tons of CO_2 equivalents than 1990 levels and would have to reduce utility emissions by at least 23% to reach the reduction target set forth by the city of Cambridge.

Figure 2-7 partitions the total amount of emissions due to campus utility use into steam, electricity, and chilled water produced on campus and purchased electricity.

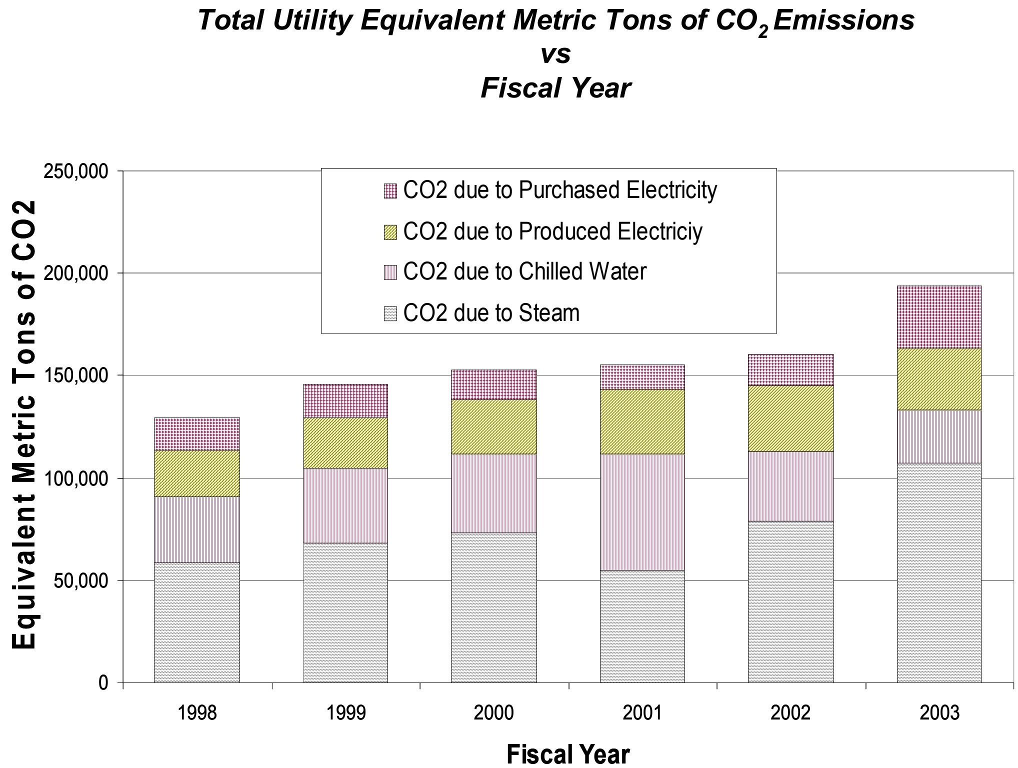

Figure 2-7: Total Utility Equivalent Metric Tons of CO_2 Emissions vs Fiscal Year

The production of steam is the largest percentage of the total amount of GHG partly due to the emission apportioning methodology. Apportioning emissions based on energy flows allocates the remaining metric tons of CO_2 in the flue gas to steam production, leading to a larger amount of emissions being apportioned to steam production. Since 1996, there is a continuous increase in emissions with jumps in fiscal year 1999 and 2003. Factors, such as fuel price and availability, weather, and campus demand influence the amounts and types of fuel purchased. Changes in these factors explain the steady increase in GHG emissions and peak in 2003.

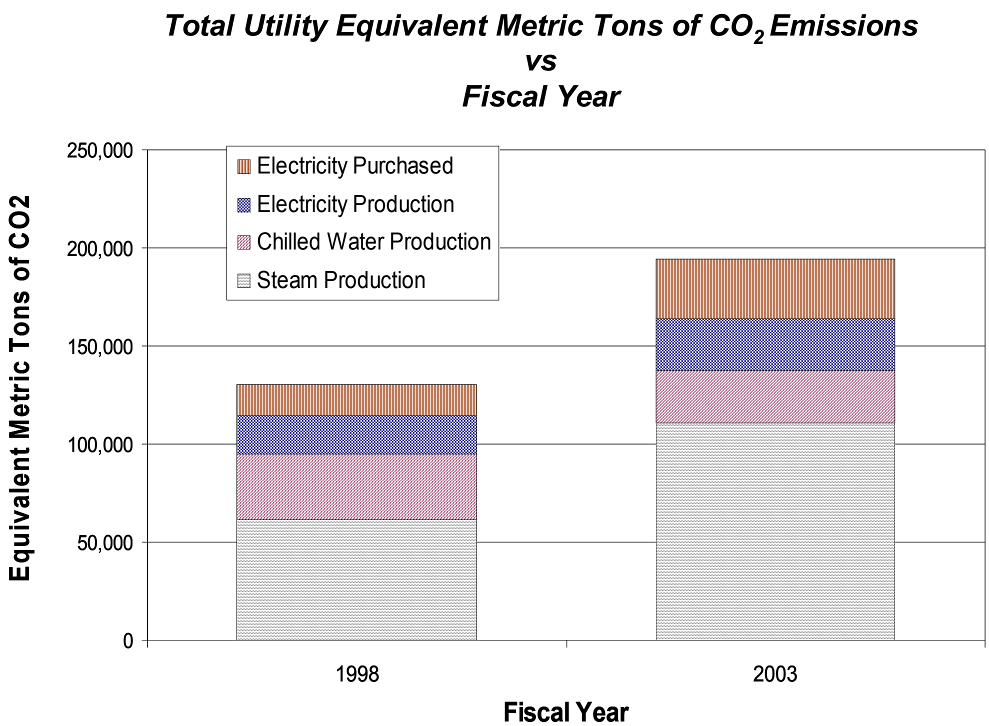

Figure 2-8: Total Utility Equivalent Metric Tons of CO_2 Emissions vs Fiscal Year

Figure 2-8 shows a comparison of 1998 and 2003 emission rates. In 2003 natural gas fuel prices were higher than that of oil and in some instances natural gas was not available in the needed amounts due to infrastructure problems. As oil purchasing and burning rates increased, emissions rates also rose due to oils higher carbon content. One example of this is the fuel burned in the gas turbine. Generally natural gas accounts for 98% of the total fuel burned. In 2003 the amount of oil and natural gas burned increased 23% and 32% respectively from 1998 values. The amount of purchased electricity increased 93% as the campus electricity demand continued to grow. Weather can also affect the demand for additional steam for heating during the winter months and additional electricity for air conditioning units in the summer months. There was a 10^{o}F difference in average winter temperatures between 1998 and 2003. Therefore, steam production to provide heat for the campus and dorms was unexpectedly high during the winter of 2003. In addition, as the campus continues to expand and new buildings and facilities go online, the demand for utilities will also increase. From 1998 to 2003 the campus square footage increased 10% creating a greater demand for utilities.

Changes in plant operation can also affect utility emission rates. The utilization of the gas turbine exhaust gas in the HRSG to produce steam is one of the main reasons emissions dropped 32% in 1996 from 1990 levels. Traditionally, the HRSG produces 80% of the total campus steam with the remaining 20% produced in Boilers 3, 4 and 5. In 2003, the HRSG dropped its steam production from 80% to 60%. The production of steam by the HRSG directly affects the utility emission rates as the HRSG steam production requires marginal additional duct firing, but rather utilizes energy that would otherwise be lost to the environment. Therefore, when the HRSG was not used additional fuel was burned in the boilers to make up for the decrease in the HRSG steam production.

While CO_2 emissions represent the majority of the total GHG emissions, Figure 2-9 and 2-10 represent the amount of equivalent metric tones of CO_2 emitted due to the emission of methane and nitrous oxide. Equivalent CO_2 emission rates for methane and nitrous oxide are at least 200 times lower than that of carbon dioxide. Combined they account for less than 1% of direct carbon dioxide emissions.

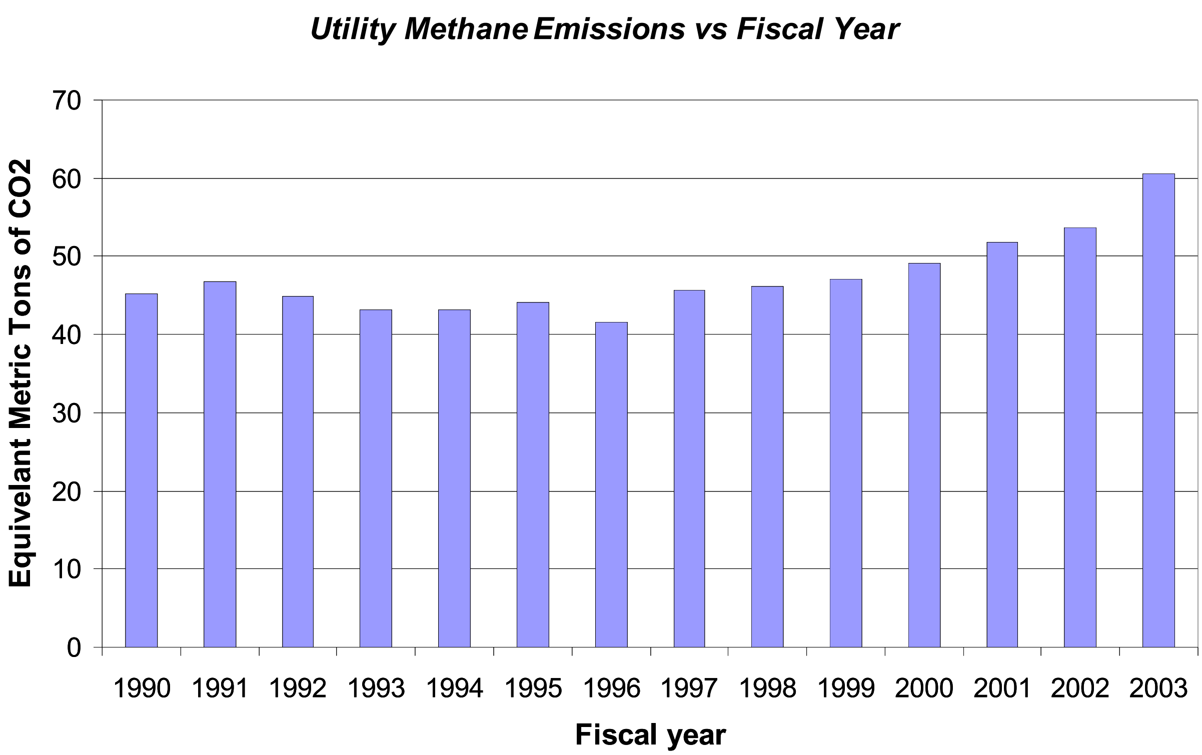

Figure 2-9: Utility Methane Emission vs Fiscal Year

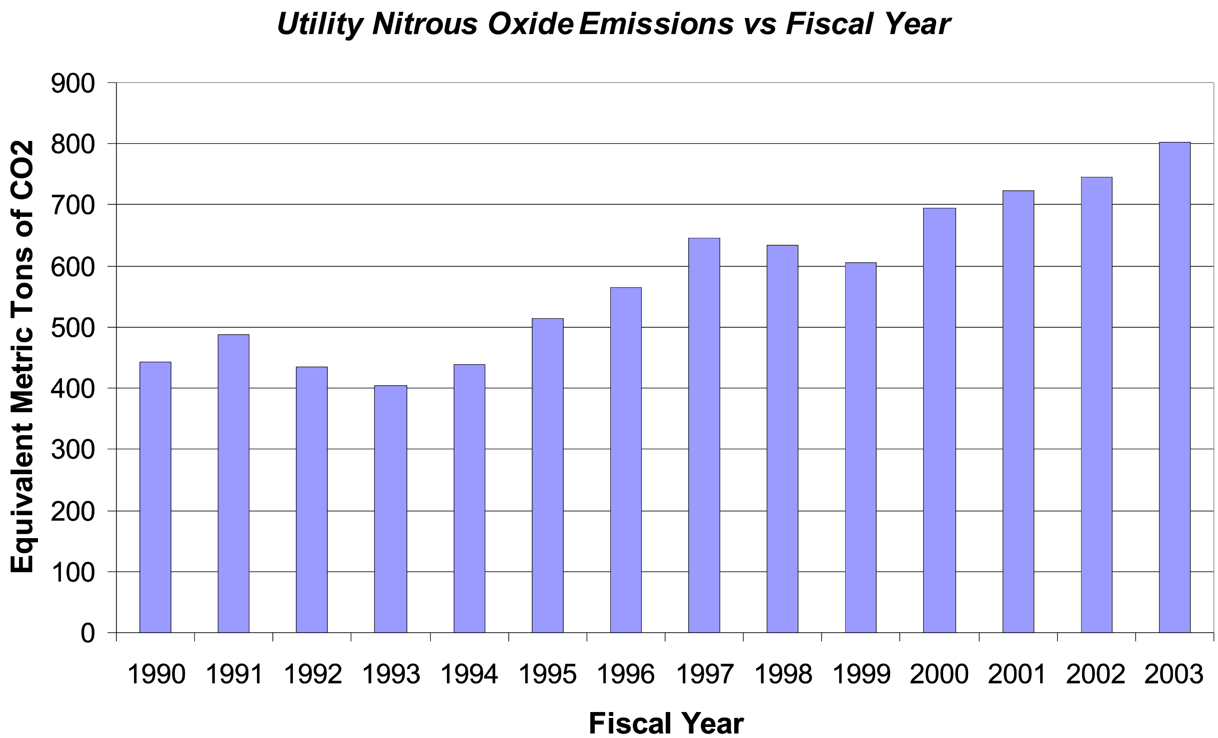

Figure 2-10: Utility Nitrous Oxide Emissions vs Fiscal Year

Therefore, even when considering the higher global warming potential, the impact of methane and nitrous oxide emissions compared to that of carbon dioxide is insignificant. Therefore, improvements in decreasing emissions should be targeted at decreasing the primary CO_2 emitted due to combustion of fossil fuels. This may be accomplished by promoting utility conservation and continual plant and campus maintenance.

2.4.1 Greenhouse Gas Emissions Based On Building Type

Different campuses GHG emissions are often compared to gauge their relative environmental impact. Emissions are often compared to one another by normalizing results with respect to total square footage, energy use, or population. However, this attempt to normalize parameters, often does not fully capture the explanation for differences in a variety of emission numbers. When comparing two different campuses or buildings emissions per square-foot one fails to consider how different types of building space, such as labs, offices, and residential vary in energy use. One instead should compare emissions from the same type of square-footage space. By determining a parameter based on type of building square-feet one can normalize and compare emission results based on this more appropriate parameter. A parameter based on metric ton of CO_2 per type of square-foot was determined based on data supplied on annual building energy use, building square-footage, and building type (lab, office, and residential). Table 2-6 contains total campus building information for fiscal year 2003.

Fiscal Year 2003 Data			
	MIT Campus Building Square Feet	**Number of MIT Buildings**	**% Of Total Campus Square-Feet**
Lab	5,825,683	89	55.5%
Office	2,360,828	47	22.5%
Housing	2,316,068	26	22.1%
Total	10,502,579	162	100.0%

Table 2-6

Available data to determine the emission parameter based on type of square-feet is represented in table 2-7. Information on 52% of the campuses total square footage was available to determine the energy use per type of square-foot and metric tons of CO_2 per type of square-foot. As expected lab space is the most energy intensive and thus has a 2-3 higher emission factor. Office space is approximately 30% more energy intensive then housing space, as most housing buildings contain less electrical equipment and most on campus housing space does not have air conditioning units. Applying the calculated emission factors to the available data in table 2-7, 98,333 metric tons of CO_2 is accounted for, which represents 51% of the total utility emissions for fiscal year 2003. But, when applying these emission factors to the total amount of total type of square foot in table 2-6 one obtains an annual emission rate 15% higher than the actual 2003 emission value of 194,474 MTCDE. This discrepancy is due to the limited amount of data available. Though 90% of data on buildings used for housing is accounted for, data related to lab and office space only represents 20% of the total amount of space.

Fiscal Year 2003 Collected Data						
	MIT Campus Building Square Feet	Number of MIT Buildings	% Of Square Footage Analyzed	Energy Use per Square-Foot (MMBTU/sq-ft type)	CO_2 Emissions per Square Foot (Metric Tons CO_2 / sq-ft type)	CO_2 Emission (Metric Tons of CO_2)
Lab	2,002,824	21	34.4%	0.387	0.030	60,362
Office	1,327,566	20	56.2%	0.159	0.013	16,991
Housing	2,077,927	14	89.7%	0.123	0.010	20,980
Total	5,408,317	55	51.5%	-	-	98,333

Table 2-7

Therefore, the accuracy of the average emission factor for lab space and office space is mainly responsible for the 15% difference between the actual utility emissions in 2003 and the emissions obtained using these factors. This 15% difference still allows for an approximate value for campus emissions based on square footage since it is still relatively close to the actual campus emission rate. Future efforts in continuing to add meters to buildings will help obtain a more accurate emission factor based on type of lab and office space. In addition, table 2-6 includes buildings not connected to the MIT utility distribution network and therefore over estimates the amount of included square-feet. By separating emissions by type of square footage two different campuses GHG emission sources can be compared on a more appropriate scale.

2.4.2 Errors in Results

Errors in utility GHG emission results, is mainly due to data quality issues, process simplifications, and assumptions. Challenges in obtaining an accurate data set stem from problems in the data collection programs and a lack of a systematic methodology when dealing with erroneous data. Erroneous data is defined as data obtained from the facility operating system PI that either indicates when the equipment is not in use or when the metering device has an error. Currently days with invalid data are dropped from all calculations. When calculating efficiency's, which are ratios, this has little effect on the outcome. An error does occur in the total integrated numbers, such as total fuel use or utility produced per year, which directly affects GHG emission results and plant assessment analysis. Other challenges faced are times when meters were not installed during the entire time period being analyzed. In these instances purchasing orders are used to determine the amount of fuel burned. Additionally, due to the annual time scale analyzed, average fuel heating values, mass flow rates, and temperatures are assumed though these can vary with fuel composition and load. In the future, improved metering technology and creating an appropriate methodology for dealing with invalid data must be developed so that a more annual accurate data can be provided.

Chapter 3 Carbon Dioxide Emissions Due To Commuters

MIT currently has approximately 20,000 people that either work or study on campus. Therefore, transportation to and from campus is an important emissions component that the institute must understand. MIT's commuting population utilizes a variety of transportation options including; walking, cycling, driving, and public transportation. Currently MIT issues 3,711 parking permits to staff and students. This number is limited by the city of Cambridge and by the Federal Clean Air Act of 1973, which states that MIT can only provide on-campus parking for no more that 36% of the MIT non resident commuting population[12]. To create an incentive to use public transportation and to decrease the cost of commuting to campus, MIT provides subsidized T, bus, and commuter rail passes. Currently, MIT subsidizes over 5,000 T/bus passes monthly. MIT also provides commuters with vanpool options, shuttles, and zip cars. A large majority of the student population, which accounts for approximately 50% of the total campus population, live on campus and therefore either walk or bike to campus. In addition to the commuting population, MIT also has a fleet of campus vehicles. This fleet includes vehicles operated by facilities, the transportation office, and various academic departments on campus. The analysis of MIT's GHG emissions due to the commuting population includes people with parking permits, T/buses passes, and portions of the MIT campus fleet. Carbon dioxide is the only GHG considered in this portion of the analysis. To determine the amount of CO_2 emitted the three above mentioned sections will be calculated separately.

3.1 Automobiles with Parking Permits

To determine the amount of CO_2 emitted by commuters with parking permits the average commuter distance is needed. A 2002 transportation survey included 80% of parking permit holders and contained residential information that is used to determine a daily average trip length per vehicle. Below are a list of assumptions and constants used [13]:

1. Average one-way trip length – 8.8 miles
2. 3,711 parking permit holders
3. Average 220 working days per year
4. Average fuel efficiency – 20 miles per gallon

5. Gasoline heating value – 0.115 MMBTU per gallon
6. Gasoline carbon content – 42.8 lbs Carbon per MMBTU
7. Carbon to CO_2 conversion – 44/12

Using the above mentioned assumptions and constants the amount of CO_2 emitted due to commuters with parking permits can be calculated. A similar but more direct approach to the emissions calculation is to use the constant 5,815 BTU/vehicle-mile and the carbon content of gasoline to determine the amount of carbon and thus CO_2 emitted [14]. A difference of 1% is seen when comparing these two approaches.

3.2 T/Bus Passes

The MIT transportation office sells passes for all bus routes, T combo zones, and commuter rail options. Table 3-1 lists the assumptions and constants used to determine the amount of CO_2 emitted due to bus and subway use [14]. When determining the amount of CO_2 emitted due to subway use, the amount of consumed electricity is determined then the methodology explained in section 2.2.2 is applied.

Bus (Transit)	
Energy Intensity (BTU/passenger-mile)	4,802
Average One-Way Trip Length (mile)	8
Working Days per Month	20
Average Working Days per Year	220
Diesel Carbon Content (lbs C / MMBTU)	44
CO_2 Content (g CO_2 / MMBTU)	73,180

Subway (Commuter)		
Energy Intensity (BTU/Passenger-Mile)	2,932	Electricity Consumption
Average One-Way Trip Length (Mile)	8.8	
Working Days per Year	220	

Table 3-1

To determine the amount of carbon dioxide for combo passes, which include both bus and T access, a range of values were calculated to represent the maximum and minimum amount of

CO_2 emitted. This was done by calculating the amount of CO_2 emitted if all combo passes were assumed bus passes only and then if all combo passes were then assumed to be T passes only.

3.3 MIT Vehicle Fleet

The MIT vehicle fleet consists mainly of vehicles used by facilities, the transportation office, and the MIT police. Facility vehicles are used to care for 153 acres of landscape and to maintain 11 million square-foot of labs, classrooms, office, and residences. The transportation office provides a variety of free shuttles and vanpool services. The vehicle fleet data reported is in gallons of gasoline per year. The same methodology and gasoline constants are used to determine the amount of carbon dioxide emitted as in section 3.1.

3.4 Carbon Dioxide Commuter Emissions Accuracy

One question to ask is, how accurately does this method account for the MIT commuting population? This section addresses this question by providing an approximate break down of the MIT population into commuting sections. MIT has a population of 20,000 that is separated approximately 50% students and 50% faculty and staff. For the 50% student population 40% are undergraduates and 60% are graduate students. MIT provides housing for all undergraduate and approximately one-third of the graduate population. Therefore, according to these assumptions approximately 30% of the MIT population, or 6,000 students live on campus in resident halls. According to this assumption at least 6,000 people either walk or bike to campus. The campus population and number of bus/T passes purchased varies from year to year, table 3-2 provides a break down for how in 2003 twenty thousand people commuted to campus.

2003 Commuter Population Break Down	
Parking Permits	3,711
Bus Passes	480
T Passes	2,430
Combo Passes	1,891
Total Resident Hall Population (walk/bike)	6,000
Car/Van Pool	500
Shuttle Use	500
Total	15,512
Total MIT Population	20,000
Percent Represented	77.6%

Table 3-2

This does not include the additional 22.4% of people who live off campus, both student and administrators, that walk, bike, take the bus or subway that do not buy a subsidized pass from the transportation office, or drive and park on the street. Therefore at least 77% of the commuting population is accounted for in this inventory. To account for the 22.4% of the campus population that is not included in this commuter inventory, the data set could be proportionally extend from 77.6% to 100%. This was not done for this inventory, because the carbon dioxide emissions due to transportation account for less than 10% of the total emissions and the difference in total transportation emissions would be insignificant.

3.5 Commuter Emission Results and Discussion

Figure 3-1 and table 3-3 provides a break down of carbon dioxide emissions by sectors included in the GHG inventory. There are two CO_2 emission results for combo passes to provide a minimum and maximum amount of total emissions due to transportation to and from the MIT campus. According to the figure 3-1 carbon dioxide emissions are higher for combo passes that are considered to be subway passes.

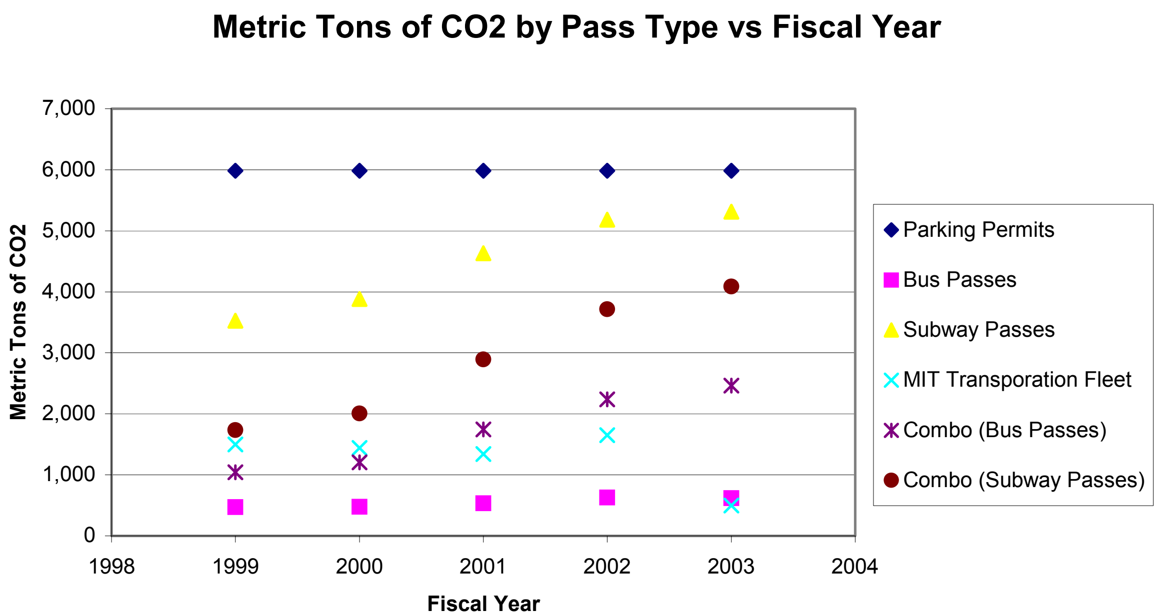

Figure 3-1: Metric Tons of CO_2 By Pass Type vs Fiscal Year

Table 3-3 provides a break down for the amount of metric tons of CO_2 emitted by the transportation sector. Emissions due to parking are similar to the emissions of the combined public transportation sector. Since there are more passes sold per year than parking passes, this shows that on a per person basis the public transportation sector emits less than emissions due to people driving a vehicle to campus.

