Sustainable Energy Opportunities with Solids Stabilization

George Bisbano and Walter Bashaw

Because of challenges from rising power and fuel costs, budget constraints, sometimes lower reliability of beneficial-use land application, and developing concern with greenhouse gas greenhouse gas emissions, municipalities are faced with new issues that alter the way biosolids management planning is approached.

This paper reviews proven solids stabilization technologies as the first major step in biosolids management planning. The review is performed for a hypothetical 55 million-gallon-per-day (MGD) treatment plant located in Florida.

Each option includes thickening, stabilization, and dewatering. Gravity belt thickeners and belt filter presses are used to analyze each option, which is assessed for its greenhouse gas emissions offsets, based upon the utility's power plant emission rates. A complete carbon footprint was not pursued, since off-site disposal is the same for each option, differing for the amount of solids to be disposed of.

This article also discusses opportunities for renewable energy use from stabilization as a step toward sustainability and as a mechanism to defray capital expenditures. Strategies for alternative uses of renewable energy sources are presented and compared.

Three solids stabilization processes were investigated, since each is a proven process with successful operating municipal histories. All were deemed suitable for application in Florida. Each reduces solids prior to ultimate disposal, and each was assessed to comply with either a PSRP or PFRP Standard of CFR 503 Biosolids Regulations as a requirement established locally for disposal. These solids stabilization processes include:

- Aerobic Digestion (Class B)
- Mesophilic Anaerobic Digestion to Class B
- Autothermal Thermophilic Aerobic Digestion, or ATAD (Class A)

Aerobic digestion was investigated because of its preponderance in Florida and also for its inherent operational simplicity. This article recognizes the value of aerobic digestion, especially for smaller plants of up to 10 MGD. ATAD was included for its enhanced solids reduction and also for its enhanced pathogen reduction. A baseline anaerobic digestion process was the last stabilization process considered for its reduction of solids; its low power requirements; and its generation of digester gas, a renewable fuel.

Biosolids Handling Options

This section presents the criteria used to compare each stabilization process.

Option 1 – Aerobic Digestion – Class B

The target process criterion for aerobic digestion was set to provide at least 38 percent volatile solids reduction to meet the definition of Class B biosolids. Under Option 1, the aerobic digesters would be sized to provide 28 days solids retention time (SRT) for the MAX30 loads, which is appropriate for Florida.

A conventional approach was used to implement aerobic digestion, operating at about 2 percent total solids (TS) concentration. A total of 12 digestion tanks, each with a diffused aeration system are proposed for operational flexibility. Each digestion tank would be 2.1 million gallons (MG) in volume. The installed horsepower for Class B aerobic digestion is 8,250 horsepower.

Option 2 – Anaerobic Digestion

Anaerobic digestion is a time-tested stabilization process that provides consistent destruction of volatile solids and results in a sludge which has improved dewatering characteristics. It requires more operator attention than aerobic digestion, but not unreasonably so.

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Typically, anaerobic digestion stabilizes combined sludges—that is, sludge withdrawn from both primary clarifiers and from the biological process. In Florida, however, many plants do not provide for primary settling, since wastewaters are warm and there is concern for associated odor releases.

Several wastewater facilities in South Florida have been anaerobically digesting waste-activated sludge successfully for decades. On this basis, anaerobic digestion was considered a suitable stabilization option with process performance assessed accordingly.

This study evaluated single-stage, mesophilic anaerobic digestion in egg-shaped digesters, as depicted in Figure 1. The anaerobic digesters would be sized to provide 16 days SRT at MAX30 loads, which would meet

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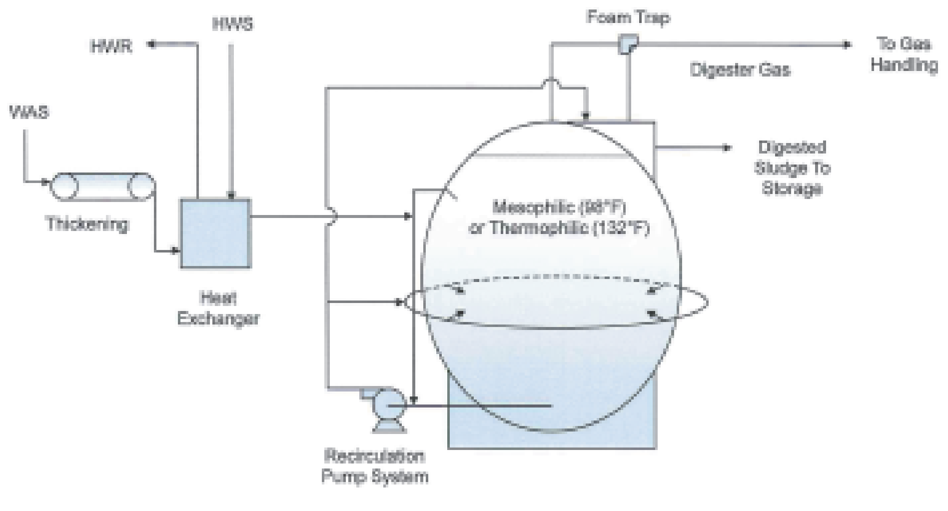

Figure 1. Process Diagram of Egg-Shaped Digesters

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volatile solid destruction standards under peak design loads in order to assure compliance with Class B standards.

