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Final Energy Independence Project

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Executive Summary

Oregon’s domestic wastewater treatment facilities are leaders in the protection of public health and the environment by providing water quality services to our urban areas. Some of the valuable services they provide include: sewerage collection and treatment, regulation of industries to prevent toxic substance discharges into treatment plants, leadership in promoting innovative water quality policies, and partnerships with other members of their community to restore local bodies of water. These facilities are often use energy efficient processes and frequently implement sustainable practices such as recycled water and biosolids recycling. Nonetheless, there is opportunity for these facilities to build upon their leadership in environmental stewardship by further reducing their need for energy.

This report is an investigation into what it would take for Oregon domestic wastewater treatment plants to become energy independent by optimizing plant energy efficiency and using renewable resource opportunities. For the purposes of this report the term “energy independence” means to use digester gas and renewable resources to eliminate the need for purchased electricity. This report provides valuable information for plant operators and managers, and policy-makers, and will be a valuable tool in directing significant investment in wastewater treatment plants. The report estimates the benefits and costs of implementing recommended energy efficiency measures while describing the cost, the operational impacts, and the environmental impacts of developing selected renewable resources. The project was conducted for the Oregon Association of Clean Water Agencies (ACWA) in partnership with the Energy Trust of Oregon (Energy Trust).

The analysis was based on an evaluation of two demonstration facilities at the Gresham Wastewater Treatment Plant and Corvallis Wastewater Reclamation Plant in Oregon. Energy audits were initially conducted at the two demonstration sites including the review of prior energy audits and installed energy efficiency measures (EEMs) were reviewed to identify opportunities for additional energy efficiency improvements. Following the facility analysis, the project team researched and analyzed seven renewable resource options for consideration in seeking energy independence. The seven renewable resources included in this investigation were:

1. fuel cells using digester gas
2. internal combustion (IC) engines using digester gas
3. micro-hydro using a treatment plants outfall to a river
4. microturbines using digester gas
5. solar photovoltaic (PV) systems
6. on-site small wind turbines, and
7. using fats-oils-and-grease (FOG) and green waste to increase digester gas production and related energy production).

The resources were assessed using a common template that was developed using with standardized criteria to assess each of the facilities. Costs were determined using a standardized spreadsheet with consistent assumptions and formulas to facilitate in comparing the various renewable options. The resource assessments described a brief history of the resource, how the resource works, and its size and kilowatt-hour (kWh) production. The resources assessment also included potential funding and incentives, its cost, the political and community impacts, as well as the environmental, greenhouse gas and operational impacts of each resource option.

Seven evaluation criteria were developed by the Project Team and approved by the Association of Clean Water Agencies (ACWA) Energy Independence Project Technical Advisory Committee (TAC). To simplify the evaluation process, the evaluation criteria were prioritized and given a weighted score that reflects their importance to the TAC as decision-making criteria. The weighted scoring system allowed a maximum of 100 total points to be assigned to each resource option. The weighted scoring of the evaluation criteria was:

Evaluation Criteria	Possible Points
Cost	50
Environmental Impacts	20
Technology Maturity & Reliability	10
Political and Community Impacts	5
Adequate Size	5
Greenhouse Gas Impacts	5
Operational Impacts	5
TOTAL =	**100**

Based on the criteria and weighting described above, the evaluation team analyzed each of the seven resource options for the report. A score was then developed for each of the resources to provide a basis for comparison. The resource scoring is summarizes as:

1. FOG & Green Waste – 88 points
2. IC Engines (385 kW) – 82 points
3. Microturbines (35 kW) – 72 points
4. Fuel Cells (400 kW) – 66 points
5. Micro-Hydro Turbines (35 kW) – 58 points
6. Small Wind (10 kW) – 55 points
7. Solar PV (100 kW) – 52 points
8. Small Wind (100 kW) – 50 points
9. Micro-Hydro Turbines (5 kW) – 46 points.

Summary of Recommendations for the Gresham Wastewater Treatment Plant

Since the Gresham Wastewater Treatment Plant (WWTP) already uses nearly all of the available digester gas in its Caterpillar IC Engine, none of the resource options that use digester gas as a fuel (IC engines, microturbines, or fuel cells) would be available for this facility to become energy independent. In addition, the plant site does not appear to have a significant wind resource eliminating the use of the small wind resource at this site.

To achieve energy independence the Gresham WWTP would need to rely on a combination of energy efficiency, micro-hydro and solar PV. The first recommendation is to install the three cost-effective energy efficiency measures identified in this study: replacing four existing motors with premium efficiency motors, reducing the system's pressure, and replacing the aeration diffusers with newer more efficient fine bubble diffusers. This facility could also investigate and implement potential energy efficiency savings associated with changes to their process. The second recommendation would be to install one of the micro-hydro 35 kW units. The final recommendation would be to meet the balance of the plant's energy needs (kWh) with 22 solar PV units of 100 kW each for a total of 2.2 MW of energy if sufficient land is available. The estimated total net cost to become energy independent would be approximately $9.6 million.

Summary of Recommendations for the Corvallis Wastewater Reclamation Plant

The Corvallis Wastewater Reclamation Plant (WWRP) has commendably already implemented all the cost-effective EEMs available to them. Since the Corvallis WWRP site does not appear to have a significant wind resource, small wind is not available to help achieve energy independence. Additionally, the micro-hydro option is not recommended because of the cost of the micro-hydro option and its lowest overall score; the micro-hydro option is not recommended. Since the Corvallis WWRP has commendably already implemented all the available cost-effective EEMs in their facility, they could also investigate potential energy efficiency savings associated with changes to their treatment process.

To achieve energy independence the Corvallis WWRP would need to rely on a combination of microturbines using their existing digester gas supply and solar PV. The first recommendation is to install two microturbines, to make use of the available digester gas. While IC Engines are a more cost-effective option, the Corvallis plant only has a limited amount of available digester gas which is insufficient to operate an IC Engine. Two microturbines use roughly one-third the digester gas that an IC Engine would use making them a much better fit for the Corvallis plant given their limited digester gas.

Serious consideration should be given to a lease option for the microturbines that would not require up-front capital from the plant. It could result in some of the savings available to the leasor from tax credits being passed along to the municipality while requiring no additional staff for operations and maintenance (O&M) and potentially lower operating costs. The second recommendation would be to meet the balance of the plant's energy needs (kWh) with 28 solar PV units of 100 kW each to produce a total of 2.8 MW of energy if sufficient land is available. The estimated total net cost for the Corvallis WWRP to become energy independent would be about $12.1 million.

Summary of Recommendations to Further Investigate a FOG and Green Waste Program

It is recommendation that Gresham and Corvallis further investigate the development of FOG and Green Waste to energy projects. Both the Corvallis and Gresham wastewater treatment plants currently have excess digester capacity for which they could use FOG and Green Waste to generate more digester gas to run renewable resource options. A FOG and Green Waste project would cost about $1.1 million to process 3,000 gallons of grease and 20 tons of food scrap per day; would create approximately 107,000 CFD of digester gas, and could generate enough digester gas to run three microturbines (1.6 million kWh/year), one fuel cell at 80 percent capacity (1.4 million kWh/year), or one Caterpillar IC Engine at approximately two-thirds capacity (0.9 million kWh/year).

Section 1: Introduction

1.1 Project Objective

Oregon's domestic wastewater treatment facilities are leaders in the protection of public health and the environment by providing water quality services to our urban areas. Some of the valuable services they provide include: sewerage collection and treatment, regulation of industries to prevent toxic substance discharges into treatment plants, provide leadership in promoting innovative water quality policies, and partner with other members of their community to restore local streams. These facilities often use energy efficient processes and implement sustainable practices such as recycled water and biosolids recycling. Nonetheless, there is opportunity for these facilities to build upon their leadership in environmental stewardship by further reduce their need for energy.

This report is an investigation into what it would take for Oregon wastewater treatment plants to become energy independent by optimizing plant energy efficiency and using renewable resource opportunities. For the purposes of this report the term "energy independence" means to use digester gas and renewable resources to eliminate the need for purchased electricity. It provides valuable information for plant operators and managers, and policy-makers. The report calculates the benefits and costs of implementing recommended energy efficiency measures; and describes the cost, the operational impacts, and the environmental impacts of developing selected renewable resources.

In the wake of the recent energy crisis, the recent passage of Oregon's Renewables Portfolio Standard and global warming laws, increasing cost of energy, and the constant pressure to control operating costs, an investigation into optimizing energy efficiency and the use of renewables is indeed very timely. Oregon wastewater utilities use approximately 5 percent of the state's electricity, and energy accounts for about 15 percent of a typical domestic wastewater treatment plant's operating budget. Reducing either of these percentages can pay dividends to Oregon and the local wastewater treatment plant.

State energy policy (ORS 469.190) calls for the development of energy efficiency resources first, followed by the development of renewable resources. This policy is embodied in the mission of the Energy Trust of Oregon (Energy Trust), and is reinforced by numerous local and state-wide political and regulatory drivers that are putting pressure on wastewater treatment plant operators to do more. The goal of this project is to help alleviate some of that pressure by providing information on sensible and cost-effective energy efficiency solutions. It can put wastewater treatment plants in Oregon ahead of the curve, and give them the necessary well researched information to answer the call to be more green, more sustainable, and to control costs. While the project only analyzed two wastewater treatment plants, the results are widely applicable to nearly all other wastewater treatment plants with an emphasis on plants that have anaerobic digesters. The results of this report can be used to foster Council and Commission support for additional capital to invest in plants to make them more energy independent, more environmentally sensitive, and to lower their operating costs year after year.

The results of this project will enable plant operators and other decision-makers to assess roughly how much efficiency and savings to expect from given improvements, and what type of energy efficiency measures are appropriate in their plants. It will also give them a clearer picture of which renewable resources are most appropriate to develop over time to allow them to become more energy independent.

To assist plant operators and managers in pursuing energy efficiency measures and savings for their individual plants, the following sources of information are recommended:

- Ensuring a Sustainable Future: An Energy Management Guidebook for Wastewater and Water Utilities, January, 2008, published by the US Environmental Protection Agency and available for free download at http://www.epa.gov/waterinfrastructure/bettermanagement_energy.html

- Portfolio Manager, EPA's online benchmarking tool, facilitates tracking of a wastewater treatment plant's energy use, energy costs, and associated carbon emissions. It also provides the ability to compare the energy use of a plant with other peer plants using the EPA energy performance rating system. To access this tool and other resources, visit http://www.energystar.gov/index.cfm?c=government.wastewater_drinking_water.

This project was conducted for the Oregon Association of Clean Water Agencies (ACWA) in partnership with the Energy Trust of Oregon. The ACWA Request for Proposals was issued on 29 February 2008. A copy of the Request for Proposal is included in Appendix K.

1.2 Demonstration Project Selection

The ACWA Energy Independence Project Technical Advisory Committee (TAC) selected the two demonstration wastewater treatment plants included in the evaluation. To be considered as a demonstration plant, a wastewater treatment plant needed to meet several criteria as follows: be served by Pacific Power or Portland General Electric, need to use an anaerobic digester in their treatment plant process, and need to be treating effluent to advanced secondary treatment plant standards with no requirement to achieve nutrient removal.

To make the study results as useful as possible to other wastewater treatment plant facilities, the project focused its energy efficiency and renewable energy feasibility analyses inside the fence line of the respective treatment plants. The only pumping included in the evaluation was the pumping needed to bring influent wastewater into the treatment plant. No collection system pumping was included in the analysis.

The two selected facilities are described below. Detailed descriptions of the treatment processes are provided in Section 2.

- **City of Gresham Wastewater Treatment Plant**
    - Gresham operates a 20 million gallon per day (MGD) facility (average dry weather flow) using activated sludge as its primary treatment plant process. Electrical power is provided by Portland General Electric. The plant uses liquid chlorine for disinfection, and sodium bisulfite for dechlorination.

- The Gresham plant relies primarily on gravity to convey flow through the treatment process. No influent pumping or intermediate pumping is needed for effluent to reach the treatment plant processes or effluent to reach the receiving stream.

- **City of Corvallis Wastewater Reclamation Plant**
  - Corvallis operates a 9.7 MGD facility (average dry weather flow) using a combination of tricking filters and activated sludge for secondary treatment. Electric power is provided by Pacific Power. The plant uses sodium hypochlorite for disinfection. Biosolids from the primary and secondary treatment processes are thickened, anaerobically digested, and stored in lagoons.

  - All influent flow at the Corvallis plant is pumped into the site through the influent pumping station.

1.3 Wastewater Treatment Plants in Oregon

Table 1 below shows the distribution of Oregon wastewater treatments plants by the size of permitted capacity in MGD. Both the Corvallis plant at 9.7 MGD and the Gresham plant at 20 MGD are considered large plants in Oregon -- in the top five percent.