Metric Tons of CO_2 Emissions By Sector					
Fiscal Year	**1999**	**2000**	**2001**	**2002**	**2003**
Parking Permits	5,986	5,986	5,986	5,986	5,986
Bus	472.07	479.04	536.62	628.38	617.02
Subway	3,525	3,883	4,634	5,182	5,315
Combo (Bus)	1,045	1,207	1,747	2,239	2,460
Combo (Subway)	1,732	2,005	2,891	3,717	4,088
MIT Transportation Fleet	1,500	1,440	1,339	1,648	2,028
*1999 MIT Transportation Fleet assumed					

Table 3-3

For a given number of passes, emissions due to subway use are 40% higher than bus use, while driving is still the highest emission sector. Emissions due to parking passes are constant due to the fact that the number of parking permits has not changed

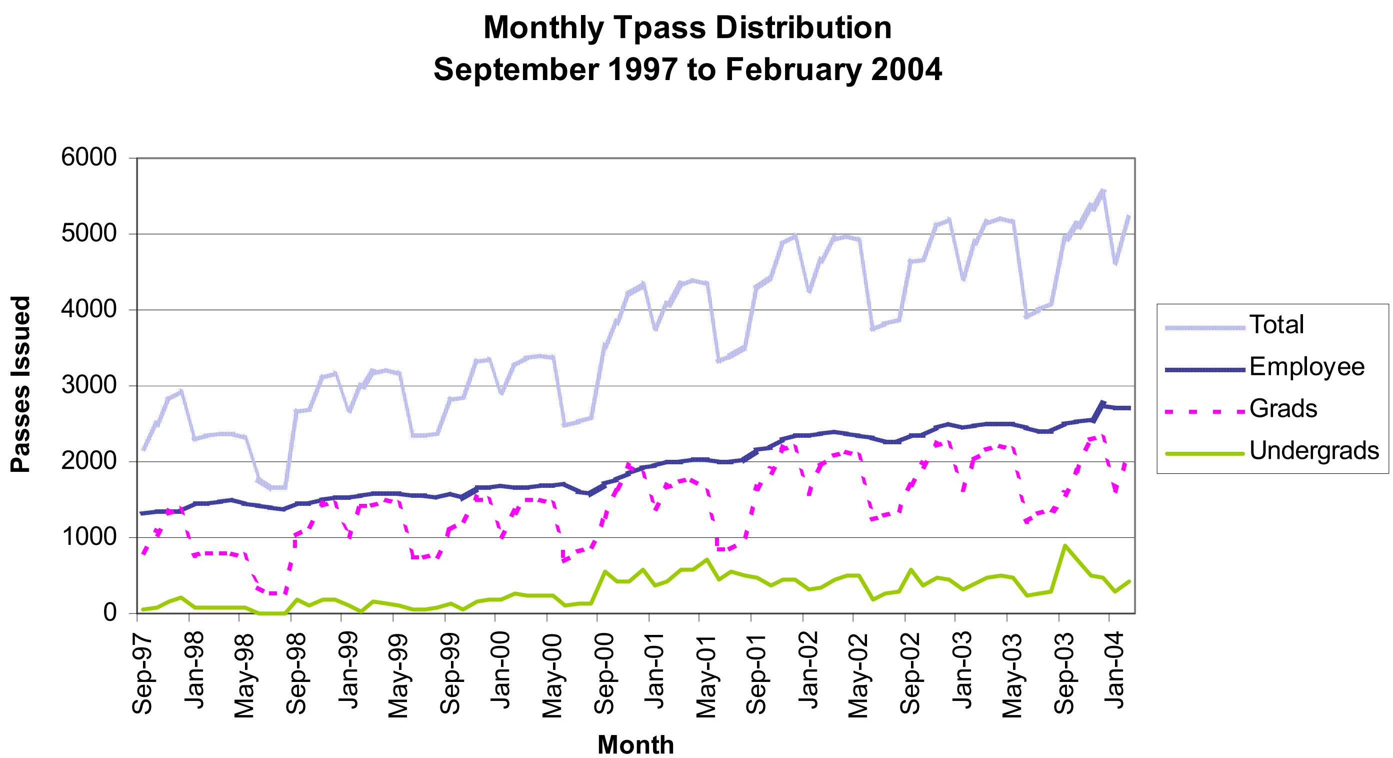

Figure 3-2: Monthly Tpass Distribution (September 1997 to February 2004)

from 1999 to 2003 and the same average traveled miles was assumed for all years. Emissions due to subway passes have been increasing as seen in figure 3-1. This coincides with an increase in the total subway or T passes sold from 1997 to 2003 as seen in figure 3-2. Monthly T passes sold to graduate students and employees have been increasing over the past 6 years as subsides and graduate and employee population has increased. In addition to population increase, as parking becomes scarcer and the cost of housing near campus increases people are choosing to live further from campus and depend more on public transportation.

Table 3-4 compares the amount of MTCD emitted per type of pass sold. Parking permit passes have the highest emission rate per pass, being 93% higher than bus passes. The emissions per subway pass sold are also 40% higher than that for bus passes. This indicates that promoting bus use benefits the environment more than expanding subway and parking permit programs.

Metric Tons of CO_2 Emissions Per Pass Sold	
Parking Permits	1.613
Bus	0.112
Subway	0.186

Table 3-4

Table 3-5 contains the minimum and maximum amount of carbon dioxide emitted due to the transportation sector. The minimum value assumes that all combo passes are assumed to be bus passes only. Therefore, combo pass emissions are determined by the same methodology bus pass emissions are calculated.

Total Metric Ton of CO_2 Emitted due to Transportation Sector					
Fiscal Year	1999	2000	2001	2002	2003
Total Metric Tons CO_2 (Minimum)	12,528	12,995	14,242	15,684	16,407
Total Metric Tons CO_2 (Maximum)	13,215	13,793	15,386	17,161	18,034
Percent Difference	5.2%	5.8%	7.4%	8.6%	9.0%

Table 3-5

The maximum value corresponds to the assumption that all combo passes are assumed to be subway passes only. Therefore, combo pass emissions are determined by the same methodology subway pass emissions are calculated. From 1999 to 2003 carbon dioxide emissions due to the transportation sector has increased 36%. Table 3-5 also provides the percent difference between the maximum and minimum total metric tones of CO_2 emitted due to the transportation sector. The rise in the percent difference between the maximum and minimum values is due to increased purchasing of combo passes as well as other public transportation passes.

Figure 3-3 displays the maximum total amount of carbon dioxide emissions by commuters broken up by sector.

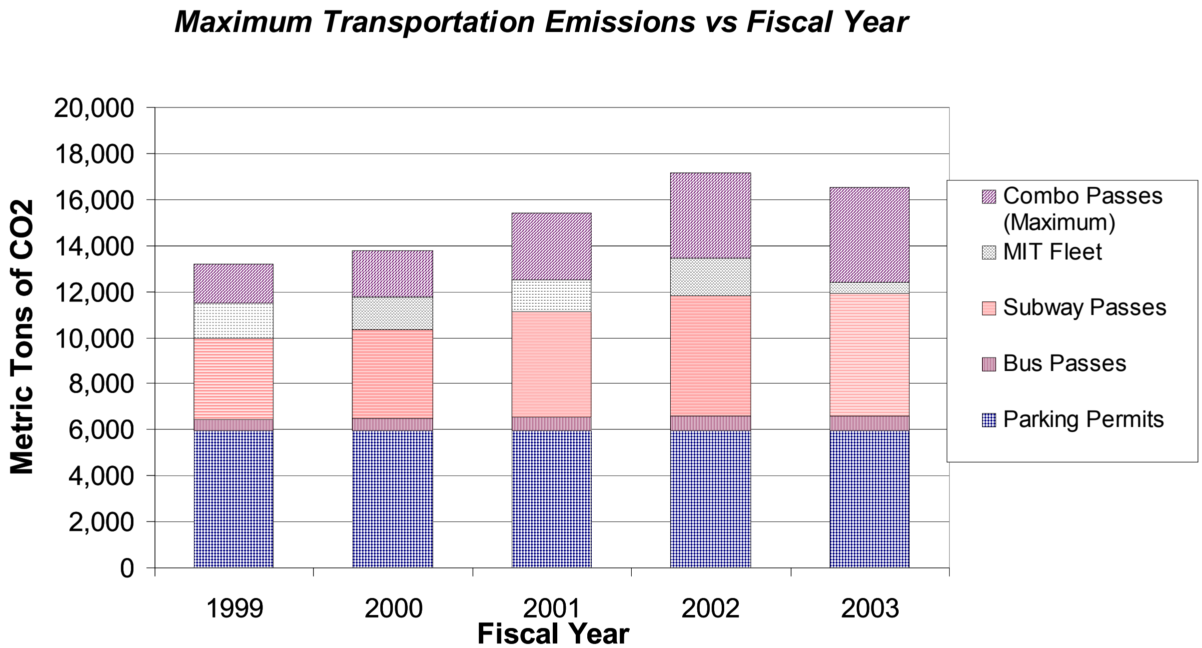

Figure 3-3: Maximum Transportation Emissions vs Fiscal Year

Emissions due to subway passes sold and considering combo passes as subway passes, accounts for 40% of the maximum amount of CO_2 emitted. Emissions due to parking permits sold account for between 35-45% depending on the year.

While this accounts for the campus commuting population to and from campus there are emissions due to other types of travel related to the MIT campus and its community that have not be included. These include air travel by faculty and students, delivery freight travel to and from campus, tourist travel, and business travel. These are areas where improvements in the transportation emission calculation can be made to obtain a high degree of scope and accuracy.

Due to federal and city regulations and environmental concerns MIT is committed to promoting alternate means of transportation to accommodate the campus populations need to travel to and from campus. MIT's subsidized transportation programs promote the use of public transportation as an alternate mode to driving a vehicle to campus. These programs contribute to the increase in bus and T passes while parking permits remain constant. This has a direct impact on the amount of CO_2 emitted as emissions due to automobiles are at least 88% higher than emission due to subway use and are 93% higher than that of bus use.

Chapter 4 MIT's Solid Waste Greenhouse Gas Emissions

The US accounts for 22 percent of world energy consumption with 4% of the world's population. The average American throws away 4.4 pounds of trash per day and uses 650 lbs. of paper per year [15]. This consumption trend, which is mostly driven by high production and consumption countries like the US is one reason why the worldwide energy consumption rate is expected to increase 54% from 2001 to 2025 [15]. Therefore, the need to promote reduced consumption and advocate recycling programs is becoming increasingly important as landfill space and our natural resources are decreasing. MIT is committed to leading the way in promoting consumption reduction and increasing recycling programs.

4.1 Emission Assumptions, Methodology, and Calculation

MIT has an aggressive recycling program that pledges to increase its 1999 recycling value of 5% to 40% by the year 2005 as prescribed by the Cambridge Climate Protection Plan. Current recycling programs have already increased the campuses recycling rate to 22% in the year 2002. In addition, MIT composts all of its landscaping/yard waste and incinerates all of its solid waste in the waste-to-energy (WTE) Covanta Energy plants in Haverhill Massachusetts. In the United States, 15% of municipal solid waste (MSW) is combusted while 55% is discarded in landfills. Covanta Energy, in addition to other WTE facilities, burns municipal solid waste to utilize the thermal energy to produce steam. The steam produced is then used to drive steam turbines to generate electricity. WTE plants are held to strict federal and state emission standards. Therefore, exhaust gases pass through an advanced pollution and filter control system where acid forming gases, such as sulfur oxides and hydrogen chloride, are reduced and 99% of particulate matter is removed. While burning MSW releases thermal energy, it also reduces the amount of waste by up to 90 percent in volume and 75 percent in weight.[15]

MIT separates its solid waste into four different categories; basic recyclables, organic waste, other recyclables, and solid waste. Examples of basic and other recyclables include paper, cardboard, fluorescent lamps, wood pallets, and electronics while organic waste mainly consists of landscaping and food waste. MIT's solid waste consists of everything that is thrown away and not recycled. MIT also makes great efforts to recycle demolition debris as the campus continues to evolve. In 2001, 96% of the Media Lab demolition debris was recycled. Table 4-1 contains total tons of waste for each of the four sections described.

MIT's Annual Municipal Solid Waste (Tons/yr)				
Fiscal Year	**2000**	**2001**	**2002**	**2003**
Total Campus Waste	5,783	8,876	9,326	8,867
Basic Recyclables	231	284	245	568
Organic Waste (Composted)	335	564	871	844
Other Recyclables	82	993	1,329	1,667
Solid Waste	5,135	7,035	6,881	5,788

Table 4-1

All of MIT's solid waste is used in combustion resulting in the emission of CO_2, because nearly all the carbon in MSW is converted to CO_2. Though MIT utilizes multiple waste disposal techniques, only CO_2 emitted due to incineration of MSW is considered for this analysis. Composting mainly results in biogenic CO_2 emissions associated with decomposition, both during the composting process and when it is added to the soil. Because this CO_2 is biogenic in origin it does not add to the GHG emission inventory[16]. Manufacturing from recycled inputs generally requires less energy, and thus lower GHG emissions, than manufacturing from virgin inputs[16]. Therefore, emissions due to recycling are also not included in the inventory.

When determining the amount of CO_2 emitted during a cycle of burning MSW and producing electricity two amounts need to be calculated. The first being the total amount of CO_2 emitted due to combustion of MSW and the second is the amount of displaced emissions from producing electricity. Burning solid waste to generate electricity displaces additional burning of fossil fuels, and thus emissions, that otherwise would have been emitted to produce the same amount of electricity. Therefore, these avoided GHG emissions are subtracted from the GHG emissions associated with the combustion of the solid waste to produce a net GHG emission rate due to MIT's solid waste.

MSW is considered to be basic trash components such as product packaging, bottles, and food scrapes, but excludes items such as construction debris and non-hazardous industrial waste[16]. Therefore, it is estimated that there are 0.135 pounds of non-biogenic carbon in the plastic, textiles, rubber, and leather contained in 1 pound of mixed MSW. It is also assumed that during incineration 98% of all carbon is converted to carbon dioxide with the balance going to the ash remains. This then results in 0.485 MTCDE emitted per ton of mixed MSW [16].

Covanta Energy Plant in Haverhill Massachusetts recovers energy with MSW combustion to produce electricity. To determine the avoided electric utility emissions associated with the combustion of MSW two data elements were assumed. First, the energy content of mixed MSW, second the combustion efficiency from converting energy released in MSW to electricity. Table 4-2 provides the values that coincide with the needed assumptions.

Utility CO_2 Avoided Emissions		
kW-hr generated by mass burned per ton of MSW	550	
kW-hr delivered by mass burn per ton of MSW	523	Considers 5% transportation and distribution losses
WTE System Efficiency	17.8%	
Energy Content (MMBTU/ton)	10.0	
BTU/kW-hr for mass burn	19,200	
Lbs. CO_2 Emitted per kW-hr Generated	1.726	Based on regional average utility fuel mix
Avoided Utility CO_2 per Ton Combusted at Mass Burn Facility (MTCDE/ton MSW)	0.41	

**SOLID WASTE MANAGEMENT AND GREENHOUSE GASES*
http://www.epa.gov/epaoswer/non-hw/muncpl/ghg/greengas.pdf

***Emission Factors, GWP, Unit Conversion, Emissions, and Related Facts*
http://www.epa.gov/appdstar/pdf/brochure.pdf

Table 4-2

The WTE estimated efficiency is based on losses in converting energy in the fuel into steam, converting energy in steam into electricity, and delivering electricity. Table 4-2 allows one to calculate the 0.41 avoided utility CO_2 emitted per ton of combusted MSW.

4.2 Greenhouse Gas Solid Waste Emission Results and Discussion

Based on the above-mentioned assumptions and constants in table 4-2 the net amount of carbon dioxide emitted due to MIT's annual solid waste disposal is calculated in table 4-3.

MTCDE Emissions of MIT's Annual Municipal Solid Waste (MTCDE/yr)				
Fiscal Year	**2000**	**2001**	**2002**	**2003**
Emissions Due to Burning MSW	2,490	3,412	3,337	2,807
Avoided Emission	2,102	2,880	2,817	2,370
Net Emissions	**388**	**532**	**520**	**438**

Table 4-3

The net amount of MTCDE emitted considers the emissions due to combustion of MSW and also considers the avoided emissions due to also generating electricity with the thermal energy produced. The net amount of MTCDE due to the MIT's campus solid waste accounts for less than 1% when compared to the amount of MTCDE emitted by the MIT utility sector. Incinerating campus solid waste in a waste-to-energy plant displaces 85% of MTCDE emissions due to campus solid waste generation, and therefore is not included in the total emission numbers. Table 4-4 compares emissions due to incineration and different landfill disposal options.

Metric Tons of CO_2 Equivalents Released due to Solid Waste Disposal				
Fiscal Year	**Waste Incineration and Electric Generation**	**Landfilled Only**	**Landfilled w/ CH_4 Recovery**	**Landfilled w/ CH_4 Recovery and Electric Generation**
2000	388	5,253	1,415	606
2001	532	7,198	1,938	830
2002	520	7,040	1,896	812
2003	438	5,922	1,595	683

Table 4-4

As seen from the table above, waste-to-energy plants produce the least amount of emissions, ranging from a difference of 95% when compared to disposal in landfills only, to 36% when compared to landfills with methane recovery and electric generation. Therefore, in disposing of campus solid waste, utilizing waste-to-energy plant provides the best option for limiting the amount of MTCDE released into the atmosphere.

MIT waste disposal portfolio consists of recycling, composting, and waste incineration. As the amount of recycled waste increases to a target of 40% the amount of waste incinerated will decrease and thus campus emissions will decline. Increasing recycling programs and composting amounts while promoting decreased consumption will lead MIT's campus towards reduced GHG emissions but not by a significant amount since emissions due to solid waste account for less than 1% of the total utility emissions. Therefore, reducing emissions in other sectors would bring the campus closer to the 20% GHG reduction target set by the city of Cambridge.

Chapter 5 MIT Power Plant Performance & Availability Analysis

An annual assessment and availability analysis performed on the gas turbine and the HRSG allows one to track component performance and degradation. Both a first and second law energy analysis, are performed because of the different information each can provide. A first law energy balance first applies energy conservation principles and compares actual energy changes to theoretical energy changes at specific conditions. A second law or availability balance is a non-conservative analysis. During a process, the second law efficiency measures losses within a system. This provides insight into where losses are occurring so that actions can be taken to minimize them and increase efficiencies. This understanding of system losses provides an opportunity to take appropriate actions to counteract component degradation and decreased system efficiencies. This chapter will discuss the applicable availability theory, analysis methodology, and results. The availability theory addresses open-system flow availability, fuel availability, the transfer of availability through a heat and work transfer process, and the availability in flue gases.

5.1 Availability Theory

Availability, also known as exergy, allows one to calculate the maximum work that can be obtained by a system running down to equilibrium interacting with the environment by undergoing a set of reversible processes. Availability unlike energy is not conserved and is actually destroyed by irreversibilities within the system, thus decreasing the maximum amount of useful work that can be produced. The amount of availability destroyed is equivalent to the amount of irreversibilities within the system. An availability analysis allows one to define and locate irreversibilities within a system and then take steps to reduce losses and increase productivity. To evaluate the maximum reversible work, one first needs to define the state at which the system and the environment are in complete thermal and chemical equilibrium, this is known as the dead state. Another common environmental reference state is known as the restricted dead state, which is where the system and the environment are in thermomechanical equilibrium but not in chemical equilibrium. The standard environmental dead state in either case is defined as 59^{o} F (300K) and 1atm (1.013 bars). Assumptions relative to the environmental dead state include that the environment is homogenous in temperature and pressure. All components are at rest relative to one another and that the environment is large enough to act as a source or sink for internal energy. The maximum work potential of a system relative to its dead state is defined as its availability. Availability is defined as,

$$\psi = (E - U_o) + P_o(V - V_o) - T_o(S - S_o) \qquad \text{Eq. 5-1}$$

where E(=U+KE+PE), V, S denote, respectively, the energy, volume, and entropy of the control mass at a given state and U_o, $V_{o,}$ and S_o are the same properties when the control mass are at rest at the restricted environmental dead state.

The change in availability of two states for a closed system is therefore defined as,

$$\psi_2 - \psi_1 = (E_2 - E_1) + P_o(V_2 - V_1) - T_o(S_2 - S_1) \qquad \text{Eq. 5-2}$$

While the availability at a state cannot be negative the change in availability can be. The change in availability of a system can either be positive, negative, or zero. Availability can also be defined for a control volume but one then needs to account for the availability transfer accompanying mass flow and flow work. Specific flow availability accounts for both these and is given by,

$$a_f = (h - h_o) - T_o(s - s_o) + \frac{V^2}{2} + gz$$

The steady state availability rate balance is then,

$$0 = \sum_j \left(1 - \frac{T_o}{T_j}\right)\dot{Q}_j - \dot{W}_{cv} + \sum_i \dot{m}_i a_{fi} - \sum_e \dot{m}_e a_{fe} - \dot{S}_{gen} \qquad \text{Eq. 5-3}$$

Equation 5-3 indicates that the rate at which availability is transferred into the control volume must exceed the rate at which availability is transferred out, the difference being the rate at which availability is destroyed within the control volume due to irreversibilities. To evaluate the difference in availability stream flow for a single mass flow rate at two different states would then be,

$$a_1 - a_2 = (h_1 - h_2) - T_o(s_1 - s_2) + \frac{V_1^2 - V_2^2}{2} + g(z_1 - z_2) \qquad \text{Eq. 5-4}$$

5.1.1 Fuel Chemical Availability

The chemical availability of a fuel, such as hydrocarbon fuels, requires that the chemical potential, μ_i of each of the components be known. For a pure fuel the fuel chemical availability in the restricted dead state is given by[17],

$$\psi_{ch,f} = g_{fuel,o} + \nu_{O_2}\mu_{O_2,00} - \sum_P \nu_i \mu_{i,00} \qquad \text{Eq. 5-5}$$

The "00" represents the unrestricted or environmental dead state. The variable ν, represents the stoichiometric combustion reaction coefficients. The chemical potential of the i^{th} component is represented by $\mu_i = \bar{g}_i = \bar{h}_i - T\bar{s}_i$. The above equation applies to a case where pure fuel enters into a control volume at the restricted dead state along with the oxidant, O_2, from the environment. Only the availability of oxygen in air is considered during the combustion processes since N_2 is mainly non-reactive.

For a fuel that can be modeled as an ideal gas the chemical potential of the i^{th} component takes the format of,

$$\mu_{i,T,ideal} = g^\circ{}_{i,T} + RT\ln\frac{P_i}{P_o} \qquad \text{Eq. 5-6}$$

For an environmental state where $P_i = y_{i,00}P_o$ where $y_{i,00}$ is the mole fraction of the i^{th} gas in standard atmosphere calculated for relative humidity's of 60, 80, and 100 percent, along with the definition of the Gibbs function at T_o to be $g_{i,0} = g^\circ_{i,T_O}$, the above equation becomes,

$$\mu_{i,T,ideal} = g_{i,0} + RT_o \ln y_{i,00} \qquad \text{Eq. 5-7}$$

For a complete combustion of a hydrocarbon fuel C_xH_y the only products of interest are carbon dioxide (CO_2) and water vapor (H_2O), and the only environmental reactant considered is oxygen (O_2). Therefore the three chemical potential, $\mu_{i,0}$, equations required for equation 5-7 are,

$$\mu_{O_2,00} = g_{O_2,0} + RT_o \ln y_{O_2,00}$$
$$\mu_{CO_2,00} = g_{CO_2,0} + RT_o \ln y_{CO_2,00} \qquad \text{Eq. 5-8}$$
$$\mu_{H_2O,00} = g_{H_2O,0} + RT_o \ln y_{H_2O,00}$$

Equations 5-8 are then substituted into equation 5-5 for $\mu_{i,00}$ one finds that[17],

$$\psi_{ch,f} = -\Delta G_{R,0} + RT_o \ln \frac{(y_{O_2,00})^{v_{O_2}}}{(y_{CO_2,00})^{v_{CO_2}} (y_{H_2O,00})^{v_{H_2O}}}$$
$$where, \qquad \text{Eq. 5-9}$$
$$\Delta G_{R,0} = v_{H_2O} g_{H_2O,0} + v_{CO_2} g_{CO_2,0} - g_{fuel,0} - v_{O_2} g_{O_2,0}$$

The quantity $\Delta G_{R,0}$ is the change in the Gibbs function per mole of fuel for the stoichiometric reaction at the restricted environmental dead state (T_o, P_o). To provide a general form, consider a hydrocarbon fuel with the general formula C_xH_y, reacting with the environment to produce CO_2 and H_2O,

$$C_x H_y + \left(x + \frac{y}{4} \right) O_2 \rightarrow xCO_2 + \frac{y}{2} H_2O(g)$$

In this format the general equation for equation 5-9 becomes,

$$\psi_{ch,f} = -\Delta G_{R,0} + RT_o \ln \frac{(y_{O_2,00})^{x+y/4}}{(y_{CO_2,00})^{x} (y_{H_2O,00})^{y/2}} \qquad \text{Eq. 5-10}$$

where,

$$\Delta G_{R,0} = x g_{H_2O,0} + \frac{y}{2} g_{CO_2,0} - g_{fuel,0} - \left(x + \frac{y}{4} \right) g_{O_2,0} \qquad \text{Equation 5-11}$$

Both these equations allow one to evaluate the chemical availability of a mole of gaseous fuel C_xH_y in the restricted dead state, which is transformed into the products CO_2 and H_2O in the unrestricted dead state or the environmental state. For many types of hydrocarbon fuels, the main contribution to $\psi_{ch,f}$ is from the $\Delta G_{R,0}$ term, which can account for 95% of the fuels total availability. This implies that the mole fractions chosen for modeling dry atmospheric air have very little impact on the value of $\psi_{ch,f}$. In addition, the choice of the relative humidity, and thus the water vapor content, to model the environment also has very little effect on the chemical availability of the fuel. This is fortunate since there is no universal environmental model for air or its water content. The chemical availability for many pure fuels has already been tabulated in reference tables in appendix B.

