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CASE STUDIES OF SEWAGE TREATMENT WITH RECOVERY OF ENERGY FROM METHANE

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MASTER

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Finally, the findings and conclusions of the report are those of Wander Associates and do not necessarily represent the views held by the U.S. Department of Energy or the Tennessee Valley Authority.

CASE STUDIES OF SEWAGE TREATMENT
WITH RECOVERY OF ENERGY FROM METHANE

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EXECUTIVE SUMMARY

There is increasing evidence and growing world-wide concern that the global atmosphere is being negatively affected by major change gases like methane and by combustion of fossil fuels. Methane is produced by wastewater treatment facilities that use anaerobic technologies for treatment. Using the energy from methane captured at these facilities reduces the need for other energy sources such as coal or electricity. The United States Department of Energy's Southeastern Regional Biomass Energy Program at the Tennessee Valley Authority funded a study to survey wastewater treatment facilities that recover the methane produced. Under this study, no attempt was made to place a value on the positive effect on the region or on the global impact from present or future potential recoveries of energy from methane gas at wastewater treatment plants.

In the Southeast, there are about 3,000 wastewater plants with a capacity of over one million gallons per day; and some of these have reported fuel savings of over \$10,000 per month. Under this study, operating data and available financial information on a variety of technologies for large and small plants was documented for ten facilities. Summary case reports were written and reviewed by participants and several peer reviewers.

Studies were done on wastewater treatment plants (WWTPs) with design capacities ranging from 9.5 million gallons per day (MGD) to 120 MGD. All of these WWTPs recover the gas produced in their anaerobic digesters and use at least part of it as fuel for boilers and/or internal combustion engines. The engines power generators, blowers, or pumps, and most are equipped with heat recovery systems.

Based on the historical data provided by the participants in this study and from our own technical analysis, methane recovery and utilization systems appear to be cost effective, although the degree of cost effectiveness varies widely. The types of energy recovery systems are not uniform among all the participants so that the cases in this limited survey are not precisely comparable to each other. Also, reliance on historical data and cost information generated from portions of total plant operations and estimates makes it difficult to complete analysis of specific variables.

The fact remains, however, that regardless of the individual type(s) of digester gas energy recovery system in use, data from seven of the ten participants reflected annual savings ranging from \$67,200 to more than \$700,000. Further, Wander Associates current analysis reflects that nine of the ten realized annual savings ranging from \$5,000 to more than \$600,000, as shown on Table 1.

Table 1 - Listing of Case Studies and Cost Savings

<u>City</u>	<u>Plant</u>	<u>Type of Energy Recovery System</u>	<u>Estimated Annual Digester Heating Savings (\$)</u>	<u>Estimated Annual Alternative Fuel Savings (\$)</u>
Birmingham, AL	Valley Creek WWTP	Engine Blowers	157,000*	66,500*
Chester, VA	Proctors Creek WWTP	Boilers	55,000*	-
Dayton, OH	North Regional WWTP	Engine Generators Engine Pump	24,700	2,600
Durham, NC	Northside WWTP	Engine Blowers	35,500	69,100
Fort Worth, TX	Village Creek WWTP	Engine Generators and Engine Blowers	188,000*	357,000*
Little Rock, AR	Fourche Creek WWTP	Engine Generators	105,000	59,200
Plantation, FL	Plantation WWTP	Boilers and Auto Fuel	10,700*	9,300*
Tampa, FL	Hookers Point WWTP	Engine Generators	44,000*	575,000*
Virginia Beach, VA	Nansemond WWTP	Boilers and Engine Blower	37,800	5,300
Winston-Salem, NC	Muddy Creek WWTP	Boilers and Engine Blower	51,400*	37,400*

The values listed in Table 1 above do not include the cost of debt recovery and those with an asterisk (*) do not include operation and maintenance costs (O&M). In these situations, O&M costs are not kept on individual items like the energy recovery system, but are kept for the plant as a whole. To accurately monitor the cost effectiveness of the energy recovery equipment, more detailed O&M records are required.

Neglecting the debt recovery and O&M costs, every WWTP studied realized significant cost savings by recovering and utilizing their digester gas. A few of the plants are not able to use all of the gas produced due to various circumstances. These plants should evaluate their systems and look at other digester gas utilization systems to determine if the wasted gas can be cost effectively used.

Key Findings:

- Recovery of energy from methane reduces overall WWTP operating costs and saves energy. This has a beneficial effect on the global environment because less fossil fuel is burned.
- Federal grant and state permit programs lack data, criteria, and incentives which would encourage and support methane generation and recovery.
- Skilled operation and maintenance are necessary components of an efficient energy recovery program and are key variables which have a substantial impact on efficiency of energy recovery and on cost savings.

INTRODUCTION

The U.S. Department of Energy has established regional biomass energy programs to promote the development of effective uses of biomass for energy. One of these, the Southeastern Regional Biomass Program (SERBEP), is managed by the Tennessee Valley Authority (TVA).

Recent studies of gases that affect global climate found methane gas to be 20 to 30% more effective in trapping radiation than carbon dioxide and, therefore, a major change gas. Federal and state authorities are currently evaluating ways of including the costs of externalities in the decision making process. A number of public utility commissions have been including estimates of externality costs in their capacity planning decisions. Methane recovery, however, has shown the potential to be cost effective on its own merits, without accounting for savings due to a reduction of externalities. SERBEP initiated this study to determine the energy and cost effectiveness of sewage treatment plant methane recovery systems. Ten municipal authorities cooperated in providing technical information and cost data on operating methane recovery systems.

GENERAL PROCESS DESCRIPTION

Methane production is accomplished using anaerobic digestion. Conventional two-stage anaerobic digestion requires at least two digesters which operate in series. The first tank is used for digestion, and the second for storage and concentration of digested sludge and for formation of a relatively clear supernatant. In the first stage, the sludge is heated to achieve optimum digestion rates. In the second stage, the heating and recirculation is discontinued, and the sludge is encouraged to separate, as shown in Figure 1.

The digesters are fed by primary sludge or a combination of primary and waste activated sludge from the wastewater treatment plant (WWTP). The sludge contains both organic (volatile) and inorganic (fixed) solids. The digestion process breaks down the volatile solids to produce methane, carbon dioxide, trace gases, and stabilized sludge.

Digester gas typically contains 33-38% carbon dioxide, 55-65% methane, and a small concentration of nitrogen and hydrogen sulfide. About 12-18 cu ft of gas can be produced from each pound of volatile solids destroyed. The gas can be collected, stored, purified, and used in a variety of productive, energy efficient ways. Although many plants still flare off most or all of their gas, others have installed systems to optimize the use of digester gas and maximize both heat and energy recovery. Increases in fuel costs, the escalating cost of electricity, and growing recognition of environmental problems caused by burning fossil fuels have all placed a new emphasis on the use of digester gas. Many innovative systems have been developed which use the gas as a fuel to power boilers, engine generators, engine blowers, and other equipment. Another step in the energy conservation process is to capture the heat produced by the engines to heat the digesters and/or buildings.

Some of the more commonly used energy recovery systems and the corresponding energy conversion efficiency can be found in Table 1. Figure 2 shows a typical energy balance using engine generators as the method of energy recovery.

TABLE 1

EFFICIENCY OF ANAEROBIC DIGESTER
GAS COMBUSTION AND CONVERSION SYSTEMS

<u>PROCESS</u>	<u>ENERGY CONVERSION EFFICIENCY (%)</u>
Digester Heating	70-85
Gas Fired Boilers	75-85
Internal Combustion Engines with Full Water Jacket	30-35
With Waste Heat Recovery (a)	50-70
Engines and Electrical Generators with Full Water Jacket	25-30
With Waste Heat Recovery	60-70
Engines and Centrifugal Pumps with Full Water Jacket	25-30
With Waste Heat Recovery (b)	60-70
Engines and Positive Displacement Blowers With Waste Heat Recovery (c)	60-70
Pipe Line Quality Export (d)	70-75
Cleaned, Compressed for Vehicular Use	50-60
Steam Turbine Generator	25-30
With Waste Heat Recovery	50-60

(a) 96% generator efficiency

(b) 70% pump efficiency

(c) 70% PD blower efficiency

(d) 98% methane, 2% CO₂, 0.0001% water vapor, 0.000004% H₂S

FIGURE 2

TYPICAL ENERGY RECOVERY AND UTILIZATION SYSTEM
USING ENGINE/GENERATORS WITH HEAT RECOVERY EQUIPMENT

Table 2 - Case Studies used in the Survey

<u>City</u>	<u>Plant</u>	<u>Plant Capacity</u>	<u>Type of Energy Recovery System</u>
Birmingham, AL	Valley Creek WWTP	50 MGD	Engine Blowers
Chester, VA	Proctors Creek WWTP	14 MGD	Boilers
Dayton, OH	North Regional WWTP	11.2 MGD	Engine Generators Engine Pump
Durham, NC	Northside WWTP	9.5 MGD	Engine Blowers
Fort Worth, TX	Village Creek WWTP	120 MGD	Engine Generators and Engine Blowers
Little Rock, AR	Fourche Creek WWTP	15 MGD	Engine Generators
Plantation, FL	Plantation WWTP	15 MGD	Boilers and Auto Fuel
Tampa, FL	Hookers Point WWTP	70 MGD	Engine Generators
Virginia Beach, VA	Nansemond WWTP	10 MGD	Boilers and Engine Blower
Winston-Salem, NC	Muddy Creek WWTP	15 MGD	Boilers and Engine Blower

SURVEY PROCEDURE

Ten municipal authorities cooperated to allow evaluation of the energy and cost effectiveness of sewage treatment plants that recover energy from methane gas. Table 2 lists the participants. Technical questionnaires were mailed to each participant, requesting information on process, recovery systems, and operating and maintenance data. Financial questionnaires were also provided, requesting information on yearly cash flow, payback, and capital and operating data. The financial questionnaire was designed to approach the financial analysis from a number of different approaches in order to encourage capture of as much financial information as possible.

An environmental engineering analyst and a financial analyst contacted the participants to assist in preparation of the responses. Follow-up discussions were

held to clarify issues and to explore possibilities for additional data. Six of the planned original participants had to be replaced due to lack of sufficient data. Without exception, all of the participants cooperated fully in their efforts to provide available data. Analyses were completed for each case study and include:

- Introduction
- Description of anaerobic digestion process
- Estimated System Savings based on plant efficiency and market information during study
- Estimated financial results based on historic cost data and best judgements of participants

CASE STUDY 1

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE VALLEY CREEK WASTEWATER TREATMENT PLANT IN BIRMINGHAM, ALABAMA

INTRODUCTION

The Valley Creek Wastewater Treatment Plant (WWTP) in Birmingham, Alabama has a design capacity of 50 million gallons per day (MGD), and currently receives about 41.3 MGD influent flow. The anaerobic digestion system receives about 440,000 gallons per day (gpd) of an equal mixture of primary and waste activated sludge. The gas produced in the digestion process is used to fuel engine powered blowers. Heat produced by the engines is captured and used to heat the control building, pump building and digesters. A general plant flow diagram is shown on Figure 1.

The following sections present more detailed information on the Valley Creek WWTP anaerobic digestion process, energy recovery, energy efficiency, and estimated system costs and savings.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are seven digesters, five primary and two secondary. Three of the primary digesters and one of the secondary digesters are 65 feet in diameter and have 0.5

million gallons (MG) of capacity. The remaining tanks are all 90 ft. in diameter and hold 1.0 MG each. The gas produced in the digesters is stored in the dome of one secondary digester and in a 54 ft. diameter sphere with 82,242 cubic feet (CF) of storage capacity and a maximum storage pressure of 50 psi. Gas compressors are used to pressurize the gas for storage in the sphere. A summary of plant operating data from the period of August, 1991 through July, 1992 is shown in Figure 2.

The treatment plant is operating at about 83% of its rated capacity. The digesters achieve a 32% destruction of the volatile solids (VS) it receives from the raw sludge, producing about 7.1 cu. ft. of gas per pound (lb) of VS destroyed. The digesters have an average hydraulic detention time of almost eleven (11) days and the sludge temperatures are kept around 95°F in the summer and 90°F in the winter. The primary digesters are fed automatically using timers which control variable speed plunger pumps. The sludge feed is rotated between the primary digesters to provide an equal flow to digester volume ratio, or in other words, the 0.5 MG tanks are fed for one hour per cycle and the 1 MG tanks are fed for two hours during one cycle. The sludge in the primary digesters is continuously mixed with recirculated gas to assure consistency, to increase the metabolic rate and to reduce sludge digestion time. The overflow goes into the secondary digesters where the digested sludge is allowed to settle out and the supernatant is drawn off and returned to the head of the plant. The sludge is collected from the bottom of the digester, dewatered with belt filter presses and disposed of at a landfill.

ENERGY RECOVERY SYSTEM

The energy recovery system consists of (3) 450 HP methane gas fueled engines, each directly coupled to an 8,000 cfm blower and fitted with heat recovery equipment. The detailed specifications for this equipment is shown in Table 1. The engines are 26-28% efficient in converting fuel into work energy, but the heat recovery systems can return about 46% of the fuel energy as heat from the engine cooling water system (34%) and the engine exhaust heat recovery system (12%). Heat recovered from the engines is used to maintain the digesters at 90-95°F, heat the main control building and heat pump building "A" at the plant. The smaller digesters are insulated by earthen embankments and the larger ones are insulated with concrete, styrofoam and brick to minimize heat losses. The digester gas produced at Valley Creek has a relatively high hydrogen sulfide (H_2S) content which could build up in the engines and increase maintenance. To reduce H_2S levels, the gas is cleaned by gas purifiers containing an iron sponge which absorbs and precipitates hydrogen sulfide.

FIGURE 2

VALLEY CREEK WASTEWATER TREATMENT PLANT
BIRMINGHAM, AL
ANAEROBIC DIGESTER OPERATING DATA
(AUGUST, 1991 - JULY, 1992)

Average Operating Conditions (all digesters)

Temperature = 90.2° F
Volatile Acids = 246 mg/L
Alkalinity = 3,606 mg/L
pH = 7.1
Hydraulic detention time = 11 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

TABLE 1

VALLEY CREEK WWTP (Birmingham, AL)
ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - Jefferson County Environmental Services Dept., Birmingham, AL
Design Engineer - Paul B. Krebs & Assoc.
Contractor - Cebor Construction Co.

Equipment	Number	Manufacturer	Model #	Rating
Gas Engine Driven Blower*	3	Caterpillar	G398	450 HP
Digester Gas Storage Compressors	3	Joy	WG9LL	250 SCFM @ 50 psi
Gas Purifiers**	2	Varec	234	48,000 - 80,000 CF/day
Heat Exchangers	4 3	Bell & Gossett unknown	Varies unknown	225 GPM 200 GPM

* Driving (3) Ingersoll Rand, 8,000 CFM blowers which supply the aeration tanks.

** Uses wood shavings impregnated with hydrated iron oxide.

There are two sets of closed loop heat exchangers used to recover heat from the engines to heat the digesters. Water used to cool the engines, exchanges its heat with water that circulates back to two (2) water-to-sludge heat exchangers at the digester. Excess heat from the engine heat exchangers is dissipated via a "summertime cooler" which cools the water by passing it through the plant effluent stream with a closed system series of loops.

During normal operation, two (2) engine/blower sets are on line at the plant. The third engine/blower is used occasionally during peak demand periods, or if excess gas is being produced, but typically is kept on standby. With two of the 450 HP engines in operation, the fuel demand is about 66,900 BTU/min.

A typical energy balance diagram for the Birmingham system is shown in Figure 3.

FIGURE 3

ENERGY BALANCE FOR THE VALLEY CREEK
WASTEWATER TREATMENT PLANT
DIGESTER GAS COGENERATION SYSTEM

This energy balance is based on current average operating conditions of sludge production, operating two engines on digester gas only, gas production of 7 cu ft gas/lb VS destroyed, 32% VS destruction and 550 BTU/cu ft of digester gas. The balance also assumes that 90% of the heat recovered is used by the digesters and 10% is used by the buildings.

The volume of gas produced per pound of VS destroyed (7 cu ft/lb vs) is relatively low at the Valley Creek WWTP. However, gas sometimes escapes through the digester pressure relief valves because the gas transmission lines are too small and unable to handle the volume produced. The escaped gas is not measured, captured or used. Steps are currently being taken by plant management to correct this situation.