At annual average design rating, the SRT would be on the order of 21 to 22 days. These SRTs are longer than usual because the feed stock is exclusively waste-activated sludge. Installed horsepower for anaerobic digestion is estimated to be 655.

All waste-activated sludge would be thickened using gravity belt thickeners. After thickening, the solids would undergo anaerobic digestion in egg-shaped digesters. The initial determination is that three such digesters, each 2.5 MG in volume, would be needed.

The digesters would be heated to maintain the contents in the mesophilic temperature range (around 98°F). The digested biosolids would be discharged to one of two storage tanks, each with 0.75 MG volume. Transfer pumps would be installed to pump digested biosolids to the belt filter press building. The digested biosolids would be dewatered on belt filter presses and the cake solids would be managed by an off-site composting operation. Dewatering and disposal were the same for all alternatives.

Renewable Energy Strategies

A consideration for anaerobic digestion is utilization of the fuel value of digester gas, which is a sustainable resource. One strategy is to use the biogas to reduce utility power costs, which could be desirable in an era when power utilities are facing increasing cost and environmental challenges of their own. Anaerobic digestion provides an opportunity to defray operating costs by generating power.

Wastewater treatment facilities that use the anaerobic digestion process produce significant quantities of methane rich gas with a heating value between 50 percent and 65 percent of natural gas. This gas can be used in a number of ways. Three strategies in which digester gas is used include:

- Plant Heating
- Direct Drive Systems
- Total Energy System or Combined Power and Heat

In its elemental form and for sustainability, the methane gas can be used in boilers to supply process and building heating. Operating efficiencies of this application can be 80 percent or higher.

Sulfides in the methane gas can be a corrosion problem requiring treatment, for example, by Iron Sponge or Sulfa Treat technologies; however, and more important, during summer much of the digester gas would be flared, providing little or no chance for energy utilization. Alternatively, absorptive chilling could be applied.

Another possible use of the digester gas is to drive process equipment directly. This arrangement typically couples a prime mover with a process equipment element, such as a process blower or main wastewater pump.

The arrangement provides high fuel-energy-to-mechanical-work efficiency, but process demands do not always coincide with gas production, defraying from this implicit advantage. Also, in practice, reliability of such systems is compromised because power generation is coupled directly with process equipment. Failure of sub-system components for either major component can cause the system to be shut down.

A third possible use of digester gas is incorporating it into a total energy system, currently called a combined heat and power system (CHP). This last strategy uses the digester gas as a fuel to generate power. Generally, an engine would be coupled with a generator to furnish power for process needs, and net available thermal energy would be recovered from the engine to offset process heating and space heating. In southern climates, the possibility also exists for use of residual heat in a centrifugal adsorption chiller to defray some air conditioning costs.

A CHP system would co-generate power, reducing reliance upon utility power. Typically, the co-generation system can furnish between 40 percent and 60 percent of the total electric demand of the plant. Ultimately an overall efficiency of electric power generation and thermal recovery can yield efficiencies of 80 percent and more. In colder climates, recovered thermal energy would more likely be dedicated for process heating, with less or no heat available for space heating during the coldest weather.

For this theoretical wastewater plant, modeling indicates that an anaerobic digestion process would produce enough digester gas to generate 1,800 kilowatts of electrical power and 100 percent of the thermal demands of the anaerobic digestion process without need for supplementary heating. This article discusses alternative power sources, their advantages, and their disadvantages in a subsequent section.

Option 3 – ATAD

ATAD, the third stabilization process considered for this hypothetical evaluation, uses aerobic digestion similar to Option 1, but operates in the thermophilic temperature range around 150°F. Maintaining this temperature does not require external heat input because aerobic oxidation is exothermal and provides the heat needed to elevate the temperature of the sludge.

The critical feature to maintaining the temperature in the ATAD process is to reduce the amount of water in the reactors, so that the heat from oxidation is sufficient to warm up the digester contents. At this temperature range, oxidation of the solids occurs at an accelerated rate, which reduces the SRT required to around 12 to 15 days.

A benefit of operating in the thermophilic temperature range is that pathogens are destroyed quickly. The biosolids produced contain so few pathogens that they meet the Class A standards. While meeting Class A pathogen reduction standards is not needed for this hypothetical plant, it provides the greatest opportunity for beneficial use compared to Options 1 and 2.

