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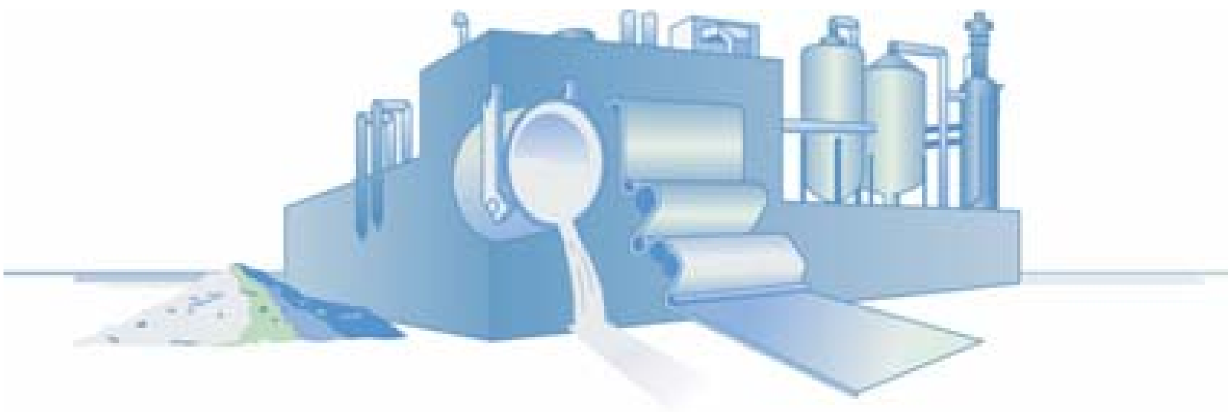
Identifying Opportunities and Impacts of Fuel Switching in the Industrial Sector



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Executive Summary

Natural gas and petroleum prices have risen dramatically since the late 1990s. As illustrated in Figure 1, natural gas prices have risen by almost 300 percent since 1998 and oil prices have risen by more than 300 percent. The rise in natural gas prices is coupled to the increasing cost of petroleum, but is also the result of a shift in the U.S. supply and demand balance, where demand has outpaced North American production. Natural gas and oil prices are volatile and are expected to continue to increase long term.

This increase in energy prices undermines the economic competitiveness of domestic industry, which is particularly reliant on natural gas. Especially vulnerable are the energy intensive manufacturing industries, such as the chemical industry, which uses natural gas as a feedstock as well as a fuel. The chemical industry is the largest industrial consumer of natural gas, and estimates it has lost 90,000 jobs and $50 billion in sales to foreign competition since 2000 due to high natural gas prices (ACEEE 2005). High natural gas prices also have the indirect effect of increasing electricity prices, as much of the U.S. generating capacity is fueled by natural gas.

Fuel switching from natural gas and oil to alternative fuels is an important strategy for responding to these fuel price increases and allowing energy intensive industries to remain competitive. Converting from natural gas and oil to fuels with lower prices and more stable supplies—such as coal and biomass—will make U.S. industry less vulnerable to volatile oil and gas prices. Industrial equipment that is able to switch between fuels as prices change will provide more security for industry, and also act as a stabilizer for fuel prices.

Industry currently has a significant fuel switching capacity, including 1.1 quads of its natural gas consumption. But this fuel switching capacity is declining and is likely an overestimate of the degree of fuel switching that is practically possible. Less than half of this switchable consumption may be actually useable, due to regulations and changes in equipment. In addition, most of the current fuel switching

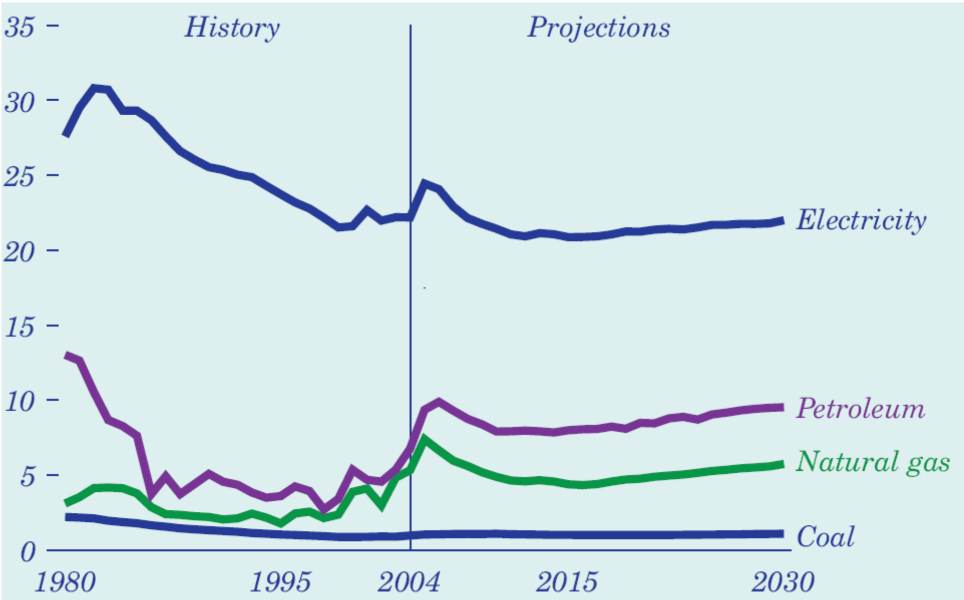


Figure 1. Energy price history and forecast, 1980-2030, in 2004 dollars per million Btu (EIA 2006)

capability is for switching between natural gas and petroleum fuels. Switching to other alternatives with more stable supplies—such as biomass, biomass-based gas, and coal gas—are now also being considered.

The industrial sector has a large potential for reducing oil and gas demand by fuel switching, particularly for natural gas. Industry accounts for over a third of the total U.S. natural gas consumption, and 85 percent of the industrial natural gas used as fuel is consumed in boilers and process heaters, which are the equipment types best suited for fuel switching. 5.0 quads of natural gas and 0.2 quads of oil are used in industrial boilers and process heaters. A further 1.4 quads of oil and gas are used in commercial boilers, which have similar characteristics to industrial boilers. This total of 6.6 quads represents the most important fuel switching potential for the industrial and commercial sectors. Further fuel switching from natural gas and oil may be possible for feedstocks in the chemical industry, but this would have to be evaluated for each individual process.

Most of this fuel switching potential lies in the energy intensive industries, including the chemical, refining, paper, food, and primary metals industries. These five industries account for almost 75 percent of the total industrial natural gas consumption. The refining, chemical, and primary metals industries currently have less fuel switching capacity than the other manufacturing industries, but are heavy users of by-product fuels, and so are familiar with alternative fuels.

Boilers in the U.S. industrial and commercial sectors consume about 8.1 quads, accounting for about 40 percent of the total energy consumption of these sectors. Industrial boilers are typically larger units and are concentrated in the energy intensive industries, especially the paper and chemicals industries. Commercial boilers are typically smaller units, but are numerous and consume about 1.6 quads per year, half of which is consumed in healthcare and office buildings.

The alternative fuels for boilers considered in this report are coal-based gas, biomass-based gas, biomass, residual oil, coal-oil mixture, coal-based liquids, electricity, solar/wind, and coal. Converting from oil and natural gas to biomass, coal, or electricity would only be possible by replacing the boiler. Switching to the other gas and liquid fuels is possible by modifying the existing equipment. Some of coal and biomass gas fuels have a low heating value and would require extensive

Key Benefits of Fuel Switching

Reduces industry's vulnerability to high natural gas and oil prices – Alternative fuels have more stable prices.

Reduces volatility of natural gas prices – By switching to alternative fuels as natural gas prices increase, industry can serve as a buffer against spikes in the price of natural gas, thus benefiting all sectors.

Reduces demand for high-priced fuels in the electric power and industrial sectors

Does not significantly alter operations and maintenance costs for liquid and gaseous fuels – Conversion to alternative liquid and gaseous fuels typically comes with relatively minor capital costs for modifications, but without a significant increase in operations and maintenance costs.

Key Barriers to Fuel Switching

New fuel supply, transportation, and storage requirements – This is particularly important for liquid and solid fuels. Extra equipment for fuel handling will also require additional space.

Equipment de-rating for coal, biomass, oil, and coal-oil mixture – Derating is the result of higher heat release rates and ash deposition; modifications to restore original capacity may involve large capital costs.

Emissions control for coal-based fuels – Coal, coal gas, and coal-oil mixture contain sulfur and other pollutants that must be removed from fuel or exhaust, requiring additional pollution control equipment.

Fuel availability – Conversion to coal gas, biomass gas, or coal-oil mixture (COM) will require onsite production or a nearby central fuel production facility.

High capital cost for conversion to solid fuels or electricity – Conversion from oil or natural gas to solid alternative fuels or electricity requires boiler replacement, with a high capital cost.

modification, and so are less suitable for conversion. Medium to high heating value gas fuels can be used to replace natural gas with modifications to the burners and fuel supply headers. The fuel gas or exhaust stream would also require purification, especially for coal gas, which contains sulfur and other pollutants. Switching from natural gas or oil to coal-based liquids or coal-oil mixture would also involve modification of heat transfer surfaces within the boiler and adding systems for removing ash and storing the fuel.

Over 220,000 process heaters are used by the U.S. manufacturing industry, consuming 6.2 quads per year. The refining, iron and steel, and chemical industry consume over 60 percent of this total, mostly in large furnaces, dryers, and process fluid heaters. Other process heaters used by industry include ovens, kilns, melting furnaces, and heat treating furnaces. Very few industrial process heaters fire oil, so only switching from natural gas was considered in this report. The alternative fuels considered for process heaters are residual oil, coal-based gas, biomass gas, solar/wind, and electricity. The modifications required for switching to these fuels are similar to those required for boilers.

The fuel switching potential in industrial boilers and process heaters could be realized with strategic technology development that builds on existing Department of Energy (DOE) research and development activities. The DOE Office of Fossil Energy (FE) already has programs in coal gasification and synthetic gas combined heat and power systems. Further technology development for industrial fuel switching could build on this work through joint programs with DOE Office of Energy Efficiency and Renewable Energy (EERE) programs. To establish these joint programs, further analysis is required to determine the technology areas that will have the greatest impact, and to understand the important technical, economic, and environmental issues involved with fuel switching.

Other important needs include market conditioning strategies to encourage U.S. manufacturing plants to adopt newly developed technologies (e.g., coal and biomass gasification); system improvement technologies (e.g., new burners for conversion fuels); and system advancement technologies (e.g., multiple-fuel process heaters). Further studies are needed to analyze the market penetration of new technologies under various possible economic and regulatory environments.

Introduction

The recent high prices of natural gas and oil have been felt acutely in the industrial sector, where they are undermining the economic competitiveness of some of the more energy intensive industries. Switching from natural gas and oil to alternative fuels is an important solution to this problem: both long-term conversion to other fuels and shorter-term fuel flexibility, which allows switching between fuels as prices vary. Fuel switching can protect industry from spikes in natural gas and oil prices, and short-term fuel flexibility has the advantage of temporarily reducing fuel demand to avoid large price increases during supply shortfalls.

The underlying purpose of this white paper is to examine fuel switching opportunities in the U.S. industrial sector and make strategic recommendations—leading to application of the best available technologies and development of new technologies—that will introduce fuel use flexibility as an economically feasible option for plant operators, as a means to condition local fuel demands and a hedge against the local rises in fuel prices. In order to achieve this purpose, an effort is made to:

- Discuss the present energy situation, in which rising fuel prices are causing financial distress in the U.S. industrial sector;
- Discuss industrial fuel use that has a significant impact on the U.S. economy;
- Examine the high priced fuels and factors that contribute to their increased prices;
- Identify opportunities for fuel switching in the industrial sector and the impact that this fuel switching will have on fuel prices (together with the impacts of energy efficiency improvements), in light of current industrial energy use and projected fuel prices;
- Describe fuel switching methods applicable to industries where fuel availability is vital to their economy and associated technical and market barriers; and
- Make strategic recommendations to enable fuel switching as an economically feasible option to hedge against rising fuel prices, and for industry and DOE decision-makers to plan techno-economic and market potential studies to identify needed research.

This discussion of fuel switching follows the outline above, beginning with a summary of the price and industrial demand situation for natural gas, distillate fuel oil, and electricity, fuels of primary importance for fuel switching. The next section provides an overview of industrial energy use, which highlights the importance of natural gas to U.S. industry and its potential for fuel switching. The following sections give an overview of current fuel switching capacity and the potential impact of fuel switching. The following chapters then consider specific implications for fuel switching in industrial equipment, and technology development needs for increased fuel switching.

Current Energy Situation

Volatility and large increases in energy prices have a detrimental effect on overall economic growth, and are particularly problematic for industry. The following section focuses on industrial fuels with high and increasing prices—natural gas, distillate fuel oil, and electricity. Given the price situation, these fuels are primary targets for fuel switching.

Natural Gas

Natural gas prices began to increase dramatically in 2000, with city gate prices rising from around $2 per million Btu to a peak of $12 per million Btu in late 2005 (EIA 2006b). This price increase marks a shift in natural gas supply, with North American sources unable to meet the growth in U.S. demand (NPC 2003). During the 1990s government and industry forecasts had predicted stable low natural gas prices, based on expanding North American production keeping pace with U.S. demand and relatively low oil prices (Rosenberg 2005). These predictions have now been revised to show increasing natural gas imports and more rapid price increases.

Most analysts now believe that domestic natural gas production has already peaked or will peak in the next decade (Figure 2). Domestic production declined by 7 percent from 2001 to 2005, and the only significant increase expected is through the Alaskan pipeline (supported by 2004 legislation), which is expected to deliver 1.5 quads (1.5 trillion cubic feet) annually, when completed around 2015. But the pipeline will only provide 24 percent of the predicted incremental supply, leaving the remaining 76 percent for liquefied natural gas (LNG) imports.

The dramatic increase in LNG imports needed to meet U.S. natural gas consumption will require large investments domestically and overseas, and raises important concerns. There are currently four LNG import terminals, and three are planning to expand. Proposals for new LNG terminals have faced substantial public opposition (Rosenberg 2005). LNG imports increase the nation's dependence on suppliers, which currently include Trinidad and Tobago, Algeria, Nigeria, Oman, Malaysia, and Qatar.

Figure 4 shows EIA projections from the 2006 Annual Energy Outlook, which indicates a steady growth in natural gas supply after 2005. However, according to a National Petroleum Council Study, no net increase in the gas supply to U.S. markets could be expected before the end of 2007, considering the flat or declining U.S. production, modest near-term increases in LNG imports, declining imports from Canada, and expanding exports to Mexico (NPC 2003). Instead, with the absence of the aggressive action to address both supply and demand, significant economic consequences could result from the growing gap (NCEP 2004).

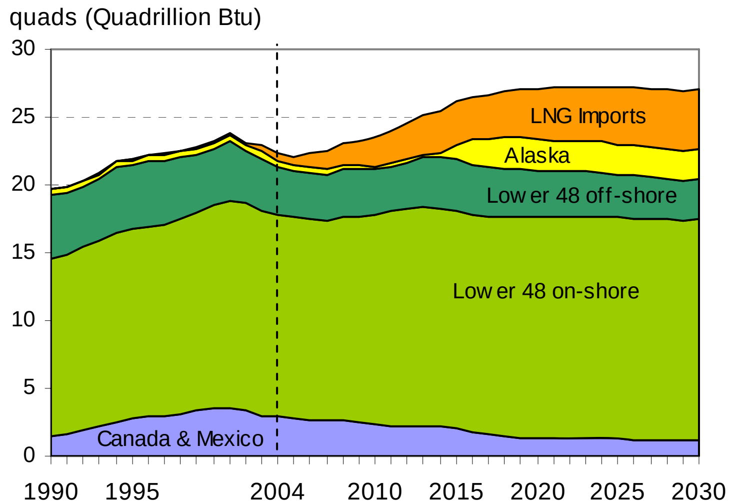


Figure 2. Natural gas supply projections (EIA 2006a)

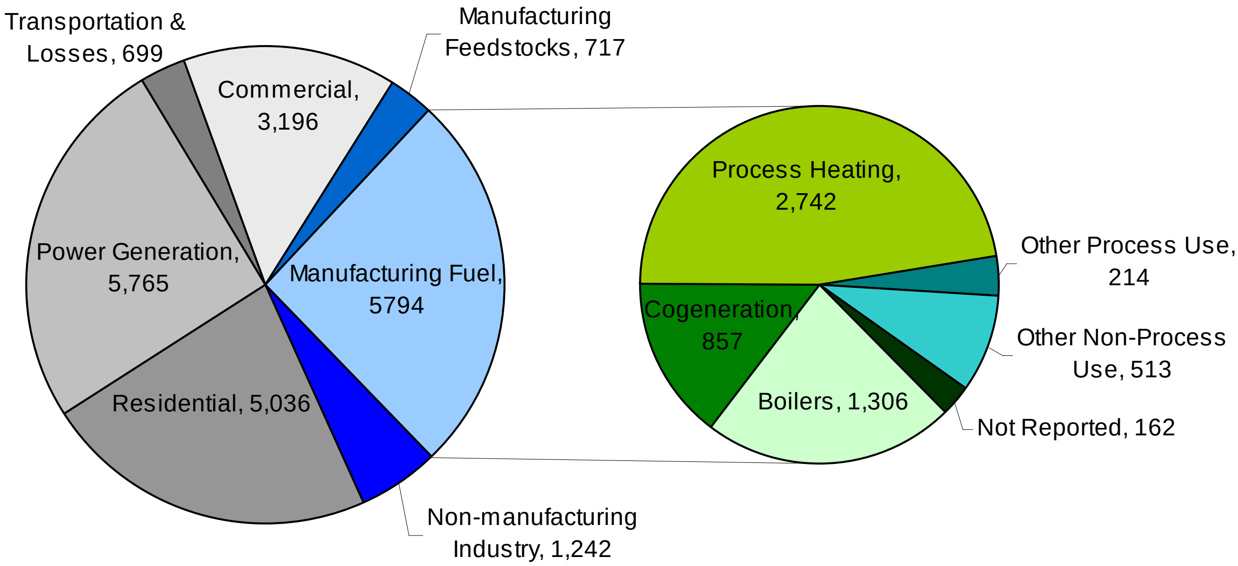


Figure 3. 2002 Natural gas consumption by sector and by end-use for manufacturing, in trillion Btu (EIA 2005a and analysis based on EIA 2005b)

The industrial sector is the largest natural gas consumer, using over a third of the total U.S. consumption (Figure 3). Most of the industrial sector's natural gas consumption is used as a fuel for process heating and steam generation in the manufacturing industries. Many of the energy-intensive industries have been hardest hit by natural gas price increases, as natural gas makes up a large portion of their operating costs. In particular, the U.S. chemical industry has been most affected by the rising natural gas prices, since it uses 11% of the total U.S. natural gas consumption. The chemical industry uses derivatives of natural gas (including ethane, propane, butane, and pentane) as major feedstocks, and uses natural gas to generate electricity and steam with cogeneration technology. Rising natural gas prices have led to shut-downs in plants producing ammonia for fertilizer, as natural gas costs account for 70 – 90 percent of the cost of ammonia production. In 2003, 21 percent of U.S. capacity had been closed, and only 50 percent of the remaining capacity was operating (Rosenberg 2003).

A further 26 percent of the U.S. natural gas consumption is used for electric power generation. The low gas price assumptions of late 1990s and the environmentally-friendly nature of natural gas power generation led to an unprecedented surge in construction of gas-fired power plants. As a result, since 1995, over 230,000 MW of the new natural gas generating capacity came on line (including 184,000 MW since 2000) while the supply of natural gas did not keep up with the growing demand of the U.S economy (Senate 2003). With rising natural gas prices, the cost of generating electricity with natural gas has increased substantially. Natural gas power plants in regulated electricity markets pass the high costs on to consumers, while many in deregulated markets have been operating far below capacity and are in financial distress. Several of these facilities have already been turned over to banks and the others sold for less than 20 percent of their original cost (Rosenberg 2005).

The demand for natural gas is also expected to increase substantially in the residential and commercial sectors. About 67 percent of new homes use natural gas for heating, especially in the north where heating loads are higher. According to the 2006 Annual Energy Outlook, the total natural gas demand in these sectors could reach 8.5 quads per year by 2010 and 9.3 quads per year by 2020.

Distillate Oil

The price of distillate fuel oil closely follows the price of crude oil, as illustrated in Figure 4. As with crude oil, the price of distillate fuel has risen by about 350 percent from 1998 levels. The large price increases for both petroleum fuels and natural gas began in 2000.

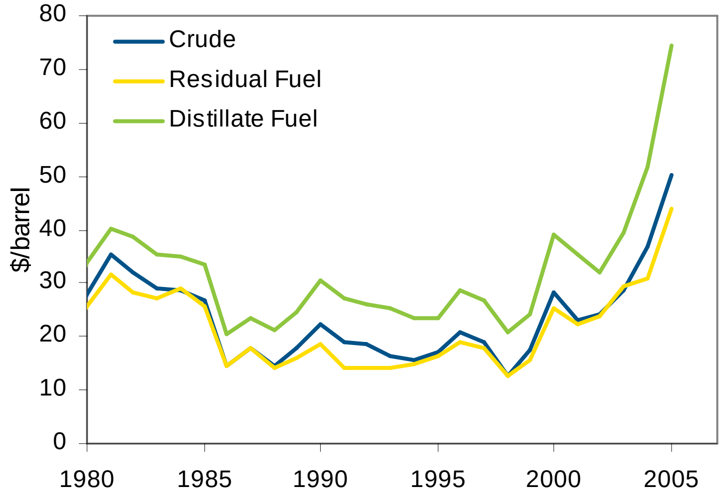


Figure 4. Price history of crude oil, residual oil, and distillate oil (EIA 2006a)

In contrast to the U.S. natural gas supply, domestic petroleum production accounts for less than half of the domestic consumption. Imports supplied 58 percent of U.S. crude oil demand in 2004 and are projected to supply 60 percent in 2025 (EIA 2006a). Because of the large dependence on imports, oil prices are vulnerable to international variables such as changes in world oil demand, political stability, and OPEC policies.

Distillate oil is not a major fuel for the manufacturing industry; it accounts for less than 1 percent of the total manufacturing energy consumption. Distillate oil is used much more heavily by the non-manufacturing industries—agriculture, construction, and mining—which are more reliant on diesel-powered transportation equipment and other vehicles (Figure 5). Of the 1,190 trillion Btu of distillate oil consumed by industry, 88 percent is consumed by the non-manufacturing industries.

