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Market Potential for Flexible Opportunity Fuels: Industrial Steam Generation and Process Heating

September 2012

Prepared for:
Oak Ridge National Laboratory

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Executive Summary

The majority of industrial process heating and steam generation is currently fueled by natural gas or coal. Other fuels that are not used throughout industry, such as biomass, anaerobic digester gas and petroleum coke can potentially supplement or replace natural gas and coal in various process heating and steam generation applications. These non-traditional fuel supply options, also known as opportunity fuels, can enhance energy security for industrial facilities by increasing fuel flexibility and reducing or eliminating reliance on traditional fossil fuels. They can also provide significant economic benefits, by reducing fuel costs and improving profit margins. Some fuels may even be available at a negative cost, as owners seek to dispose of waste products that may have energy content.

Opportunity fuels can come from a variety of sources, with different benefits and complexities that relate to their use. In many cases, the fuels can be blended with other opportunity fuels, as well as with traditional fuels, to improve the energy security and flexibility of industrial process heating and steam generation equipment. This report examines the potential role that opportunity fuels can play at industrial facilities in the United States, as part of an effort supported by the Department of Energy's Office of Energy Efficiency and Renewable Energy in the area of fuel flexibility for the Advanced Manufacturing Office.

Six fuel sources with the potential for industrial utilization are evaluated in this report:

1. **Anaerobic digester gas** (ADG), from municipal and industrial wastewater treatment plants
2. **Landfill gas** (LFG), from landfills
3. **Industrial waste gases** from steel mills, merchant coke plants and oil refineries
4. **Biomass fuels** from crop residues, forest residues, mill residues and urban wood waste
5. **Tire-derived fuel** (TDF), from scrap tire processing centers
6. **Petroleum coke**, a by-product of oil refineries

For the gaseous opportunity fuels (ADG, LFG and industrial waste gases), various process heating applications are considered, including dryers, heaters, furnaces, heat exchangers, ovens and also boilers. The potential for biomass gas applications (using gasifiers and solid biomass resources) was also evaluated in this report, but it was eliminated prior to the economic analysis due to the high cost and commercialization status of advanced gasifiers.

For solid opportunity fuels (Biomass fuels, TDF and petroleum coke), different types of solid fuel boilers are evaluated, with a focus on stokers and fluidized bed boilers as they are inherently the most fuel flexible of the types evaluated.

Potential for Opportunity Fuels

The availability and technical potential for each fuel in the United States is estimated in this report, primarily using data from the U.S. Environmental Protection Agency (EPA), the U.S. Energy Information Administration (EIA), and the National Renewable Energy Laboratory (NREL). Biomass fuels are shown to have the most technical potential, but much of this potential is from crop and forest residues in remote locations with relatively high collection and transportation costs. Resource competition could also be a concern for biomass fuels, as they are sought for other applications such as biofuel production. However, there is a large quantity of biomass resources to draw from in most states, and only the resources located close to industrial plants are expected to show economic potential for industrial utilization. Petroleum coke and landfill gas also have a large amount of technical potential, although there are similar limitations to their economic viability. The other opportunity fuels show relatively modest technical potential. Figure ES-1 shows the estimated technical potential for all opportunity fuels, compared to national industrial natural gas and coal consumption.

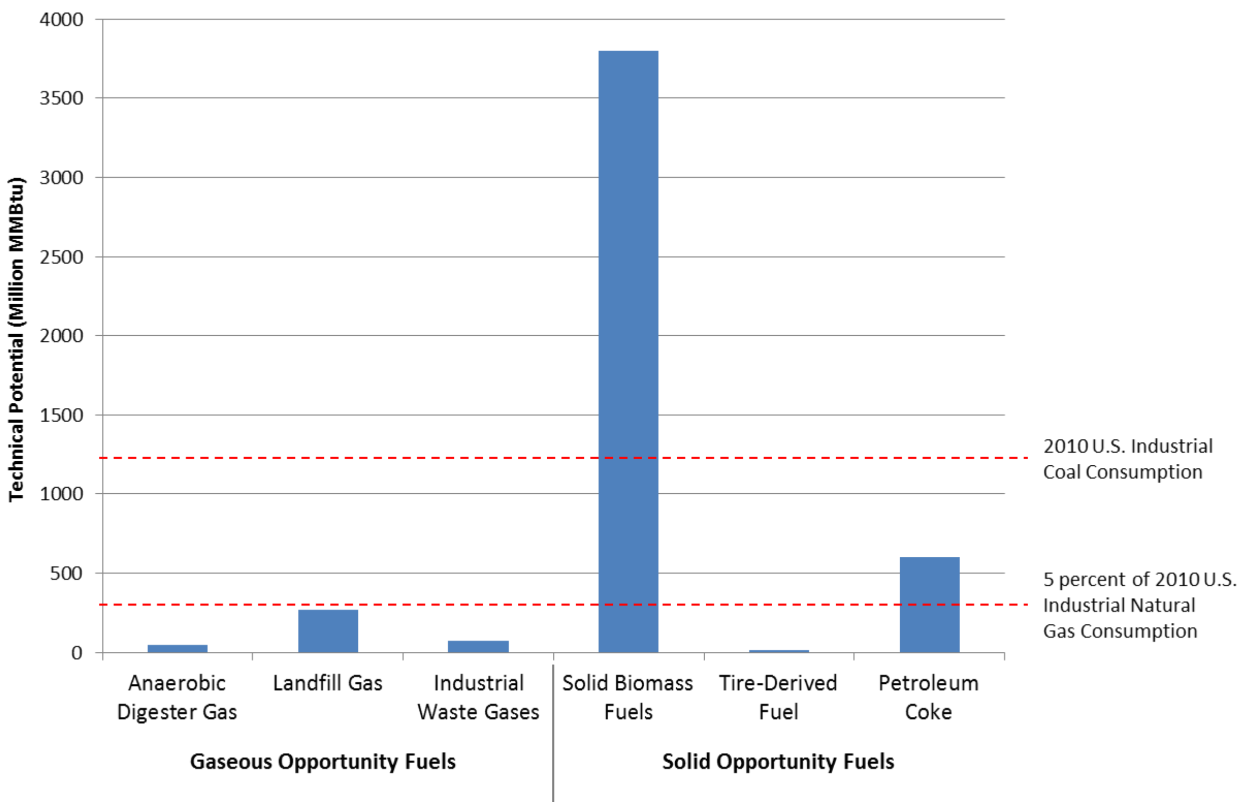

Figure ES-1. Technical Potential for Industrial Process Heating and Steam Generation with Opportunity Fuels

While the technical potential from gaseous opportunity fuels pales in comparison to the total industrial natural gas consumption (6.7 billion MMBtu in 2010[1]), as shown in Figure ES-1, the potential for a single opportunity fuel source to replace a large percentage of natural gas consumption at a given industrial facility can be substantial. For example, the Olinda Alpha Secured Landfill Facility in Orange County, California currently powers a reciprocating engine to generate electricity with its landfill gas, but it is estimated to have enough additional gas to provide 3 million MMBtu/year to an industrial site. A large industrial facility consuming 1 million MMBtu per year could potentially procure LFG from a similar landfill and replace all of the natural gas it consumes. Overall, 20 landfills are estimated to be capable of

[1] United States Energy Information Administration, Natural Gas Consumption by End Use, 2010.

replacing at least 1 million MMBtu/year of natural gas with LFG, and over 50 landfills could replace half that amount. Other gaseous opportunity fuels such as digester gas or refinery gas can also replace fossil fuels at large industrial facilities, but they would need to be economically viable.

Industrial facilities as a whole consume far less coal than natural gas (1.3 billion MMBtu in 2010[2], about one-fifth of natural gas consumption), and the technical potential for solid opportunity fuels can more than replace the coal supply for many facilities. Biomass fuel resources are extremely high at 3.8 billion MMBtu, three times the U.S. industrial coal use. The technical potential for petroleum coke is also fairly high at 600 million MMBtu, almost half of the current industrial coal consumption. However, this figure is based on current petroleum coke exports, and industrial sites would need to outbid overseas markets to obtain the fuel, and incur necessary transportation costs. Solid opportunity fuels do not necessarily need to replace coal at industrial sites, as cofiring can help reduce fuel costs, but facilities already employing solid-fueled boilers are more likely to convert to opportunity fuels than facilities that do not have solid-fuel capability.

For biomass fuels, the key in translating technical potential to economic potential is locating industrial sites with a substantial amount of available biomass resources within a relatively small (less than 25 miles) radius. Several Midwest counties (over 30 in Iowa alone) are estimated to contain more than 300,000 dry tons of crop residues on an annual basis[3], which would translate to over 4 million MMBtu/year. Many more counties in the Midwest and other areas of the country contain an estimated 100,000-300,000 dry tons of crop residues, translating to over 1.5 million MMBtu/year. Forest residues are another potential source of biomass fuels, and many counties in the South, Pacific Northwest, and other forest-rich areas are estimated to contain over 100,000 dry tons of resources[4], which also translates to over 1.5 Million MMBtu/year. A 1 million MMBtu/year industrial site located in any of these counties should be able to economically collect and transport enough biomass to replace all of their traditional boiler fuel. Maps of United States counties with estimated biomass production are provided in Appendix A of this report.

Current industrial installations were examined to identify potential issues utilizing the fuels. Opportunity fuel pretreatment requirements for gaseous opportunity fuels are less stringent for steam generation or process heating than for distributed generation or combined heat and power (CHP) applications. As a result, utilization practices for process heating and steam generation are more flexible and less resource-intensive. Solid opportunity fuels can be blended with coal in stokers and fluidized bed boilers with few modifications, but the economics of transporting the fuels over long distances can be difficult to justify.

Improving the Economics of Fuel Supply

To reduce fuel costs, facilities can draw upon opportunity fuels. The economic analysis presented in this report shows that, for gaseous opportunity fuels, the estimated costs to secure the gas supply, construct a pipeline to a nearby industrial site, install pretreatment equipment, and use the gas for process heating or steam generation can be lower than the average industrial cost for the equivalent supply of natural gas.

[2] United States Energy Information Administration, U.S. Coal Consumption by End-Use Sector, 2005-2011
[3] A Geographic Perspective on the Current Biomass Resource Availability in the United States. Technical Report. Milbrandt, A. National Renewable Energy Laboratory. December 2005.
[4] Ibid.

For solid opportunity fuels, the cost to collect, process, and transport the fuels can be significantly less than the industrial coal cost. If the fuel can be transported a reasonable distance while remaining less expensive than the equivalent amount of coal, it can be economically utilized by industrial facilities. The detailed analysis and assumptions that were used are provided in Chapter 6 of the report.

States with high industrial natural gas prices (for gaseous opportunity fuels) or high industrial coal prices (for solid opportunity fuels) tend to have the best project economics when analyzing potential flexible opportunity fuel applications. However, some states (such as those located in the New England region) can have favorable economics while lacking opportunity fuel resources, or industrial sites that could potentially utilize the fuels. The economic potential for gaseous opportunity fuels in a given state is limited to the state's industrial natural gas consumption. Similarly, solid opportunity fuels are assumed to replace coal in industrial boiler applications, so economic potential is limited to the amount of industrial coal consumption. In some cases, cofiring solid opportunity fuels along with coal is the most favorable option, so the economic potential is limited to 20 percent of industrial coal use (assuming a maximum limit of a 20 percent blend for cofiring applications).

When considering all of the potential fuel sources and the industrial sites that could utilize these fuels on a state-by-state basis, the total economic market potential for opportunity fuels is estimated at 420 million MMBtu/year. This potential amounts to 6.3 percent of 2010 United States industrial natural gas consumption, but it consists of numerous resources spread across many different states. It offers more than ample fuel supplies for a substantial number of industrial facilities to augment some of their natural gas purchases. The potential is broken down by fuel in Figure ES-2.

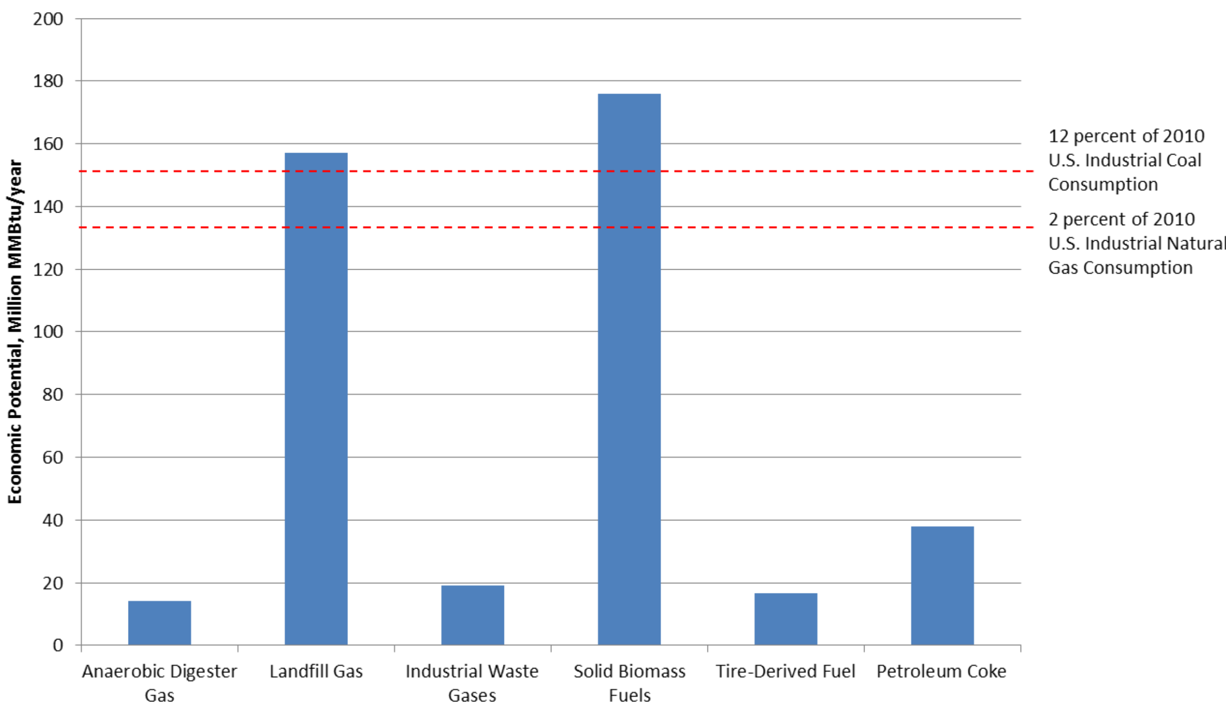

Figure ES-2. Estimated Economic Potential for Industrial Opportunity Fuel Applications

The technical and economic potential for each of the opportunity fuels are compared in Table ES-1. The technical potential is based on the total available resources, without any cost considerations. The economic potential takes other factors into account, such as local electricity and fuel prices, locations of industrial facilities, their estimated fossil fuel consumption, and opportunity fuel collection and transportation costs.

Table ES-1. Technical and Economic Potential for Industrial Opportunity Fuel Utilization

Opportunity Fuel	Available Sources	Estimated Potential (million MMBtu/year)		Notes
		Technical	Economic	
Anaerobic Digester Gas	Wastewater treatment plants using anaerobic digestion	48	14.3	Economic potential is primarily from industrial WWTPs – more process heating potential could be realized if ADG-fueled CHP wasn't a more favorable option for municipal WWTPs
Landfill Gas	Large landfills that flare most of their gas	268	157	Landfills are typically found in remote locations – long pipelines are necessary, but most large landfills can support industrial process heating or steam generation projects within a 20 mile radius.
Industrial Waste Gases	Merchant coke plants, oil refineries	71	19	Merchant coke plants are large enough to support industrial utilization projects between 5 and 20 miles away, assuming cleanup requirements are comparable with other waste gases.
Solid Biomass Fuels	Residues from crops, forests, mills; urban waste	3,800	176	Most biomass reserves are located too far from industrial facilities for technical potential to be realized, but urban wood waste and other low-cost sources show great potential for coal cofiring.
Tire-Derived Fuel	Tire recycling/ processing plants	17	16.7	The economics for TDF utilization are sound, and allow transportation distances of over 100 mile in many cases, but supply can be limited.
Petroleum Coke	Oil refineries	600	38	Industrial facilities located less than 50-75 miles from major ports should be able to economically cofire pet coke with coal. It is difficult to determine the exact number of facilities that meet the criteria.
Totals		4,859	421	Economic potential is 9 percent of technical potential

Gaseous opportunity fuels show some promise for industrial utilization, especially with new multi-fuel burner technologies able to blend natural gas seamlessly with various opportunity fuels.[5] However, the proximity to the fuel source can be a major hurdle for potential projects. While anaerobic digester gas has a relatively modest estimated potential, it is likely to be produced close to (or on-site) industrial facilities that can utilize the fuel, which bodes well for potential project economics. Alternatively, landfill gas typically requires several miles of pipeline to reach the closest industrial site, but industrial utilization with a 5-20 mile pipeline can still be more economical than landfill gas electricity generation for many United States locations. Industrial waste gases like coke oven gas are only produced at certain facility types that are limited in number, and many of these sites already utilize the majority of their waste gases, but the analysis shows that piping the gas to industrial sites can prove beneficial in certain circumstances.

With solid opportunity fuels, collection, transportation and processing costs can add up, and erode economics. This is why most current projects take place directly at the industrial facilities that produce biomass waste products, eliminating much of the collection and transportation requirements. Similarly, the limited number of facilities processing waste tires into TDF can create high transportation and processing costs for industrial facilities that are interested in using the fuel, but located far from TDF processing centers. Petroleum coke faces a similar issue, with the limited locations of petroleum refineries, and the difficulty in transporting the fuel to facilities located far from major ports. For all three of these fuel types, the supply issue and corresponding transportation costs are the primary economic hindrances to most potential projects. Tire-derived fuel applications in particular can also run into issues with local opposition due to potential environmental and public health concerns. Additionally, the air permitting process can be long, complicated and costly when applying for air permits to utilize fuels like TDF, petroleum coke, and other waste products. Information from trial burn experiences could help provide data on cost and emissions impacts. Making efforts to expand the availability of opportunity fuels and streamline the permitting processes are two areas where barriers could be lowered.

Although some opportunity fuels can face local opposition due to air quality issues, there are several benefits from utilizing opportunity fuels that can be used to generate positive press for potential installations. Biomass fuels, including ADG and LFG, can be described as renewable fuels that promote sustainability and the conservation of resources. Developing positive press for TDF and industrial waste products could prove more difficult, but the displacement of fossil fuels and the conservation of resources are themes that can be used to counter any negative press that the opportunity fuels may receive.

While all opportunity fuels have issues that hinder their potential, there are several ways that industrial facility operators can improve the performance and economics of opportunity fuel projects and maximize their use. For industrial facilities that produce solid biomass waste, or are located near others that produce wood waste, utilization of the waste as a thermal source should be closely examined. Other industrial sites with coal or wood boilers could find economic benefits from looking into nearby sources of biomass, TDF, or petroleum coke for cofiring. Wastewater treatment plants with anaerobic digesters should be utilizing or marketing all of their ADG, and large plants without digesters may want to consider the potential benefits of anaerobic treatment, including savings generated from waste gas utilization.

[5] The Department of Energy's Industrial Technologies Program is currently conducting a research effort to develop a new fuel blending and combustion system that can handle a wide variety of fuel compositions.

Industrial facility operators located close to landfills or other sources of waste gas should determine the availability of surplus gas and thoroughly examine the potential advantages and disadvantages of piping the gas to their facility for utilization.

1. Introduction

Throughout the United States, the vast majority of industrial process heating and steam generation is fueled by either natural gas or coal. Other fuels that are not used throughout industry, such as biomass, wood chips and tire-derived fuel, can potentially supplement or replace natural gas and coal for process heating and steam generation applications. These fuel supply options can enhance energy security for industrial facilities by increasing fuel diversification and reducing or eliminating reliance on traditional fossil fuels. Non-traditional fuels, also known as opportunity fuels, can come from a variety of sources, with different benefits and complexities that relate to their use. In many cases, the fuels can be blended with each other, as well as with traditional fuels, to improve the energy security and flexibility of industrial process heating and steam generation equipment. This report will examine the potential role that opportunity fuels can play at industrial facilities in the United States, as part of an effort supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy in the area of fuel flexibility for the Advanced Manufacturing Office.

Opportunity fuels have gathered more attention in recent years due to the volatility of natural gas pricing, pending carbon legislation, and government incentives such as renewable portfolio standards coming into play. Figure 1-1 demonstrates the volatility of natural gas prices over the past decade, with the price spikes of winter 2005-2006 and summer 2008 almost doubling the average price of natural gas over this period. These price spikes have created strong interest in alternative fuel options, as industrial firms seek to hedge their exposure to volatile energy supplies. While many project plentiful natural gas in the future[1], there are still concerns of becoming too reliant on this fuel and its history of price volatility. In fact, a recent study by MIT concluded that, while natural gas appears to be the lowest cost way of reducing carbon emissions, prices could approach $6.8 per MMBTU by 2020[2], without any carbon mitigation policy. The prevailing wisdom is to expect moderate natural gas prices for several years, but to hedge against unanticipated price increases would benefit from building in the potential use of alternative sources of fuel.

[1] Bloomberg, Cheap Shale Gas Means Record U.S. Chemical Industry Growth, August 10, 2011
[2] Massachusetts Institute of Technology, The Future of Natural Gas, June 2011

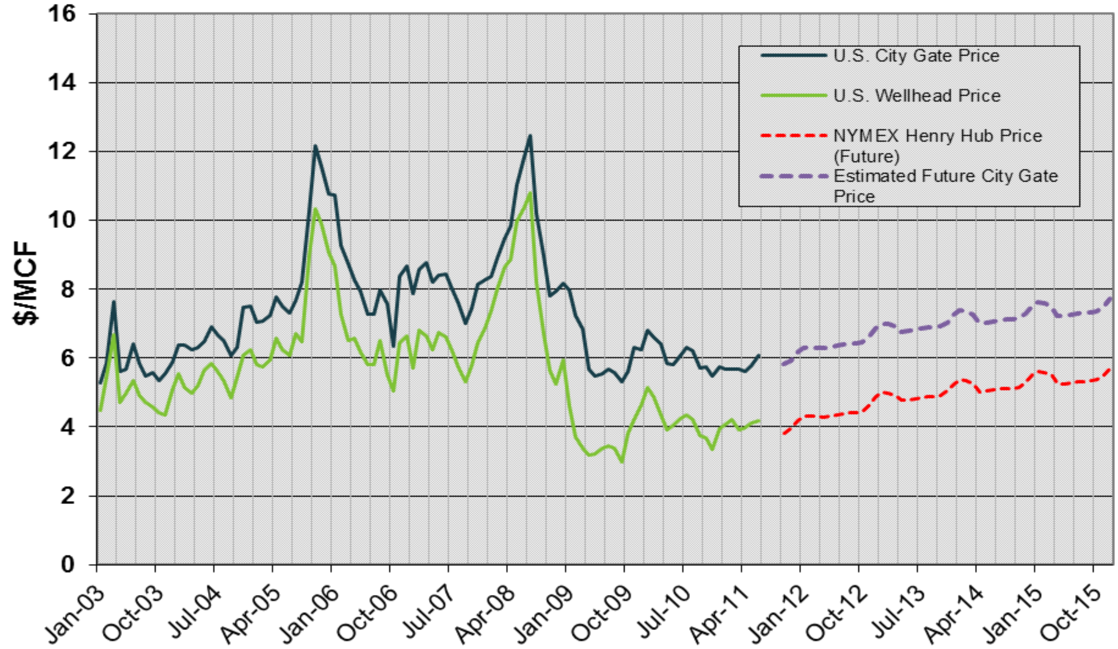

Figure 1-1. Historical and Future United States Natural Gas Prices
Source: EIA (Historical), TradingCharts.com (Future)

Additionally, biomass-fueled boilers have in some cases been applied as an alternative to natural gas boilers, and many coal boilers are blending biomass and other opportunity fuels in order to reduce emissions, save on fuel costs, and become more “green” or sustainable. Opportunity fuels are often blended with either coal or natural gas, because most equipment is designed for these fuels. Figure 1-2 provides data on the current usage of fuels for thermal industrial applications the United States. End-use applications for black liquor and biomass were not reported with fuel consumption data, but it is assumed that the vast majority is used in boilers for steam generation.

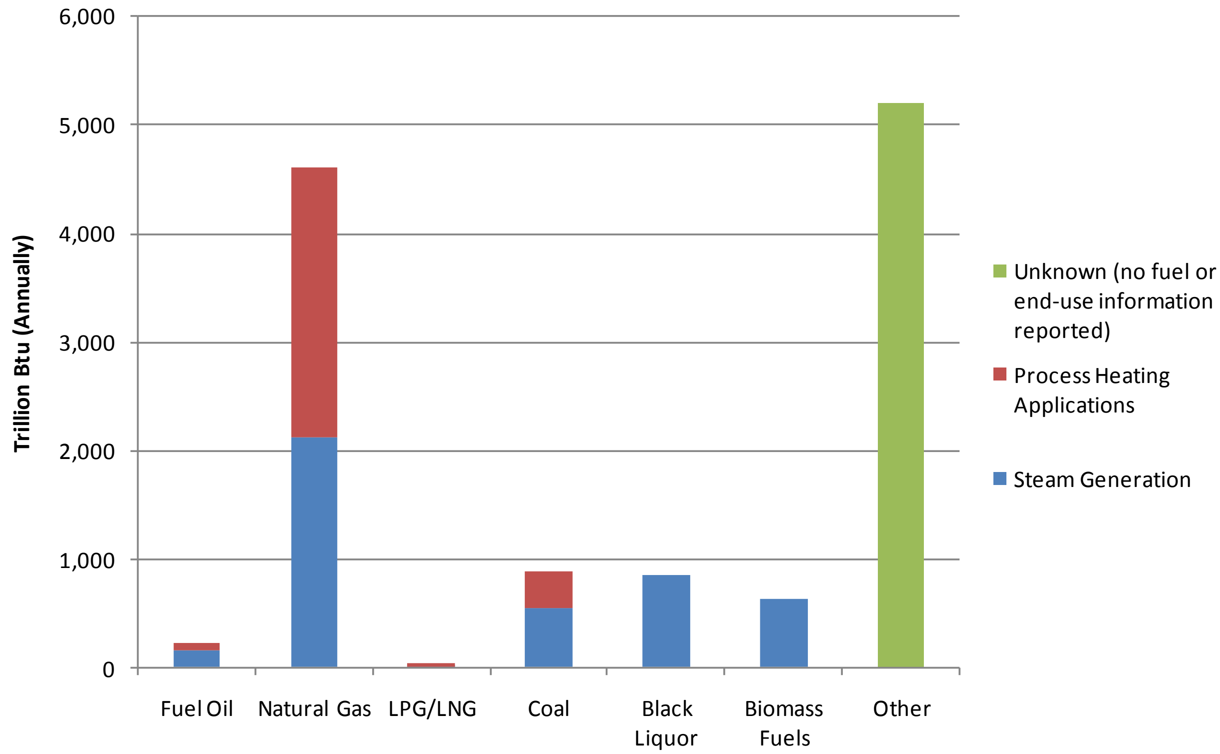

Figure 1-2. Fuels Currently Utilized for Industrial Process Heating and Steam Generation Source: EIA 2006 Manufacturer's Energy Consumption Survey

Based on the high installed capacity of industrial natural gas process heating and steam generation equipment, there is likely substantial potential for gaseous opportunity fuels to replace or be blended with natural gas in industrial applications.

Black liquor and biomass fuels are most extensively utilized at paper mills and wood processing plants. All known facilities that utilize black liquor are pulp and paper mills, and nearly all installed biomass capacity is at wood or paper processing facilities. While most black liquor is likely limited to on-site use, there is a small market for biomass fuels sold to power plants and some industrial facilities, and other opportunity fuels also have the potential to be utilized in various process heating and steam generation applications. For example, some food processing sites use waste agricultural biomass as a fuel.

The availability of opportunity fuels is often inconsistent in volume and quality, requiring varying levels of fuel processing and changes to traditional combustion equipment. In some cases special fuel handling equipment or process equipment such as anaerobic digesters or gasifiers are necessary. Additionally, the use of certain opportunity fuels can cause boilers to foul, slag, corrode, or otherwise degrade at a higher rate than with traditional fuels, increasing cleaning and maintenance requirements. Fuel cleanup equipment may be necessary to remove potentially harmful particulates, and for some locations, emission control technologies must be applied. For these reasons, these fuels are not fully used, and may still be available for industrial sites throughout the U.S.

Recently proposed rules could have a negative impact on the use of opportunity fuels for steam generation and process heating. In 2011, the U.S. Environmental Protection Agency (EPA) proposed changes to standards that would reduce emissions of air pollutants from existing and new boilers (Boiler MACT) and commercial and industrial solid waste incinerators (CISWI). The EPA recognized that boilers use a wide variety of fuels, including coal, oil, natural gas and biomass. The CISWI proposal recognizes the important relationship to the Non-Hazardous Secondary Materials (NHSM) rule, which defines solid waste for purposes of the air rules. The NHSM rule helps categorize units as either boilers or CISWI units. EPA is also proposing revisions to its final rule which identified the types of nonhazardous secondary materials that can be burned in boilers or solid waste incinerators.

Following the release of that final rule, stakeholders expressed concerns regarding the regulatory criteria for a non-hazardous secondary material to be considered a legitimate, non-waste fuel, and how to demonstrate compliance with those criteria. To address these concerns, EPA's proposed revisions provide clarity on what types of secondary materials are considered non-waste fuels, and greater flexibility. The proposed revisions also classify a number of secondary materials as non-wastes when used as a fuel and allow for a boiler or solid waste operator to request that EPA identify specific materials as a non-waste fuel.

During the review process, industry groups have raised significant issues related to the how the rule will affect the use of opportunity fuels such as digester gas and landfill gas, and stipulate that the proposed rule will limit how industry can use these fuels[3]. Furthermore, the rule has attempted to clarify which secondary materials would categorize units as CISWI as opposed to boilers, and could affect how units that rely on solid opportunity fuels be affected by these rules. Industry comments have raised concerns in this area as well[4]. While this study does not address these issues, as they are proposed and not yet final, it remains to be seen how these rules will impact the use of opportunity fuels for steam generation and process heating. Revised proposed rules were released by the EPA on December 12, 2011, and industry comments on the revisions have yet to be assessed.

The focus of this report will lie in the research and analysis of the current options for opportunity fuels to be used at industrial facilities, and where growth opportunities lie in the industrial sector. Fuel supply issues and constraints for using opportunity fuels with current technologies will be examined, with a focus on the benefits of fuel flexibility. Research and development needs, in terms of fuel preparation and equipment utilization, as well as existing barriers to market adoption, will also be analyzed. In the

[3] Petition for Administrative Stay of the National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 76 Fed. Reg. 15,554 and the Identification of Non-Hazardous Secondary Materials That Are Solid Waste, 76 Fed. Reg. 15,456, filed by the Council of Industrial Business Owners, March 21, 2011.
[4] COMMENTS OF THE COUNCIL OF INDUSTRIAL BOILER OWNERS on EPA Proposed Rule Identification of Nonhazardous Secondary Materials That Are Solid Waste 75 FR 31844, EPA-HQ-RCRA-2008-0329, filed by Council of Industrial Boiler Owners, August 3, 2010

end, ***the goal of the report is to determine the feasibility and potential benefits of incorporating various opportunity fuels into industrial steam generation and process heating applications throughout the country***.

This report is organized in the following Chapters:

1. Introduction – this Chapter provides an overview of the study and report organization

2. Opportunity Fuels for Process Heating and Steam Generation – in this Chapter, the opportunity fuels with the most potential for industrial heating applications are identified, summarizing their current use, advantages, drawbacks, and outlook for future implementation at industrial sites.

3. Process Heating and Steam Generation Technologies for Opportunity Fuels – this Chapter examines the limitations of technologies for traditional fuels, the adjustments required to incorporate opportunity fuels, and flexible fuel technologies that can utilize a variety of fuel sources.

4. Availability and Technical Potential for Opportunity Fuels – this Chapter presents data and provides estimates for the availability and technical potential for opportunity fuels to contribute to industrial process heating and steam generation applications in the United States.

5. Current Projects and Future Prospects – this Chapter provides an overview of some current projects and case studies utilizing opportunity fuels at industrial sites, discussing the implications for potential projects in the future.

6. Assessing the Market Potential for Opportunity Fuels – in this Chapter, the current market potential for each opportunity fuel is thoroughly assessed, based on the findings in this report and several analytic cost-benefit analyses.

Finally, the findings of the report are concluded and background information and detailed results are presented in the Appendices.

2. Opportunity Fuels for Process Heating and Steam Generation

Opportunity fuels are not widely used in the United States, but have the potential to be economically viable sources of fuel for industrial process heating and steam generation. Opportunity fuels are often composed of byproducts of industrial operations, so they can become an inexpensive and self-sustaining source of energy for industrial plants. Other opportunity fuels can be transported to industrial facilities, often at a lower delivered cost than traditional fuels like natural gas and coal.

This study focuses on the potential for opportunity fuels to be used in process heating and steam generation applications, and highlights how these fuels can improve fuel flexibility by being blended with or substituted for more traditional fuels. This report evaluates the opportunity fuels with the greatest economic potential.

First, the potential for gaseous opportunity fuels is examined, including anaerobic digester gas, biomass gas, and industrial waste gases (refinery fuel gas, blast furnace gas and coke oven gas). These gaseous fuels must be properly cleaned and treated in order to be mixed with fuels like natural gas. This often involves the removal of moisture, particulates, and other potentially damaging compounds from the fuel. In addition, their use may require low NOx burners, and occasionally post-combustion emission controls like catalytic reduction in severe non-attainment areas. Fuel treatment can be resource-intensive, and the economic analysis of gaseous opportunity fuels often comes down to the costs to clean the fuel so that it can comply with emissions regulations and be compatible with natural gas equipment. This section will examine this issue, and evaluate the advantages and disadvantages associated with utilizing each gaseous opportunity fuel.

Next, the possibilities for solid opportunity fuels, such as wood waste pellets, biomass crops, petroleum coke and tire-derived fuel are analyzed. When prepared properly, these fuels can be blended with coal in large industrial boilers or in process heating applications. However, technical issues could arise in the process of converting non-uniform waste materials into fuel for mixing with coal and other fuels, depending on the composition and quality of the source. The process can also be expensive, sometimes narrowing or eliminating the price advantage for industrial plant operators. If the processing costs are too high, project economics can be affected negatively, causing plants to opt for traditional fuels instead. This crucial aspect of solid opportunity fuel development will be examined for each fuel that is analyzed.

Based on the findings from a previous opportunity fuel market study, conducted for potential combined heat and power (CHP) applications[5], as well as research into the flexibility of opportunity fuels in terms of blending with other fuels, seven fuels were chosen for this analysis:

[5] *Combined Heat and Power Market Potential for Opportunity Fuels*. Prepared by Resource Dynamics Corporation, for the United States Department of Energy Office of Energy Efficiency and Renewable Energy and Oak Ridge National Laboratory, June 2006.

Gaseous Opportunity Fuels

1. Anaerobic Digester Gas
2. Landfill Gas
3. Biomass Gas (using gasifier technology to convert solid biomass fuels into a gaseous fuel)
4. Industrial Waste Gases (blast furnace gas, coke oven gas, refinery fuel gas)

Solid Opportunity Fuels

1. Biomass Fuels (wood waste, forest/crop residues, dedicated energy crops)
2. Tire-Derived Fuel
3. Petroleum Coke

After each opportunity fuel has been evaluated, the fuel flexibility of process heating and steam generating technologies will be assessed. More details on fuel qualities and characteristics can be found in Chapter 4, which analyzes the availability and technical potential of the various fuel sources.

Gaseous Opportunity Fuels for Process Heating and Steam Generation

Gaseous opportunity fuels are typically derived from some sort of waste, and can be blended with natural gas for a wide variety of industrial applications. The flexibility of fuels in terms of their ability to mix with natural gas depends on the heating value and composition. There are four different types of gaseous opportunity fuels that were analyzed in this report:

1. **Anaerobic Digester Gas** (from municipal and industrial wastewater treatment plants)
2. **Landfill Gas** (from large landfills with sufficient gas production)
3. **Biomass Gas** (from gasification processes, using solid fuel resources)
4. **Industrial Waste Gases** (from various industrial plants)
    - Blast Furnace Gas
    - Coke Oven Gas
    - Refinery Fuel Gas (Still Gas)

All of these fuels are analyzed for industrial heating applications in this report. Other gaseous opportunity fuels like coalbed methane and wellhead gas were considered, but they were not included in the analysis because they are produced at remote locations with little nearby demand for industrial process heating and steam generation.

Anaerobic Digester Gas

Anaerobic digester gas (ADG) is a gas recovered from the decomposition of organic material by bacteria in the absence of oxygen. The anaerobic digestion process is often used to treat municipal and industrial wastewater sludge. The process, illustrated in Figure 2-1, involves sealing the waste in a tank that is deprived of oxygen, allowing anaerobic bacteria to digest the waste and produce a methane gas. The gas is also produced at some farms that employ anaerobic digesters to treat their waste, but their locations and small size generally limit them to on-site use. ADG is typically composed of about 60 percent methane, 30 percent carbon dioxide, and 10 percent nitrogen and other trace components.

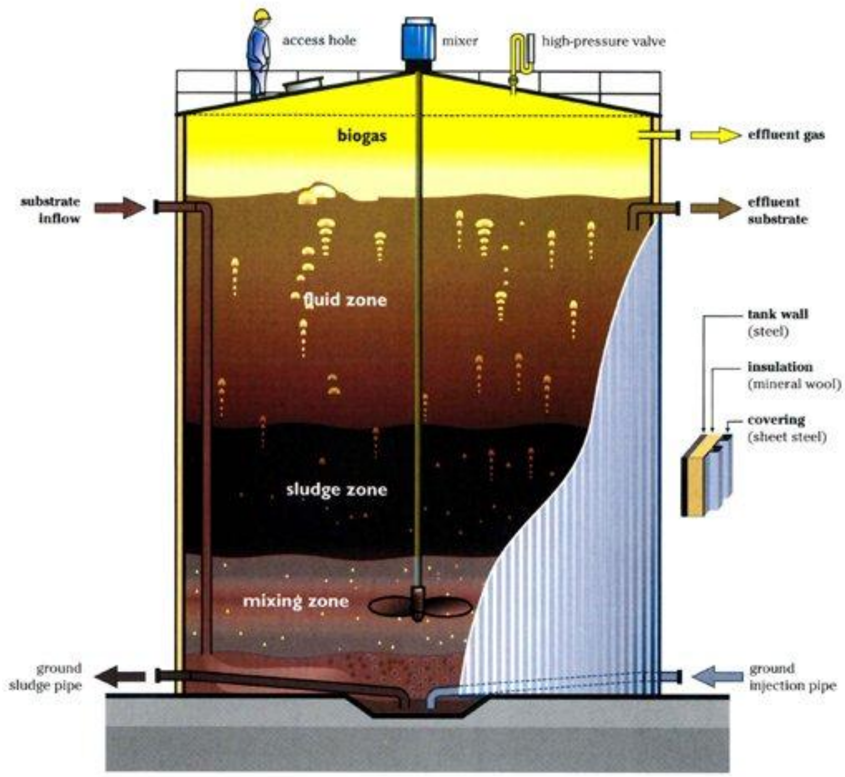

Figure 2-1. Anaerobic Digester Tank
Source: David Darling, The Encyclopedia of Alternative Energy and Sustainable Living

There are over 75,000 wastewater treatment plants (industrial and municipal) in the United States, although only about 5,000 currently employ anaerobic digesters. Most industrial treatment plants use *aerobic* digestion, and many smaller industrial plants simply send their wastewater to the local municipal treatment facilities, which also mostly utilize aerobic digestion. However, anaerobic digestion does offer several benefits over aerobic digestion, including no power required (with the exception of keeping the digester tank heated at about 95 degrees), less solid waste, and the potential to utilize anaerobic digester gas. The most common industries for anaerobic wastewater treatment are food and beverage processing, pulp and paper mills, and petrochemicals. Anaerobic digesters require a continuous, steady stream of wastewater sludge to function properly, so they are best suited for larger facilities with a relatively constant, high-volume organic waste stream.[6]

According to the EPA Clean Water Needs Survey, less than one-fifth of municipal wastewater treatment plants with anaerobic digesters currently utilize ADG for heat or power. There are over 1,500 treatment

[6] Kleerebezem, Robbert and Herve Macarie. "Process Wastewaters: Anaerobic's Bigger Bite". *Chemical Engineering*. April 2003.

plants with anaerobic digesters processing at least 1 million gallons of wastewater per day, and only about 300 of these plants are known to utilize ADG for heat.[7] However, there are several treatment plants with reciprocating engines that have been utilizing digester gas for power generation for years, and recently, several wastewater treatment plants have installed CHP systems with fuel cells and microturbines. In addition, it is believed that a number of sites do use at least a portion of their ADG to heat their digester. The data suggests, however, that some of these plants would have surplus ADG that can also be used for industrial process heating or steam generation if it is pipelined from municipal plants. Additionally, several industrial facilities treat their own wastewater with anaerobic digestion, allowing ADG to potentially be used on-site. This report will examine the potential for ADG utilization in these applications.

Fuel Flexibility

Anaerobic digester gas is a flexible fuel that can be combined with natural gas or other biogas fuels for heat and power generation applications. ADG can vary in quality, however, so when the methane content is low, its mixing capabilities can be limited. Along with moisture, some contaminants and particulates may need to be removed from the gas prior to use. The required level of moisture and contaminant removal varies according to a number of factors. Hydrogen sulfide and siloxanes are typically found in ADG, and these contaminants can foul and corrode combustion equipment, so removal may be required, or maintenance will be more frequent.

Generally, anaerobic digester gas that is properly cleaned of contaminants can be blended up to 50 percent with natural gas in industrial heating operations with no adverse effects on equipment, and without increasing maintenance requirements. When ADG is the primary fuel, however, modifications to natural gas equipment will likely be required, and more frequent maintenance of the combustion chamber could be necessary.

Economics and Market Considerations

For a wastewater treatment plant (WWTP) with an anaerobic digester already in place, ADG is an extremely low-cost fuel source for plant operators after the initial purchase of gas collection and cleaning equipment. Gas cleaning and treatment costs can be substantial, although boilers and process heating equipment have higher tolerances for impurities compared to CHP engines. Also, for municipal ADG to be utilized for industrial process heating, it must be pipelined to a nearby site, which can be expensive (about $330,000 per mile of pipe[8]). For plants without anaerobic digesters, utilization of ADG could be an incentive for adopting anaerobic digestion technology, among several other benefits like reduced odors and lower power requirements. Still, only plants with aging aerobic treatment systems are likely to consider a complete overhaul to anaerobic treatment, which would require the renovation of many of the plant's operations.

[7] Clean Water Needs Survey, 2004, United States Environmental Protection Agency.

[8] United States Environmental Protection Agency. Landfill Methane Outreach Program. LFG Energy Project Development Handbook. 2010. http://www.epa.gov/lmop/publications-tools/handbook.html

A plant processing 1 million gallons of wastewater each day would generate about 8.4 cubic feet of biogas per minute. This amount of biogas could provide 5.4 MMBtu/day, or about 1,970 MMBtu annually, assuming a 75 percent efficient heating system. If ADG is replacing natural gas at $7/MMBtu, an industrial plant could potentially save about $14,000 each year. If 1 mile of ADG pipeline is required at $330,000, it would take over 20 years to recover that investment. However, a wastewater treatment plant ten times the size (processing 10 million gallons per day) could potentially save $140,000 annually, recovering most of the $330,000 pipeline investment in a couple of years. Because pipeline costs remain roughly the same regardless of gas volume, larger WWTPs can support much longer pipelines than smaller plants, allowing them greater flexibility in finding an industrial site to utilize the fuel.

This report will focus on WWTPs processing more than 1 million gallons per day with existing anaerobic digesters, examining the potential costs and benefits of utilizing ADG from these sources for process heating and steam generation applications.

Environmental Issues

Anaerobic digester gas is considered a renewable source of energy, and it is a Tier 1[9] fuel in most state renewable portfolio standard (RPS) programs. However, some definitions of sustainable biomass do not include ADG, potentially making it a lower-tier renewable fuel in some states. Anaerobic digesters reduce the odor, pathogens, water and air pollution associated with some other waste sludge treatment methods. The combustion of ADG prevents the release of methane, a potent greenhouse gas, into the atmosphere. During combustion, carbon monoxide, nitrous oxides, organic compounds and some dioxins are produced, but the formation of these pollutants can be minimized with a well-designed combustion process employing emission control technologies, such as those currently used with natural gas combustion systems.

Outlook for Industrial Potential

Anaerobic digester gas is a promising fuel for industrial process heating and steam generation applications, but its potential is generally limited to industrial and municipal wastewater treatment plants that utilize anaerobic digestion technology to treat their waste. ADG is a flexible fuel that can be blended with natural gas or other biofuels, so it can be utilized in many different applications. There are a great number of wastewater treatment plants in the United States, so the overall potential could be fairly large despite the limitation.

Landfill Gas

Landfill gas (LFG) is generated from the same process that produces anaerobic digester gas. The underground landfill acts like a large digester tank, sealing the waste in an oxygen-free environment.

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[9] Many state renewable portfolio standard programs have different tiers of eligible fuels, with Tier 1 consisting of solar, wind, and sustainable biomass power. Tier 1 fuels receive the most renewable energy credits.

Because of operating practices to limit odors, the landfill gas is drawn out of the landfill using a field of wells placed throughout the landfill, with some air infiltrating as blowers remove the gas. As a result, some oxygen and nitrogen leaks in, diluting the gas. Largely due to this infiltration, LFG generally has a slightly lower quality and heating value than anaerobic digester gas. While the heating value of ADG typically ranges from 500-600 Btu/ft^3, LFG can sometimes fall below 500 Btu/ft^3. Still, when properly cleaned, LFG can be blended with natural gas or other biogas fuels and used in a number of industrial applications.

The Environmental Protection Agency's Landfill Methane Outreach Program encourages landfill developers to find a beneficial use of their landfill gas, either for direct heating applications or electricity production. Large landfills are required to collect their gas and flare it if they do not utilize it, so they already have the gas collection equipment in place.

Figure 2-2. Landfill gas collection
Source: Arthurstown Landfill website (Ireland)

In most cases, however, there are either no facilities close to landfills that can utilize the gas or the landfill has chosen another use for its gas. The majority of LFG-to-energy projects simply clean up the landfill gas and install a modified natural gas genset on-site, generating electricity at the landfill to sell to the local utility. Others will clean the gas and scrub out the carbon dioxide to create a pipeline-quality gas that can be sold as a natural gas substitute or even a "green" gas. However, if the gas is pipelined a few miles to an industrial facility, which is not always explored as an option, it can be used in a number of different applications. This report examines the economic potential and market drivers for LFG to be utilized for process heating and steam generation at industrial facilities throughout the United States.

Fuel Flexibility

With a lower heating value and higher levels of contaminants in most cases, landfill gas is not quite as flexible as anaerobic digester gas. But with proper pretreatment, it can be mixed with natural gas as well as other biofuels. Equipment using a large percentage of landfill gas in comparison to natural gas may require some modifications, but small amounts of LFG can be blended with natural gas for most industrial uses. When large amounts of LFG are used, more frequent cleaning and maintenance of the combustion chamber and downstream components are required.

In order for LFG to be more flexible for use in natural gas systems, extensive gas cleanup is usually required, which can be an economic hindrance for potential projects. Additionally, LFG can have a low heating value (sometimes below half that of natural gas), which limits its flexibility with natural gas equipment. The economic and technical limitations of LFG cleaning equipment are further explored later in this report.

Economics and Market Considerations

The potential market for industrial LFG applications is likely limited to a 2-5 mile radius around a landfill, due to the high pipeline installation cost (about $330,000 per mile), although some large industrial sites have piped the gas over 15 miles. Gas cleanup equipment is another economic factor that can add hundreds of thousands of dollars to LFG projects. Larger landfills benefit from economies of scale with both gas cleanup equipment and pipeline construction. Gas collection equipment, such as the piping shown in Figure 2-2, is already in place for most landfills because they are required to collect and either flare or utilize the gas, but additional gas wells and blowers could be necessary for steady and sustainable LFG production.

Finding a nearby industrial facility that is willing to make the investment of building a pipeline and committing to LFG utilization is often the most difficult task for potential industrial projects. This is why the majority of LFG to energy projects involve on-site electricity production (sold as wholesale power, sometimes with renewable energy credits) or cleanup of the gas to a high Btu level (to be sold as a natural gas substitute). However, there are also opportunities for industrial applications to transport the gas via pipeline, and there are several current projects providing examples of this practice (see Chapter 5). As with ADG, larger landfills are able to support longer pipeline distances, providing more flexibility in finding an industrial site. Although there are far fewer landfills than wastewater treatment plants in the country, landfills tend to be larger and produce much more gas on average, giving them an economic advantage. Finding nearby industrial sites that are able to utilize large amounts of landfill gas during the limited time frame of high-yield LFG production (about 20 years for most landfills) is the primary impediment to potential industrial LFG projects.

This report will examine current industrial landfill gas applications and assess the economic potential for additional industrial facilities capable of utilizing LFG.

Environmental Issues

The utilization of landfill gas conserves resources and prevents the release of methane and carbon dioxide. According to the EPA, utilizing 1 million tons of waste for landfill gas energy has the same greenhouse gas impact as planting 8,300 acres of trees.[10] LFG utilization also reduces unpleasant odors and explosion threats from landfills. Like anaerobic digester gas, it is a form of biomass, and is usually considered a top-tier renewable fuel in state renewable portfolio standards. However, some states do not include LFG in their definition of sustainable biomass, demoting it to a lower RPS tier that receives fewer incentives. The combustion of landfill gas as a fuel does produce some criteria pollutant emissions like

[10] United States Environmental Protection Agency – Landfill Methane Outreach Program. May 2006. http://www.epa.gov/lmop/index.htm

nitrous oxide and carbon monoxide, though they are controllable with today's combustion equipment designs and associated emission controls.

Outlook for Industrial Potential

The total potential for LFG industrial applications is likely relatively low. Many of the landfills best-suited for energy projects are already converting their LFG to energy through the EPA's Landfill Methane Outreach Program, and those landfills that could be good candidates would require a nearby industrial facility willing to utilize the gas and support the development of a pipeline to reach their facility. This report will assess the economic potential for industrial LFG process heating and steam generation projects in the United States.

Biomass Gas

Biomass gasification has been around for many years, but gasification systems have still not advanced to the point of commercialization as a fuel source that can be used to replace natural gas. The process of converting solid biomass into a gaseous fuel would provide flexibility for biomass fuels, allowing them to be used in a number of different industrial applications. Additionally, equipment costs aside, the gasification of biomass fuels should cost significantly less than purchasing natural gas, provided an inexpensive nearby source of biomass can be found. However, the gasifiers have a high installation cost, and there are some issues with the quality of biomass gas, requiring high levels of cleanup.

To date, there have been numerous installations in the United States of gasifiers that produce a hot syngas for a kiln or boiler system. Some refer to these as close-coupled gasifier systems, because the gasifier must be closely located and connected to the boiler or kiln. In order to extract a high-quality biogas that could be used flexibly in various natural gas applications, an expensive advanced gasification system with extensive cleanup equipment would be required. While these types of gasifiers have been demonstrated in large-scale combined cycle turbine systems, they are still not commercially viable, and this is not expected to change in the near future.[11] This report assesses the potential for biomass gas systems for industrial process heating and steam generation applications, taking these factors into consideration.

There are several different types of gasifiers, with varying sizes and feedstock requirements. Fixed and fluid bed gasifiers are the most common, but fluid beds have traditionally been utilized in biomass gas applications, because they can handle a wide variety of feedstocks. New fixed bed updraft gasifier designs can be utilized in smaller scale applications. Entrained bed gasifiers are the most efficient and produce no tar, but they can only be used in large installations where the feedstock must consist of very fine particles. The focus of this report will be primarily on biomass gas produced from updraft fixed bed gasifiers, and circulating fluid bed gasifiers for larger applications.

[11] Peterson, David and Haase, Scott. *Market Assessment of Biomass Gasification and Combustion Technology for Small- and Medium-Scale Applications*. Technical Report for National Renewable Energy Laboratory, July 2009.

Fuel Flexibility

Air blown gasifiers generally produce a gas with low heat content (150-250 Btu/ft^3) that can be useful, but is limited in its ability to be blended with natural gas. These gasifiers, produced by manufacturers such as Primenergy, Nexterra, Chiptec are a relatively low-cost option, often used in close-coupled configurations with boilers and kilns. Generally this type of gas is used with equipment that has been designed for high-temperature, low-Btu content fuels. Oxygen blown gasifiers like the SilvaGas® system (discussed in Chapter 3) produce a gas that is more on par with ADG and LFG in terms of heating value (300-500 Btu/ft3) that can be more easily blended with natural gas and used with natural gas heating equipment. However, there have been issues with particulates, tars, and other contaminants in biomass gas that are difficult to expel with hot gas cleanup methods. Typically, the gas needs to be cooled to condense out some tars and particulates, while the remaining contaminants are removed with additional treatment. In fixed bed updraft gasifiers, excessive tar production can be a major problem, so high levels of gas cleanup is usually necessary and gasifier maintenance requirements can be significant.

Economics and Market Considerations

The market for biomass gas applications faces the same potential hurdles as the market for solid biomass fuels, with the purchase of a gasification system as an added requirement. Condensers, filters, and compressors are necessary for biomass gas to blend well with natural gas, adding to capital and maintenance costs, and expensive oxidants are often required to produce a relatively high-quality gas. Industrial facilities must be located close (generally within 25-50 miles) to large and sustainable sources of biomass, otherwise transportation costs can become prohibitively high. However, the potential for fuel savings with biomass versus natural gas is relatively high[12], so in locations where large quantities of biomass fuels can be obtained at a low price; and when higher natural gas prices are expected to continue, industrial applications could show great potential.

Environmental Issues

Biomass gas, cleaned up properly from an efficient gasifier, does not produce significantly greater emissions than natural gas. Biomass gasification systems also generally produce fewer emissions than biomass boilers. Additionally, biomass is a renewable resource and is eligible for RPS benefits in many states if used for electricity production. The particulates and contaminants within biomass gas vary depending on the gasification system and the feedstock that is used – some types of biomass produce more tar than others. Gasifiers also produce a great deal of ash that must be disposed of, some feedstocks producing more than others. However, if biomass gas is properly cleaned, it is comparable to natural gas in terms of criteria pollutant emissions, and it is generally seen as a friendly fuel for the environment.

[12] Some biomass fuels can be purchased for less than $2/MMBtu, while most future forecasts for industrial natural gas prices are over $6/MMBtu.

Outlook for Industrial Potential

The outlook for the industrial potential of biomass gas depends on two key criteria:

1. The cost and performance of gasifiers to produce a high-quality biogas that does not require extensive cleanup
2. The cost of biomass fuels and proximity to industrial facilities

If an industrial facility is expecting higher natural gas prices to be sustained, and has access to low cost biomass and can make the investment in a gasifier, then biomass gas could be the most economic fuel choice. This report will analyze the potential for biomass gas to be used in industrial process heating and steam generation applications.

