Albany County Water Purification District

Saratoga County Sewer District

REGIONAL BIOSOLIDS FACILITY

Feasibility Study

March 5, 2018
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Feasibility Study

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EXECUTIVE SUMMARY

The Albany County Water Purification District (ACWPD) and Saratoga County Sewer District (SCSD) are evaluating options for a regional biosolids handling facility. Both ACWPD and SCSD have, or will be, transitioning away from incineration as the mechanism of biosolids disposal at their wastewater treatment plants and have elected to jointly evaluate a regional biosolids facility that would take advantage of capital construction cost and operation and maintenance (O&M) economies of scale. This study investigates the economic feasibility of a regional biosolids handling facility, to be located at the ACWPD North Plant to take advantage of the existing 925 kW Organic Rankine Cycle (ORC) turbine.

Projections for loadings to the new regional biosolids facility were made in a previous technical memo over a design and planning period ending in 2035. These projections are presented in the tables below.

<table>
<thead>
<tr>
<th>Source</th>
<th>Average Conditions</th>
<th>Maximum Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Sludge Flow</td>
<td>Dry Solids Loading</td>
</tr>
<tr>
<td></td>
<td>Gal/day or CY/day</td>
<td>Dtpd</td>
</tr>
<tr>
<td>North Plant Primary Sludge</td>
<td>110,300</td>
<td>9.2</td>
</tr>
<tr>
<td>North Plant TWAS</td>
<td>38,600</td>
<td>8.1</td>
</tr>
<tr>
<td>South Plant Cake</td>
<td>48 CY/day</td>
<td>8.2</td>
</tr>
<tr>
<td>Bethlehem Sludge</td>
<td>9,000</td>
<td>1.6</td>
</tr>
<tr>
<td>East Greenbush/Coeymans Cake</td>
<td>8.3 CY/day</td>
<td>1.4</td>
</tr>
<tr>
<td>SCSD Cake</td>
<td>75 CY/day</td>
<td>13.2</td>
</tr>
<tr>
<td>FOG</td>
<td>40,000</td>
<td>10.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>51.7</strong></td>
<td></td>
</tr>
<tr>
<td>North Plant Primary Sludge</td>
<td>230,200</td>
<td>19.2</td>
</tr>
<tr>
<td>North Plant TWAS</td>
<td>54,200</td>
<td>11.3</td>
</tr>
<tr>
<td>South Plant Cake</td>
<td>67 CY/day</td>
<td>11.4</td>
</tr>
<tr>
<td>Bethlehem Sludge</td>
<td>9,000</td>
<td>1.6</td>
</tr>
<tr>
<td>East Greenbush/Coeymans Cake</td>
<td>8.3 CY/day</td>
<td>1.4</td>
</tr>
<tr>
<td>SCSD Cake</td>
<td>93 CY/day</td>
<td>16.5</td>
</tr>
<tr>
<td>FOG</td>
<td>40,000</td>
<td>10.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>71.4</strong></td>
<td></td>
</tr>
</tbody>
</table>
A spreadsheet model was developed to track the flow of mass and energy throughout the potential solids treatment processes for various operating scenarios at the new regional biosolids facility. The primary process inputs to the solids and energy flow model were established by the design criteria analysis. The preliminary results of the model are shown in Table ES-3. In total 11 scenarios were evaluated.

### Table ES-2: Projected 2035 Future Expansion Loadings Summary

<table>
<thead>
<tr>
<th>Source</th>
<th>Sludge Flow</th>
<th>Dry Solids Loading</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gal/day or CY/day</td>
<td>Dtpd</td>
</tr>
<tr>
<td>Average Conditions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>25% of Haul Cake Market</td>
<td>52 CY/day</td>
<td>8.8</td>
</tr>
<tr>
<td>25% of HSW/Organic Waste Market</td>
<td>17,500</td>
<td>21.9</td>
</tr>
</tbody>
</table>

### Table ES-3: Initial Model Scenario Outputs

<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Scenario</th>
<th>Annualized Cost ($)</th>
<th>GHG Reduction (MT eCO$_2$)</th>
<th>Net kW</th>
<th>Total Project Cap Ex ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>No Project</td>
<td>$7,974,000</td>
<td>0</td>
<td>0</td>
<td>$5,600,000</td>
</tr>
<tr>
<td>1</td>
<td>Separate Projects – Class A</td>
<td>$6,723,000</td>
<td>NA</td>
<td>NA</td>
<td>$51,367,000</td>
</tr>
<tr>
<td>2</td>
<td>Separate Projects – Class B</td>
<td>$7,571,000</td>
<td>NA</td>
<td>NA</td>
<td>$66,000,000</td>
</tr>
<tr>
<td>3</td>
<td>Digestion, Biogas to Boilers, Sludge to Landfill</td>
<td>$7,509,000</td>
<td>2,050</td>
<td>326</td>
<td>$43,364,000</td>
</tr>
<tr>
<td>4</td>
<td>Digestion, Biogas to Boilers, Class B Sludge</td>
<td>$5,781,000</td>
<td>2,050</td>
<td>326</td>
<td>$43,064,000</td>
</tr>
<tr>
<td>5</td>
<td>Digestion, PAD, Biogas to Turbine, Class B Sludge</td>
<td>$5,708,000</td>
<td>3,120</td>
<td>848</td>
<td>$52,300,000</td>
</tr>
<tr>
<td>6</td>
<td>Digestion, Lystek, Biogas to Turbine</td>
<td>$6,132,000</td>
<td>4,700</td>
<td>1,236</td>
<td>$58,300,000</td>
</tr>
<tr>
<td>7</td>
<td>WAS Lysis, Digestion, Biogas to Boilers, Class B Sludge</td>
<td>$5,096,000</td>
<td>3,130</td>
<td>498</td>
<td>$42,776,000</td>
</tr>
<tr>
<td>8</td>
<td>WAS Lysis, Digestion, Biogas to Engines, Class B Sludge</td>
<td>$5,357,000</td>
<td>10,870</td>
<td>2,098</td>
<td>$52,971,000</td>
</tr>
<tr>
<td>9</td>
<td>WAS Lysis, Digestion, Biogas to Turbines, Class B Sludge</td>
<td>$5,107,000</td>
<td>7,240</td>
<td>1,501</td>
<td>$48,512,000</td>
</tr>
<tr>
<td>10</td>
<td>WAS Lysis, Digestion, PAD, Biogas to Turbines, Class B Sludge</td>
<td>$5,139,000</td>
<td>4,190</td>
<td>1,017</td>
<td>$52,012,000</td>
</tr>
<tr>
<td>11</td>
<td>WAS Lysis, Digestion, Lystek, Biogas to Turbines</td>
<td>$5,743,000</td>
<td>6,010</td>
<td>1,429</td>
<td>$58,012,000</td>
</tr>
</tbody>
</table>
From there, user selected processes could be activated in isolation or in combination with selections affecting model parameters to generate a model output. Model outputs include such parameters as total project capital cost, total annualized cost, greenhouse gas reduction, and net electric consumption or generation. The results from this analysis provide a quantitative framework to better understand each potential operating scenario and to aid in selecting the most beneficial combination of process options for the new regional facility.

Scenarios 2 and 3 presented in Table ES-3 represent ACWPD and SCSD completing separate projects for the creation of either a Class A or B biosolid. For the Class A biosolids project for each utility, the estimated capital costs are $26,000,000 and annualized costs are $4,340,000 for ACWPD (reference the CDM Smith report for Thermal Chemical Hydrolysis Process (TCHP) and the estimated capital costs are $19,100,000 and annualized costs are $2,383,520 for SCSD (reference the GHD report utilizing Lystek). If SCSD pursued anaerobic digestion, the estimated capital costs would be $40,000,000 and annualized costs are $3,370,000 (reference the GHD report with anaerobic digestion and combined heat and power). Annualized costs are inclusive of O&M costs, revenues and debit service amortized over 20 years with a 3% interest rate.

Several options were examined for potential unit processes at the new regional facility. Solids handling processes evaluated for feasibility included:

- Solids loadout and receiving facilities
- Improvements to sludge thickening equipment
- Thermal Alkaline Hydrolysis
- Mesophilic anaerobic digestion
- Post Aerobic Digestion (PAD)
- Lystek

Several biogas utilization processes were evaluated for feasibility. When examining biogas utilization, provisions for keeping the existing ORC turbine in operation were included as part of each option. Biogas utilization processes evaluated included:

- Thermal oil boiler to drive the ORC turbine
- Gas Turbine Combined Heat and Power (CHP)
- Reciprocating Engine CHP

Based on preliminary modeling results and collaborative discussions with ACWPD and SCSD, the most beneficial solids process arrangement was a single phase mesophilic anaerobic digestion facility with pre-digestion thickening and waste activated sludge (WAS) lysis with a thermal alkaline hydrolysis process. This would produce a class B biosolids product that would be contract hauled for final end use. This process is represented in Scenarios 7, 9 and 10. Scenario 7 represents the most basic improvements for anaerobic digestion and biogas utilization, where biogas is utilized to fuel a thermal oil boiler and drive the existing ORC. Scenario 9 replaces the thermal oil boiler with a gas turbine CHP, where the waste heat is recovered and used to drive the ORC turbine. This would increase energy production by 1 MW. Scenario 10 includes PAD which would reduce phosphorous and nitrogen in the sludge and increase volatile solids destruction to reduce the ultimate sludge hauling and disposal costs.
Scenarios 7 and 9 will result in an additional ammonia load to the aeration system. Initial estimates indicate that these scenarios could increase ammonia loading by approximately 2,700 lb/day. Depending on the month this is between a 60 and 110 percent increase in ammonia loading, which the North Plant has sufficient aeration tank and aeration blower capacity. PAD was not recommended for the initial facility to reduce capital costs. The PAD process effectively address sidestream nutrient removal and possible Class A biosolids generation. Although considered, at this time these drivers are not strong enough to warrant the additional capital expenditures. If future permit discharge requirements result in more stringent phosphorous and nitrogen limits, PAD could be easily implemented in one of the existing aeration tanks.

Selection of a biogas utilization process required an additional round of scenario modeling and analysis, as future expansion, energy prices, and the availability of net metering all have varying effects on the most beneficial direction for the new regional facility. Based on current net metering laws, the realized net value of the generated electricity is maximized by matching on-site generation with on-site use (i.e., using all electricity behind-the-meter), which is currently approximately 1,250 kW. A sensitivity analysis was conducted on the chosen solids handling configuration with a thermal oil boiler or a turbine CHP unit for biogas utilization. Results indicated that the turbine CHP unit has a higher capital cost but comparable annualized cost to the thermal oil boiler option. However, the turbine CHP unit does have significant advantages over the thermal oil boiler option if net metering is permitted at the Plant or if PAD is implemented in the future by increasing electricity production. With a turbine CHP unit operating solely off produced biogas, the plant is expected to produce approximately 969 kW of electricity, all of which can be used behind-the-meter. If net metering is permitted, the turbine CHP unit can be operated at maximum production by supplementing with natural gas. Under this condition, the facility could be expected to produce approximately 2.1 MW of electricity, resulting in approximately $350,000 in annualized cost savings compared with no natural gas supplementation.

For the purpose of planning, Arcadis recommends that ACWPD and SCSD consider moving forward with a project capital expenditure budget of $48.5M (for Scenario 9) and within the first three months of the design schedule determine if additional funding maybe available after the final 2018 New York State budget is passed. Based on the preliminary design, both options have the same annualized cost of $5,100,000 (with a 50/50 split) the estimated annual cost per utility to be approximately $2,550,000.
1 INTRODUCTION

The Albany County Water Purification District (ACWPD) and Saratoga County Sewer District (SCSD) are evaluating options for a regional biosolids handling facility. ACWPD owns and operates two wastewater treatment Plants (Plants), the North and South Plants. SCSD owns and operates a single Plant. All three Plants are equipped with sewage sludge incinerators (SSIs) which have historically been the sole mechanism of solids disposal at each of the three facilities. Due to increasing emissions regulations and the need for large capital upgrades in order to maintain compliance and functionality of the incinerators, incineration is not considered viable for future operations. SCSD decommissioned its SSI in 2016 and has been hauling dewatered sludge cake to a landfill disposal facility at considerable cost. ACWPD still incinerates sludge at both the North and South Plants but plans to discontinue operations and decommission the SSIs in the near future.

Both ACWPD and SCSD recognize that hauling undigested sludge cake to a landfill is not a cost effective or sustainable long-term approach to biosolids management. Each organization has individually conducted studies into implementing new biosolids treatment onsite. Based on the findings of the individual studies, both organizations have elected to jointly evaluate a regional biosolids facility that would take advantage of capital construction cost and operation and maintenance (O&M) economies of scale. In addition to treating biosolids from the ACWPD and SCSD Plants, this facility could also target the import of other municipal sludges, high strength organic waste and/or fats, oils and grease (FOG) streams from the surrounding area to further drive beneficial economics and enhance energy recovery.

