Development of a comprehensive plan for utilization of digester gas moves towards energy self-sufficiency in Chicago, USA

Thomas E. Kunetz, Jarek Fink-Finowicki, Steve McGowan and Eric Auerbach

ABSTRACT

The Metropolitan Water Reclamation District (MWRD) of Greater Chicago’s Stickney Water Reclamation Plant (SWRP) anaerobically digests approximately 430 dry tons per day (dtpd) (390 dry metric tons per day) of solids and produces 3.4 million ft³/day (96 thousand m³/day) of biogas from the anaerobic digesters, making it one of the largest municipal digester gas complexes in the world. Installation of new treatment processes, as well as future increases in flows and loads to the plant, are expected to significantly increase production of biologically degradable sludge and biogas. This paper presents a comprehensive planning study that was completed to identify and evaluate alternatives for utilization of this biogas. The best, sustainable approach was identified, taking into consideration economics, social impacts, and environmental impacts. The model results indicate that the most economically favorable scenario involves installing a cogeneration facility to produce electricity on-site, and operating it in conjunction with the plant’s existing boilers to satisfy the heating needs of the plant. This scenario also provides the greatest reduction in GHG offsets at the power plants.

Key words | biogas, digester gas, energy utilization

INTRODUCTION

The Metropolitan Water Reclamation District (MWRD) of Greater Chicago has one of the largest anaerobic digester complexes in the world, processing 430 dry tons per day of solids (dtpd) (390 dry metric tons per day), and producing 3.4 million ft³/day (96 thousand m³/day) of biogas. MWRD currently utilizes the biogas to fuel boilers, which produce steam to heat the anaerobic digester treatment process and to provide heat to buildings on the plant property. Installation of new treatment processes, as well as future increases in flows and loads to the plant, will result in a higher production of biologically degradable sludge, as well as significant increases in biogas production. This additional biogas production will be greater than the demand of the boilers, offering an unprecedented opportunity for the MWRD to capitalize on this free energy source. By effectively and efficiently capturing and beneficially utilizing the increased amounts of biogas, MWRD can save money by reducing purchases of natural gas and/or electricity and also significantly reduce greenhouse gas (GHG) emissions by utilizing a sustainable fuel source. However, how to actually utilize the biogas is not a straightforward question to answer, due to the complexities of the plant processes, the plant-wide heating system, and the variety of forms in which energy is used by plant processes (electricity, natural gas, digester gas). Therefore, the MWRD has undertaken a comprehensive planning study to identify and evaluate alternatives for utilization of the expected increase in biogas, and then identify the best, sustainable approach, taking into consideration economics, social impacts, and environmental impacts.

This paper presents a summary of the investigations at the MWRD Stickney Water Reclamation Plant (SWRP) for the increased production of biogas, the energy balance for the plant, and the evaluation of options for utilizing the biogas. Central to this process was the development of a comprehensive energy flow model to assist in the evaluation process by predicting the economic life cycle cost, GHG reduction, and overall energy potential of various scenarios.

doi: 10.2166/wst.2012.132
METHODS

Background

The SWRP treats an average daily flow of 750 million gallons per day (2.8 million m³/day). The sludge generated from the liquid stream treatment processes is treated for solids reduction and stabilization in 24 floating cover anaerobic digesters. SWRP also treats the combined primary and waste activated sludge from the North Side Water Reclamation Plant (NSWRP). The NSWRP has an average daily flow of approximately 250 million gallons per day (0.95 million m³/day) and is located about 17 miles (27 km) north of the SWRP. As such, SWRP currently digests sludge from an equivalent 1 billion gallons per day (3.8 million m³/day) of wastewater flow. The solids fed to plant digesters have a relatively low volatile solids content of 55–65%VS. This is due to the current plant configuration which employs Imhoff Tanks instead of primary clarifiers to treat approximately half the plant flow. The Imhoff Tanks essentially function as open air digesters that remove much of the readily degradable organics from the primary sludge and vent them to the atmosphere (Design of Municipal Wastewater Treatment Plants: WEF Manual of Practice No. 8 2010). A major improvement project under way at SWRP is the conversion of these Imhoff Tanks to traditional primary clarifiers.