Industrial Waste Gases

Industrial facilities often produce waste gases that can be utilized on-site. The most common of these gases are blast furnace gas, produced in the steel-making process, coke oven gas, generated from coal coke production (coal coke is used to manufacture steel), and refinery fuel gas, produced at oil refineries. These waste gases are typically utilized in some manner by the industrial facilities that produce them, but there is often leftover gas that is flared. The practice of mixing these fuels with natural gas and other fuel streams at the facilities for process heating and steam generation applications could potentially play a larger role compared to current utilization efforts. The potential for blast furnace gas, coke oven gas and refinery fuel gas utilization in the United States will be further analyzed in this report.

Blast furnace gas (BFG) is produced when iron ore, coke and lime stone are combined in a blast furnace to produce steel, as shown in Figure 2-3. The hot waste gases are in excess of 750 degrees Fahrenheit, and are typically used at the steelmaking plant in some capacity, although some of the gas is often flared. There could be opportunities for BFG to be utilized more effectively at these facilities in process heating or steam generation operations.

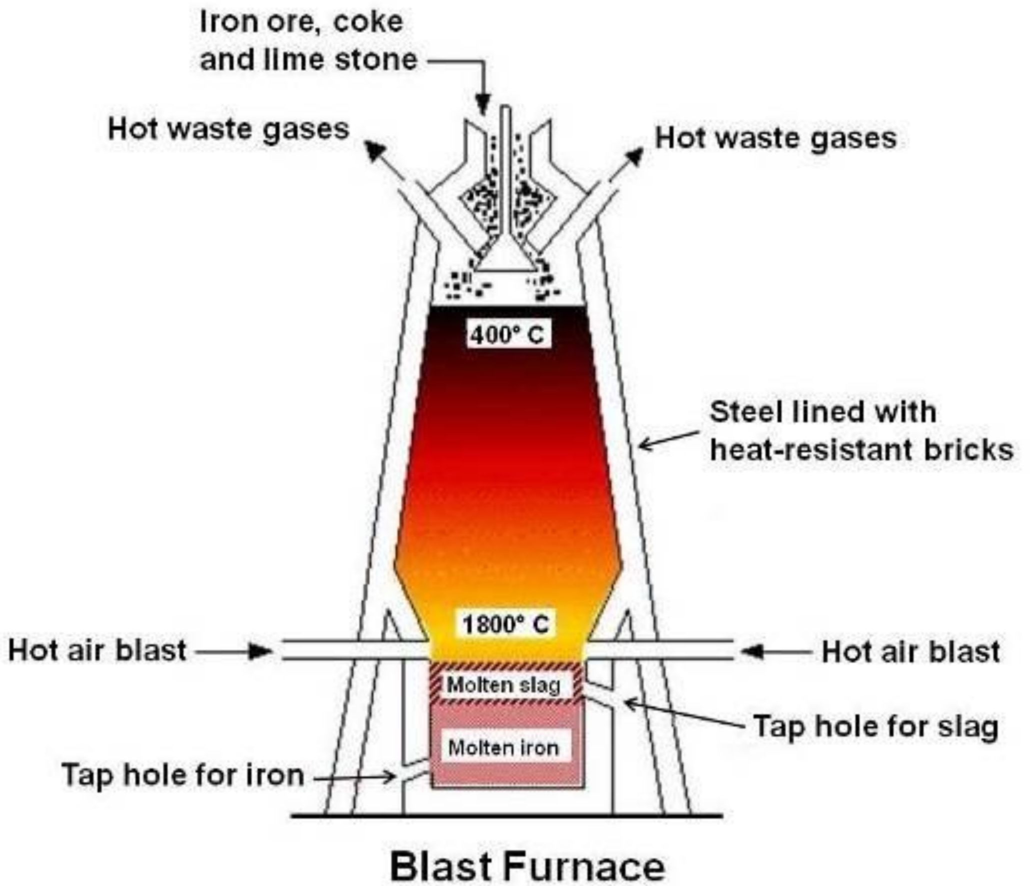

Figure 2-3. A Blast Furnace Uses Coke and Produces Hot Blast Furnace Gas
Source: practicalmaintenance.net

Coke oven gas from coal coke leaves the oven at around 2,000 ^{o}F, where it is immediately quenched by direct contact with a spray of aqueous flushing liquor. The cooled gas is water saturated and has a temperature closer to 200 ^{o}F. It is collected, and the remaining unevaporated flushing liquor provides a liquid stream that flushes away condensed tar and other compounds. The coke oven gas and flushing liquor are then separated and the dried coke oven gas, rich in hydrogen and methane, can be used as a fuel. Blast furnace gas, on the other hand, is often directly used on-site as a hot gas. Due to the low calorific value, high-temperature blast furnace gas can be more effectively utilized for its thermal energy in heat exchanging applications.

Refinery fuel gas (also known as still gas or off gas) is a product of the oil refinery cracking process that separates light and heavy crude oil. This gas is often utilized by oil refineries, but some of it is inevitably flared, either for safety purposes or for lack of better use. The gas is typically high in sulfur, and EPA regulations dictate allowable sulfur concentrations for refinery fuel gas combustion and utilization, so sulfur emission control devices may be required. Wellhead gas, captured at oil and natural gas wells, was also examined as a potential fuel, but high levels of gas cleanup are typically required, and wells tend to be located in remote areas with no nearby industrial facilities to utilize the gas.

Volatile organic compounds were also considered among industrial waste gases. These compounds are produced from paint and various industrial processes, and are typically vented and flared to prevent their release into the environment. Some facilities have experienced success venting these compounds into the combustion chambers of natural gas boilers, to provide additional energy for steam generation while eliminating the hazardous compounds. However, because these compounds are vented with air, the mixture is very dilute and the ability to blend with other fuels is limited. Additionally, the amount of volatile organic compounds available to provide fuel for industrial facilities is difficult to quantify. These waste gases will not be considered for further analysis in this report.

Fuel Flexibility

Industrial waste gases usually must be cleaned and filtered extensively in order to blend with natural gas, but some high-temperature industrial process heating applications at steel mills and oil refineries may tolerate higher percentages of contaminated gas than others. Coke oven gas contains small amounts of ammonia, hydrogen sulfide and hydrogen cyanide that are typically removed prior to usage. The combustion of blast furnace gas produces large amounts of NOx, CO and CO_2 emissions, so its use could be more limited in areas with strict environmental regulations. Refinery fuel gas contains high levels of hydrogen sulfide and sulfur dioxide that often must be treated, but blending with natural gas can potentially bring the sulfur concentration down to acceptable levels.[13]

The waste gases are produced at varying volumes throughout daily plant operations, so facilities tend to use them as supplementary fuels for natural gas heating applications. Coke oven gas is only about 25 percent methane, but over 50 percent hydrogen, with relatively small concentrations of nitrogen, acetylene, carbon and oxygen. The resulting heating value averages 450-500 Btu/ft^3, about half that of natural gas. Petroleum refinery fuel gas tends to have similar properties, but with more carbon monoxide and carbon dioxide compared to hydrogen. Blast furnace gas contains very little methane, and large amounts of nitrogen, CO and CO_2, so its ability to blend with natural gas is limited, and emission controls can be a major factor. It also has a very low heating value. Overall, the fuels are not considered to be very flexible as a stand-alone fuel, but all but blast furnace gas have the potential to be blended with natural gas in various industrial heating operations.

Economics and Market Considerations

Industrial waste gases are essentially free fuel sources to the plants that produce them, but at the cost of collecting, transporting, and cleaning the gaseous fuels. For most industrial plants, the cost to incorporate waste gas into heating applications is less than the cost to purchase natural gas in the long run. Most plants already have equipment in place to collect and treat the gases, which are typically flared when they

[13] *Review of New Source Performance Standards for Petroleum Refinery Fuel Gas*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. October 1986.

are not utilized. However, the finite number of oil refineries, integrated steel mills and merchant coke plants in the country could limit the total potential for waste gas applications. Additionally, many industrial plants that produce these waste gases could already utilize their own supply. This report will examine the economic considerations for industrial waste gas utilization, and estimate how large the potential market could be.

Environmental Issues

The processes that produce industrial waste gases create some environmental concerns, but the utilization of waste gases from these processes increases plant efficiency, reduces fossil fuel consumption, and lowers plant emissions compared to flaring. Nitrous oxide emissions, along with particulates, are produced when utilizing these waste gases for fuel, and they must be controlled or removed to satisfy air permitting requirements. Blast furnace gas also contains high amounts of carbon, producing CO and CO_2 emissions. With coke oven gas, ammonia, hydrogen sulfide and hydrogen cyanide must be removed prior to combustion. For both coke oven gas and blast furnace gas, emission control technologies could be necessary in order to keep certain emissions at natural gas levels. Otherwise sites would be limited to cofiring only a small percentage with natural gas.

Outlook for Industrial Potential

The number of integrated steel mills, merchant coke plants and oil refineries in the United States is relatively small, and many of these facilities already utilize their waste gases at least in part. The quantity of waste gas available for industrial heating applications is unclear, but it is likely that the total number of potential projects is relatively small. Nevertheless, this report does examine the potential for blast furnace gas, coke oven gas and refinery fuel gas to be utilized for industrial process heating and steam generation applications.

Solid Opportunity Fuels for Process Heating and Steam Generation

Solid opportunity fuels are usually derived from an industrial or agricultural waste stream that has useful energy content, and are often blended with coal or wood chips in large industrial boilers. While this practice of co-firing has increased in recent years, there is a large amount of untapped potential in these waste streams that could ultimately provide revenue for industrial developers. Wood waste is the most common example, often broken down into pellets and mixed with coal, or utilized in wood-burning stokers and boilers. Tire derived fuel is composed of processed scrap tires, and actually has a higher heating value than coal. Petroleum coke, produced at oil refineries, is another opportunity fuel with coal-like properties. This section examines the characteristics and properties of each of these solid fuels.

Biomass Fuels

Biomass fuels considered in this report have been broken down into three categories:

1. **Wood waste fuels** – industrial wood waste is produced at facilities manufacturing wood products, and urban wood waste is gathered from tree trimmings and yard clippings, as well as construction and demolition debris
2. **Forest and crop trimmings and residues** – these are collected from existing forests and agricultural operations. The thinning of forests has become a common way to prevent forest fires, and this biomass could be used as a source of fuel. Slash from logging operations is another source of forest biomass. Agricultural crop collecting always leaves a large amount of biomass behind, so agricultural residues are another potential fuel source.
3. **Dedicated energy crops –** these plants are grown and harvested specifically to be used as biomass fuels.

Wood waste from industrial operations is the type of biomass fuel most commonly utilized by industrial plants for process heating and steam generation. The process of turning trees into logs, logs into lumber, and lumber into manufactured products produces residues like sawdust, shavings, cut offs, and bark, that can be used as fuel for many different heating applications. Utilizing wood waste on-site eliminates transportation costs and can provide industrial facilities with an inexpensive source of heat for steam generation and process heating applications. However, the potential for wood waste utilization for process heating and steam generation at industrial facilities is likely much higher than what is currently being utilized. This report will examine the different economic factors that influence the decision industrial plants face when considering how best to utilize their wood waste streams.

Urban wood waste consists of pieces of wood collected from homes, construction sites, demolition sites, typically through wood recycling programs. The wood waste could potentially be processed and transformed into wood pellets for various applications, including industrial heating and steam generation. The raw materials for urban wood waste can be extremely inexpensive to obtain, so if the fuel can be processed for a reasonable price, a market for urban wood waste has the potential to grow among industrial facilities. However, due to the nature of the waste, there are several issues involved with processing some forms of urban wood waste (i.e. construction and demolition debris) into a usable fuel, which will be discussed later in this report.

For the second category of biomass fuels, branches and clippings from forests or agricultural operations, the costs of collecting and transporting the materials, in addition to converting the large clippings into small pellets for efficient burning and mixing, are most often prohibitive. The only exception is crop residues that can be utilized at nearby agricultural facilities or forest thinnings and logging slash that can be used at forest products industry sites. Otherwise, collection and transportation from rural or forest areas typically raises the price of these fuels to the point where they are no longer competitive. The heating value of biomass is significantly lower than coal, so transportation can be twice as expensive per unit weight. This makes it extremely difficult for biomass fuels to be cost-competitive when substantial travel distances are involved.

Figure 2-4. Miscanthus, grown as a dedicated energy crop
Source: Biomass Technology Group
www.btgworld.com

The third category, dedicated energy crops, is relatively new to the United States, with only a few niche applications and studies growing biomass crops for fuel. However, the same problems with transportation costs would apply to energy crops like switchgrass, hybrid poplar trees, or miscanthus, shown in Figure 2-4. While they may have a slightly higher energy content than crop residues or forest thinnings, the cost of transportation remains the most prohibitive factor for these plants. The energy crops are grown and harvested on large areas of land to be sold for energy, so there is some extra cost beyond collection and transportation that is associated with purchasing this type of biomass fuel. Because of this, it is likely that dedicated energy crops will not become prevalent in the United States in the near future without the help of large new government incentives and subsidies. Another possibility is the cultivation of energy crop plantations near industrial sites, which would reduce transportation costs.

Wood waste is heavily utilized for fuel at industrial facilities in the United States, but there is a large amount of wood waste that is either land filled or not utilized to its full potential. The other biomass fuels are currently only utilized by a small number of industrial facilities, typically located close to farms or other sites that generate waste biomass. Current use and performance of biomass fuels in the United States will be studied in detail later in this report, along with the estimated potential for industrial heating applications. Case studies and current installations will be examined in Europe, where biomass fuels are more commonly used, as well as the United States.

Fuel Flexibility

Biomass fuels are fairly flexible, with the ability to be cofired with coal and tire-derived fuel. However, the effectiveness of co-firing can be limited due to wood's poor grindability. Pulverizers for coal are unable to handle high quantities of biomass fuels. Stokers and cyclone boilers are better suited for biomass co-firing, and fluidized bed boilers, which produce fewer emissions, can also be used. Equipment is often assigned an acceptable biomass percentage, typically between 5 and 20 percent, based on how well-suited it is for co-firing with a particular type of biomass fuel. However, this percentage can vary depending on the size, consistency, and quality of the biomass, so equipment operators must be careful to avoid using more than the system can handle. Using a high percentage of biomass fuels could cause slagging and fouling, increasing maintenance requirements, negatively affecting boiler performance, and potentially causing the system to shut down for extended periods of time.

Table 2-1 provides a comparison of coal and biomass fuels.

Table 2-1. Percentage Composition Comparison of Bituminous Coal to Biomass Fuels

Fuel	Carbon	Hydrogen	Oxygen	Nitrogen	Sulfur	Heat Content (MMBtu/lb)
Bituminous Coal	83-89	4-6	3-8	1.4-1.6	1.4-1.7	12,000-13,000
Wood (clean and dry)	50	6.1	43	0.2	n/a	6,000-8,000
Switchgrass	48	5.5	43	0.2	n/a	5,000-7,500

Source: Penn State College of Agricultural Sciences
HHV = higher heating value

While biomass fuels have a lower heating value than coal, they offer several advantages, such as lower carbon, nitrogen and sulfur content. The moisture content for biomass fuels can be as high as 50 percent for green wood, resulting in heating values as low as 4,000 MMBtu/lb, but biomass used for fuel is typically dried to a moisture content of about 20 percent. Biomass fuels with high moisture contents are more expensive to transport and result in lower boiler efficiencies, both of which can hinder project economics. However, it is not always practical to dry large quantities of biomass, and fuels known as green chips, with moisture contents of 40-50 percent, are sometimes used out of necessity.

There are three steps project developers can take to increase the fuel flexibility of biomass:

1. Utilize only biomass sources with a low moisture content – biomass fuels with a high moisture content do not combust as easily, provide less energy, and can reduce boiler efficiency. Do not store biomass fuels uncovered outdoors, as they will absorb rain water.
2. Process the biomass into small uniform pellets, to facilitate combustion – this process can be expensive, depending on the source and quality of the biomass. Some sites blend in pellets to improve average moisture content and boiler efficiency.
3. Make necessary adjustments to the fuel feeding and combustion systems of coal boilers to facilitate more biomass fuel – if no adjustments are made, the boiler will tolerate a lower percentage of biomass, and biomass preparation will need to be controlled to tighter tolerances

Most of the solid-fueled industrial process heating and steam generation equipment currently in use was originally designed for coal, with the only fuel feeding system modified to accept biomass. If new fuel-flexible equipment is introduced, designed to accept a wide variety of fuel types, the acceptable percentages of biomass would rise significantly, allowing for more emission reductions and cost savings from biomass utilization.

Biomass fuels can also be gasified and mixed with natural gas or other gaseous fuels. However, gasification technologies that produce high-quality biogas are relatively new, and in many cases the required gas cleanup costs can become prohibitive. The potential for biomass gas applications is explored in the Gaseous Opportunity Fuels section later in this Chapter.

Economics and Market Considerations

The collection and transportation of biomass fuels can be labor intensive and expensive. Biomass can typically be hauled for up to 75 miles at about $10-$20 a ton[14], with delivered costs typically ranging from $20 to $60 per dry ton[15], depending on the level of processing and the amount of transportation involved. This translates to $1.25 to $3.75 per MMBtu, a large range due to varying collection and transportation costs. Comparatively, delivered coal typically costs $40-$80 per ton, translating to $1.60 to $3.20 per MMBtu. There are certainly some areas of the country where biomass fuels are less expensive than coal on a Btu-basis. Wood waste fuels are often utilized on-site by the industrial wood processing facilities where the waste is created. At these sites, only fuel processing and on-site transportation costs are incurred, generally making wood waste the most economical fuel choice.

The availability of wood waste fuels depends highly on location. Wood fuels are only economically competitive with coal when the user is located very close to the source. In general, any truck-based transportation over 50 miles will become economically prohibitive. Rail and barge can be feasible over longer distances, but require special handling facilities to receive deliveries. However, some states offer incentives for utilizing renewable fuels, and in these locations, economics may hold up for further transportation distances. Overall, although availability can be spotty, the market for wood waste fuels is fairly large, and state incentives could expand the market even further.

Transportation costs are the primary reason that biomass fuels have trouble competing economically with other fuel sources. The heating value of biomass fuels is relatively low, so the cost to transport can become high on a $/Btu basis. A study that was recently conducted for Colorado's Office of Energy Management and Conservation quantified this problem.[16] The study showed that while nearly 36,000 dry tons of biomass are available from Summit and Eagle County's forest thinnings each year (enough to produce 3 MW of electricity), the delivered biomass fuel would cost about $100 per dry ton on average to obtain. In general, biomass can only compete with other fuels at less than $50 per dry ton. Users of biomass fuels must be located very close to the source to obtain economical fuel pricing.

One possible use of agricultural biomass could be to provide power to ethanol plants, which produce ethanol fuel from corn. These plants require heat for a number of different processes, and they are located close to sources of crop residues such as corn stover. A number of these ethanol production plants have recently been installed in the United States to provide fuel for vehicles (most of the ethanol is blended

[14] *Study of Processing and Utilizing Urban Wood Waste and Pallets for Fuel in the State of Minnesota*. M.L. Smith Environmental, Tinley Park, IL: January 1995.
[15] *Biomass Feedstock Availability in the United States: 1999 State Level Analysis*. United States Department of Energy - Oak Ridge National Laboratory. May 2006. http://bioenergy.ornl.gov/resourcedata/index.html
[16] *From Forest Thinnings to Boiler Fuel*, McNeil Technologies. Prepared for Colorado Office of Energy Management and Conservation. August 2004.

with gasoline). A study was conducted recently on the potential for biomass to be used for electricity and process heating at ethanol plants (see Chapter 5), although the near-term market for new ethanol plants is expected to be limited.

Environmental Issues

Biomass fuels are considered renewable resources, eligible for first-tier renewable portfolio standards in most states with RPS statutes. However, some states are specifying that only sustainable biomass fuel sources are eligible for top-tier RPS status and/or funding. The definition of sustainable, however, is difficult to pinpoint, with some definitions including such fuels as ADG, wood waste, and landfill gas (waste fuels that are constantly being produced). Other definitions of sustainable include only biomass derived from crops that are continuously grown, so only crop residues, forrest thinnings, and dedicated energy crops would apply. Regardless, utilizing biomass resources is seen as beneficial to the environment in comparison to fossil fuels, even though some forms of biomass may be more sustainable and carbon-neutral than others.

While combusting biomass fuels produces carbon dioxide, the planting of new crops or trees would cancel out many carbon emissions, causing some to label biomass fuels as carbon-neutral (i.e. the net amount of carbon dioxide released into the atmosphere is zero). This notion has recently been challenged by states such as Massachusetts, where new rules for biomass state incentives are being proposed and a state-sponsored study has suggested that some forms of biomass fuels may not be carbon-neutral in the short run.[17] There are some emissions produced in collecting, processing and transporting of biomass fuels, but this is generally the case for all fuels, renewable or not. Biomass fuels typically produce fewer NOx and SOx emissions than coal, so power plants could purchase biomass for co-firing in order to help reduce their emissions. Many coal power plants currently practice this with wood waste fuels. Biomass fuels produce about the same amount of particulate (PM-10) emissions as coal, so the same technologies (cyclones, multicyclones, core separators, etc.) can be used to bring particulates down to acceptable levels. Average uncontrolled and controlled emissions for wood fuels and coal are compared in Table 2-2.

[17] *Biomass Sustainability and Carbon Policy Study*, Manomet Center for Conservation Sciences. Prepared for Commonwealth of Massachusetts, Department of Energy Resources. June 2010.

Table 2-2. Average Uncontrolled Emissions from Wood and Coal

	Uncontrolled Emissions (lb/MMBtu)		Controlled Emissions (lb/MMBtu)	
Pollutant	**Wood**	**Coal**	**Wood**	**Coal**
Carbon Dioxide	206.94	214.04	206.94	214.04
Carbon Monoxide	0.600	0.025	0.35	0.025
Nitrogen Dioxide	0.220	0.510	0.10	0.07 - 0.38
Particulate Matter	0.570	0.460	0.01 - 0.02	0.001 - 0.02
Sulfur Dioxide	0.025	0.890	0.025	0.18 - 0.044

Source: Washington State Department of Natural Resources[18]

Wood ash is non-toxic and does not contain pollutants or heavy metals, unless using urban wood waste with pressure treated wood. However, some states still consider wood ash as hazardous waste, so disposal standards would need to be adhered.

Outlook for Industrial Potential

The outlook for the industrial potential of biomass fuels is uncertain. While there is a great amount of biomass in the United States that could be used as fuel, the cost of transportation is simply prohibitive for all but those located relatively close to the sources, which are often in remote areas. A recent Wall Street Journal article highlighted how several biomass power plants have recently shut down primarily because the high feedstock costs could not compete with traditional fossil fuels.[19] However, the outlook for wood waste in particular appears to be more positive than other biomass fuel types. While wood waste is already used extensively at industrial plants, there is a great deal more potential that could be realized, and urban sources of wood waste could provide inexpensive fuel to industrial facilities with shorter transportation distances.

Later in this report, the potential for biomass as a fuel for industrial heating applications is further explored, current biomass projects are examined, and the prospects for future projects in the United States are analyzed.

[18] *Forest Biomass and Air Emissions*, Washington State Department of Natural Resources.
[19] Carlton, Jim. *(Bio)Mass Confusion: High costs and environmental concerns have pushed biomass power to the sidelines in the U.S.* The Wall Street Journal. Page R5. October 18, 2010.

Tire-Derived Fuel

Tire-derived fuel (TDF) is a solid fuel derived from scrap rubber tires. The fuel's properties are similar to coal and if it is processed properly, it can be cofired with coal using no equipment modifications. There are 20 different grades of ground and shredded rubber from discarded tires, based on the size and consistency of the rubber chips. Typical TDF grades are 0.25 to 3 inches in size with varying degrees of wire removal. In order for TDF to be used as an independent fuel, high grade TDF with complete wire removal is usually required, but co-firing with coal allows for more tolerance of some metal content.

The composition of tire-derived fuel is similar to coal, with the main differences being a much lower nitrogen content, so less NOx is produced, a higher carbon content, and a lower moisture content. It has a heating value of 15,000-16,000 Btu/lb, while coal averages just over 13,000 Btu/lb. Table 2-3 charts the differences in composition, as obtained from an EPA study[20].

Table 2-3. Coal and TDF: Fuel Analysis by Weight Percent

Fuel	Carbon	Hydrogen	Oxygen	Nitrogen	Sulfur	Ash	Moisture	Heating Value (HHV, Btu/lb)
Coal	73.92	4.85	6.41	1.76	1.59	6.23	5.24	~13,000
TDF	83.87	7.09	2.17	0.24	1.23	4.78	0.62	~15,500

Source: EPA, Air Emissions from Scrap Tire Combustion

There are four steps followed when processing TDF:

1. Primary Shred – Double rotor shear shredder – strips 2 to 4 inches wide
2. Secondary Shred – Second shredder/granulator makes the finished size chips
3. Screening – Chips are screened with trammel or disc screens – oversize chips returned to #2
4. Metal Removal – Metal bead and wire is removed with magnets

Once all of these steps have been performed, the tire chips are ready to be used as fuel. The chip size and extent of metal wire removal determine how compatible TDF is with coal boilers – smaller chips with full wire removal can generally be blended with coal in coal boilers with no modifications or maintenance setbacks.

[20] Reisman, Joel I. and Lemieux, Paul M. *Air Emissions from Scrap Tire Combustion*, Environmental Protection Agency, Oct. 1997.

About 300 million tires are discarded each year in the United States.[21] Several hundred million tires are currently in landfills or tire piles, like the one shown in Figure 2-5. While there are many uses for recycled rubber from tires, the United States produces more tires than it can currently recycle each year. TDF has the potential to be a relatively lucrative option, and there is still plenty of room for TDF market growth in industrial co-firing applications. In many locations, tire-derived fuel could be less expensive than coal on a Btu-basis, so co-firing would be an easy way to save on energy costs.

Currently, TDF is used as a fuel for some cement kilns, because the high temperature of the kilns allows them to incinerate TDF with very little processing and wire removal – in many cases whole tires are used. There are also a few locations throughout the country where TDF is cofired with coal in large boilers at power plants. There could be a large potential market among industrial facilities and power plants for TDF co-firing applications.

Fuel Flexibility

Tire-derived fuel can generally be blended up to 20 percent with coal with no degradation in equipment performance, and no modifications are required for most coal boilers. Occasionally TDF can cause hot spots to develop in coal boilers, but this can be minimized by removing all metal and processing TDF into small chips. High grade TDF can even completely replace coal in some boilers, with only a slight increase in boiler maintenance costs. In order to successfully blend TDF in coal boilers, the following precautions should be taken:

1. Ensure the TDF is processed into rubber chips that are less than 1 square inch in size – small chips will blend and combust better than large ones
2. Remove all metal wiring from the tires – if all of the metal is not removed, the boiler will require significantly more maintenance and down time
3. Use higher boiler temperatures to completely combust the TDF – this can be more difficult in non-attainment areas, because high temperature combustion can increase emission levels

TDF can also be blended with biomass fuels such as wood chips. One 2009 Department of Energy Office of Energy Efficiency and Renewable Energy project is a pilot demonstration of a boiler at a Frito-Lay food processing plant in Topeka, Kansas that runs off a combination of wood waste and tire-derived fuel.[22] If this project is successful, it could open up a market for flexible fuel boilers that utilize a combination of biomass fuels and TDF. However, there are several technological hurdles that the project will need to overcome. These issues will be discussed later in the report.

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[21] *Scrap Tire Markets in the United States, 2005 Edition*. Rubber Manufacturers Association, November 2006.

[22] *Development and Demonstration of a Biomass Boiler for Food Processing Applications: Pilot Demonstration of a Boiler that Utilizes a Combination of Wood Waste and Tire-Derived Fuel*. United States Department of Energy Office of Energy Efficiency and Renewable Energy. http://www1.eere.energy.gov/industry/fuelflexibility/pdfs/biomass_boiler.pdf

Economics and Market Considerations

The processing costs for tire-derived fuel generally fall between $15 and $25 per ton, with the fuel selling for about five dollars more ($20-$30 per ton). A rule of thumb for transportation for solid fuels is typically around $10 per ton, per fifty miles. Therefore, with a fifty-mile trip, taking the heating value into account, TDF would cost about $1.00-$1.25 per MMBtu to obtain. This is less expensive than coal in most areas (coal is typically priced at over $1.50 per MMBtu), so co-firing with coal is an easy way for coal power plants to save money.

TDF does not require any special handling, and with a high energy content, transportation is not as costly as it is for biomass fuels. Still, transportation costs can add up over long distances, and a proximity of less than 100 miles to the TDF source is generally preferred. TDF ash can contain several different metals, potentially making it a hazardous material, so it can require special handling and disposal methods. However, this ash problem can be mitigated by completely removing metal wiring from the tires prior to combustion, which is also a recommended practice for preventing boiler fouling.

Government subsidies for waste tires are available in many states, and this can significantly reduce the cost of the fuel. In some cases, states without subsidies may purchase tires from nearby subsidized states because it is actually less costly than obtaining the tires from within their state. For example, TDF users and producers in California often purchase tires from Utah, Oregon and Arizona, where significant government subsidies are available.

Environmental Issues

The sulfur content of tire-derived fuel is fairly high, although it generally contains less sulfur than coal and produces slightly less SO_2 emissions as a result. NOx levels produced when combusting tire-derived fuel are extremely low in comparison. However, particulates have been known to increase substantially when TDF is added to coal boilers. The emission reduction technologies used with coal boilers also perform well with TDF, and theoretically, boilers built specifically for TDF would not require the extensive NOx treatment that is typically necessary for coal facilities. However, even for boilers

Figure 2-5. Tire Piles can be a Source of TDF
Source: Discard Studies, discardstudies.wordpress.com

that only utilize 10-20 percent TDF blends, additional particulate controls such as electrostatic precipitators or fabric filters would likely be necessary. For boilers combusting 100 percent TDF, substantial add-on controls for particulates would certainly be required.[23]

Although TDF is technically not considered a renewable resource, new tires are produced for all that are discarded, and the stockpile of waste tires grows in the United States each year. The utilization of TDF reduces waste, lowers emissions from coal boilers, and promotes the conservation of resources.

Outlook for Industrial Potential

Tire-derived fuel has the potential to be heavily utilized in industrial co-firing applications, due to its high heating value and ability to mix well with coal. TDF can also be cofired with biomass or petroleum coke, so it is a very flexible fuel. If TDF can be competitive with coal in price, and estimates show that it could be cost competitive with up to 100 miles of transportation, it has the potential to replace large amounts of coal at industrial plants. However, there is currently not a large infrastructure for TDF production, making availability an issue for some locations. If an infrastructure for TDF production and delivery is developed, resulting in widely available processed TDF at a lower energy cost than coal, there could be a very large nationwide demand for the fuel.

Petroleum Coke

Petroleum coke (pet coke), a carbon-rich black solid, is the byproduct of the coking conversion process that separates light and heavy crude oil products. There are two grades of petroleum coke: fuel grade, used as a fuel, and anode grade, used for the manufacture of dry cells and electrodes. Fuel grade pet coke is abundant in supply and its price has always been less than that of coal. Some drawbacks of pet coke include a low volatility, a high sulfur content, and high nickel and vanadium contents in the ash. However, the fuel offers a high heat content (14,000 Btu/lb) and favorable grindability for use in coal boilers, at a very low cost. The cost has been so low that some industrial facilities in China and Japan import petroleum coke from the United States rather than using coal. In fact, the majority of pet coke produced in the U.S. is exported to foreign markets.

In the United States, the Department of Energy estimates that the largest users of petroleum coke (other than refineries) are independent power producers, who often fire 100 percent coke, not a coal-coke blend, in large boiler/steam turbine systems. However, the fuel is capable of being blended with coal, tire-derived fuel and a number of other solid fuels in industrial heating applications. It is commonly used at pulp and paper mills in the Gulf States area, where petroleum coke supply is plentiful.

[23] Reisman, Joel I. and Lemieux, Paul M. *Air Emissions from Scrap Tire Combustion*, Environmental Protection Agency, Oct. 1997.

Fuel Flexibility

Petroleum coke can easily be cofired with coal and tire-derived fuel, and likely biomass fuels as well. Pet coke can be cofired in coal boilers with no modifications required, although more frequent maintenance is necessary when it is used in high percentages, and additional environmental controls for sulfur may need to be applied. Pet coke is very similar to coal in its properties, so it is generally an ideal and flexible fuel that can be used in any coal boiler. However, pet coke's combustion properties are not as favorable as coal, which can be an issue for some boiler types. This also causes problems when cofiring high percentages of pet coke with coal, so cofiring is typically limited to about 20 percent. Fluidized bed boilers are generally preferred in order to ensure complete combustion. Another potential drawback is slightly increased maintenance compared to coal, with pet coke more prone to incomplete combustion and fouling. The level of increased maintenance depends on the boiler design.

Economics and Market Considerations

The production of petroleum coke is driven by the demand for light crude oil products, not by the demand for pet coke itself. With light crude oil products like butane and jet fuel in high demand, the supply of pet coke will be high for years to come. This surplus is what drives down the price of pet coke. Recently, the price has fallen to as low as \$15/ton, as compared to coal prices of about \$30/ton during the same period.

In the United States, large independent power producers and refineries are the main users of pet coke, with utilities and some industrial sites using it sparingly as an alternative boiler fuel. Worldwide, petroleum coke is most often used in cement kilns and calcining operations. The best markets for pet coke are places where coal is less readily available and/or more expensive, such as China and Japan. Strict environmental regulations in the United States prevent pet coke from overtaking coal as a boiler fuel for industrial operations, but when it can be purchased for less than coal, co-firing could be an attractive option.

Environmental Issues

Petroleum coke typically has a very high sulfur content (up to 8 percent), which causes significant sulfur oxide emissions. Pet coke also produces more NOx emissions than coal. According to EPA eGRID2010 data, the CII Carbon LLC plant that combusts petroleum coke as a primary fuel produces 11.67 lb/MWh of NOx and 134.58 lb/MWh of SO_2, both of which are several times more than coal plants produce.[24] As a result, there are very few facilities that combust petroleum coke as a primary fuel, and most facilities that use pet coke blends have to install additional controls for both criteria pollutants. Petroleum coke also produces a high number of particulate emissions that must be properly filtered, and pet coke carbon emissions are on about the same level as coal.

[24] Emissions and Generation Resource Integrated Database, United States Environmental Protection Agency. 2010.

In addition to high emission levels, petroleum coke combustion leaves behind large amounts of ash containing high levels of nickel and vanadium. The ash is considered hazardous waste and must be disposed of properly, which adds a considerable amount to operation and maintenance costs. Finally, pet coke is prone to produce more dust than most coals, so fuel storage and handling facilities may need to construct covers that prevent pet coke dust from polluting the nearby air.

Outlook for Industrial Potential

Emission controls and environmental concerns are the primary barriers to most United States petroleum coke projects, limiting the amount of pet coke facilities can use. Blending small percentages of pet coke with coal could provide savings for industrial facilities without significantly increasing emissions. Additionally, if the price of pet coke is considerably less than coal, installing emission controls and utilizing more pet coke could prove beneficial in the long run. This report will explore these issues and estimate the potential for petroleum coke in industrial process heating and steam generation applications.

Summary

There are several gaseous and solid opportunity fuels with the potential to be utilized in industrial heating applications. Gaseous opportunity fuels can be blended with natural gas, and sometimes other gaseous fuels. Solid fuels can be blended with coal, or with each other, in industrial boilers. The flexibility of the opportunity fuels to perform in various industrial process heating and steam generation applications is examined in this report. Additionally, estimates will be made for the total industrial potential for opportunity fuel utilization in the United States.

The following chapter outlines the various industrial heating technologies that can be used with solid and gaseous opportunity fuels. After that, the availability and technical potential for each of these fuels is further explored, current projects are analyzed, and future prospects for projects in the United States are considered. Finally, the industrial market potential for each opportunity fuel is assessed, conclusions are drawn, and recommendations for future projects are made.

3. Process Heating and Steam Generation Technologies for Opportunity Fuels

In order for opportunity fuels to be utilized at industrial facilities, process heating and/or steam generation equipment must be able to handle at least a small percentage of the fuels without significant increases to operational costs or system maintenance requirements. Typically, equipment that was designed for natural gas or coal must be modified to accept opportunity fuels. When blended in small proportions, opportunity fuels can be cofired with conventional fuels, often with no equipment modifications required. Alternatively, fuel-flexible burners can be designed to handle a wide variety of both conventional and unconventional fuels for both boilers and process heating equipment. In this chapter, both approaches are considered for each opportunity fuel, and the technical and economical issues associated with utilizing the fuels in process heating and steam generation applications are explored.

Gaseous Opportunity Fuels

Gaseous opportunity fuels can generally be accommodated with more flexibility than solid fuels, allowing blends of multiple gaseous fuels to be utilized with minimal oversight. Gaseous opportunity fuels can supplement or replace natural gas in a wide variety of industrial process heating and steam generation applications. Solid opportunity fuels, on the other hand, are typically limited to steam generation applications using boilers, with potential fuel blending issues arising for several boiler types. Gaseous fuels are, however, more challenging to transport if pipeline infrastructure is not in place. Gas-fired boilers have a smaller footprint and require roughly half the initial investment of solid-fueled boilers, so they are more common for industrial applications with access to natural gas pipelines. The following types of steam generation and process heating equipment for gaseous opportunity fuels are analyzed in this section:

- Boilers
- Conduction/Convection Heaters
- Dryers
- Furnaces
- Heat Exchangers
- Ovens

Process heating applications can be placed into three categories: fuel-based, electricity-based, and steam-based applications. Steam-based process heating applications utilize boilers to generate steam. Electricity-based process heating systems typically use electric resistance or induction heating, but electricity can also be used to generate infrared, ultraviolet, radio-frequency and microwave radiation, which can be used for heating. Fuel-based process heating systems combust fuels for heat, using convection, conduction and/or radiation to transfer heat to a material. In this section, the technical aspects of fuel-based process heating systems incorporating gaseous opportunity fuels will be analyzed, along with steam-based systems (boilers) that utilize gaseous fuels. Thermal systems that use electricity will not be considered, because opportunity fuels cannot replace electric-based heating systems without major equipment replacement, and this is not common practice.

While most gaseous-fueled boilers and process heating systems are designed for natural gas, some minor modifications can allow them to utilize different blends of opportunity fuels. This section provides an overview of the industrial steam generation and process heating technologies that can utilize gaseous opportunity fuels, identifying problem areas and potential research and development opportunities.

Boilers and Process Heating Equipment for Gaseous Opportunity Fuels

The process of combusting natural gas in a boiler is relatively simple compared to the several different methods that are employed to break down and combust solid fuels like coal. Process heating applications using natural gas are also relatively simple in design, due to the consistent qualities of natural gas and efficient combustion methods. In process heating systems, natural gas enters the combustion chamber and is mixed with air and flame, resulting in a steady controlled burn. Heat is then exchanged through one of several different methods including conduction, convection and fluid heat transfer. With boilers, the heat is transferred to pipes or a drum filled with water in order to generate steam, which can be used for various industrial purposes. With other process heating systems, heat is typically transferred to a material or object, as part of an industrial manufacturing process. Process heaters can transfer heat directly (via radiation and contact with combusted gas) or indirectly, through convection and conduction.

Figure 3-1 shows an industrial gas-fired oven used for preheating aluminum billets. Natural gas is fed to the combustion chamber above the conveyor, and the heat is transferred via forced convection to the aluminum billets that are continuously fed into the oven. The heated billets are then incorporated into a manufacturing process that takes advantage of aluminum's thermal properties at this particular temperature. This oven represents a typical industrial process heating application.

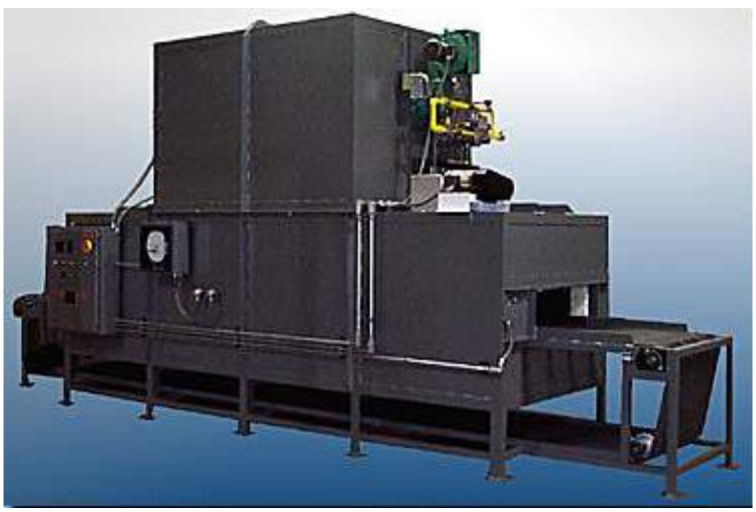

Figure 3-1. Industrial Oven for Process Heating Aluminum Billets
Source: Engineered Production Systems

The industrial oven could potentially be modified to incorporate fuels other than natural gas, a process that typically involves two steps: 1) fuel pretreatment, removing contaminants and particulates from the gaseous opportunity fuel, and 2) modifications to piping and fuel/air ratio in the combustion chamber, to accommodate lower heating values, while maintaining the desired flame temperature. The quality of the fuel, in terms of contaminants and heating value, as well as the percentage to be blended with natural gas, determines the extent of the modifications that are required. In many cases, properly treated opportunity fuels are capable of supplementing or replacing natural gas without any equipment modifications, although there could be some undesirable results such as increased cleaning and maintenance intervals. Higher percentages of opportunity fuels tend to disrupt the proper fuel-to-air ratios for natural gas combustion, so major modifications could be required to adjust the flow rates and combustion timing. This section details how the different opportunity fuels perform with natural gas heating equipment, and what adjustments or modifications are required to maintain natural gas performance levels.

Anaerobic Digester Gas and Landfill Gas

Anaerobic digester gas and landfill gas are produced by similar mechanisms, and have similar compositions, with heat contents ranging from 400 to 600 Btu/ft^3. While ADG is typically of a slightly higher quality than LFG, this is not always the case, and the primary difference in the two gases is the locations where they are produced. ADG is produced at wastewater treatment plants and farms with anaerobic digesters, while LFG is produced at landfills, which have minimal on-site heat and power demands. In terms of performance, the two fuels can be thought of as interchangeable, and in this section, they will commonly be referred to as biogas.

Table 3-1 provides a breakdown of the composition of ADG and LFG compared to natural gas.

Table 3-1. Typical Concentration Ranges for ADG/LFG (Water Removed)

Constituent Gas	ADG	LFG	Natural Gas
Methane	40-65%	35-60%	87-96%
Carbon Dioxide	30-55%	30-50%	0.1-1%
Nitrogen	1-5%	2-10%	1-6%
Oxygen	0.1-1%	0.1-2%	0-0.1%
Ammonia	0.1-1%	0.1-1%	N/A
Hydrogen	<0.2%	<0.2%	0-0.1%
Hydrogen Sulfide	<0.2%	<0.2%	<0.2%
Siloxanes	<0.01%	<0.01%	N/A

Sources: EPA reports, Montgomery County MD Landfill data, Union Gas Natural Gas data

Hydrogen, hydrogen sulfides and siloxanes are particularly undesirable, with LFG and ADG often containing significantly higher levels than natural gas. Hydrogen can embrittle metal over time, while the presence of hydrogen sulfide leads to the creation of sulfuric acid, which is corrosive in nature and can erode metals. Siloxanes tend to accumulate on metals and create large deposits that can affect heat transferring capabilities. In addition, sometimes relatively high levels of halogens are present in LFG, which can lead to the creation of toxic dioxin compounds when combusted, and potential formation of corrosive acid which could foul combustor surfaces if not properly treated.

Modifying Industrial Equipment for Anaerobic Digester Gas and Landfill Gas

In general, biogas that has been properly cleaned and treated can be used to supplement natural gas in industrial heating equipment without a noticeable change in heat output. When large percentages of biogas are used, heat output can be slightly degraded and larger gas inlet piping, burner adjustments and modified controls may be required to maintain the desired flame temperature. This is largely due to high amounts of carbon dioxide found in biogas, as CO_2 does not provide energy in the combustion process, but does increase the system mass flow. Water washing, a technique that uses counter-flows of cascading water to scrub CO_2 and other trace elements out of the gas, can be used to upgrade the heating value of ADG/LFG. Effective scrubbing can remove most of the carbon dioxide in the gas, improving biogas quality to natural gas BTU levels, although selling the scrubbed biogas as natural gas could prove to be more profitable than utilizing it for industrial process heating. Some current projects at landfills produce a higher BTU level gas for sales by removing the CO_2 with water washing and other scrubbing or absorption techniques.

Industrial sites can retrofit current natural gas boilers or process heaters to utilize ADG or LFG by making adjustments to the burner, fuel train and controls. Some current installations have retained the original burner, but modified it by installing a separate fuel train and gas spuds for the lower-quality biogas, allowing the existing fuel train to be used for natural gas cofiring. Other sites have replaced the entire burner, controls and fuel train with a dual-fuel burner and dual-fuel trains designed to handle the lower heating value of biogas.[1] The decision usually comes down to whether or not the existing burner and controls are close to the end of their useful lives. Biogas also typically contains more moisture than natural gas, so corrosion-resistant materials such as stainless steel should be used, but effective pretreatment will remove most water from the gas.

The majority of expenditures for industrial sites that seek to incorporate biogas involve the pretreatment process, as opposed to equipment modifications. Basic biogas pretreatment typically involves the removal of water and particulates prior to utilization, and pressurization to natural gas pipeline levels. Hydrogen sulfide and siloxanes may also require processing, depending on levels of contamination, but removing these contaminants is an expensive process. Gas samples can be evaluated to determine contamination levels and develop an appropriate treatment strategy. There are several different methods for project operators to consider, but process heating equipment can generally tolerate higher levels of contaminants than engines or turbines. For example, siloxane deposits may be a minor concern for

[1] United States Environmental Protection Agency, Landfill Methane Outreach Program, *Adapting Boilers to Utilize Landfill Gas: An Environmentally and Economically Beneficial Opportunity.*

industrial process heating operations, even though they can cause severe damage to CHP engines over time.

For sites that utilize blends of biogas and natural gas, the biogas is often compressed and utilized directly after the pretreatment process, with the level of natural gas flow adjusted accordingly using modern controls, oxygen analyzers and/or flame sensors. However, other applications may require the storage of treated biogas in order smooth out irregularities in gas quality and flow rate and maintain a steady fuel stream. In these cases, pressurized storage vessels will be required. If required, high-pressure storage typically needs steel vessels, while most applications with lower pressure requirements allow concrete, plastic, or membrane storage vessels to be used.

Technology Costs and Limitations

The primary costs for biogas-fueled process heating and steam generation systems involve the fuel pretreatment equipment. For most applications, unless concentrations are very high, siloxane removal will not be required. This is especially true for applications blending ADG/LFG with natural gas. The only requirements for biogas pretreatment will typically be water removal, the filtering of particulate matter, and possibly hydrogen sulfide removal via an iron mesh or sponge. The biogas also needs to be compressed to natural gas pressure levels prior to mixing or utilization. The overall equipment cost will depend on the size of the application and the composition of the gas, but published costs of similar systems have ranged from $50,000-$250,000. For larger industrial applications, total pretreatment costs could rise to $500,000 or more. The EPA's Landfill Methane Outreach program estimates that direct use of landfill gas (i.e. steam generation or process heating) requires about $960 per cubic foot per minute for gas pretreatment and compression, plus $90 per cubic foot per minute on an annual basis for equipment maintenance.[2] While larger landfills may produce enough gas to lower the unit costs, these basic estimates are used throughout the economic analysis.

While ADG and LFG that has been properly cleaned can often be blended with natural gas with no equipment modifications, using 100 percent ADG or LFG requires several changes to a natural gas boiler system. Retrofitting the fuel train, adjusting the process controls and modifying the burner tends to cost between $100,000 and $400,000 for most boiler systems.[3] For process heating equipment, similar costs can be expected when switching to 100 percent opportunity fuels.

One limitation for potential ADG sources at wastewater treatment plants is only a small fraction of plants (about one fourth of municipal plants, and far fewer industrial plants) contain anaerobic digesters. The anaerobic process is best suited for larger wastewater treatment plants. The majority of treatment plants use the process of aerobic digestion to treat their waste, although anaerobic digestion could offer several benefits, including significantly less power usage. Still, the likelihood of convincing a facility owner to overhaul their treatment system is small because the cost to install an anaerobic digester is high, with a

[2] United States Environmental Protection Agency, Landfill Methane Outreach Program, *LFG Energy Project Development Handbook*, 2010. http://www.epa.gov/lmop/publications-tools/handbook.html
[3] Ibid.

larger footprint than aerobic systems. For this reason, the market potential analysis later in this report will only consider wastewater treatment plants that already have anaerobic digesters installed, and are not currently utilizing their gas for power.

The main limitation with LFG is the distance that the gas be pipelined for use at industrial facilities, and the effort required to resolve right-of-way issues. Landfill gas projects are typically limited to a 2 to 5 mile radius of the landfill, after which pipeline costs (at over $300,000/mile) begin to become prohibitive. Some industrial projects have involved pipelines over 10 miles in length, so 5 miles is not a firm limitation. Later in this report, the economic analysis will determine how pipeline lengths affect the economics of LFG industrial process heating applications.

Examples of Flexible Industrial ADG/LFG Utilization

At the White Street Landfill in North Carolina, landfill gas is routed three miles to the Cone Mills White Oak Plant, which manufactures denim clothing. In the 1990s, the plant installed two multi-fuel burners in a boiler with a total steaming capacity of 30,000 lb/hr. The multi-fuel burners utilize all of the LFG from the landfill, and use varying levels of natural gas or fuel oil as a supplement. The steam produced is used for various plant operations. With the multi-fuel burners, natural gas or fuel oil can be used to increase boiler capacity when additional steam is needed.

Figure 3-2. Dual-Fuel ADG Burner
Source: Burns & McDonnell

A recent example of industrial ADG utilization can be found at the Penford Foods plant in Richland, Washington. The plant treats its food waste on-site with an anaerobic digester, but ADG production is prone to large fluctuations, making it difficult to utilize. A new multi-burner design by Burns & McDonnell was recently installed that allows their ADG to be utilized without a storage vessel to regulate gas flow.[4] The digester gas is burned at the same variable rate at which it is produced, while an auto-regulated natural gas stream is used to keep the flame steady. This new system opens the door for smaller ADG utilization projects, which could be beneficial to industrial sites that use anaerobic digestion on a smaller scale than most municipal wastewater treatment plants.

Going forward, most industrial ADG and LFG utilization projects will likely incorporate boilers or process heating systems with multi-fuel burners that can react to variations in biogas flow rate. The

[4] Burns & McDonnell – Biogas Utilization System for Manufacturing Facility, http://www.burnsmcd.com/Projects/Detail/Biogas-Utilization-System-for-Manufacturing-Facility

United States Department of Energy's Advanced Manufacturing Office is currently conducting a research effort to develop a fuel blending and combustion system to handle a wide variety of fuel compositions, including ADG, LFG, natural gas, synthetic biomass gas and refinery fuel gas. ENVIRON International is managing the project and conducting the modeling analyses, while Callidus Technologies by Honeywell will help with the conceptual designs and test activities, ultimately manufacturing and marketing the technology. When this research effort has been completed, the multi-fuel burners could facilitate the implementation of industrial ADG and LFG in various process heating applications.

More examples of current LFG and ADG utilization projects are provided in Chapter 5, which reviews the current status of industrial projects and evaluates future prospects for flexible opportunity fuel utilization.

Biomass Gas

Biomass gas, a synthetic gas produced from gasifying solid biomass fuels, can vary greatly in quality and composition depending on the biomass source and the type of gasifier. Biomass gasification systems have been under development since World War II, where low-quality (~150 Btu/ft^3) syngas made from waste wood was used to provide fuel for troops. Recently, advanced gasifiers have been developed that are capable of producing a higher-quality biogas with a heat content of 450-600 Btu/ft^3, capturing up to 80 percent of the solid energy content. Close-coupled gasification systems utilize the hot biogas on-site as it exits the gasifier, usually in boilers or kilns which make use of its high thermal energy. However, when gasification is used to develop a cleaner, higher heating value fuel, some difficulties have arisen due to high levels of tars and other contaminants, especially when hot gas cleanup methods are necessary.

There are several advanced gasification processes that can produce biomass gas with a relatively high calorific value. Typically, the synthetic biogas contains less than 20 percent methane, but relatively high percentages of carbon monoxide and hydrogen help increase the heating value. Methods such as the SilvaGas® process could be employed on a large scale, most likely utilizing a combined cycle turbine system where leftover steam is used in the gasification process. The SilvaGas gasification method, developed by Future Energy Resources Corporation and currently owned by Rentech, utilizes two circulating fluidized bed reactors to produce synthetic biomass gas. Circulating sand is used as a heat transfer medium to rapidly heat incoming biomass and convey char from the gasification reactor into the combustor. This process is illustrated in Figure 3-3.

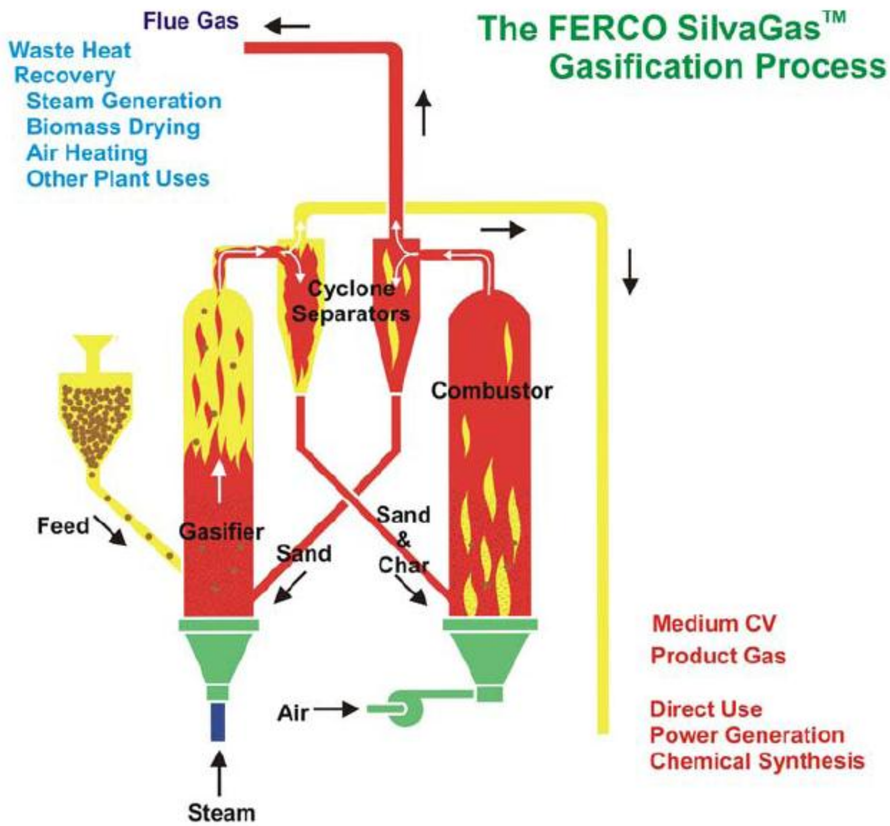

Figure 3-3. The SilvaGas Gasification Process

Source: Future Energy Resources (now Rentech), http://rentechinc.com/silvaGas.php

The Taylor gasification process developed at the Taylor Recycling Facility in Montgomery, NY and the European FCIFB gasification process incorporate similar dual-reactor fluidized bed methods. All of these indirect gasification systems produce biomass gas with a heat content of 450-600 Btu/ft^3. While these gasifiers have been developed for large power generation systems, they can potentially be used for close-coupled industrial steam generation applications. The cost of a close-coupled gasification system, however, can be significantly higher than a biomass boiler, and it is likely that additional gas cleanup/pretreatment equipment will be required. Table 3-2 provides the composition percentages for all three advanced gasification systems.