The selected site for the new regional biosolids facility was the ACWPD North Plant. This site has several beneficial aspects such as greenfield space to build anaerobic digesters, idle aeration tanks that could be repurposed and utilized, and an existing (and currently underutilized) Organic Rankine Cycle (ORC) turbine system in place that can generate electricity from captured waste heat. The regional biosolids facility would treat solids generated onsite at the ACWPD North Plant, receive solids from ACWPD’s South Plant and the SCSD Plant, and could also receive imported material from other sources such as cake from other municipal treatment Plants, high-strength organic waste from local industries, commercial food processing and prepping facilities, and FOG.

1.1 Purpose

This study details the development and results from a Solids and Energy Flow Modeling effort, which was undertaken to investigate the potential configurations and processes to be included in the new regional biosolids facility. The purpose of the study was to determine if a new regional biosolids facility would be economically viable. Additional goals of the study included:

- Establishing the most economical strategy to maximize energy recovery while making use of existing facilities on site;
- Determining the viability of producing Class A biosolids;
- Developing an overall operational strategy for the regional biosolids facility;
- Estimating capital and O&M costs for the facility; and
- Determining how regionalization could make biosolids handling more efficient and effective for both ACWPD and SCSD.
2 DESIGN CRITERIA FOR FUTURE SOLIDS LOADING

Projections for loadings to the new regional biosolids facility were made in a previous technical memo, *Regional Biosolids Facility Design Criteria* (included as Appendix A), over a design and planning period ending in 2035. The projected future solids loading to the regional biosolids facility was broken into two loading scenarios. The “baseline” scenario is comprised of solids sources which are either already contributing to the Plant solids loading or can be reasonably depended upon to contribute sludge to the facility in the future. The solids streams included in the baseline scenario include:

- ACWPD North Plant primary sludge and waste activated sludge (WAS)
- ACWPD South Plant primary sludge and WAS
- SCSD primary sludge and WAS
- Village of Coeymans liquid sludge (currently hauled to South Plant)
- Village of Bethlehem liquid sludge (currently hauled to South Plant)
- Town of East Greenbush sludge cake (historically hauled to South Plant prior to installation of belt filter presses)
- Projected FOG loading from both counties

Table 1 summarizes the projected 2035 baseline loadings to the facility. Cake volumetric loading rates have been converted to cubic yards per day (CY/day)

Potential additional loadings were estimated but were not included in the initial study. These loadings may be considered as part of future expansion or may be able to be accepted during periods when sludge loading to the facility is less than the design loading. Future expansion loadings include:

- Additional imported sludge cake hauled from nearby wastewater treatment plants
- Imported organic/high strength waste from nonresidential waste generators

The actual percentage of the total estimated market for hauled cake or high strength waste which can be captured is highly site-specific and can fluctuate quite dramatically. It is typically assumed for high-level analysis that 25% of the available market can be captured. Table 2 summarizes the projected 2035 future expansion loadings to the regional biosolids facility.
### Table 1: Projected 2035 Baseline Loadings Summary

<table>
<thead>
<tr>
<th>Source</th>
<th>Sludge Flow</th>
<th>Dry Solids Loading</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gal/day or CY/day</td>
<td>.dtpd</td>
</tr>
<tr>
<td><strong>Average Conditions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Plant Primary Sludge</td>
<td>110,300</td>
<td>9.2</td>
</tr>
<tr>
<td>North Plant TWAS</td>
<td>38,600</td>
<td>8.1</td>
</tr>
<tr>
<td>South Plant Cake</td>
<td>48 CY/day</td>
<td>8.2</td>
</tr>
<tr>
<td>Bethlehem Sludge</td>
<td>9,000</td>
<td>1.6</td>
</tr>
<tr>
<td>East Greenbush/Coeymans Cake</td>
<td>8.3 CY/day</td>
<td>1.4</td>
</tr>
<tr>
<td>SCSD Cake</td>
<td>75 CY/day</td>
<td>13.2</td>
</tr>
<tr>
<td>FOG</td>
<td>40,000</td>
<td>10.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>51.7</strong></td>
</tr>
</tbody>
</table>

| **Maximum Conditions**                    |             |                    |
| North Plant Primary Sludge                | 230,200     | 19.2               |
| North Plant TWAS                          | 54,200      | 11.3               |
| South Plant Cake                          | 67 CY/day   | 11.4               |
| Bethlehem Sludge                          | 9,000       | 1.6                |
| East Greenbush/Coeymans Cake              | 8.3 CY/day  | 1.4                |
| SCSD Cake                                 | 93 CY/day   | 16.5               |
| FOG                                       | 40,000      | 10.0               |
| **Total**                                 |             | **71.4**           |

### Table 2: Projected 2035 Future Expansion Loadings Summary

<table>
<thead>
<tr>
<th>Source</th>
<th>Sludge Flow</th>
<th>Dry Solids Loading</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gal/day or CY/day</td>
<td>.dtpd</td>
</tr>
<tr>
<td><strong>Average Conditions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25% of Hauled Cake Market</td>
<td>52 CY/day</td>
<td>8.8</td>
</tr>
<tr>
<td>25% of HSW/Organic Waste Market</td>
<td>17,500</td>
<td>21.9</td>
</tr>
</tbody>
</table>
3 SOLIDS HANDLING EQUIPMENT AND PROCESSES

This section describes the current solids handling processes employed at the Plants and provides technical descriptions of the various unit processes which were considered to be reutilized or repurposed as part of the new regional biosolids facility.

3.1 Existing Solids Handling Equipment and Processes

3.1.1 ACWPD North Plant

Figure 1 presents a layout of the ACWPD North Plant showing the location of the equipment described below.

3.1.1.1 Sludge Holding Tanks

The North Plant is equipped with four sludge holding tanks with a total storage capacity of approximately 1.1 million gallons (MG). These tanks are equipped with paddle mixers to prevent settling of sludge and to blend primary sludge and WAS into a homogenous mixture. Primary sludge is drawn from the primary settling tanks at approximately 2% total solids (TS) and is pumped directly to the sludge holding tanks. WAS is pumped to the sludge holding tanks after undergoing thickening in the solids disposal building.

3.1.1.2 Solids Disposal Building

The solids disposal building houses sludge thickening and dewatering equipment, along with the incinerators. Unthickened WAS is drawn from the return activated sludge (RAS) wet well in the RAS pump station adjacent to the secondary clarifiers. Unthickened WAS is pumped to the solids handling building, where it is split among five dissolved air flotation thickeners (DAFTs). Currently only three of the DAFTs are operational. Sludge is discharged from the DAFTs as thickened WAS (TWAS) and is sent to the sludge holding tanks to be blended with primary sludge prior to dewatering. The North Plant adds polymer to the DAFT influent to improve solids coagulation and result in a TWAS solids content of approximately 5% TS. From the sludge holding tanks, combined sludge is pumped back into the solids handling building, where it is fed to two belt filter presses (BFPs). Currently, the BFPs are capable of achieving approximately 22% TS. In the new regional biosolids configuration these existing BFPs will be repurposed to dewater digested solids from anaerobic digesters prior to loadout for final end use.

From the BFPs, belt conveyors carry the dewatered cake to the Plant’s incinerators. The Plant has two multiple-hearth incinerators (MHIs). These incinerators are currently the final sludge disposal mechanism employed by the Plant. The incinerators, which have been running since the 1970s, are expensive to operate and maintain with current air emissions requirements and are expected to become even more expensive with future regulations. Ash from the incinerators is sent to an on-site lagoon in the northeast corner of the Plant site.
3.1.1.3 Organic Rankine Cycle Turbine

The North Plant has an ORC turbine generator which utilizes waste heat from the MHIs to boil an organic working fluid (silica oil) to turn a turbine generator and produce electricity. The ORC is similar in nature to a steam turbine but with a lower boiling temperature fluid that allows the use of lower grade heat sources. Currently the ORC reclaims heat from the incineration flue gases via heat exchangers retrofitted into the incinerator exhaust stacks. The heat exchangers heat a thermal oil loop, which is then used to heat the working fluid of the ORC. The ORC is currently running well below its rated capacity due to issues with these thermal oil heat exchangers. These units have finned tube heat exchange surfaces which experience substantial clogging from the ash contained in the incinerator flue gas. At full capacity, the ORC can produce up to 925 net kW of power for internal plant use; however, currently it is typically operating at less than half of its rated output. Since the ORC is relatively new and can utilize waste heat to generate renewable power, the Plant staff would like to keep the ORC operational as part of the new regional biosolids facility.

3.1.1.4 Aeration Tanks and Blowers

The North Plant has excess aeration tank capacity, with up to three full tanks (each tank consisting of four cells arranged in a row) sitting idle at any given time. Some of the unused tanks could be repurposed for a suitable process such as digested sludge holding or post aerobic digestion (PAD). The Plant also has two 14,000 scfm rated blowers for aeration, with one typically operating at any time. If these blowers have excess aeration capacity, this could also be used to support specific processes. For the purposes of this analysis, excess aeration capacity was not considered.

3.1.2 ACWPD South Plant

The South Plant contains many of the same unit processes found at the North Plant. Primary sludge is drawn from the primary settling tanks at approximately 2% TS and is pumped directly to the three sludge holding tanks. Unthickened WAS is drawn from the RAS wet well in the RAS pump station located adjacent to the secondary clarifiers and is pumped to the solids disposal building where it is dosed with polymer and split among three DAFTs. The DAFTs at the South Plant typically achieve a solids content of approximately 5.5% TS. From the DAFTs, the TWAS stream flows into a wet well, and is pumped to the sludge holding tanks where it is blended with the primary sludge and with imported sludge from the Village of Coeymans and the Village of Bethlehem.

From the sludge holding tanks, blended sludge is pumped back into the solids disposal building, which houses two BFPs. Only one of the BFPs is currently operable. The South Plant typically achieves approximately 22% TS. The majority of the solids handling process at the South Plant described up to this point will remain unchanged by this project, with the exception of adding a second operational BFP. The cake that is produced at the South Plant will be hauled by truck to the North Plant for processing at a projected frequency of two truckloads per weekday or 1-2 truckloads per day on a 7-day per week basis.

Currently, pressed cake at the South Plant is conveyed to a pair of MHIs. As with the North Plant, ash from the incinerators is sent to lagoons on the northern side of the site. Periodically, ash is removed from the lagoons and sent to a landfill.
3.1.3 SCSD Plant

Primary sludge from the SCSD Plant is drawn from the primary settling tanks and sent directly to one of four sludge holding tanks. WAS is drawn from the RAS pump station wet well and pumped to two gravity belt thickeners (GBTs), where it is dosed with polymer and thickened. Thickened WAS leaves the GBTs at approximately 6% TS and is combined with primary sludge in the sludge holding tanks. The combined sludge stream is pumped to two BFPs on the top floor of the solids disposal building. The BFPs produce sludge cake at a typical solids content of approximately 22% TS. Pressed cake is conveyed horizontally and dropped through a chute into a truck loadout facility on the ground floor. Cake is hauled from the Plant to a landfill for disposal. The solids handling process at the SCSD Plant will not be altered by this project, with the exception of solids loadout facility improvements.

3.2 Unit Processes Examined for New Regional Biosolids Facility

A variety of processes were considered to enhance the performance and feasibility of a regional biosolids handling facility. The following section summarizes the improvements being considered and provides a brief technical description where appropriate. Model input parameters and project cost estimates are also given. Cost estimates, which can be found in Appendix B, include soft cost adders of 11% for Division 1 work, 30% general contingency, 15% overhead and profit, and 4% for taxes/bonds/insurance. Engineering costs are not included in these project cost estimates. Vendor quotes can be found in Appendix C.

3.2.1 Loadout Facilities

In order to bring solids to the ACWP North Plant for centralized solids treatment, sludge cake loadout facilities are necessary at each of the satellite plants. It was determined that hauling liquid sludge from the South Plant was undesirable due to the large number of truck trips that would be required on a daily basis. Additionally, the cake loadout facility is not operational and needs to be upgraded for final product offloading at the new regional biosolids facility. The following sections describe the recommended loadout improvements.