Biodiesel is the most suitable alternative fuel for replacing distillate oil used in diesel engine-driven equipment. After minor engine modifications, biodiesel can be substituted for petroleum diesel or blended with it. Equipment manufacturers are also beginning to certify their products for use with

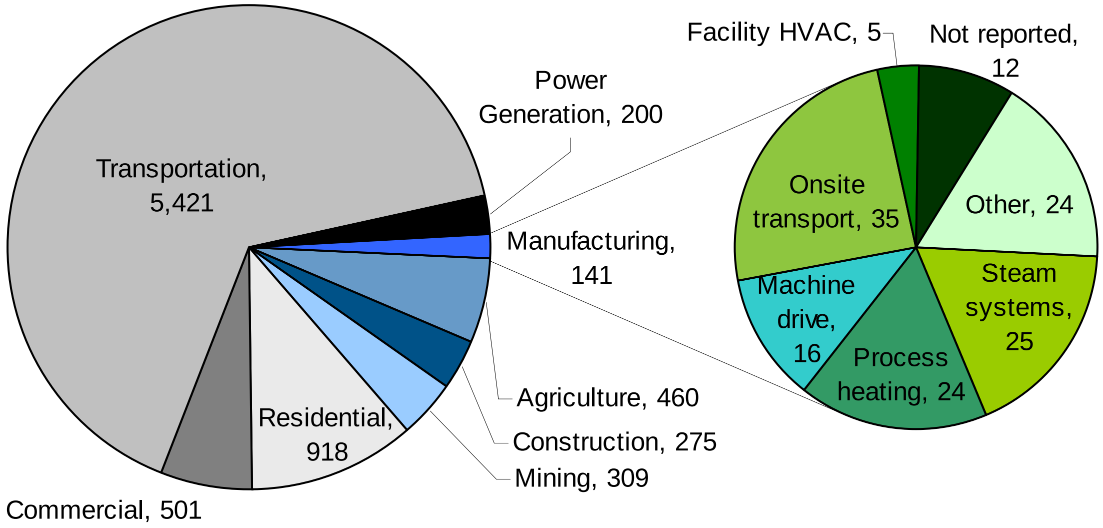


Figure 5. 2002 Distillate fuel oil consumption by sector and by end-use for manufacturing, in trillion Btu (EIA 2005a and analysis based on EIA 2005b)

biodiesel blends. Domestic biodiesel production grew from almost zero in 2000 to 75 million gallons, or about 9.7 trillion Btu, in 2005 (NBB 2006). The total capacity under construction in April 2006 is 714 million gallons (NBB 2006).

Of the 141 trillion Btu of distillate fuel that is used in the manufacturing industry, about one third is used in engines for onsite transport and machine drive (Figure 5). A further third is burned in boilers and process heaters, applications that are suited to a variety of alternative fuels other than biodiesel. Very little distillate oil (about 11 trillion Btu) is used as feedstock in the manufacturing industry.

Electricity

Electricity has always been a more expensive energy source, and electricity prices have also seen some increase since 2000. The average price of electricity for industrial customers fell gradually during the 1990s to a low of 4.4 ¢/kWh ($13 per million Btu) in 1999, and then rose to 5.3 ¢/kWh ($16 per million Btu) in 2004. This rise in price is, in part, a result of the increase in natural gas prices, as natural gas fuels about 18 percent of U.S. electric generation.

The industrial sector accounts for about 28 percent of U.S. electricity demand, with most of the demand in the manufacturing sector (Figure 6). EIA anticipates increasing onsite power generation in the industrial sector, which will cause the purchased electricity consumption to grow considerably slower than in the commercial and residential sectors (EIA 2006a).

In the manufacturing industry, half of the electricity consumption is used for machine drive. Much of the energy consumed in process cooling and facility HVAC is also used to drive electric motors. For larger motors, there is potential for replacement with engines or turbines fired with alternative fuels. However this would require additional fuel and exhaust systems, and potentially extra permitting requirements. Absorption refrigeration systems are an alternative for facilities with both high-temperature processes and cooling. Absorption refrigeration uses waste heat and can replace compressor-driven systems.

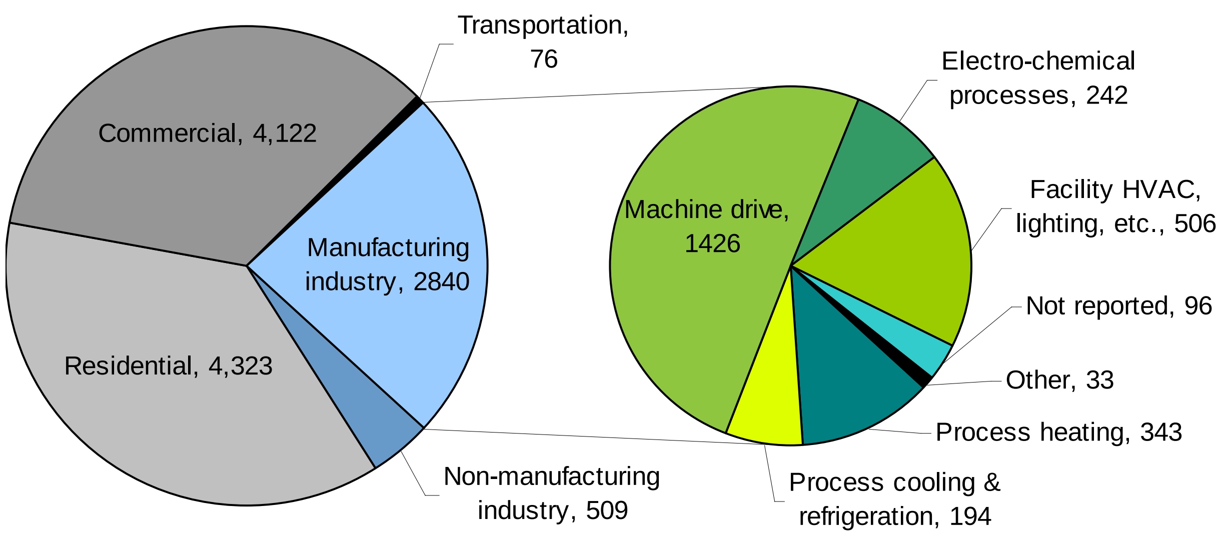


Figure 6. 2002 Electricity consumption by sector and by end-use for manufacturing, in trillion Btu (EIA 2005a and analysis based on EIA 2005b)

Facility lighting and electro-chemical processes comprise 15 percent of manufacturing electricity consumption. These two specialty applications are not likely opportunities for fuel switching. There is more potential for switching in the 12 percent used for process heating. In process heating applications, the higher fuel price is weighed against various benefits of electricity, including lower capital costs, ease of control, smaller footprint, and ability to reconfigure without fuel and exhaust systems. Equipment fired by other fuels also requires environmental permits which can cause significant delays in plant construction or modification.

Overview of Industrial Energy Consumption

The U.S. industrial sector consumed a third of the nation's total energy consumption of 98 quads (quadrillion Btu) in 2002 (EIA 2005a). The majority of this industrial energy consumption is used by the manufacturing industries, as shown in Figure 7.a. The non-manufacturing industries—agriculture, construction, and mining—consume 5.3 quads. Subtracting electricity generation losses from the industrial consumption of 32.6 quads gives a delivered energy total of 25.2 quads. The delivered energy consumption is expected to grow at 0.9 percent per year, to reach 30.6 quads in 2025 (EIA 2006a). The industrial sector growth rate is slightly slower than the total consumption growth rate, which is 1.2 percent per year.

Figure 7.b shows the manufacturing industry energy consumption by source, including electricity generation losses. Petroleum and natural gas are the largest energy sources, together accounting for 70 percent of the total fuel and feedstock consumption. But much of the petroleum is used as feedstock (as liquefied petroleum gases, LPG), so natural gas is the largest fuel source, accounting for almost half of the total non-electricity fuel consumption. The second largest fuel in Figure 7.b is by-product fuels, such as blast furnace gas used by the iron and steel industry and black liquor used by the pulp and paper industry.

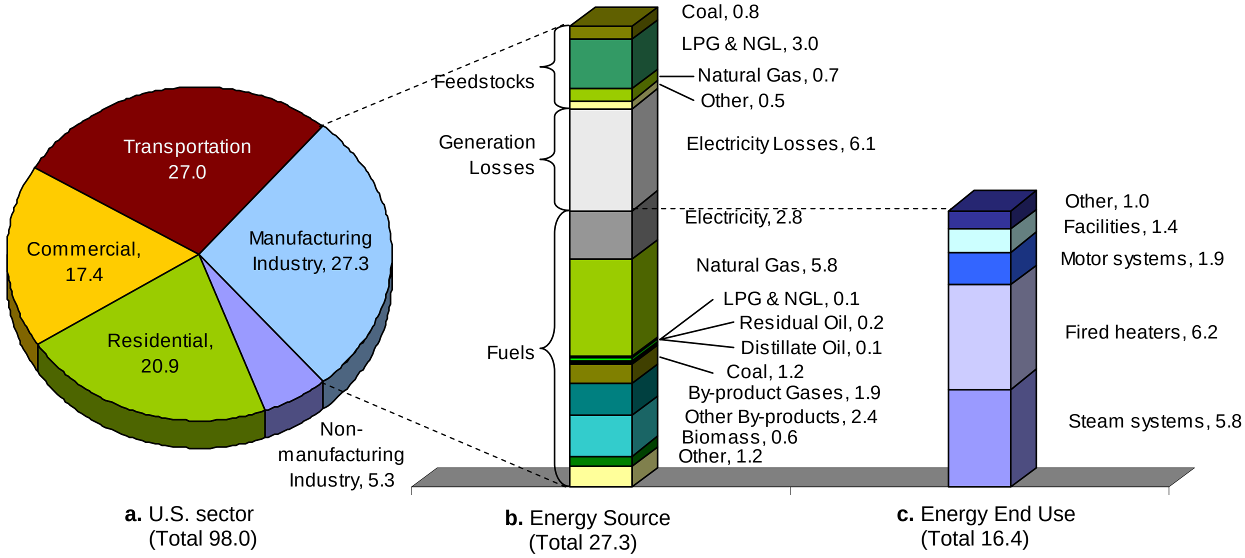


Figure 7. Overview of U.S. industrial energy use, in quads (quadrillion Btu):
a. 2002 energy consumption by sector (EIA 2005a).
b. Manufacturing sector consumption by energy source (EIA 2005b)
c. Manufacturing sector fuel consumption by end use (EIA 2005b)

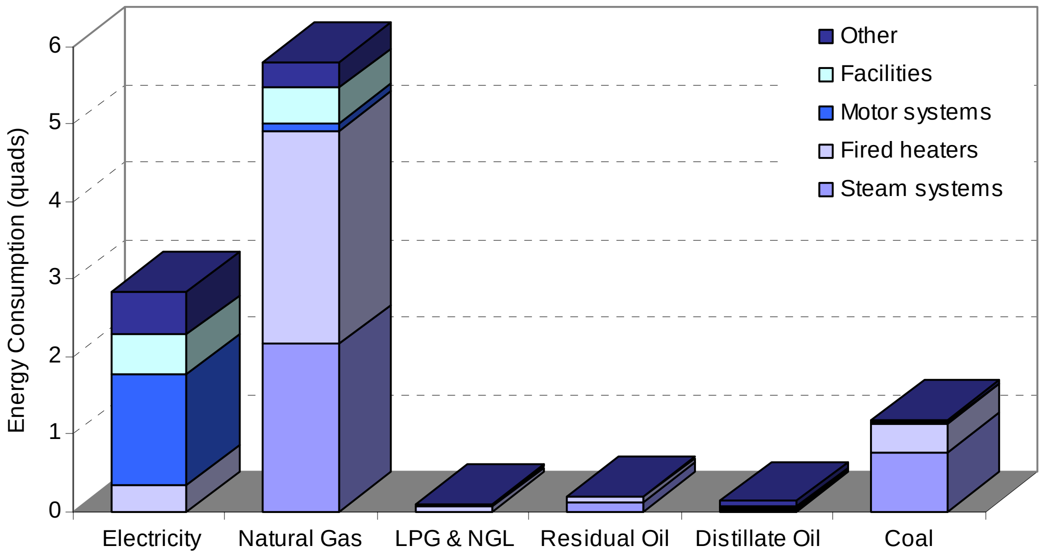


Figure 8. Consumption by end use for several fuels in the manufacturing sector (EIA 2005b)

The end use for fuel and electricity used in the manufacturing sector is summarized in Figure 7.c. Fired heaters and steam systems (boilers) consume 12 quads, or 73 percent of the total. In fired heaters, the fuel is combusted to provide process heat in furnaces, ovens, fluid heaters, etc. In steam systems, the fuel is combusted in a boiler to generate both electric power and steam (cogeneration) or just steam. Fuel and electricity is also used to power motors for process equipment such as pumps, fans, and material handlers; provide energy for facilities; and for other uses, such as process cooling and electro-chemical processes.

A more detailed breakdown of fuel consumption by end use for several of the fuel sources is shown in Figure 8. Natural gas, residual oil, and coal are used primarily for combustion in boilers and process heaters (85 percent, 89 percent, and 97 percent, respectively). Natural gas is also the primary fuel used for heating in manufacturing facility heating, ventilation, and air conditioning (HVAC) systems, and this consumes 7 percent of the natural gas total. Electricity is mostly used for motor-driven systems, facility lighting and HVAC, refrigeration, and electro-chemical processes. The purchased electricity does not include electricity produced on site, which constitutes an additional 0.5 quads.

The top industrial energy consumers of both fuels and electricity are the chemicals, petroleum refining, forest products, iron and steel, and food and beverage industries. These industries also are the major users of byproduct fuels which are comprised mostly of fossil-based fuel gases and liquid products, and wood processing wastes and byproducts.

Fuel Switching Background

U.S. industry has some existing fuel switching capacity. EIA's 2002 Manufacturing Energy Consumption Survey indicates that about 30 percent of the manufacturing sector's petroleum and coal is used by equipment that is able to switch fuels (Figure 9). Natural gas is an alternate fuel for 80 percent of this switchable consumption (Figure 10). (Some facilities are able to switch to multiple fuels, so the alternative fuel totals shown in Figure 10 are higher than the switchable consumption shown in Figure 9.) Almost 20 percent of the natural gas is switchable, mostly to petroleum fuels. Much less of the electricity consumption is able to switch fuels—only 3 percent.

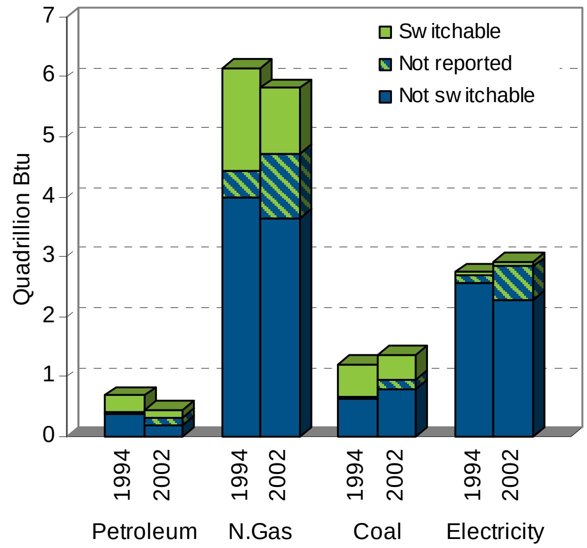


Figure 9. U.S. manufacturing sector fuel switching capacity (EIA 1997 and EIA 2005b)

Figure 9 also includes 1994 data to show that the industrial fuel switching capacity is decreasing. The switchable consumption of natural gas decreased from 1.7 to 1.1 quads over this 8-year period. Even so, the lower 2002 values may be an overestimate of the practical fuel switching capacity. For example, EIA data indicates 26 percent of industrial boilers are able to switch fuels. However, an NPC workgroup found that the practical level of fuel flexibility was much lower—only 5 to 10 percent (NPC 2003). The 1994 Manufacturing Energy Consumption Survey asked operators what difference in price between fuels would cause them to switch. Of those that provided an estimate, over 40% would not switch fuels because of price differences.

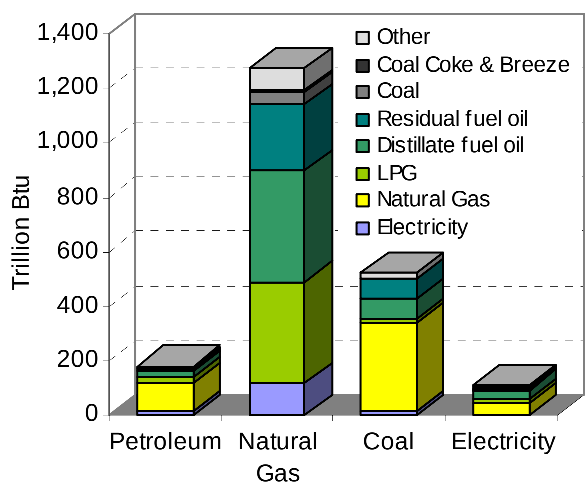


Figure 10. Alternate fuels for the 2002 fuel switching capacity shown in Figure 9 (EIA 2005b)

One reason for the reduced fuel switching capacity is newer industrial equipment that is not suited to fuel switching. Many new industrial cogeneration units are based on efficient combustion turbines, which are able to switch to distillate oil, but not more economical residual oil. The combustion turbine technology replaces boilers, which are well suited to fuel switching.

Industrial fuel switching capacity has also been limited by regulations, such as siting restrictions on fuel backup. Environmental restrictions also limit some fuel switching options. In modeling natural gas consumption, the NPC estimated that without environmental restrictions, multiple-fuel boilers switch from natural gas to residual fuel oil below $4/million Btu (NPC 2003). With environmental restrictions, they do not switch until natural gas reaches almost $6/million Btu. Many regions allow fuel switching for a short duration and only during a certain period (usually winter). Longer-term switching would require the installation of additional emissions control equipment.

Most of the existing fuel switching capacity allows switching between natural gas and petroleum fuels (Figure 10), both of which have seen large price increases. Very little current fuel switching capacity allows switching to other alternative fuels with more stable prices.

The recent Energy Policy Act provides federal loan guarantees and other incentives to encourage investment in gasification technology, which will allow switching from natural gas to coal- and biomass-based gas. This approach was presented as a solution to current natural gas supply problems in a DOE Office of Fossil Energy (DOE- FE) report, "National Gasification Strategy: Gasification of Coal & Biomass as a Domestic Supply Option." According to the DOE-FE report, the incentives for gasification (similar to those provided for the Alaska gas pipeline) can produce gas supplies equivalent to those expected from the Alaska gas pipeline, but in a more immediate time frame (Rosenberg, 2005).

Gasified and liquid fuels are a relatively easy substitute for natural gas and oil. Industrial facilities can usually switch to these fuels by modifying existing equipment. Many industrial facilities may also consider replacing larger boilers and process heaters with equipment that uses alternative solid fuels, including coal and biomass. This report considers natural gas, coal, oil, electricity, biomass, and renewable energy sources.

Other conversion fuels are being investigated as options for industrial fuel switching, including land fill gas, digester gas, industrial waste streams, lubricating oils, and emulsified fat. This report does not cover these fuels because their availability is very site dependant and sufficient data on demography and reserves are not yet available.

Industrial Fuels

Natural gas is an ideal energy source for many applications because of its combination of low emissions, controllability, operational flexibility, and low space requirements. It is easy to transport in pipelines and does not require onsite storage. Natural gas can be flexibly applied to many processes and used in direct contact with most products. It can be used in high-efficiency combined cycles or other advanced technologies, and in conjunction with by-product gas fuels in the steel, refining, and chemicals industries.

Coal is typically the lowest cost fuel, but is the most difficult to transport and use. It does not allow fine control or quick response and has high pollutant emissions. Coal cannot be used in most direct contact applications, including many drying, curing, heating, and melting applications. The primary uses of coal are in very large boilers and cogeneration facilities and in cement calcining. Even in these limited applications, coal use is threatened due to its high emissions and difficulty of use. Few new coal-fired boilers or cement kilns have been built, and some were converted to cleaner fuels such as natural gas.

Residual oil has been a significant competitor to natural gas, although its sulfur content can be higher than that of coal. Its uses are concentrated in large boilers, refinery heaters, and lime calcining.

Distillate oil has been of much better operational characteristics than residual oil or coal, but is generally more expensive than natural gas. Distillate oil sometimes facilitates the use of natural gas by serving either as the backup fuel to natural gas or as the primary fuel for small and mid-sized refinery boilers and process heaters.

Electricity is a flexible energy source that is used for machine drives, lighting, and specialty applications such as aluminum smelting. In addition, it competes with natural gas and other fuels for process applications such as drying, heating, curing, and melting. Electricity has many desirable characteristics that make it competitive: it is easy to transport, install, control, and reconfigure; requires no onsite storage; produces no onsite emissions; and can be used in direct contact with any product. However, electricity typically has very low overall efficiencies, resulting in disproportionately high greenhouse-gas emissions and energy resource consumption. Electricity typically has the highest cost per unit energy, giving electrical equipment higher life-cycle costs. But electric systems often have a lower capital cost, and so can be desirable for a near-term perspective. Electrical equipment also does not require environmental permits, which sometimes cause significant delays in plant construction or modification.

Biomass is being used increasingly for power generation and large combined heat and power (CHP) units. The average size of existing bio-power plants is 20 MW (the largest one approaches 75 MW). The stand-alone bio-power facilities largely use non-captive residues, including wood waste purchased from forest products industries and from urban wood waste streams, agricultural residues from harvesting and processing, used wood pallets, and some waste wood from construction and demolition, to generate electricity. All of today's bio-power capacity is based on mature, direct combustion boiler/steam turbine technology.

Renewable energy sources such as wood or solar thermal can be used for low temperature industrial processes. Solar thermal, wind power, and fuel cell systems could be investigated for applications to industrial and commercial boilers.

Considering fuel switching capacity by industry, some of the most energy intensive industries have the least fuel switching capacity. Figure 11 shows that the three largest industrial natural gas consumers—the chemicals, refining, and primary metals industries—are below average for fuel switching. Only 10 percent of the chemical industry natural gas consumption is switchable, compared to 24 percent for the other less energy intensive industries. However, these energy intensive industries may be the most likely to consider long-term switching to new fuel options, as they are most vulnerable to fuel price increases are also already familiar with alternative fuels. The energy-intensive refining, chemicals, paper, and primary metals industries are also the largest users of byproduct fuels.

Increased fuel switching from natural gas would provide a buffer against spikes in natural gas prices, but is not expected to cause demand destruction. Natural gas is an ideal fuel for many industrial applications, and customers with multiple-fuel capability will likely switch back to natural gas as gas prices return to acceptable levels. Industrial gas customers with multiple-fuel capability would be able to take advantage of interruptible gas contracts, which provide gas at low rates but cut off supply during shortages.

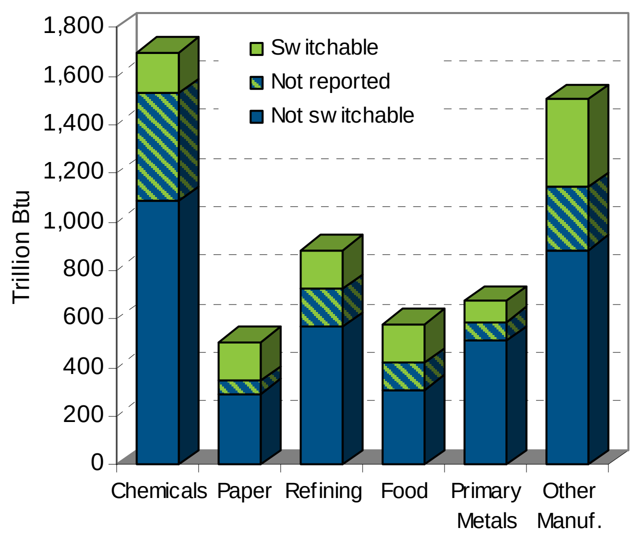


Figure 11. Natural gas consumption that can be switched to alternate fuels (EIA 2005b)

Potential Impact of Fuel Switching

Energy efficiency measures have become increasingly important for industry with current high natural gas and petroleum prices. A 2005 study by the American Council for an Energy-Efficient Economy (ACEEE) indicates that increasing the national commitment to energy efficiency could reduce natural gas prices by over 10 percent. The 2003 National Petroleum Council (NPC) report on natural gas policy also included energy efficiency as its first major recommendation for actions to achieve a stable, affordable natural gas future. But switching to alternative fuels has a greater potential for displacing natural gas and petroleum consumption, and will play a major part in curbing the rising prices of these fuels.