Table 1: Size of Oregon Wastewater Treatment Plants[(a)]

Size of Plant	Number of Plants	% of Total
< 1.0 MGD	156	74%
1-5 MGD	37	17%
5-10 MGD	11	5%
10-30 MGD	5	2%
>49 MGD	3	1%
TOTAL	212	100%

Note:

(a) Data provided by Oregon DEQ based on permitted capacity in approximately 2002. Permitted discharge capacity may have increased since this information was developed, but relative sizes of facilities is likely similar.

1.4 Approach and Scope

A phased approach was used to asses energy use, identify renewable resource options, and develop recommendations for wastewater treatment plant improvements. The five phases are described below.

1. **Energy Audit** – an engineer performed walk-through energy audits of the two demonstration project sites (Gresham and Corvallis) with plant personnel, reviewed previous energy audits and installed energy efficiency measures (EEMs), and identified cost-effective energy efficiency measures still to be implemented.
2. **Energy Use Analysis** - Kennedy/Jenks completed an analysis of the energy used in calendar year 2007 for each of the two demonstration facilities.

3. **Resource Assessments** – Kennedy/Jenks researched and analyzed seven renewable resource options for consideration in seeking energy independence. The seven renewable resources are:
   - Fuel Cells using digester gas
   - Internal Combustion (IC) Engines using digester gas
   - Micro-Hydro Turbines
   - Microturbines using digester gas
   - Solar Photovoltaic (PV)
   - Small Wind
   - Using Fats-Oils-and-Grease (FOG) and Green Waste to increase digester gas production (and thereby energy production).
4. **Recommendations** – Each resource option was scored and ranked based on evaluation criteria determined in conjunction with the ACWA TAC. Using this information, recommendations on how to become energy independent using renewable resources were developed for both demonstration sites -- Gresham and Corvallis. The results were then extrapolated to all Oregon waste treatment plants.
5. **Report and PowerPoint Presentations** – The results of the study will be disseminated through a final report, and two PowerPoint presentations (one geared toward operators and the other for policy-makers).

1.5 Project Team and Technical Advisory Committee

The Kennedy/Jenks Consultants Project Team consisted of:

- Alan Zelenka, Project Manager
- Heather Stephens, P.E.
- Jeff Foray, P.E.
- Sherri Peterson
- Cindy Ryals
- Greg Chung
- James Krumwied
- Ryan Ray
- Brad Musik

The Kennedy/Jenks Consultants worked in close collaboration with the ACWA TAC and with staff of the two demonstration wastewater treatment plants at the City of Gresham and City of Corvallis. Their help was invaluable in completing this project. Members of the TAC include:

- Janet Gillaspie – ACWA Executive Director
- Stephanie Eisner – City of Salem
- Guy Graham – City of Gresham
- Dan Hanthorn – City of Corvallis
- Jim Hill – City of Medford
- Terry Hosaka – Landau Associates
- Alan Johnston – City of Gresham
- Erin Johnston – Energy Trust of Oregon
- Mark Kendall - Oregon Department of Energy

- Brenda Kuiken – City of Stayton
- Annette Liebe – Oregon Department of Environmental Quality
- Darrell McLaughlin – City of Lebanon
- Walt Mintkeski - Energy Trust of Oregon
- Michael Nacrelli – City of Gresham
- Tom Penpraze – City of Corvallis
- Elaine Prause - Energy Trust of Oregon
- Thad Roth - Energy Trust of Oregon
- Bob Sprick – City of Eugene.

The TAC met three times with the consultant, provided important guidance to the Project Team, reviewed all the documents, and provided valuable comments that were incorporated into this report. At the first meeting on 20 March 2008, the TAC went over in detail Kennedy/Jenks' approach to this project. At the second meeting on 13 May 2008, the TAC reviewed the energy audit results, commented on a preliminary draft of a resource assessment, reviewed and finalized the evaluation criteria, and discussed an example of the scoring matrix. At the third meeting on 13 June 2008, the TAC reviewed the draft report and recommendations, and provided input for the final report. TAC meeting summaries and PowerPoint slides are provided in Appendices E, F, and G.

1.6 Organization of the Report

This report follows the five project phases as outlined above. The first section discusses the energy audits and the recommended EEMs for the two demonstration plants. The list of EEMs already implemented along with the recommendations should comprise an overall list of potential EEMs applicable to activated sludge and trickling filter wastewater treatment plants. Next, the energy profiles of the Gresham and Corvallis wastewater treatment plants are analyzed and discussed, and the amount of net energy required to become energy independent is calculated. The bulk of the report is provided in the section discussing the seven resource assessments. The final section of the report reviews the evaluation criteria, the scoring matrix, and the recommendations for Gresham and Corvallis to become energy independent. These recommendations are extrapolated to determine the cost and benefits of energy independence through renewables for all of the wastewater treatment plants in Oregon. The appendices include the Excel spreadsheets showing the calculations for the energy profile, cost of resources and EEMs, greenhouse gas (GHG) calculations, summary notes from TAC meetings, and the field notes for the energy audits.

1.7 List of Abbreviations

A/C	alternating current
ACWA	Association of Clean Water Agencies
AFT	Applied Filter Technology
AWEA	American Wind Energy Association
BEF	Bonneville Environmental Foundation
BETC	Business Energy Tax Credit
bhp	brake horsepower
BTU	British thermal units
CFD	cubic feet per day
cfs	cubic feet per second
CIP	capital improvement projects
CO	carbon monoxide
CO_2	carbon dioxide
CSO	combined sewer overflow
D/C	direct current
dBA	decibels – "A-weighted"
DEQ	Department of Environmental Quality
DO	dissolved oxygen
EBMUD	East Bay Municipal Utility District
EEM	energy efficiency measures
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FOG	fats, oil, and grease
FTE	full time equivalent employees
g	grams
GE	General Electric
GHG	greenhouse gas
gpm	gallons per minute
H_2S	hydrogen sulfide
HP	horsepower
IC	internal combustion
kW	kilowatts
kWh	kilowatt-hour
lb	pound
MCFC	molten carbonate fuel cells
MGD	million gallons per day
MW	megawatts
MWh	megawatt-hour
NEG	net excess generation
NOx	nitrogen oxides
NPW	non-potable water
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
ODOE	Oregon Department of Energy
PAFC	phosphoric acid fuel cells
PEMFC	proton exchange membrane fuel cells

PGE	Portland General Electric
PP&L	Pacific Power & Light or Pacific Power
psi	pounds per square inch
PV	photovoltaic
RAS	return activated sludge
SCFH	standard cubic feet per hour
SEIA	Solar Energy Industries Association
SOFC	solid oxide fuel cells
TAC	Technical Advisory Committee
USDOE	United States Department of Energy
VFD	variable frequency drives
WAS	waste activated sludge
WWRP	wastewater reclamation plant
WWTP	wastewater treatment plant

Section 2: Energy Efficiency

2.1 Audit Process

Site visits were conducted at each facility. The energy audit included a plant operational overview, a question and answer period to discuss the energy efficiency measures (EEMs) evaluated in previous energy assessments, a review of plant record drawings, and a walk-through of the facility.

2.1.1 Gresham Wastewater Treatment Plant

The Gresham WWTP energy audit was conducted on 7 April 2008. The following people were in attendance:

- Ryan Ray, Kennedy/Jenks Consultants
- Alan Johnston, Senior Engineer, City of Gresham Wastewater Services Division
- Walt Mintkeski, Energy Trust of Oregon, Production Efficiency Project Engineer.

2.1.2 Corvallis Wastewater Reclamation Plant

The Corvallis WWRP energy audit was conducted on 8 April 2008. The following people were in attendance:

- Ryan Ray, Kennedy/Jenks Consultants
- Dan Hanthorn, City of Corvallis Wastewater Operations Supervisor
- Walt Mintkeski, Energy Trust of Oregon, Production Efficiency Project Engineer.

2.2 Gresham Facility Overview and Energy Use

The Gresham WWTP consists of the original activated sludge lower plant, constructed in the 1970s, and the new activated sludge upper plant which was constructed in 2001 and brought online in 2002. The plant is rated for approximately 20 MGD with the flow into the plant split through a diversion structure to send approximately 60 percent of the influent flow through the newer, more efficient upper plant and 40 percent of the influent flow through the older, less efficient lower plant. Biosolids from the primary and secondary treatment processes from both the upper and lower plant are thickened, anaerobically digested, dewatered, and stored prior to beneficial reuse on land application sites. Treated effluent is discharged to the Columbia River.

2.2.1 Treatment Processes

The upper and lower plants each consist of the following processes:

- Screening and Grit Removal:
  - Bar screens are provided for screening of both the upper and lower plants.
- Primary Clarification: Two rectangular primary clarifiers in the upper plant, three circular primary clarifiers in the lower plant.
  - Compressed air is used for upper plant primary sludge and scum diaphragm pumps. Compressed air is provided to an air receiver by two 60 horsepower (HP) rotary screw air compressors (Quincy Model QNW271C, 72 amps, 93.6 percent motor efficiency).
  - Compressed air is used for lower plant primary sludge and scum diaphragm pumps. Compressed air is provided to an air receiver by two 25 horsepower (HP) rotary screw air compressors (Toshiba Model B0254FLF10WH).
- Activated Sludge Processes:
  - Aeration:
    - Upper plant has one aeration basin with aeration fully automated with dissolved oxygen (DO) control. Air is provided by three 250 HP Turblex blowers (95 percent motor efficiency) and fine bubble diffusers. Typically, one blower operates to maintain DO, but two blowers are used during periods of high demand. An additional aeration basin and Turblex blower will be added during the next plant expansion.
    - Lower plant aeration is also fully automated with DO control, with air provided by six 100 HP Hoffman multistage centrifugal blowers with inlet throttling and medium bubble sock diffusers. Motors for two of the blowers were Toshiba/Houston Model B1002VLG3UD, 3530 RPM, 92.4 percent efficiency. The remaining four motors were GE Model 5K365AK105, 3550 RPM, no efficiency indicated. Some may be original from 1970s construction. Two blowers operated continuously to provide mixing. Up to five can operate to maintain DO.
  - Return Activated Sludge (RAS):
    - Upper plant RAS is pumped by two 28 HP submersible Flygt pumps each equipped with variable frequency drives (VFDs).
    - Lower plant RAS is pumped by four 40 HP centrifugal pumps (3 duty, 1 standby), each provided with VFDs and premium efficiency motors. One pump motor is less efficient (91 percent) than the other three (93.6 percent).
  - Waste Activated Sludge (WAS):
    - Upper plant WAS is pumped by two submersible 3 HP Flygt pumps each equipped with VFDs.
    - Lower plant WAS is pumped by four centrifugal pumps (3 duty, 1 standby), each provided with VFDs and premium efficiency motors.
    - Secondary Clarification: The upper plant has one secondary clarifier, and the lower plant has three secondary clarifiers.

The upper and lower plants share the following processes:

- Sludge thickening: Sludge thickening occurs in the Lower Headworks/Solids Building and is provided by three gravity belt thickeners.
- Anaerobic digestion: Each of the two digesters is provided mixing with a gas mixer that is supplied by three 40 HP rotary lobe blowers (Dresser/Roots Model 412J, one with 93.6 percent motor efficiency, the other two with 94.1 percent). Operation is operator-dependent. Some operate more frequently than others. Heat for the digester is provided from the hot water loop that obtains its heat from the cogeneration jacket water and exhaust heat recovery system. During the site visit, the hot water loop was operating between 145ºF and 150ºF, and the heat recovery system operating between 157ºF and 204ºF.
- Dewatering: Dewatering occurs in the Lower Headworks/Solids Building and is provided by 2-belt filter presses.
- Disinfection/Dechlorination: Disinfection is provided by sodium hypochlorite, stored outside the Disinfection Building. Dechlorination is provided by sodium bisulfite, stored outside the Disinfection Building.

2.2.2 Digester Gas Utilization/Cogeneration System

The facility has a 395 kW cogeneration system, consisting of a digester gas-operated Caterpillar engine and Applied Filter Technology (AFT) gas treatment system. The facility is connected only to the lower plant and produces power to meet 50 percent of the WWTP's total energy demand. The cogeneration system uses approximately 8,800 standard cubic feet per hour (SCFH) of the digester gas (or about 95 percent of the digester gas), with approximately 500 SCFH of digester gas burned in the flare (at the time of the site visit).

The gas is treated for hydrogen sulfide (H_2S) and siloxanes in the gas treatment skid. The treatment skid provides approximately 500 British thermal units per cubic foot (BTU/cf) gas, with a reduction in H_2S from approximately 400 to 1,300 ppm down to less than 100 ppm, and undetectable levels of siloxane. The gas treatment skid consists of a one H_2S tower, two siloxane towers, one 10-HP gas compressor (motor efficiency of 89.5 percent), and one 6-ton chiller [ArcticChill Model PACHPH0060S4, Serial 100009102, 50-Gallon, Total FLA 17.4, (803) 321-1891]. There have apparently been issues with the low pH of the gas (treatment system for bringing up pH clogs the system downstream of the H_2S filter and has been taken out of service).

