5 HEAT

5.1. BOILERS

A boiler is a device that extracts energy in the form of heat from some type of fuel through a combustion process that can then be distributed to necessary areas to do useful work. In the process, the carrying media (water or steam) transfers the energy as heat and is cyclically reheated again and again. There are examples that exist where the media (steam) is not returned, such as locomotives, but in the industrial processes covered in this manual it would constitute an exception for the norm. For the most part, boilers are part of systems that take advantage of the phase changes that occur in substances (for example water to steam). The phase changes are associated with large amount of energy storage which can be later harnessed to perform work.

5.1.1. Introduction

There are three principal boiler categories: (1) natural draft vs. forced draft, (2) hot water vs. steam, and (3) fire in tube vs. water in tube. In a natural draft boiler, the combustion air is drawn in by natural convection and therefor there is little control over the air/fuel ratio. For forced draft boilers, the quantities of combustion air and air/fuel mixture are controlled by a blower. Some boilers produce hot water, typically in the 160^0 to 190^0F range, while others produce steam. Steam boilers may be low pressure (approximately 15 psi), medium pressure (15 to 150 psi), or high pressure (150 to 500 psi). Finally, boilers may be fire in tube or water in tube boilers. In a fire in tube boiler, the hot gases flow through tubes that are immersed in water, where as in a water tube boiler, the water flows through tubes heated by the hot combustion gases. There are also some very high temperature and superheated boilers but these are seldom encountered in typical manufacturing operations. The typical boiler used in small to medium sized industrial operations is a forced draft steam boiler at 120-150 psi and approximately 150 hp. The following measures are also applicable to utility boilers. Other than the major differences of not being natural draft boilers and producing steam at greater than 150 psi, utility boilers are similar to boilers commonly used by industry.

This section includes demand-side management strategies for boiler systems. Combustion air blower variable frequency drives, air/fuel ratio reset, turbulators, high-pressure condensate return systems, steam trap repair, and steam leak repair are discussed in this section.

5.1.2. Boiler Operation and Efficiency

The ideal model of a boiler operation is based on the Carnot cycle. The Carnot cycle is defined as two reversible isothermal and two reversible adiabatic processes. Heat is added to the cycle during isothermal process at high temperature T_H, then follows a adiabatic process producing work as the working fluid is expanded to a lower pressure, during the next isothermal stage, heat is rejected to the low temperature reservoir at T_L. During the last stage the working fluid is adiabatically compressed to finish the cycle. Carnot cycle is the most efficient cycle for given set of low and high temperatures and its efficiency is given by:

$$\eta = 1-(\Delta T_L/T_H)$$

The efficiency of a real boiler will always be lower then the ideal cycle. If the Carnot cycle is to work using a phase changing medium, a model can be represented in a four-stage system. The first stage would be a boiler that operates at constant temperature while adding heat to the working medium. The second stage would be an expansion device (turbine) that operates adiabatically. The third stage would be a condenser that operates at constant temperature while rejecting heat from the medium and the final stage would be a compressor or a pump that adiabatically brings the medium to the starting point. Most boilers are designed to operate at near constant pressure. If the devices are operated near the saturation region, they will operate at constant temperature as well as constant pressure. The quality of medium is quite low at the end of expansion and the fluid before compression will be a mixture of liquid and vapor.

Boiler Efficiency Tips

1. Conduct flue gases analysis on the boiler every two months. Optimal percentages of O_2, CO_2, and excess air in the exhaust gases are given by:

Fuel	**O2 (%)**	**CO2 (%)**	**Excess Air (%)**
Natural Gas	2.2	10.5	10
Liquid Petroleum Fuel	4.0	12.5	20
Coal	4.5	14.5	25
Wood	5.0	15.5	30

Table 5.1: Optimal Flue Gas Composition

The air fuel ratio should be adjusted to the recommended optimum values if possible; however, a boiler with a wide operating range may require a control system to constantly adjust the air-fuel ratio.

2. A high flue gas temperature often reflects the existence of deposits and fouling on the fire and/or water side(s) of the boiler. The resulting loss in boiler efficiency can be closely estimated on the basis that a 1-% efficiency loss occurs with every 40^0F increase in stack temperature.

   It is suggested that the stack gas temperature be recorded immediately after boiler servicing (including tube cleaning) and that this value be used as the optimum reading. Stack gas temperature readings should be taken on a regular basis and compared with the established optimum reading at the same firing rate. A major variation in the stack gas temperature indicates a drop in efficiency and the need for either air-fuel ratio adjustment or boiler tube cleaning. In the absence of any reference temperature, it is normally expected that the stack temperature be less than 100^0F above the saturated steam temperature at a high firing rate in a saturated steam boiler (this doesn't apply to boilers with economizers and air preheaters).

3. After an overhaul of the boiler, run the boiler and re-examine the tubes for cleanliness after thirty days of operation. The accumulated amount of soot will establish the criterion as to the necessary frequency of boiler tube cleaning.

4. Check the burner head and orifice once a week and clean if necessary.

5. Check all controls frequently and keep them clean and dry.

6. For water in tube boilers that burn coal or oil, the soot should be blown out as much as once a day. The National Bureau of Standards indicates that 8 days of operation can result in an efficiency reduction of as much as 8%, caused solely by sooting of the boiler tubes.

7. The frequency and amount of blowdown depends upon the amount and condition of the feedwater. Check the operation of the blowdown system and make sure that excessive blowdown does not occur. Normally, blowdown should be no more than 1% to 3% of steam output.

Purity of water used for steam generation is extremely important. It is not usually possible to use waters found in nature as boiler feedwater. Most of them can be used if properly treated, though. What is necessary is the removal of impurities or their conversion into some sort of harmless form. Among other means is a systematic removal by blowdown. This way an excessive accumulation of solids is prevented. Water treatment prevents the formation of scale and sludge deposits on the internal surfaces of boilers. Scale formations severely retard the heat flow and cause overheating of metal parts. The scale build-up and heat transfer relationship is demonstrated in Figure 5.1.

Excess Air	O2 %	CO2 %	Net Stack Temperature						
			220	230	240	246	250	260	270
0.0	0.0	11.8	85.3	85.1	84.9	84.8	84.7	84.5	84.2
2.2	0.5	11.5	85.2	85.0	84.8	84.7	84.6	84.4	84.1
4.5	1.0	11.2	85.1	84.9	84.7	84.6	84.5	84.2	84.0
6.9	1.5	11.0	85.0	84.8	84.6	84.5	84.4	84.1	83.9
9.5	2.0	10.7	84.9	84.7	84.5	84.3	84.2	84.0	83.8
12.1	2.5	10.4	84.8	84.6	84.4	84.2	84.1	83.9	83.7
15.0	3.0	10.1	84.7	84.5	84.2	84.1	84.0	83.8	83.5
18.0	3.5	9.8	84.6	84.4	84.1	84.0	83.9	83.6	83.4
21.1	4.0	9.6	84.5	84.2	84.0	83.8	83.7	83.5	83.2
24.5	4.5	9.3	84.3	84.1	83.8	83.7	83.6	83.3	83.1
28.1	5.0	9.0	84.2	83.9	83.7	83.5	83.4	83.2	82.9
31.9	5.5	8.7	84.1	83.8	83.5	83.4	83.3	83.0	82.7
35.9	6.0	8.4	83.9	83.6	83.3	83.2	83.1	82.8	82.5
40.3	6.5	8.2	83.7	83.4	83.2	83.0	82.9	82.6	82.3
44.9	7.0	7.9	83.5	83.3	83.0	82.8	82.7	82.4	82.1
49.9	7.5	7.6	83.4	83.1	82.8	82.6	82.5	82.2	81.9
55.3	8.0	7.3	83.1	82.8	82.5	82.3	82.2	81.9	81.6
61.1	8.5	7.0	82.9	82.6	82.3	82.1	82.0	81.6	81.3
67.3	9.0	6.7	82.7	82.3	82.0	81.8	81.7	81.4	81.0
74.2	9.5	6.5	82.4	82.1	81.7	81.5	81.4	81.0	80.7
81.6	10.0	6.2	82.1	81.8	81.4	81.2	81.1	80.7	80.3
89.8	10.5	5.9	81.8	81.4	81.1	80.9	80.7	80.3	79.9
98.7	11.0	5.6	81.5	81.1	80.7	80.5	80.3	79.9	79.5
108.7	11.5	5.3	81.1	80.7	80.3	80.1	79.7	79.4	79.0
119.7	12.0	5.1	80.6	80.2	79.8	79.4	79.4	78.9	78.5

Table 5.2: Boiler Efficiency (Natural Gas)

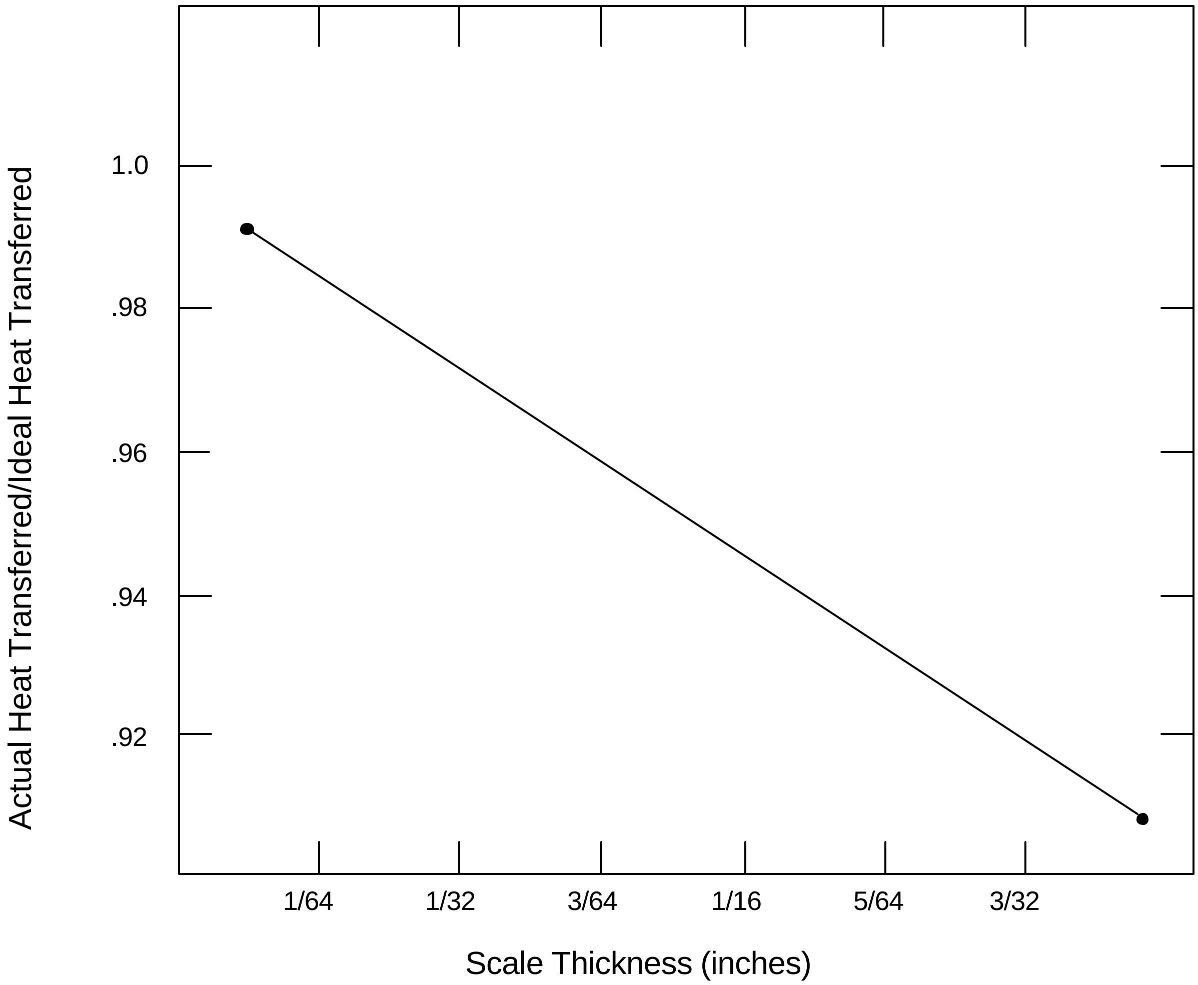


Figure 5.1: Effect of Scale Thickness in Boilers on Heat Transfer

Economizers use heat from moderately low temperature combustion gases after the gases leave the steam generating section (or in many cases also after going through a superheating segment). Economizers are heating the feedwater after it is received from the water feed pumps, so the water arrives at a higher temperature into a steam generating area. Economizers are once through forced flow convection heat transfer devices. A typical design uses steel tubes where the water is fed at pressures higher than the pressure in the steam generation part. The feed rate has to correspond to the steam output of the boiler. The following picture shows the effect of preheating of the feed water on the efficiency of a boiler unit.

