Final White Paper

Project Considerations for Distributed Generation Using Opportunity Fuels

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NOTICE

This white paper outlines the differences between the each of the four primary opportunity fuels[1] (biomass gas, anaerobic digester gas, landfill gas, and solid wood waste) and their natural gas and coal counterparts, highlighting any special considerations that must be made for opportunity fueled distributed generation (DG) projects. The information presented here was collected from research on opportunity fuels, as well as interviews with manufacturers and discussions with project developers and operators. In addition, whenever possible, actual cases with project experience are used as examples to illustrate how these differences can affect real-world DG applications.

The first section of this paper discusses the differences in fuel properties, such as composition, heat rate, pressure and flow rate. The next section addresses the contaminants typically found in these fuels, and their potential effect on prime mover systems and DG projects in general. Then, considering the differences in the fuels and the contaminants they contain, the necessary modifications and additional maintenance for prime mover equipment is analyzed. In the final section of the memorandum, the current market considerations for opportunity fuels are examined, including how the purchase of specialized equipment, fuel treatment systems, warranties, and O&M contracts can affect businesses.

1. Differences Between the Fuels

While gaseous opportunity fuels are similar to natural gas in that they primarily consist of methane and produce similar emissions, the percentage of methane and other constituents, as well as differences in gas pressure and flow rate, cause some major differences between the fuels. Similarly, wood waste fuels do not share the same properties as coal. This section outlines the differences between the three primary gaseous opportunity fuels (biomass gas, anaerobic digester gas, and landfill gas) and natural gas, and the differences between solid wood waste fuels and coal. Of particular importance is how these differences translate to increased operating costs. Here, the differences are outlined for each fuel.

Biomass Gas

Biomass gas, created in a gasifier using solid biomass feedstocks, varies greatly in quality depending on the fuel source and the type of gasifier used. Depending on the feedstock's heat content and the efficiency of the gasifier, fuels ranging from as low as 150 Btu/ft^3 (about 15% methane) to higher than 800 Btu/ft^3 (about 80% methane) can be produced. Low quality biomass gas is typically only used for heating applications. The higher quality biomass gas, which could potentially be used for DG applications, has not yet been utilized in the United States outside of testing and demonstration projects because the advanced gasifier technologies are relatively new. Also, a biomass fuel selling and trading infrastructure has not yet developed, so potential applications are limited to locations with a nearby fuel source.

In the near future, it is expected that a commercial gasifier will emerge, perhaps using technologies developed in the Hawaii or Vermont Biomass Gasifier Projects, both sponsored by the Department of Energy. In addition, for certain markets, a biomass fuel selling and trading infrastructure could develop, using dedicated switchgrass crops, harvested wood, and crop residues. However, some believe that such an infrastructure would solely supply the liquid biofuels industry, primarily for transportation purposes.

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[1] *Opportunity Fuels and Combined Heat and Power: A Market Assessment.* Resource Dynamics Corporation, conducted for U.S. DOE and Oak Ridge National Laboratory, August 2006.

The United States currently appears to be headed in this direction, so the use of solid biomass feedstocks for DG/CHP may ultimately be limited to sites with a nearby fuel source.

With an advanced gasifier and consistent high-Btu biomass feedstocks, a clean gaseous fuel of nearly the same quality as natural gas can be produced. Some DG projects could emerge from this technology, especially for large industrial applications. In Europe, several large biomass gas projects using advanced gasifiers are currently underway. While the gasification systems require additional maintenance, the fuel created is very similar to natural gas in composition, and projected operating costs are on par with natural gas-fueled systems.

Anaerobic Digester Gas

Anaerobic digester gas (ADG) is the by-product of anaerobic bacteria breaking down organic materials. Wastewater treatment plants and farms use anaerobic digesters to treat their waste streams, producing a methane gas that can be either utilized or flared. In most cases, the gas is used to heat up the waste sludge, or it is fed to a boiler to produce steam. Recently, however, ADG-based DG projects have become common, since the fuel is free to those who produce it. Figure 1 shows how a typical ADG power generation project operates.