Gas production – doubling of gas

Currently, the SWRP utilizes most of its biogas in the winter months to heat the digesters and plant buildings. The biogas is also used to heat the digesters in the summer months but due to the low demand for steam to heat the buildings, some of the gas is wasted via flaring. SWRP is undergoing some major improvements to the liquid and solid stream treatment processes. These improvements include replacing older Imhoff Tanks with new primary clarifiers, as well as adding new primary sludge gravity thickening tanks. These improvements will transfer biologically degradable solids to the anaerobic digesters more efficiently and help to maximize biogas production (Wastewater Engineering: Treatment, Disposal, and Reuse 1991). These improvements, along with estimated increases in flows and loads for the year 2040, the selected planning year, will lead to an increase in the average daily production of biogas. A spreadsheet based model was developed to predict the increased gas production for future conditions which included the major plant improvement projects and increases in plant flows and loads discussed above. For the conceptual evaluation goals of the project, a simple spreadsheet based model for gas production was considered adequate. A more detailed chemical characterization of plant solids and a more detailed analytical modeling program for biogas production was not used.

There were 16 model runs conducted covering an array of gas production scenarios. The items treated as variables in the modeling runs were: influent flow conditions, solids capture in the primary settling tanks and volatile solids reduction (VSR) within the digesters. For the parameter of gas yield, defined as the volume of biogas produced per mass of VSR, a standard reference value of 1.0 m³/kg VSR (16 cf/lb VSR) was used (Design of Municipal Wastewater Treatment Plants: WEF Manual of Practice No. 8 2010). A model run that included average annual flows and loads for the year 2040, 50% solids removal in the primary settling tanks, and a VSR of 45% was selected as the best scenario to be used for estimating future biogas production. This model run predicted an average annual biogas production rate of approximately 6.7 million ft³/day (190 thousand m³/day), which is almost double the current production. Clearly, a doubling of the current production will result in significant amounts of biogas that will be available for utilization. The 6.7 million ft³/day is equivalent to approximately 168 million Btu/hr (mmBtu/hr) (49 MW) of heating value (Lindeburg 2001). This conversion to heating value is useful for the direct comparison of energy-use alternatives, as will be discussed later in this paper.

Energy balance and consumption

The climate in the Chicago area has fairly large seasonal variations in ambient temperatures. Average low temperatures in the winter are approximately 14 °F (−10 °C) and average high temperatures in the summer are approximately 84 °F (30 °C). This range of ambient temperatures has a significant effect on the heat energy required for buildings and digesters from the summer to winter seasons. To properly evaluate the alternatives for utilizing the biogas, it is necessary to understand energy utilization at SWRP. This includes both the type of energy and the quantity. For example, the plant has a major network of steam lines and condensate return lines serving buildings across its 400 acre (1.6 km²) site. A technology that captures excess heat in the form of hot water may not have a practical use for all of the heat as it cannot be distributed in the existing steam system.

To best understand the forms of energy utilized and the amounts of energy required, a seasonal energy balance was
developed for SWRP. An accurate estimation of energy consumed at the SWRP is an important component in determining the proper size and scope of digester gas utilization systems. The amount of heating energy consumed will help determine the amount of digester gas available for alternative utilization based on the following relation:

\[
\text{Digester gas energy generated} - \text{Heating energy consumed} = \text{Digester gas energy available for alternative utilization}
\]

Also, understanding the quantity of electrical energy consumed will help to determine SWRP’s capacity to use on-site electrical generation systems.

Recent plant operational data were examined in an effort to understand and characterize the current energy consumption at the SWRP. Three full years of operational data from the years 2007, 2008 and 2009 were used. Using the operational data, an energy balance analysis of the SWRP was developed. Table 1 summarizes the most important data values obtained from the energy balance analysis.

The annual average electrical usage at the SWRP appears to be constant at approximately 31.5 MW. If an onsite electrical generator were to be installed, a 32 MW system would be the largest capacity system that could be fully internally utilized at the plant.