A second benefit of operating in the thermophilic temperature range is that volatile solids destruction is more complete than when operating at ambient temperatures. Operating facilities report 60-percent volatile solids reduction, and some facilities report higher destruction. Thermophilic bacteria exhibit high metabolic rates and hence, exhibit low sludge yields. Enhanced volatile solids destruction is desirable because the process results in fewer solids to be dewatered and managed off-site.

A third benefit of ATAD is that digested biosolids exhibit better dewatering characteristics than aerobically digested sludges. Operating plants report dewatered ATAD cake solids concentrations of 20-percent TS with belt presses and above this value at a few other facilities.

Taking all these factors in total, ATAD has shown to be an effective stabilization process for combined and waste-activated sludges and it is able to minimize solids for off-site management.

ATAD processes can produce foam and have been odorous because of the generation of high ammonia levels inherent in the thermophilic stage of the process. Second-generation ATAD systems have successfully addressed these problems with aggressive foam control systems and creation of second-stage nitrification-denitrification reactors operated at mesophilic temperatures to lower nitrogen levels, but press filtrate can be expected to return a significant ammonia load to the liquid process.

As a consequence of the process, second-generation ATAD systems always provide biofilter odor control to treat the reactors' head spaces before release to atmosphere. This article considers installation of biological filter cells for treatment of ATAD headspace air. The analysis of annual operating costs factors in anticipated service-life replacement costs of the biofilter cell media. Total ATAD system horsepower is about 6,700 hp.

Methodology for Comparisons

The analysis of solids conditioning options involved both economic and functional evaluations. The economic evaluation was based on a life-cycle cost analysis that considered both capital and operating costs. The functional evaluation included other relevant factors, some of which are qualitative. For

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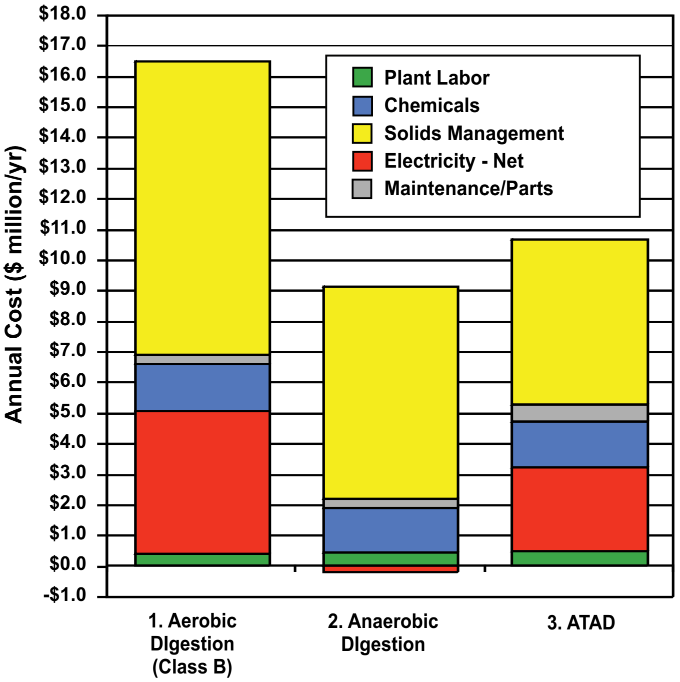
Table 1. Comparison of Capital Costs

Items	1. Aerobic Digestion	2. Anaerobic Digestion	3. ATAD Digestion
Construction			
Digesters and Ancillaries	$37	$35	$43
Odor Control Systems	$8	-	Inc. Above
Generators	-	$12	-
Site Work	$2	$2	$2
Contingency (30%)	$14	$15	$13
Total	$61	$64	$58
Engineering, Legal, Administration (10%)	$6	$6	$6
Dewatering System Improvements[1]	$13	$11	$11
Total	$80	$81	$75

[1] Estimates based on belt filter press costs and number required for each option

Figure 2. O&M Cost Comparison



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brevity, this article discusses greenhouse gas emissions as a relevant functional consideration of solids stabilization options.

Life-cycle costs were developed to consider the overall cost of each option over a 30-year planning period. This entailed consideration of both capital outlay and annual operation and maintenance (O&M) costs. A discount rate of 5 percent was used for inflation and time value of money. The life-cycle costs were expressed as their present worth.

The capital costs were developed to include structures and equipment for the conceptual layouts of the major facilities of each alternative. Cost estimates were developed from similar facilities designed by Jordan, Jones & Goulding at other treatment facilities. The construction cost estimates includes a 30-percent contingency, deemed appropriate at the conceptual level of design. Capital costs were determined at the time the study was conducted, which was fourth-quarter 2007 cost levels.

O&M costs were prepared for each solids stabilization option. These costs included O&M labor, replacement materials, electrical energy, chemical costs, and costs for managing the cake solids off-site. Management was assumed to be the same process and location for all three options, such that differential costs reflect the varying quantity of solids to be disposed of. In addition, process modeling was used to capture the cost effects of sidestreams upon the wastewater plant in establishing relevant power costs.