If the fuel supply is a mixture of gases, such as natural gas, the chemical availability of the pure fuel in the restricted dead state must be adjusted relative to its mole fraction in the mixture, $y_{f,mixt}$. Therefore the following equations adjust the chemical availability of a pure fuel to account for the fact that it is apart of a fuel gas mixture. An example of this would be methane and its proportion in natural gas.

$$\mu_{f,mixt} = g_{f,0} + RT_o \ln y_{f,mixt} \qquad \text{Eq. 5-12}$$

therefore,

$$\psi_{ch,f,mixt} = \psi_{ch,f} + RT_o \ln y_{f,mixt} \qquad \text{Eq. 5-13}$$

$\psi_{ch,f}$ represents the chemical availability of a pure fuel in the restricted dead state. Since $\psi_{ch,f}$ is always a positive value, the mixture value is always less than the pure fuel availability. While the above equations relay on data, which assumes the fuel is in the gaseous form, to evaluate the chemical availability of both pure and mixed hydrocarbon gases, the following section will explain how to determine the chemical availability of pure liquid hydrocarbon fuels. This is equally important as most commonly used hydrocarbon fuels occur naturally in the liquid phase at standard atmospheric conditions, and the chemical availability needs to be known.

Equation 5-5 is a general equation that applies to all fuels in any phase. The main requirement when using this equation is that $g_{fuel,o}$ must represent the phase of interest. When applying this equation to liquid fuels a difficultly arises because the Gibbs of formation data is more readily available for an ideal-gas state than a liquid state. Therefore an alternate method was developed to relate $\psi_{ch,f}$ in the liquid state to the gas state using vapor-pressure data.

$$\psi_{ch,f,liq} = \psi_{ch,f,gas} + RT_o \ln p^{sat} \qquad \text{Eq. 5-14}$$

This equation is applied to a fuel in the restricted dead state where the vapor pressure p^{sat} is measured at T_o. This equation is only useful when the fuels boiling point temperature is greater than $25^\circ C$.

The previous equations allow one to determine the chemical availability of pure fuels in the gaseous and liquid state along with gases of mixed composition such as natural gas. The next step is to determine the $\psi_{ch,f}$ for liquid fuels of varied composition such as light and heavy hydrocarbons. Data has shown that for hydrocarbon liquid fuels there is a relationship between the chemical availability and the fuels lower heating value (LHV). Early work in this area was done by Szargut and Petela and then revised by Rodriquez. More recently, Brzustowski and Brena have looked at the relationship between these two variables and developed the following proportionality constant based on $\psi_{ch,f}$ data and 60% relative humidity[17],

$$\frac{\psi_{ch,f}}{LHV} = 1.065 \qquad \text{Eq. 5-15}$$

One thing to note is that the correlation improves as the fuels molecular weight increases as in heavier fuels.

5.1.2 Availability Flow due to Heat and Work Transfers

The change in availability of a system undergoing a set of processes can be defined as,

$$\Delta\psi = \psi_{in} - \psi_{out} - \psi_{destroyed} \qquad \text{Eq. 5-16}$$

where, $\psi_{destroyed}$ is the destroyed availability due to irreversibilities within the system. Availability can also be transferred into or out of the system through a heat, work, and mass transfer across the system boundary. The following represents the availability transferred associated with a heat transfer, Q_i across the system boundary at temperature T_i,

$$d\psi_{HT} = dQ_i\left(1 - \frac{T_o}{T_i}\right) \qquad \text{Eq. 5-17}$$

$$\psi_{HT,Q_i} = \sum Q_i\left(1 - \frac{T_o}{T_i}\right) \qquad \text{Eq. 5-18}$$

For a system with no mass or work transfers across the system boundary the irreversibilities of the system is determined by the sum of the availability transfers into and out of the system,

$$I_Q = \sum \psi_{HT,Q_i} = \sum Q_i \left(1 - \frac{T_o}{T_i}\right) \qquad \text{Eq. 5-19}$$

One way that irreversibilities within the system are created is through heat transfer processes across a finite temperature gradient. Therefore as the resistance to heat transfer increases, possibly due to corrosion or deposits on a heat transfer surface of a pipe, the temperature gradient will also increase creating more irreversibilities within the system. Availability associated with a work transfer across the system boundary is simply defined as,

$$d\psi_W = dW$$

5.1.3 Availability In Ideal Gas Mixtures

A number of processes that occur involve gases that can be modeled as an ideal gas. The total stream availability for an ideal gas mixture per mole of mixture is given by[17],

$$\begin{aligned}\psi_{Total,Ideal\ Gas} &= \sum_{i=1}^{n} y_i \left[h_{i,T} - h_{i,T_o} - T_o (s^o_{i,T} - s^o_{i,T_o})\right] \\ &+ RT_o \ln \frac{P}{P_o} + RT_o \sum_{i=1}^{n} y_i \left(\ln \frac{y_i}{y_{i,oo}}\right)\end{aligned} \qquad \text{Eq. 5-20}$$

The first term accounts for the system and the environment not being at the same temperature, while the second term accounts for them not being at the same pressure. The last term accounts for difference in the stream and the environmental compositions. The value, y_i, is the mole fraction of the *i*th species in the stream mixture. All values are known except $y_{i,oo}$, the mole fraction of the *i*th species in the environment. These values are tabulated in appendix B and are based on standard atmosphere composition, temperature, pressure, and 60 and 100% relative humidity. The arbitrary value in this calculation is the mole fraction of water vapor. Though it can depend on geographic location and season it is highly dependent on the relative humidity, while other $y_{i,oo}$ values are not. Therefore picking 60% or 100% relative humidity does not change the result by a significant amount.

Equation 5-20 can be used to determine the availability in the turbine exhaust gas and HRSG and Boiler(3-5) flue gas. When calculating the availability in the flue gas the second term can be dropped since the exit pressure and atmospheric pressure are approximately equal. The only combustion gases considered are carbon dioxide, water vapor, nitrogen, and excess oxygen since these make up the majority of the combustion gas composition and therefore the majority of the stream availability. To determine the mole fractions of these gases one first needs to calculate the number of moles each of the gases has in the combustion gas mixture. To find the number of moles of carbon dioxide and water vapor it is necessary to only consider the stoichiometric combustion of the fuel in question since the number of moles of these gases does not change with the amount of excess air. The number of moles of nitrogen and excess oxygen can be determined from the system air-fuel ratio.

5.2 Methodology of Availability Analysis on GT and HRSG System

Gas turbine

The availability analysis focuses on the combustion turbine as a whole, rather than its' components. For this analysis the following assumptions and equations were applied,

Assumptions: steady-state operation, standard atmospheric conditions, negligible potential and kinetic energy changes

$$\dot{\psi}_{in} = \dot{\psi}_{out} + \dot{\psi}_{destroyed}$$
$$\dot{\psi}_{ch,f} = \dot{\psi}_{EG} + \dot{\psi}_{destroyed} \qquad \text{Eq. 5-21}$$

The chemical availability is given by equation 5-15 for liquid fuels and equation 5-10 for gaseous fuels. The turbine exhaust gas can be modeled as an ideal gas therefore Equation 5-20 can be applied. Equation 5-16 enables one to calculate the change of availability and therefore determine the irreversibilities within the combustion turbine. Irreversibilities are due to combustion losses, heat transfer losses, and fluid and mechanical friction. The chemical availability of air is not included because it comes into the system already in equilibrium with the environment, or at the dead state.

HRSG

The following equations are applied to the HRSG during the availability analysis:

$$\dot{\psi}_{in} = \dot{\psi}_{out} + \dot{\psi}_{Lost,Irrev}$$
$$\dot{\psi}_{EG} + \dot{\psi}_{NG} + \dot{\psi}_{BW} + \dot{\psi}_{AW} = \dot{\psi}_{Steam} + \dot{\psi}_{Flue\,Gas} + \dot{\psi}_{SV} + \dot{\psi}_{BB} + \dot{\psi}_{Lost,Irrev} \quad \text{Eq. 5-22}$$

To calculate the chemical availability in natural gas equation 5-13 or the value is tabulated in appendix B is applied to determine $\psi_{ch,NG}$,

$$\dot{\psi}_{NG} = \dot{m}_{NG}\psi_{ch,NG} \quad \text{Eq. 5-23}$$

To determine the chemical availability in any of the water/steam flows equation 5-3 is applied at the appropriate stream temperature while neglecting the potential and kinetic energy effects. Therefore,

$$\dot{\psi}_{H2O\,Flow} = \lfloor h_{T,H2O} - h_{o,T_O} \rfloor - T_o \lfloor s_{T,H2O} - s_{o,T_O} \rfloor \quad \text{Eq. 5-24}$$

Equation 5-22 enables one to determine the availability destroyed or the amount of irreversibility within the system. The HRSG effectiveness is a measure of the available outputs divided by the availability inputs.

$$HRSG_{Effectiveness} = \frac{\sum \dot{\psi}_{out}}{\sum \dot{\psi}_{in}} = \frac{\dot{\psi}_{ST} + \dot{\psi}_{SV} + \dot{\psi}_{Flue\,Gas} + \dot{\psi}_{BB}}{\dot{\psi}_{NG} + \dot{\psi}_{EG} + \dot{\psi}_{BF} + \dot{\psi}_{AW}} \quad \text{Eq. 5-25}$$

It represents the ability to transfer heat from the high temperature turbine exhaust gas to the boiler feedwater [17]. As deposits begin to collect on the inside and outside of the heat transfer surface area the temperature gradient at which heat transfer occurs increases, therefore availability losses increase and the effectiveness of the heat exchanger decreases.

5.3 Performance and Availability Analysis Results and Discussion

Figure 5-1 is a plot of the gas turbine efficiency from fiscal year 1998 to 2003. The variation of +/- 2.5% is within the uncertainty associated with the possible 9% variation in the higher heating value of natural gas. Errors associated with adding daily data to give annual data does not affect the efficiency of the gas turbine as it is defined as the ratio of the electrical work generated and the chemical fuel energy input.

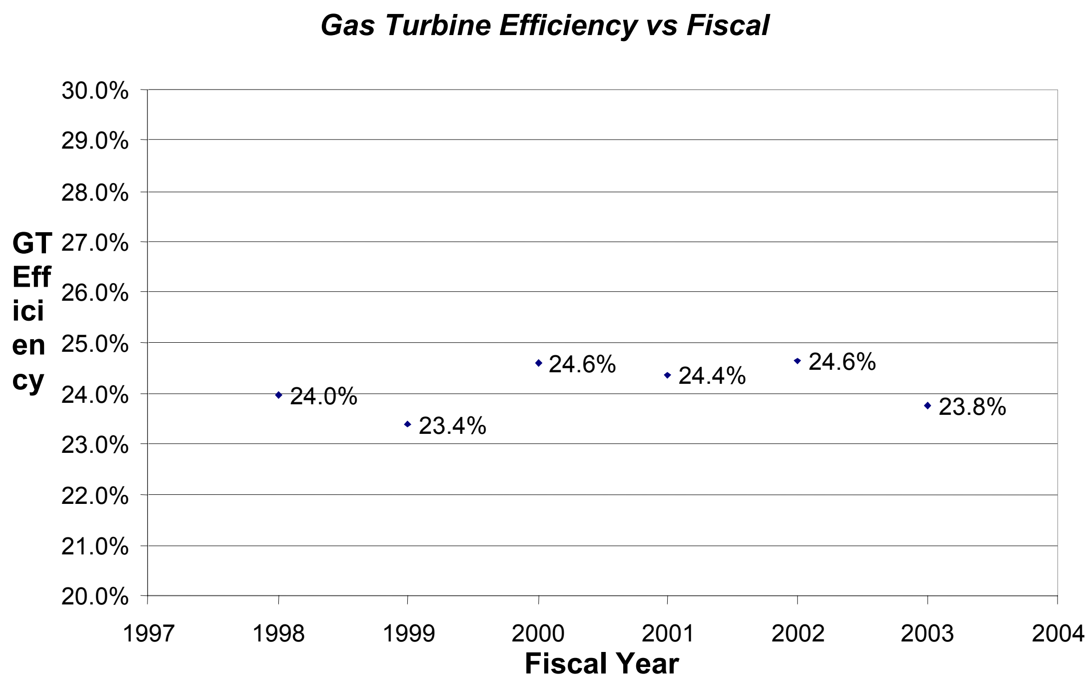

Figure 5-1: Gas Turbine Efficiency vs Fiscal Year

The gas turbine efficiency is affected by degradation of gas turbine components, such as the high-pressure turbine blades (HPT), decreased compressor inlet pressure, and increased turbine outlet pressure due to an increase in pressure drop across the HRSG. Rotating turbine components are subjected to both high rotational speeds and exhaust gas temperatures. Varying operating conditions such as load, humidity, and atmospheric conditions results in erosion, corrosion, fatigue, and oxidation which directly affect the GT performance [18]. Therefore, frequent component maintenance is required to maintain optimal levels of efficiency. The steady 24% efficiency seen over the past 6 years can in part be attributed to component maintenance by MIT's systems operations and maintenance group. Major components of the gas turbine were rebuilt in October 2002 and frequent changes to the compressor and turbine blade components occur to enhance performance. Compressor inlet air filters are also continuously changed based on the increase pressure drop due to being clogged.

Figure 5-2 plots the gas turbine tested efficiency at installation, when burning natural gas, and the actual annual gas turbine efficiency vs percent operating load. The actual annual average efficiency remains steady at 24% as the average annual load increases while the rated efficiency increase with load. The efficiency increases with load the performance characteristics of the compressor, combustion process, and turbine, are sensitive to the fuel and air mass flow rates and are optimized for rated performance.

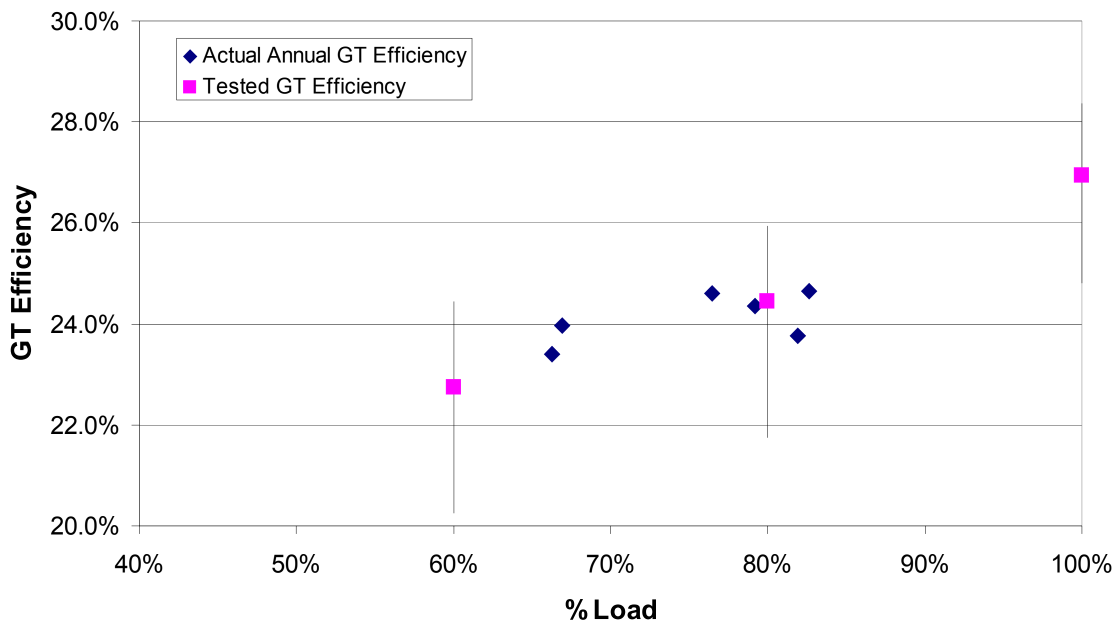

Figure 5-2: Gas Turbine Efficiency vs Percent Operation Load

Additionally, ambient conditions affect the maximum electric output and thus the gas turbine efficiency. In Boston during the winter months the air is denser and less humid due to the lower ambient temperature. Therefore, the maximum electrical output at 100% load, increases from 18.8 MW in the summer months to 22MW in the winter months. This is largely due to the increased air mass flow rate that can be achieved during the winter months when the air is denser. The increase in the maximum electric output increases the GT efficiency from 24.4% to 28.6% in the summer and winter months respectively. The expected range of variation, as depicted in figure 5-2, due to fluctuation in ambient conditions, is first calculated according to the fluctuation in the GT efficiency from summer and winter months related to the maximum rated efficiency. The ranges of variation at 80% and 60% are then assumed to scale with the rated efficiency value. The actual average annual efficiency is within the rated efficiency range at varying loads.

The Gas Turbine efficiency is also affected by the turbine outlet pressure conditions, which are determined by the pressure drop across the HRSG. Therefore, a performance analysis of the HRSG is important for not only efficient steam production but efficient electricity production as well. The HRSG effectiveness measures the device's ability to produce steam and as seen in figure 5-3, has decreased 11% since 1998. This correlates with figure 5-4 that displays an 8% increase in availability loss from 1998 to 2003. The approximately 60% loss of availability is associated with losses due to combustion, fluid flow, and heat transfers into and out of the system. In the combustion process 20% of the fuel availability is lost due to the irreversibility of the chemical reactions occurring. Therefore 5% of the 60% availability loss is due to the additional natural gas duct firing. Losses on the order of 1-3% also occur due to fluid friction within the exhaust gas and feedwater flows. The majority of the availability loss, approximately 50%, is due to the transfer of heat from the hot turbine exhaust gas to the boiler feedwater.

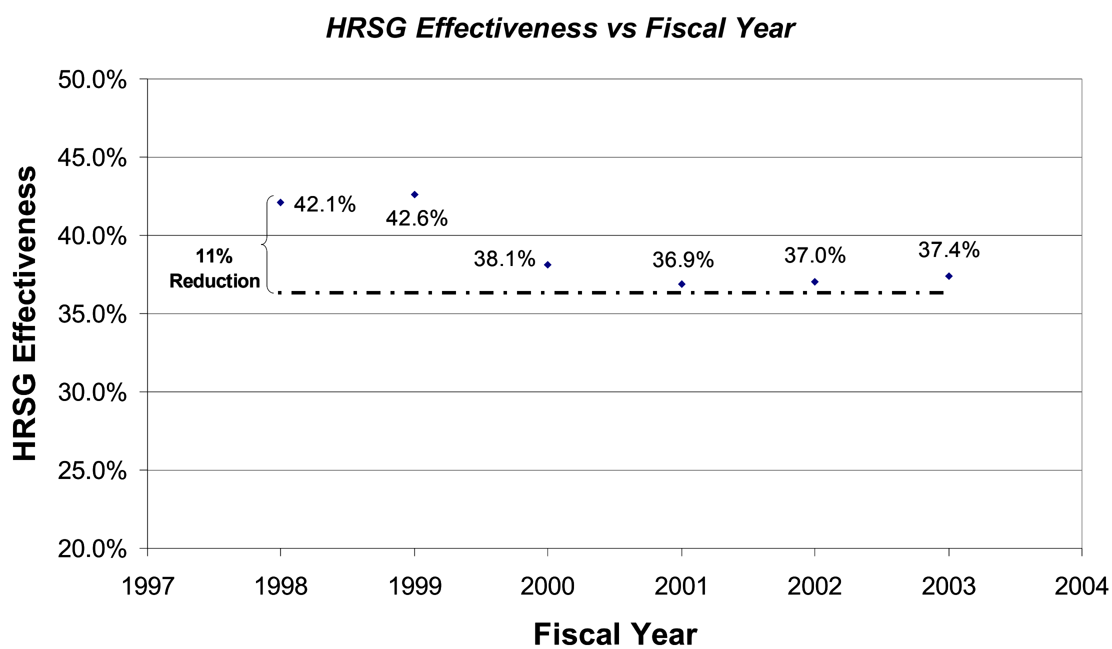

Figure 5-3: HRSG Effectiveness vs Fiscal Year

As the temperature difference between these two flows increase so does the loss of availability. The temperature difference between these two flows will increase due to the effects of fouling on both the outer and inner heat transfer surfaces of the boiler tubes. Fouling is the accumulation of undesired materials on the heat transfer surface.

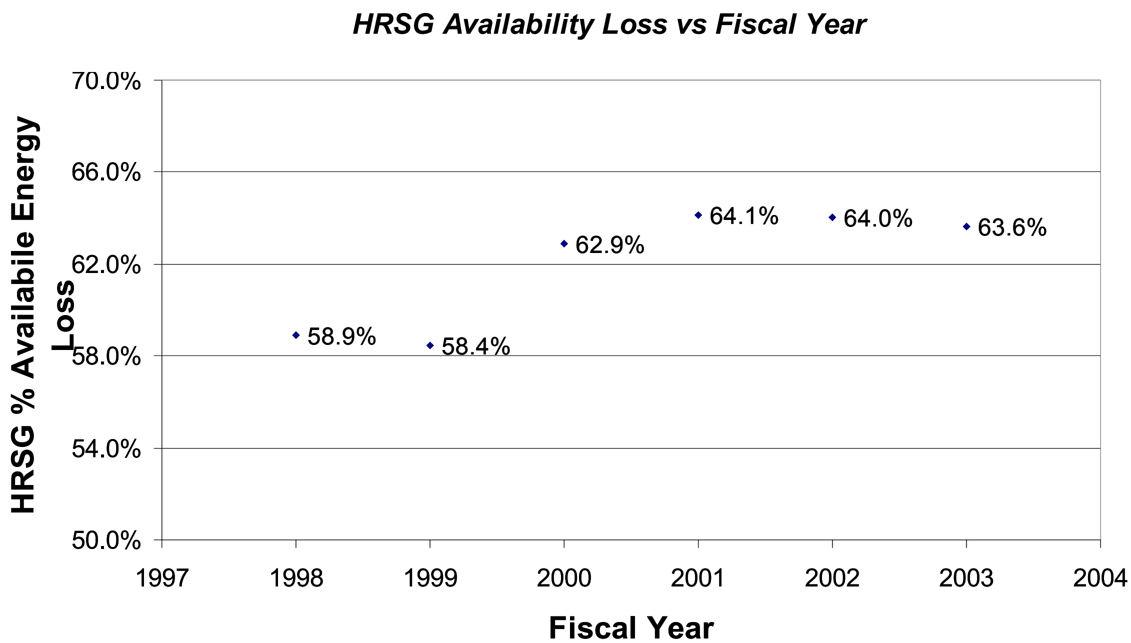

Figure 5-4: HRSG Availability Loss vs Fiscal Year

Deposit build up adds an extra heat transfer resistance that increases the temperature difference required for a given heat transfer rate, increases the availability loss, and increases flue gas availability, which increases losses to the environment.

To determine the magnitude of fouling that would need to occur to increase the availability loss by at least 8% and decrease the HRSG effectiveness, the HRSG is modeled as cylindrical tubes in cross-flow. Figure 5-5 provides a local schematic for this model. The goal is to determine the increased temperature drop, due to fouling, across the deposit buildup. As the temperature drop increases so does the availability loss due to heat transfer between the two streams. The increase in temperature drop can then be used to determine the increase in availability loss.