3.2.1.1 SCSD Plant Sludge Cake Loadout Facility

The SCSD Plant currently disposes of unstabilized sludge solely by hauling to landfill, utilizing an existing cake loadout facility. However, the existing loadout facility was intended as a contingency for the SSI, and should undergo improvements to better accommodate a permanent switch to cake hauling. The existing facility is located in one of two garage bays. The proposed improvements include structural work to widen the second bay and allow for two parallel loadout bays. This provides 100% contingency in the event of equipment malfunction or scheduled maintenance. The proposed improvements also include installation of loadout conveyors. These conveyors are suspended from the ceiling and run the length of a truck bed. Knife gates along the length of the conveyor allow loading along the entire length of the bed and facilitate the loading process. These conveyors can be fed directly from the floor above, where a screw conveyor already runs over both bays on its way from the BFPs to the abandoned incinerator.

Table 3 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from experience with similar previous projects. The power draw
of the new facility was assumed to be approximately equal to the power draw of the existing operations; therefore, the net power draw added by the recommended improvements is zero. The SCSD loadout facility was considered necessary to the project and is therefore not included as an option in the model that can be turned on and off.

Table 3: SCSD Loadout Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($))</td>
<td>$1,092,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$5,800</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>0</td>
</tr>
</tbody>
</table>

3.2.1.2 South Plant Sludge Cake Loadout Facility

The South Plant would also require a permanent cake loadout facility to haul sludge cake to the regional biosolids facility at the North Plant. Although the South Plant currently incinerates sludge, it does have a contingency loadout facility which can be repurposed. Improvements include installation of a loadout conveyor to facilitate the truck loading process. Some re-routing of conveyors from the BFPs on the top floor of the solids disposal building would be required. Site improvements such as paving would likely be required to permit a truck to navigate the site. Additionally, upgrading the South Plant by adding a second dewatering BFP was recommended to add redundancy for cake hauling to the new regional biosolids facility.

Table 4 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from experience with similar previous projects. The power draw of the new facility was assumed to be approximately equal to the power draw of the existing operations; therefore, the net power draw added by the improvements is zero. Similar to the loadout facility at the SCSD, the South Plant loadout facility was considered necessary to the project and is therefore not an option in the model that can be turned on and off.

Table 4: South Plant Loadout Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($))</td>
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<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$18,600</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>0</td>
</tr>
</tbody>
</table>

3.2.1.3 North Plant Solids Loadout Facility

Digested and dewatered solids cake will be hauled from the North Plant to the final end use for the regional facility. The North Plant was designed with a contingency loadout facility, but this facility has been abandoned and is no longer operational. A new facility would be constructed to the south of the solids disposal building with two parallel pull-through loading bays. The conveyors from the BFPs on the top floor of the solids disposal building could be re-routed and sent to this facility, which would include loadout conveyors.
Table 5 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from experience with similar previous projects. The power draw of the new facility was assumed to be approximately equal to the power draw of the existing operations; therefore, the net power draw added by the improvements is zero. Like the other two loadout facilities, the ACWPD North Plant loadout facility is considered a requisite upgrade and is not an option in the model that can be turned on and off.

Table 5: North Plant Loadout Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($</td>
<td>$2,862,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$13,400</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>0</td>
</tr>
</tbody>
</table>

3.2.2 Receiving Facilities

The regional biosolids facility would require facilities for receiving loads not generated onsite at the North Plant. These incoming loads would include dewatered sludge cake, liquid sludge and FOG.

3.2.2.1 Sludge Cake Receiving/Rewetting Facility

In order to intake sludge cake and liquid sludge from the SCSD Plant and the South Plant (as well as any potential future outlying communities or feedstock sources), a receiving/rewetting facility is required at the regional facility. Cake will generally be received at approximately 20% TS and will be re-wetted and blended with the sludge produced on-site to obtain a homogenous feed for the anaerobic digesters. The cake will be rewetted to approximately 6% TS (generally the upper limit at which sludge is still easily pumpable) using unthickened WAS from the North Plant and then pumped to the existing sludge holding tanks.

A typical layout for a cake receiving facility consists of a building with a cake hopper set below grade. Trucks back up to the hopper, open the cover, and dump a load of sludge cake into it. The hopper will have a live bottom consisting of several screw augers or a sliding frame to break up the cake and allow an offloading auger to transport it from the hopper and feed it into a sludge cake pump. The cake pump sends the cake through a macerator into a blend tank, where unthickened WAS is injected turbulently and a mechanical mixer blends and homogenizes to the desired solids content. The mixture is then pumped to the sludge holding tank, where it is blended with the rest of the Plant sludge by the sludge holding tank mixers.

For this project, two 100 CY cake hoppers with pumps are recommended to provide 1.4 days of cake storage at average conditions and operational redundancy. The liquid and sludge cake receiving facility was located adjacent to the sludge holding tanks to minimize pumping distance and to facilitate blending into the onsite sludge stream as quickly and easily as possible.

Table 6 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. The upgrades for the cake receiving facility also included costs for concrete lining repairs and the replacement of the existing top mounted mixers in the sludge holding tanks. Values were
drawn from vendor quotes and from experience with similar previous projects. The sludge cake receiving/rewetting facility is a required component of the project and is not an option in the model that can be turned on and off.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($</td>
<td>$8,101,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$62,600</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>212,300</td>
</tr>
</tbody>
</table>

### 3.2.2.2 FOG Receiving Facility

A FOG receiving facility was included to accept, process, and store incoming FOG loads prior to injecting FOG into new digesters. Based on population projections and standard per capita FOG production, it was estimated that approximately 40,000 gal/day of FOG may be received at the biosolids facility. A typical FOG receiving station consists of a truck unloading slab next to mixed, insulated, heated tanks. Heating is required to prevent the FOG from solidifying in the tanks and maintaining pumpability. A recirculation pump keeps the contents of the tank mixed and fluid. FOG is received from tanker trucks during normal business hours on weekdays but should be metered into the digesters in a constant, steady basis. For this reason, three 40,000 gallon FRP tanks with recirculation pumps were recommended for sufficient storage and redundancy. The FOG tanks will be heated and insulated to improve the viscosity of the FOG. Rock traps and/or other upfront FOG processing to remove debris that may be present in the FOG will also be included.

Table 7 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from experience with similar previous projects. The FOG receiving facility is needed for the project and is not an option in the model that can be turned on and off.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($</td>
<td>$2,306,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$10,800</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>391,900</td>
</tr>
<tr>
<td>Tipping Fee ($/gal)</td>
<td>$0.03</td>
</tr>
</tbody>
</table>

### 3.2.2.3 HSW Receiving Facility

As part of a potential future expansion of the new regional biosolids facility, a station to receive, process, and inject HSW into digesters may be included. This facility will likely be an expansion of the FOG receiving facility with additional pre-processing, storage capacity, offloading equipment, and digester injection pumps provided as needed depending on the volumes and characteristics of the HSW procured.
Table 8 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from experience with similar previous projects. The HSW receiving facility is only necessary to the project if the HSW feed stream is activated. When HSW is added to the model, the parameters below are automatically added to the model analysis.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($)</td>
<td>$1,500,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$10,000</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>130,600</td>
</tr>
<tr>
<td>Tipping Fee ($/gal)</td>
<td>$0.03</td>
</tr>
</tbody>
</table>

### 3.2.3 Pre-Digestion Sludge Processing

There were several sludge pre-processing technologies examined to maximize the operational efficiency of the new regional biosolids facility. This included a variety of enhancements ranging from screening, to thickening, to lysis.

#### 3.2.3.1 Sludge Screens - Strain Presses

Sludge screening for primary sludge and incoming loads was included to ensure that trash and debris in sludge would not compromise performance of downstream processes. Currently, the North and South Plants treat combined sewage and are equipped with 1” bar screens at the headworks which allow for considerable trash and debris to pass through and be present within the sludge. Incoming cake loads of undetermined quality should also be screened to ensure they do not create downstream maintenance issues. The selected screening process was strain presses which pass sludge flow driven by differential pressure through a slow rotating screw press. The units typically consist of a screw augur within a cylindrical screen which decreases in diameter along the length of the unit. As the auger turns, sludge and most biosolids pass through the screen while solids larger than the screen mesh size are retained within the screen. These larger solids are conveyed by the screw to the end of the unit, where they are compressed against a cone to squeeze liquid from them before dropping out of the unit and into a dumpster or other receptacle. The screened sludge continues downstream to further thickening and processing before being fed to the digesters. Figure 2 presents a typical schematic of a sludge screen.

Strain presses were selected for this project because they can handle the solids loading and hydraulic loading rates required. Additional benefits of strain presses include their compact footprint, totally enclosed construction, and their use of differential pressure to operate, which allows them to be operated in-line without additional pumping requirements.
Table 9 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes. Because of the potential for debris to be present in the sludge, and the importance of effectively removing it, two sludge screens were recommended under all scenarios and were not included as an option in the model.

Table 9: Sludge Screening Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($</td>
<td>$890,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$8,600</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>91,500</td>
</tr>
</tbody>
</table>

3.2.3.2 Sludge Thickening - Gravity Belt Thickeners

Sludge thickening was examined to provide reduced sludge flows to digesters thereby reducing the digester tank volume needed to provide sufficient solids retention time (SRT), reduce digester heating loads, and provide concentrated sludge flows to optimize potential lysis downstream.

GBTs were selected as the thickening technology for examination. GBTs thicken solids by draining the free water through a moving permeable belt which retains the solids. Similar to existing DAFT units, GBTs typically require a polymer dose to improve solids thickening. Filtrate is collected and returned to the head of the Plant, while the retained solids fall or are scraped into a hopper at the end of the unit. Units can be enclosed for odor control if desired. GBTs can achieve greater than 6% TS, although it is desirable to limit solids content to no greater than 6% TS to maintain sludge pumpability. Figure 3 shows a typical GBT installation.
Table 10 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes. Three 2.0-m GBTs are recommended under all scenarios and were not included as an option in the model. O&M costs and power draw from GBTs were not included, since it was assumed that use of the GBTs rather than the existing DAFTs will likely result in a net O&M and power savings. Polymer usage is similarly not expected to increase over the current DAFT usage, therefore the net polymer cost added by the GBTs was also assumed to be zero.

Table 10: GBT Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($)</td>
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<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$0</td>
</tr>
<tr>
<td>Additional Power Draw (kWh/yr)</td>
<td>0</td>
</tr>
<tr>
<td>Additional Polymer Cost ($/yr)</td>
<td>$0</td>
</tr>
</tbody>
</table>

3.2.3.3 WAS Lysis – Thermal Alkaline Hydrolysis

Thermal-alkaline hydrolysis is a pre-digestion process that uses caustic soda to raise pH to 11 and hot water heating (to 150°F) to hydrolyze WAS. This increases sludge degradability, improves dewaterability and decreases viscosity of the sludge. Thermal alkaline hydrolysis requires less equipment and less heat input than a thermal hydrolysis system while avoiding the use of steam. It also is designed to treat only WAS to maximize hydrolysis effects (although this prevents it from achieving Class A). The resulting lysis of cells causes a release of organic acids that return the pH to near neutral. Heated WAS is then mixed with cold primary sludge and fed to the anaerobic digesters. For mesophilic digestion the digester heating loads are similar with or without the thermal alkaline hydrolysis and recovered hot water heat from Combined Heat and Power (CHP) system can be used as a heat source. Thermal alkaline systems have a small footprint and have relatively low operations and maintenance requirements. A disadvantage of
this process is that it introduces chemical handling (caustic soda) into the solids handling scheme. Additionally, there is no pre-thickening step, so the system can only feed sludge to the digesters at the same thickness at which it is received. Therefore, the digester feed thickness would be limited by the performance of the sludge thickening process upstream. Figure 4 shows a thermal alkaline hydrolysis installation.

![Figure 4: Pondus© System in Kenosha, WI](image)

Table 11 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes and experience with similar projects. WAS lysis is included as an option in the model; the Table 11 parameters are automatically integrated into the analysis when WAS lysis is activated.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($</td>
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<tr>
<td>Power Draw (kWh/yr)</td>
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<tr>
<td>Chemical Cost ($/yr)</td>
<td>$16,000</td>
</tr>
<tr>
<td>Additional Dewaterability (% TS)</td>
<td>3%</td>
</tr>
<tr>
<td>Reduced Dewatering Polymer Use (lb/dt)</td>
<td>1</td>
</tr>
</tbody>
</table>

An additional operational benefit from lysing WAS is a significant decrease in viscosity, which greatly enhances the ease of sludge pumping, up to %TS concentrations as high as 10% TS. The addition of
WAS lysis was projected to allow average sludge feed to digesters to be increased from 6% to 8%TS thereby by lowering required digester tank volumes and reducing digester heating loads.