O&M staffing levels were estimated for each stabilization option assuming an average annual salary including benefits. The U.S. Environmental Protection Agency's *Manual for Estimating Costs and Manpower Requirements for Conventional Wastewater Treatment Facilities* and *Handbook for Estimating Sludge Management Costs* were consulted in determining O&M labor of each option.

O&M labor costs for each stabilization option were used. Thickening and dewatering O&M labor was not included because differential shift requirements were not deemed significant.

Power costs were based upon a current utility rate of $0.08 per kilowatt hour. Solids management costs were based upon $31.43 per wet ton to a regional pelletizer facility that included capital amortization, hauling, and its O&M costs.

Results

Capital Costs

The capital cost outlays for each option were developed as estimates of the funds needed to implement capital improvement projects for the proposed solids conditioning systems. The capital costs estimates are presented at fourth-quarter 2007 cost levels; they are summarized in Table 1.

Annual O&M Costs

Option 2 – Anaerobic Digestion was found to have the least O&M costs, while Option 1 – Aerobic Digestion was found to have the highest O&M costs, nearly twice the O&M costs of Option 2. A comparison of the annual O&M costs is given in Figure 2.

The O&M cost comparison reveals that the largest annual expense category for each option is management of the biosolids cake solids that are removed from the plant. The analysis presumes no differences in disposal technology or location, such that differential management costs reflect the difference in biosolids volume among the options. Hence, the stabilization options that maximize solids reduction have the lowest O&M costs (Option 2 – Anaerobic Digestion and Option 3 – ATAD).

The next-largest O&M cost category is electrical power. Option 2 – Anaerobic Digestion has the least annual expense for electrical power, because it consumes the least power and can generate power from a sustainable fuel: digester gas. This option includes the capital cost for a total energy system, now commonly called a combined heat and power system, which would generate power from the digester gas and recover heat to heat the digesters.

For Option 2 – Anaerobic Digestion, it is projected that about 1,800 kilowatts of process power can be generated from the digester gas, based upon 35 percent efficient engines. This would be more than sufficient to power the process air blowers which normally operate between 1,500 and 1,600 kilowatts. Residual power would be available for other constant operating process loads, such as return sludge pumps, or effluent water pumps. Typically in other areas, one or two raw-sewage pumps would be operated on power generated on-site.

Ultimately, it is projected that about 42 percent of plant process power is achievable with 100-percent utilization of digester gas. Together

Table 2. Life-cycle Cost Comparison
(All costs in $million)

Items		1. Aerobic Digestion	2. Anaerobic Digestion	3. ATAD
Proposed Improvements	Capital Cost	$80	$81	$75
	Salvage Value	-$1	-$2	-$1
O&M Cost	Annual Cost	$16.5 /yr	$9.3 /yr	$10.7 /yr
	Present Worth	$254	$143	$165
Total Life -cycle Cost		$333	$222	$239

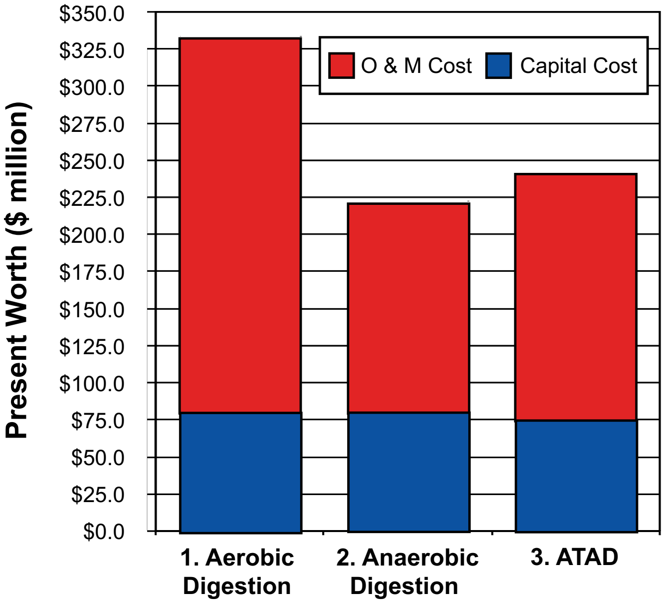

Figure 3. Life-Cycle Cost Comparison

with elimination of aerobic digester power, this represents about a 55-percent reduction from the plant if aerobic digestion is installed.

Life-Cycle Costs

Life-cycle costs were developed to encompass both capital outlays and the present worth of annual O&M costs over a 30 year service life. A discount rate of 5 percent per year was used for inflation and the time value of money over the 30-year life.

The life-cycle cost comparison for the options, summarized in Table 2, indicates that Option 2 – Anaerobic Digestion has the lowest life-cycle cost and that Option 3 – ATAD is about 10 percent higher. This could be construed to approach the sensitivity of analysis at this level of review. The life-cycle cost for Option 1 – Aerobic Digestion is significantly more than these two.