The NPC report combines its recommendation for energy efficiency with a recommendation for fuel flexibility, emphasizing the importance of multiple-fuel firing as a longer-term stabilizer of fuel prices. Industrial and power sector consumers play the key role in avoiding price volatility by switching to alternate fuels when natural gas prices begin to rise.

Long-term fuel switching to fuels with more stable supplies will also have an impact on natural gas prices, as illustrated in Figure 12, which shows ACEEE analysis predictions for the effect of energy efficiency measures combined with increased implementation of renewable energy. The combined measures could reduce wholesale gas prices by about 20 percent within five years, saving the nation over $100 billion.

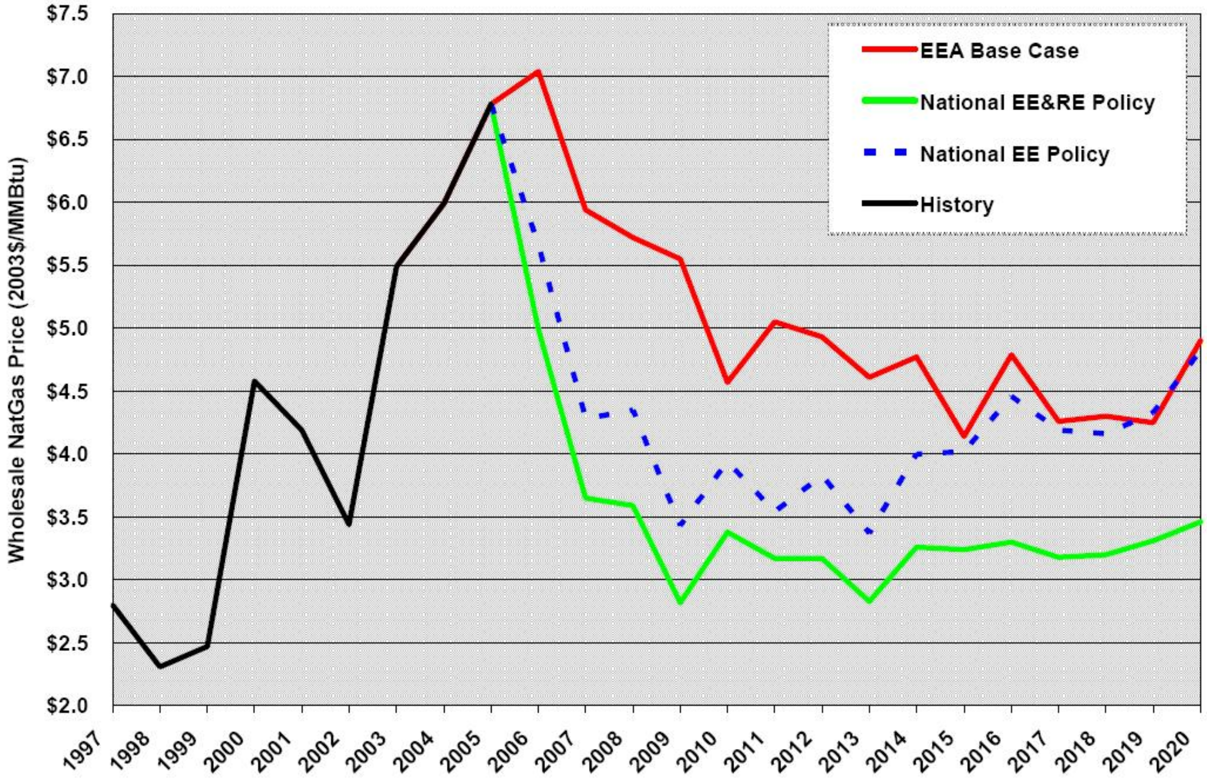


Figure 12. Natural gas price projections showing the potential impact of energy efficiency and renewable energy measures (ACEEE 2005). Projections are based on the EEA North American Gas Market Model (EEA 2004).

The energy efficiency measures modeled by ACEEE include both behavioral responses and hardware investments in electrical efficiency and gas efficiency across all sectors of the U.S. economy. These measures have the greatest impact towards the beginning of the modeling period. The renewable energy measures included in the second projection are based on regional targets for growth in the renewable energy share of the electric power market. These measures have a greater effect later in the modeling period, accounting for most of the gas price reduction in 2020. On a case-by-case basis, the gas price reduction achieved by fuel switching will be significantly greater than what can be expected from energy efficiency and renewable energy measures.

Actions to reduce natural gas demand have especially large impacts early in the forecast period because of the current tight natural gas markets (Figure 12). As other resources such as additional LNG capacity and the Alaska pipeline become available, the market rebalances and effect of demand reductions on gas prices diminish. But reductions in gas demand continue to accumulate and provide cost savings for gas customers, as shown in Figure 13. The increase in industrial gas demand shown in Figure 13 is a result of industry growth due to lower gas prices. In the base case, high gas prices cause plant closures and demand destruction, while in alternate case, industry avoids the shut-downs and benefits from gas efficiency and renewable energy investments.

Reductions in the natural gas demand from energy efficiency and renewable energy technologies will produce a two-fold benefit to gas customers: (1) significant cost savings resulting from reduced energy consumption and (2) falling natural gas prices as markets rebalance to respond to demand reduction. Fuel switching, on the other hand, can only impact reductions in natural gas prices by creating gas demand

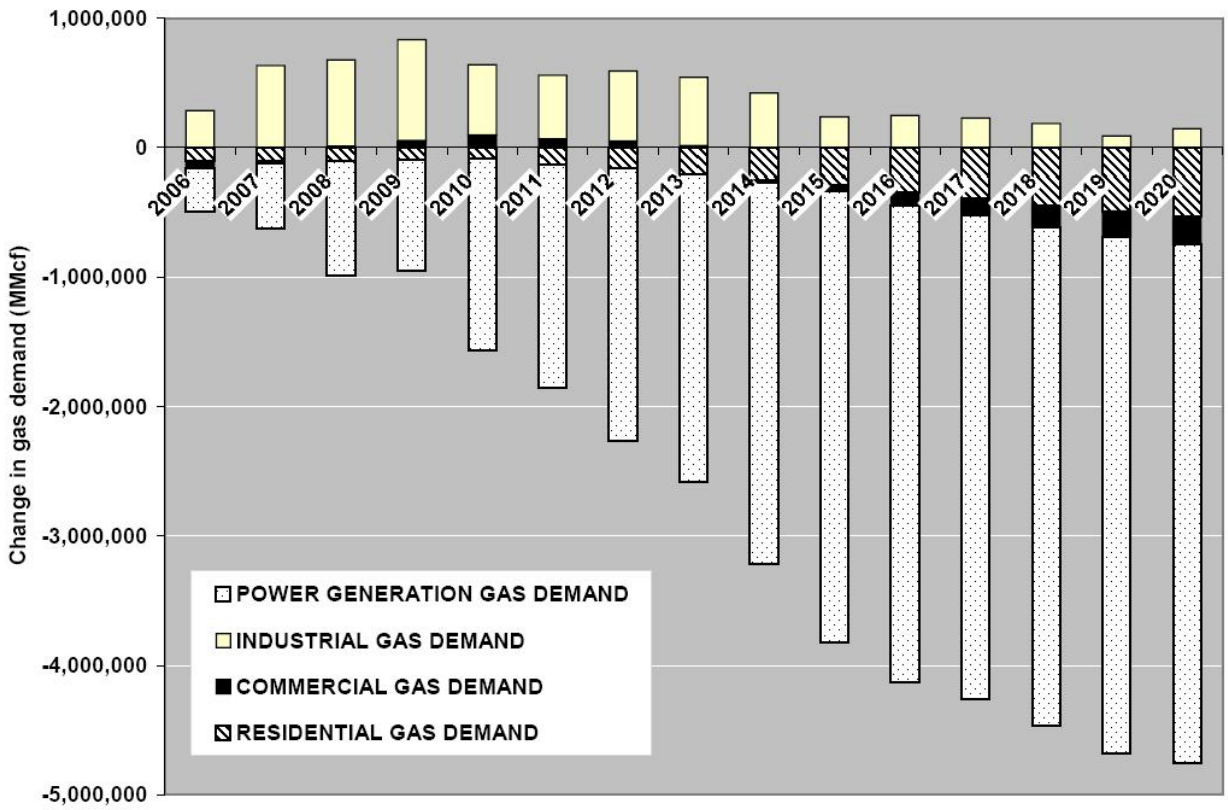


Figure 13. Projections for the change in natural gas demand with the implementation of energy efficiency and renewable energy measures (ACEEE 2005)

reductions. However, on a case to case basis, the natural gas demand reduction from fuel switching will be significantly larger than from energy efficiency technologies, since fuel switching can displace 100 percent of gas demand while energy efficiency technologies can only reduce gas demand by 20-40 percent.

Fuel switching can be a major part of the solutions to curb the rising natural gas prices. By combining fuel-use flexibility with the energy efficiency and renewable energy gas conservation technologies, decreases in the natural gas demand, and therefore decreases in the natural gas prices, can be accelerated substantially. Furthermore, the customer's ability to switch to different fuels will ensure that gas producers will not hold on to high gas prices and that the regional reductions in gas prices will "in fact" occur with the decreases in gas demand impacted by fuel switching.

Report Overview

The rising costs of natural gas and petroleum fuels provide the motivation for fuel switching. This report considers switching from both fuels, but emphasizes switching from natural gas, as natural gas provides the larger opportunity for switching. Much of the industrial petroleum consumption is consumed as feedstocks by the chemical industry or by-product/waste gases by the petroleum industry.

When switching energy sources used for fuel, the heating value is the primary consideration. Switching energy sources used for feedstock is more challenging, as the chemical composition of the feedstock is of primary importance. This report has focused on the two main end uses for fuel—boilers and fired process heaters—which constitute 70 percent of the manufacturing industry's fuels consumption. The 5.2 quads of natural gas and oil used for boilers and process heaters represents the most obvious target for fuel switching. A further 1.4 quads of natural gas and oil used by commercial boilers is also included because these units have similar characteristics as those used in the industrial sector.

To assess the impact of fuel switching from natural gas and oil to alternative solid, liquid and gaseous fuels, this report provides templates for:

- Identifying opportunities for fuel switching in industrial boilers and process heating equipment from natural gas or oil to coal and biomass based fuels, residual oil, renewable sources, and electricity;
- Assessing cost, productivity, and environmental impacts of fuel switching from natural gas or oil; and
- Identifying technology development needs for fuel switching from natural gas or oil.

The following fuel switching options have been considered as possible candidates for industrial and commercial boilers:

- Natural gas and distillate oil to coal-based gas
- Natural gas and distillate oil to biomass-based gas
- Natural gas and distillate oil to direct biomass firing
- Natural gas to residual oil
- Natural gas and distillate oil to coal-oil mixture (COM)
- Natural gas and distillate oil to coal-based liquid fuel

- Natural gas and distillate oil to electricity
- Natural gas and distillate oil to solar thermal and wind systems
- Natural gas, distillate oil, and residual oil to coal

Long-term fuel switching will likely involve conversion from expensive fuels to those with more stable prices and supplies, such as coal and biomass. However, switching between expensive fuels (including natural gas to electricity) is also included because of its value in avoiding short-term price increases.

The following fuel switching options have been considered as possible candidates for industrial process heating equipment: (Switching from oil is not considered here because residual and distillate oil only account for 1 percent of current fuel consumption in process heaters.)

- Natural gas to residual oil
- Natural gas to coal-based gas
- Natural gas to biomass and biomass-based gas
- Natural gas to solar-thermal and wind systems
- Natural gas and distillate oil to electricity
- Electricity to natural gas and other fuels

Further consideration is also given to fuel switching opportunities in onsite industrial electric power generation, with an emphasis on combustion turbine systems. Finally, switching from petroleum- and natural gas-based feedstocks to coal and biomass feedstocks is also considered.

Fuel Switching Opportunities in Boilers

Overview of Industrial and Commercial Boiler Use

Almost 180,000 boilers are used to generate steam and hot water for the U.S. industrial and commercial sectors (EEA 2005). Although this report focuses on industrial fuel switching opportunities, commercial boilers are also included because the same boilers can be used in either sector. This section also includes boilers used for combined heat and power applications.

Boilers vary greatly in size, from small commercial units with capacities below 0.5 million Btu/hr to large industrial boilers with capacities up to 10 billion Btu/hr (Figure 14). Boilers also use a variety of fuels, with some designed to fire two or three. The main fuels are natural gas, oil, and coal, but some industrial boilers are also capable of firing waste fuels such as bark, saw dust, coke oven gas, and coffee grounds.

Boilers are characterized by the configuration of their heat transfer surfaces, as sectional, fire tube, or water tube. In *sectional boilers*, the water is contained in boiler sections over a combustion section. These represent 22.5% of industrial capacity, but are small units, with an average size of 0.25 million Btu/hr. They are only suitable for low pressures (below 30 psi) and consequently are used as water heaters. In *fire tube boilers*, hot combustion gases are contained in metal tubes that pass through the main body boiler vessel, which is filled with water. These account for 18.5% of U.S. industrial boiler capacity

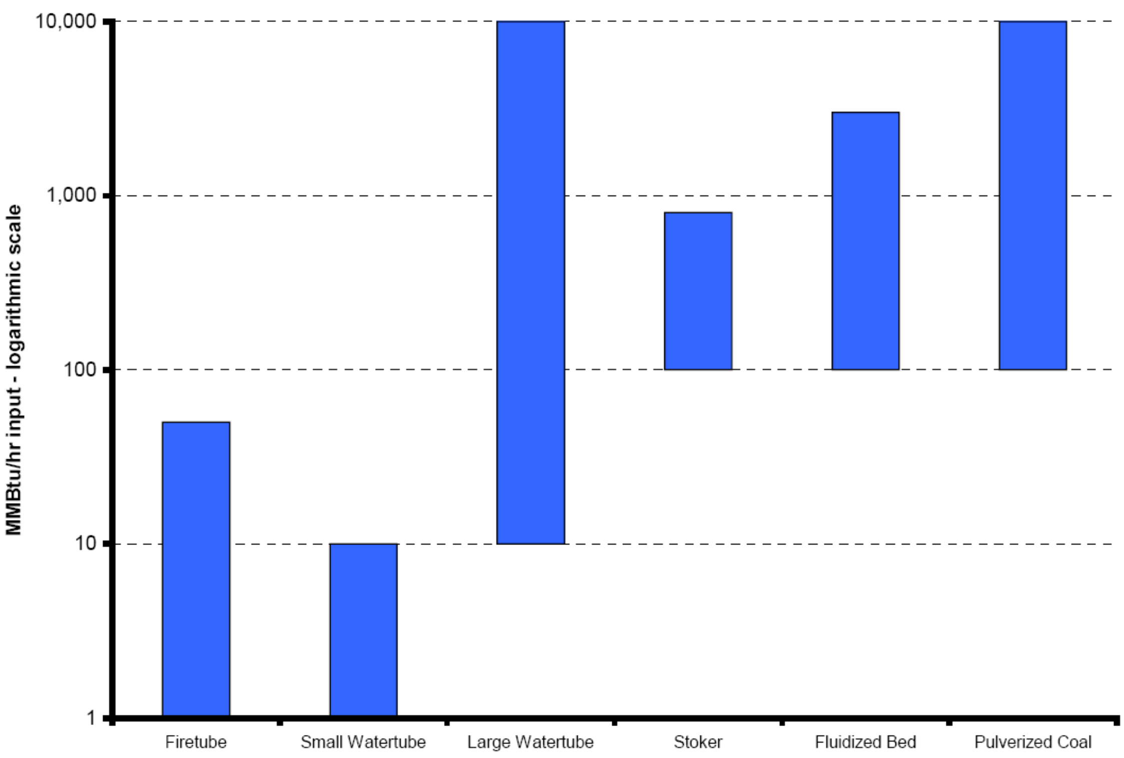


Figure 14. Boiler Types and approximate capacity ranges (EEA 2005)

and are also smaller units, typically with capacities below 10 million Btu/hr. Almost all fire tube boilers fire natural gas or oil. In *water tube boilers*, the water is contained in metal tubes that pass through the combustion chamber. These boilers are capable of high pressures and temperatures, and have capacities between 10 – 10,000 million Btu/hr. Fire tube boilers account for about 59% of U.S. industrial boiler capacity, including almost all large industrial and power generation boilers. More than 90% are smaller than 100 million Btu/hr, but the larger water tube boilers account for most steam production. Smaller "package" water tube boilers have capacities below 50 million Btu/hr. Field erected water tube boilers range from 50 million Btu/hr to over 1,500 million Btu/hr, and are more expensive.

Large water tube boilers are the most likely to use solid fuel, and can be further characterized by their fuel burning system. *Stoker boilers* employ older technology, in which the fuel (coal, wood, or waste) is moved along a grate at the base of the boiler. In *pulverized coal boilers*, fine coal dust is blown into the boiler with air and burned in suspension. The latest boiler technology is the *fluidized-bed combustor*, in which the fuel is suspended and combusted in a bed of inert material at the base of the boiler. Combustion air is injected into the bed to keep it fluidized.

In contrast to the variety of solid fuel combustion methods, burners for liquid and gaseous fuels are relatively similar: they meter fuel and air streams, ensuring the streams mix as they are injected into the combustion zone. The fuel type also affects the size of a boiler. Gas boilers are the most compact; for a given capacity, an oil boiler is nearly 30% larger in area and 20% taller than a gas fired unit. A coal boiler requires 50% more area and is 60% taller than a gas fired unit.

Figure 14 shows typical capacity ranges for some of the common boiler types on a heat input basis. Sectional boilers are not shown on the plot; because of their small size they are not likely suitable for fuel switching.

The number of units and capacity of U.S. manufacturing and commercial boilers is shown in Figure 15. Manufacturing industry boilers are much larger on average, with a mean capacity of 36 million Btu/hr, compared to 9.6 million Btu/hr for the average commercial boiler. The commercial sector employs many smaller boilers units with low utilization. Units smaller than 10 million Btu/hr account for 70 percent of the total number of units, but only 15 percent of the total capacity.

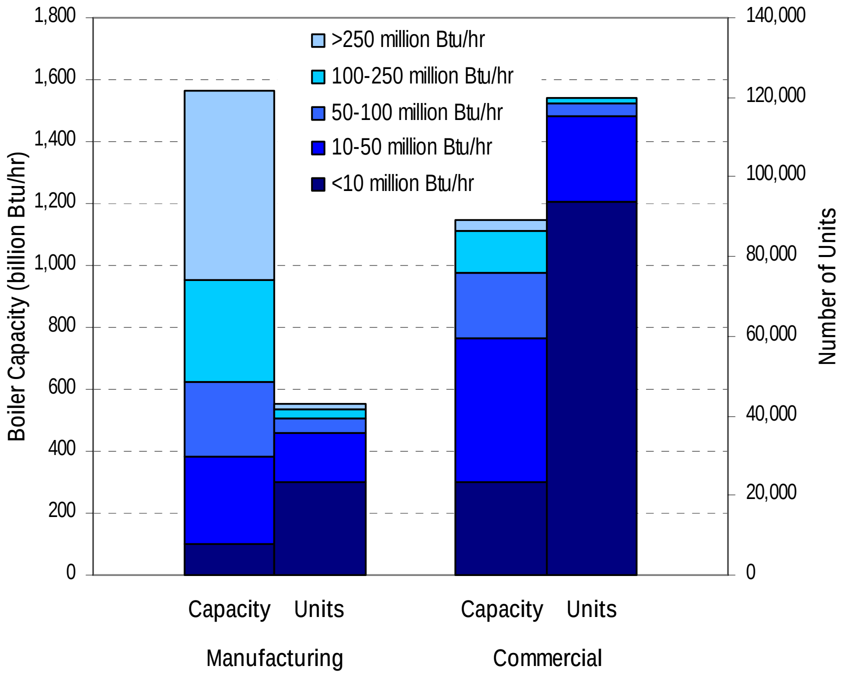


Figure 15. Capacity and number of U.S. industrial and commercial boilers (EEA 2005)

Fuel Consumption and Fuel Switching Potential in Boilers

Boilers used by the U.S. industrial and commercial sectors consume about 8,100 trillion Btu per year, accounting for about 40 percent of the total fuel energy consumption of these sectors (EEA 2005). This total boiler energy consumption is the maximum potential fuel switching opportunity in boilers. The following profiles give a better indication of which fuel switching opportunities are applicable for various industries and commercial sectors. The fuel switching potential by industry is then summarized at the end of the section in Table 1.

Industrial and commercial sectors are considered in turn below. The same basic types of boilers are used across both sectors, but commercial boilers are typically smaller and are mostly fueled by natural gas. Industrial boilers are larger and use a variety of fuels, including a large proportion of by-product fuels.

Industrial Boilers

There are 43,000 boilers in the manufacturing sector, with a total capacity of 1.5 trillion Btu/hr. Many of the units are large, with almost half having capacities greater than 10 million Btu/hr, and more than 1,300 units having capacities greater than 250 million Btu/hr. The non-manufacturing industries have only about 16,000 boilers with a capacity about 14 percent that of the manufacturing sector. The non-manufacturing sector boilers are considered at the end of this section.

Industrial boilers consume 6,470 trillion Btu/yr (37 percent of all industrial fuel energy), excluding electricity. Natural gas and byproduct/waste fuels account for more than 80 percent. By-product and waste fuels alone account for 3,249 trillion Btu/yr. Waste fuels include wood waste in the paper industry, blast furnace and coke oven gas in the primary metals industries, and refinery and other by-product gases in chemical and refinery industries. Natural gas is the largest purchased energy source for boilers (2,100 trillion Btu/yr), and the primary fuel for 78 percent of boiler units and 56 percent of boiler capacity.

Coal, oil, and wood are important in certain industries and regions but represent smaller fractions of the total capacity. Coal is the second largest purchased boiler fuel, making up to about 24 percent of the purchased fuel. Residual oil accounts for about 8 percent of purchased fuel for industrial boilers, and is used mostly the paper industry.

Five industries—Chemicals, paper, refining, food and primary metals—use 71 percent of the boiler units and 82 percent of the total capacity. The energy consumption for these industries is illustrated in Figure 16, and the number of units and capacity is shown in Figure 17.

Chemical industry – The chemical industry has the largest boiler population and capacity, with 12,000 boilers giving a total capacity of 413 billion Btu/hr. The industry uses large units for integrated facilities as well as smaller units in plants for specialty products, such as dyes and cosmetics. This gives a relatively even size distribution, as shown in Figure 17. The chemical industry is a very large natural gas consumer, using 11 percent of the U.S. total U.S. for feedstock and fuel. This is reflected in the boiler energy consumption, where natural gas accounts for almost half of the total. The average capacity factor for the chemical industry boilers is 50 percent.