### Table 1: Current energy consumption

<table>
<thead>
<tr>
<th>Digester parameter</th>
<th>Period</th>
<th>Annual average</th>
<th>Summer</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity consumed [MW]</td>
<td></td>
<td></td>
<td>31.5</td>
<td>31.4</td>
</tr>
<tr>
<td>Natural gas consumed [mmBtu/day]; [MW]</td>
<td></td>
<td>234; 2.9</td>
<td>13; 0.2</td>
<td>455; 5.6</td>
</tr>
<tr>
<td>Digester gas for heating [mmBtu/day]; [MW]</td>
<td></td>
<td>1,856; 22.7</td>
<td>1,273; 15.5</td>
<td>2,439; 29.8</td>
</tr>
<tr>
<td>Total heating energy [mmBtu/day]; [MW]</td>
<td></td>
<td>2,090; 25.5</td>
<td>1,286; 15.7</td>
<td>2,893; 35.3</td>
</tr>
<tr>
<td>Digester gas flared [mmBtu/day]; [MW]</td>
<td></td>
<td>214; 2.6</td>
<td>378; 4.6</td>
<td>49; 0.60</td>
</tr>
</tbody>
</table>

### Table 2: Estimated current digester heating and building heating demands

<table>
<thead>
<tr>
<th>Period</th>
<th>Summer [mmBtu/day]; [MW]</th>
<th>Winter [mmBtu/day]; [MW]</th>
<th>Annual average [mmBtu/day]; [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current digester heat demanda</td>
<td>557; 6.9</td>
<td>982; 12.2</td>
<td>770; 9.5</td>
</tr>
<tr>
<td>Current building heat demand</td>
<td>413; 5.1</td>
<td>1,911; 23.7</td>
<td>1,320; 16.4</td>
</tr>
</tbody>
</table>

aBreakdown of digester heating demands:
- Heating of bulk sludge to digestion temperature: 438 mmBtu/day (summer); 788 mmBtu/day (winter).
- Buried wall and floor heat losses: 45 mmBtu/day (summer and winter).
- Floating cover heat losses: 74 mmBtu/day (summer and winter).

As determined from the operational data presented in Table 1, SWRP uses approximately 2,900 mmBtu/day (35 MW) for heating in the winter and 1,500 mmBtu/day (16 MW) in the summer, for an annual average heating demand of 2,100 mmBtu/day (26 MW). The plant does not meter the quantity of heat that is directed to each of the two major heat demands, which are digester heating and building heating. It should be noted that as used in this paper, the term ‘building heating’ also includes the energy (in the form of steam) used to cool buildings in the summer via absorption chillers.

In order to quantify the two major heat demands, a heating calculation was performed to estimate the amount of heating energy that is needed to heat the digesters. These calculations include heating efficiency losses from plant boilers and piping losses. The building heat demands were then estimated by taking the difference between the observed total heating energy used (from Table 1) and the calculated digester heating demand. Table 2 below provides the estimated breakdown between digester heating and building heating of current plant heating demands.

As noted in the previous section, there are several improvement projects planned for the SWRP that will increase the biologically degradable solids to the digesters and increase digester gas production. Another consequence of these improvements is that the fluid flow to the digesters will increase by approximately 25%, causing a rise in energy...
demand to heat this additional flow. Another project at the SWRP is the construction of a new laboratory facility that will raise the demand for building heating in the future. These considerations were incorporated into the current plant heating demand values to give an estimation of plant heating demands for the design period of 2040. Table 3 provides the projected future heating demands for the SWRP.

The results shown in Table 3 represent a conceptual level estimate of the amount of energy that must be delivered to plant boilers as fuel in order to satisfy the projected 2040 plant heat demands. The values presented in Tables 2 and 3 assume that 20% of the system energy is lost in the boiler exhaust (i.e. the boilers are 80% efficient) and that 5% of the energy is lost from the piping distribution network either as radiant heat or through leaking steam traps.

It is important to distinguish between the two major heat demands at the plant, which are digester heating and building heating. Digester heating is subject to less seasonal fluctuation and is heated by condensing steam from the plant heating loop to heat a secondary hot water loop which is used to heat the digesters. Building heat has more seasonal variation and the heat is provided directly by the plant steam heating loop. As various types of combined heat and power (CHP or Cogeneration) systems were being evaluated, it was important to understand the quantity of heat that is required at the plant, what form of heat transmission can be employed, and the seasonal variation of the heat demand.