The comparison illustrates a contrast in the options, since Option 1 – Aerobic Digestion has over 70 percent of its life-cycle cost comprised of O&M costs, while Option 2 – Anaerobic Digestion has a 40-percent-to-60-percent split between capital and O&M costs, respectively. Life-cycle costs for each option are depicted graphically in Figure 3.

Although capital requirements of anaerobic digestion are similar to the other options, over time O&M cost savings make this option cost effective. Furthermore, the capital spent for digestion tanks provides an investment life of 50 years and longer. Ultimately, when viewed from very long-term perspectives, return on investment (ROI) increasingly favors anaerobic digestion with power generation.

Energy Consumption

Energy consumption is an important consideration apart from cost, since there is an increasing awareness of environmental consequences from power production. For the foreseeable future, power costs are anticipated to rise; therefore, processes that are inherently efficient would have a long-term advantage over power-intensive processes.

Figure 4 compares the liquid and solids process electrical require-ments for all three options. As shown, Option 1 – Aerobic Digestion (Class B) consumes the most energy, mostly because of digestion power requirements. Option 3 – ATAD also consumes large amounts of energy for solids conditioning.

By contrast, Option 2 – Anaerobic Digestion reduces plant power requirements by eliminating digestion blowers, and the process as implemented in a CHP system is able to produce energy on-site to further reduce utility energy expenditures.

Option 2 – Anaerobic Digestion requires the least process power (less than 400 horsepower), and it provides a sustainable fuel that can be used to generate power to reduce utility power consumption. It is projected that the plant with anaerobic digestion and co-generation would provide about 60-percent less power than the closest option.

About 1,800 kilowatts of power is available from the digester gas, assuming 100-percent utilization and 35-percent efficient

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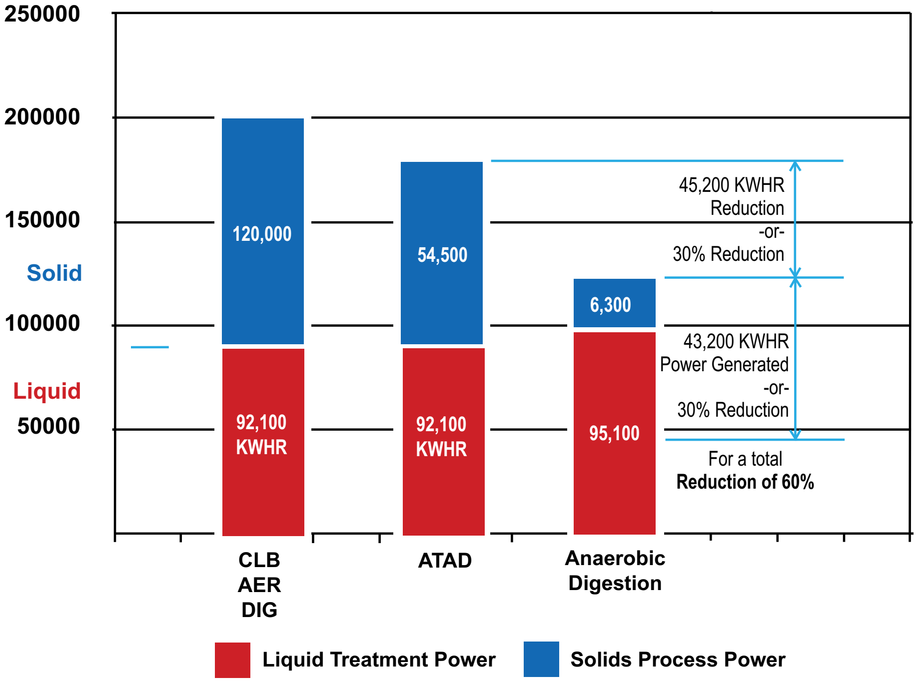
Figure 4. Comparison of Energy Consumption



Option	Annual Emissions (TPY)		
	CO_2 (x1000)	NO_x	SO_2
Existing Facility	27	26	42
Aerobic Digestion – Class B	70	68	109
Anaerobic Digestion - No power generation	36	35	56
Anaerobic Digestion - Biogas power generation	21	35	32
Anaerobic Digestion - Biogas + natural gas power generation	15	35	0
ATAD	92	89	143

Table 3. Comparison of Emissions for Solids Conditioning and Power Generation Alternatives

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engines. This is more than sufficient for the process blowers and possibly the anaerobic digestion process or other similarly sized continuous power loads.

To minimize environmental issues with power generation, reciprocating engines would be the prime mover of choice. They can be made for 100-percent on-line generation reliability, and they require the least degree of digester gas treatment. It is anticipated that refrigerant drying would be the principal gas treatment step.