Table 3-2. Biomass Gas Composition from Three Advanced Fluidized Bed Gasifiers

Component, o/v	Taylor	FICFB	SilvaGas®
Hydrogen	45-48	37.7	20.7
Carbon Monoxide	15-20	29.1	46
Methane	10-13	10.4	15.6
Ethylene	1-3	2.8	5.3
Carbon Dioxide	18-20	19.6	11.1
Ethane	0-1	0.3	0.7
Nitrogen	trace	0.1	0.6

Source: Taylor Biomass Energy, http://www.taylorbiomassenergy.com/berlin.pdf

Other gasification processes have been developed that are essentially low-oxygen fluidized bed boilers designed to produce a gas, rather than provide heat for steam generation (although steam production is often a useful by-product). These systems utilize direct gasification, rather than the indirect dual-reactor systems previously described. The Gas Technology Institute (GTI) patented the RENUGAS® process, which uses this direct gasification method. With these gasifiers, the product gas is extremely high-temperature, and hot gas cleanup could be required prior to utilization. This can be a major hindrance to potential projects, since it is an expensive process. In addition, direct gasification systems tend to produce biomass gas with a lower heating value than their indirect counterparts. However, some companies such as Energy Products of Idaho (EPI) have recently begun to install these fluidized bed gasifier systems at industrial facilities, generating both steam and high-temperature gas in a close-coupled system for on-site use. These installations will be explored later in this report.

For fluidized bed gasifiers, aside from a few close-coupled industrial boiler installations, most applications have been large-scale power generation with combined cycle turbine systems (primarily limited to demonstration projects). Fixed bed, updraft current gasifiers, on the other hand, are capable of producing biomass gas on a much smaller scale, and could be more suitable for some industrial process heating applications. Nexterra produces an advanced fixed bed updraft gasifier that generates biomass gas at 500-700 ^{o}F. The company has been working on the design for many years, and its product is nearly ready for commercialization. However, gas cleanup issues have been a concern in demonstration projects, so Nexterra is working on gas conditioning technologies that will allow their biomass gas to replace natural gas in CHP engine applications. These same technologies could potentially be used for industrial process heating, although the company plans call for commercialization of this application after 2013.

Close-coupled gasifiers with boilers are already commercially available, although they are typically only used at industrial plants that produce biomass waste products. Existing natural gas or fuel oil boilers at industrial sites can be retrofit to work with close-coupled gasifiers, using solid waste for fuel. The best prospects for fuel-flexible implementation of biomass gas at industrial facilities lie with advanced two-stage gasifiers that can produce a clean syngas for use in various process heating applications. These systems, including fluidized bed and fixed bed updraft gasifiers, are currently under development. Current installations of both close-coupled and two-stage gasification systems will be further examined in Chapter 5 of this report.

Modifying Industrial Equipment for Biomass Gas

Close-coupled gasification systems can produce biomass gas for steam generation applications using commercially available technology, with boilers that have been modified to work with the high-temperature syngas. An example of this practice can be found at the University of Vermont, where a feasibility study was recently conducted for converting an existing natural gas boiler into a close-coupled gasification system with a Chiptec gasifier. The gasifier would utilize various types of wood fuel from nearby resources in Vermont, while the modified boiler combusts the syngas to produce steam and hot water for University operations. Significant adjustments to the boiler house would be required to accommodate the gasifier and biomass storage/feeding equipment, while modifications to the boiler itself are expected to be fairly minimal.[5] Although hopes are high that the gasification system will cut down on boiler fuel costs while taking advantage of Vermont's renewable resources, many of the cost estimates in the feasibility study are rough estimates, and it is uncertain if the University will ultimately follow through with their plan.

For industrial heating processes requiring gas that has been cleaned, cooled and compressed, advanced two-stage gasifiers could potentially be capable of substituting or replacing natural gas in most industrial steam generation and process heating equipment.[6] For most process heating applications, a gasifier (with biomass storage and feeding systems), a gas treatment skid (to cool and clean the gas) and a compressor (to pressurize the gas to NG levels) would be required for industrial sites to utilize biomass gas with traditional process heating equipment. Some minor modifications to the fuel input and air inlet settings for the combustion chamber would likely be required. However, current hot gas cleanup methods are expensive and difficult to implement, so the gas typically must be cooled below 100 ^{o}F before it is treated. This is the main reason that only close-coupled gasification systems utilizing hot syngas have had commercial success.

Technology Costs and Limitations

Gasifiers are expensive systems, with high capital costs and significant operation and maintenance requirements, and advanced gasifiers yielding a clean and versatile syngas have yet to reach commercialization status. When hot gas cleanup and pretreatment equipment are required, the initial capital costs can be extremely prohibitive. In addition, a steady source of low-cost biomass fuel deliveries must be obtained, along with a storage silo and feeding system for the gasifier. Overall, biomass gas projects are very capital intensive, with considerably higher maintenance costs compared to

[5] Nichols, Lance, Peterson, Nick and Patterson, Isaiah, *Trinity Campus Biomass Feasibility Study*, The University of Vermont, Physical Plant Department.

[6] Peterson, David and Haase, Scott, *Market Assessment of Biomass Gasification and Combustion Technology for Small- and Medium-Scale Applciations*, Technical Report for National Renewable Energy Laboratory, July 2009.

natural gas, so savings from fuel purchases must be significant in order to achieve a return on the investment. As with any opportunity fuel, expectations that conventional fuels such as natural gas could experience elevated and/or volatile pricing are critical to considering such an investment.

These constraints alone cause severe limitations on potential industrial applications for biomass gas, and the fact that advanced two-stage gasifiers are not seen as commercially available further limits current options for project operators. At present, only close-coupled gasification systems are commercially available, and the potential for these applications will be further explored later in this report.

Examples of Flexible Industrial Biomass Gas Utilization

The Shaw Waste to Energy facility in Dalton, Georgia was the first of its kind in the United States to employ gasification to utilize waste from their industrial operations. The gasifier, a joint effort of Shaw, Primenergy and Siemens Technologies, uses carpet waste and laminate wood flour from Shaw's manufacturing facilities to produce steam to be used in carpet dyeing operations. The hot synthetic gases from the gasifier are absorbed by a boiler in a close-coupled system, eliminating the need for hot gas cleanup. Primenergy has tested more than 25 different feedstocks for the gasification system, including some that are recognized as the most difficult for energy conversion, such as sugar cane bagasse, tire-derived fuel, refuse-derived fuel, paper-plant pulp sludge, and sewage sludge. For all of the biomass materials that were tested, the process required no auxiliary fossil fuel to maintain continuous operation, and the same was true for the carpet waste.[7]

While there have been other industrial gasifier installations (see Chapter 5 for a full review of current projects), only close-coupled gasification systems that directly utilize the hot syngas have been successfully utilized at industrial sites. Advanced two-stage gasifiers have been used in demonstration projects for power generation, but their results have been under scrutiny due to gas cleanup and equipment maintenance issues. However, new close-coupled gasifiers such as those show some promise for industrial boiler applications, with the potential to utilize solid waste fuels that would pose difficulties in traditional boiler systems.

Currently, biomass gas is difficult to justify for industrial steam generation or process heating applications, because the gasification technologies are very capital intensive and, for processes that require a clean syngas, they have not been commercially established. But with more research and development, successful demonstration projects, and fully commercialized technology, biomass gasifiers could create many opportunities for the utilization of waste biomass fuels at industrial manufacturing sites.

[7] Ritchie, Ed, *Wall-to-Wall Energy Solution: A new gasification plant could save millions in fuel and landfill costs*, Distributed Energy – The Journal of Energy Efficiency & Reliability. http://www.distributedenergy.com/july-august-2006/energy-solution-gasification.aspx

Industrial Waste Gases

Blast furnace gas and coke oven gas must undergo extensive treatment in order to be used as a fuel for industrial steam generation or process heating operations. Both gases contain several impurities that need to be removed to avoid corrosion and fouling of equipment, and also to meet environmental regulations. Both of these waste gases have already been extensively utilized for fuel, so there are established methods for cleaning and treating the gas to make it safe for industrial equipment.

Blast Furnace Gas Cleaning

Blast furnace gas contains dust particles up to a quarter inch in size, generally referred to as flue dust, which includes particles of coke and chemical compounds formed in the blast furnace reactions. The cleaning of blast furnace gas first involves removing these dust particles with a dust catcher system that removes and collects dust and particulates in the gas. This system consists of a brick-lined cylindrical structure with a conically shaped section at the bottom. The gas enters through a pipe at the top, which flares outward at the bottom to slow down the velocity, dropping many of the larger dust particles. The gas then reverses direction, moving up to the outlet at the top of the dust catcher, causing more small particles to drop out of the gas stream. After this process, the gas travels to the wet cleaning system where very fine particles of dust are scrubbed out of the gas with water. The gas is then ready to be utilized, and it is typically used on-site to heat the blast furnace stoves, or it can be blended with natural gas in boilers or other heating applications.

Coke Oven Gas Cleaning

Coke oven gas contains several impurities like ammonia, hydrogen sulfide and hydrogen cyanide that need to be removed through specific methods. First, coke oven gas is sprayed with an aqueous flushing liquor, causing it to become saturated with water vapor. To condense out the vapor, the gas must be cooled. This process also removes some other contaminants from the coke oven gas, and causes tar vapor to condense and form aerosols. These tar particles would contaminate and foul downstream processes, so they must be removed from the gas. This is accomplished with tar precipitators that charge the tar particles with high voltage electrodes, allowing them to be collected from the gas through electrostatic attraction.

With the next step, ammonia is then removed from the coke oven gas, through one of two processes. Historically, ammonia has been removed with a sulfuric acid solution. This process creates ammonium sulfate, a fertilizer that can be packaged and sold. However, the cost to produce ammonium sulfate often outweighs the revenue from the product, so more modern processes for ammonia removal have been developed. The most common method is the water wash process, which scrubs coke oven gas with water and dissolves ammonia, along with some hydrogen sulfide and hydrogen cyanide. The solution is then pumped to an ammonia still where steam is used to strip out the ammonia.

Light oils are then removed from the coke oven gas, and it is desulfurized through one of several processes. Hydrogen sulfide can be absorbed using the vacuum carbonate process, the ammonia wash process, or the sulfiban process. All of these processes involve the absorption of hydrogen sulfide, using different solutions, and stripping out the sulfur in a still. Once the gas is cleaned, it is typically used by the plant for heating purposes. At coke plants, about 40 percent of the recovered coke oven gas is used in the coke oven itself, with some used in heating and annealing furnaces and boilers. The remaining gas is flared, although integrated steel mills tend to utilize the vast majority of their coke oven gas for on-site operations. Merchant coke plants do not have much use for the gas outside of heating the coke ovens, so these facilities are seen as primary potential sources of surplus coke oven gas.

Modifying Equipment for Industrial Waste Gases

With the exception of refinery fuel gas, which is close to natural gas in quality, industrial waste gases tend to have low heat contents and unfavorable emission-producing qualities. Natural gas equipment can be modified to incorporate these fuels by using larger fuel piping and adjusting the gas flow rate to air intake ratio in the combustion chamber. In some cases, additional emission control equipment could be required. More often, industrial waste gases are used in conjunction with natural gas, and modifications to process heating or steam generation equipment are minimal.

Technology Costs and Limitations

The process of cleaning blast furnace gas and coke oven gas is fairly intensive, and plants without cleaning equipment would require a large capital cost investment. However, most plants with blast furnaces or coke ovens have this equipment in place already, and utilize a large portion of the waste gas for on-site heating operations. Any natural gas-fueled process heating system can incorporate a small percentage of coke oven or blast furnace gas, and equipment modifications to allow higher waste gas percentages should not be cost-prohibitive, aside from potential air permitting issues depending on the site location.

The main limitation on the potential for industrial waste gases then, is the number of facilities that produce the fuels, and their current waste gas utilization strategies. Industrial waste gases are generally limited to on-site use, with little marketability, and emissions can be a problem in areas with strict environmental regulations. Local air quality permit requirements could determine the level of gas cleanup that is required prior to utilization.

Examples of Flexible Industrial Waste Gas Utilization

Blast furnace gas is commonly captured and used on-site at steel mills, but it is not always completely utilized. In 2009, a project funded by the American Recovery and Reinvestment Act was proposed to construct and operate a blast furnace gas recovery boiler at ArcelorMittal's Indiana Harbor Steel Mill in East Chicago, Indiana. Currently, ArcelorMittal flares about 22 percent of the blast furnace gas, while the remaining 78 percent is used to power boilers for on-site operations. The proposed project would use the excess gas to power a new 80-percent efficient boiler and produce steam to be used in existing steam turbines for 38 MW of power generation. The final environmental assessment for the project was completed in August 2010.[8] Groundbreaking for the $63.2 million project began on October 28, 2010, with an expected completion date in early 2012.[9]

Coke oven gas utilization is common practice in the United States steel industry. For example, at the Clairton, Pennsylvania coke plant, which produces coke for use in steel making at the nearby Mon Valley Works facility, coke oven gas is cleaned, transported to the Mon Valley Works site via pipeline, and injected into modified blast furnace nozzles that previously used natural gas. The Clairton plant also utilizes its coke oven gas for on-site boilers, reheat furnaces, and as a fuel for the coke ovens themselves.

Refinery fuel gas, also known as still gas, is also heavily utilized at the oil refineries that produce it. This gas, collected during refinery operations, is closer to natural gas in composition than the other industrial waste gases. Refineries utilize the gas on-site for various process heating applications using natural gas equipment, but depending on fuel balance at a given refinery, excess still gas may inevitably be produced, and this gas is typically flared.

A recent initiative from the Department of Energy's Advanced Manufacturing Office to develop a multi-fuel combustion system for process heaters could encourage utilization of this excess gas. The low-emissions fuel blending and combustion system, being developed by ENVIRON International and Callidus Technologies, with the support of Shell Global Solutions, will handle a range of fuel compositions including refinery fuel gas as well as natural gas and various forms of biogas. If this ongoing project yields a fully commercialized fuel flexible combustion system, the prospects for utilizing excess refinery fuel gas are likely to improve.

Summary for Gaseous Opportunity Fuels

For gaseous opportunity fuels, there are several steps that must be taken to blend with natural gas and power industrial process heating or steam generation equipment. First, the fuels need to be cleaned and impurities must be removed to protect industrial equipment and to meet environmental regulations. The requirements for fuel cleaning depend on both the fuel source and the equipment being used, with the potential to contribute significantly to capital costs. Next, the fuel must be compressed to natural gas levels and either blended with natural gas or injected into the combustion chamber. Air to fuel ratios may need to be adjusted when opportunity fuels have lower heat contents, but otherwise most equipment should continue to perform normally when using opportunity fuel blends.

There are a great number of industrial facilities with natural gas-fueled process heating equipment. In most cases, required modifications to accept opportunity fuels are minor, and combustion chambers can be designed to handle lower quality fuels more efficiently. Opportunities for research and development

[8] United States Department of Energy, National Energy Technology Laboratory, *Final Environmental Assessment for the Blast Furnace Gas Flare Capture Project at the ArcelorMittal USA, Inc. Indiana Harbor Steel Mill, East Chicago, Indiana.*

[9] Tweh, Bowdeya, *New Boiler Fires Up ArcelorMittal*, October 29, 2010, Northwest Indiana Times, www.nwitimes.com.

lie primarily with gas collection methods, fuel cleanup technologies, multi-fuel combustion systems and advanced gasifiers.

Solid Opportunity Fuels

Solid opportunity fuels are most often utilized for steam generation in boilers that were originally designed to handle coal. Cement kilns also use coal and other solid fuels, including opportunity fuels like petroleum coke and tire-derived fuel. Due to their large size and high-temperature incineration, opportunity fuel blends can generally be used with no equipment modifications in cement kilns, so they are already heavily used for this practice. This report will focus on steam generation equipment (i.e. boilers) for methods of solid opportunity fuel utilization that are not yet widely utilized.

For existing industrial coal boilers, several modifications are typically required in order to accept high levels of solid opportunity fuels. New boilers designed to handle different fuel types could also be utilized, but more research and development may be required before flexible fuel boilers can operate reliably on solid fuels of differing composition and quality. In either case, emission permits for existing coal boilers at industrial facilities will typically need to be modified for cofiring projects, and maintenance requirements could be negatively affected. This section analyzes the technical, procedural and economical considerations for utilizing each solid opportunity fuel, and pinpoints areas that may benefit from additional research and development.

Types of Boilers for Utilizing Solid Opportunity Fuels

The four most common types of industrial boilers considered in this analysis are: cyclone, fluidized bed, pulverized coal, and stoker. The primary differences with these boiler types lie in the fuel feeding mechanisms and furnace designs. A brief description of each type of boiler is provided, along with an accompanying schematic diagram of a typical system.

Stoker Boilers

Stoker boilers use traveling grates to transport fuel particles to the burner, where heat is generated to produce steam. Stokers are one of the most suitable boiler types for cofiring significant amounts of unconventional fuels, since large pieces can be used and the fuels travel slowly through the incinerator, ensuring complete combustion. The fuels are either fed onto the grate from below (underfeed stokers) or they are spread evenly across the gate using fuel spreaders located above the grate (spreader stokers). Spreader stokers with traveling grates are the most common type of stoker boiler. In these boilers, the fuel is mechanically or pneumatically spread from the front of the boiler onto the rear of the traveling grate. Smaller particles burn in suspension above the grate, while larger particles burn on the grate as it moves the fuel from the back to the front of the boiler. A schematic depicting a traveling-gate spreader-stoker boiler is shown in Figure 3-4.

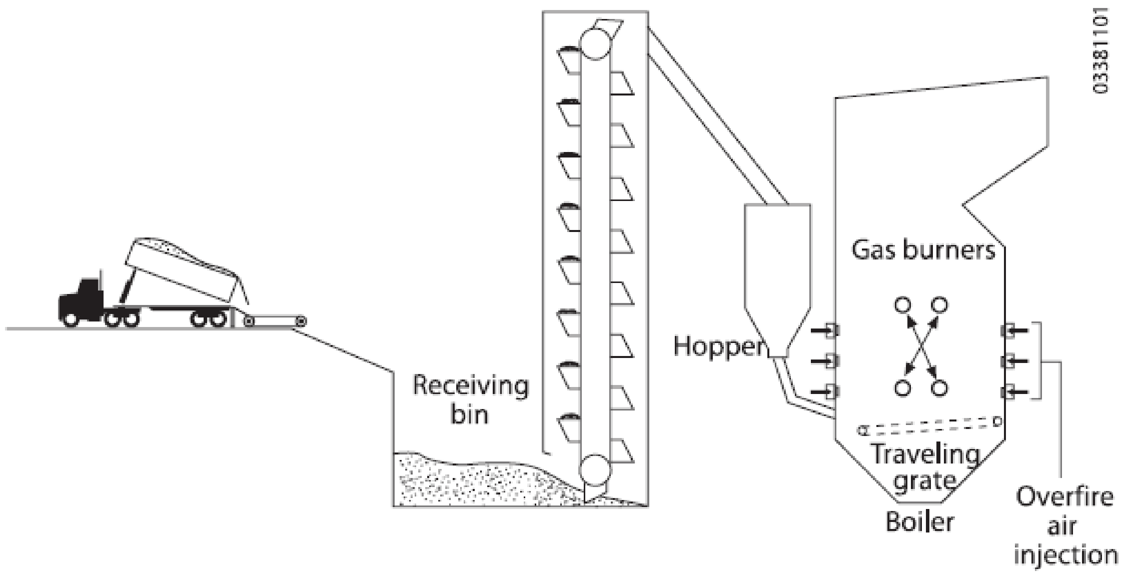

Figure 3-4. Schematic of a Traveling-Grate Spreader-Stoker
Source: U.S. DOE Federal Energy Management Program

With stoker boilers, replacing or modifying the fuel feeding systems is typically all that is required to utilize opportunity fuels along with coal. One common arrangement for stoker boilers is to have multiple coal hoppers that discharge onto a common conveyor. With properly-sized chips, one or more of these coal hoppers can be used to discharge opportunity fuels instead. In this case, the only required modifications are likely replacing coal feeders with opportunity fuel feeders, and with some fuels, the same feeders could be used. However, this method is typically limited to a certain percentage of opportunity fuels compared to coal, depending on various site-specific factors. With certain fuels, this hopper-replacement method may not be feasible, and more modifications to stoker boilers could be required.

Pulverized Coal Boilers

It is difficult to implement opportunity fuels into pulverized coal boiler systems. Pulverized coal consists of small powdery particles, so any fuels that are to be blended also need to be pulverized into a near-powdery consistency. Pulverized coal boilers typically contain one hopper that feeds coal into the furnace, as shown in Figure 3-5. There are two ways of blending opportunity fuels into pulverized coal boilers. The first method, mixing the fuels together before they enter the hopper, is the least expensive, but it is typically limited to very small amounts of alternative fuels. The second option is adding a separate feeder for the opportunity fuel, which injects the fuel directly into the combustion chamber. With this method, higher percentages of alternative fuels can be tolerated, but it is more costly to implement.

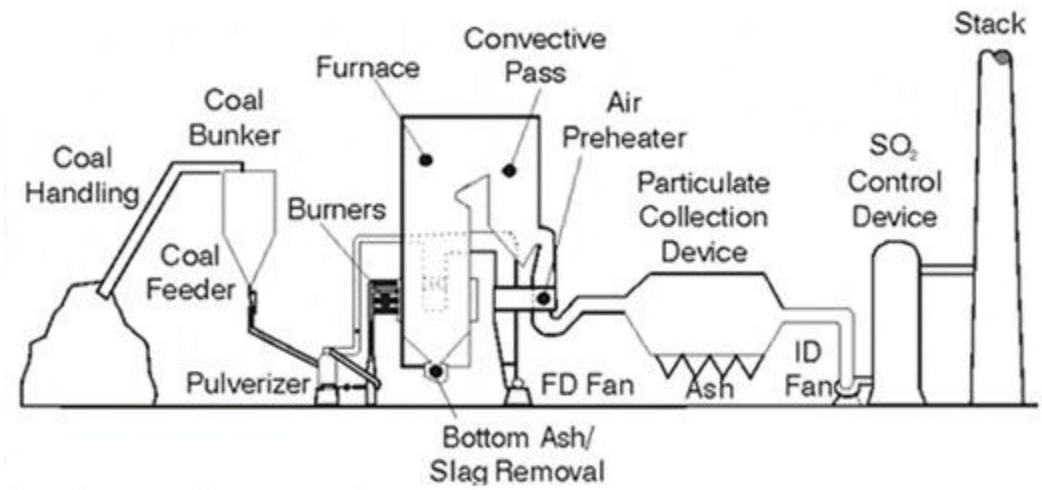

Figure 3-5. Typical Pulverized Coal Boiler System

Source: www.arihantcomputech.com/coal-combustion.html

Utilizing opportunity fuels in pulverized coal boilers can be a challenge. The fuels must be broken down into uniform particles smaller than ¼ of an inch, which increases processing costs and limits the types of fuels that can be utilized. In addition, pulverized coal boilers are most commonly used for large utility power generation applications, not industrial process heating and steam generation. The potential for pulverized coal boilers to utilize opportunity fuels at industrial facilities is fairly limited for these reasons, so these types of boilers will not be considered in the technical analyses.

Cyclone Boilers

Cyclone boilers utilize cyclone furnaces that blow heated air and coal in a centrifugal motion through the burner, which combusts the coal more efficiently than other furnace types that are less dynamic. Compared to pulverized coal boilers, the cyclone process allows lower-grade and larger-sized fuel particles to be used, with higher moisture and ash contents. Cyclone boilers also have a smaller footprint and can be utilized in smaller-scale applications. This greater flexibility can be advantageous for opportunity fuel utilization. However, cyclone boilers are most often used by electric utilities as opposed to industrial facilities, which tend to use stokers and fluidized bed boilers.

In cyclone furnaces, a high powered fan blows heated air and particles of fuel into one end of a cylinder, while additional heated combustion air is injected along the cylinder's curved surface, causing the fuel/air mixture to swirl in a centrifugal motion. This motion enhances the burning properties, producing high heat densities and high combustion temperatures. Tertiary air is then released further downstream to complete combustion of the remaining fuel, greatly reducing NOx formation. The hot combustion gases then leave the cylinder and enter the boiler to produce steam. A schematic of a cyclone furnace is provided in Figure 3-6.

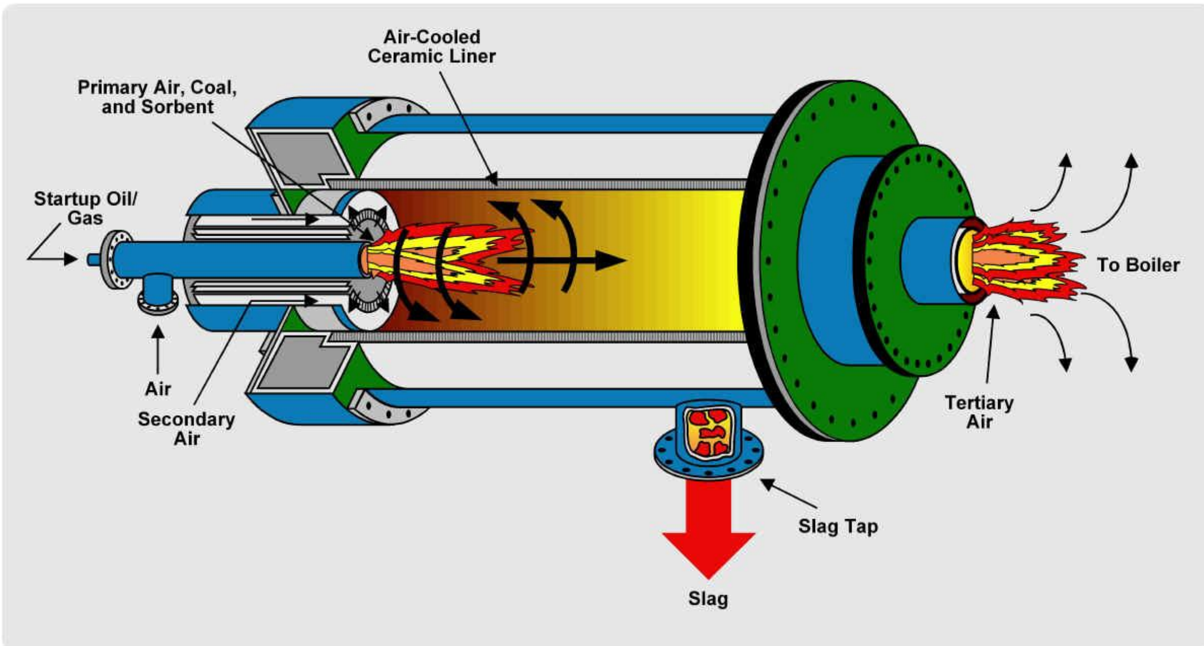

Figure 3-6. Schematic of a Cyclone Furnace, used in Cyclone Boilers
Source: U.S. DOE National Energy Technology Laboratory

Some slag remains on the walls insulating the burner while the rest drains through the slag trap into a collection tank where it is solidified and disposed of. The ability to collect ash is a big advantage over pulverized coal systems. Typically only 40% of the ash leaves with the exhaust gases in cyclone boilers, compared to 80% for pulverized coal boilers.[10] However, some disadvantages of cyclone boilers include the high power requirements of the fans, and frequent replacement of cylinder liners due to the erosion caused by the high velocity of the coal. Additionally, cyclone boilers require fuels to be broken down to fairly small sizes, and adjustments must be made to ensure that secondary fuels burn properly as they spiral around the cylinder.

Xcel Energy Regulatory Policy Manager David Donovan, who is overseeing the implementation of a new cyclone biomass boiler (converted from a cyclone coal boiler) says, "the biomass has to burn at a certain place in the boiler, otherwise the heat retention and heat exchanges are messed up. [an internal study] showed that the retention time is not long enough if the fuel in the cyclones is biomass. It burns in the back half of the boiler and it doesn't allow us to capture the heat and energy in our exchange system."[11]

[10] Coal Fired Power Generation - How It's Done. Online. March 2010. http://www.rst2.edu/ties/acidrain/IEcoal/how.htm
[11] Austin, Anna. *A Colossal Conversion*. Biomass Magazine, August 2009. Online.

While this quote was referencing a complete conversion from coal to biomass, the issue is still present when coal is blended with opportunity fuels. Using high percentages of opportunity fuels may require significant air flow adjustments for the combustion chamber, and deviating from that particular fuel blend would require additional air flow adjustments, potentially limiting the fuel flexibility of these systems.

Fluidized Bed Boilers

Fluidized bed combustion (FBC) involves suspending solid fuels in upward-blowing jets of air, resulting in a turbulent mixing of gas and solids that resembles a bubbling fluid. This method of combustion provides more effective chemical reactions and maximizes heat transfer capabilities. Fluidized bed combustion systems are also fuel-flexible, allowing various types of fuels to be effectively utilized. However, to date, FBC has generally been limited to larger applications.

Compared to other combustion methods, FBC is a relatively new technology, but a rapid increase has recently been seen in its use. There are three reasons for this: 1) the ability to utilize different fuels which can be difficult to burn using other technologies, 2) the ability to naturally achieve low nitrous oxide (NOx) emissions through lower combustion temperatures. The second reason in particular has been a driver for installing fluidized bed boilers at coal plants in recent years with tightening emissions regulations in certain areas of the country. The removal of sulfur oxides (SOx) is also handled easily, by lining the bed with limestone, or injecting crushed limestone into the boiler. The limestone combines with sulfur to create inert solid, preventing SOx emissions from forming. Figure 3-7 shows a schematic of a circulating fluidized bed boiler system that is used to power a steam turbine generator.

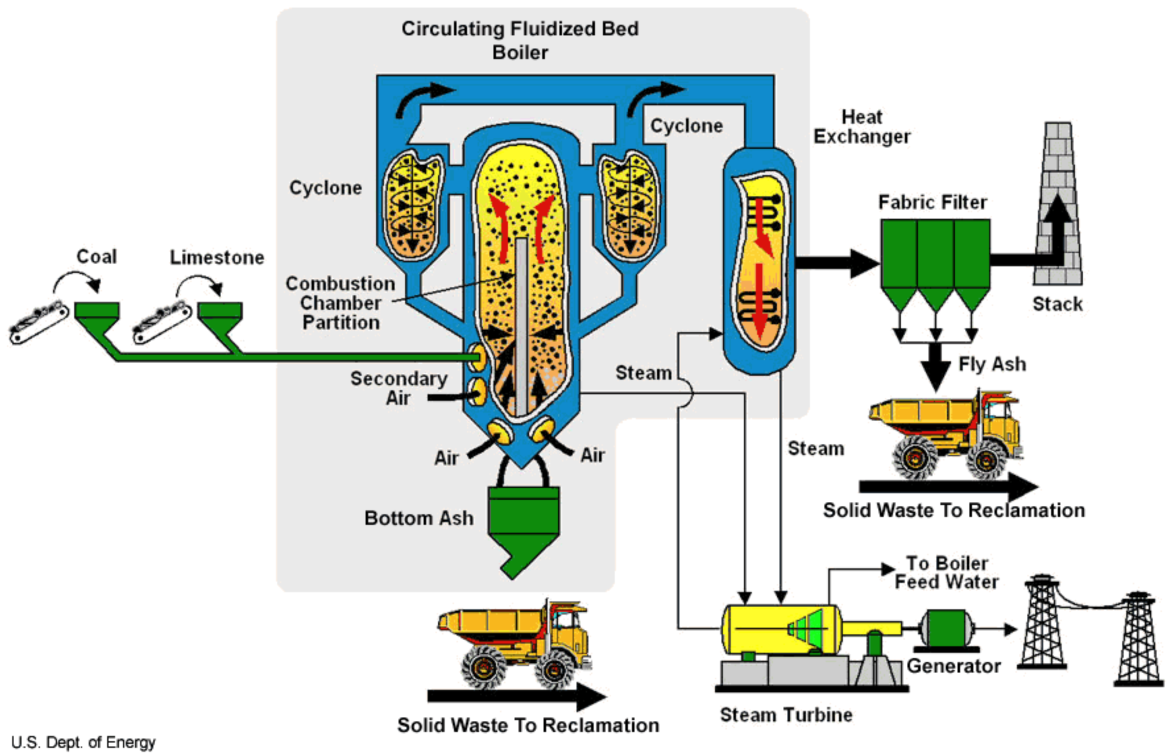

Figure 3-7. Schematic of Circulating Fluidized Bed Boiler System
Source: U.S. Department of Energy

With a circulating boiler design, fuel that has not completely combusted is recirculated along with ash and inert material through cyclone mixers that feed back into the combustion chamber. Bubbling fluidized bed boilers do not utilize cyclones in their designs. With both types of boilers, opportunity fuels can either be mixed with coal before it is fed into the hopper, or a separate hopper can be added strictly for the secondary fuel. With fluidized bed combustion, the difference between the two methods is minimal due to the turbulent mixing in the combustion chamber.

In this section, all of the solid opportunity fuels are evaluated in terms of the technological capabilities and economical limitations when utilizing the different boiler types. Potential areas of improvement are identified for future research and development efforts.

Biomass Fuels

While coal is relatively uniform and easily broken down into small combustible partlicles, the handling and combustion of biomass fuels is a slightly more difficult process. Biomass fuels, especially wood-based, can compact and pieces can lock together, creating bridges in storage vessels. This can be prevented with tapered storage bins and screw-conveyor designs for removing fuel from the silo. Biomass fuels are not uniform and can have drastically different moisture contents depending on the fuel source and drying method, potentially resulting in uneven or incomplete combustion. Boilers using biomass fuels are also less efficient than coal boilers. An industrial boiler running on 100 percent biomass likely has a 60-75 percent efficiency, while coal boilers typically range from 75 to 90 percent efficient.

There are several types of coal boilers that can utilize biomass fuels, including stokers, cyclone boilers, fluidized bed boilers, and pulverized coal boilers. In addition to the fuel handling and transportation challenges, each boiler type requires that solid biomass fuels be broken down into various sizes in order to blend with coal. Generally, boilers that can accept larger fuel chips require fewer modifications to accept biomass fuel sources. Table 3-3 provides a summary of types of existing boilers, and the corresponding size requirements for biomass fuels.

Table 3-3. Biomass Size Requirements for Existing Coal Boilers

Existing Boiler Type	Size Required (inches)
Cyclone	< 1/2
Fluidized Bed	< 3
Pulverized Coal	< 1/4
Stoker	< 3

Source: Akbrut, Alexander. *Feeding the Beast: How coal-fired boilers handle co-fired biomass fuels*. Power Engineering. March 1, 2010.

Stokers and fluidized bed boilers are able to handle chips up to 3 inches in size, as opposed to less than half an inch for other boiler types. However, biomass that is processed into small pellets can potentially be used in cyclone boilers and pulverized coal boilers. Issues with cyclone boilers can arise if they are not properly designed to burn biomass particles at certain locations in the combustion chamber. Otherwise the heat retention and heat exchanges can be thrown off, and incomplete combustion can occur. Pulverized coal boilers require even smaller biomass pellets, whose processing costs can lead to higher fuel prices than coal. Stokers and fluidized bed boilers are simply more flexible, and can utilize various sources of biomass fuels that don't require quite as much processing. For these reasons, only stokers and fluidized bed boilers are considered for industrial steam generating and process heating applications with biomass fuels.

Stokers for Biomass Fuels

Stoker boilers that were designed for coal can typically handle biomass blends up to 20 percent[12] with minimal equipment modifications. These boilers are used extensively in the forest products and pulp and paper industries for waste biomass utilization, and coal stokers are also found in various types of industrial facilities. Stoker boilers are typically small to medium in size, which makes them ideal for

[12] 20 percent in terms of heating value, which means over 30 percent biomass on a mass-basis.

many industrial processes that require less than 100,000 lb/hr of steam, although larger systems are also employed.

Coal stoker boilers often utilize multiple coal hoppers with conveyor belts that transport the fuel to the large traveling gate in the combustion chamber. A simple method of incorporating biomass fuels into these coal boilers involves using one or more of the existing coal hoppers (and associated conveying equipment) strictly for biomass fuels. With this scenario, existing equipment is used and on-site capital expenses are minimized. Alternatively, if properly sized biomass fuel is delivered to the facility premixed with coal, no operational changes are required and capital expenses would be negligible. If neither of these low-cost options is feasible, new handling and storage equipment will need to be added, properly suited for biomass fuels.

For most stoker boilers, minimal modifications are required to incorporate biomass fuels. Biomass that is sufficiently dried and properly-sized (less than 3 inch chips) will not significantly add to maintenance requirements, but slight changes to operational procedures such as increasing over-fire air and fuel feeder speeds may be needed.[13] In addition, facilities using biomass high in sulfur content would require SO_2 scrubbers, although biomass typically contains less sulfur than coal, so any facility with an existing coal stoker boiler should already have these scrubbers in place.

Fluidized Bed Boilers for Biomass Fuels

The installed base of fluidized bed boilers has grown drastically in recent years, due to low NOx emissions and their ability to handle a wide variety of fuel types. There are two different types of fluidized bed boilers: bubbling and circulating. Circulating boilers utilize cyclones to recirculate unburned fuel, ash and inert material through the combustion chamber, increasing the thermal efficiency. Bubbling fluidized bed boilers have a simpler design, can be scaled down to a small size, and have been used in most biomass boiler installations to date. However, both boiler types are flexible and capable of utilizing various biomass fuel blends.

Bubbling fluidized bed boilers (BFBs) are utilized heavily at paper mills, running on black liquor, and they are also currently used for several biomass steam/power generation applications using wood waste and crop residues. The boilers incorporate a bubbling bed of sand that acts as a heat sink in the combustion chamber, allowing various types of fuels with variable moisture contents to be utilized with no changes to equipment maintenance and performance. Bottom-supported BFBs are ideal for medium-sized applications (100,000 to 250,000 lb/hr) while top-supported units are ideal for larger applications up to 700,000 lb/hr. Figure 3-8 shows a schematic of a top-supported BFB system. For existing coal-fired bubbling fluidized bed boilers at industrial facilities, adding different fuel sources is often as simple as replacing coal hoppers or blending the fuels ahead of time, with minimal capital costs incurred.

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[13] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Federal Energy Management Program, Federal Technology Alert: *Biomass Cofiring in Coal-Fired Boilers*, May 2004.

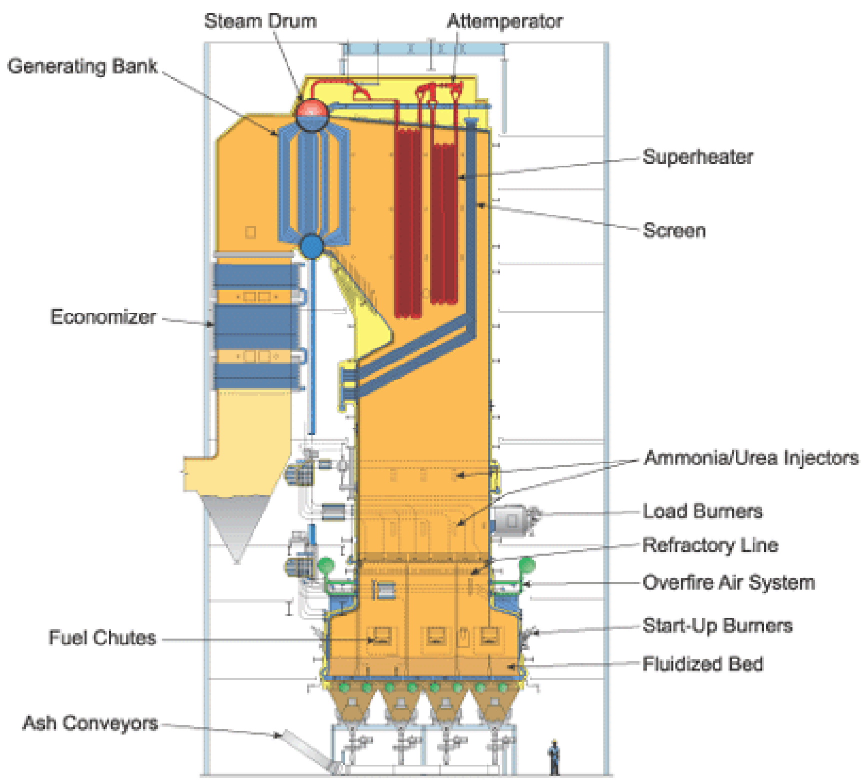

Figure 3-8. Top-Supported Bubbling Fluidized Bed Boiler System
Source: Babcock & Wilcox

Circulating fluidized bed boilers (CFBs) are typically designed for large coal-burning applications that generate anywhere from 250,000 to 1,500,000 lb/hr of steam. These boilers have the lowest NOx emissions possible without any post-combustion treatment. Additionally, SO_2 removal is handled by simply injecting limestone into the circulating fluidized bed. These qualities make CFBs ideal for coal power plant operators that have to comply with increasingly strict emission regulations. There could be potential for biomass to replace coal at a number of large industrial CFB installations, and the capital costs involved with switching fuels should be minimal, as with BFBs.

Technology Costs and Limitations

For both stokers and fluidized bed boilers, equipment modifications to incorporate biomass fuels are relatively small in both scope and capital cost. Typically, some coal hoppers and conveyor equipment must be replaced with hoppers and conveyors designed for biomass, and new storage silos for biomass fuels may be required. Total costs for boiler equipment modifications are often as low as $50-$100/kW (for a boiler connected to a steam turbine generator). For heating applications, this is equivalent to $3-$6 per pound of steam, per hour of steaming capacity.[14] However, these costs tend to be higher for

[14] Ibid.

herbaceous biomass fuels (crop residues), fuels with high moisture contents, and for co-firing over 10 percent heat input.

For stoker boilers, the fuel feeding equipment and moving grates that were designed for coal are not always compatible with biomass fuels. In a worst-case scenario, a small-scale stoker boiler that requires a completely new receiving, storage and handling system could cost as much as $350/kW, or over $20 per pound of steam per hour of steaming capacity.[15]

Maintenance costs are likely to remain about the same as coal for stoker boilers, BFBs and CFBs, although some increased slagging and fouling can occur inside the combustion chamber when biomass fuels are used. Results from a joint Sandia/NETL/NREL project found that wood-based biomass fuels are favorable in terms of slagging and fouling when compared to herbaceous crops, which have high alkali and chlorine contents.[16] These problems can be minimized by screening fuel supplies for chlorine and alkalis, which contribute to slagging and fouling, and limiting biomass blends to 15 percent or less, or by increasing soot blowing. In addition, several demonstration projects have shown that biomass has no significant impact on boiler efficiency at these levels of cofiring.

Most industrial sites that change fuel sources need to apply for a modified air quality permit. Permit requirements can vary from site to site, but emission permits typically have to be modified when introducing biomass into stoker boilers that traditionally fire coal. With most biomass fuels, this is a fairly straightforward process, as results from earlier cofiring projects in which emissions were not negatively affected can be used in the permit modification process.

Overall, the costs to implement biomass fuels at existing industrial coal boilers appear to be minimal, and the cost for a biomass or flex-fuel boiler (stoker or fluidized bed) should be on par with the cost of coal-fired systems. The next chapter will evaluate the availability and cost of biomass fuels, the following chapter will examine existing industrial applications, and the final chapter will provide an economic analysis for industrial steam generation from biomass fuels.

Examples of Flexible Industrial Biomass Fuel Utilization

In New Jersey, the Rex Lumber Company recently began utilizing their wood waste for on-site process heating and steam generation applications. Rex Lumber produces over 44,000 cubic yards of wood waste and sawdust each year. While the waste was previously trucked away to a landfill for disposal, a wood waste boiler system was recently installed to utilize the wood waste and sawdust, providing heat for the kiln-drying process. More steam is produced by the boiler than is needed for kiln-drying, so a 150 kW

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[15] Ibid.

[16] *Federal Technology Alert: Biomass Cofiring in Coal-Fired Boilers*, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Federal Energy Management Program, June 2004.

steam turbine was added to the system to lower plant electricity costs. Close to half of the funding for this system was provided by the New Jersey Clean Energy Program.[17]

In general, modified biomass boilers have been successful at industrial sites where wood waste is produced, while the cost of transported biomass fuels can become prohibitive for facilities that lack an on-site source. The extent of this issue will be further explored later in this report when biomass transportation costs are estimated for potential projects. Government funding from programs such as the New Jersey Clean Energy Program can also provide an impetus for wood processing facilities like Rex Lumber Company to install biomass utilization equipment. Several more examples of industrial process heating and steam generation applications powered by solid biomass fuels are provided in Chapter 5 of this report.

Tire-Derived Fuel

Tire-derived fuel (TDF) has similar qualities to coal, and processed TDF can be used in place of coal in most industrial boilers. However, TDF that has not been properly processed can cause combustion issues and create maintenance problems for project operators. This section examines the technical issues involved with TDF steam generation, and discusses ways that industrial facilities can prevent and mitigate these issues.

In general, heavily processed TDF can replace coal in any industrial boiler, with no degradation in performance and slightly shortened maintenance intervals. In fact, the heat content of TDF is considerably higher than coal, so performance often improves when introducing TDF to a coal boiler system. However, the degree of processing required depends on the type of boiler and the blend of fuels that is utilized. Pulverized coal boilers require the highest level of TDF processing, raising fuel costs too high for the majority of coal plants. Cyclone boilers also require a high level of TDF processing, but larger chips can be used and the combustion chamber design is more favorable for tire-derived fuel compared to pulverized coal boilers. Most electric utilities that utilize TDF blends use cyclone boilers.

To date, most of the industrial uses for TDF have been firing cement kilns, where the high combustion temperatures allow whole unprocessed tires to be utilized. TDF has also been used in boilers at pulp and paper mills and other industrial sites, along with electric utilities. At most of these sites, TDF is used as a supplemental fuel for coal boilers. In demonstration projects, various biomass fuels have also been successfully blended with TDF, and paper mills typically blend TDF with both wood waste and coal. Aside from utility applications that use cyclone boilers, most of these facilities use either stokers or fluidized bed boilers. These boiler types don't require the high level of processing that pulverized coal and cyclone boilers do, although complete wire removal from the tires is recommended.

[17] Biomass System Helps Lumber Distributor Chop Energy Costs and Recycle Wood Waste, New Jersey Clean Energy Program. http://www.njcleanenergy.com/files/file/casestudy07_rex_lumber.pdf

Stoker Boilers for Tire-Derived Fuel

Stoker boilers are ideal for TDF because the slowly moving grate provides ample time for complete combustion, and allows larger pieces of tire to be used compared to pulverized coal and cyclone boilers. For stoker boilers, the optimum size for TDF is 2 inches square, while it is 1 square inch for cyclones, and even smaller for pulverized coal boilers.[18] Larger TDF pieces cost less to process, giving stoker boilers an advantage. Complete metal removal is preferred for all boiler types, although this can increase fuel costs by 50 percent compared to TDF that has simply been shredded.

When metals have been completely removed from tire-derived fuel, it can be used to replace or supplement coal in stoker boilers with minimal capital costs. With highly processed TDF, hoppers and conveyors designed for coal can often be used, and no additional capital costs are incurred aside from new fuel storage and handling equipment. TDF could also be blended with coal before it arrives at the facility, but in most cases, TDF is purchased from a separate vendor.

Adding highly processed TDF to a coal stoker boiler should not affect maintenance schedules or costs. However, if metal wires remain in the tires, increased fouling will occur in the combustion chamber, and ash from TDF will contain several different metals, requiring special handling and disposal.

Fluidized Bed Boilers for Tire-Derived Fuel

Fluidized bed boilers are often used with lower-quality fuels such as herbaceous biomass crops and sludge waste. The fluidized bed combustion chamber design allows for fluctuations in fuel quality and consistency, with no effect on the level of steam generation. Tire-derived fuel can be used in conjunction with these lower quality fuels, as coal often is used, to help provide a high-quality, low-moisture base for the fuel mixture. While wire-removal is only a recommended option for stokers, it is generally required for fluidized bed boilers, because metals can potentially cause accumulation and bed defluidization, which can lead to lengthy outages.

As with stokers, coal-fired fluidized bed boilers should not require any substantial capital costs when incorporating TDF. Coal hoppers and conveyors can be used, and no equipment modifications should be necessary. With highly processed TDF that has had all metal wiring removed, maintenance costs should also remain about the same.

Technology Costs and Limitations

With most TDF cofiring applications, coal boilers remain unchanged, and a certain percentage of the coal is replaced by TDF. With cyclone boilers, stokers, and fluidized bed boilers designed for coal, highly processed TDF can be generally be cofired at up to 20 percent with no equipment modifications and an

[18] United States Environmental Protection Agency, Tire-Derived Fuel. http://www.epa.gov/osw/conserve/materials/tires/tdf.htm#boilers

increased efficiency and heat rate compared to 100% coal boilers.[19] TDF has a higher heating value than coal, produces less ash, and generates fewer NOx emissions, making it an attractive option for operators of coal power plants and industrial steam generators. Maintenance costs are also largely unaffected when highly processed TDF is used for cofiring.

There are three primary limitations to TDF use at industrial facilities:

1. Level of TDF processing: If TDF is not shredded into small enough chips, incomplete combustion will occur, and if wires are not completely removed, the metal will foul the combustion chamber and create hazardous metal-laden ash. Metal removal adds about 50% to the cost of processed TDF.
2. TDF availability: Although sites could purchase whole tires and create TDF themselves, this is rarely ever practiced – a third party collects the tires, shreds them, removes the wires, and sells TDF as a product, typically for about the same price as coal per ton, and less expensive on a Btu-basis in many areas. However, there is a limited number of TDF producers, so availability and transportation distance can potentially create issues in acquiring the fuel.
3. Public opposition: TDF combustion can create some hazardous emissions, although typically the emissions are on par with coal plants. Still, some TDF projects have been cancelled or shut down due to public opposition – this issue will be explored in Chapter 5, when case studies and recent opportunity fuel projects are discussed.

Additionally, coal-burning facilities that wish to utilize TDF may need to obtain a new air quality permit. The addition of TDF, however, should not significantly impact emissions for coal plants, so it is not likely to cause any significant hurdles for facility owners.

The main opportunity for research and development lies in determining the feasibility of on-site TDF production, as whole tires can be obtained far more easily than processed TDF in many areas. It is likely that only large industrial coal users would benefit from investing in TDF equipment, and the scale required for attractive economics is uncertain. This issue will be further explored in the final chapter of this report.

Examples of Flexible Industrial TDF Utilization

While the industrial utilization of TDF has been limited to date, the Wickliffe Paper Company (owned by NewPage Corporation) recently received a grant of $750,000 from the Kentucky's Waste Tire Trust Fund for equipment to utilize TDF on-site in their wood waste boiler. The grant requires that the facility consume the equivalent of 750,000 tires per year through 2012 by burning about a 15 percent TDF blend. In 2001, a similar grant was given to Owensboro Municipal Utilities to incorporate 750,000 tires per year at their power plant. While the grant has expired, the utility continues to use about 900,000 tires per year in the form of TDF. The Wickliffe Paper facility will also likely continue using TDF as a supplemental

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[19] United States Environmental Protection Agency, Pacific Environmental Services, *Scrap Tire Technology and Markets*, Noyes Data Corporation, Park Ridge, New Jersey. 1993.

fuel after their contract expires due to its low price and high heating value, and the fact that all of the equipment is already owned and installed.[20]

State grants can help TDF projects gain footing, but most states have not set aside substantial resources for waste tire recycling and utilization. More TDF utilization projects will be discussed in Chapter 5, which covers current projects and future prospects for industrial opportunity fuel usage.

Petroleum Coke

Petroleum coke (pet coke) can be used in place of coal with most types of boilers, but due to lower combustibility and differences in composition, several modifications and changes to coal boilers need to be made. In many cases, boilers designed specifically for petroleum coke are used, but there are several boiler systems in place that utilize pet coke along with other fuels such as coal, tire-derived fuel and biomass. This section analyzes the boiler technologies that are compatible with petroleum coke, discusses their advantages and disadvantages, and identifies potential opportunities for growth in the industrial sector.

In addition to potential combustion issues, increased fouling can occur when petroleum coke is blended with coal. A Tennessee Valley Authority study showed that blending 50 percent pet coke with coal in a fluidized bed system caused fouling in several areas of the boiler. The fouling was caused primarily by the carbonation and sulfation of limestone-derived materials in the fluidized bed.[21] Pet coke contains significantly more carbon and sulfur than coal, so additional steps such as soot blowing must be taken to remove excess carbon and sulfur from the combustion chamber, and reduce carbon and sulfur dioxide emissions.

Petroleum coke has been used with both pulverized coal and fluidized bed boilers, although it has most often been used for utility power generation. Potential technologies for utilizing pet coke in industrial steam generation applications are explored in this section. Pulverized coal boilers are primarily used for large-scale electricity generation, and rarely used at industrial facilities, only fluidized bed boilers and stokers will be considered for this analysis.

Stokers for Petroleum Coke

Stoker boilers are rarely used for petroleum coke fuel applications, which are typically large-scale utility operations. Pulverized coal boilers are often used for the largest applications because when pet coke has been pulverized, it is easier to combust and blend with coal. With traveling grate stokers, larger pieces of fuel are typically used, which have less desirable combustion qualities, and these types of boilers are

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[20] "Wickliffe Paper Will Use Scrap Tires for Fuel", *The Carlisle Weekly*, July 24, 2006. http://www.carlisleweekly.com/modules.php?name=News&file=print&sid=48

[21] Anthony, E.J., et. All., *Fouling in a 160 MW FBC Boiler Firing Coal and Petroleum Coke,* CETC, Natural Resources Canada, Nepan, ON; University of Toronto, Toronto, ON.

generally not used for large-scale utility applications like most current U.S. installations. Additionally, the higher sulfur content in pet coke typically requires SO_2 emission controls, so fluidized bed boilers with limestone to neutralize SO_2 are generally preferred in cases where additional treatment would be required. The fluidized bed design also allows for complete petroleum coke combustion.