FINANCIAL BENEFITS

There are no data available regarding relevant capital costs, O&M costs, or revenues (savings). However, Valley Creek management estimates that annual overall savings range between \$80,000 and \$90,000. Due to the lack of actual cost and revenue data, it is not possible to produce estimates related to either cash flow or payback.

Using Alabama Power Company (APC) rates and applying plant energy usage figure from January 1993, the plant spent about \$75,000 for electrical usage. This does not include the savings realized by using digester gas to power the blower. These estimated savings in electrical costs are detailed in Table 2 and total approximately \$157,000 per year.

Plant personnel perform the routine preventive maintenance on the energy recovery system at Valley Creek, but most of the repairs are made by outside forces. As noted above, average annual operation and maintenance (O&M) cost figures on the system are not kept separately by plant management; therefore, the cost saving figures shown on Table 2 are not entirely accurate. The O&M costs should be subtracted from the estimated annual savings to get the true amount.

The WWTP also saves a significant amount of natural gas cost by recovering the heat from the blower engines to heat the buildings and digesters. These estimated natural gas cost savings, which are about \$66,500 per year, are outlined in Table 3. The total energy savings resulting from the methane gas energy recovery system is estimated to be about \$223,500 per year.

TABLE 2

VALLEY CREEK WASTEWATER TREATMENT PLANT -
BIRMINGHAM, ALABAMA
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY
(1993)

	Monthly Electrical Costs			
	Utility Rates (\$)	Using All Alabama Power Co. Electricity Use Charge (\$)	Using Electricity w/Digester Gas Supplement Use (1) Charge (\$)	
Power Supply Demand Charge	5.43/KVA	2472 KVA ⁽²⁾ 13,422.96	2,065 KVA 11,212.95	
Energy Charge	0.0431/kwhr	1,730,794 kwhr ⁽³⁾ 74,597.22	1,478,400 kwhr 63,719.04	
Total Monthly Electrical Costs		\$88,020.18	\$74,931.99	
Operation and Maintenance Costs		0.00	unknown	
Total Monthly Costs		\$88,020.18	\$74,931.99	
Total Monthly Difference			\$13,088.19	
Total Estimated Annual Savings on Electrical Costs			\$157,058.28/yr	

Notes:

(1) Based on actual usage in January, 1993.

(2) Output of two blowers = 18,100 BTU/min. If blowers were powered by electric motors, the efficiency would be about 92%. Divide 92% into 18,100 BTU/min to get 19,674 BTU/min.

$$19,674 \text{ BTU/min} \times 0.01757 \text{ KW/BTU/min} = 345.7 \text{ KW}$$

$$345.7 \text{ KW} / 0.85 \text{ Power Factor} = 406.7 \text{ KVA}$$

$$2,065 \text{ KVA} + 406.7 \text{ KVA} = 2,472 \text{ KVA}$$

(3) $19,674 \text{ BTU/min} = 8.62 \times 10^8 \text{ BTU/month}$

$$8.62 \times 10^8 \text{ BTU/mo} \times 2.928 \times 10^{-4} \text{ kwhr/BTU} = 252,394 \text{ kwhr/month}$$

KVA - Kilovolt amperes (includes consideration of power factor)

TABLE 3

VALLEY CREEK WASTEWATER
TREATMENT PLANT - BIRMINGHAM, ALABAMA
ESTIMATED ANNUAL ENERGY SAVINGS FOR NATURAL GAS
(1993)

	Monthly Natural Gas Costs			
	Unit Price	Using Natural Gas Only Use Charge (\$)		Using Digester Gas Use Charge (\$)
Natural Gas	\$0.5252/ 100 cu ft	1,173,400 cu ft ⁽¹⁾	6,162.70	117,340 cu ft ⁽²⁾ 616.27
O&M Costs		(3)		(3)
Total Monthly Costs		6,162.70		616.27
Total Monthly Difference				\$5,546.43
Total Estimated Annual Savings on Fuel Oil Costs				\$66,557/yr ⁽⁴⁾

Notes:

- (1) Average annual heat recovered and used to heat digesters and buildings:

Engine jacket - 18,750 BTU/min

Exhaust - 8,040 BTU/min

Average Volume of Natural Gas Saved

Engine Jacket - $18,750 \text{ BTU/min.} \times \text{CF}/1000 \text{ BTU} = 18.75 \text{ CF/min}$

Exhaust - $8,040 \text{ BTU/min.} \times \text{ICF}/100 \text{ BTU} = \underline{8.04} \text{ CF/min}$

Total 26.79 CF/min

$26.79 \text{ CF/min} \times 60 \text{ min/hr} \times 24 \text{ hrs/day} \times 365 \text{ days/12 months} =$
1,173,400 CF/month

- (2) Assume 10% natural gas fuel supplement which applies in cold weather only.
- (3) The O&M costs are unknown, but they should be approximately the same for each system, therefore it does not significantly effect the estimated annual savings.
- (4) Assumes all heat recovered is used to heat the digesters and buildings and none is wasted in summer cooler.

CASE STUDY 2

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE PROCTOR'S CREEK WASTEWATER TREATMENT PLANT IN CHESTER, VIRGINIA

INTRODUCTION

The Proctor's Creek Wastewater Treatment Plant (WWTP) in Chester, Virginia has a design capacity of 14 million gallons per day (MGD) and currently receives about 7.7 MGD influent flow. The anaerobic digestion system receives about 43,000 gallons per day (gpd) of a primary and waste activated sludge mixture. The gas produced by the digestion process is used to fuel boilers which provide heat to the digesters and digester building. A general plant flow diagram is shown in Figure 1.

The following sections present more detailed information on the anaerobic digestion process, energy recovery, energy efficiency and estimated system costs and savings.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are two (2) 85 foot diameter, 1.08 million gallon digesters. One of the digesters is typically operated as the primary, and the other as the secondary digester. Interconnecting piping allows the operator the flexibility of operating both digesters in either the primary or secondary mode. Sixty percent (60%) of the feed sludge to the digesters is captured in the primary clarifiers and the remainder is waste activated sludge from the secondary process. A summary of digester operating data from the period January 1990 through December 1991 is shown in Figure 2.

The treatment plant is operating at about 55% of its rated capacity and the digesters achieve a 48% destruction of the volatile solids (VS) it receives in the feed sludge. The sludge has an average detention time of 32 days and the sludge temperature in the primary digester is kept around 95°F. The digesters are approximately 32.6 feet high with about 20.3 feet being below grade. The walls are also insulated by 16 inches of concrete, 2 inches of foam and the section above ground has brick veneer. The digester covers are constructed of a 1/4" steel ceiling plate and insulated with 3" of lightweight concrete.

Primary and thickened waste activated sludge is mixed with recirculated sludge and warmed by one of two boiler/heat exchangers before it is discharged into the primary digester. The sludge is continuously recirculated through a heat exchanger to achieve consistent sludge temperatures. Digester sludge is drawn from the primary digester at the center invert and discharges into the center of the secondary digester. After reaching the secondary digester, no recirculation or heating occurs and the sludge is allowed to settle out and thicken. It is then pumped to belt filter presses where it is dewatered and land applied. The supernatant is normally drawn from the secondary digester only and is returned to the head of the plant.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system consists of two (2) anaerobic digesters with fixed covers, a gas storage sphere and two 1,250,000 BTU/hr boiler/heat exchangers. The detailed specifications for the equipment is shown in Table 1.

FIGURE 2

PROCTOR'S CREEK WASTEWATER TREATMENT PLANT
CHESTER, VIRGINIA
ANAEROBIC DIGESTER OPERATING DATA
(JANUARY, 1990 - 1992)

Average Operating Conditions (all digesters)

Temperature = 95° F
Volatile Acids = 364 mg/L
Alkalinity = 2,500 mg/L
pH = 6.8
Hydraulic detention time = 32 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

¹ Records are not kept on actual gas production, 78,132 cu ft/day is based on 6,511 lb VS lost per day and a gas production rate of 12 cu ft/lb VS destroyed

TABLE 1
ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - Proctor's Creek Wastewater Treatment Plant
Design Engineer - Metcalf and Eddy
Contractor - Envirex

Equipment	Number	Manufacturer	Model #	Rating
Boilers/Heat Exchangers	2	Envirex	712	1,250,000 BTU/hr
Gas Storage Sphere	1	Envirex	Dystor	47,000 cu ft

The boilers are approximately 80% efficient at converting digester gas into usable heat and require no filtering or compressing of the gas prior to burning. Except in very cold weather, only one of the boilers is used at a time. The second unit is used as a standby and operates on a six month rotation with the first. The boilers each have a built-in heat exchanger which transfers the heat in the water warmed by the boilers to the mixture of raw and recirculated sludge.

The gas storage sphere is a free standing unit with a dual membrane. The outer membrane is inflated with air from a small electric powered compressor and is kept at a relatively constant pressure. The inner membrane is filled with digester gas and the pressure fluctuates as the gas is produced and used. The digester gas pressure inside the bag will vary between 4.5 and 6.5 inches W.C.

During the winter months when more fuel is required to warm the digesters, nearly all of the digester gas produced is used by the boilers. In the summer months, 10-15% of the digester gas is flared off using the waste gas burner. No. 2 fuel oil is required as a fuel supplement during extremely cold weather and when there is a problem with the gas recovery system.

A typical energy balance diagram for the Chester system is shown in Figure 3. This energy balance is based on design conditions while operating only one of the boilers and assumes a primary sludge concentration of 5% TS which equals the average over the two year study period. Gas production of 15 cu. ft. gas/lb. v.s destroyed, 48% volatile solids destruction and 550 BTU/cu ft gas were used to calculate fuel usage and energy production. The boiler is assumed to be 80% efficient as suggested by the manufacturer.

FIGURE 3
 PROCTORS CREEK WASTEWATER TREATMENT PLANT
 CHESTER, VIRGINIA
 METHANE GAS ENERGY BALANCE DIAGRAM

The gas recovery and utilization system at Chester is simple, efficient, cost effective and requires little maintenance. Since the system went on line in 1988, the Owner has done no maintenance or repair on the storage sphere and the boilers require only an annual cleaning.

FINANCIAL BENEFITS

Management at Chesterfield County, VA, WWTP believes that savings attributable to methane recovery and utilization are "significant", but neither actual financial data nor estimates are available.

Plant personnel perform the routine maintenance on the boilers and few repairs have been required since the system went on line in 1988. Average annual maintenance and repair cost for the gas storage sphere and boilers is very low, but the actual amount is unknown.

The WWTP saves a significant amount of fuel oil cost by operating the boiler using digester gas to provide heat for the digester building and the digesters. The estimated annual fuel oil cost savings are nearly \$55,000 per year and are outlined in Table 2.

The energy recovery system at the Proctor's Creek WWTP is cost effective and utilizes nearly all of the digester gas produced without having to rely heavily on supplemental fuel. In 1989 a study sponsored by the Commonwealth of Virginia, Department of Mines, Minerals and Energy was performed to investigate the feasibility and cost effectiveness of using the digester gas produced at the Proctor's Creek plant to fuel engine/generators. The study concluded that an engine/generator with heat recovery would be cost effective and result in significant net annual savings.

TABLE 2
PROCTOR'S CREEK WASTEWATER TREATMENT PLANT
CHESTER, VA
ESTIMATED ANNUAL ENERGY SAVINGS FOR FUEL OIL

	Monthly Fuel Oil Costs			
	Unit Price	Using Fuel Oil Only Use Charge (\$)	Using Digester Gas and Fuel Oil Supplement Use Charge (\$)	
#2 Fuel Oil	\$0.57 / gal ⁽¹⁾	8,134 gal. ⁽²⁾ 4,636.38	100 gal ⁽³⁾ 57.00	
O&M Costs		unknown ⁽⁴⁾	unknown ⁽⁴⁾	
Total Monthly Costs Fuel Oil		4,636.38	57.00	
Total Monthly Difference			\$4,579.38	
Total Estimated Annual Savings on Fuel Oil Costs				\$54,953/yr

Notes:

(1) Average fuel price in February, 1993

(2) Average fuel consumed: Assumes one boiler is fired continuously

Boiler (design firing rate) - 26,000 BTU/min = 1.14×10^9 BTU/mo.

Assume 140,000 BTU/gallon of fuel oil = 8,134 gallons of fuel oil/mo.

(3) Assumes No. 2 fuel oil is required occasionally as an alternate fuel source during extremely cold weather or equipment downtime. Average fuel oil use is less than 1,000 gallons per year. Use 100 gallons per month.

(4) Actual O&M costs are unknown, but minimal. The O&M costs do not affect the estimated annual savings because they should be approximately the same for either fuel alternative.

CASE STUDY 3

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE NORTH REGIONAL WASTEWATER TREATMENT PLANT IN DAYTON, OH (January, 1993)

INTRODUCTION

The North Regional Wastewater Treatment Plant (NRWWTP) in Dayton Ohio has a design capacity of 11.2 million gallons per day (MGD) and currently receives about 7 MGD influent flow. The plant co-settles secondary waste sludge and raw sludge in primary clarifiers. The primary sludge is collected and pumped to anaerobic digesters for methane gas production and recovery. Currently the NRWWTP cogenerates about 90% of its electrical requirements with engine/generators that are fueled by anaerobic digester gas and by pipeline natural gas in approximately equal proportions. In addition, raw sewage lift pumps are powered by digester and natural gas-driven engines. This energy efficient plant also uses trickling filters for secondary treatment and nitrification towers for ammonia removal and is built on the side of a hill to take advantage of gravity flow through the processes. A schematic flow diagram of the NRWWTP follows in Figure 1.

FIGURE 1

FLOW DIAGRAM OF THE NORTHEAST REGIONAL
WASTEWATER TREATMENT PLANT IN DAYTON, OHIO

More detailed information on NRWTP's anaerobic digestion process, energy recovery and efficiency, and estimated system costs and savings is presented in the following sections.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There is one fixed cover 1.5 MG primary digester (80 ft. diameter) and two floating cover 1.5 MG secondary digesters (80 ft. diam.) that have a gas storage capacity of 125,000 cubic feet (cu. ft.) at 7 inches water column pressure, each. All of the digesters are built into the ground to minimize heat losses. The digesters receive primary sludge only, which includes co-settled secondary bioroughing and nitrification tower sludge removed from the treatment plant final clarifiers. A summary of the anaerobic digestion process operating data from the period of October, 1990 through October, 1992 is shown in Figure 2.

The treatment plant is operating at about 62% of its rated capacity. The digesters are efficiently operated and achieve an overall 53 percent (%) destruction of the volatile solids (VS) it receives in the primary sludge, producing about 20 cu. ft. of gas per pound (lb.) of VS destroyed. The digesters have a detention time of 82 days, and the temperatures are maintained slightly above 95°F. During normal operation, the plant uses two (2) engine generators and one (1) engine pump that run on digester gas and switch automatically to natural gas with a low digester gas pressure. The raw sewage pump engines are variable speed units that are operated from a wet well level controller. The objectives of the plant operators are to maximize digester gas production and minimize the use of purchased electric power in order to limit demand charges and electrical usage charges.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system consists of two engine/generator sets and two engine/pump sets with heat recovery on all systems. The detailed specifications for this equipment is shown in Table 1.

FIGURE 2

NORTH REGIONAL WASTEWATER TREATMENT PLANT
DAYTON, OHIO
ANAEROBIC DIGESTER OPERATING DATA
(OCTOBER, 1990 - 1992)

Average Operating Conditions (all digesters)

Temperature = 97.8° F
Volatile Acids = 345 mg/L
Alkalinity = 4,522 mg/L
pH = 7.4
Hydraulic detention time = 82 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

Design Engineer - Max Schertzenger, Inc.
 Owner - Miami Conservancy District
 Facility Contract Operator - Wheelabrator EOS, Inc.

PUMP ENGINE DATA						
Number	Manufacturer	Model No.	Rated Power (BHP)		Fuel Usage (BTU/min.)	
			@900 rpm	@1200 rpm	@900 rpm	@1200 rpm
2	Waukesha	F1905GR	186	233	21,643	29,110

Driving two (2) 7 MGD centrifugal raw sewage lift pumps, variable speed from 900-1200 rpm through right angle gear drive

GENERATOR ENGINE DATA - Two (2) engines driving asynchronous AC generators at constant speed (900 rpm) through direct couple. Same engine as above using 22,875 BTU/min. fuel.