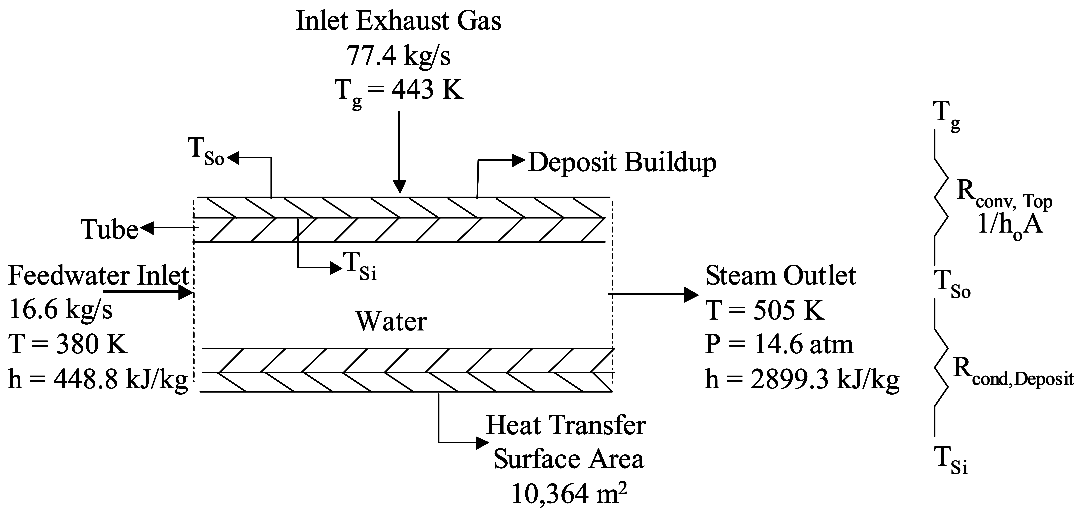

Figure 5-5: Tube In Cross Flow Heat Transfer Schematic

An increased temperature difference is due to the buildup of deposits on the outer tube surface. Deposits result form particles in the air, ash from oil firing, and soot for locally rich fuel combustion. Inner surface water deposits include mineral deposits on the tube side. To model the heat transfer process, the two resistances considered are the convective resistance from the gas to the outer tube surface and the resistance through the deposit buildup. The tube resistance is neglected as it is small compared to the surface resistance [19]. In addition, heat exchanger units are designed such that internal cleaning on the tube side is not necessary. Therefore, the resistance due to deposit buildup on the water side can be neglected when compared to the added resistance on the shell side[19].

The HRSG is designed to produce a given amount of steam at a desired temperature and pressure. The amount of energy needed to produce this amount of steam must remain constant, along with the inlet and outlet water conditions. Equation 5-24 calculates the amount of energy needed to produced a given amount of steam. Equation 5-25 describes the heat transfer from the turbine exhaust gas to the water stream with and without the effects of fouling.

$$\dot{Q}_{Water} = \dot{m}_{H2O}(h_{out} - h_{in}) = 40{,}675\frac{kJ}{s} \quad \text{Eq. 5-26}$$

$$\dot{Q}_{Water} = \frac{\overline{T}_{EG} - T_{So}}{1/h_o A} = \frac{A(\overline{T}_{EG} - T_{Si})}{\frac{1}{h_o} + R_{fouling}} \quad \text{Eq. 5-27}$$

The HRSG inlet temperature of the turbine exhaust gas varies with GT load and ambient conditions. An average exhaust gas temperature of 783^{o}K (950^{o}F) is used along with the properties of air to apply an ideal gas model for the heat transfer from the exhaust gas to the water stream. Table 5-1 describes typical fouling resistances for heat transfer from both flue gas from natural gas and No.2 oil to a water stream.

Flue Gas Flow	Fouling Thermal Resistance	
	m^2K/W	hr –ft^2 F/BTU
Natural Gas Flue Gas	0.0029	0.005
No. 2 Oil Flue Gas	0.0012	0.002
Source: http://www.processassociates.com/process/heat/fouling2.htm		

Table 5-1

To determine the convective heat transfer coefficient, h_o, a Reynolds number of 3,685 is calculated based on the outside tube diameter, $D = .05m$. The Nusselt number is calculated based on equation 5-26 for forced convection for cross flow across a tube. A convective heat transfer coefficient of 20.6 W/mK was determined which is consistent with forced convection in a turbulent air flow.

$$Nu_D = C\,\mathrm{Re}_D^m\,\mathrm{Pr}^{1/3} \quad \text{Eq. 5-28}$$

Based on the above mentioned assumptions, parameters, coefficients, and equations, a 12K temperature change is experienced across a deposit buildup due to natural gas flue gas. When applying equation 5-9, this temperature change corresponds to an 8% increase in availability loss. When No.2 oil flue gas is considered, a 4.6 temperature change across the deposit build is experienced, and a 4% increase in availability loss is seen. The natural gas flue gas assumption has greater validity since the HRSG only burns natural gas and 99% of the annual GT fuel use is natural gas. This analysis leads to the conclusion that fouling on the heat transfer surface does create an increase temperature drop from the turbine exhaust gas to the water stream. Additionally, it is this increase that leads to the increase in availability loss and decrease in the effectiveness of the HRSG.

Fouling can also increase the pressure drop across the HRSG by creating additional fluid friction. An increased HRSG inlet pressure coincides with a higher gas turbine outlet pressure and a lower gas turbine efficiency. Data shows that in 1997 the average HRSG inlet pressure was 10 psig (1.68 atm), that value has steadily risen to an average value of 13 psig (1.88 atm). This is a 12% increase in the pressure drop across the HRSG since going online in fiscal year 1997. Over time, as fouling persists the availability loss and pressure drop will increase. This will continue to decrease the effectiveness of the HRSG and may start to affect the GT efficiency. The decrease in performance in the HRSG also affects the overall combined GT HRSG efficiency defined as,

$$\eta_{Combined} = \frac{\dot{W}_{Electric} + \dot{Q}_{HRSG\ Steam}}{\dot{Q}_{GT\ Fuel\ Input} + \dot{Q}_{HRSG\ Fuel\ Input}} \qquad \text{Eq. 5-29}$$

Figure 5-6 displays how the GT HRSG combined system efficiency has decreased since 1998.

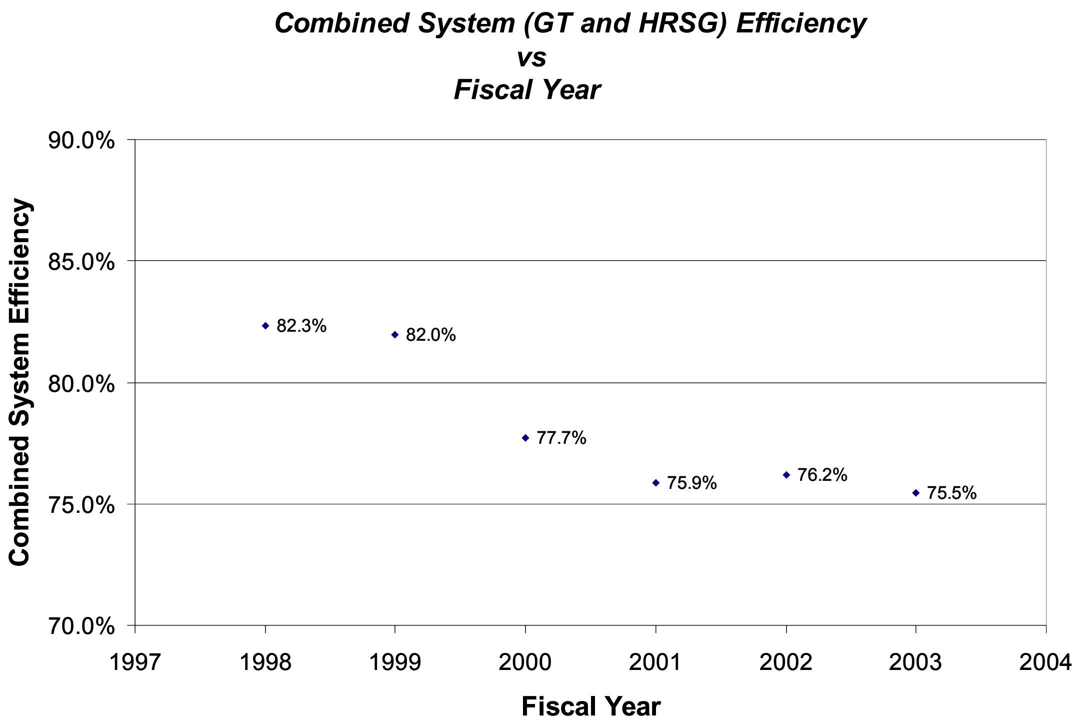

Figure 5-6: Combined System (GT and HRSG) Efficiency vs Fiscal Year

The combined system efficiency has decreased by 8% from 1998 to 2003. As expected it is the same magnitude as the reduction in the HRSG efficiency since the gas turbine performance is relatively constant. The reduction in the HRSG efficiency is decreasing the overall performance of the combined system.

Performing this type of plant assessment provides insight into trends of component and system performances. It locates losses within the system so that steps can be taken to counteract component degradation and other factors, such as fouling that may increase the loss of potential to produce a desired output. The availability analysis performed showed a decrease in the effectiveness of heat transfer from the turbine exhaust gas to the water stream. A first law and thermal resistance analysis validated that the effects of fouling on the outer heat transfer surface can cause such a decrease in the HRSG effectiveness. By applying both principles a good understanding of the system performance is now formed. Future work can look at long term effects of increasing fouling effects on the effectiveness of the HRSG and the impact this has on the increasing HRSG pressure drop that ultimately affects the GT performance.

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Chapter 6 MIT's Total GHG Emissions: Summary and Conclusions

This thesis has calculated MIT's total emissions from utility use, commuters, and campus solid waste. Utility, transportation, and solid waste emissions account for approximately 90%, 9%, and 1% respectively of the total campus emissions. Figure 6-1 represents the total equivalent GHG emissions for the MIT campus from 1990 to 2003. To reach the desired 20% GHG emission reduction, from 1990 levels, by the year 2010 the campus would have to decrease emission rates by 29% of 2003 emission levels.

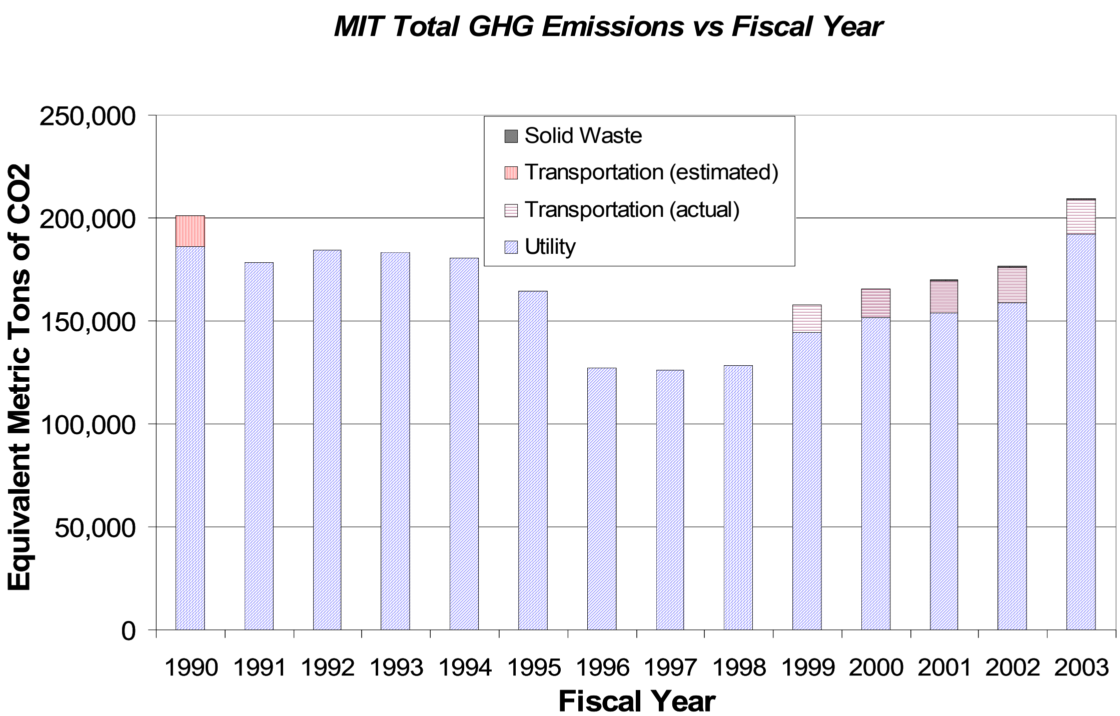

Figure 6-1: MIT Total GHG Emissions vs Fiscal Year – Accounts for total campus emissions due to utility, transportation, and solid waste. An estimate for 1990 transportation emissions allows for a more accurate campus emissions goal of 161,150 equivalent metric tons of CO_2. Therefore, a reduction of 22% of 2003 campus emission levels would be needed to attain the city of Cambridge's 20% reduction target from 1990 emission levels

The 1990 level considered, for the 29% emission reduction target, only takes into account emissions due to utility use, since data for transportation and solid waste were not available till fiscal year 1999 and 2000. An adjusted emissions reduction target can be calculated to take into account emissions due to transportation and solid waste. Since the total campus population has remained relatively constant since 1990, an average of the five years actual transportation emissions, 15,212 equivalent metric tons of CO_2, can be added to 1990 utility emission levels. Therefore MIT's actual emissions target would be 161,150 metric tons of equivalent CO_2, and the campus would have to decrease 2003 emissions levels by 22%. This analysis has also shown that the equivalent metric tons of CO_2 due to methane and nitrous oxide emissions are insignificant when compared to direct CO_2 emissions.

Figure 6-2 represents emissions due to transportation, which are included after fiscal year 1999, and emissions from campus solid waste disposal, starting from 2000 fiscal year. Solid waste emissions account for approximately 0.5% of the total campus emissions and therefore are difficult to see on the graph.

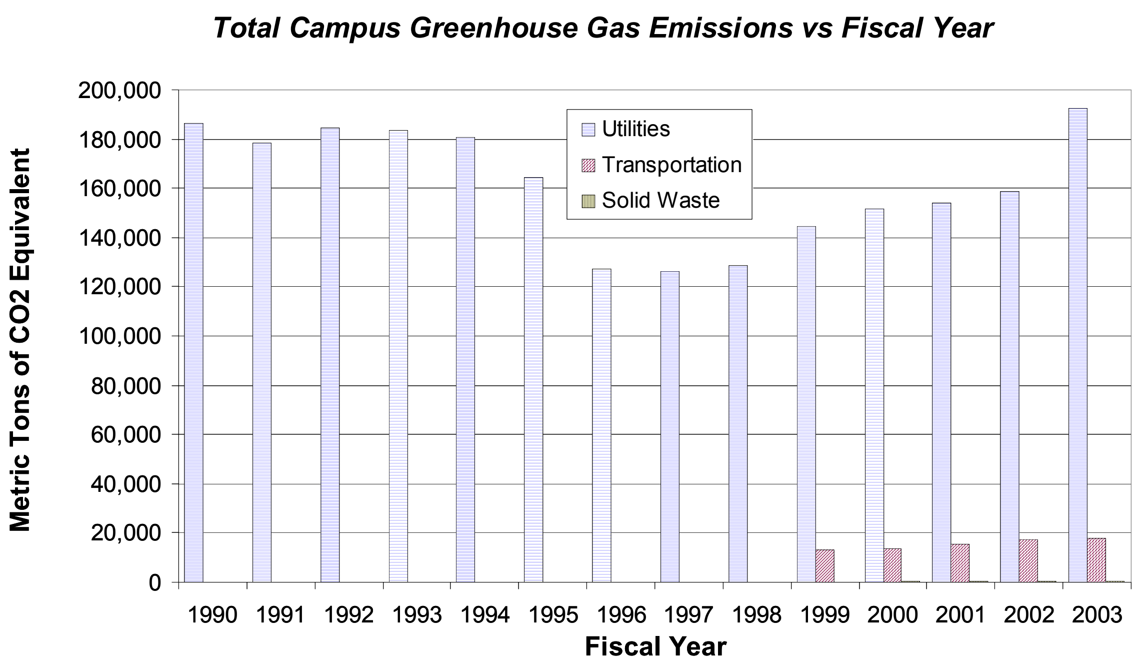

Figure 6-2: Total Campus GHG Emissions Separated By Sector vs Fiscal Year

Developing and implementing programs that target utility emission reduction strategies would have the largest impact on GHG emission levels, since as seen in figure 6-2, proportionally emissions released from campus utility use dominate. Developing strategies and programs related to utility production and consumption would tackle utility emissions from both a generating and a demand side. Continual monitoring of plant and component performances is necessary to obtain the largest product output for a given energy/emission input. As component performance decreases and more fuel is burned, emission levels will rise proportionally to fuel use even if campus demand is held constant. Understanding where and why losses occur in the system creates the opportunity to reverse such trends and decrease emissions. Increasing campus emission trends are also largely governed by the increase in the campus energy demand. Promoting energy conservation within the MIT population is an additional approach to decrease utility use and thus reduce utility emissions.

Transportation emissions are approximately 9% of the total campus GHG emission. Transportation emission rates are relatively low because of the high utilization of public transportation by the MIT commuting population. Reasons for high public transportation use include limited parking permit availability and bus/T pass subsides. If the number of people that commute by bus or subway all drove a car to campus the GHG emissions due to transportation would be about 5 times larger, equivalent to 48% of the emissions due to campus utility consumption. Therefore, governmental and campus programs are directly effecting the amount of GHG emissions attributed to the MIT population commuting to and from campus. More incentives to use public transportation, promoting ridesharing, increased shuttle service, and advocating the use of green transportation alternatives, such as cycling and walking could continue to decrease emissions due to commuters.

Solid waste emissions account for 0.5% of MIT total GHG emissions. When compared to emissions from campus utility use and commuters, solid waste emissions represents 0.3% and 2.5% respectively. Though it represents a small portion of campus emissions, solid waste emissions will continue to decrease as campus recycling levels rise to 40%. Increasing rates of composting and promoting reduced consumption will also reduce campus solid waste levels.

A performance assessment and availability analysis, on the MIT cogeneration plant, provided component performance trends and identified losses within the system. Our analysis has shown that the GT efficiency has remained constant over the past 6 years while the heat recovery steam generator effectiveness has decreased by 11%. This decrease in effectiveness is mostly due to deposit buildup on the heat transfer surface thus raising the availability loss and decreasing the effectiveness of the HRSG. Increasing the effectiveness of the HRSG through scheduled cleaning maintenance would decrease the added the resistance, and therefore would decrease fuel use and thus lower utility GHG emissions.

This MIT campus GHG emission inventory and plant assessment has quantified MIT's environmental impact on the local and global community. These analyses aid in the understanding of campus emission trends and identify promising emission reduction techniques. This analysis is an important step in developing plans to reduce campus emissions and join the city of Cambridge's environmental protection commitment.

Appendix A Fiscal Year 2000 Sample Electricity Purchase and Production Emission Calculation

1. **Purchased Electricity**

   Fiscal Year – 2000

   Purchased Electricity = 22,421,000 kW-hr

- To properly calculate the amount of green house gases (GHG'S) associated with purchased electricity one needs to first find the actual amount of energy that was consumed at the power plant to produced this amount of electricity. The first step in doing this would be to determine how much electricity was first produced at the power plant before transmitted to MIT. Power plants have to produce more electricity than is actually delivered due to distribution and transmission losses. In the New England power grid system, distribution and transmission losses are approximately 8%.

$$Electricity\ Produced\ at\ Power\ Plant = \frac{Electricty\ Purchased}{1-\%\ losses}$$

$$Electricity\ Produced\ at\ Power\ Plant = \frac{22.421{,}000\ kW-hr}{1-.08} = 24{,}370{,}652\ kW-hr$$

$$Energy\ of\ Produced\ Electricity = Electricity\ Produced \times energy\ conversion$$

$$Energy\ of\ Produced\ Electricity = 24{,}370{,}652\ kW-hr \times \frac{3413\ BTU}{1\ kW-hr} \times \frac{1\ MMBTU}{1{,}000{,}000\ BTU} = 83{,}177\ MMBTU$$

- GHG emissions depend on the type of fuel or power used to produce a given amount of electricity. Therefore, knowing the energy source portfolio of New England power plants is necessary. Power plants use a variety of sources to produce electricity. The New England energy portfolio consists of coal, natural gas, distillate oil, residual oil, hydroelectric, nuclear power, and renewable energy. These sources vary due to availability and price. Massachusetts's electricity energy portfolio from 1990-2003 was obtained from: http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls.
  Along with knowing how energy is produced it is also necessary to know the efficiency of production by each source. This will allow us to calculate the total energy consumed at the power plant by energy source to produce a given amount of electricity.

% Source of Electricity Production		Efficiency of Power Production (%)
Fuel		
Coal	28.8%	34.0%
Natural Gas	27.6%	41.2%
Distillate Oil (1 - 4)	22.6%	34.2%
Residual Oil (5 - 6)	0.0%	34.2%
Hydroelectric	0.9%	35.0%
Nuclear	14.2%	34.0%
Renewable	5.9%	35.0%

2000 energy source and efficiency of power production
www.transportation.anl.gov:80/ttrdc/greet/index.html
http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls.

Table 1

$$Consumption\ of\ \Pr oduced\ Electricity\ by\ Source = Total\ amount\ of\ energy \times \%\ Source\ of\ electcity\ production$$

$$= 83{,}177\ MMBTU \times .288 = 23{,}955\ MMBTU \quad - Coal$$

$$= 83{,}177\ MMBTU \times .276 = 22{,}957\ MMBTU \quad - Natural\ Gas$$

$$= 83{,}177\ MMBTU \times .226 = 18{,}798\ MMBTU \quad - No\ 2\ Oil$$

$$= 83{,}177\ MMBTU \times .009 = 748.6\ MMBTU \quad - Hydroelectric$$

$$= 83{,}177\ MMBTU \times .142 = 11{,}811\ MMBTU \quad - Nuclear$$

$$= 83{,}177\ MMBTU \times .059 = 4{,}907\ MMBTU \quad - \mathrm{Re}\,newable$$

$$EnergyConsumed\ at\ thePowerPlant = \frac{Consumption\ of\ \Pr oduced\ Electricity\ by\ Source}{Efficiency\ of\ Source}$$

$$= \frac{23{,}955\ MMBTU}{.34} = 70{,}456\ MMBTU \quad - Coal$$

$$= \frac{22{,}955\ MMBTU}{.412} = 55{,}716\ MMBTU \quad - Natural\ Gas$$

$$= \frac{18{,}798\ MMBTU}{.342} = 54{,}965\ MMBTU \quad - No\ 2\ Oil$$

$$= \frac{748.6\ MMBTU}{.35} = 2{,}139\ MMBTU \quad - Hydroelectric$$

$$= \frac{11{,}811\ MMBTU}{.34} = 34{,}738\ MMBTU \quad - Nuclear$$

$$= \frac{4{,}907\ MMBTU}{.059} = 83{,}169\ MMBTU \quad - \mathrm{Re}\,newables$$

$$Total\ Energy\ Consumed\ at\ Power\ Plant = 301{,}183\ MMBTU$$

- GHG emissions can be calculated once the total energy consumed by source is known. Each type of fuel has associated with it an emission factor for a variety of green house gases. An emission factors is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. Emission factors are based upon emission testing performed at similar facilities and may not accurately reflect emissions at a single source. Emission factors vary depending on equipment and operating conditions and therefore averages are taken from available industry-wide data.

