FEASIBILITY AND COST OF CONVERTING OIL- AND COAL-FIRED UTILITY BOILERS TO INTERMITTENT USE OF NATURAL GAS

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Abstract - The continuous or intermittent use of natural gas in place of oil or coal in existing utility boilers would reduce emissions of sulfur and thereby the concentration of sulfate ions in precipitation. This report examines the technological feasibility and capital cost of retrofitting oil and coal fired utility boilers to burn intermittently natural gas and the parent fuel. Using extensive studies of the retrofitting of such boilers to burn synthetic gas of low to moderate heating value (LBG), it is found that natural gas closely simulates the combustion properties of LBG of medium heating value. Based upon this comparison, it is concluded that little or no modifications to the boiler are required to achieve the same boiler rating as when burning the original fuel, and that only a small efficiency penalty must be paid. Examination of the history of four eastern utility boiler conversions from oil to natural gas confirms these performance estimates, and shows that conversion costs for in-plant equipment are very small, less than 19 \$(1985)/KW in all instances, while conversion times are less than one year (with little down time beyond that required for annual maintenance). Pipelining costs will vary with the local conditions.

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EXECUTIVE SUMMARY

This report examines the technical feasibility and capital cost of retrofitting oil- and coal-fired utility boilers to burn intermittently natural gas (NG) and the parent fuel. Of particular interest is the summer substitution of NG for coal and oil in utility boilers. The summer use of NG may be a cost- and environmentally-effective way to reduce acid deposition and airborne particle concentrations resulting from emissions of sulfur dioxide and nitrogen oxides.

Since boilers are usually designed for a specific type of fuel (and even for a certain kind of coal), it is not obvious a priori that substituting NG for the design fuel will avoid degrading the performance of the boiler, even if major modifications are undertaken. Burning different fuels in the same boiler can alter the heat transfer rates, the wall and tube temperatures and the boiler efficiency. Fortunately, NG possesses combustion properties which make possible its use in coal- or oil-fired boilers with minimal effects on the boilers' performance.

There are few examples of the use of NG in oil-fired boilers, and no recent ones of NG conversion of coal-fired boilers. However, extensive recent studies of the conversion of coal- and oil-fired boilers to the use of a variety of synthetic natural gas mixtures provides a basis for estimating the modifications needed and the resulting boiler performance if NG were to replace the synthetic gas of equivalent combustion properties. Based upon these studies, we conclude that the boiler's maximum continuous rating (MCR) will be maintained upon NG substitution with only minor modifications to the boiler, such as addition of the gas burners, proper tilting of the nozzles, and windbox modifications. Furthermore, there will be no derating upon reverting to the parent fuel, oil or coal. On the other hand, there will be a slight drop of boiler efficiency, expressed as the heat content of the steam generated per fuel heat input. Efficiency drops of 3-5% are expected upon NG substitution for either coal or oil.

We verified the above conclusions by studying four utility boilers where summer substitution of NG for oil is actually practiced. In fact, two of the boilers were originally designed for coal burning. In no case was any derating experienced, although it should be noted that these boilers are usually not operated at full rating. Where measured, the efficiency drop was

between 2-6%.

From the utility operators of these units we obtained estimates of the capital cost of conversion. These ranged from $5.25/kW (1982 $) to $19/kW (1985 $). Pipeline installation costs are difficult to estimate since these costs are highly dependent on location of the plant vis-a-vis a high pressure transmission line. In the investigated cases, the range was $100-150/ft (1982-85 $).

Finally, it should be mentioned that summer NG substitution would have additional benefits on plant operations; namely, reduced furnace corrosion and erosion; reduced soot and slag formation; less ash disposal; no particulate (fly ash) formation, vitiating the need for operation of electrostatic precipitators; and last but not least, reduced NOx emissions.

INTRODUCTION

In order to reduce acid deposition and airborne sulfate particles, it would be necessary to reduce sulfur emissions from major emission sources. Several bills considered by Congress in recent years would require reduction in sulfur emissions from large coal and oil fired boilers, primarily those in electric generating stations. It is expected that the sulfur emission reductions would be accomplished either by substituting lower sulfur coal or oil for current fuels or by installing flue gas desulfurization equipment, commonly called scrubbers.

With recent changes in fuel prices, natural gas (NG) is becoming competitive with other fuels, especially when the cost of desulfurizing these fuels (or their combustion products) is taken into account. In fact, some electric utilities are already substituting NG for oil, not only for environmental reasons, but because NG is cheaper than oil at certain locations and in the summer months when NG supply is plentiful.

Natural gas substitution becomes even more favorable when one considers the environmental goal of sulfur deposition reduction, rather than its surrogate, sulfur emission reduction. Several years of monitoring at sites in eastern North America has shown that the deposition of acidic sulfur is much more intense in the summer half of the year (April through September) than in the winter half. At ecologically sensitive receptors in the Northeast, about 70% of the annual deposition of sulfuric acid occurs in the summer half-year (Golomb, Fay and Kumar, 1986). If the extra deposition benefit of the summer emission reduction were to be factored in, NG substitution in the summer months would be economically competitive in almost all oil-fired power plants and many coal-fired power plants (Galeucia, 1986; Golomb, Fay and Galeucia, 1986).

For these reasons it appears worthwhile to assess the technical feasibility and the capital cost of intermittent (e.g. seasonal) NG substitution in large (greater than 100MW thermal) oil and coal fired boilers. We stress intermittency because we have to consider the feasibility and performance characteristics not only of firing NG in an oil or coal fired boiler, but also of reverting to the original fuel in the winter months.