Fluidized Bed Boilers for Petroleum Coke

In many ways, fluidized bed boilers are the most ideal method of utilizing petroleum coke for steam generation. The fluidized bed design allows for the complete combustion of pet coke, which can be difficult in dry boiler types, and it also offers flexibility in allowing other fuels to be used. With circulating fluidized bed boilers, the recirculation of fuels through the combustion chamber ensures that complete petroleum coke combustion will always occur. Bubbling fluidized boilers are also capable of complete combustion, and are better-suited for small-to-medium-sized industrial applications. In both cases, limestone is used to decrease SO_2 emissions, and also to help reduce erosion caused by both SO_2 and metallic elements like vanadium and nickel. NOx emissions from fluidized bed boilers are also significantly lower than boilers that use other combustion methods.

Technology Costs and Limitations

Despite the several advantages that fluidized bed boilers offer over other boiler types, there is some evidence that increased agglomeration and fouling can occur as a result of carbon and sulfur interactions with the limestone.[22] The increased fouling leads to more frequent maintenance intervals and higher maintenance costs, which can potentially hinder project economics. However, this problem is most pronounced when 100 percent petroleum coke is used, and blending with coal, TDF, and/or biomass can reduce the agglomeration and fouling. The additional maintenance costs for pet coke boilers are difficult to quantify and depend on many different factors, but total costs should be slightly greater than coal-fired boilers.

Capital costs for fluidized bed boilers that run on petroleum coke are generally on par with their coal-fired counterparts. Coal hoppers and conveyors can be used for petroleum coke, and equipment modifications are generally not required for fluidized bed systems. Pulverized coal boilers and stokers, however, can require significant modifications to accept large percentages of pet coke, giving fluidized bed boilers another advantage. For all boiler types, air permits could pose a challenge to project operators due to high carbon and sulfur dioxide emissions. Additional emission control technologies may need to be employed in order to qualify for air quality permits, depending on local environmental regulations.

[22] Ibid.

Examples of Flexible Industrial Pet Coke Utilization

At Georgia Pacific's Port Hudson mill in Zachary, Louisiana (pictured in Figure 3-9), a new multi-fuel circulating fluidized bed boiler was recently installed. The boiler burns about 300,000 tons of petroleum coke per year, along with wood waste and sludge from the plant, replacing a boiler that previously was fueled by natural gas. The boiler powers a steam turbine generator that provides 58 MW of power to the plant, while heat recovered from the system is used for process heating. This installation shows that for many applications, aging boilers (fueled by natural gas, fuel oil or coal) can be replaced with fuel-flexible boilers, whether it uses gaseous or solid fuels. In this case, a natural gas boiler was replaced by one that utilizes petroleum coke as well as other solid waste fuels.

Figure 3-9. Port Hudson Mill Energy Project
Source: Industrial Specialty Contractors, LLC

Summary for Solid Opportunity Fuels

Stokers and fluidized bed boilers are the two best options for utilizing solid opportunity fuels at industrial facilities. Sites with coal-fired boilers can incorporate blends of opportunity fuels with very few modifications required, and no significant increase in operation and maintenance costs. With these types of boilers, the only changes needed to implement other fuels are typically with the fuel storage and feeding mechanisms. Boilers with combustion chambers designed for specific opportunity fuels, such as biomass, will provide more efficient operation and allow higher percentages of opportunity fuels to be used.

Woody biomass fuels (including wood waste and harvested wood) offer some of the most ideal opportunities, with the most potential to contribute significantly to industrial steam generation applications. Herbaceous biomass fuels show potential for agricultural facilities, but their properties are generally not as ideal for cofiring. Tire-derived fuel and petroleum coke perform similarly to coal and show some potential for industrial CHP cofiring, but they both face several potential hurdles to widespread adoption. Other than resolving issues related to gasification, most opportunities for research and development do not involve equipment design or modifications. Infrastructure improvements to make biomass fuels and TDF more readily available to industrial sites would benefit from further development. There are also some opportunities to improve fuel processing and solid fuel blending techniques to make opportunity fuels less expensive to obtain and less complex to mix with coal and other fuels in stokers and fluidized bed boiler systems.

Summary of Steam Generation and Process Heating Technologies

For solid opportunity fuels, stokers and fluidized bed boilers offer the greatest opportunities for flexible fuel applications at industrial facilities. Both of these technologies are able to handle a wide variety of fuels with different heat and moisture contents, making them ideal for opportunity fuel blends. With gaseous fuels, process heating applications provide more opportunities for industrial utilization, in addition to gas-fired boilers. For both boilers and process heating equipment, modifications are typically limited to the combustion chamber and fuel handling systems. The use of gaseous fuels may require new pipeline construction if the fuel source is not located on-site, whereas solid fuels may require a separate storage and fuel feeding system. Multi-fuel burners designed to adjust the fuel-to-air ratio in real time, according to gas composition, would be ideal for gaseous opportunity fuels. Later in this report, current installations in the United States will be examined to determine how these technologies have been utilized, and if there is room for improvement in their adaptations.

The next chapter quantifies the resources available in the United States for opportunity fuel utilization at industrial facilities, and estimates the technical potential for both solid and gaseous opportunity fuels.

4. Availability and Technical Potential for Industrial Opportunity Fuel Utilization

In this chapter, the availability of each of the seven opportunity fuels in the United States is explored. Data on the fuel sources is used to approximate each fuel's availability, in terms of the total amount that can potentially be utilized by industrial facilities, regardless of cost. From this figure, the technical potential for industrial facilities is estimated, assuming complete utilization of all available opportunity fuels. The economic potential, which estimates the quantities of opportunity fuels that can be consumed economically at industrial facilities, is explored later in this report, and depends on several different factors like transportation distance and processing requirements.

The opportunity fuels evaluated in this report comprise a variety of gaseous and solid fuel options for industrial facilities.[1] Anaerobic digester gas (ADG) is found at municipal and industrial wastewater treatment plants, but industrial utilization projects are likely limited to drawing from larger treatment plants. Landfill gas (LFG) is recovered from landfills, but only large landfills are likely to produce enough gas to be pipelined to nearby industrial sites. The availability of biomass gas is tied to the availability of solid biomass fuels and the use of expensive gasifier technology, and industrial waste gases are produced at steel mills and oil refineries, but could require extensive clean-up. For solid opportunity fuels, biomass can be obtained from a variety of potential sources, tire-derived fuel (TDF) availability depends on local scrap tire markets and TDF-processing capabilities, and petroleum coke production and availability is tied to oil refinery operations. This chapter examines how these factors affect the availability of each opportunity fuel for industrial consumption, and estimates the associated technical utilization potential for industrial facilities.

Gaseous Opportunity Fuels

The availability of most gaseous opportunity fuels is tied to facilities that produce energy-rich waste gases. The number and locations for of each of these facility types is explored in this chapter, and the amount of gas generated can be estimated according to the relative facility size. The only exception is biomass gas created with advanced gasifier technologies. In this case, the availability of solid biomass fuels is the primary factor. This section estimates the quantities of available gaseous opportunity fuels in the United States, and projects the total technical potential for industrial utilization.

Anaerobic Digester Gas

Wastewater treatment plants are ubiquitous throughout the United States. There are tens of thousands of wastewater treatment plants in the country, although the majority of plants are not large enough to support anaerobic digester gas to energy projects. For municipal WWTPs, mainly used for treating sewage water, location and size is often directly linked to population centers. Industrial plants however, are more regional, depending on where the various industries have settled over the years. Food and beverage processing is by far the most common industry for anaerobic wastewater treatment, followed by pulp,

[1] The fuels were chosen in Chapter 2 of this report, based on their availability, affordability, and ability to be used with other fuels in industrial space heating or steam generation applications

paper, and petrochemicals.[2] Anaerobic digestion is only applicable to waste streams that contain organic compounds, so it follows that the top industries are those that draw from organic feedstocks.

The EPA Clean Watersheds Needs Survey is used to provide a database of municipal wastewater treatment plants every four years, including information on wastewater flow rate and treatment methods used. A correlation between the wastewater flow rate and the quantity of ADG produced provides an estimate of the potential for ADG utilization at each facility.

A Focus on Energy study assessing digester gas to energy projects in Wisconsin profiled 60 different municipal wastewater treatment plants, giving the daily wastewater flow rate and digester gas production for each facility.[3] The results were averaged for facilities producing more than 1 million gallons per day (MGD) of wastewater, and it was found that a facility that producing 1 MGD generates about 8.4 cubic feet of biogas each minute. With an average heating value of 600 Btu/ft^3, this amounts to over 7 MMBtu of energy from the gas each day.

The 2004 EPA Clean Watersheds Needs Survey (CWNS) data[4] indicates that there are 1,552 municipal wastewater treatment plants with anaerobic digesters that treat 1 million gallons per day or more. In the survey, 254 of these facilities responded that they are utilizing their digester gas in some way, so these plants may not be able to support additional utilization. It is likely that some facilities currently utilizing their digester gas produce a surplus of ADG that could potentially be piped to a nearby industrial facility, but the technical potential will focus on the availability from plants that are not currently utilizing ADG. Figure 4-1 shows which states have the highest ADG production rates from these plants.

[2] Kleerebezem, Robbert and Herve Macarie, "Process Wastewaters: Anaerobic's Bigger Bite", *Chemical Engineering*, April 2003.
[3] Vik, Thomas E., *Anaerobic Digester Methane to Energy – A Wisconsin Statewide Assessment,* Prepared for Focus On Energy by McMahon Associates, Inc., January 23, 2003.
[4] United States Environmental Protection Agency, *CWNS 2004 Report to Congress*. http://water.epa.gov/scitech/datait/databases/cwns/2004reportdata.cfm

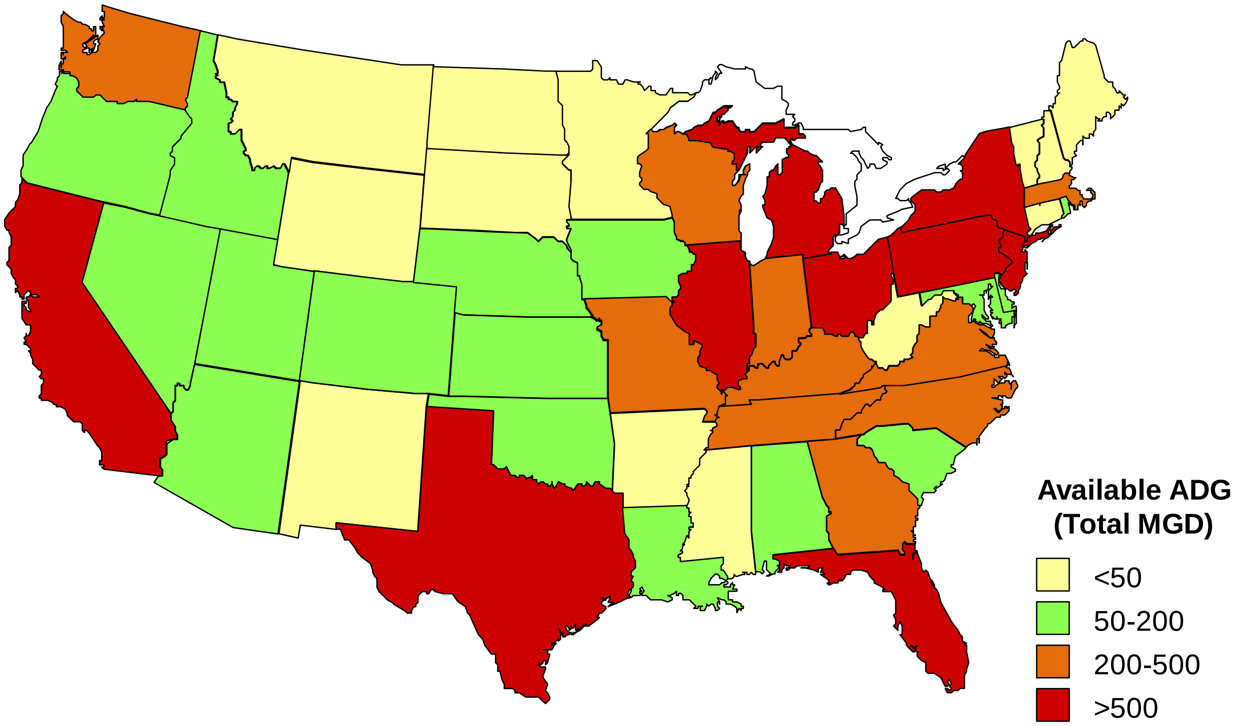

Figure 4-1. Map of Municipal ADG Production by State (Treatment Plants Not Utilizing ADG)
Source: EPA, 2004 Clean Watersheds Needs Survey

According to the Clean Watersheds Needs Survey, about 13,100 MGD of wastewater is processed at municipal plants with anaerobic digesters that are greater than 1 MGD in size. At 8.4 ft^3/minute for each MGD processed and 600 Btu/ft^3, this translates to a technical potential of about 35 million MMBtu/year.[5] As can be seen in Figure 4-3, the concentration of ADG availability is in both highly populated areas like California, Texas, Florida and the Mid-Atlantic, and industrial areas like Ohio, Michigan and Illinois.

For municipal wastewater treatment plants with digesters, ADG is often fired in a boiler to provide heat for the digester, or it can be used for on-site power production. However, neither of these methods constitutes industrial ADG utilization. For industrial sites to utilize the gas in process heating or steam generation applications, a pipeline would need to be constructed from the municipal treatment plant. Therefore, potential industrial users can compare the cost to construct a pipeline and purchase the ADG from the municipal plant to the expected cost of purchasing the equivalent amount of natural gas. The economics of these decisions, based on pipeline length and local gas prices, are considered in Chapter 6.

[5] Ibid.

Opportunity Fuel Source: Anaerobic Digester Gas from Municipal WWTPs	
Heat Content:	500-600 Btu/ft^3
Sources:	Municipal Wastewater Treatment Plants (> 1 MGD)
Technical Potential:	35 Million MMBtu/year
Delivery/Requirements:	Pipeline construction from anaerobic digester to industrial site for delivery; gas pretreatment equipment may be required

While many of the municipal WWTPs in the CWNS database include large industrial wastewater flows, there are several food and chemical manufacturing facilities in the country that treat their wastewater on-site with anaerobic digestion. The number of industrial wastewater treatment plants in the country is very small compared to municipal plants. Additionally, data is not available to determine which industrial plants use anaerobic digesters. Still, a list of industrial facilities with wastewater discharge permits was obtained from the EPA's Envirofacts database[6], providing the locations and flow rates of industrial plants in the food, pulp/paper and chemical processing industries. These industries were chosen because only facilities processing organic chemicals or feedstocks produce the type of waste that can be processed with anaerobic digestion. At some industrial facilities, the wastewater is significantly more potent than the dilute streams found in municipal plants. In extreme cases, levels of biological oxygen demand exceed 25 times the amount found in municipal wastewater.[7] However, with a lack of detailed wastewater composition data for various types of industrial facilities, the same conversion factor from wastewater flow to technical potential for municipal treatment plants is used in this analysis. The total number of facilities, wastewater flow, and estimated technical potential is provided in Table 4-1, assuming an ADG heat content of 600 Btu/ft^3.

Table 4-1. Potential Industrial Wastewater Treatment Plants

Industry	Sites >1 MGD	Total Flow (MGD)	Estimated Technical Potential (MMBtu/yr)
Food Processing	55	355	940,000
Pulp/Paper Mills	116	2,402	6,356,000
Organic Chemical Processing	125	2,113	5,592,000
Totals	296	4,870	12,888,000

Source: EPA Envirofacts Database (2011)

[6] United States Environmental Protection Agency, Envirofacts Database, http://www.epa.gov/enviro/

[7] *A Biography of Biogas*. Global Water Intelligence. http://www.globalwaterintel.com/archive/9/8/market-insight/a-biography-of-biogas.html, May 2011.

Opportunity Fuel Source: Anaerobic Digester Gas from Industrial WWTPs	
Heat Content:	500-600 Btu/ft^3
Sources:	Industrial Wastewater Treatment Plants (> 1 MGD)
Technical Potential:	13 Million MMBtu/year
Delivery/Requirements:	On-site pipeline construction, organic waste stream and anaerobic digester required; gas pretreatment equipment may be required.

Figure 4-2 illustrates where these industrial plants are located by state, according to the estimated wastewater production. Many states do not have any sites in the three primary industries for organic wastewater production, so they are assumed to lack any industrial ADG potential.

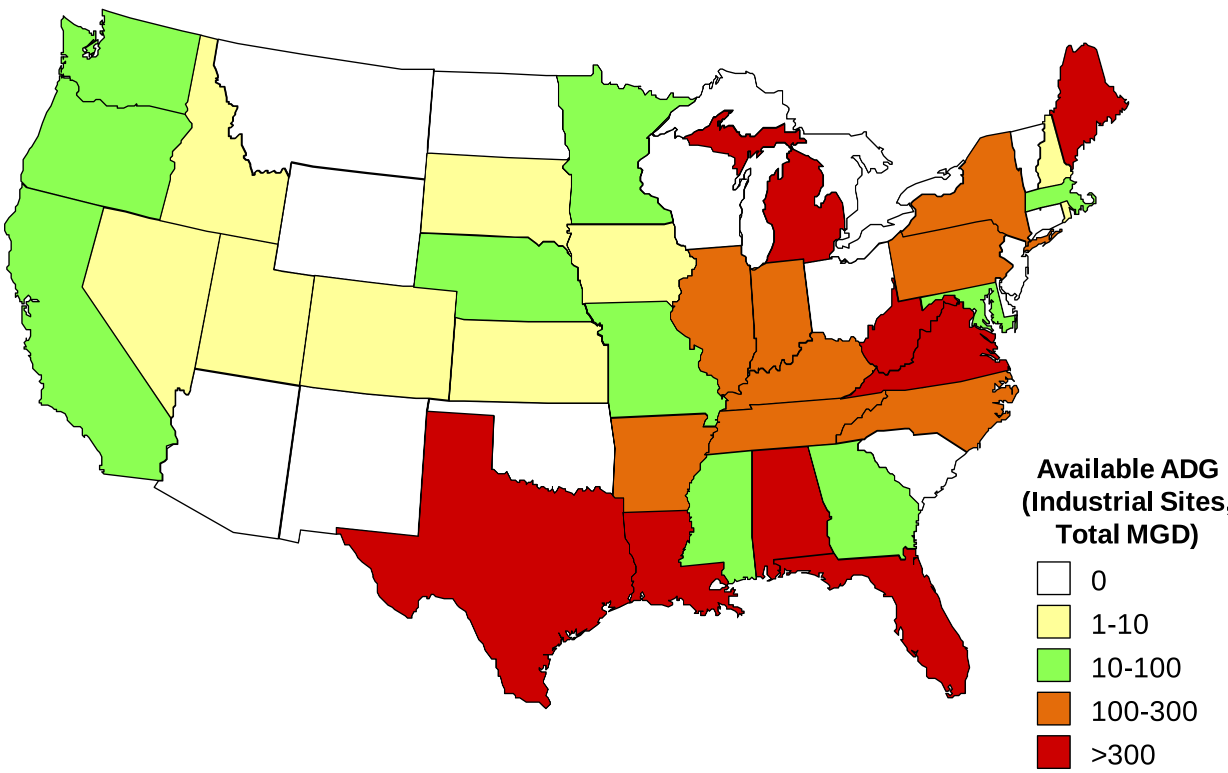

Figure 4-2. Map of Estimated Industrial ADG Production by State

While it is uncertain if these industrial sites have already installed digesters, the technical potential is calculated assuming that they either have a digester or are willing to adopt anaerobic digestion for wastewater treatment. Even if all of the industrial sites contain anaerobic digesters, the total technical potential is only about one third of the potential calculated for municipal plants with digesters. Overall, the total technical potential for anaerobic digester gas (municipal + industrial) is estimated at 48 million MMBtu/year.

Landfill Gas

As part of the Landfill Methane Outreach Program (LMOP), the Environmental Protection Agency maintains a database that documents landfills in the United States, providing information and categorizing their landfill gas (LFG) project status (Operational, Construction, Shut Down, Candidate and Potential). Sites with LFG projects that are operational, under construction, or those that have been shut down are not considered potential sites for industrial utilization. However, in some cases, landfills with current projects are also listed as candidate or potential sites. Usually this occurs when a landfill is not utilizing all of its gas with its current LFG to energy project, leaving room for more potential usage. For example, the Olinda Alpha Secured Landfill Facility in Orange County, California currently powers a reciprocating engine to generate electricity with its landfill gas. This site, however, is estimated to have enough additional gas to provide 3 million MMBtu/year, which could potentially be employed by an industrial site. A large industrial facility consuming 1 million MMBtu per year could potentially procure LFG this landfill and replace all of the natural gas it consumes. Overall, 20 landfills nationwide are estimated to be capable of replacing at least 1 million MMBtu/year of natural gas with LFG, and over 50 landfills could replace half that amount. Several of these landfills are currently engaged in relatively small energy projects, typically involving electricity production and sales.

Candidate landfills have been identified by the EPA as strong locations for LFG-to-energy projects, meaning a landfill gas collection system would be easy to implement and LFG production should be strong for many years to come. The status of Potential landfills is more uncertain, although typically this label only means that a detailed study has not yet been performed. In order to quantify the potential for new LFG projects, all of the landfill sites labeled Candidate and Potential in the LMOP database were analyzed. Most sites contained a value for "waste in place", which shows how many tons of waste are currently stored at the landfill. For sites missing this information, the median waste in place for landfills not currently participating in LFG projects (about 1,000,000 tons) was used.[8]

Using a ratio derived from a formula given by the EPA that correlates waste in place to LFG flow rate[9], the amount of gas produced by each site and the corresponding technical potential were approximated. For landfills with current LFG to energy projects that are still listed as Candidate or Potential, the gas flow to the project was subtracted from the estimated gas available. Additionally, the 20 largest landfills were reviewed to ensure that they are not already involved with LFG projects. Recent and planned future projects were found at some of these sites, and in each case the estimated gas flow to the project was subtracted from the total available gas. The numbers were tallied for each state, and California appears to have the most potential for new LFG projects, followed by Texas, New York and Florida. Predictably,

[8] The average waste in place for candidate and potential landfills is about 2,000,000 tons, but this is heavily weighted by the few largest landfills – the median value for waste in place was seen as a better predictor of size for undocumented landfills.

[9] Formula indicates that a landfill with 1,000,000 tons of waste in place could generate about 300 cfm of landfill gas (close to 80,000 MMBtu/year)

these are the four most populated states in the country. The top 20 states for estimated landfill gas production are presented in Table 4-2.

Table 4-2. Top States for LFG Availability, with Estimated Technical Potential

State	Number of Potential Landfills	Estimated Waste in Place (tons)	Estimated LFG Flow Rate (CFM)	Technical Potential (Million MMBtu/yr)
California	246	432,520,795	118,163	31.1
Texas	88	290,724,854	88,833	23.3
New York	58	230,269,622	61,523	16.2
Ohio	44	151,791,308	45,237	11.9
Florida	53	160,973,051	44,995	11.8
Illinois	51	138,861,887	42,380	11.1
Georgia	60	108,792,493	40,538	10.7
North Carolina	110	113,736,800	35,048	9.2
Tennessee	123	97,303,406	34,373	9.0
Indiana	76	99,108,636	31,644	8.3
Colorado	28	102,457,114	31,587	8.3
Missouri	93	78,710,241	29,573	7.8
Pennsylvania	36	83,178,400	28,945	7.6
Alabama	34	86,241,560	28,272	7.4
Kentucky	32	77,373,252	24,112	6.3
Washington	46	57,778,105	23,933	6.3
Nevada	10	88,525,180	22,991	6.0
Virginia	41	67,824,346	21,175	5.6
Mississippi	25	62,820,599	19,746	5.2
South Carolina	37	59,991,560	19,720	5.2
Rest of U.S.*	522	640,562,130	225,379	59.2
Total	1,813	3,229,545,339	1,018,167	267.6

*Continental U.S. only

Source: EPA LMOP Database, 2010, Candidate and Potential landfills; Median waste in place (1,000,000 tons) used for landfills lacking waste-in-place data

The top states for LFG production should be those with the highest populations, and that is true for many of the states listed above. However, some states in the Midwest and Southeast have large numbers of potential landfills producing significant amounts of gas, despite having smaller populations. It is likely that LFG-to-energy projects have not been as prominent in these states, leaving more untapped landfills to choose from. Overall there is an estimated 267.6 MMBtu/year of technical potential for industrial LFG utilization.

While the total technical potential based on LFG production is a good indicator of industrial LFG project potential, in some states most of the LFG is produced at 1 or 2 large landfills that may be located too far from other industrial facilities. With an average cost of $330,000 per mile[10], pipeline costs can add up quickly for remote landfills. In some cases, a better indicator of project potential is the number of landfills in the state, because more landfills should lead to more potential matches with nearby industrial sites. Figure 4-3 illustrates which states have the most landfills for potential projects in the continental United States.

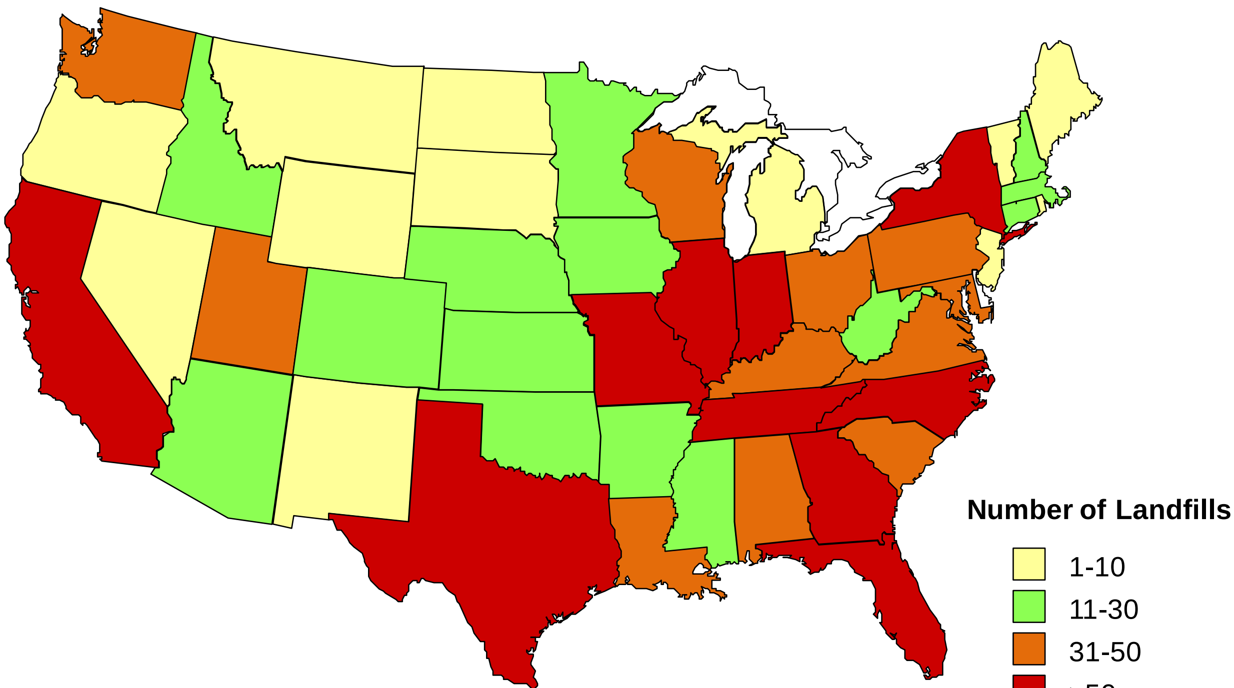

Figure 4-3. Number of EPA LMOP Candidate/Potential Landfills in Each State

A highly populated state like Michigan having only 10 potential landfills seems odd, but it turns out that Michigan already has 53 landfills with LFG projects that are either operational or under construction. Similarly, Utah wound not be one of the top LFG states based on population, but there are currently only 5 LFG-to-energy projects in the state, so most of the landfills are untapped. Factors that contribute to project development are distance to natural gas pipelines or electrical transmission lines, prevailing natural gas and wholesale electricity pricing, plus the potential value of renewable energy credits for states with a Renewable Portfolio Standard[11]. Where landfills are far from energy transportation infrastructure or local energy costs are low, more projects are undeveloped.

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[10] United States Environmental Protection Agency, Landfill Methane Outreach Program, *LFG Energy Project Development Handbook*, 2010. http://www.epa.gov/lmop/publications-tools/handbook.html

[11] Some states may lack a Renewable Portfolio Standard but have access to renewable energy credits through their wholesale power market.

Opportunity Fuel Source: Landfill Gas	
Heat Content:	400-600 Btu/ft^3
Sources:	Landfills Not Fully Utilizing Their LFG
Technical Potential:	268 Million MMBtu/year
Delivery/Requirements:	Pipeline construction from landfill to industrial site; gas pretreatment equipment could be required

The estimated technical potential for all of the potential landfills (assuming 500 Btu/ft3) is 268 Million MMBtu per year. This is much higher than the technical potential for anaerobic digester gas, but the remote locations of many of these landfills could be a limiting factor when calculating the economic potential.

Biomass Gas

The availability of biomass fuels for industrial gasification projects draws from the same fuel supply that determines the availability of solid biomass fuels for industrial boilers. The various resources for biomass fuels and their estimated availability is explored in detail in the Solid Opportunity Fuels section later in this chapter. The technical potential, however, would differ because of the conversion inefficiencies associated with gasification equipment. In general, about 80 percent of the energy from biomass can be recovered with gasifiers[12]. Using this assumption, the technical potential was calculated for the various types of biomass fuels, shown in Table 4-3. This can be compared to the technical potential for solid biomass fuels in Table 4-10 later in this chapter.

Table 4-3 Availability and Technical Potential for Biomass Gas

Biomass Fuel	Availability Concentration	Estimated Tons Available (Million)	Estimated Technical Potential (Million MMBtu/yr)
Crop Residues	Midwest	157	1,880
Forest Residues	Southeast, Midwest	57	724
Mill Residues	Northwest, Southeast	4	53
Urban Wood Waste	Urban Areas	31	371
All Biomass Fuels	**n/a**	**250**	**3,028**

Source: Milbrandt, A., *A Geographic Perspective on the Current Biomass Resource Availability in the United States*, Technical Report, National Renewable Energy Laboratory, December 2005.

[12] Basu, Prabir, *Biomass Gasification and Pyrolysis: Design and Theory*, Elsevier Inc., 2010.

Opportunity Fuel Source: Biomass Gas	
Heat Content:	~600 Btu/ft^3
Sources:	Crop Residues, Forest Residues, Mill Residues, Urban Wood Waste
Technical Potential:	3 Billion MMBtu/year
Delivery/Requirements:	truck/rail/barge delivery of biomass, unless produced on-site; requires installed gasifier

Note that the technical potential calculated here draws from the same biomass resources as the technical potential calculated for solid biomass fuels, so they are not additive.

Industrial Waste Gases

This study initially evaluated several potential industrial waste gases, including coke oven gas, blast furnace gas, refinery fuel gas, wellhead gas, and volatile organic compounds. With most of these gases, the quantities produced, as well as the quantities available, are difficult to quantify. Volatile organic compounds (VOCs), produced from numerous industrial operations, can be vented into boilers to thermally oxidize the waste and enhance steam production. However, the level of VOC production at industrial facilities is difficult to pinpoint, and there are few potential uses for the gas outside of boiler fuel enhancement due to its dilute nature and low energy content. Wellhead gas is produced in large amounts at oil and natural gas wells, but the gas is normally highly contaminated and located too far from most industrial facilities, and has higher value when processed to provide natural gas. The three waste gases that are most promising for industrial utilization are coke oven gas, blast furnace gas, and refinery fuel gas.

Coke Oven Gas and Blast Furnace Gas

Coke oven gas is most commonly produced at integrated steel manufacturing plants, where coke is blended with iron and limestone in a blast furnace. The carbon-rich coke is created in coke ovens, where volatiles are driven off and the resulting coke oven gas can be captured and used for various applications. Integrated steel mills produce their own coke and use blast furnaces for steel manufacturing, so coke oven gas can be used to heat the blast furnace, and blast furnace gas can also be captured and utilized. In addition to integrated mills, coal coke is produced at merchant coke plants that sell coke to steel mills, and some of their coke oven gas can be collected and utilized at these facilities. While merchant plants are more numerous than steel mills, they are typically much smaller in size, and have less demand for thermal energy, so complete gas utilization could be a challenge. Merchant plants are therefore more likely to have excess coke oven gas that could potentially be utilized at nearby industrial facilities.

Non-integrated steel manufacturing facilities, also known as mini-mills, do not produce industrial waste gases with significant energy content. Instead of processing the base materials, these mills start with scrap iron or steel and melt it in an electric arc furnace, rather than a blast furnace.

In order to estimate the levels of coke oven gas and blast furnace gas production in the United States, the locations and sizes of integrated steel manufacturing facilities and merchant plants were consulted. Information on the locations of these plants was extracted from the American Coke and Coal Chemicals Institute, but data on coke and blast furnace gas production can be difficult to obtain.

A previous study on the prospects for coke oven gas utilization in Pennsylvania for hydrogen vehicle fueling stations revealed that the coke-producing plant for Mon Valley Works generates 4,700,000 tons of coke each year, producing 98,091 million cubic feet of coke oven gas. This equates to a gas production rate of 21 cubic feet per thousand tons of coke. By comparison, the two merchant coke plants in Pennsylvania combine for 450,000 tons of coke production, and about 6,589 million cubic feet of coke oven gas each year.[13] These facilities yield around 15 cubic feet per thousand tons of coke.

Overall, there are 20 operating coke plants in the united states: 9 integrated steel manufacturing plants and 11 merchant coke plants. Integrated steel manufacturing plants tend to produce significantly more coke than merchant plants, especially large U.S. Steel plants like Mon Valley Works. Other than U.S. Steel, AK Steel Corporation, ArcelorMittal and Severstal Wheeling, Inc. have integrated steel plants in the United States. Merchant steel plants are owned by DTE Energy Services, SunCoke Energy (Sunoco), ABC Coke (Drummond Company, Inc.), and other small, single-plant operators. Table 4-4 provides a full listing of coke plants in the United States.

[13] *Analysis of Hydrogen Energy Stations for Initial Hydrogen Infrastructure in Northeastern States along the I-95 Corridor*. Resource Dynamics Corporation and Concurrent Technologies Corporation. May 2009.

Table 4-4. Operating Coke Plants in the United States

State	City	Company	Type of Plant
Alabama	Tarrant	ABC Coke (Drummond Company)	Merchant
Alabama	Birmingham	Walter Coke	Merchant
Illinois	Granite City	U.S. Steel	Integrated Steel
Illinois	Granite City	Gateway Energy & Coke Company	Merchant
Indiana	East Chicago	Indiana Harbor Coke Company	Merchant
Indiana	Burns Harbor	ArcelorMittal	Integrated Steel
Indiana	Gary	U.S. Steel	Integrated Steel
Kentucky	Ashland	AK Steel Corporation	Integrated Steel
Michigan	Ecorse	DTE Energy Services	Merchant
New York	Tonawanda	Tonawanda Coke Corporation	Merchant
Ohio	Middletown	AK Steel Corporation	Integrated Steel
Ohio	Middletown	Middletown Coke Company	Merchant
Ohio	Warren	ArcelorMittal	Integrated Steel
Ohio	Haverhill	SunCoke Company (Sunoco)	Merchant
Pennsylvania	Erie	Erie Coke Corporation	Merchant
Pennsylvania	Monessen	ArcelorMittal	Integrated Steel
Pennsylvania	Pittsburgh	DTE Energy Services	Merchant
Pennsylvania	Clairton	U.S. Steel	Integrated Steel
Virginia	Vansant	Jewell Coke and Coal	Merchant
West Virginia	Follansbee	Severstal NA	Integrated Steel

Figure 4-4 shows the locations of operating coke plants in the United States.

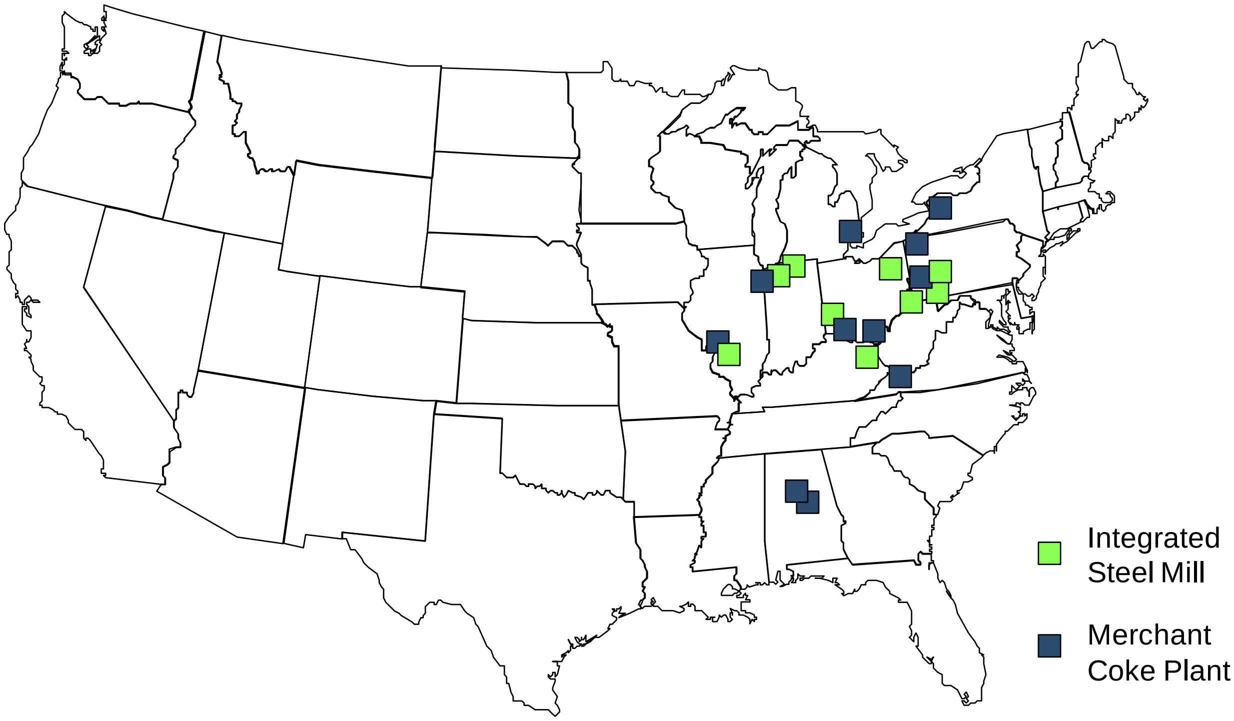

Figure 4-4. Locations of Operating Coke Plants

The majority of these plants are located in the same region of the country, west of the Appalachian Mountains where most coal is mined. There could be potential for other industrial facilities to utilize the coke oven gas or blast furnace gas, but since the number of facilities is limited, and most gas is utilized on-site, the opportunities for industrial waste gas utilization in the United States appear to be few and far between.

The four plants in Pennsylvania combine for an estimated 98,091 million cubic feet per year of coke oven gas production.[14] Assuming an average heating value of 500 Btu/ft^3, the technical potential for Pennsylvania would be approximately 49 million MMBtu. The four plants in Pennsylvania provide a representative sample of coke plant activity in the United States, with one large U.S. Steel integrated plant, one smaller integrated plant, and two merchant coke suppliers. Assuming each of the other coke plants in the United States produce similar levels of coke oven gas compared to the four Pennsylvania plants, the total technical potential is in the range of 245 Million MMBtu per year. However, many of these facilities utilize coke oven gas for plant operations, so the surplus actually available is considerably less.

For example, the large U.S. Steel Plant in Pennsylvania (with the country's largest coking facility) claims to utilize all of the coke oven gas that it produces, which takes away the vast majority of Pennsylvania's potential. It is likely that most of the integrated steel mills in the country also utilize the majority of their coke oven gas. Additionally, with only 20 coke plant locations, the ability of a nearby industrial facility

[14] Ibid.

to utilize all of the excess waste gas at a given plant is questionable, and the total number of potential projects is highly limited. Assuming that all of the integrated steel mills utilize their coke oven gas on-site, the estimated technical potential falls to about 31 Million MMBtu per year, which is a more conservative estimate of available coke oven gas. However, as discussed in Chapter 3, about 40 percent of coke oven gas is typically recirculated to heat the coke ovens themselves. This leaves 19 million MMBtu per year of coke oven gas for potential industrial utilization.

Delivery of coke oven gas from a merchant plant to a nearby industrial site would require the construction of a new gas pipeline, which costs about $330,000 per mile, assuming no right-of-way issues or land purchasing requirements. Also, gas pretreatment equipment such as scrubbers and filters would need to be installed and maintained. These factors will be considered in the economic analysis later in this report.

Opportunity Fuel Source: Coke Oven Gas	
Heat Content:	~500 Btu/ft^3
Sources:	Merchant Coke Plants (Integrated Steel Mills likely to fully utilize gas)
Technical Potential:	19 Million MMBtu/year
Delivery/Requirements:	Pipeline construction from coke plant to industrial site; gas pretreatment equipment required

Refinery Fuel Gas

Refinery fuel gas, also referred to as still gas or off gas, is generated at the same oil refineries that produce petroleum coke (see Table 4-12 later in this chapter), with a heavy concentration in the Gulf coast states. The Energy Information Administration tracks the production and consumption of this gas. While oil refineries consume the majority of the still gas they produce, there is usually a significant amount of gas that is flared. Recent practices to increase the output of LPG and high-octane gasoline at these refineries have led to higher reactor temperatures, increasing still gas production. The quality of the hot still gas is too low to sell to nearby facilities without significant cleanup costs, and there are no known records of refineries piping their waste gas to industrial sites.

According to the EIA, in 2009, refineries produced the equivalent of 236 million barrels of oil in still gas, while they consumed 219 million barrels as fuel. This leaves the equivalent of over 16 million barrels of oil in still gas, containing about 96 million MMBtu of energy. However, much of this gas was likely flared during operational upsets (to prevent fires or explosions during power outages or other incidents). Also, it is uncertain how much gas is used for flare pilot flames, to ensure the timely flaring of gas during these upsets. For the technical potential estimate, it is assumed that all of the still gas not consumed by oil refineries is available for industrial utilization. The figures for still gas production and consumption are broken down by EPA Petroleum Administration for Defense (PAD) District in Table 4-5.

Table 4-5. Still Gas Production, Consumption and Technical Potential, by PAD District

	Thousand Barrels of Oil Equivalent (annual)			Million MMBtu/yr
PAD District	Still Gas Production	Still Gas Consumption	Potentially Marketable Still Gas	Technical Potential
I. East Coast	16,300	15,400	900	5.2
II. Midwest	47,800	48,700	0	0.0
III. Gulf Coast	118,200	107,000	11,200	65.0
IV. Rocky Mtn	9,600	9,600	0	0.0
V. West Coast	43,900	39,500	4,400	25.5
All U.S.	235,800	220,200	16,500	95.7

Source: EIA Petroleum Administration for Defense (2009 Data)

This data shows that each year, about 96 million MMBtu of still gas is not consumed by oil refineries. However, some of this gas is sent to processing plants to extract propane, ethylene, hydrogen, and other valuable components. A further analysis of flared gas levels was conducted using data from the South Coast Air Quality Management District on flare volumes at Southern California refineries, as well as data from two refineries located in Colorado and New Mexico that have installed absorption refrigeration units (discussed in previous chapter).

Flare data for five large California refineries was collected and compared to their size in terms of oil processing. For the California refineries, it was found that each barrel of oil processed corresponds to about 5 standard cubic feet of flared still gas. When this analysis was performed for the Colorado and New Mexico refineries, higher levels of flaring were found, with each barrel of oil corresponding to 11 and 8 standard cubic feet of flared gas, respectively. Flare levels are expected to be particularly low in California, where emissions regulations are stricter than most other states. Therefore, the average value of 8 cubic feet of gas for each barrel of oil is assumed to be roughly the national average. Using this number along with the total barrels of oil processed each year, the estimated amount of still gas currently being flared was estimated to be 51.5 million MMBtu per year. This is just over half the amount of unconsumed still gas according to EIA data. The available still gas at each refinery in the country was estimated using this correlation, and the results were tallied up for each state. Figure 4-5 maps where the technical potential for refinery fuel gas is located, by state.

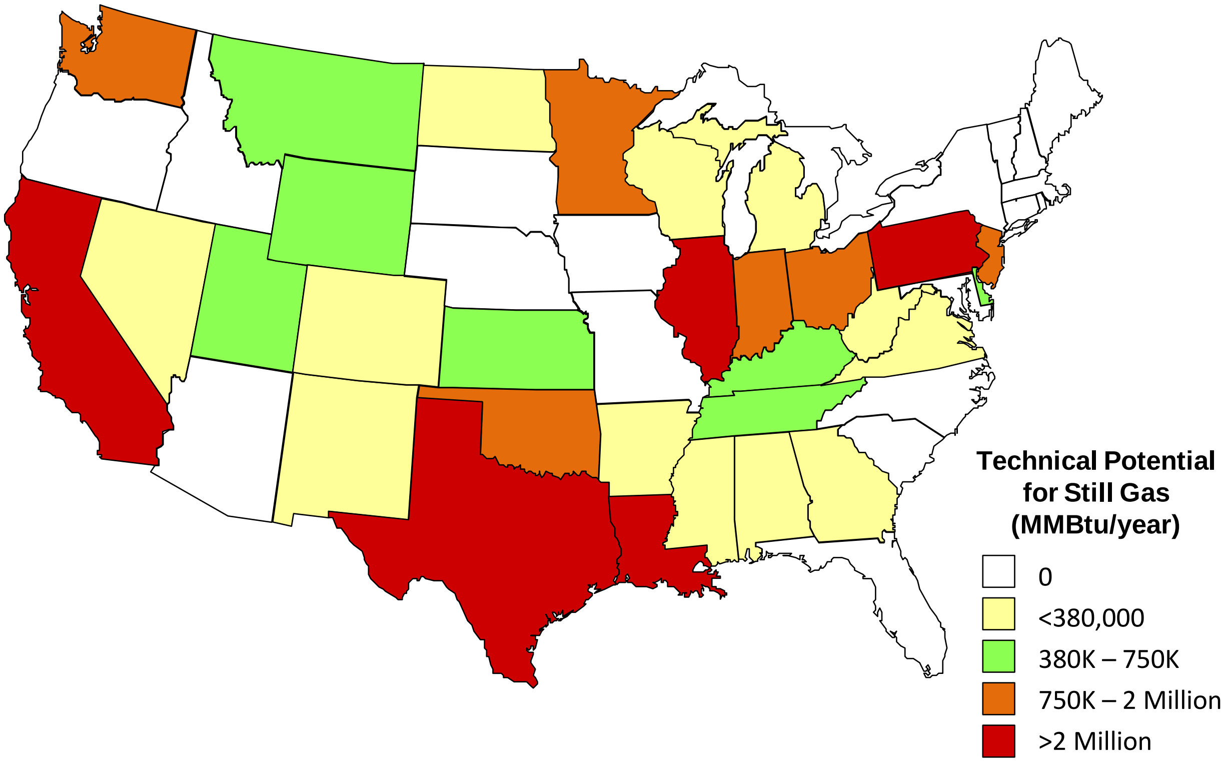

Figure 4-5. Estimated Technical Potential for Refinery Fuel Gas (Still Gas) by State

The 51.5 million MMBtu of technical potential is primarily located in Texas (13.4 million MMBtu/yr), Louisiana (8.4 million MMBtu/yr) and California (5.8 million MMBtu/yr). Illinois and Pennsylvania have the potential for over 2 million MMBtu, and several states fall in the 1-2 million MMBtu/year range.

Delivery of refinery fuel gas from an oil refinery to a nearby industrial site would require the construction of a new gas pipeline, which costs roughly $330,000 per mile, assuming no right-of-way issues or land purchasing requirements. In addition, gas pretreatment equipment (primarily scrubbers and filters) and potentially gas storage equipment would need to be installed and maintained.

Opportunity Fuel Source: Refinery Fuel Gas (Still Gas)	
Heat Content:	~1,000 Btu/ft^3
Sources:	Oil Refineries
Technical Potential:	52 Million MMBtu/year
Delivery/Requirements:	Pipeline construction from oil refinery to industrial site; gas pretreatment equipment and gas storage may be required.

Technical Potential for Industrial Waste Gases

With an estimated 19 million MMBtu of technical potential from coke oven gas and 52 million MMBtu of potential from refinery fuel gas, there is a total of 71 million MMBtu of technical potential for industrial waste gases to be used for steam generation and process heating applications.

Summary for Gaseous Opportunity Fuels

The characteristics and delivery requirements for each solid opportunity fuel are summarized in Table 4-6. The estimated technical potential for each opportunity fuel is summarized at the end of the chapter.

Table 4-6. Summary of Characteristics and Delivery Requirements of Gaseous Opportunity Fuels

Fuel	Heat Content (Btu/ft^3)	Sources	Delivery Requirements
Anaerobic Digester Gas	500-600	Municipal and industrial WWTPs	Pipeline construction, gas pretreatment
Landfill Gas	400-600	Large landfills	Long-distance pipeline construction, gas pretreatment
Biomass Gas	~600	Gasified biomass fuels	Truck/rail/barge delivery of biomass; advanced gasifier
Coke Oven Gas	~500	Steel mills, merchant coke plants	Pipeline construction, gas pretreatment
Industrial Waste Gases	1,000	Oil refineries	Pipeline construction, gas treatment and storage

Solid Opportunity Fuels

The availability of solid opportunity fuels is difficult to determine. There are vast biomass resources in the country that could be used as fuel if properly processed, and similarly, there are a large number of discarded tires that could be processed into TDF. The available supply of petroleum coke can be difficult to pinpoint due to overseas demand for exports, but large quantities of pet coke are produced in the U.S. every year. This section estimates the available solid opportunity fuels in the country, as well as estimating the technical potential for industrial utilization.

Biomass Fuels

The availability of biomass fuels for industrial facilities depends both on the type of biomass and the proximity to biomass resources. Industrial sites like pulp and paper mills, lumber processing facilities, and manufacturing plants that produce wood or paper products have on-site access to wood waste. Facilities like these need only to invest in processing equipment to convert the wood waste into uniform chips or pellets for enhanced combustibility, and fuel handling equipment to feed the waste fuel into a boiler. Similarly, agricultural facilities have access to crop residues that can be processed into fuel. Most other sites would have to rely on external sources of biomass fuel, typically purchasing processed wood chips from a nearby source.

In 2005, the National Renewable Energy Laboratory (NREL) conducted a comprehensive biomass availability study[15] which examined potential sources of biomass, estimated the amount available in each county, and added up the available biomass resources for each state. The biomass fuels were broken down into several categories, including crop residues, forest residues, mill residues, and urban wood waste. This section examines the availability of these different biomass fuels by state, and estimates the technical potential for industrial steam generation and process heating applications. Competition for biomass resources (i.e. for biodiesel fuels) is not considered in this analysis.

Crop Residues

Crop residues, obtained from agricultural collection and processing operations, are widely available throughout the country, and most heavily concentrated in the Midwest. The top five states (Iowa, Illinois, Minnesota, Nebraska and Indiana) account for about half of the country's total potential. Like all biomass fuels, transportation distances are a limiting factor in their effectiveness for use at industrial sites. However, there are also inherent collection costs for crop residues that give them a fairly high initial cost. NREL's 2005 report on biomass availability provides data on the estimated amount of crop residues available in each state, with a total of 157 million dry tons. This figure is comparable to the 2012 baseline amount of unused agricultural land biomass in the Department of Energy's recent Billion Ton Update.[16] Table 4-7 shows the top 15 states in terms of crop residue availability, along with the estimated technical potential for industrial utilization.

[15] Milbrandt, A., *A Geographic Perspective on the Current Biomass Resource Availability in the United States*, Technical Report, National Renewable Energy Laboratory, December 2005.

[16] United States Department of Energy, Office of Energy Efficiency and Renewable Energy, *U.S. Billion Ton Update – Summary Findings*, August 2011.

Table 4-7. Top States for Crop Residue Availability, with Technical Potential

State	Crop Residues (1,000 dry tons)	Estimated Technical Potential (Million MMBtu/year)
Iowa	23,590	330
Illinois	19,593	274
Minnesota	14,231	199
Nebraska	10,931	153
Indiana	8,976	126
Kansas	7,614	107
North Dakota	6,602	92
Texas	6,089	85
Missouri	6,007	84
South Dakota	5,140	72
Ohio	5,001	70
Arkansas	4,796	67
Wisconsin	4,419	62
Louisiana	4,335	61
Michigan	3,586	50
Rest of U.S.	26,285	368
Total	157,195	2,201

Source: Milbrandt, A. *A Geographic Perspective on the Current Biomass Resource Availability in the United States*. Technical Report. National Renewable Energy Laboratory. December 2005.

The county-specific NREL map for crop residue availability is presented in Appendix A.With over 150 million tons of biomass available, there is a great deal of technical potential for crop residue utilization. Assuming an average heat content of 7,000 Btu/lb, the total technical potential is estimated at 2.2 billion MMBtu/year. However, the actual economic potential is much less, and tied to the location of the crop residue sources. The economic potential for biomass fuels will be explored in Chapter 6 of this report.

Forest Residues

Forest residues, also known as harvested wood fuels, come from forest thinnings and lumber processing activities. As with crop residues, there is an inherent collection cost that drives up the initial cost, and forest residues tend to be found in remote locations where large transportation distances are typically required. According to data from NREL, the highest concentrations of useable forest residues lie in the Southeast and Midwest regions of the country. Top states for harvested wood availability are presented in Table 4-8, along with their estimated technical potential. The total estimated potential is about 57 million dry tons, slightly less than the amount of unused forestland biomass in the 2012 baseline scenario of the recent Billion Ton Update performed by the U.S. Department of Energy.[17]

Table 4-8. Top States for Forest Residue Availability, with Technical Potential

State	Forest Residues (1,000 dry tons)	Estimated Technical Potential (Million MMBtu/year)
Mississippi	3,825	61
Georgia	3,556	57
Louisiana	3,384	54
North Carolina	2,995	48
Maine	2,890	46
Arkansas	2,874	46
Alabama	2,555	41
Virginia	2,403	38
Minnesota	2,242	36
Texas	2,060	33
Kentucky	2,055	33
Wisconsin	2,011	32
Missouri	1,840	29
Florida	1,778	28
South Carolina	1,733	28
Rest of U.S.	18,412	295
Total	56,613	906

Source: Milbrandt, A., *A Geographic Perspective on the Current Biomass Resource Availability in the United States*, Technical Report, National Renewable Energy Laboratory, December 2005.

The technical potential for forest residues is considerably less than crop residues, estimated at over 900 million MMBtu/year. Wood chips from forest residues, when dried, tend to have a higher heating value than crop residues, and these figures assume an average value of 8,000 Btu/lb. Due to the relatively high initial cost and transportation distances to industrial facilities associated with forest residues, it is likely that most of this technical potential will prove to be uneconomical. The location of harvested wood reserves in the United States is illustrated down to the county level in Appendix A.

[17] United States Department of Energy, Office of Energy Efficiency and Renewable Energy, *U.S. Billion Ton Update – Summary Findings*, August 2011.