GENERATOR DATA							
Number	Manufacturer	Continuous Duty Rating					
2	Kato Engineering Reliance Electric	115 KW	3 phase	60 Hz	277/480V	900 rpm	173 amps

TABLE 1

The engines are 26-28% efficient in converting fuel into work energy, but the heat recovery systems can return about 46% of the fuel energy as heat from the engine cooling water system (34%) and the engine exhaust heat recovery system (12%). Heat recovered from the engines is used to maintain the digesters at 95-98°F. About 90% of this make-up heat is required to heat the incoming sludge and 10% is required for digester heat losses. The digesters are built into the ground to minimize heat losses.

There are two sets of closed loop heat exchangers used to recover heat from the engines to heat the digesters. Water used to cool the engines exchanges its heat with water that circulates back to a water-to-sludge heat exchanger at the digester. Digester sludge is externally circulated through a hot water draft tube heat exchanger. If additional heat is required for the digesters, a separate heat exchanger on the exhaust gas can automatically transfer hot water to the cooling water heat exchanger, as well.

An energy balance for current operating conditions for the North Regional WWTP system is shown in Figure 3. When the plant receives higher wastewater flows and produces more sludge, the plant would be able to run two (2) engines entirely on digester gas without natural gas. The energy balance assumes primary sludge concentrations of 5.2% TS, a gas production of 15 cu ft gas/lb VS destroyed, 53% VS destruction and 550 BTU/cu ft of gas. There is usually excess heat available which can be diverted to the exhaust silencer on the engine, or to a waste heat exchanger using plant effluent water as cooling water.

The control equipment for the generators requires a lot of attention. The generator feeds directly in parallel with the main electrical distribution facility through an import/export controller. The controller uses on-site generated power, unless the voltage, synchronization and frequency are out of balance, and then it switches automatically to power from the utility company, Dayton Power & Light (DP&L).

During normal operation two (2) engine-generators and one (1) engine pump are on line at the plant. This requires about 67,000 BTU/min. of fuel, but only 29,800 BTU/min. of digester gas is currently available. Therefore, natural gas is used as a supplemental fuel to fire the engines and cogenerate electricity to avoid the high demand and energy charges from Dayton Power and Light (DP&L) Company. About 44% of the total fuel used by the engines is digester gas.

FINANCIAL BENEFITS

Although many historical accounting records are not available, the capital cost of the cogeneration facility is estimated by North Regional WWTP management to be \$988,000. Interest costs are estimated to be in the ratio of the cost of the cogeneration facility to the amount financed, or $988,000/31,395,000 = 3.15\%$. Applying this ratio to the past five years' total interest costs and adding to each 1/20 of the principal amount (assuming the term of the bonds to be equal to the equipment's useful life), annual debt service costs would be as follows:

1990	\$78,931
1989	\$79,721
1988	\$80,459
1987	\$81,111
1986	\$81,710

Natural gas is purchased to supplement methane generated on site. Because of this, management is reluctant to calculate or estimate annual savings from cogeneration. Similarly, no estimate of annual O&M costs is available.

Because of the lack of actual data regarding savings and O&M costs, it is not possible to provide payback projections.

Plant personnel perform all maintenance on the engines, except machine shop or engine rebuild work. A major part of the plant maintenance budget is consumed by work required on the engine. Maintenance is continuous on the engines, which have had cylinder head failures, valve seat recessions, and carbon accumulation in the cylinders. About \$60,000 may be spent annually to maintain the engines, or about \$0.02/kwhr of power generated. This would include materials, parts and mechanical and electrical labor.

Natural gas costs \$3.38 per million BTU, and electric rates from DP&L for the current electrical usage are as follows:

Demand charge = \$13.04/KW
Electric usage = \$0.026/kwhr

Table 2 is an analysis of the estimated potential cost savings for the NRWWTTP using digester gas. The current practice of supplementing digester gas with natural gas to operate two engine generators and one engine pump does not appear to save the plant money because of the maintenance costs for the engines and the inefficiency (27%) of converting natural gas fuel into electrical energy. However, if the plant did not purchase natural gas and operated the engines only on the available digester gas, the annual cost savings would appear to be about \$26,852. The plant would then be purchasing more electricity and would have a higher demand charge, but there would be lower maintenance costs on the engine and no natural gas charges.

FIGURE 3

ENERGY BALANCE FOR THE NORTH REGIONAL
WASTEWATER TREATMENT PLANT
DIGESTER GAS COGENERATION SYSTEM

TABLE 2

NORTH REGIONAL WWTP, DAYTON, OH
ENERGY COST ANALYSIS USING DIGESTER GAS
TO OPERATE ENGINE/GENERATORS AND ENGINE/PUMPS

<u>Energy</u>	<u>Alternative #1</u> Current Operation with Natural Gas and Digester Gas		<u>Alternative #2</u> Operation with Digester Gas Only (no Natural Gas)		<u>Alternative #3</u> Operation with No Digester Gas	
	<u>Usage</u>	<u>Annual Cost (\$)</u>	<u>Usage</u>	<u>Annual Cost (\$)</u>	<u>Usage</u>	<u>Annual Cost (\$)</u>
Electrical						
Demand (KW)	40	10,368 ^(a)	200	31,296 ^(b)	387	60,558
Usage (kwhs/d) ^(c)	<u>960</u>	<u>9,110</u>	<u>4,800</u>	<u>45,552</u>	<u>9,288</u>	<u>88,143</u>
Subtotal		19,478		76,848		148,701
Natural Gas ^(d) (x 10 ⁶ BTU/d)	54	66,620	--	--	--	--
Maintenance on Engines/Generator	--	<u>60,000</u>	--	<u>45,000</u>	--	--
Total Annual Costs		\$146,098		\$121,848		\$148,701

(a) Special minimum demand rate of \$4/KW for 216 KW/month

(b) DP&L demand costs are \$13.04/KW

(c) DP&L rate for low usage (Alternative #1) is \$0.132/kwhr and \$0.026/kwhr

(d) Natural gas cost is \$3.38/10⁶ BTU

The North Regional WWTP also saves approximately \$24,700 per year by capturing the heat from the pump and generator engines and using it to heat the digesters. Table 3 provides a detailed accounting of the estimated costs if the digesters were heated using natural gas fueled boilers in place of the existing system.

TABLE 3
NORTH REGIONAL WASTEWATER TREATMENT PLANT
IN DAYTON, OH
ESTIMATED ANNUAL ENERGY SAVINGS FOR NATURAL GAS

The engine heat recovery systems provide about 13,900 BTU/min. of heat to the digesters. The table below outlines the costs if this heat were provided by boilers fired by natural gas and the heat recovery systems were not used.

	Monthly Natural Gas Costs to Heat Digesters		
	Unit Price	Using Natural Gas Only Use Charge (\$)	Using Digester Gas Use Charge (\$)
Natural Gas	\$3.38/10 ⁶ BTU	609 x 10 ⁶ BTU ⁽¹⁾ 2,058.42	0
Total Monthly Costs		2,058.42	0
Total Monthly Difference			2,058.42
Total Estimated Annual Savings on Fuel Oil Costs ⁽²⁾			\$24,701.04/yr

Notes:

- (1) Average amount of natural gas required if the engine heat recovery system were not used to heat digesters. Assume 1,000 BTU per cuft of natural gas.
 $13,900 \text{ BTU/min} = 6.09 \times 10^8 = 609 \times 10^6 \text{ BTU/month}$
- (2) Does not include operation and maintenance cost on the methane recovery and utilization system which are included in Table 2.

CASE STUDY 4

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE NORTHSIDE WASTEWATER TREATMENT PLANT IN DURHAM, NORTH CAROLINA

INTRODUCTION

The Northside Wastewater Treatment Plant (WWTP) in Durham, North Carolina has a design capacity of 9.5 million gallons per day (MGD), and currently receives about 6.3 MGD influent flow. A plant rehabilitation and expansion project is currently under way to increase the plant capacity to 20 MGD. When the expansion is complete, the plant will receive significantly more flow as several small surrounding plants are taken out of service. The anaerobic digestion system receives about 42,300 gallons per day (gpd) of a mixture of primary and waste activated and intermediate sludge. The gas produced in the digestion process is used to fuel engine powered blowers. The Northside plant was the first in the United States to capture the heat produced by the engines and use it to heat the digesters. A general plant flow diagram is shown on Figure 1.

The following sections present more detailed information on the Northside WWTP anaerobic digestion process, energy recovery, energy efficiency, and estimated system costs and savings.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are four (4) 60 feet diameter high rate, completely mixed anaerobic digesters with a total hydraulic capacity of 1.8 million gallons. The gas produced in the digesters is stored in a 50,000 cuft wood framed floating gas holder on one of the digesters. The gas holder was built in 1933 and remains in near perfect condition. The normal storage pressure of the gas is 6.5 to 7 psi. A summary of the digester operating data from the period of January through April, 1990 is shown in Figure 2.

The treatment plant is currently operating at about 66% of its rated capacity. The digesters achieve a 45% destruction of the volatile solids (VS) it receives from the raw sludge, producing about 26 cu. ft. of gas per pound (lb) of VS destroyed. The amount of gas produced per pound of VS destroyed is much higher than the average of 12-18 CF/lbs VS destroyed. The reason for this is unknown, but it may be the result of inaccurate gas meters or the grease trap wastes, which are pumped into the digesters and are inconsistent and difficult to accurately test, may be higher in total solids and volatile solids than estimated. The digesters have an average hydraulic detention time of forty-five (45) days and the sludge temperatures are kept around 97° in the summer and 90° in the winter. Waste activated sludge is normally pumped to the primary clarifiers and co-settled with primary sludge before being pumped to the digesters. The digesters are fed on a 24 hour cycle. Sludge is pumped to a single digester for 24 hours then to the second digester for 24 hours and so on. The treatment plant also accepts about 50,000 gallons of grease trap waste per month from septage haulers. The haulers discharge the waste into holding tanks and then it is pumped directly into the digester being fed. The sludge in the digesters is continuously mixed with recirculated digester gas through draft tubes to assure consistency, increase the metabolic rate and reduce sludge digestion time. The digested sludge is dewatered with belt filter presses or sand drying beds and land applied.

ENERGY RECOVERY SYSTEM

The energy recovery system consists of (2) 275 HP methane gas fueled engines, each directly coupled to a 6,000 cfm blower and fitted with heat recovery equipment. The detailed specifications for this equipment are shown in Table 1. The engines are 26-28% efficient in converting fuel into work energy, but the heat recovery systems can return about 40% of the fuel energy as heat from the engine cooling water system (28%) and the engine exhaust heat recovery system (12%). Heat recovered from the engines is used to maintain the digesters at 90-97°F and heat the main control building. A diesel fired boiler is used to provide back up heat when the engine heat recovery system is out of order and during extremely cold weather. Before the digester gas is fed to the engines, it is passed through an air filter which separates the solids and acts as a condensate drain.

FIGURE 2

NORTHSIDE WASTEWATER TREATMENT PLANT
DURHAM, NORTH CAROLINA
ANAEROBIC DIGESTER OPERATING DATA
(JANUARY - DECEMBER, 1990)

Average Operating Conditions (all digesters)

Temperature = 93.4° F
Volatile Acids = No data
Alkalinity = No data
pH = 6.7 - 7.2
Hydraulic detention time = 45 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

TABLE 1

NORTHSIDE WWTP (Durham, NC)
ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - Department of Water Resources, Durham, North Carolina
Design Engineer - W.M. Piatt and Company
Contractor - English Construction Co.

Equipment	Number	Manufacturer	Model #	Rating
Gas Engine Driven Blower*	2	Waukesha	2895	275 HP
Boiler	1	Peerless	0-716FD-W	1.25 Mbtu/hr
Gas Filters**	1	Dolinger	-	-

* Driving (2) Roots, 6,000 CFM blowers which supply the aeration tanks.

** Separates the solids and acts as a condensate drain. Does not remove CO₂ or other gas constituents.

The heat recovery and utilization system at Northside is different than most because the heat is transferred to the digesters through coils in the digester walls instead of water-to-sludge heat exchangers. The water heated by the engine jacket and exhaust heat recovery silencer is continuously pumped through the wall coils to keep the structure warm. This system was constructed in 1933, and although it continues to work well, it isn't as efficient as conventional heat exchangers and it is difficult to keep the digester at 95°F in the winter months. Plant management is considering installing heat exchangers in a future project.

During normal operation, one (1) engine/blower set is on line at the plant. A single blower will supply enough air for the entire plant, therefore the second unit is kept on standby, but regularly rotated with the first unit. With one of the 275 HP engines in operation, the fuel demand is about 37,600 BTU/min.

A typical energy balance diagram for the Durham system is shown in Figure 3. This energy balance is based on current average operating conditions of sludge production, operating one engine on digester gas only, gas production of 26 cu ft

FIGURE 3
ENERGY BALANCE FOR THE NORTHSIDE
WASTEWATER TREATMENT PLANT
IN DURHAM, NC
DIGESTER GAS COGENERATION SYSTEM

ESTIMATED ENERGY RECOVERY EFFICIENCIES	
Engine/Blower	27%
Cooling Water Recovery	28%
Exhaust Gas Recovery	12%

gas/lb VS destroyed, 44.6% VS destruction and 550 BTU/cu ft of digester gas. The balance also assumes that 30% of the heat recovered is wasted through an aeration tank cooling loop, 95% of the remaining 70% is used to heat the digesters and the rest is used to heat the control building.

FINANCIAL BENEFITS

The system uses two gas engines, each of which cost \$145,000, or a total capital cost of \$290,000. One of the engines was purchased outright by the City. The other was financed 87 1/2% by EPA and state grants and 12 1/2% by 20 year 6% bonds.

Assuming level amortization of principal, annual debt service related to the financed amount (\$18,125) would consist of interest of \$1,088 and principal of \$906, or a total of \$1,994.

Annual O&M expenses are, perhaps conservatively, estimated at \$2,500.

Management estimates annual gross savings related to power costs saved to be \$72,398. Annual net cash flow would therefore be as follows:

Gross Savings	\$72,398
Less Debt Service	(1,994)
Less O&M	<u>(2,500)</u>
Annual Net Cash Flow	\$67,904

At this \$67,904 rate of net annual savings, the original \$290,000 investment would be recouped in about 4 1/3 years. To the extent that O&M costs may be understated, the payback term would be somewhat longer.

As noted below, our technical analysis estimates that annual electricity cost savings net of O&M costs realized by utilizing the gas engines to drive the blowers is \$69,100, and that fuel oil costs savings realized by using digester gas to provide heat for the control buildings and the digesters is \$35,500, for total savings of \$104,600 annually.

At this higher rate of savings, net cash flow would be as follows:

Gross Savings Net of O&M Costs	\$104,600
Less Debt Service	<u>(1,994)</u>
Annual Net Cash Flow	\$102,606

At this \$102,606 rate of net annual savings, the original \$290,000 investment would be recouped in about 2.8 years.

Using Duke Power Company electric rates and average fuel consumption data, the

estimated monthly electrical savings realized by utilizing the gas engines to drive the blowers is \$5,760 per month or \$69,100 per year (See Table 2). This does not include the annual operation and maintenance costs associated with the system.

The WWTP also saves a significant amount of fuel oil or natural gas costs by operating the boiler using digester gas to provide heat for the control building and the digesters. The fuel oil cost savings which are approximately \$35,500 per year are outlined in Table 3. The total energy savings resulting from the methane gas energy recovery system is estimated to be about \$104,600 per year, not including debt service.