Our approach to investigating the feasibility of retrofitting coal and oil burning power plants to burn natural gas (NG) is to examine previous studies of the use of low BTU (LBTU) gas and intermediate BTU (IBTU) gas (both referred to as LBG)in such boilers, identifying the LBG gas which most closely resembles NG in its combustion and heat transfer characteristics. This is necessary since there exists no published literature on use of NG as a substitute for other fuels in these boilers. Thus we interpolate from the LBG studies to find the characteristics of NG conversion. Most importantly, we then can verify the conclusions by analyzing several existing retrofits in utilities where NG replaced oil.

This report contains six sections. Section 1 identifies the effects of fuel type on boiler design; Section 2 analyzes the potential problems in retrofitting to burn NG; Section 3 interpolates from the estimates of the LBG studies; Section 4 verifies our conclusions by examining the performance of retrofits of some oil fired utility boilers and also presents the capital costs of conversion; Section 5 describes the experience in piping gas to utility boilers and Section 6 briefly summarizes our main conclusions.

1. EFFECT OF FUEL TYPE ON BOILER DESIGN

Every boiler is designed to burn a particular type of fuel and, conversely, the selected fuel type is an important factor in the design of boilers. The major effects of fuel type on boiler design are the following:

- Furnace size
- Design, amount and location of heating surfaces (superheater, reheater, economizer)
- Equipment to prepare and burn fuel
- Type and size of heat recovery equipment
- Flue gas treatment, ash handling and particulate control equipment

Figure 1 shows the relative volume and arrangement of heat transfer surfaces of typical boilers for different fuels but for the same power rating. These differences are a result of the characteristics of each fuel as summarized in Table 1. It can be seen that NG boilers are smaller than coal or oil fired boilers and thereby have higher overall heat transfer rates. It might seem that there would be no problem in using natural gas in oil or coal boilers, but such is not the case because the distribution of heat transfer to the boiler surfaces must be replicated in any such conversion.

The design, amount and location of heating surfaces must be such:

- As to maintain a sufficient temperature difference between combustion gases and steam
- That the heating surface use is optimized
- As to avoid undesirable high metal temperatures
- As to achieve desirable flue gas velocities and therefore prevent erosion from flyash. Depending upon the ash quantity and abrasiveness (silica, alumina content), the design velocity in the superheater, reheater, economizer and convection passes is generally about 55 ft/s for coal, 125 ft/s for oil and 135 ft/s for NG. Such velocities are based on the predicted average gas temperature entering the tube section, at the maximum continuous rating (MCR) of the boiler at normal excess air.

Selecting a furnace size, its wall tubing and its circulation system is primarily a function of two distinct design parameters: the complete combustion of the fuel and the preservation of satisfactory furnace-wall metal temperatures. When burning pulverized solid fuels, the combustion gas flow path must be configured to prevent the formation of objectionable slag deposits that can increase the furnace outlet-gas temperature above design values. The upper portion of the furnace must also provide sufficient radiant heat transfer surface to reduce furnace gas exit temperatures.

The net effect of the different fuel properties and the ensuing restrictions on flame size and heat transfer distribution within the furnace and boiler results in the highest overall heat transfer rate in NG boilers, an intermediate rate in oil fired boilers and the lowest rate in coal fired units. For a given power rating, therefore, the relative boiler sizes are as shown in Figure 1.

2. RETROFITTING COAL AND OIL-FIRED POWER PLANTS WITH NATURAL GAS

2.1 Introduction

The description in Section 1 of the characteristics of a boiler required to burn a particular fuel serves as an indication of the type of modifications that might be necessary for the same boiler to burn a different fuel; i.e., those needed to duplicate the heat transfer pattern of its original fuel.

Although it is clear from Figure 1, and the discussion of Section 1, that a NG boiler cannot be fully converted to burn oil or coal at its original maximum continuous rating (MCR), we seek to demonstrate that a coal or oil boiler should be able to convert to natural gas, with minimum modifications if necessary.

In order to address the basic concern about the ability of a coal or oil boiler to burn natural gas without any derating or drop in efficiency, one needs to investigate the consequences of the different combustion properties of the three fuels, as summarized in Table 1. We need to address the following issues:

- Changes in the fuel weight and stoichiometry and the resultant change in the total combustion products which will flow over the heat absorbing surfaces. Does burning NG produce more mass of products per heat input than burning oil or coal, which cannot be handled by the existing induction (ID) fan ?
- Changes in the amount of combustion products result in changes in gas velocities that shift the heat absorption patterns within the components of the boiler. Will any changes in the heat absorption surface be required for the superheater/reheater? If the velocities turn out to be too high (and hence excessive heat transfer), the quantities of both superheater and reheater desuperheating spray water capability may be insufficient.
- The flue gas emissivity of natural gas is considerably greater than that from coal and oil. What effect does this have on superheater steam temperature?
- Will the possibly high spray water desuperheating requirement for the reheater reduce reheat inlet temperature below saturation at high loads? If so, removing a portion of the reheater surface may be necessary. This will lead to lower reheat outlet temperature, but the load carrying capability of the original fuel will no longer be retained, i.e., there will be a derating when using the original fuel.
- Will removal of portion of the economizer surface be required to prevent steaming in the economizer? Is installation of an evaporator section required above the economizer? Reduction in the economizer surface will lead to increased exit gas temperatures, resulting in reduction of efficiency and load carrying capability of the original fuel.

- Increased velocities increase the pressure drops. Is redesign of gas ductwork necessary for the possibly higher flows and higher negative pressure operation? Is reinforcement necessary on the furnace backpass buckstay system to accommodate the higher negative head potential that would result if large (or more) ID fans are needed?
- If higher negative pressure operation is required, are structural modifications necessary to the air heaters?
- If the combustion air requirements are increased, is the forced draft (FD) fan capable of handling this air flow?