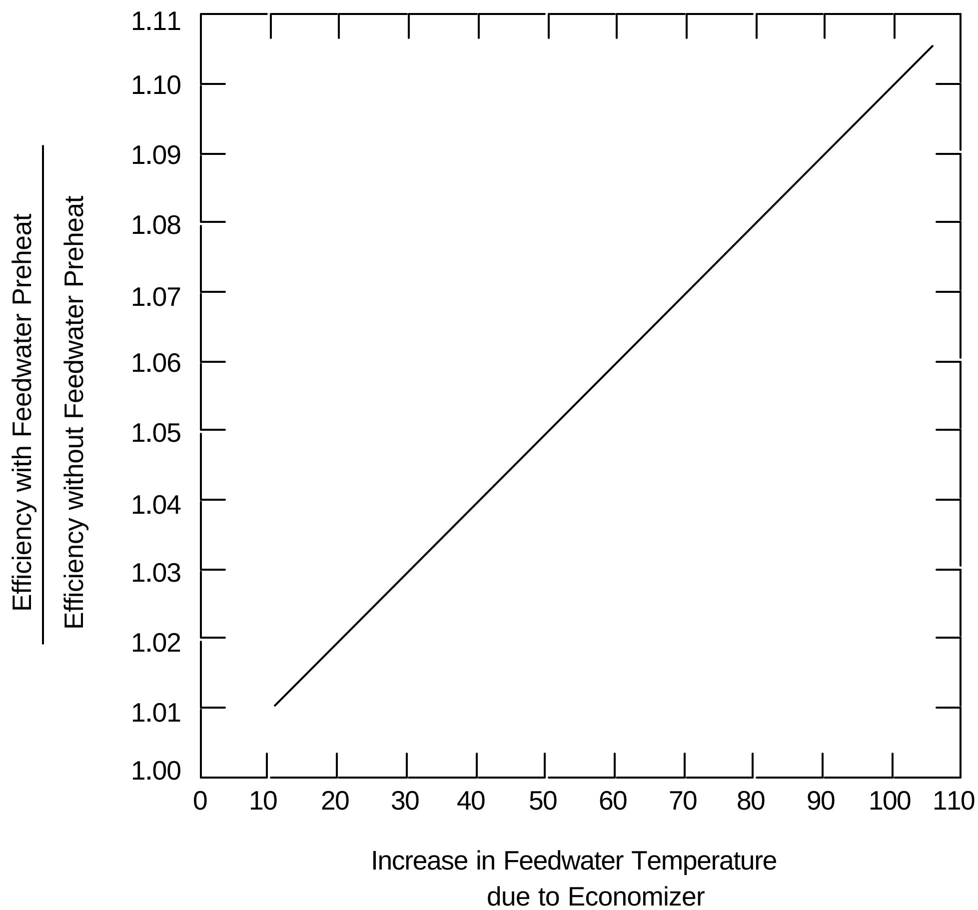
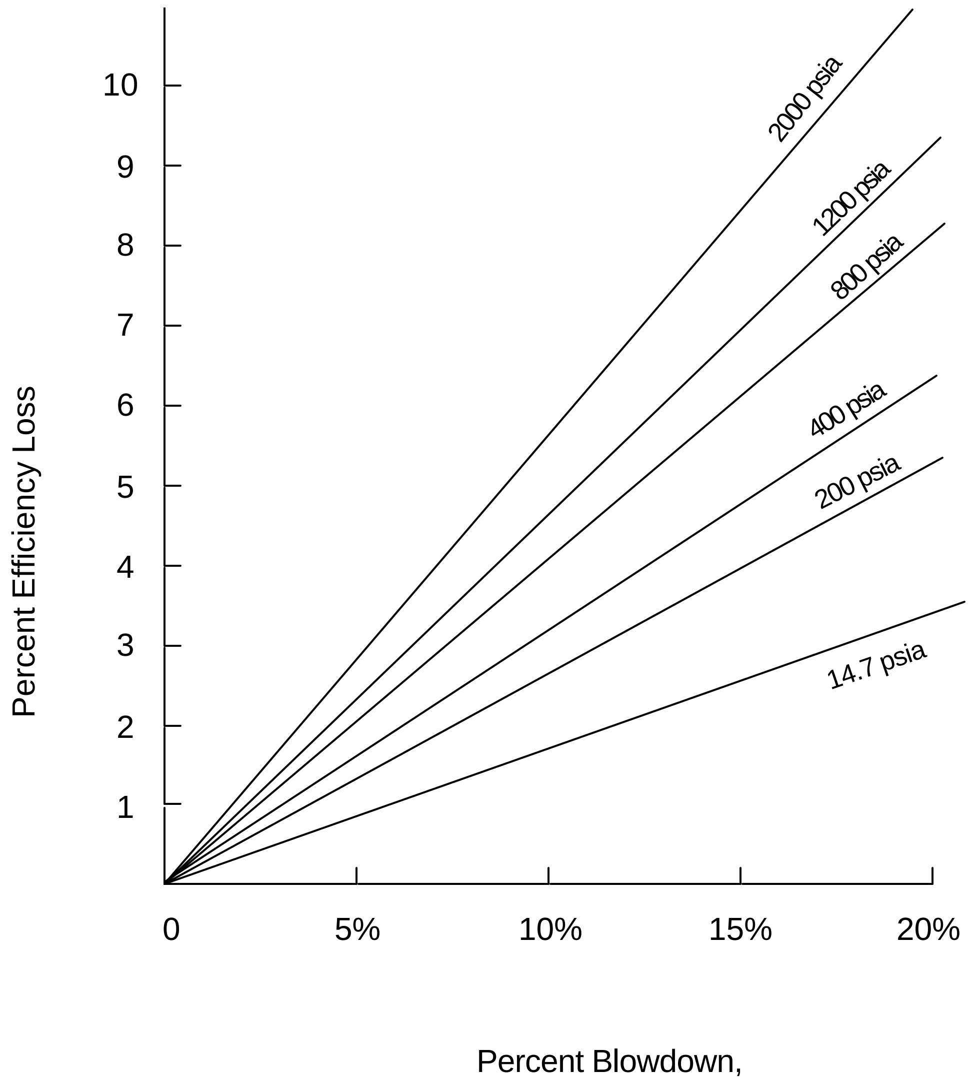


Figure 5.2: Effects of Feedwater Preheat on Boiler System Efficiency

Although blowdowns are an absolute necessity for the operation of a boiler, it is important that one realizes that, depending on the pressure, each blowdown decreases the efficiency of the boiler. The following picture illustrates this. Note how sharply the efficiency loss increases with higher pressures.



$$\frac{\dot{M}_{\text{Blowdown}}}{\dot{M}_{\text{Steam Produced}}} \times 100$$

Figure 5.3: Efficiency Loss Due to Blowdown

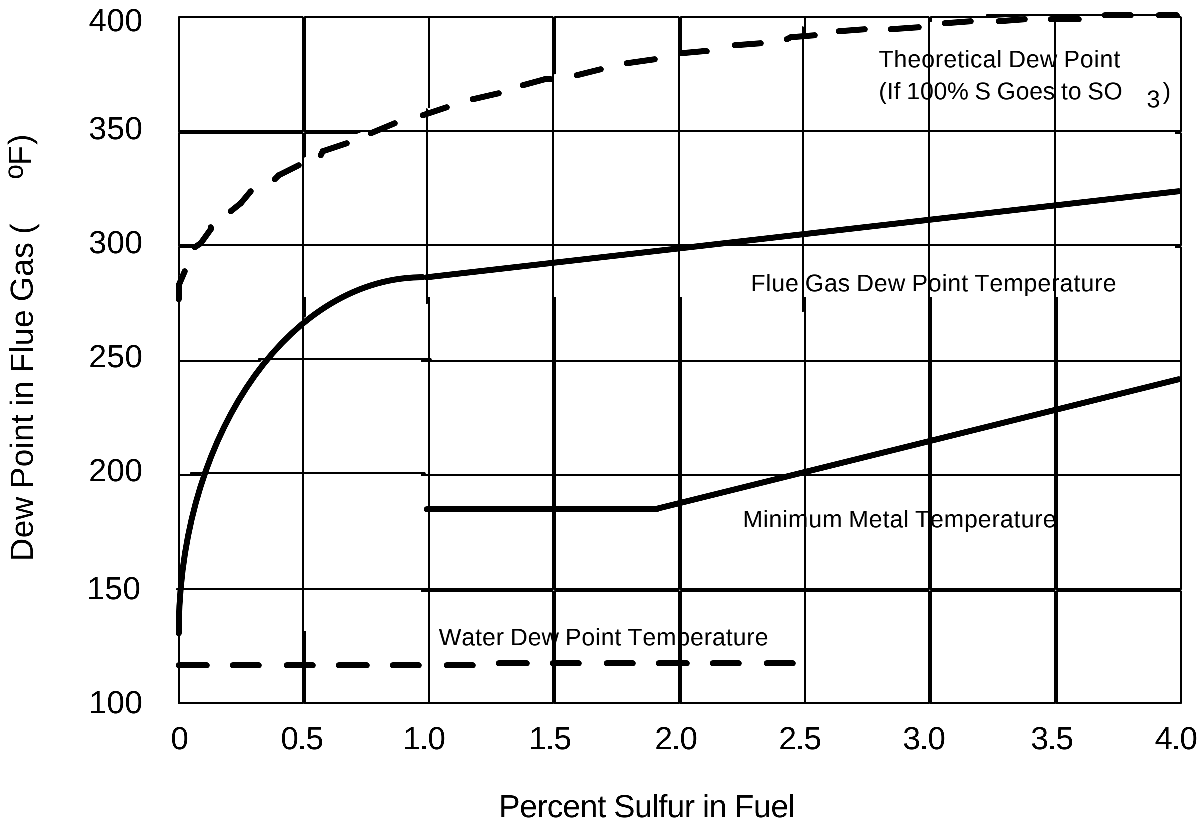


Figure 5.4: Acid Dew Point

Combustion in Boilers

Heat is released through a process called "combustion" burning. Combustion is the release of energy in the form of heat through the process of oxidation. The energy is stored in the bonds of carbon based fuels that are broken down during combustion.

To make the combustion happen a mixture of fuel, oxygen and heat is necessary. During the process of combustion, elements of fuel mix with oxygen and reconfigure to form new combinations of the same elements. The result is heat, light and new element combinations. The goal is to maximize heat and that can happen when the combustion process is tightly controlled.

<u>Complete Combustion</u>:

CARBON HYDROGEN	+	OXYGEN NITROGEN	=	WATER CO_2 NITROGEN

<u>Incomplete Combustion:</u>

CARBON HYDROGEN	+	OXYGEN NITROGEN	=	SOOT + ALDEHYDES WATER CO_2 CO NITROGEN

Perfect combustion (stoichiometric combustion) is the process of burning the fuel without an excess of combustion air. This process should develop the "ULTIMATE CO2" amounts in the combustion products.

Natural Gas (can vary)	11.7 - 12.1%
Propane	13.7%
No. 2 Oil	15.2%
No. 4 Oil	16.0%

Table 5.3: Ultimate CO2 Values

While these values can be sometimes achieved, Table 5.4: "Boiler Combustion Mixtures" shows realistic values.

Fuel	CO2	O2	Excess Air
Natural Gas	10.5%	3.5 - 4.0%	20%
Propane	11.0 - 11.5%	3.5 - 4.0%	20%
No. 2 Oil	11.5 - 12.0%	3.5 - 4.0%	20%
No. 4 Oil	12.5 - 13.0%	3.5 - 4.0%	20%

Table 5.4: Boiler Combustion Mixtures

Carbon in burning to carbon monoxide, gives off only about one third of the available heat. A 1/8 in. of soot on the heat exchanger increases fuel consumption by over 8% as a rule of thumb. Incomplete combustion, which results in the formation of CO, is dangerous because it is odorless, colorless, tasteless, and contrary to popular belief, it is non-irritating. The gas is also lighter than air and consequently, if it is escaping from a plugged or leaking boiler fireside, can rise to occupied areas. CO can only be detected with special test or monitoring equipment.

Causes of Incomplete Combustion

1. Insufficient or Too Much Oxygen
   - Air problems (rule of thumb - 1 cubic foot of air for every 100 Btu's of gross heating value).
   - Minimum air intake openings for a given input.

     Oil - unconfined = 28 square inches per gallon
     confined = 140 square inches per gallon
     Gas - draft hood = 1 square inch per 5,000 Btu
     barometric = 1 square inch per 14,000 Btu
     direct = 1 square inch per 17,500 Btu

2. Insufficient or too much fuel
   - Fuel is not vaporized - possible reasons
     - ◊ Worn nozzle
     - ◊ Clogged nozzle
     - ◊ Pump pressure is incorrect
     - ◊ Pump, lines, filter or tank lines are clogged
     - ◊ Cold fuel
   - Water in fuel - possible causes
     - ◊ Supplier doesn't supply quality fuel
     - ◊ Tank outside
     - ◊ Cover of the fill and vent not protected from elements

3. Insufficient or inconsistent heat
   - The ignition system is used to provide the proper temperature (called kindling point) for the light off of the vaporized fuel under design conditions. When design conditions are not met, light off will not occur.
   - An established flame is usually sufficient to maintain the kindling point. However, any time the combustion temperature falls below the kindling point, the combustion triangle is broken and combustion stops.
   - Safety device will shut the fuel off within 3 seconds of flame failure.

Calculating Combustion Efficiency

The calculation of combustion efficiency is based upon three factors.

1. Chemistry of fuel
2. Net temperature of the stack gases
3. The percentage of oxygen or carbon dioxide by volume in the stack gases

Eyeballing the flame for color, shape and stability is not enough for maximizing efficiency. Commercial analyzers are available to accurately gauge combustion efficiency. The simplest units measure only O_2 or CO_2.

Process Type	Efficiency [%]
Fireplace	10-30
Space Heater	50-82
Commercial Atmospheric Gas Boiler	70-82
Oil Power Burner	73-85
Gas Power Burner	75-83
Condensing Furnace (Gas or Oil)	85-93

Table 5.5: Combustion Efficiencies

There are no standard performance efficiency levels that commercial boiler manufacturers must adhere to. The efficiency is reported in different terms:

Thermal Efficiency - A measure of effectiveness of the heat exchanger. It does not account for radiation and convection losses.
Fuel to Steam Efficiency - This term is a measure of the overall efficiency of the boiler. It accounts for radiation and convection losses.
Boiler Efficiency - Used both ways.