### Potential alternatives for utilization

There are many alternatives available for utilization of biogas. A long list of technologies investigated for this project included existing boilers, reciprocating engines, combustion (gas) turbines, steam turbines, combined-cycle turbines, microturbines, compressed natural gas quality, an on-site biosolids drying facility operated by a third party, stirling engines, fuel cells, and direct drive engines (California Distributed Energy Resource Guide). In addition to utilization alternatives, biogas cleaning technologies were also evaluated. The long list of cleaning alternatives included media adsorption, media oxidation, gas refrigeration, biological oxidation, biological additives, physical solvents, resins, pressure swing adsorption, iron salt addition, and membrane separation. The advantages and disadvantages of each biogas utilization technology and cleaning technology were evaluated to develop a short list of alternatives for further consideration.

The selected utilization alternatives for further evaluation included existing boilers, reciprocating engines, combustion turbines, steam turbines, and utilization in an on-site biosolids drying facility. The on-site biosolids drying facility which produces pellets for beneficial reuse is owned and operated by a third party enterprise. The selected gas cleaning technologies for further evaluation were biological oxidation for hydrogen sulfide removal and refrigeration and media adsorption for siloxane removal. These selected technologies, in addition to the existing plant processes, make up the components of the energy flow model.

The concept of selling biogas to a third-party vendor, whether to an off-site or on-site facility, was deemed a potential option; however, as there are numerous ways in which such a scheme could work, it was decided to not include this aspect in the energy flow model. Nevertheless, the energy flow model becomes a powerful tool for evaluating such potential offers, as MWRD now has the means to quantify the economic and environmental value of its biogas, and can add such a module to the energy flow model in the future.

### Building a modeling framework

Due to the dynamic nature of digester gas utilization, including seasonal variations, varying degrees of heat recovery, multiple options for utilization, and the changing costs of natural gas and electricity, a model was developed to simulate the potential for routing biogas flow to various alternatives. The modeling framework allows for the development of scenarios by allowing the user to choose which combination of plant processes are activated during any given instance. The quantitative modeling results can then be used to compare various scenarios on the basis of economics, environmental impact, and energy usage.

Three main processes with the potential to utilize biogas at SWRP were evaluated: existing plant boilers (for heating digesters and buildings), an on-site biosolids drying facility, and various potential cogeneration systems. The only biogas utilization process currently in use is plant boilers for heating. The on-site, third party drying facility can use

### Table 3 | Projected heat demands for 2040

<table>
<thead>
<tr>
<th></th>
<th>Summer</th>
<th>Winter</th>
<th>Annual average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>[mmBtu/day]</td>
<td>[MW]</td>
<td>[mmBtu/day]</td>
</tr>
<tr>
<td>2040 Digester heat demand</td>
<td>709; 8.8</td>
<td>1,145; 14.2</td>
<td>928; 11.5</td>
</tr>
<tr>
<td>2040 Building heat demand</td>
<td>492; 6.1</td>
<td>2,093; 25.9</td>
<td>1,293; 16.0</td>
</tr>
</tbody>
</table>
either digester gas or natural gas as its primary fuel. A cogeneration facility would use biogas to generate electricity as well as generate heat energy that could be used for plant heating. The main operational variable in the model is the priority in which biogas is used between plant heating, fueling a cogeneration system or used at the solids drying facility. By varying the priority of biogas flow, MWRD is able to identify the most cost-effective operational scenario. The scenarios were analyzed using a spreadsheet-based energy flow model. Scenarios were evaluated for annualized cost, GHG reduction and quantity of unused energy. A schematic of the energy flow model is presented in Figure 1.

Running the model

Two of the most important parameters of the model are the amount of biogas energy produced and the amount of heating energy demanded by the plant digesters and buildings. The projected biogas energy that was used as an input to the model is 168 mmBtu/hr (49 MW). This value is the projected production rate in the selected evaluation scenario discussed in an earlier section. Heating demands for SWRP digesters and buildings were also used as inputs to the model. The heating loads discussed previously were converted from daily loads to hourly loads. The projected heating demands will vary seasonally with digesters requiring a rate of approximately 40 mmBtu/hr (12 MW) in the winter and 25 mmBtu/hr (7 MW) in the summer. The building heating and cooling demands are projected to be 52 mmBtu/hr (15 MW) in the winter and 17 mmBtu/hr (5 MW) in the summer.