It is evident that a detailed analysis of these factors is required in designing modifications to oil or coal fired units needed to burn natural gas with minimum performance penalties.

2.2 Evaluation of Previous Studies

Because there is no published literature since 1970 on NG retrofitting, our effort focused on interpolating from recent retrofit studies performed for low BTU (LBTU) and intermediate BTU (IBTU) gases (both referred to as LBG). This section briefly discusses these studies, and by investigating the combustion and heat transfer characteristics of these fuels, establishes the relevance of interpolating to NG retrofitting.

To evaluate the factors described in the introduction and the associated costs of retrofitting, four major studies have been carried out for LBG (Combustion Engineering, 1975; Babcock & Wilcox, 1976; Bechtel National, 1979; Fluor Engineers, 1983). The first two studies focused primarily on the technical feasibility of conversion and the last two on the economics of such conversions. The approach followed was to investigate a number of "typical" existing power plants of different sizes that were originally designed to burn:

- pulverized coal (900 MW, 510 MW, 450 MW)
- fuel oil (600 MW, 580 MW, 500 MW, 410 MW, 360 MW)
- natural gas (750 MW, 500 MW, 330 MW, 250 MW)

These plants were to be converted to burn LBG, but at the same time were to retain maximum capability of the original fuel as a secondary fuel to the base firing of LBG.

Our study has identified two major areas of concern when a fuel is fired in a boiler originally designed for a different fuel:

- plant derating
- reduction in boiler efficiency

Even though it is desirable to compare the estimates of each study on a one-to-one basis, we cannot follow this approach since the extent of modifications investigated in each study were not identical (although similar) and because each study was case-specific. It is however encouraging that all studies lead to very similar results, and the minor differences will not affect our (interpolated) conclusions for natural gas retrofitting.

2.3 Combustion Properties

In this section we analyze the thermodynamic combustion properties of LBG, oil and coal to see how they compare with NG. This is necessary in order to justify the LBG interpolations for NG retrofitting. Each fuel has a different chemical composition and therefore a different heating value, adiabatic flame temperature, combustion air requirements and amount of flue products. Table 2 shows the composition of the LBG used in this study.

2.3.1 Heating Value and Adiabatic Flame Temperature

A comparison of the heating values of the fuels listed in Table 3 shows that approximately 1 lb of NG, 1.2 lb of oil, 1.7 lb of coal, 2.4 lb of IBTU or about 10 lb of LBTU must be fired to release 1000 BTU. The heating value of the fuel, however, has no direct effect on the rating or efficiency of a boiler but does determine the size of the fuel handling equipment needed to achieve the same boiler rating.

A primary factor in the design of a boiler is the flame temperature of the fuel fired. The actual flame temperature is related to the adiabatic flame temperature (at some reasonable amount of excess air). Table 3 shows that the adiabatic flame temperature (@ 20% excess air) of IBTU is about 400^{o}F higher, and of LBTU about 800^{o}F lower, than NG. For coal and oil, it is about 100^{o}F and 200^{o}F higher than NG, respectively. In terms of adiabatic flame temperature, NG lies in the LBG region between 172 and 300 BTU/scf even though its fuel heat value is about 1000 BTU/scf.

2.3.2 Combustion Air Requirements

A specific boiler can pass only a given volume of air determined by the allowable pressure drop in the ductwork and air heater, and the capacity of the FD fan. When burning NG instead of coal or oil, if the required combustion air cannot be supplied with the existing equipment, derating will result since less fuel (on a BTU basis) will have to be fired per hour (unless the limiting component is retrofitted, at a cost). The combustion air requirements for each fuel must therefore be calculated.

Burners are typically operated at 5-20% excess air (at full load) to insure complete combustion. Assuming air and fuel are at standard temperature and pressure, the required combustion air can be determined. For a heat release of one million BTU, the combustion air requirements (lb, @ 20% excess air) for coal, oil and NG are 914, 895 and 875, respectively (Table 3). Therefore, switching to NG is not expected to cause any air-handling problems.

2.3.3 Flue Products of Combustion

The flue gas flow configuration of a specific boiler can pass only a given mass flow rate of flue gases as determined by the allowable pressure drop in the ductwork and the capacity of the ID fan. Boiler rating (lb steam/hr at a given temperature) is therefore partly limited by the flue gas capacity of the boiler.

To ensure that on this basis no derating will result, it is necessary to determine the changes in the amount of flue gases for a given BTU input when switching from coal or oil to NG. The products of combustion for coal, oil and NG are 991, 949 and 919 lb/MBTU, respectively, @ 20% excess air (Table 3). Thus less mass of flue gas must be handled when converting to NG.

The most relevant parameters in retrofitting a boiler to burn a different fuel than the one it was originally designed for, are the amount of products per heat input and the adiabatic flame temperature. In Figure 2 we plot the adiabatic flame temperature versus the pounds of products per million BTU at 20% excess air, for different types of fuel. In respect to both the above relevant parameters, NG lies somewhere in the LBG range between 172 BTU/scf and 300 BTU/scf, but closer to the latter (although its heating value is about 1000 BTU/scf). It is also not very different from coal or oil. This implies that it would not be difficult to substitute it for coal or oil in a boiler having approximately the same flue gas flow and adiabatic flame temperature. We may therefore interpolate (from the LBG studies) for the fuels within this range.