### 3.2.4 Single-Stage Mesophilic Anaerobic Digestion

The new regional biosolids facility includes mesophilic anaerobic digesters to break down and remove volatile solids in the influent feed, producing biogas as a beneficial byproduct. The target treatment capacity for maintaining mesophilic digestion is a 20-day SRT under average conditions, with one digester unit offline. Thus, digester sizing is highly dependent on the level of sludge thickening that can be accomplished prior to feeding sludge to the digesters. It should be noted that certain technologies such as thermal-alkaline hydrolysis (lysis) could increase the allowable solids content in the digester feed by rendering high-solids sludge more pumpable.

Mesophilic digestion is a common technology in municipal WWTPs. The process consists of sending sludge into a heated and mixed tank. A recirculation pump constantly recirculates the contents of the tank through a heat exchanger to maintain mesophilic temperatures within the digester. Heating demands are less than that of thermophilic digestion, as mesophilic digesters are typically operated at 95°F. However, this means that mesophilic digestion alone will not achieve Class A biosolids status. Digestion produces biogas, which can be captured in the digester under a floating cover or membrane or sent to a separate gas holder. Digested sludge is drawn from the tank and sent downstream for dewatering and disposal.

For this project, three tanks are proposed, sized such that two tanks can meet the 20-day average SRT. Digester size is calculated within the model, and automatically updates when digester feed flow changes to maintain the 20-day SRT with two digesters in service. The third tank provides redundancy and can operate as a secondary digester which stores the residuals from the other two digesters if necessary. It may also be assumed that adding additional types of digester tanks such as a Post Aerobic Digestion (PAD) tank would provide enough buffer and additional digestion capacity that an additional redundant mesophilic digester tank would not be needed. This would eliminate the need to reserve the third digester as a redundant or secondary digester, effectively raising the capacity of the anaerobic digestion process and the volume of outside sludges and alternative feedstocks that can be accepted.

Table 12 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes and experience with similar projects for both concrete and steel digesters. Cost was determined on a per MG or per tank basis, since tank size and number of tanks were variables within the model. As tank size or number of tanks changes, the cost for the digesters automatically updates within the model.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value (Concrete)</th>
<th>Model Value (Steel)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($/MG)</td>
<td>$3,305,000</td>
<td>$2,891,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr/tank)</td>
<td>$50,000</td>
<td>$50,000</td>
</tr>
<tr>
<td>Power Draw (kWh/yr/tank)</td>
<td>196,000</td>
<td>196,000</td>
</tr>
</tbody>
</table>
Depending on upstream process selections made in the model, required digester volume ranges from 5 to 7 MG. If concrete is selected for digesters, the estimated capital cost range is $15-$20 million. This represents the largest capital cost component of the new regional biosolids facility.

### 3.2.5 Post Aerobic Digestion (PAD)

Post Aerobic Digestion (PAD) is the addition of an aerobic digester process following anaerobic digestion. PAD provides a range of advantages including an additional 30%-40% destruction of incoming VSR, thereby decreasing cumulative digested solids production by 10-20%. It also can remove up to 98% of the ammonia load present in digested sludge when operated with intermittent aeration, as well as remove organic sulfur compounds that are the main source of odors. PAD also improves dewatering performance and lowers the necessary polymer dosage. PAD reactors can also double as sludge storage tanks, which may save future capital expenditure. The PAD process includes an increase in annual aeration costs but eliminates the need for a separate sidestream treatment process to manage nitrogen and can reduce some ortho-phosphorus (ortho-P) by forming struvite as the reactor pH increases. The amount of ortho-P reduction will be dependent on the magnesium concentration in the biosolids. Additional magnesium (in the form of MgCl₂) can be dosed into the PAD reactor to enhance removal of ortho-P. For a system sized for the projected digested flow, it is estimated that a blower of approximately 100 hp would be required. There is also potential to recover heat from the PAD sludge and transfer that heat into colder incoming digester sludge feeds, thereby reducing the overall heating demands for digestion and providing cooling to the PAD reactor.

PAD is not currently recognized as capable of achieving Class A quality material. The temperatures maintained in the PAD process are not sufficient to achieve the requirements under Part 503 regulations. It should be noted that the issues preventing achieving Class A with PAD are related to defining this newer process with regulators, and that the actual pathogen reduction performance of PAD is generally considered to be sufficient to achieve Class A quality material.

This analysis assumed conversion of three available existing aeration tank cells to PAD tankage, for a total SRT of approximately 7.5 days. This conversion would include raising the tank walls by three feet to provide enhanced oxygen transfer from increased side water depth. The primary capital cost of PAD installation at the regional biosolids facility would be these structural alterations and installation of new aeration diffusers and blowers. Figure 5 shows a partially drained PAD installation, with the aeration equipment visible. The following cost and performance parameters were used as process parameters for the solids flow model.

An additional benefit of PAD would be its ability to function as a secondary digester, providing some storage for digested sludge. This would eliminate the need for a redundant mesophilic digester and allow additional digester capacity for importing feedstocks to the facility.
Table 13 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes and experience with similar projects. PAD was included as an option within the model. The parameters below are automatically activated and integrated into the analysis when PAD is activated within the model.

### Table 13: PAD Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($$)</td>
<td>$3,500,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$20,000</td>
</tr>
<tr>
<td>Power Draw (kWh/yr)</td>
<td>4,691,000</td>
</tr>
<tr>
<td>Additional VSR</td>
<td>16.5%</td>
</tr>
<tr>
<td>Additional Dewaterability</td>
<td>1.5%</td>
</tr>
</tbody>
</table>

#### 3.2.6 Lystek

Lystek is a proprietary technology wherein digested sludge is dewatered and lysed under a thermal-alkaline reaction. In the Lystek reactor, alkali solution is added to the digested material to raise its pH to 11 or higher, then low pressure steam is injected to breakdown complex organics. The product of Lystek is a liquid solution of approximately 15% to 17% TS and pH 8 to 9 which is rich in COD and other nutrients. This product must be stored seasonally and then is typically land applied to nearby agricultural sites in the spring and fall. One benefit of Lystek is that they have a delivery model option that includes full service management of the final end product, essentially taking responsibility for the solids product once it is sent to their unit process by the Plant. Additionally, Lystek’s product is recognized as a Class A material, with all biosolids going to beneficial reuse. Lystek has also performed technical analyses.
demonstrating that a slip stream of lysed product can be recycled back to the anaerobic digesters to boost gas production and enhance digester performance, although this operation would increase the required digester SRT and has not yet been executed at full scale.

For this project, the existing BFPs at the North Plant would be repurposed for dewatering digested material prior to processing with Lystek, and one additional BFP would be purchased for redundancy. Lystek product would be stored seasonally in a bladder reservoir in the ash lagoon to the east of the proposed anaerobic digesters.

Table 14 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes and experience with similar projects. Capital cost includes the installed Lystek system, storage requirements, and the additional BFP. O&M costs include chemical use and maintenance costs. Lystek was included as an option within the model. The parameters below are automatically activated and integrated into the analysis when PAD is activated within the model.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($)</td>
<td>$9,500,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$800,000</td>
</tr>
<tr>
<td>Power Draw (kWh/yr)</td>
<td>638,140</td>
</tr>
<tr>
<td>Additional VSR</td>
<td>15%</td>
</tr>
<tr>
<td>Product Disposal Cost ($/wt)</td>
<td>$25</td>
</tr>
</tbody>
</table>

### 3.2.7 Biogas Utilization

Biogas is an energy by-product of anaerobic digestion that can be utilized in a variety of processes. Currently there are not any digestion or biogas systems at the North Plant, so all biogas utilization systems would be completely new. There is a waste heat recovery process onsite which is the previously described ORC generator powered by the heat from incinerator flue gases. Although the incinerators are being decommissioned, the biogas produced by anaerobic digestion provides multiple options for generating heat flows that could be utilized to keep the ORC in operation and also increase the output capacity of the ORC over current, underutilized levels. Several options were evaluated for biogas utilization with each option including a method to provide heat to drive the ORC.

#### 3.2.7.1 Biogas-Fired Hot Water Boilers

The biogas can be used to generate hot water using biogas-fired boilers. Boiler processes are typically approximately 80% efficient and recover heat in the form of hot water that can be used to heat the digesters via sludge-water heat exchangers or can be used for building heating. Typically, minimal biogas conditioning is required for combusting biogas in boilers. For the Solids and Energy Flow Model it was assumed filters and a chiller would be used to remove particles and moisture prior to the boilers. It was assumed new boilers would also be provided with the ability to fire natural gas in the event that biogas
was not available. These new boilers would be tied into the existing natural gas hot water boilers in the solids disposal building.

Table 15 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from experience with similar projects. Biogas-fired hot water boilers are recommended under all scenarios and are not included as an option in the model. This is because boiler heating for digesters is needed as backup even if digesters are primarily to be heated by a CHP process. Operating cost and power draw was only activated in the non-CHP options where the boiler would be in regular operation as the primary digester heating source. Those parameters are automatically activated and integrated into the analysis when biogas is sent to boilers in the model.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($$)</td>
<td>$750,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$25,000</td>
</tr>
<tr>
<td>Power Draw (kWh/yr)</td>
<td>65,350</td>
</tr>
<tr>
<td>Boiler Efficiency</td>
<td>80%</td>
</tr>
</tbody>
</table>

It should be noted that biogas fired hot water boilers would not provide high enough quality heat to power the ORC. So, an additional biogas utilization process would need to be paired with the hot water boilers as part of the requirements to keep the ORC in operation.

3.2.7.2 Biogas-Fired Thermal Oil Heater

One option for powering the ORC off biogas is to heat the existing thermal oil loop directly with a biogas-fired thermal oil heater. Thermal oil heaters are available in models which can run off either biogas, natural gas, or a blend of biogas and natural gas. A quote from Heatec was solicited for this study. Heatec recommended a three-pass heater for ease of maintenance, since biogas can necessitate more frequent cleaning. Biogas conditioning for the thermal oil heater would be more extensive, including filters, chiller for moisture removal, and an additional activated carbon polishing process to prevent excessive contaminant buildup in the thermal oil boiler components. This option also necessitates some minor modifications to the thermal oil loop, which were included in the cost estimate.

Table 16 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from experience with similar projects. Biogas-fired thermal oil boilers are included as an option. The parameters below are automatically activated and integrated into the analysis when biogas is sent to boilers in the model in amounts greater than what is required for digester heating. Heat output from the thermal oil boilers is utilized to power the ORC.
Table 16: Biogas-Fired Thermal Oil Heater Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($)</td>
<td>$1,902,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$63,000</td>
</tr>
<tr>
<td>Power Draw (kWh/yr)</td>
<td>65,350</td>
</tr>
<tr>
<td>Boiler Efficiency</td>
<td>80%</td>
</tr>
</tbody>
</table>

3.2.7.3 Medium Turbine CHP

Biogas can also be combusted in prime mover to turn a generator and produce electricity. Waste heat can also be recovered off the combustion reaction for beneficial use to make it a CHP process. For this fairly unique application in conjunction with the ORC, a medium gas turbine CHP prime mover was examined. Gas turbines are less electrically efficient than the more typical reciprocating engines, but they produce a large amount of high temperature exhaust gas that is thermally similar to incinerator flue gas. The exhaust from the turbine could be used with a thermal oil heat exchanger to capture the large amount of exhaust heat to drive the ORC.

A quote was solicited for an OPRA OP16-3B industrial single-shaft, all-radial gas turbine. A visual of the turbine is shown in Figure 6. This turbine is rated for 1,850 kW and has the ability to burn biogas, natural gas, or a blend. The turbine units were originally designed for burning well head gas from oil drilling and can operate on very low gas quality and require relatively little maintenance. Biogas conditioning requirements would be dictated by the exhaust heat recovery equipment and its resistance to contaminants. For the Solids and Energy Flow Model it was assumed filters and a chiller would be used to remove particles and moisture prior to the turbine CHP. Downstream thermal oil heat exchangers would be constructed of stainless steel or other corrosion resistant materials. The turbine also requires significant biogas compression prior to use in CHP. The option includes a two-stage reciprocating compressor, which blends the biogas and natural gas and discharges at 180 psig. A new thermal oil heat exchanger would be installed in one of the existing incinerator stacks to heat the thermal oil loop. Exhaust from the turbine would be ducted directly into the existing incinerator stack, allowing the thermal oil loop to remain largely intact.

Exhaust heat from the turbine would also be utilized to provide heat to the digesters as a primary mode of digester heating. There currently is an existing thermal oil to hot water heat exchanger in the basement of the solids disposal building. This unit takes heat from thermal oil loop and generates hot water that is tied into the existing natural gas boiler hot water loop. Currently this unit only operates as a means of backup heating when the ORC is out of service. This unit would be modified to allow for regular operations for digester heating when the ORC is also in service.