2.2.3 Natural Gas Usage

Natural gas is used in the demonstration system for the digester gas flare, as well as for the water heater for the Administration building.

2.2.4 Odor Control

Odor control systems are provided for both the upper and lower plant.

- Air from the headworks and primary basins is collected in the upper plant and treated in a biofilter. Air is extracted using two 30 HP, variable speed blowers. They typically operate one of the two fans at a time, but are having problems getting the fans to operate at full capacity.

- Air from the Lower Headworks/Solids Building is collected in the lower plant. Although the lower plant odor control system is provided with a bioscrubbing tower, it is not operated and the system provides ventilation only.

2.2.5 Heating, Ventilation, and Air Conditioning

The following are heating, ventilation, and air conditioning (HVAC) energy efficiency measures:

- Electric heating and cooling is provided for the Electrical Rooms in the upper plant Blower and Headworks Buildings, as well as the entire Administration Building. Mechanical ventilation is provided in the other rooms. This equipment is relatively new (2001).
- Typically, heat recovered from the cogeneration system is used to heat a hot water loop that provides hot water for heating of the digesters and space heating for the buildings located in the lower plant. A gas-fired boiler is provided to heat the hot water loop in the event that the cogen unit is not available (Weil McLain Model AH-1994WS Series 3, 6.495 MBH Input/ 5.23 MBH Output, 8 to 18.5 inches WC gas pressure.
- Hot water for the Administration Building is provided by a natural gas-fired water heater.
- Heating of the lower plant Blower Building is provided by electric unit heaters. It appeared that heating and ventilation systems for the lower plant Blower Building were operating at the same time.

2.2.6 Non-Potable Water

Non-potable water (NPW) for the plant is provided by three 40 HP pumps with premium efficiency motors and VFDs. The system operating pressure at the time of the site visit was 84 psi. Booster pumps are provided for the NPW feeding the belt filter presses, which require high pressure.

2.2.7 Lighting

All of the upper plant lighting installed as part of the 2001 expansion was energy efficient. Most of the lighting in the lower plant was upgraded to energy efficient lighting in 1998 through a joint energy efficiency project with Portland General Electric (PGE). The project replaced magnetic ballast T12 lighting with electronic ballast T8 fluorescent lighting throughout the whole plant. Some larger wattage, non-fluorescent lighting has not been upgraded in the lower plant.

2.3 Corvallis Facility Overview and Energy Use

The Corvallis WWRP consists of the main activated sludge secondary treatment plant (originally constructed in the 1950's) and the new Combined Sewer Overflow (CSO) plant (online in 2001). The main plant is rated for approximately 9.7 MGD average dry weather flow and 28 MGD peak wet weather flow. The CSO Plant is rated for approximately 85 MGD, with flow above 53 MGD going to the wet weather treatment reservoirs. Biosolids from the primary and secondary treatment from the plants are thickened, anaerobically digested, and stored in lagoons. Treated effluent is discharged to the Willamette River. The plants are provided electrical service from two substations.

2.3.1 Treatment Processes and Equipment

The plants consist of the following major liquid treatment processes:

- Screening: Bar screens are provided for screening
- Aerated Grit Removal
- Primary Clarification
- Secondary Treatment Using Trickling Filters and Activated Sludge
- Secondary Clarification
- Chlorination and Dechlorination.

The main plant consists of the following solids treatment processes:

- Sludge thickening
- Anaerobic digestion
- Lagoon storage.

The major energy consumers and large motor loads at the plant include the following:

- Treatment plant influent pumps: Four pumps total, three 125 HP with inverter duty motors (93 percent efficiency) and one 60 HP with inverter duty motor (91 percent efficiency). Pumps are variable speed, centrifugal-type with vertical motor and large drive shaft spanning two building levels.
- CSO Influent Pumps: Seven total, three 250 HP and four 135 HP variable speed submersible pumps.
- Aeration blowers for aerated grit removal and activated sludge processes: Four total; one 250 HP, two 75 HP, and one 60 HP multi-stage centrifugal, constant speed blowers. The 250 HP blower never operates.
- Trickling filter pumps: Two constant speed, 50 HP vertical turbine-type pumps. Pumps are from 1964 construction. Nameplate efficiency was not available.
- Reclaimed water pumps: Four variable speed, 40 HP vertical turbine-type pumps. Pumps provide reclaimed water for plant use.
- Effluent pumps: Two variable speed (one duty, one standby), 100 HP vertical turbine-type pumps. One pump is from 1978 and has an older GE induction motor. The other pump is provided with an inverter duty motor (93 percent efficiency).
- Primary sludge pumps: Four constant speed Wemco pumps (one per primary clarifier), 20 HP motors each with 92.4 percent nominal efficiency.
- Grit pumps: Eight constant speed Wemco pumps (two per grit tank), 20 HP motors each with 92.4 percent nominal efficiency.

- Flushing water pumps: Two constant speed, 75 HP vertical turbine-type pumps. Pumps provide water for cleaning/flushing.
- Digester mixing motors: four total.
- Air compressors for pneumatic valves: Total of three; one at 30 HP, one at 20 HP, and one at 7.5 HP.

2.3.2 Digester Gas Utilization/Cogeneration System

Digester gas is currently used in a gas-fired boiler to provide heat for digester and space heating. Digester gas not utilized in the boiler is flared.

A 43 kW Stirling Biopower demonstration unit is currently operating in Corvallis providing electricity and heat for building and space heating. The Stirling engine is an external combustion engine in which fuel combustion occurs outside of the cylinders and the moving parts of the engine. The Stirling engine does not require gas treatment for removal of siloxane and H_2S. For full-scale implementation, current gas production would operate three to four similarly-sized units and would provide all of the hot water necessary to heat the digester and plant building. If the test unit is successful, the system may be expanded to utilize all of the available digester gas (approximately 150 kW assuming boiler operation is not required at the same time).

2.3.3 Natural Gas Usage

Natural gas is used in the demonstration system for the digester gas flare, as well as for the various gas-fired unit heaters and water heaters around the plant.

2.3.4 Odor Control

Odor control systems are provided for both the upper and lower plant. Air from the sludge thickening building is collected and treated in a biofilter. Air is extracted using two 15 HP, constant speed blowers. Typically only one blower is operated at a time. The fans were installed around 2000.

2.3.5 Heating, Ventilation, and Air Conditioning

The following are HVAC energy efficiency measures:

- Typically, heat from the gas-fired boiler is used to heat a hot water loop that provides hot water for heating of the digesters and space heating for the remainder of the plant.
- Natural gas is used to heat the Disinfection Building via a gas-fired make-up air unit. Ventilation is provided at a continuous rate of 12 air changes per hour. An exhaust heat recovery system was installed recently to reduce the required heat provided by natural gas.
- Natural gas is used to heat a portion of the Solids Building via a gas-fired make-up air unit.
- Electric air conditioning is provided for the Administration Building/Lab.
- Hot water for the Administration Building is provided by a natural gas-fired water heater.

2.3.6 Lighting

The original T12 lighting and magnetic ballasts in the plant were replaced with more energy efficient T8 lighting and electronic ballasts in 2004.

2.4 Gresham Facility Audit History

Two energy assessments have previously been completed at the WWTP, one of the lower plant by HDR in 1996 and one of the combined plants by BacGen in 2006.

The 1996 HDR Energy Assessment evaluated energy efficiency measures (EEMs) for the lower plant, rated at 15 MGD (prior to construction of upper plant). The 2006 BacGen Energy Efficiency Optimization evaluated EEMs for both the lower plant and upper plant, rated for 20 MGD after construction of the upper plant. The EEMs included in the assessments are discussed in the following sections.

2.4.1 EEMs Not Recommended and Not Implemented

The following EEMs were identified in the 1996 Energy Assessment but were not recommended, and they were thus not implemented. These EEMs could be measures other wastewater treatment plants might want to investigate and implement. There were no EEMs not recommended and not implemented in the 2006 Energy Efficiency Optimization.

- EEM 1B: Partially automate aeration blowers – not recommended in the 1996 report and not implemented.
- EEM 3: Replace Wemco Model C digester recirculation pump with Wemco Hydrostal Pump – not recommended in the 1996 report. The Wemco Model C pump, with an efficiency of approximately 38 percent, is still in place. However, grinders have been added to the system upstream of the recirculation pump. This could provide improved efficiency over the existing Wemco Model C pump.

2.4.2 EEMs Not Recommended but Implemented

The following EEM was not recommended in the 1996 Energy Assessment, but was implemented. There were no EEMs not recommended but implemented in the 2006 Energy Efficiency Optimization.

- EEM 1A: Fully automate multistage centrifugal aeration blowers. Although not recommended in the 1996 report, the lower plant aeration system was fully automated in 2001 during construction of the upper plant.

2.4.3 EEMs Recommended and Implemented

The following EEMs were recommended in the 1996 Energy Assessment, and were implemented.

- EEM 2A: Install VFDS and premium efficiency motors on three of four RAS pumps (already provided on one pump) – recommended in 1996 report. Premium efficiency motors and VFDs were installed on the remaining three pumps in 2001 during construction of the upper plant.
- EEM 5: Maximize 250 kilowatt (kW) cogeneration operating time – recommended in 1996 report. The cogeneration system has been upgraded to 395 kW and includes gas treatment. The cogeneration system operates continuously.
- EEM 7: Reduce odor control fan operating time – already implemented at time of 1996 report and dropped from consideration.

The following EEMs were recommended in the 2006 Energy Efficiency Optimization and implemented.

- EEM-3: Check and realign blowers. This has been completed, and improved blower efficiency observed.
- EEM 4: Change Hoffman blower startup sequencing at Lower Plant (lead, lag 1, lag 2, lag 3, standby), using the most efficient blower first. This has been implemented. Lead 1 and Lead 2 are modulating blowers; the others are set to run at full capacity.

2.4.4 EEMs Recommended but Not Implemented

The following EEMs were recommended in the 1996 Energy Assessment, but were not implemented.

- EEM 1C: Install premium efficiency motors on four of six aeration blowers in the lower plant (already provided on two blowers) – recommended in report. Has not been implemented, and some of the blowers are from the original 1970's plant construction. Two motors are Toshiba/Houston Model B1002VLG3UD motors rated at 100 HP, 3,530 RPM, 460/3/60 VAC, and 92.4 percent efficiency. The remaining four blowers are equipped with GE Model 5K365Ak105 motors rated for 100 HP, 3,550 RPM, 4603/60 VAC. Efficiency of these four motors was not indicated on the nameplate. The costs and savings resulting from replacing the motors assuming similar conditions that were present during 1996 are as follows:

Cost for replacing four existing motors with premium efficiency motors	$25,000
Annual Energy Savings	400,400 kWh/yr
Annual Energy Savings	$28,980
Energy Trust Incentive	$ 4,000
Net Cost	$ 21,000
Simple Payback	0.72 years

Since the time of original analysis the upper plant was constructed, reducing aeration demands on the blowers at the lower plant. Based on an average day demand of 13 MGD and an estimate of 40 percent of the flow to the Lower Plant, the savings are as follows:

Cost for replacing four existing motors with premium efficiency motors	$25,000
Annual Energy Savings	192,810 kWh/yr
Annual Energy Savings	$13,950
Energy Trust Incentive	$ 4,000
Net Cost	$ 21,000
Simple Payback	1.5 years

- EEM 4: Reduce digester gas mixing time from 40 minutes on/20 minutes off to 30/30 – recommended in report. This reduces the operating time of the 40 HP rotary lobe blowers. This is apparently operator-dependant. Although possible to reduce mixing time, some operators are not comfortable with the reduced mixing time and often operate 1 mixing blower continuously. Replacing the gas mixing with hydraulic mixing will be included in the July 2008 Design CIPs.
- EEM 6: Reduce non-potable water (NPW) pressure from 86 to 75 psi – recommended in report. This has not been implemented. Operating pressure during site visit was approximately 84 psi. There are booster pumps on the NPW system serving the belt filter presses, therefore lower operating pressure can likely be implemented. Cost and savings for implementation of this EEM are as follows:

Cost for modifying set point and making set point adjustable	$1,425
Annual Energy Savings	58,850 kWh/yr
Annual Energy Savings	$4,260
Energy Trust Incentive	$ 861
Net Cost	$ 564
Simple Payback	0.13 years

The following EEMs were recommended in the 2006 BacGen Energy Efficiency Optimization but were not implemented.

- EEM 1: Replace lower plant medium bubble sock diffusers with fine bubble diffusers. Has not been implemented. A feasibility study for replacing the diffusers is being performed, although not completed. According to this study, costs and saving for installing fine bubble diffusers are as follows:

Cost for replacing diffusers	$155,000
Annual Energy Savings	289,080 kWh/yr
Annual Energy Savings	$20,920
Energy Trust Incentive	$ 92,506
Net Cost	$62,494
Simple Payback	3.0 years

- EEM-2: Divert more influent flow through upper plant. This may be possible provided the upper plant can handle more flow. However, motor-operated control valves/gates would be required in the diversion structure. Primary can also be diverted from the upper plant to the lower plant.
- EEM 5: Operate a single blower in lieu of multiple when possible. Can operate upper plant using one Turblex blower. However, not possible in lower plant. Two of the lower plant blowers are always required to operate to provide adequate mixing.