3. INTERPOLATION OF NATURAL GAS PERFORMANCE ESTIMATES FROM LBG STUDIES

In Section 2 we determined that the most relevant parameters in retrofitting a boiler to burn a different fuel than its design fuel are the amount of products per heat input and the adiabatic flame temperature. On this basis, NG is considered to be similar to LBG of heating value just below 300 BTU/ft^3. In this section we present the estimates of previous LBG retrofit studies and interpolate them for NG.

Tables 4 through 8 summarize the performance estimates of retrofitting tangentially fired units to burn LBG. These estimates are based on boilers originally designed to burn the "design fuel" indicated.

3.1 Boiler Derating when Firing Natural Gas

The effects on the maximum continuous rating (MCR) of various LBG conversions, with only minor modifications to the boiler, are shown in Table 4. Minor modifications would consist of the addition of the gas nozzles with appropriate modification of the windbox. MCR can be achieved for LBG $\geq$ 300 BTU/ft^3. The factors which limit the load capability for LBG $\leq$ 180 BTU/ft^3 are similar to those described in Section 2 and are case specific.

Table 5 shows the effects of conversions with full modifications. In addition to the minor modifications, full modifications would consist of the increase in desuperheater water spray capacity, tube upgrading or removal, and increase of the capacities of the FD and ID fans. MCR can be achieved with all gases (except 105 BTU/ft^3 in an oil boiler).

Since, in respect to the relevant parameters, LBG = 300 BTU/ft^3 is similar to NG, very little or no derating is expected for NG, for either coal or oil boiler conversion. The exact amount of derating, if any, depends on the specific boiler characteristics. It is also quite common in utilities that oil is being fired in boilers originally designed for coal. This further complicates an exact estimate if any retrofitting has previously taken place.

The main conclusion regarding derating, therefore, is that depending on the particular characteristics of the boiler, NG can be fired in a coal or oil boiler without any derating provided the appropriate modifications are made (minor or full). It is, however, not necessary for a utility boiler to achieve MCR if the full load is not required (due to low demand), in which case the additional investment for full modifications may not be justified.

3.2 Boiler Derating for the Original Fuel

In the case where it is necessary to remove some fuel nozzles of the original fuel or remove part of the superheater tube sections in order to achieve maximum continuous rating (MCR) firing LBG, the original fuel can no longer be fired at MCR since the superheat and reheat outlet temperature will be reduced. This will also result in lower efficiency.

The load carrying capability of the original design fuel after the retrofit (minor or full) to burn LBG, is shown in Tables 6 and 7. At the maximum indicated load, the metal temperatures of pressure part components are within allowable limits. Oil boilers show no derating, but coal boilers range from 0-15% derating, depending on how extensive the modifications are. For NG retrofit, however, none of the original fuel nozzles need to be removed (only additional NG nozzles are added), in which case no derating need to occur in a coal boiler either (except if superheater surface is removed).

3.3 Boiler Efficiency Drop

All other parameters being equal, a boiler efficiency drop requires an increase in the fuel heat input rate in order to reach MCR. In the case of substituting NG for coal or oil, a boiler efficiency drop will require an additional amount of NG beyond what is needed to match the original heat input.

The boiler efficiency drop that would result at MCR is shown in Table 8. For NG, a boiler efficiency drop in the range 3-5% is expected for either coal or oil boilers.

4. EXISTING NATURAL GAS RETROFITS

This section summarizes briefly the experience of those utilities in the northeastern U.S. that have retrofitted some boilers to dual oil/NG firing. As far as we know, at the present time no utility is switching between coal and NG, although "coal-designed" boilers that are firing oil have been retrofitted to dual firing with NG. Our intention is to verify our estimates regarding efficiency drop and possible derating, and also to present the actual costs of conversion.

Four plants at three utilities have been selected:

- Consolidated Edison Co., NY
- Northeast Utilities Service Co., CT
- Boston Edison Co., MA

In all cases, the switching is done in the months June through September on a day-by-day basis. The decision on which fuel to fire depends entirely on fuel price differential and NG availability. Of the utilities surveyed, only Northeast Utilities reports occasional insufficient NG supply.

Operational and maintenance benefits which may be realized by utilities from switching to NG can be grouped as follows (Ashton, 1984):

A. Fuel Handling and Storage
   1. Reduced oil deliveries
      a. Reduced exposure to oil spills
      b. Reduced labor (and overtime) for barge unloading
      c. Reduced risk of damage to screen house by tug and barge traffic.
      d. Reduced steam requirements for barge oil heating
   2. Reduced storage tank heating costs
   3. Reduced maintenance and operating cost
      a. Maintenance of pumps, heaters, valves and guns
      b. Cleaning of strainer baskets and disposal of solvents.

B. Boiler
   1. Steam temperatures easier to maintain because of higher convective energy release
   2. Reduced cleaning
      a. Superheater and reheater tubes
      b. Air heaters (also reduced sulfuric acid damage)
      c. Fuse box
      d. Drop-out hoppers

3. Reduced general maintenance due to lower furnace corrosion
4. Reduced energy costs in induced draft and forced draft fans, air heater drives and soot blowing
5. Cost of fireside additives is eliminated

C. Precipitators and Ash Systems
1. Reduced cleaning and maintenance
2. Reduced precipitator energy consumption
3. Reduced ash disposal
4. Particulate and SO_x emissions virtually eliminated; NO_x possibly reduced

D. By improving the unit's ranking on the priority commitment table, the longer run times reduces the amount of thermal cycling and reduces maintenance on the entire steam path.