Mill Residues

The availability of mill residues is tied to the location of lumber processing plants, pulp and paper mills, and other industrial facilities that produce wood or paper products. Therefore, the likelihood of mill residues being located close to an industrial facility is much greater than crop residues, and the mills themselves can potentially utilize their residues for fuel. Additionally, the collection costs for mill residues are significantly less than crop residues, which helps the economic potential for utilization.

Most pulp and paper mills in the United States are located in the Southeast and the Northwest, but this is not necessarily reflected in mill residue availability, since most mills utilize the majority of their residues for boiler fuel. According to the 2005 NREL report, there is only about 4 million tons of mill residue available in the United States each year. Table 4-9 provides the estimated availability of mill residues along with the technical potential.

Table 4-9. Top States for Mill Residue Availability, with Technical Potential

State	Mill Residues (1,000 dry tons)	Estimated Technical Potential (Million MMBtu/year)
Pennsylvania	271	4
California	255	4
Tennessee	228	4
Missouri	199	3
Georgia	163	3
Texas	156	2
New York	143	2
Ohio	142	2
Florida	134	2
Alaska	133	2
Kentucky	129	2
North Carolina	129	2
West Virginia	129	2
Colorado	128	2
Virginia	128	2
Rest of U.S.	1,760	28
Total	4,227	68

Source: Milbrandt, A., *A Geographic Perspective on the Current Biomass Resource Availability in the United States*, Technical Report, National Renewable Energy Laboratory, December 2005.

Assuming an average heating value of 8,000 Btu/lb, the technical potential for mill residues is estimated to be 68 million MMBtu/year. While the technical potential is considerably less than other biomass fuel sources, the lower delivered prices for mill residues will likely lead to a strong economic potential among this group of biomass fuels. The location of available mill residues throughout the country is depicted graphically with NREL's county-level map provided in Appendix A. The economic potential for mill residues will be further explored later in this report.

Urban Wood Waste

The final category of biomass to be studied in this report is urban wood waste, consisting of construction/demolition debris, yard trimmings, and other sources of wood that would normally be thrown away or recycled. This form of wood waste can be obtained at a lower price than most others, and since it is produced at urban and suburban locations, the average distance to industrial facilities can be relatively small. In NREL's report on biomass availability, the available urban wood waste was estimated for each state. Table 4-10 provides the top states for urban wood waste availability, as well as the estimated technical potential.

Table 4-10. Top States for Urban Wood Waste Availability, with Technical Potential

State	Urban Wood Waste (1,000 dry tons)	Estimated Technical Potential (Million MMBtu/year)
California	3,901	59
Texas	2,307	35
New York	2,041	31
Florida	1,678	25
Illinois	1,337	20
Ohio	1,272	19
Pennsylvania	1,238	19
Michigan	1,196	18
Georgia	924	14
New Jersey	894	13
North Carolina	833	12
Virginia	813	12
Indiana	715	11
Massachusetts	687	10
Washington	675	10
Rest of U.S.	10,390	156
Total	30,901	464

Source: Milbrandt, A., *A Geographic Perspective on the Current Biomass Resource Availability in the United States*, Technical Report, National Renewable Energy Laboratory, December 2005.

As expected, the states with the highest populations tend towards the top of the list. Assuming an average heating value of 7,500 Btu/lb, the technical potential of urban wood waste for industrial applications is about 464 million MMBtu/year.

The amount of urban wood waste produced each year varies more than other types of biomass, and depends heavily on the construction market. With the recent downturn in the real estate market, it is likely that urban wood waste production has declined, and the list of top states now may not be reflective of what was found in 2005. The map of data provided in Appendix A breaks down the available resources for urban wood waste by county.

Summary: Biomass Fuel Availability

While the availability of crop residues and harvested wood is highly regional, mill residues and urban wood waste are available throughout the country. All of these biomass fuels are capable of providing industrial facilities with low-cost fuel options compared to coal. Table 4-11 summarizes the availability and technical potential for each of the four types of biomass.

Table 4-11 Availability and Technical Potential of Biomass Fuels

Biomass Fuel	Availability Concentration	Estimated Tons Available (Million)	Estimated Technical Potential (Million MMBtu/yr)
Crop Residues	Midwest	157	2,201
Forest Residues	Southeast, Midwest	57	906
Mill Residues	Northwest, Southeast	4	68
Urban Wood Waste	Urban Areas	31	464
All Biomass Fuels	**n/a**	**250**	**3,639**

Source: Milbrandt, A., *A Geographic Perspective on the Current Biomass Resource Availability in the United States*, Technical Report, National Renewable Energy Laboratory, December 2005.

Figure 4-6 illustrates the availability of biomass fuels according to the NREL data on a state-by-state basis.

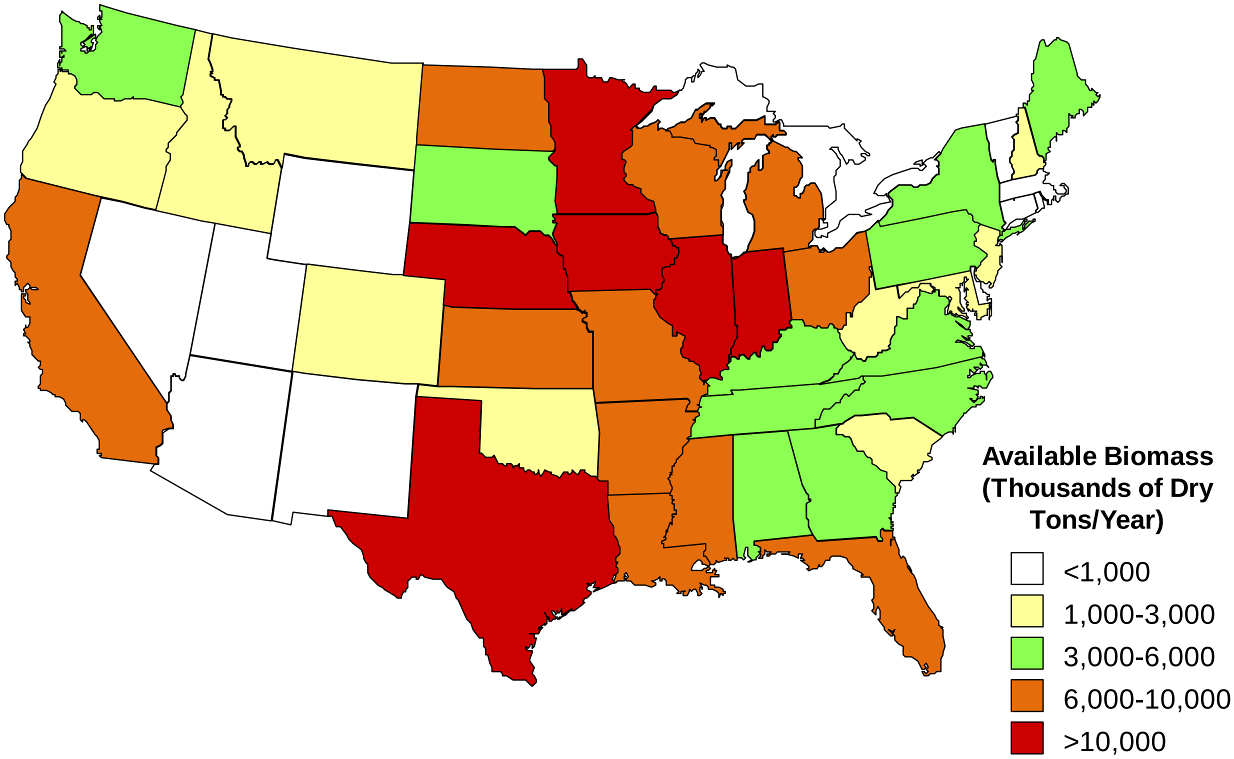

Figure 4-6. Map of Biomass Availability in the United States

Biomass is widely available in the Midwest, and to a lesser extent the South. Overall, the technical potential for biomass utilization at industrial facilities amounts to 3.8 billion MMBtu/year. Later in this report, the economic potential for biomass fuels will be further explored, to estimate how much of this technical potential could be realized.

Opportunity Fuel Source: Solid Biomass Fuels	
Heat Content:	7,000-8,000 Btu/lb
Sources:	Crop Residues, Forest Residues, Mill Residues, Urban Wood Waste
Technical Potential:	3.8 Billion MMBtu/year
Delivery/Requirements:	Biomass must be collected and dried prior to truck delivery (25-50 mile radius); rail/barge also an option for large-scale operations; industrial facilities that produce biomass waste on-site do not require transportation

Tire-Derived Fuel

Although the exact number of tires available for tire-derived fuel in each state is uncertain, there are some regional differences that affect the supply. States with higher populations tend to produce more waste tires, but they are not always stockpiled or stored in-state. Some smaller states like Indiana and Ohio contain large stockpiles of tires from various states in the general vicinity. In addition, certain states have had government subsidies to encourage scrap tire utilization. This tends to result in increased TDF utilization for these states. It also results in nearby states importing scrap tires at the subsidized rate for their own tire-derived fuel projects.

For example, in the late 1990s, the majority of scrap tires utilized by TDF projects in California were imported from nearby states with subsidies. As a consequence, ninety percent of California's scrap tires were stockpiled instead of utilized, and the tires used for TDF projects came mostly from Arizona, Oregon, and Washington.[18] Oregon and Washington have since terminated their TDF subsidy programs, along with several other states that previously offered subsidies.

The number of tires stockpiled and the current levels of TDF utilization are the determining factors in a state's tire-derived fuel availability. States with cement kilns and pulp and paper mills are most likely to already utilize a large amount of TDF. At the end of 2005, 58 million tires were consumed in the United States by a total of 17 cement companies in a total of 78 cement kilns, at 47 different facilities. At pulp and paper mills, 39 million scrap tires were consumed in 2005 by 24 different mills, up from 26 million scrap tires at 17 mills in 2003. Additionally, 16 industrial boilers and 17 electric utilities consumed the equivalent of 48 million scrap tires in 2005.[19] Finally, two dedicated tires-to-energy projects use about 11 million tires each year. These TDF utilization trends are summarized in Figure 4-7.

[18] Scrap Tire Management Council. Scrap Tire Use/Disposal Study. Washington, DC. 1997.
[19] *Scrap Tire Markets in the United States*. 2005 Edition. Rubber Manufacturers Association. November 2006.

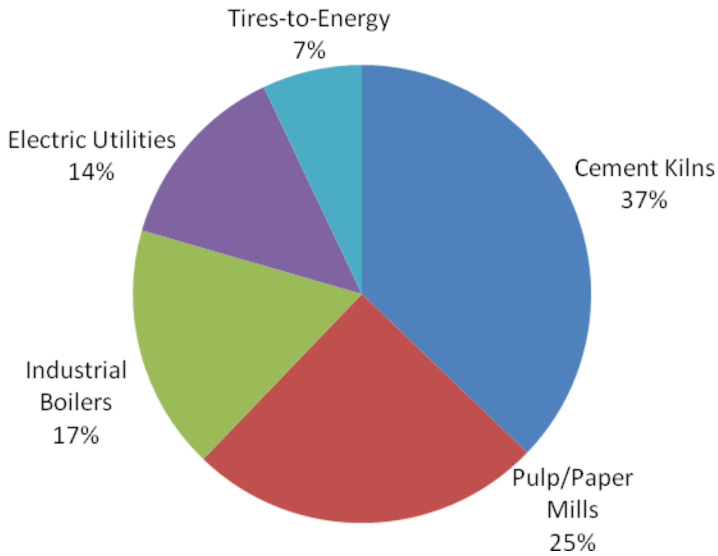

Figure 4-7. Current Markets for TDF Utilization
Source: Rubber Manufacturer's Association

Overall, an estimated 150 million tires are used as fuel each year, compared to roughly 300 million scrap tires that are discarded annually in the country. The majority of the other tires are used for ground rubber or civil engineering applications, while a large amount are landfilled. For facilities located close to existing TDF users, the local supply of TDF could be constrained. Alternatively, the presence of these facilities could indicate nearby sources of scrap tires and TDF processing plants.

The TDF market can also be affected by what other fuel sources are locally available to industrial sites. In the Northwest, where there is a relatively abundant supply of low cost petroleum coke, the demand for TDF at pulp and paper mills is practically non-existant. At present, no Northwest pulp and paper mills use TDF, and this is not expected to change in the forseeable future.[20] Similarly, wood processing facilities that have a cheap source of wood waste fuel would be less inclined to incorporate TDF into their plant operations. Still, there are numerous industrial facilities with coal boilers that could potentially utilize TDF. The availability of scrap tires is a primary driver for TDF markets, and is generally the best indicator of where industrial TDF utilization can be realized.

According to the Rubber Manufacturers Association, 188 million scrap tires remained in stockpiles at the end of 2005, a reduction of 91 percent since 1990. State efforts to abate stockpiled tires and develop sustainable scrap tire markets have led to this reduction. For example, as of the late 1990s, Ohio, Maine, California, Louisiana, Rhode Island, Illinois and Indiana accounted for 40 percent of the nation's stockpiled tires[21], but at the end of 2005, these states accounted for less than 15 percent. However, not all states have been actively reducing their stockpiles. Seven states that accounted for less than 30 percent of

[20] Ibid.
[21] Scrap Tire Management Council. Scrap Tire Use/Disposal Study. Washington, DC. 1997.

stockpiled tires in the late 1990s combined for 85 percent of the nation's remaining scrap tire stockpiles at the end of 2005.[22] States with the most stockpiled tires include:

- Alabama
- Colorado
- Connecticut
- Michigan
- New York
- Pennsylvania
- Texas

The states with the largest stockpiles could be good candidates for near-term TDF projects, but the sustainable use of TDF requires newly discarded tires, and there are about 300 million tires discarded in the United States each year (close to twice the amount currently stockpiled). Each tire is equivalent to about 2.5 barrels of fuel oil according to heat content, meaning each tire contains about 340,000 Btu. If the 300 million tires discarded each year were used for fuel, the total heat capacity would be about 77 million MMBtu per year. However, the actual potential for new tire-derived fuel projects is much lower, as there are many useful products that are currently being manufactured from recycled tires. Only about half of the scrap tires in the U.S. are available for TDF utilization, and much of this potential is already being realized.

In 2005, the Rubber Manufacturers Association estimated that by weight, 82 percent of of the 300,000 scrap tires generated were were either recycled or utilized for fuel.[23] Assuming the current recycle/utilization rate has remained the same, about 54 million tires per year should be available for new TDF projects. This amount of tires has the technical potential to satisfy close to 17 million MMBtu per year at industrial sites.

Opportunity Fuel Source: Tire-Derived Fuel	
Heat Content:	~16,000 Btu/lb (about 340,000 Btu/tire)
Sources:	Scrap tire markets, monofills, stockpiled tires
Technical Potential:	17 Million MMBtu/year
Delivery/Requirements:	Truck delivery (limited radius from processing site); tires must be processed into small (1-inch) pieces with metal wiring removed in order to be used in most coal boilers

[22] *Scrap Tire Markets in the United States*. 2005 Edition. Rubber Manufacturers Association. November 2006.
[23] Ibid.

Petroleum Coke

The Energy Information Administration keeps records on the domestic production and supply of petroleum coke, including all exports and imports. This data is separated by the Petroleum Administration for Defense Districts, defined as:

- PAD District I: East Coast
- PAD District II: Midwest
- PAD District III: Gulf Coast
- PAD District VI: Rocky Mountain
- PAD District V: West Coast

Table 4-12 provides the data for petroleum coke supply and disposition data for 2010.

Table 4-12. 2010 Petroleum Coke Supply and Disposition Data

	Thousand Barrels of Oil (Equivalent)					
PAD District	**Pet Coke Production**	**Imports**	**Exports**	**Products Supplied**	**Stock Change**	**Ending Stocks**
I. East Coast	12,286	2,871	4,069	11,153	397	43
II. Midwest	52,325	703	2,795	51,658	-65	701
III. Gulf Coast	171,115	1,131	116,228	53,972	-1,425	6,248
IV. Rocky Mountain	7,855	0	0	8,104	2,046	411
V. West Coast	52,802	316	40,776	12,252	-249	1,441
All U.S.	263,383	5,021	163,868	137,139	90	8,844

Source: EIA, Petroleum Coke Supply and Disposition Data, 2010.

This data shows that the vast majority of pet coke is either exported or supplied as a product, most likely for boiler fuel at refineries and other nearby industrial sites, as well as lime kilns at pulp and paper mills. Exports mostly go to China, where there has been a growing demand for energy with less stringent environmental regulations than the United States. Exports have increased steadily over the past decade, along with the growth of the Chinese economy. In 2005, 42 percent of the total pet coke supply was exported, while in 2010, 55 percent of all U.S.-produced petroleum coke was exported.[24] During this time, Chinese markets have been willing to pay significantly more for petroleum coke than U.S. markets, but this could change if China's economic growth diminishes.

The stocks of petroleum coke in the U.S. have remained steady at around 9,000 barrels (1,400 tons) for several years, continuing through 2010. These stocks are maintained by the oil refineries, and represent

[24] United States Department of Energy, Energy Information Administration, Petroleum Coke Supply and Disposition Data.

the petroleum coke supply currently available to U.S. markets. Not surprisingly, the district with the largest pet coke stocks is the Gulf Coast, which produces over half of the United States' pet coke. Significant stocks are also available in the Midwest and West Coast districts, although they are more widely dispersed.

The names and locations of the country's largest oil refineries are provided in Table 4-13, with oil processing and petroleum coke availability levels. All of the facilities listed have the capacity to process over 100,000 barrels of oil a day. According to EIA data, however, not all of the refineries produce marketable petroleum coke. These sites likely either utilize most of the petroleum coke that they produce, or their refining processes do not include pet coke production. The amount of marketable pet coke available is not necessarily tied to the size of the refinery, for these same reasons.

Table 4-13. Petroleum Coke Production at Largest U.S. Oil Refineries

			Barrels per Calendar Day	
Company	State	Site	Oil Processing Capacity	Marketable Pet Coke Produced
EXXONMOBIL REFINING & SUPPLY CO	Texas	BAYTOWN	572,500	22,750
EXXONMOBIL REFINING & SUPPLY CO	Louisiana	BATON ROUGE	503,000	31,525
BP PRODUCTS NORTH AMERICA INC	Texas	TEXAS CITY	455,790	13,750
CITGO PETROLEUM CORP	Louisiana	LAKE CHARLES	429,500	30,000
BP PRODUCTS NORTH AMERICA INC	Indiana	WHITING	405,000	14,200
EXXONMOBIL REFINING & SUPPLY CO	Texas	BEAUMONT	344,500	15,039
SUNOCO INC (R&M)	Pennsylvania	PHILADELPHIA	335,000	0
CHEVRON USA INC	Mississippi	PASCAGOULA	330,000	35,500
DEER PARK REFINING LTD PARTNERSHIP	Texas	DEER PARK	329,800	33,500
WRB REFINING LLC	Illinois	WOOD RIVER	306,000	6,500
Flint Hills Resources LP	Texas	CORPUS CHRISTI	288,468	3,925
PREMCOR REFINING GROUP INC	Texas	PORT ARTHUR	287,000	32,240
Motiva Enterprises LLC	Texas	PORT ARTHUR	285,000	15,616
Flint Hills Resources LP	Minnesota	SAINT PAUL	280,500	20,900
CHEVRON USA INC	California	EL SEGUNDO	279,000	20,000
HOUSTON REFINING LP	Texas	HOUSTON	270,600	29,960
BP West Coast Products LLC	California	LOS ANGELES	265,000	11,400
MARATHON PETROLEUM CO LLC	Louisiana	GARYVILLE	256,000	29,000
CONOCOPHILLIPS COMPANY	Louisiana	BELLE CHASSE	247,000	5,982
CONOCOPHILLIPS COMPANY	Texas	SWEENY	247,000	22,800
CHEVRON USA INC	California	RICHMOND	245,271	0
CONOCOPHILLIPS COMPANY	Louisiana	WESTLAKE	239,400	22,500
EXXONMOBIL REFINING & SUPPLY CO	Illinois	JOLIET	238,600	18,595
CONOCOPHILLIPS COMPANY	New Jersey	LINDEN	238,000	0
Motiva Enterprises LLC	Louisiana	NORCO	236,400	7,316
Motiva Enterprises LLC	Louisiana	CONVENT	235,000	0
TOTAL PETROCHEMICALS INC	Texas	PORT ARTHUR	232,000	0
MARATHON PETROLEUM CO LLC	Kentucky	CATLETTSBURG	226,000	0
BP West Coast Products LLC	Washington	FERNDALE	225,000	16,250
FLINT HILLS RESOURCES ALASKA LLC	Alaska	NORTH POLE	210,000	0
MARATHON PETROLEUM CO LLC	Illinois	ROBINSON	204,000	7,000
VALERO REFINING CO TEXAS LP	Texas	TEXAS CITY	199,500	15,600
CONOCOPHILLIPS COMPANY	Oklahoma	PONCA CITY	198,400	6,300
Chalmette Refining LLC	Louisiana	CHALMETTE	192,500	11,000
VALERO REFINING NEW ORLEANS LLC	Louisiana	NORCO	185,003	23,785
CONOCOPHILLIPS COMPANY	Pennsylvania	TRAINER	185,000	0
PREMCOR REFINING GROUP INC	Delaware	DELAWARE CITY	182,200	0
PREMCOR REFINING GROUP INC	Tennessee	MEMPHIS	180,000	0
SUNOCO INC	Pennsylvania	MARCUS HOOK	178,000	0
VALERO ENERGY CORPORATION	Texas	SUNRAY	171,000	0
PDV Midwest Refining LLC	Illinois	LEMONT	167,000	16,500
TESORO REFINING & MARKETING CO	California	MARTINEZ	166,000	11,000
CITGO REFINING & CHEMICAL INC	Texas	CORPUS CHRISTI	163,000	14,200
VALERO REFINING CO NEW JERSEY	New Jersey	PAULSBORO	160,000	7,500
SUNOCO INC	Ohio	TOLEDO	160,000	0
Shell Oil Products US	California	MARTINEZ	156,400	8,600
EXXONMOBIL REFINING & SUPPLY CO	California	TORRANCE	149,500	16,700
LIMA REFINING COMPANY	Ohio	LIMA	146,200	4,000
WRB REFINING LLC	Texas	BORGER	146,000	8,200
Shell Oil Products US	Washington	ANACORTES	145,000	8,400
SUNOCO INC	New Jersey	WESTVILLE	145,000	0
VALERO REFINING CO CALIFORNIA	California	BENICIA	144,000	6,800
VALERO REFINING CO TEXAS LP	Texas	CORPUS CHRISTI	142,000	6,270
CONOCOPHILLIPS COMPANY	California	WILMINGTON	139,000	16,800
FRONTIER EL DORADO REFINING CO	Kansas	EL DORADO	130,000	5,500
BP-HUSKY REFINING LLC	Ohio	TOLEDO	125,600	10,000
WESTERN REFINING COMPANY LP	Texas	EL PASO	122,000	0
CONOCOPHILLIPS COMPANY	California	RODEO	120,200	17,600
Tesoro West Coast	Washington	ANACORTES	120,000	0
MURPHY OIL USA INC	Louisiana	MERAUX	120,000	0
COFFEYVILLE RESOURCES RFG & MKTG LLC	Kansas	COFFEYVILLE	115,700	8,700
MARATHON PETROLEUM CO LLC	Michigan	DETROIT	102,000	0
CONOCOPHILLIPS COMPANY	Washington	FERNDALE	100,000	0
PASADENA REFINING SYSTEMS INC	Texas	PASADENA	100,000	2,200

Source: EIA Production Capacity of Petroleum Refineries (as of January 1, 2010)

When all of the marketable pet coke that the EIA has identified is added together, there is a total of 278 million barrels of pet coke available each year, or about 43 million tons. This supply of pet coke contains over 1,200 MMBtu/year of energy, but most of it is either exported or sold for lime kiln fuel. In fact, the stock of excess petroleum coke in the U.S. has remained constant at around 9,000 barrels (1,400 tons) for the past decade, showing that overseas demand has been effective at eliminating all surplus pet coke.[25]

If overseas markets for pet coke could be outbid by domestic industrial sites, or if overseas demand falters, there would be a large supply of pet coke available for U.S. markets, equal to the current amount being exported. According to EIA data, about half of the marketable pet coke, or 21 million tons, is exported each year. If all of this pet coke could be utilized domestically, assuming a heating value of 14,000 Btu/lb, the potential for new utilization would be approximately 600 million MMBtu/year.

Opportunity Fuel Source: Petroleum Coke	
Heat Content:	14,000 Btu/lb
Sources:	Oil Refineries
Technical Potential:	600 Million MMBtu/year (if exported pet coke is utilized)
Delivery/Requirements:	Most often transported via barge due to the location of oil refineries, but could also be transported by rail or truck

Summary for Solid Opportunity Fuels

The characteristics and delivery requirements for each solid opportunity fuel are summarized in Table 4-14. The estimated technical potential for each opportunity fuel is summarized at the end of the chapter.

Table 4-14. Summary of Characteristics and Delivery Requirements of Solid Opportunity Fuels

Fuel	Heat Content (Btu/lb)	Sources	Delivery Requirements
Biomass Fuels	4,000-8,000	Forest/crop/mill residues, urban wood waste	Collection, processing/drying, truck/rail/barge delivery
Tire-Derived Fuel	16,000	Scrap tire markets, monofills, stockpiled tires	Tire processing and truck delivery
Petroleum Coke	14,000	Oil refineries	Typically transported via barge; rail/truck also possible

[25] United States Department of Energy, Energy Information Administration, Petroleum Coke Supply and Disposition Data.

Summary: Availability and Technical Potential

The availability of opportunity fuels for a given industrial site depends on a number of different factors. The total availability and technical potential for each fuel was estimated in this chapter, and the results are summarized in Table 4-15.

Table 4-15. Estimated Technical Potential for the Industrial Utilization of Opportunity Fuels

Opportunity Fuel	Available Sources	Estimated Technical Potential (MMBtu/yr)	Notes
Anaerobic Digester Gas	Municipal and industrial WWTPs with digesters (over 1,000)	48,000,000	More technical potential could be realized if more plants installed anaerobic digesters
Landfill Gas	Large landfills (over 1,000 potential sites)	268,000,000	Landfills typically found in remote locations – long pipelines are necessary in most cases
Biomass Gas*	Residues from crops, forests, mills; urban waste	3,000,000,000	In addition to transporation costs for biomass fuels, an advanced gasifier carries a high installed cost
Industrial Waste Gas (Coke Oven Gas, Refinery Fuel Gas)	Steel mills, merchant coke plants, oil refineries	71,000,000	With only 20 plants producing coke oven gas, potential sites are limited. More potential is likely at oil refineries.
Biomass	Residues from crops, forests, mills, manufacturing plants; urban waste	3,800,000,000	Most biomass reserves are located too far from industrial facilities (high transportation costs)
Tire-Derived Fuel	Tire piles, tire recycling/ processing plants	17,000,000	Most scrap tires are currently either used as fuel or recycled for other purposes
Petroleum Coke	Oil refineries	600,000,000	Based on U.S. industrial sites outbidding overseas markets
Total*	All listed above	4,859,000,000	Bulk of technical potential comes from biomass, pet coke and landfill gas

*Technical potential for biomass gas is not additive with solid biomass, as they both draw from the same resources, so biomass gas is not included in the total calculation

In the next chapter, current projects using these opportunity fuels are examined to determine their feasibility. Then, the economic potential is estimated for the different fuels and recommendations are made for potential industrial opportunity fuel development.

5. Examining Current Industrial Opportunity Fuel Projects

This Chapter examines current industrial projects using opportunity fuels for process heating and steam generation applications. First, gaseous opportunity fuels are examined, including ADG and LFG applications, biomass gasifiers, and industrial waste fuel utilization. Next, solid opportunity fuel applications are studied, with several biomass, tire-derived fuel and petroleum coke projects already in place, often using multi-fuel boilers. The experiences of industrial sites currently utilizing opportunity fuels will help determine the prospects for the implementation of future projects.

Gaseous Opportunity Fuels

Anaerobic digester gas and landfill gas have most commonly been used for power generation applications, but there are also projects using the gas for industrial process heating and steam generation. Biomass gas projects with advanced gasifiers are still in the demonstration phases, but other biomass gasifiers that produce a lower quality, high-temperature syngas have developed a track record at various industrial facilities. Utilization projects for industrial waste gases (i.e. blast furnace gas, coke oven gas, refinery fuel gas) have traditionally been limited to on-site applications. In this section, various gaseous opportunity fuel applications from across the country are analyzed.

Anaerobic Digester Gas

Municipal Wastewater Treatment Plants

Municipal wastewater treatment plants that produce ADG most often utilize the gas for heating the digester tank, although there has been an increase in ADG-fueled CHP systems in recent years. When these plants only use their digester gas for heating, there tends to be a surplus of ADG that is most often flared, particularly during non-winter months. Instead of flaring, when the surplus is significant, this gas can be routed to nearby industrial facilities for use in process heating or steam generation applications. However, wastewater treatment facilities often don't consider this as an option, instead looking for other ways to utilize the gas on-site, especially in combined heat and power configurations. When the City of Tacoma, Washington evaluated the utilization of their flared digester gas, several options for implanting a CHP system were considered, all with high capital costs and relatively high payback periods. However, no consideration was given for other potential utilization methods, such as nearby industrial sites.[1]

The Columbia Boulevard Wastewater Treatment Plant in Portland, Oregon (pictured in Figure 5-1) provides a good example of how excess ADG from a municipal plant can be utilized in a number of different ways, including sales to nearby industrial sites. For years, the plant sold a portion of their digester gas to the nearby Malarkey Roofing Company for boiler fuel. Malarkey, located about a mile down the road, installed a pipeline to utilize some of the digester gas while the rest was combusted at the

[1] Holland, Jeremy, P.E. and Wolstenholme, Philip, P.E., *Technical Memorandum to Eric Johnson, P.E. City of Tacoma Central Treatment Plant (CTP) – Utilization of Flared Digester Gas at the Tacoma CTP*, Brown and Caldwell, December 3, 2003.

treatment plant in boilers to heat the digester tanks and buildings. Despite high moisture content of the gas and the presence of hydrogen sulfide and siloxanes, the gas was not cleaned or dried prior to boiler use, and there was always a surplus of ADG that was simply flared.

In 1998, a 200 kW fuel cell was installed at the treatment plant with the help of both state and federal government funding, and in 2003, four 30-kW microturbines were installed. However, these were primarily demonstration projects, and plant operators soon found that CHP engines would be more economical than these new technologies, so they decided to install two 850 kW engines in 2006.[2] A gas processing unit removes hydrogen sulfide, halogens and siloxanes from the ADG so that it can be utilized by the engines, which now provides power and heat for the plant. The facility still uses ADG-fueled boilers (without gas pretreatment) to provide the remainder of heat for all of the buildings, and they still sell about 10 million cubic feet per month to Malarkey Roofing.[3] Despite high levels of ADG utilization, the plant consistently produces a surplus of gas, which is currently flared, but could potentially be piped and sold to other nearby industrial facilities.

Figure 5-1. Columbia Boulevard Wastewater Treatment Plant in Portland
Source: www.oregonlive.com

In order for ADG from municipal plants to be utilized at industrial facilities, they must be located relatively close to each other to minimize pipeline construction costs. The local cost of electricity is another important factor, determining how much plants can save with ADG power generation. When the electricity cost is high, treatment plants are more likely to benefit from power generation, and less likely to sell the gas to nearby industrial facilities. Combined heat and power units that recover waste heat tend to be the most economical options for municipal WWTPs, who have significant electric and thermal demands. Over 200 WWTPs have installed ADG-fueled CHP systems to date, and there are government incentives for biogas electricity production in some states including renewable energy credits and project funding . However, the cost of gas pretreatment can be high for CHP, especially when siloxane removal is necessary, and boilers and process heating systems do not demand the high level of gas cleanup that CHP units require. The economic potential for industrial ADG utilization from municipal treatment plants is explored in the next chapter.

[2] Telephone conversation with William Park, plant engineer, March 7, 2011.
[3] Ibid.

Industrial Wastewater Treatment Plants

There are several types of food and chemical processing plants in the industrial sector that utilize anaerobic digestion to treat their wastewater on-site. These industrial wastewater treatment facilities commonly utilize their ADG in a boiler that heats the digester tank and flare whatever is left, but there could be potential to use the gas for other industrial heating applications.

An example of industrial ADG utilization can be found at the Penford Foods plant in Richland, Washington. While the facility only processes about 200,000 gallons of wastewater each day, all of the ADG is utilized on-site to power a boiler, which is used to heat the digester tank. However, the food processing plant also produces a great deal of starch waste, which is too chemically complex for anaerobic bacteria to break down. The plant owners say they are looking into installing a jet cooker that would liquefy the starch so that it could be broken down in the digester. This would significantly increase ADG production and allow it to be utilized for purposes other than heating the digester tank, including process heating applications.

The Penford Foods facility completed the installation of a new dual fuel boiler burner in 2005. The burner eliminates the need for ADG storage and compression, allowing the fuel to be burned at the variable rate that it is produced.[4] Natural gas is used to supplement the ADG with a burner that adjusts and responds to fluctuations in ADG flow. The burner uses a programmable logic controller that can be adjusted to respond to different ADG flow levels.[5] Therefore, if the jet cooker mentioned in the previous paragraph is installed, the burner could adjust to the new ADG composition and flow rates. This new flexible fuel burner technology, manufactured by Germany's Weishaupt Corporation and being distributed by Burns and McDonnell, could open the door for more ADG utilization projects at industrial wastewater treatment plants. Facilities with smaller digesters and more variable wastewater flow rates would especially benefit, as these sites are often challenged to fully utilize their ADG.

Summary of Current Industrial ADG Projects

Although most current ADG utilization projects involve producing heat or power at municipal wastewater treatment plants, there is some economic potential for steam generation and process heating at industrial facilities, as evidenced by sites that are currently utilizing the gas. The Columbia Boulevard WWTP in Oregon shows how ADG can be used for a variety of diverse applications, including pipeline sales to a nearby industrial facility for boiler fuel. Advances in ADG utilization from industrial facilities can also be seen at the Penford Foods facility in Washington, where new dual fuel burner designs have improved the stability and efficiency of ADG usage. The economic potential of industrial ADG applications from both municipal and industrial wastewater treatment plants will be explored in the following chapter.

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[4] Industrial wastewater treatment plants often have large fluctuations in wastewater flow, and accordingly, ADG production. Municipal wastewater treatment plants tend to have a continuous stream of waste water, so ADG production occurs more steadily.

[5] Snider, Christopher J. and Worthington, Pat, Energy Savings and Economic Viability of Smaller Projects, BioCycle, July 2006, Vol 47, No. 7, p. 52.

Landfill Gas

To date, landfill gas utilization efforts have primarily been focused on power generation, where electricity from LFG is sold to local utilities. This is especially true in states with renewable portfolio standards, where electricity produced from LFG qualifies for renewable energy credits (RECs) which create additional revenue. Out of 512 current LFG to energy projects, 368 produce electricity, 54 use LFG in a boiler, and 42 use LFG for direct thermal energy (i.e. process heaters). Only 22 projects involve improving the LFG to natural gas quality for pipeline sales.[6] This section examines current LFG projects for industrial boilers and process heating applications.

There are several examples of landfill gas being pipelined to nearby facilities for fuel-flexible steam generation or process heating applications, including the NASA Goddard Space Flight Center in Greenbelt Maryland. The flight center began firing LFG from the nearby Sandy Hill Landfill in 2003, via a 5-mile pipeline. The gas is used to power two boilers that have been modified to burn blends of LFG, natural gas, and fuel oil. Landfill gas provides the total firing requirement for the boilers 95 percent of the time, but when flow rates drop or additional heat is required, natural gas and/or fuel oil are used to supplement the LFG. NASA estimates annual fuel savings of over $350,000 from LFG utilization.[7]

In a more traditional industrial application, in North Carolina, landfill gas is routed three miles from the White Street Landfill to the Cone Mills White Oak Plant (depicted in Figure 5-2). In the mid-1990s, the denim-manufacturing plant installed two multi-fuel burners in a boiler with 30,000 lb/hr steaming capacity. The steam produced is used for various plant operations. With multi-fuel burners, natural gas or fuel oil can be used when additional steam is needed. These burners also allow for occasional dips in LFG productivity, which can occur from time to time.

Figure 5-2. Cone Mills White Oak Plant
Source: www.textilehistory.org

The White Street Landfill was originally supplying gas under a partnership between Duke Engineering and the City of Greensboro, but that contract expired in 2007, leaving the city in charge of the landfill's operations. A three-year incentive deal was worked out in 2007 to keep the White Oak Plant in operation, but it is uncertain what the future holds for the plant, especially considering that denim production has slowed and the work force has been reduced from 738 to about 300 employees.[8] Regardless of what happens with the plant, it has been a prime example

[6] United States Environmental Protection Agency, Landfill Methane Outreach Program, LFG Energy Project Development Handbook, 2010. http://www.epa.gov/lmop/publications-tools/handbook.html
[7] United States Department of Energy, Federal Energy Management Program, *NASA's Goddard Space Flight Center Harnesses the Energy of Landfill Gas*, April 30, 2003. http://www1.eere.energy.gov/femp/news/news_detail.html?news_id=7199
[8] Lehmert, Amanda, News & Record, Greensboro, North Carolina. http://www.news-record.com/content/2010/06/19/article/landfill_changes_may_affect_gas_deal

of successful industrial LFG utilization for over a decade, and could serve as a model for future landfill/industrial plant relationships.

The traditional rule-of-thumb has been that industrial facilities should be located within 5 miles of a landfill in order to economically utilize the gas, but some new installations are questioning this notion. In Virginia, Honeywell International Inc.'s massive Hopewell manufacturing plant completed a 23-mile pipeline from a large landfill in Waverly, owned by Atlantic Waste Disposal Inc. The Hopewell plant uses natural gas for various plant operations, as well as a raw material to manufacture a key ingredient in nylon. According to plant manager Rick Higbie, "we are probably the largest consumer of natural gas on the East Coast and one of the largest in the United States".[9]

As natural gas prices increased around the turn of the century, the Hopewell plant began looking for ways to cut their dependency on the fuel, and an agreement with Atlantic Waste Disposal was reached. An 18-inch polyethylene pipe was constructed underground to transport landfill gas, spanning 23 miles. A third party, DTE Energy, operates the gas collection system and pipeline. When LFG reaches the Hopewell plant, it is blended with natural gas and used for steam generation, power production and other industrial processes. Landfill gas now displaces about 15 percent of the plant's natural gas fuel requirements, and eventually it will displace up to 50 percent of the plant's fuel needs as the landfill grows in capacity.[10]

In another example, the Three Rivers Solid Waste Authority in Aiken, South Carolina recently completed construction on a 15.8 mile pipeline to the Kimberly-Clark Corporation's manufacturing facility in Beech Island, which produces tissue and diapers, among other products. In April 2008, the Authority began compressing and drying the gas and piping it to the Kimberly-Clark facility, where it is used in boilers to generate steam for paper production. The LFG collection and compression system is computer controlled and monitored to ensure maximum gas utilization and environmental compliance.[11]

Summary of Current Industrial LFG Projects

While LFG projects at industrial facilities have become fairly common since the EPA's LMOP initiative in the 1990s, the primary goal of the majority of LFG to energy projects has been electricity generation. The White Street Landfill in North Carolina is a good example of industrial LFG utilization for steam generation (at the Cone Mills White Oak denim manufacturing plant). The new 23-mile pipeline construction to Honeywell's Virginia manufacturing plant shows how mutually beneficial relationships between landfills and industrial facilities can be reached, even when separated by large distances. The next chapter will examine the economic potential for similar industrial sites that could utilize LFG via pipeline transport.

[9] Blackwell, John Reid, *Honeywell Finds a Solution to its Gas Needs*, Richmond Times-Dispatch, April 24, 2006.
[10] Ibid.
[11] Three Rivers Solid Waste Authority, Landfill Gas to Energy Facility, Online. http://www.trswa.org/landfillgas.html

Biomass Gas

While gasification technologies have been around for many years, and various types of gasifiers have been installed at industrial facilities since as early as the 1980s, results have been mixed, and product gases have been limited in heat content and flexibility. Advanced two-stage gasification systems that produce higher quality biomass gas have recently been developed, with the promise of greater flexibility and widespread utilization potential. To date, experience with biomass gas from two-stage gasifiers (not close-coupled systems) has been primarily limited to large-scale demonstration projects using combined cycle turbines with heat recovery steam generators, and progress in this area has been slowed considerably. However, some smaller fluidized bed close-coupled gasifier systems have recently been installed at industrial facilities, and these technologies could show greater promise for industrial utilization. This section examines the various advanced biomass gasifier systems currently in operation throughout the United States.

The SilvaGas biomass gasifier is still in the demonstration project phase, but there is some operating experience from the wood-fired 50 MW McNeil station in Burlington, Vermont that has since ceased gasifier operation. The power plant normally uses a conventional biomass stoker grate boiler with a steam turbine generator, but it has been reconfigured to utilize gas from the SilvaGas gasifier. The first operation of the gasifier occurred in August 1999, and it became apparent that numerous design and operational changes to the plant were necessary to improve the performance of process auxiliary systems like materials handling, solids separation, and product gas scrubbing. Improvements were made and continuous around-the-clock operation was achieved in August 2000. Testing has produced generally positive operating results in terms of gas composition, gas production, feedstock flexibility, and gas conditioning and cleanup. The product gas heating value remained stable at close to 500 Btu/ft3, regardless of changes in feedstock type and moisture content, allowing various biomass fuels to be used.[12]

However, the SilvaGas technology remained limited to the Vermont demonstration project, largely due to extensive hot gas cleanup requirements, and Future Energy Resources was forced to sell the rights to SilvaGas technologies through bankruptcy. After a long hiatus, Rentech, the current SilvaGas owners, have begun making adjustments (including a hot-gas conditioning catalyst that reduces the required amount of hot gas scrubbing) and more demonstration projects are in the planning process.

The Taylor Gasification Process, developed by Taylor Biomass Energy for potential use at its wood recycling facility, is another advanced gasification system that is still in the demonstration project phases. The biogas from the wood waste would be used to power a boiler-steam turbine power generation system. The facility, located in Montgomery, NY, has completed the design, permitting, financing, and site preparations for the gasifier, and construction of the gasification modules is underway. The installed capital cost for the gasifier is estimated to be \$550-\$600 per kW of generating capacity, which is close to

[12] Paisley, M.A. and Overend, R.P., *Verification of the Performance of Future Energy Resources' SilvaGas Biomass Gasifier – Operating Experience in the Vermont Gasifier*, Future Energy Resources Corporation and U.S. Department of Energy National Renewable Energy Laboratory.

the cost of a natural gas reciprocating engine genset.[13] In 2010, Taylor Biomass Energy received approval for a $100 million loan guarantee and a 30 percent federal grant from the Department of Energy to build the biomass gasification power plant, which is expected to produce 20 MW of electricity.[14] There could be potential for industrial use of this gasification system, but even if this project is successful, it would be many years before the technology is ready for commercialization.

Probably the only potential applications for industrial biomass gas utilization in the near-term could come from close-coupled systems that directly utilize the gas to produce steam in a boiler, eliminating the need for hot gas cleanup. Primenergy has been installing these systems at industrial facilities since the1990s, producing biomass gas with a heating value of about 150 Btu/ft^3 from rice hulls and other biomass feedstocks. After a controlled-temperature gasification process, the biomass gas passes through a cyclone to remove particulates, and then enters a staged combustion process that minimizes NOx emissions. The resulting flue gas is then used to provide heat for a boiler, which generates steam for various industrial practices. Because of the low heating value, it is not practical to cool and clean this biomass gas, but utilizing it directly in a close-coupled boiler has proven beneficial to some industrial facilities. Chiptec and Nexterra also produce fixed bed close-coupled gasifier systems, with many of the same benefits and drawbacks.

A recent example of an industrial close-coupled gasifier installation can be found at the Shaw Waste to Energy site. The Shaw Waste to Energy facility in Dalton, Georgia is the first of its kind in the United States to gasify industrial waste for on-site utilization in a close-coupled boiler system. The gasifier, which is a joint effort of Shaw, Primenergy and Siemens Technologies, uses carpet waste and laminate wood flour from Shaw's manufacturing facilities to produce biomass gas with low calorific value. After the gas is combusted, the hot flue gas is used by boilers to generate steam, which is used in Shaw's carpet dyeing operations. Primenergy has tested over 25 different feedstocks for this gasification system, including some that are considered the most difficult for energy conversion, like sugar cane bagasse, tire-derived fuel, refuse-derived fuel, paper-plant pulp sludge, and sewage sludge. For all of the biomass materials that were tested, the process required no auxiliary fossil fuel to maintain continuous operation, and the same was true for the carpet waste at the Shaw facility.[15]

Fluidized bed gasification systems, which function similarly to fluidized bed boilers, have recently shown some promise as fuel-flexible alternatives for industrial applications, particularly with close-coupled boiler systems. In 2009, the Masonite Corporation installed a fluidized bed gasifier from Energy Products of Idaho (EPI) at their Laurel, Mississippi facility. The gasification system uses plant waste materials and other biomass resources as fuel, producing hot synthetic biomass gas and acting as a boiler to generate steam for the plant. Gas is collected from the close-coupled fluidized bed gasifier, typically at 150-200

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[13] Paisley, Mark, *Advanced Biomass Gasification for the Economical Production of Biopower, Fuels, and Hydrogen – Implementation in Montgomery, New York*, Taylor Biomass Energy, LLC.

[14] *Waste to Energy Gasification Facility Under Construction in Montgomery, New York,* Waste Management World, December 10, 2010.

[15] Ritchie, Ed, *Wall-to-Wall Energy Solution: A new gasification plant could save millions in fuel and landfill costs*, Distributed Energy – The Journal of Energy Efficiency & Reliability. http://www.distributedenergy.com/july-august-2006/energy-solution-gasification.aspx

Btu/ft^3, and immediately combusted. The resulting flue gas (at 1750°F) is then collected and used for two purposes: providing heat for a boiler, and process heating applications (both using heat exchangers).[16] At the Masonite plant, the hot, combusted biomass gas provides all of the heat for the plant's chip dryers (which dry the wood chips for the gasifier).[17] Steam from the boiler system is used for other plant heating processes. Although the heat content of the biomass gas is low, and it must be utilized immediately, these fluidized bed gasifier/boiler systems can provide great fuel flexibility for industrial facilities that produce various forms of biomass waste. Several equipment manufacturers, including Foster Wheeler and Ebara, have produced similar fluidized-bed close-coupled boiler systems that are commercially available.[18]

While close-coupled gasification systems are commercially available and show some promise for industrial waste fuel utilization, the economics of these systems can still be prohibitive. A 2009 report from the National Renewable Energy Laboratory estimated the simple payback periods for close-coupled gasification systems with various wood and natural gas prices. Even when wood fuel can be obtained at no cost (for facilities that produce wood waste on-site), payback periods of 9-12 years are expected when natural gas prices are in the $5-$7/MMBtu range. For wood fuels at more typical prices of $20-$30/green ton, simple payback periods range from 12-20 years for sites with $7/MMBtu gas, or 20-33 years for sites that can obtain natural gas for $5/MMBtu.[19] For advanced two-stage gasifier systems, the economic outlook is even less promising due to their lack of commercialization status.

Summary of Current Industrial Biomass Gas Projects

In the late 1990s and early 2000s there was some hope that a new two-stage advanced gasifier technologies would develop, producing a high-quality biomass gas from various biomass feedstocks. Issues with gasifier maintenance and hot gas cleanup have slowed down progress in this area, with advanced gasifiers being limited to demonstration projects. Other technologies like fluidized or fixed bed gasifiers used with close-coupled boiler systems have been successfully installed at industrial facilities throughout the years, using biomass waste to produce a low-quality syngas that must be utilized immediately to take advantage of its thermal properties. However, the capital costs involved with these systems can become prohibitive, especially when combined with potential fuel costs, and they will not be further considered in this report.

Industrial Waste Gases

The use of industrial waste gases is typically limited to the facilities from which the gas is produced. Most steel mills with blast furnaces and coke ovens attempt to utilize their waste gases to their maximum potential, because it makes sense for resource-intensive facility operations. The same holds true for

[16] Telephone conversation with Patrick Travis of EPI, March 22, 2011.
[17] *Energy Products of Idaho to Provide a Biomass Fired Energy System for Masonite in Laurel, Mississippi*, Press Release, Energy Products of Idah, September 2009.
[18] Massachusetts Technology Collaborative Advanced Technology Assessment. *Advanced Biomass Conversion Technologies*. Black & Veatch. January 2008.
[19] Peterson, David and Haase, Scott, *Market Assessment of Biomass Gasification and Combustion Technology for Small- and Medium-Scale Applications*, Technical Report, National Renewable Energy Laboratory, July 2009.

refinery fuel gas produced at oil refineries. However, many plants and refineries end up flaring a large amount of gas. All of these waste gases must be cleaned extensively prior to use, especially for power generation or process heating applications. Examples of waste gas utilization can be difficult to pinpoint because most projects are internal to the plant and not publicized, unless public funding is used to develop the project.

U.S. Steel provides an example of coke oven gas being used to provide process heat, and utilizing all coke oven and blast furnace gas on-site, such as their integrated steel mill in Pennsylvania firing blast furnaces for steel production. Coke oven gas produced at the Clairton coke plant is cleaned, transported to Mon Valley Works, and injected into modified blast furnace nozzles that previously used natural gas. The project was approximately $6 million to implement, without federal or state funding, and it produced just over $6 million in annual savings, resulting in a payback period of about one year.[20] The plant also uses coke oven gas for boilers, reheat furnaces, and as a fuel for the coke ovens themselves. According to the plant operator, all coke oven gas produced at the Clairton plant is utilized, and none of it is flared. Exhaust gas from the blast furnaces (blast furnace gas) is also captured and utilized for various heating applications at the Mon Valley Works facility.

At many U.S. steel mills, blast furnace gas is used for several on-site operations, but with some excess gas that is typically flared. A recent project funded by the American Recovery and Reinvestment Act of 2009 was proposed to construct and operate a blast furnace gas recovery boiler at ArcelorMittal's Indiana Harbor Steel Mill in East Chicago, Indiana. Prior to the project announcement, ArcelorMittal flared about 22 percent of their blast furnace gas, while the remaining 78 percent was used to power various boilers for on-site operations. The proposed project would use all of the excess gas to fuel a new 80-percent efficient boiler and produce steam to be used in existing steam turbines for power generation. This project is expected to be complete in early 2012.

While there may be some opportunities to utilize excess blast furnace gas that is currently flared, its low heat content limits its value to nearby industrial facilities, and immediate on-site utilization of the hot gas to capture the thermal energy is preferred. The opportunities for further industrial utilization of these fuels at integrated steel mills are limited, so these facilities will not be considered as fuel sources for other industrial process heating or steam generation applications.

For merchant coke plants, however, on-site thermal demands are not as high, primarily limited to heating up the coke oven. Excess coke oven gas that is currently flared at merchant coke plants could potentially be sold to nearby industrial sites. However, there are only 11 merchant coke plants in the United States (see Chapter 4 for availability analysis), so the number of potential utilization opportunities will be limited.

There is some promise for industrial waste gas utilization at oil refineries, which produce refinery fuel gas, or still gas. This fuel gas is generally utilized to its maximum potential on-site, but a large amount is

[20] United States Department of Energy, Office of Energy Efficiency and Renewable Energy, Steel Best Practices: Technical Case Study, *Using Coke Oven Gas in a Blast Furnace Saves Over $6 Million Annually at a Steel Mill*, December 2000.

inevitably flared each year. Refineries strive to sell the higher-grade components for profit, and instead collect and blend unmarketable light by-product gases (i.e. still gas) and use them for on-site process heating requirements. There may be opportunities for more efficient on-site utilization of still gas that would lead to less frequent flaring, but these would need to be addressed on a case-by-case basis. Alternatively, nearby industrial sites could potentially benefit from piping excess still gas to their facility to replace natural gas in process heating applications.

At most oil refineries, still gas is utilized in process heating operations with dual-fuel burners that incorporate natural gas when still gas production drops off. Occasionally there are fluctuations or disturbances in the oil refining processes that lead to temporarily high quantities of still gas production, requiring the excess gas to be flared. Some recent projects at refineries are finding ways to utilize excess still gas where large quantities were previously flared. The Ultramar Diamond Shamrock refinery in Denver, Colorado was suffering from low efficiency with large amounts of flared still gas, but a waste-heat-powered ammonia absorption refrigeration unit was installed to recover propane and gasoline from the gas. Now the facility is recovering 200 barrels per day of liquid propane gas, and it is now rare that any gas is flared. A similar waste heat powered ammonia absorption refrigeration unit was installed at the Western Refining Company's Bloomfield, New Mexico refinery in 2008. The refinery now recovers 50,000 barrels per year of liquefied petroleum gas that was previously flared, reducing CO_2 emissions by 17,000 tons per year.[21] While this is not considered a fuel flexible option for process heating or steam generation, it may be the most viable use at these locations for excess still gas. For refineries like these who have found a favorable option to flaring, potential for industrial utilization of still gas is negligible.

For refineries that flare their excess still gas, there is rarely a steady stream of unused still gas to be flared. For nearby industrial facilities, a stilted and sporadic stream of fuel gas is of questionable value. Most likely, large compressors and gas storage vessels would be required to collect gas during brief upsets and smooth out the flow of refinery fuel gas to the industrial site, but even with storage there may still be periods of down-time. Furthermore, still gas is produced from a number of different refinery operations, all of which are designed to route the gas to the flare during operational upsets. For industrial utilization, new gas collection and transportation equipment would be necessary wherever still gas is produced, keeping in line with refinery safety standards that require the gas to be promptly directed away from process heaters during power outages or other operational upsets.

For a refinery, making all of these accommodations for an industrial facility to utilize their excess still gas is a capital-intensive proposition with potential impacts on site operations. Owners of the industrial facility would need to convince refinery owners that they could install and utilize the equipment without interfering with refinery operations, while providing adequate compensation for access to the gas. In states with tight flare gas emission standards, however, refineries may be more willing to engage in projects that prevent still gas flaring.

Still gas contracts with industrial facilities could be difficult to work out, due to the variable nature of excess still gas flow. Refineries may not be able to predict when excess still gas will be created, and in

[21] Refinery Chilling. Energy Concepts: Providing practical solutions to pressing energy problems. http://www.energy-concepts.com/refinery

what quantities. For example, the ExxonMobil refinery in Torrance, California flared over 132 million cubic feet of still gas in the first quarter of 2009. However, in the second quarter, flared gas dropped off by a factor of 16, down to only 8.6 million cubic feet. The third and fourth quarter of 2009 saw the ExxonMobil refinery flare 10.8 million and 20.9 million cubic feet of still gas, respectively.[22] In the last three quarters of the year, the refinery flared less than a third of the still gas that it flared in the first quarter. While this is an extreme example of excess still gas variability, other refineries also tend to fluctuate with their flared gas volumes throughout the year.