A CHP scheme has proven operating records at many installations for achieving 85-percent or higher energy utilization of input energy. There are newer reciprocating engines available that can increase this utilization above 85 percent, but they are large and would be suitable for very large plants or eliminating utility power all together in medium to medium-large wastewater treatment plants.

Spark-ignited engines would be favored, especially in instances when natural gas supplies are readily available to minimize NO_x emissions. These engines are among the cleanest, since they are gas engines able to use digester gas and natural gas. This is illustrated in the sub-section that discusses greenhouse gas emissions.

Otherwise, dual fuel engines could be selected. Several technologies exist that minimize diesel consumption, including micro-chamber injection and advanced injection timing. One last advantage of this approach is reliability of power generation. Supplemental fuel supplies would be considered if permits required the use of multiple engines during a utility outage. Natural gas or diesel fuel would serve these purposes.

Greenhouse Gas Emissions

Today, there is motivation to minimize greenhouse gas emissions for their implied impacts upon global climate change. This section discusses greenhouse emissions from each option that would be emitted by the power generation stations of Florida Power and Light Company (FPL). In performing this analysis, FPL provided information regarding their system's emission rates. It is a means to quantify an important environmental impact in distinguishing between solids stabilization processes.

This study did not engage in assessing a complete carbon footprint of each option because solids management is the same for all options studied. The process would consider all aspects of emissions emanating from activities associated with an option. Such an analysis would consider site activities, site fuel usage, hauling, utility power, and activities at the disposal site, as well as fugitive emissions. For the purposes of this study, greenhouse gas emissions were viewed from a perspective of offset emissions from the power utility.

It is important to understand that from an environmental perspective, anthropogenic sources of carbon dioxide emissions are those produced by human activities. This is viewed as adding to the earth's inventory of carbon dioxide as caused by human activities.

For example, these activities include burning of fossil fuels at utility power plants in order to sustain plant processes. Thus, solids stabilization options that require the most power contribute the greatest to anthropogenic-source carbon dioxide emissions, while power generation and carbon dioxide emissions from bio-fuels is not included in the "added" carbon dioxide emission inventories, since the gas is created by living organisms that are part of the earth's natural inventory. Also, this carbon would decay on its own.

A bio-fuel such as digester gas would not be included in anthropogenic carbon dioxide inventories, since it comes from a biogenic source and it is not deemed to add to the earth's inventory of carbon dioxide. Rather, it is considered to be part of the naturally occurring carbon cycle.

One other perspective regarding GHG is the relative heat trapping characteristics of gases emitted by fossil fuel combustion. The Intergovernmental Panel on Climate Change, IPPC, has established heat-trapping qualities of several gases that contribute to global warming. These gases principally are methane and nitrous oxide. The IPPC has established carbon dioxide equivalencies or GHG equivalencies for these gases as follows:

CH_4 at 23 times CO_2 and
N_2O at 296 times CO_2

Based on system-wide emissions factors furnished by FPL, estimates of the CO_2, NO_x and SO_2 emissions for the various solids stabilization options and for three different digestion technologies were determined. To frame the analyses, the greenhouse gas emissions for the existing facility operating at about 38 MGD are also included; greenhouse gas emissions for all other options are at the design rating for the facility.

Emissions factors and efficiency data were used based on data published by the engine manufacturers and actual test data available for spark-ignited, 4-stroke, lean-burn gas engines. As shown in Table 3, anaerobic digestion alone presents a decrease in utility greenhouse gas emissions. Specifically, anaerobic digestion with cogeneration provides for further reductions, since the digester gas is considered a biogenic fuel. In addition, cogeneration using digester gas reduces NO_x and SO_2 emissions since utility power-generating stations principally use coal or fuel oil to generate power.

Figure 5 on page 38 presents the anticipated emissions for the three options graphically for offset of utility power generating station greenhouse gas emissions. It is noted that some leakage is anticipated for the anaerobic digesters. At large urban plants, 1 to 2 percent digester gas leakage has been estimated.

Assuming such leakage and considering the digester gas with 65-percent CH_4 content, about 1,300 to 2,600 tons of equivalent greenhouse gases would be emitted annually. This is minor compared to the offset of power utility greenhouse gas emissions. The high greenhouse gas emissions for the ATAD alternative are due to high energy expenditures during the thermophilic react mode of the process. Power expenditures are much higher during this several-hour period that would not be reflected in an annual O&M analysis.

Power Generation Alternatives

There are several prime mover options that would generate power and that achieve heat utilization. These are gas turbines, microturbines, fuel cells, and reciprocating engines. Each is reviewed in turn.