GHG Emission Factors for Electric Utilities			
Fuel	Carbon Emission Factors (Metric Tons C / MMBTU)	Methane Emission Factors (g/MMBTU)	Nitrous Oxide Emission Factors (g/MMBTU)
Coal	0.027	0.75	0.298
Natural Gas	0.01633	1.1	1.1
Distillate Oil (1 - 4)	0.0225	0.91	0.36
Residual Oil (5 - 6)	0.0225	0.91	0.36
Hydroelectric	0	0	0
Nuclear	0	0	0
Renewable	0	0	0

Table 2

$$
\begin{aligned}
Carbon\,Content &= Energy\,Consumption \times Emission\,Factor \\
&= 70{,}456\,MMBTU \times .027 = 1{,}902\,Metric\,Tons\,C && -Coal \\
&= 55{,}716\,MMBTU \times .01633 = 910\,Metric\,Tons\,C && -Natural\,Gas \\
&= 54{,}965\,MMBTU \times .0225 = 1{,}237\,Metric\,Tons\,C && -No\,2\,Oil \\
&= 2{,}139\,MMBTU \times 0 = 0 && -Hydroelectric \\
&= 34{,}738\,MMBTU \times 0 = 0 && -Nuclear \\
&= 83{,}169\,MMBTU \times 0 = 0 && -\mathrm{Re}newables
\end{aligned}
$$

$$Total\,Metric\,Tons\,of\,Carbon = 4{,}049\,Metric\,Tons\,C$$

- The total metric tons of carbon, is the amount of carbon in the fuel inputs. During combustion fuel and air react and produce carbon dioxide, water, and particulates. 99% of the carbon oxidizes, while the amount of particulates such as methane and nitrous oxide depend on the combustion environment.

$$
\begin{aligned}
Metric\,Tons\,C &= Total\,Metric\,Tons\,C \times \%\,Oxidized \\
&= 4{,}049\,Metric\,Tons\,C \times .99 = 4{,}008\,Metric\,Tons\,C
\end{aligned}
$$

- The next step is to convert the amount of carbon into carbon dioxide.

$$Metric\,Tons\,of\;CO_2 = Metric\;Tons\,C \times \frac{Metric\;Tons\;CO_2}{Metric\;Tons\;C}$$

$$= 4{,}008\,Metric\;Tons\;C \times \frac{44\,Metric\;Tons\,CO_2}{12\,Metric\;Tons\;C} = 14{,}698\,Metric\;Tons\;CO_2$$

- Once the total energy consumed is known then the effects of other green house gases, such as methane and nitrous oxide can also be analyzed by using their respective emission factors given in table 2.
-

$$Energy\,Consumed\;\;at\,the\,Power\;Plant\;=\frac{Consumption\;of\;Produced\;\;Electricity\;by\;Source}{Efficiency\;\;of\;\;Source}$$

$$= \frac{23{,}955\,MMBTU}{.34} = 70{,}456\,MMBTU \qquad -Coal$$

$$= \frac{22{,}955\,MMBTU}{.412} = 55{,}716\,MMBTU \qquad -Natural\;\;Gas$$

$$= \frac{18{,}798\,MMBTU}{.342} = 54{,}965\,MMBTU \qquad -No\;2\,Oil$$

$$= \frac{748.6\,MMBTU}{.35} = 2{,}139\,MMBTU \qquad -Hydroelectric$$

$$= \frac{11{,}811\,MMBTU}{.34} = 34{,}738\,MMBTU \qquad -Nuclear$$

$$= \frac{4{,}907\,MMBTU}{.059} = 83{,}169\,MMBTU \qquad -\mathrm{Re}\,newables$$

$$Total\;\;Energy\;\;Consumed\;\;at\;Power\;\;Plant\;\;=\;\;301{,}183\,MMBTU$$

$$Amount\,of\;\;Methane = Energy\,Consumption \times Emission\,Factor$$

$$= \frac{70{,}456\,MMBTU \times .75}{10000} = 52.8\,kg\,CH_4 \qquad -Coal$$

$$= \frac{55{,}716\,MMBTU \times .1.1}{1000} = 61.3\,kg\,CH_4 \qquad -Natural\,Gas$$

$$= \frac{54{,}965\,MMBTU \times .91}{1000} = 50\,kg\,CH_4 \qquad -No\,2\,Oil$$

$$= 2{,}139\,MMBTU \times 0 = 0 \qquad -Hydroelectric$$

$$= 34{,}738\,MMBTU \times 0 = 0 \qquad -Nuclear$$

$$= 83{,}169\,MMBTU \times 0 = 0 \qquad -\mathrm{Re}\,newables$$

$$Total\;\;CH_4 = 164.1\;kg\,CH_4$$

- To be able to compare different types of green house gas' effects we need to convert to one common unit of measurement, metric tons of carbon dioxide equivalents. This is done by using a gases global warming potential (GWP). GWPs are used to compare the abilities of different green house gases to trap heat in the atmosphere. GWPs are based on the radioactive efficiency (heat-absorbing ability) of each gas relative to that of carbon dioxide, as well as the decay rate of each gas (the amount removed from the atmosphere over a given time period) relative to that of CO_2. The GWP provides a construct for converting emissions of various gases into a common measure of carbon dioxide equivalents, which allows climate analysts to compare the impact of various green house gases. http://www.eia.doe.gov/oiaf/1605/ggrpt/summary/global.html

Global Warming Potential (GWP)	
Methane	21
Nitrous Oxide	310

Source: http://www.epa.gov/appdstar/pdf/brochure.pdf
GWP Units – kg CO_2/ kg Pollutant

Table 3

$$CH_4 \ Total\ Metric Tons\ CO_2\ Equivalents = Total\ CH_4 \times GWP$$
$$= \frac{164.1 kg\ CH_4 \times 21}{1000} = 3.4\ Metric Tons\ CO_2\ Equivalents$$

- The same step is repeated of other green house gases and added together and the total metric tons of CO2 emitted by the power plant for a given amount of electricity bought is calculated.

2. Purchased Fuel

Fiscal Year – 2000

Purchased Fuel:

No 2 Oil - 46,861 gallons

No 6 Oil - 1,664,735 gallons

Natural Gas - 1,953,999 MMBTU

- The first step is to calculate the energy content of the fuel used, which is done by making use of the appropriate heating value for a particular fuel. The heating values is the quantity of heat generated by complete combustion of a unit of specific fuel is constant and is termed the heating value, heat of combustion, or caloric value of that fuel. It can be determined by measuring the heat released during combustion of a known quantity of the fuel in a calorimeter. Depending on the state that water is in, vapor or liquid, and higher or lower heating value is used. Burning fuel produces both CO_2 and H_2O, if the water is in the liquid form then the higher heating value (HHV) is used. It includes the latent heat of vaporization and is determined when water vapor in the fuel combustion is condensed. If the water is in the gaseous form then the lower heating value (LHV) is used. The latent heat of vaporization is not included. In the United States the convention is to use the higher value. Deciding which heating value to use is arbitrary and the only warning is to be consistent throughout the calculation.

Fuel	Higher Heating Value	Units
No 2 Oil	141,000	BTU/gal
No 6 Oil	142,000	BTU/gal
Natural Gas	1040	BTU/scf

Table 4

- Here is an example calculation using No 2 oil.

$$Energy\ Content\ \ No\,2\ Oil = Amount\,Fuel \times HHV$$

$$= 48{,}861\,gallons \times 141{,}000\frac{BTU}{gal} \times \frac{1MMBTU}{10^6\,BTU} = 6{,}889\,MMBTU$$

- Once the energy content is known the calculation is the same as the example done above in the electricity calculation.

$$Carbon\ \ Content = Energy\,Consumption \times Emission\,Factor$$
$$= 6{,}889\,MMBTU \times .0225\frac{Metric\ Tons\,C}{MMBTU} = 155.0\,Metric\,Tons\,C$$

$$Metric\,Tons\,of\ CO_2 = Metric\ Tons\,C \times \frac{Metric\ Tons\ CO_2}{Metric\ Tons\ C}$$
$$= 155.0\,Metric\ Tons\ C \times \frac{44\,Metric\ Tons\,CO_2}{12\,Metric\ Tons\ C} = 568.4\,Metric\,Tons\ CO_2$$

- The same calculation can also be done for the other green house gases.

$$Amount\,of\ Methane = Energy\,Consumption \times Emission\,Factor$$
$$= \frac{6{,}889\,MMBTU \times .91}{1000} = 6.3\ kg\,CH_4$$

$$Total\,Metric\ Tons\ of\ CO_2\ \ Equivalents\,due\ to\,CH_4 = Total\,CH_4 \times GWP$$
$$= \frac{6.3\ kg\,CH_4 \times 21}{1000} = 0.131\ Metric\,Tons\ CO_2\ \ Equivalents$$

The same procedure can be applied for the all of the fuels purchased by MIT.

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Appendix B GHG Constants and Conversions

Carbon Emission Factors	
Fuel	Factor
No 2 Oil	0.0225
No 6 Oi	0.0225
Natural Gas	0.01633
Coal	0.0265
Propane	0.01951

Carbon Emission Factors Units - Metric Tons of Carbon / MMBTU
Source - Emission Factors - www.cleanair-coolplanet.org
Stationary Emission Factors

Fuel	Higher Heating Value	Units
No 2 Oil	141,000	BTU/gal
No 6 Oil	142,000	BTU/gal
Natural Gas	1040	BTU/scf

Conversions	
SI Units	**English Units**
1kW-hr	3413 BTU
1 gal	0.1337 scf
1 barrel	6.3 MMBTU
1 barrel	42 gal
1 Ton Cilled Water	12,000 BTU/hr
1 kg	2.2046 lb

Other GHG Emission Factors				
	Methane (CH4)	**Nitrious Oxide (N2O)**	**Methane (CH4)**	**Nitrious Oxide (N2O)**
	Sationary Sources		**Electric Utilities**	
Fuel	Factor		Factor	
No 2 Oil	0.7	0.357	0.91	0.36
No 6 Oi	0.7	0.357	0.91	0.36
Natural Gas	1.1	1.1	1.1	1.1
Coal	0.75	0.298	0.75	0.298
Propane	1.08	4.86	-	-

Emission Factors Units - g / MMBTU, Stationary Emission Factors, Transmission Losses = 8%
Source - Emission Factors - www.cleanair-coolplanet.org

Global Warming Potential (GWP)	
Methane	21
Nitrious Oxide	310

Source - Emission Factors - www.cleanair-coolplanet.org

GWP Units - kg of CO2/kg pollutant

1,000 kg = 1 metric ton

Mole fraction yi,00 of gases in a standard atmosphere for relative humidity's of 60, 80, and 100 percent

	Relative Humidity		
Substance	**60%**	**80%**	**100%**
N2	0.7662	0.7613	0.7564
O2	0.2055	0.2042	0.2029
CO2	0.0003	0.0003	0.0003
H2O	0.0188	0.025	0.0313
Other	0.0092	0.0092	0.0091

Advanced Therodynamics For Engineers

Author: Kenneth Wark, JR.

The lower heating value, higher heating value, and chemical availability for various pure fuels, in kJ/kmol in the restricted dead state, T=25C and P=1atm

			Chemical Availability	
Fuel	**LHV**	**HHV**	**RH = 100%**	**RH = 60%**
H2(g)	241.8	285.8	235.2	237.6
CO(g)	283	283	275.4	275.4
C(s)	393.5	393.5	410.5	410.2
CH4(g)	802.3	890.3	829.8	832.4

Advanced Therodynamics For Engineers

Author: Kenneth Wark, JR.

Appendix C Emission Calculator Spreadsheets

Boilers						
Fiscal Year	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Inputs/Outputs						
No 6 Oil HHV (MMBTU/gal)	0.142	0.142	0.142	0.142	0.142	0.142
Natural Gas HHV (MMBTU/E6 scf)	1040	1040	1040	1040	1040	1040
Flue Gas Specific Heat (BTU/lbF)	0.264	0.264	0.264	0.264	0.264	0.264
Total No 6 Oil (gallons)	721,052	1,783,501	1,664,735	1,396,046	1,335,796	2,368,409
Boiler 3						
Fuel						
Natural Gas (MMBTU)	77,702	38,825	52,511	9,416	31,664	126,904
Natural Gas (scf/yr)	74,713,285	37,331,492	50,491,150	9,053,840	30,446,196	122,022,776
Boiler Feed Water						
Mass Flow Rate (lbs/yr)	104,171,209	74,626,311	94,881,374	67,424,535	110,024,899	202,108,824
Temperature (F)	225	225	225	225	225	225
Enthalpy (BTU/lb)	193	193	193	193	193	193
Steam Produced						
Steam Produced (lbs)	97,061,637	70,032,775	73,065,095	62,200,230	101,579,040	177,985,034
Temperature (F)	450	450	450	450	450	450
Pressure (Psig)	200	200	200	200	200	200
Enthalpy (BTU/lb)	1239	1239	1239	1239	1239	1239
Boiler Blowdown						
Mass Flow Rate (lbs/yr)	7,109,572	4,593,536	21,816,278	5,224,305	8,445,859	24,123,790
Saturation Temperature (F) @ 200psig	387	387	387	387	387	387
Enthalpy (BTU/lb) Saturated Liquid	362	362	362	362	362	362
% Blowdown Water	6.8%	6.2%	23.0%	7.7%	7.7%	11.9%

Boiler 4						
Fuel						
Natural Gas (MMBTU)	65,612	60,228	90,500	22,236	40,398	98,566
Natural Gas (scf/yr)	63,088,906	57,911,296	87,018,908	21,380,708	38,844,537	94,774,616
Boiler Feed Water						
Mass Flow Rate (lbs/yr)	77,540,595	102,684,989	122,669,107	88,926,429	86,550,846	187,139,435
Temperature (F)	225	225	225	225	225	225
Enthalpy (BTU/lb)	193	193	193	193	193	193
Steam Produced						
Steam Produced (lbs)	74,369,927	94,981,536	103,167,374	82,504,786	79,599,923	166,263,626
Temperature (F)	450	450	450	450	450	450
Pressure (Psig)	200	200	200	200	200	200
Enthalpy (BTU/lb)	1238	1238	1238	1238	1238	1238
Boiler Blowdown						
Mass Flow Rate (lbs/yr)	3,170,668	7,703,453	19,501,733	6,421,644	6,950,923	20,875,809
Saturation Temperature (F) @ 200psig	387	387	387	387	387	387
Enthalpy (BTU/lb) Saturated Liquid	362	362	362	362	362	362
% Blowdown Water	4.1%	7.5%	15.9%	7.2%	8.0%	11.2%
Boiler 5						
Fuel						
Natural Gas (MMBTU)	52,974	54,712	71,204	28,727	39,159	96,436
Natural Gas (scf/yr)	50,936,681	52,608,004	68,465,067	27,622,364	37,652,458	92,726,752
Boiler Feed Water						
Mass Flow Rate (lbs/yr)	69,995,703	74,479,807	64,555,592	64,299,383	49,614,761	186,414,562
Temperature (F)	225	225	225	225	225	225
Enthalpy (BTU/lb)	193	193	193	193	193	193
Steam Produced						
Steam Produced (lbs)	67,071,736	71,498,384	57,372,921	59,432,836	45,560,722	172,410,284
Temperature (F)	450	450	450	450	450	450
Enthalpy (BTU/lb)	1,239	1,239	1,239	1,239	1,239	1,239
Boiler Blowdown						

Energy Content (MMBTU)						
Boiler 3						
Fuel Energy Content						
Natural Gas (MMBTU)	77,702	38,825	52,511	9,416	31,664	126,904
Boiler Feed Water						
Energy Content (MMBTU)	20,105	14,403	18,312	13,013	21,235	39,007
Steam Generated						
Steam Energy Content (MMBTU)	120,259	86,771	90,528	77,066	125,856	220,523
Boiler Blowdown						
Energy Content (MMBTU)	2,574	1,663	7,897	1,891	3,057	8,733
Boiler 4						
Fuel Energy Content						
Natural Gas (MMBTU)	65,612	60,228	90,500	22,236	40,398	98,566
Boiler Feed Water						
Energy Content (MMBTU)	14,965	19,818	23,675	17,163	16,704	36,118
Steam Generated						
Steam Energy Content (MMBTU)	92,070	117,587	127,721	102,141	98,545	205,834
Boiler Blowdown						
Energy Content (MMBTU)	1,148	2,789	7,060	2,325	2,516	7,557
Boiler 5						
Fuel Energy Content						
Natural Gas (MMBTU)	52,974	54,712	71,204	28,727	39,159	96,436
Boiler Feed Water						
Energy Content (MMBTU)	13,509	14,375	12,459	12,410	9,576	35,978
Steam Generated						
Steam Energy Content (MMBTU)	83,102	88,586	71,085	73,637	56,450	213,616
Boiler Blowdown						
Energy Content (MMBTU)	1,058	1,079	2,600	1,762	1,468	5,070

Total No 6 Oil Input (gallons)	721,052	1,783,501	1,664,735	1,396,046	1,335,796	2,368,409
Total No 6 Oil Energy Input (MMBTU)	102,389	253,257	236,392	198,239	189,683	336,314
Total Natural Gas Input (MMBTU)	196,288	153,765	214,214	60,379	111,221	321,905
Total Boiler Blowdown Output (MMBTU)	4,780	5,531	17,557	5,978	7,041	21,359
Total Fuel Energy Input (MMBTU)	298,678	407,022	450,607	258,618	300,904	658,219
Total Feed Water Energy Input (MMBTU)	48,580	48,596	54,446	42,586	47,515	111,103
Total Boiler Steam Energy (MMBTU)	295,431	292,944	289,334	252,844	280,851	639,974
Total Boiler(3-5) System Efficiency	98.9%	72.0%	64.2%	97.8%	93.3%	97.2%

Gas Turbine						
Fiscal Year	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Inputs/Outputs						
GT Operating hours per year	6977.8	7,280	7,389	8,360	8,155	7,230
Operating Time Percent per year	79.7%	83.1%	84.4%	95.4%	93.1%	82.5%
Annual Average % Operating Load	68.9%	68.2%	78.7%	81.5%	85.1%	84.3%
Fuel						
Natural Gas (MMBTU)	1,246,019	1,291,964	1,638,851	1,937,349	1,958,598	1,674,624
Natural Gas (scf)	1,198,095,192	1,242,273,077	1,575,818,269	1,862,835,577	1,883,267,308	1,610,215,385
Natural Gas HHV (MMBTU/E6 scf)	1040	1040	1040	1040	1040	1040
No 2 Oil (gal/yr)	1,061,339	1,320,138	46,861	71,355	4,523	796,915
No 2 Oil HHV (BTU/ gal)	141,000	141,000	141,000	141,000	141,000	141,000
Turbine Exhaust Gas						
Mass Flow Rate (lbs/hr)	555,552	554,029	578,954	585,599	594,003	592,328
Temperature (F)	852.2	850.1	884.5	893.6	905.2	902.9
Specific Heat (BTU/lbF)	0.264	0.264	0.264	0.264	0.264	0.264
Electricity						
Electricity Generated (kW-hr/yr)	98,001,000	101,299,000	118,627,000	138,991,000	141,460,000	124,369,000

Energy Content (MMBTU)						
Fuel Energy Content						
Natural Gas (MMBTU)	1,246,019	1,291,964	1,638,851	1,937,349	1,958,598	1,674,624
No 2 Oil (MMBTU)	149,649	186,139	6,607	10,061	638	112,365
Turbine Exhaust Gas						
Energy Content (MMBTU)	947,267	982,910	1,110,493	1,289,450	1,295,167	1,136,178
Electricity						
Energy Content (MMBTU)	334,477	345,733	404,874	474,376	482,803	424,471
Total Energy In	1,395,668	1,478,103	1,645,458	1,947,410	1,959,236	1,786,989
Total Energy Out	1,281,744	1,328,643	1,515,367	1,763,827	1,777,970	1,560,649
Gas Turbine % Losses	8.2%	10.1%	7.9%	9.4%	9.3%	12.7%
% Exhaust Gas Energy	67.9%	66.5%	67.5%	66.2%	66.1%	63.6%
% Energy in Electricity Generated	24.0%	23.4%	24.6%	24.4%	24.6%	23.8%
Gas Turbine Efficiency	24.0%	23.4%	24.6%	24.4%	24.6%	23.8%

Heat Recovery Steam Generator						
Fiscal Year	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Inputs/Outputs						
Fuel						
Natural Gas (MMBTU)	95,500	87,798	100,934	83,595	65,358	86,239
Natural Gas (scf/yr)	91,826,923	84,421,154	97,052,188	80,380,144	62,844,108	82,922,291
Natural Gas HHV (MMBTU/E6 scf)	1040	1040	1040	1040	1040	1040
Turbine Exhaust Gas						
Energy Content (MMBTU)	947,267	982,910	1,110,493	1,289,450	1,295,167	1,136,178
Boiler Feed Water						
Mass Flow Rate (lbs/yr)	682,361,881	704,165,018	712,262,253	811,414,206	816,914,405	777,782,962
Temperature (F)	225	225	225	225	225	225
Enthalpy (BTU/lb)	193	193	193	193	193	193
HRSG Generated Steam						
Steam Generated (lbs/yr)	720,887,000	756,883,000	768,830,000	861,037,000	855,476,000	798,336,000
Temperature (F)	450	450	450	450	450	450
Pressure (psig)	200	200	200	200	200	200
Enthalpy (BTU/lb)	1,239	1,239	1,239	1,239	1,239	1,239
Sky Valve						
Amount of time open (days/1year)	2.4	3.1	5.1	1.1	1.8	1.0
Mass Flow Rate (lbs/yr)	4,486,763	5,980,580	9,952,158	2,445,358	4,028,619	2,130,912
Temperature (F)	450	450	450	450	450	450
Enthalpy (BTU/lb)	1239	1239	1239	1239	1239	1239
Boiler Blowdown						
Mass Flow Rate (lbs/yr)	13,647,238	14,083,300	14,245,245	16,228,284	16,338,288	15,555,659
Saturation Temperature (F) @ 200psig	387	387	387	387	387	387
Enthalpy (BTU/lb) Saturated Liquid	362	362	362	362	362	362
Attemporation Water						
Mass Flow Rate (lbs/yr)	56,659,120	72,781,862	80,765,150	68,296,436	58,928,502	38,239,609
Temperature (F)	225	225	225	225	225	225
Enthalpy (BTU/lb)	193	193	193	193	193	193

Energy Content (MMBTU)						
Fuel Energy Content						
Natural Gas (MMBTU)	95,500	87,798	100,934	83,595	65,358	86,239
Turbine Exhaust Gas						
Energy Content (MMBTU)	947,267	982,910	1,110,493	1,289,450	1,295,167	1,136,178
Boiler Feed Water						
Energy Content (MMBTU)	131,696	135,904	137,467	156,603	157,664	150,112
HRSG Generated Steam						
Steam Energy Content (MMBTU)	893,179	937,778	952,580	1,066,825	1,059,935	989,138
Sky Valve						
Released Steam Energy Content (MMBTU)	5,559	7,410	12,331	3,030	4,991	2,640
Boiler Blowdown						
Energy Content (MMBTU)	4,940	5,098	5,157	5,875	5,914	5,631
Attemporation Water						
Energy Content (MMBTU)	10,935	14,047	15,588	13,181	11,373	7,380
Total Energy In (MMBTU)	1,185,398	1,220,658	1,364,481	1,542,830	1,529,562	1,379,909
% Energy from Turbine Exhaust Gas	90.8%	91.8%	91.7%	93.9%	95.2%	92.9%
% Energy from Natural Gas Duct Firing	9.2%	8.2%	8.3%	6.1%	4.8%	7.1%
HRSG Efficiency	85.7%	87.6%	78.6%	77.7%	77.9%	80.9%

Chillers

Fiscal Year	1998	1999	2000	2001	2002	2003
Inputs/Outputs						
Steam Driven Chillers						
Constants						
Temperture (F)	450	450	450	450	450	450
Pressure (Psig)	200	200	200	200	200	200
Enthalpy (BTU/lb)	1239	1239	1239	1239	1239	1239
Chiller 1						
Amount of Steam Used (lbs/yr)	21,800,388	15,191,768	13,589,324	7,879,299	5,007,171	0
Amount of Chilled Water Produced (Tons/yr)	2,440,404	1,730,319	1,644,237	1,005,078	663,975	0
Chiller 2						
Amount of Steam Used (lbs/yr)	20,576,908	22,245,678	13,738,987	12,351,580	7,113,115	8,615,132
Amount of Chilled Water Produced (Tons/yr)	2,126,619	2,379,425	1,439,078	1,331,356	771,268	930,542
Chiller 3						
Amount of Steam Used (lbs/yr)	26,409,240	9,578,648	0	3,364,472	21,713,989	6,826,888
Amount of Chilled Water Produced (Tons/yr)	2,034,553	798,342	0	383,425	1,507,366	675,901
Chiller 4						
Amount of Steam Used (lbs/yr)	43,968,273	41,109,021	58,933,084	28,598,465	8,712,491	51,590,339
Amount of Chilled Water Produced (Tons)	3,979,847	5,018,809	5,434,468	2,432,846	969,304	5,006,201
Chiller 5						
Amount of Steam Used (lbs/yr)	228,003,278	259,983,242	261,538,625	144,894,373	168,092,892	115,861,249
Amount of Chilled Water Produced (Tons/yr)	7,532,783	13,375,403	18,493,538	23,533,894	13,492,333	19,876,545
Chiller 6 (Installed 7/01)						
Amount of Steam Used (lbs/yr)				341,560,677	113,748,962	72,679,167
Amount of Chilled Water Produced (Tons/yr)				341,561	113,749	72,679

Electric Driven Chillers						
Chiller 1						
Electricty Used (kW-hr)				206,321	57,523	70,071
Chiller 2						
Electricty Used (kW-hr)				0	444	38,795
Chiller 3						
Electricty Used (kW-hr)				64,101	44,386	51,496
Total Chilled Water Produced (Tons/Yr)				3,541,804	4,145,703	5,569,181

Total Energy Content						
Steazm Used (MMBTU)	422,199	431,306	430,924	667,386	401,917	316,655
Chilled Water Produced due to Steam Chillers (MMBTU)	21,737	27,963	32,414	34,834	21,022	31,874
Electrcity Used (MMBTU)	0	0	0	923	349	547
Chilled Water Produced due to Electric Chillers (MMBTU)	0	0	0	4,250	4,975	6,683
Total Energy Content of Chilled Water (MMBTU)	21,737	27,963	32,414	39,084	25,996	38,557
Total Energy Used to Produce Chilled Water (MMBTU)	422,199	431,306	430,924	668,309	402,267	317,202

Purchased Utilities & Fuel

Fiscal Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Purchased Fuel														
Natural Gas (MMBTU)	598,028	810,790	498,978	343,221	464,859	747,444	1,447,600	1,794,720	1,537,807	1,533,527	1,953,999	2,081,324	2,135,177	2,082,768
No 2 Oil (gallons)	0	0	0	0	0	0	207,121	276,163	1,061,339	1,320,138	46,861	71,355	4,523	796,915
No 2 Oil (MMBTU)	0	0	0	0	0	0	29,204	38,939	149,649	186,139	6,607	10,061	638	112,365
No 6 Oil (gallons))	3,985,887	1,957,028	4,456,465	5,382,697	5,010,599	3,247,817	1,806,655	333,627	721,052	1,783,501	1,664,735	1,396,046	1,335,796	2,368,409
No 6 Oil (MMBTU)	565,996	277,898	632,818	764,343	711,505	461,190	256,545	47,375	102,389	253,257	236,392	198,239	189,683	336,314
Purchased Utilities														
Purchased Electricity (kW-Hr)	145,270,248	144,958,398	145,875,313	145,788,160	142,731,295	126,687,645	27,000,000	16,665,000	23,308,000	24,344,280	22,421,000	18,389,804	22,173,369	45,018,095
Electricity Energy Content (MMBTU)	495,807	494,743	497,872	497,575	487,142	432,385	92,151	56,878	79,550	83,087	76,523	62,764	75,678	153,647
Purchased Steam (Mlbs)														
Purchased Chilled Water														