There is one current example of refineries routing their still gas to another plant for consumption, at MarkWest-Javelina Company in Corpus Christi, Texas. This gas processing plant receives still gas from six area refineries via pipeline, and separates the valuable ethylene and hydrogen components from the fuel to sell them as chemical and plastic feedstocks. When all six refineries are on-line, the facility can process 138 million standard cubic feet per day of still gas. From this gas, MarkWest-Javelina produces ethane, propylene, propane, butane and gasoline, in addition to ethylene and hydrogen.[23] With a single oil refinery, the still gas volume and average flow may not be sufficient to justify the high cost of processing equipment, but when multiple area plants pipe their still gas to a collective site, the economics improve considerably. There are likely not many opportunities in the country for this practice, but this facility shows that refineries would be willing to pipe their gas off-site for the business opportunity.

Summary of Current Industrial Waste Gas Projects

Blast furnace gas, coke oven gas and refinery fuel gas all tend to be utilized to the fullest extent possible by the plants that produce them, using their current process heating and steam generation equipment. With equipment upgrades, it is possible that more of these fuels could be used by these facilities, but the most likely opportunity for new industrial waste gas utilization comes from nearby sites. Pipeline construction would allow industrial facilities to utilize excess waste gas from the plants, while creating revenue for the plants through fuel sales. Extensive gas storage facilities, however, may be required to enable a reliable gas supply, and this appears to be too costly to justify the investment. Blast furnace gas has been eliminated from further consideration for off-site uses, but the following chapter will examine the economic potential of this practice for potential coke oven gas and refinery fuel gas applications.

[22] South Coast Air Quality Management District. ExxonMobil Refinery, 2009 Rule 1118 Quarterly Flare Emissions. http://www.aqmd.gov/comply/1118/exxon.htm

[23] MarkWest Javelina Company Profile, Corpus Christi Regional Economic Development Corporation. http://www.ccredc.com/Markwest_Javelina_Company_Profile_Local_Company_Profiles_Local_Company_Profiles_Awards.cfm

Solid Opportunity Fuels

Industrial process heating and steam generation projects are common for biomass and wood waste fuels, while applications utilizing TDF and pet coke are not as widespread, but are common practice at cement kilns and some pulp and paper mills. In this section, various opportunity fuel projects from across the country are analyzed.

Biomass Fuels

Biomass fuels, such as wood waste, crop residues and forest thinnings, have been utilized for numerous industrial boiler applications. Biomass from these various sources is typically dried and processed into combustible chips that are blended with coal in large boilers for steam generation and/or power production. Wood and paper manufacturers also process and utilize their waste on-site in boilers specifically designed to handle wood waste fuels, or in coal boilers. There are opportunities for biomass utilization at many industrial plants throughout the country, and the experience of current biomass installations can help ensure that future projects will be successful.

The majority of industrial biomass applications to date have been industrial facilities converting their wood waste into boiler fuel. Armstrong, a leading floor covering producer in the United States, has a facility in Beverly, West Virginia that produces approximately 1.5 million square feet of pre-finished hardwood flooring per week. The plant runs 6 mill lines and 2 sanding/finishing lines that produce three primary types of residue: course from the mill, finish dust from the sanders, and ball splinters and sawdust from the hog grinder. On-site, the wood waste fuels two boilers which produce steam for wood drying and provide heat for the facility. However, the wood waste produced is more than enough to fuel their boiler system, so Armstrong markets and sells all of the excess dust and edgings.[24]

The fuel storage system that Armstrong uses requires that boiler operators monitor the system constantly. Changes in moisture content or particulate size can require adjustments to the system, in order to consistently produce the required level of steam. Armstrong has made large investments in air pollution control equipment, including an electrostatic precipitator to remove fine particulates, and oxygen analyzers in the stacks for safety and to control emissions. Still, even with these drawbacks, the system saves a great deal of money compared to using natural gas as fuel, and the site is prepared to temporarily switch to natural gas if there is a problem with the wood waste delivery system.

[24] *Case Studies on Wood Biomass Use in the Northeastern United States*. Appalachian Hardwood Center, West Virginia University Division of Forestry.

The United States Department of Energy's Savannah River Site in Aiken, South Carolina (pictured in Figure 5-3) is another type of industrial facility that utilizes the waste that they produce on-site. The Savannah River facility handles, recycles, and processes basic nuclear materials like tritium and plutonium, and produces paper and wood waste from day-to-day plant operations. The site recently began shredding and compacting this low-moisture paper and wood waste into dense "process engineered fuel" (PEF) cubes, which will replace about 20 percent of the coal used at their steam plant. The plant uses two moving-grate spreader stoker boilers to produce steam for on-site process heating applications. Test burns showed that no modifications were needed to the existing boiler fuel-handling equipment to successfully fire the PEF/coal mixture, and no increase in maintenance was expected to be necessary at the steam plant.[25]

Figure 5-3. The Department of Energy's Savannah River Site

Source: U.S. Department of Energy

Before utilizing their waste, coal costs at the Savannah River Site were about $550,000 per year, while about 280 tons of wood and paper waste was produced each month. The site had been paying $23 per ton to landfill this waste, amounting to over $77,000 per year. In addition, the facility incinerated about 70 tons per month of paper in an on-site burn pit, which cost about $83,000 per year to operate. The new PEF facility uses a shredder and a cubing machine that increases the bulk density of the waste materials and makes them compatible with fuel conveyors and handling equipment at the steam plant. The utilization of this waste eliminates disposal costs and reduces coal consumption by about 20 percent, resulting in a net cost savings of $254,000 per year. Design, construction, and equipment costs for the PEF facility totaled about $850,000, so the payback period is expected to be under four years.[26]

Energy Products of Idaho (EPI) has been supplying fluidized bed boilers to industrial facilities and power producers for over 30 years, specializing in converting biomass and difficult waste products into usable forms of energy. A recent example the Langboard plant in Willacoochee, Georgia that uses medium density fiberboard waste along with sander dust, board trim and hogged fuel to provide 163 MBtu/hr of thermal energy for the facility. The MacMillan Bloedel Clarion L.P. plant in Shippensville, Pennsylvania and uses a similar fuel mixture to provide 141 MBtu/hr of total energy including 44,000 lb/hr of steam generation. In another example, a DuPont plant in Brevard, North Carolina uses corrugated paper, wood, and polyethylene and polyvinyl trimmings for fuels, producing 70,000 lb/hr of saturated steam. All of these plants are able to utilize unconventional waste fuels along with biomass using EPI's fluidized bed boiler design.

[25] *Biomass Cofiring in Coal-Fired Boilers.* United States Department of Energy, Office of Energy Efficiency and Renewable Energy. Federal Technology Alert. Federal Energy Management Program. May 2004.

[26] Ibid.

While industrial sites can save money by utilizing their own waste products, it is also possible for facilities to purchase biomass fuels from a variety of sources in order to generate heat and power. The Northumberland Cogeneration Facility in Pennsylvania is a good example of this practice. The facility obtains various types of wood fuel from a range of nearby sources, and uses the wood to produce power and heat in a boiler/steam turbine configuration. Chips and shredded wood from logging and recycling sources, tree debris from development land clearing, yard waste, sawmill residue, and other types of wood waste fuel are all combined and processed into wood chips. The chips are screened and sorted, metal is removed, and they are incorporated into the stack of wood chips, using augers and belts to feed the combustion chamber. While 16.2 MW of net electricity is produced and sold to Pennsylvania Power and Light, there is also a steady supply of expanded steam that is sold to a nearby processing plant. This facility demonstrates how biomass fuels varying in origin, quality and consistency, can be flexibly combined in boilers to produce steam for industrial processes at a competitive price.

In New Jersey, the Rex Lumber Company recently began utilizing their wood waste for on-site process heating and steam generation applications. The company produces over 44,000 cubic yards of wood waste and sawdust each year. Previously the waste was trucked away to a landfill for disposal, which can be a significant expense, but a wood waste boiler system was recently installed to provide heat for the kiln-drying process that the company employs. More steam is produced by the boiler than is needed for kiln-drying, so a 150 kW steam turbine was added to the system to lower plant electricity costs. While the installation of industrial biomass boilers can be economically viable without government assistance, close to half of the funding for this system was provided by the New Jersey Clean Energy Program.[27] Overall, the project has been touted as a great success and Rex Lumber Company has saved thousands of dollars in annual energy costs while conserving natural resources.

An example of a smaller biomass boiler installation can be found at Darby Public Schools in Darby, Montana. With assistance from a program called "Fuel for Schools and Beyond", a biomass boiler system was installed to offset heating oil use, supplying heat to three schools on a single campus. A 3 MBtu/hr direct combustion boiler was integrated into the central heat distribution system, producing hot water and low-pressure steam for the buildings. The boiler burns 750 tons of wood chips annually, and feedstocks are obtained from forest thinnings on nearby lands. The total project cost for the boiler system was $556,000, and the simple payback period is estimated at 10 years.[28]

The Lyonsdale Biomass Facility, located in Lyons Falls, New York, is a 290 MMBtu per hour wood-fired power plant with a 19 MW rated output. While the primary goal of the Lyonsdale facility is power production, there are some lessons to be learned that also apply to large industrial biomass utilization. The plant had been in financial distress for periods since 1998, and has even closed down at times due to unprofitability. The high cost of biomass in comparison to fossil fuels can be difficult to overcome, especially when wood fuels containing high amounts of moisture must be used. While the plant is back in operation under Central Hudson utility ownership, relationships with some biomass suppliers have been

[27] *Biomass System Helps Lumber Distributor Chop Energy Costs and Recycle Wood Waste*, New Jersey Clean Energy Program. http://www.njcleanenergy.com/files/file/casestudy07_rex_lumber.pdf
[28] Peterson, David and Haase, Scott, *Market Assessment of Biomass Gasification and Combustion Technology for Small- and Medium-Scale Applications*, Technical Report, National Renewable Energy Laboratory, July 2009.

strained, and profit margins are very thin. As plant manager Dave BonDurant explained, "The moisture content of the chips makes a big difference, and it varies constantly, as well as the kind of wood being burned. There's a big difference between how you operate the plant if you're burning primarily beech," he explains, "compared to something a lot less dense like willow."[29]

While the Lyonsdale plant primarily uses chips from forest thinnings, another resource stream that is being explored is the fast-growing willow crop, which is being grown on a nearby 60-acre test plot with the help of Syracuse University's Environmental Science and Forestry Department. Syracuse University has been researching the use of willow biomass crops for energy production for nearly two decades. Recently, a 60-acre plot of willow biomass has commenced cultivation in central New York (the same plot being considered for the Lyonsdale facility). The fuel could ultimately end up being used at the Lyonsdale plant, but currently it is being grown for testing purposes. The Environmental Science and Forestry Department's project is managed by the Salix Consortium, with 25 university, association, corporate, utility, and government partners. Willow trees make an ideal dedicated energy crop because they are easily propagated, grow fast, have high yields, the ability to resprout after multiple harvests, and they produce a biomass fuel with a good heat content. In the near future, biomass fuel made from New York grown willow crops will be sold to power producers such as the Lyonsdale Biomass Facility, or possibly to coal plants for co-firing. However, the prospects for dedicated energy crops to play a role in industrial heating applications are in their infancy, so they will not be further explored in this report.

Another potential method of utilizing crop residues for industrial heating comes from the numerous facilities in the United States that produce ethanol from corn. Recent government incentives and initiatives for ethanol fuel to be used in vehicles have led to the construction of a number of ethanol plants throughout the Midwest. It has been emphasized that corn stover and other coproducts of ethanol production can be used to provide process heat and electricity at corn dry mill ethanol plants.[30] The study showed there can be significant annual energy cost savings over a wide range of natural gas and biomass prices. However, the capital and operating costs of biomass combustion, emission control, fuel handling, and electricity generation technologies need to be accounted for in order to determine the overall economic feasibility, which remains uncertain at this time.

Summary of Current Industrial Biomass Projects

The vast majority of industrial biomass utilization projects to date have been located at wood processing facilities who use their wood waste in a boiler to generate steam. Armstrong's manufacturing facility in West Virginia is a good example of this practice. In addition, the installations at Savannah River and Rex Lumber show that saving disposal costs can further help project economics. However, with the country's large amount of biomass resources, it is possible to purchase biomass fuels and utilize them with a variety of steam generation and process heating equipment. The following chapter will analyze the economic

[29] Johnson, Eric, *Biomass Power Plant Hangs in There in New York*, The Northern Logger, http://www.hardhat.com/hh0203/biomass.html, April 2006.
[30] Morey, R.V., Tiffany, D.G., Hatfield, D.L., *Biomass for Electricity and Process Heat at Ethanol Plants*, Applied Engineering in Agriculture, American Society of Agricultural and Biological Engineers. 2006.

potential for industrial facilities purchasing biomass fuels from nearby sources, by determining the maximum transportation distances for biomass fuels to compete with coal.

Tire-Derived Fuel

The use of tire-derived fuel for industrial applications has been fairly limited to date, but there are several examples of both successful and unsuccessful TDF projects to analyze. The first facilities to burn tires for energy were large cement kilns, whose high-temperature incinerators allowed whole tires to be burned. This practice caught on, and several cement kilns, as well as utilities and other industrial facilities looking for a low-cost fuel source, began utilizing TDF for fuel. Recent advances in TDF processing and fuel feeding equipment, along with improvements to TDF supply and delivery, have helped to eliminate some problems that early TDF users faced. However, the combustion of tires produces emissions and has been blamed for unpleasant odors, so community opposition to this practice quickly developed in some areas.

Today, TDF is most often processed into small pieces (no bigger than two inches) with extensive removal of the metal used in tires to protect against puncture. TDF is primarily used in high temperature cement kiln operations and utility-scale coal boilers that incorporate more intensive emission controls. TDF utilization has been on the rise since the early 1990s, despite public opposition causing several TDF projects to be halted or cancelled, and it is currently used in several coal-burning facilities. The market for TDF could be growing again in fuel flexible boilers, however, with recent projects blending TDF with biomass and other fuels. Strong community opposition has primarily been limited to large power plants, so smaller industrial applications, especially with renewable fuel blends, are less likely to draw negative attention.

Cement kilns that utilize TDF most often use whole tires, or TDF that hasn't been thoroughly processed, since the high-temperature incinerator can provide complete combustion. This is not the case with most industrial process heating or steam generation applications, where more refined TDF with full metal removal is most commonly used. There are several examples of cement manufacturers in the United States currently utilizing waste tires strictly for cement kiln fuel, and it has become common practice in the industry. However, these applications do not represent the target of this report, which is to identify new opportunities for the flexible use of alternative fuels in various industrial heating applications.

Pulp and paper mills are the second largest industrial users of TDF, typically blending it with wood waste and/or coal to generate steam for on-site heating applications. A good example of this practice is seen at the Wickliffe Paper Company (owned by New Page Corporation) in Wickliffe, Kentucky. This paper mill recently received a grant of $750,000 from the state's Waste Tire Trust Fund to underwrite capital costs for equipment to utilize TDF on-site in their wood waste boiler. The grant requires that the facility consume the equivalent of 750,000 tires per year through 2012 by burning about a 15 percent TDF blend. In 2001, a similar grant was given to Owensboro Municipal Utilities to incorporate 750,000 tires/year at their power plant. While the grant has expired, the utility continues to use about 900,000 tires per year in the form of TDF. The Wickliffe Paper facility has also stated its intent to continue using TDF after their contract expires due to its low price and high heating value, and the fact that all of the equipment is already owned and installed.[31] State grants can help TDF projects gain footing, but unfortunately most states have not set aside substantial financial resources for new waste tire recycling and utilization projects.

The New Page mill in Bucksport, Maine also incorporates TDF into mill operations. It substitutes tires for up to 14.5 percent of the heat input from coal. At that level, there has been no significant change in NOx or Sox emission levels, a six percent increase in particulates, and a 1 percent increase in total hydrocarbons. Zinc and cadmium emissions also increased considerably, although beryllium and chromium emissions decreased.[32] Facilities must be screened carefully, usually by performing a test burn, to determine whether adding tires to coal burners will increase emissions beyond acceptable environmental limits. A relatively small percentage of industrial boilers have the required combination of system design, permitting conditions and fuel type that would make TDF an attractive option.[33]

Pacifica Papers Inc. operates a mill in Port Alberni, British Columbia that produces 1,200 tonnes per day of paper for telephone directories and newspapers, among other products. The mill uses a fluidized bed boiler powered by wood waste fuels, and recently began incorporating TDF as a secondary fuel. The wood waste fuel occasionally has a high moisture content, so TDF is used to increase the operating temperature of the boiler by as much as 100°F, enhancing the combustion of the moist wood waste and increasing the boiler efficiency. While only a five percent TDF blend is typically used with this boiler, there have been no negative impacts on boiler operation or ash removal. Residual wire in the TDF was either oxidized or reduced to very small pieces in the fluidized bed.[34]

While pulp and paper mills can be good candidates for TDF utilization, other industrial facilities are also looking at TDF as an option, particularly for cofiring applications using fluidized bed boilers. The Archer Daniels Midland plant in Decatur, Illinois uses a combination of high-sulfur coal and TDF to produce steam for grain processing facilities, and electric power. This plant has been operational since the early 1990s. In 2006, Archer Daniels announced that construction would begin on a cogeneration facility to help power its corn milling and ethanol operations in Columbus, Illinois. The facility will be permitted to utilize a variety of fuels, including high and low sulfur coals, TDF and biomass.

In another example of TDF-biomass cofiring, a demonstration project at the Frito-Lay food processing plant in Topeka, Kansas that started in April 2009 is blending TDF with biomass fuels in a stoker boiler in place of natural gas consumption. The boiler can produce 60,000 lb/hr of steam, and will serve a significant portion of the process steam demand at the plant. It is estimated that the boiler will consume 75,000 tons of wood waste and TDF each year.[35] The success of this project could pave the way for similar boiler installations at other industrial sites.

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[31] *Wickliffe Paper Will Use Scrap Tires for Fuel*, The Carlisle Weekly, July 24, 2006. http://www.carlisleweekly.com/modules.php?name=News&file=print&sid=48
[32] *Use of Tire-Derived Fuel In Virginia*, Virginia State Advisory Board, Air Pollution, November 2007.
[33] Ibid.
[34] Cross, Larry and Ericksen, Bob. *Use of Tire Derived Fuel (TDF) in a Fluidized Bed Hog Fuel Power Boiler at Pacifica Papers Inc. Alberni Specialties Mill*. Alberni Valley Local Events.
[35] United States Department of Energy, Fuel and Feedstock Flexibility, Quarterly Status Reports, March 31, 2010.

According to the Rubber Manufacturers Association, several industrial facilities have recently expressed interest in TDF as a source of fuel, with at least five industrial boilers pinpointed as being capable of economically incorporating TDF in 2005, so there could be some potential for near-term growth in this sector.[36] However, there are several potential disincentives to TDF projects that should be taken into consideration. A 2007 study on the use of TDF at industrial facilities in Virginia interviewed nine plants that had either burned tires as a fuel in industrial boilers or performed burning trials and chose not to continue. From these nine plants, six major problems were found. [37]

1) Seven plants felt they were hampered because the permitting process limited the amount of TDF they could burn, thereby limiting the economic advantage
2) Five plants found the permitting process to be excessively difficult, lengthy and costly
3) Four plants observed that wires from the tires clogged the grates in the boilers, creating hot spots that required temporary shutdowns and increased maintenance costs, and some plants reported difficulties mixing shredded tires with wood or other fuels
4) Four plants reported excessive zinc in the ash, which kept it from being sold in some cases
5) Two plants encountered high costs of additional pollution controls
6) Two plants faced strong negative public opinion

These issues are typical for TDF projects, although there are several ways to overcome them. A shorter and more streamlined permitting process, along with more consistent TDF processing, could help to alleviate most of these problems. Public opposition to local TDF projects, however, can be difficult to overcome. To help curb local opposition, press releases can focus on the positive aspects of TDF utilization, such as the displacement of fossil fuels and the conservation of resources.

Summary of Current Industrial TDF Projects

Recently, with advances in fluidized bed boiler technologies, tire-derived fuel has become an option for industrial plants to cofire with coal, biomass, pet coke, or other solid fuels. TDF can often be obtained for a much lower cost than these other fuels, so cofiring can be an attractive option for industrial sites with TDF access. Wickliffe Paper in Kentucky, Archer Daniels in Illinois, and Frito-Lay in Kansas are all good examples of this practice. The following chapter will examine the economic potential of industrial TDF utilization, particularly in cofiring applications.

Petroleum Coke

The majority of industrial petroleum coke installations in the United States have been at pulp and paper mills in the Northwest and the Gulf states, using pet coke to fire lime kilns that are essential in the pulping process. However, recent advancements in fluidized bed boilers allow them to handle pet coke's high sulfur content, making them a more attractive option for industrial steam generation applications.

[36] *Scrap Tire Markets in the United States*, 2005 Edition, Rubber Manufacturers Association, November 2006.
[37] *Use of Tire-Derived Fuel In Virginia*, Virginia State Advisory Board, Air Pollution, November 2007.

The supply of Petroleum Coke in the Northwest and the Gulf states is very abundant, so the fuel can often be obtained for a low cost relative to coal. This has caused owners of some pulp and paper mills to switch from traditional fossil fuels to petroleum coke in their lime kilns, which continuously burn large amounts of fuel. Even with initial capital costs for the fuel storage and feeding systems, and increased maintenance requirements, most plants are able to save money in the long run by using pet coke instead of fossil fuels.

An example of this practice can be found at the Smurfit Stone Containerboard Division in Hodge, Louisiana, where pet coke feeds two lime kiln burners. The fuel is fed to both burners from a common 180 ton silo with a dual discharge hopper bottom. The feeding system includes dual pneumatic convey systems with variable rate blowers to deliver pet coke to the burners in accordance with specific air flow requirements. The system was installed by Matrix Engineering, who has extensive experience designing pet coke feeding systems. It allowed the mill to substitute 90 percent ground petroleum coke for natural gas in each of their lime kiln burners, resulting in substantial energy cost savings. Many other pulp and paper mills throughout the Southeast and the Northwest have recently incorporated similar pet coke fuel systems into their natural gas lime kilns.

Some pulp and paper mills also incorporate pet coke into black liquor recovery boilers or wood waste boilers to provide additional energy to the plant. Any new boiler system can be designed to be capable of utilizing a wide variety of fuels. An example can be found at Georgia Pacific's Port Hudson mill in Zachary, Louisiana, where a new circulating fluidized bed boiler was recently installed. The boiler burns about 300,000 tons per year of petroleum coke, along with wood waste and sludge from the plant, replacing a boiler that previously was fueled by natural gas. The boiler powers a steam turbine generator that provides 58 MW of power to the plant, while heat recovered from the system is used for process heating. Even though the most likely candidates for pet coke boiler projects are facilities that have coal-fired boilers, this installation shows that aging natural gas boilers can be replaced with fuel-flexible boilers that are capable of utilizing petroleum coke as well as other waste fuels.

Summary of Current Industrial Petroleum Coke Projects

Most industrial petroleum coke applications to date have been located at pulp and paper mills, using the fuel for lime kilns. Recently some mills like Georgia Pacific's Port Hudson mill in Louisiana have incorporated pet coke into fluidized bed boilers. These fuel-flexible boiler applications could also be utilized by other industrial facilities with access to petroleum coke. The following chapter will examine the economic potential of petroleum coke use at various industrial sites.

Lessons Learned from Current Projects

From analyzing current opportunity fuel projects, it is apparent that most of the issues associated with utilizing the fuels have been identified, and problems that plagued early adopters of these fuels have largely been ironed out. In some cases, high levels of fuel pretreatment and contaminant-removal are required, and in others, modifications are necessary to utilize equipment that was designed for traditional fuels. Sometimes, only specific types of equipment (i.e. fluidized bed boilers) can properly handle the fuels, or limited percentages of the fuels can be cofired with existing equipment.

The examples provided in this chapter show that successful opportunity fuel projects at industrial sites are possible, given the right circumstances. In many cases, opportunity fuels provide significant cost savings for industrial facilities, while fuel flexibility and energy security are enhanced by their utilization. The next chapter takes information from current projects, fuel availability, and equipment requirements into account to estimate the economic potential for the industrial utilization of opportunity fuels across the United States.

6. Economic Analysis of Opportunity Fuels for Industrial Process Heating and Steam Generation

Many opportunity fuels are available throughout the United States and are capable of providing a significant alternative to natural gas or coal for industrial heating applications. Not all applications, however, are economically viable when compared to the more traditional options. In this chapter, the economic potential for each opportunity fuel is estimated, by comparing the economics of using the opportunity fuels with those of using traditional fuels for potential industrial installations. Gaseous opportunity fuels are compared with the economics of purchasing natural gas, and solid opportunity fuels are compared with coal.

Gaseous Opportunity Fuels

The economics for industrial applications of gaseous opportunity fuels are directly tied to the cost of natural gas. Natural gas is the most common fuel used for industrial process heating and steam generation applications, so opportunity fuels must be cost-competitive with natural gas in order to be considered a viable option. Natural gas is widely available in the United States, but some industrial sites may not have access to natural gas pipelines, and the price varies from state to state due to a number of different factors. The 2010 average state prices for natural gas used at industrial sites, according to EIA data, are mapped in Figure 6-1. States with high industrial natural gas prices should be prime candidates for gaseous opportunity fuel projects, if there are affordable opportunity fuel resources nearby.

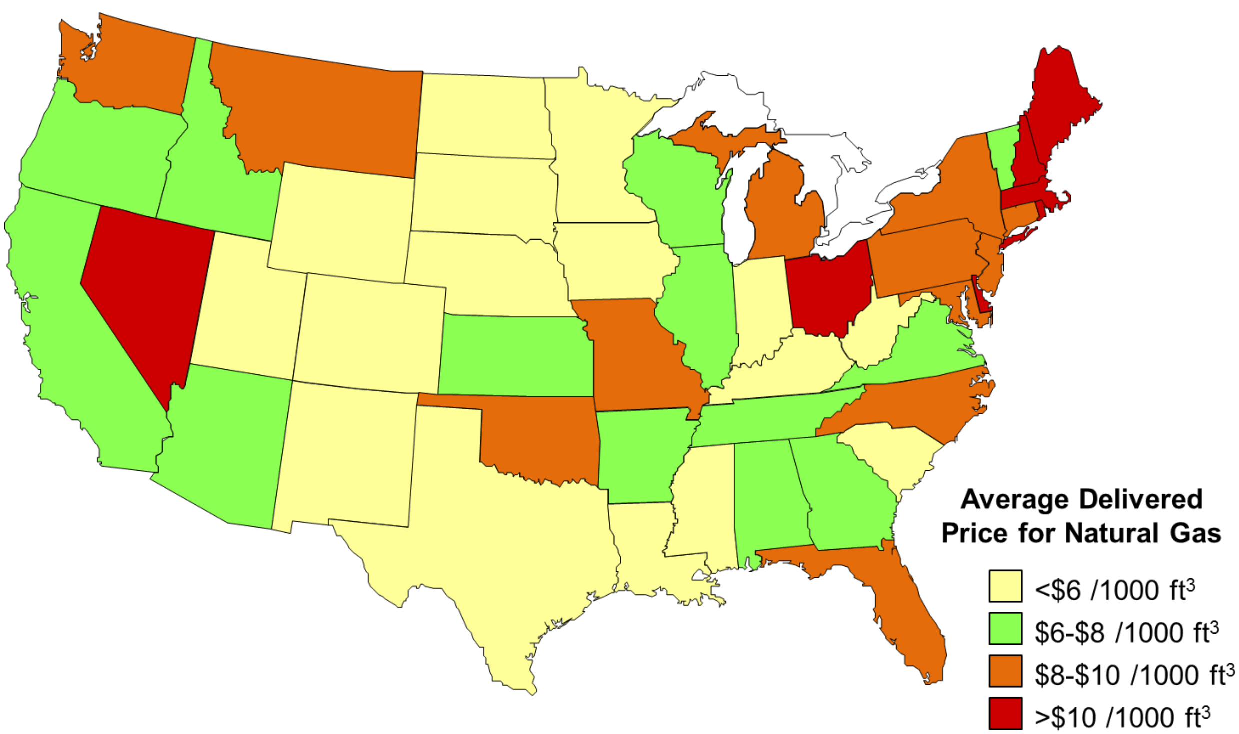

Figure 6-1. 2010 Average State Natural Gas Prices for Industrial Sites
(Source: EIA)

The price of natural gas at industrial sites is fairly regional, with the highest prices found in the Northeast, and the lowest prices generally located in gulf region as well as the central states. States with high natural gas prices, plentiful gaseous opportunity fuels available, and numerous industrial sites will be the best contenders for gaseous opportunity fueled process heating and steam generation. The use of natural gas is so prevalent at industrial sites that every state has some capacity for opportunity fuels to replace natural gas in various industrial process heating and steam generation applications. This section examines the potential markets for each opportunity fuel by state, and estimates the economic potential for new industrial applications.

Anaerobic Digester Gas

The economics of anaerobic digester gas utilization are fairly straightforward for wastewater treatment plants that use anaerobic digesters. At many of these plants, ADG is only used to heat the digester tank, while the remaining gas is flared, often during summer periods when digester heating loads are minimal. Some use surplus gas for space heating as well. Maintaining a constant temperature of about 95°F for the digester tank[1] usually requires only a portion of the gas produced, so larger plants could have significant amounts of excess gas to potentially sell or utilize. ADG can be blended with natural gas in boilers or process heating equipment, with only minor burner modifications, and the avoided natural gas purchases can significantly bring down plant energy costs.

For municipal wastewater treatment plants, electric and thermal loads are fairly high, so combined heat and power (CHP) installations utilizing ADG are becoming more common. For sites that have already implemented CHP, the amount of surplus ADG is likely to be minimal, so opportunities for industrial utilization are limited. For sites that only use ADG for digester tank heating, or not at all, there is likely a considerable amount of excess gas that is flared at certain times. Instead of flaring, this gas could be routed to a nearby industrial facility with a pipeline and sold as a low-cost supplement to natural gas. The factors influencing the profitability of this practice are the length of pipeline required, the amount of ADG that can be utilized, its sale price, and comparatively, the potential on-site savings that could be generated through ADG-fueled CHP. Evaluation of ADG uses, however, typically focuses on other options, such as on-site CHP utilization.[2]

For industrial wastewater treatment plants producing ADG at food, paper, chemical processing, or other industrial facilities, there are many potential process heating and steam generation applications that could utilize ADG, eliminating the need for a pipeline. For industrial treatment plants with anaerobic digesters, utilizing ADG to its maximum potential for on-site industrial operations is cost-effective and practical. For industrial plants using other methods of wastewater treatment, installing an anaerobic digester and utilizing ADG could prove beneficial in the long run.

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[1] Mesophillic designs require a constant temperature of around 95 F; thermophyllic designs, while less common, require higher temperatures around 130 F.

[2] Holland, Jeremy, P.E. and Wolstenholme, Philip, P.E., *Technical Memorandum to Eric Johnson, P.E. City of Tacoma Central Treatment Plant (CTP) – Utilization of Flared Digester Gas at the Tacoma CTP*, Brown and Caldwell, December 3, 2003.

For either type of wastewater treatment plant, ADG requires some form of pretreatment prior to utilization. Pretreatment typically includes the removal of harmful particulates and water, as well as compressing the gas. In some cases, contaminants such as hydrogen sulfide must be removed to avoid damage to the combustion equipment. For engines and turbines, siloxane buildup can be a major problem, but it can be treated more easily with boilers and process heating equipment, with no change or only a slight increase in maintenance requirements.

A previous study by the Resource Dynamics Corporation analyzed the costs of pretreatment for gases like ADG and LFG for New York CHP applications. It was found that without siloxane removal, ADG pretreatment equipment installation generally ranges from $50,000 to $250,000, depending on the amount of gas to be utilized and the level of cleanup required (when siloxane removal is included, pretreatment installation costs can reach as high as $500,000 for large projects).[3]

The pretreatment requirements for ADG in process heating or steam generation applications can be compared to direct-use projects for landfill gas. The EPA has documented several of these projects as part of the Landfill Methane Outreach Program, and they recently compiled an estimate of average pretreatment costs for direct utilization based on LFG flow rate. Pretreatment costs for LFG projects average $960 per scf/minute, with $90 per scf/minute for annual equipment maintenance.[4] These costs were used for both the ADG and LFG economic analyses in this report.

In addition to gas pretreatment, pipelines must be installed at municipal plants to transport ADG to nearby industrial facilities. Estimates for LFG pipeline costs obtained from the EPA's Landfill Methane Outreach Program reveal that pipelines cost about $330,000 per mile to install.[5] Other reports have cited pipeline costs as low as $100,000/mile[6] or as high as $500,000/mile[7], but average figures tend to fall between $250,000 and $350,000 per mile. Higher costs may be incurred in urban areas where pipelines must be built around existing infrastructure, and long pipelines are more likely to encounter right-of-way difficulties, but the average cost of $330,000/mile cited by the EPA is used for all potential ADG and LFG projects in this report.

Municipal WWTP Economics

The economics for different-sized municipal wastewater treatment plants were calculated based on the estimated costs for pretreatment and pipeline construction, and the average state price of natural gas. It was assumed that industrial facilities would purchase ADG at the treatment plant site for half of the 2010 NYMEX/Henry Hub natural gas price. This is based on anecdotal data from discussions with landfill

[3] *Installed Costs for Opportunity Fueled Prime Mover Equipment*. Memorandum from Resource Dynamics Corporation to NYSERDA. March 9, 2007. Report is in publication review.

[4] United States Environmental Protection Agency. Landfill Methane Outreach Program. *LFG Energy Project Development Handbook*. 2010. http://www.epa.gov/lmop/publications-tools/handbook.html

[5] Ibid.

[6] *Biomethane from Dairy Waste*. Prepared for Western United Dairymen. July 2005.

[7] Edgar, Thomas F. *Evaluation of Environmental Emissions for Combustion of Landfill Gas in a Texas Petrochemical Plant.* University of Texas, Department of Chemical Engineering.

operators and project developers, as well as EPA LMOP estimates, and assumes that ADG from municipal plants can be sold for the same price as LFG. For a given WWTP size, the maximum pipeline distance for industrial sites to economically offset natural gas purchases with ADG was calculated for each state.

For municipal WWTPs with enough ADG production to replace 5 million cubic feet of natural gas annually (corresponding to about 2 million gallons per day of wastewater flow), the pipeline distance is a limiting factor. For most states, in order to achieve a 5-year payback on the investment, pipeline construction would be limited to less than half a mile, which in most cases is not long enough to transport ADG to an industrial facility. According to the estimates, Massachusetts is the only state in the continental U.S. that could economically justify 1-mile pipelines for treatment plants of this size. For project flexibility, an economic pipeline distance of over two miles is preferred to allow a radius around the WWTP large enough to find a suitable site.

Larger wastewater treatment plants that produce more ADG can support larger pipeline investments and thus offer a larger radius to find a suitable site to use the fuel. If an industrial facility was able to replace 25 million cubic feet of natural gas each year with ADG from a nearby plant, pipeline distances greater than two miles are economically possible for most states. A WWTP with this much gas would have to process at least 10 million gallons per day (MGD) of wastewater. However, most municipal plants of this size that employ anaerobic digesters already utilize some of their ADG. For these cases, even larger facilities with higher volumes of wastewater flow would be required for additional industrial utilization. Regardless, the maximum pipeline distances for 5-year paybacks were calculated for industrial sites capable of replacing 25 million cubic feet of natural gas each year with ADG. The results were also calculated for industrial sites near very large (>40 MGD) municipal treatment plants, capable of replacing 100 million cubic feet of natural gas each year. These results are presented in Table 6-1.

Table 6-1. Economics for Industrial ADG Utilization from Municipal Wastewater Treatment Plants

State	Avg Ind Natural Gas Price ($/1000 ft^3)	Industrial Natural Gas Use (ft^{3}x10^6)	Maximum Pipeline Distance (5 year Payback) Replacing 25 million ft^3/yr (~10 MGD)	Replacing 100 million ft^3/yr (~40 MGD)
Massachusetts	16.15	41,849	5.0	19.9
New Hampshire	15.76	5,139	4.8	19.3
Maine	12.65	25,344	3.7	14.6
Rhode Island	12.52	6,775	3.6	14.4
Delaware	12.30	18,216	3.5	14.1
Nevada	11.28	11,402	3.1	12.6
Pennsylvania	11.22	171,990	3.1	12.5
New York	10.82	72,639	3.0	11.9
Maryland	10.72	23,651	2.9	11.7
Ohio	9.88	225,215	2.6	10.4
Michigan	9.64	125,649	2.5	10.1
Missouri	9.47	61,449	2.5	9.8
Oklahoma	9.44	166,660	2.4	9.8
Montana	9.06	25,894	2.3	9.2
New Jersey	8.85	48,992	2.2	8.9
Florida	8.83	65,776	2.2	8.8
Washington	8.77	71,330	2.2	8.8
Arkansas	8.48	77,553	2.1	8.3
Connecticut	8.44	24,585	2.1	8.3
North Carolina	8.30	82,181	2.0	8.0
Oregon	8.18	57,318	2.0	7.9
Arizona	8.16	17,809	2.0	7.8

Even when replacing 25 million ft^3 of natural gas each year, WWTPs in most states cannot support ADG pipeline lengths of 2 miles or greater. It takes an extremely large treatment plant, with an abundance of excess ADG, to support industrial utilization in most locations. The main issue for municipal wastewater treatment plants is that they may see greater value in using ADG-fueled CHP for on-site thermal and electric demands. The best hope for the industrial utilization of ADG from municipal treatment plants lies with high-volume WWTPs that currently flare a large portion of their digester gas. Still, aside from industrial sites located within 1-2 miles of municipal WWTPs, the economics for ADG sales to industrial sites are simply not as favorable as on-site CHP installations.

Using estimates for the installation and maintenance costs of ADG engine generator sets taken from the Combined Heat and Power Partnership[8], the potential savings generated with CHP were compared to the

[8]Opportunities for Combined Heat and Power at Wastewater Treatment Facilities: Market Analysis and Lessons from the Field. Prepared by: Eastern Research Group, Inc. and Resource Dynamics Corporation. Prepared for: U.S. Environmental Protection Agency Combined Heat and Power Partnership. October 2011.
Estimates: $3,600/kW, $0.02/kWh for 10 MGD plant (~250 kW unit); $2,500/kW, $0.015/kWh for 40 MGD plant (~1 MW unit) Estimated costs include gas pretreatment equipment. Based on data from

potential revenue from ADG sales to nearby industrial sites in a second analysis. It is assumed that the industrial site makes the investment in the pipeline construction and gas compression/cleanup equipment, so that the municipal plant only sells raw, unfiltered gas for 50 percent of the 2010 NYMEX/ Henry Hub natural gas price, with no additional costs incurred. The analysis assumes that the municipal plant invests in CHP and does not sell its gas to another site (such as a nearby industrial facility), but the lost potential for external ADG sales is treated as a negative expenditure in the payback period calculations in order to directly compare the economics of both utilization practices.

Simple payback periods for CHP installations were calculated for municipal plants in each state using average values for natural gas and electricity price, also considering maintenance costs and the lost potential for ADG sales. The average simple payback period to recover the cost of a CHP system while losing ADG sales revenue turned out to be 5.0 years for 10 MGD plants, and 2.9 years for 40 MGD plants. While large plants able to achieve payback periods of less than 5 years would likely opt for on-site CHP, smaller plants with CHP payback periods over 5 years may prefer to sell ADG to an industrial site and avoid the CHP system investment. Table 6-2 provides the estimated relative CHP payback periods for 10 and 40 MGD plants by state, so that those with the weakest CHP economics can be pinpointed and targeted.

Table 6-2. States with Longest Payback Periods for CHP in Lieu of ADG Sales at Municipal WWTPs

				Payback Period for CHP vs. ADG sales	
State	Avg Industrial Electricity Price, Apr 10 ($/kWh)	Avg Industrial Natural Gas Price ($/1000 ft^3)	Industrial Natural Gas Use ($ft^3 x 10^6$)	Replacing 25 million ft^3/yr (~10 MGD)	Replacing 100 million ft^3/yr (~40 MGD)
Wyoming	4.83	4.78	37,300	13.8	7.6
Kentucky	4.84	5.63	93,036	12.0	6.9
Utah	4.82	5.91	29,749	11.6	6.7
Iowa	5.01	6	157,169	10.9	6.3
Washington	3.89	8.77	71,330	10.3	6.3
Idaho	4.77	7	24,207	10.2	6.0
Louisiana	6.03	4.33	761,347	10.2	5.8
Kansas	6.11	4.22	108,982	10.1	5.7
Nebraska	5.41	5.95	76,456	9.8	5.7
South Carolina	5.29	6.48	64,130	9.5	5.6
West Virginia	5.65	5.9	24,473	9.3	5.5
New Mexico	6.1	5.09	17,019	9.2	5.3
Indiana	5.7	6.2	244,655	8.9	5.3
Minnesota	5.95	5.71	109,165	8.9	5.2
South Dakota	5.85	5.99	33,462	8.8	5.2
North Dakota	6.22	5.21	15,804	8.8	5.1
Alabama	5.74	6.36	130,352	8.7	5.1
Texas	6.5	5.06	1,184,365	8.4	4.9
Georgia	5.53	7.27	138,035	8.3	5.0
Mississippi	6.06	6.29	98,937	8.1	4.8
Arkansas	5.12	8.48	77,553	8.0	4.9
Missouri	4.74	9.47	61,449	7.8	4.9
Oklahoma	5.03	9.44	166,660	7.4	4.6
Oregon	5.65	8.18	57,318	7.4	4.5
North Carolina	5.82	8.3	82,181	7.1	4.3
Virginia	6.55	6.83	62,642	7.0	4.2
Tennessee	6.31	7.59	84,345	6.9	4.2
Montana	5.72	9.06	25,894	6.8	4.2
Arizona	6.25	8.16	17,809	6.6	4.1
Wisconsin	6.45	7.78	118,581	6.6	4.0
Colorado	6.95	7.4	113,921	6.3	3.8
Ohio	5.81	9.88	225,215	6.2	3.9
Illinois	7.23	7.29	233,859	6.0	3.7
Michigan	7.1	9.64	125,649	5.2	3.3
Nevada	6.62	11.28	11,402	5.0	3.2

Large 40 MGD plants are able to offer CHP payback periods of less than 5 years in most states when considering lost ADG sales potential. In addition, large WWTPs may have a difficult time finding a nearby industrial facility willing to purchase such high quantities of ADG. However, there are 35 states with estimated payback periods greater than 5 years for CHP at smaller 10 MGD plants. These states tend to have low industrial electricity prices, averaging 5.65 cents/kWh. By comparison, the remaining

continental states average over 10 cents/kWh. For the 35 states listed in Table 6-2, municipal WWTPs in the 5-15 MGD size range that have digesters, but are not currently utilizing ADG for CHP, were targeted as potential projects. The analysis showed that 177 plants fit these criteria, with the capacity to provide a total of 3.6 million MMBtu/year to industrial sites. As can be seen in the fourth column of Table 6-2, there is more than enough existing industrial natural gas use in these states for ADG to fully realize its economic potential. Even when only considering New Mexico, the smallest state in the table in terms of industrial natural gas use, over 17 billion cubic feet of natural gas (about 17 million MMBtu) is utilized each year. The top states for industrial ADG utilization from municipal WWTPs are presented in Table 6-3, in terms of estimated potential.

Table 6-3. Top States with Potential for Industrial ADG Utilization from Municipal Treatment Plants

State	Number of Sites 5-15 MGD	Total MGD	Estimated MMBtu/year
Illinois	22	192	378,432
Ohio	21	192	378,235
Texas	20	188	369,957
North Carolina	12	109	213,854
Georgia	10	96	190,004
Indiana	9	85	166,747
Virginia	7	66	129,101
Idaho	6	65	127,130
Michigan	6	65	128,115
Missouri	7	62	121,611
Alabama	7	62	121,217
Wisconsin	7	62	121,217
Kansas	8	58	114,712
Tennessee	7	55	108,405
Minnesota	5	49	96,776
Washington	6	45	88,892
Utah	4	41	80,023
South Carolina	4	37	73,321
Iowa	6	37	72,730
Louisiana	5	37	71,942
Colorado	4	35	68,394
Oklahoma	3	27	53,808
Kentucky	4	26	51,049
South Dakota	2	22	43,362
Other States	14	116	227,651
All U.S.	**206**	**1,825**	**3,596,681**

Industrial WWTP Economics

Manufacturing and processing facilities that produce organic wastewater, such as food processing or paper manufacturing, can treat their industrial wastewater with anaerobic digestion. According to EPA Envirofacts data, there are 296 of these sites that process more than 1 million gallons of wastewater per day.[9] These facilities may be ideal candidates for industrial ADG utilization, since the fuel gas is produced on-site when a digester is installed. The states with the highest allowable pipeline distances for municipal plants in Table 6-1 are also the states with the most favorable economics for industrial ADG utilization. In both cases, natural gas is being replaced with ADG, with higher volumes producing greater savings and allowing higher capital expenditures. With industrial treatment plants, a pipeline is not required, so any facility with an existing anaerobic digester should profit greatly from utilizing ADG in place of natural gas.

For industrial plants that use other methods of wastewater treatment, the investment in an anaerobic digester along with gas pretreatment equipment could be offset by avoided natural gas costs for on-site process heating and steam generation. However, anaerobic digester systems are expensive to install (generally ranging from $100,000 to $2,000,000 depending on size and facility accommodations) and they require a relatively large footprint. It is likely that only large industrial plants that produce high volumes of wastewater would benefit from installing a new anaerobic digestion system.

When only estimated digester costs, pretreatment costs, and avoided natural gas purchases are considered, the payback period for a 2 MGD wastewater treatment plant averages about 8 years, although this can vary considerably with the local price of natural gas. For example, states in New England are able to achieve favorable payback periods with 2 MGD plants, while some Gulf Coast states would require more than 10 years to make a return on their investment.

When larger wastewater treatment plants are analyzed, the economics begin to improve. For a 10 MGD plant, the payback period for most states falls to 3-4 years, which is attractive to potential project developers. For large 40 MGD plants, which are fairly rare, payback periods of 1-2 years can generally be expected.[10] These figures assume that any additional costs for digester maintenance are negligible, considering the previous treatment system likely required maintenance and the requirements for anaerobic digester systems are fairly minimal. The states with the best economics for anaerobic digester installations at industrial facilities are presented in Table 6-4 on the following page. States with the highest natural gas prices are the states where the economics are most favorable, although the locations of

[9] United States Environmental Protection Agency. Envirofacts Database: Water Discharge Permits. http://www.epa.gov/enviro/

[10] Data used in economic analysis:
2 MGD plant:$200,000 digester, $100,000 piping & gas pretreatment, replaces 5 million ft^3/year of NG
10 MGD plant:$500,000 digester, $150,000 piping & gas pretreatment, replaces 25 million ft^3/year of NG
40 MGD plant:$800,000 digester, $200,000 piping & gas pretreatment, replaces 100 million ft^3/year of NG

capable industrial sites do not necessarily coincide (see Chapter 4 for an analysis of Industrial WWTP locations).

It should be noted that these calculations assume that the wastewater sludge at industrial sites is of similar composition to the sludge at municipal WWTPs, which is not always the case. Sometimes industrial wastewater streams can be dilute, and sometimes they can produce more energy than municipal wastewater. Facilities with dilute waste streams, including some food processing plants and pulp and paper mills, would require larger digesters with higher capital costs, and the low energy output would likely cripple the economics of digester gas utilization. For the purposes of this project, however, it is assumed that the waste streams from industrial sites have a similar energy composition to wastewater sludge at municipal WWTPs.

Table 6-4. Top States with Potential for Industrial ADG from Industrial (On-Site) Digesters

			Payback Period for Anaerobic Digester		
State	**Avg Ind Natural Gas Price ($/1000 ft3)**	**Industrial Natural Gas Use (ft3x106)**	**Replacing 5 million ft3/yr (~2 MGD)**	**Replacing 25 million ft3/yr (~10 MGD)**	**Replacing 100 million ft3/yr (~40 MGD)**
Massachusetts	16.15	41,849	3.72	1.61	0.62
New Hampshire	15.76	5,139	3.81	1.65	0.63
Maine	12.65	25,344	4.74	2.06	0.79
Rhode Island	12.52	6,775	4.79	2.08	0.80
Delaware	12.3	18,216	4.88	2.11	0.81
Nevada	11.28	11,402	5.32	2.30	0.89
Pennsylvania	11.22	171,990	5.35	2.32	0.89
New York	10.82	72,639	5.55	2.40	0.92
Maryland	10.72	23,651	5.60	2.43	0.93
Ohio	9.88	225,215	6.07	2.63	1.01
Michigan	9.64	125,649	6.22	2.70	1.04
Missouri	9.47	61,449	6.34	2.75	1.06
Oklahoma	9.44	166,660	6.36	2.75	1.06
Montana	9.06	25,894	6.62	2.87	1.10
New Jersey	8.85	48,992	6.78	2.94	1.13
Florida	8.83	65,776	6.80	2.94	1.13
Washington	8.77	71,330	6.84	2.96	1.14
Arkansas	8.48	77,553	7.08	3.07	1.18
Connecticut	8.44	24,585	7.11	3.08	1.18
North Carolina	8.3	82,181	7.23	3.13	1.20
Oregon	8.18	57,318	7.33	3.18	1.22
Arizona	8.16	17,809	7.35	3.19	1.23

Smaller sites (~2 MGD) have a hard time achieving a 5-year payback period except in states with the highest natural gas prices. The average estimated payback periods for the different-sized plants are illustrated graphically in Figure 6-2.

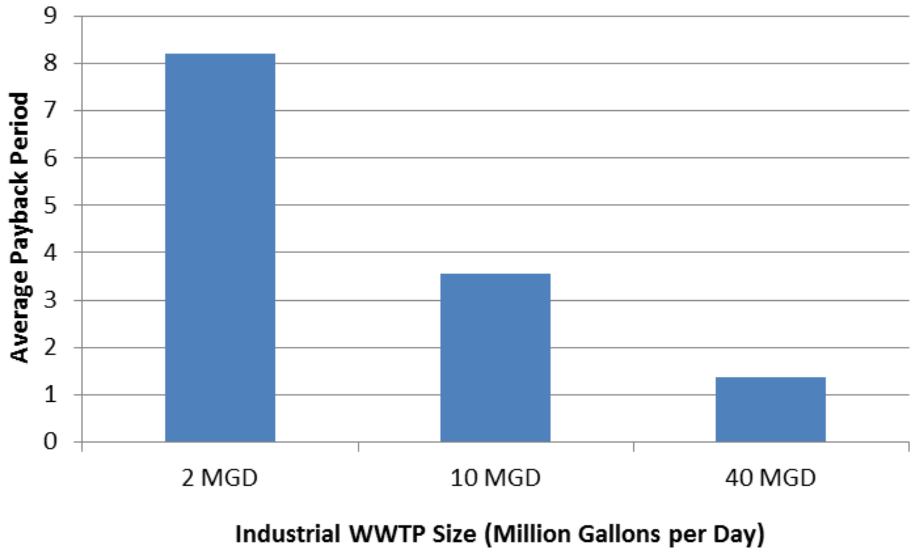

Figure 6-2. Average Estimated Payback Periods for Industrial WWTPs Installing Digesters

Data Used:
2 MGD* plant:$200,000 digester, $100,000 piping & gas pretreatment, replaces 5 million ft^3/year of NG
10 MGD* plant:$500,000 digester, $150,000 piping & gas pretreatment, replaces 25 million ft^3/year of NG
40 MGD* plant:$800,000 digester, $200,000 piping & gas pretreatment, replaces 100 million ft^3/year of NG
**MGD sizes and capital expenditures assume that industrial treatment plants have a similar sludge loading (around 8% solids) compared to a municipal plant. Industrial plants with higher sludge loading rates may require large, more costly systems.*

Somewhere between 2 MGD plants and 10 MGD plants, anaerobic digester installations begin to become economically beneficial, with a payback period of about 5 years. For most states, this occurs at a size of about 5 million gallons of wastewater processing per day. However, for the 22 states that are listed in Table 6-4 as having the best project economics, industrial treatment plant sizes of 2-4 MGD can still produce positive results. Conversely, states with low natural gas prices (<$6/MMBtu) tend to require plants 6 MGD or larger in size. Louisiana has many potential industrial sites, but some of the lowest natural gas prices in the country, and it is estimated that treatment plants in this state would need to be over 12 MGD in order to achieve a 5-year payback. Only plants that are estimated to be capable of supporting anaerobic digester installations with a payback period of 5 years or less are considered to have economic potential in the analysis. Again, this analysis is based on the assumption that MGD sizes and capital expenditures assume that industrial treatment plants have a similar sludge loading (around 8% solids) compared to a municipal plant. Industrial plants with higher sludge loading rates may require larger, more costly systems.

Overall, the economics for industrial wastewater treatment plants with anaerobic digesters are very favorable for ADG-fueled process heating and steam generation. Based on the number of applicable industrial sites and their relative sizes, and assuming all projects with estimated 5-year payback periods are not already utilizing ADG (and would be willing to change treatment methods if necessary), the economic potential was calculated. The states with the most potential for ADG utilization from industrial

WWTPs are shown in Figure 6-3. While high natural gas prices help project economics, generally the states with the highest number of large industrial facilities in the food processing, pulp and paper, or organic chemical industries show the most potential. Overall, industrial facilities processing organic wastewater throughout the country are estimated to be capable of replacing 11.2 million MMBtu/year of natural gas with anaerobic digester gas from 197 sites.

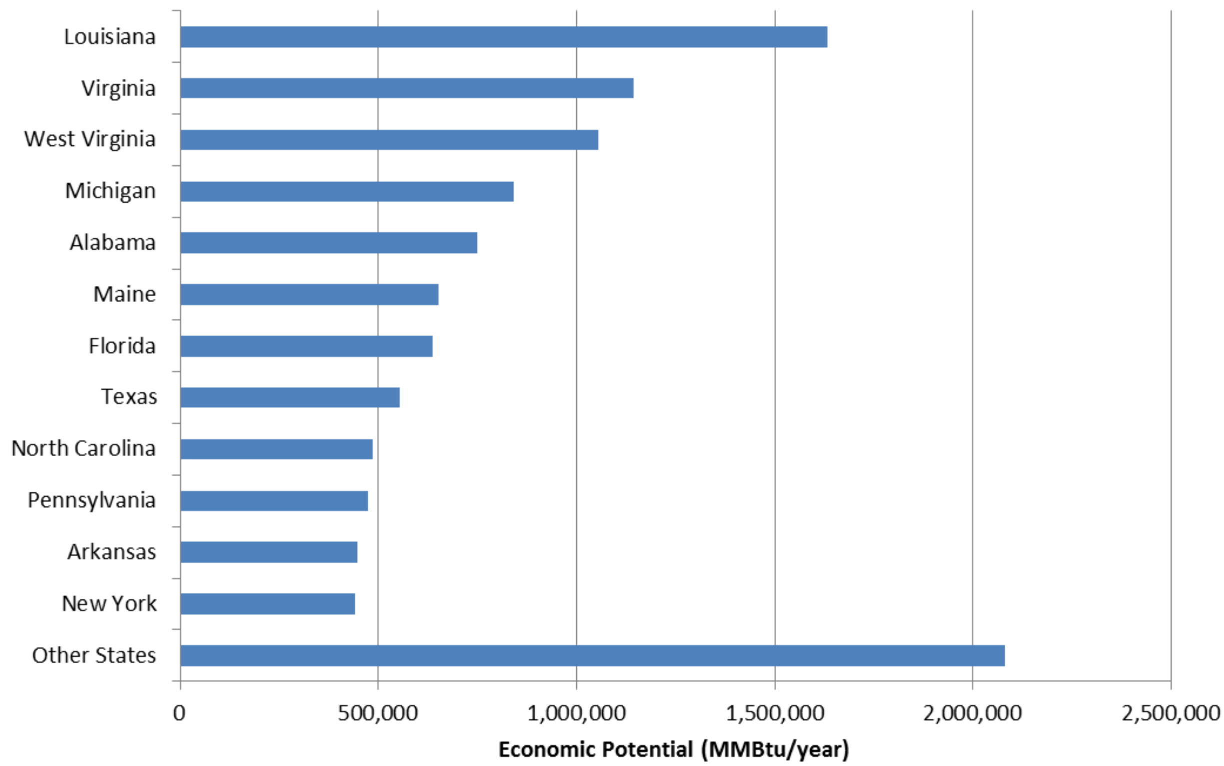

Figure 6-3. Economic Potential for On-Site Industrial ADG Utilization, Including Digester Cost

The exact economics of implementing a new wastewater treatment system can be difficult to quantify. In addition to their large footprints, plants must consider all of the potential benefits and drawbacks of anaerobic digester systems compared to the current treatment method. Industrial sites may prefer to avoid the capital investment required to install a digester, and instead continue to incur costs for solids disposal/treatment and wastewater treatment surcharges/operating expenses as budgeted operating costs. A five year payback period may also be too long for an industrial plant to deem attractive. There are many cost and revenue streams that could be affected by changing the wastewater treatment system, and each industrial site should thoroughly evaluate the site-specific economics before making a decision to install an anaerobic digestion system.