TABLE 2
NORTHSIDE WASTEWATER TREATMENT PLANT
DURHAM, NC
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY

	Monthly Electrical Costs for Blowers				
	Utility Rates (\$)	Using All Duke Power Co. Electricity ⁽¹⁾ Charge (\$)		Using Electricity w/Digester Gas Engine Supplement ⁽²⁾ Charge (\$)	
		Use		Use	
Power Supply (on peak)	\$10.31/KW ⁽³⁾	194 KW ⁽⁴⁾	2,000.14	-0-	-0-
Demand Charge (off peak)	\$1.03/KW	194 KW	199.82	-0-	-0-
Energy Charge (on peak)	4.3370/kwhr	33,500 kwhr ⁽⁵⁾	1,452.90	-0-	-0-
(off peak)	2.2016/kwhr	107,012 kwhr	2,355.98	-0-	-0-
Total Monthly Electrical Costs			\$6,008.84		-0-
Operation and Maintenance Costs			0.00		\$250
Total Monthly Costs			\$6,008.84		\$250
Total Monthly Difference					\$5,758.84
Total Estimated Annual Savings on Electrical Costs					\$69,106.08/yr

Notes:

- (1) Assumes one blower is powered by electricity at all times.
- (2) Assumes one blower is powered by a gas engine 24 hours per day, seven days per week with no supplemental fuel.
- (3) The demand charge from June-September is \$12.98/KW and from October - May it is \$7.64/KW. The yearly average is then \$10.31/KW.
- (4) Blower output is 10,152 BTU/min. and electric motor efficiency is about 92%, therefore the blower input is 11,035 BTU/min. using electric motor.

$$11,035 \text{ BTU/min.} \times 0.01757 \text{ KW/BTU/min.} = 194 \text{ KW}$$

The gas engine reduces the electrical demand by 194 KW during both on-peak and off-peak periods since it runs at all times.

TABLE 2 (continued)

NORTHSIDE WASTEWATER TREATMENT PLANT
DURHAM, NC
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY

- (5) On peak energy use: Winter = 7 hrs/day for eight months, summer = 10 hrs/day for four months, average = 8 hrs/day

$$11,035 \text{ BTU/min} \times 60 \text{ min/hr} \times 8 \text{ hr/day} \times 21.6 \text{ days/month} \times 2.928 \times 10^{-4} \text{ kwhr/BTU} \\ = 33,500 \text{ kwhr/mo}$$

Off peak energy use: Assume 21.6 week days per month and 8.6 weekend days per month

$$\text{Weekdays} - 11,035 \text{ BTU/min} \times 60 \text{ min/hr} \times 16 \text{ hr/day} \times 21.6 \text{ day/month} \times 2.928 \times 10^{-4} \\ \text{kwhr/BTU} \\ = 66,999 \text{ kwhr/mo}$$

$$\text{Weekends} - 11,035 \text{ BTU/min} \times 60 \text{ min/hr} \times 24 \text{ hr/day} \times 8.6 \text{ day/month} \times 2.928 \times 10^{-4} \text{ kwhr/BTU} \\ = 40,013 \text{ kwhr/mo}$$

$$\text{Total off peak use} = 107,012 \text{ kwhr/mo}$$

TABLE 3

NORTHSIDE WASTEWATER TREATMENT PLANT
DURHAM, NC
ESTIMATED ANNUAL ENERGY SAVINGS FOR FUEL OIL

Monthly Fuel Oil Costs			
	Unit Price	Using Fuel Oil Only Use Charge (\$)	Using Engine Heat Recovery System Use Charge (\$)
#2 Fuel Oil	\$0.90/gal	3,556 gal ⁽¹⁾ 3,200.40	270 gal ⁽²⁾ 243.00
O&M Costs		(3)	(3)
Total Monthly Costs Fuel Oil		3,200.40	243.00
Total Monthly Difference			\$2,957.40
Total Estimated Annual Savings on Fuel Oil Costs			\$35,488.80/yr

Notes:

- (1) The heat recovery system on the engine blowers provides about 10,500 BTU/min. of heat to the digesters and main control building. If this heat was provided by boilers fueled by diesel fuel, it would require 3,286 gallons per month as calculated below

Average fuel consumed:

Boiler - 10,500 BTU/min = 4.60×10^8 BTU/mo.
 Assume 140,000 BTU/gallon of fuel oil = 3,286 gallons of fuel oil/mo.

Assume auxiliary boiler is operated on the 30 coldest days of the year

$$10,500 \text{ BTU/min} \times 60 \text{ min/hr} \times 24 \text{ hr/day} \times 30 \text{ days} = 4.54 \times 10^8 \text{ BTU/yr}$$

$$4.54 \times 10^8 \text{ BTU/yr} \times 1 \text{ yr/12 months} = 3.78 \times 10^7 \text{ BTU/mo}$$

$$3.78 \times 10^7 \text{ BTU/mo} \times 1 \text{ gal/140,000 BTU} = 270 \text{ gal/mo}$$

- (2) Using engine generator only, the fuel oil used by the auxiliary boiler is included (270 gal/mo)

- (3) The O&M costs are unknown, but they should be near the same for each fuel alternative.

CASE STUDY 5

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE CITY OF FORT WORTH VILLAGE CREEK WASTEWATER TREATMENT PLANT

INTRODUCTION

The Village Creek Wastewater Treatment Plant in Ft. Worth, Texas has a design capacity of 120 million gallons per day (mgd), and currently receives about 112 mgd influent flow. The anaerobic digestion system receives about 870,000 gallons per day (gpd) of an equal mixture of primary and waste activated sludge. The gas produced from the digestion process is used to power two engine generators, two engine blowers and one auxiliary boiler. The heat from the engines is captured and used as the primary heat source for the digesters. A general plant flow diagram is shown in Figure 1.

The following sections present more detailed information on the Village Creek anaerobic digestion process, energy recovery and utilization and estimated system costs and savings.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are fourteen (14) high rate, completely mixed anaerobic digesters. They are 90 feet in diameter and each has 1.3 million gallons of capacity. The gas produced by the digestion process is stored in the domes of the floating covers and a storage sphere with 225,000 cu. ft. of capacity at 46 psig working pressure. A summary of digester operating data from the period October, 1989 through September, 1991 is shown in Figure 2.

The treatment plant operates at about 93% of its rated capacity. The digesters achieve a 22% destruction of the volatile solids (VS) it receives in the feed sludge, producing about 20 cubic feet of gas per pound of VS destroyed. The digesters have an average detention time of almost 20 days and the sludge temperatures average 90°F (95°F over the last 12 months of the study period). The digesters are fed in series on an approximate 10 minute rotation basis. Prior to entering the digesters, the feed sludge is injected with digester gas to improve mixing and heating. The digester sludge is continuously mixed using a draft tube gas lift mixing system and mechanical agitators to assure consistency, increase the metabolic rate and reduce sludge digestion time. About 70% of the digested sludge is disposed of by a private contractor who dewateres and land applies it, and the remaining sludge is pumped to sand drying beds. The City uses the material as a soil supplement on its own property. Approximately 100 dry tons of sludge is produced per day.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system has four (4) methane gas fueled engines with heat recovery systems driving two (2) generators and two blowers. There are also four (4) gas compressors, ten (10) heat exchangers and one (1) boiler. The detailed specifications for the equipment are shown in Table 1.

The methane gas driven engine generators and blowers are 25-30% efficient in converting fuel into work energy, but the heat recovery systems can return about 40% of the fuel energy as heat from the engine cooling water system (28%), and the engine exhaust heat recovery system (12%). Heat recovered from the engines is used to maintain the digesters at 90°F by continuously recirculating sludge through water-to-sludge heat exchangers. The heat from the engines warms water which is passed through the heat exchanger and the heat in the water is transferred to the sludge which is then returned to the digester. If additional heat is required, the auxiliary boiler is used. The methane recovery system is not able to transfer all of the gas produced to the compressors because of piping problems and therefore an average of 20%-25% of the gas is flared off using the waste gas burners. The rest of the gas is compressed and stored in the storage sphere or used immediately by the engines. The digesters produce an average of 746,000 cu. ft. of gas per day which converts to about 285,000 BTU/min of energy, assuming the gas is 62% methane and

FIGURE 2

VILLAGE CREEK WASTEWATER TREATMENT PLANT
FT. WORTH, TEXAS
ANAEROBIC DIGESTER OPERATING DATA
(OCTOBER, 1989 - SEPTEMBER, 1991)

Average Operating Conditions (all digesters)

Temperature = 90° F
Volatile Acids = 367 mg/L
Alkalinity = 3,213 mg/L
pH = 7.2
Hydraulic detention time = 20 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

TABLE 1
ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner -Ft. Worth Water Department - Wastewater Treatment Division
Design Engineer - Freese and Nichols Consulting Engineers
Contractor - Martin K. Edy

Equipment	Number	Manufacturer	Rating
Boilers	1	Cleaver Brooks	150 HP
Gas Engine Driven Generators	2	Cooper Energy	1 - 1760 HP, 1275 KW 1 - 1620 HP, 1170 KW
Gas Engine Driven Blowers	2	Cooper Energy Root	2 - 1200 HP 25,000 CFM
Heat Exchangers	4 6	Dorr Oliver Dorr Oliver	2 million BTU/hr 1 million BTU/hr
Compressors	4	Worthington	2 - 272 CFM, 50 HP 2 - 513 CFM, 75 HP

each cubic foot of gas produces 550 BTUs. A typical energy balance diagram for the Village Creek system is shown on Figure 3. This energy balance is based on current average operating conditions of sludge production and assumes four engines are operating.

During normal operation both engine blowers and both engine generators are on-line 24 hours per day, seven days per week to reduce electric demand charges. The engines are capable of running on digester gas, natural gas or diesel fuel, but at least 10% of the feed must be diesel fuel to provide adequate spark. The methane recovery system will not handle enough digester gas to run all four engines therefore supplemental diesel fuel or natural gas is always required. Currently, natural gas is less expensive than diesel fuel in the Forth Worth area.

The City of Forth Worth is currently conducting a Prime Power Evaluation to review the history of the existing energy utilization system and investigate the feasibility of installing additional electric generation facilities. The upgrade being considered includes a 5,210 HP, 3,765 KW engine generator set, additional fixed cover digesters with gas storage, additional gas compression facilities, a new 800 HP auxiliary boiler, and possibly a gas scrubbing system. The existing on-site generation

FIGURE 3

ENERGY BALANCE FOR THE
CITY OF FORT WORTH, VILLAGE CREEK
WASTEWATER TREATMENT PLANT
DIGESTER GAS COGENERATION SYSTEM

Notes:

- The design full load firing rate for all four engines is 695,527 BTU/min. Based on data from fiscal year 1990-91, the engines used an average of 466,134 BTU/min.
- Assume 20% of digester gas is flared off.

facilities will produce approximately 30% of the plant's total electrical demand and the proposed upgrade could increase this to a total of 70%.

FINANCIAL BENEFITS

Management calculates the probable initial investment related to the methane recovery and utilization equipment to be \$5,928,370. The investment was financed by a combination of federal grants and bond sales. Annual debt service outlay is estimated at \$509,672. Annual O&M costs are calculated at \$156,662.

When compared to the alternative of purchasing electricity at the FY 90/91 rate of 2.41¢/KWH, management estimates the annual savings realized through the production of electricity to be \$1,281,461. In addition, \$98,420 is saved through the jacket water heat recovery system; total annual savings are therefore \$1,379,881.

Net savings would be calculated as follows:

Gross Savings	\$1,379,881
Less O&M	(156,662)
Less Debt Service	<u>(509,672)</u>
Net Savings	\$713,547

At an annual net savings rate of \$713,547, the initial capital investment of \$5,928,370 would be recouped in approximately 8 1/3 years.

Currently, electricity is the most expensive fuel source in the Fort Worth area, and plant management is investigating ways to use alternate fuels to produce more of the required electricity on site. With a 37% electrical demand increase scheduled to go into effect in August, 1993, producing more of its own electricity from purchased natural gas will become more cost effective to the plant.

On the attached Table 2, a comparison of costs has been made to determine how much the Village Creek WWTP saves by using digester gas powered engine/generators and blowers. If the electricity produced by the generators was purchased from Texas Utilities (TU), and if the two engine/blowers were powered by electricity purchased from TU, the annual cost savings is about \$357,000.

This does not include annual operation and maintenance costs on the system or debt service. The Village Creek WWTP's methane recovery system also saves approximately \$188,000 per year in diesel fuel or natural gas cost (refer to Table 3) by capturing the heat from the engines and using it to heat the digesters. The total energy savings resulting from the energy recovery system is approximately \$545,000 per year.

TABLE 2

VILLAGE CREEK WASTEWATER TREATMENT PLANT
IN FT. WORTH, TEXAS
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY

	Monthly Electrical Costs				
	Utility Rates (\$)	Using All Texas Utilities (TU) Power		Using Engine/Generator and Blowers	
		Use	Charge (\$)	Use	Charge (\$)
Demand Charge	10.71/KW ⁽¹⁾	2,387 KW ⁽²⁾	25,564.77	0	0
Energy Charge	0.024152/kwhr	1,741,285/kwhr ⁽³⁾	42,055.52	0	0
Supplemental Fuel Costs					
Natural Gas	\$2.26/MM BTU	0	0	5,212 MM BTU ⁽⁴⁾	11,779.12
Diesel Fuel	\$0.70/gal	0	0	37,228 gal ⁽⁴⁾	26,059.60
Total Monthly Costs			67,620.29		37,838.72
Total Monthly Difference					29,781.57
Total Estimated Annual Savings on Electrical Costs ⁽⁵⁾					\$357,378.84/yr

Notes:

- (1) Current rate is \$10.71/KW, but this is scheduled to increase to \$14.50/KW in August, 1993.
- (2) The two generators produced an average of 79,049 BTU/min. and the blowers 52,258 BTU/min. in fiscal year 1990-91. If the blowers were powered by electric motors with a typical efficiency of 92%, the fuel required by the blowers would be (52,258 BTU/min./0.92) 56,802 BTU/min.
The total fuel demand is 79,049 + 56,802 = 135,851 BTU/min.
135,851 BTU/min. x 0.01757 KW/BTU/min. = 2,387 KW
- (3) Average Energy Use - Assumes all four engines run 24 hrs/day, seven days/week.
135,851 BTU/min. x 60 min./hr x 24 hrs./day x 30.4 days/mo. x 2.928×10^{-4} kwhr/BTU = 1,741,285 kwhr/mo.
- (4) Based on past performance, approximately 49% (228,000 BTU/min.) of the fuel used to run all four engines is digester gas and 51% (238,134 BTU/min) is either diesel fuel or natural gas. Assume that half of the supplemental fuel is diesel and half is natural gas. The amount of supplemental fuel required per month to produce 238,134 BTU/min. is as follows.

Natural Gas

- 238,134 BTU/min x 50% = 119,067 BTU/min.
- 119,067 BTU/min. x 60 min/hr x 24 hr./day x 30.4 days/mo. = 5,212 MM BTU/month

Diesel Fuel

- 5,212 MM BTU/month x 1 gallon./140,000 BTU = 37,228 gallons/mo.

- (5) Does not include operation and maintenance costs.

TABLE 3

VILLAGE CREEK WASTEWATER TREATMENT PLANT
IN FT. WORTH, TEXAS
ESTIMATED ANNUAL ENERGY SAVINGS FOR NATURAL GAS

The engine heat recovery systems provide about 186,453 BTU/min. of heat to the digesters. The table below outlines the costs if this heat were provided by boilers fired by natural gas and the heat recovery systems were not used.

	Monthly Natural Gas Costs to Heat Digesters		
	Unit Price	Using Natural Gas Only Use Charge (\$)	Using Digester Gas Use Charge (\$)
Natural Gas	\$2.26/MM BTU	6,938 MM BTU ⁽¹⁾ 15,679.88	0
Total Monthly Costs		15,679.88	0
Total Monthly Difference			\$15,679.88
Total Estimated Annual Savings on Fuel Oil Costs ⁽²⁾			\$188,158.56/yr

Notes:

- (1) Average heat supplied by engine heat recovery system
 $158,485 \text{ BTU/min} = 6.94 \times 10^9 \text{ BTU/month} = 6,938 \text{ MM BTU/month}$

Assumes that 30% of the recovered heat is not required for digester heating in the summer months (6 months/year). This amounts to 15% of heat wasted over the entire year.

- (2) Does not include operation and maintenance cost on the methane recovery and utilization system.

CASE STUDY 6

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE FOURCHE CREEK - LITTLE ROCK, AK WASTEWATER TREATMENT PLANT

INTRODUCTION

The Fourche Creek Wastewater Treatment Plant (WWTP) in Little Rock, Arkansas has a design capacity of 15 million gallons per day (mgd), and currently receives about 17.5 mgd influent flow. It is designed to reduce the pollutant load by approximately 90% and utilizes two parallel secondary treatment processes. The anaerobic digestion system receives about 290,000 gallons per day (gpd) of feed sludge. The gas produced by the digestion process is used to power three engine generators which supply all of the electricity used by the plant. The heat from the engines is captured and used to heat the digesters and two on-site buildings. A general plant flow diagram is shown in Figure 1.