Paper industry – The paper industry has a total capacity slightly lower than the chemical industry (376 billion Btu/hr), but an average capacity factor of 66 percent, resulting in a larger total energy consumption than the chemical industry. It uses many large boilers for steam and cogeneration, and has an average capacity of 109 million Btu/hr. By-product fuels account for 54 percent of the paper

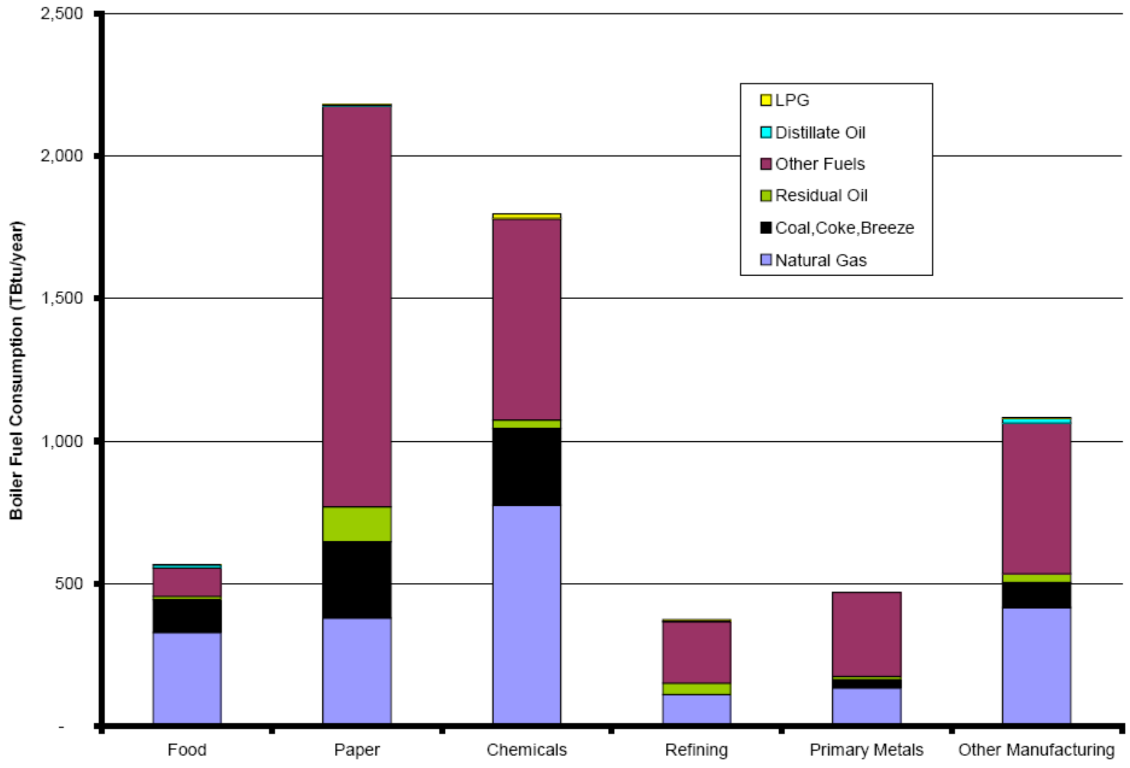


Figure 16. Boiler energy consumption by industry and fuel (EEA 2005)

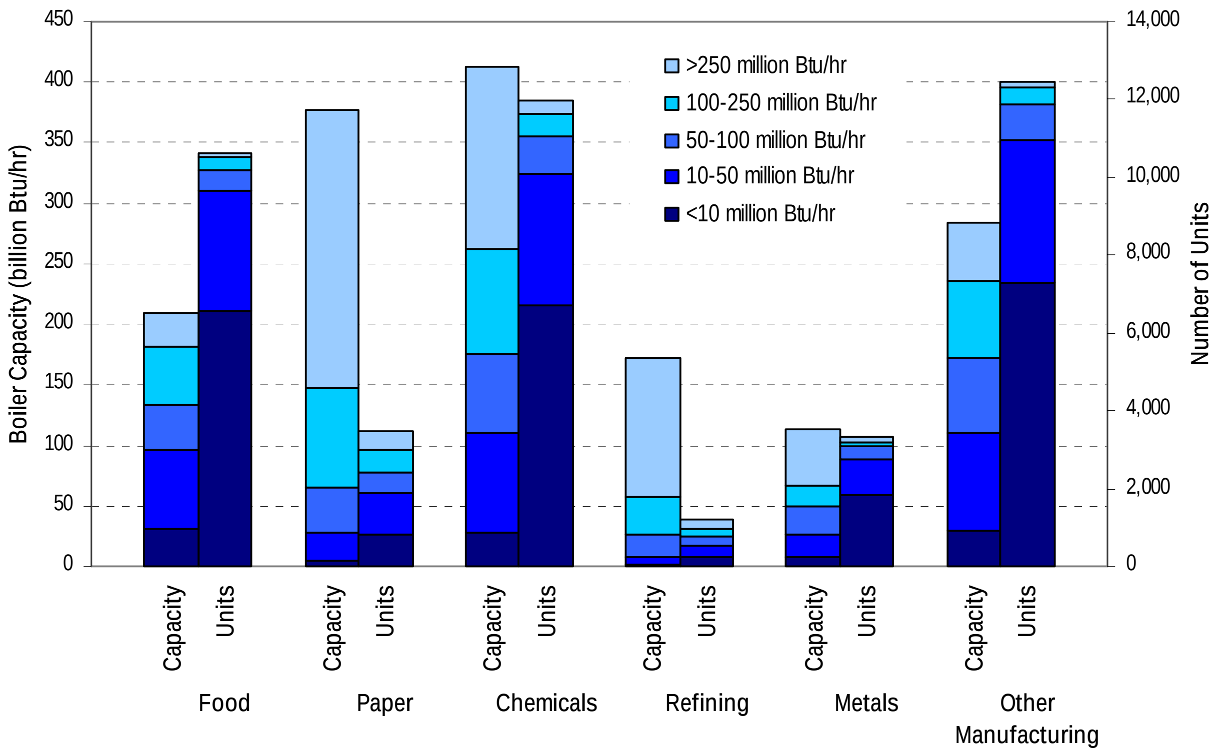


Figure 17. The number of units and boiler capacity of boilers in the industries of interest

industry's total energy consumption, but about 64 percent of its boiler fuel. The dominant fuel is black liquor, which has a low heat content and lower boiler efficiency. Other by-product fuels used include bark, wood chips, and production wastes.

Refining industry – The refining industry has only 1,200 boilers, but the largest average size (143 million Btu/hr). More than 200 boilers have a capacity greater than 250 million Btu/hr. Although the industry has a total capacity of 172 billion Btu/hr, the average capacity factor is only 25 percent, so the total fuel consumption is the lowest of the top five industries. The refining industry uses a large proportion of by-product fuels, including refinery gas and carbon monoxide. By-product fuels make up 58 percent of energy consumption, followed by natural gas (29 percent) and residual oil (11 percent).

Food industry – The food industry has almost as many boiler units as the chemical industry, but the smallest average size: 20 million Btu/hr. The food industry is comprised of many relatively small facilities, and predictably has many smaller boiler units. Small boilers are typically gas-fired package units, and the food industry's primary fuel is thus natural gas (58 percent). The food industry is also a large coal consumer, mostly for wet corn milling or other large steam applications.

Primary metals industry – The primary metals industry has over 3,300 units but a total capacity of 113 billion Btu/hr which is lowest of the five major industries. Over half of these units are smaller than 10 million Btu/hr. Integrated steel mills have over 70 percent of the total capacity, and use steam for on-site power generation and turbine-driven equipment. Newer electric "mini-mills," which are growing faster than integrated mills, do not use much steam. By-product fuels account for 63 percent of boiler fuel, natural gas for 29 percent, and coke/coke/breeze for 6 percent. The main by-product fuels have a low heating value (500 Btu/cf for coke oven gas, 80 Btu/cf for blast furnace gas), and so are often blended with natural gas.

Non-manufacturing industries – The non-manufacturing industries—agriculture, mining, and construction—are not included in Figure 16 and Figure 17. These industries have about 16,000 units with a combined capacity of approximately 260 billion Btu/hr (about 14 percent of the manufacturing boiler capacity), and they consume about 16 percent of all industrial energy and 1,242 trillion Btu/yr of natural gas[1].

Commercial Boilers

This section considers the 120,000 commercial boilers with capacities over 1 million Btu/hr (with a total capacity of 1.1 trillion Btu/hr). The energy consumption for these boilers is shown in Figure 18. The commercial sector also has other smaller units that are not considered here: 387,000 units with capacities below 1 million Btu/hr and 22,000 electric water heaters.

Commercial boilers consume approximately 1,630 trillion Btu per year, and the vast majority of this consumption is natural gas (83 percent). Coal boilers account for only 1 percent of commercial units, but are larger, with 5 percent of capacity and 8 percent of energy consumption. Oil accounts for 7 percent of the energy consumption, and other fuels, such as propane, account for 2 percent.

Commercial boilers are used primarily for space heating (about two thirds) and water heating (about one third). Because of the dominant space heating function, commercial boilers are more heavily distributed

[1] The majority of the natural gas consumed by the non-manufacturing industries is used by the mining industry for oil and gas extraction.

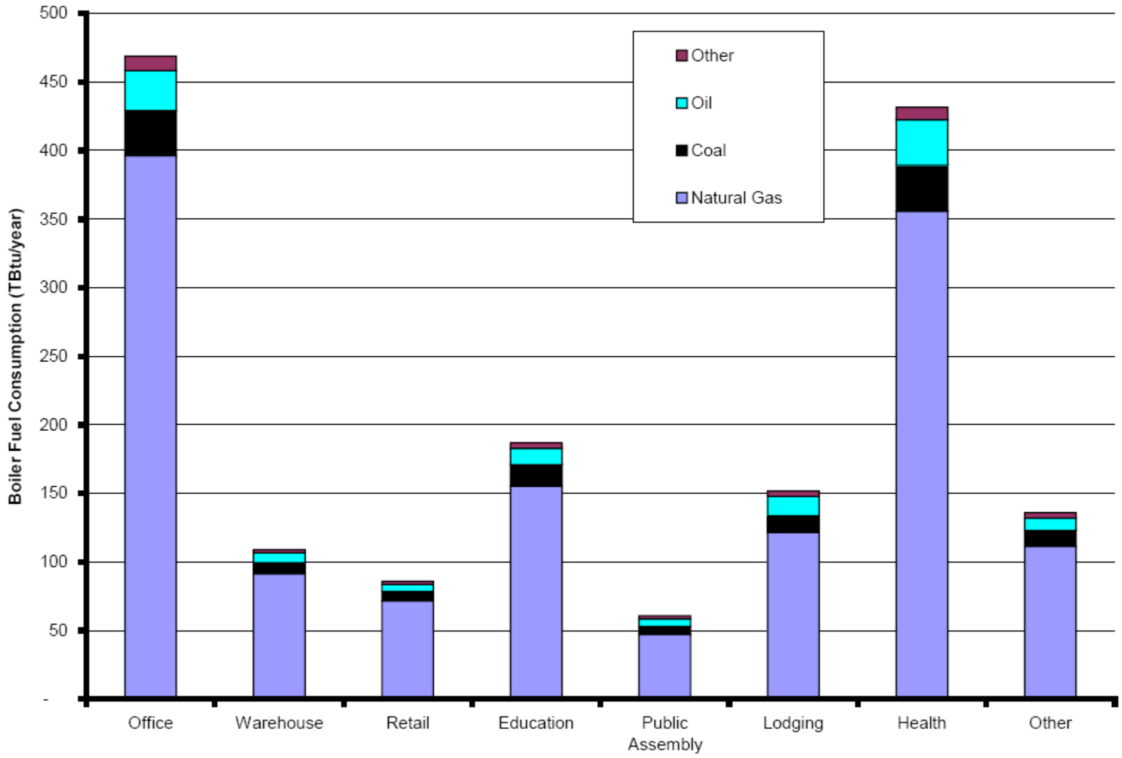


Figure 18. Boiler fuel consumption for major commercial sectors (EEA 2005)

in the northern regions of the country. Commercial boilers also operate at lower pressures and temperatures than industrial boilers.

The energy consumption of commercial boilers is shown in Figure 18 by sector. Healthcare facilities consume about 430 trillion Btu/yr; they also have the largest total capacity (317 billion Btu/hr) and average capacity (20.9 million Btu/hr). Together with office facilities, they make up over half of the total commercial capacity and energy consumption. The third largest energy consumer is the education sector, which has the largest number of boilers (35,900) with the smallest average size (3.6 million Btu/hr).

Opportunities for Fuel Switching in Industrial and Commercial Boilers

The potential opportunities for fuel switching are summarized in Table 1. The fuel switching amounts shown represent the total natural gas and oil consumption for each industry or sector. Applicable fuel switching options are also given for each sub-sector. The applicability of each option for an industry is ranked based on two primary criteria: (1) the substitute fuels available and (2) the types and sizes of boilers used. It is assumed that boiler operators will place first preference on boiler modification as the fuel switching method unless boiler replacement is found to be clearly more economical. It is also assumed that, if the space permits, the boiler operators will prefer to keep the old boilers in place and connect them to the new boiler to achieve the dual-fuel capability.

Table 1. Fuel switching targets for industrial and commercial boilers

Sector	Fuel Switching Opportunity (trillion Btu/yr)	Applicable Fuel Switching Options								
		Coal gas	Biogas	Biomass	Residual oil	Coal-oil mixture	Electricity	Solar/wind	Coal	Other
Industrial sector										
Chemicals Industry	775	3	4		5	6		7	2	1 – By-product fuels
Paper Industry	379	4	3	2				5		1 – Black liquor gas
Refining Industry	109	7	4	3	2	6		8	5	1 – By-product fuels
Food Industry	320	1	2				3	4		
Primary Metals Industry	135	2	3		4			5	1	1 – By-product fuels
Non-manufacturing Industries	416	1	2				3	4		
Commercial sector	1,350	2	3		4				1	

Implications of Fuel Switching for Boilers

This section describes boiler modifications, cost implications, and environmental impacts associated with several of the most likely fuel switching scenarios. It focuses on the qualitative information related to fuel switching; up-to-date quantitative information is not available for cost and environmental impacts of fuel switching. The latter will require detailed analyses based on the current technical, economic, and regulatory situation.

In order to determine which fuel switching options are most likely, the annualized comparative costs for each would be determined. This would include:

- Cost of fuel;
- Capital charges for equipment, modifications, and pollution control;
- Operating and maintenance costs;
- Costs associated with the current and proposed regulations; and
- Cost of replacing the boiler capacity lost due to boiler de-rating that results from fuel switching.

A rough estimate of capital costs and operations and maintenance costs can be obtained from the charts provided in the Appendix. These Figures are taken from the 1978 EPA Report, “Industrial Boilers-Fuel Switching Methods,” and show 1978-1979 cost estimates for a variety of boiler types and capacities. They also project cost trends from 1978-1995, and could be extrapolated to obtain reasonable 2005 estimates. This would require data comparing labor, materials, and fuel costs in 1978-1995 to current values. A helpful rule of thumb can also be employed in estimating capital cost. The “six-tenths factor rule” states that the capital cost of a piece of equipment is approximately $(X)^{0.6}$ times the cost of a similar piece of equipment of known capital cost, where the first has a capacity X times that of the second.

The age of the existing equipment is another important consideration for any fuel switching. Especially for larger units, switching by replacement is more likely for equipment that is close to retirement.

Switching from Natural Gas and Distillate Oil to Coal-Based Gas Firing

Coal gasification can permit existing industrial gas and oil boilers to switch to coal. The gasification process converts coal to fuel gas and offers a serious alternative to pulverized coal technology for large (100-10,000 million Btu/hr) boilers. The coal gas has properties similar to natural gas and it can be burned in existing gas- or oil-fired boilers with minimum modifications. However, the gasification process is complex and many factors must be examined when considering fuel switching to coal gasification: (1) type of gasification process, (2) boiler modification requirements, (3) gas purification requirements, (4) onsite or offsite gasification, (5) cost of gasification, and (6) pollution control.

Coal Gasification Processes – Coal gasification involves the reaction of coal, water vapor, and oxygen to produce a gas rich in hydrogen, carbon monoxide, and methane. The mix of product gases and heating value depends on the type of gasification process:

- *Low-Btu gasification* uses air for the gasification reaction and produces fuel with a heating value of approximately 150 Btu/scf.
- *Medium-Btu gasification* uses pure oxygen for the reaction and produces fuel with a heating value of about 350 Btu/scf.
- *High-Btu gasification* further processes medium-Btu gas to produce fuel with a heating value of about 1000 Btu/scf, which is nearly identical to that of natural gas.

Switching from natural gas to coal gas produced by high-Btu gasification requires no significant modifications. But the high-Btu gasification process is less efficient and can become economically less attractive than the other two processes.

Boiler Modifications – Because the heating value of low- and medium-Btu gas is lower than that of natural gas, switching to the coal-based gas results in a significant increase in fuel and flue gas flow rates. The fuel flow rate increases as the heating value decreases, so low- and medium-Btu gases require modification of existing burners and fuel supply headers.

The increased gas flow for low-Btu gas causes an increased pressure drop in the boiler and can cause boiler de-rating. In some cases modifications of the boiler, burners, and fuel supply system permit full capacity operation while burning coal-based gas. Combustion of medium-Btu gas, on the other hand, does not result in any significant changes in flow, and causes only minor changes in boiler heat absorption. As a result, most existing gas boilers can burn medium-Btu gas with changes in fuel supply system and burners, but little or no modification to the boiler itself.

Gas Purification – Coal-based gas contains a variety of compounds in addition to the major components, such as ash, tars, oils, H_2S, CS_2, NH_3, cyanides, phenols, and thio-cyanates. Direct combustion of raw gasifier gas in industrial boilers could result in the production of particulates, sulfur dioxide, and nitrogen oxides, and may require additional pollution control equipment for the flue gases. However, it is possible to clean coal-based gas prior to combustion and thus reduce or eliminate the need for additional emissions controls.

Gas purification is simpler than cleaning the flue gases because it requires treatment of less than one-half the volume of gas involved in flue gas cleaning. Commercially proven technology is available to remove sulfur from the coal-based gas. Also, the elemental sulfur removed from the fuel gas can be easily handled and sold, while many flue gas de-sulfurization (FGD) systems produce solid wastes that are toxic or expensive to dispose of.

Cost Implications – Gasification has not yet been used extensively to supply boiler fuel, because natural gas and oil have been less expensive than fuel gas, especially for smaller boilers with capacities less than 250 million Btu/hr. Only for very large gasification facility of over 4,000 million Btu/hr, does the benefit of scale begin to level the fuel gas costs. Thus, most fuel gas targeted for use in industrial boilers will have to be produced at large central gas facilities.

There are two main costs involved for switching from natural gas to fuel gas. The first is the cost of gasifier and associated process equipment, such as gas purification equipment. For smaller boilers this would be absorbed into the cost of fuel gas purchased from a central gasification facility. The second cost is the cost of modifications and the change in operating and maintenance costs.

The capital costs of modifications to permit the use of low- and medium-Btu gas will depend on the extent of modifications. Modifications may be as simple as changes in the fuel supply systems and burners. Or they could be large, expensive modifications requiring changes in the boiler to offset expected de-rating.

Costs for modifying an existing gas or oil boiler to fire low- and medium-Btu fuel gas have been estimated for utility boilers. These costs can be applied to industrial boilers by assuming that the relative change in cost as a function of gas heating value is the same for both utility and industrial boilers. Based on this assumption, the cost of modifying a gas boiler to fire low-Btu gas at full capacity is over four times the cost of modifications to fire medium-Btu gas at full capacity. For an oil boiler the cost of modifications for low-Btu gas is over sixteen times that of medium-Btu gas. With such high modification costs, the use of the low-Btu gas is likely not economical.

Operating and maintenance costs will not change significantly as a result of switching from natural gas to medium- and high-Btu coal gas. (Combustion of these gases is similar to that of natural gas, in terms of flow rate, pressure drop, and heating value.)

Switching from Natural Gas and Distillate Oil to Biomass-Based Gas Firing

The gaseous fuel produced by gasification of biomass has properties similar to natural gas and can be burned in existing gas- and oil-fired boilers with minimum modifications. Like coal-based gas, biomass-based gas is suitable for use in gas turbine cogeneration systems, and it has benefited from investments made in developing coal-based gasification combined cycle (CGCC) systems (NREL 2003). As with coal gasification, the biomass gasification process is complex and involves many factors that must be examined when considering fuel switching. In addition to the gasifier processes and gasifier types discussed below, many of the considerations in the previous section are relevant here.

Gasification processes – In the gasification process biomass is converted with steam or air to a medium- or low-calorific gas. This conversion involves two basic processes: (1) pyrolysis and (2) char conversion.

Pyrolysis involves low-temperature heating to release volatile components, including hydrocarbon gases, hydrogen, carbon monoxide, carbon dioxide, tars, and water vapor. Biomass fuels have more volatile components (70 - 86% on a dry basis) than coal (30%), so pyrolysis plays a larger role in biomass gasification than in coal gasification. The non-vaporized component, char, consists mainly of fixed carbon and ash.

Char conversion involves the gasification of carbon remaining after pyrolysis (i.e., steam + carbon) and/or combustion (carbon + oxygen). The latter provides the heat energy to drive the pyrolysis and char gasification reactions. Due to the high reactivity of biomass compared to coal and other solid fuels, a biomass gasifier can convert all of the biomass feed, including the char, in a single pass.

Gasifier types – Biomass gasifiers fall into two main categories: (1) direct gasifiers producing low-Btu gas and (2) indirect gasifiers producing medium-Btu gas.

In *direct gasifiers,* the whole process—pyrolysis, gasification, and combustion—takes place in a single vessel. Air is fed into the vessel to drive the reactions, and nitrogen from the air has a diluting effect, causing the fuel gas to have a low heating value of 150 – 200 Btu/scf (5.6 - 7.5 MJ/Nm^3). As mentioned for conversion to coal gas, the cost of modifying a gas boiler to fire low-Btu gas at full capacity can be over four times the cost of modifications to fire medium-Btu gas at full capacity, making the direct biomass gasifier unfeasible for fuel switching.

In *indirect gasifiers*, the combustion takes place is a separate vessel from the pyrolysis and gasification reactions. An inert heat transfer medium, such as sand, carries heat from the combustion vessel to the gasifier vessel, to drive the pyrolysis and char gasification reactions. Because the fuel-producing reactions take place in a separate vessel, the product gas is free of nitrogen dilution and has a medium heating value of 350 - 503 Btu/scf (13 - 18.7 MJ/Nm^3). This heating value is sufficiently close to that of natural gas (1020 Btu/scf (38 MJ/Nm^3)) for economical conversion.

Switching from Natural Gas and Distillate Oil to Direct Biomass Firing

Switching from natural gas or distillate oil to direct biomass firing will require boiler replacement. Direct firing of biomass involves oxidation of biomass with excess air in one of the following common boiler designs:

- *Stationery gate combustors (Pile burners)* for wood combustion consist of a two-stage combustion chamber with a lower pile section for primary combustion and an upper secondary-combustion section located below the furnace and the boiler.
- *Traveling grate (Stoker) combustors* consist of a moving grate which permits continuous ash collection, thus eliminates the cyclic operation characteristic of the pile burners. These also give more efficient combustion because a stoker spreads the fuel more evenly and in a thinner layer.
- *Fluidized-bed combustors* for biomass use air as the fluidizing medium and the bed of sand or limestone. A change in cross-sectional area above the bed lowers gas velocity below fluidization and acts as a disengaging zone for introducing the over-fire air. A cyclone returns fines to the bed or removes ash-rich fines from the system.
- *Circulating fluidized bed combustors* allow easy introduction of an adsorbent such as limestone or dolomite to control SO_2 emissions without the need for back-end sulfur removal equipment.