Energy input into the model was either through available biogas production or purchased natural gas if necessary. The energy was directed to flow into one or more utilization processes. Gas cleaning technologies were added or not added to the flow scheme as desired. The amount of energy flowing into a given process was modified based on the particular scenario being examined. One of the boundary conditions established for the model was that all scenarios were required to direct enough energy to digesters and building heating to meet the plant heating demands. Heat recovery from the biosolids drying facility or CHP could also be used in the modeling to meet or supplement plant heating demands. Because of the difference in seasonal energy demands, the model produces its results under summer conditions and winter conditions.

Figure 1 | Energy flow modeling framework.
Performance parameters such as capital cost, operational and maintenance (O&M) cost, electrical efficiency and heat recovery efficiency were quantified for each process in the modeling framework. As energy was passed through each activated process, these performance parameters were triggered. The performance parameters for each activated process contributed to the aggregate modeling result by adding or subtracting cost, GHG emissions and energy usage. If a gas cleaning process was activated, it could affect the economic output of the downstream CHP systems by reducing maintenance cost and improving efficiency.

Developing modeling scenarios

A set of modeling scenarios was developed to help guide the decision making process for the best way to utilize biogas at SWRP. The main variable used to distinguish between scenarios was the priority by which biogas was allocated to each of the main utilization processes. ‘Priority’ means giving biogas to that process until the process no longer needs or can no longer handle that quantity of biogas. Then the biogas is sent to the next selected priority process until its capacity is met, and so on. The modeling results from these scenarios could then be compared to determine which processes provide more benefit when given a higher priority to receive biogas. Table 4 gives a list of scenarios developed for evaluation with the energy flow model.

From Table 4, Scenario Groups 1 and 2 consider operations with no CHP system installed at SWRP. Scenario Groups 3–6 consider operations with various CHP systems installed at SWRP. In Scenario Group 4, the biosolids drying facility is fueled entirely with natural gas purchased from the utility pipeline. In Scenario Group 5, plant heating boilers are fueled by natural gas. In Scenario Group 6, both the plant heating boilers and the biosolids drying facility are fueled by natural gas. It should be noted that in Scenario Groups 5 and 6, recovered heat from CHP is used for plant heating and natural gas is used to supplement any remaining heating demands.

Outputs

The outputs from the energy flow model are: Economic Performance, Environmental Impact, and Unused Energy. For purposes of comparing scenarios, a baseline condition was