FIGURE 1

SCHEMATIC DIAGRAM OF FOURCHE CREEK
15 MGD WWTP IN LITTLE ROCK, AK

The Fourche Creek plant is a secondary treatment facility constructed in 1983 and upgraded in 1989. It operates in tandem with the Adams Field WWTP to provide wastewater treatment to the Fourche Creek valley. Sludge from both of the plants is thickened, digested and stored at the Fourche Creek Plant.

More detailed information on the anaerobic digestion process, energy recovery, energy efficiency, and estimated system costs and savings is presented as follows.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are eight (8) 100 foot diameter, 1.0 million gallon digesters. Six are used as primary digesters with fixed concrete covers and two as secondary digesters with floating covers capable of storing up to 125,000 cubic feet (CF) of gas at 10" w.c. Primary and waste activated sludge from the Adams Field and Fourche Creek WWTPs is thickened by gravity thickeners prior to being pumped to the primary digesters. A summary of plant operating data for the anaerobic digestion process from the period of January, 1990 through December, 1991 is shown in Figure 2.

The treatment plant is operating at about 100% of its rated capacity. The digesters achieve a 49% destruction of the volatile solids (VS) it receives in the feed sludge, producing about 14.4 cubic feet of gas per pound of VS destroyed. The digesters have an average detention time of 30 days and the sludge temperature in the primary digester is kept around 98°F.

The primary and waste activated sludge mixture is thickened in one of four 175,000 gallons, 52 ft. diameter gravity thickener tanks. It is then mixed with recirculated sludge and warmed by heat exchangers before it is discharged into the primary digesters. Sludge is fed to each of the six primary digesters on a two (2) hour rotation basis. After entering the digesters, the sludge is continuously recirculated through the heat exchangers to keep it warm. The sludge in the digesters is mixed using digester gas compressors to assure consistency, increase the metabolic rate and reduce sludge digestion time. After approximately 20 days, the sludge is drawn from the primary digesters and discharged into the secondary digesters. After reaching the secondary, no recirculation or heating occurs and the sludge is allowed to settle out and thicken. From there it is pumped to sludge storage basins where it remains until it is land applied on a local sod farm. The supernatant is normally drawn from the secondary digester only and is pumped to the sludge storage basins where it is decanted to the head of the plant.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system has three (3) 800 horsepower (HP) engines, three (3) 500 kilowatt (KW) engine driven generators with heat recovery systems, six (6) heat exchangers and two (2) gas purifiers. The detailed specifications for the equipment is shown in Table 1.

FIGURE 2

FOURCHE CREEK WASTEWATER TREATMENT PLANT
LITTLE ROCK, AK
ANAEROBIC DIGESTER OPERATING DATA
(JANUARY 1990 - DECEMBER 1992)

Average Operating Conditions (all digesters)

Temperature = 98° F
Volatile Acids = 113 mg/L
Alkalinity = 2,156 mg/L
pH = 7.1
Hydraulic detention time = 30 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

TABLE 1
ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - Little Rock Waste Water Utility
Design Engineer - Garver and Garver Engineers
Contractor - Neilson's, Inc.

Equipment	Number	Manufacturer	Model #	Rating
Gas Engine	3	White Superior	8G825	800 HP
Driven Generators	3	CATO	--	500 KW
Heat Exchangers	6	American Heat Reclamation	unknown	unknown
Gas Purifiers*	2	Varec	234	unknown

* Uses wood chips impregnated with hydrated iron oxide.

The methane gas driven engine generators are 17-20% efficient in converting fuel into work energy, but the heat recovery systems can return about 40% of the fuel energy as heat from the engine cooling water system (28%), and the engine exhaust heat recovery system (12%). Heat recovered from the engines is used to maintain the digesters at 98°F by continuously recirculating sludge through water-to-sludge heat exchangers. The heat from the engines warms water which is passed through the heat exchangers. The heat in the water is transferred to the sludge which is then returned to the digester. Excess heat from the engines is dissipated using plant process water circulated through an auxiliary heat exchanger.

Before entering the generator engines, the digester gas is passed through sodium hydroxide-impregnated filters which remove hydrogen sulfide and other corrosive gases. During normal operation two of the three engine generators are on-line at the plant and tied into the plant's main electrical grid. The third unit is used solely as a standby and started only when one of the other two units are out of service. Two of the engines can use more digester gas than can be produced and therefore none is wasted or flared off. With two of the engines operating, the average fuel demand is approximately 148,000 BTU/min., while the digesters are producing approximately 121,000 BTU/min. The fuel deficit which is about 1% in the winter and 10% in the summer, is made up with supplemental natural gas. The on-site electric generation facilities supply all of the electrical requirements of the plant and will occasionally produce an excess which is sold to the Arkansas Power and Light Company.

A typical energy balance diagram for the Fourche Creek system is shown in Figure 3. This energy balance is based on current average operating conditions of sludge production and assumes two engines are operating. It also assumes the filtered gas is 65% methane, produces 550 BTU per cubic foot of digester gas and 10% of the required engine heat is wasted through the auxiliary heat exchanger because it is not required to heat the digester. The plant actually wastes about 30% of the recovered heat in the summer months and none of it throughout the winter.

FINANCIAL BENEFITS

In a paper presented in 1989⁽¹⁾, which is quoted extensively in the following paragraphs, the cost of the cogeneration complex is stated as \$2.4 million. Based on a 20-year project life and 7% annual interest rate, annual debt service costs are projected at \$224,000.

The paper indicates that, for the first five years, the cogeneration complex's cash expenditures (annual debt service and O&M expenses) exceeded revenues (defined as annual receipts for power sold plus the value of power consumed in the plant). Two primary reasons for this deficiency were:

- higher than anticipated O&M expenses; and
- the low revenue realized from the local power authority;

with the latter being the most significant reason. However, in 1989, a major addition to the Fourche Creek plant went on line, resulting in a 300% increase in the plant's electric power needs. As a result, since sales to the local power authority immediately became minimal, cash flow became positive. Since savings from the value of power consumed in the plant are projected to increase during the remaining life of the facility because of the tendency for the local power authority's rates to increase over time, while annual debt service costs, by definition, are a constant, cash flow will tend to become increasingly more positive.

Based on historical projections, the \$2.4 million capital cost will be recouped in the fifteenth year of operation. However, if the first five years' deficits are ignored, the capital cost is projected to be recovered in the ninth year of positive cash flow.

(1) "Cogeneration of Electricity: Is it "Really" Cost Effective? A Case Study"; Presented at the Waste-to-Energy Conference, Lake De Gray State Park, November 16-17, 1989; by Rick L. Barger, P.E., DEE, Director of Operations, and James A. Barham, Director of Finance and Administration, Little Rock Wastewater Facilities.

FIGURE 3
FOURCHE CREEK - LITTLE ROCK, AK
WASTEWATER TREATMENT PLANT
METHANE GAS ENERGY BALANCE DIAGRAM

Actual, through 1988, and projected, through 2003, excesses (deficiencies) of net annual value (annual electricity value minus debt service and O&M costs) are as follows:

1984	\$(39,580)	1994	\$315,000
1985	(251,486)	1995	342,000
1986	(103,005)	1996	370,000
1987	(86,538)	1997	400,000
1988	(159,063)	1998	431,000
1989	198,500	1999	464,000
1990	220,000	2000	498,000
1991	242,000	2001	534,000
1992	265,000	2002	572,000
1993	290,000	2003	615,000

Wander Associates' technical analysis yielded complementary conclusions. Plant personnel perform the routine maintenance and make most of the repairs to the energy recovery and utilization system. The operation and maintenance costs from 1984 to 1988 averaged about \$130,000 per year or \$0.027 per Kwh produced. For budgeting purposes, management uses \$0.03/Kwh for O&M costs. All three of the generator engines had to be overhauled only two years after the system was installed, but since then no unusual problems have been encountered.

Based on data recorded during February 1992, the plant produced an average of 483,170 cubic feet of digester gas per day with an energy value of 585 Btu/cu ft. An average of 22,770 cu ft/day of natural gas with an estimated energy value of 1,000 Btu/cu ft was also purchased. These two gases combined were used to power two engine generators which produced an average of 13,622 kwhr of electricity. Using these figures, the efficiency of the engine generators is only about 17.5%. A conversion efficiency of about 25-30% is normally expected on systems similar to Fourche Creek's. Nonetheless, the methane utilization system saves the WWTP approximately \$59,200 per year in electricity costs, not including debt service (refer to Table 2) or electricity sold to Arkansas Power and Light.

The Fourche Creek WWTP also saves approximately \$105,000 per year by capturing the heat from the generator engines and using it to heat the digesters. Table 3 provides a detailed accounting of the costs if the digesters were heated using natural gas fueled boilers in place of the existing system.

The total estimated energy savings resulting from the energy recovery system is approximately \$164,200 per year.

TABLE 2
FOURCHE WASTEWATER TREATMENT PLANT
IN LITTLE ROCK
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY
(Based on Data Recorded in February, 1992)

	Monthly Electrical Costs				
	Utility Rates (\$)	Using All AP&L Utilities Power		Using On-Site Generator Facilities	
		Use	Charge (\$)	Use	Charge (\$)
Demand Charge	9.03/KW ⁽¹⁾	663 KW ⁽²⁾	5,986.89	723 KW	0
Energy Charge	0.03458/kwhr ⁽¹⁾	394,717/kwhr ⁽²⁾	13,649.31	394,717	0
Supplemental Fuel Costs					
Natural Gas	0.4130/CCF	0	0	6,926 CCF ⁽³⁾	2,860.44
O&M Costs	\$0.03/kwhr ⁽⁴⁾	0	0	394,717	11,841.51
Total Monthly Costs			19,636.20		14,701.95
Total Monthly Difference					4,934.25
Total Estimated Annual Savings on Electrical Costs ⁽⁵⁾					\$59,211.00/yr

Notes:

- (1) If electricity used at the WWTP were purchased from Arkansas Power and Light, the demand charge would be \$10.02/KW from June to September and \$8.53/KW from October to May. This averages out to \$9.03/KW. The energy use charge would be \$0.0389/kwh (June to Sept) and \$0.03242/kwhr (Oct. to May) or average \$0.0345/Kwhr.
- (2) The maximum daily kilowatt hours used in February 1992 was 15,920 Kwhr or 663 kw which is being used as the basis of the demand charge. The average daily kilowatt hours used was 12,977 kwhr which equals 394,717 kwhr/month
- (3) To produce the electricity noted in item (2), an average of 22,770 cuft/day (692,588 cuft/month) of natural gas was required as a fuel supplement.
- (4) The operation and maintenance costs between 1984 and 1988 for the cogeneration facilities was \$130,000 per year or \$10,833 per month. This converts to about \$0.027/kwh produced, however for budget purposes, \$0.03/kwh is used.
- (5) Does not include annual debt service.

TABLE 3

FOURCHE WASTEWATER TREATMENT PLANT
IN LITTLE ROCK, AK
ESTIMATED ANNUAL ENERGY SAVINGS FOR NATURAL GAS

The engine heat recovery systems provide about 48,430 BTU/min. of heat to the digesters. The table below outlines the costs if this heat were provided by boilers fired by natural gas and the heat recovery systems were not used.

Monthly Natural Gas Costs to Heat Digesters			
	Unit Price	Using Natural Gas Only Use Charge (\$)	Using Digester Gas Use Charge (\$)
Natural Gas	\$0.4130/CCF	21,200 CCF ⁽¹⁾ 8,755.60	0
Total Monthly Costs		8,755.60	0
Total Monthly Difference			8,755.60
Total Estimated Annual Savings on Fuel Oil Costs ⁽²⁾			\$15,067.20/yr

Notes:

- (1) Average amount of natural gas required if the engine heat recovery system were not used to heat digesters. Assume 1,000 BTU per cuft of natural gas.

$$48,430 \text{ BTU/min} = 2.12 \times 10^9 \text{ BTU/month}$$

$$2.12 \times 10^9 \text{ BTU/month} \times \text{cuft}/1,000 \text{ BTU} = 2,120,000 \text{ cuft} = 21,200 \text{ CCF}$$

Assumes that 30% of the recovered heat is not required for digester heating in the summer months (3 months/year). In the winter, all of the heat is used and in the spring and fall about 10% is wasted. The average amount wasted for the whole year is about 10%.

- (2) Does not include operation and maintenance cost on the methane recovery and utilization system which are included in Table 2.

CASE STUDY 7

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE CITY OF PLANTATION, FL WASTEWATER TREATMENT PLANT

INTRODUCTION

The Plantation Wastewater Treatment Plant (WWTP) in Plantation, Florida has a design capacity of 15 million gallons per day (MGD), and currently receives about 10.5 MGD influent flow. The anaerobic digestion system receives about 25,000 gallons per day (gpd) of a mixture of primary and secondary sludges. The gas produced by the digestion process is used to fuel boilers, power an emergency generator and as an alternative fuel for city vehicles converted to use methane gas. A general plant flow diagram is shown in Figure 1 below. More detailed information on the WWTP's anaerobic digestion process, energy recovery, energy efficiency and estimated system costs and savings are presented in the following sections.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are four (4) 55 foot diameter, 373,000 gallon digesters. Three (3) are operated as primary digesters and the other as a secondary digester. The primary digesters have covers that float on the liquid and provide no gas storage capacity, while the secondary digester has a gas holding cover with 15,000 cubic feet (CF) of capacity at 9 in. water column (W.C.). The primary digesters are fed continuously on an 8 hour rotation with a mixture of primary and secondary sludge. The primary sludge is fed continuously at a feed rate of 80 gallons per minute, and secondary sludge is fed on the basis of plant wasting requirements. A summary of digester operating data from the period January, 1990 through December, 1991 is shown in Figure 2. It should be noted that the WWTP received approximately 2 MGD of drinking water from the water treatment plant during the period of June to December, 1991 because a valve was inadvertently left open. This added flow diluted the incoming sewage and the digestion process was adversely affected due to the high salt content in the water. If not for this problem, the digester feed rates, volatile solids production and gas production would have been higher.

The treatment plant is operating at about 70% of its rated capacity. The digesters achieve a 28% destruction of the volatile solids (VS) received in the feed sludge, producing about 11.0 cubic feet of gas per pound of VS destroyed. The digesters have an average detention time of 45 days and the sludge temperature in the primary digesters is kept around 95°F.

Primary and centrifuge thickened waste activated sludge are mixed with recirculated sludge and warmed by one of three boiler heat exchangers before it is discharged into the primary digesters. The sludge is continuously recirculated through the heat exchangers to achieve consistent sludge temperatures. A draft tube gas lift mixing system compresses the digester gas and discharges it through lances in the draft tubes. The system is designed to recirculate the digester contents in 20 minutes. Digester sludge is drawn from the primary digesters through lines at the center invert and discharges into the center of the secondary digester. After reaching the secondary, no recirculation or heating occurs and the sludge is allowed to settle out and thicken. From there it is pumped to belt filter presses and land applied by a private contractor. The supernatant is normally drawn from the secondary digester only and is pumped to the head of the plant.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system consists of three (3) 1,125,000 BTU/hour boiler/heat exchangers, one 1500 KVA emergency (stand-by) generator, a digester gas scrubber and seven city owned vehicles converted to operate on methane gas. The detailed specifications of the equipment is shown in Table 1 as follows.