The addition of wood chip dryers and incorporation of more-rigorous steam cycles to the current direct combustion systems is expected to raise their efficiency by about 10%. In bio-power generation systems, this increase in efficiency could lower the capital investment from the present $2,000/kW to about $1275/kW.

Also, the suspension burning of pulverized wood in the “dedicated biomass boilers” is a recent development which has also been accomplished in lime kilns. This direct combustion system will require the wood chip moisture content to be reduced from 50-55% to less than 15%, and a particle size less than 0.0015m, to raise boiler efficiencies from 65% to up to 80% in a stoker grate or a fluidized bed. The higher efficiency will result in a smaller furnace size but will be offset by the cost and power required for chip drying and comminuting, and the need for special burners such as the scroll-cyclonic and vertical-cylindrical burners.

The use of direct fired biomass combustion systems will require feedstock storage and handling systems such as wood chip feed, storage and feed conveyors, surge bins, and augers to meter chips to boiler stokers.

Switching from Natural Gas to Residual Oil

Only minor modifications may be required to convert an existing gas boiler to oil firing (EPA 1978). However, since the supply of oil is as unsure as the supply of natural gas, any conversion from natural gas to oil firing may represent only a temporary solution. Residual oil may contain significant quantities of ash and sulfur, but despite this, some conversion to residual oil may take place. The extent to which an existing gas fired boiler must be modified for conversion to residual oil depends on its original design. Each conversion will be site specific and require consideration of (1) furnace size, (2) oil storage, (3) boiler modifications, and (4) pollution control.

Furnace size – Oil, especially residual oil, has a higher furnace heat release rate than natural gas. As a result, for a given capacity, more heat will be absorbed in a furnace fired with residual oil than in a furnace fired with natural gas. Therefore, when a furnace is converted from natural gas to oil, de-rating will be necessary to maintain a safe furnace heat release rate unless the gas boiler was designed with a large safety margin. The amount of de-rating necessary will depend on how large a margin of safety is provided for the gas boiler relative to its design furnace heat release rate.

Oil storage requirement – The cost of installing oil storage tanks will one of the major expenditures for the conversion from natural gas to oil. A good design practice requires a 10 day storage capacity.

Boiler modifications – Because natural gas and residual oil burn with different flames and have different furnace heat release rates, boilers designed to burn these fuels are also different, and conversion of a gas boiler to residual oil may require modification of boiler internals. Also, ash present in the residual oil can deposit on the super-heater and re-heater tubes, reducing heat transfer. Coupled with the increased absorption in the radiative section of the furnace, this ash deposition makes it difficult to obtain design steam temperature at full load.

Because natural gas and oil burn with different flames and have different furnace heat release rates, boilers designed to burn these fuels are also different, and conversion of a gas boiler to residual oil may require modification of boiler internals. Ash from the residual oil can deposit on super-heater and re-heater tubes, reducing heat transfer in these convective sections. Coupled with the increased absorption in the radiative section of the furnace, this ash deposition makes it difficult to obtain design steam temperature at full load. The following major boiler modifications will be needed:

- Installation of new fuel supply lines and oil burners;
- Modification of boiler internals to accommodate different flames and heat release rates;
- Addition of heat transfer surface to the super-heater or the re-heater;
- Removal of heating surface from the furnace;
- Installation of particulate control and sulfur dioxide removal equipment;
- Soot blowers for super-heater, re-heater, economizer, and pre-heater sections;
- Modifications of the economizer and air pre-heater (more tubes, bare-tube instead of finned, addition of steam coil to prevent acid dew point corrosion of pre-heater); and
- Modifications of existing fans due to larger combustion air flow resulting in higher pressure drop.

Cost implications – According to an EPA study, modifications required for gas to oil conversion will have a capital cost less than 25% of the cost of a new gas-fired boiler (EPA 1978). This excludes the additional cost of outage time, which is generally equals about 3 weeks. Oil storage and handling costs represent 75% of the gas to oil conversion costs.

Operating and maintenance costs for oil boilers are nearly identical to those for gas boilers, and are relatively insensitive to boiler size below 100 million Btu/hr (30 MW) capacity. For boilers with capacities greater than 100 million Btu/hr, labor requirements begin to increase exponentially.

Environmental impact – Conversion from gas to residual oil could cause nitrogen oxide emissions to increase 3 times and sulfur dioxide emissions to increase significantly, while the other pollutants may not increase significantly. This conversion may require installation of particulate control and sulfur dioxide removal equipment. The need to dispose of byproducts or waste material produced by the flue gas de-sulfurization (FGD) system will limit its use on conversion boilers.

Switching from Natural Gas and Distillate Oil to Coal-Oil Mixture (COM)

Coal-oil mixture (COM) consists of finely ground coal suspended in oil. The mixture is a liquid slurry and is a potentially attractive method for firing coal in a gas or oil boiler. Many existing gas and oil fired boilers could be converted to COM (using coal-residual oil slurry) with a minimum of modifications, de-rating, outage time, and cost. However, this conversion will require consideration of: (1) COM preparation, (2) boiler modifications, (3) costs, and (4) pollution control.

COM preparation – Although COM preparation is fairly complex, it employs commercially available equipment. COM preparation requires facilities for receiving, storing, and handling the fuel, as well as mills for pulverizing coal. Coal concentration ranges from 5 – 20 percent by weight, depending upon the application. Higher concentrations may increase fuel viscosity, making the COM difficult to pump and adversely impacting system performance. Only operators of large boilers (125 – 625 million Btu/hr) will prepare COM on site, while others will purchase it from a large, central facility. COM can be prepared with coal particles ranging in size from 15 - 75 microns.

Boiler modifications required – Modifications to convert from gas to COM will be similar to those required for residual oil firing:

- Installation of COM supply and storage systems,
- Installation of oil burners,
- Modification of furnace or super-heater to obtain design steam temperature,
- Addition of soot blowers to remove ash deposits from convection tubes,
- Modification or replacement of economizer and air pre-heater to prevent acid corrosion, and
- Installation of an ash removal and handling system.

Cost implications – Two distinctive capital costs are associated with conversion from gas to COM: (1) the costs of boiler modification, and (2) the costs of COM preparation equipment. These costs increase exponentially with size. The loss of capacity due to boiler de-rating would create an additional cost which could exceed the cost of boiler modification.

The operating and maintenance costs associated with a COM-fired boiler should not be much different than those for a residual oil-fired boiler. However, problems of plugging and erosion of the burners, pipes etc., arising from the use of COM will dictate how much additional operations and maintenance costs are incurred. The cost of COM preparation can be also estimated as 2.3 percent of the annualized costs for COM boilers in the 340 – 44,000 million Btu/hr (100 to 13,000 MW) range (EPA 1978).

Environmental impact – Emissions from a COM boiler will vary, based on the sulfur content and other properties of the coal and oil used for preparing the COM. Depending on the fuel properties, equipment may be needed to control emissions of particulates and sulfur dioxide. Combustion modifications can be used to control emissions of nitrogen oxides.

Switching from Natural Gas and Distillate Oil to Coal-Based Liquids

Existing gas and oil boilers may be switched to coal-based liquids produced by coal liquefaction. Converting an existing gas-fired industrial boiler to coal liquids is not significantly different from converting a gas-fired unit to residual fuel oil. The important factors to consider are: (1) type of coal liquefaction process, (2) furnace size, (3) coal-liquid storage, (4) coal-liquid firing equipment, (5) boiler modifications, and (6) pollution control.

Coal liquefaction processes – In these coal liquefaction processes, solid fuels such as coal and oil shale are converted to a liquid fuel which has properties (e.g. viscosity, heating value) similar to fuel oils used by industrial boilers (EPA 1978).

- *Catalytic hydrogenation (H-coal)* – In this process, a slurry of pulverized coal and coal-derived oil is mixed with hydrogen and fed into reactor utilizing a hydro-sulfurization catalyst to increase the hydrogen transfer.
- *Solvent hydrogenation process* – In this process, no hydrogen or catalyst is used. Instead, a donor solvent, composed of organic compounds which boil at 400°F - 900°F, is used to provide hydrogen to free radicals as they break away from coal polymer. This solvent must be regenerated after hydrogen depletion.
- *Carbonization process* – In this process, heat is applied to coal, either without the direct addition of hydrogen (pyrolysis), or with the addition of hydrogen (hydro-carbonization). Most of the carbon is rejected as solid, but the liquid products that are recovered have higher hydrogen/carbon ratio than the original coal. The coal-to-liquid fuel conversion efficiency is low, and the carbonization process is therefore not suitable for producing an industrial boiler fuel.
- *Gasification to coal-liquid synthesis process* – Also known as the *Fischer-Tropsch synthesis process*, this process uses gasification followed by coal-liquid synthesis. However, it is very complex and the costs of producing liquid fuel by this process may not be competitive with those of the other liquefaction processes.

Effect of furnace size – Like oil and coal-oil mixture, coal-liquids have a higher furnace heat release rate than natural gas, and de-rating may be necessary to maintain a safe furnace heat release rate, unless the gas boiler was designed with a large safety margin.

Boiler modifications – The modifications required to convert from natural gas and distillate oil to coal-based liquids depend upon the composition and physical properties of the coal-derived liquid fuel. The modifications are similar to those required for coal-oil mixture and residual oil firing, and include the following:

- Installation of a coal-liquid storage system and coal-liquid supply lines (a minimum of 10 day fuel storage is necessary, and this may present problems at some industrial locations);
- Installation of burners that can accommodate coal-based liquid fuel instead of natural gas or distillate oil;

- Removal of heat transfer surface from the furnace to mitigate the reduced heat absorption by convective section that can occur due to deposit of ash from coal-based fuel;
- Addition of heat transfer surface to the super-heater or re-heater to maintain the steam temperature under the conditions of the higher heat release rates and the presence of ash;
- Addition of soot blowers to periodically remove ash deposits;
- Modification or replacement of economizer and air pre-heater; and
- Installation of an ash removal and handling system.

Cost implications – The two major costs associated with switching to coal liquid fuel are: (1) installing principal equipment to produce coal-liquid on site, or purchasing coal-liquid from a central supplier; and (2) converting existing natural gas- or distillate oil-fired boiler to coal-liquid firing. As an estimate, the conversion costs for switching a natural gas boiler to coal liquids may be similar to switching from natural gas to residual oil.

The operating and maintenance costs for combustion of coal liquid in an existing boiler will be essentially identical to combustion of residual fuel oil. Therefore, O&M costs should not change significantly when an existing gas or oil fired boiler switches to firing coal-liquid fuel.

Environmental impact – Conversion from natural gas to coal liquid will result in significant increases in emissions of particulates, sulfur dioxide, and nitrogen oxides, and pollution control equipment will be required. For conversion from distillate oil to coal liquid, the changes in emissions will not be nearly as significant. Conversion from residual fuel oil to coal liquid will cause no significant change in emissions of particulates, carbon monoxide, or hydrocarbons, but substantial reductions in emissions of sulfur dioxide and nitrogen oxide.

Switching between Natural Gas or Distillate Oil and Electricity

Industries could save millions of dollars a year in utility costs by considering fuel switching with electricity. Fuels that offer the best switching opportunities are those that are cyclical in cost and have opposing cycles, as do natural gas and electricity. Even though it requires separate gas and electric boilers, fuel switching between gas and electricity is an attractive option with the following advantages:

- Instead of purchasing firm gas, an interruptible rate can be obtained at a considerably lower cost;
- Operating redundancy is available in the event of a boiler failure; and
- Electric boilers can cost less than gas boilers to operate during much of the year.

Energy costs are seasonal: for gas use, peak season is winter, while electric use peaks in the summer. A fuel switching strategy compares the cost of electricity and the cost of gas and considers the efficiency of the gas boiler. The boiler, or the operating fuel, with the lowest operating costs can then be dispatched based on the breakeven point, i.e., electric during the winter months when the gas prices are higher, and natural gas when electricity prices go above a predetermined set point.

Electric equipment often has a lower upfront capital cost than natural gas equipment, so that even when the lifecycle cost of natural gas equipment is substantially lower, customers with a near-term perspective may choose the lower upfront cost.

Switching from Natural Gas and Distillate Oil to Solar Thermal and Wind

Renewable solar and wind energy could be used to replace natural gas with storage systems designed to store thermal energy at temperatures high enough to produce steam for industrial processes as well as for power generation, cogeneration, absorption refrigeration, and comfort heating systems. If the storage system can be designed to keep the heat losses from the system at a minimal level, it could be used, around the clock if necessary, to run an industrial or commercial boiler with a capacity of 3 – 200 MW.

The following case study provides an example of a thermal storage system suitable for industrial applications. This system may be installed as a retrofit to an existing gas-fired boiler, or may be installed in parallel with the existing gas boiler to provide the base load capability, while the existing boiler takes up the slack load. The Lloyd system also incorporates dual source capability, which facilitates fuel switching between electrical and thermal energy sources.

In regions where wind is available as a reliable resource, wind energy can be converted to electricity and then on to heat energy and stored. This stored energy could then be used to produce steam for industrial and commercial applications, as with solar energy.

CASE STUDY

Graphite Thermal Storage

Lloyd Energy Systems has developed a system for high-density storage of thermal energy in pure graphite. This system could provide a dependable power supply from cyclical energy sources, such as solar and wind energy. It can be used for distributed generation, and potentially supplying power for peak loads. The system uses either thermal or electrical energy as input, and provides either thermal or electrical energy as output.

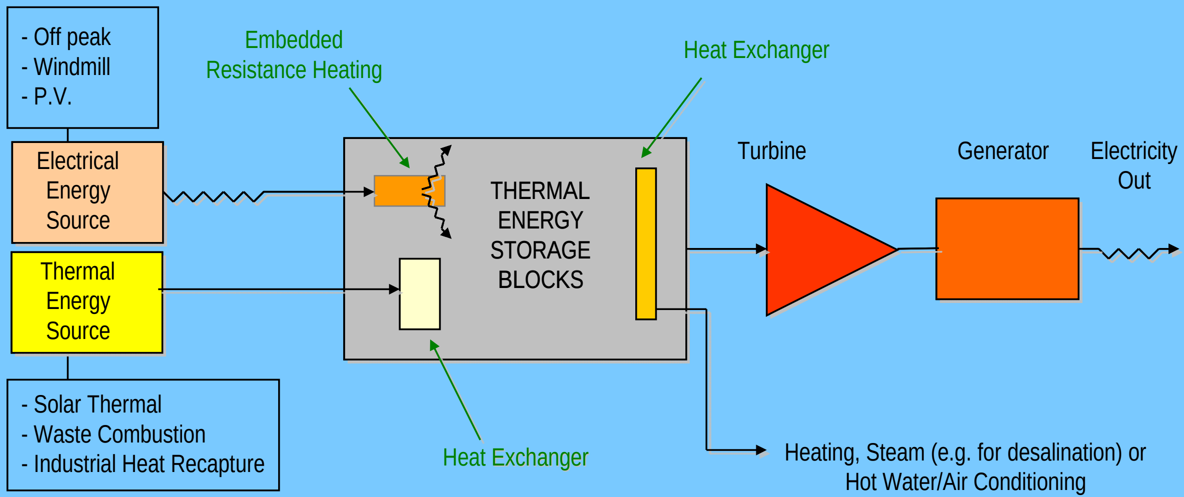
The energy storage system consists of a set of graphite blocks with integrated heat exchangers and heating element chambers. An operational demonstration unit uses 10 tons of graphite to store up to 4 MWh (see picture). The energy is extracted by heat exchangers and can be used to generate steam or electricity with a turbine generator unit.

High-purity graphite has a very high melting point (over 3500°C) and high specific heat, which allow an energy density over 10 times that of batteries. Lloyd Energy Systems has developed a patented process for producing this high-purity graphite economically.

The Lloyd system could use the intermittent electricity generated by wind turbines. Lloyd Energy Systems has worked with a partner solar energy company to design a concentrating solar thermal system that directly heats the Lloyd storage system to 800 - 1000°C.

Benefits of the Lloyd Energy Storage System

- High Efficiency – When used as a boiler, the Lloyd system has a 24-hour cycle efficiency of 98%.
- Rapid response – Graphite has a high thermal conductivity, so heat can be rapidly added to or drawn from the whole thermal mass.
- Long life – Graphite is thermally and chemically stable
- Input/output Versatility – The storage system can be configured for multiple energy types



Source: Lloyd Energy Systems

Switching from Natural Gas, Distillate Oil, and Residual Oil to Coal

Switching to coal from natural gas or oil by boiler modification is practically impossible due to the large extent of the modifications required.[2] Therefore, this section focuses on switching to coal by boiler replacement. In replacing an existing gas or oil boiler with a coal unit, several factors must be considered: (1) coal availability, (2) auxiliary equipment requirements, (3) type of replacement boiler, (4) costs, and (5) pollution control.

Coal availability – To maintain continuous production, the operator will need an adequate supply of coal and adequate transportation to deliver coal from the mine to the facility.

Auxiliary equipment – Coal handling, coal storage, and ash handling are necessary auxiliary equipment. These must be selected carefully to fit into available plant space, especially when the new boiler is placed in the same location.

Type of replacement boiler – To replace a gas or oil boiler, a stoker boiler is generally suitable for capacities below 250 million Btu/hr (75 MW) and pulverized coal boilers for larger units.

- *Spreader stokers* represent majority of new stoker-fired boilers having capacities of 5 - 500 million Btu/hr (1.5 - 150 MW). These are capable of burning coals from high-rank eastern bituminous to low-rank lignite. Because of fine ash in suspension, fly ash reinjection is used.
- *Mass burning stokers* are chain grate for bituminous coal or traveling grate for anthracite, and range in capacity from 7.5 - 250 million Btu/hr.
- *Pulverized coal boilers* have higher capital and operating costs and therefore are only economical in capacities above 250 million Btu/hr, even though they are 3-5% more thermally efficient than stoker-fired boilers.

Cost implications – Capital costs of a new coal-fired boiler will include: (1) direct costs of land, permits, yard work, fuel handling, storage, boiler house, boiler equipment, ash handling, and utilities; and (2) indirect costs associated with construction, engineering, contingency, and working capital. Pulverized coal boilers are more expensive, 20 to 25 percent higher than the cost of stoker-fired units.

Operating and maintenance costs for coal fired boilers are relatively insensitive to boiler size below 100 million Btu/hr (30 MW). However, above 100 million Btu/hr, these costs could increase rapidly, depending on the sulfur content of the fired coal.

Environmental impact – Replacement of a gas or oil boiler with a coal boiler will result in an increase in uncontrolled emissions. However, pollution controls to reduce these emissions are available:

- *Particulate control equipment* such as mechanical collectors to remove 98% of particulates larger than 5 microns, fabric filters and electrostatic precipitators to remove 99.5% and 99.9% of particulates, and wet scrubbers to remove over 99% of fly ash;
- *Physical coal cleaning* to remove up to 80% of pyrites comprising 20-80% of total sulfur content;
- *Chemical coal cleaning* to remove 90% of pyritic sulfur and 40% of organic sulfur; and
- *Flue gas desulfurization* (FGD) to reduce sulfur dioxide emissions by 90%.

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[2] An exception is the case of natural gas boilers that were originally designed to fire coal.

Fuel Switching Opportunities in Process Heaters

Overview of Industrial Process Heater Use

Over 220,000 process heaters are used in the domestic manufacturing sector (BNP 2005). Over 80 percent of these process heaters are ovens, heating furnaces, process fluid heaters, dryers, and heat treating furnaces. Other process heaters used in manufacturing include kilns and melting furnaces.

The distribution by heater type and industry is illustrated in Figure 19 and the data is presented in Table 2. The types of process heaters used by each industry vary significantly. The chemical industry uses many fluid heaters and dryers, while the electronics and food industries use many ovens. Note that the data gives the number of process heaters, not the capacity, and so emphasizes industries with many smaller heaters. The following section presents energy consumption and shows which industries are largest in terms of energy used for process heaters.

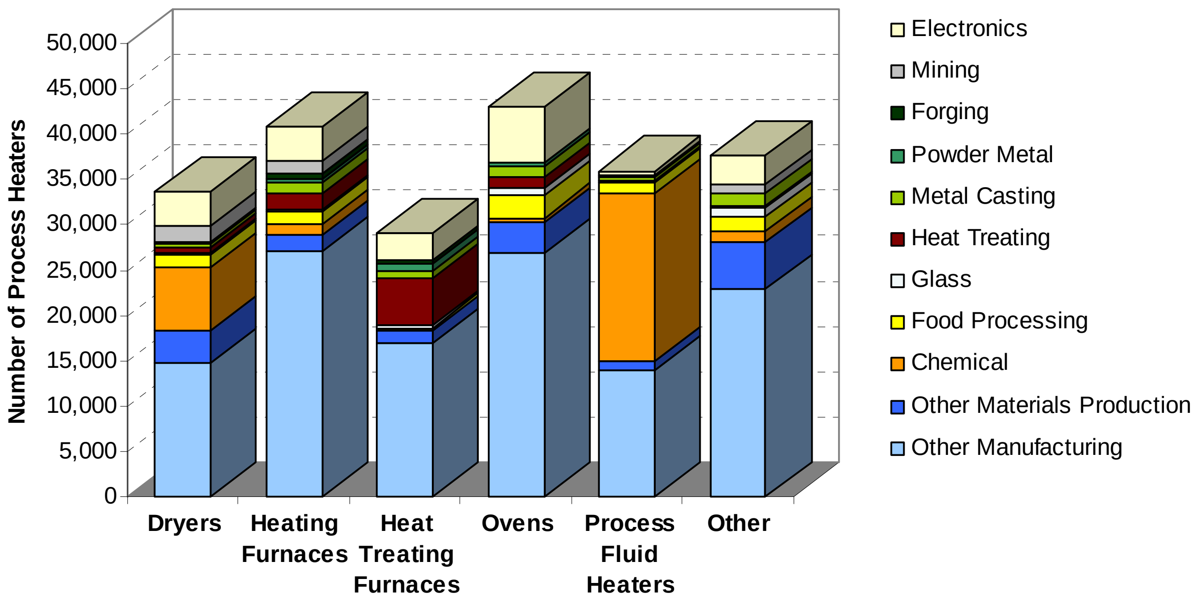

Figure 19. Process heater types and distribution by industry (BNP 2005).

Table 2. Process heater types and distribution by industry (BNP 2005).