The following table summarizes the costs and savings associated with the EEMs recommended but not implemented.

	Replace Four Existing Motors With Premium Efficiency	Reduce NPW Pressure	Replace Diffusers
Cost	$25,000	$1,425	$155,000
Annual Energy Savings (kWh/yr)	192,810	58,850	289,080
Annual Energy Savings	$13,950	$4,260	$20,920
Energy Trust Incentive	$4,000	$861	$92,506
Net Cost	$21,000	$564	$62,494
Simple Payback (yrs)	1.5	0.13	3.0

2.5 Corvallis Facility Audit History

Multiple energy assessments have previously been completed at the Corvallis WWRP. CH2MHill conducted a Methane Utilization Evaluation in 2002 to evaluate potential systems to utilize available digester gas at the plant. The 2002 SBW Consultant's Disinfection Building Heat Recovery Analysis evaluated recovering heat from the exhaust air from both the Sodium Bisulfite Room and the Sodium Hypochlorite Room to minimize the amount of natural gas heating required for the supply air to each room. The 2002 SBW Consultant's Energy Analysis Report evaluated EEMs for the WWRP, not including the CSO Plant now online. The 2004 BacGen Energy Conservation Analysis also evaluated EEMs for the WWRP, some of which were previously recommended in the 2002 Energy Analysis Report. The EEMs included in the assessments are discussed in the following sections.

2.5.1 EEMs Eliminated from Consideration

The 2002 Methane Utilization Evaluation eliminated the following EEMs from further consideration.

- Liquefied Methane Production: First identified in 1994 evaluation. No further consideration warranted.

- Compressed Methane Gas Production: First identified in 1994 evaluation. No further consideration warranted.
- Methanol Production: First identified in 1994 evaluation. No further consideration warranted.
- Engine-Driven Process Equipment: First identified in 1994 evaluation. No further consideration warranted.
- 250 kW Cogeneration System Utilizing 250 kW Reciprocating Engine-Generator: First identified in 1994 evaluation. No further consideration warranted.
- Sludge Drying: One of the most expensive options considered. As long as land application of liquid biosolids is still viable, no further consideration warranted.
- Supply Raw Gas to Public Works Department Boiler: Straightforward and low cost, but heating demand for PWD boiler occurs at same time as peak heating demand for WWRP. During periods of no heat demand, excess gas would still be wasted. No further consideration warranted.
- Supply Raw Gas to Aquatic Center Boiler: Constant demand for the digester gas would exist, regardless of season. Would require compressing of gas and piping a great distance resulting in high capital and operation and maintenance (O&M) costs. No further consideration warranted.
- Supply Heating Water to New Disinfection Facility: Building is heated by natural gas and has high heat demand due to large ventilation requirements. During periods of no heat demand, excess gas would still be wasted. No further consideration warranted.

2.5.2 EEMs Not Recommended and Not Implemented

The following EEMs were not recommended in the 2002 Methane Utilization Evaluation, and were not implemented. There were no EEMs not recommended and not implemented in the 2002 Disinfection Building Heat Recovery Analysis, the 2002 Energy Analysis Report, or the 2004 Energy Conservation Analysis.

- Cogeneration Utilizing 150 kW Packaged Reciprocating Engine-Generator: Most economically feasible alternative, but has larger size, higher complexity, high O&M requirements, gas treatment and increased air emissions..
- Cogeneration Utilizing Five (5) 30 kW Microturbines: Low cost, small modular packaging, and low emissions. However, high level of gas treatment results in increased capital costs and increased O&M effort and costs.
- Cogeneration Utilizing 200 kW Fuel Cell: Low emissions and quiet operation. However, high capital cost and high level of gas treatment resulting in increased O&M effort and costs.

2.5.3 EEMs Not Recommended but Implemented

There were no EEMs not recommended but implemented in the 2002 Methane Utilization Evaluation, the 2002 Disinfection Building Heat Recovery Analysis, the 2002 Energy Analysis Report, or the 2004 Energy Conservation Analysis.

2.5.4 EEMs Recommended and Implemented

The following EEM was recommended in the 2002 Methane Utilization Evaluation, and was implemented.

- Cogeneration Utilizing Six (6) 25 kW Stirling Engine-Generators: Recommended alternative due to low cost, small unit size, lack of gas treatment, low emissions, and modular packaging. Recommended installation of a 25 kW Stirling engine-generator beta unit from STM, with the intent of expanding the system to 150 kW. This unit was provided, and upgraded to a 55 kW unit. It has been taken out of service and will be replaced with an upgraded unit de-rated to 43 kW.

The following EEM was recommended in the 2002 Disinfection Building Heat Recovery Analysis, and was implemented.

- Recover exhaust heat to supplement supply heat required. This required the following modifications:
  - Add a new air filter and 42 by 42-inch, six row heat recovery coil across air intake plenum serving the supply air handling unit AHU-1.
  - Add 24 by 24-inch six row heat recovery coils to exhaust ducts feeding exhaust fans EF-1 and EF-2 (top and bottom duct to each fan, four coils total).
  - Install a glycol run-around loop with insulated copper piping and fractional horsepower pump connecting the coils. Control system to operate only when AHU-1 gas burner is firing.

  Recommended heat recovery improvements have been implemented and are operating. Both rooms are maintained at approximately 55 degrees Fahrenheit.

The following EEMs were recommended in the 2002 Energy Analysis Report, and were implemented.

- EEM 4: Improve aeration mixer efficiency. Recommended installing submersible mixers to replace the mechanical mixers. Two Flygt submersible mixers (3 HP each) were installed in each basin to replace the 5 HP mechanical mixers.
- EEM 5: Upgrade interior fluorescent lighting. All T12 fluorescent lighting with mechanical ballasts were replaced with T8 fluorescent lighting with electronic ballasts at a cost of approximately $7,740 per the 22 December 2003 Memorandum regarding the Award of RFB No. 250478.

The following EEM was recommended in the 2004 Energy Conservation Analysis, and was implemented.

- EEM 4: Replace RAS pumps. Four new pumps with premium efficiency motors and VFDs were installed.

2.5.5 EEMs Recommended but Not Implemented

There were no EEMs recommended but not implemented in the 2002 Methane Utilization Evaluation or the 2002 Disinfection Building Heat Recovery Analysis.

The following EEMs were recommended in the 2002 Energy Analysis Report, but were not implemented. The reason for not implementing the measures is stated below:

- EEM 1: Add VFDs to Trickling Filter Pump motors. Trickling filters operate in parallel, with the flow from one pump split between the two trickling filters during the winter, and one pump dedicated to each trickling filter during the summer. Significant recycle operating time across the trickling filters is required because of the constant speed pumps. This EEM was not implemented because of operating preference to nitrify secondary effluent. VFDs are viewed as complicating operations and are not desired.
- EEM-2: Decrease influent head and optimize sequencing. Increase the wet well water level to decrease pumping head and operate pumps such that the fewest horsepower are on at any one time. Design is currently underway to modify the wet well to increase water levels.
- EEM-3: Add VFDs to one aeration blower motor. This was not implemented because it was not desired to install an automatic dissolved oxygen control system.

The following EEMs were recommended in the 2004 Energy Conservation Analysis, but were not implemented. The reason for not implementing the measures is stated below:

- EEM 1: Modify influent pump station. This was originally recommended in the 2002 Energy Analysis Report. Increasing the wet well water level and operating the pumps such that the fewest horsepower are on at any one time would decrease pumping head and reduce energy usage. Design in currently underway to modify the wet well to increase water levels.
- EEM-2: Add VFDs to Trickling Filter Pump motors. This was originally recommended in the 2002 Energy Analysis Report. This EEM was not implemented because of operating preference to nitrify secondary effluent. VFDs are viewed as complicating operations and are not desired.
- EEM-3: Add VFDs to aeration blower motors. This was originally recommended in the 2002 Energy Analysis Report. This EEM was not implemented because of operating preference. VFDs are viewed to complicate operations and are not desired. Blowers are needed for mixing and are sized to meet that need.

2.6 List of Energy Efficiency Measures to Consider

The following is a list of specific energy efficiency measures discussed in the report that should be considered by any wastewater treatment plant when they investigate doing energy efficiency projects. Guides for more generic measures may be found in Appendix A.

- Optimize pump station wet well set points, increasing the wet well water level and operating the pumps such that the fewest horsepower are on at any one time will decrease pumping head and reduce energy usage.
- Add VFDs to motors of pumps and blowers.

- Install premium efficiency motors on pumps, blowers, and process equipment.
- Automate aeration blower operation based on maintaining desired dissolved oxygen level, and provide sequencing to operate most efficient blowers first or a single blower in lieu of multiple blowers.
- Upgrade aeration systems with more efficient diffusers by replacing medium bubble sock diffusers with fine bubble diffusers.
- Improve aeration mixer efficiency by installing submersible mixers to replace mechanical mixers.
- Maximize cogeneration operating time.
- Reduce odor control fan operating time to minimum required for acceptable odor abatement.
- Upgrade digester mixing system from gas mixing to hydraulic mixing.
- Reduce digester gas mixing time.
- Reduce non-potable water (NPW) pressure.
- Recover exhaust heat to supplement supply heat required.
- Replace lighting with more energy efficient lighting.

Section 3: Energy Profile

3.1 Description

Both the Gresham WWTP and the Corvallis WWRP provided 2007 monthly energy data and billing information from their respective utility providers, which were used to perform an energy assessment for each facility within the footprint of each plant. PGE is the electricity provider for the Gresham WWTP, and Pacific Power is the electricity provider for the Corvallis WWRP. A summary of each facility's energy profile is provided below, and detailed breakdown of the data is provided in Appendix B.

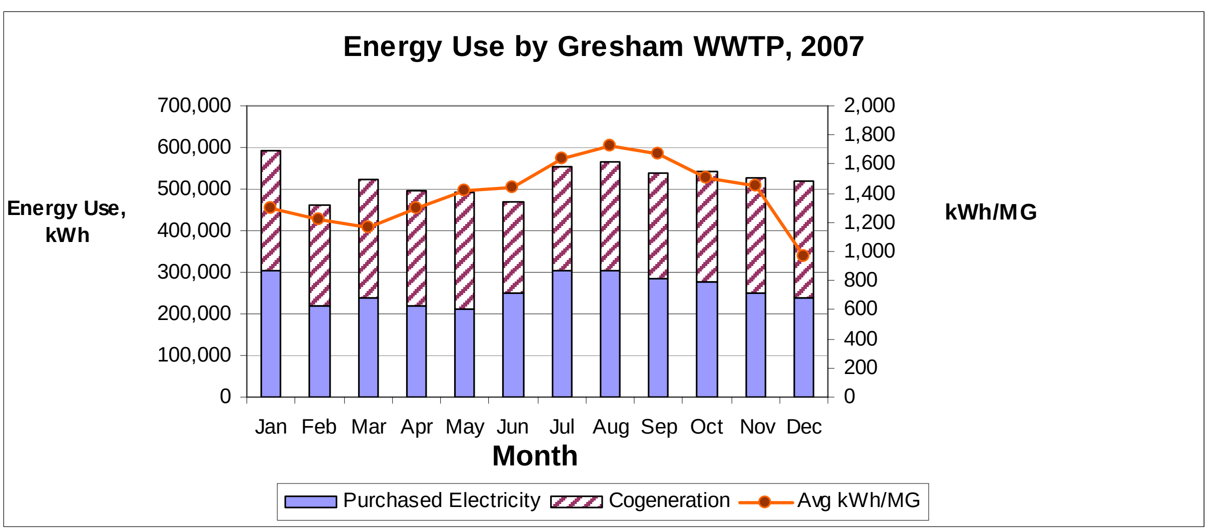
3.2 Energy

Energy is the measure of the use of electricity over time. It is measured in kilowatt-hours (kWh) or megawatt-hours (MWh), where 1 MWh is 1,000 kWh. One kWh is a kW used for 1 hour.

3.2.1 Gresham Facility

The Gresham WWTP monthly energy consumption from PGE ranged from 211,200 kWh (May) to 302,400 kWh (July), and monthly cogeneration facility production ranged from approximately 218,000 kWh to 290,000 kWh as shown in Figure 1. In general, late summer months and the month of January had the highest energy use. Total consumption from PGE for 2007 was 3,100,800 kWh, with a monthly average of 258,400 kWh and total cogeneration production was 3,179,000 kWh with a monthly average of 264,900 kWh. Total overall energy consumption was 6,279,800 kWh, with a monthly average of 523,318 kWh. Average energy use in the plant was 1,400 kWh/million gallons of wastewater treated.