FIGURE 2

CITY OF PLANTATION WASTEWATER TREATMENT PLANT
PLANTATION, FLORIDA
ANAEROBIC DIGESTER OPERATING DATA
(JANUARY 1990 - DECEMBER 1991)

¹ Assumes 66% Primary Sludge
and 33% Secondary Sludge

Average Operating Conditions (all digesters)

Temperature = 95° F
pH = 7.1
Hydraulic detention time = 45 days
Volatile Acids/Alkalinity Ratio = 0.39

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

TABLE 1

ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - City of Plantation, Florida
 Design Engineer - Camp Dresser & McKee
 Contractor - Widdell Associates

Equipment	Number	Manufacturer	Model #	Rating
Boilers/Heat Exchangers	3	Walker Process	Heat X-EB	1,125,000 BTU/hr
Gas Engine Driven Generator	1	Caterpillar		1500 KVA
Gas Scrubber	1	Alameda Tank Co.	246	350 PSI @ 200°F
Compressors	1	RIX	2KX2G-100	2000 CFH

The boiler heat exchangers are approximately 80% efficient at converting digester gas into usable heat, and the engine driven generator is 25-30% efficient in converting fuel into work energy. The engine driven generator does not have a heat recovery system because it is used as an emergency standby unit and runs only during plant power outages. During normal operation, each of the three primary digesters is heated by its own boiler/heat exchanger although the piping system is designed to allow heating of all digesters by any of the three boilers.

The average ambient temperature is about 80°F in Plantation, Florida, and a minimal amount of heat is required to keep the digesters at 95°F. Therefore, less than 30% of the digester gas produced is required to fuel the boilers. The boilers use natural gas as a backup fuel source if there is a problem with the methane recovery system, but this rarely occurs since the average firing rate of the boiler is only 3300 BTU/min.

The hydrogen sulfide (H₂S) concentration in the digester gas can vary from 2 parts per million (ppm) to 8,000 ppm. The high H₂S concentrations are caused by salt water infiltration which is common for this City near the ocean. To limit H₂S production, ferric chloride is mixed with the feed sludge to form insoluble iron salts. In addition to the H₂S, the digester gas contains about 60-70% methane, 30-35% carbon dioxide and low levels of nitrogen and hydrogen. Before it is used as fuel for

the engine/generator or the methane gas powered automobiles, the gas is purified using a gas scrubbing tower. The gas is compressed and forced up the tower while a counter flow of reclaimed secondary effluent is sprayed through it. The effluent water absorbs the contaminants and leaves the purified methane to exit the top of the tower. After the water has passed through the tower, it is discharged to the aeration basins.

The Plantation gas scrubbing tower is easy to operate and maintain, does not require the use of chemicals and produces methane gas that is better than 99% pure. When the methane leaves the tower, it is dried and stored in gas cylinders at a pressure of 3,600 psi. The cylinders are arranged in three banks of 20 cylinders each and are operated in series. The gas is then either used in the engine generator, or regulated down to 2400 psi, and used in the modified methane gas powered automobiles.

Operating the automobiles on methane gas requires a conversion system consisting of a gas/air mixer, pressure and regulator lines, control panel gas tanks and a refueling connection. The conversion equipment requires little modification to the vehicle, leaves the gasoline system intact and can be transferred to replacement vehicles. A dash mounted fuel gauge and selector switch allows the driver to see when the methane gas is getting low and allows switching to gasoline while driving. The only apparent drawbacks to the system are a loss of trunk space due to the cylinders, a slight reduction in acceleration and a slight odor emission during refueling.

Originally, 16 utility vehicles and 23 police patrol cars were to be converted to methane gas. Currently only 7 vehicles have been converted and there are no immediate plans to convert more. Plant management is strongly in favor of converting more vehicles, but have been unsuccessful at obtaining authorization from the city government because of resistance from the users.

The converted automobiles use a very small percentage of the gas produced and the boiler/heat exchangers require only about 25-30% of the gas, therefore, up to 70% of the digester gas produced is flared off. The City of Plantation investigated the possibility of selling their excess gas to the local gas utility, but found it to not be cost effective. The required gas meter, regulator, quality monitor and other appurtenances would have cost in excess of \$500,000, and with the relatively small amount of gas produced, it could not be justified.

A typical energy balance diagram for the City of Plantation Wastewater Treatment Plant digester gas recovery system is shown in Figure 3. This energy balance is based on current average operating conditions of sludge production, while operating three boilers with a total average firing rate of 3,300 BTU/min.

FIGURE 3
CITY OF PLANTATION, FLORIDA
WASTEWATER TREATMENT PLANT
DIGESTER GAS ENERGY BALANCE DIAGRAM

ESTIMATED ENERGY RECOVERY ASSUMPTIONS	
Boilers	80%
Engine/Generator	28%
93% of methane will be recovered from scrubbing tower	
99% methane produces 1,000 BTU/CF of gas	
Digester gas is 65% methane, therefore it loses 35% of its volume in scrubbing tower	

FINANCIAL BENEFITS

Actual data regarding the Plantation WWTP's energy recovery and utilization system are not available. The following paragraphs summarize Wander Associates' savings estimates.

Plant personnel perform routine maintenance and make most of the repairs to the energy recovery and utilization systems. Average annual operation and maintenance (O&M) costs are not kept on individual systems such as this, therefore, the cost savings figures shown on the attached Table 2 do not include plant O&M costs. There have been no major problems with the systems, and O&M costs are minimal.

The boilers at the Plantation WWTP are equipped to use diesel fuel if the digester gas recovery system is not operational. If digester gas were not used to fuel the boilers and diesel fuel was used instead, the increase in cost would be approximately \$900 per month, or \$10,700 per year. A detailed accounting of these figures is shown in Table 2.

The methane powered vehicle utilization system is not being used in the most cost effective way. There are no records to document the actual cost of operating the system or the amount of gasoline saved, but the system would undoubtedly be more efficient and cost effective if more vehicles were converted to methane gas. An estimate of the current gasoline savings is shown on Table 3. The current annual savings are \$9,331, or about \$1,333 per car per year. If 39 vehicles are converted as originally planned, and the same assumptions are applied, the annual gasoline savings would be \$51,987. These savings do not include plant O&M costs for the gas processing system.

TABLE 2

CITY OF PLANTATION, FLORIDA WASTEWATER TREATMENT PLANT
ESTIMATED ANNUAL ENERGY SAVINGS FOR DIESEL FUEL

	Monthly Diesel Fuel Costs			
	Unit Price	Using Diesel Fuel Only ⁽¹⁾ Use Charge (\$)	Using Digester Gas ⁽²⁾ Use Charge (\$)	
Diesel Fuel Oil	\$0.90/gal	1,032 gal. ⁽³⁾ 928.80	39 gal. ⁽⁴⁾	35.10
O&M Costs		(5)		(5)
Total Monthly Costs Diesel Fuel		928.80		35.10
Total Monthly Difference				\$893.70
Total Estimated Annual Savings on Diesel Fuel Costs				\$10,724/yr

Notes:

- (1) Assumes all primary digesters are heated by boilers fueled by diesel fuel.
- (2) Assumes boilers are fueled by diesel fuel two weeks per year while mechanical repairs are being done to digesters or gas recovery equipment. Digester gas is used to fuel the boilers for the remainder of the year.
- (3) Average Fuel Consumed
Boilers - $3,300 \text{ BTU/min.} = 1.44 \times 10^8 \text{ BTU/month}$
Assume $140,000 \text{ BTU/gallon of diesel fuel} = 1,032 \text{ gallons/month}$
- (4) Diesel fuel used in two weeks ($3,300 \text{ BTU/min.}$) = $3.3 \times 10^7 \text{ BTU/week}$
 $6.6 \times 10^7 \text{ BTU/2 weeks} / 140,000 \text{ BTU/gallon} = 471 \text{ gallons/yr} = 39 \text{ gallons/month}$
- (5) The O&M costs will be approximately the same using either fuel.

TABLE 3

CITY OF PLANTATION, FLORIDA WASTEWATER TREATMENT PLANT
ESTIMATED ANNUAL ENERGY SAVINGS FOR DIESEL FUEL

	Annual Gasoline Costs per Vehicle			
	Unit Price	Using Gasoline Only ⁽¹⁾ Use Charge (\$)		Using Digester Gas ⁽²⁾ Use Charge (\$)
Gasoline	\$1.00/gal	1,333 gal.	1,333.00	(2) 0.00
O&M Costs			0.00	unknown
Total Annual Costs			1,333.00	
Total Annual Difference per Car				\$1,333.00
Total Estimated Annual Savings on Gasoline Cost for seven cars				\$9,331/yr

Notes:

- (1) Assumes vehicle is fueled by gasoline, is driven 20,000 miles per year, gets 15 mpg and gasoline costs \$1 per gallon.
- (2) Assumes vehicle is fueled by methane gas retrieved from digesters
- (3) Actual O&M costs of methane gas recovery, cleaning and storage system are not kept, but includes the power costs to compress, purify and dry the methane plus the normal maintenance to the equipment. The O&M costs for the vehicles is the same for both fuels.

CASE STUDY 8

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE CITY OF TAMPA, FLORIDA ADVANCED WASTEWATER TREATMENT PLANT

INTRODUCTION

The Tampa Advanced Wastewater Treatment Plant in Tampa, Florida has a design capacity of 70 million gallons per day (mgd), and currently receives about 54 mgd influent flow. The anaerobic digestion system receives about 500,000 gallons per day (gpd) of feed sludge. The gas produced by the digestion process is used to power five engine generators. The heat from the engines is captured and used to heat the digesters. A general plant flow diagram is shown in Figure 1. The Hooker's Point plant is an advanced treatment facility and is required to nitrify, denitrify, chlorinate and dechlorinate and uses a heat drying pelletization process for final sludge processing before marketing. More detailed information on Tampa's anaerobic digestion process, energy recovery, energy efficiency, and estimated system costs and savings is presented in the following sections.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are seven (7) high rate, completely mixed anaerobic digesters with a total hydraulic capacity of 10 million gallons. All of the digesters have floating covers and four have gas holders capable of storing up to 22,500 cubic feet of gas each. The digester feed sludge consists of approximately 44 percent (%) raw primary sludge and 56% waste activated sludge (WAS). WAS produced in the pure oxygen carbonaceous and nitrification systems is thickened with gravity or belt thickeners prior to being pumped to the digesters. A summary of plant operating data for the anaerobic digestion process from the period of January, 1990 through December, 1991 is shown in Figure 2.

The treatment plant is operating at about 78% of its rated capacity and a plant expansion to 96 MGD is scheduled for completion in 1995. The digesters achieve a 54% destruction of the volatile solids (VS) they receive in the feed sludge, producing about 11.9 cubic feet of gas per pound of VS destroyed. The digesters have an average detention time of 19 days and the sludge temperatures in the digesters are kept at 95°F.

The primary and thickened waste activated sludge mixture is pumped to the digesters directly from the mixed sludge pumping station. The digester contents are continuously recirculated through a heat exchanger and mixed using gas eductors to achieve consistent sludge temperatures, increase the metabolic rate and reduce sludge digestion time.

Figure 1

FIGURE 2

CITY OF TAMPA, FLORIDA WASTEWATER TREATMENT PLANT
ANAEROBIC DIGESTER OPERATING DATA
(JANUARY 1990 - DECEMBER 1991)

Average Operating Conditions (all digesters)

Temperature = 95° F
pH = 7.2
Hydraulic detention time = 19 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

After approximately 19 days of detention time in the digesters, the sludge is pumped to sludge storage tanks and dewatered using belt filter presses. Back up dewatering using sand drying beds, is also available. The dewatered sludge is conveyed to a heat drying facility where it is dried to produce an organic fertilizer product which is distributed and marketed through local fertilizer blenders. The digestion process in this plant is used to generate an acceptable odor characteristic for the final product prior to distribution and then marketed.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system has five (5) 818 horsepower (HP) engines, five (5) 500 kilowatt (KW) engine driven generators with heat recovery systems, four (4) 2.5 million BTU/hr standby boilers, five (5) 10 HP gas compressors and 11 gas cleaning filters. Detailed specifications for the equipment are shown in Table 1.

TABLE 1
ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - City of Tampa, Florida - Department of Sanitary Sewers
Design Engineer - Greeley and Hansen

Equipment	Number	Manufacturer	Model #	Rating
Boilers	4	Bryan	L48-W-FDSGO	2560 Million BTU/hr
Engine	5	Waukesha	L7042GU	818 HP
Generators	5	KATO	8P6-2050	500 KW
Heat Exchangers	5	Wells Products	531-037/039	2 Million BTU/hr 120 GPM
Gas Compressors	3	Sutorbilt	4L X B	177 CFM 3.7 HP
	2	Sutorbilt	5MXB-C-5	254 CFM 7.6 HP
	3	Sutorbilt	5MV-F HS	Varied Speeds
Gas Filters	10	Nelson-winslow	96402A	Varies
	3	Nelson-winslow	98626G	Varies
J.W. Intercoolers	5	American Standard	12 inch	300 GPM
Auxiliary Intercoolers	5	American Standard	10 inch	100 GPM

The methane gas driven engine generators are 25-30% efficient in converting fuel into work energy, but the heat recovery systems can return about 40% of the fuel energy as heat from the engine cooling water system (28%), and the engine exhaust

heat recovery system (12%). Heat recovered from the engines is used to maintain the digesters at 95°F by continuously recirculating sludge through a water-to-sludge heat exchanger. The heat from the engines warms water which is passed through the heat exchanger. The heat in the water is transferred to the sludge which is then returned to the digester. Excess heat from the engines is dissipated using plant effluent water circulated through a heat exchanger which is integral with the engine/generator set.

Before entering the engine/generators, the digester gas is passed through sodium hydroxide-impregnated filters which remove hydrogen sulfide and other corrosive gases. It is then compressed and filtered again to obtain the pressure and purity required for the engines.

The digester gas-powered boilers are available to heat the digesters if the heat recovery system on the engine generators is out of service. Plant management indicates that the boilers are rarely used and not an integral part of the methane gas utilization system.

During normal operation four of the five engine generators are on-line at the plant and tied into the plant's main electrical grid. The fifth unit is used during daily peak electrical demand periods if excess gas is available. The engines can use more digester gas than can be produced and therefore none is wasted or flared off. With four of the engines operating, the fuel demand is approximately 250,000 BTU/min., while the digesters are producing approximately 299,000 BTU/min. The remainder of the gas is held in the gas storage domes until the fifth engine is started.

A typical energy balance diagram for the Tampa system is shown in Figure 3. This energy balance is based on current average operating conditions of sludge production and assumes four engines are operating. It also assumes the filtered gas is 65% methane, produces 550 BTU per cubic foot of digester gas and 50% of the engine heat is wasted through the auxiliary heat exchanger because it is not required to heat the digester.

FINANCIAL BENEFITS

According to conversations with plant management, there are no accounting data to support the cogeneration facility. However, management believes that the methane recovery/electrical generation process is financially slightly ahead of breaking even. According to a set of presentation slides provided during technical review, Tampa WWTP has produced between 10% and 25% of its total electric requirement since 1987, with the figure for the most recent year cited (1991) being about 20%. This same source indicates that the value of the electricity produced (savings) has risen during that period, increasing from 8.9% of energy costs to 26.7% in 1991. The following is the presentation's summary of electric production and savings:

FIGURE 3
CITY OF TAMPA, FLORIDA
WASTEWATER TREATMENT PLANT
METHANE GAS ENERGY BALANCE DIAGRAM

	<u>Total Production</u>	<u>% of Consumption Produced</u>	<u>Savings (%)</u>
FY 1987	5,850,400 KWH	10.0%	\$274,800 (8.9)
FY 1988	7,865,830 KWH	14.2%	\$350,525 (11.5)
FY 1989	10,387,000 KWH	17.8%	\$533,500 (16.4)
FY 1990	12,722,000 KWH	21.7%	\$713,286 (23.0)
FY 1991	14,102,004 KWH	22.06%	\$727,417 (26.7)

Because of the lack of actual accounting data, it is not possible to produce estimates related to either cash flow or payback.

Plant personnel perform routine maintenance and make most of the repairs to the energy recovery and utilization system. As noted above, average annual operation and maintenance (O&M) costs are not kept on individual systems, such as this; therefore, the cost saving figures shown on Table 2 do not reflect them. The only major problem with the system is that the original iron gas piping of the engine fuel manifold was replaced with stainless steel due to the corrosive nature of the gas.

Plant management has made the facility more energy efficient by adapting the sludge pumping schedules to produce maximum gas production during peak electrical demand hours and by storing gas in the domes in low demand periods for use in high demand periods. By doing so, the electric generation facilities are capable of producing at the maximum rate during peak hours when the energy charges are the highest.

Using Tampa Electric Company (TECO) rates and applying plant energy usage figures from December, 1992, the monthly electric cost is approximately \$230,000. If digester gas driven engine generators were not used to supplement TECO's electrical supply, the monthly cost would be approximately \$285,000. The difference is about \$660,000 per year. A detailed accounting of these figures is shown in Table 2.