Turbines are able to provide power gener-

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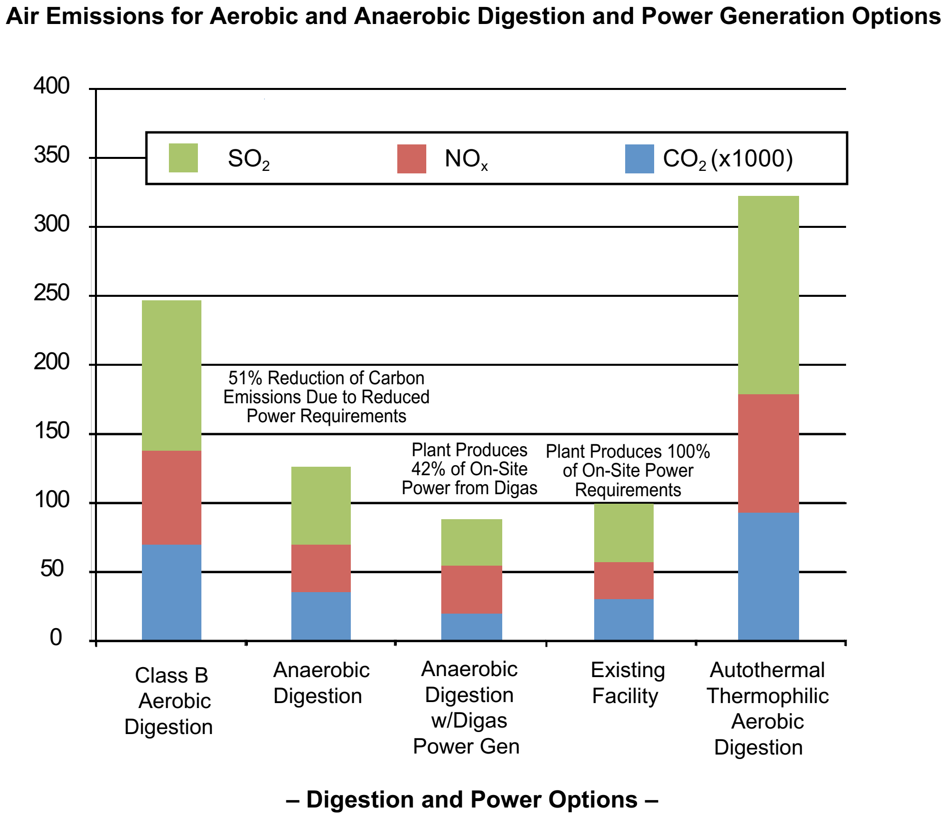
Figure 5. Comparison of Emissions for Solids Digestion And Power Generation Alternatives



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ation efficiencies from 25 to 30 percent, with low NO_x levels but with high CO and hydrocarbon emissions compared to other prime movers. Typically, installed costs vary from about $1,800 to about $2,400 per kilowatt and modest annual O&M costs of $0.008/kilowatt-hour.

Turbines have a narrow band of high efficiency, which detracts from generation efficiencies if not operated within this band. They exhibit low exhaust temperatures, which limit heat recovery utilization. Turbines can be expected to provide electrical and thermal or overall efficiencies of between 75 and 80 percent.

Turbines require consistent, clean gas quality which would involve a high degree of purification for removing sulfides and siloxanes. Turbines generally require parallel operation with the utility, which provides very large demands to achieve efficient output. Accordingly, they are best suited for very large facilities of more than 100 MGD in capacity.

Microturbines, on the other hand, are small units with projected electrical efficiencies from 25 to 28 percent and overall efficiencies of 70 to 75 percent. They would be applied for smaller facilities; however, for small units, reduced effective thermal heat generation is the norm.

They, too, require extensive gas treatment and exhibit narrow power bands. Like large turbines, they are furnished as package units and exhibit low annual O&M costs, about $0.08/kilowatt hour, which does not include the costs for gas treatment. Installed costs are between $1,000 and $1,500/kilowatt of capacity.

Fuel cells are a leading-edge technology, but without subsidy, they are not cost competitive. Electrical efficiencies of 40 percent and higher are possible, and thermal conversion efficiencies of about 25 percent are achievable. Overall efficiencies can be expected of between 65 percent and 80 percent maximum. The small thermal efficiency detracts from heat recovery potential.

Fuel cells require the most gas treatment of any generation device. Gas treatment for fuel cells can defray 15 to 25 percent of electrical energy generated. They are units that must furnish power to a large grid, and therefore they are not suitable for use as a plant emergency power source.

Reciprocating engines are the oldest type of generation device, but they exhibit the highest overall efficiency of all others. Typical electrical efficiencies of 35 percent are expected with standard design engines, but the Advanced Reciprocating Engine System (ARES) Program conducted in cooperation with the U.S. Department of Energy is advancing generation efficiency to about 40 percent with future units expected to be above this value.

Targets of the ARES program are to achieve an electrical efficiency of 50 percent, with a 95-percent reduction in NO_x emissions. Engines also provide the highest available thermal energy of all generation types, and typically 50-percent thermal utilization efficiency is achieved. Thus, with standard engines, an overall efficiency of about 85 percent can be expected.