CO2 From Purchased Utilities & Fuel

Fiscal Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Purchased Electricity														
Purchased Electcity (Kw-hr)	145,270,248	144,958,398	145,875,313	145,788,160	142,731,295	126,687,645	27,000,000	16,665,000	23,308,000	24,344,280	22,421,000	18,389,804	22,173,369	45,018,095
Total Energy From Purchased Electcity (MMBTU)	495,807	494,743	497,872	497,575	487,142	432,385	92,151	56,878	79,550	83,087	76,523	62,764	75,678	153,647
Total Energy Consumed at Power Plant (MMBTU)														
Metric Tons of CO2	104,313	106,955	103,038	100,297	94,646	81,765	17,286	11,445	15,746	16,575	14,592	12,131	15,097	30,650
Equilvalent Metric Tons of CO2 due to Methane	7.8	7.8	7.8	7.8	7.7	6.8	1.5	0.9	1.3	1.3	1.2	1.0	1.2	2.4
Equilvalent Metric Tons of CO2 due to Nitrous Oxide	45.8	45.7	46.0	46.0	45.0	39.9	8.5	5.3	7.3	7.7	7.1	5.8	7.0	14.2
Total CO2 Emitted From Purchased Electricity	104,312.9	107,008.6	103,091.8	100,351.3	94,698.8	81,811.8	17,295.9	11,451.1	15,754.8	16,583.7	14,600.4	12,138.0	15,104.8	30,667.0
Purchased Fuel														
Natural Gas (MMBTU)	598,028	810,790	498,978	343,221	464,859	747,444	1,447,600	1,794,720	1,537,807	1,533,527	1,953,999	2,081,324	2,135,177	2,082,768
Metric Tons of CO2	35,629	48,305	29,728	20,448	27,695	44,531	86,244	106,925	91,618	91,363	116,414	124,000	127,208	124,086
Equivalent Metric Tons of CO2 due to Methane	13.8	18.7	11.5	7.9	10.7	17.3	33.4	41.5	35.5	35.4	45.1	48.1	49.3	48.1
Equivalent Metric Tons of CO2 due to Nitrous Oxide	203.9	276.5	170.2	117.0	158.5	254.9	493.6	612.0	524.4	522.9	666.3	709.7	728.1	710.2
Total Effective Metric Tons of CO2	35,846.6	48,599.9	29,909.4	20,573.1	27,864.3	44,802.8	86,771.1	107,578.0	92,178.3	91,921.7	117,125.4	124,757.4	127,985.5	124,844.0
No 2 Oil (MMBTU)	0	0	0	0	0	0	29,204	38,939	149,649	186,139	6,607	10,061	638	112,365
Metric Tons of CO2	0	0	0	0	0	0	2,385	3,180	12,223	15,203	540	822	52	9,177
Equivalent Metric Tons of CO2 due to Methane	0	0	0	0	0	0	0	1	2	3	0	0	0	2
Equivalent Metric Tons of CO2 due to Nitrous Oxide	0	0	0	0	0	0	3	4	17	21	1	1	0	12
Total Effective Metric Tons of CO2	0	0	0	0	0	0	2,389	3,185	12,241	15,226	540	823	52	9,191
No 6 Oil (MMBTU)	565,996	277,898	632,818	764,343	711,505	461,190	256,545	47,375	102,389	253,257	236,392	198,239	189,683	336,314
Metric Tons of CO2	46,228	22,697	51,685	62,428	58,112	37,668	20,953	3,869	8,363	20,685	19,307	16,191	15,492	27,468
Equivalent Metric Tons of CO2 due to Methane	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Equivalent Metric Tons of CO2 due to Nitrous Oxide	63	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Effective Metric Tons of CO2	46,299	22,697	51,685	62,428	58,112	37,668	20,953	3,869	8,363	20,685	19,307	16,191	15,492	27,468
Total CO2 Emitted From Purchased Fuel	81,857	71,297	81,595	83,001	85,976	82,471	110,113	114,633	112,782	127,833	136,973	141,772	143,530	161,504
Total CO2 Emitted From Utilities	186,170	178,306	184,687	183,352	180,675	164,282	127,409	126,084	128,537	144,416	151,574	153,910	158,635	192,171

Green House Gas Emissions

Fiscal Year	1998	1999	2000	2001	2002	2003
Fuel Inputs						
Fuel Energy Totals by Equipment						
Boiler (3-5)						
No 6 Oil (MMBTU)	102,389	253,257	236,392	198,239	189,683	336,314
Natural Gas (MMBTU)	196,288	153,765	214,214	60,379	111,221	321,905
Total Energy (MMBTU)	298,678	407,022	450,607	258,618	300,904	658,219
Gas Turbine						
Natural Gas (MMBTU)	1,246,019	1,291,964	1,638,851	1,937,349	1,958,598	1,674,624
No 2 Oil (MMBTU)	149,649	186,139	6,607	10,061	638	112,365
Total Energy (MMBTU)	1,395,668	1,478,103	1,645,458	1,947,410	1,959,236	1,786,989
HRSG						
Natural Gas (MMBTU)	95,500	87,798	100,934	83,595	65,358	86,239

CO2 Emissions by Equipment (Metric Tons of CO2)						
Boiler						
CO2 Emissions due to No 6 Oil	8,363	20,685	19,307	16,191	15,492	27,468
CO2 Emissions due to Natural Gas	11,636	9,115	12,698	3,579	6,593	19,082
Total Boiler CO2 Emissions	19,998	29,800	32,006	19,770	22,085	46,550
Gas Turbine						
CO2 Emissions due to Natural Gas	73,861	76,585	97,148	114,842	116,102	99,268
CO2 Emissions due to No 2 Oil	12,223	15,203	540	822	52	9,177
Total Gas Turbine CO2 Emissions	86,084	91,788	97,687	115,664	116,154	108,446
HRSG						
CO2 Emissions due to Natural Gas	5,661	5,204	5,983	4,955	3,874	5,112
Total Direct CO2 Emissions From the Cogen Plant	111,743.2	126,792.0	135,676.0	140,389.4	142,113.3	160,108.0

Methane Emissions by Equipment						
Boiler						
Methane Due to No 6 Oil (kg)	71.7	177.3	165.5	138.8	132.8	235.4
Methane Due to Natural Gas (kg)	215.9	169.1	235.6	66.4	122.3	354.1
Eqivalent Metric Tons of CO2	6.0	7.3	8.4	4.3	5.4	12.4
Gas Turbine						
Methane Due to Natural Gas (kg)	1,370.6	1,421.2	1,802.7	2,131.1	2,154.5	1,842.1
Methane Due to No 2 Oil (kg)	104.8	130.3	4.6	7.0	0.4	78.7
Eqivalent Metric Tons of CO2	31.0	32.6	38.0	44.9	45.3	40.3
HRSG						
Methane Due to Natural Gas (kg)	105.1	96.6	111.0	92.0	71.9	94.9
Eqivalent Metric Tons of CO2	2.2	2.0	2.3	1.9	1.5	2.0
Total Equivalent Metric Tons of CO2 Due to Methane	39.2	41.9	48.7	51.1	52.1	54.7

Nitrous Oxide Emissions by Equipment						
Boiler						
Nitrous Oxide Due To No 6 Oil (kg)	71.7	177.3	165.5	138.8	132.8	235.4
Nitrous Oxide Due To Natural Gas (kg)	215.9	169.1	235.6	66.4	122.3	354.1
Eqivalent Metric Tons of CO2	89.2	107.4	124.3	63.6	79.1	182.7
Gas Turbine						
Nitrous Oxide Due To Natural Gas (kg)	1,370.6	1,421.2	1,802.7	2,131.1	2,154.5	1,842.1
Nitrous Oxide Due To No 2 Oil (kg)	53.4	66.5	2.4	3.6	0.2	40.1
Eqivalent Metric Tons of CO2	441.5	461.2	559.6	661.7	668.0	583.5
HRSG						
Nitrous Oxide Due To Natural Gas (kg)	105.1	96.6	111.0	92.0	71.9	94.9
Eqivalent Metric Tons of CO2	32.6	29.9	34.4	28.5	22.3	29.4
Total Equivalent Metric Tons of CO2 Due to Nitrous Oxide	563.2	598.5	718.3	753.9	769.3	795.6

Equivalent Metric Tons of CO2 Apportioned to Steam, Electricity, Chilled Water

Fiscal Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Electricity Produced and Purchased														
Produced Electricity (MMBTU)									334,477	345,733	404,874	474,376	482,803	424,471
Purchased Electricity (MMBTU)	495,807	494,743	497,872	497,575	487,142	432,385	92,151	56,878	79,550	83,087	76,523	62,764	75,678	153,647
Total Electricity	495,807	494,743	497,872	497,575	487,142	432,385	92,151	56,878	414,028	428,821	481,397	537,141	558,481	578,118
% Electricity Produced	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	80.8%	80.6%	84.1%	88.3%	86.4%	73.4%
% Electricity Purchased	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	19.2%	19.4%	15.9%	11.7%	13.6%	26.6%
Purchased Electricity														
MTCDE Due to Purchased Electricity	104,313	107,009	103,092	100,351	94,699	81,812	17,296	11,451	15,755	16,584	14,600	12,138	15,105	30,667
Total MTCDE From Purchased Fuels (1990-1997)	81,857	71,297	81,595	83,001	85,976	82,471	110,113	114,633						
Gas Turbine														
Total Gas Turbine Energy (MMBTU)									1,395,668	1,478,103	1,645,458	1,947,410	1,959,236	1,786,989
Total Gas Turbine									86,556	92,282	98,285	116,370	116,867	109,069
MTCDE Due to Produced Electricity									22,587	24,013	26,260	31,297	31,735	29,665
MTCDE Due to Turbine Exhaust Gas									63,969	68,268	72,025	85,073	85,132	79,404
HRSG														
Total Fuel Input (MMBTU)									95,500	87,798	100,934	83,595	65,358	86,239
Total Turbine Exhaust Gas Input (MMBTU)									947,267	982,910	1,110,493	1,289,450	1,295,167	1,136,178
MTCDE Due to Duct Firing w/ NG									6,105	5,668	6,545	5,619	4,544	5,698
MTCDE in Turbine Exhaust Gas									63,969	68,268	72,025	85,073	85,132	79,404
Total HRSG MTCDE Emissions									70,074	73,936	78,570	90,692	89,676	85,102

Boiler (3-5)														
Total Fuel Input (MMBTU)									298,678	407,022	450,607	258,618	300,904	658,219
Total Boiler MTCDE Emissions									20,093	29,914	32,138	19,838	22,170	46,745
CO2 due to Steam, Chilled Water, and Electricity														
Steam														
Total Steam Produced (MMBTU) (Boilers and HRSG)									1,188,610	1,230,722	1,241,914	1,319,669	1,340,786	1,629,112
Total MTCDE Due to Steam Production									58,139	67,456	72,294	54,633	78,318	106,220
Chilled Water														
Total Steam Used (MMBTU)									422,199	431,306	430,924	667,386	401,917	316,655
Total Electicity Used (MMBTU)									0	0	0	923	349	547
% of steam used for Chillers									35.5%	35.0%	34.7%	50.6%	30.0%	19.4%
% of electricity used for Chillers									0.0%	0.0%	0.0%	0.2%	0.1%	0.1%
MTCDE Emissions Due to Steam Driven Chillers									32,028	36,394	38,414	55,898	33,527	25,627
MTCDE Emissions Due to Electric Driven Chillers									0	0	0	190	70	125
Total MTCDE Emissions Due to the Production of Chilled Water									32,028	36,394	38,414	56,087	33,597	25,752
Electicity														
MTCDE Emissions Due to Electricity Production									22,587	24,013	26,260	31,297	31,735	29,665
MTCDE Emissions Due to Purchased Electricty	104,313	107,009	103,092	100,351	94,699	81,812	17,296	11,451	15,755	16,584	14,600	12,138	15,105	30,667
Total MTCDE Emissions Due to Electricty	104,313	107,009	103,092	100,351	94,699	81,812	17,296	11,451	38,342	40,597	40,860	43,361	46,810	60,275
Total MTCDE Emitted	186,170	178,306	184,687	183,352	180,675	164,282	127,409	126,084	128,509	144,447	151,569	154,081	158,726	192,247

Appendix D Fiscal Year 2000 Example Calculation

This document provides detailed information about the excel spreadsheet that calculates green house gases (GHG) for the MIT Cogeneration Power Plant. It is separated by worksheet and piece of equipment. Though the MIT Cogeneration Plant came on line in July of 1995 the calculations begin in fiscal year 1998 due to the accuracy of the data that could be provided. The following steps and calculations were preformed for the fiscal year 2000. Within the excel spreadsheets certain rows are highlighted. These highlighted rows indicate information that would need to be inputted into the spreadsheet.

1. Boilers (3-5)

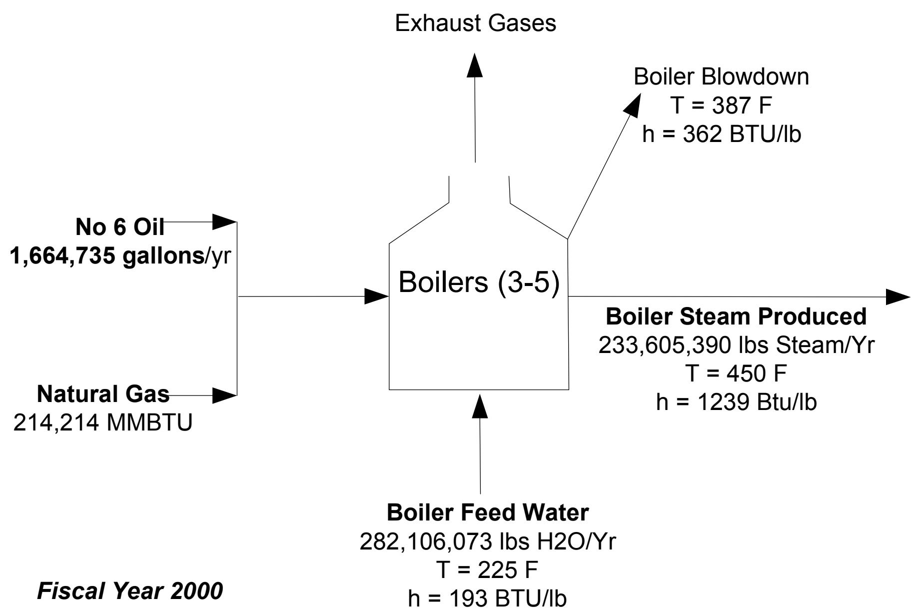
Needed Inputs:

- Amount of No 6 Oil (gallons/yr) per boiler
- Amount of Natural Gas (MMBTU/yr) per boiler
- Amount of Steam Produced (lbs/yr)
- Amount of Boiler Feed Water (lbs/yr)

Desired Outputs (MMBTU/yr):

- Total Energy in No 6 Oil
- Total Energy in Natural Gas
- Total Energy in Steam Produced
- Total Energy in Boiler Feed Water
- Total Energy in Boiler Blowdown
- Boiler Efficiency

The diagram below describes the total inputs and outputs that would need to be provided by institute.



Row 4: The higher heating value for No 6 fuel (0.142 MMBTU/gallon). The heating values is the quantity of heat generated by complete combustion of a unit of specific fuel is constant and is termed the heating value, heat of combustion, or caloric value of that fuel. It can be determined by measuring the heat released during combustion of a known quantity of the fuel in a calorimeter. Depending on the state that water is in, vapor or liquid, and higher or lower heating value is used. Burning fuel produces both CO_2 and H_2O, if the water is in the liquid form then the higher heating value (HHV) is used. It includes the latent heat of vaporization and is determined when water vapor in the fuel combustion is condensed. If the water is in the gaseous form then the lower heating value (LHV) is used. The latent heat of vaporization is not included. In the United States the convention is to use the higher value. Deciding which heating value to use is arbitrary and the only warning to be consistent throughout the calculation.

Row 5: The higher heating value for Natural Gas (1040 MMBTU/E6 scf)

Row6: Flue gas specific heat (BTU/lb F)

Row 7: Total amount of No 6 Oil (gallons/yr)

Note: Only the total amount of No 6 oil is known, therefore its energy content is on a total scale and not based on each boiler.

Row 8: Starts the specific inputs for each boiler, starting with boiler 3. Boiler inputs are broken up according to energy stream; fuel, boiler feed water, steam produced, flue gas, and boiler blowdown

Row 10: Total amount of natural gas burned in the number 3 boiler (MMBTU/yr)

Row 11: Total amount of natural gas (scf/yr). Conversion 1040 MMBTU/E6 scf)

$$Natural\ Gas\,(scf\ /\ yr) = \frac{Amount\ of\ Natural\ Gas\,(MMBTU)}{Conversion} = \frac{5{,}2510\ MMBTU}{1040\ MMBTU\ /\ E6\,scf} = 50{,}491{,}150\,scf\ /\ yr$$

Row 12: **Boiler Feed Water**

Row 13: Mass flow rate of the boiler feed water (lbs/yr)

Row 14: Average Boiler Feed Water Temperature (deg F)

$$Boiler\,Feedwater\ Temperature = 225\,F$$

Row 15: Enthalpy of water at the specified temperature (BTU/lb)

$$Boiler\,Feedwater\,Enthalpy = 193\,BTU\,/\,lb$$

Row 16: **Steam Produced**

Row 17: Amount of Steam produced (lbs/yr)

$$Amount\,of\ Steam\ Produced = 73{,}065{,}095\ \ lbs\,/\,year$$

Row 18: Temperature (deg F) of the steam produced

$$Steam\ Temperature = 450\,F$$

Row 19: Pressure (Psig) of the steam produced

$$Steam\ \mathrm{Pr}essure = 200\,Psig$$

Row 20: Enthalpy (BTU/lb) of the steam produced at the given temperature

$$Steam\,Enthalpy = 1239\,BTU\,/\,lb$$

Row 21: **Boiler Blowdown**

Blowdown is the stream of water that is bled from the boiler drum or in this case the steam supply to control the concentration of total solids in the boiler water. It can either be continuous or intermittent. The rate at which this occurs depends on the quality of water used. MIT's boiler blowdown rate varies from 2%-5%, which allows for 50-20 cycles of water use before dumping.

Row 22: Boiler Blowdown mass flow rate (lbs/yr)

$$Mass\ Flow\ Rate(lbs/yr) = Boiler\ Feedwater - Steam\ \text{Pr}oduced$$
$$= 94{,}881{,}374 - 73{,}065{,}095 = 21{,}816{,}279\ lbs/yr$$

Row23: Saturation Temperature of water at 200 psig.

$$Saturation\ \ Temperature = 387F$$

Row 24: Enthalpy (BTU/lb) of water at the given temperature

$$Boiler\ Blowdown\ \ Enthalpy = 362\ BTU/lb$$

Row25: Percent blowdown water – the percent of the total boiler feedwater that is lost to blowdown

$$\%Blowdown = \frac{Mass\ Flow\ of\ Blowdown\ Water}{Boiler\ Feedwater} = \frac{21{,}816{,}279\ lbs/yr}{94{,}881{,}374\ lbs/yr} = 23\%$$

Note: This system was designed to have a blowdown of 2% of the boiler feedwater

Row 26-61: The same above calculation was performed for Boilers 4 and 5.

Row 62: **Energy Content –** The section below calculates the energy content of each stream for a particular boiler

Row 63: Boiler 3 energy calculations

Row 64: **Fuel Energy**

Note: Does not include No 6 oil as noted above

Row 65: Natural Gas energy content – equals energy input in row 10

Row 66: **Boiler Feedwater**

Row 67: Boiler Feedwater energy content

$$BFW\ Energy\ Content = BFW\ Mass\ Flow\ Rate \times Enthalpy$$
$$= \frac{94{,}881{,}374\ lbs/yr \times 193\ BTU/lb}{10^6\ BTU/MMBTU} = 18{,}312\ MMBTU$$

Row 68: **Steam Generated**

Row 69: Steam energy Content

$$Steam\,Energy\,Content = Amt\,of\ Steam \times Enthalpy$$
$$= \frac{73{,}065{,}095\,lbs/yr \times 1239\,BTU/yr}{10^6\,BTU/MMBTU} = 90{,}528\,MMBTU$$

Row 70: **Boiler Blowdown**

Row 71: Boiler Blowdown energy content

$$Boiler\,Blowdown\ Energy\ Content = Amount\,of\ Boiler\ Blowdown \times Enthalpy$$
$$= \frac{21{,}816{,}278\,lbs/yr \times 362\,BTU/yr}{10^6\,BTU/MMBTU} = 7{,}897\,MMBTU$$

Row 72-90: The same above calculation was performed for Boilers 4 and 5

Row 91: Total No 6 Oil (gallons)

Row 92: Total No 6 Oil energy content

$$No\,6\,Oil\,Energy\,Content = Amount\,of\ fuel \times heating\ value$$
$$= 1{,}664{,}735\,gallons \times .142\,MMBTU/gallon$$
$$= 236{,}392\,MMBTU$$

Row 93: Total Natural Gas Input (MMBTU)

The sum of the natural gas inputs to each of the three boilers.

$Total\,Natural\,Gas\,Input = 214{,}214\,MMBTU/yr$

Row 94: Total Boiler Blowdown Output (MMBTU)

Sum of the each of the three boiler blowdowns.

$Total\,Boiler\,Blowdown\,Energy\,Content = 17{,}557\,MMBTU/yr$

Row 95: Total Fuel Energy Input (MMBTU) – sum of the natural gas and No 6 oil energy inputs.

$Total\,Input\,Fuel\,Energy = 450{,}607\,MMBTU/yr$

Row 96: Total Boiler Feedwater energy input (MMBTU)

The sum of each of the three boiler feedwater steams.

$Total\,Boiler\,Water\,Energy\,Content = 54{,}446\,MMBTU/yr$

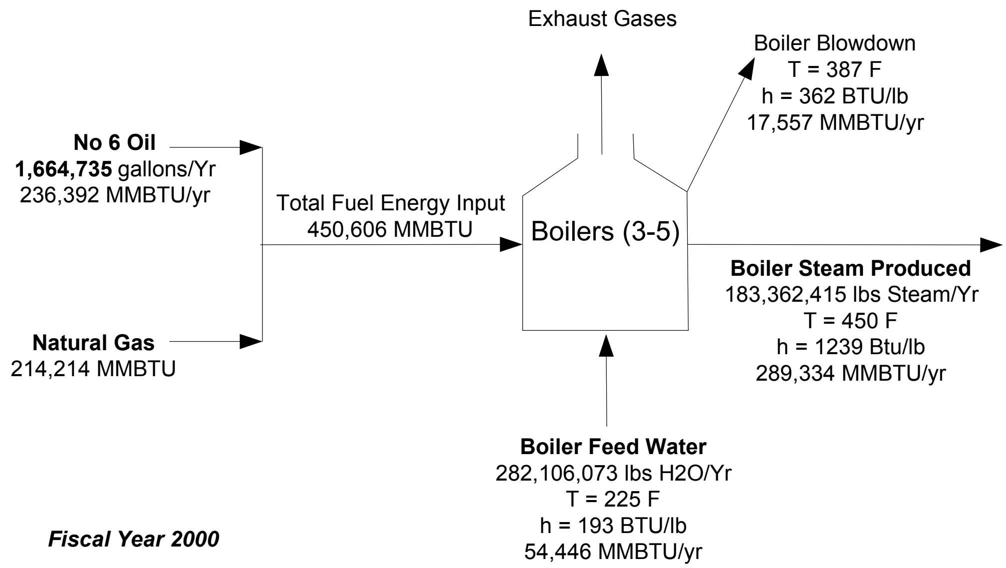
Row 97: Total Boiler Steam energy (MMBTU)

The sum of the energy content in the steam produced by each of the three boilers.

$$Total\ Steam\ Energy\ Content = 289{,}334\ MMBTU\ /\ yr$$

Row 98: Boiler efficiency

$$Boiler\ \ Efficiency = \frac{Total\ Boiler\ Steam\ \ Energy\,(MMBTU)}{Total\ Fuel\ Input\ Energy}$$



2. Gas Turbine

GT10 Gas Turbine used by the MIT power plant has an average maximum operating load of 21 MW. The gas turbine load varies on a daily basis depending on campus demand.

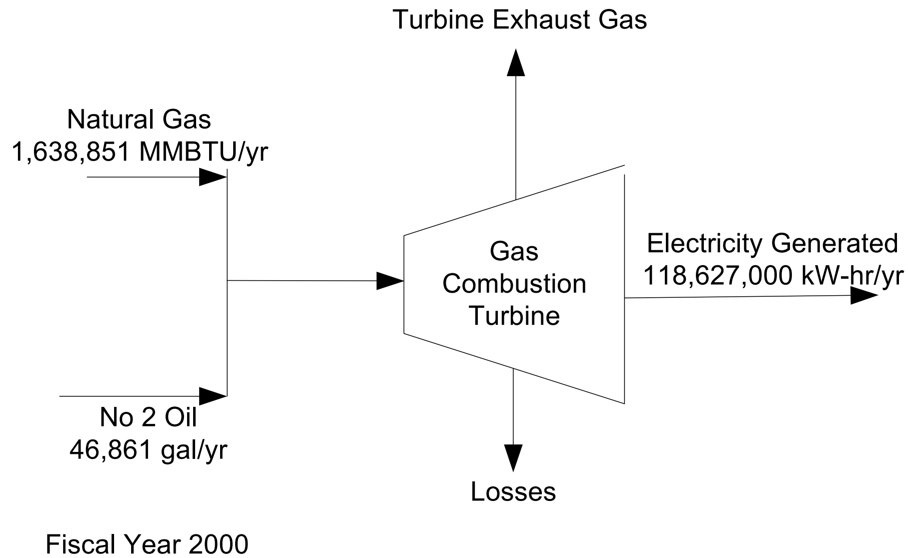
Needed Inputs:

- Annual GT Operating Hours (hrs/yr)
- Amount of Natural Gas (MMBTU/yr)
- Amount of No 2 Oil (gal/yr)
- Amount of Electricity Generated (kW-hr/yr)

Desired Outputs (MMBTU/yr):

- Total Energy in Natural Gas
- Total Energy in No 2 Oil
- Total Energy in Exhaust Gas
- Total Energy in Electricity Generated
- Total Gas Turbine Percent Losses
- Percent of Total Energy in the Exhaust Gas
- Percent of Total Energy in the Electricity Generated
- Gas Turbine Efficiency

The diagram below describes the total inputs and outputs that were provided by MIT.