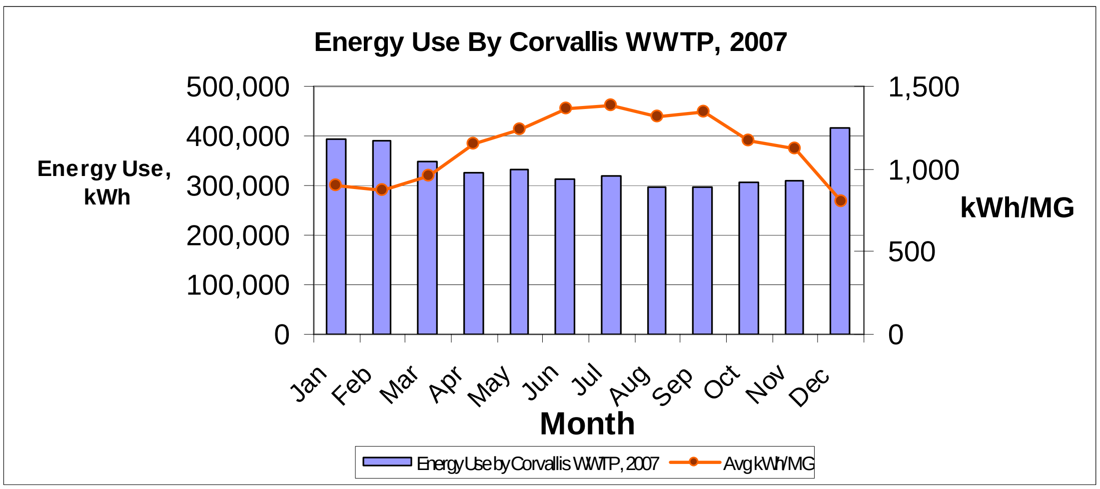
Figure 1:   2007 Gresham WWTP Energy Use



3.2.2 Corvallis Facility

The Corvallis WWRP monthly energy consumption from Pacific Power ranged from 296,040 kWh (September) to 414,854 kWh (December), as shown in Figure 2. Winter months had the highest energy use. Total consumption from Pacific Power for 2007 was 4,042,448 kWh, with a monthly average of 336,871 kWh. Average energy use in the plant was 1,136 kWh/million gallons of wastewater treated.

Figure 2: 2007 Corvallis WWRP Energy Use



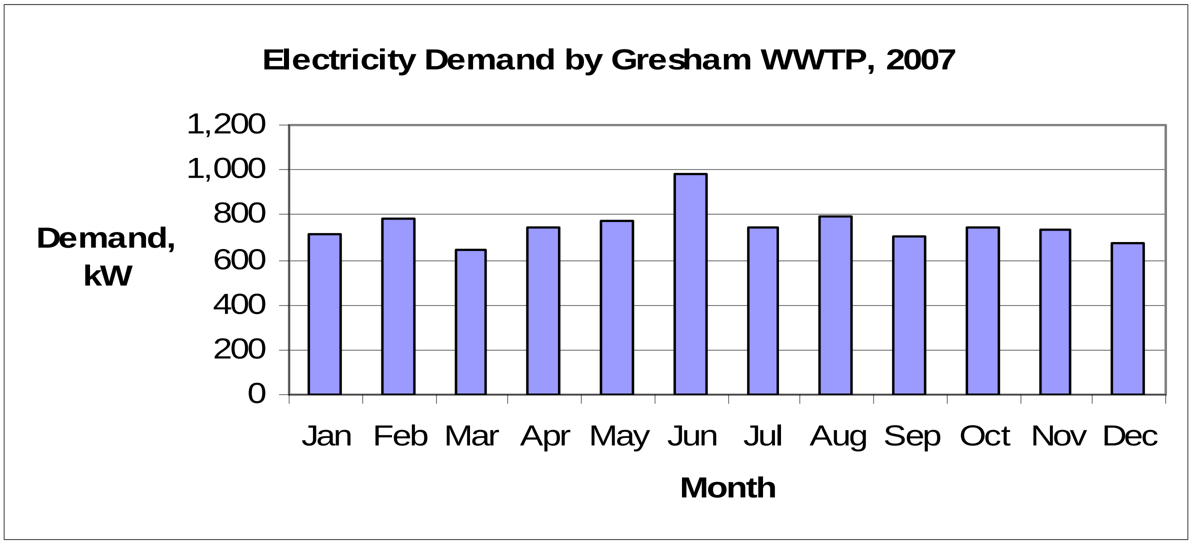
3.3 Demand

Demand is the measure of the use of instantaneous electricity at a single point in time, otherwise known as peak demand. It is measured in kW or MW (1 MW is 1,000 kW).

3.3.1 Gresham Facility

The Gresham WWTP maximum monthly demand from PGE ranged from 648 kW (March) to 981 kW (June), as shown in Figure 3. Although the maximum demand was in June, there is no clear trend in changes in demand throughout the year. The average monthly maximum demand from PGE for Gresham WWTP was 753 kW.

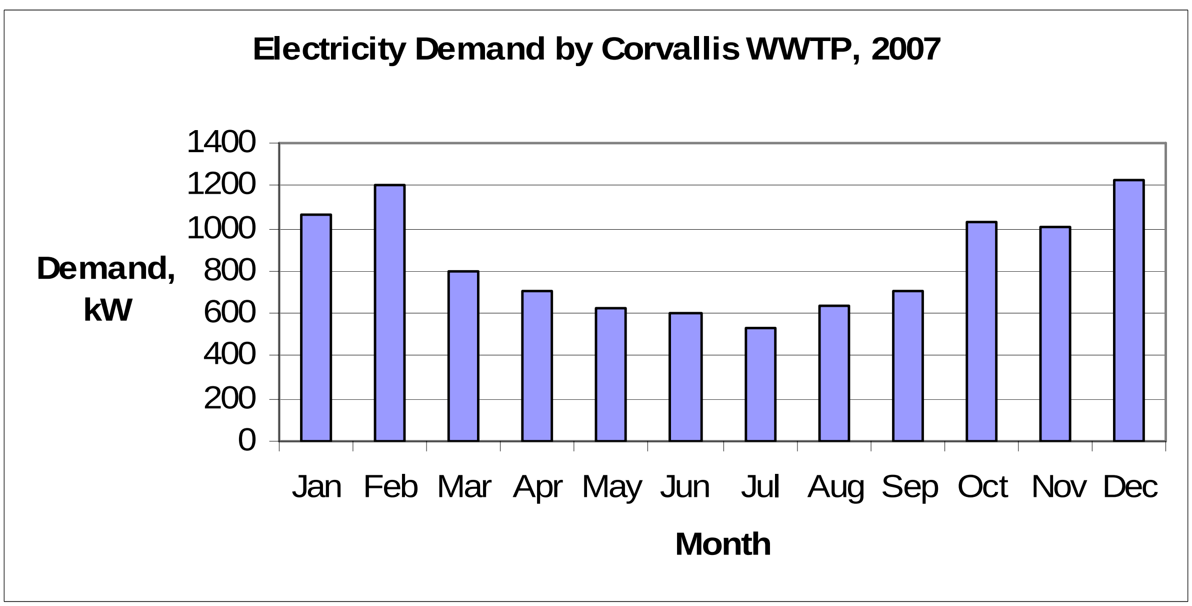
Figure 3: 2007 Gresham WWTP Electricity Demand



3.3.2 Corvallis Facility

The Corvallis WWRP maximum monthly demand from Pacific Power & Light (PP&L) ranged from 536 kW (July) to 1,223 kW (December), as shown in Figure 4. There is a clear trend in demand shifts throughout the year, with decreased demand in the summer months, and highest demand in the winter months. The average monthly maximum demand from Pacific Power for Corvallis WWRP was 845 kW.

Figure 4: 2007 Corvallis WWTP Electricity Demand



3.4 Cost

Cost is the average amount paid per kWh by the respective plants, and is reported in cents/kWh.

3.4.1 Gresham Facility

Gresham WWTP costs for energy purchases from PGE in 2007 were estimated based on the PGE Price Summary for Schedule 83-P. Calculations included a basic charge, demand charge, distribution facilities charge, and an energy charge. The average monthly charge for total demand was $3,760; the average monthly energy charge was $14,780, and the total monthly average charge was $18,640. A monthly breakdown of estimated charges is provided in Appendix B. The total monthly charge was divided by energy consumed from PGE to determine the average cost per kWh, which was **$0.0724/kWh**.

3.4.2 Corvallis Facility

Corvallis WWRP costs for energy purchases from Pacific Power in 2007 were estimated based on the Pacific Power Price Summary for Schedule 48-P. Calculations included a basic charge, a facility capacity charge, and on-peak demand charge, and on-peak energy charge, and off-peak energy charge, and a reactive power charge. The average monthly charge for total demand was $3,040; the average monthly energy charge was $11,990, and the total monthly average charge was $15,590. A monthly breakdown of estimated charges is provided in Appendix B. The total monthly charge was divided by energy consumed from Pacific Power to determine the average cost per kWh, which was **$0.0463/kWh**.

3.5 EEM Savings Total

The EEMs discussed in each facilities' Energy Audits either have the potential to, or already have saved energy, money, and carbon dioxide (CO_2) emissions, which is a greenhouse gas contributing to global warming. This section discusses potential energy savings and carbon dioxide emission reductions from EEMs that have been recommended but not implemented for both the Gresham WWTP and Corvallis WWRP.

3.5.1 Gresham Facility

There are four EEMs recommended for the Gresham WWTP that have not yet been implemented, but could result in significant savings of both energy consumed and carbon dioxide emissions. These are discussed in Section 2.4.4, and presented in Table 2.

Table 2: Savings from Implementing EEMs at Gresham WWTP

EEMs Recommended but Not Implemented	Energy Saved per Year		CO_2 Emissions Saved per Year	
Install premium efficient motors on 4 of 6 aeration blowers	192,810	kWh/yr	191,814	lbs

EEMs Recommended but Not Implemented	Energy Saved per Year		CO_2 Emissions Saved per Year	
Reduce non-potable water (NPW) pressure from 86 to 75 psi	58,850	kWh/yr	58,546	lbs
Replace lower plant medium bubble sock diffusers with fine bubble diffusers.	289,080	kWh/yr	287,587	lbs
TOTAL	540,740	kWh/yr	537,938	lbs

The utility provider for the Gresham WWTP is PGE, whose energy resource mix results in an estimated 995 lbs of CO_2 emitted per MWh of electricity (email communication from Philip H. Carver, 29 May 2008). Multiplying Gresham WWTP's energy savings by this emissions factor results in the pounds of CO_2 emissions reduced per year as a result of EEM implementation. If all four EEMs presented above are implemented, Gresham WWTP could reduce their CO_2 emissions by 537,938 lbs per year. This is a 17 percent reduction in estimated emissions from PGE electricity purchased in 2007.

3.5.2 Corvallis Facility

There are no additional EEMs which have been recommended for the Corvallis WWRP and not implemented that would increase energy savings for the facility.

3.6 Net Energy Use

Implementing additional EEMs would reduce the net energy use of the WWTP by the amount of electricity saved.

3.6.1 Gresham Facility

As presented in Section 3.5, the Gresham WWTP would save an estimated 540,740 kWh/yr by implementing the recommended EEMs discussed in Section 2.4.4. In 2007, the Gresham WWTP consumed 6,279,813 kWh of electricity between energy purchased from PGE and its own cogeneration system (about 50/50 split). Implementation of all four EEMs would make Gresham's net energy use approximately 5,739,073 kWh/yr, a reduction of approximately nine percent. Implementation of the EEMs would reduce Gresham's PGE purchases from 3,100,800 kWh/yr to 2,560,060 kWh/yr, and 17 percent reduction.

3.6.2 Corvallis Facility

Because the Corvallis WWRP has already implemented a number of EEMs that reduce energy use, and there are no further recommended EEMs to implement for energy reduction, the net energy use for the Corvallis facility was not calculated. The current Corvallis energy use is 4,042,448 kWh/yr.