The cost savings in boiler operation can be achieved by employing system controls. Temperature setback devices can result in savings up to 18% of annual heating costs. The controllers can sense the temperature inside or outside, possibly both. They control the boiler cycling and/or control valves based upon the ratio of the two inputs and the rate of change of each. Burner controls maximize the burner's efficiency. This can be done by using two-stage (high-low) burners. Another possibility is utilization of higher voltage electronic ignition, which improves light off and consequently reduces associated soot accumulation. Employment of interrupted ignition reduces the run time of ignition components by approximately 98% during heating season. This in turn increases ignition life.

5.1.3. Typical Performance Improvements

Some performance improvements are easily achieved and most of them are really just proper maintenance or operation procedures. This section covers a few of the more common ones.

Adjustment of Fuel and Air Ratio

Description

For each fuel type, there is an optimum value for the air/fuel ratio. For natural gas boilers, this is 10% excess air, which corresponds to 2.2% oxygen in the flue gas. For coal-fired boilers, the values are 20% excess air and 4% oxygen. Because it is difficult to reach and maintain these values in most boilers, it is recommended that the boiler air/fuel ratio be adjusted to give a reading of 3% oxygen in the flue gas (about 15% excess air) for gas-fired boilers and 4.5% (25% excess air) for coal-fired boilers. Combustion analyzers are available that give readings are available for less than $1,000, and it is often recommended that these be purchased. For natural gas boilers, the efficiency is a function of excess/deficient air and stack temperature. The curves for oil- and coal-fired boilers are similar. Because the efficiency decreases rapidly with deficient air, it is better to have a slight amount of excess air. Also, the efficiency decreases as the stack gas temperature increases. As a rule of thumb, the stack temperature should be 50^0 to 100^0F above the temperature of the heated fluid for maximum boiler efficiency and to prevent condensation from occurring in the stack gases. It is not uncommon that as loads on the boiler change and as the boiler ages, the air/fuel ratio will need readjusting. It is recommended that the air/fuel ratio be checked as often as monthly.

Definitions

Stack Gases - The combustion gases that heat the water and are then exhausted out the stack (chimney).

Air/Fuel Ratio - The ratio of combustion air to fuel supplied to the burner.

Applicability

Facility Type - Any facility that has a forced draft boiler.

Climate - All climates.

Demand-Side Management Strategy - Strategic conservation.

For More Information:

Dyer, D.P., G. Maples, etc., Boiler Efficiency Improvement, Boiler Efficiency Institute, Auburn, AL, 1981, pp. 4-31.

Air/Fuel Ratio Reset: Costs and Benefits1

Options	Installed Costs ($)2	Energy Savings (MMBtu/yr)	Cost Savings ($/yr)3	Simple Payback (yr)
Air/Fuel Ratio Reset	1,673	2,339	5,691	0.3

1. Tabulated data were taken from the Industrial Assessment Center (IAC) database. All values are averages based on the data base data. The implementation rate for this measure was 70%.
2. One example from the IAC data base to further clarify the costs is as follows: Adjusting the air/fuel ratio on a 6.3 MMBtu/h boiler at a concrete plant resulted in energy and cost savings of 1,814 MMBtu/yr and $4,760/yr. The implementation cost was $1,500, which was the cost for flue gas analysis equipment and labor.

3. The energy cost savings are based on proposed dollar savings as reported to IAC from the center, usually almost identical to actual savings reported from the facility.

§ *Case Study #1: Adjust Boiler Air-Fuel Ratio*

IMPLEMENT PERIODIC INSPECTION AND ADJUSTMENT
OF COMBUSTION IN A NATURAL GAS FIRED BOILER

Current Practice and Observations

During the audit, the exhaust from the boilers was analyzed. This analysis revealed excess oxygen levels that result in unnecessary energy consumption.

Recommended Action

Many factors including environmental considerations, cleanliness, quality of fuel, etc. contribute to the efficient combustion of fuels in boilers. It is therefore necessary to carefully monitor the performance of boilers and tune the air/fuel ratio quite often. Best performance is obtained by the installation of an automatic oxygen trim system, which will automatically adjust the combustion to changing conditions. With the relatively modest amounts spent last year on fuel for these boilers, the expense of a trim system on each boiler could not be justified. However, it is recommended that the portable flue gas analyzer be used in a rigorous program of weekly boiler inspection and adjustment for the two boilers used in this plant.

Anticipated Savings

The optimum amount of O2 in the flue gas of a gas fired boiler is 2.0%, which corresponds to 10% excess air. Measurements taken from the stack on the 300 HP boiler gave a temperature of 400^{0}F and a percentage of oxygen at 6.2%. By controlling combustion the lean mixture could be brought to 10% excess air or an excess O2 level of 2%. This could provide a possible fuel savings of 3%.

The 300 HP natural gas boiler is used both for production and heating. It is estimated that 100% of the natural gas is consumed in the boiler.

Therefore the total savings would be:

Savings in Fuel (thermos/yr): = (% burned in boilers) x (annual thermos per year) x (percent possible fuel savings)

= (1.0 x (56,787 thermos/yr) x (0.02)

= 1,136 thermos/yr

Savings in Dollars ($/yr): = (thermos Saved/yr) x (cost/therm)
= 1,136 thermos/yr x $0.644/therm
= $732/yr

Implementation

It is recommended that you purchase a portable flue gas analyzer and institute a program of monthly boiler inspection and adjustment of the boilers used in the plant. The cost of such an analyzer is about $500 and the inspection and burner adjustment could be done by the current maintenance personnel. The simple payback is:

$500 cost / $732 = 8.2 months

<u>Simple Payback = 8.2 months</u>

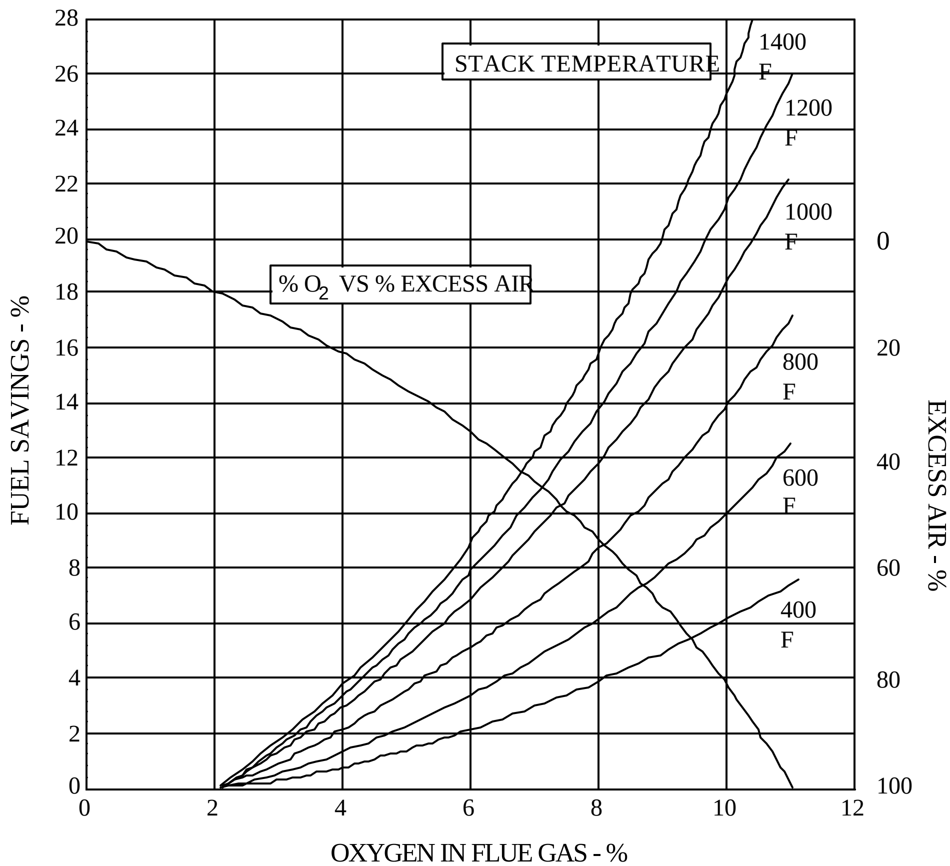


Figure 5.5: Natural Gas Fuel Savings[1]

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[1]. ***Energy Conservation Program Guide for Industry and Commerce***, National Bureau of Standards Handbook 114, September 1974, p.3-48.

Note: Fuel savings determined by these curves reflect the following approximation: The improvement in efficiency of radiant and combination radiant and convective heaters or boilers without air pre-heaters that can be realized by reducing excess air is 1.5 times the apparent efficiency improvement from air reduction alone due to the accompanying decrease in flue gas temperature.

As an example, for a stack temperature of 600^0FF and O2 in flue gas of 6%, the fuel savings would be 3%. If desired, excess air may be determined as being 36%.

§ *Case Study #2: Adjust Boiler Air-Fuel Ratio*

IMPLEMENT PERIODIC INSPECTION AND ADJUSTMENT
OF COMBUSTION IN AN OIL FIRED BOILER

Current Practice and Observations

During the audit, flue gas samples were taken from the boiler. The boiler was operating with too much excess air resulting in unnecessary fuel consumption.

Recommended Action

Many factors including environmental considerations, cleanliness, quality of fuel, etc. contribute to the efficient combustion of fuels in boilers. It is therefore necessary to carefully monitor the performance of boilers and tune the air/fuel ratio quite often. Best performance is obtained by the installation of an automatic oxygen trim system that will automatically adjust the combustion to changing conditions. With the relatively modest amounts spent last year on fuel for these boilers, the expense of a trim system on each boiler could not be justified. However, it is recommended that the portable flue gas analyzer be used in a rigorous program of weekly boiler inspection and adjustment for the two boilers used in this plant.

Anticipated Savings

The optimum amount of O2 in the flue gas of an oil fired boiler is 3.7%, which corresponds to 20% excess air. The boiler measured had an O2 level of 8.5 % and a stack temperature of 400^0F. From the Figure 5.6, using the measured stack temperature and excess oxygen for the boiler indicates a possible fuel saving of nearly 4.0% for the oil fired boiler.

It is assumed that the boiler consumes all of the fuel oil consumed during the year. The possible savings is then the sum of the products of amount used and percent saved.

ES = (10,339 gallons/yr) x (0.04 savings.) = 414 gallons/yr

Therefore the total cost savings would be:

Cost Savings = (414 gallons/yr) x ($1.03/gallon) = $426/yr

<u>*Total Annual Savings = $426*</u>

<u>Implementation</u>

It is recommended that you purchase a portable flue gas analyzer and institute a program of monthly boiler inspection and adjustment of the boilers used in the plant. The cost of such an analyzer is about $500 and the inspection and burner adjustment could be done by the current maintenance personnel. The simple payback period will then be:

$500 implementation cost / $426 savings = 1.2 years

<u>***Simple Payback = 1.2 years***</u>

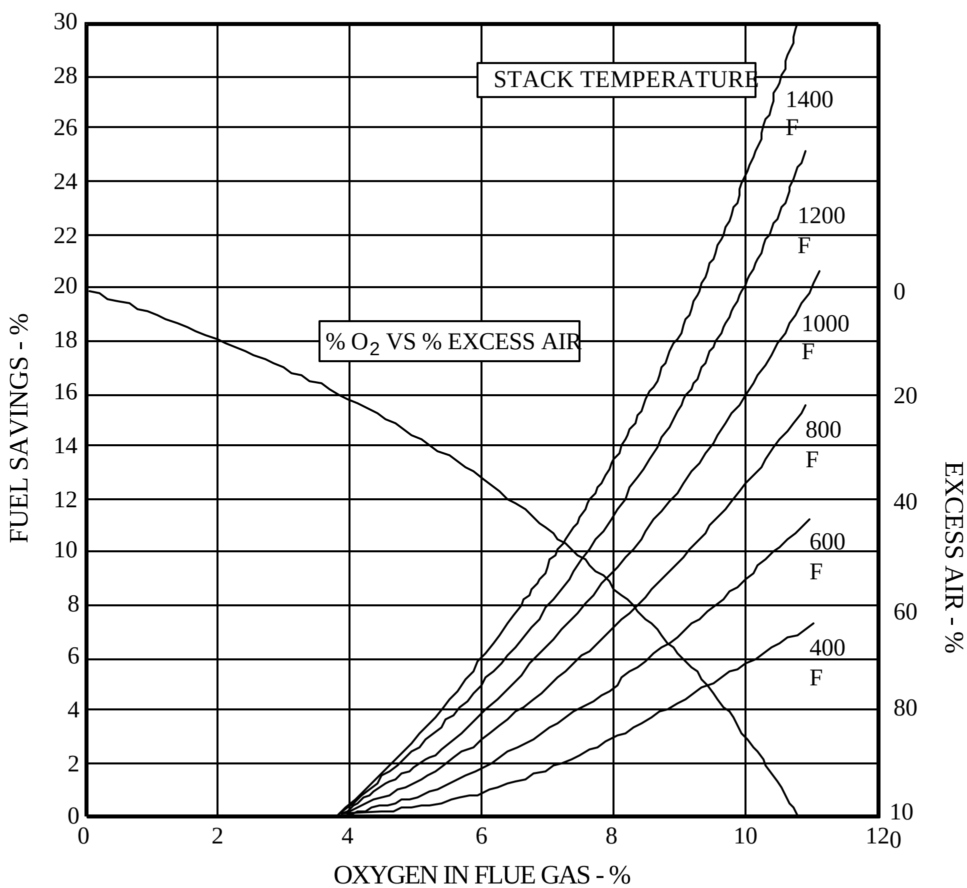


Figure 5.6: Liquid Petroleum Fuel Savings[2]

Note: Fuel savings determined by these curves reflect the following approximation: The improvement in efficiency of radiant and combination radiant and convective heaters or boilers without air pre-heaters that can be realized by reducing excess air is 1.5 times the apparent efficiency improvement from air reduction. This is due to the decrease in flue gas temperature which must follow increased air input.