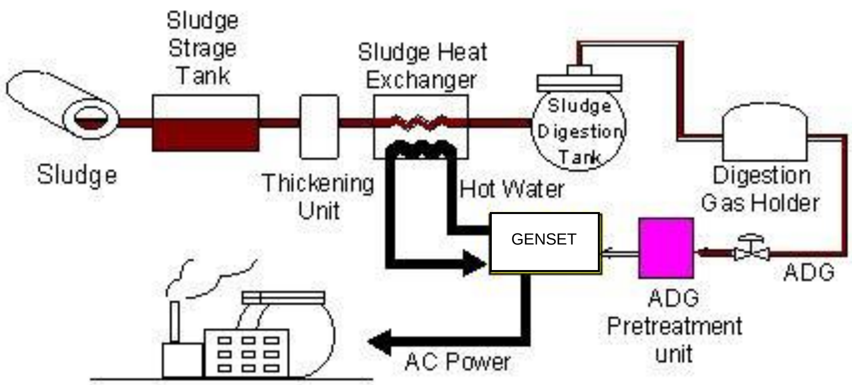

Figure 1. A Typical ADG Power System
Source: www.toshiba.co.jp/product/fc/fce/adg.htm

The heat content of anaerobic digester gas typically falls between 500 and 600 Btu/ft3, about 50-60% that of natural gas. The gas is comprised of one-half to two-thirds methane, and the balance carbon dioxide and other minor gases and particulates, whose presence can vary greatly between different digesters, and also at the same digester over time, due to changes in wastewater input. Because of ADG's lower heat content, some modifications must be made to existing natural gas prime mover systems. In addition, ADG is produced at a low pressure, so a compressor must be used to pressurize the gas before it is combusted. Also, the flow rate is not always consistent, and occasional dips in flow rate can cause engines and turbine blades to stall. To prevent this, natural gas can be used as a secondary fuel, supplementing the ADG when the flow rate begins to drop. For example, the Oxnard Wastewater Treatment Plant (WWTP) in California has connected a natural gas supply to their ADG-powered gensets, triggered to begin supplying natural gas when the ADG flow rate falls below a certain baseline. However, plant operators contend that such dips in the ADG flow rate are very infrequent, and the natural gas hasn't been used for several years. All of these factors (low heat rate, low pressure, and potentially low flow rates) can work to increase the price of ADG-powered DG applications. In addition, gas pre-treatment is often required to remove hydrogen sulfide and siloxanes. The impact of these issues on equipment costs is explained later in this paper.

Landfill Gas

Landfill gas (LFG) is very similar in nature to anaerobic digester gas. This is because a landfill is essentially a large anaerobic digester, with natural bacteria consuming the organic waste and releasing methane gas as a by-product. One difference is that in collecting the gas from the landfill, some air is usually collected too, diluting the gas. Once the gas is collected and piped, it is either flared or utilized for power. Like ADG, the gas consists of about half methane and half carbon dioxide, with some other minor constituents, although the more dilute LFG rarely reaches higher heating values than 500 Btu/ft^3. The pressure of LFG must be raised before it is combusted, so a compressor is required. There are also some particulates (e.g. hydrogen sulfide, siloxanes) in the gas that must be treated beforehand. The consistency of landfill gas, including particulates, varies greatly from landfill to landfill, and even at the same landfill over time, due to changes in rainfall and temperature. For example, at the Gude Landfill in Montgomery County, Maryland, the methane percentage varied from 38 to 53 percent over the course of 2006.[2] Typical composition percentages for ADG, LFG, and natural gas, assembled from a variety of sources, are provided in Table 1.

Table 1. Typical Composition Percentage Ranges for ADG/LFG/NG (by volume)

Constituent Gas/ Particulate	ADG	LFG	NG
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: Environmental Protection Agency reports, Montgomery County Landfill data, Union Gas Natural Gas data

In the future, landfills with extremely low levels of harmful constituents may benefit from a real time monitoring system. Rather than treating the gas beforehand, the monitoring system would only use the gas if contaminant levels fell below certain threshold levels. When the contaminants in the fuel become too dangerous, a secondary natural gas fuel could be used. This type of system could benefit certain landfills that would like to avoid the expensive capital costs associated with LFG pretreatment.