Section 4: Renewable Resource Assessments

4.1 How to Read the Resource Assessments

The following resource assessments have been developed using a common format to facilitate comparing and contrasting the various renewable resource options. Each resource assessment includes the following sections:

1. **History** – includes a brief history of the resource.
2. **Technical Description** – explains how the resource works.
3. **Vendors** – provides a few examples of vendors who provide this particular resource or provided data for this report.
4. **Size and kWh Production** – describes the kW size of a typical unit or module of the resource, and how much of the resource it would take for the Gresham and Corvallis plants to become energy independent.
5. **Examples of Projects** – lists and describes similar project(s) in Oregon or in other locations around the country.
6. **Potential Funding Sources** – describes the estimated incentives that are potentially available to Gresham and Corvallis to help fund the development of the resource. The exact amount offered and whether a particular project is eligible must be evaluated on a project-by-project basis and verified with the agency or program offering the incentive. Detailed information regarding potential incentives and tax credits is provided in Appendix C.
    - **a.** The Business Energy Tax Credit (BETC) is available to tax-exempt public entities, such as publicly owned wastewater treatment plants, via the "pass-through" that gives them 33.5 percent of the total capital cost in a lump sum payment.
    - **b.** The Energy Trust incentive is based on the above market cost of the renewable energy project. For the current analysis this incentive was estimated by first calculating the net present value of the annual resource generation cost over the life of the resource option and subtracting the net present value of the utility cost over the life of the resource option. A higher discount rate is used in this calculation for higher risk resources (higher risk resources are those that are not longstanding proven technologies or widely commercially available). The Energy Trust has previously used a 12 percent discount rate for an IC Engine project, and since the other options evaluated in this study are more risky than an IC engine project, a conservative discount rate of 20 percent was assumed to calculate their incentives. Using a higher discount rate resulted in a lower Energy Trust incentive for the higher risk resources.
    - **c.** Net Metering incentives are a result of Oregon law and are a credit to the customer. Customers of PGE and Pacific Power have net metering available for nonresidential applications of up to 2 MW. Net metering is a method of metering the energy consumed and produced at a facility that has a renewable energy generator and crediting the customer with the retail value of the generated electricity. Generation of electricity using biomass resources is eligible for this program. The systems must be intended primarily

to offset part or all of the customer's requirements for electricity. Net excess generation (NEG) beyond that month's actual usage is carried over as a credit for a 12-month cycle. At the end of the 12-month period, any NEG is zeroed out.

7. **Cost** – This section provides information regarding the equipment cost, total installed cost, and operating cost. The costs provided are estimated and not actual costs of projects. Costs are provided primarily to indicate relative costs of the various resources and to help prioritize a wastewater treatment plant's efforts toward achieving energy independence. Costs were estimated by contacting vendors requesting they provide installed cost including equipment, shipping, installation, and commissioning. Engineering costs were added to the vendors cost estimates to derive total installed costs. Actual capital costs can vary significantly from facility to facility based on the size of equipment and the degree of retrofit or new construction required to install the equipment.

   The cost table in each Resource Assessment summarizes the detailed cost analysis shown on the cost spreadsheets in Appendix H. Each part of the cost table is described below:

   a. Listed Equipment – major pieces or major categories of equipment are listed separately with their costs as provided by vendors.
   b. Engineering Cost –estimated at 25 percent of the total equipment costs and includes design, construction management, and administration and legal costs.
   c. Total Installed Costs –sum of the equipment and engineering cost. This is an estimate of the total capital cost necessary to build the particular resource option.
   d. Starting O&M Cost –estimate of the first year operations and maintenance (O&M) costs including: labor, parts, and materials. The cost is provided in cents/kWh, and is escalated at 3 percent per year.
   e. Power Costs –estimated assuming capital costs are borrowed and a 6 percent bond, including a 13 percent allowance for issuance costs, amortized over the life of the resource to determine the annual debt service. O&M costs are added to the annual debt service to determine the annual gross cost of generation. Incentives from the BETC, the Energy Trust, and from net metering are then deducted to estimate the annual net cost of generation.
   f. First Year Cost – it was assumed that the publicly-owned wastewater treatment plant used the BETC pass-through and received the incentive as a lump sum in the first year. Energy Trust incentives were also assumed to be paid as a lump sum in the first year. Net metering payments were assumed to be paid out over the life of the resource. The up-front incentives are so large and they are substantially more than the annual gross generation costs, thus creating a negative first year cost. The larger the negative cost the greater the up-front incentives. The annual net cost of generation was then divided by the annual kWh production by the resource to estimate the first year cost of power. The First year cost of power is reported in cents/kWh.
   g. 10 Year Average Cost - average over 10 years of the annual net generation cost, reported as cents/kWh.
   h. Levelized Cost - Levelized cost uses present value analysis to convert all costs to a single comparable present year cost. The present value analysis assumes a real discount rate of 3.1 percent, and a nominal discount rate of 5.7 percent. This calculation allows the reader to easily compare the cost of the different resource options.

i. Utility Cost – the cost of the utility power is calculated the same way as the resource cost. First year costs are escalated at a rate of 1.8 percent per year for the life of the resource.

8. **Political and Community Impacts** – describes the likely issues around acceptance by political and community groups.
9. **Environmental Impacts** – describes the resources impacts on the air, land, water, noise, aesthetic/visual, and if it creates waste by-products.
10. **Greenhouse Gas (GHG) Impacts** – describes the amount of carbon the resource will create or reduce compared to continued reliance on utility power.
11. **Operational Impacts** – describes the impact of developing the resource on the waste treatment plants: staffing, maintenance practices, boilers, air permit compliance, discharge permit compliance, and need for heat for the digesters and buildings.

4.2 Fuel Cells using Digester Gas

4.2.1 Introduction

Many wastewater treatment plants have a source of renewable energy from anaerobic digestion -- digester gas. Traditionally, digester gas has been used in boilers to provide heat back to the digester and for heating of buildings. Often, excess digester gas is flared. However, digester gas may also be used to produce electricity in addition to heat. The most efficient way to utilize the energy in the digester gas is through a cogeneration system. Cogeneration is the simultaneous production of electricity and heat, both of which are used in the WWTP. This assessment provides an overview of the use of fuel cells for cogeneration at the Corvallis facility.

4.2.2 History

Fuel cells were invented over 100 years ago, but it was the space program in the 1960s that impelled their commercial development. Fuel cells are commercially available, and while they seem to have overcome their past history of poor performance they are still a relatively new technology. Vendors are overcoming these perceptions by only leasing their fuel cells and providing all the O&M themselves.

Fuel cells provided the power on Gemini and Apollo spacecraft, and provide power on the space shuttle as well. Fuel cells generate electricity by a chemical reaction. Each fuel cell has one positive and one negative electrode, called, respectively, the cathode and anode. The reactions that produce electricity occur at the electrodes. Each fuel cell also has an electrolyte, which carries charged particles from one electrode to the other. There are several different types of fuel cells. Each type uses different electrolytes and temperatures. The type of fuel cell used in the space program requires pure fuels, limiting its terrestrial applications. The four primary fuel cell technologies in development include phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC), and proton exchange membrane fuel cells (PEMFC).

PAFCs use liquid phosphoric acid as the electrolyte. The PAFC is the oldest technology used today. Generally, PAFCs have higher capital costs and lower efficiencies than other types of fuel cells such as MCFC and SOFC. Power plants utilizing PAFCs are generally large and heavy and require warm-up time, making them most appropriate for stationary applications. Efficiencies of approximately 35 to 45 percent are achievable with PAFCs.

MCFCs use an electrolyte composed of a molten carbonate salt mixture. These fuel cells operate at high temperatures and have efficiencies as high as 45 to 60 percent. However, the high operating temperatures accelerate component breakdown and corrosion, decreasing the life of the cell.

SOFCs use a hard ceramic compound as the electrolyte. SOFCs also operate at high temperatures, with efficiencies approximately 45 to 60 percent. This technology is still at a relatively early stage of development compared with other fuel cell technologies.

Development of PEMFCs has generally been driven by the automotive sector, because of their low temperature operation which allows them to start quickly, and their light weight. PEMFCs use a thin solid membrane as an electrolyte. They are generally good candidates for smaller applications, and have efficiencies of approximately 35 to 50 percent.

Fuel cells run on hydrogen, and can use a variety of hydrogen sources. If the fuel source is not pure hydrogen, a “fuel reformer” is generally required to extract the hydrogen. Natural gas (methane) is considered to be the cleanest fuel next to hydrogen. Fuel reformers break the methane molecule and separate the hydrogen for use by the fuel cell. When digester gas is used as the source of methane, it must first be cleaned to remove impurities such as siloxanes and hydrogen sulfide. The first fuel cell operated on digester gas was a PAFC placed into service in 1997 at a wastewater treatment plant in New York. Since that time an increasing number of fuel cells have been installed using digester gas, most using either PAFC or MCFC technologies. Many have been in operation for more than 50,000 hours (almost 6 years). The following discussion focuses on digester gas-fed fuel cells.

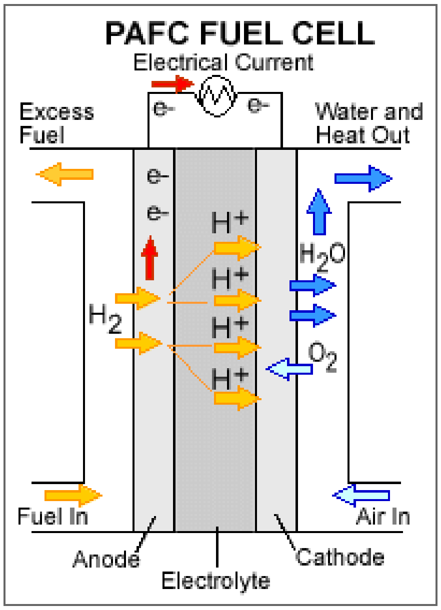
A single fuel cell generates a small amount of electricity, so in practice many fuel cells are typically assembled into a stack to generate the desired power output.

4.2.3 Technical Description

Fuel cells work like batteries, making electrical energy from chemical energy without combustion. Unlike batteries, fuel cells require refueling. Fuel cells use hydrogen as their fuel source. Methane in digester gas or natural gas can be used as the source of hydrogen. However, impurities in the gas must first be removed, as they can poison the fuel cell catalyst, limiting its ability to ionize hydrogen, thereby reducing the fuel cell’s efficiency.

After cleaning of the gas, a fuel reformer or fuel processor is used to extract the hydrogen from the methane. The fuel cell has one positive electrode (the cathode) and one negative electrode (the anode) with an electrolyte between them. The hydrogen is fed to the anode and air (oxygen) is fed to the cathode. A catalyst on the surface of the anode splits the hydrogen into protons (hydrogen ions) and electrons. As the hydrogen ions move from the anode to the cathode through the electrolyte, electricity is created. Electrons cannot flow through the electrolyte and flow through an external circuit as an electric current. At the cathode, a catalyst on the surface recombines the hydrogen ions and electrons with oxygen to produce water and heat. A diagram of a PAFC fuel cell is shown in Figure 5 (picture source: USDOE, Office of Energy Efficiency and Renewable Energy).

Figure 5: PAFC Fuel Cell Diagram



This process is different than the traditional two-step process of combustion where fuel is first burned, and the subsequent heat is used to produce power. Avoiding the two-step process makes the fuel cells more efficient than combustion technologies.

Individual fuel cells generate a relatively small voltage. The current produced by an individual cell is related to the cell surface area. To develop the desired voltage, individual cells are stacked and connected in series. The number of fuel cells in the stack determines the total voltage, and the surface area of each cell determines the total current. The total electrical power generated is equal to the voltage multiplied by the current. Fuel cells produce direct current (DC) electricity. The electrical standard for most uses, such as building power, is alternating current (AC), so the fuel cell uses a power inverter to convert the electricity from DC to AC. This decreases its efficiency.

4.2.4 Vendors

More than 60 companies worldwide are involved in the development of fuel cells. Generally, most companies focus on one of the primary types of fuel cell technologies. Developers of PAFCs include UTC Power, Fuji Electric Company, and Mitsubishi Electric Corporation. Fuel Cell Energy and Hitachi are developing MCFC technology. More than 40 companies are developing PEMFCs, and include ReliOn, Ballard Generation Systems, UTC Power and Nuvera Fuel Cells. There are more than 20 developers of SOFC technology, including Siemens Westinghouse Power Corporation, SOFCo, and ZTEK Corporation. UTC Power provided information about sizing and cost estimates for this resource assessment. UTC Power is a subsidiary of United Technologies Company. UTC is a Fortune 500 company with annual revenues of about $60 billion.

4.2.5 Size and kWh Production

The Corvallis facility produces an average of 65,000 cubic feet per day of digester gas with a methane content of approximately 60 percent. The amount of digester gas available varies somewhat throughout the year. For this analysis, equipment is sized assuming 65,000 cubic feet per day of digester gas is available, with the assumption that natural gas would be supplemented as necessary to keep the fuel cells operating at a minimum of 50 percent load.

Based on the above flow rate of digester gas, the facility could utilize one PureCell Model 400 fuel cell (a PAFC), which has a total output of 400 kW at full load. Unfortunately, vendors do not manufacture many different size fuel cells; they usually focus on one or two sizes. This can make sizing of fuel cells for smaller plants difficult. The digester gas supplied by the Corvallis plant would provide enough fuel to operate the fuel cell at a little less than 50 percent load, generating approximately 180 kW on average, and generating 1.7 million kWh. UTC Power's PureCell Model 400 fuel cell system is provided with an integrated heat recovery module, and the recovered heat would be used for process and building heating requirements. During 2007, the Corvallis WWRP's total energy consumption was approximately 4 million kWh. At 50 percent load, the fuel cell could provide approximately 1,752,000 kWh, or approximately 68 percent of net energy purchases by the plant. The fuel cell is equipped for dual fuel use, and can automatically blend in natural gas if the supply of digester gas drops, to maintain full load. The facility does not have to blend in natural gas, however, and can operate the fuel cell only on the available supply of digester gas. Operating the fuel cell at full load would provide approximately 85 percent of the total energy used by the plant.