As an example, for a stack temperature of 800^0F and O2 in flue gas of 6%, the fuel savings would be 3%. If desired, excess air may be determined as being 36%.

For further recommendations, see the “Boiler Efficiency Tips” in Section 5.1.2.1.

Elimination of Steam Leaks

Description

Significant savings can be realized by locating and repairing leaks in live steam lines and in condensate return lines. Leaks in the steam lines allow steam to be wasted, resulting in higher steam production requirements from the boiler to meet the system needs. Condensate return lines that are leaky return less condensate to the boiler, increasing the quantity of required make-up water. Because make-up water is cooler than condensate return water, more energy would be required to heat the boiler feedwater. Water treatment would also increase as the make-up water quantity increased. Leaks most often occur at the fittings in the steam and condensate pipe systems. Savings for this measure depend on the boiler efficiency, the annual hours during which the leaks occur, the boiler operating pressure, and the enthalpies of the steam and boiler feedwater.

Definitions

Enthalpy - A measure of the energy content of a substance.

Applicability

Facility Type - Any facility having a steam boiler.

Climate - All climates.

Demand-Side Management Strategy - Strategic conservation.

Steam Leak Repair: Costs and Benefits1

Options	Installed Costs ($)2	Energy Savings (MMBtu/yr)	Cost Savings ($/yr)3	Simple Payback (yr)

2. *Energy Conservation Program Guide For Industry and Commerce,* National Bureau of Standards Handbook 115, September 1974, p.3-48.

Steam Leak Repair	873	1,628	5,548	0.2

1. Tabulated data were taken from the Industrial Assessment Center (IAC) database. All values are averages based on the data base data. The implementation rate for this measure was 81%.
2. One example from the IAC data base to further clarify the costs is as follows: Repairing steam leaks on a 600 hp boiler system at a rendering plant resulted in energy and cost savings of 986 MMBtu/yr and $4,535/yr. The implementation cost was $350.
3. The energy cost savings are based on proposed dollar savings as reported to IAC from the center, usually almost identical to actual savings reported from the facility.

Maintenance of Steam Traps

Description

A steam trap holds steam in the steam coil until the steam gives up its latent heat and condenses. In a flash tank system without a steam trap (or a malfunctioning trap), the steam in the process heating coil would have a shorter residence time and not completely condense. The uncondensed high-quality steam would be then lost out of the steam discharge pipe on the flash tank. Comparing the temperature on each side of the trap can easily check steam trap operation. If the trap is working properly, there will be a large temperature difference between the two sides of the trap. A clear sign that a trap is not working is the presence of steam downstream of the trap. Nonworking steam traps allow steam to be wasted, resulting in higher steam production requirement from the boiler to meet the system needs. It is not uncommon that, over time, steam traps wear and no longer function properly.

Definitions

Condensate - The hot water that is created from the steam that has condensed.

Applicability

Facility Type - Any facility having a steam boiler.
Climate - All climates.
Demand-Side Management Strategy - Strategic conservation.

For More Information

Kennedy, W.J., W.C. Turner, Energy Management, Prentice-Hall, Englewood Cliffs, NJ, 1984.

Steam Trap Repair: Costs and Benefits**1**

Options	Installed Costs ($)2	Energy Savings (MMBtu/yr)	Cost Savings ($/yr)3	Simple Payback (yr)
Steam Trap Repair	2,560	5,431	14,885	0.17

1. Tabulated data were taken from the Industrial Assessment Center (IAC) database. All values are averages based on the data base data. The implementation rate for this measure was 79%.

2. One example from the IAC data base to further clarify the costs is as follows: Repairing one steam trap resulted in energy and cost savings of 105 MMBtu/yr and $483/yr on a 600 hp boiler at a rendering plant. The implementation cost was $220.
3. The energy cost savings are based on proposed dollar savings as reported to IAC from the center, usually almost identical to actual savings reported from the facility.

High Pressure Condensate Return Systems

Description

If pressurized condensate return is exposed to atmospheric pressure, flashing will occur. Flash tanks are often designed into a pressurized return system to allow flashing and to remove noncondensable gases from the steam. The resulting low-pressure steam in the flash tank can often be used as a heat source. A more efficient alternative is to return the pressurized condensate directly to the boiler through a high-pressure condensate return system. Heat losses due to flashing are significant, especially for high-pressure steam systems. Steam lost due to flashing must be replaced by water from the city mains (at approximately 55^0F). This causes the feedwater mixture to the boiler to be significantly below its boiling point, resulting in higher fuel consumption required by the boiler to increase the temperature of the feedwater to the boiling point. The water treatment costs are also greater with increased amounts of flash losses.

In a retrofit application, a closed, high-pressure condensate return system would prevent the flashing that occurs in the existing system by returning the condensate to the boiler at a higher pressure and temperature, thereby reducing boiler energy requirements and water treatment costs. Noncondensable gases (such as air and those formed from the decomposition of carbonates in the boiler feedwater treatment chemicals) can be removed from a closed condensate return system through the use of variable orifice discharge modules (VODMS). VODMS are similar to steam traps in that they return condensate but also can remove noncondensable gases. In a system that does not contain VODMS, these gases can remain in the steam coil of the equipment being heated and can form pockets of gas that have the effect of insulating the heat transfer surfaces, thus reducing heat transfer and decreasing boiler efficiency.

Definitions

Flashing - Pressurized condensate changes phase into steam if the pressure is suddenly reduced.

Applicability

Facility Type - All facilities that have a steam system with a high-pressure condensate return system.
Climate - All climates.
Demand-Side Management Strategy - Strategic conservation.

For More Information

Industrial Assessment Center (IAC). Contact the IAC nearest to your area.

High Pressure Condensate Return Systems: Costs and Benefits1

Options	Installed Costs ($)[2]	Energy Savings (MMBtu/yr)	Cost Savings ($/yr)[3]	Simple Payback (yr)
High Pressure Condensate Return	31,341	2,850	12,791	2.4

1. Tabulated data were taken from the Industrial Assessment Center (IAC) data base. All values are averages based on the data base data. The implementation rate for this measure was 59%.
2. One example from the IAC data base to further clarify the costs is as follows: Installing of high-pressure condensate return system equipment at food processing plant resulted in energy and cost savings of 4,727 MMBtu/yr and $14,100/yr. The implementation cost was $37,000.
3. The energy cost savings are based on proposed dollar savings as reported to IAC from the center, usually almost identical to actual savings reported from the facility.

Variable Frequency Drives for Combustion Air Blowers

Description

The load on a boiler typically varies with time, and, consequently, the boiler varies between low and high fire. The amount of combustion air required changes accordingly. Common practice has been to control a damper or vary the positions of the inlet vanes in order to control the air flow; that is, when inlet air is required the damper is essentially closed and is opened, as more air is required. This is an inefficient method of air flow control because air is drawn against a partially closed damper whenever the maximum amount of combustion air is not required. It is much more efficient to vary the speed of the blower by installing a variable-frequency drive on a blower motor (Note that it is sometimes expensive to install a variable-frequency drive if inlet vanes exist). Because the power required to move the air is approximately proportional to the cube of the air flow rate, decreasing the flow rate by a factor of two will result in a reduction of power by a factor of eight. This measure is particularly significant on boilers of 3.3 MMBtu/h or greater.

Combustion air blower variable-frequency drives are available from boiler manufacturers for new boiler installation. They also may be retrofitted to an existing boiler with few changes to the boiler.

Definitions

Firing Rate - As the load on a boiler varies, the amount of fuel supplied to the boiler varies in order to match the load.

Applicability

Facility Type - Applicable to any facility that has a large, forced draft boiler

Climate - All climates.

Demand-Side Management Strategy - Strategic conservation.

For More Information

Industrial Assessment Center (IAC). Contact the IAC nearest to your area.

Witte, L.C., P. S. Schmidt, D.R. Brown, Industrial Energy Management and Utilization, Hemisphere Publishing Corp., Washington, DC, 1988, pp. 530-532.

(ASD) - Variable-Frequency Drives: Costs and Benefits1

Options	Installed Costs ($)2	Energy Savings (MMBtu/yr)	Cost Savings ($/yr)3	Simple Payback (yr)
Combustion Air Blower Variable-Frequency Drives	23,967	1,115	13,789	1.7

1. Tabulated data were taken from the Industrial Assessment Center (IAC) data base. All values are averages based on the data base data. The implementation rate for this measure was 33%.
2. One example from the IAC data base to further clarify the costs is as follows: Installing variable speed drives and corresponding controls on two 250 hp combustion air fans at a food processing plant resulted in energy and cost savings of 488,445 kWh/yr and $28,000/yr. The implementation cost was $80,000.
3. The energy cost savings are based on proposed dollar savings as reported to IAC from the center, usually almost identical to actual savings reported from the facility.

5.2. HEAT RECOVERY SYSTEMS

Heat recovery systems are installed to make use of some of the energy which otherwise would be lost into the surroundings. Usually, the systems use a hot media leaving the process to preheat other, or sometimes the same, media entering the process. Thus energy otherwise lost, does useful work.

5.2.1. General Considerations

The first step in heat recovery analysis is to survey the plant and take readings of all recoverable energy that is being discharged into the atmosphere. The survey should include analysis of the following conditions:

- Exhaust stack temperatures
- Flow rates through equipment
- Particulates, corrosives of condensable vapors in the air stream

Ventilation, process exhaust and combustion equipment exhaust are the major sources of recoverable energy. Table 5.6 illustrates typical energy savings achieved by preheating combustion air with hot exhaust gases from process or furnaces.

Furnace outlet	Combustion air preheat temperature, ^{0}F

Temp. ^{0}F	400	500	600	700	800	900	1000	1100	1200	1300
2600	22	26	30	34	37	40	43	46	48	50
2500	20	24	28	32	35	38	41	43	45	48
2400	18	22	26	30	33	36	38	41	43	45
2300	17	21	24	28	31	34	36	39	41	43
2200	16	20	23	26	29	32	34	37	39	41
2100	15	18	22	25	28	30	33	35	37	39
2000	14	17	20	23	26	29	31	33	36	38
1900	13	16	19	22	25	27	30	32	34	36
1800	13	16	19	21	24	26	29	31	33	35
1700	12	15	18	20	23	25	27	30	32	33
1600	11	14	17	19	22	24	26	28	30	32
1500	11	14	16	19	21	23	25	27	29	31
1400	10	13	16	18	20	22	25	27	28	30

Note: 1. Numbers represent fuel savings, in percent.
2. Natural gas with 10% excess air. Other charts are available for different fuels and various amount of excess air.

Table 5.6: Fuel Savings Realized by Preheating Combustion Air

Regardless of the amount or temperature of the energy discharged, recovery is impractical unless the heat can be effectively used somewhere else. Also, the recovered heat must be available when it is needed.

Waste and heat recovery systems can be adapted to several applications:

- ♦ Space heating
- ♦ Make-up air heating
- ♦ Water heating
- ♦ Process heating
- ♦ Combustion air preheating
- ♦ Boiler feed water preheating
- ♦ Process cooling or absorption air conditioning

5.2.2. Types of Heat Recovery Equipment

Choosing the type of heat recovery device for a particular application depends on a number of factors. For example air-to-air equipment is the most practical choice if the point of recovery and use are closely coupled. Air-to-liquid equipment is the logical choice if longer distances are involved. Included in this section are five types of heat recovery systems.

⇒ Economizers
⇒ Heat pipes
⇒ Shell and tube heat exchangers

⇒ Regenerative units
⇒ Recuperators

Economizers

Economizers are air-to-liquid heat exchangers. Their primary application is to preheat boiler feed water. They may also be used to heat process or domestic water, or to provide hot liquids for space heating or make-up air heating equipment.

The basic operation is as follows: Sensible heat is transferred from the flue gases to the deaerated feed water, as the liquid flows through a series of tubes in the economizer, which is located in the exhaust stack.

Most economizers have finned tube heat exchangers constructed of stainless steel while the inlet and outlet ducts are carbon steel lined with suitable insulation. Maximum recommended waste gas temperatures for standard units are around $1{,}800^{0}$F. According to economizer manufacturers, fuel consumption is reduced approximately 1% for each 40^{0}F reduction in flue gas temperature. The higher the flue gas temperature the greater potential for energy savings.

Heat Pipes

The heat pipe thermal recovery unit is a counter flow air-to-air heat exchanger. Hot air is passed through one side of the heat exchanger and cold air is passed through the other side in the opposite direction. Heat pipes are usually applied to process equipment in which discharge temperatures are between 150 and 850 ^{0}F. There are three general classes of application for heat pipes:

1. Recycling heat from a process back into a process (process-to-process)
2. Recycling heat from a process for comfort and make-up air heating (process-to-comfort)
3. Conditioning make-up air to a building (comfort-to-comfort)

Heat pipes recover between 60 to 80% of the sensible heat between the two air streams. A wide range of sizes is available, capable of handling 500 to 20,000 cubic feet of air per minute. The main advantages of the heat pipe are:

No cross contamination
Operates without external power
Operates without moving parts
Occupies a minimum of space

Shell and Tube Heat Exchangers

Shell and tube heat exchangers are liquid-to-liquid heat transfer devices. Their primary application is to preheat domestic water for toilets and showers or to provide heated water for space heating or process purposes.