4.1 Consolidated Edison, Waterside Plant, NY

Boiler size : Two boilers 160 MW each
Fuel type : Oil/NG
Efficiency drop : 2-4%
Derating : None
Conversion time (from planning to implementation): 7 months
Boiler outage beyond routine annual overhaul: None
Boiler conversion cost: 5.2 M$(1983) or 16.3 $(1983)/KW

Comments

The observed efficiency drop of 2-4% agrees with our conclusions from the LBG studies. By tilting the gas nozzles downwards, the superheat steam temperature is reduced to levels that the existing desuperheater capacity can reduce even further to the design value. Hence no superheater surface is removed and therefore no derating results in either oil or NG firing.

The total boiler conversion cost was 5.2 M$(1983). As shown in Table 9, this includes:

- company and contract labor
- equipment and material cost
- price escalation, 6%
- overhead, 54%

The major cost components are:

	\$(1983)/KW	% of Total Cost
- valves, instrumentation and controls	3.0	18
- boiler modifications	3.2	20
- gas, ventilation & purge piping	3.2	20
- gas ignition control system	3.5	21

4.2 Consolidated Edison (Con Ed), Ravenswood Plant, NY

Boiler size : 1000 MW/650MW

Fuel type : Oil/NG

Efficiency drop : Not available

Derating : Not applicable

Conversion time (from planning to implementation): 8 months

Boiler outage beyond routine annual overhaul: None

Total conversion cost: 10.04 M\$(1985) or 15.4 \$(1985)/KW

Comments:

Ravenswood unit #30, rated at 1000 MW, was initially a coal boiler, but for many years it has been firing oil. Due to low demand it is operated at reduced load and Con Ed therefore decided to convert it to NG at a reduced rating. On NG it is rated at 650 MW and since its conversion in June 1986 it has operated without any problems. It has not yet undergone full testing and the efficiency drop has not yet been reported.

The actual boiler conversion cost to achieve the 650 MW rating was 10.04 M\$(1985) or 15.45 \$(1985)/KW, as shown in Table 10. This includes:

- Company and contract labor
- Equipment and material cost
- Price escalation, 5%
- Overhead, 52%

The major cost components are:

	\$(1985)/KW	% of Total Cost
- Valves, controls, boiler equipment	4.21	27
- Superheater upgrading	2.31	15
- Mechanical erection pkg	2.90	19

Also investigated by Con Ed was the conversion to full rating (1000 MW). The cost breakdown estimate for a full conversion is shown in Table 11. Although the per KW cost of this 100% conversion is roughly the same as the 65% conversion (15 $(1984)/KW), Con Ed opted for the 65% conversion since the additional 5 M$ required for the 100% conversion was not justified due to the reduced demand.

4.3 Northeast Utilities (NU), Montville Plant, CT

Boiler size : 80 MW

Fuel type : Oil/NG

Efficiency drop : 6%

Derating : None

Conversion time (from planning to implementation) : 13 months

Boiler outage beyond routine annual overhaul : 1 week

Boiler conversion cost : 1.61 M$(1985) or 18.9 $(1985)/KW

Comments

Montville Unit #5 went into dual oil/NG operation in June 30, 1984. In the first 6 months of operation the conversion produced savings to NU customers of over 40% of the total project cost (customers are billed at the highest incremental gas cost).

The boiler, originally designed for coal, has a high spraywater desuperheater capacity. This, together with the downward tilting of the gas nozzles, achieves the design ouput steam temperature without any superheater modifications. Therefore no derating results in either oil or NG firing.

A detailed boiler test program has not yet been carried out, but preliminary results indicate (Ashton, 1985; Tameo, 1986; Wade, 1986) a degradation of heat rate on NG in the order of 5-7%.

The total boiler conversion cost was 18.9 $(1985)/KW as shown in Table 12. The major cost component is equipment purchase at 9.2 $(1985)/KW or 50% of total boiler conversion cost.

4.4 Boston Edison, Mystic Plant, MA

Boiler size	: 565 MW
Fuel type	: Oil/NG
Efficiency drop	: 5-6%
Derating	: None
Conversion time (from planning to implementation)	: 8 months
Boiler outage beyond routine annual overhaul	: 1 week
Boiler conversion cost	: 3 M$(1982) or 5.25 $(1982)/KW

Comments

The observed efficiency drop of 5-6% (Harris, 1986) when firing NG agrees with our conclusions from the LBG study. By tilting the gas nozzles downwards, the superheat steam temperature is reduced to levels that the existing desuperheater capacity can reduce even further to the design value. Hence, no superheater surface is removed and therefore no derating results in either oil or NG firing (Buckingham, 1986).

The total boiler conversion cost was approximately 3 M$(1982) or 5.25 $(1982)/KW as shown in Table 13. This includes material, labor and control changes. The major cost component is mechanical equipment and piping at 4.04 $(1982)/KW or 77% of the total boiler conversion cost. Boston Edison installed 1000 feet of 20" pipe from the meter run to the boiler. Approximately 200 feet of 16" main pipe had to be installed by Boston Gas to bring the gas to the meter site.

5. PIPING NATURAL GAS TO AN ELECTRIC UTILITY BOILER

5.1. Equipment Configuration

The gas supply alternatives for an electric utility are either to connect to a high-pressure transmission line of a gas distribution company or to build a take station from an interstate/intrastate transmission line. In either case the basic equipment configuration is the same. A gas main brings gas from the transmission line to the plant site, and through metered feeder lines to a regulator which adjusts the pressure to a suitable level for the boiler. The most complicated part is the metering. The meters are designed to be highly accurate and are monitored and operated via telemetry. They monitor volume, pressure and heat content of the natural gas. The equipment requires 3000-6000 square feet on plant property.