Row 4: Gas turbine annual operating hours GT operating hours = 7,389 hrs/yr

Row 5: Operating Time Percent per Year

Operating time percent = (7,389 hrs/yr)/(8,760 total hrs/yr) = 84.4 %

Row 6: Annual Average Operating Load

The load on the gas turbine fluctuates on a daily basis as demand by the MIT community changes. The key is to determine the average annual operating load on the turbine so that other parameters, which are dependent on load, can be calculated. The gas turbine has an average maximum capacity of 20.4 MW. Therefore, the average percent annual operating load would be the ratio of the amount of electricity generated to the average maximum capacity.

$$Average\,Annual\ \%\ Operating\ Load = \frac{Electricity\ Generated}{Average\ Max.Turbine\ Capacity}$$

The first thing is to get both quantities into the same units.

$$Max. Amount\ of\ Electricity\ Generated = \left(20.4\times 10^{6} W\right)\times\left(3.413\frac{BTU}{W-hr}\right)\times\left(7{,}389\frac{hrs}{yr}\right)$$

$$= 514{,}461 MMBTU / yr$$

$$Amount\ of\ Electricity\ Generated = \left(118{,}627{,}000\, kW - hr\right)\times\left(3413\frac{BTU}{kW-hr}\right)\times\left(\frac{1 MMBTU}{10^{6}\ BTU}\right)$$

$$= 404{,}874\, MMBTU / yr$$

$$Average\ Annual\ \%\ Operating\ Load = \frac{404{,}874\, MMBTU / yr}{514{,}461\, MMBTU / yr}\times 100 = 78.7\%$$

Row 7: **Fuel**

Row 8: Total amount of Natural Gas (MMBTU/yr) = 1,638,851 MMBTU/yr

Row 9: Total amount of Natural Gas (scf/yr). HHV Conversion 1040 MMBTU/E6 scf)

$$Natural\ Gas\,(scf / yr) = \frac{Amount\ of\ Natural\ Gas\,(MMBTU)}{Conversion} = \frac{1{,}638{,}851\, MMBTU}{1040\, MMBTU / E6\, scf} = 1{,}575{,}818{,}269\, scf / yr$$

Row 10: The higher heating value for Natural Gas (1040 MMBTU/E6 scf)

Row 11: Total Amount of No 2 Oil (gal/yr) = 46,861 gal/yr

Row 12: The higher heating value for No 2 Oil (141,000 BTU/gal)

Row 13: **Turbine Exhaust Gas**

As the operating conditions such as load, fuel type, and ambient conditions change so do the turbine exhaust gas mass flow rate and temperature. Therefore, to be able to approximate the energy in the exhaust gas stream, average values of these variables need to be determined for the year. The specific heat of the turbine exhaust gas is approximated based on the Ideal Gas Law. A linear trend based on load was made for the exhaust gas mass flow rate and temperature from data taken at 60%, 80%, and 100% load. Once an average operating load for the year was determined, this was then used to approximate the average mass flow rate and temperature of the exhaust gas for the year.

Row 14: Exhaust gas mass flow rate (lb/hr)

From the graph of the exhaust gas mass flow rate vs % load, the equation of the linear trend is: y = 2,375x + 392,000 where y is the mass flow rate and x is the % load.

Therefore, at a 78.9% average annual operating load the exhaust gas mass flow rate is 578,954 lbs/hr or 4,277,891,106 lbs/yr, when operating 7,389 hrs/yr.

Row 15: Exhaust Gas Temperature (F)

From graph of the exhaust gas temperature vs % load, the equation of the linear trend is: y = 3.275x + 626.67 where y is temperature and x is % load. Therefore, at a 69.9% average annual operating load the exhaust gas temperature is 884.5^{o}F

Row 16: Exhaust Gas Specific Heat – 0.264 BTU/lb F

This is approximated as being independent of load. There is a minimal variation in the specific heat as the temperature changes.

Row 17: Electricity

Row 18: Total Amount of electricity generated (kW-hr) – 118,627,000 kW-hr

Row 20: **Energy Content (MMBTU/yr)**

Row 21: Fuel Energy Content

Row 22: Natural Gas energy content (MMBTU/yr) – 1,638,851 MMBTU

Row 23: No. 2 Oil energy content (MMBTU/yr)

$$No\,2\,Oil\ Energy\ Content = Amount\ of\ No\,2\,Oil \times Higher\ Heating\ Value$$

$$= 46{,}861\frac{gal}{yr} \times 141{,}000\frac{BTU}{gal} = 6{,}607\ MMBTU/yr$$

Row 24: Turbine Exhaust Gas

Row 25: Turbine Exhaust Gas Energy Content

To determine the turbine exhaust gas energy content we cannot simply just multiply the mass flow rate by the flue gas enthalpy, since it is not known. Once the fuel and air are burned, the hydrocarbon air mixture combusts to produce products such as carbon dioxide, water, nitrogen, and particulates such as nitrous oxide and methane. Since it is a mixture of all these things the thermodynamic properties, such as enthalpy, are not conveniently tabulated in tables. Therefore, to determine the energy content of the exhaust gas one needs to start by approximating the gas as being ideal. The ideal gas approximation assumes that the gas follows the equation of state, *PV=RT*. The Thermodynamic relations for an ideal gas are as follows:

$$
\begin{aligned}
&h = u + Pv \\
&h = c_v T + RT \quad ideal\ gas \\
&h = T(c_v + R) \\
&h = c_p T \quad (ideal\ \ gas) \\
&Therefore, \\
&\dot{m}h = \dot{m}c_p T
\end{aligned}
$$

Though this defines the energy of a gas at a specific state, it is not referenced to anything and therefore has little meaning. When looking at the energy streams into and out of the gas turbine system one needs to be careful when comparing different energy streams. To compare the energy content in the fuel and the flue gas the reference state of each of the streams needs to be the same. The energy content of the fuel is dependent on its heating value, where the lower or upper heating value can be used. The heating value is the quantity of heat generated by complete combustion of a unit of specific fuel. It can be determined by measuring the heat released during combustion of a known quantity of the fuel in a calorimeter at standard atmosphere and pressure (STP). For that reason, the reference state for the exhaust gas needs to be at STP as well. Therefore the energy of the gas is $\dot{m}h = \dot{m}_{EG} c_P (T_{EG} - T_{atm})$.

The next thing that needs to be consistent is the use of the higher heating value. To determine the energy content of the fuel, the MIT and the US standard is to use the higher heating value of the fuel, which assumes that the water in the products has condensed. Therefore any other stream of energy calculated needs to follow this same standard. The lower and higher heating value are related as follows:

$$
Q_{HHV} = Q_{LHV} + \frac{m_{H2O}}{m_{Fuel}} h_{fg\ H2O}
$$

where the second term accounts for the heat released do to water condensing. Thus,

$$
Q_{Exhaust\ Gas} = \dot{m}_{EG} c_p (T_{EG} - T_{atm}) + \frac{m_{H2O}}{m_{Fuel}} h_{fg\ H2O}
$$

This relation takes into account both the energy in the gas as well as accounting for the energy released due to condensation, as required by the higher heating value. To determine the enthalpy of condensation the partial pressure of the water needs to be approximated.

To approximate the partial pressure of water in the products one first needs to write the balanced chemical reaction that is taking place. Natural gas will be used as the working fuel since it accounts for approximately 99% of the total fuel energy into the turbine. The balanced stochiometric equation is:

$$CH_4 + 2(O_2 + 3.77N_2) \rightarrow CO_2 + 2H_2 0 + (2 \times 3.77)N_2$$

Though the system is running lean, the stochimetric equation is used because, even when burning access air, the fuel to water ratio would still be constant. By using the same ideal gas approximation the partial pressure of water can be related to the mole fraction.

$$\frac{P_{H2O}}{P_{Total}} = \frac{x_{H2O}}{x_{Total}}$$

$$\frac{P_{H2O}}{P_{Total}} = \frac{N_{H2O}}{N_{Total}}\left(\frac{1}{x_{Total}}\right)$$

The maximum higher heating value is wanted so that the maximum flue gas energy content could be determined and the greatest amount of turbine losses can be determined. This is done by finding the maximum P_{H2O} that would yield the highest rate of condensation. According to the equation above, to maximize the partial pressure of water one would need to minimize the total mole fraction of exhaust gases and thus this provides another reason why the stochimetric reaction is used.

$$N_{Total} = 10.54$$

$$x_{Total} = 1$$

$$N_{H2O} = 2$$

$$\frac{m_{H20}}{m_{Fuel}} = \frac{(\#moles \times Molecular\ Weight)_{H2O}}{(\#moles \times Molecular\ Weight)_{CH_4}} = \frac{2 \times 18}{1 \times 16} = 2.25 \frac{kg\ H_2O}{kg\ Fuel_{CH_4}}$$

$$P_{H2O} = (0.189)P_{Total}$$

Though the total pressure depends on the turbine load, the percent difference between the pressure at 60% load and at 100% load is less than 1%. The total pressure of the flue gas is thus approximated as 15.0 lb/in^2.

$$P_{H2O} = (0.189)P_{Total}$$

$$P_{H2O} = 2.85 \frac{lb}{in^2} \rightarrow h_{fg\ H2O} = 1019.4 \frac{BTU}{lb_{H2O}}$$

Once the enthalpy of the water is known then the energy content in the exhaust stream can be calculated. The mass flow rate and the temperature of the exhaust gas have already be calculated (Rows 14-15) by determining the average annual load on the gas turbine. Thus,

$$Q_{Exhaust\,Gas} = \dot{m}_{EG} c_p (T_{EG} - T_{atm}) + \frac{m_{H2O}}{m_{Fuel}} h_{fg\,H2O}$$

$$Q_{Exhaust\,Gas} = \left[\left(4{,}277{,}891{,}106 \frac{lbs}{yr}\right)\left(0.264 \frac{BTU}{lb\,F}\right)(855.6\,F - 59\,F)\right] +$$

$$\left[\left(2.25 \frac{kg\,H_2 0}{kg\,CH_4}\right)\left(1019.4 \frac{BTU}{lb_{H_2O}}\right)\underbrace{\left(2.2046 \frac{lb_{H2O}}{kg\,H_2O}\right)}_{Mass\ Conversion}\underbrace{\left(0.79 \frac{kg_{CH4}}{m^3_{CH4}}\right)}_{CH_4\ Density}\underbrace{\left(\frac{1\,m^3}{35.315\,ft^3}\right)}_{Volume\,Converaion}\left(Amount\ of\ Fuel \frac{ft^3}{yr}\right)_{CH4}\right]$$

$$Q_{Exhaust\,Gas} = \left[\left(4{,}277{,}891{,}106 \frac{lbs}{yr}\right)\left(0.264 \frac{BTU}{lb\,F}\right)(884.5\,F - 59\,F)\right] + \left[\left(113.2 \frac{BTU}{ft^3}\right)\left(1{,}575{,}818{,}269 \frac{ft^3}{yr}\right)_{CH4}\right]$$

$$Q_{Exhaust\,Gas} = 1{,}110{,}514 \frac{MMBTU}{yr}$$

Row 26: **Electricity**

Row 27: Total Electricity Content (MMBTU/yr)

$$Energy\ \ due\ to\ Electricit\,y\,\mathrm{Pr}\,oduction = Amount\,of\ Electricit\,y\,\mathrm{Pr}\,oduced \times Conversion$$
$$= 118{,}627{,}000 \frac{kW-hr}{yr} \times \frac{3413\,BTU}{1\,kW-hr} \times \frac{1\,MMBTU}{10^6\,BTU} = 404{,}874 \frac{MMBTU}{yr}$$

Row 28: Total Energy going into the gas turbine – Total fuel energy input

(1,645,458 MMBTU/yr)

Row 29: Total Energy going out of the gas turbine – Electricity and Exhaust Gas

(1,515,367 MMBTU/yr)

Row 30: Gas Turbine percent loss – the difference between the inputs and outputs divided by the total energy going into the system

$$\%\,Gas\,Turbine\;Loss = \frac{1{,}645{,}458 - 1{,}515{,}367}{1{,}645{,}458} \times 100 = 7.9\%\,loss$$

Row 31: Percent of the total energy that is in the exhaust gas – 67.5%

Row 32: Percent energy in electricity generated – 24.6%

Row 33: Gas Turbine Efficiency

$$\eta_{Turbine} = \frac{W_{Electrity}}{Q_{Toal\,Fuel}} = \frac{404{,}874\,MMBTU}{1{,}645{,}458\,MMBTU} \times 100 = 24.6\%$$

3. Heat Recovery Steam Generator (HRSG)

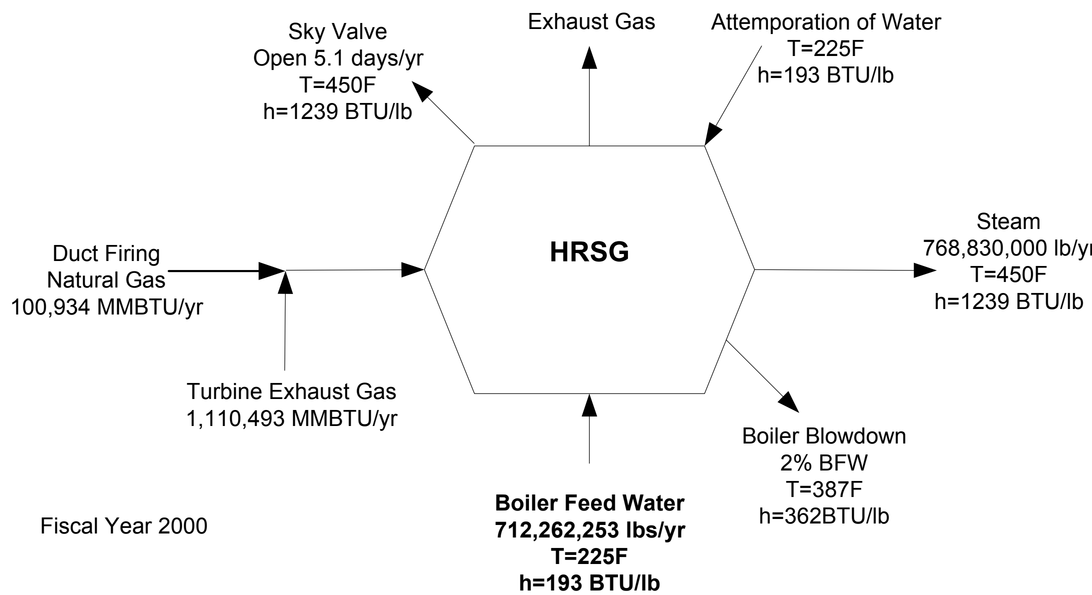
HRSG, also know as a waste recovery heat boiler (WHRB), is a key element in a cogeneration plant design. Though it increases the initial start up cost, its long term effects on plant operation and overall cycle efficiency make it increasing used in new power plant designs. A HRSG acts as a boiler by producing steam by utilizing the energy in the form of heat that is in the turbine exhaust stream. In typical power systems, such as the Brayton and Rankine cycle this energy is generally lost to the environment. It is the production of steam of the energy in the turbine exhaust stream that makes a plant a cogeneration system. Through the utilization of the waste heat, the total energy utilization can approach 80% as compared to the 40% to 50% in the best gas turbine combined cycle systems without process steam use.

Needed Inputs:

- Amount of Natural Gas (MMBTU/yr) for supplemental duct firing
- Amount of Boiler Feedwater (lbs/yr)
- Amount of Steam Produced
- Amount of days the sky valve is open during the year

Desired Outputs:

- Total Energy in Natural Gas (MMBTU/yr)
- Total Fuel energy into the HRSG
- Total Energy in the Steam Produced (MMBTU/yr)
- Percent of the total energy in the Turbine Exhaust Gas
- Percent of the total energy in the Natural Gas



Row 4: **Fuel**

Row5: Total amount of Natural Gas (MMBTU/yr) that was used during supplemental duct firing – 100,934 MMBTU/yr

Row 6: Total amount of Natural Gas (scf/yr) – 97,052,188 scf/yr

Row 7: Higher Heating value for Natural Gas – 1040 MMBTU/ E6 scf

Row 8: **Turbine Exhaust Gas**

Row 9: The energy content in the turbine exhaust gas that is going into the HRSG

$$Q_{Exhaust\,Gas} = 1{,}110{,}493 \frac{MMBTU}{yr}$$

Row 10: **Boiler Feedwater (BFW)**

Row 11: Boiler Feedwater mass flow rate (lbs/yr) – 712,262,253 lbs H2O/yr

Row 12: Feedwater Temperature (F) – 225 F

Row 13: Feedwater Enthalpy at 225 F – 193 BTU/lb F

Row 14: **HRSG Generated Steam**

Row 15: Amount of steam generated by the HRSG – 768,830,000 lbs steam/yr

Row 16: Temperature of the steam (F) – 450 F

Row 17: Pressure of the steam (Psig) – 200 psig

Row 18: Enthalpy of the steam (BTU/lb F) – 1239 BTU/lb F

Row 19: Sky Valve - used to vent steam during testing

Row 20: Amount of time the sky valve was open (days/1year) – 5.1 days/yr

Row 21: Mass flow rate of steam out of the sky valve (lbs/yr)

$$\dot{m}_{Sky\,Valve} = Mass\,Flow\,Rate\,of\;BFW \times Open\,Sky\,Valve\,Time$$

$$= 712{,}262{,}253 \frac{lbs\,H_2O}{yr} \times 5.1 \frac{days}{yr} \times \frac{1\,yr}{365\,days} = 9{,}952{,}158 \frac{lbs\,H_2o}{yr}$$

Row 22: Temperature released steam (F) – 450 F

Row 23: Enthalpy of the released steam (BTU/lb F) – 1239 BTU/lb F

Row 24: Boiler Blowdown

Blowdown is the stream of water which is bled from the boiler drum or steam supply system to control the concentration of total solids in the boiler water. Blowdown can be continuous or intermittent. . The rate at which this occurs depends on the quality of water used. MIT's boiler blowdown rate varies from 2%-5%, which allows for 50-20 cycles of water use before dumping.

Row 25: Mass flow rate of water from the boiler blowdown (lbs/yr) – This should be approximately 2% of the BFW mass flow rate – 14,245,245 lbs/yr

Row 26: The saturation temperature at pressure of 200 psig – 387 F

Row 27: Enthalpy (BTU/lb F) – 362 BTU/lb F

Row 28: **Attemperation Water**

Attemperation is one of several ways to regulate steam temperatures. With attemperation, steam temperatures are controlled by diluting high temperature steam with low temperature water or by removing heat from the steam.

Row 29: Mass flow rate (lbs/yr) – determined by a mass balance around the HRSG

Row 30:Temperature (F) – 225 F

Row 31: Enthalpy (BTU/lb F) – 193 BTU/lb F

Row 32: Blank

Row 33: **Energy Content (MMBTU/yr)**

Row 34: **Fuel Energy Content**

Row 35: Natural gas duct firing energy content – 100,934 MMBTU/yr

Row 36: **Turbine Exhaust Gas**

Row 37: Energy content in the turbine exhaust gas going into the HRSG – 1,110,493 MMBTU/yr

Row 38: **Boiler Feedwater**

Row 39: Energy content in the boiler feedwater (MMBTU/yr)

$$Q_{BFW} = BFW\ Mass\ Flow\ Rate \times Enthalpy$$

$$= 712{,}262253 \frac{lbs}{yr} \times 193 \frac{BTU}{lb\,F} \times \frac{1\,MMBTU}{10^6\,BTU} = 137{,}647 \frac{MMBTU}{yr}$$

Row 40: **HRSG Steam Generated**

Row 41: Energy content in the steam generated (MMBTU/yr)

$$Q_{Steam} = Steam\ Mass\ Flow\ Rate \times Enthalpy$$

$$= 768{,}830{,}000 \frac{lbs}{yr} \times 1239 \frac{BTU}{lb\,F} \times \frac{1\,MMBTU}{10^6\,BTU} = 952{,}580 \frac{MMBTU}{yr}$$

Row 42: Sky Valve

Row 43: Energy content in the steam leaving out the sky valve –12,331 MMBTU/yr

Row 44: Boiler Blowdown

Row 45: The amount of energy that is in the water going through the boiler blowdown – 5,157 MMBTU/yr

Row 46: Attemporation Water

Row 47: Energy content in the attemporation water – 15,588 MMBTU/yr

Row 48: Total energy into the HRSG – Includes the energy in duct firing, the turbine exhaust gas, boiler feedwater, and attemportation – 1,364,481 MMBTU/yr

Row 49: % of the energy input from turbine exhaust gas – only considers the amount of energy from the supplemental duct firing and turbine exhaust gas – 91.7%

Row 50: % of the energy input from the supplemental natural gas duct firing - only considers the amount of energy from the supplemental duct firing and turbine exhaust gas – 7.7%

Row 51: HRSG Efficiency – defined as the ratio of the steam produced divided by the total energy input (natural gas and GT exhaust gas) – 78.6%

4. **Steam Driven Chillers(1-6) and Electric Driven Chillers(1-3)**

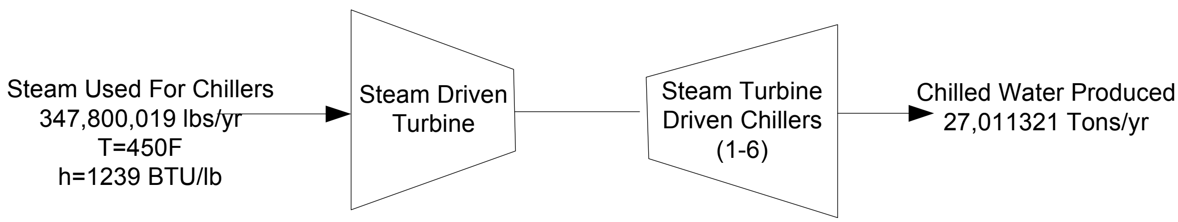
Steam Driven Chillers:

Needed Inputs:

- Amount of Steam used (lbs/yr)
- Amount of Chilled Water Produced (Tons/yr)

Desired Outputs:

- Total Energy in Steam Used (MMBTU/yr)
- Total Energy in Chilled Water Produced (MMBTU/yr)



Row 4: **Steam Driven Chillers**

Row 5: **Constants**

Row 6: Temperature (F) – 450 F

Row 7: Pressure (Psig) – 200 psig

Row 8: Enthalpy (BTU/lb) – 1239 BTU/lb

Row 9: **Chiller 1**

Row 10: Amount of steam used by chiller 1 – 13,589,323 lbs/yr

Row 11: Amount of chilled water produced by chiller 1 – 1,644,236 tons/yr

Row 12: **Chiller 2**

Repeat steps (9-11) for chillers (2-6) – Account for rows (12-26)

Electric Driven Chillers:

Needed Inputs:

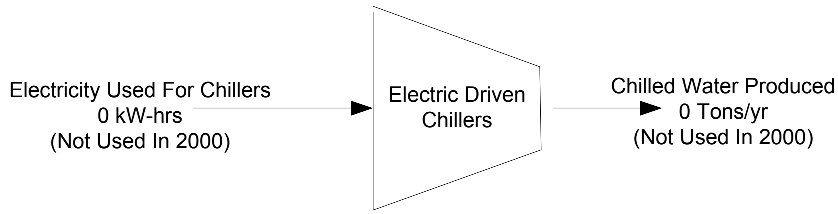
Amount of Electricity used (kW-hrs/yr)

- Total Amount of Chilled Water Produced (Tons/yr)

Desired Outputs:

- Total Energy in Electricity Used (MMBTU/yr)

- Total Energy in Chilled Water Produced (MMBTU/yr)



Row 27: Electric Driven Chillers

Row 28: **Chiller 1**

Row 29: Electricity Used (kw-hrs) – 0 kW-hrs (Not Used In 2000)

Repeat steps (28-29) for electric driven chillers (1-3)- Rows (30-33)

Row 34: Total chilled water produced (tons/yr) – 0 tons/yr (Not used in 2000)

Row 36: Energy Content

Row 37: Total Energy in Steam Used (MMBTU/yr) – 430,924 MMBTU/yr

Row 38: Total energy needed to produce chilled water produced by the steam driven chillers (MMBTU/yr) – 32,414MMBTU/yr

Row 39: Total Electricity Used (MMBTU/yr) – 0 MMBTU/yr

Row 40: Total energy in the chilled water produced by the electric driven chillers (MMBTU/yr) – 0 MMBTU/yr

Row 41: Total energy in total chilled water produced (MMBTU/yr) – 32,414 MMBTU/yr

Row 42: Total energy used to produce the total amount of chilled water (Includes steam and electricity) (MMBTU/yr) – 430,924 MMBTU/yr

5. Purchased Fuel and Utilities

MIT data on purchased fuels and utilities is taken from 1990-2003. The MIT Cogeneration Power Plant was first fired in July of 1995 but accurate data was not first available till fiscal year 1998. Therefore, all data taken from fiscal year 1990-1997 is calculated by assuming gross numbers for purchased fuel and utilities. Starting fiscal year 1998, data was calculated to account for cogeneration, and greenhouse gas emissions are categorized into produced electricity, steam, chilled water, and electricity purchased. All fuel purchases after 1998 are assumed to be for the cogeneration plant and are counted with respect to the type of equipment used. After 1997, the only utility still purchased by MIT is electricity, when campus demand exceeds the plant capacity. Steam and chilled water have always been produced on campus.