The shell and tube heat exchanger is usually applied to a furnace process cooling water system, and is capable of producing hot water approaching 5 to 10^0F of the water temperature off the furnace. To determine the heat transfer capacity of the heat exchanger the following conditions of the operation must be known:

1. The amount of water to be heated in gallons per hour
2. The amount of hot process water available in gallons per hour
3. Inlet water temperature and final water temperature desired
4. Inlet process water temperature

Regenerative Unit (Heat Wheel)

The heat wheel is a rotary air-to-air energy exchanger which is installed between the exhaust and supply air duct work in a make-up or air heating system. It recovers 70 to 90% of the total heat from the exhaust air stream. Glass fiber ceramic heat recovery wheels can be utilized for preheating combustion air with exhaust flue gas as high as $2{,}000^0$F. Heat wheels consist of rotating wheel, drive mechanism, partitions, frames, air seals and purge section. Regeneration is continuous as energy is picked up by the wheel in the hot section, stored and transferred to the cooler air in the supply section as the wheel rotates through it.

Recuperators

Recuperators are air-to-air heat exchangers built to provide efficient transfer of heat from hot exhaust gases to cooler air stream. Recuperators are generally used in the following processes:

- Preheating combustion air
- Preheating material that has to be heated in the process
- Recovery heat from hot gas to supplement or replace the primary heat source in process or comfort heating applications

There are many different types of recuperator designs available today. The recuperator described below is primarily used for combustion air preheating.

It consists of three basic cylinders, the hot gases flow up through the inner cylinder, cold combustion air enters at the bottom of the outer cylinder, flows upward and down through the middle cylinder, exiting from the bottom of the middle cylinder. Heat energy from exhaust gases is transferred through the inner cylinder wall to the combustion air by a combination of conduction and radiation heat transfer. The net effect is preheated air temperature as high as $1,000^0$F with inlet exhaust gases entering at $2,000^0$F and exiting at $1,300^0$F.

5.3. HEATING SYSTEMS

Heating systems are an integral part of industry today. They are used for process heating, drying, and comfort/space heating. The main purpose of industrial space heating is to provide comfortable conditions for the people working in these areas but also for purposes such as storage of goods or providing a precise environment for sensitive equipment.

5.3.1. Overview

The objective of heating is to produce a steady, balanced environment regardless of the outside conditions. The type of clothing worn and the additional heat sources such as process waste heat must also be considered when implementing a system. Conservation of energy in heating means getting the most efficient use out of energy while consuming as little as possible. Energy can be conserved by reducing building heat loss by filling gaps and properly insulating. Avoiding overheating practices such as heating a building when it is unoccupied can also save in energy costs.

The existing industrial heating systems are for the most part inefficient, dated and are often the principal consumers of energy. The most widely used system is the conventional convection heater which is highly inefficient and consumes large amounts of energy. Convection heaters use the circulation of steam or high-pressure hot water in order to generate space heat. Inefficiencies can be attributed to the fact that much energy is lost in heating the space, or the medium, surrounding the object. It then relies on convection between the medium and the surface of the object to increase its temperature, or create warmth.

Another dilemma associated with space heating involves the loss of heat due to stratification. Most systems are designed to heat an area in order to maintain a desired temperature. Energy is wasted because a majority of the heat is either lost to infiltration and ventilation or eventually rises to the ceiling level requiring more energy to keep the working level heated. There are several energy conservation opportunities that can be applied to these operations to reduce the use of energy. This section describes these measures, namely destratification fans and radiant heating systems, and how they can be applied in industry.

5.3.2. Destratification Fans

Destratification fans are used to destratify air in buildings. In this section the theory of operation and some design considerations will be covered.

Introduction

Stratification is a result of an increasing air temperature gradient between the floor and the ceiling in an enclosed area, usually due to stagnant air. When there is insufficient air movement, the hot air will rise to the ceiling, resulting in warmer temperatures in the upper portion of the area and cooler air temperatures at the working level near the floor. An example of stratification is shown in Figure 5.7(a). If stratification is present, the heating requirements of the facility are increased because the heating system is continually working to maintain the thermostat setpoint temperature. The thermostat setpoint operates according to the temperature at the working level. Much effort is required to make up for the heat the working level loses due to this physical occurrence. The destratification process initiates the movement of the air, creating a more uniform temperature distribution within the enclosed space. The air temperature at the floor level becomes nearly equal to the air temperature at the ceiling thus reducing the amount of energy needed to heat the facility. The amount of heat lost to ventilation and infiltration is also reduced due to the overall reduction in heat being generated.

Ceiling Fans

The basic function in destratification is to pull the air from the ceiling level down to the floor level and allow it to mix with the cooler air and increase the temperature at the working level. This benefits the comfort of the workers and also reduces the energy use of the facility. This process can be accomplished by two different means. The first and most common device used is the ceiling fan. The fan draws the air from above the fan and forces it downward by the power of the specific motor and blade combination. The resulting motion is an air plume, with the warm air moving downward and outward and essentially creating an mixture like the one shown in Figure 5.7(b). The total air volume and coverage is dependent on the motor size, height of the fan and the specifications of the fan blade (design, size, rpm). Ceiling fans are also applicable in cooling conditions. It creates motion in the air and this can assist with evaporative cooling of the skin surface. The total number of fans needed for a facility can be determined by the following equation.

$$\frac{\text{Total Plant Area}}{\text{Fan Area Coverage}} = \text{Number of Fans Needed}$$

The Fan area coverage depends on the type and size of fan used and this information can usually be obtained from the fan manufacturer. Placement of the fans is also important. The simplest method of determining placement is to calculate distance between each fan. This can be accomplished by using

$$\text{Distance} = \sqrt{(\text{Fan Area Coverage})}$$

Corner fans should be placed half this distance from each wall and consecutive fans should be placed this distance apart to obtain maximum coverage. Obstacles such as stacked merchandise or office partitions should be taken into consideration when choosing and placing fans.

§ *Case Study*

In calculating the energy and cost savings of this implementation it is first necessary to calculate the Energy Savings of the fans ($E_{S,F}$).

$$E_{S,F} = \{[(U \text{ x } A)_W + (U \text{ x } A)_I \text{ x } DH_{AT} + (U \text{ x } A)_C \text{ x } DH_{CT} - [(U \text{ x } A)_W + (U \text{ x } A)_I + (U \text{ x } A)_C] \text{ x } DH_{PT}\} / EFF$$

where

U = heat transfer coefficient
A = area
DH_{AT} = annual heating degree hours at current average temperature
DH_{CT} = annual heating degree hours at ceiling temperature
DH_{PT} = annual heating degree hours at proposed mixed temperature
EFF = efficiency of the heating system

subscripts
W = of the walls, windows, and doors
I = of the infiltration
C = of ceiling/roof

The amount of additional energy consumed by the destratification fans is given by

$$E_{DF} = \text{Number of Fans} \times W \times OH$$

where

W = wattage of each fan
OH = operating hours during the heating season

The total annual energy savings (ES) can now be found by

$$ES = E_{S,F} - E_{DF}$$

Using this information, it is simple to calculate the annual cost savings (CS) of this implementation.

$$CS = (E_{S,F} \text{ x Fuel Cost}) - (E_{DF} \text{ x Fuel Demand Cost})$$

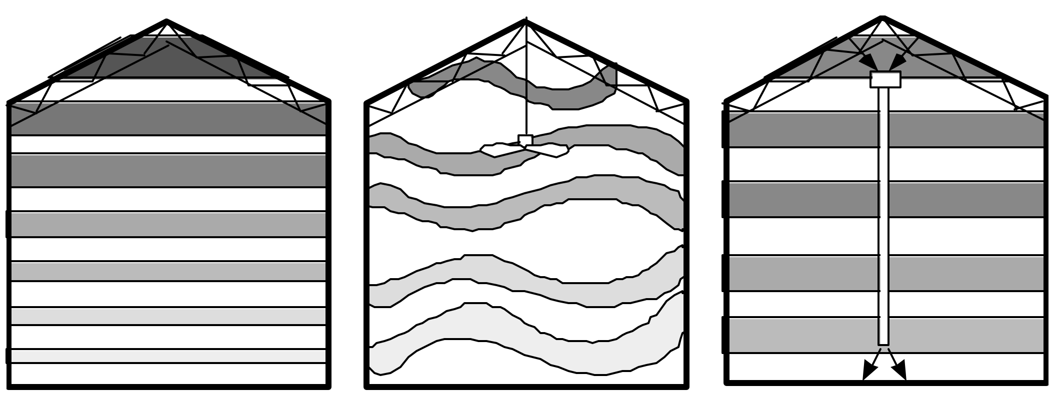
Finally a simple payback can be found using

$$\text{Payback} = (\text{Number of Fans x (Cost per Fan + Installation Cost)}) / CS$$

A case study for one plant yielded a potential energy savings of 305.59 MMBtu/yr with cost savings of $1,643.20. This measure, which involved 19 fans, had an implementation cost of $3,420. The suggested fan type was the 60" model, estimated to cover about 2,150 ft2, with a price of approximately $90 per unit and an installation cost of $90, resulting in a total of $180 per fan. The simple payback period was 2.08 years. The typical payback period for the installation of destratification fans is approximately 2 years.

Ducting

Another option for destratifying the air is to install a hanging device that uses a fan to pull the warm air from the ceiling, sends it downward through a duct/tube and redistributes the air at the floor level as shown in Figure 5.7(c). This device has its advantages and disadvantages. It aids in the destratification process and creates a more uniform temperature distribution without creating disturbing drafts. It is also simple to install and can easily be relocated throughout the building. On the other hand, these devices may be a bit cumbersome and unsightly. They would extend from the ceiling down to the floor and create additional obstacles for the workers or just may not be appropriate for some areas of the plant. These devices also do not possess the cooling applications of the ceiling fans and are only useful for the heating season.



(a) (b) (c)

Figure 5.7: Stratification and Destratification of Air

a) Stratification air pattern, (b) Destratification air pattern using a ceiling fan,

(c) Destratification air pattern using ducting

5.3.3. Electric Heating

Electrical resistance heating is often inexpensive and convenient to install. However, electric energy costs at least twice as much as other sources of heat, such as steam or natural gas, although greater efficiency in use may partially offset this difference. Before a decision is made to heat with electricity, the savings these alternative sources can produce should be evaluated in relation to the cost to install them. For example, consider the replacement of a 500,000-Btu-per hour electric heater with a 500,00-Btu-per-hour natural gas dryer.

Annual Cost of ELECTRIC HEATER
$= 500{,}000 \text{ Btu/hr} \times \$14.65/10^6 \text{ Btu} \times 80\% \text{ Eff.} \times 6{,}000 \text{ hrs/yr} = \$35{,}200$

Annual Cost of Natural Gas Dryer
$= 500{,}000 \text{ Btu/hr} \times \$3.00/10^6 \text{ Btu} \times 50\% \text{ Eff.} \times 6{,}000 \text{ hrs/yr} = \$4{,}500$

The energy cost saving is = $35,200 - $4,500 = $30,700/yr

5.3.4. Radiant Heaters

Radiant heaters are used for heating spaces by converting electric or gas energy. It is important to think thoroughly about the whole picture before recommending radiant heaters because if considered in isolation they probably would not make an economic sense.

Introduction

When dealing with the use of energy for the purpose of heating sometimes it is better to deal directly with the source of the problem. Convection heaters are inefficient heating devices in themselves. A lot of energy is wasted in heating the space and using that heated air to convectively warm the people and/or objects within that space. Radiant heaters take a different approach. Radiant heaters operate similar to the sun. Radiant energy is transferred at the speed of light as electromagnetic waves. The heaters emit infrared radiation which is absorbed by the people/objects that it strikes, which elevates the temperature of the body, but does not heat the air through which it travels.

Types of Radiant Systems

Radiant heating systems can be gas-fired or electric. The type of radiant heating system used is determined by the sources available from the building in which the system is installed. For example, electric radiant heating systems may be installed in an area of the building where gas is unavailable. Natural gas is more cost effective than electricity and produces lower operating costs. The efficiencies for both electric and gas systems are approximately the same but natural gas infrared systems have a longer lifetime. A radiant heating system is often a relatively easy retrofit measure but may also be integrated into new construction. Radiant heaters come in different sizes, styles and shapes according to their application. Figure 5.8 shows a typical example of a radiant heater. In relation to equipment performance, radiant sources can be categorized into four groups. A low temperature system has source temperatures up to 300^0F and would typically be used as a floor or ceiling heater. A low-intensity system has sources up to 1200^0F. A medium-intensity system has temperatures up to 1800^0F and would typically include a porous matrix unit. High-intensity systems have source temperatures up to 5000^0F and usually consist of an electrical reflector lamp and high temperature resistors. Low-temperature heating systems are usually use in residential and perimeter heating applications such as schools, offices, and airports. These systems are often incorporated directly into the building structure. Low-, medium-, and high-intensity systems have more industrial and commercial uses and are usually assembled units that are installed into existing structures.