In the Pacific Northwest with our large hydro-electric system, the vast majority of our energy costs come from energy rather than demand or peak. To reduce costs most of the effort in the Pacific Northwest goes to reducing energy, rather than reducing demand. To become energy independent Corvallis, provided they had sufficient digester gas which they do not, would need 2.4 fuel cells at 400 kW each. However, should one chose to become completely energy independent one would also need to provide sufficient peak power from a resource option to eliminate the facility's peak electrical demand. This is typically expensive and not done in the Pacific Northwest. For Corvallis the peak demand is approximately 1,200 kW, and it would be necessary to have three 400 kW fuel cells. The majority of the fuel supply to supply the entire facility's energy needs would be from natural gas. To judge the cost-effectiveness of using fuel cells using only natural gas one would need to consider operating costs plus the cost of natural gas versus the avoided cost of purchasing electricity.

The PureCell Model 400 fuel cell system is currently under development, and a model built to utilize digester gas will not be available until 2010.

4.2.6 Examples of Fuel Cell Projects

In late 1999, the City of Portland Columbia Boulevard Wastewater Treatment Plant installed a 200 kW fuel cell operating on digester gas as part of a research and testing project. The fuel cell is a PAFC manufactured by ONSI Corporation (now United Technologies Corporation). The City of Portland received financial support for this project from the U.S. Department of Defense, the Oregon Department of Energy, and the Fuel Cell Climate Change Program. The average operating time for the fuel cell between 1999 and 2004 was approximately 76 percent. Over that five-year period, the largest cost of operating the fuel cell was maintenance costs, which averaged approximately $33,000 per year and were higher than expected. Because the cost of replacing the “power section” of the fuel cell after 5 years of operation was not cost-effective the plant was decommissioned in 2004.

4.2.7 Potential Funding Sources

Oregon offers a Business Energy Tax Credit (BETC) incentive for installation of renewable energy projects equal to 50 percent of the installed cost for private developers. A federal tax incentive is also available for installation of microturbines, after first applying the state tax incentive. The federal incentive is the smaller of $1,000/kW or 30 percent of the cost. The federal incentive currently is set to expire at the end of 2008, but could be extended by Congress. As a tax exempt entity, the City of Corvallis would not be eligible for these incentives. However, tax exempt governmental entities can access the BETC through the “pass-through” mechanism that gives them 33.5 percent of the installation cost which is nearly $792,000.

As well, a tax exempt entity could take advantage of these incentives through a lease arrangement with UTC Power. UTC Power has a financing division that would calculate the installed cost of the microturbine system, including the cost of a service contract, would apply the tax incentives, and provide the system to the City through a lease based on these costs. UTC’s lease, or Energy Services Agreement, term is typically 10 years. Leasing the equipment through UTC allows the City to gain some of the advantage of the tax incentives. UTC would be responsible for service and maintenance of the equipment during the term of the agreement. UTC would monitor the system through their 24/7 call center.

The Energy Trust of Oregon (Energy Trust) may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. The table below provides an estimate of the above market cost for the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. The Energy Trust will either disburse its incentives over time or as a lump sum. We assumed the incentive was paid as a lump sum in the first year. The Energy Trust incentives can vary widely from project-to-project and the Energy Trust focuses on investing in the most cost-effective technology for the application.

In Oregon, the electric distribution utility is obligated by state law to provide a net-metering agreement for renewable energy systems with a capacity of 2 MW or less for non-residential customers, including customers of PGE and Pacific Power. Net metering is a method of metering the energy consumed and produced at a facility that has a renewable energy generator and crediting the customer with the retail value of the generated electricity. Generation of electricity using biomass resources (i.e. – digester gas) is eligible for this program. Effectively the electricity meter runs backward, causing a credit with the local power company. Net metering costs would be the deferred costs of electricity that the generating facility does not have to buy, providing the customer with the full retail value of the electricity produced. The systems must be intended primarily to offset part or all of the customer’s requirements for electricity. Net excess generation (NEG) beyond that month’s actual usage is carried over as a credit for a 12-month cycle, but at the end of the 12-month period, any NEG is zeroed out.

The potential funding from the three funding sources for the City of Corvallis project is provided in the Table 3.

Table 3: Potential Funding Sources – Fuel Cell

Source	Incentive
BETC	$791,900
Energy Trust	$608,300
Net Metering	$81,100
Total	$1,481,300

(Note: Available incentives from the Energy Trust of Oregon are project specific and can vary widely. The numbers provided in this report are an estimate.)

4.2.8 Cost

The rising cost of energy has made cogeneration increasingly attractive for wastewater treatment facilities. Wastewater treatment facilities have available free fuel (digester gas), use substantial amounts of on-site electricity, have a need for stand-by power (during utility power outages) for reliability, and can utilize the waste heat in the digesters. State and federal governments offer incentives to encourage “green” energy from renewable resources. These factors can make cogeneration more cost effective for smaller wastewater facilities than it has been in past years.

Fuel cells are typically the most expensive cogeneration technology. However, tax incentives are higher for fuel cells than for microturbines or reciprocating engines. The estimated cost for one PureCell Model 400 fuel cell is presented in Table 4.

Table 4: Estimated Costs for 400 kW Fuel Cell for Corvallis WWRP

Item	Cost	Corvallis Utility Cost
PureCell Model 400 fuel cell	$1,320,000	
Gas Clean up skid (sized for 400kW)	$300,000	
Shipping, installation, commissioning	$350,000	
Subtotal:	$1,970,000	
Engineering costs (20%)	$394,000	
Total installed cost:	$2,364,000	
Starting O&M costs (with 3% annual escalation for inflation)	$0.03/kWh	
First year cost power (cents/kWh)	-60.84	4.63
10-Year average cost (cents/kWh)	11.06	5.02
Levelized cost (cents/kWh)	7.87	4.39

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

Design life for the PureCell Model 400 fuel cell is estimated to be 20 years. UTC Power can provide leases for the equipment for periods between 10 and 20 years.

With the aforementioned incentives the net capital cost of the fuel cell would be $882,700 or $2,207 per kW.

4.2.9 Political and Community Impacts

One of the common complaints about wastewater treatment plants by the public and regulatory agencies is odors and methane emissions. Use of a cogeneration system helps plants by minimizing methane emissions and odors, while producing both electric power and useable heat. The use of fuel cells for cogeneration is readily accepted by regulatory agencies because there are virtually no emissions, mostly water vapor and carbon monoxide (CO), and because they are substantially quieter than IC engines.

The increased cost of fuel and concern with greenhouse gas emissions has renewed interest in pursuing renewable energy alternatives. As well, state and federal policies encourage the use of renewable energy sources, and there is an increased expectation by the public for public agencies to be "green." State policies have required electricity suppliers to purchase an increasing percentage of renewable energy over time. One growing trend since the late 1990s is for municipal governments to purchase green power for use in government buildings and infrastructure, or to set a goal requiring utilities to generate or purchase a given percentage of renewable energy. The use of a renewable energy such as digester gas with cogeneration can contribute to attainment of these local policy goals.

The City of Corvallis has a sustainability policy, and increasing use of renewable energy, such as digester gas, is an important part of the policy.

4.2.10 Environmental Impacts

Air: Air emissions from fuel cells are very low, and are exempt from many Clean Air Act permitting requirements. The PureCell Model 400 fuel cell is estimated to have emissions of nitrogen oxides (NOx) of 0.035 lb/MWh, and CO emissions of 0.008 lb/MWh, which meets 2007 California Air Resources Board standards.

Land: The PureCell Model 400 fuel cell is packaged as a modular unit that consists of the power module, which contains the fuel reformer, fuel cell stack, and power inverter; and a cooling module that is used during time periods when all of the waste heat from the power module is not required by the plant. The power module occupies an area of approximately 29 by 11 feet, and the cooling module requires 16 by 8 feet. Additional space is required for the equipment used to clean the digester gas. At this point, UTC Power has not designed the clean-up skid that would be used with the PureCell Model 400, but anticipate it would likely occupy approximately the same or a little more than the clean-up skid that would be utilized by microturbines. The microturbine clean-up skid is approximately 8 by 12 feet, the chiller occupies 4 by 4 feet, and the control panel occupies approximately 1 by 3 feet, for a total area of approximately 100 square feet.

Water: The PureCell Model 400 fuel cell uses a steam reformer to collect the water in the discharge for use in the fuel reformer. Under normal operating conditions (ambient temperature less than 86 degrees Fahrenheit), there is no water consumption or discharge. Under conditions where the ambient temperature is greater than 86 degrees Fahrenheit, supplemental water may need to be supplied to the fuel cell. In this case, the fuel cell would be initially built with a water line and water treatment system (the fuel cell requires water cleaner than drinking water).

Noise: Fuel cells are relatively quiet equipment. Environmental noise is typically measured as "A-weighted" sound levels in decibels, abbreviated as dBA. The A-weighted scale represents the noise scale that corresponds closest to the range heard by the human ear. Noise emissions from the PureCell Model 400 fuel cell is expected to be approximately 60 dBA at 30 feet, which is roughly equivalent to the sound of heavy highway traffic at 300 feet, or normal conversation at the distance of three feet. Installing equipment further from receptors also will reduce perceived noise, as there is approximately a 6dBA reduction in noise level for each doubling of distance from the noise source to the receptor.

Aesthetic/Visual: It is not expected there would be visual impacts from installation of the fuel cell. Equipment would be contained within the existing footprint of the facility, and there would be no smoke stacks or visible emissions.

Waste By-Products: The only waste product produced by fuel cells is water. The water is present as moisture in the exhaust heat. A steam reformer in the power module collects this water for use in the fuel reformer. However, the gas clean-up equipment will generate some solid waste. The media used to remove siloxanes will periodically require replacement. Used media can be disposed as solid waste. Particulate filters will also require periodic replacement, and can be disposed as solid waste.

4.2.11 Greenhouse Gas Impacts

Use of fuel cells for WWTPs converts methane, which is a greenhouse gas, to hydrogen for use by the fuel cell. Because there is no combustion in this process, emissions are less than if the methane were flared, and minimal from the renewable resource technology itself. However, replacing the electricity purchased from a WWTP's utility provider with electricity produced by this technology would result in a net reduction of greenhouse gas emissions. Assuming this technology could replace 85 percent of each WWTP's current electricity needs, carbon dioxide emissions would be reduced by an estimated 2,620,000 pounds per year for Gresham WWTP, and 6,130,000 pounds per year for Corvallis WWRP. Calculations are shown in Appendix D.

4.2.12 Operational Impacts

The operational impacts of the utilization of digester gas through fuel cells for energy and hot water generation are important to consider. Digester gas that is to be run through a fuel cell must be cleaned to a very high level. The complexity of the gas cleaning coupled with that of the fuel cell would result in substantial operational impacts.

The increased labor requirements associated with the operation and maintenance of a fuel cell system are the result of:

- Increased maintenance skills, knowledge, and time
- Increased operator monitoring and recordkeeping
- Increased attention to the anaerobic digestion process to maximize gas quality.

There is some offset in labor compared to a conventional (boiler-based) gas utilization system in that the facility would not require on-going maintenance and operation of a boiler; only to maintain it as a back-up heat source. However, the net gain in manpower requirement is estimated to be approximately 0.25 full time equivalent employees (FTEs) for a utility utilizing fuel cell technology.

When compared to other digester gas utilization options, the fuel cell is the best in regard to impacts on air quality and air permit discharge compliance. Since the fuel cell does not burn the gas, it has little or no negative impact on air quality. Operational impacts from a fuel cell are summarized in Table 5.

Table 5: Operational Impacts of Fuel Cell

Parameter	Operational Impact
FTE / Labor	0.25 FTE increase
Maintenance Requirements	New skill-set and increased maintenance time
Boilers	Not needed with fuel cell option
Air Permit Compliance	No air permit issues
Discharge Permit Compliance	Not applicable
Need for Heat	Can be used to heat the digesters with excess used for buildings.

4.3 Internal Combustion Engines using Digester Gas

4.3.1 Introduction

Wastewater treatment plants have a source of renewable energy from anaerobic digestion - digester gas. Traditionally, digester gas has been used in boilers to provide heat back to the digester and for heating of buildings. Often, excess digester gas is flared. However, digester gas may also be used to produce electricity in addition to heat. The most efficient way to utilize the energy in the digester gas is through a cogeneration system. Cogeneration is the simultaneous production of electricity and heat, both of which are used in the WWTP. This assessment provides an overview of the use of internal combustion (IC) engines at the Corvallis facility.