While most landfill gas power projects only produce wholesale electricity, several direct use (boiler fuel) and CHP projects have been implemented when a suitable facility is located nearby. The MountainGate

[2] Montgomery County, Maryland landfill data

Landfill in West Los Angeles is a good example of this practice. At this large landfill, LFG is collected, treated, and pipelined to UCLA, where it is used extensively as boiler fuel. The gas is analyzed routinely for: methane, carbon dioxide, hydrogen, nitrogen, oxygen, and Btu content. The fuel could just as easily be used in a modified reciprocating engine system to produce electricity, but for the time being, it is only used for heat. Figure 2 provides a diagram of how this LFG utilization system is configured.

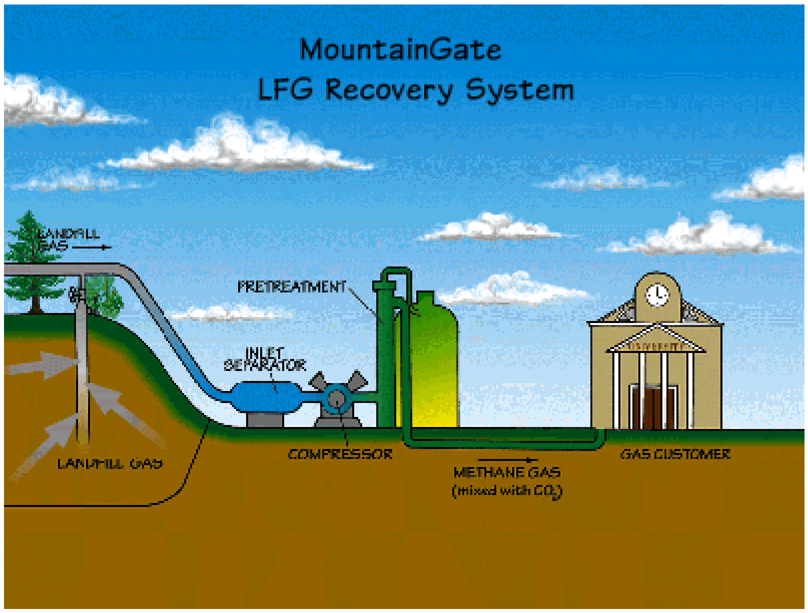

Figure 2. Example of a LFG Utilization Project at the MountainGate Landfill

Source: http://www.nstengineers.com/Landfill_Gas.htm

One particular problem often encountered with LFG is that the flow rate from the pipes is very low. Sometimes it is too slow to accommodate a DG project, so more gas wells need to be drilled to speed up the flow of the gas. At the Avery County Landfill in Newland, North Carolina, project developers began construction on a project, but it turned out that the LFG flow rate was much too low. In order to solve this problem, more gas wells were drilled, but so many wells had to be drilled that the extra costs nearly crippled the project. Most of the time, however, the LFG flow rate is adequate as-is, and extra gas wells are not necessary.

Solid Wood Waste

Wood waste fuels have very different characteristics from coal. The heating value of wood fuels is usually about half that of coal, and it is not easily pulverized. Instead, wood fuels are cut into chips before being fed to a boiler. Only certain types of boilers can accommodate wood chips. Stokers are often the most fuel-flexible choice, since they will work with almost any solid fuel and require no modifications, but fluidized bed boilers are sometimes required due to issues with emissions. Circulating fluidized bed boilers are a popular choice for wood-fueled boiler-steam turbine systems.

Another issue with wood waste fuels in particular is impurities. Urban wood waste consists of waste wood from various sources, sometimes containing paints or metals that must be treated and/or disposed of prior to cutting the wood into chips for incineration. This can significantly add to the fuel's processing cost. In addition, for most urban locations, selling/trading infrastructures for the fuel have not yet been developed.

2. Contaminants

One of the most significant hurdles for opportunity fuel projects (ADG and LFG in particular) is fuel treatment and contaminant removal. The composition of these fuels varies from site to site, and can even periodically change at the same site. A given fuel treatment method may work at one plant, but leave significant contaminants in the gas at another. Or contaminant levels may rise after installation of the DG unit, requiring the project operator to upgrade their equipment. When the fuel isn't treated properly, damage to the power generator or boiler often occurs before the problem is noticed. Furthermore, the cost for fuel treatment and the maintenance of treatment systems is often very high, and can be high enough to render a DG project unprofitable.