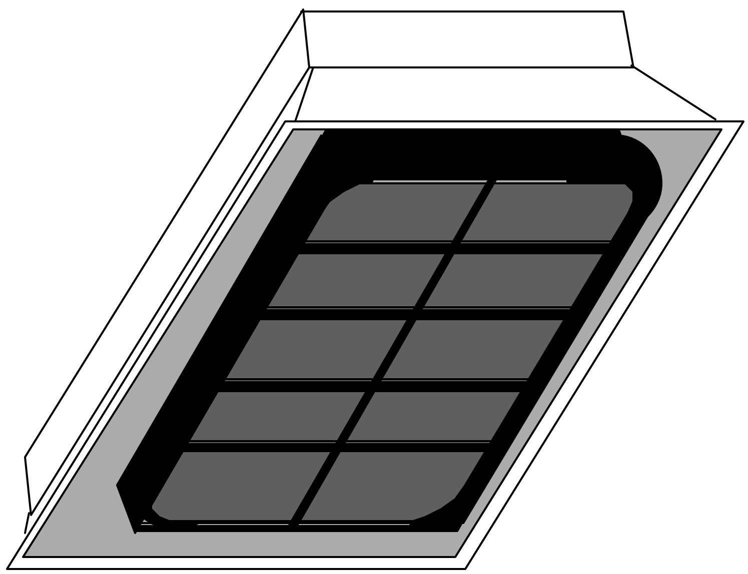


Figure 5.8: Infrared Radiant Heater

Applications

Use of radiant systems is ideal for comfort heating. Since the infrared radiation elevates body temperature without heating the air through which it travels, the same degree of comfort provided by the convection heaters can be maintained at lower indoor air temperatures with radiant heaters. This measure also eliminates the problem of stratification. It is beneficial to use these heaters in spaces where the ceilings are high and stratification is prominent. It is also very practical for areas that are frequently exposed to the outside air such as loading docks. Radiant spot heating helps workers to maintain a comfortable working temperature even though the space air may be cold. Radiant heat, unlike convection, does not require a medium to travel through and thus has a much higher heat transfer rate.

An advantage of this is its short response time. The person/object will feel the effects of the system shortly after it is engaged. The rate of energy transfer is dependent upon many different factors including temperature, emissivity, reflectivity, absorptivity, and transmissivity. Emissivity is a radiative property that indicates how efficiently the surface emits compared to an ideal radiator and its value ranges between 0 and 1. Reflectivity, absorptivity, and transmissivity are the fractions of incident radiation reflected, absorbed, and transmitted, respectively.

For use in process heating, the conventional heating methods can also be replaced with radiant systems. Since radiation does not need to travel through a medium, more heating work can be accomplished in less space. The response time when compared with convection heaters can prove to be an advantage in these industrial applications. The shut down time for an infrared burner varies from one to 30 seconds. Gas or electric radiant heaters may be used for different heating applications. Applications include cooking, broiling, melting and curing metals, curing and drying rubber and plastics, and preshrinking and finishing of textiles.

§ *Case Studies*

In calculating the energy and cost savings for using infrared radiant heaters the method differs according to the application of the system.

Comfort heating

For the radiant comfort heating system, the method is quite simple. First calculate the amount of energy (E_{RH}) consumed by the infrared units.

$$E_{RH} = HL \times \text{Number of Units} \times PR \times OH$$

where

HL = average heating load
PR = total power rating of each unit
OH = operating hours per year

Next, an estimate of the current energy usage for the convective heaters (E_{CH}) must be made. Then taking the difference in these two values,

$$ES = E_{CH} - E_{RH}$$

the total annual energy savings can be determined. Multiplying this number by the cost of fuel yields the total cost savings for the year.

$$CS = ES \times \text{Fuel Cost}$$

Or an alternate method for computing these savings is simply

$$ES = \text{Current Usage x } \{1- (EFF_c / EFF_R)\}$$

and

$$CS = ES \times \text{Fuel Cost}$$

where

EFF_C = efficiency of the convective system
EFF_R = efficiency of the radiant system

Note that although this evaluation is generally valid, these savings are based on the efficiency of the systems, where in most cases the savings are determined by the cost of the fuel. This is especially true in the case where different energy sources are being considered, i.e. natural gas or electricity.

One study estimated a current energy use of 5,000 x 106 Btu/yr. Installation of 18 radiant heaters yielded energy savings of 2,786 x 106 Btu/yr and cost savings of $10,406/yr. The implementation cost including piping and labor came to a total of $28,960 resulting in a payback period of 2.8 years.

<u>Process heating</u>

To find the savings for replacing a process unit with an infrared system, many more factors must be taken into account. For example, one case study involved replacing process ovens with infrared burners. The ovens were used to heat molds which in turn, baked cones. The first step in this savings estimation was to calculate the efficiency of the current ovens. This was accomplished by estimating the amount of energy (E_C) used to heat the product per year.

$$E_C = BS \times B \times OH \times [H_V + CP \times (Tf - Ti)]$$

where

BS = average batch size
B = # of batches per hour
OH = operating hours per year
Hv = heat of vaporization of water (assuming batch is 100% water)
CP = specific heat of water
Tf = final temperature of cone
Ti = initial temperature of batter

Once the total amount of energy consumed by the ovens (E_O) is obtained, the overall oven efficiency can be determined by

$$EFF_C = E_C / E_O$$

The heat transfer rates for the new and the old system were then found and compared. The convective heat transfer rate in the blue flame mode was approximated to be around 1.0 Btu/hr-ft2-deg. F based on the characteristics of the current ovens. The radiant heat transfer rate (U_R) was found by using the following equation.

$$U_R = F \times a \times \sigma \times (T_1^4 - T_2^4)/(T_g - T_m) = 1.3 \text{ Btu/ hr ft}^2 \text{ F}^\circ$$

where

F = radiation shape factor
a = absorptivity of the mold
σ = Boltzmann's constant
T_1 = radiant heater surface temperature
T_2 = mold surface temperature
T_g = gas temperature in the oven
T_m = mold temperature

Comparing these rates, U_R was found to be 30% larger than U_C, the convective coefficient. If there were 30% savings, the energy savings would be

$$ES = \text{Total Gas used by Ovens} \times \text{Percent Savings}$$

And the cost savings

$$CS = ES \times \text{Cost of Natural Gas}$$

Calculating the payback is simply

$$\text{Payback} = \text{Implementation Costs} / CS$$

where the implementation costs include equipment and installation.

The results of this study showed that there was a total energy savings of 5,440 MMBtu/yr and a total cost savings of $31,280/yr. For estimation purposes, it was assumed that 65% of the total gas use was consumed in order to obtain these approximations. The cost of implementation for each oven was $10,500. For all nine ovens the total implementation cost was $94,500. This data yields a payback period of 3.0 years.

5.4. FURNACES AND BURNERS

Furnaces and burners are devices designed to release energy from one form (hydrocarbon bonds) and convert it into another form (heat). The energy is typically released from gas or oil fuels through a combustion process. What type of burner or furnace to use and what is the most efficient way of operation highly depends on the process where it is used? There is always more than one way of solving an engineering problem, however, in some industries years of research and study of the processes involved might indicate to one recognized approach and therefore define quite narrowly the equipment best suited. It is obvious that one has to be careful not to recommend a change of a furnace without knowing the reason why the old seemingly inefficient one is used. On the other hand, with the sufficient knowledge supporting the change, the most desirable thing to do is to implement such a proposal.

5.4.1. Burner Combustion Efficiency

Conserving fuel in heating operations such as melting or heat treating is a complex operation. It requires careful attention to the following:

- Refractories and insulation
- Scheduling and operating procedures
- Preventative maintenance
- Burners
- Temperature controls
- Combustion controls

Providing the correct combustion controls will increase combustion efficiency measurably. Complete combustion of Natural Gas yields:

a) Carbon dioxide
b) Water vapor

If gas is burned with the chemically correct amount of air, an analysis of the products of combustion will show it contains about 11-12% CO_2 at 20-22% water vapor. The remainder is nitrogen, which was present in the air and passed through the combustion reaction essentially unchanged.

If the same sample of natural gas is burned with less than the correct amount of air ("rich" or "reducing fire"), flue gas analysis will show the presence of hydrogen and carbon monoxide, products of incomplete combustion. Both of these gases have fuel value, so exhausting them from furnaces is a waste of fuel (see Figure 5.9).

If more than the required amount of air is used (lean or oxidizing flame), all the gas will be burnt but the products of combustion will contain excess oxygen. This excess oxygen is an added burden on the combustion system - it is heated and then thrown away thereby wasting fuel.

The following steps should be taken to upgrade burner and combustion controls:

1. Use sealed-in burners. Make all combustion air go through the burner - open cage type burners are very inefficient.
2. Use power burners. Inspirator or atmosphere burners have very poor mixing efficiency at low inputs, especially if gas pressure is low.
3. Install a fuel/air ratio control system.

5.4.2. Premix Burner Systems

Premix burner systems commonly use a venturi mixer known as an aspirator or proportional mixer. Air from the blower passes through the venturi, creating suction on the gas line, and the amount of gas drawn into the mixer drops in proportion to air flow. Aspirator systems are fairly simple to adjust and maintain accurate air/fuel ratios over wide turndown ranges, but their use is limited to premix burners.

5.4.3. Nozzle Mix Burners

Nozzle mix burners used with a Ratio Regular System is widely used for industrial furnace applications. Orifices are installed in the gas and air lines to a burner and then adjusted so that air and gas are in correct burning proportions when pressure drops across the orifices are equal. Once the orifices are set, they will hold the correct air/gas ratio as long as the pressure drop remains the same, no matter what firing rate. Ratio Regular systems have good accuracy and are fairly easy to adjust.

On large furnaces where fuel consumption is extremely high, or on furnaces where very close control of the atmosphere is required, extremely accurate air/fuel ratio control is vital, both for fuel economy and product quality. On these installations hydraulic or electronic flow controls are often used.

These systems feature fixed orifices in both gas and air streams, and these orifices are sized to pass proportional amounts of gas and air at equal pressure drops, pressure drop signals are fed to a ratio controller which compares them. One of the outstanding features of this system is that the air/fuel ratio can be adjusted by turning a dial. Since a burner can be thrown off correct gas ratios by changes in ambient air temperature and humidity, this ratio adjustment feature permits the operator to set the burner back to peak operating efficiency with very little effort.

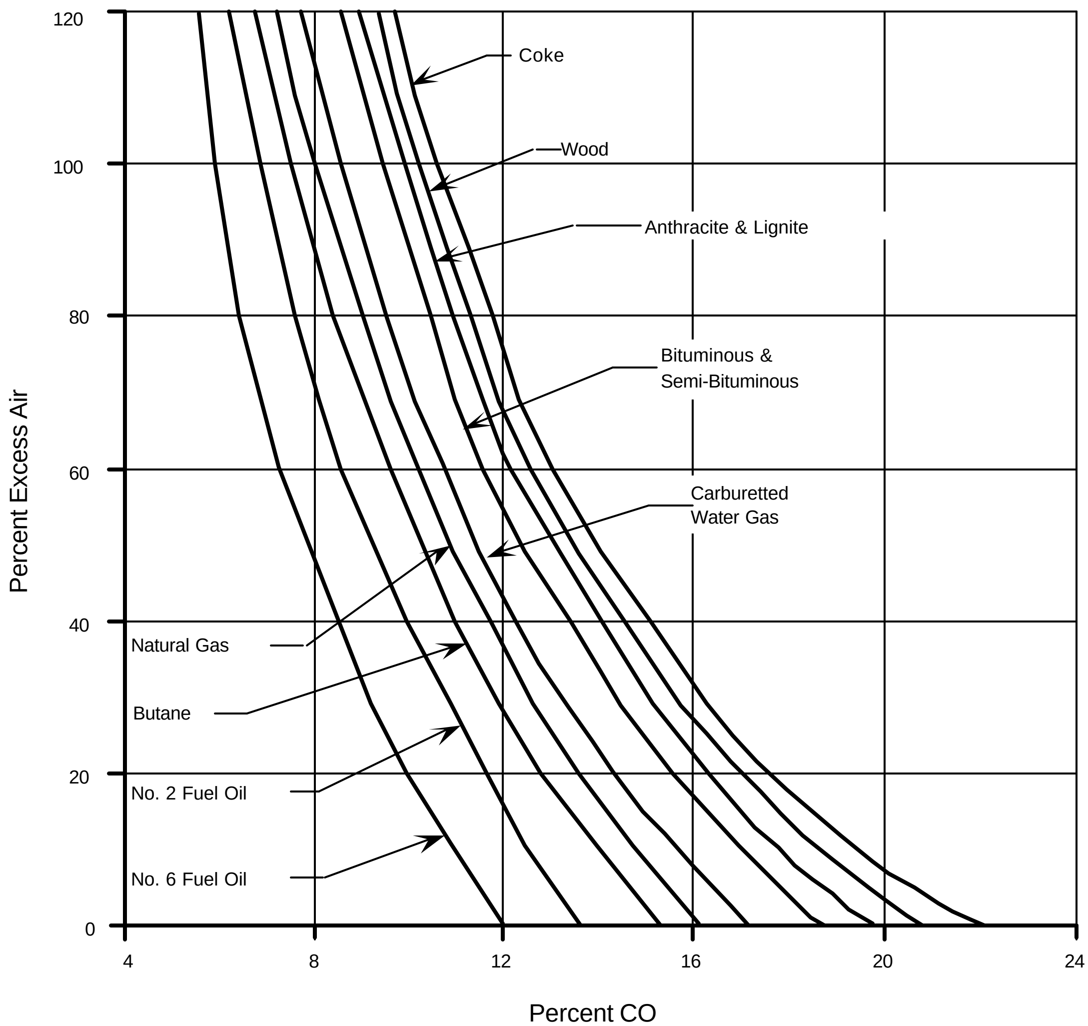


Figure 5.9: Percent Excess Air From CO2 Reading

On multiple burner furnaces, the combustion products of all burners mix together before they reach the flue gas sampling point (Furnaces should have manifold flue gas outlets in order to obtain common sampling point for flue gas analysis.) If, for example, some of the burners are unintentionally set lean, and others rich, the excess air from the lean burners could consume the excess fuel from the rich burners, producing flue gas with ultimate CO2 and practically no free oxygen or combustibles. Samples of these gases could be misleading and show correct air/gas ratio, when in fact they are not. Also, if a burner is set rich and the excess combustibles in the flue gases find air in the stack and burn there, flue gas analysis will again suggest that the burner be properly adjusted.