Table 17 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes and experience with similar projects. The CHP turbine unit is included in the model as an option. The parameters below are automatically activated and integrated into the analysis when biogas is sent to the CHP turbine option.
Table 17: Turbine CHP Unit Cost and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($)</td>
<td>$7,542,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$85,000</td>
</tr>
<tr>
<td>100% Load Electrical Efficiency</td>
<td>23%</td>
</tr>
<tr>
<td>Exhaust Heat Recovery Efficiency</td>
<td>50%</td>
</tr>
</tbody>
</table>

Figure 6: Turbine Visual (from OPRA)

Figure 7: Turbine Installation (from Kinsley Energy Systems)
3.2.7.4 Engines

Biogas could be combusted in a more traditional reciprocating engine CHP system. Engines have higher electrical efficiencies, on the order 40% at full load, and recover waste both as hot water from the engine block and hot exhaust gas from the engine. Due to higher energy recovery efficiencies in other parts of the process, engines make less exhaust heat that would be available to drive the ORC. Hot water recovered directly from the engines could be used to heat digesters without an intermediate hot water recovery heat exchanger. Biogas conditioning for engines would be the most extensive, requiring hydrogen sulphide ($H_2S$) removal, filters, moisture removal, and siloxane treatment. Based on the projected amount of biogas available, the engine system selected for this application was a pair of Jenbacher J420 engines each rated for approximately 1,400 kW electric output. These units were assumed to be containerized and located in the area adjacent to the ORC.

Table 18 presents the cost and performance parameters that were used as inputs for the Solids and Energy Flow Model. Values were drawn from vendor quotes and experience with similar projects. The CHP engine unit is included in the model as an option. The parameters below are automatically activated and integrated into the analysis when biogas is sent to the CHP engine option.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Model Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost ($)</td>
<td>$10,445,000</td>
</tr>
<tr>
<td>Annual O&amp;M Cost ($/yr)</td>
<td>$0.025/kWh</td>
</tr>
<tr>
<td>100% Load Electrical Efficiency</td>
<td>39.4%</td>
</tr>
<tr>
<td>HW Heat Recovery Efficiency</td>
<td>25%</td>
</tr>
<tr>
<td>Exhaust Heat Recovery Efficiency</td>
<td>26%</td>
</tr>
</tbody>
</table>

3.2.7.5 Maximum Onsite Generation Capacity

Hourly electrical demand trends at the North Plant were analyzed for 2017 to determine the capacity to utilize power generated onsite. This is shown in Figure 8 below.
Based on these trends, it appears the average power draw at the Plant is approximately 1,250 kW with minimum hour demand for the year of approximately 900 kW. Under current tariff structures, the greatest financial benefit associated with on-site electrical generation occurs when all electricity is used on-site, behind the meter. Consequently, the construction and operation of infrastructure that produces greater than 1,250 kW on average becomes less financially attractive. To avoid being required to construct additional protective relays to the grid, onsite generation would be capped and would need to incorporate control functions that allow generation to closely follow on-site loads to prevent export of power. It should be noted that the proposed facilities will result in additional electrical demand that has been considered as part of these analyses. There are ongoing discussions amongst the State electric utilities and the Public Services Commission related to distributed generation. If virtual net metering provisions were enacted for biogas-fired generation or alternative rates were set on the wholesale market for renewable energy, then this maximum capacity for onsite generation would not be applicable as excess power could be allocated to other County-owned accounts or put back on the grid at a more beneficial price point.

### 3.2.8 Solids End Use

Digested biosolids from the digesters would be dewatered in existing BFPs in the solids handling building and sent to a final end use application. Various options exist for disposal based on the quality of residuals produced.

#### 3.2.8.1 Disposal to Landfill

Disposing of solids to landfill is not considered an attractive option, either from a price or sustainability standpoint. If the incinerators are decommissioned without constructing the digester facility, hauling to a
landfill is the only disposal alternative to incineration. Discussion with local contract haulers indicates that a typical fee for hauling residual solids to a landfill is approximately $100 per wet ton. This is consistent with what SCSD currently pays for landfill disposal of their solids. Landfill disposal can be activated in the model by choosing a percent of digested biosolids to send to landfill.

3.2.8.2 Disposal of a Class B Material

Digested biosolids that meet specific time and temperature metrics are considered to be Class B materials and can be land-applied at agricultural sites with certain restrictions. Discussion with local contract haulers indicates that a typical fee for accepting and hauling Class B material in the area is approximately $60 per wet ton. This figure can vary somewhat based on market demand and storage requirements, since land application of sludge is seasonal. The rate of $60 per wet ton was reported to be a conservative number considering storage. Class B material disposal can be selected in the model by choosing a percent of residual solids to have contract hauled and selecting “Class B” in a dropdown menu.

3.2.8.3 Disposal of a Class A Material

Digested biosolids that meet more stringent time and temperature metrics or have undergone a regulator recognized process to further reduce pathogens are considered to be Class A materials and can be used in a wide range of agricultural, commercial, and landscaping applications. Discussion with local contract haulers indicates that a typical fee for accepting and hauling Class B material in the area is approximately $25 per wet ton. Again, this figure can vary somewhat based on market demand and storage requirements, since Class A application can be seasonal in nature. The rate of $25 per wet ton was reported to be a conservative number considering storage. Class A material disposal can be selected in the model by choosing a percent of residual solids to have contract hauled and selecting “Class A” in a dropdown menu.

3.2.8.4 Disposal of Lystek Material

As discussed previously, Lystek will retain responsibility for the management and distribution of the material generated by their process. The estimated cost for those services that was included in Lystek’s quote was $25 per wet ton, which is consistent with the estimate obtained for contract hauling Class A material. The Lystek disposal fee is automatically activated when Lystek is selected in the model.

4 MODEL METHODOLOGY

A spreadsheet model was developed to track the flow of mass and energy throughout the potential solids treatment processes for various operating scenarios at the new regional biosolids facility. All scenarios were evaluated for annualized cost and greenhouse gas (GHG) emissions reductions. The results from this analysis provide a quantitative framework to better understand each potential operating scenario and to aid in selecting the most beneficial combination of processes for the new regional biosolids facility.
4.1 Input and Framework for Solids and Energy Flow Modeling

The primary process inputs to the solids and energy flow model were established by the design criteria analysis described in Section 2. Input values can be referred to in Table 1. From there, user selected processes could be activated in isolation or in combination with selections affecting values such as dry tons per day, digester feed or cake %TS, chemical costs, volatile solids reduction, etc. Process results that were dependent on these selections included wet tons per day to be offloaded, Plant heating loads, and digester gas produced for use in energy production.

Process performance parameters and costs were adapted from vendor quotes, reported project data, literature values, and in some cases direct experience with the technology. These parameters were documented in Section 3.2. Performance parameters dependent on other processes were built into the logic behind the solids and energy flow model. For example, the lysis process improves the dewaterability of sludge, and that relationship is calculated automatically in the model when lysis and mechanical dewatering technologies are included in the scenario. Activation of a process and its effects also activates the capital and operational costs associated with implementing that process. An example of the solids and energy flow model dashboard is provided in Figure 9.

4.2 Outputs for Solids and Energy Flow Modeling

The two main outputs for the solids and energy flow model are annualized cost and greenhouse gas (GHG) emission reductions. Annualized cost translates the estimated capital cost into an annual payment, similar to a payment that would be made on a bond. When annualizing capital costs, this analysis assumed a 20-year term at a 3% interest rate. Annualized capital costs were combined with the yearly O&M costs and estimated net power savings to yield a total annualized cost for each scenario examined.

The reduction in GHG emissions was also quantified for each scenario, with the main reduction source being energy recovered from renewable biogas. Energy generated from biogas will offset energy that must be generated from fossil fuels. The amount of GHG reduction will depend on the type of energy being offset. Provided below are factors for determining CO₂ emissions equivalents (CO₂e) associated with offsetting various types of energy consumption. While GHG emissions are a composite of many different gases, emissions are typically converted to CO₂ equivalents since CO₂ is the predominant component in most GHG emissions.

The CO₂e associated with electricity usage was retrieved using eGRID 2014 (the most recent available version) which is an EPA created software application. eGRID is used to derive composite data from regional electric generation zones to approximate the composite amount of CO₂e emitted for each MWh of electricity produced/consumed in the region. The reported value for Table 19 is from the NCPP eGRID sub-region which contains the Albany and Saratoga area.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Electrical Output Emission Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual eCO₂ emissions</td>
<td>1,254 lb CO₂e/MWh</td>
</tr>
</tbody>
</table>

Table 19: Default eCO2 Emissions Factor for Electrical Usage
The values listed in Table 20 below were taken from Table C-1 of Subpart C to CFR 98 that identifies default CO2e emission factors for combustion of natural gas.

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Default high heat value</th>
<th>Default eCO2 emission factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline Natural Gas</td>
<td>$1.026 \times 10^{-3}$ mmBtu/scf</td>
<td>53 kg CO$_2$e /mmBtu</td>
</tr>
</tbody>
</table>

The values listed in Table 21 below were taken from the “Carbon Dioxide Emissions Coefficients Table” published by the U.S. Energy Information Administration that identifies default CO2e emission factors for combustion of diesel fuel.

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Default eCO2 emission factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel Fuel</td>
<td>10.16 kg CO$_2$e /gal</td>
</tr>
<tr>
<td></td>
<td>161 lb CO$_2$e /mmBtu</td>
</tr>
</tbody>
</table>

The net GHG emissions for each scenario are calculated as the reduction resulting from using biogas for power generation, less the parasitic electric loads, combustion of natural gas, and use of vehicle fuel involved with each scenario.
5 INITIAL MODEL SCENARIO DEVELOPMENT

Several initial scenarios were analyzed using the model. The results of this analysis were used to select options for further analysis.

5.1 Improvements Common to All Scenarios

Certain improvements were determined to be necessary or sensible under all scenarios considered and were included in the analyses in that fashion (i.e., as default requirements). As described previously, improvements to the loadout facilities at each of the three Plants are required for implementation of any regional biosolids facility. Similarly, sludge cake receiving/rewetting and FOG receiving stations are required for the intake of solids at the regional facility. The costs for these improvements were carried under every regional biosolids facility scenario considered.

Preliminary analysis of the solids flow demonstrated the most effective configuration of sludge thickening at the North Plant. Initially, two basic scenarios were modeled:

1. Sending the rewetted cake, primary sludge and WAS generated at the North Plant into the sludge holding tanks to blend all the sludge into one homogenous digester feed prior to thickening
2. Sending only rewetted cake and the primary sludge to the sludge holding tanks and thickening the WAS stream separately.

Both scenarios have benefits. Blending all sludge into one homogenous feed before thickening and sending to digestion is operationally simpler, consolidating everything into a single feed. However, treating WAS as a separate stream significantly reduces the required storage capacity of the sludge storage tanks, as unthickened WAS contains a significant amount of water volume which takes up storage. Additionally, maintaining a separate WAS stream is necessary for some scenarios, such as WAS lysis. Ultimately, preliminary analysis showed that maintaining a separate WAS stream was beneficial under all scenarios. If unthickened WAS is sent to the sludge storage tanks, the tanks have capacity for less than 2 days of storage under average flow conditions. Thickening the WAS stream separately increases the hydraulic retention time of the storage tanks to 5 days under average conditions.

The proposed reconfigured sludge thickening process would be located in the solids disposal building where the DAFTs are currently located. The first step would be sludge screening with strain presses. Two strain press units are recommended, one to screen the stream coming from the sludge holding tanks (primary and rewetted cake) and one to screen the WAS stream. It is likely that the WAS stream will not require screening; thus, two sludge screens can be considered to satisfy redundancy, since in the event of equipment malfunction or servicing, the WAS stream can be bypassed around sludge screening.

The next step would be gravity belt thickening. Three 2.0-m GBTs are recommended, with one dedicated to thickening the flow from sludge holding tanks (primary and rewetted cake), one dedicated to thickening the WAS stream, and one standby unit. The thickened streams can either be combined or sent downstream to the next respective process, depending on what treatment options are selected.
5.2 Initial Model Scenarios

This section describes the scenarios selected for primary analysis. Results of the scenarios are summarized at the end of the section.

5.2.1 Scenario 0: No Project

This scenario serves as a baseline for comparison. In this scenario, both SCSD and ACWPD would abandon and decommission their incinerators, but not implement any additional biosolids handling project or process upgrades and improvements. Both facilities would simply dewater their undigested sludge and haul it to a landfill for disposal. In the absence of any biosolids handling facility construction, this disposal approach would be the only option.