Other larger spark-ignited engines available today achieve electrical efficiencies from 45 to 48 percent. These engines permit overall efficiencies above 90 percent, much higher than any other generation device.

Engines also provide the widest efficient power bands of all generation types. They require the least gas treatment of all options and can be operated in parallel with or isolated from utility grids, making them suitable for emergency power duty. In the latter configuration, the operating engines can provide emergency power, eliminating the need for separate emergency generators.

The engines can be either dual fuel, compression ignition or spark-ignited type. It is noted that dual fuel would emit higher levels of NO_x than spark-ignited gas engines. Advances in engine control technology and ignition arrangements, as well as the ARES program, enable dual fuel engines to reduce NO_x emissions.

Engine annual O&M costs can be expected to be mid-range, at about $0.015/kilowatt hour, but with lesser gas treatment overall, O&M costs should approach the lower end of O&M costs. Installed costs of between $1,500 to $2,500/kilowatt are common, since they are typically not packaged systems, but are custom-engineered systems.

Digester Gas Treatment

There are three component treatment issues for generation devices: moisture, hydrogen sulfide, and siloxanes.

Moisture causes corrosion and, together with acids formed from the presence of sulfides and nitrogen compounds, accelerates corrosion. Sulfide can be found to be in high concentrations of more than 500 ppmv that accelerate this corrosion. Furthermore, the acid can break down lubricants, seals, and other critical components.

Generally, engines can tolerate higher concentrations of hydrogen sulfide, on the order of 300 ppmv or higher. Turbines can tolerate sulfides of 25 ppmv, but microturbines and fuel cells require sulfide to be reduced to below 1 ppmv.

For smaller and medium plants with moderate sulfide concentrations of 1,000 ppmv or less, Iron Sponge and Sulfa Treat are two catalyst-precipitation technologies used to reduce sulfide in digester gas streams. These are batch technologies, however, requiring either regeneration or media replacement. A cost comparison should be performed for installations to lead to a least-cost option for installations.

As opposed, chemical oxidation scrubbers may be more cost effective for large facilities, since they are able to respond to varying sulfide inlet concentrations and have the ability to achieve stringent removals—especially for turbines and fuel cell applications. Siloxane removal has become well known. Through plant experimentation, refrigerant dryers providing dewpoints of between -10°F and -20°F have been shown to remove 90 percent or more in digester gas. Experience with reciprocating engines indicates this would be the normal expectation for treatment.

When a high degree of siloxane removal is required for fuel cells and turbines, the addition of carbon adsorption has been shown to be effective, in some cases, to reduce siloxane to non-detectible limits.

In summary, problems that have plagued earlier co-generation or generation projects caused by these environment issues within the digester gas have become known and solvable. As with all projects, a case-by-case approach is best to determine what works for the least overall cost.

Siloxanes are byproducts of commercial personal hygiene and healthcare products. Industrially, silicones appear in sealants. They manifest in the biological sludges at plants and in digester gas. Siloxanes have scaled heat transfer surfaces in boilers reducing their heat transfer efficiency, and are destructive to turbines and microturbines. As silicon-based material, they are abrasive, accelerating wear of critical metal parts.

Moisture traditionally has been reduced through physical traps, but with the advent of siloxane issues, refrigerant dryers are more commonly employed to lower gas dewpoints to about -10°F. Such treatment has generally been successful in lowering concentrations of both to levels for use in engines.

For turbines, microturbines, and fuel cells further reductions of siloxane are required. Generally, concentrations of about 1 ppmv are tolerated by this equipment. Carbon filtration has been used to achieve these concentrations for use in them.

Summary

For the hypothetical case of a 55-MGD wastewater treatment plant in Florida, a life-cycle cost comparison demonstrated the advantage of anaerobic digestion over aerobic digestion and ATAD. Lower O&M costs for anaerobic digestion were attributed to the value of electrical power generated from the digester's gas. For this case, it is estimated that about 1,800 kilowatt of electrical power can be generated from the digester gas.

Furthermore, anaerobic digestion with power generation will produce the least amount of greenhouse gases of the three options evaluated. This is a result of the lower demand for electrical power from the utility grid when power is generated at the plant and from the digester gas, which is considered a biogenic fuel. Also, co-generation using digester gas reduces NO_x and SO_2 emissions, since utility power generating stations in Florida principally use coal or fuel oil to generate power.

Of the prime movers currently in use today for generating power from biogas, reciprocating engines demonstrate the highest overall efficiency. ARES engines can attain about 40-percent electrical conversion efficiency, and engine heat can be recovered for several uses. Also, engines provide the highest thermal energy recovery of all generation types.

An overall efficiency of about 85 percent to 90 percent can be expected, which is much higher than any other generation device. For large plants, other engines are available commercially that increase electrical power generation efficiency above 44 percent, yielding overall energy efficiency of better than 93 percent. ◊