To overcome the problem of misleading flue gas analysis in multi-burner furnaces, metering orifices should be installed on the gas lines to each burner. If pressure drops across all orifices are identical, gas flow to each burner will be the same.

5.4.4. Furnace Pressure Controls

Furnace Pressure Controls will afford additional energy savings, particularly on top-flued furnaces. If a furnace operates under negative pressure, cold air is drawn into it through badly fitted doors and cracks. This cold air has to be heated, adding to the burden on the combustion system and wasting fuel. If the furnace operates at high positive pressure, flames will sting out through doors, site ports and other openings, damaging refractories and buckling shells. Ideally a neutral furnace pressure overcomes both these problems.

Automatic furnace pressure controls maintain a predetermined pressure at hearth level by opening or closing dampers in response to furnace pressure fluctuations.

In summation, good air/fuel ratio control equipment and automatic furnace pressure controls are two useful weapons for combating gas energy wastage in heating operations.

Properly applied, they also offer the side benefits of improved product quality and shortest possible heating cycles.

5.4.5. Furnace Efficiency

Conventional refractory linings in heating furnaces can have poor insulating abilities and high heat storage characteristics. Basic methods available for reducing heat storage effect and radiation losses in melt and heat treat furnaces are:

1. Replace standard refractory linings with vacuum-formed refractory fiber insulation material.
2. Install fiber liner between standard refractory lining and shell wall.
3. Install ceramic fiber linings over present refractory liner.

The advantages?

- Refractory fiber materials offer exceptional low thermal conductivity and heat storage. These two factors combine to offer very substantial energy savings in crucible, reverberatory and heat treat furnaces.
- With bulk densities of 12-22 lbs/cu ft, refractory fiber linings weigh 8% as much as equivalent volumes of conventional brick or castables.
- Refractory fibers are resistive to damage from drastic and rapid changes in temperature.
- Fiber materials are simple and fast to install.
- The density of fiber refractory is low, so there is very little mass in the lining, therefore much less heat is supplied to the lining to bring it to operating temperature. This results in rapid heating on the start-up. Conversely, cooling is also rapid, since there is less heat stored in the lining.
- More comfortable working environment is attainable due to lower shell surface temperatures.

The basic design criteria for fiber lined crucible furnaces are the same as used for furnaces lined with dense refractories. Two rules should be followed.

1. The midpoint of the burner should be at the same level as the bottom of the crucible, and the burner should fire tangentially into the space between the crucible and lining.
2. The space between the outside of the crucible, and the furnace lining near the top should be about 10% of the crucible diameter.

Crucible furnaces can be constructed using a combination of fiber with dense refractory or almost entirely out of fiber. Increasing the proportion of fiber will increase the energy savings and maximize the other benefits previously listed.

Fiber materials are available in varying thickness, suitable for a complete monolithic installation, and composition to handle 2,400^{0}F, 2,600^{0}F, and 2,800^{0}F.

The higher temperature compositions contain high aluminum fiber, which lowers the amount of shrinkage at elevated operating temperatures.

5.4.6. Furnace Covers

If preheating of combustion air utilizing furnace flue gas temperatures is contemplated, installation of furnace covers is mandatory. The difficulty in the past, in the fabrication and use of furnace covers, has been the problems of thermal shock and spalling, materials available today, such as refractory fiber, have eliminated these problems.

In addition to technological advantages of fiber insulation, industry has also developed the capability of vacuum forming these materials over a variety of metallic support structures. Fiber insulation can be formed over either expanded metal or angle iron frames, or both, with V-type anchors attached. The anchors are made from high temperature alloys, holding the fiber to the metallic support structures to provide an integral, fully secured assembly. No part of the anchor system is exposed to excessive temperatures, this eliminates attachment problems for ladle preheaters, crucible furnace covers, and induction furnace covers. Installation of furnace covers improves the thermal efficiency of the process by approximately 50%.

5.5. *COGENERATION*

Cogeneration is the simultaneous production of electric power and use of thermal energy from a common fuel source. Interest in cogeneration stems from its inherent thermodynamic efficiency. Fossil fuel-fired central stations convert only about one-third of their energy input to electricity and reject two-thirds in the form of thermal discharges to the atmosphere. Industrial plants with cogeneration facilities can use the rejected heat in their plant process and thereby achieve a thermal efficiency as high as 80 percent.

5.5.1. The Economics of Cogeneration

In-plant generation of electricity alone is not usually economical; a variable use must be made of the by-product waste heat. For this reason the demand for both types of energy must then be in balance, typically 100 kW versus 600,000 Btuh, for a gas turbine installation.

In most potential applications of industrial cogeneration, more electric power would be produced in meeting the plant's thermal requirement than could be used internally. However, the enactment of PURPA (Public Utility Regulatory and Policies Act " of 1978) greatly expanded the application for cogeneration by granting qualified cogenerators the right to:

- Interconnect with a utility's grid.
- Contract for backup power with the utility at nondiscriminatory rates.
- Sell the power to the utility at the utility's avoided cost.

There are several reasons for considering cogeneration besides energy savings.

- Energy independence
- Replacement of aging equipment
- Expansion of facilities
- Environmental considerations
- PURPA franchise to sell electricity
- Power factor improvement

However, plant conditions must fit certain requirements for a successful cogeneration application. Some factors are:

- The nature of the process must be suitable for cogeneration. Certain processes lend themselves more readily to cogeneration, such as refining, petrochemical, and pulp and paper industries, which have accounted for many of the larger cogeneration installations to date.

- The rate differential between electricity and fossil fuels should be relatively high on an equivalent Btu basis.

- Plant operation of 6,000 hours per year is usually the minimum needed to justify an installation and continuous operation improve reliability by minimizing dependence on the starting system.

- A source of waste fuel in suitable quantity provides an attractive incentive for cogeneration.

Although plant conditions may appear favorable for cogeneration, the long-term situation should also be considered before proceeding with a project.

1. The long-range cost of fuel for gas- and oil-fired units must be considered. Fuel prices have varied widely so that current prices may not be a reliable benchmark on which to base project returns. Inevitably the price of gas and oil can be expected to increase as worldwide reserves continue to diminish.

   Gas-fired cogeneration accounts for the major portion of present generating capacity because of the advantages of gas as a fuel. However, the recent glut of natural gas should not be taken as an assured long term supply at current prices.

   High-sulfur-bearing and solid-waste fuels with fluidized bed combustion are alternate fuels involving less price risk but greater investment.

2. Excess coal-fired generating facilities and abundant coal supplies can result in increased competition from utilities and lower avoided costs.

3. Utilities may press for repeal of PURPA or at least the ability to discount the avoided cost purchase rate. Accordingly, the future is uncertain for cogeneration projects based on avoided cost revenues.

   Utilities' cogeneration contracts may also impose certain restrictions or penalties for plant maintenance, outages, hours of operations, backup power charges, etc. based on the utilities' needs for additional cogeneration capacity.

4. The economic viability of the plant that would use the steam or electricity from a cogeneration facility should be assured. Foreign competition and corporate mergers are causing many revisions in manufacturing facilities. Because significant investment is involved in cogeneration facilities, long-term continuity of operations is important.

5. Reliability requirements of the cogeneration facility will be important. If third-party financing or operation is being considered, the plant loses some control over an important part of its operation. With in-plant generation, providing a reliable electric supply places additional responsibility and demands on plant operating and maintenance personnel. Because cogeneration systems generally involve a complex system of engines, generators, heat recovery equipment, controls, and accessories, the nature of the installation increases the possibility of problems. The cost of penalty for additional utility charges for any outage can be significant where demand charges are high.

Aside from long-term effects, other alternatives to cogeneration may negate some of its benefits.

1. Renegotiating rates may enable an industrial plant to duplicate the potential economic benefits of cogeneration without the risk of building and operating a power plant.

2. Load management techniques may be able to modify peak demands.

3. Major technological improvements or process changes can occur and significantly alter the present energy requirements.

4. Where available capital is limited, energy conservation may be able to reduce electrical consumption significantly by using projects with more attractive returns.

5.5.2. Cogeneration Cycles

There are many possible types of cogeneration cycles but most can be considered variations of the two basic cycles shown in Figure 5.10.

In the case of the cogeneration cycle with a gas turbine topping cycle, air is compressed and injected into the combustor along with the fuel, generally natural gas. The combustion gases at high temperature and pressure expand rapidly in the turbine, doing work in the process. The turbine drives an electrical generator and air compressor. The exhaust gas from the turbine, which is still at a high temperature, is then used to generate steam in a waste heat boiler.

The cost of a gas turbine with heat recovery equipment ranges between $600 to $1,000/kW, depending on the specific design conditions. Gas turbine systems costs are reduced by over 50 percent with larger units.

There are several advantages of the gas turbine system in comparison with the steam/turbine system.

- Lower capital cost (normally 50 to 70 percent of steam/turbine cost)
- Lower operating and maintenance cost.
- Higher power-to-heat ratio which is generally more desirable in industrial applications.

A reciprocating engine, generally a diesel, can be used in lieu of the turbine to supply the motive power. Since the exhaust from the engine is at a much lower temperature, only low pressure steam (maximum of 50 psig) or hot water can be generated without supplemental heating.