5.2.2 Scenario 1: Separate Projects, Class A Material

This scenario combines the results of the feasibility analyses conducted for ACWPD and SCSD to individually implement biosolids handling and obtain Class A material. The scenario serves as a baseline for comparison. The costs estimated for ACWPD were obtained from a 2016 CDM report entitled Albany County Sewer District North Plant Biosolids Feasibility Study. The Class A alternative presented was a combination of thermal hydrolysis and digestion. The costs estimated for SCSD were obtained from a 2016 GHD report entitled Saratoga County Sewer District Incineration Evaluation. The Class A alternative presented was a Lystek installation. Table 22 summarizes the estimated costs obtained from the reports.

<table>
<thead>
<tr>
<th>Project</th>
<th>Cap Ex ($)</th>
<th>Op Ex ($/yr)</th>
<th>Net kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACWPD – Thermal Hydrolysis, Digestion</td>
<td>$32,267,000</td>
<td>$2,171,000</td>
<td>NA</td>
</tr>
<tr>
<td>SCSD – Lystek</td>
<td>$19,100,000</td>
<td>$1,100,000</td>
<td>NA</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$51,367,000</strong></td>
<td><strong>$3,271,000</strong></td>
<td>NA</td>
</tr>
</tbody>
</table>

5.2.3 Scenario 2: Separate Projects, Class B Material

This scenario combines the results of the feasibility analyses conducted for ACWPD and SCSD to individually implement biosolids handling and obtain Class B material. The scenario serves as a baseline for comparison. The costs estimated for ACWPD were obtained from a 2016 CDM report entitled Albany County Sewer District North Plant Biosolids Feasibility Study. The Class B alternative presented was a combination of thermal chemical hydrolysis and digestion. The costs estimated for SCSD were obtained from a 2016 GHD report entitled Saratoga County Sewer District Incineration Evaluation. The Class B alternative presented was an anaerobic digestion installation. Table 23 summarizes the estimated costs obtained from the reports.
### Table 23: Separate Projects, Class B Material

<table>
<thead>
<tr>
<th>Project</th>
<th>Cap Ex ($)</th>
<th>Op Ex ($/yr)</th>
<th>Net kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACWPD – Thermal Chemical Hydrolysis,</td>
<td>$26,000,000</td>
<td>$2,453,000</td>
<td>NA</td>
</tr>
<tr>
<td>Digestion</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCSD – Digestion</td>
<td>$40,000,000</td>
<td>$683,000</td>
<td>NA</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$66,000,000</strong></td>
<td><strong>$3,136,000</strong></td>
<td><strong>NA</strong></td>
</tr>
</tbody>
</table>

#### 5.2.4 Scenario 3: Digestion, Sludge to Landfill, Biogas to Boilers

This scenario is the most basic regional biosolids option considered. In addition to the loadout facilities, receiving facilities, and sludge thickening improvements described above, the scenario includes an anaerobic digestion facility consisting of three 2.14 MG digesters. Residual material in this scenario would be hauled to a landfill. The digesters in this scenario produce 652 Mcf/day of biogas, which would be sent to boilers and a biogas-fired thermal oil heater to provide heat to the digesters and use the ORC to produce electricity.

#### 5.2.5 Scenario 4: Digestion, Sludge Contract Hauled (Class B), Biogas to Boilers

This scenario consists of the three 2.14 MG anaerobic digesters, with the residual material being contract hauled as a Class B material at lower cost than sending to a landfill. As in the previous scenario, 652 Mcf/day of biogas would be produced and sent to boilers and the biogas-fired thermal oil heater.

#### 5.2.6 Scenario 5: Digestion, PAD, Sludge Contract Hauled (Class B), CHP Turbine

This scenario adds PAD on the back end of the digesters, with the residual material being contract hauled as a Class B material. For this scenario, 652 Mcf/day of biogas was produced and sent to a CHP turbine, with natural gas blended as needed to keep the turbine and ORC operating in the higher-efficiency part of their curves.

#### 5.2.7 Scenario 6: Digestion, Lystek, CHP Turbine

This scenario adds Lystek instead of PAD after the digesters. The residual material is disposed of by Lystek at their contracted rate. For this scenario, 652 Mcf/day of biogas was produced and sent to a turbine, with natural gas blended as needed to keep the turbine and ORC operating in the higher-efficiency part of their curves.
5.2.8 **Scenario 7: WAS Lysis, Digestion, Sludge Contract Hauled (Class B), Biogas to Boilers**

This scenario adds lysis to the WAS stream prior to digestion, with no PAD or Lystek downstream. Lysis has the benefit of rendering the lysed material more digestible and dewaterable, which increases biogas output and decreases residual solids for disposal. Lysis has the additional benefit of thickening the digester feed. Because lysed material is inherently more liquid and pumpable, sludge in this scenario was assumed to be able to be thickened up to 8% TS. This allows for smaller digesters at 1.75 MG, reducing capital costs.

For this scenario, 747 Mcf/day of biogas was produced. The biogas was assumed to be sent to boilers and a thermal oil heater to operate the ORC.

5.2.9 **Scenario 8: WAS Lysis, Digestion, Sludge Contract Hauled (Class B), Engine CHP with Ductburner**

Solids handling in this scenario matches Scenario 7, but the biogas produced is sent to an engine CHP unit. The engine produces electricity, with natural gas combusted in a ductburner and added to the exhaust to operate the ORC.

5.2.10 **Scenario 9: WAS Lysis, Digestion, Sludge Contract Hauled (Class B), Turbine CHP**

Scenario 9 matches Scenarios 7 and 8 in solids handling, but the biogas produced is sent to a turbine CHP unit to produce electricity with the ORC operated off the turbine exhaust. Natural gas is used as a supplement in the turbine to operate the turbine and ORC in the higher-efficiency part of their curves.

5.2.11 **Scenario 10: WAS Lysis, Digestion, PAD, Sludge Contract Hauled (Class B), Turbine CHP**

Scenario 10 matches Scenario 9, but with PAD added after digestion.

5.2.12 **Scenario 11: WAS Lysis, Digestion, Lystek, Turbine CHP**

Scenario 11 matches Scenario 9, but with Lystek added after digestion. Residual solids would be disposed of by Lystek.

5.3 **Initial Model Scenario Results**

The results of the initial model scenario analyses are presented in Table 24. Annualized scenario costs and greenhouse gas reduction are plotted in Figure 10. As can be seen, the most expensive option on an annualized scenario cost basis is the “No Project” scenario. This scenario is followed by the Class B separate projects scenario (Scenario 2), the most basic digester scenario with hauling to landfill (Scenario 3), and the Class A separate projects scenario (Scenario 1). On a capital cost basis, the separate project scenarios (Scenarios 1 and 2) are the most expensive.
The initial model scenarios also show that adding WAS lysis reduces capital cost and annualized cost (as seen by comparing Scenarios 4 and 7, Scenarios 5 and 10, and Scenarios 6 and 11). This is partially due to the accompanying decrease in digester size. When taking into account all the benefits and savings of WAS lysis, this process appears to be a very sensible option for the regional facility.

Table 24: Initial Model Scenario Outputs

<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Scenario</th>
<th>Annualized Cost ($)</th>
<th>GHG Reduction (MT eCO$_2$)</th>
<th>Net kW</th>
<th>Total Project Cap Ex ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>No Project</td>
<td>$7,974,000</td>
<td>0</td>
<td>0</td>
<td>$5,600,000</td>
</tr>
<tr>
<td>1</td>
<td>Separate Projects – Class A</td>
<td>$6,723,000</td>
<td>NA</td>
<td>NA</td>
<td>$51,367,000</td>
</tr>
<tr>
<td>2</td>
<td>Separate Projects – Class B</td>
<td>$7,571,000</td>
<td>NA</td>
<td>NA</td>
<td>$66,000,000</td>
</tr>
<tr>
<td>3</td>
<td>Digestion, Biogas to Boilers, Sludge to Landfill</td>
<td>$7,509,000</td>
<td>2,050</td>
<td>326</td>
<td>$43,364,000</td>
</tr>
<tr>
<td>4</td>
<td>Digestion, Biogas to Boilers, Class B Sludge</td>
<td>$5,781,000</td>
<td>2,050</td>
<td>326</td>
<td>$43,064,000</td>
</tr>
<tr>
<td>5</td>
<td>Digestion, PAD, Biogas to Turbine, Class B Sludge</td>
<td>$7,571,000</td>
<td>NA</td>
<td>NA</td>
<td>$52,300,000</td>
</tr>
<tr>
<td>6</td>
<td>Digestion, Lystek, Biogas to Turbine</td>
<td>$6,132,000</td>
<td>4,700</td>
<td>1,236</td>
<td>$58,300,000</td>
</tr>
<tr>
<td>7</td>
<td>WAS Lysis, Digestion, Biogas to Boilers, Class B Sludge</td>
<td>$5,096,000</td>
<td>3,130</td>
<td>498</td>
<td>$42,776,000</td>
</tr>
<tr>
<td>8</td>
<td>WAS Lysis, Digestion, Biogas to Engines, Class B Sludge</td>
<td>$5,357,000</td>
<td>10,870</td>
<td>2,098</td>
<td>$52,971,000</td>
</tr>
<tr>
<td>9</td>
<td>WAS Lysis, Digestion, Biogas to Turbines, Class B Sludge</td>
<td>$5,107,000</td>
<td>7,240</td>
<td>1,501</td>
<td>$48,512,000</td>
</tr>
<tr>
<td>10</td>
<td>WAS Lysis, Digestion, PAD, Biogas to Turbines, Class B Sludge</td>
<td>$5,139,000</td>
<td>4,190</td>
<td>1,017</td>
<td>$52,012,000</td>
</tr>
<tr>
<td>11</td>
<td>WAS Lysis, Digestion, Lystek, Biogas to Turbines</td>
<td>$5,743,000</td>
<td>6,010</td>
<td>1,429</td>
<td>$58,012,000</td>
</tr>
</tbody>
</table>
The scenarios show that both PAD and Lystek add significantly to the capital cost of the project. PAD also consumes a large amount of energy due to the aeration equipment, adding significantly to the Plant electric load. The North Plant may currently have additional aeration capacity beyond what is required for their aeration basins; any excess capacity currently used which could be diverted for use in the PAD system could decrease the impact of PAD on the Plant energy consumption and reduce capital costs by eliminating the need for new blowers. This analysis does not account for any current excess aeration capacity.

The scenarios also show that adding turbines or engines for electricity production adds capital cost but allows for higher electric production and greater greenhouse gas reduction than using the biogas to fire a boiler or thermal oil heater.
5.3.1  Scenarios Selected for Further Analysis

Based on the results of the initial modeling analysis, it was decided that WAS lysis appears to make sense on a cost basis. WAS lysis was included as a baseline for all scenarios selected for further analysis. It was also decided that due to the large capital cost of PAD and Lystek and the somewhat limited benefit provided during the initial years of operation, these processes would be evaluated for future implementation but not included in this phase of the project. Thus, scenarios selected for further analysis included Scenario 7, Scenario 8, and Scenario 9.

6  FURTHER MODEL ANALYSES

Currently, net metering is supported in New York State for some renewable generation. However, biogas-fired electricity generation similar to that proposed for this project is not currently eligible. Net metering is when a facility has a electric meter that can turn in both directions (import and export) and is credited at their current retail rate for all electricity generated over the course of a year (or some other pre-determined period), up to their annual consumption. Electricity that is generated on-site in excess of their annual on-site consumption realizes only the avoided wholesale cost of electricity. Since net metering is not currently available (although ongoing discussions are taking place within the State), full retail value of electricity generated on-site is only realized when all electricity is continuously consumed behind the meter. As opposed to net metering where the reconciliation is based on annual use, absent net metering the excess electricity produced at any given time (not strictly when it exceeds annual consumption) is only valued at the avoided wholesale rate. Virtual net metering and net metering where on-site generated electricity can be assigned to any electricity accounts owned by the same entity (versus strictly the on-site electricity meter(s)) or to a third party through a power purchase agreement provide even greater financial benefits. For the purposes of these analyses, when a scenario considers "net metering", it is assumed that 100% of the on-site generated power can be valued at the retail rate.

Because the North Plant cannot currently sell electricity on a net meter basis and the current market price for the environmental attributes of renewable energy generation (e.g., RECs) is somewhat low, it does not currently make sense for the project to produce more electricity than the Plant’s current average usage of 1250 kW. It is possible that net metering will be permitted in the future. Thus, the scenarios were considered in light of both current conditions and potential future electricity tariffs and market structures.

6.1  Further Analysis of Selected Scenarios

Costs and assumptions for the three scenarios selected from the initial modeling were refined, and the scenarios were re-analyzed. Each of Scenario 7, Scenario 8 and Scenario 9 were divided into sub-scenarios for analysis.