Row 3:**Purchased Fuel**

Row 4: Amount of total natural gas purchased, includes all natural gas burned in boilers (3-5), gas turbine, and HRSG – 1,953,999 MMBTU/yr

Row 5: Amount of No 2 oil purchased for the gas turbine – 46,861gal/yr

Row 6: Energy Content of the No 2 Oil – 6,607 MMBTU/yr

Row 7: Amount of No 6 oil purchased for boilers (3-5) – 1,664,735 gallons/yr

Row 8: Energy Content of the No 6 Oil – 236,392 MMBTU/yr

Row 9: **Purchased Electricity**

Row 10: Amount of Purchased Electricity – 22,421,000 kW-hr/yr

Row 11: Energy Content of the purchased electricity – 76,523 MMBTU/yr

Conversion: 3413 BTU = 1 kW-hr

Row 12: Amount of purchased Steam – 0 Mlbs/yr

Row 13: Amount of purchased Chilled Water – 0 Tons/yr

6. Greenhouse Gas Emission Calculation for Purchased Fuel and Utilities

Row 3: **Purchased Electricity**

When determining the amount of metric tons of carbon dioxide (CO2) emitted due to the purchase of electricity by the MIT community multiple factors such as transmission losses, energy composition, and global warming potentials need to be considered. A detailed explanation and sample calculation for fiscal year 2000 is performed in appendix A. To determine the amount of CO2 emitted due to purchased electricity, an emission calculator computer program developed by *Cool Air Clean Planet* is used.

Row 4: Total Amount of Purchased Electricity – 22,421,000 kW-hr/yr

Row 5: Total Energy Content from Purchased Electricity – 76,523 MMBTU/yr

Conversion: 3413 BTU = 1 kw-hr

Row 6: Total Energy Consumed at the Power Plant to produce the given amount of electricity purchased by MIT. This is determined by considering transmissions losses and percent source of electricity production. The *Cool Air Clean Planet* emission calculator calculates this separately and the values are pasted into the cells.

Row 7: Metric Tons of CO_2 due to purchased electricity – Separately Calculated by the *Cool Air Clean Planet* emission calculator and pasted into the cells.

Row 8: Total Equivalent amount of metric tons of CO_2 due to Methane

$$\begin{aligned}Equivalent\ Metric\ Tons\,CO_2\,DueTo\,Methane &= 1.2\\ &= Plant\ \ Energy\,Consumtpion \times EF_{CH4,Electric} \times GWP_{CH4} \times Unit\,Conversion\end{aligned}$$

Row 9: Total Equivalent amount of metric tons of CO_2 due to Nitrous Oxide

$$\begin{aligned}Equivalent\ Metric\ Tons\,CO_2\,DueTo\,Nitrous\,Oxide &= 7.1\\ &= Plant\ \ Energy\,Consumtpion \times EF_{N2O,Electric} \times GWP_{N2O} \times Unit\,Conversion\end{aligned}$$

Row 10: Total equivalent metric tons of CO_2 due to purchased electricity

The sum of rows (7-9) = 14,600

Row 11: Purchased Fuel

This takes into account purchased fuel from fiscal year 90-96. Therefore, for this sample calculation of the year 2000, all the fuel that is purchased is assumed to be used for the cogeneration plant, and thus has already been taken into account.

Row 12: Total Amount of Natural Gas Purchased – 1,953,999 MMBTU/yr

Row 13: Metric Tons of CO_2 due to purchased Natural Gas

$$Carbon\ \ Content = Energy\ Consumption \times Emission\ Factor$$

$$Metric Tons\, of\ CO_2 = Metric\ Tons\, C \times \frac{Metric\ Tons\ CO_2}{Metric\ Tons\ C} = 116{,}141$$

Row 14: Total Equivalent amount of metric tons of CO2 due to Methane

$$Amount\, of\ \ Methane = Energy\, Consumption \times Emission\, Factor$$

$$Total\, Metric\ Tons\ \ of\ CO_2\ \ Equivalents\, due\ to\, CH_4 = Total\, CH_4\ \times GWP \times Unit\, Conversion = 45.1$$

Row 15: Total Equivalent amount of metric tons of CO_2 due to Nitrous Oxide – 666.3, the same calculation is done for Nitrous Oxide as done for Methane.

Row 16*:*Total equivalent metric tons of CO_2 due to the purchase of natural gas = 117,125

Row 17*:* Total Amount of No 2 Oil Purchased – 6,607 MMBTU/yr

The same calculation is done for No 2 Oil as done for natural gas. Therefore, to see a detailed calculation refer to appendix A purchased fuels.

Row 18: Metric tons of CO_2 due to purchased No 2 oil - 540

Row 19: Total equivalent amount of metric tons of CO_2 due to Methane - 0

Row 20: Total equivalent amount of metric tons of CO_2 due to Nitrous Oxide - 1

Row 21: Total equivalent metric tons of CO_2 due to the use of No. 2 oil - 541

Row 22: Total Amount of No 6 Oil Purchased – 236,392 MMBTU/yr

The same calculation is done for No 6 Oil as done for natural gas. Therefore, to see a detailed calculation refer to appendix A purchased fuels.

Row 23: Metric Tons of CO2 due to purchased No 6 oil – 19,307

Row 24: Total Equivalent amount of metric tons of CO2 due to Methane - 0

Row 25**:** Total Equivalent amount of metric tons of CO2 due to Nitrous Oxide – 0

Row 26: Total equivalent metric tons of CO_2 due to the use of No. 6 oil – 19,307

Row 27: Total equivalent metric tons of CO_2 due to purchased fuels – 136,973

***Row 28**:* Total equivalent metric tons of CO_2 from utilities – 151,574

7. Greenhouse Gas Emission Calculations for MIT Cogeneration Power Plant

Row 3: Fuel Inputs

Row 4: Fuel Energy Totals by Equipment (MMBTU/yr)

Row 5: Boiler (3-5)

Row 6: No 6 Oil – 236,392 MMBTU/yr

Row 7: Natural Gas – 214,214 MMBTU/yr

Row 8: Total Fuel Energy Inputed into Boilers (3-5) – 450,607 MMBTU/yr

Row 9: Gas Turbine

Row 10: Natural Gas – 1,638,851 MMBTU/yr

Row 11: No 2 Oil – 6,607 MMBTU/yr

Row 12: Total Fuel Energy Inputed into the Gas Turbine – 1,645,458 MMBTU/yr

Row 13: HRSG

Row 14: Natural Gas – 100,934 MMBTU/yr

Row 17: CO2 Emission Factors separated by type of equipment

Row 18: Boiler (3-5)

Row 19: CO2 Emissions due to No. 6 Oil

$$MetricTons\,CO_2\ due\ to\ No\ 6\ Oil = Energy\ Consumption \times Emission\ Factor \times \frac{MetricTons\,CO_2}{MetricTons\,C}$$

$$= 236{,}392\frac{MMBTU}{yr} \times .0225\frac{MetricTons\,C}{MMBTU} \times \frac{44\,MetricTons\,CO_2}{12\,MetricTons\,C}$$

$$= 19{,}307\,MetricTons\,CO_2$$

Constants such as emission factors can be found in the program excel workbook in a worksheet named constants.

Row 21: CO2 Emissions due to Natural Gas

$$MetricTons\,CO_2\ due\ to\ Natural\ Gas = Energy\ Consumption \times Emission\ Factor \times \frac{MetricTons\,CO_2}{MetricTons\,C}$$

$$= 214{,}214\frac{MMBTU}{yr} \times .01633\frac{MetricTons\,C}{MMBTU} \times \frac{44\,MetricTons\,CO_2}{12\,MetricTons\,C}$$

$$= 12{,}698\,MetricTons\,CO_2$$

Row 21: Total CO_2 Emissions due to No 6 Oil and Natural Gas being burned in Boilers (3-5) – 32,006 Metric Tons of CO2

Row 22: Gas Turbine

Row 23: CO_2 Emissions due to Natural Gas

$$Metric\,Tons\,CO_2\;due\;to\,Natural\;Gas = Energy\;Consumption \times Emission\;Factor \times \frac{Metric\,Tons\,CO_2}{Metric\,Tons\,C}$$

$$= 1{,}638{,}851\frac{MMBTU}{yr} \times .01633\frac{Metric\,Tons\,C}{MMBTU} \times \frac{44\,Metric\,Tons\,CO_2}{12\,Metric\,Tons\,C}$$

$$= 97{,}148\;Metric\,Tons\,CO_2$$

Row 24: CO_2 Emissions due to No. 2 Oil

$$Metric\,Tons\,CO_2\;due\;to\,No\;2\;Oil = Energy\;Consumption \times Emission\;Factor \times \frac{Metric\,Tons\,CO_2}{Metric\,Tons\,C}$$

$$= 6{,}607\frac{MMBTU}{yr} \times .0225\frac{Metric\,Tons\,C}{MMBTU} \times \frac{44\,Metric\,Tons\,CO_2}{12\,Metric\,Tons\,C}$$

$$= 540\,Metric\,Tons\,CO_2$$

Row 25: Total CO_2 Emissions due to Natural Gas and No 2 Oil being burned in the Gas Turbine – 97,687 Metric Tons of CO_2

Row 26: HRSG

Row 27: Total CO_2 Emissions due to Natural Gas

$$Metric\,Tons\,CO_2\;due\;to\,Natural\;Gas = Energy\;Consumption \times Emission\;Factor \times \frac{Metric\,Tons\,CO_2}{Metric\,Tons\,C}$$

$$= 100{,}934\frac{MMBTU}{yr} \times .01633\frac{Metric\,Tons\,C}{MMBTU} \times \frac{44\,Metric\,Tons\,CO_2}{12\,Metric\,Tons\,C}$$

$$= 5{,}983\;Metric\,Tons\,CO_2$$

Row 28: Total Direct CO_2 Emissions from the MIT Cogeneration Power Plant – 135,676 metric tons of CO_2

Row 31: Methane Emission by Equipment

Row 32: Boiler (3-5)

Row 33: Methane emitted due to No 6 Oil (kg)

$$Amount\ of\ Methane = Energy\,Consumption \times Emission\,Factor$$
$$= \frac{236{,}392\,MMBTU}{1000\,g/kg} \times 0.7\frac{g}{MMBTU} = 165.5\ kg\,CH_4$$

Row 34: Methane emitted due to Natural Gas (kg)

$$Amount\ of\ Methane = Energy\,Consumption \times Emission\,Factor$$
$$= \frac{214{,}214\,MMBTU}{1000\,g/kg} \times 1.1\frac{g}{MMBTU} = 235.6\,kg\,CH_4$$

Row 35: Equivalent Metric tons of CO2 due to Methane emissions – 8.4

Row 36: Gas Turbine

Same calculations as for the boiler.

Row 37: Methane emitted due to Natural Gas – 1,802 kg

Row 38: Methane emitted due to No 2 Oil – 4.6 kg

Row 39: Equivalent Metric Tons of CO_2 due to Methane emissions - 38

Row 40: HRSG

Same calculation as for the boiler

Row 41: Methane emitted due to Natural Gas – 111 kg

Row 42: Equivalent metric tons of CO_2 – 2.3

Row 43: Total Equivalent Metric Tons of CO_2 due to Methane Emissions – 48.7

Row 45: Nitrous Oxide Emissions By Equipment

Row 46: Boiler

Row 47: Nitrous Oxide due to No. 6 oil

$$Amount\ of\ Nitrous\,Oxide = Energy\,Consumption \times Emission\,Factor$$
$$= \frac{236{,}392\,MMBTU}{1000\,g/kg} \times 0.7\frac{g}{MMBTU} = 165.5\ kg\,N_2O$$

Row 48: Nitrous Oxide emitted due to Natural Gas (kg)

$$Amount\ of\ Nitrous\ Oxide = Energy\ Consumption \times Emission\ Factor$$

$$= \frac{214{,}214\,MMBTU}{1000\,g/kg} \times 1.1 \frac{g}{MMBTU} = 235.6\,kg\ N_2O$$

Row 49: ***Equivalent Metric tons of CO_2 due to nitrous Oxide emissions – 124.3***

Row 50: Gas Turbine

Calculations are the same as for the boiler**.**

Row 51: Nitrous Oxide emitted due to Natural Gas – 1,802 kg

Row 52: Nitrous Oxide emitted due to No 2 Oil – 2.4 kg

Row 53: Equivalent Metric Tons of CO_2 due to Nitrous Oxide emissions – 559.6

Row 54: HRSG

Same calculation as for the boiler

Row 55: Nitrous Oxide emitted due to Natural Gas – 111 kg

Row 56: Equivalent metric tons of CO_2 – 34.4

Row 57: Total Equivalent Metric Tons of CO_2 due to Nitrous Oxide Emissions – 718.3

Row 59: Total equivalent CO_2 emissions for the MIT cogeneration plant – 136,443

7. Amount of CO_2 produced, separated into utility products (purchased electricity, and produced electricity, steam, and chilled water)

Row 3: Electricity Purchased and Produced

Row 4: Produced Electricity – 404,874 MMBTU/yr

Row 5: Purchased Electricity – 76,523 MMBTU/yr

Row 6: Total Electricity – 481,397 MMBTU/yr

Row 7: Percent of electricity produced – 84.1%

Row 8: Percent of electricity purchased – 15.9%

Row 9: Purchased Electricity

Row 10: Equivalent metric tons of CO_2 from purchased electricity –14,600

Row 11: Total metric tons of CO_2 from fuels purchased – 0

The fuel purchased after 1998 is account for in the components of the cogeneration system

Row 13: Gas Turbine

Row 14: Total Gas Turbine Energy Use – 1,645,458 MMBTU/yr

Row 15: Total gas turbine equivalent metric tons of CO_2 – 98,285

One wants to proportion the amount of equivalent metric tons of CO_2 produced in the GT to the electricity generated and the energy in the exhaust gas that will be used to produce steam. In addition, the energy losses are apportioned to each of these streams based on percent energy content.

Row 16: Equivalent metric tons of CO_2 due to produced electricity – 26,260

$$\%\,Energy\ in\ electricity = \%\,Electricity\ Energy + \left(\%GT\ Loss \times \left(\frac{\%\ Electricity\ Energy}{\%\,Electricity\ Energy + \%\,EG\ Energy}\right)\right)$$

$$MTCDE = \%\,Energy\ in\ Electricity \times Total\ GT\ MTCDE\ Emissions = 26{,}260\ MTCDE$$

Row 17: *Equivalent metric tons of CO_2 due to energy in the turbine exhaust gas – 72,025.*

$$\% \, Energy \; in \; GT \; Exhaust \; Gas = \% \; EG \; Energy + \left(\%GT \; Loss \times \left(\frac{\% \; EG \, Energy}{\% \, Electricity \, Energy + \% \, EG \, Energy} \right) \right)$$

$$MTCDE = \% \, Energy \; in \, GT \; Exhaust \times Total \, GT \; MTCDE \; Emissions \; = \; 72{,}025 \, MTCDE$$

Row 19: HRSG

Row 20: Total Fuel Input – 100,934 MMBTU/yr

Row 21: Total Turbine Exhaust Gas Input – 1,110,493 MMBTU/yr

Row 22: Equivalent metric tons of CO_2 due to duct firing with natural gas – 6,545

Row 23: Equivalent metric tons of CO_2 in turbine exhaust gas – 72,025

Row 24: Total HRSG equivalent metric tons of CO_2 – 78,570

Row 26: Boiler

Row 27: Total Fuel input – 450,607 MMBTU/yr

Row 28: Total boiler (3-5) equivalent metric tons of CO_2 – 32,138

Row 30: CO_2 due to steam, chilled water and electricity

Row 31: Steam

Row 32: Total steam produced (HRSG+Boilers(3-5)) – 1,241,914 MMBTU/yr

Row 33: Total equivalent metric tons of CO_2 due to steam production – 72,294

Row 34: Chilled Water

Row 35: Total steam used – 430,924 MMBTU/yr

Row 36: Total electricity used – 0 MMBTU/yr

Row 37: Percent steam used to drive the steam driven chillers – 34.7%

Row 38: Percent of electricity use to driven the electric driven chillers – 0%

Row 39: Equivalent metric tons of CO_2 due to steam driven chillers – 38,414

Row 40: Equivalent metric tons of CO_2 due to electric driven chillers – 0

Row 41: Total equivalent metric tons of CO_2 due to chilled water production – 38,414

Row 42: Electricity

Row 43: Equivalent metric tons of CO_2 due to electricity production – 26,260

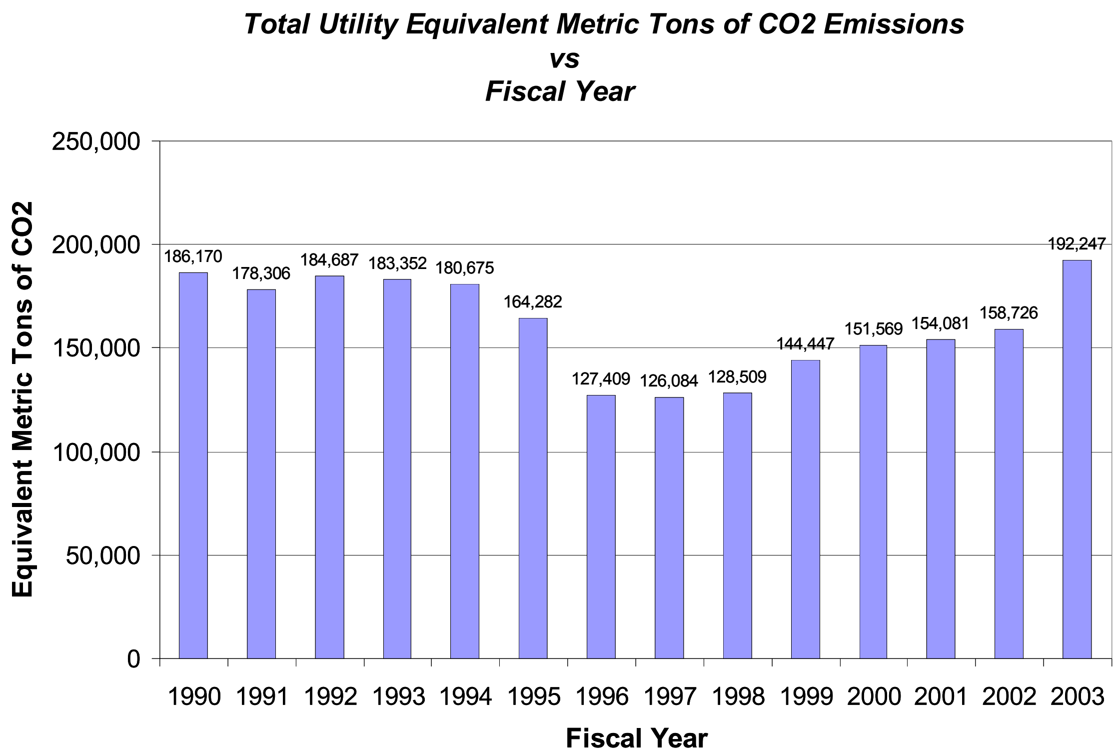
Row 44: Equivalent metric tons of CO_2 due to purchased electricity – 14,600

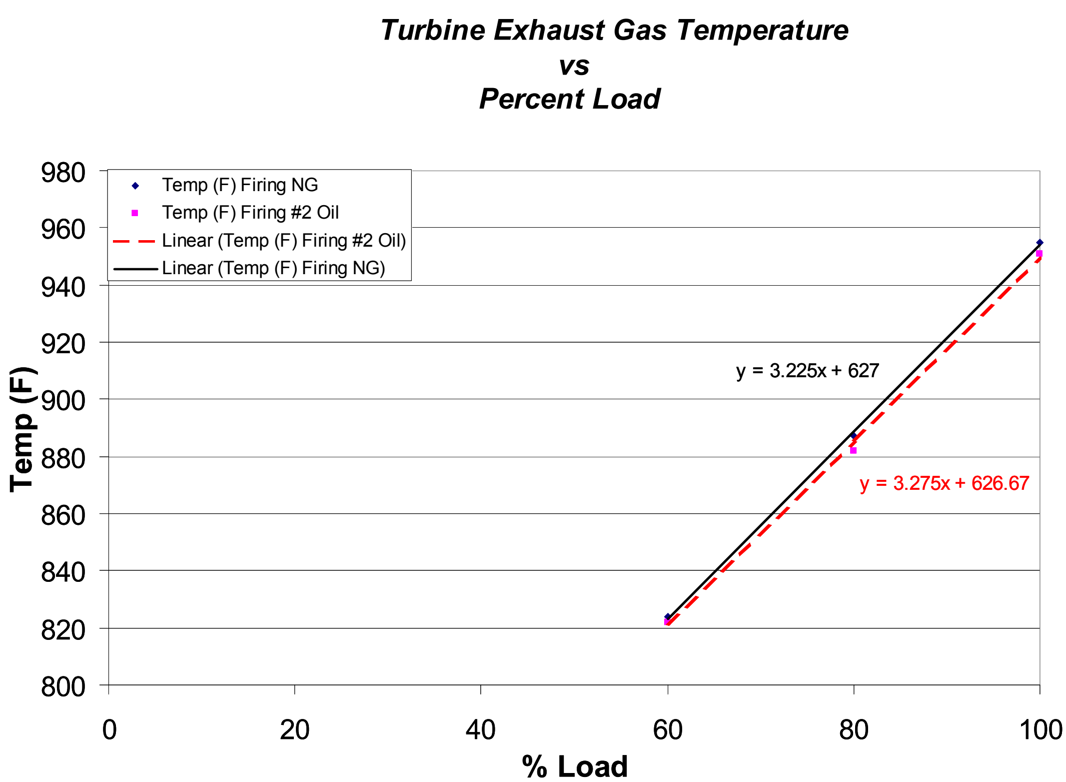
Row 45: Total Equivalent metric tons of CO_2 due to electricity – 40,860

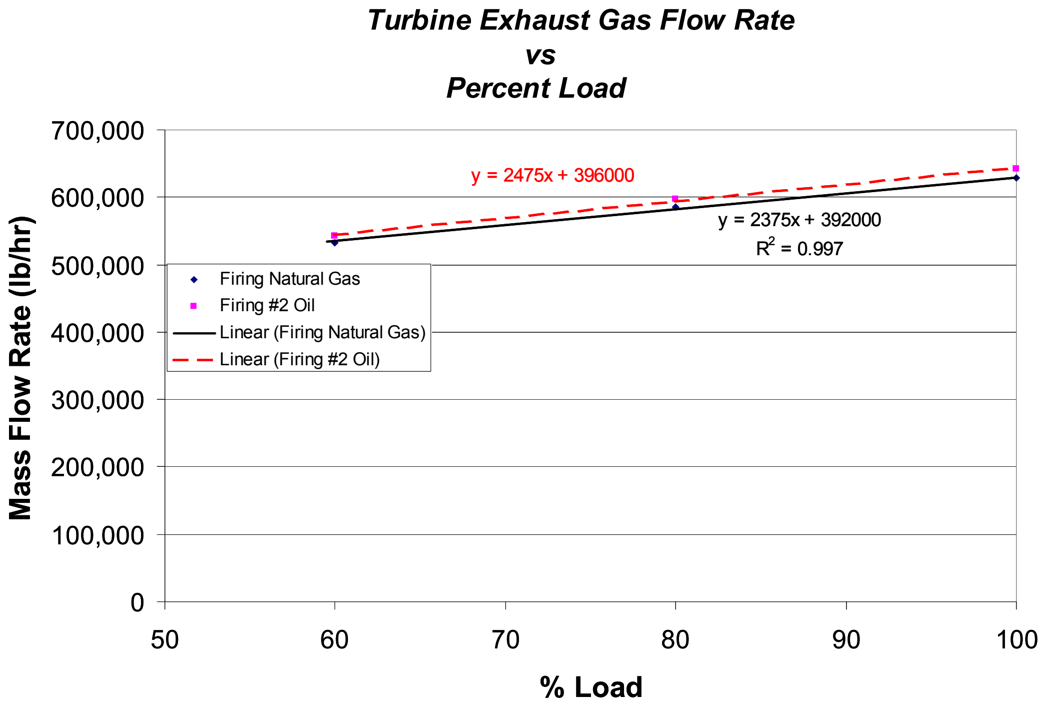
$$MTCDE_{Electrcity} = Total\,MTCDE\,From Total\,Consumed\,Electricit\,y \times (1 - \%Electricit\,y\,For\,Electric\,Chillers)$$

Row 47: Total equivalent metric tons of CO_2 emitted – 151,569

Appendix E Utility Emission & GT Exhaust Graphs






Turbine Exhaust Gas Flow Rate
vs
Percent Load
Mass Flow Rate (lb/hr)
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
50
60
70
80
90
100
% Load
y = 2475x + 396000
y = 2375x + 392000
$R^2 = 0.997$
Firing Natural Gas
Firing #2 Oil
Linear (Firing Natural Gas)
Linear (Firing #2 Oil)

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