Industry	Dryers	Heating Furnaces	Heat Treating Furnaces	Ovens	Process Fluid Heaters	Melters	Kilns	Other	Total
Iron & Steel	--	112	72	--	--	--	--	--	184
Aluminum	4	--	12	4	8	28	--	36	92
Petroleum Refining	28	16	--	--	--	--	--	--	44
Chemical	7,040	1,144	--	528	18,656	528	44	484	28,424
Cement	--	16	--	2	2	--	--	--	20
Food Processing	1,408	1,376	320	2,432	1,216	--	96	1,504	8,352
Glass	176	224	224	880	38	608	192	192	2,534
Heat Treating	648	1,728	5,184	1,224	72	24	72	120	9,072
Metal Casting	264	1,272	936	1,152	360	1,080	193	120	5,377
Powder Metal	264	456	744	312	--	--	48	--	1,824
Forging	--	576	360	12	--	12	12	--	972
Mining	1,776	1,392	24	96	192	--	960	24	4,464
Electronics	3,852	3,708	2,952	6,228	540	648	2,412	144	20,484
Other Materials Prod.	3,560	1,720	1,360	3,320	1,000	80	3,920	1,240	16,200
Other Manufacturing	14,688	27,064	16,864	26,928	13,872	9,656	2,040	11,152	122,264
Total	33,708	40,804	29,052	43,118	35,956	12,664	9,989	15,016	220,307

Table 3. Typical applications and materials processed by the main process heater types (BNP 2005)

Process Heater Category	Typical Applications	Typical Materials Processed
Dryers	Product drying, crystallizing, cleaning, coating	Metal parts, food, beverages, ceramics, clay, paper, air, coatings
Heating Furnaces	Preheating, electrical process heating, part warming, pasteurizing	Aluminum, steel, other metals, ceramic, graphite, ceramics, mineral products
Heat Treating Furnaces	Annealing, carburizing, hardening, austenitizing, stress relieving	Steel, iron, copper, brass, other metals and alloys, glass, ceramics
Ovens	Curing, baking, tempering, cleaning, testing, printing	Ceramics, food, electronic components, coatings, composites, metals, plastics
Process Fluid Heaters	Reaction, separation, cleaning	Water, oil, beverages, other chemicals
Melters	Melting, re-melting, reducing	Aluminum, glass, other metals, minerals
Kilns	Calcining, Sintering	Ceramics, limestone, iron ore

Fuel Consumption of Process Heating Equipment

Fired heaters in the U.S. manufacturing industries consume 6,170 trillion Btu per year, about 38 percent of the total energy consumption of the sector. As shown in Figure 20, natural gas and other fuels, such as by-product gases, constitute over 85 percent of the fuel used for process heaters. Petroleum and natural gas liquids only account for 2 percent of process heater fuel use. The energy use per unit of production is highest for heating furnaces, followed by melting furnaces, and kilns.

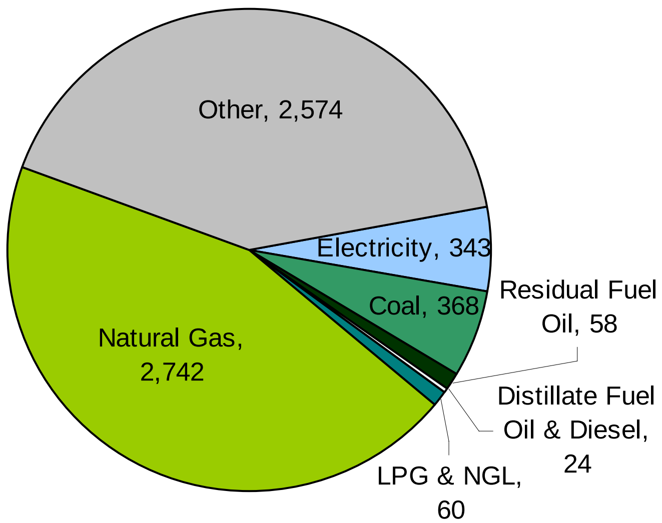

Figure 20. Fuel consumption by fuel type for fired process heaters in the U.S. manufacturing sector, in trillion Btu/year (Analysis based on EIA 2005b).

Three industries—petroleum refining, chemicals, and steel—consume over 60 percent of the manufacturing total. The ten industries with highest fired heater energy consumption are shown in Figure 21.

Petroleum Refining – The petroleum refining industry consumes 1,717 trillion Btu/yr for fired heaters, mainly heating furnaces and dryers. This energy consumption represents 56 percent of its total fuel energy consumption

Iron and Steel Industry – Over 75 percent of the iron and steel industry energy input is consumed in fired heaters, mainly heating furnaces and heat treating furnaces.

Chemical Industry – The chemical industry uses a variety of process heaters, especially process fluid heaters and dryers. The energy use for process heaters (996 trillion Btu/yr) accounts for 26 percent of the chemical industry total fuel use, and includes 588 trillion Btu/yr of natural gas.

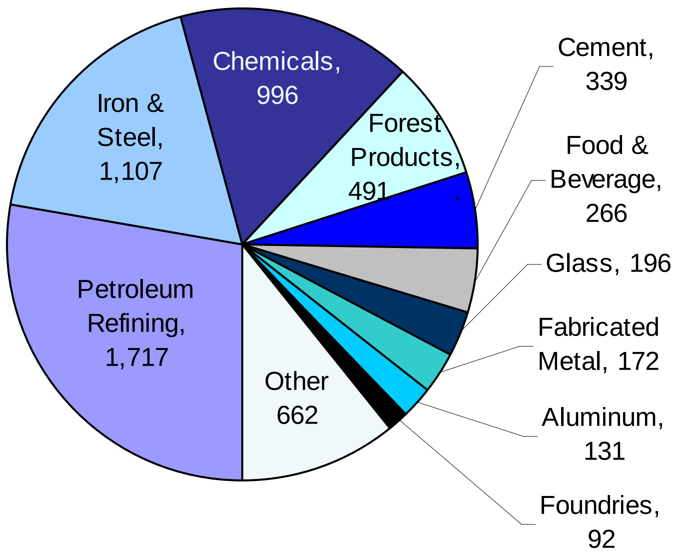

Figure 21. Fuel consumption for fired process heaters, showing the ten manufacturing industries with largest consumption, in trillion Btu/year (Analysis based on EIA 2005b).

Forest Products Industry – Only about 18 percent of the forest product industry energy input is used for fired heaters, but this still amount to 491 trillion Btu/yr. This industry mainly uses process heaters and dryers for its manufacturing processes.

Cement Industry – The vast majority of the cement industry's energy input is used for fired heaters (largely heating furnaces)—about 83%.

Food and Beverage Industry -- This food and beverage industry uses many ovens, dryers, heating furnaces, and fluid heaters. These consume 266 trillion Btu/yr, or 22 percent of the industry's total energy input.

Prospects for Fuel Switching in Process Heating Equipment

This subsection identifies possible fuel switching alternatives for process heating equipment. The cost implications and environmental impacts correspond to similar concerns identified in the previous chapter on boilers. As with the previous chapter, this section provides qualitative information to help select suitable methods for fuel switching, but does not include the quantitative information on the cost and environmental impacts of fuel switching, due to lack of available information. A detailed analysis of current technical and economic factors, as well as environmental regulations and fuel prices, is required to obtain reliable quantitative information. (EI 2004)

Natural Gas to Residual Oil

Residual oil can be substituted for natural gas in most fired process heaters, including refinery heaters, dryers, lime calcining furnaces, and kilns. As with boilers, only minor modifications are required to convert existing gas-fired process heating equipment to oil, and operations and maintenance costs are identical. The various technical, cost, and environmental concerns and solutions associated with fired heaters will be similar to those for boilers. These issues include furnace de-rating, oil storage, differing flame qualities and heat release rates, and emissions of ash, particulates, nitrogen oxides, and sulfur dioxide.

Natural Gas to Coal-Based Gas

Medium-Btu coal-based gas can be substituted for various gas-fired process heaters. As with boilers, the existing gas/oil fired process heating equipment can be converted to coal gas firing with minimum modifications. The concerns involved with fuel switching are also similar to those described for boilers: higher fuel flow rates for coal bas; burners and fuel supply headers modifications to accommodate different burning; furnace de-rating due to increased flow to burners; and emission controls required for particulate matter, sulfur dioxide, and nitrogen oxides. The cost implications are similar to boilers, with operations and maintenance costs remaining identical to those for natural gas.

Natural Gas to Biomass and Biomass Gas

Large gas-fired furnaces may be replaced with fluidized bed biomass furnaces using solid biomass. Also, woodchips and pellets can be used to substitute for gas-fired stoves for heating. Biomass-based gas can be used more broadly, substituting for various gas-fired dryers, heating and heat treating furnaces, cement kilns, indirect fired melting furnaces, process heaters, etc.

The gaseous fuel produced from biomass has properties similar to natural gas and it can be burned in the existing gas/oil process heating equipment with minimum modifications. The important concerns for fuel switching are similar to those for boilers: significantly higher fuel flow rates for biomass gas, modification of existing burners and fuel supply headers, furnace de-rating due to increased gas flow, and emissions of particulates, sulfur dioxide, and nitrogen oxides. The cost implications will also be similar to those for boilers.

Natural Gas to Solar-Thermal and Wind Based Systems

Solar-thermal and wind-based heating systems can supply heat to low temperature industrial processes and therefore be substituted for gas-fired pre-heating furnaces, dryers, process heaters, hot forging furnaces, curing, part warming heaters, water heaters, calcining kilns, sintering furnaces, baking ovens, plating heaters, and others.

As with boilers, in regions where wind is available as a reliable resource, the wind energy can be converted to electricity and then on to heat energy and stored for supplying heat to the process heating equipment. The wind to thermal energy could also be a suitable option for large industrial plants where a wind farm could be constructed on site or electricity purchased from an off-site central wind generation facility.

Natural Gas and Distillate Oil to Electricity

Electric process heating equipment can be substituted for gas-fired aluminum smelting furnaces, and a wide variety of dryers, curing ovens, heating furnaces, and melting furnaces. As with boilers, if process heaters are furnished with dual fuel capability, fuel switching between gas and electric will be economically attractive and offers several advantages:

- Instead of purchasing firm gas, an interruptible rate can be obtained at a considerably lower cost;
- Operating redundancy is available for the event of process heating equipment failure; and
- Electric heating equipment may have lower operating costs than gas equipment for much of the year.

Electric equipment often has a lower capital cost than natural gas equipment, so that even when the lifecycle cost of natural gas equipment is substantially lower, customers with a near-term perspective may choose the lower upfront cost. In some applications, switching to electric can save energy and thus reduce the lifecycle cost (e.g., microwave heating and drying in the following case study).

Electricity to Natural Gas and Other Fuels

Electric process heaters are currently used for many specialized applications, such as electric arc furnaces for steel-making, induction heaters for the aluminum industry, ultra-violet curing, plasma gas heaters, and microwave ovens for cooking and drying. Many of these applications make use of the high heating rates and efficiency of electric heating to reduce energy consumption. In others electricity can be irreplaceable because of size restrictions or contamination concerns. Switching from electric to other fuels may have greater effects on productivity and product quality than other fuel switching options.

Although in many specialized cases electricity may be irreplaceable, in many other cases the higher operating costs with increasing electricity prices may provide sufficient motivation for switching to alternative fuels. This may be particularly true for cases where electric heaters were initially installed because of lower capital costs. In a life-cycle cost analysis, the capital cost of a process heater often accounts for as little as 3 percent of the total cost, while fuel costs account for 96 percent (DOE 2004).

Aside from electric arc furnaces and other special large applications, electric process heaters are typically smaller units, so natural gas would be a suitable alternative, as well as other gas or liquid fuels, depending on availability. In some cases the electric heating equipment may be retained to allow dual-fuel capability and the economical advantages of short-term fuel switching.

CASE STUDY

Microwave Process Heating

Microwave ovens are used widely in the residential and commercial sectors for food heating. Continued research in microwave heating has demonstrated a broad range of industrial applications in which microwave processing can save energy, increase production, and improve product quality. Microwave heating can achieve temperatures up to 2000°C, and has been demonstrated for sintering, brazing, and melting processes. Microwave heating was initially not considered applicable for metals, but research at Pennsylvania State University has demonstrated that all common metals can be heated by microwaves if in powdered form or if preheated to about 400°C.

Benefits of Microwave Heating

- Increased Production – Microwave heating depends on direct influence of electric and magnetic fields on the material. It is, therefore, much more rapid than conventional heating schemes, which rely on radiation and convection heat transfer.
- Reduced Energy Consumption – Microwave heating eliminates losses associated with combustion, exhaust gases, and longer processing times.
- Reduced CO_2 Emissions – Reduced CO_2 emissions are linked to energy savings and elimination of carbon burnout.
- Improved Product Quality – Rapid heating can produce finer, more homogenous microstructure and improved physical properties.

MicroCure™ Variable Frequency Furnace – This commercial furnace is used for electronics manufacturing and other materials processing applications. It reduces curing time by 95% and saves an estimated 200 million Btu per year. Lambda Technologies developed the furnace with Industrial Technologies Program support and now has 80 commercial systems in operation.

Sources: Pennsylvania State University (Agrawal 2006) and Lambda Technologies

Fuel Switching Opportunities in Power Generation

Overview of Industrial Power Generation

In 2002 the manufacturing industries generated 134 billion kWh of electricity on-site, providing 14 percent of the total electricity demand for these industries. The vast majority of industrial power generation (93 percent) employs cogeneration (or combined heat and power) to supply plant heating needs with waste heat from power generation. The chemical and paper industries produce the most on-site electricity, together generating 100 billion kWh, or 75 percent of the manufacturing industry total.

Conventional industrial power generation systems typically use boilers to generate steam for turbine generators in a Rankine power cycle. Fuel switching in these systems affects only the boiler, so they are included in the previous discussion on industrial boilers.

Recent developments in combustion turbines have allowed higher efficiencies for electrical generation and cogeneration. Combined cycle power systems use high-pressure exhaust gases to run combustion turbines in a primary power cycle and then use the remaining heat to drive a secondary vapor power cycle. Fuel switching in these systems is given further attention below.

Microturbines are small gas combustion turbines that are well suited to run on a variety of gaseous and liquid fuels. The following case study provided further details on fuel switching with microturbines.

CASE STUDY

Fuel Switching with Microturbines

Microturbines do not currently account for a large part of industrial energy consumption, but they are an important, growing cogeneration option with great potential for fuel flexibility. Numerous projects have used biogas, landfill gas, and other waste fuels in microturbines. Turbine manufacturer Turbec lists natural gas, diesel, ethanol, and biogas as potential fuels for its microturbines.

Efficient small-scale generation – The power generation efficiency of a microturbine is about 30 percent, but the efficiency jumps to about 80 percent for combined heat and power applications. Most units come in models ready for direct process heating or water heating. Microturbine units come in sizes down to 30 kW, so can be used in many applications where larger cogeneration systems are not economical.

Sources: U.S. Environmental Protection Agency (EPA 2002) and Turbec AB (Turbec 2006)

Integrated Combined Cycle Power Generation Systems

Natural gas combined cycle (NGCC) power generation systems have improved the efficiency of natural gas power generation by 15 percent. The combined cycle power plant has also been under development for solid fuels, particularly coal: integrated gasification combined cycle (IGCC). Significant economic and environmental impacts must be considered for switching to IGCC systems.

Cost Implications – Large coal- or biomass-based integrated gasification combined cycle (IGCC) systems could replace current natural gas combined cycle (INGCC) systems, but will require large capital investments and will demand strong insight into future industry conditions. As a consequence, many uncertainties will need to be considered in making economic comparisons for these large systems (DOE 2004):

- Future electricity demand and price,
- Changes to the environmental regulatory framework under which the power industry operates,
- Technological advances in the proposed system and power industry technology alternatives, and
- Future fuel prices.

According to a 2003 U.S. Senate Committee on Energy and Renewable Resource report, the operations and maintenance costs of coal gas combined cycle systems are somewhat higher than conventional pulverized coal system, but were offset by lower fuel costs and lower environmental treatment and waste disposal costs.

Environmental Impact – Combined cycle systems firing coal gas produce more emissions than natural gas systems. However, if compared with conventional pulverized coal generation, the environmental benefits associated with coal gasification are: (1) lower air pollution in the short-term; and (2) more cost-efficient CO_2 capture and sequestration in the long-term. In coal gasification process, it is possible to remove the sources of SO_2 and Hg and the CO_2 from the synthesis gas before combustion when it is much easier and thus less expensive to remove. Also, because the syngas is much cleaner than the raw coal itself, lower quantities of NO_x and particulate matter are produced during the combustion process. Also, there is minimal solid waste generation and water consumption.

Feedstock Switching Opportunities

The fuel switching opportunities described in previous chapters involve the major energy-consuming equipment used across industry: boilers, process heaters, and power generators. This equipment does not change greatly between various applications, so a broadly-applicable discussion is possible. When considering switching opportunities for feedstocks in the chemical industry, large differences between various chemical processes preclude a similar general discussion. In combustion applications, the fuel heating value is the primary concern. For chemical processes, the exact chemical composition of the feedstock is crucial, so a different fuel may require an entirely different process.

The two case studies below illustrate applications of coal- and biomass-based feedstocks, two primary alternatives that are used commercially. They also cover two of the largest markets in the chemical industry: fertilizers and plastics for packaging.

CASE STUDY

Fertilizers from Coal

High natural gas prices have generated much interest in coal-based feedstocks in the fertilizer industry. The two U.S. facilities that currently produce fertilizer from coal or petroleum coke are highlighted below. Others are following their lead, including an 830 ton/day fertilizer plant in Illinois, which Rentech, Inc., bought in April 2006 and plans to convert from natural gas to coal gas.

Dakota Gasification – The Great Plains Synfuels plant began operations in 1984, and since 1988 has been owned by Dakota Gasification. The facility uses local lignite coal to produce 54 billion cf of synthetic natural gas. The plant also produces 400,000 tons/yr of anhydrous ammonia, ammonium sulfate fertilizer (by a flue gas desulfurization system), and several other by-products.

Coffeyville Resources – Full-scale operations for this Coffeyville, Kansas, plant began in 2003. The plant gasifies petroleum coke from an adjacent refinery using a partial oxidation gasification process to produce a hydrogen-rich synthesis gas. The synthesis gas is converted to ammonia, yielding over 400,000 tons per year. Two thirds of the ammonia is upgraded to produce 660,000 tons of urea ammonium nitrate (UAN) solution.

Sources: Environmental Observatory (EO 2006), Dakota Gasification (DG 2006), and Coffeyville Resources (CR 2006)

CASE STUDY

Plastics from Corn

Polylactide (PLA) is a polymer derived from renewable biomass that can be used to produce packaging, food serviceware, flim, and fibers for fabric and carpeting. PLA matches or exceeds the performance of other petroleum- and natural gas-based plastics, but is based on corn-derived lactic acid monomer. NatureWorks, LLC, used Industrial Technologies Program funding to improve the processing technology, and is now operating a 300 million pound per year PLA plant.

Annual U.S. thermoplastic production from oil/natural gas totals 60 billion pounds. Projections indicate that PLA could replace 10% of non-renewable plastic packaging.

Benefits of PLA

- Reduces Energy Consumption – PLA requires 20 - 50% less fossil fuel energy to produce than comparable thermoplastics.
- Reduces CO_2 emissions
- Biodegrades on disposal – PLA is meets criteria for U.S. composting facilities.

Source: NatureWorks, LLC

Summary of Benefits & Barriers to Fuel Switching

Fuel switching from natural gas and oil to coal, residual oil, and biomass fuels in industrial applications will support DOE's energy efficiency and renewable energy efforts to reduce the demand and wholesale prices of natural gas and oil in the United States. However, the implementation of fuel switching options discussed will face a variety of issues, including fuel and fuel transportation availability, transportation and storage of conversion fuels, costs of emissions control, costs of conversion, loss of capacity due to equipment de-rating, and limitations of plant space. While fuel switching can create business and commercial benefits nationally, it does not provide a direct energy saving benefit to the industrial manufacturing or commercial facilities except for cases where a primary fuel is switched to a waste or a byproduct fuel.

Benefits of Fuel Switching from Natural Gas

By contributing to the reduction of wholesale natural gas prices, multi-fuel firing or fuel switching from natural gas to other alternate fuels in industrial manufacturing facilities will result in substantial benefits to industry:

- Allow domestic industrial natural gas consumers to become more competitive in the world market;
- Shift chemical production, which requires natural gas as a feedstock, back to U.S. plants from foreign sources which currently have lower feedstock costs; and
- Reduce the cost of nitrogen fertilizer for U.S. agriculture, as natural gas is the main feedstock for the fertilizer industry.

The benefits of reducing gas prices will accrue not only to gas consumers who employ fuel switching, but also to all other natural gas consumers. Industrial fuel switching will have several key benefits for other sectors:

- Reduce fuel costs for natural gas in the electric power sector, keeping electricity prices more affordable;
- Help the U.S. natural gas supply to meet the projected growth in residential and commercial demand of almost 1 trillion cubic feet from 2004 to 2015; and
- Assist in the transition to the expected hydrogen economy through the initial use of natural gas as the primary hydrogen feedstock.

Only minor modifications may be required to convert an existing gas-fired boiler to oil, COM, or medium- to high-Btu biomass and coal gas firing, because these fuels, unlike solid coal, have properties similar to natural gas and can be burned in the existing gas fired boilers with minimum of modifications. Modifications to converting to COM will be similar to those for converting to oil.

Switching to distillate and residual oil could result in significant natural gas savings. Cambridge Energy Research Associates (CERA) estimates that focused investment in switching to residual oil could allow natural gas saving up to 1.3 billion cf/day. Switching to distillate oil could also save nearly 1.3 billion cf/day. However, this switching to distillate oil would create an additional demand of over 200,000 barrels per day in a U.S. distillate oil market of 3.8 million barrels (CERA 2000).

Conversion from natural gas to electricity in industrial boilers and heaters, where gas and electric costs are cyclical, and where they have opposite cycles, offer several advantages:

- Instead of purchasing firm gas, an interruptible rate can be obtained at a considerably lower cost.
- Operating redundancy is available in the event of equipment failure.
- Electric boilers can cost less than gas boilers to operate during much of the year.

The example of microwave heating provides an illustration of how fuel switching also has the potential for significant energy savings. Although microwave heating uses electricity, and thus involves generation losses, it is well suited to some material processing applications and gives higher overall efficiencies than traditional furnaces, which rely on radiative and convective heat transfer. However, the various fuel switching options discussed in this report are not specifically intended to save energy. These options primarily displace high-priced fuels with lower-cost alternatives, thus conditioning demand for the high-priced fuels, and thereby impacting the price of these fuels. Any energy savings through increased efficiency is secondary, and is not the focus of this report.

Barriers to Fuel Switching from Natural Gas and Oil

Switching from natural gas to liquid or solid fuels presents several challenges:

- Fuel storage is required for at least a 10 day capacity according to appropriate design practices (for switching a natural gas boiler to oil, this storage expenditure can run up to 75 percent of the total boiler modification cost);
- A suitable fuel source and adequate transportation is required, especially for coal;
- Equipment de-rating may occur due to higher furnace heat release rates and presence of fuel ash associated with coal, biomass, oil, or coal-oil mixture.
- Equipment for these fuels is physically larger than for a gas-fired system of the same capacity, potentially creating problems for replacing units where there is limited plant space available.

Switching from natural gas to distillate oil presents some additional problems (also relevant to a lesser degree for coal-oil mixture):

- Operations and maintenance costs for gas and oil boilers are nearly identical and relatively insensitive to boiler capacity below 100 million Btu/hr, but for boilers larger than 100 million Btu/hr, labor requirements for oil units begin to increase exponentially;
- Switching from natural gas to distillate oil, to the theoretical limit of 1.3 Bcf per day, will create additional distillate demand over 200,000 barrels per day, a significant increase in the U.S. market of 3.8 million barrels; and
- The supply of oil is as unsure as the supply of natural gas, and any conversion from natural gas to oil may represent only a temporary solution.

Natural gas is a very clean-burning fuel, and switching from natural gas to the other solid, liquid, and solid-based gas fuels could result in higher pollutant emissions and directly impact on the air quality levels. Nitrogen oxide, sulfur dioxide, and particulates are particular concerns. Equipment to control these emissions exists, but adds another cost to fuel switching.