Table 4 | Description of energy modeling scenarios

<table>
<thead>
<tr>
<th>Name</th>
<th>Description</th>
<th>Biogas 1st priority</th>
<th>Biogas 2nd priority</th>
<th>Biogas 3rd priority</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario Group 1 – No CHP, Biogas to plant heating 1st priority</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1A</td>
<td>No CHP</td>
<td>Plant heating</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2A</td>
<td>No CHP</td>
<td>Biosolids dryer</td>
<td>Plant heating</td>
<td></td>
</tr>
<tr>
<td>Scenario Group 2 – No CHP, Biogas to biosolids dryer 1st priority</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3A</td>
<td>CHP = Engines</td>
<td>Plant heating</td>
<td>Biosolids dryer</td>
<td></td>
</tr>
<tr>
<td>3B</td>
<td>CHP = Gas turbines</td>
<td>Plant heating</td>
<td>Biosolids dryer</td>
<td></td>
</tr>
<tr>
<td>3C</td>
<td>CHP = Steam turbines</td>
<td>Plant heating</td>
<td>Biosolids dryer</td>
<td></td>
</tr>
<tr>
<td>Scenario Group 3 – CHP, Biogas to plant heating 1st priority</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4A</td>
<td>CHP = Engines</td>
<td>Plant heating</td>
<td>Biosolids dryer</td>
<td>CHP</td>
</tr>
<tr>
<td>4B</td>
<td>CHP = Gas turbines</td>
<td>Plant heating</td>
<td>Biosolids dryer</td>
<td>CHP</td>
</tr>
<tr>
<td>4C</td>
<td>CHP = Steam turbines</td>
<td>Plant heating</td>
<td>Biosolids dryer</td>
<td>CHP</td>
</tr>
<tr>
<td>Scenario Group 4 – CHP, Digester to plant heating 1st priority, Biosolids dryer fueled by natural gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5A</td>
<td>CHP = Engines</td>
<td>Biosolids dryer</td>
<td>Plant heating</td>
<td>Biosolids dryer (NG)</td>
</tr>
<tr>
<td>5B</td>
<td>CHP = Gas turbines</td>
<td>Biosolids dryer</td>
<td>Plant heating</td>
<td>Biosolids dryer (NG)</td>
</tr>
<tr>
<td>5C</td>
<td>CHP = Steam turbines</td>
<td>Biosolids dryer</td>
<td>Plant heating</td>
<td>Biosolids dryer (NG)</td>
</tr>
<tr>
<td>Scenario Group 5 – CHP, Biogas to biosolids dryer 1st priority, Plant heating fueled by natural gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6A</td>
<td>CHP = Engines</td>
<td>ChP</td>
<td>Plant heating (NG)</td>
<td>Biosolids dryer (NG)</td>
</tr>
<tr>
<td>6B</td>
<td>CHP = Gas turbines</td>
<td>ChP</td>
<td>Plant heating (NG)</td>
<td>Biosolids dryer (NG)</td>
</tr>
<tr>
<td>6C</td>
<td>CHP = Steam turbines</td>
<td>ChP</td>
<td>Plant heating (NG)</td>
<td>Biosolids dryer (NG)</td>
</tr>
</tbody>
</table>
established with which all other scenarios would be compared. This approach makes it easier to recognize a scenario’s benefits or detriments graphically. The baseline condition was established as planning year 2016, when approximately half of the planned plant improvements would be completed, and biogas production has increased, but not to the fullest extent expected. Under the baseline scenario assumptions, biogas is used only for plant heating, with any excess being flared. There is no biogas sent to the biosolids drying facility, and no other utilization processes available.

**Economic performance**

The output parameter of ‘annualized cost’ was selected as the best description of the economic performance of each scenario. Annualized cost included O&M costs, annualized capital cost, cost for purchasing natural gas and cost savings derived from electrical production. Capital costs associated with each scenario were translated into an annualized capital cost assuming a 20 year service lifetime at a 6% interest rate (A/P, 6%, 20). The baseline scenario is estimated to cost approximately US$1.75 M per year. This is mostly due to the purchase of natural gas to fuel the biosolids drying facility.

The overall economic impact for each scenario or ‘Net Annualized Cost’ was calculated as the difference between the annualized cost of the scenario in question and the baseline scenario. The greater the ‘Net Annualized Cost’ value, the greater the savings. 

*Annualized cost example (scenario 4A)*

<table>
<thead>
<tr>
<th>Capital cost</th>
<th>US$49,203,590</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annualized capital cost</td>
<td>US$4,290,553/yr (A/P, 6%, 20 years)</td>
</tr>
<tr>
<td>O&amp;M cost</td>
<td>US$2,761,244/yr</td>
</tr>
<tr>
<td>Natural gas cost for biosolids drying</td>
<td>US$1,752,000/yr</td>
</tr>
<tr>
<td>Electrical cost savings</td>
<td>US$9,368,184/yr</td>
</tr>
<tr>
<td>Annualized cost performance</td>
<td>US$9,368,184/yr–US$4,290,553/yr=US$5,077,631/yr</td>
</tr>
<tr>
<td>Net Annualized Cost</td>
<td>US$5,077,631/yr</td>
</tr>
</tbody>
</table>

**Environmental impact**

The environmental impact for each scenario was measured as the increase or decrease in GHG production. GHG reductions are assumed to be the reductions of emissions that would be realized by not producing electricity from existing power plants off-site, or by not burning natural gas on-site. The use of additional natural gas or the use of electricity to run new equipment (for example, a compressor to run a new gas cleaning system) was factored into the GHG calculation. Similar to annualized cost, the ‘Net GHG Reduction’ for each scenario is determined by taking the difference between the GHG emissions from the scenario in question and the GHG emissions from the baseline scenario. The greater the ‘Net GHG Reduction’ value, the greater the positive impact on the environment. GHG emissions are presented in equivalent metric tons of carbon dioxide per year (MT eCO2/yr).