With biomass gas, contaminants are removed in the gasifier. In a well-designed and properly maintained advanced gasifier unit, the product gas is nearly identical to natural gas, and the gasification process leaves behind most of the impurities that exist in solid biomass feedstocks.

Solid wood waste fuels are typically treated and cut into chips prior to purchase or use, so contaminants are typically no worse than coal, and the boilers that utilize these fuels are generally designed to handle them without any major issues reported. One exception is biomass feedstocks high in chlorides or potassium, which can erode or foul boiler surfaces. Wood from exotic species such as palm trees can create unique fouling problems, such as silicate deposits. Regular cleaning and maintenance of the boiler, however, should prevent any potential problems, although the schedule may need to be accelerated with certain biomass fuels. In some cases, thinning of superheater tubes has been reported with various types of wood and biomass fuel combinations, however, restricting the boiler to wood fuels only will typically keep contaminants such as chlorides low, and protect boiler surfaces.

With ADG and LFG fuels, however, the waste gases contain many contaminant products that must be treated prior to combustion. The four main contaminants encountered in ADG/LFG applications are: water, particulates, siloxanes, and hydrogen sulfides. All of these contaminants have proven (although sometimes expensive) treatment solutions, but they are not always effectively implemented. Instead of relying on genset manufacturers, some users are becoming pro-active and purchasing the appropriate fuel treatment equipment to meet their particular site's needs. The characteristics and potential damage caused by these four contaminants are now discussed.

Water

With both landfill gas and anaerobic digester gas, water tends to condense inside piping and occasionally in engine or turbine parts, causing corrosion and potentially stripping off lubricants. This can cause higher wear and increased maintenance for project operators. In addition, gas with a high water concentration does not burn nearly as well, which can result in incomplete combustion of the gases. Removing excess water, however, is a relatively simple and inexpensive process.

The earliest known wastewater treatment plant to utilize ADG for electric power, the Village Creek Wastewater Treatment Center in Arlington, Texas, encountered this very problem. Their solution was to dry the gas before it entered the pipes, and to place some water traps in the piping system that would collect most of the condensation that occurs. Almost every wastewater treatment plant that utilized ADG for energy faces the same problem at some point, and the standard solution is the same: use a coalescing dryer to dry the gas, and install strategically-placed water traps in the pipes. Neither of these measures is particularly expensive or difficult to employ. While excess moisture is not as much of a problem for LFG, it can still happen occasionally. The combination of drying and water traps should solve moisture problems for any ADG or LFG project operator. Or, as an alternative, some use refrigerating condensers to condense out the moisture before the prime mover gas inlet. Either way, the problem can be readily solved.

Particulates

Particulates can be a serious problem when using waste gas such as ADG and LFG, potentially causing abrasive wear in the combustion chamber and damaging engine/turbine parts. The coalescing dryer and filter often used for water removal effectively removes the majority of stray particulates from the gas. Sometimes, additional filtration is needed, and a particulate filter may be desired. Using a particulate filter can reduce the cost of replacing coalescing filter elements when particulate concentration is high. Sometimes, corrosion in the fuel piping and treatment systems can add particulates to the gas after the filters have been applied. These particulates have a greater chance of invading the combustion chamber and prime mover equipment. However, regular cleaning and maintenance of the system should prevent any serious damage from occurring if proper filtration is in place.

Two potentially dangerous particulates, siloxanes and hydrogen sulfide, have the potential to cause major damage to engine/turbine parts. These types of particulates pass through most simple filters and must be specially treated, as described below.

Siloxanes

Siloxanes, chemicals composed of silicon and oxygen found in shampoos and cosmetic products, form some of the most potentially harmful particulates. Although concentrations in ADG and LFG are typically less than 0.01 percent by volume, this is still enough to cause significant damage over time. Tolerance levels are typically less than 5 parts per billion, or virtually indetectable, according to microturbine manufacturers Capstone and Ingersoll Rand. If a siloxane-rich gas is used in the prime mover, silicon dioxide deposits known as “white ash” will collect and foul transport tubes and engine/turbine parts, potentially causing serious damage. Also, occasionally an amber lacquer deposit from siloxanes can form, with similar damage possible.