Summary: ADG Potential from All WWTPs

The economic potential for the industrial utilization of anaerobic digester gas can be difficult to pinpoint, due to a number of factors. The proximity of industrial facilities to municipal plants determines the economic feasibility of pipeline development, but the distances to nearby industrial facilities, and their potential willingness to participate in an ADG utilization project are unknown quantities. For industrial treatment plants, it is uncertain which facilities contain anaerobic digesters, how they are currently utilizing the ADG that is produced, and how many sites without digesters would be capable or willing to switch to anaerobic digestion. For these reasons, the economic potential can be hard to quantify, and the best estimate is likely about 14.8 million MMBtu/year. This number is a combination of the estimated economic potential for industrial wastewater treatment plants (11.2 million MMBtu/year) and municipal WWTPs 5-15 MGD in size (3.6 million MMBtu/year).

Figure 6-4 illustrates where the most potential is found for ADG utilization at industrial WWTPs, by mapping the estimated economic potential for each state. A comparison with state industrial natural gas consumption levels confirmed that each state has sufficient industrial natural gas use for ADG to replace NG.

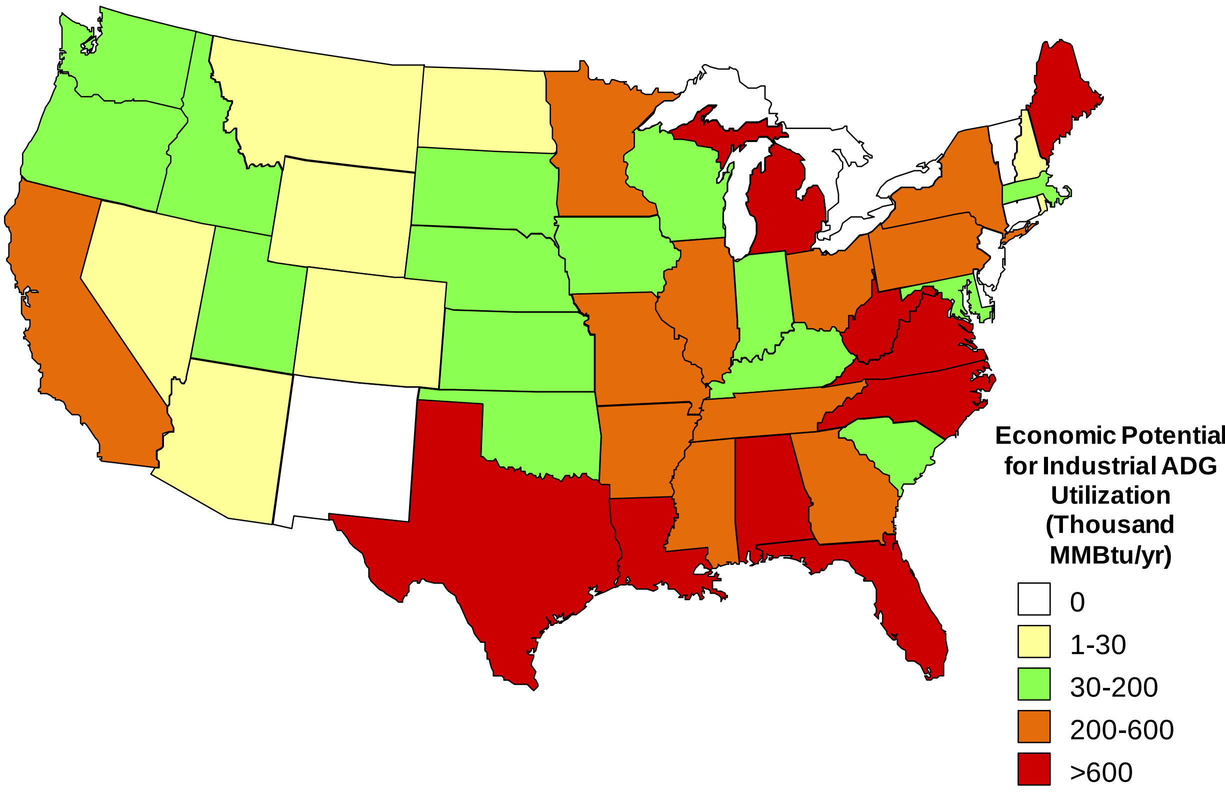

Figure 6-4. Map of Economic Potential for ADG Utilization from All WWTPs

Landfill Gas

In the economic analysis, treating and transporting landfill gas is compared to the cost of an equivalent amount of natural gas for different-sized landfills in each state. The average size of landfills is much larger than wastewater treatment plants in terms of the amount of gas produced, and there is little demand for heat and power at landfill sites, so it is conceivable that a pipeline from a single landfill could replace over 500 million standard cubic feet per year in natural gas purchases. To date, most direct-use projects have involved pipelines under 30 miles. For pipelines with high levels of gas production (in the range of 500 million scf/year), however, economics suggest that pipelines close to 100 miles long could be feasible in some areas of the country. Practical considerations, however, such as rights of way, could impede lengthy pipeline projects.

The pipeline is often the predominant cost hurdle for potential industrial LFG utilization projects. Pipelines for landfill gas typically cost about $330,000 per mile to install, so estimated costs for a 5-mile pipeline to an industrial facility would be over $1.5 million. Pretreatment equipment for LFG is also required in order to utilize the gas, costing an estimated $960 per cubic foot per minute, plus $90 per cubic foot per minute each year for maintenance.[11] Some landfills may require additional wells to be drilled to facilitate gas collection, but all large landfills are required to collect and flare (or utilize) their gas, so most candidate landfills already have a sufficient number of wells in place.

The results of the economic analysis for landfill gas in industrial applications are provided in Table 6-5. As with anaerobic digester gas, the maximum pipeline distance is calculated for facilities to achieve a 5-year payback period on their investment. The purchase price for landfill gas is estimated at 50 percent of the 2010 NYMEX/Henry Hub natural gas price. Industrial natural gas use is high enough in every state to assume that there are a sufficient number of potential facilities for utilizing LFG within a reasonable distance to a given landfill. With longer maximum economical pipeline distances, the number of potential industrial facilities increases, along with the likelihood of industrial LFG utilization.

[11] United States Environmental Protection Agency. Landfill Methane Outreach Program. *LFG Energy Project Development Handbook.* 2010. http://www.epa.gov/lmop/publications-tools/handbook.html

Table 6-5. Economics for Industrial LFG Utilization

State	Potential Landfills	Avg Ind Natural Gas Price ($/1000 ft^3)	Industrial Natural Gas Use (ft^3x10^6)	Maximum Pipeline Distance for 5 year Payback: Replacing 25 million ft^3/yr	Replacing 100 million ft^3/yr	Replacing 500 million ft^3/yr
Massachusetts	23	$16.15	41,849	4.9	19.7	98.5
New Hampshire	20	$15.76	5,139	4.8	19.1	95.5
Maine	9	$12.65	25,344	3.6	14.4	72.0
Rhode Island	4	$12.52	6,775	3.5	14.2	71.0
Delaware	2	$12.30	18,216	3.5	13.9	69.3
Nevada	10	$11.28	11,402	3.1	12.3	61.6
Pennsylvania	36	$11.22	171,990	3.1	12.2	61.1
New York	58	$10.82	72,639	2.9	11.6	58.1
Maryland	33	$10.72	23,651	2.9	11.5	57.3
Ohio	44	$9.88	225,215	2.5	10.2	51.0
Michigan	10	$9.64	125,649	2.5	9.8	49.2
Missouri	93	$9.47	61,449	2.4	9.6	47.9
Oklahoma	20	$9.44	166,660	2.4	9.5	47.6
Montana	3	$9.06	25,894	2.2	9.0	44.8
New Jersey	7	$8.85	48,992	2.2	8.6	43.2
Florida	53	$8.83	65,776	2.2	8.6	43.0
Washington	46	$8.77	71,330	2.1	8.5	42.6
Arkansas	21	$8.48	77,553	2.0	8.1	40.4
Connecticut	20	$8.44	24,585	2.0	8.0	40.1
North Carolina	110	$8.30	82,181	2.0	7.8	39.0
Oregon	6	$8.18	57,318	1.9	7.6	38.1
Arizona	25	$8.16	17,809	1.9	7.6	37.9
Wisconsin	33	$7.78	118,581	1.8	7.0	35.1
Tennessee	123	$7.59	84,345	1.7	6.7	33.6
Colorado	28	$7.40	113,921	1.6	6.4	32.2
Illinois	51	$7.29	233,859	1.6	6.3	31.4
Georgia	60	$7.27	138,035	1.6	6.2	31.2
Vermont	5	$7.03	2,894	1.5	5.9	29.4
Idaho	28	$7.00	24,207	1.5	5.8	29.2
Virginia	41	$6.83	62,642	1.4	5.6	27.9
California	239	$6.54	745,745	1.3	5.1	25.7
South Carolina	37	$6.48	64,130	1.3	5.0	25.2

While smaller landfills are limited to relatively short (< 3 mile) pipelines, larger landfills can be more flexible, and pipelines over 5 miles could prove economical for many industrial facilities. In most states, landfills that are capable of replacing over 100 million ft^3 of natural gas each year will provide enough economic flexibility to pipe LFG to nearby industrial facilities, with some states allowing longer pipeline lengths than others. The likelihood of locating a large industrial facility to utilize landfill gas increases greatly with longer economical pipeline distances.

Out of over 1,800 landfills listed as “Candidate” or “Potential” in EPA’s 2010 LMOP database, 320 sites in the continental U.S. are estimated to produce enough LFG to replace more than 100 million standard cubic feet of natural gas on an annual basis. This considers all current LFG energy projects, with the available gas representing the estimated amount not currently being utilized. For all of the 32 states listed in Table 6-5, pipeline distances of 5 miles or greater would be possible for landfills of this size. However, states with lower natural gas prices require larger landfills to support 5-mile pipelines. A sliding scale was created to determine the landfill size at which 5-mile pipelines can achieve a 5-year payback period in each state. At the top of this scale is Massachusetts, capable of supporting 5-mile pipelines when replacing only 25 million ft^3 of natural gas with LFG. States like Kansas and Louisiana are at the bottom of the scale, requiring landfills to replace about 300 million ft3 of natural gas in order to support a 5-mile pipeline. Landfills above the sizes determined by the sliding scale (those capable of generating a 5-year payback with a 5-mile pipeline) were considered to have economic potential in the analysis.

The economic potential for LFG is estimated at 157 million MMBtu per year from 466 sites, assuming all available LFG is utilized from candidate and potential landfills capable of supporting 5-mile pipelines. This potential is much higher than what was estimated for ADG, as there are a number of very large landfills with the potential to provide vast amounts of energy to industrial sites. Finding nearby industrial facilities that are willing to undertake LFG projects or purchase LFG supply over a long term, however, can be challenging.

Figure 6-5 maps the states with the most economic potential for industrial LFG utilization.

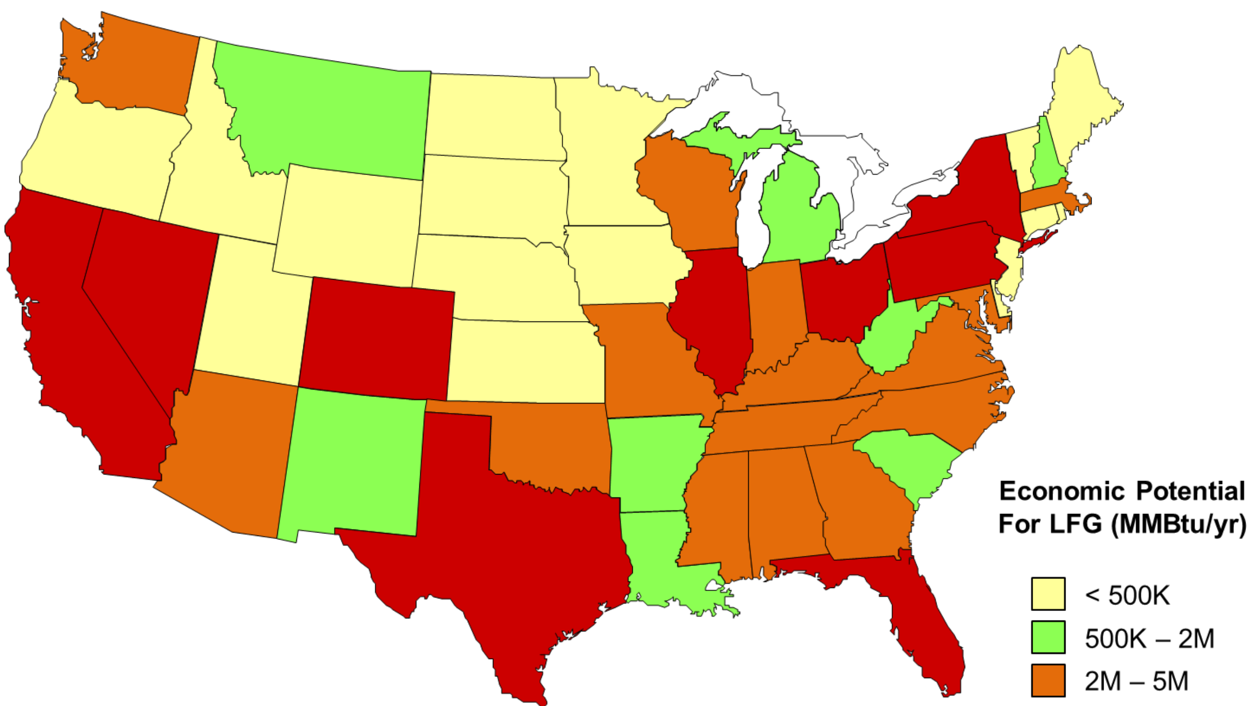

Figure 6-5. Economic Potential for Industrial LFG Utilization by State

The states with the most economic potential are California, New York, Texas, Illinois, Ohio, Florida and Georgia, all of which have relatively strong industrial markets with heavy natural gas use. Of these states, New York, Ohio and Florida appear to have the best project economics, primarily due to high natural gas prices. Texas has the least promising project economics with its low natural gas prices, but its potential is still high because it contains a higher number of large landfills than most states. The potential for the top states is summarized in Table 6-6.

Table 6-6. Top States with Economic Potential for Industrial LFG Utilization

State	Landfills with Economic Potential	Total Potential (MMBtu/yr)
California	38	20,485,769
New York	47	14,367,076
Texas	23	13,801,858
Ohio	28	11,020,338
Florida	22	8,891,289
Illinois	18	8,627,911
Colorado	13	6,675,290
Pennsylvania	29	6,204,373
Nevada	8	5,868,508
Alabama	12	4,798,448
Georgia	15	4,702,479
North Carolina	21	4,130,737
Indiana	14	4,010,085
Mississippi	9	3,769,584
Kentucky	9	3,480,760
Oklahoma	12	3,369,866
Arizona	9	3,307,622
Missouri	12	3,240,020
Virginia	6	2,952,916
Tennessee	9	2,496,014
Rest of U.S.	112	20,929,837
Total	**466**	**157,130,781**

In most cases, the primary competitor to industrial LFG utilization is electricity generation, where third parties install distributed generation (DG) systems at landfills and sell electricity to the local utility or wholesale power market[12]. The economics for these electricity generators are generally only favorable for very large landfills in areas with relatively high electricity wholesale prices. An analysis was conducted, assuming a third party purchases the LFG for $2/MMBtu (less than half of the 2010 NYMEX/Henry Hub price), produces electricity with a reciprocating engine and sells it at a wholesale price of 5 or 6 cents per kWh, including renewable energy credit (REC) revenue. In all situations, including large landfills capable of replacing 500 million ft^3/year of NG, payback periods below five years cannot be achieved

[12] Another less common alternative, cleaning the LFG to provide a substitute for wholesale natural gas, is not evaluated in this report.

through LFG electricity sales.[13] Figure 6-6 charts the estimated payback periods as they correlate with landfill size and wholesale electricity prices.

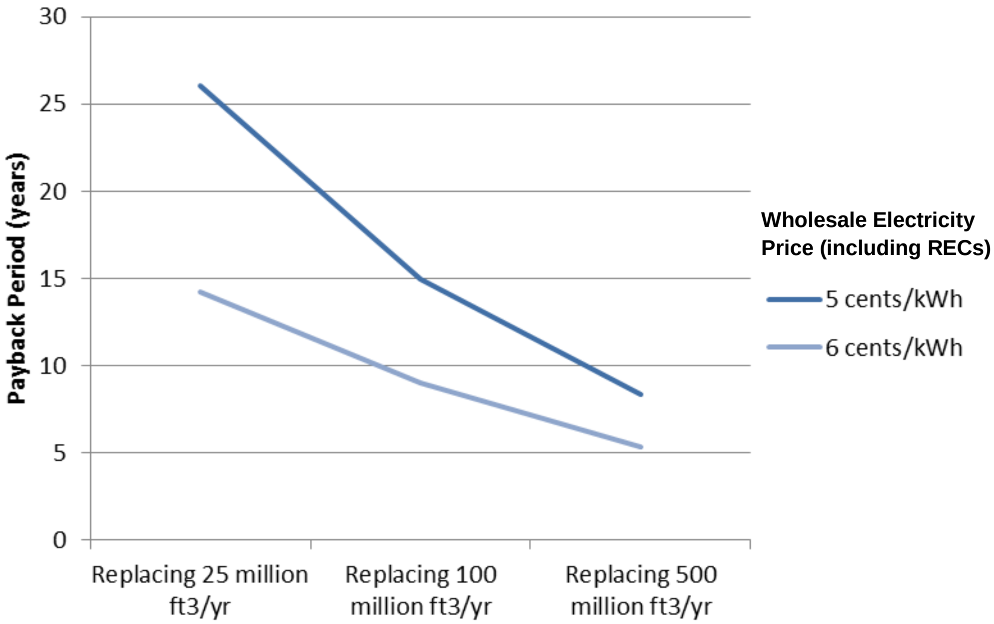

Figure 6-6. Estimated Payback Periods for LFG Electricity Sales

The average wholesale price for New England and PJM power pools was about 5 cents/kWh for 2009, and an additional 1 cent/kWh is assumed for states that offer a market for renewable energy credits. Even in this high electricity price scenario, estimated payback periods for industrial utilization projects with 5-10 mile pipelines are almost always favorable to payback periods for electricity generation. For most of the country, wholesale electricity costs tend to range from 3-4 cents/kWh, so electricity sales alone do not provide enough revenue to offset the required generation equipment. In conclusion, a third party who wishes to construct a pipeline to a nearby industrial site for LFG sales can make a positive return on their investment faster than third parties who install DG equipment for electricity generation. The end-use of the gas should make no difference to landfill operators, who presumably would sell their LFG at the same rate for either type of beneficial project. Based on this LFG electricity generation analysis, the previously estimated economic potential of 157 million MMBtu/year remains for industrial LFG applications.

Industrial Waste Gases

The economic viability of industrial waste gases can be difficult to ascertain for a number of reasons. The majority of blast furnace gas, coke oven gas, and refinery fuel gas is utilized by the sites at which they are produced, with the remainder typically flared. Blast furnace gas, which has a low heating value of about 150 MMBtu/ft^3, is best utilized when it is still hot, to take advantage of its thermal energy, and it is

[13] Figures used in DG analysis: $2,500/kW, $0.018/kWh for small landfill DG (~250 kW); $1,800/kW, $0.015/kWh for large landfill DG (~1 MW); $1,200/kW, $0.012/kWh for very large landfill DG (~5 MW)

typically utilized to its fullest extent, leaving little room for additional industrial usage. Coke oven gas is a medium-Btu fuel, and byproduct coke plants are typically used to quench the gas and extract useful byproducts, leaving a potentially useful fuel. While integrated steel mills tend to utilize all of their coke oven gas on-site, merchant coke plants may not have much use for the fuel outside of heating the coke oven. Refinery fuel gas, or still gas, is produced at oil refineries, and performs similarly to natural gas when contaminants have been removed. For industrial utilization projects, coke oven gas or refinery fuel gas could be transported via pipeline for use in boilers or process heating applications, which can often incorporate the fuels into natural gas blends with no required equipment modifications.

The majority of coke oven gas available for industrial utilization is likely to be located at merchant coke plants, since integrated steel mills like Mon Valley Works use the vast majority of their coke oven gas on-site. There are 11 merchant coke plants in the United States, so assuming the estimated 19 million MMBtu of technical potential (calculated in Chapter 4) is split among these plants, they should each average about 1.7 million MMBtu/year. With the limited number of merchant coke plants, there are few opportunities for industrial projects, but there is potential for large-scale utilization at individual sites located close to merchant coke plants. Assuming each plant is the average size (producing 1.7 million MMBtu/year), they should all be able to support pipeline distances of 5-20 miles according to the economic analysis. The exact levels of coke oven gas production and utilization at these plants are unknown, so they would need to be examined on a case-by-case basis.

With refinery fuel gas, there are over 100 oil refineries in the country, with an estimated technical potential of 52 million MMBtu/year (see Chapter 4), so there are more opportunities for industrial utilization. However, there are several aspects of still gas production that can pose difficulties for potential projects. Refineries utilize their still gas to the fullest extent possible for on-site operations, while excess gas is typically flared. The excess gas is produced sporadically, mostly from upsets like power outages or equipment malfunction, but some may be due to surplus supply. In order for an industrial site to effectively utilize gas from upsets, it must be compressed and stored in a gas storage vessel where it can be released to the pipeline at a more constant rate. Additionally, the refinery's gas collection and transportation system would need to be reconfigured to route excess still gas to compression and storage as opposed to the flare. Both of these factors were taken into account for the economic analysis, which estimates the maximum pipeline distance for still gas to compete economically with natural gas at industrial sites.

The Flare Minimization Plan for the Shell Martinez Refinery in Martinez, California provided data on 2010 flare events for the facility. Based on the size and frequency of these events, requirements for natural gas storage capacity using the flared gas were estimated. Overall, there were 11 small flare events and 2 larger flare events at the Shell facility in 2010, totaling roughly 800,000 standard cubic feet of flared gas.[14] Based on the magnitudes of the largest events, it was estimated that a 125,000 scf storage vessel would be sufficient to capture all of the 2010 gas and maintain a relatively steady flow throughout the year. A 400,000 scf storage tank, including compressors, costs $10 million to install[15], so adequate

[14] Shell Martinez Refinery Regulation 12 Rule 12 Flare Minimization Plan (Redacted Version). Updated October 1, 2010. Submitted to Bay Area Air Quality Management District.
[15] Ibid.

storage for 125,000 scf would be estimated to cost about $3.1 million. This cost and fuel storage capacity was extrapolated to other refineries based on oil processing capacity, and the resulting costs were incorporated into the economic analysis.

For the analysis, the estimated sale price for the gas is assumed to be the same as ADG and LFG, at 50 percent of the NYMEX/Henry Hub natural gas price. Storage tank costs are estimated using the figures in the previous paragraph, and pipeline costs are estimated at $330,000 per mile. Unfortunately, the high cost of gas storage hinders project economics so much that larger refineries (requiring more gas storage) fare worse than smaller refineries, and no facilities were able to achieve a positive return on their investment. Even if no pipeline is required, the gas storage costs are simply too high for industrial sites to recoup.

There is no economic potential shown here for excess refinery fuel gas, but there could be potential for coke oven gas utilization from merchant coke plants (an estimated 19 million MMBtu/year, or 1.7 million MMBtu at each site). If each site contains the average amount of coke oven gas, the economic analysis shows that pipeline distances of ten miles or more could generally be supported. The locations of merchant coke plants are provided in Figure 6-7.

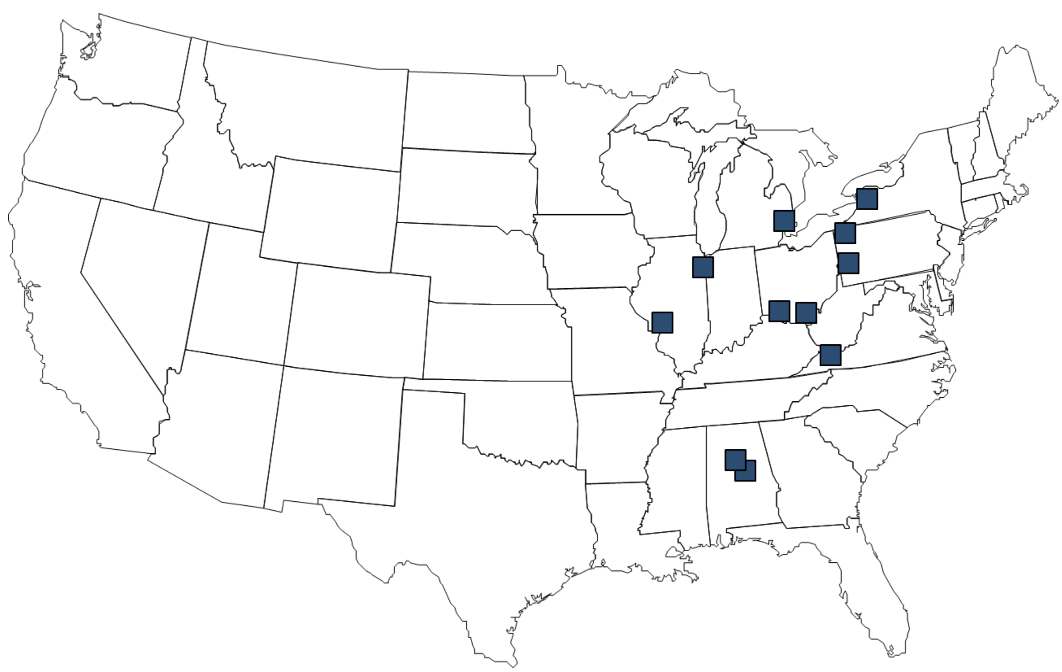

Figure 6-7. Merchant Coke Plant Locations (19 Million MMBtu/year of Economic Potential)

It is recommended that industrial facilities located close to merchant coke plants pursue the availability of coke oven gas. Prospective gas purchasers should then explore requirements to clean up and pipe the gas to their facility for utilization. The data for gas cleanup costs for these types of waste gases is not as prevalent as it is for ADG/LFG, as there have not been nearly as many projects implemented, with most occurring internally at refineries and steel mills. More detailed economic studies for individual cases, examining specific gas cleanup requirements, will determine if the projects are feasible.

Gaseous Opportunity Fuels: Summary

The economic analyses of the gaseous opportunity fuels showed that there is great potential for waste gases to replace natural gas at numerous industrial facilities throughout the country. The economic potential for all gaseous opportunity fuels totals 191 million MMBtu/year. By comparison, there is an estimated 6.7 *billion* MMBtu/year of industrial natural gas use in the United States[16], so the economic potential for gaseous opportunity fuels represents about 4 percent of the total industrial natural gas market. This is based on 2010 natural gas pricing, and lower prevailing natural gas prices would somewhat reduce this potential. There could be some unexpected difficulties involving gas cleanup requirements, emission control and permitting requirements, and right-of-way for pipeline construction, and these factors make it a very site-specific process to determine if it makes economic sense. The industrial site needs to be:

- Located near a facility with gaseous fuel available
- Close enough to justify pipeline construction costs (improved prospects where the site is located far from a natural gas pipeline where the gas could otherwise be sold wholesale)
- Clean enough to not require any pretreatment or at worst minimal treatment such as water and particulate removal, otherwise CHP may be more economic
- Steady enough supply to provide a regular source of fuel and not require extensive gas storage capacity

As long as gaseous opportunity fuel sources offer these attributes, the estimated economic potential should be achievable. Incorporating these waste gases into natural gas-fueled industrial operations will improve the fuel flexibility and energy security of the industrial facilities, and potentially reduce energy costs as well. While the potential for opportunity fuels is very small in comparison to current industrial natural gas use (see Figure 6-8), there are a large number of potential sites that could benefit from gaseous opportunity fuel utilization.

[16] United States Energy Information Administration. Natural Gas Consumption by End Use, 2010.

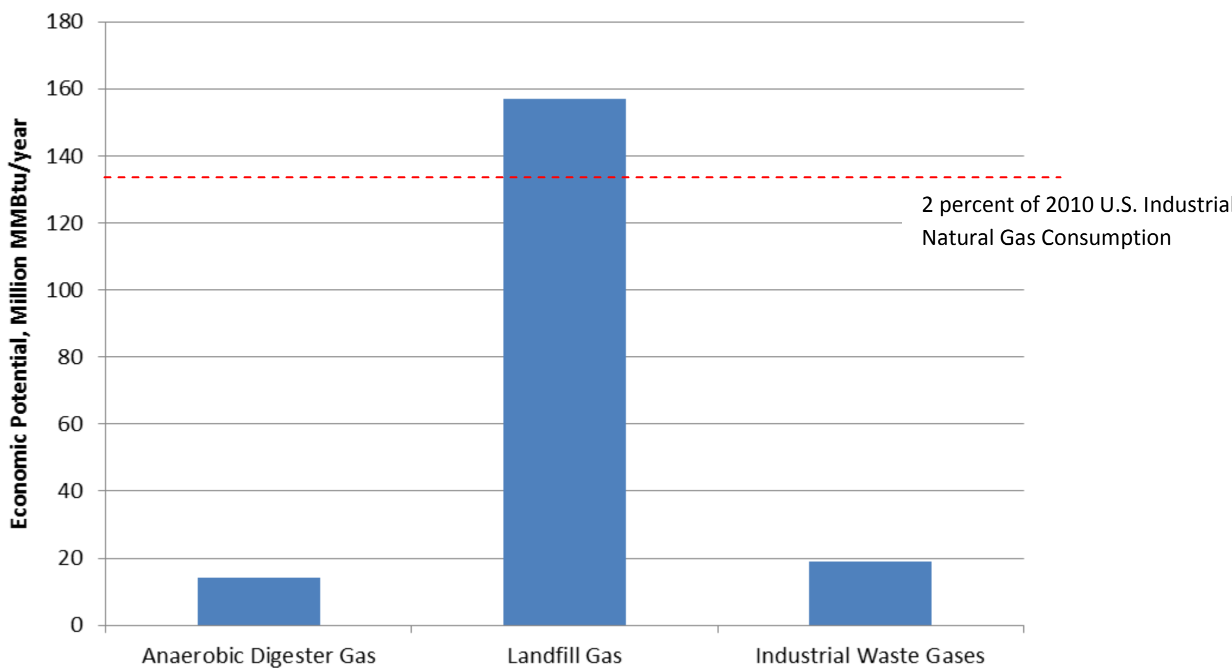

Figure 6-8. Economic Potential for Gaseous Opportunity Fuels Compared to Current Industrial Natural Gas Use (EIA)

Solid Opportunity Fuels

The economics of solid opportunity fuels for industrial applications is largely tied to the price of coal. Coal is the most common solid fuel used for industrial steam generation, so in most cases, opportunity fuels must be competitive with coal on a $/Btu basis in order to be considered as a replacement. While coal is widely available in the United States, its cost varies greatly according to regional supply and local transportation options. The 2009 average state prices for coal used at industrial sites, according to EIA data, are mapped in Figure 6-9. States with high industrial coal prices should be prime candidates for solid opportunity fuel projects, provided there are ample and affordable opportunity fuel resources.

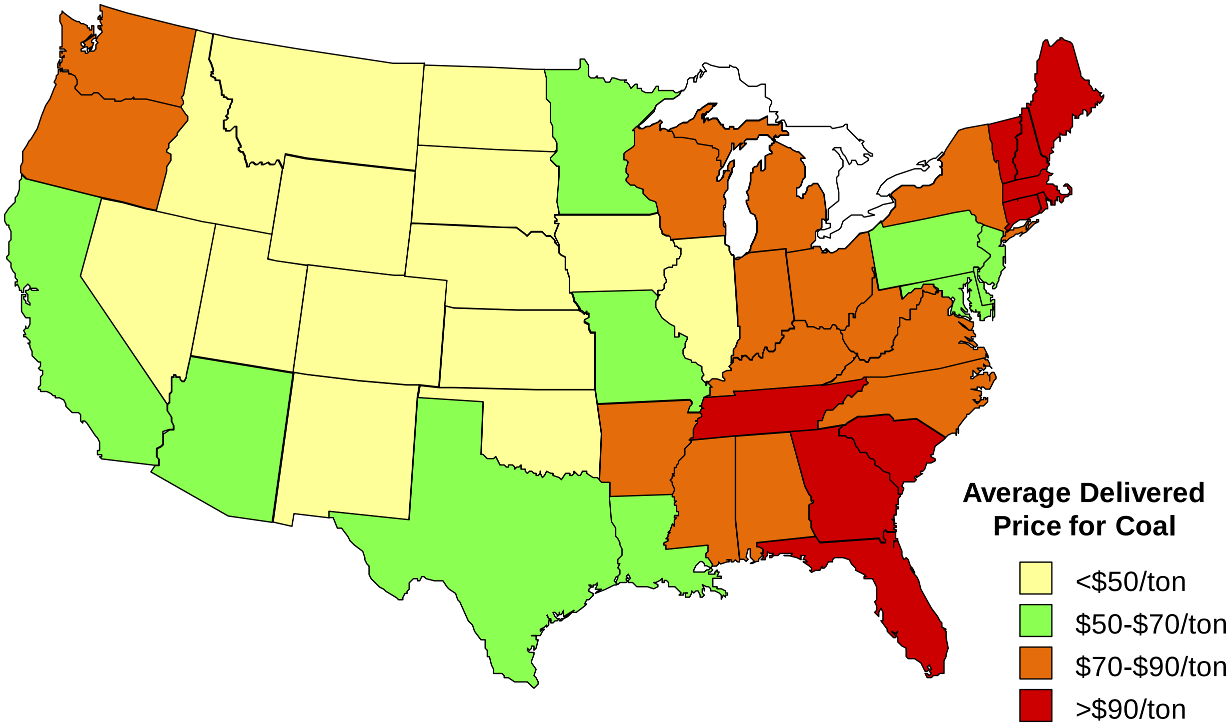

Figure 6-9. 2009 State Average Prices for Industrial Coal
(Source: EIA)

As can be seen in the map, the price of coal is highly regional. The areas with the highest industrial coal prices are New England and the Southeast. However, New England states lack coal-fueled industrial facilities that could potentially utilize solid opportunity fuels, so the Southeast states likely have much more economic potential. The Great Plains and Mountain states have the lowest industrial coal prices, with a low demand for industrial coal and ample supply from states like Wyoming playing major factors. States like Ohio and Indiana, which are located close to large coal mines, still have relatively high prices due to heavy utility and industrial coal demand. Areas such as these, with high coal prices as well as numerous coal-fueled industrial sites, will likely have the most potential for industrial opportunity fuel applications. In this section, these issues are explored for each fuel, and estimates are made for each solid opportunity fuel's economic potential.

Biomass Fuels

Although biomass fuels are widely available with the highest technical potential of all opportunity fuels, the cost to procure most biomass fuels tends to be prohibitive. For crop residues and forest residues, the fuel types with the most available resources, the cost of collecting and processing are highly variable. As a result, the initial cost of the fuels can range from $20/ton to over $60/ton on a dry basis, with most falling somewhere in the middle. Urban wood waste and mill residues do not require as much labor to collect, so they can typically be obtained for $20 per dry ton or less.

According to REPP-CREST, urban wood waste and mill residues cost approximately $1 per MMBTU, or about $15 per dry ton, to obtain.[17] These figures apply to all U.S. locations, as the cost of collecting the waste fuels is roughly the same at each site. Because of more labor-intensive collection requirements, crop residues and forest residues tend to cost more, averaging between $30 and $45 per dry ton at the source. Transportation costs for solid fuels, previously estimated at 20 cents per ton-mile via truck (or $10 to haul a ton of fuel 50 miles), have risen considerably in recent years, due to inflation and increasing fuel prices. In 2001, the Bureau of Transportation Statistics calculated an average transportation cost of 26.6 cents per ton-mile, which translates to about 33 cents per ton-mile in 2011 dollars.[18] However, transportation costs have risen considerably during that time for trucks using diesel fuel. A conservative estimate for current truck-based transportation would be 40 cents per ton-mile, or $20 to haul a ton of fuel 50 miles.

Biomass is more costly to transport than coal on an energy basis, as coal has a heating value of about 13,000 Btu/lb, while biomass ranges from 4,000-8,000 Btu/lb, depending on fuel type and moisture content.[19] The cost difference between coal and locally available biomass fuels is the key economic driver[20] for potential biomass utilization projects. Urban wood waste and mill residues have a cost advantage over crop and forest residues, and industrial sites are expected to seek out the lowest cost fuel sources. In areas where coal can be obtained at a lower price than most biomass fuels, it becomes economically unattractive for industrial plants to convert to biomass, unless driven by other concerns such as sustainability.

In order to determine which states have the best markets for biomass fuels, several sources of data were considered, including the estimated available biomass resources, the current level of industrial coal use, the average delivered cost of coal, and the variable cost to obtain biomass fuels. The estimated quantities of biomass resources, from NREL's 2005 report on biomass availability, are used as an upper limit for each state's potential, along with the current level of industrial coal use, assuming that all potential biomass projects would be replacing or supplementing coal. The average cost of delivered coal in each state was used to determine the maximum cost that industrial plant owners would pay for biomass fuels on a Btu-basis. Three different price points for biomass fuels were considered: $15, $30, and $45 per dry ton, not including transportation costs. The state average delivered coal prices were used to determine how far biomass could be transported for $0.40/ton-mile at these different price points while remaining competitive with coal.

At an initial cost of $15/dry ton (for urban wood waste and mill residues), 29 continental states offer industrial sites the opportunity to transport biomass from a radius of 50 miles or greater. Four of these

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[17] *Costs of Bioenergy*. Renewable Energy Policy Project & Center for Renewable Energy and Sustainable Technology. http://www.repp.org/bioenergy/link5.htm. May 2011.

[18] Average Frieght Revenue per Ton-Mile. Research and Innovative Technology Administration, Bureau of Transportation Statistics. http://www.bts.gov/publications/national_transportation_statistics/2004/html/table_03_17.html

[19] The biomass fuels analyzed in this project are assumed to be fully dried to 7,000 Btu/lb for herbaceous biomass, or 8,000 Btu/lb for woody biomass.

[20] Reduction in greenhouse gas emissions or "going green" are other compelling reasons to switch to biomass, as it is currently considered to be carbon neutral.

states, all located in the Southeast (Florida, Georgia, South Carolina and Tennessee) allow industrial sites to transport biomass from 100 miles or further while remaining less expensive than the average industrial coal price. Conversely, four other states (Kansas, North Dakota, South Dakota and Wyoming) have such low industrial coal prices that biomass is only cost-competitive when transportation is limited to less than 10 miles. The states with the best project economics have the highest industrial coal prices (see Figure 6-8 at the beginning of the Solid Opportunity Fuels section).

At $30/dry ton, a low price point for other types of biomass fuels, 12 states (all located in the Southeast and New England) could offer industrial sites the ability to transport biomass from distances of 50-100 miles. Transportation distances of 25-50 miles could be supported by industrial facilities in 14 different states, while 16 states are unable to support 10-mile distances. At $45/dry ton, a high price point for biomass fuels, no states are able to support transportation distances of 50 miles, with only four (Florida, Georgia, South Carolina and Tennessee) allowing transportation distances greater than 25 miles for industrial sites. With the high biomass price point, the vast majority of states cannot support 10-mile transportation distances. Table 6-7 summarizes this information.

Table 6-7. States With Most Economic Potential for Industrial Biomass Utilization

			Maximum Economic Transportation Distance		
State	**Total Biomass Resources (MMBtu)**	**Industrial Coal Use (MMBtu)***	**$15/Dry ton Biomass**	**$30/Dry ton Biomass**	**$45/Dry ton Biomass**
Tennessee	**54,930,000**	76,388,000	>100 miles	70 miles	25 miles
Virginia	57,690,000	**51,766,000**	90 miles	50 miles	15 miles
Ohio	108,165,000	**47,580,000**	80 miles	40 miles	n/a
Alabama	52,440,000	**44,798,000**	80 miles	40 miles	n/a
Wisconsin	106,155,000	**43,732,000**	70 miles	35 miles	n/a
Michigan	92,760,000	**43,160,000**	85 miles	50 miles	10 miles
Georgia	84,600,000	**37,466,000**	>100 miles	80 miles	45 miles
Kentucky	65,400,000	**32,474,000**	80 miles	45 miles	n/a
South Carolina	38,670,000	**29,874,000**	>100 miles	65 miles	25 miles
Florida	102,795,000	**27,898,000**	>100 miles	70 miles	25 miles
North Carolina	81,765,000	**27,716,000**	90 miles	50 miles	15 miles
Mississippi	96,525,000	**26,000,000**	80 miles	40 miles	n/a
New York	57,030,000	**24,258,000**	85 miles	45 miles	5 miles
West Virginia	25,380,000	**24,258,000**	85 miles	45 miles	10 miles
Arkansas	120,270,000	**10,088,000**	85 miles	45 miles	8 miles

*EIA data, 2009

The lesser of the total biomass reserves and the industrial coal use figure for each state determines the maximum economic potential (indicated by the bold numbers in Table 6-7). For most states, industrial coal use is the limiting factor, and for cofiring applications, potential biomass utilization is limited to about 20 percent of the industrial coal use. The cost to obtain processed biomass and the required transportation distances, measured against any equipment modifications required to convert from coal to biomass, will determine the actual economic potential.

For industrial sites that wish to replace coal equipment with biomass equipment, a large amount of biomass resources would be required to sustain operation, and these resources are likely to be scattered at various distances (with varying collection and transportation costs). It would be more feasible for most industrial sites to introduce biomass in cofiring applications, where up to twenty percent of coal is replaced with biomass. With a smaller demand for biomass resources, those that are less expensive and closer to the facility can be used preferentially, without the need to seek out more distant (and expensive) biomass fuel sources.

To illustrate which states have the best economics for industrial biomass utilization in traditional coal boiler applications, Figure 6-10 maps the states in terms of maximum transportation distance for biomass at $30/dry ton. At the maximum distance, the cost of biomass is estimated to be equal to the average cost of delivered coal for industrial facilities in the state.

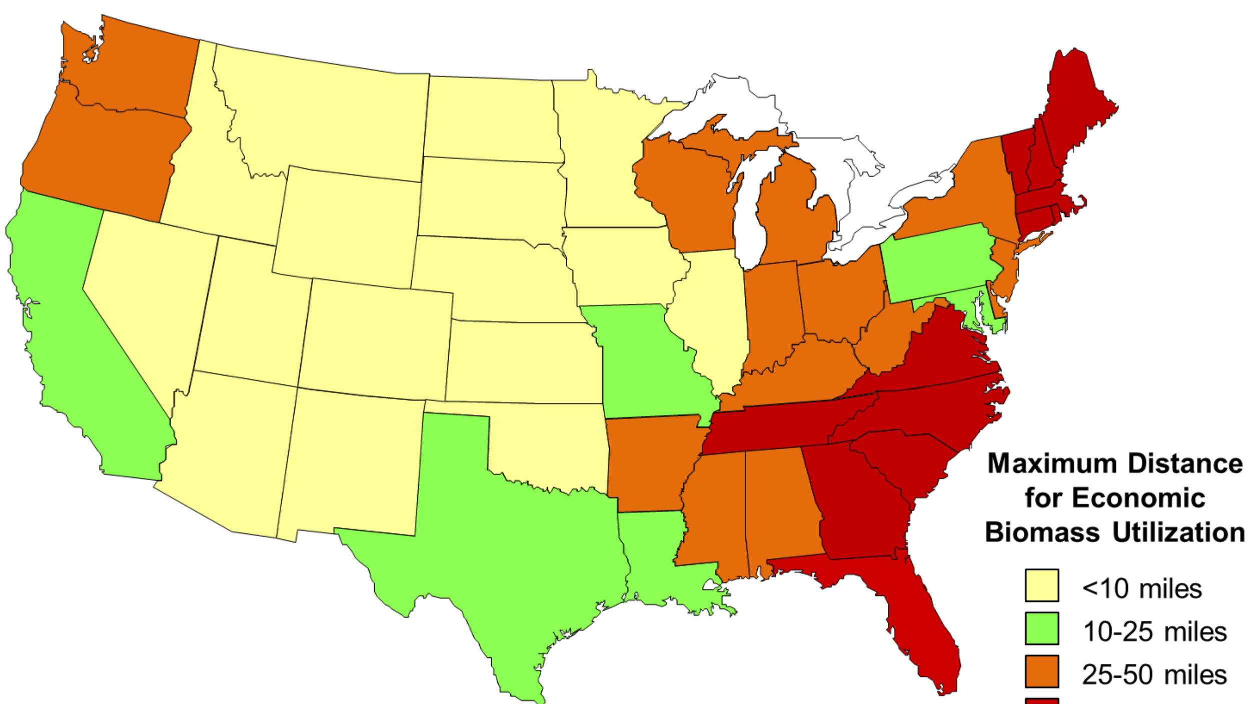

Figure 6-10. Maximum Transportation Distance for Economic Biomass Utilization by State (Assuming $30/ton Biomass)

Many states in the Midwest, Great Plains, and Mountain regions of the country are only able to support biomass transportation distances of less than 10 miles. Industrial sites located in these states are unlikely to find sufficient biomass resources close enough to economically replace a significant portion of their traditional boiler fuel. However, the potential for industrial biomass utilization is promising for states that can support transportation distances of 25 miles or more. According to county-level biomass availability data, hundreds of individual counties throughout the country are capable of supplying over 100,000 dry tonnes of crop residues on an annual basis.[21] This amount of biomass translates to over 1.5 million MMBtu/year, which is enough to meet the steam generation requirements of most large industrial facilities. Forest residues are one potential source of biomass fuels, and many counties in the South, Pacific Northwest, and other forest-rich areas are estimated to contain over 100,000 dry tonnes of forest residue resources alone.[22] An industrial site requiring 1 million MMBtu/year located in any of these counties should be able to economically collect and transport enough biomass to replace all of their traditional boiler fuel. Maps of United States counties with estimated biomass production are provided in Appendix A of this report.

The states with the best economics for using biomass to replace coal in industrial applications are concentrated in the eastern half of the country, in areas where coal prices are the highest. Florida, Georgia, South Carolina and Tennessee are the states with the most favorable economics for industrial biomass utilization. New England also has very favorable economics due to high coal prices. Biomass resources are plentiful in the New England states, but industrial coal use is minimal, so the economic potential would be extremely low in comparison to the Southern states. According to EIA data, Florida, Georgia, South Carolina and Tennessee combine for about 150 million MMBtu/year of industrial coal use, while the entire New England region only uses about 5 million MMBtu/year. Compared to the high availability of woody biomass in New England, the potential for industrial utilization through replacing coal is minimal.

The National Energy Renewable Laboratory produced a 2005 report on biomass availability, with estimated quantities of available urban wood waste, mill residues, crop residues, and forest residues.[23] With urban wood waste and mill residue resources costing an average of $15/ton to obtain, the economic potential for these fuels can be calculated separately for cofiring applications, using state availability statistics and 20 percent of current industrial coal use as limiting factors. The other biomass resources (crop and forest residues) are likely to cost $30-$45/ton, and their potential can be analyzed in the same way, assuming that the less expensive resources are preferentially used by industrial facilities.

Based on these assumptions, the economic potential for biomass at $15 and $30 per ton is estimated for each state, with the results provided in Table 6-8. In some cases, a state's industrial coal usage provides a limit on the economic potential of $30/ton biomass, because biomass at $15/ton is used preferentially. When this was the case, the potential at $30/ton is presented in gray italic numbers (most often zero when the potential has already been fully realized by the less expensive biomass fuels).

[21] *A Geographic Perspective on the Current Biomass Resource Availability in the United States*. Technical Report. Milbrandt, A. National Renewable Energy Laboratory. December 2005.
[22] Ibid.
[23] Ibid.

Table 6-8. Economic Potential for Industrial Biomass Cofiring Applications, By State

State	Industrial Coal Use (MMBtu/year)	Max Biomass Use for 20% Cofiring (MMBtu/year)	$15/Ton Biomass: Biomass Available (1,000 dry tons)	$15/Ton Biomass: >25 Mile Transportation Distance?	$15/Ton Biomass: Estimated Cofiring Potential (MMBtu/year)	$30/Ton Biomass: Biomass Available (1,000 dry tons)	$30/Ton Biomass: >25 Mile Transportation Distance?	$30/Ton Biomass: Remaining Cofiring Potential (MMBtu/year)
Alabama	44,798,000	8,959,600	550	Yes	8,250,000	2,946	Yes	709,600
Alaska	2,054,000	410,800	198	Yes	410,800	738	Yes	0
Arizona	16,328,000	3,265,600	567	Yes	3,265,600	410	No	0
Arkansas	10,088,000	2,017,600	348	Yes	2,017,600	7,670	Yes	0
California	43,888,000	8,777,600	4,156	Yes	8,777,600	2,962	No	0
Colorado	3,900,000	780,000	579	No	0	1,620	No	0
Connecticut	858,000	171,600	400	Yes	171,600	78	Yes	0
DC	2,600,000	520,000	56	Yes	520,000	0	Yes	0
Delaware	0	0	93	Yes	0	296	Yes	0
Florida	27,898,000	5,579,600	1,812	Yes	5,579,600	5,041	Yes	0
Georgia	37,466,000	7,493,200	1,087	Yes	7,493,200	4,553	Yes	0
Hawaii	2,054,000	410,800	143	Yes	410,800	396	Yes	0
Idaho	10,998,000	2,199,600	218	Yes	2,199,600	2,661	No	0
Illinois	93,964,000	18,792,800	1,447	No	0	20,257	No	0
Indiana	135,720,000	27,144,000	812	Yes	12,180,000	9,839	Yes	14,964,000
Iowa	75,478,000	15,095,600	351	Yes	5,265,000	23,949	No	0
Kansas	6,266,000	1,253,200	356	No	1,253,200	7,748	No	0
Kentucky	32,474,000	6,494,800	583	Yes	6,494,800	3,777	Yes	0
Louisiana	26,000,000	5,200,000	521	Yes	5,200,000	7,719	No	0
Maine	858,000	171,600	183	Yes	171,600	2,890	Yes	0
Maryland	30,524,000	6,104,800	657	Yes	6,104,800	847	No	0
Massachusetts	858,000	171,600	739	Yes	171,600	89	Yes	0
Michigan	43,160,000	8,632,000	1,323	Yes	8,632,000	4,861	Yes	0
Minnesota	35,334,000	7,066,800	620	Yes	7,066,800	16,473	No	0
Mississippi	26,000,000	5,200,000	419	Yes	5,200,000	6,016	Yes	0
Missouri	25,818,000	5,163,600	812	Yes	5,163,600	7,847	No	0
Montana	3,900,000	780,000	160	No	0	2,264	No	0
Nebraska	10,790,000	2,158,000	211	No	0	11,003	No	0
Nevada	3,900,000	780,000	249	No	0	9	No	0
New Hampshire	858,000	171,600	163	Yes	171,600	986	Yes	0
New Jersey	0	0	952	Yes	0	120	Yes	0
New Mexico	3,900,000	780,000	204	No	0	239	No	0
New York	24,258,000	4,851,600	2,184	Yes	4,851,600	1,618	Yes	0
North Carolina	27,716,000	5,543,200	962	Yes	5,543,200	4,489	Yes	0
North Dakota	84,396,000	16,879,200	74	No	0	6,629	No	0
Ohio	47,580,000	9,516,000	1,414	Yes	9,516,000	5,797	Yes	0
Oklahoma	18,538,000	3,707,600	400	Yes	3,707,600	2,296	No	0
Oregon	2,054,000	410,800	477	Yes	410,800	1,608	Yes	0
Pennsylvania	68,640,000	13,728,000	1,509	Yes	13,728,000	2,489	No	0
Rhode Island	858,000	171,600	115	Yes	171,600	8	Yes	0
South Carolina	29,874,000	5,974,800	514	Yes	5,974,800	2,064	Yes	0
South Dakota	84,396,000	16,879,200	87	No	0	5,265	No	0
Tennessee	76,388,000	15,277,600	842	Yes	12,630,000	2,820	Yes	2,647,600
Texas	46,930,000	9,386,000	2,463	Yes	9,386,000	8,149	No	0
Utah	22,672,000	4,534,400	266	Yes	3,990,000	118	No	0
Vermont	858,000	171,600	74	Yes	171,600	496	Yes	0
Virginia	51,766,000	10,353,200	941	Yes	10,353,200	2,905	Yes	0
Washington	2,054,000	410,800	766	Yes	410,800	2,780	Yes	0
West Virginia	24,258,000	4,851,600	313	Yes	4,695,000	1,379	Yes	156,600
Wisconsin	43,732,000	8,746,400	647	Yes	8,746,400	6,430	Yes	0
Wyoming	45,786,000	9,157,200	110	No	0	164	No	0
Total U.S.	**1,461,486,000**	**292,297,200**	**35,128**	**n/a**	**172,975,800**	**213,808**	**n/a**	**18,477,800**

Overall, there is an estimated 173 million MMBtu/year available for cofiring from biomass at $15/ton (urban wood waste and mill residues), which allows for over 50 miles of transportation in most states. With $30/ton biomass, while there are significantly more resources available, fewer sites can utilize these resources economically and some states do not have the industrial site capacity to support additional biomass cofiring after the $15/ton biomass has been used. Overall, there is a total estimated potential of 191 million MMBtu/year for industrial biomass cofiring applications. This corresponds to about 15 percent of total industrial coal consumption in 2010.[24]

These estimates were obtained based strictly on fuel price and transportation distances, assuming minimal capital expenditures are incurred when complimenting coal boilers with biomass fuels. While this may be true for most cofiring operations, switching from coal to 100 percent biomass fuels would require more boiler modifications, resulting in more substantial capital costs. These costs would vary from site to site, depending on the type of boiler and the nature of the biomass fuels.