Technology Development Needs for Fuel Switching

To assess technology development needs for enhancing fuel switching, it will be important to explore joint programs with the DOE Office of Fossil Energy (FE) Clean Coal Program and the other DOE EERE programs. Technology areas in which joint programs could result in large natural gas savings include coal gasification, biomass gasification, and solar-thermal and wind resource systems programs. Efforts for establishing joint programs with the DOE Office of Fossil Energy (FE) are already going on in the areas of industrial coal gasification and synthetic gas combined heat and power systems.

To establish joint programs for alternate fuels other than one for coal-based gas, it will be important to first carry out the following analyses: (1) technical/economic and market assessments of selected technology areas to determine where research will have the most economic impact in industrial sectors, and (2) detailed analyses to understand specific technical, economic, and environmental issues, and the impact of fuel switching on the future demands and prices of substitute fuels. The costs and environmental implications of fuel switching from natural gas and oil to various substitute fuels are described in the chapters on boilers and process heaters, which can be used as a template for calculating the costs of modifications and replacement.

Further, joint meetings and workshops will determine what specific research may be needed in each technology area. The following DOE offices appear to be most suitable for partnerships for developing the fuel switching technologies of common interest:

- DOE-FE Clean Coal Program for coal gasification;
- DOE-EERE Biomass Program for biomass gasification;
- DOE-EERE Solar Energy and Wind & Hydropower programs for solar-thermal and wind resource storage and electric conversion; and
- DOE-OE (Office of Electricity Delivery and Energy Reliability) Distributed Energy Program.

Workshops may be held for individual equipment types, or combined workshops may be held to include both boilers and process heating equipment. During these workshops and the prior joint meetings, discussions may be focused on:

- Market conditioning strategies to attract U.S. manufacturing plants to adopt newly developed technologies (such as coal and biomass gasification); and
- Developing system improvement technologies (retrofit or modification technologies) and system advancement technologies (replacement technologies), with the objective of creating multiple-fuel firing capability, and thereby reducing the natural gas, distillate, and purchased electricity demands, based on choice, in the U.S. industrial sector.

Following are some examples of the system improvement technologies that are likely to be of common interest to potential DOE partners and therefore may be considered for further discussions:

- *Single- and multiple-fuel burners for firing gaseous conversion fuels (such as coal gas, biomass gas, and byproduct gases, such as refinery gas, coke oven gas and blast furnace gas) in existing natural gas boilers and process heaters.* To accomplish this switching the conversion gas must be available either from a central facility in the area, or from an onsite generation system. Coal and biomass gas fuels having low heating values would be less suitable for this conversion. If medium to high heating value gaseous conversion fuels are available, the conversion from NG, in some cases, could be accomplished simply by making modifications to the existing gas burners and the fuel supply headers. The potential applications of these new burners are small boilers (10 - 100 million Btu/hr) in the food industry, the non-manufacturing industry, the primary metals industry, and commercial buildings, and large boilers (greater than 100 million Btu/hr and 250 million Btu/hr) in the chemical and refining industries.

- *Single- or multiple-fuel burners for firing liquid conversion fuels (including residual oil, coal-oil mixture, and coal-based liquid) in existing natural gas boilers and process heaters.* Switching to liquid conversion fuels is possible by modifying the existing equipment. The potential applications of these new burners are via boiler conversions to residual and COM firing in the chemical and refinery industries, and via boiler conversions to residual fuel firing in the primary metals industry and commercial facilities.
- *Technologies or methodologies for reducing the operating costs of controlling the particulate matter and sulfur dioxide emissions* resulting from the conversion from NG to residual oil, coal-oil mixture, coal gas, and biomass gas.
- *Modifications and methodologies for mitigating the de-rating effects of boiler conversions* from natural gas to coal and oil fuels—on super-heaters, re-heaters, economizers and scrubbers (e.g., adding soot blowers, fuel preparation, new coal pulverizing designs, spiral-wound furnace tubes, PTFE-covered heat-exchanger tubes, and oxygenated water-treatment to control corrosion).
- *Automatic scheduling in boilers and process heaters* designed to fire different fuels or NG blended with other fuels.

Following are some examples of the system advancement technologies that may be also likely to be of common interest to potential DOE partners and therefore considered for further discussion:

- *Dual- or multiple-fuel boilers and process heaters for firing gaseous fuels, including natural gas, coal gas, and biomass gas.* For boilers, this may involve developing compact designs such that the boiler can be mounted along side the existing natural gas boiler and connected in parallel to take up the base load (e.g., spiral tube designs for the boiler section).
- *Dual or multiple-fuel boilers and process heaters for firing natural gas and liquid fuels, including residual oil, COM, and coal-based liquid*. For boilers, this may involve developing compact designs such that the boiler could be mounted in the space occupied by the existing natural gas boiler, or along side the natural gas boiler and connected in parallel to take up the base load).
- *Compact, high-efficiency direct coal-fired process heaters.* Many industrial facilities may consider replacing larger process heaters with equipment that uses alternative solid fuels including direct coal and direct biomass.
- *Compact, high-efficiency direct coal-fired boilers that could replace existing natural gas boilers and fit into the space occupied by the gas boilers.* Converting from oil and natural gas to direct biomass, direct coal, or electricity would only be possible by replacing the boiler. Many industrial facilities may also consider replacing larger boilers with equipment that uses alternative solid fuels including direct coal and direct biomass.
- *Suspension firing kilns and boilers, and special burners required for this method of burning pulverized wood, bagasse, and dedicated biomass.*
- *Compact single- or multiple-fuel gasification systems for the onsite generation of fuel gases from solid fuels such as coal, biomass, and black liquor.*

To enhance market penetration of new conversion technologies, such as integrated coal and biomass combined cycles, pulverized coal combustion, and suspension burning, studies will be needed to determine market penetration strategies for individual cases. These studies will analyze potential market penetration under different scenarios of environmental requirements, technology progression/ advancement, natural gas prices, and policy incentives (loan guarantees, tax incentives, etc.).

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Appendix: Cost Implications for Boiler Fuel Switching

The following plots are taken from a 1978 study on fuel switching in boilers conducted by the Environmental Protection Agency (EPA 1978). Although the cost information is out of date, the qualitative relationships shown in these plots are still valuable. The basic technology used in industrial boilers has not changed greatly since this publication.

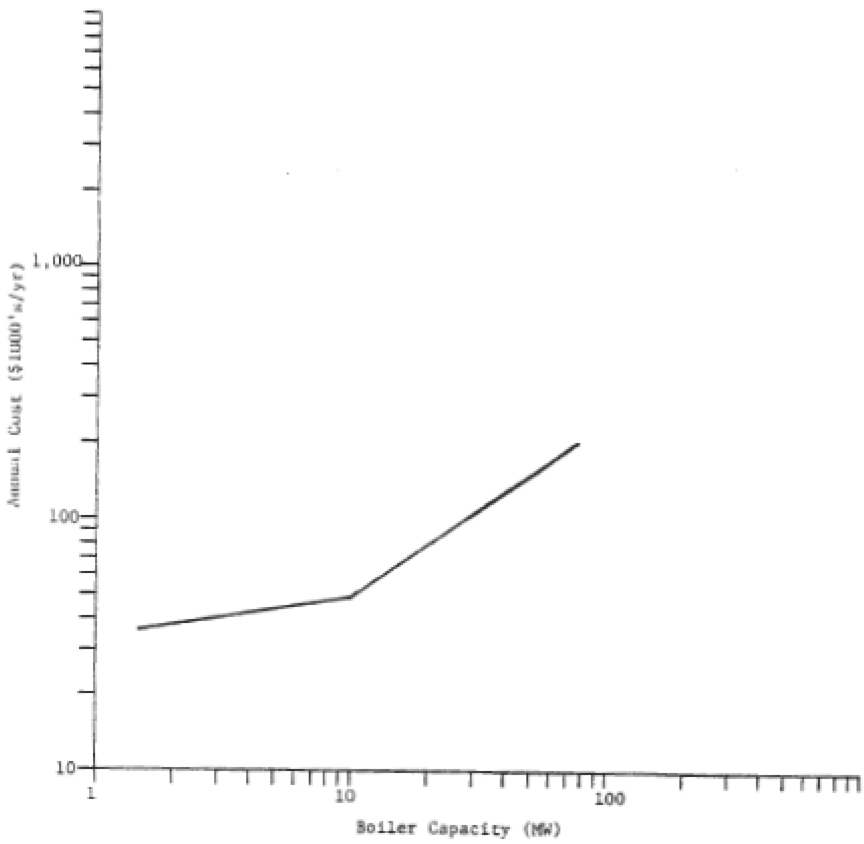

Figure 22. Estimated operating and maintenance costs for a gas- and oil-fired boiler, with a load factor of 4000 hr/yr at 100 percent capacity (EPA 1978)

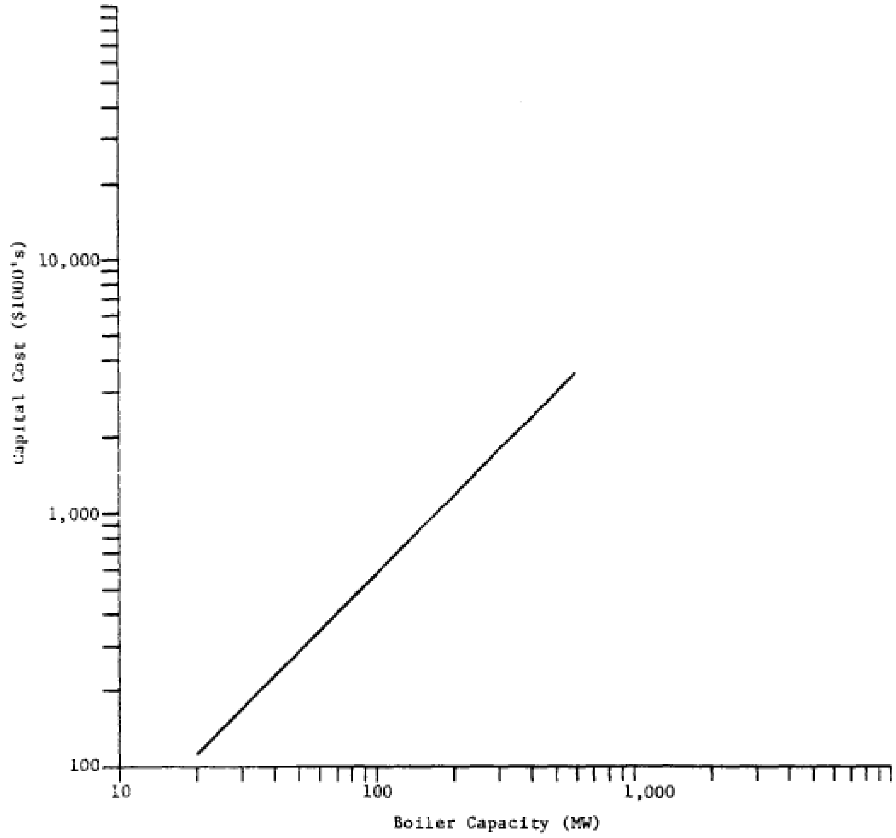

Figure 23. Estimated capital costs of a gas to oil conversion based on new boiler costs, in 1978 dollars (EPA 1978)

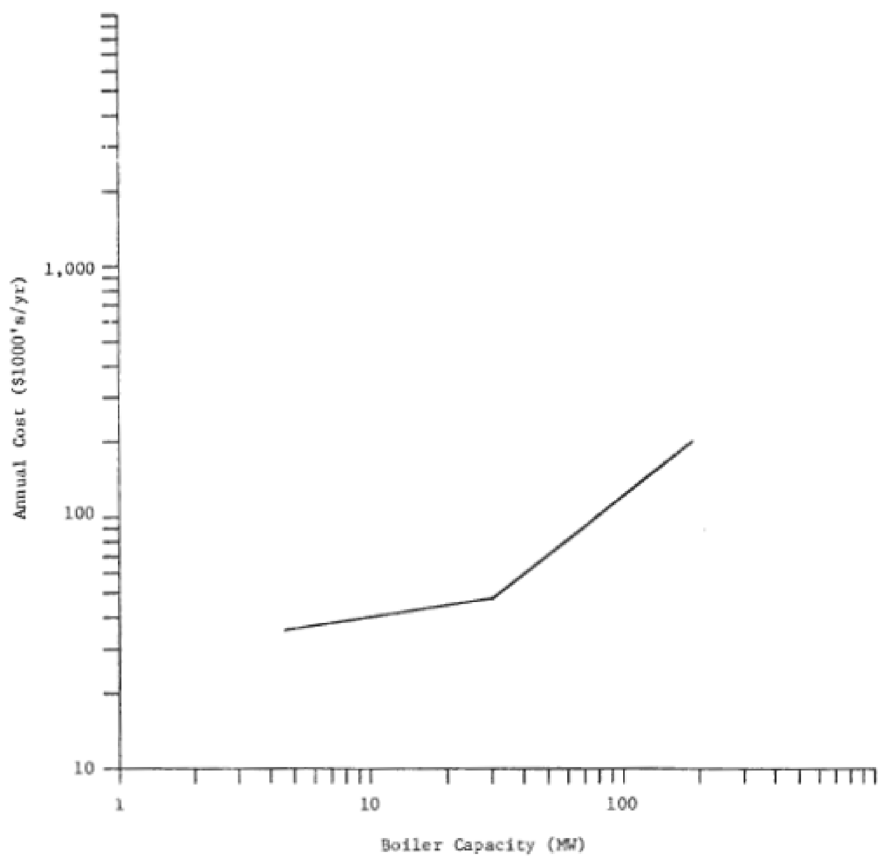

Figure 24. Estimated capital costs of a gas to oil conversion based on oil storage costs, in 1978 dollars (EPA 1978)

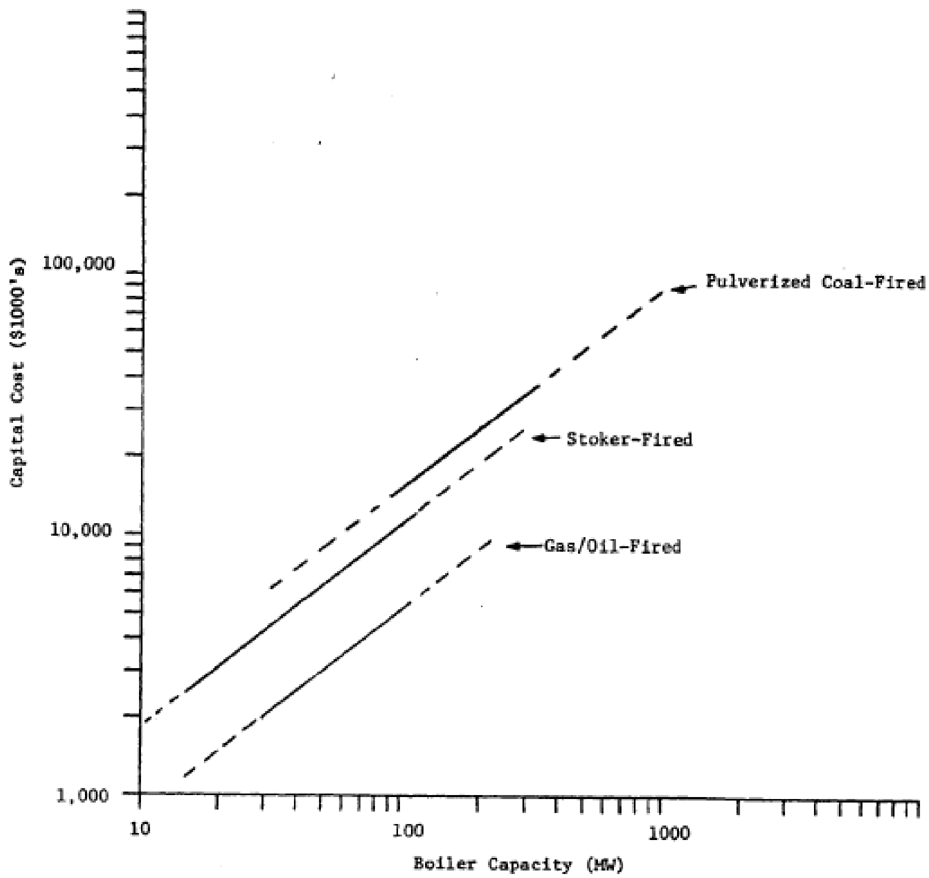

Figure 25. A comparison of stoker-, pulverized coal- and ga/oil-fired boiler capital costs, in 1978 dollars (EPA 1978)

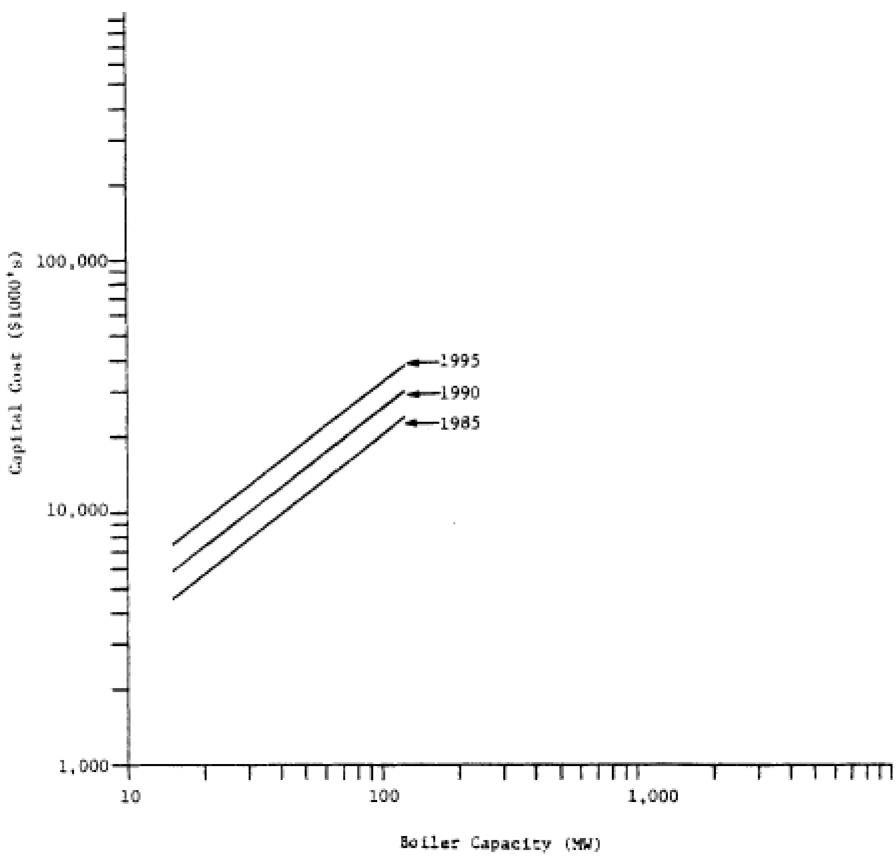

Figure 26. Projected capital costs for a stoker-fired boiler (EPA 1978)

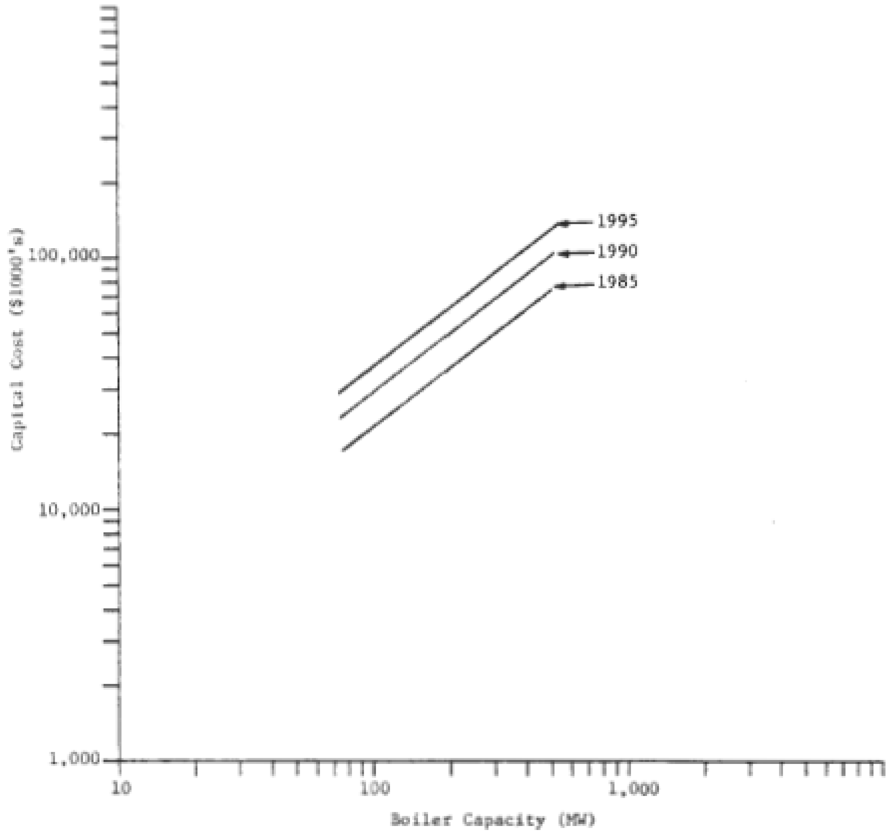

Figure 27. Projected capital costs for a pulverized coal-fired boiler (EPA 1978)

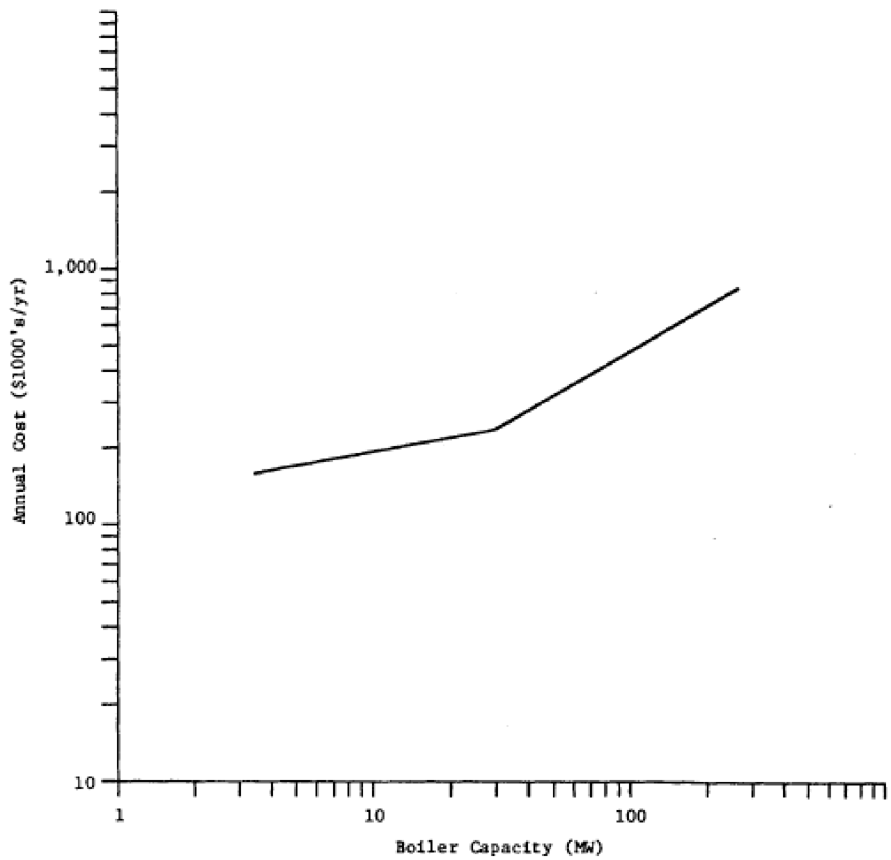

Figure 28. Estimated operating and maintenance costs for a coal-fired boiler, with a load factor of 4000 hr/yr at 100 percent capacity (EPA 1978)