If siloxanes are detected in the gas, a special carbon filter is the typical remedy, although another treatment method cools the gas with a refrigeration/compressor unit, condensing out the siloxanes with the liquids. If they are not detected, the project operator may opt to forgo the purchase of an expensive carbon filter or refrigeration system to save on capital costs. However, even if no siloxanes are initially found, future waste gas could contain the chemicals, and if the gas is not periodically tested, there is no way to tell if siloxanes are causing damage until it is too late. Therefore, it is recommended that all ADG and LFG project operators either install a carbon filter to combat any potential siloxanes in the fuels, or at least regularly inspect the gas for these chemicals, and act accordingly when they are found. The only exceptions are farm-based ADG projects where only animal manure is treated. Digester gas produced at these facilities should not contain any traces of siloxanes.

Figures 3 and 4 show the damage that siloxane can cause to engine pistons and boiler tubes.

Figure 3. Siloxane Damage to Engine Pistons
Source: Applied Filter Technologies (http://appliedfiltertechnology.com/page1224.asp)

Figure 4. Siloxane Damage to Boiler Tubes
Source: Applied Filter Technologies (http://appliedfiltertechnology.com/page1224.asp)

One of the first successful microturbine projects was at the Lewiston Wastewater Treatment Plant in Lewiston, New York. They encountered a siloxane problem rather quickly, with silicon dioxide white ash building up in the transport tubes and on the turbine blade. Plant operators cleaned the equipment and installed a carbon filter with specialized absorption media from Applied Filter Technology (http://appliedfiltertechnology.com) upstream, and they have not noticed any problems with siloxanes since. However, these specialized filters and their associated equipment are typically expensive, often becoming the single cost hurdle that a potential project cannot overcome.

Hydrogen Sulfide

Hydrogen sulfide (H_2S) is another contaminant that can cause similar problems with ADG and LFG systems. This compound is formed as part of the digestion process, so it is always present in ADG and LFG, although typically at concentrations of less than 0.2 percent. When combusted, it forms sulfur dioxide, which can then combine with water to form sulfuric acid (H_2SO_4), which is extremely corrosive to engine/turbine parts. In general, H_2S must be brought down to a detection level of about 200 parts per million before it is safe to use. Simple iron oxide filters, wood chips covered with iron oxide, or iron oxide pellets can be used to form iron sulfide, which is oxidized with air, eliminating the contaminant. Using chips or pellets increases the surface to volume ratio for more chemical reactions.

The Oxnard Wastewater Treatment Plant in Oxnard, California, which houses three 500 kW engines, opted for a different solution: injecting ferric chloride directly into the waste sludge, preventing the hazardous compound's formation, and creating iron sulphide salt particles instead. Many municipal WWTPs already incorporate H_2S removal via ferric chloride injection, even if their digester gas is not utilized. While this method has proven extremely effective in reducing high H_2S levels, and may be sufficient by itself in some cases, additional treatment may be needed for DER/CHP projects that require a more thorough removal of the particulate.

Another possible solution that has recently gained attention uses a biological method to combat the hydrogen sulfide. By running the gas through a soda solution containing thiobacillus bacteria, the H_2S in is captured and converted into elemental sulfur through natural biochemical reactions in the bacterium.

Air/oxygen dosing is another common method for removing hydrogen sulfide from biogas in anaerobic digester tanks. Although a digester requires an oxygen-free environment, mixing air with the biogas at the top of the tank produces a biological reaction that separates the sulfur and reduces H2S concentrations by as much as 95%, down to as little as 50 ppm.[3] This practice is use extensively in parts of Europe.

Water scrubbing, which can be used to remove carbon dioxide, giving biogas a higher methane content, also has the effect of removing hydrogen sulfide from the gas. The gas is pressurized and fed to the bottom of a packed column, where water is fed on top, creating a counter-current absorption process. Carbon dioxide and hydrogen sulfide are more soluble in water than methane, so these compounds are naturally absorbed by the water. With large anaerobic digesters, a combination of water scrubbing and air/oxygen dosing is often employed.[4]

[3] IEA Bioenergy. Biogas Upgrading and Utilisation. Task 24: Energy from biological conversion of organic waste.
[4] Ibid.