*GHG reduction example (scenario 4A)*

Net electrical production = 112,958,479 kWh/yr
GHG reduction from Elec. production = 112,958,479 kWh/yr × 0.0007 MT CO2/kWh = 78,968 MT CO2/yr
GHG emission from Nat. gas for biosolids drying = 438,000 mmBtu/yr × 0.053 MT CO2/mmBtu = 23,214 MT CO2/yr
GHG reduction = 78,968 MT CO2/yr–23,214 MT CO2/yr = 55,754 MT CO2/yr

**Unused energy**

Unused Energy is a measure of the available energy that is not utilized in the scenario, and would be lost as heat. Unused energy is calculated as the sum of the amount of biogas energy flared plus the amount of recovered heat energy (from the biosolids drying facility or CHP) that could not be beneficially used for plant heating. Generally, this unused energy is of a low temperature, sometimes called ‘low grade’ heat, as there is no real practical use for this energy at this time. It is possible that in the future, technologies will be available to beneficially use the recovered low grade heat. This metric was captured to give a sense of how efficiently each scenario utilizes the available biogas energy.

*Unused energy example (scenario 4A)*

Digester gas flared = 0 mmBtu/yr
Recovered waste heat from cogeneration that cannot be utilized = 177,430 mmBtu/yr
Unused energy = 177,430 mmBtu/yr.

**RESULTS**

The results from the energy flow modeling scenarios listed in Table 4 are presented in graphical form in Figure 2. The three bars that appear for each scenario represent annualized cost, GHG reduction and unused energy as described above. These results can be used to identify general trends...
and identify the most desirable scenarios for closer evaluation.

A general trend that can be identified from the Figure 2 results is that the most beneficial scenarios are those that include the implementation of a CHP system and also give that CHP system first priority for receiving biogas. These types of scenarios were included in Scenario Groups 4 and 6. This result was somewhat surprising, as intuitively it seemed that it would be more effective to priority-feed the plant heating boilers with biogas as this option would require no additional natural gas purchase for plant heating, and the boilers do not require gas cleaning. However, it appears that due to the higher unit price of electricity per its energy value versus that of natural gas, maximizing electrical production and heat recovery from CHP provides greater economic benefit than other utilization options, even when the cost for constructing and operating the CHP facility and biogas cleaning system is factored in.

Another trend that emerged from the modeling results was the comparison of Reciprocating Engines versus Steam Turbine CHP systems. Within a common grouping, for example Scenario Groups 4 and 6, Steam Turbines provide higher annualized cost savings, while engines provide more GHG reduction. As noted earlier, the GHG reduction is not a direct reduction at the treatment plant, but rather a theoretical reduction at a power plant as a consequence of not having to produce the electricity that is offset by the reciprocating engine. The reason for the difference in GHG reduction between reciprocating engines and steam turbines is that reciprocating engines are more efficient in converting the biogas into electricity. This difference in efficiency also has economic implications that will be discussed further.

Two input parameters to the model that had a significant effect on the modeling results are the assumed energy utility prices for electricity and natural gas. Utility prices used in this analysis were US$0.08/kWh for electricity, and US$8/mmBtu for natural gas. These values were used for all modeling scenarios. However, with energy prices being notoriously volatile, a sensitivity analysis was conducted to examine how the selected scenarios would respond to fluctuations in both natural gas and electricity prices.

Results of this sensitivity analysis showed that Scenario Groups 4 and 6, in which priority was given to CHP systems, were much more sensitive to changes in electrical prices than natural gas prices. Figure 3 shows an example of results from these sensitivity analyses for Scenarios 4A, 4C and 6A. The results in Figure 3 showed the effects of varying electrical prices when natural gas prices are held constant at the

Figure 2 | Energy flow modeling results.
From Figure 3 it can be seen that the scenarios that use an engine CHP system (4A and 6A) are more sensitive to shifts in electrical prices than the scenario that uses a steam turbine CHP system. At the current electric price of US$0.07/kWh or the projected baseline electric price of US$0.08/kWh, the steam turbine (4C) has the best annualized cost performance. As electricity prices rise, the engine scenarios (4A and 6A) become cost competitive with, and eventually surpass, the steam turbine scenario (4C).