6.1.1  Sub-Scenarios

6.1.1.1  Scenario 7a: Thermal Oil Heater, No Net Metering

Under Scenario 7a, the full amount of biogas produced by WAS lysis and digestion is sent to hot water boilers and a thermal oil heater; no additional natural gas is supplemented for electricity production.
Current conditions with no net metering were assumed, so the net electricity production was not allowed to exceed 1250 kW under this scenario (because the ORC is the only generator active in this sub-scenario, 1250 kW of net electric production is not possible anyway).

6.1.1.2 Scenario 8a: Engine CHP, No Net Metering

Under Scenario 8a, biogas produced by WAS lysis and digestion is sent to an engine CHP unit to produce electricity, hot water, and exhaust to operate the ORC. Current conditions with no net metering were assumed, so the net electricity production was not allowed to exceed 1250 kW under this sub-scenario. Because the engines produce so little exhaust heat, it was necessary to supplement with 9 mmBTU/hr via a natural gas duct burner in the exhaust stack to provide enough heat to operate the ORC. Due to the 1250 kW cap, only 50% of the available biogas was able to be combusted in the engines. The balance would have to be flared.

6.1.1.3 Scenario 9a: Turbine CHP, No Net Metering

Under Scenario 9a the full amount of biogas produced by WAS lysis and digestion is sent to a CHP turbine unit, with the ORC operated off the turbine exhaust. No natural gas is supplemented in this scenario. Current conditions with no net metering were assumed, so the net electricity production was not allowed to exceed 1250 kW under this scenario.

6.1.1.4 Scenario 7b: Thermal Oil Heater, Net Metering

Under Scenario 7b the full amount of biogas produced by WAS lysis and digestion is sent to hot water boilers and a thermal oil heater; no additional natural gas is supplemented for electricity production. For this sub-scenario net metering was assumed, so the net electricity production was allowed to exceed 1250 kW. However, because the ORC is the only generator active in this sub-scenario, 1250 kW of net electric production is not possible anyway.

6.1.1.5 Scenario 8b: Engine CHP, Net Metering

Under Scenario 8b the full amount of biogas produced by WAS lysis and digestion is sent to an engine CHP unit to produce electricity, hot water, and exhaust to operate the ORC. For this sub-scenario net metering was assumed, so the net electricity production was allowed to exceed 1250 kW. The engines were supplemented with 8 mmBTU/hr of natural gas to maximize their output. However, because the engines produce so little exhaust heat, it was necessary to supplement with 5 mmBTU/hr via a natural gas duct burner in the exhaust stack to provide enough heat to operate the ORC.

6.1.1.6 Scenario 9b: Turbine CHP, Net Metering

Under Scenario 9b the full amount of biogas produced by WAS lysis and digestion is sent to a CHP turbine unit, with the ORC operated off the turbine exhaust. For this sub-scenario net metering was assumed, so the net electricity production was allowed to exceed 1250 kW. The turbine was supplemented with 9.5 mmBTU/hr of natural gas to maximize its production.
6.1.2 Results of Further Analysis of Selected Scenarios

The results of the sub-scenario analyses are presented in Table 25 and Figure 11. Scenario 0, the “No Project” scenario, is included as well for comparison. The analysis shows that the engine CHP option is not well suited to this application. This option has significantly higher capital cost and annualized cost compared with the other two options. Additionally, the engine CHP option is operationally intensive and cannot be fully utilized in the absence of net metering. In order to maintain operation of the ORC with the engines without net metering, natural gas must be supplemented via a duct burner and half of the available biogas must be wasted by flaring. The engine CHP can be ruled out of subsequent analyses.

The analysis also shows that Scenario 7 is not impacted by net metering, since this option cannot produce enough electricity to meet the average Plant demand of 1,250 kW. Consequently, Scenario 7a and 7b are identical. Under current conditions, Scenario 7a and Scenario 9a have similar annualized cost. Scenario 7a has a lower capital cost, but Scenario 9a has additional greenhouse gas reduction. Without net metering, the two scenarios are comparable, but the lower capital cost of Scenario 7a gives this option a slight edge. However, if net metering is taken into account, the annualized cost of Scenario 9b is driven down by the turbine’s ability to produce excess electricity. The advantage in greenhouse gas reduction similarly increases under net metering conditions. Therefore, if net metering is expected to be available in the future, the turbine CHP option (Scenario 9) is more advantageous than the thermal oil heater option (Scenario 7).

Table 25: Results of Further Analysis of Selected Scenarios

<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Scenario Description</th>
<th>Annualized Cost ($)</th>
<th>GHG Reduction (MT eCO₂)</th>
<th>Net kW</th>
<th>Total Project Cap Ex ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>No Project</td>
<td>$7,974,000</td>
<td>0</td>
<td>0</td>
<td>$5,600,000</td>
</tr>
<tr>
<td>7a</td>
<td>Thermal Oil Heater, No Net Metering</td>
<td>$4,828,000</td>
<td>2,420</td>
<td>486</td>
<td>$43,500,000</td>
</tr>
<tr>
<td>8a</td>
<td>Engine CHP, No Net Metering</td>
<td>$5,678,000</td>
<td>1,730</td>
<td>1,184</td>
<td>$52,800,000</td>
</tr>
<tr>
<td>9a</td>
<td>Turbine CHP, No Net Metering</td>
<td>$4,871,000</td>
<td>4,840</td>
<td>969</td>
<td>$48,600,000</td>
</tr>
<tr>
<td>7b</td>
<td>Thermal Oil Heater, Net Metering</td>
<td>$4,828,000</td>
<td>2,420</td>
<td>486</td>
<td>$43,500,000</td>
</tr>
<tr>
<td>8b</td>
<td>Engine CHP, Net Metering</td>
<td>$5,150,000</td>
<td>8,980</td>
<td>2,973</td>
<td>$52,800,000</td>
</tr>
<tr>
<td>9b</td>
<td>Turbine CHP, Net Metering</td>
<td>$4,518,000</td>
<td>6,350</td>
<td>2,112</td>
<td>$48,600,000</td>
</tr>
</tbody>
</table>
Figure 11: Results of Further Analysis of Selected Scenarios

6.2 Future Implementation of PAD or Lystek

Scenario 7 and Scenario 9 were also evaluated for their potential compatibility with a future buildout to include PAD or Lystek. Additional sub-scenarios were created for each scenario. Each sub-scenario then underwent sensitivity analyses to compare the performance of the thermal oil heater with the turbine CHP and to compare the performance of PAD with the performance of Lystek.

6.2.1 Future PAD or Lystek Sub-Scenarios

6.2.1.1 Scenario 7c: Thermal Oil Heater, PAD

Under Scenario 7c, the biogas produced by WAS lysis and digestion would be sent to a thermal oil heater and PAD would be implemented after anaerobic digestion. No natural gas was supplemented under this scenario. As discussed previously, since Scenario 7 is not impacted by net metering, Scenario 7c applies under both current conditions and potential future net metering conditions.

6.2.1.2 Scenario 7d: Thermal Oil Heater, Lystek

Under Scenario 7d, the biogas produced by WAS lysis and digestion would be sent to a thermal oil heater and Lystek would be implemented after anaerobic digestion. No natural gas was supplemented under this
scenario. As discussed previously, since Scenario 7 is not impacted by net metering, Scenario 7d applies under both current conditions and potential future net metering conditions.

6.2.1.3 Scenario 9c: Turbine CHP, PAD, No Net Metering

Under Scenario 9c, the biogas produced by WAS lysis and digestion would be sent to a turbine and PAD would be implemented after anaerobic digestion. Current conditions with no net metering were assumed, so the net electricity production was not allowed to exceed 1250 kW under this scenario. Natural gas was supplemented at a rate of 6 mmBTU/hr to meet the current Plant capacity.

6.2.1.4 Scenario 9d: Turbine CHP, Lystek, No Net Metering

Under Scenario 9d, the biogas produced by WAS lysis and digestion would be sent to a turbine and Lystek would be implemented after anaerobic digestion. Current conditions with no net metering were assumed, so the net electricity production was not allowed to exceed 1250 kW under this scenario. Natural gas was supplemented at a rate of 2.5 mmBTU/hr to meet the current Plant capacity.

6.2.1.5 Scenario 9e: Turbine CHP, PAD, Net Metering

Under Scenario 9e, the biogas produced by WAS lysis and digestion would be sent to a turbine and PAD would be implemented after anaerobic digestion. Net metering was assumed for this scenario. The turbine was supplemented with 9.5 mmBTU/hr of natural gas to maximize its production.

6.2.1.6 Scenario 9f: Turbine CHP, Lystek, Net Metering

Under Scenario 9f, the biogas produced by WAS lysis and digestion would be sent to a turbine and Lystek would be implemented after anaerobic digestion. Net metering was assumed for this scenario. The turbine was supplemented with 9.5 mmBTU/hr of natural gas to maximize its production.

6.2.2 Thermal Oil Heater Analysis

Table 26 summarizes the results of the thermal oil heater scenarios, including Scenarios 7a and 7b (which are combined, since they are identical) for comparison; Figure 12 presents the results. The results show that PAD essentially does not impact the annualized cost, in large part due to the additional reduction in digested solids for disposal. Lystek, which has a greater capital cost, adds to the annualized cost.

<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Scenario</th>
<th>Annualized Cost ($)</th>
<th>GHG Reduction (MT eCO₂)</th>
<th>Net kW</th>
<th>Total Project Cap Ex ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7a/b</td>
<td>Thermal Oil Heater</td>
<td>$4,828,000</td>
<td>2,420</td>
<td>486</td>
<td>$43,500,000</td>
</tr>
<tr>
<td>7c</td>
<td>Thermal Oil Heater, PAD</td>
<td>$4,821,000</td>
<td>120</td>
<td>23</td>
<td>$47,000,000</td>
</tr>
<tr>
<td>7d</td>
<td>Thermal Oil Heater, Lystek</td>
<td>$5,464,000</td>
<td>1,290</td>
<td>413</td>
<td>$53,000,000</td>
</tr>
</tbody>
</table>
In addition to the cost benefits of PAD, the process provides nutrient removal, which may become an issue for the Plant in the future. The main advantage of Lystek over PAD is that it insulates the Plant from volatility in disposal/end use costs, which have the largest impact of any variable on annualized cost. Figure 13 shows how annual costs for Scenario 7a/b, Scenario 7c, and Scenario 7d vary with contract hauling cost. Rising hauling costs increase the annualized costs of Scenarios 7a/b and 7c, but do not impact the costs of Lystek. It should be noted that with the thermal oil heater option, none of the scenarios are impacted by the implementation of net metering.
6.2.3 Turbine CHP Analysis

Table 27 summarizes the results of the turbine CHP scenarios, which include scenarios covering permutations with PAD, with Lystek, with and without net metering. Figure 12 presents the model results. The addition of PAD and Lystek had similar effects to the turbine scenario as was seen in Scenario 7 analysis. One difference is that PAD adds significant electrical demand to allow the turbine capacity to become better utilized even without net metering. The sensitivity analysis conducted for Class B contract hauling price for the Scenario 7 sub-scenarios applies to the turbine CHP analysis as well.

As described in early scenario analyses, addition of net metering improves the turbine CHP economic performance under all conditions. This is because the turbine is able to operate near its rated output which improves efficiency and utilizes installed generation capacity to its fullest extent.

![Figure 13: Thermal Oil Heater Contract Hauling Sensitivity Analysis](image-url)
### Table 27: Turbine CHP Analysis Results

<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Scenario</th>
<th>Annualized Cost ($)</th>
<th>GHG Reduction (MT eCO₂)</th>
<th>Net kW</th>
<th>Total Project Cap Ex ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9a</td>
<td>Turbine CHP, No Net Metering</td>
<td>$4,871,000</td>
<td>4,840</td>
<td>969</td>
<td>$48,600,000</td>
</tr>
<tr>
<td>9b</td>
<td>Turbine CHP, Net Metering</td>
<td>$4,518,000</td>
<td>6,350</td>
<td>2,112</td>
<td>$48,600,000</td>
</tr>
<tr>
<td>9c</td>
<td>Turbine CHP, PAD, No Net Metering</td>
<td>$4,681,000</td>
<td>3,190</td>
<td>1,169</td>
<td>$52,100,000</td>
</tr>
<tr>
<td>9d</td>
<td>Turbine CHP, Lystek, No Net Metering</td>
<td>$5,445,000</td>
<td>3,870</td>
<td>1,150</td>
<td>$58,100,000</td>
</tr>
<tr>
<td>9e</td>
<td>Turbine CHP, PAD, Net Metering</td>
<td>$4,559,000</td>
<td>3,680</td>
<td>1,577</td>
<td>$52,100,000</td>
</tr>
<tr>
<td>9f</td>
<td>Turbine CHP, Lystek, Net Metering</td>
<td>$5,155,000</td>
<td>5,220</td>
<td>2,039</td>
<td>$58,100,000</td>
</tr>
</tbody>
</table>

**Figure 14: Turbine CHP Analysis Results**

- **Annualized Scenario Cost [$]**
- **GHG Reduction [MT eCO₂]**
  - **Natural Gas ($5/mmBtu)**
  - **Electricity ($0.075/kWh)**
  - **Vehicle Fuel ($3/gal)**

![Bar chart showing annualized cost and GHG reduction for each scenario.](chart.png)
One benefit to the turbine CHP option over the thermal oil heater option is that, should net metering be available in the future, the turbine CHP is capable of taking advantage by increasing electricity production. The thermal oil heater is not capable of producing surplus energy. As seen by comparing Scenario 9a to 9b, 9c to 9e, and 9d to 9f, net metering would lower the cost of any of the future buildout scenarios.