Whichever method is used to treat the H_2S, it is a significant and necessary cost for project operators to eliminate this corrosive compound.

Catalyst Poisoning

One potential problem, which is of concern to ADG and LFG project operators utilizing internal combustion engines in non-attainment areas, is the poisoning of catalysts with siloxanes and hydrogen sulfide. When post-combustion catalysts are used to combat NOx emissions, excess siloxanes or hydrogen sulfides in the gas can hinder catalyst operation, rendering them useless and leaving NOx uncontrolled. In these cases, extensive fuel treatment to completely rid the gas of siloxane and hydrogen sulfide and protect catalysts is required.

3. Prime Movers and Other Equipment: Costs and Special Considerations

Because of the differences between the opportunity fuels and their conventional counterparts, some modifications to prime mover equipment, and additional fuel treatment equipment may be required for smooth operation. This section examines the additional equipment purchases and costs that are incurred when using each of the opportunity fuels.

Biomass Gas

With an advanced gasifier and a consistent source of biomass feedstocks, biomass gas should perform nearly as well as natural gas in all areas of consideration. There are few impurities that arise out of the gasification process, so additional fuel treatment (other than the expense of a gasifier unit) is not required. Furthermore, the fuel should be compatible with natural gas gensets with only a slight degradation in power output and efficiency. Advanced gasifiers are projected to cost between $1,000-$2,000/kW in the future, but price estimates based on current technologies and capabilities put them in the range of $2,400-$4,000 per kW.

Anaerobic Digester Gas and Landfill Gas

Despite some variations in their makeup, ADG and LFG are essentially the same fuel, sometimes referred to as “biogas”. Biogas usually has a heat content of about 40 to 60 percent that of natural gas, and typically contains numerous contaminants and impurities, so fuel treatment systems are necessary, and natural gas-based prime mover equipment usually must be modified. Maintenance costs are also increased, depending on the level of fuel treatment and the initial quality of the gas.

Because ADG and LFG have a lower heat content than natural gas, most modifications to prime mover equipment focus on increasing the flow rate so that larger volumes of the low-Btu biogas enter the system. This is accomplished by building larger combustion areas and intake manifolds for rich burn engines, or by utilizing lean burn technologies for larger engines, which works well with these gases. Also, since the pressure and flow rate of the gas is low to begin with, heavy-duty compressors are required, adding significantly to capital costs and taking up about 10 percent of the power output by the genset. Finally, fuel treatment equipment must be purchased and maintained, depending on the severity of contaminants in the biogas. Coalescing dryers to reduce moisture and particulates, and filters to further reduce particulates, including special carbon filters for siloxane and iron oxide filters for hydrogen sulfide, are all typically required for an ADG or LFG project. For many projects, treatment costs are the most difficult hurdle to overcome.

Overall, the cost of a gas conditioning or pre-treatment unit can add as much as $3,000-5,000/kw for a small (30-100 kW) microturbine project, or $1,000-$2,000/kW for a medium-sized (300-1,000 kW) engine project. Pretreatment for larger engines and turbines (>2 MW) typically costs $500/kW or less. Because the same components (compressor, general particulate filter, H_2S filter, siloxane filter) are required for gas conditioning, only at different sizes, it is much more costly on a per-kW basis for small projects to treat their gas. However, pretreatment costs vary greatly, and some smaller projects with low levels of contaminants are able to effectively limit their costs, such as farm-based ADG operations that do not require siloxane removal.

In addition, if the purchase of an anaerobic digester is required for an ADG project, this generally costs between $1,500 and $3,000/kW. However, the installation of a digester usually has other positive impacts on a facility. For a wastewater treatment plant, anaerobic digestion is generally the superior treatment method for larger facilities, and this alternative does not require the amounts of electricity that aerobic digestion aeration requires. For farms, reduced odor and improved waste treatment, as well as the ability to use the digested waste sludge as fertilizer, are some of the benefits of utilizing anaerobic digestion. These positive impacts may help to reduce the effective cost of a digester system, and in many cases, a facility may make a commitment to a digester installation independent of the prospects of a power generating project.