For sites replacing aging coal boilers with new biomass boilers, the capital costs incurred are effectively the cost of a new biomass boiler system, although one must consider the preexisting need for upgrading or replacing the aging coal boiler. The costs of stoker and fluidized bed biomass boilers are outlined in the Department of Energy's Biomass CHP Catalog of Technologies, and presented in Table 6-9.

Table 6-9. Installed Costs for Biomass-Fueled Stokers and Fluidized Bed Boilers

	Biomass Fuel Feed (tons/day)		
Characteristics	**100**	**600**	**900**
Biomass heat input (MMBtu/hr)	35.4	297.5	446.3
Steam pressure (psig)	275	750	750
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Stoker boiler equipment cost	$1,195,000	$7,980,000	$10,790,000
Other equipment and installation	$795,000	$10,020,000	$12,460,000
Total Installed Boiler System Cost	$1,990,000	$18,000,000	$23,250,000
Total Installed Biomass Prep-Yard*	$2,640,000	$5,430,000	$7,110,000
Total Installed Steam Plant Cost	**$4,630,000**	**$23,430,000**	**$30,360,000**
Unit Cost ($/lb steam)	$232	$142	$121
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Fluidized bed boiler equipment cost	$6,175,000	$14,490,000	$19,790,000
Other equipment and installation	$795,000	$10,020,000	$12,460,000
Total Installed Boiler System Cost	$6,970,000	$24,510,000	$32,250,000
Total Installed Biomass Prep-Yard*	$2,640,000	$5,430,000	$7,110,000
Total Installed Steam Plant Cost	**$9,610,000**	**$29,940,000**	**$39,360,000**
Unit Cost ($/lb steam)	$480	$171	$151

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5
Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

Source: DOE Biomass CHP Catalog of Technologies

[24] United States Energy Information Administration. U.S. Coal Consumption by End-Use Sector, 2005-2011.

When the capital costs of a new boiler are factored in, the sources of biomass must be closer for the project economics to work in favor of the industrial sites. Essentially, this eliminates biomass sources in the range of $30-45/ton, except for special cases where minimal transportation is required. For $15/ton biomass, transportation distances of 50 miles or more could be possible for sites in some states, depending on the system size/type and the credit given for the aging coal boiler system. The potential for smaller boilers, which cost significantly more per energy unit than medium-to-large size boilers (as shown in Table 6-9), would be severely limited. Even with larger boilers, 5-year payback periods are hard to obtain when transportation distances greater than 50 miles are required. It appears that users of 100% biomass boilers generally need to be located at or near the source of the biomass fuels. This finding agrees with most current industrial biomass boiler installations, which are invariably located at facilities that produce large amounts of wood waste or other biomass byproducts. The desire to minimize their carbon footprint also factors into many of these decisions.

For industrial biomass applications, the most efficient way to economically haul biomass fuels in from various sources is to cofire biomass in an existing coal boiler. This avoids the capital costs associated with new biomass equipment, and allows biomass fuels to compete directly with coal for the lowest cost. This provides flexibility to industrial facilities who can revert to 100 percent coal operation if nearby biomass resources are not sustainable, or if transportation costs rise. For plants that wish to switch to a 100 percent biomass boiler, the source of biomass needs to be inexpensive and close, preferably produced on-site, for economics to be favorable. However, many of these industrial facilities are already utilizing their on-site waste products as boiler fuel, and this report is focused on new sources of biomass that can be purchased and utilized flexibly in various industrial applications. Overall, the economic potential for the industrial utilization of biomass fuels is estimated to be 176 million MMBtu/year, when limited to 20 percent cofiring applications.

Tire-Derived Fuel

The economic potential for tire-derived fuel depends on the availability of scrap tires, the locations of tire processing centers, and the distance to transport processed TDF to industrial facilities. Tire-derived fuel has a heating value roughly twice that of biomass fuels, so transporting an equivalent amount of TDF could provide twice as much energy. This significantly reduces the effect that transportation costs have on project economics, which is especially important considering the limited number of tire processing centers.

The availability of scrap tires varies from state to state, and depends not only on scrap tire production, but current markets for scrap tires. These markets primarily consist of TDF, ground rubber and civil engineering applications. In many states, nearly all scrap tires are either utilized or transported to states with stronger scrap tire markets. For these states, finding available tires for new TDF projects can be difficult. It is possible that industrial sites could outbid other scrap tire markets in these states, but ideal states for industrial TDF utilization would produce a surplus of scrap tires with relatively few end-use markets.

The Rubber Manufacturers Association has analyzed the scrap tire markets for the ten U.S. EPA Regions, providing data on annual generation and consumption and trends for state scrap tire markets, along with the estimated number of stockpiled tires in each region.[25] The results are summarized in Table 6-10, which shows the difference between scrap tires generated and scrap tires utilized or landfilled in each region, along with the number of stockpiled tires as of 2005. Although stockpile reduction efforts have decreased the total number of tires stockpiled in the U.S. from 186 million in 2005 to 114 million in 2009[26], the number of tires generated and utilized in each state is expected to remain similar to the 2005 statistics. This analysis is combined with industrial coal use data to determine the states with the most ideal conditions for new TDF utilization projects at industrial sites.

[25] *Scrap Tire Markets in the United States*. 2005 Edition. Rubber Manufacturers Association. November 2006.
[26] *U.S. Scrap Tire Management Summary, 2005-2009*. Rubber Manufacturers Association. October 2011.

Table 6-10. Regional Scrap Tire Market Data

EPA Region	Key States	Tires Generated - Tires Utilized/Landfilled (Millions of Scrap Tires, Annual)	Stockpiled Tires (Millions of Scrap Tires)	Notes
Region I	CT, MA	-7	22	New England's scrap tire markets are currently strong, pulling in tires from New York and New Jersey, so there is little room for new TDF development. Also, industrial coal use is limited.
Region II	NY, NJ	17	39	New York and New Jersey produce a surplus of scrap tires each year, sending a large amount to New England markets. Both states are good candidates for new TDF utilization projects
Region III	MD, PA, VA	11	14	Pennsylvania has the most room for TDF market growth, with Maryland and Virginia also showing decent potential. Low coal prices in Western Pennsylvania could undermine TDF's appeal.
Region IV	AL, NC, TN	-9	19	While this region currently utilizes or landfills all of its scrap tires, some of the tires in Alabama, North Carolina and Tennessee that are currently being landfilled could be used for TDFapplications.
Region V	IL, IN, MI	4	16	Producing a surplus of 4 million tires in 2005, Michigan and Indiana appear to be the most promising states for new TDF utilization in this region.
Region VI	AR, LA, TX	-7	26	The South-Central region utilizes significantly more tires than it generates, even though some tires are sent to Southeastern markets. These states are not good candidates for new TDF utilziation projects.
Region VII	IA, MO	3	2	With a surplus of about 3 million tires in 2005, there could be potential for new TDF utilization in this region, but the lack of industrial coal usage could limit potential aplications.
Region VIII	CO, UT	5	43	This region has few markets for scrap tires, because of transportation issues created by large expanses of land with low population densities.
Region IX	AZ, CA, NV	18	1	This region created the largest surplus of scrap tires as of 2005, and there are more tires currently being landfilled in California that could potentially be utilized for TDF. California in particular is one of the strongest state markets for new projects.
Region X	ID, OR, WA	9	2	Overall, this region produces significantly more tires than it utilizes, so there is room for growth in the industrial TDF market. Transportation distances between population centers can be a hindrance, however, along with a lack of industrial coal use.

Source: Rubber Manufacturers Association (2006)

The most promising areas for new industrial TDF utilization are the West Coast, the Southeast, and some states in the Midwest and Mid-Atlantic regions. All of these areas generally produce more scrap tires than they utilize, and many either landfill or monofill[27] a large percentage of their scrap tires that could be used for TDF.

When state average coal prices are used to determine the maximum profitable transportation distance for TDF, the economics were highly favorable. As with biomass fuels, transportation costs of $40 per ton-

[27] Scrap tires are often not permitted to be landfilled with other garbage, so special landfills are created that are only used to dispose of scrap tires – these landfills are often referred to as monofills.

mile are assumed, although TDF can provide about twice as much energy per ton (a heating value of 16,000 Btu/lb is assumed for TDF). Processed TDF typically costs around $30/ton at the source[28], and at this cost, all but four states would be able to transport the fuel greater than 50 miles while maintaining a lower delivered cost than the state average industrial coal price. Even with 100-mile transportation as the limiting factor, coal is still more expensive than TDF in 34 of the continental states. Highly processed TDF could cost up to $40/ton, and at this price, most states are still capable of economically transporting the fuel over 50 miles, with most capable of more than 100 miles of transportation.

Overall, there are eight states identified as having strong potential TDF markets for industrial utilization, based on estimated TDF economics, market information gathered from the Rubber Manufacturers Association, and EIA industrial coal usage statistics. The economic potential for industrial TDF use in these eight states (Alabama, California, Indiana, Michigan, Pennsylvania, New York, North Carolina, and Tennessee) is estimated in Table 6-11. The number of scrap tires generated and available for use in each state is calculated based on regional data from the 2005 Rubber Manufacturers Association report along with state population statistics. Tires that are currently land disposed are considered to have TDF potential. The number of tires available, the potential for industrial utilization, and the maximum cost for processed TDF is calculated for each state, assuming 100 miles of transportation is required.

Table 6-11. Leading States for Potential Industrial TDF Development

State	Estimated Annual Scrap Tires Generated	Estimated Annual Scrap Tires Available	Potential Industrial TDF Utilization (MMBtu/yr)	Maximum $/ton Cost for 100-mile Transport
Alabama	4,664,000	1,913,000*	651,000	$58/ton
California	36,576,000	20,545,000	6,985,000	$45/ton
Indiana	6,204,000	1,581,000	537,000	$51/ton
Michigan	9,629,000	2,454,000	835,000	$66/ton
New York	18,677,000	11,760,000	3,999,000	$62/ton
North Carolina	9,291,000	3,810,000*	1,295,000	$70/ton
Pennsylvania	13,088,000	4,363,000	1,483,000	$39/ton
Tennessee	6,236,000	2,557,000*	869,000	$80/ton
Totals (8 States)	**104,365,000**	**40,703,000**	**16,654,000**	**n/a**

*Assuming that all land-disposed tires in Region IV are concentrated in AL, NC and TN

The states with the most economic potential for TDF are California and New York, which is not surprising for these highly populated states. There is also a great deal of potential in North Carolina and Pennsylvania, both of which produce a large surplus of tires with no current market. Between the eight states analyzed, there is an estimated 40 million scrap tires available that could provide over 16 million MMBtu of heat to industrial facilities. The maximum cost of processed TDF with 100-mile transportation was calculated using the average state industrial coal costs. These costs show that TDF can

[28] State of Wisconsin. Department of Administration. *Tire Derived Fuel*. June 30, 2009. Contract No. 15-40502-900.

be a viable fuel even when it costs over $50/ton. Processed TDF is rarely sold for over $30/ton, so this bodes well for potential industrial TDF projects. However, potential barriers to TDF utilization such as emissions, volatility and public opposition (discussed in the previous chapter) could hinder certain projects

Petroleum Coke

The supply of petroleum coke is directly related to the location of oil refineries, which are concentrated along the Gulf Coast. Petroleum coke is most often transported by ship to its destination, either to overseas markets or up the Mississippi River to domestic markets. Many potential users of pet coke, such as pulp and paper mills, are located along waterways to facilitate the delivery of wood feedstocks as well as water intake and discharge of wastewater. In this economic analysis, the cost to transport pet coke via ship to certain points will be considered, with additional truck transportation added for facilities located far from commercial shipping routes.

A rule of thumb used for shipping large quantities of solid fuels is that it costs roughly $10/ton to transport from port to port.[29] Obviously there are many factors that can change the shipping rate, including the quantity being shipped, the distance travelled, and the accessibility of the destination, but for this economic analysis, a standard charge of $10/ton is used. Assuming the pet coke is shipped from the Gulf up the Mississippi River to the Midwest states, or along the coast to East or West Coast ports, the cost of truck transportation to the final destination is added to the $10/ton shipping rate.

In order for pet coke to be sold domestically, sites must compete with overseas markets that pay up to $50/ton for the fuel. While TDF and some biomass sources are sold for as low as $20/ton, this is not the case with petroleum coke. With $10/ton for ship transportation added to the cost, pet coke at $50/ton (effectively $60/ton including shipping) was analyzed in a cost comparison with average state prices for industrial coal. The maximum ground transportation distance for pet coke was calculated in each state, for each initial price point, assuming $40 per ton-mile. Figure 6-11 shows which states have the best economics for industrial petroleum coke utilization in terms of maximum ground transportation distance.

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[29] Argus Freight – Daily International Freight Rates and Market Commentary. Freight Rates, Issue #09-032, February 16, 2009.

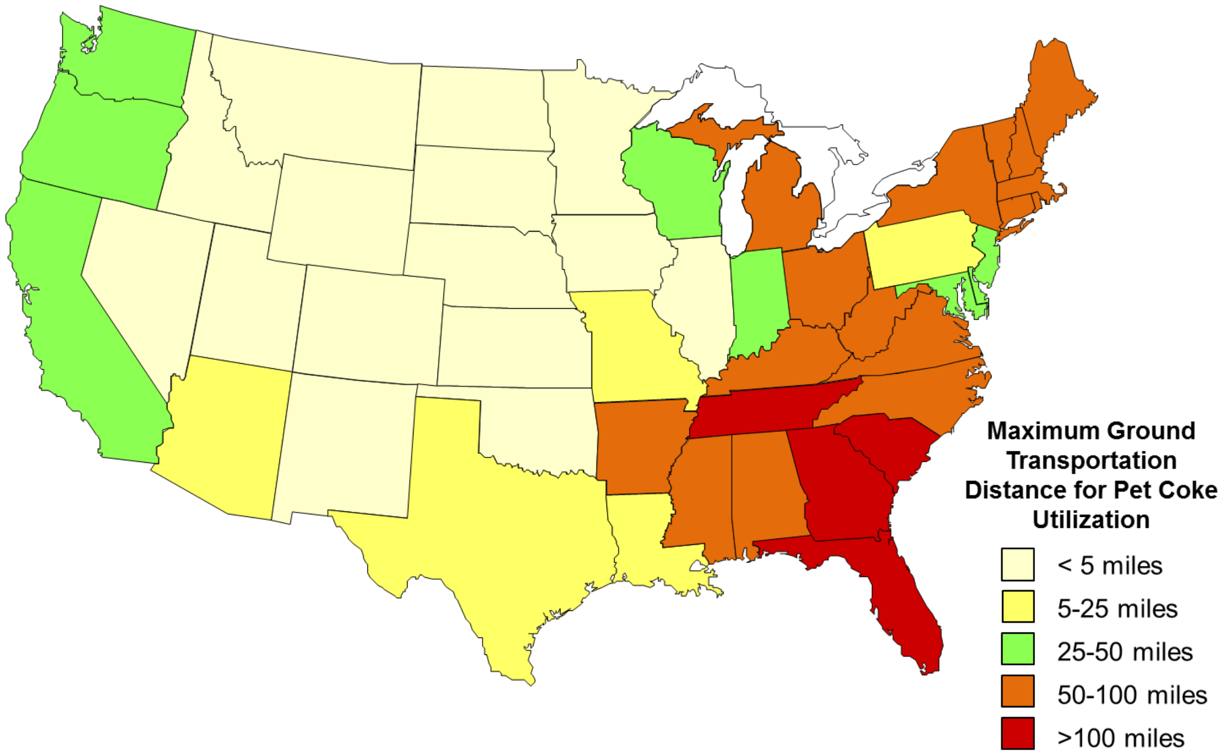


Figure 6-11. States With Most Favorable Economics for Industrial Pet Coke Utilization at $50/ton

As with all solid opportunity fuels, the Great Plains states do not fare well economically due to low coal prices and a lack of demand for industrial coal. Additionally, there are no major waterways to ship the pet coke to most of these states. The majority of states east of the Mississippi River show favorable economics for petroleum coke, allowing over 50 miles of ground transportation while remaining under the average industrial coal price. Pet coke can supplement coal up to 20 percent in most boilers with very few modifications required, although sites switching from coal to 100% pet coke would likely require new boiler equipment. Newer designs, such as circulating fluidized bed units, can be fired with larger portions of pet coke.

One can argue that there is likely more potential for pet coke in the Southeast where industrial coal use is common, as opposed to New England where it is rare. The limited ground transportation distances require industrial sites to be located near major ports. This could be a potential hindrance to pet coke's potential, although industrial sites tend to be concentrated in these locations. Still, the amount of pet coke available is limited, and overseas markets would need to be outbid in order to secure a substantial supply, so the actual economic potential for industrial sites is difficult to quantify.

Assuming coal cofiring applications are limited to 20 percent pet coke, the current maximum industrial potential is 191 million MMBtu/year. This number is based on EIA industrial coal usage statistics in the states with at least somewhat favorable economics for pet coke utilization. In states like Texas and Pennsylvania, where transportation distance is limited to less than 25 miles, many industrial sites are too far from major ports for pet coke to be economically viable. Large states like California, Oregon and Washington are limited to 25-50 miles of ground transportation, eliminating much of their potential.

However, a large portion of industrial sites are located close to coastlines and waterways, so it is difficult to determine exactly how much of each state's potential is limited by transportation distances. In the red-colored states of Figure 6-11 where ground transportation of over 100 miles is possible, the percentage of industrial facilities that could benefit from pet coke utilization is likely higher, but there are still several areas located too far from major ports, particularly in the Appalachian Mountain region.

The potential for industrial pet coke use will generally be limited to areas within 50 miles of a major port or close to a refinery source of pet coke. In the United States, most major ports are located on the coasts, but there are several other ports along the Mississippi River and its tributaries that could be used to transport the fuel. Figure 6-12 shows the locations of some of the major U.S. coastal ports, along with blue lines indicating the major rivers that stem from the Mississippi.

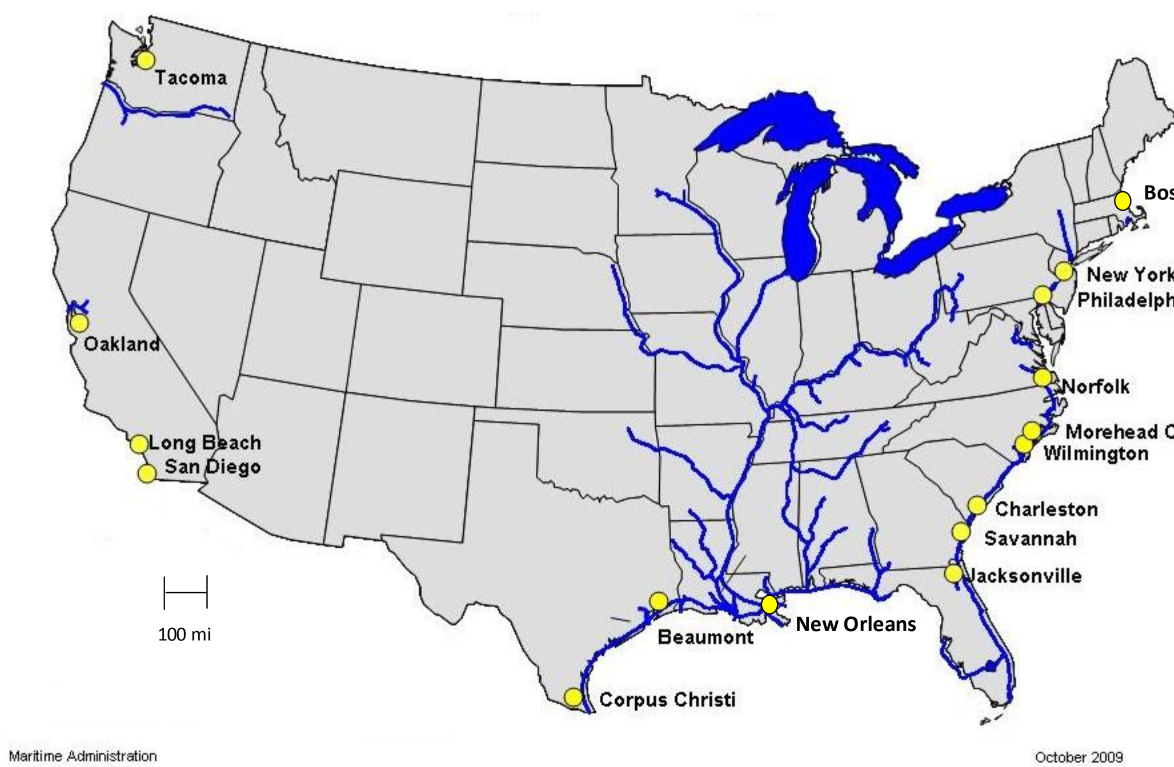


Figure 6-12. Major Coastal Ports and Rivers for Transporting Petroleum Coke
Source: United States Maritime Administration

While it is difficult to calculate the exact number of industrial facilities that are located close enough to ports to potentially benefit from petroleum coke utilization, a general estimate can be made. Based on the limited sources of petroleum coke shipments, the likely locations of industrial facilities, and the required transportation distances, about 20 percent of the total estimated potential is likely realizable.

Assuming that all of the petroleum coke currently being exported could be utilized domestically at industrial facilities, the total potential would be approximately 600 million MMBtu/year. While there are several boilers utilizing 100% pet coke for power production, at industrial facilities, cofiring applications with existing coal boilers are far more common. The maximum potential based on 20-percent coal cofiring applications is 191 million MMBtu/year (limited by industrial coal usage), and as previously mentioned, about 80 percent of this potential (153 million MMBtu/year) is likely unattainable due to required transportation distances, leaving 38 million MMBtu/year for industrial utilization. In conclusion, the economic potential for industrial petroleum coke utilization is estimated to be 38 million MMBtu/year, lacking a more precise analysis involving the measured distances of individual industrial facilities to nearby ports in each state.

Solid Opportunity Fuels: Summary

The economic potential for solid opportunity fuels in industrial applications, on a Btu basis, is on par with the potential for gaseous opportunity fuels. However, the number of industrial sites using coal is dwarfed by the number of industrial sites using natural gas for process heating and steam generation. There are far more opportunities for gaseous opportunity fuels to be blended with natural gas in various industrial process heating applications, while solid fuels are typically limited to large-scale steam generation. Still, there is a significant share of realizable potential for cofiring biomass, tire-derived fuel and petroleum coke with coal in industrial boilers. The combined economic potential for solid opportunity fuels is estimated to be over 230 million MMBtu/year, which is slightly less than the estimated potential for gaseous opportunity fuels. It represents, however, a much larger portion of industrial coal use than the gaseous opportunity fuels do compared to industrial natural gas use. Figure 6-13 shows the economic potential for each solid opportunity fuel in comparison to current industrial coal usage.

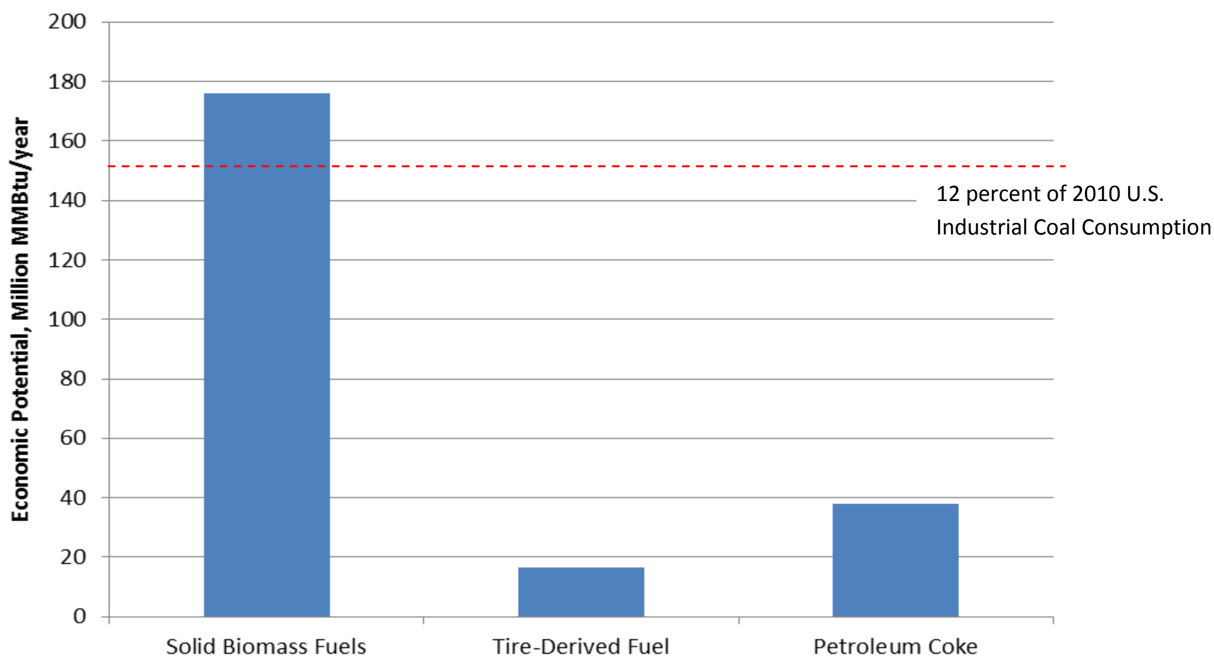


Figure 6-13. Economic Potential for Solid Opportunity Fuels Compared with Current Industrial Coal Use (EIA)

Summary of Economic Potential for Industrial Opportunity Fuel Utilization

Several of the opportunity fuels analyzed show strong potential to be economically utilized in industrial process heating and steam generation applications. Landfill gas, industrial waste gases (primarily refinery fuel gas), and solid biomass fuels show the most potential. The estimated economic potentials for each fuel are summarized in Table 6-12 and Figure 6-14.

Table 6-12. Economic Potential for Industrial Opportunity Fuel Applications

Opportunity Fuel	Available Sources	Estimated Economic Potential (MMBtu/yr)	Notes
Anaerobic Digester Gas	Wastewater treatment plants	14,800,000	Potential is primarily from industrial WWTPs – more potential could be realized if ADG-fueled CHP wasn't a favorable option for municipal WWTPs.
Landfill Gas	Large landfills	157,000,000	Landfills are typically found in remote locations – long pipelines are necessary, but most large landfills can support industrial process heating or steam generation projects within a 20 mile radius.
Coke Oven Gas	Merchant coke plants	19,000,000	Merchant coke plants are large enough to support industrial utilization projects between 5 and 20 miles away, assuming cleanup requirements are comparable with other waste gases.
Solid Biomass Fuels	Residues from crops, forests, mills; urban waste	176,000,000	Most biomass reserves are located too far from industrial facilities, but urban wood waste and other low-cost sources show great potential for coal cofiring.
Tire-Derived Fuel	Tire recycling/ processing plants	16,700,000	The economics for TDF utilization are sound, and allow transportation distances of over 100 mile in many cases, but supply is limited.
Petroleum Coke	Oil refineries	38,000,000	Industrial facilities less than 70-120 miles from major ports should be able to utilize pet coke in most states. It is difficult to determine the number of facilities that meet the criteria, so a rough estimate was made.

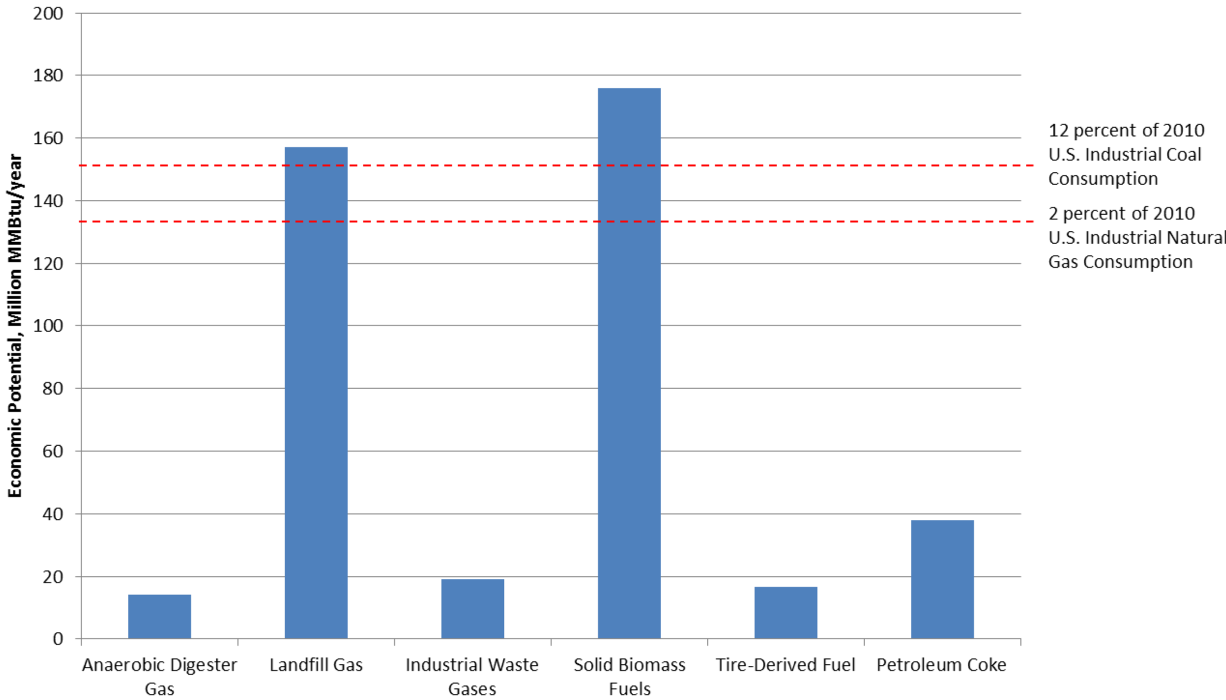


Figure 6-14. Estimated Economic Potential for Industrial Opportunity Fuel Applications

Overall, it is estimated that industrial facilities could replace over 420 million MMBtu/year of coal or natural gas with opportunity fuels. These fuels could be utilized by blending with natural gas or coal in existing industrial equipment, providing more flexibility and energy security to industrial operations throughout the country. Additionally, industrial sites could employ new fuel-flexible burner/boiler designs to eliminate dependence on traditional fossil fuels. In the final chapter of this report, the most promising areas of development for industrial opportunity fuel utilization are identified, and recommendations are made for integrating opportunity fuels into industrial process heating and steam generation applications.

7. Conclusions and Recommendations

With an estimated 420 million MMBtu/year of opportunity fuels available to economically replace coal and natural gas in industrial process heating and steam generation applications, a significant reduction in the fossil fuel dependence of industrial facilities could be achieved. The increased fuel flexibility would provide plant operators with options for cutting energy costs as well as providing energy security during spikes in fossil fuel prices or shortages in supply. Some of the opportunity fuels are more economical than others, with some requiring just the right circumstances in terms of local fuel and electricity prices, as well as an accessible opportunity fuel supply. The findings from this report are now summarized for each fuel, followed by conclusions and recommendations for future industrial opportunity fuel research and development.

Anaerobic Digester Gas

The estimated market potential for ADG sales to industrial sites is somewhat limited at 14.3 million MMBtu/year. For most large municipal wastewater treatment facilities, on-site combined heat and power units are likely to provide more value than routing the gas to a nearby industrial facility and selling it at a fraction of the natural gas price. There are likely some municipal plants producing excess ADG with nearby industrial facilities that could benefit from utilizing the gas, but these opportunities are limited.

However, for food and chemical processing facilities that treat their wastewater on-site with anaerobic digestion, new multi-fuel burner technologies could be employed to utilize their ADG without the need for large storage vessels. In addition, jet cookers can be installed at food and beverage processing facilities to break down starch waste and provide additional ADG production. In the economic analysis it was found that industrial sites currently using other wastewater treatment methods could also benefit from installing an anaerobic digester and utilizing the ADG. According to the estimates, most industrial facilities processing over 5 million gallons per day could support new anaerobic digester installations through avoided natural gas purchases, but this is based on a five year payback criteria and sludge loading rates similar to municipal plants.

Landfill Gas

The estimated market potential for LFG is more promising at 157 million MMBtu/year. Landfill gas projects at industrial facilities have become fairly common since the EPA's Landfill Methane Outreach Program initiative in the 1990s, so several lessons have been learned from previous projects. These installations have shown that with proper gas cleaning, routine equipment maintenance, and a burner system that can supplement LFG with natural gas, there are limited drawbacks to using LFG as a fuel. While a large number of the most ideal landfills are already engaged in LFG energy projects, the market is far from saturated and there are a great number of landfills with industrial project potential. Furthermore, landfills with existing energy projects may still be able to offer excess LFG to nearby industrial sites.

The main issue with potential LFG utilization projects is the distance from the landfill to the industrial facility, and potential obstacles involved with laying down several miles of pipeline. New projects like the 23-mile pipeline to a Virginia Honeywell manufacturing plant are showing that these obstacles can be overcome. The economic analysis showed that the gas supply at most large landfills was capable of supporting investments in pipeline distances of 10-20 miles.

Biomass Gas

The estimated market potential for biomass gas was not quantified, since advanced gasifiers (producing a medium-Btu syngas with the potential to replace or supplement natural gas) have primarily remained in the demonstration phase. The high capital costs and uncertainties involved with gasification systems, along with the operation and maintenance requirements, have prevented them from achieving commercial success. Some early demonstration projects for advanced gasifiers exhibited high ancillary costs involved with fuel handling and gas cleanup, and did not lead to commercial success as a result. Further research, development, and experience is needed before advanced biomass gasifiers become commercially viable, and it will likely take several successful demonstrations before industrial plant owners consider the technology for steam generation or process heating applications.

Close-coupled gasification systems that utilize the thermal energy of the hot gas to generate steam have proven successful at some industrial facilities. If advanced gasifiers could be used to produce biomass gas with a higher heating value, gasification systems could show even more potential. Fluidized bed gasifiers are a relatively new technology able to utilize a wide variety of biomass feedstocks, and some promise has been shown for future industrial utilization.

Industrial Waste Gases

The estimated market potential for industrial waste gases is limited to 19 million MMBtu/year, due to a limited number of sites and complexities involved in transporting or storing the gas.

The treatment and utilization of industrial waste gases is common practice at steel mills and oil refineries, but the potential for utilization beyond its current scope is difficult to pinpoint. There appears to be little demonstrated value to the gases outside of on-site utilization, and plants see often excess gas as more of a liability (in terms of air emissions, etc.) than an opportunity due to its inconsistent supply. The cost to store, treat and transport the gas could outweigh its value to other industrial sites, especially when it is produced sporadically like flared refinery fuel gas, as this would require extensive gas storage. As a result, most of the industrial waste gases are currently utilized to their maximum capability on-site, but any remaining gas is generally flared.

There are examples like Mon Valley Works where considerable savings can be achieved through innovative waste gas utilization strategies, but due to the limited number of integrated steel mills in the country, and the general practice of fully utilizing coke oven gas at these facilities, opportunities for new on-site utilization projects appear to be few and far between. Merchant coke plants, who may not have other uses for coke oven gas beyond heating the coke ovens themselves, are the most likely source of excess gas for potential industrial utilization. The estimated economic potential for pipelined coke oven gas is 19 million MMBtu/year, but the quantities of gas available at each individual plant is uncertain, and more site-specific research is needed to determine where the best opportunities lie.

Solid Biomass Fuels

The estimated market potential for solid biomass fuels is estimated to be 176 million MMBtu/year, the largest of the opportunity fuels, based on 20 percent coal cofiring applications. This potential is available throughout much of the United States.

The prospects for solid biomass fuel use in industrial process heating and steam generation applications are fairly strong. For facilities that produce wood waste, it is generally less expensive to process and utilize the wood waste for fuel, as opposed to purchasing traditional fuels. This practice is already common for the wood products and pulp and paper industries. Other sites that are located close to wood waste or biomass resources can potentially purchase the fuels to blend with coal in their industrial heating and steam generation applications. Alternatively, the facilities can invest in flexible fuel boilers that can handle a wide range of biomass and other solid fuels, allowing them to choose the best available fuel options for their particular site.

The economic analysis showed that biomass resources at $15-$30/ton could provide 176 million MMBtu/year to industrial facilities, when limited to transportation distances of 50 miles or less. At these transportation distances, delivered biomass prices can be competitive with delivered coal prices, but for distances over 50 miles, the higher heating value of coal affords it a cost advantage.

Tire-Derived Fuel

The estimated market potential for tire-derived fuel is limited, estimated to be 16.7 million MMBtu/year. The prospects for industrial TDF development are hindered by two important factors: the location of industrial plants, and the local availability of processed TDF. Many plants that could potentially benefit from TDF utilization are simply located too far from TDF sellers, who are few and far between in most areas of the country. The demand for TDF is beginning to outweigh the supply in areas like the Southeast, and in other areas it may not be the most economical fuel choice.

Still, there could be substantial potential for industrial steam generation applications, blending TDF with coal and/or biomass in fluidized bed boilers. If there is a market for TDF at these facilities, more TDF producers/suppliers could emerge around the country, and fuel availability would be less of a constraint. Public opposition to TDF projects could be a problem in some communities, but with small industrial applications that use a variety of fuels, it is not expected to be a major hindrance. Any publicity, if desired, can focus on positive impacts of TDF utilization such as the displacement of fossil fuels and the conservation of resources.

Petroleum Coke

The economic potential for petroleum coke is estimated to be 38 million MMBtu/year. Future prospects for industrial pet coke applications are most promising in areas of the country where petroleum coke is in abundant supply (i.e. the Gulf states and the Northwest). In these locations, a movement towards pet coke as a fuel for industrial facilities has already begun. Lime kiln applications can potentially utilize large amounts of petroleum coke, and they have become prominent at pulp and paper mills in the Gulf Coast states.

In other states, the cost to transport pet coke can become prohibitive, and in the Northeast and Midwest states, the price of coal is more competitive. However, sites with access to ports along the Mississippi River and its tributaries could have pet coke transported via ship from the Gulf Coast states for a much lower price than ground transportation. Lacking a detailed method of analyzing petroleum coke shipping costs and options, the economic potential was assumed to be limited to industrial sites located near major ports, and was estimated at 20 percent of the technical potential, or 38 million MMBtu/year.

Areas Where Opportunity Fuel Potential Converges

Fuel-flexible industrial boilers and process heaters can accept a wide range of opportunity fuels. Fluidized bed boilers and stokers can handle various amounts of biomass, TDF, petroleum coke and coal as fuels, and drawing from a wide variety of fuel sources increases the flexibility and stability of an industrial site's energy supply. Similarly, multi-fuel combustors like the system being developed by the Department of Energy's Industrial Technologies Program can handle a wide variety of gaseous fuels. If an industrial site is located close to a landfill, a wastewater treatment plant, or a merchant coke plant, pipelines could potentially be constructed to all of these facilities for waste gas access.

For gaseous fuels, the Southeastern United States, including the Gulf Coast, is home to a large numbers of industrial facilities with nearby wastewater treatment, landfills with project potential and oil refineries that sometimes flare excess still gas. Despite relatively low natural gas prices hindering opportunity fuel economics, this region of the country has the highest concentration of potential gaseous opportunity fuel projects with the chance to utilize more than one fuel source. California is another area with favorable conditions for gaseous opportunity fuel convergence, with a large number of landfills, WWTPs, refineries and industrial sites, and improved project economics due to higher natural gas prices.

For solid opportunity fuels, the Southeast (including the Gulf Coast) is also a high potential area for convergence, with substantial biomass reserves, several states with scrap tire surpluses, and the majority of the country's petroleum coke production. California also proves to be an ideal location for solid opportunity fuel utilization, with large amounts of biomass, a surplus of scrap tires and a considerable amount of petroleum coke from oil refineries. Some areas of the Midwest, especially along the Mississippi where pet coke could be transported by ship, also show strong potential for solid opportunity fuel convergence.

In terms of the ability to converge multiple sources of both gaseous and solid opportunity fuels, the Southeast/Gulf Coast region and California appear to offer the most potential for fuel-flexible projects. Other areas of the country, like the Northeast (New England in particular) have more favorable economics due to higher fossil fuel prices, but a lack of industrial sites and potential fuel resources could make it difficult to incorporate projects using multiple opportunity fuels.

Conclusions and Recommendations

With solid opportunity fuels, collection, transportation and processing costs can add up quickly. This is why most current projects take place directly at the industrial facilities that produce biomass waste products, eliminating much of the collection and transportation requirements. Similarly, the limited number of facilities processing waste tires into TDF can create high transportation and processing costs for industrial facilities that are interested in using the fuel, but located far from TDF processing centers. Petroleum coke faces a similar issue, with the limited locations of petroleum refineries, and the difficulty in transporting the fuel to facilities located far from major ports. For all three of these fuel types, the supply issue and corresponding transportation cost are the primary economic hindrances to most potential projects. Additionally, the permitting process can be long, complicated and costly when applying for air permits to utilize fuels like TDF and petroleum coke. Information from trial burn experiences could help provide data on cost and emissions impacts. Making efforts to expand the availability of opportunity fuels and streamline the permitting processes are two areas where barriers could be lowered.

Gaseous opportunity fuels show some promise for industrial utilization, with new multi-fuel burners able to blend natural gas seamlessly with various opportunity fuels. However, the proximity to the fuel source can be a major hurdle for potential projects. While anaerobic digester gas has a relatively modest estimated potential, it is likely to be produced close to (or directly at) industrial facilities that can utilize the fuel, which bodes well for potential project economics. Alternatively, landfill gas typically requires several miles of pipeline to reach the closest industrial site, but industrial utilization with a 5-20 mile pipeline can still be more economical than electricity generation for many United States locations. Industrial waste gases like coke oven gas are only produced at certain facility types that are limited in number, and many of these sites already utilize the majority of their waste gases, but the analysis showed that piping the gas to industrial sites can prove beneficial in certain circumstances. Potential biomass gas projects face the same supply problems of biomass fuels, along with the requirement of purchasing an expensive gasifier system that is not widely commercially accepted at this time.

While all opportunity fuels have some issues, there are several ways that industrial facility operators can improve the performance and economics of opportunity fuel projects and maximize their use. For industrial facilities that produce wood waste, utilization of waste as a thermal source should be closely examined, and other industrial sites with coal boilers should look into nearby sources of biomass, TDF, or petroleum coke for cofiring. Wastewater treatment plants with anaerobic digesters should be utilizing or marketing all of their ADG, and plants without digesters may want to consider the potential benefits of anaerobic treatment, including savings generated from waste gas utilization. Industrial facility operators located close to landfills or other sources of waste gas should examine the potential advantages and disadvantages of piping the gas to their facility for utilization. Any evaluation must consider the costs of removing contaminants in the gases to a level acceptable to their heating system tolerances. Despite some early missteps, project developers have caught on to this and gas pretreatment methods and knowledge of cost-effective treatment levels have improved.

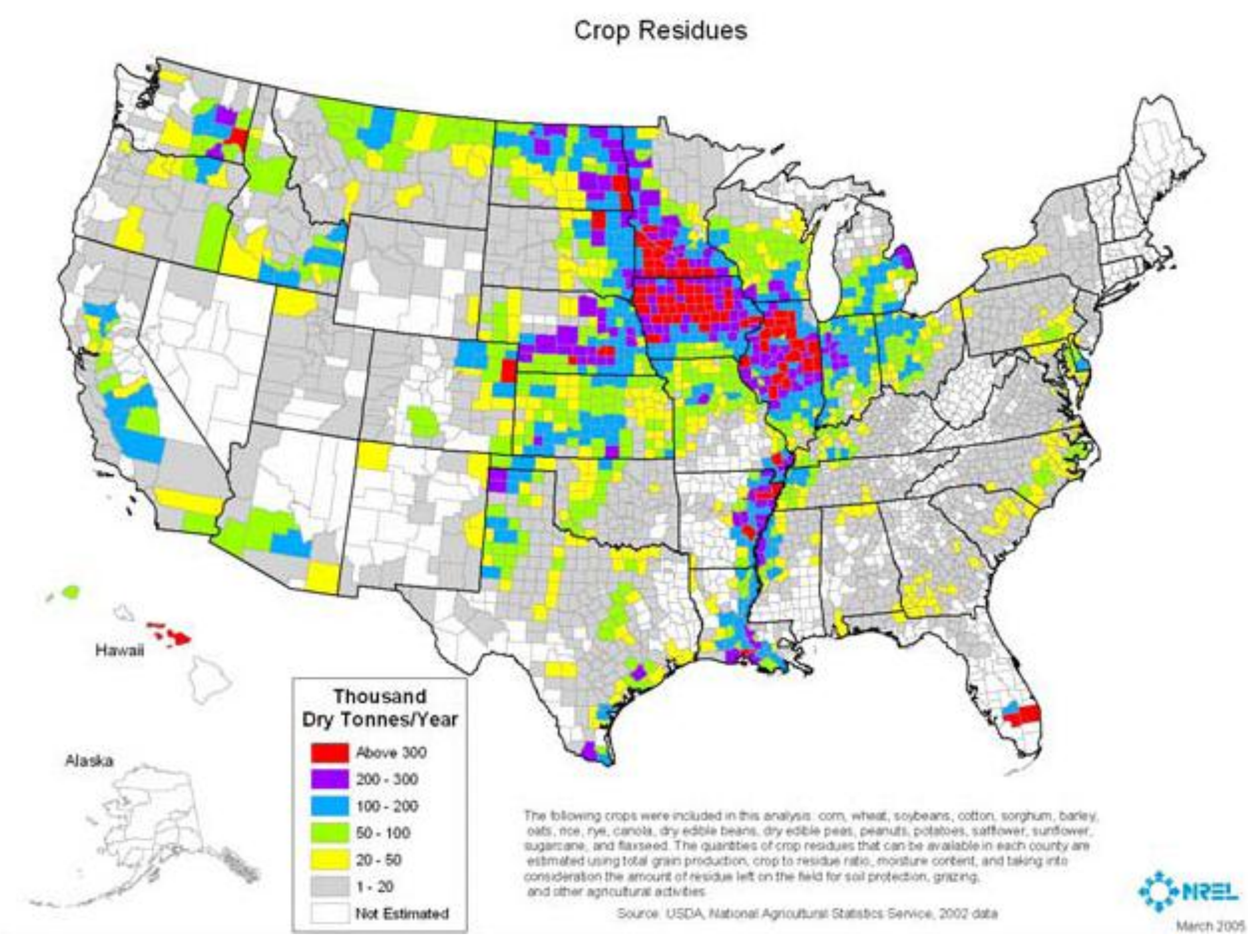
For future research and development in the area of industrial opportunity fuel utilization, further economic analyses can be performed on a more site-specific level to determine the accuracy of the generalizations made in this report. Industrial wastewater treatment plants, merchant coke plants, TDF and biomass processing centers, and potential landfill gas to energy projects should be sought out and identified, along with the industrial sites that can potentially utilize the fuels. In areas like the Southeast and California where different opportunities converge, fuel-flexible systems using multiple opportunity fuel resources can be implemented.

While this report used state average prices to determine where the best general markets for each fuel are located, the first step in narrowing down the field would be to identify the most promising states and the most promising opportunity fuels for industrial utilization, and to perform detailed analyses using local utility pricing. For example, potential ADG and LFG projects in California or the Northeast, biomass and TDF projects in the Southeast, and petroleum coke projects in the Gulf States could all be examined more thoroughly in a detailed economic evaluation. When the most promising markets for opportunity fuels have been identified and confirmed, site-specific case studies can be performed, and education to promote the use of opportunity fuels in these areas can be considered.

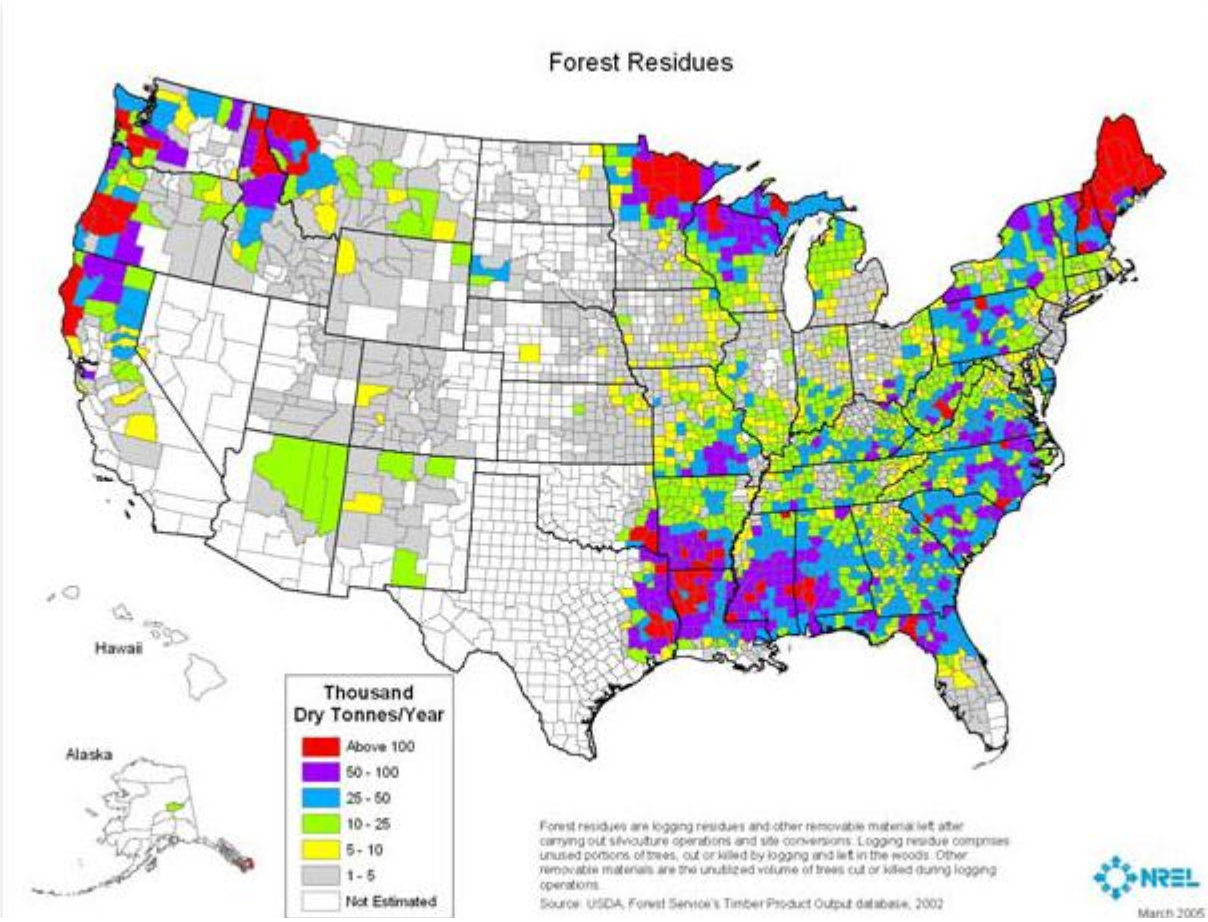
Appendix A. Biomass Availability Maps

This appendix provides biomass availability data maps from NREL's 2005 study: A Geographic Perspective on the Current Biomass Resource Availability in the United States (A. Milbrandt), by biomass source. The maps visually show where the counties with the most biomass resources are located. For state totals, see the Tables 4-6 through 4-9 in the report.

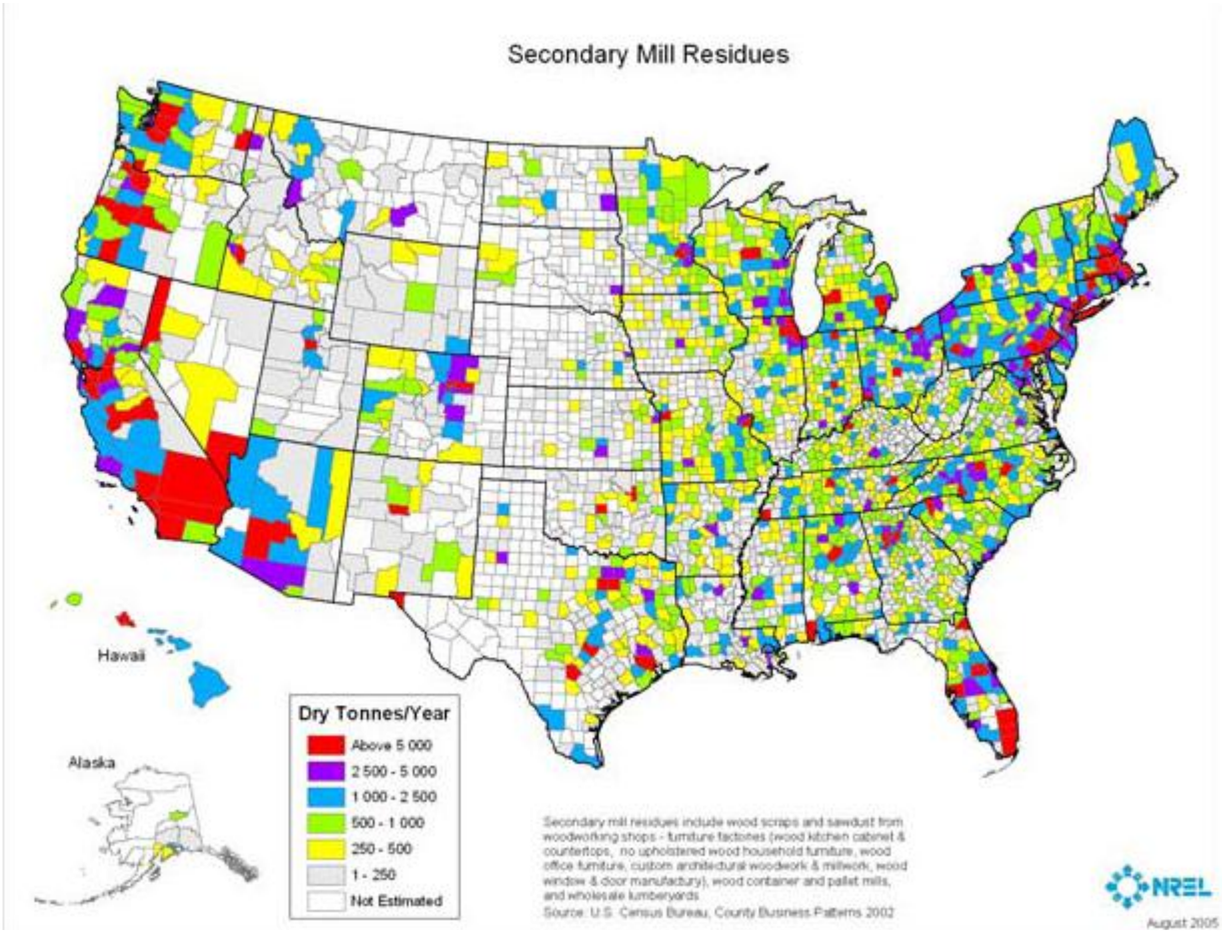
Crop Residues



Forest Residues



Mill Residues



Urban Wood Waste