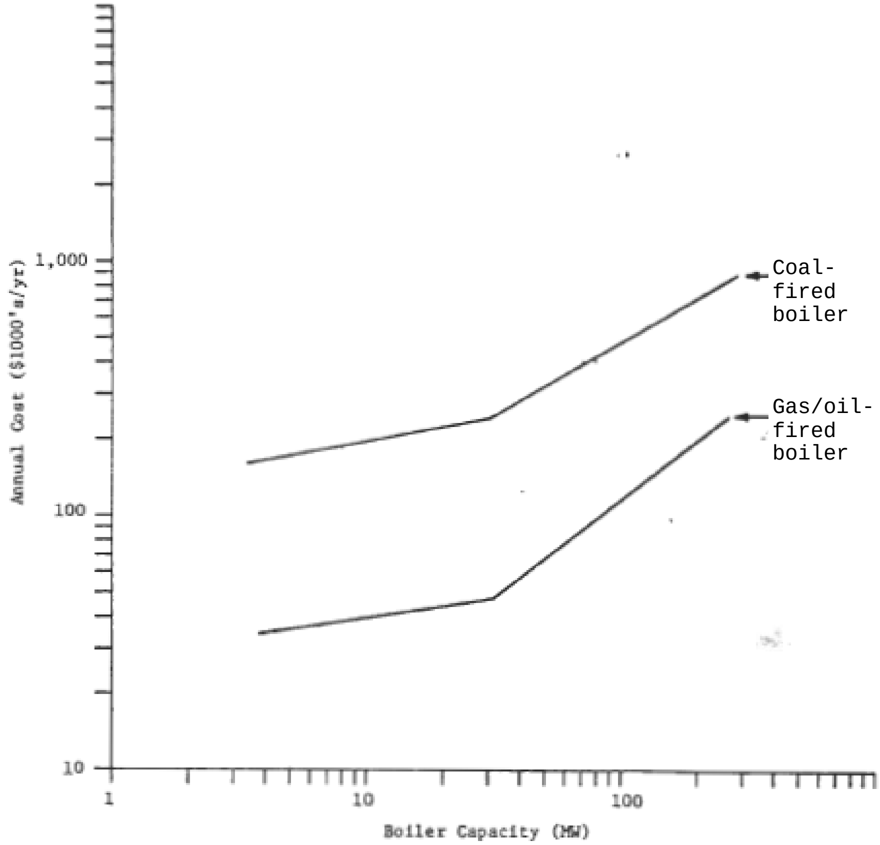

Figure 29. Comparison of operating and maintenance cost of a gas/oil-fired boiler and a coal-fired boiler, with a load factor of 4000 hr/yr at 100 percent capacity (EPA 1978)

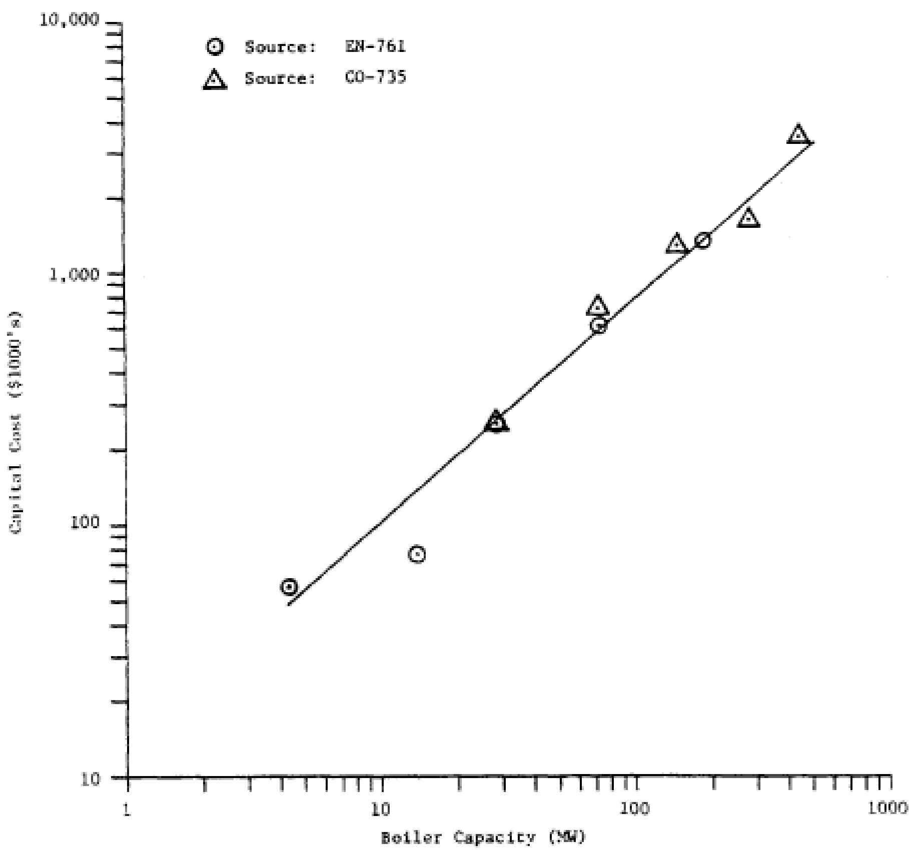

Figure 30. Estimated capital costs for coal handling and storage, in 1977 dollars (EPA 1978)

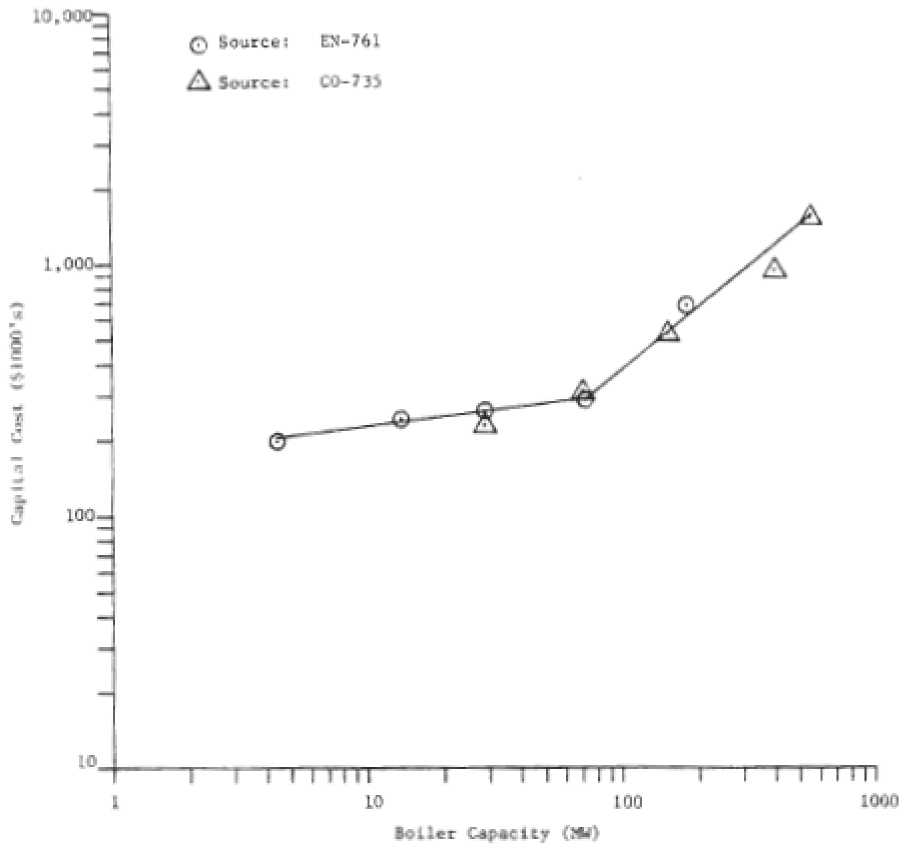

Figure 31. Estimated costs for ash handling equipment, in 1977 dollars (EPA 1978)

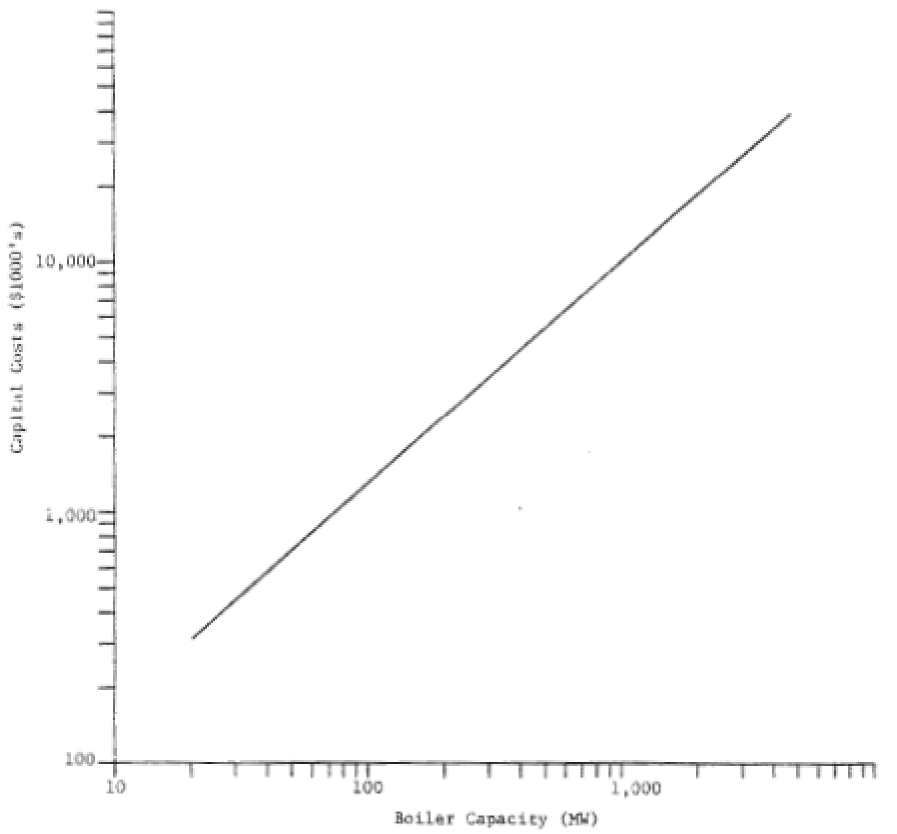

Figure 32. Estimated cost of boiler modifications required to fire coal-oil mixture (COM), in 1978 dollars (EPA 1978)

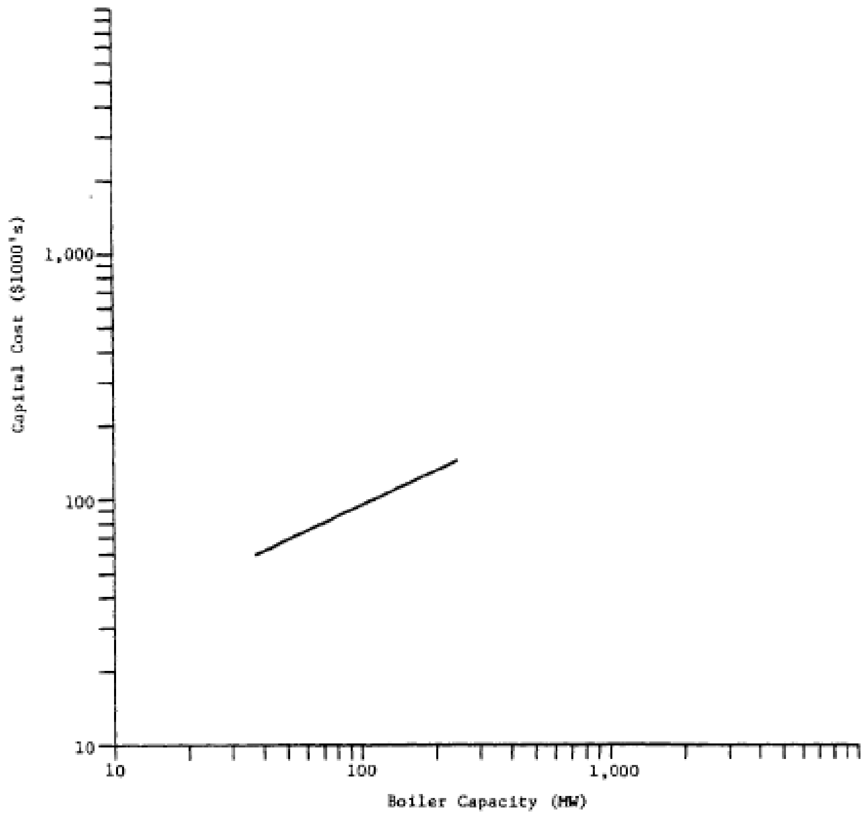

Figure 33. Estimated capital costs for conversion of a residual oil boiler to coal-oil mixture (COM) firing, in 1978 dollars (EPA 1978)

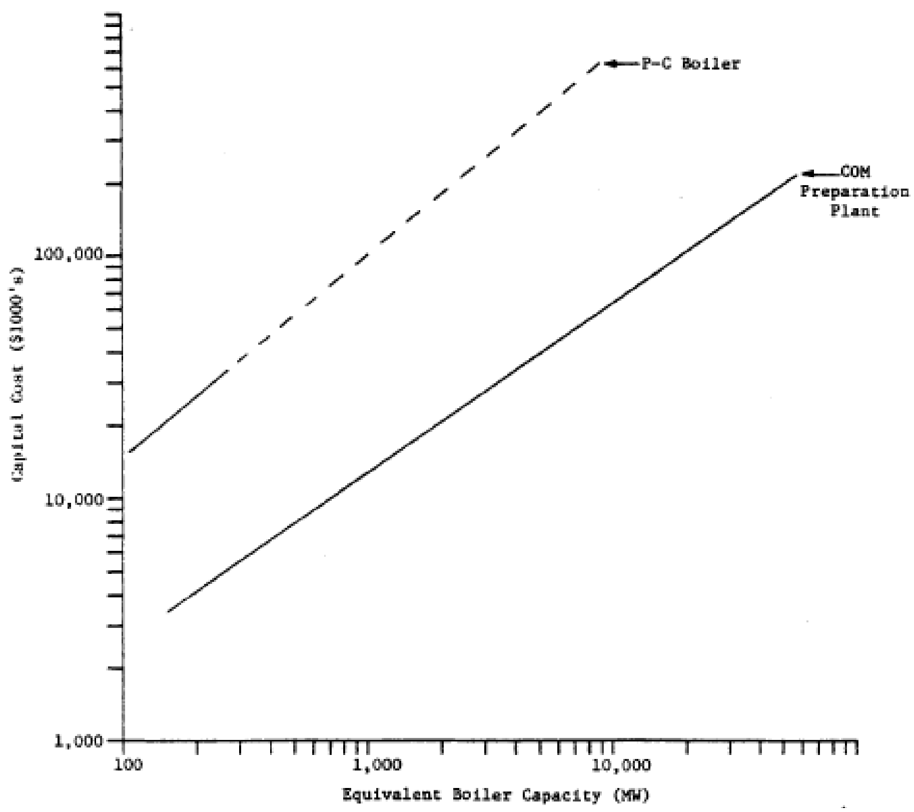

Figure 34. A comparison of coal-oil mixture (COM) preparation plant capital costs with the capital cost of a pulverized coal-fired boiler, in 1978 dollars (EPA 1978)

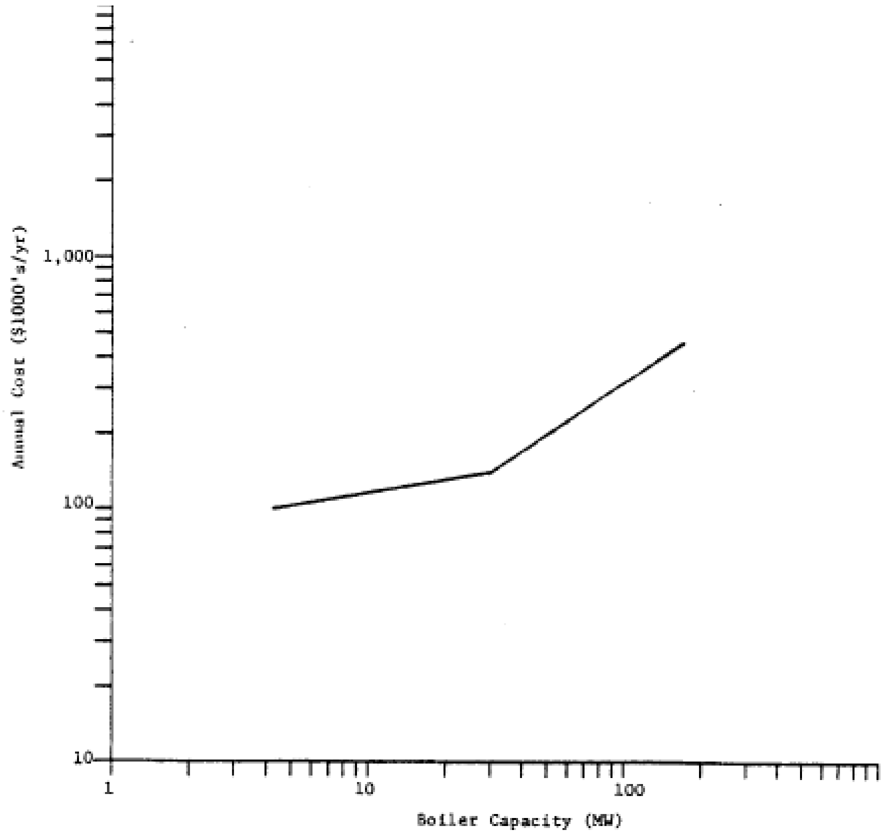

Figure 35. Estimated operating and maintenance costs for a coal-oil mixture (COM) fired boiler, with a load factor of 4000 hr/yr at 100 percent capacity (EPA 1978)

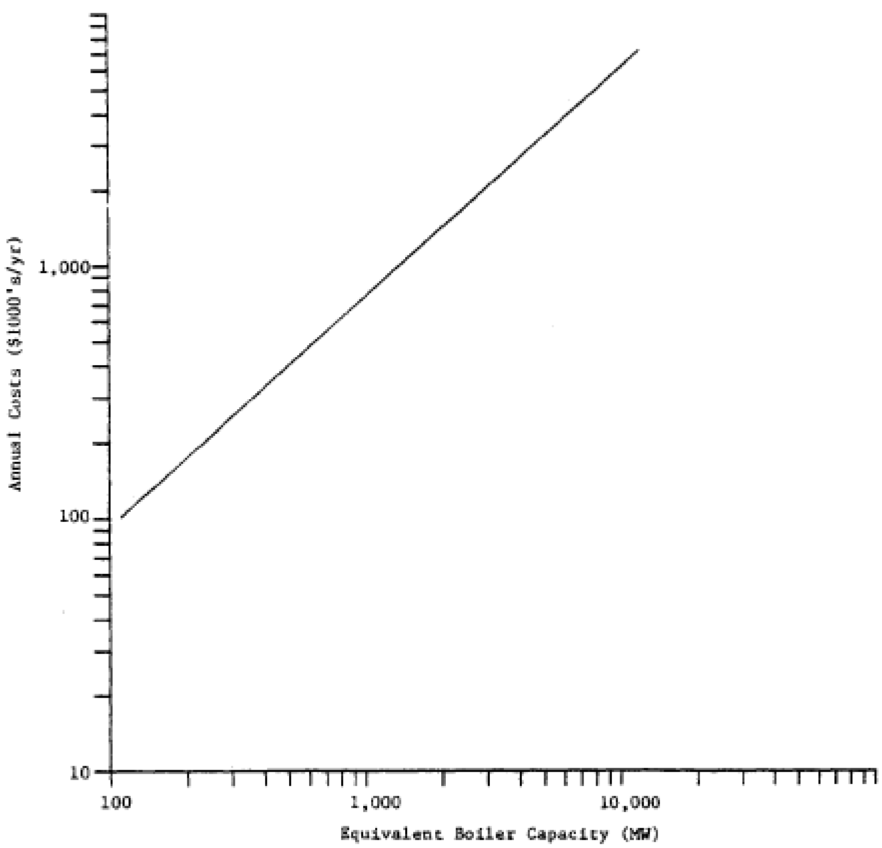

Figure 36. Estimated operating and maintenance costs for a coal-oil mixture (COM) preparation plant, with a load factor of 6400 hr/yr at 100 percent capacity (EPA 1978)

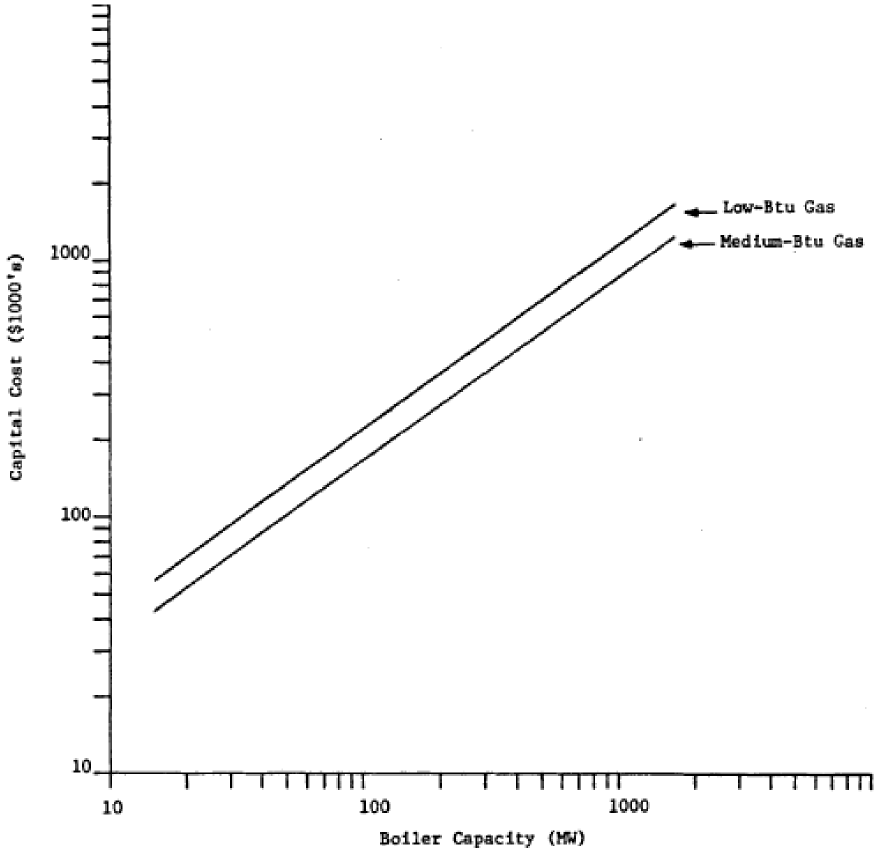

Figure 37. Estimated capital costs of modification to boiler fuel supply system and burners, in 1978 dollars (EPA 1978)