Several factors affect the design and cost of the gas supply system:

- minimum inlet pressure
- flow rate
- distance from source

Most important is the minimum inlet pressure (minimum pressure available in the transmission line). When inlet pressure is low, pipe and meters of a larger diameter are required in order to maintain the desired volume of gas flowing to the boiler. The larger equipment are naturally more expensive to purchase and install. It is necessary to design the system for the expected minimum inlet pressure so that the boiler still receives the desired volume of gas when inlet pressure is lowest.

The gas flow rate (volume of gas needed for boiler firing) affects the size and number of feeder pipe and meters required. The higher the required flow rate the more expensive the system will be. An approximate rule of thumb (Fleck, 1986) for determining flow rate is to allow 10,000 cf/hr for 1 MW. Typically, a 5-10% efficiency drop is assumed when firing gas instead of oil.

The further the utility is from a suitable supply source the greater the expense for the gas main. A caveat to bear in mind when considering pipeline construction is that cities and towns may limit the pipeline pressure which flows through their jurisdiction.

5.2. Some Current Experience in Utility Pipeline Installations

5.2.1 Gas Pipeline (Main) Cost

To construct the supply system for Boston Edison's Mystic #7 Unit (565 MW) a 16" main, approximately 200 feet long, was run from one of Boston Gas' high pressure transmission lines. It cost $29,000 or $145/foot (Table 13). A 16" main running for 20,000 ft at the Boston Edison New Boston plant cost $2.6 million or $130/foot (Fleck, 1986). Northeast Utilities' 16" main cost $85-110/foot depending on the site topography. It would seem that pipeline costs are $100-150/foot to purchase and install. Costs vary with size of pipe, site topography, location (urban vs. rural), etc.

5.2.2 Pressure Reducing Station

The pressure in the Boston Gas transmission line is normally 200 psi but falls as low as 90 psi. Boston Edison's Mystic #7 boiler operates on gas at 50 psi so a minimum pressure drop of 40 psi was factored into the system design. (The smaller the pressure drop the more expensive the system because of the need for larger pipe and meters). Because of the large flow rates involved, it was necessary to install six feeder lines with associated metering. The equipment cost for each feeder line with metering was approximately $20,000 (for a total of $120,000). Flow computers, chromatography, telemetering and their installation and testing were $70,000. The total cost of $190,000 for the 565 MW plant, compares favorably with the $200,000 cost of the Northeast Utilities' Montville plant (85 MW) pressure reducing station.

5.2.3 Gas Supply Construction Time

In Boston Gas' experience, design and construction of a supply system to a utility boiler involves 3-4 months of preparation and 5-6 months of construction depending on the location (Fleck, 1986). Similar periods were experienced in the Northeast Utilities Gas Conversion Project (Barker, 1986). Boiler outage was in all cases less than four weeks, which can be planned to coincide with the annual boiler overhaul.

CONCLUSIONS

- The significant thermodynamic properties of NG, which are not too different from those of coal or oil, can be closely matched by LBG of about 300 BTU/ft^3. By making use of the extensive studies on the retrofitting of coal and oil fired boilers with a range of LBG fuels, we can, by interpolation, soundly conclude the following regarding NG substitution for coal and oil:
  - With minor modifications (windbox only) little or no derating may be expected when firing NG in a boiler originally designed to fire coal or oil.
  - With full boiler modifications, the original maximum continuous rating (MCR) can be achieved when firing NG.
  - No derating is expected for an oil boiler when it reverts to oil, after it has been retrofitted (minor or major modifications) to fire NG as well.
  - A derating of up to 15% may be expected for a boiler designed for coal when it reverts to coal after it has been retrofitted (minor or major modifications) to fire NG as well.
  - At MCR, boiler efficiency may drop by 3-5%, for either coal or oil boilers, when they fire NG.
- Actual total boiler retrofit costs (gas piping and controls, civil and electrical work, boiler modifications, contingencies and overhead) for oil to NG switching range from 7 to 19 $(1985)/KW. The higher value is characteristic of small boilers, less than 100MW, because there seems to be a relatively high fixed cost associated with services and purchased material, irrespective of boiler size. No costs for coal fired boiler retrofits with NG are available.
- Experience shows that pipeline installation costs are in the range of 100-150 $(1985)/ft.

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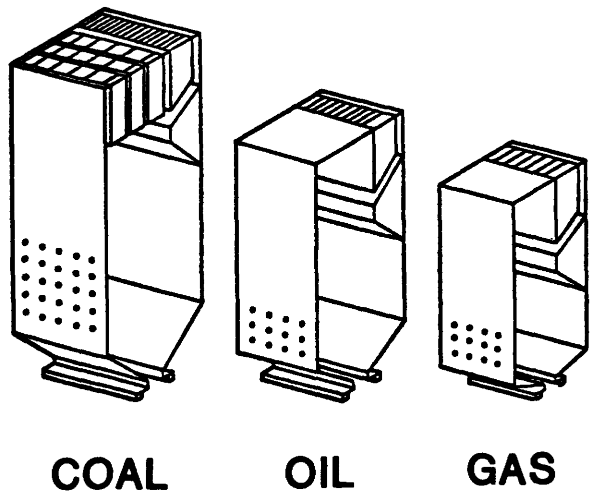

Figure 1. Relative sizes of coal, oil and gas fired boilers having the same maximum continuous rating (Erlich, Drenker and Manfred, 1980).