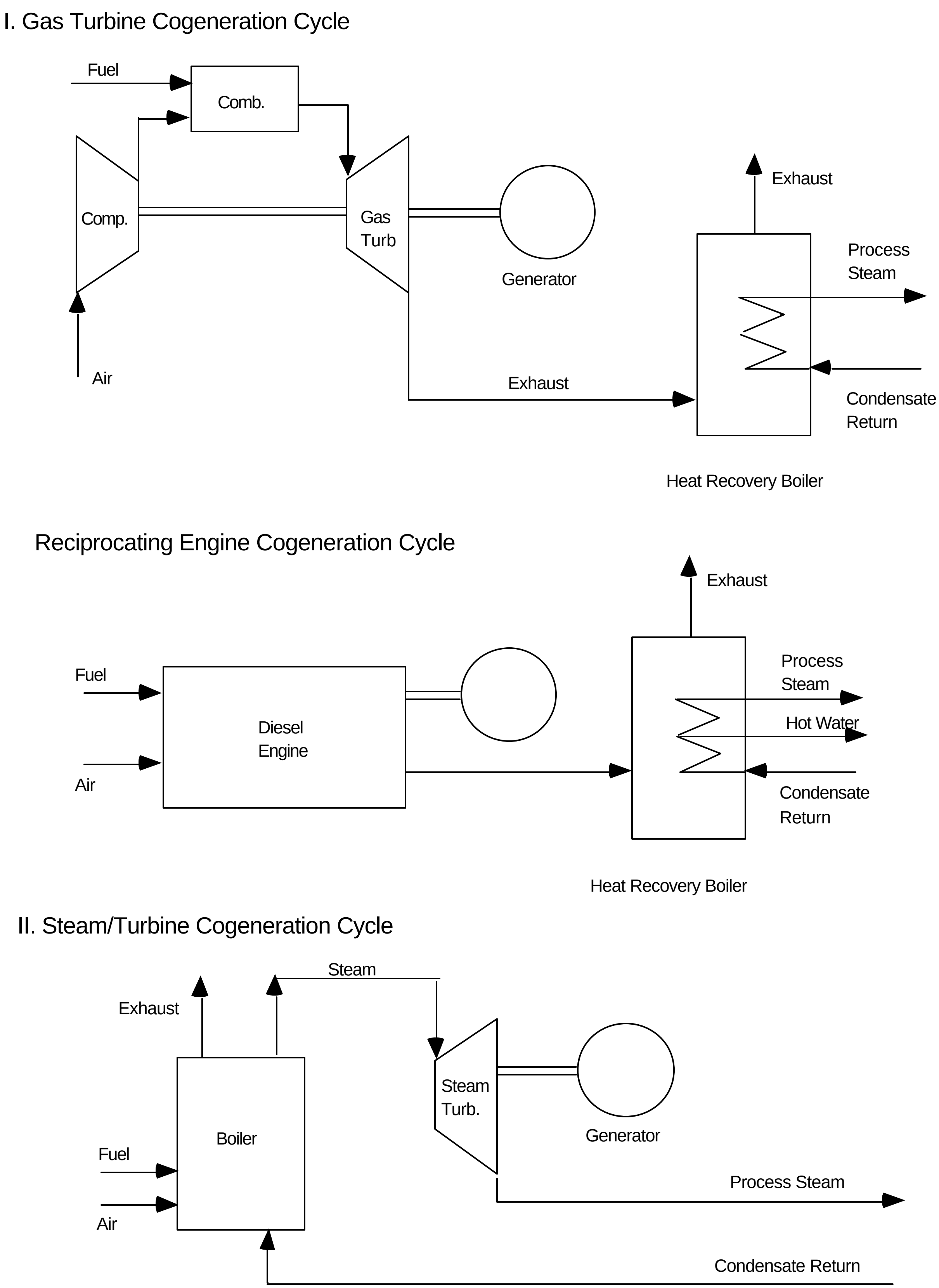


Figure 5.10: Cogeneration Cycles

5.5.3. Cogeneration High-Spot Evaluation

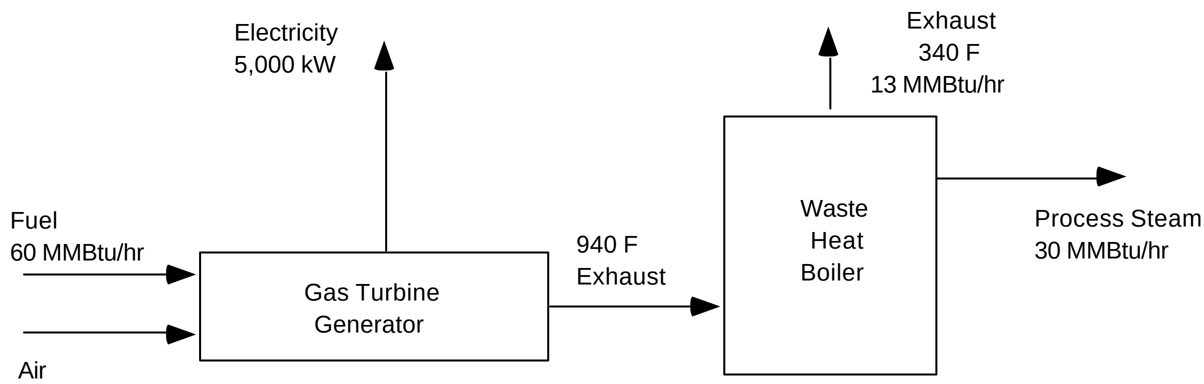


Figure 5.11: Gas-Turbine Cycle

Given process steam demand = 30,000 lbs/hr equivalent to 30 MMBtu/hr

Heat Input to Boiler = (30 MMBtu/hr) / (70% Waste heat eff.) = 43 MMBtu/hr

Exhaust = 43-30 = 13 MMBtu/hr
Electrical output (based on typical 100 kW/600,000 Btu):

= {(30 MMBtu/hr) / (0.6 MMBtu/hr)} x 100 kW = 5,000 kW

Equivalent Btu's = 5,000 kW × 3413 Btu/kW = 17 MMBtu/hr
Total Energy Input = 17 + 30 + 13 = 60 MMBtu/hr
Annual cost of operation:

= 60 MMBtu/hr × 8,000 hrs × \$3.00/MMBtu/hr = \$1,440,000/yr

Avoided cost of purchased electricity:

= 5,000 kW × 8,000 hr ×\$0.05/kWh = \$2,000,000/yr

Avoided cost of steam:

= {[(30 MMBtu/hr) x (80,000 hr)] / [80% Steam boiler eff.]} x \$3.00 / MMBtu = \$900,000 per year

Annual Saving = \$2,000,000 + \$900,000 - \$140,000 = \$1,460,000/yr
Investment = \$1,000/kW × 5,000 kW = \$5,000,000/yr

Payback = \$5,000,000 / 1,460,000 = 3.4 years

Given - process steam demand = 30,000 lbs/hr, equiv. to 30 MMBtu/hr

- boiler steam = 600 psig, 750 F
- turbine steam rate = 12.2 lbs/kWh @ 70% eff. = 17.4 act. lbs/kWh
  (Refer to Turbine Steam Tables for other conditions)

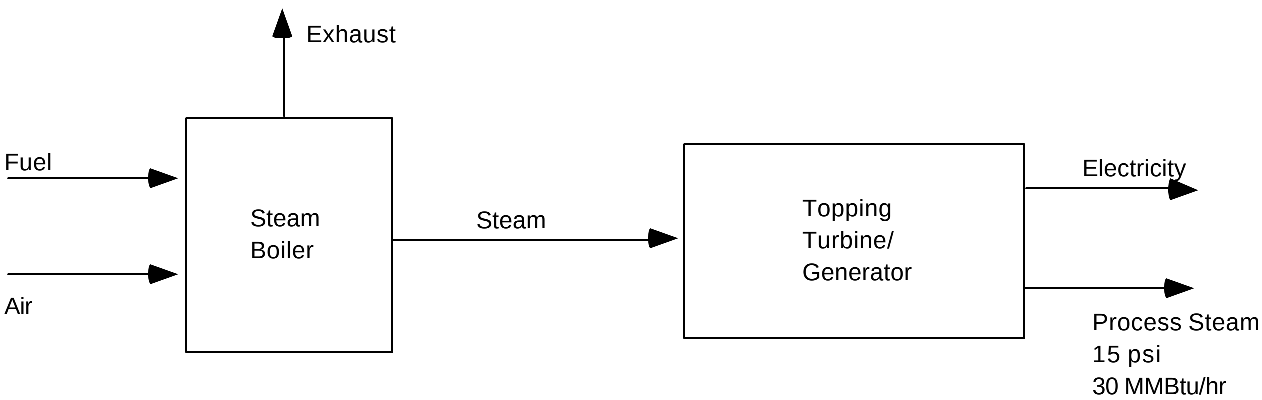


Figure 5.12: Steam-Turbine Cycle

KWh = (30,000 lbs/hr) / (17.4 lbs/kWh) = 1720 kW

Equivalent Btu/hr = 1720 × 3413 × 10-6 = 5.4 MMBtu/hr

Total energy input = (5.4 + 30) / (80% boiler eff.) = 44 MMBtu/hr

Annual cost of operation:
= 44 MMBtu/hr × 8,000 hrs × \$3.00/MMBtu = \$1,056,000/yr
Avoided cost of electricity:
= 1720 kW × 8,000 hrs × \$0.05/kWh = \$688,000/yr
Avoided cost of process steam:

= [(30 MMBtu/hr) / (80% boiler eff.)] x (80,000 hrs) x (\$3,00/MMBtu/hr) = \$900,000/yr

Annual Saving = \$688,000 + \$900,000 - \$1,056,000 = \$532,000/yr
Investment = \$1,500/kW × \$1,720 kW = \$2,580,000/yr

Payback = (\$2580,000) / (\$532,000) = 4.8 years

Oil- and gas-fired engine cogeneration systems are most suitable for smaller installations (under 1 MW). Packaged units are available from a few kilowatts to over a megawatt. The systems include a prime mover, generator switchgear, heat recovery, and controls. Equipment costs range from \$500 to \$1,000/kW. Installation costs for plumbing, electrical, and other facilities typically add 50 to 150 percent to the equipment cost. Total turnkey costs range from \$700 to \$2,000/kW.

Experience with the smaller size units (under 100 kW) has been relatively short. In the steam/turbine system, fuel is burned in a boiler to generate steam. The steam is passed through a topping turbine, which drives the electric generator. The exhaust steam is then used for process heating.

The greatest advantage of these systems is their ability to use practically any kind of fuel including lower-cost solid or waste fuels, either alone or in combination.

Capital cost of steam turbine systems is higher, typically 50 to 100 percent greater than a gas turbine system using natural gas or oil.

5.5.4. Estimate of Savings

A high-spot of savings should be made as early in the investigation as possible to confirm that cogeneration is merited, a detailed energy-load analysis should be made. This involves preparing a profile on the plant's steam and electric usage, taking into account daily, weekly, monthly, and seasonal variations. Using actual loads instead of average loads is important to determine whether periods of low-load factor are a problem. System performance will be best where output is steady instead of fluctuating with load.

With this data, plant personnel can select the most advantageous cogeneration cycle, taking into account various possible operating conditions and equipment options. A computer model analysis is very useful for this purpose. Equipment vendors can be utilized if outside assistance is needed to make the computer analysis.

The options which can be considered are as follows:

- Combined cycle - permits the use of a flexible instead of fixed ratio of electrical to thermal energy to adjust for variations in the steam demand.
- Steam pressure - the higher the pressure the more efficient the turbine steam rate.
- Steam injection - adds to turbine efficiency.
- Extraction turbine - provides process steam for use at different pressures.
- Water treatment method - high-pressure steam turbines require more sophisticated boiler feedwater treatment.
- Dual burners - burners capable of burning more than one fuel add flexibility to use lowest cost fuel.
- Degree of automation - fully automatic systems increase price significantly.
- Duct burner in exhaust stream - increases output and permits generation of higher pressure steam.
- Steam condenser - permits additional electrical generation from steam turbine at some loss in efficiency.
- Generator type - power factor is improved with higher cost synchronous generator.
- Parallel or independent operation will affect switchgear selection.

After the operating conditions and cogeneration facilities have been fully defined, the savings and investment estimates should be revised to complete the initial evaluation of the cogeneration facility.

When high-pressure steam or gas must be reduced in pressure through a pressure-reducing valve, a simpler system known as "induction generation" can be used to generate electricity.

Summary

If circumstances indicate there may be an application for cogeneration, certain precautions should be taken before proceeding with an evaluation. Assurance should be obtained that a change in conditions that would significantly affect the project economics is not likely to occur.

Also, the possibility of alternate approaches should be investigated. Similar benefits of cogeneration may be realized through other means which would require less capital and provide better return.

Where cogeneration is determined to be a viable option, a high-spot estimate of savings will confirm the need for further study. For a more detailed evaluation, an energy load analysis is required. Based on this information, the most appropriate cogeneration cycle and various equipment options can be selected. A full evaluation can then be made based on the projected production of electric power and thermal energy and required investment in facilities.

5.6. THERMOENERGY STORAGE SYSTEMS

The application of thermal storage is based on savings from using lower cost electrical rates with nighttime operation to provide daytime thermal needs.

5.6.1. General

Basically, two conditions must be present to make thermal storage attractive. First, there must be a significant difference between night and daytime electrical costs. The difference can be increased by higher summertime rates and inclusion of a ratchet provision for the next 11 months. Utilities generally encourage thermal storage because it permits them to transfer a portion of their daytime load from expensive peaking facilities to nighttime base-loaded, higher efficiency coal and nuclear plants.

Accordingly, the electric rate structure will encourage customers to shift their electrical load from daytime peak hours to nights and weekends by any or all of the following provisions in the rate structure.

- Time-of-day energy charge.
- Demand charges (per kW peak power consumed during peak hours each month).
- Winter/summer rates for energy and/or demand charges.
- A ratchet clause (monthly demand is the same or same percentage of the highest demand in previous 11 months).

Second, the daytime refrigeration load must result in high daytime cost, generally from peak demands, which have the potential to be reduced with thermal storage. Plants with one-shift operation or high solar load can be good candidates. Thermal storage has found application, for example, in office air conditioning. On the other hand, industrial plants with three-shift operation are normally not good candidates because of their more constant load.

Before considering thermal storage as a means of reducing electrical cost, alternate methods should be evaluated, as in most energy conservation approaches. Some possible alternate methods are absorption refrigeration, demand control, load scheduling, and using an emergency generator for peak shaving.

5.6.2. High Spot Evaluation

Where thermal storage appears to be a viable option, a high spot evaluation should be made to determine if further investigation is justified (see Table 5.7). The incremental electrical cost must be detailed into its separate components for this evaluation. In this example, it is assumed there is no off-peak demand charge and the off-peak electrical energy rate is less than the on-peak rate. For simplicity it is also assumed that the daytime refrigeration load increases the peak demand directly by 1 kW for each kW of load. In practice, the peak demand may be caused in part by other operations, so therefore, the actual potential reduction in peak demand from thermal storage would depend on its interrelationship with other loads.

5.6.3. Electric Load Analysis

Because of this interrelationship with other loads, a detailed electrical load analysis is necessary to determine the impact thermal storage will have on the existing peak demand. Use of average loads will not be satisfactory for this purpose.

The operating cost per ton for a thermal storage system is also higher than for a conventional system. The refrigeration machine must operate at a lower temperature, which requires more energy per ton. There is also some inherent loss in storage. One system reported that power consumption increased by 17 percent when the system was producing ice.

Table 5.7 shows that incremental investment for thermal storage results in an attractive payback. However, it should be emphasized that the example attributes maximum demand saving over the full year of operation and for the full capacity of the unit. A well-documented analysis of all energy flows and costs is needed for a more in-depth evaluation. A number of questions will also have to be answered as part of the evaluation, such as:

- should the thermal storage be for heating storage, cooling storage, or both?
- should the system handle 100 percent of the cooling load or only the portion needed for load leveling?
- should the storage system be water or ice?
- should the storage system be for a daily or weekly cycle?

Generally, systems have been for daily cycles and load levelers only.

Electrical Rate:	On-Peak	Off-Peak
Demand kW	$9.40	NC
Energy kWh	$0.03	$0.025
Conventional Refrigeration System		
Demand Cost/ton-yr = $/kW × 12 months		
	= $9.40 × 12 =	$113/yr
Energy Cost/ton-yr = 1 kWh/ton × $/kWh × hrs/yr		
	= $0.03 × 8,000 =	$240
Total Cost/ton-yr	= $113 + $240 =	$353
Thermal Storage System		
Cost/ton-yr = 1 kWh/ton × % increase × $/kWh × hrs/yr		
	= 1 × 1.20 × $0.025 × 8,000 =	$240
Savings = $353 - $240 =		$113
Investment		
Investment/ton - Conventional Refrigeration System		$400
Investment/ton - Thermal Storage System		$550
Additional Investment/ton ($550 - $400)		$150

Table 5.7: Thermal Storage High Spot Evaluation

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