### 6.2.4 Comparison of Thermal Oil Heater to Turbine CHP

A sensitivity analysis of electricity prices was conducted to compare the thermal oil heater option to the turbine CHP option. For both options, the scenarios without either PAD or Lystek were compared, and the scenarios with PAD were compared. Scenarios were considered both with and without net metering. Figure 15 presents the results.

![Figure 15: Electricity Sensitivity Analysis](chart.png)

The analysis shows that the turbine option is more heavily influenced by electricity prices than the thermal oil heater option. Net metering, which does not impact the thermal oil heater option, increases the influence of electricity prices. This trend is because options that produce greater amounts of electricity increase the impact of changing electricity prices. Lower electricity prices tend to decrease the benefits of the turbine option relative to the thermal oil heater.
7 RECOMMENDATIONS

7.1 Solids Handling Recommendations

Based on the modeling results and feedback from ACWPD and SCSD, it is recommended that the counties pursue a regional biosolids handling facility. Figure 16 presents a conceptual site plan for the facility, showing the potential location of all the equipment. Sludge cake and liquid sludge hauled from the South Plant and the SCSD Plant, as well as any other participating facilities, would be received at the sludge receiving station located adjacent to the sludge holding tanks. Cake would be thinned to 6% TS at this station using unthickened WAS generated by the North Plant, and the rewetted cake would be sent to the sludge holding tanks where it would be combined with primary sludge produced at the North Plant. Combined sludge from the sludge holding tanks would be pumped to the solids disposal building, where it would undergo sludge screening and gravity belt thickening in new thickening equipment installed in place of the existing DAFTs. Thickened combined sludge would be discharged from the GBTs at 8% TS and sent to the thickened sludge wet well below the thickening equipment.

Using the average loading numbers, the model predicts that approximately 72,000 gal/day of unthickened North Plant WAS would be required to rewet sludge cake. The balance of the unthickened WAS would be pumped directly to the solids disposal building, where it would pass through sludge screens and be thickened to 8% TS by GBTs. Thickened WAS would then be sent to a WAS lysis system installed adjacent to the sludge thickening equipment. Figure 17 presents a conceptual layout of this equipment in the existing DAFT area. In the lysis reactor, caustic would be injected to raise the pH and hot water would be used to increase the temperature of the WAS and break apart the biomass. The resulting lysed stream, still at 8% TS, would be sent to the thickened sludge wet well and combined with the thickened sludge from the sludge holding tanks. The resulting stream would be pumped to the digesters as feed.

Parallel to the sludge streams, a FOG receiving station would be installed adjacent to the digesters as shown in Figure 16. This station would consist of a truck offloading slab next to three 40,000 gallon insulated and heated FRP tanks. FOG would be kept heated and recirculated while stored in these tanks to prevent solidifying. The FOG stream would be pumped directly to the digesters and fed parallel to the sludge stream.

To provide the required digester SRT and redundancy, three 95-ft diameter digesters are recommended. Two of these digesters operated in parallel are sufficient to achieve the 20-day SRT required for mesophilic anaerobic digestion. The third would operate as a secondary digester, providing storage downstream of the digesters when required. The digester facility would include a new mechanical building to house pumps and heat exchangers. Floating steel covers mounted with linear motion mixers are recommended to mix the digesters and store biogas produced.

Residual digested solids would be sent to the existing BFPs in the solids disposal building, which would dewater the material. The resultant cake would be conveyed to a new offloading facility located to the south of the solids disposal building, where it would be picked up by a contract hauler as a Class B material.
Conceptual Site Layout

- 3 Digesters
- Digester Mechanical Building
- Cake Receiving and Rewetting
- CHP Turbine
- Sludge Screening, Thickening, WAS Lysis
- Liquid Sludge/FOG Receiving
- New Loadout Facility

ACWPD/SCSD REGIONAL BIOSOLIDS FACILITY
As discussed previously, the recommended configuration represents the first step in a phased approach. The recommended option can be relatively easily expanded to include either PAD or Lystek in the future. The expansion would allow the third anaerobic digester to be operated in parallel as a primary digester, since PAD or Lystek would essentially take over as a secondary digester. This would expand the capacity of the facility and allow for the import of additional outside material to increase gas production to enable generation of surplus power and to realize additional tipping fees.

Addition of high strength waste (HSW) can also be considered for future expansion of the regional biosolids facility. It should be noted that net metering or some type of market pricing change would need to be enacted to allow the regional facility to beneficially utilize additional energy generation potential that is provided from this HSW.

### 7.2 Biogas Utilization Recommendations

A secondary analysis was conducted to determine the most beneficial biogas utilization configuration. Two main options were considered for inclusion in the regional biosolids facility:

- **Install a thermal oil heater in the thermal oil loop which operates the ORC.** The heater would be fired off the biogas produced by digestion, as well as supplemented with natural gas if necessary. This biogas heater would essentially replace the hot oil heaters currently installed in the incinerator exhaust stack, which heat the thermal oil loop using incinerator flue gas.

- **Install a CHP turbine unit adjacent to the ORC.** This turbine would be fired off the biogas produced by digestion, as well as supplemented with natural gas if necessary. The exhaust from the turbine would be ducted into the existing incinerator exhaust stack, and new thermal oil heat exchangers would be installed in the stack to allow the ORC to be operated off the reclaimed heat from the turbines. An existing thermal oil/water heat exchanger would allow the thermal oil loop to provide heat to the digesters and buildings as well.

Under current conditions without net metering or robust generation incentives for renewable energy, thermal oil heaters and turbines are projected to have comparable annualized costs. The thermal oil heater option has lower capital cost than the CHP turbine option. However, if net metering becomes available or market pricing for renewable energy or renewable energy attributes becomes more valuable, the analysis shows that the turbine option becomes cheaper on an annualized cost basis due to the ability to produce excess electricity. The turbine option is also more sensitive to electricity prices, resulting in greater flexibility to respond to changing energy prices. Additionally, the turbine option better suits a future expansion to PAD given its ability to offset energy use.

Based on the analysis, PAD and Lystek both show potential as future expansion options. PAD is less expensive and provides sidestream nutrient removal, which could be a benefit in the future. PAD also can function as a secondary digester/holding tank which would free up additional digester capacity as units would eventually have to be taken offline for cleaning. Lystek provides insulation from volatility in contract hauling prices for Class B material. The initial regional biosolids facility should be constructed with either of these two processes in mind for future expansion. As the future drivers addressed by these processes develop, the value of these processes will become more clearly defined and likely warrant implementation.
7.3 Governance Recommendations

As part of the feasibility study, Raftelis Financial Consultants, Inc. (Raftelis) was engaged to identify and evaluate various governance structure alternatives to support the ownership, operation, maintenance, and funding of the facility. Raftelis identified two predominant alternatives that ACWPD and SCSD could utilize for the governance and management of a joint biosolids handling facility. These are (1) forming a separate, independent Authority, and (2) entering into a “joint services” intermunicipal agreement (IMA). Both of these alternatives are enabled under New York State Municipal Law, and both would allow the districts to take advantage of the economies of scale associated with jointly developing a biosolids handling facility. However, Raftelis found that sharing services under an IMA has advantages of the Authority alternative in that it is simpler, requires the least amount of change, may be the most cost-effective alternative to establish and maintain, and is likely to take the least amount of time to establish. Raftelis’ memo is provided in Appendix D.

7.4 Funding Opportunities

There are various funding opportunities available to ACWPD and SCSD to support implementation of this project.

7.4.1 New York State Environmental Facilities Corporation

New York State enacted the Clean Water Infrastructure Act of 2017. The Clean Water Infrastructure Act of 2017 invests $2.5 billion in clean and drinking water infrastructure projects and water quality protection across New York. Clean water projects may be eligible for a Water Infrastructure Improvement Act (WIIA) grant of up to the lesser of $5 million or 25% of the total net project costs after deducting other grant funds awarded for the project. Intermunicipal Water Infrastructure (IMG) grants are available for clean water projects that serve multiple municipalities, for example, a shared water quality infrastructure project or interconnection of multiple municipal water quality infrastructure projects. Cooperating municipalities with eligible projects may be awarded an IMG grant up to $10 million or 40% of net eligible project costs, whichever is less.

It appears that this project will meet the requirements for the IMG grant. These grants are competitive and are available during the open consolidated funding application (CFA) period typically in May through July. A preliminary engineering report, a Board resolution and an executed intermunicipal agreement are required for submission prior to applying for the IMG grant through the CFA from the New York State Environmental Facilities Corporation.

7.4.2 New York State Department of Environmental Conservation

The New York State Department of Environmental Conservation administers the Water Quality Improvement Project (WQIP) program and the Climate Smart Communities program.

The WQIP program funds projects that directly address documented water quality impairments. The competitive, statewide grant program is open to local governments and not-for-profit corporations. Grant recipients may receive up to 85% of the project costs for high priority wastewater treatment improvement projects or up to 40% for general wastewater infrastructure improvement projects. If PAD was
implemented, there would be a direct reduction in nutrient (phosphorous and nitrogen) discharge from the North Plant. Most likely this would qualify for 40% funding as a single project of $3.5M.

The Climate Smart Communities program has several methods receiving funding through the increase of renewable energy (biogas) or reducing greenhouse gas inventories. Both could be achieved by replacing the incinerators in Saratoga and Albany Counties with anaerobic digesters with CHP for energy production. The amount of the available funding is unknown currently.

### 7.4.3 New York State Energy Research & Development Authority

The New York State Energy Research and Development Authority (NYSERDA) provides financial incentives and grants for projects that support the State’s Clean Energy Fund (CEF) and Reforming the Energy Vision (REV) goals. In fact, NYSERDA funding was used to partially fund this study. Other potential funding sources that may be available from NYSERDA to support implementation and long-term operation of the project include:

- **Clean Energy Communities (CEC) Program** – Those local governments that have enrolled in the CEC Program and met specific criteria have the potential to receive up to $250,000 of grant money to support clean energy projects.

- **On-site Energy Manager Pilot** – Although the program may no longer be available by the time the facility is operational, it is worth considering this program as a means to retain a full-time on-site energy manager to support facility-wide energy performance, while also optimizing performance and generation associated with the project. Through this program, NYSERDA will pay up to 75% of the cost to have a full-time on-site energy manager for 15 months, up to a maximum of $175,000. Additional milestone incentives are available if specific objectives are met.

- **Industrial Process Efficiency (IPE) Program** – The IPE program provides performance-based incentives for projects that result in energy savings or efficiency improvement. Projects that achieve savings through improved operations and maintenance receive $0.04/kWh saved or $3/MMBTU saved. Process and energy-efficiency projects receive an incentive of $0.10/kWh saved or $6/MMBTU saved. The maximum incentive is 50 percent of the project cost, capped at $500,000 for fossil fuel savings and $1,000,000 for electricity savings.

- **NYSERDA is developing one or more new CEF programs focused on the wastewater sector.** There may be an opportunity to help shape these programs or to access grants or cost-share through these programs to support demonstration of new or emerging technologies that provide energy savings.

- **Renewable Energy Credits (REC) Auction** – Periodically NYSERDA manages auctions for RECs to support development and operation of green power. Typically, these are geared toward large, utility scale projects (e.g., wind farms). However, there may be an opportunity to sell RECs either through this mechanism to increase the value of the generated electricity associated with the project.
7.4.4 Other Funding Sources

In addition to the funding sources identified above, there may be an opportunity to enter into a power purchase agreement (PPA) with the State of New York directly through the New York State Office of General Services or the New York Power Authority to sell green power and receive a higher value for the electricity that is generated as part of this project. Similar opportunity may be available through a PPA with another interested party. Discussion has commenced related to sale to the State of New York and further assessment cannot be made at this time. Ultimately, the costs and complexity of developing the PPA, as well as the ongoing costs to measure and certify the amount of green electricity being sold, will need to be considered to determine the overall viability of either approach.