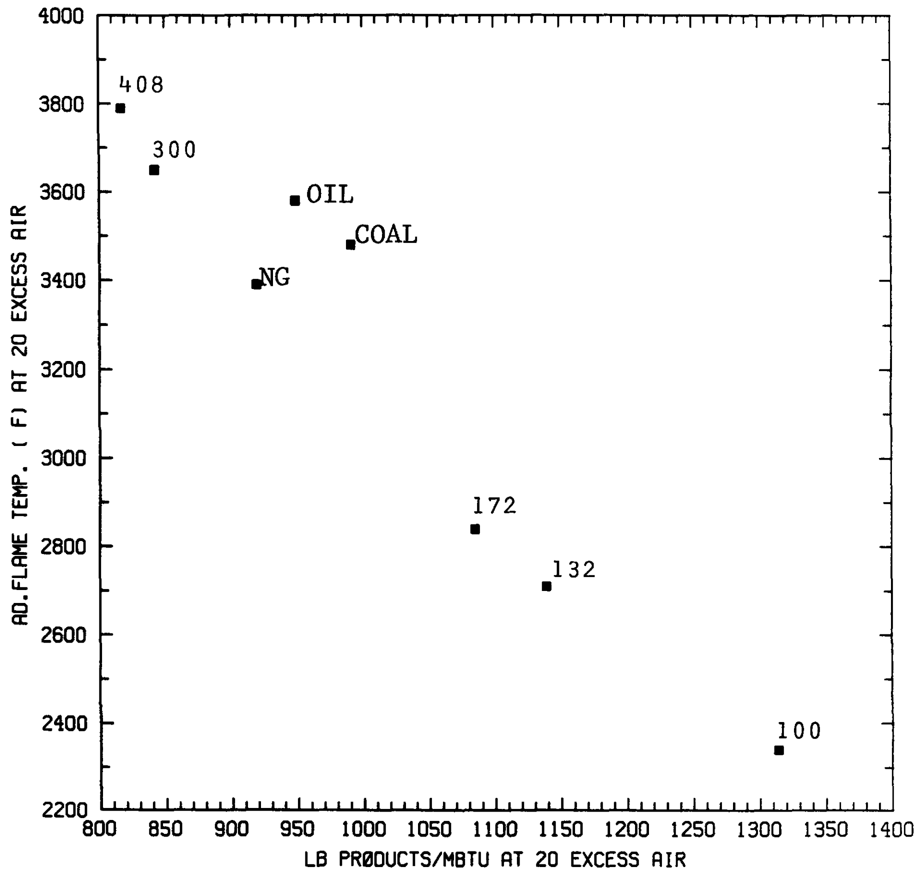

Figure 2. Adiabatic flame temperature (^{o}F) versus combustion products (lb/MBTU) at 20% excess air.

TABLE 1 - Characteristics of Natural Gas, Oil and Coal[1]

	Natural Gas	Oil	Coal
Relative power density (RPD)	1.6	1.0	0.73
Heating value (10^3 BTU/lb)	22.5	18.5	13
Stoich. air/fuel ratio by weight	16.4	13.8	9.9
Adiabatic temp. of flue gases @ 20% excess air (^oF)	3380[2]	3600[3]	3513[3]
Hydrogen/Carbon by weight	1:3	1:9	1:20
by atom	4	1.6	0.8
SO_2 emission (lbs/10^6 BTU)	0	0.5 - 3	1 - 6
CO_2:H_2O molar ratio	0.5:1	1.2:1	2.5:1
Burning time	fast	intermediate	slow
Flame emissivity	low	medium	high
Flue gas emissivity	high	middle	low
Ash content (percent)	0	0.2 - 0.5	1 - 10

(1) Green (1981); with some modifications.

(2) "Marks Standard Handbook for Mechanical Engineers", McGraw Hill, 1978.

(3) Babcock & Wilcox (1978).

TABLE 2 - Gasified Coal Fuel Analysis[1]

Fuel	GCF-1	GCF-2	GCF-3	GCF-4	GCF-5	NG
Fuel Heating Value (Btu/ft^3)	132	172	300	408	100	1005
	% by volume					
CO_2	3.6	12.5	6.0	1.0	2.7	-
CO	23.0	14.1	55.9	30.5	17.4	-
H_2	17.9	20.9	37.4	55.0	13.5	-
CH_4	-	5.8	-	13.0	-	90.0
C_2H_6	-	-	-	-	-	5.0
N_2	55.5	40.1	0.7	0.5	66.3	5.0
H_2O	-	6.6	-	-	-	-

(1) Babcock & Wilcox, 1976

TABLE 3 - Thermodynamic Properties of Fuels

	LBG(1)					NG(1)	OIL(2)	COAL(3)
Fuel heat content (BTU/scf)	100	132	172	300	408	1005		
(10^3 BTU/lb)	1.57	2.17	2.92	6.15	12.70	22.5	18.5	13.0
Weight ratio (air/fuel)	0.89	1.23	1.81	3.49	7.81	16.4	13.8	9.9
Air/heat input ratio(4) (lb/MBTU)	679	680	743	680	738	875	895	914
Products/heat input ratio(5) (lb/MBTU)	1202	1028	961	730	694	773	800	839
Products/heat input ratio(4) (lb/MBTU)	1314	1139	1085	842	817	919	949	991
Flame temp. (adiabatic)(4) (^oF)	2340	2710	2840	3650	3790	3390	3580	3480

(1) Composition as in Table 2

(2) Typical values for #6 oil (Babcock & Wilcox, 1978)

(3) Typical values for Bituminous coal (Combustion Engineering, 1981)

(4) At 20% excess air

(5) Stoichiometric

TABLE 4 - Approximate Maximum Rating That Can be Achieved Firing LBG With Minor Modifications to the Windbox and Firing System Equipment(1)

	Original Design Fuel	
BTU Content (BTU/Ft^3)	Coal	Oil
396	MCR	MCR
292	MCR	MCR
179	75%	70%
128	70%	65%
105	60%	50%

(1) Combustion Engineering, 1975

TABLE 5 - Approximate Maximum Rating That Can be Achieved Firing LBG With Full Modifications to Steam Generating Unit and Auxiliary Components(1)