Records kept by the City of Tampa indicate that the on-site generation facilities produced about 22% of the electricity required to operate the plant at a cost savings of around \$700,000 per year. The savings calculated in Table 2 are lower because it was assumed for this case history that only four of the five engine generators are on line throughout the day, when in fact the fifth generator may be operated when maintenance and fuel conditions allow.

The Tampa WWTP's methane recovery system also saves approximately \$44,000 per year (refer to Table 3) by capturing the heat from the generator engines and using it to heat the digesters. Currently, up to 50% of the heat captured has to be wasted because there is no use for it. The City is investigating ways to use this excess heat to make the plant even more energy efficient.

The total estimated energy savings resulting from the energy recovery system are therefore approximately \$704,000 per year.

TABLE 2

**CITY OF TAMPA, FLORIDA WASTEWATER TREATMENT PLANT
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY**

	Monthly Electrical Costs			
	Utility Rates (\$)	Using All TECO Power		Using TECO Power w/Engine/Generator Supplement ⁽¹⁾
		Use	Charge (\$)	Use Charge (\$)
Basic Charge	195		195	195
Demand Charge				
Actual Supplemental	6.75/kw	8,200 kw ⁽²⁾	55,350	6,640 kw 44,820.00
Other	2.65/kw			1,585 kw 4,200.25
Energy Charge				
On Peak	0.03102/kwhr	1,338,790 kwh ⁽³⁾	41,529.27	1,036,390 kwhr 32,148.82
Off Peak	0.01256/kwhr	4,347,220/kwh ⁽³⁾	54,601.08	3,454,420 kwhr 43,387.51
Fuel Costs				
On Peak	0.02578/kwhr	1,338,790/kwh ⁽³⁾	34,514.00	1,038,683 kwhr 26,777.25
Off Peak	0.02275/kwhr	4,347,220/kwh ⁽³⁾	98,899.26	3,464,317 kwhr 78,813.21
Total Monthly Costs			285,088.61	230,342.04
Total Monthly Difference				54,746.57
Total Estimated Annual Savings on Electrical Costs ⁽⁴⁾				\$656,958.84/yr

Notes:

(1) Numbers based on actual charges to City of Tampa WWTP in December, 1992.

(2) Average Site Load = 8,200 kw
 Scheduled Supplemental = 6,640 kw ———— TECO
 Power Supply Reservation = 1,585 kw ————

(3) Energy produced by generators (4 units in operation).
 Average output per generator = 450 kw
Off Peak = (450 kw)(31 days)(4 generators)(16 hrs/day) = 892,800 kwh
On Peak = (450 kw)(21 days)(4 generators)(8 hrs/day) = 302,400 kwh

(4) Does not include operation and maintenance costs.

TABLE 3

CITY OF TAMPA, FLORIDA WASTEWATER TREATMENT PLANT
ESTIMATED ANNUAL ENERGY SAVINGS FOR NATURAL GAS
(1992)

Monthly Natural Gas Costs to Heat Digesters ⁽¹⁾			
	Unit Price	Using Natural Gas Only Use Charge (\$)	Using Digester Gas Use Charge (\$)
Natural Gas	\$0.33163/Therm	22,000 Therms ⁽²⁾ 7,295.86	0
Total Monthly Costs		7,295.86	0
Total Monthly Difference			\$7,295.86
Total Estimated Annual Savings on Fuel Oil Costs $7,295.86 \times 6 \text{ mos.} =$ \$43,775.16/yr			

Notes:

- (1) Average fuel required to heat digesters in winter
 $50,320 \text{ BTU/min} = 2.2 \times 10^9 \text{ BTU/month} = 22,000 \text{ Therms/month}$
- (2) Assume recovered heat is required to heat digesters 6 months per year and that 50% of the heat recovered from the generator engines is wasted through the auxiliary heat exchanges. Assume natural gas would be used to fuel boilers if heat recovery system was not in place.

CASE STUDY 9

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE HAMPTON ROADS - NANSEMOND WASTEWATER TREATMENT PLANT

INTRODUCTION

The Hampton Roads-Nansemond Wastewater Treatment Plant (NWWTP) in Virginia Beach, Virginia has a design capacity of 10 million gallons per day (MGD), and currently receives about 10.2 MGD influent flow. They are in the design phase of a plant expansion to 30 MGD capacity. Construction on the expansion is scheduled to begin in 1994 and will be finished in 1996. A general flow diagram of the existing plant is shown in Figure 1.

Detailed information on Nansemond's anaerobic digestion process, energy recovery system and estimated system cost savings is presented in the following sections.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are two 90 foot diameter, 1.5 million gallon digesters. Each has a floating cover capable of storing 80,000 cubic feet of gas at 11 inches W.C. One is typically operated as the primary digester, and the other as a secondary digester. Interconnecting piping allows the operator the flexibility of operating both digesters in either the primary or secondary mode. Seventy percent (70%) of the feed sludge to the digesters is captured in the primary clarifier and the remainder is waste activated sludge from the secondary process. A summary of plant operating data from the period August 1990 through July 1992 is shown in Figure 2.

The treatment plant is operating at about 100% of its rated capacity. The digesters achieve a 50% destruction of the volatile solids (VS) it receives in the primary sludge, producing about 9.2 cubic feet of gas per pound of VS destroyed. The digesters have an average detention time of 33 days and the sludge temperature in the primary digester is kept around 96°F.

Thickened primary and waste activated sludge is mixed with recirculated sludge and warmed by one of two heat exchangers before it is discharged into the primary digester. The sludge is continuously recirculated through a heat exchanger by two 350 gpm centrifugal pumps to achieve consistent sludge temperatures. The sludge is mixed using digester gas. Digester sludge is drawn from the primary digester through an 8-inch line at the center invert and discharges into the center of the secondary digester. After reaching the secondary, no recirculation or heating occurs and the sludge is allowed to settle out and thicken. From there it is pumped to a sludge holding tank where it remains until disposal. The supernatant is normally drawn from the secondary digester only and is pumped to the aeration tanks distribution chamber.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system consists of two 100 horsepower (HP) boilers, one 475 HP, 7200 cfm engine driven blower, four 12,000 cfm gas compressors and two heat exchangers. The detailed specifications for the equipment are shown in Table 1 which follows.

FIGURE 2

HAMPTON ROADS - NANSEMOND WASTEWATER TREATMENT PLANT
VIRGINIA BEACH, VA
ANAEROBIC DIGESTER OPERATING DATA
(AUGUST 1990 - JULY 1992)

Average Operating Conditions (all digesters)

Temperature = 96° F
Volatile Acids = 209 mg/L
Alkalinity = 3,747 mg/L
pH = 7.2
Hydraulic detention time = 33 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

TABLE 1

ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - Hampton Roads Sanitation District
 Design Engineer - Hazen and Sawyer
 Contractor - Pizzagali, Inc.

Equipment	Number	Manufacturer	Model #	Rating
Boilers	2	Cleaver Brooks	CD 200	100 HP
Gas Engine Driven Blower	1	Waukesha	L-3711	475 HP 7200 CFM
Heat Exchanger	2	Envirex	621	360 SF
Compressors	4	Eclipse	Booster	12000 CFH

The boilers are approximately 80% efficient at converting digester gas into usable heat and the engine driven blower is 26-28% efficient in converting fuel into work energy. The engine driven blower does not have a heat recovery system which could save another 40-50% in energy losses. During normal operation, only one boiler is used. The second boiler is for standby and operates on a six month rotation with the first. The boiler burns the digester gas to heat water used in heating the on-site buildings and anaerobic digesters. The engine driven blower is being utilized on weekdays from 10:00 a.m. to 2:00 p.m. to help reduce the power supply demand charges from the electric utility company. The digesters are built above ground, but are well insulated by 26" thick concrete sidewalls. The floating covers are insulated with 2-inches of lightweight concrete.

There are two closed loop heat exchangers used to heat the incoming raw sludge and recirculated sludge from the digester. Water heated by the boilers exchanges its heat with the sludge in the heat exchangers. The heated sludge is then recirculated into the digester to maintain a digester temperature of 96°F. Supplemental fuel (No. 2 Heating Oil) is required only when there are maintenance problems with the gas recovery system.

The boiler is capable of variable firing rates which range from 4,300 BTU/min to 55,000 BTU/min. Records are not kept on how much fuel the boiler actually uses, but since the digesters are producing an average of only 21,800 BTU/min, and no

alternate fuel source is required, it is safe to assume the boiler is using less than 20,000 BTU/min.

A typical energy balance diagram for the Nansemond system is shown in Figure 3. This energy balance is based on current average operating conditions of sludge production, while operating one boiler with an average firing rate of 15,000 BTU/min and the engine blower (20 hours/week only) operating with a firing rate of 20,159 BTU/min.

FINANCIAL BENEFITS

The treatment plant was partially financed by bonds. However, no bond data regarding the methane recovery facility specifically are available nor can they be readily extrapolated.

Management reports that historical data indicates \$140,000 is saved annually by utilizing methane to fuel the boilers and the gas-driven blower. The plant receives credits from the power company for using an emergency generator during peak loads or as requested by the power company.

Plant personnel perform the routine maintenance on the boilers and engine blower, but most repairs are made by outside forces. Average annual maintenance and repair cost for the engine blower is \$10,000 and for the boilers is \$4,000 each. This cost includes materials, parts and labor.

Using Virginia Electric and Power Co. (VE&P) rates and applying historical plant energy usage figures, plant management has budgeted \$22,398.80 per month for electrical usage. This does not include the savings realized by utilizing digester gas to power the blower. These savings in electrical costs are detailed in Table 2 and total approximately \$5,360 per year.

The WWTP also saves a significant amount of fuel oil cost by operating the boiler using digester gas to provide heat for the buildings and for the digester. The fuel oil cost savings which are nearly \$37,775 per year are outlined in Table 3. The total energy savings resulting from the methane gas energy recovery system is estimated to be about \$43,000 per year.

FIGURE 3

HAMPTON ROADS - NANSEMOND WASTEWATER
TREATMENT PLANT - VIRGINIA BEACH, VA
METHANE GAS ENERGY BALANCE DIAGRAM

Estimated Energy Recovery from Methane-Fueled Equipment

- Engine/Blowers - 27%
- Boilers - 80%
- 30% of boiler heat goes to buildings. 70% to digesters

TABLE 2

HAMPTON ROADS - NANSEMOND WASTEWATER
TREATMENT PLANT - VIRGINIA BEACH, VA
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY
(1992)

The engine/blower does not run all of the time, but is run during the peak demand period to level out the power supply demand and the distribution demand costs charged by VE&P. It is assumed that if digester gas was not used, the demand costs would be based on 104 KW more than if it was used.

	Monthly Electrical Costs			
	Utility Rates (\$)	Using All VE & P Electricity		Using Electricity w/Digester Gas Supplement
		Use	Charge (\$)	Use Charge (\$)
Basic Charge	72.58		72.58	72.58
Power Supply				
Distribution		1108 kw		1,004 kw
Demand Charges				
1st 700 kw	1.4120/kw		988.40	988.40
Next 4,300 kw	1.1280/kw		460.22	342.91
Over 5,000 kw	0.9710/kw		0.00	0.00
Power Supply Demand Charge	9.7660/kw	1052 kw	10,273.83	948 kw 9258.17
Energy Charge		595,007 kwhr		586,000 kwhr
1st 24000 kwhr	0.0292/kwhr		702.96	702.96
Next 186,000	0.02253/kwhr		4190.58	4190.58
Over 210,000	0.01820/kwhr		7,007.13	6,843.20
Total Monthly Electrical Costs			\$23,695.70	\$22,398.80
Operation and Maintenance Costs			0.00	850.00/mo.
Total Monthly Costs			\$23,695.70	\$23,248.80
Total Monthly Difference				\$446.90
Total Estimated Annual Savings on Electrical Costs				\$5,362.80/yr

Notes:

If the blower were powered by an electric motor, it would be about 92% efficient. Divide 92% into the blower output of 5,443 BTU/min to get 5,916 BTU/min.

Engine/Blower - 5,916 BTU/min. @ 20 hrs/wk = 3.08×10^7 BTU/mo.

$3.08 \times 10^7 \times 2.928 \times 10^{-4} \frac{\text{kwhrs}}{\text{BTU}} = 9,007 \text{ kwhrs/mo.}$

$5,916 \text{ BTU/min.} \times 0.01757 \text{ kwhrs/BTU/min.} = 104 \text{ kw}$

TABLE 3

HAMPTON ROADS - NANSEMOND WASTEWATER
TREATMENT PLANT - VIRGINIA BEACH, VA
ESTIMATED ANNUAL ENERGY SAVINGS FOR FUEL OIL
(1992)

	Monthly Fuel Oil Costs			
	Unit Price	Using Fuel Oil Only Use Charge (\$)	Using Digester Gas Use Charge (\$)	
#2 Fuel Oil	\$0.70/gal	4,693 gal ⁽¹⁾ 3,285.10	196 gal ⁽²⁾ 137.20	
O&M Costs		667.00	667.00	
Total Monthly Costs Fuel Oil		3,952.10	804.20	
Total Monthly Difference			\$3,147.90	
Total Estimated Annual Savings on Fuel Oil Costs				\$37,775/yr

Notes:

(1) Average fuel consumed:

Boiler - 15,000 BTU/min =

6.57×10^8 BTU/mo.

Assume 140,000 BTU/gallon of fuel oil =

4,693 gallons of fuel oil/mo.

(2) Assume boiler is fueled by fuel oil two weeks per year while mechanical repairs are being done.

CASE STUDY 10

DIGESTER GAS ENERGY RECOVERY SYSTEM AT THE MUDDY CREEK WASTEWATER TREATMENT PLANT IN WINSTON SALEM, NC

INTRODUCTION

The Muddy Creek Wastewater Treatment Plant (MCWWTP) in Winston Salem, NC has a design capacity of 15 million gallons per day (MGD), and currently receives about 12.7 MGD influent flow. The plant removes raw sludge in primary clarifiers and removes waste activated sludge from the aeration basins. The sludge is collected and pumped to anaerobic digesters for processing. The resultant methane gas that is produced is captured and used as fuel for a water tube boiler which heats the digesters and for a methane gas powered-engine/blower set. A general flow diagram of the existing Muddy Creek WWTP is shown in Figure 1.

Detailed information on Muddy Creek's anaerobic digestion process, energy recovery system and estimated system cost savings is presented in the following sections.

DESCRIPTION OF ANAEROBIC DIGESTION PROCESS

There are four (4) 100 foot diameter, 2 million gallon digesters. Each has an Eimco spiral guide gas holding cover capable of storing 14,000 cubic feet of gas at 9 inches W.C. Three are typically operated as the primary digesters, and the other as a secondary digester. Interconnecting piping allows the operator the flexibility of operating two of the digesters in either the primary or secondary mode. Approximately sixty percent (60%) of the feed sludge to the digesters is captured in the primary clarifier and the remainder is waste activated sludge from the secondary process. A summary of digester operating data from the period September, 1990 through August, 1992 is shown in Figure 2.

The treatment plant is operating at about 85% of its rated capacity. The digesters achieve a 52% destruction of the volatile solids (VS) they receive in the primary sludge, producing about 11.2 cubic feet of gas per pound of VS destroyed. The digesters have an average detention time of 82 days and the sludge temperature in the primary digester is kept around 98°F.

Primary and thickened waste activated sludge is pumped through a preheater before it is discharged into the primary digesters. The sludge is continuously recirculated through a heat exchanger and mixed by a 15 HP, 15000 GPM propeller type mixer to achieve consistent sludge temperatures, increase the metabolic rate and reduce sludge digestion time. Digester sludge is drawn from the primary digesters and discharged into the center of the secondary digester. After reaching the secondary, no recirculation or heating occurs and the sludge is allowed to settle out and thicken. The digested sludge is pumped to belt filter presses or storage lagoons and then land applied. The supernatant is normally drawn from the secondary digester only and is pumped to the aeration tanks distribution chamber.

ENERGY RECOVERY SYSTEM

The digester gas energy recovery system consists of three 4.8 million BTU/hr boilers, two 800 HP, 11,500 cfm engine driven blowers, one 360 gpm sludge preheater, eight heat exchangers, and one 33,510 cuft high pressure gas storage sphere. The detailed specifications for the equipment are shown in Table 1 which follows.