Similar types of sensitivity analyses were conducted by holding electrical prices constant and varying the cost of natural gas. The model was also used to examine ‘extreme’ scenarios in which both natural gas and electricity prices were varied to examine a wide array of possible energy prices. This type of analysis demonstrates the value of the Energy Flow Model for MWRD policy makers and risk managers as many different future scenarios can be quickly analyzed side by side to aid in making decisions for future capital improvements.

**Triple bottom line (TBL) analysis**

A triple bottom line (TBL) analysis was used to compare the energy flow model scenarios and to aid in making a final selection for implementation. The general evaluation categories were economics, environmental, and social. As all the biogas utilization scenarios would have little effect on parties outside the plant fence line, the ‘social’ category was used to define the effects of each option on the MWRD’s internal staff and operations. Each main category was assigned a weighting based on the importance to the MWRD and also broken down into several sub-categories. These weightings and subcategories are listed below.

**Main category – economics (weighting = 50)**
- Sub category – Net cost savings
- Sub category – Sensitivity

**Main category – environmental (weighting = 30)**
- Sub category – Green house gas (GHG) reduction
- Sub category – Air pollution

**Main category – social (weighting = 20)**
- Sub category – Operability
- Sub category – Maintainability
- Sub category – Implementability

Each biogas utilization scenario examined was assigned a score in each of the sub categories listed above. Quantitative energy flow model results were used to determine scores
for ‘Net Cost Savings’, ‘Sensitivity’, and ‘GHG Reduction’. A separate analysis on regulated air contaminant emissions was used to determine the score for ‘Air Pollution’. For the Social sub-categories, scores were assigned based on a variety of sources including manufacturer’s data, interviews with equipment operators and site visits to reference installations.

It should be noted that as of this writing, the final selection process for biogas utilization at SWRP has not been decided. Therefore a final selected technology cannot be presented in this paper.

CONCLUSIONS

1. The utilization of biogas at a plant the size of SWRP is a complex situation. A flexible and comprehensive tool was needed to evaluate the multiple options for interrelated processes such as electrical generation, process heating, gas cleaning and energy sale or purchase.
2. The energy flow model developed for SWRP proved valuable and robust in its ability to model various biogas use scenarios. The model also functioned as a learning tool to better understand the fundamental issues that most significantly affect the benefits of biogas utilization.
3. Flexibility was a key benefit to the utility of the energy model. By giving the user the ability to activate any desired combination of processes, a diverse set of scenarios could be developed to answer any number of questions that may be considered meaningful or interesting.
4. A Combined Heat and Power process would provide the greatest economic advantage of all the modeled processes, so long as the CHP process was priority loaded with the biogas.
5. Sensitivity analysis on utility prices showed that scenarios that included priority loaded CHP systems were most sensitive to fluctuations in electrical prices. At lower electricity prices in the range of US$0.07–$0.08/kWh, steam turbines had the more beneficial economic performance. When electric prices were increased to US$0.09–$0.10/kWh, reciprocating engines became more cost competitive and eventually surpassed the steam turbines.
6. The quantitative aspect of the energy flow model also allows MWRD to affix a monetary value to their biogas which can be used for exploratory discussions with 3rd party energy suppliers and purchasers, if this approach is deemed desirable.
7. The modeling results did not lead directly to a decision on a specific system for implementation, but rather served as a filter to identify the most desirable group of options for more detailed evaluation. A TBL analysis was used for evaluating the scenarios, using the model outputs of Economic Performance and Environmental Impact, and operation and maintenance considerations not included in this model, to determine a path forward.

SUGGESTED READING


REFERENCES

Design of Municipal Wastewater Treatment Plants: WEF Manual of Practice No. 8 2010 5th edition. American Society of Civil Engineers/Environmental and Water Resources Institute, Reston, VA.