	Original Design Fuel	
BTU Content (BTU/Ft^3)	Coal	Oil
396	MCR	MCR
292	MCR	MCR
179	MCR	MCR
128	MCR	MCR
105	MCR	60%

(1) Combustion Engineering, 1975

TABLE 6 - Approximate Maximum Rating of the Boiler When the Original Design Fuel is Fired, After Necessary Retrofitting to Burn LBG (Minor Modifications)[1]

Minor Modifications	Original Design Fuel	
	Coal	Oil
396	85%-MCR	MCR
292	85%-MCR	MCR
179	85%-MCR	MCR
128	85%-MCR	MCR
105	85%	MCR

(1) Combustion Engineering, 1975

TABLE 7 - Approximate Maximum Rating of the Boiler When the Original Design Fuel is Fired, After Necessary Retrofitting to Burn LBG (Full Modifications)[1]

Full Modifications	Original Design Fuel	
	Coal	Oil
396	85%-MCR	MCR
292	85%-MCR	MCR
179	65%-85%	MCR[2]
128	46%-85%	MCR[2]
105	0%-60%	MCR[2]

(1) Combustion Engineering, 1975

TABLE 8 - Reduction in Boiler Efficiency when Firing LBG at MCR, as in Table 4 or 5, below that of the Original Design Fuel[1]

	Original Design Fuel	
BTU Content (BTU/Ft^3)	Coal	Oil
396	-6%	-5%
292	-4%	-3%
179	-9%	-10%
128	-8%	-9%
105	-12%	NA

(1) Combustion Engineering, 1975

TABLE 9 - Actual Retrofit Costs at Waterside Plant (2x160 MW)[1]

	\$(1983)	\$(1983)/KW)
Valves, instruments and controls	950,600	3.0
Boiler modifications	1,024,600	3.2
Gas, vent. & purge piping	1,025,300	3.2
Gas ignition control system	1,113,000	3.5
Vendors field representative	25,600	0.1
Gas house extension	144,500	0.5
Grating & pipe supports	92,400	0.3
Conduit & cable	638,100	2.0
Project management & inspection	175,200	0.5
	5,189,300	16.3

(1) Burns, W., 1986.

TABLE 10 - Actual Retrofit Costs at Con Ed Ravenswood Plant (650 MW)[1]

	$(1985)	$(1985)/KW
Purchased equipment		
Valves, controls, boiler equipment	2,739,700	4.21
Cable	104,800	0.16
	2,844,500	4.37
Construction contracts		
Superheater upgrading	1,500,000	2.31
Mechanical fabrication pkg	471,200	0.72
Mechanical erection pkg	1,884,900	2.90
Insulation	404,000	0.62
Fans, ducts, temperature probes	65,200	0.10
Regulator house extension	84,100	0.13
Platforms and support	109,400	0.17
Electrical pkg	973,500	1.50
	5,492,300	8.45
Company labor		
Ignitor modifications	369,300	0.57
Purging	4,800	0.01
Test, start-up, calibration	139,400	0.21
Transportation	8,400	0.01
	521,900	0.80
Service representatives	569,100	0.88
Project management & inspection	616,900	0.95
	10,044,700	15.45

(1)Burns, W., 1986.

TABLE 11 - Estimated Retrofit Costs at Con Ed Ravenswood Plant (1000 MW)[1]

	$(1984)	$(1984)/KW)
Building & excavation	487,000	0.5
Gas ignitors & windbox	2,087,300	2.1
U.G. piping & tap	302,800	0.3
Meters, regulators & scrubbers	2,619,500	2.6
Gas piping (Boiler house)	4,808,500	4.8
Pipe insulation	587,200	0.6
Controls	358,900	0.4
Electrical (Gas meter house)	628,200	0.6
Electrical (Boiler house)	2,005,300	2.0
Start-up labor	80,300	0.1
Service representative	538,300	0.5
Project management & inspection	469,600	0.5
	14,972,900	15.0

(1) Burns, W., 1986.

TABLE 12 - Actual Boiler Retrofit Costs at Northeast Utilities Montville Plant (85 MW)[1]

	\$(1985)	\$(1985)/KW
SERVICES		
Engineering, Design, Material Procurement, Project Management, Administrative, Overheads, Training, Etc.	150,000	1.83
PURCHASED MATERIAL		
Burner Management System Control Valves, Fans, Boiler Controls, Flow Meters, Boiler Modifications, Miscellaneous Mechanical Equipment, Miscellaneous Electrical Equipment, Etc.	785,000	9.2
CONSTRUCTION/INSTALLATION		
Construction representative(s) and Temporary Facilities related to Construction Management, Mechanical (Labor), Electrical (Labor), Etc.	675,000	7.9
Total	1,610,000	18.9

(1) Wade, D., 1986

TABLE 13 - Actual Retrofit Costs at Boston Edison Mystic #7 Plant (565 MW)

	10^3 $(1982)	$(1982)/KW	$(1984)/ft
BOILER CONVERSIONS[1]			
Engineering	285	0.50	
Structural	134	0.24	
Mechanical/Piping	2,280	4.04	
Electrical	156	0.28	
Overheads	110	0.19	
Total	2,965	5.25	
GAS SUPPLY[2]			
Gas equipment & metering	120	0.21	
Instruments	70	0.12	
Main pipe (16")	29	0.05	145
Overhead	19	0.03	
Total	238	0.41	
OTHER	297	0.52	
TOTAL	3,500[3]	6.20	

(1) Patel, M., 1986
(2) Kearney, D., 1986
(3) Harris, H., 1986