For landfills, sometimes gas collection equipment, pipelines, and additional gas wells are required, which can significantly add to the capital costs of a DG project. According to the EPA, gas collection equipment costs approximately $600,000 per million tons of waste-in-place, although facilities with greater than 2.75 million tons of waste are required to collect and either flare or utilize their gas, and should already have the equipment in place. Pipeline construction costs are estimated at around $260,000 per mile, according to the EPA's data. If additional gas wells are required to increase the flow rate, as with the Avery County Landfill in Newland, North Carolina, this could be another substantial capital cost.

Overall, when all of the necessary fuel treatment methods have been employed, all of the necessary prime mover modifications have been made, and all of the equipment has been installed correctly, users report no project-crippling problems in using ADG and LFG as fuels. It is typically when necessary precautions and equipment purchases are not made that issues begin to arise. The question for potential project developers is then, with all of the extra equipment and precautionary measures that must be taken, does the benefit of a free fuel source outweigh these added project costs? The answer varies from site to site, and should be evaluated carefully.

Solid Wood Waste

For boilers that are stokers or fluidized beds, wood waste fuel can be used with relatively few modifications or difficulties as long as the fuel is processed into chips prior to combustion. Since steam is the working fluid in a boiler-steam turbine system, there are no modifications required for the turbine itself. Boilers for wood waste fuels can cost up to 50% more than those designed for coal, depending on the original boiler design and the characteristics of the fuel to be used. Maintenance costs are also slightly increased because of the impurities and tar build-up associated with wood waste fuels.

Urban wood waste, which can contain construction and demolition debris, as well as yard and landscape trimmings, is generated in populated areas and can be obtained for cheaper than most other biomass feedstocks. Circulating fluidized bed boilers are the most popular choice for wood-fueled boiler-steam turbine systems because they require few modifications and perform well with urban wood waste and nearly any other biomass fuel. In most cases, a test burn of the wood waste is performed prior to use, to determine what, if any, particulates and impurities need to be removed and/or treated. For example, during pre-construction activities, the Russell Biomass Power Plant in Massachusetts found chlorides in their wood waste fuel that created hydrogen chloride deposits. Their solution was to incorporate a limestone injection system into the boiler that would neutralize the acid and prevent damage from occurring.[5] In most cases, however, as long as the wood waste is thoroughly screened and processed into chips, no fuel treatment or additional boiler modifications are typically required. The only significant cost increases for the boiler systems resulting from typical use of wood usually come in the form of increased maintenance and more frequent equipment inspections.

One of the keys to keeping boiler modification and maintenance costs down is obtaining a reliable and consistent source of processed wood waste chips. In order for project economics to make sense, the processed fuel must be cheaper than coal on a Btu-basis. Finding processed wood waste fuels at cheap prices, however, can sometimes prove a difficult task. Cofiring wood chips with coal has become a common practice when the fuel can be obtained at a cheap price. When cofiring, typically no boiler modification is required, and maintenance costs are about the same, although biomass concentrations of 10-15 percent are usually as high as operators choose to cofire.

4. Special Market Considerations

This section discusses the special considerations that must be taken for the opportunity fuel market, particularly the purchase of special equipment, warranties, and maintenance contracts for the DG systems.

Opportunity fuels often require the purchase of specialized equipment, treating the fuels for contaminants and impurities, and allowing the fuels to work in prime mover systems designed for conventional fuels. Purchasing all of this equipment is a large and sometimes risky investment. If, for whatever reason, the project does not work out, the operator may find it difficult to sell or salvage such specialized equipment. While the reward from using less expensive and occasionally free opportunity fuels can be great money-saving ventures, there is a higher level of risk involved. Therefore, a thorough analysis must be conducted prior to making a decision on opportunity-fueled projects. Also, special warranties and maintenance contracts are a good idea for project developers looking to minimize their risk. Sometimes, however, these precautionary measures can have caveats of their own.

While warranties for the prime mover equipment associated with opportunity fuel projects are vital to obtain financing and satisfy project economics, often the warranties offered by the manufacturer are too short, and become void if contaminants such as siloxane or hydrogen sulfide cause damage. Most engine/turbine manufacturers offer the bare minimum 1-year warranty by default, or up to 5 years at a much higher cost for ADG/LFG projects, but damage from particular contaminants may void the contract.