FIGURE 2

MUDDY CREEK WASTEWATER TREATMENT PLANT
WINSTON SALEM, NC
ANAEROBIC DIGESTER OPERATING DATA
(SEPTEMBER, 1990 - AUGUST, 1992)

Average Operating Conditions (all digesters)

Temperature = 98° F
Volatile Acids = 90 mg/L
Alkalinity = 4,092 mg/L
pH = 7.4
Hydraulic detention time = 82 days

Abbreviations

TS - Total Solids
VS - Volatile Solids
lbs - pounds
mg/L - milligrams per liter
°F - degrees Fahrenheit
MGD - million gallons per day

TABLE 1

ENERGY RECOVERY EQUIPMENT SPECIFICATIONS

Owner - Muddy Creek WWTP, Winston Salem, NC

Design Engineer - Malcolm Pirnie Engineers, Inc.

Contractor - Paul A. Lawrence Co. & Miller Mechanical, Inc.

Equipment	Number	Manufacturer	Model #	Rating
Boilers	3	Cleaver Brooks	M4W-6000	4.8 million BTU/hr
Gas Engine	2	Waukesha	L-7042GU	800 HP
Driven Blowers	2	HV Turbo	KA22	11,500 CFM
Heat Exchangers	6	Eimco		50 GPM
	2	Eimco		360 GPM
Compressors	4	Joy	WG8	60 psi
Gas Storage Sphere	1	Chicago Bridge and Iron		33,510 cuft

The boilers are approximately 80% efficient at converting digester gas into usable heat and the engine driven blowers are 26-28% efficient in converting fuel into work energy. The engine does not have a heat recovery system which could save another 40-50% in energy losses. During normal operation, only one boiler is used in warm weather and up to three are used in cold weather. The boiler burns digester gas and supplemental fuel oil to heat water for the on-site buildings heating systems, anaerobic digesters and digester feed sludge. The blower is driven by the digester gas-fueled engine about 12 hours per day during the electric company's peak demand period. During off-peak periods, which include weekends, electric motor-driven blowers are used. The digesters are about 40 feet high with 28' 9" below grade. They are further insulated by concrete walls with foam insulation and brick veneer (above ground).

There are six small heat exchangers used to heat the constantly recirculated sludge. Water heated by the boilers exchanges its heat with the sludge in the heat exchanger, and the sludge is returned to the digester to maintain a digester temperature of 98°F. The two large heat exchangers use water heated by the same boilers to preheat the feed sludge before it enters the digesters.

The boilers use digester gas as their primary fuel source, but an average of twelve gallons of fuel oil is used each day as supplemental fuel. Fuel oil is required primarily in the winter months. The boiler's full load fuel consumption rate is

10,900 cu ft/hr, but they use an average of only 51,211 cu ft per day.

A typical energy balance diagram for the Muddy Creek system is shown in Figure 3. This energy balance is based on current average operating conditions of sludge production, while operating one boiler with an average firing rate of 51,211 cu ft/day or 19,560 BTU/min and one engine blower operating 12 hours per day, five days each week. The firing rate for the engine at full load is 11,000 cu ft of gas per hour, therefore the average fuel usage is 86,200 cu ft/day or 32,924 BTU/min. It is assumed that 10% of the heat produced by the boilers is used to heat the buildings and 85% of the remaining heat is used in the preheating heat exchanger. The remaining 15% is used in the recirculation heat exchanger.

FINANCIAL BENEFITS

Although no capital cost data relating specifically to the methane recovery portion of the treatment system can be estimated, the system was partially financed by revenue bonds. City management completed an historical analysis for this study and determined:

Annual savings from boiler operations	\$46,800
Annual savings from blower operations	<u>103,400</u>
Total gross savings	\$150,200
Less O&M costs	<u>(83,000)</u>
Net annual savings	\$67,200

Because of the lack of capital costs, it is not possible to produce estimates related to either cash flow or payback.

Plant personnel perform most of the routine maintenance and repairs on the boilers and engine/blower; they have had problems with cracks in the boiler tubes, and the impure gas has caused the failure of regulating valves and engine carburetors.

Using Duke Power Company electric rates and average fuel consumption data, the estimated monthly electrical savings realized by utilizing the gas engines to drive the blowers is \$3,120 per month or \$37,400 per year (See Table 2). This does not include the annual operation and maintenance costs associated with the system.

The WWTP also saves a significant amount of fuel oil cost by operating the boiler using digester gas to provide heat for the buildings and for the digester. The fuel oil cost savings which are approximately \$51,400 per year are outlined in Table 3. The total energy savings resulting from the methane gas energy recovery system is estimated to be about \$88,800 per year.

FIGURE 3

MUDDY CREEK WASTEWATER TREATMENT PLANT
WINSTON SALEM, NC
METHANE GAS ENERGY BALANCE DIAGRAM

Estimated Energy Recovery From Methane-Fueled Equipment

- Engine/Blowers - 27%
- Boilers - 80%
- 10% of boiler heat goes to buildings. 90% to digesters

TABLE 2

MUDDY CREEK WASTEWATER TREATMENT PLANT -
WINSTON SALEM, NC
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY

	Monthly Electrical Costs for Blowers			
	Utility Rates (\$)	Using All Duke Power Co. Electricity ⁽¹⁾ Use Charge (\$)	Using Electricity w/Digester Gas Engine Supplement ⁽²⁾ Use Charge (\$)	
Power Supply (on peak)	\$10.31/KW ⁽³⁾	170 KW ⁽⁴⁾	1,752.70	
Demand Charge (off peak)	\$1.03/KW			170 KW ⁽⁶⁾ 175.10
Energy Charge (on peak)	4.3370/kwhr	28,333 kwhr ⁽⁵⁾	1,228.80	-0- -0-
(off peak)	2.2016/kwhr	93,707	2,063.05	79,447 ⁽⁷⁾ 1,749.11
Total Monthly Electrical Costs			\$5,044.55	\$1,924.21
Operation and Maintenance Costs			0.00	unknown
Total Monthly Costs			\$5,044.55	\$1,924.21
Total Monthly Difference				\$3,120.34
Total Estimated Annual Savings on Electrical Costs				\$37,444.08/yr

Notes:

- (1) Assumes blowers are powered by electricity at all times.
- (2) Assumes blowers are powered by gas engine 12 hours per day, five days per week.
- (3) Assumes total plant demands less than 2,000 KW. The demand charge from June-September is \$12.98/KW and from October - May it is \$7.64/KW. The yearly average is then \$10.31/KW.
- (4) Blower output is 8,890 BTU/min. and electric motor efficiency is about 92%, therefore the blower input is 9,663 BTU/min. using electric motor.

$$9,663 \text{ BTU/min.} \times 0.01757 \text{ KW/BTU/min.} = 170 \text{ KW}$$

TABLE 2 (continued)

MUDDY CREEK WASTEWATER TREATMENT PLANT -
WINSTON SALEM, NC
ESTIMATED ANNUAL ENERGY SAVINGS FOR ELECTRICITY

(5) On peak energy use:

$$9,663 \text{ BTU/min} \times 60 \text{ min/hr} \times 8 \text{ hr/day} \times 21.6 \text{ days/month} \times 2.928 \times 10^{-4} \text{ kwhr/BTU} \\ = 28,333 \text{ kwhr/mo}$$

Off peak energy use:

$$\text{Weekdays} - 9,663 \text{ BTU/min} \times 60 \text{ min/hr} \times 16 \text{ hr/day} \times 21.6 \text{ day/month} \times 2.928 \times 10^{-4} \text{ kwhr/BTU} \\ = 58,669 \text{ kwhr/mo}$$

$$\text{Weekends} - 9,663 \text{ BTU/min} \times 60 \text{ min/hr} \times 24 \text{ hr/day} \times 8.6 \text{ day/month} \times 2.928 \times 10^{-4} \text{ kwhr/BTU} \\ = 35,038 \text{ kwhr/mo}$$

$$\text{Total off peak use} = 93,707 \text{ kwhr/mo}$$

- (6) The gas engine reduces the demand by 170 KW during the peak demand periods. In the off-peak periods (nights and weekends), the blower demand is still 170 KW, but the charge is only \$1.03 /KW instead of \$10.31/KW.
- (7) The engine runs 60 hrs/week or 260 hrs/month during on-peak energy periods, therefore the on-peak energy use is 0 kwhrs. When the engine is not running (108 hrs/wk, 468 hrs/mo), the off peak rates are charged.

$$9,663 \text{ BTU/min} \times 60 \text{ min/hr} \times 468 \text{ hr/month} \times 2.928 \times 10^{-4} \text{ kwhr/BTU} \\ = 79,447 \text{ kwhr/mo}$$

TABLE 3

MUDDY CREEK WASTEWATER TREATMENT PLANT -
WINSTON SALEM, NC
ESTIMATED ANNUAL ENERGY SAVINGS FOR FUEL OIL

Monthly Fuel Oil Costs				
	Unit Price	Using Fuel Oil Only Use Charge (\$)		Using Digester Gas Use Charge (\$)
#2 Fuel Oil	\$0.70/gal	6,486 gal ⁽¹⁾	4,540.20	365 gal ⁽²⁾ 255.50
O&M Costs			(3)	(3)
Total Monthly Costs Fuel Oil			4,540.20	255.50
Total Monthly Difference				\$4,284.70
Total Estimated Annual Savings on Fuel Oil Costs				\$51,416.40/yr

Notes:

(1) Average fuel consumed:

Boiler - 20,726 BTU/min =

9.08×10^8 BTU/mo.

Assume 140,000 BTU/gallon of fuel oil =

6,486 gallons of fuel oil/mo.

(2) Assume boiler uses an average of 12 gallons per day or 365 gallons/mo of supplemental fuel oil.

(3) The O&M costs are unknown, but they should be nearly the same for each fuel alternative.

CONCLUSIONS

Reliance on historical records has a number of limitations. For example, in most cases the methane recovery system was only one aspect of the design and construction of the treatment plant. Because of this, it was not common practice to identify capital costs separately, and it was difficult to estimate with confidence many years after the fact. In addition, operating and maintenance costs, while known for the total treatment plant, are not captured for that part of the facility used to recover and use methane. In some cases, major maintenance items are known; in others, an educated guess regarding likely current, not historical, operating and maintenance costs is possible.

Ideally, the capital costs of the methane recovery and utilization facility would have been separately accounted for, whether construction did or did not take place at the same time as the plant as a whole. Also, data regarding the methane recovery and utilization facility's anticipated useful life would have been entered into the accounting system when the facility began operation. Also ideally, annual costs of operating and maintaining the facility would have been captured through the work order system or other appropriate accounting mechanism. Further, principal and interest debt service costs for the facility alone would be accounted for.

Under such ideal circumstances, historical annual cash flow analyses would be easily calculated. Revenues would be defined as receipts from energy sales, plus savings resulting from not purchasing electricity or other power source, and then adjusted for other relevant factors, as required. Costs would include all costs of operations and maintenance (excluding depreciation) as well as annual principal and interest debt service payments. The difference between revenues and costs would be each year's positive or negative cash flow.

Projected or actual payback calculations can be defined in various ways; among them, to simply compare original investment to annual excesses of cash revenues over cash costs, or to include such non-cash costs as depreciation, thereby allowing for replacement of the facility at the end of its life, or to compensate for projected inflation using a discounting approach. Any of these, or others, could be readily calculated under the ideal circumstances cited above. In addition, the payback period could be based on the generation of annual statements of accrued basis net income, comparable to the method used in private industry.

When the accounting data are other than ideal, as was the situation in this study, conclusions are less than precise, but certainly not without value. There is substantial precedent for making financial decisions based on the best judgements/estimates of management and engineering personnel. In other words, circumstances can be such that accounting shortcomings alone need not necessarily preclude arriving at, and being comfortable with, a financial decision.

Conclusions from Historical Cost Data

Payback: In only three instances was it possible to calculate a sufficient cash flow analysis and/or to sufficiently determine capital cost data to be able to project a payback period. These three are as follows:

<u>Participant</u>	<u>Payback Period Using Historical Data</u>	<u>Current Payback Using Wander Associates Estimates</u>
Durham, NC	4 1/3 years	2.8 years
Fort Worth, TX	8 1/3 years	10.9 years
Little Rock, AK	15 years ¹	N/A

¹ Or, the ninth year of a positive cash flow

Capital Costs: Four participants could provide indications of the probable capital costs of their methane recovery installations. These data are presented below, and each are related to the participant's design capacity.

<u>Capital Costs</u>			
<u>Participants</u>	<u>Initial Capital Cost</u>	<u>Design Capacity in MGD</u>	<u>Capital Cost/MGD</u>
Dayton	\$988,000	11.2	\$88,214
Durham	\$290,000	9.5	\$30,526
Fort Worth	\$5,928,370	120	\$49,403
Little Rock	\$2,400,000	15	\$160,000

Capital costs per MGD for these four participants range from \$30,526 to \$160,000; the arithmetic mean of the four is \$82,036. Because various percentages of the four participants' methane recovery installations were financed (the remainder being directly purchased and/or grant funded), no meaningful comparisons of debt service costs per MGD can be drawn.

O&M Costs: Four participants were able to quantify O&M costs from historical data. O & M costs and related design capacity are shown below:

<u>Participant</u>	<u>Recent Annual O & M Costs</u>	<u>Design Capacity in MGD</u>	<u>O & M /MGD</u>
Durham	\$2,500	9.5	\$263
Fort Worth	\$156,662	120	\$1,306
Little Rock	\$130,000	15	\$8,667
Winston Salem	\$83,000	12.5	\$6,640

O&M costs/MGD range from \$263 to \$8667; the arithmetic mean is \$4,219/MGD.

Savings: Wander Associates technical analysis estimated that all but one of the participants could demonstrate probable annual savings, ranging from \$5,000 to \$619,000. Seven of the participants historical records also indicate that their methane recovery systems result in annual savings, ranging from \$67,200 to more than \$727,000. An eighth participant believes that savings are significant, but cannot provide data. The remaining two do not have sufficient historical data to venture an estimate.

The following table isolates the savings data and relates each item to the participants' design capacity. Participants' records indicate savings per MGD range from \$1,600 to \$17,667, averaging \$8,957/MGD. Wander Associates estimates, using current data, range from \$400 to \$11,011, averaging \$5,530/MGD.

Historical and Current Savings per MGD

	Design Capacity in MGD	Participants' Historical Data		Wander Associates Current Estimates	
		<u>Savings</u>	<u>Savings/MGD</u>	<u>Savings</u>	<u>Savings/MGD¹</u>
Birmingham	50	\$80,000 to \$90,000	\$1,600 to \$1,800	\$223,500	\$4,470
Chester	14	"significant" ²	N/A	\$55,000	\$3,929
Durham	9.5	\$72,398	\$7,621	\$104,600	\$11,011
Fort Worth	120	\$713,547	\$5,946	\$545,000	\$4,542
Hampton Roads	10	\$140,000	\$14,000	\$43,000	\$4,300
Little Rock	15	\$265,000	\$17,667	\$164,200	\$10,947
Plantation	15	N/A	N/A	\$20,000	\$1,333
Tampa	70	\$727,417	\$10,392	\$619,000	\$8,843
Winston Salem	12.5	\$67,200	\$5,376	\$5,000	\$400

¹ MGD - Million Gallon Per Day Design Capacity

² Could increase to more than \$62,000 as more vehicles are connected

ABBREVIATION INDEX

BHP	Brake Horsepower
BTU	British Thermal Units
CCF	Hundred Cubic Feet
cfm	Cubic Feet per Minute
Cuft	Cubic Feet
DOE	Department of Energy
FT	Feet
gal	Gallon
HP	Horsepower
KW	Kilowatts
Kwhrs	Kilowatt Hours
lbs	Pounds
mg/L	Milligrams per Liter
MG	Million Gallons
MGD	Million Gallons per Day
rpm	Revolutions per Minute
SERBEP	Southeastern Regional Biomass Energy Program
TS	Total Solids
TS/d	Total Solids per Day
TVA	Tennessee Valley Authority
VS	Volatile Solids
VS/d	Volatile Solids per Day
WWTP	Wastewater Treatment Plant