[5] Russell Biomass Power Plant: Pre-Construction Development Activities Final Report. Prepared by Russell Biomass LLC, for the Massachusetts Technology Collaborative. September 2005.

For example, microturbine manufacturer Ingersoll Rand's warranty covers damage from siloxanes, since they are removed as part of the pretreatment process (for pretreatment, Ingersoll Rand uses a compressor to refrigerate the gas, which effectively removes siloxanes with the condensate). However, hydrogen sulfide removal is left entirely up to the project operator, and the warranty is void if any damage from H_2S occurs. Capstone Microturbines, on the other hand, employs filters on their pretreatment skids to rid the gas of both of these impurities, and their pre-treatment skid lowers both siloxanes and H_2S to acceptable levels prior to use. Still, the warranty is void if these units are not properly operated and maintained, resulting in contaminants slipping through and causing damage to the microturbines. However, the process for operating and maintaining these filters is simple, and typically only requires periodic replacement. Also, complete turnkey systems can be purchased, in which the microturbine manufacturer installs, operates, and maintains the prime mover and generator, as well as any gas pretreatment equipment.

Caterpillar and other engine manufacturers generally leave all pretreatment of the gas up to the project operator, while voiding their warranty agreement in the event of any damage caused by H2S or siloxanes. However, complete turnkey solutions can be purchased, whereby the engine manufacturer will install and maintain all of the necessary pretreatment and engine equipment as necessary, and the project operator assumes no responsibility for engine damage or failure.

Another potential problem with opportunity fuel projects are that the maintenance costs required are often higher than what was originally proposed. Service contracts can become very expensive if fuels with high contaminant-levels are involved. Furthermore, in some cases, equipment manufacturers do not specify which fuel treatment methods can and should be used with their equipment when certain opportunity fuels are used. Recently, however, as these projects are becoming more common, manufacturers are becoming familiar with the required fuel treatments and are doing a better job of communicating this information to project developers. Also, all manufacturers now offer more extensive and expensive contracts where all of the necessary equipment is installed and adequately maintained by their employees (either extended maintenance contracts or complete turnkey solutions). Still, it is the responsibility of the project developer/operator to make sure that the necessary fuel treatment equipment is put in place and maintained in order to prevent excessive damage to engine/turbine parts.

A special consideration that must be taken for biomass gas and solid wood waste fuels is that there is not yet a well-defined market infrastructure for biomass fuels. The availability of biomass varies greatly depending on region and proximity to the fuel source. Transportation can be unreliable and costs are often so high that these fuels become more expensive than their conventional counterparts as the distance from the fuel to the site increases. Until a reliable selling and trading infrastructure for biomass fuels is established on a large scale, the availability of these fuels will be severely limited by location.

Furthermore, a mass-produced commercial gasifier designed for biomass feedstocks has not yet been produced. It will take at least a few years for one to be widely available, most likely coinciding with the rise of a biomass fuel selling and trading infrastructure. Since a gasifier is a specialized piece of equipment, special warranties and service contracts will likely be required.

5. Conclusions

There are several considerations that must be taken for DG projects utilizing opportunity fuels. The fuel properties, including pressure, composition, and flow rate, are typically different than conventional fuels. Contaminants are also a serious issue that cannot be ignored. Effective fuel treatment methods are necessary in order to maintain proper genset operation and prevent damage to engine/turbine parts. The fuel properties can mean that conventional natural gas or coal-fired prime mover systems must be modified in order to accommodate the opportunity fuels, and special warranties and service contracts are usually necessary in order to protect the project developer's investment. For solid wood waste, the risk of contamination is typically limited to more extensive downtime and maintenance, which need to be managed to justify use of an alternative fuel. For gasified biomass and wood waste fuels, availability will be limited until the rise of a biomass fuel selling and trading infrastructure and the development of a commercial biomass gasifier takes place.

Overall, while there are many precautionary (and sometimes costly) measures that must be taken with opportunity fuels, the prospect of a cheap (and sometimes free) fuel source often outweighs these costs, allowing the project developer to profit from taking advantage of these unconventional fuel sources. This is particularly true as natural gas and coal are much more expensive than they were five years ago. In the future, when treatment methods have been refined and a more robust market for biomass fuels develops, it is expected that opportunity fuels will play a significant role in the country's DG market.