4.3.2 History

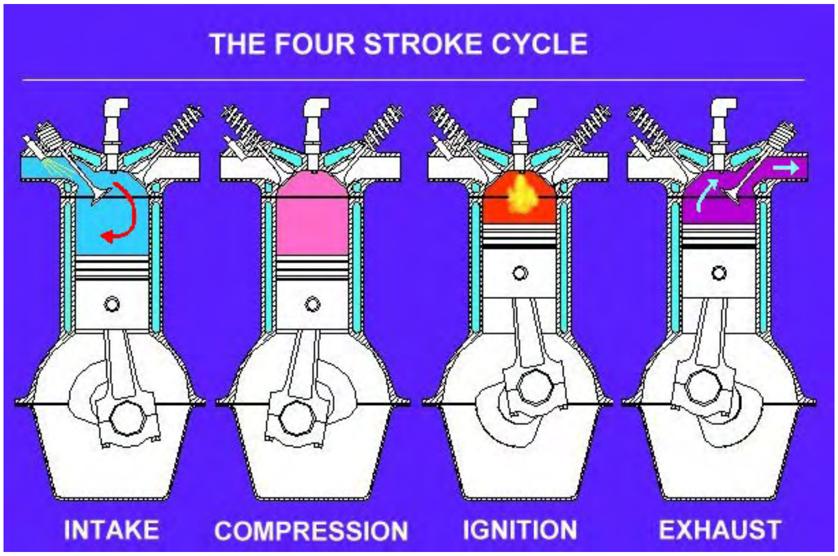
People first experimented with IC engines as far back as the late 1600's. However, it wasn't until the late 1800's that effective internal combustion engines were built, and their use became much more common. Different engine designs have different applications. IC engines are used for automobiles, trucks, construction and mining equipment, marine propulsion, lawn care, and power generation. Typically, for cogeneration applications, four-cycle turbocharged and intercooled reciprocating engines have been used. Digester gas has been used as fuel for internal combustion engines for over 50 years. IC engines are normally used for sizes from 250 to 5,000 kW. Electricity conversion efficiency ranges from 25 to 35 percent. The overall efficiency ranges from 70 to 90 percent. Reciprocating engines are popular for cogeneration because there are many successful installations of this type, the equipment is well understood, and they perform well and are reliable when properly maintained.

4.3.3 Technical Description

In an internal combustion engine, fuel and air is combusted in a combustion chamber. This reaction creates gases at high temperature and pressure, which expand. The expanding gases move parts of the engine, such as a piston, to perform work. The IC engines typically used for cogeneration use a four-stroke spark ignition system. A single cycle of operation (intake, compression, power, and exhaust) occurs over four strokes of a piston.

During the intake stroke, the intake valve opens and the descending piston draws the air-fuel mixture into the cylinder. During the compression stroke, the intake valve closes and the piston moves up, compressing the air-fuel mixture at the top of the cylinder. The ratio of the volume of the cylinder when the piston is at the bottom to the volume when the piston is at the top is called the compression ratio. Higher compression ratios result it more powerful and efficient engines. However, higher compression ratios typically are not compatible with air pollution devices often required for this type of equipment. The next stroke of the cycle is the power stroke, where the spark plug fires and ignites the air-fuel mixture. Combustion of this mixture creates hot gases that expand, forcing the piston down. This is what gives the engine its power. The final stroke in the cycle is the exhaust stroke. During the exhaust stroke, the exhaust valve opens, the combustion products -- mainly carbon dioxide, carbon monoxide, nitrogen oxides, and unburned fuel -- are forced out of the cylinder, the piston moves back up again, and the four stroke cycle is repeated. A diagram of the four stroke cycle is provided in Figure 6.

Figure 6: Four Stroke Cycle



IC engines are sensitive to some of the impurities typically contained in digester gas. These impurities include hydrogen sulfide, siloxanes, particulate matter, moisture, and other compounds, and engine manufacturers typically recommend these be removed or reduced before use in the engine. These constituents can cause, or form products that cause, accelerated wear on the engine. Gas clean-up usually includes dehydration and filtration, and can require sulfur removal if gas sulfur levels are high. If siloxanes are not removed, more frequent maintenance may be necessary; however, the cost of equipment to remove siloxane from the gas can be high.

In an IC engine cogeneration system, heat can be recovered from the exhaust, the jacket water, and the engine oil. This allows for fairly high overall efficiencies for these systems.

4.3.4 Vendors

The primary manufacturers of IC engines for cogeneration are Waukesha, Caterpillar, Jenbacher, and Deutz. The vendor contacted for information about sizing and cost estimates for this resource assessment was Peterson Power Systems, who is a distributor for Caterpillar equipment.

4.3.5 Size and kWh Production

The Corvallis facility produces an average of 65,000 cubic feet per day of digester gas with a methane content of approximately 60 percent. The amount of digester gas available varies somewhat throughout the year. For this analysis, equipment is sized assuming 65,000 cubic feet per day of digester gas is available, with the assumption that only digester gas would be used to fuel the engine.

According to Peterson Power Systems, the Caterpillar unit they would suggest is the G3508. This is the smallest Caterpillar unit available that can run on digester gas, and at full load provides approximately 385 kW. The digester gas supplied by the plant would provide enough fuel to operate the engine at approximately 40 percent load. The facility could fully utilize one G3508 generator using a blend of approximately 60 percent natural gas and 40 percent digester gas; however, additional equipment would be necessary to blend the gas. The G3508 engine-generator system is provided with an integrated heat recovery module, and the recovered heat would be used for process and building heating requirements. During 2007, the Corvallis waste treatment plant's total energy consumption was approximately 4,000,000 kWh. Operating the engine-generator at full load would provide approximately 80 percent of the total energy used by the plant.

In the Pacific Northwest with our large hydro-electric system, the vast majority of our energy costs come from energy rather than demand or peak. To reduce costs most of the effort in the Pacific Northwest goes to reducing energy, rather than reducing demand. To become energy independent Corvallis, provided they had sufficient digester gas which they do not, would need three 400 kW fuel cells. However, should one chose to become completely energy independent one would also need to provide sufficient peak power from a resource option to eliminate the facility's peak electrical demand. This is typically expensive and not done in the Pacific Northwest. For Corvallis the peak demand is approximately 1200 kW, and it would be necessary to have four 385 kW engine-generators. The majority of the fuel supply to supply the entire facility's energy needs would be from natural gas. To judge the cost-effectiveness of using engines using only natural gas one would need to consider operating costs plus the cost of natural gas versus the avoided cost of purchasing electricity.

Other engine manufacturers can provide smaller IC engines in the 150 to 250 kW range. A smaller engine would operate at a higher load, and would have somewhat lower capital costs. Consideration of a smaller engine may be appropriate if the facility does not foresee expansions that would increase the supply of digester gas, or if the facility would prefer multiple units for redundancy. Detailed information from other vendors was not collected for this evaluation.

4.3.6 Examples of IC Engine Projects

Nine wastewater facilities in Oregon use digester gas as fuel to generate electricity using IC engines. A few examples are provided below.

- The City of Gresham Wastewater Treatment Plant installed a Caterpillar engine that generates 395 kW of electricity using digester gas. The cogeneration facility produces approximately 55 percent of the plant's power needs. The project cost $1.1 million, and the City estimated a five-year payback for the project.

- The Durham Advanced Wastewater Treatment Facility, operated by Clean Water Services installed a 250 kW engine to generate electricity using digester gas. Approximately 25 percent of the facility's electricity is provided by this system.

- Clackamas County Water Environment Services operates 250 kW IC engines on digester gas at both its Tri Cities and Kellogg Creek facilities.

- Eugene/Springfield Regional Water Pollution Control Facility (WPCF) uses an 800 kW IC engine on scrubbed digester gas to supply 54 percent of the plants annual electricity.

- Portland's Columbia Boulevard Wastewater Treatment Plan (CBWTP) brought two 850 kW IC engines on-line in May 2008. The recover the water jacket and exhaust heat to heat the digesters, and provide approximately 40-50 percent of the plants electricity.

4.3.7 Potential Funding Sources

Oregon offers a Business Energy Tax Credit (BETC) incentive for installation of renewable energy projects equal to 50 percent of the installed cost for private developers. The federal government offers a Renewable Energy Tax Credit of 0.01/kWh. The credit can be claimed over a 10-year period following installation of the equipment. This credit is set to expire 31 December 2009. As a tax exempt entity, the City of Corvallis would not be eligible for these incentives. However, tax exempt governmental entities can access the BETC through the "pass-through" mechanism that gives them 33.5 percent of the installation cost which is nearly $500,000.

The Energy Trust of Oregon (Energy Trust) may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. The table below provides an estimate of the above market cost for the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. The Energy Trust will either disburse its incentives over time or as a lump sum. We assumed the incentive was paid as a lump sum in the first year. The Energy Trust incentives can vary widely from project-to-project and the Energy Trust focuses on investing in the most cost-effective technology for the application.

In Oregon, the electric distribution utility is obligated by state law to provide a net-metering agreement for renewable energy systems with a capacity of 2 MW or less for non-residential customers, including customers of PGE and Pacific Power. Net metering is a method of metering the energy consumed and produced at a facility that has a renewable energy generator and crediting the customer with the retail value of the generated electricity. Generation of electricity using biomass resources (i.e. – digester gas) is eligible for this program. Effectively the electricity meter runs backward, causing a credit with the local power company. Net metering costs would be the deferred costs of electricity that the generating facility does not have to buy, providing the customer with the full retail value of the electricity produced. The systems must be intended primarily to offset part or all of the customer's requirements for electricity. Net excess generation (NEG) beyond that month's actual usage is carried over as a credit for a 12-month cycle, but at the end of the 12-month period, any NEG is zeroed out.

The potential funding from the three funding sources for the City of Corvallis project is provided in the Table 6.

Table 6: Potential Funding Sources – IC Engine

Source	Incentive
BETC	$496,200
Energy Trust	$425,800
Net Metering	$62,400

Source	Incentive
Total	$984,400

(Note: Available incentives from the Energy Trust of Oregon are project specific and can vary widely. The numbers provided in this report are an estimate.)

4.3.8 Cost

The rising cost of energy has made cogeneration increasingly attractive for wastewater treatment facilities. Wastewater treatment facilities have available free fuel (digester gas), use substantial amounts of on-site electricity, have a need for stand-by power (during utility power outages) for reliability, and can utilize the waste heat in the digesters. State and federal governments offer incentives to encourage “green” energy from renewable resources. These factors can make cogeneration more cost effective for smaller wastewater facilities than it has been in past years.

The capital cost of fully installed cogeneration systems generally ranges from about $900 to $1,350 per kW. Maintenance runs from $0.007 to $0.03 per kWh. In 2007 Gresham’s O&M cost (parts, maintenance, and labor) was $0.015 per kWh. Tax incentives are higher for fuel cells and microturbines than reciprocating engines. The estimated cost for one Caterpillar G3508 is presented in the Table 7.

Table 7: Estimated Costs for 385 kW IC Engine for Corvallis WWRP

Item	Cost	Corvallis Utility Cost
Caterpillar G3508	$975,000	
Gas pretreatment	$210,000	
Subtotal:	$1,185,000	
Engineering costs (25%)	$296,250	
Total installed cost:	$1,481,250	
Starting O&M costs (3% escalation) (cents/kWh)	3.00	
First year cost power (cents/kWh)	-59.16	4.63
10-Year average cost (cents/kWh)	2.32	5.02
Levelized cost (cents/kWh)	2.92	4.39

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

Although siloxanes in the digester gas can increase maintenance requirements for the engines, the manufacturer’s main concern is the sulfur content in the gas. High sulfur content results in sulfuric acid which corrodes engine parts and must be removed. Peterson Power Systems also anticipates that pretreatment of the gas to remove water and particulates would be required.

Design life for IC engines is estimated to be approximately 30 to 40 years with periodic overhauls.

With the aforementioned incentives the net capital cost of the IC Engine would be $496,850 or $1,291 per kW.

4.3.9 Political and Community Impacts

One of the common complaints about wastewater treatment plants by the public and regulatory agencies is odors and methane emissions. Use of a cogeneration system helps plants by minimizing methane emissions and odors, while producing both electric power and useable heat. The use of IC engines for cogeneration is typically more strictly regulated because they generally have higher emissions of NOx and CO than other cogeneration options, and because they are also noisier.

The increased cost of fuel and concern with greenhouse gas emissions has renewed interest in pursuing renewable energy alternatives. As well, state and federal policies encourage the use of renewable energy sources, and there is an increased expectation by the public for public agencies to be "green." State policies have required electricity suppliers to purchase an increasing percentage of renewable energy over time. One growing trend since the late 1990s is for municipal governments to purchase green power for use in government buildings and infrastructure, or to set a goal requiring utilities to generate or purchase a given percentage of renewable energy. The use of a renewable energy such as digester gas with cogeneration can contribute to attainment of these local policy goals.

The City of Corvallis has a sustainability policy, and increasing use of renewable energy, such as digester gas, is an important part of the policy.

4.3.10 Environmental Impacts

Air: Generally, internal combustion engines, particularly reciprocating engines, have moderately high emissions of air pollutants, due to incomplete combustion of fuel. Estimated emissions from the Caterpillar G3508 are approximately 2 g/bhp-hr for nitrogen oxides (NOx), approximately 3.2 g/bhp-hr of carbon monoxide (CO), and approximately 3.2 g/bhp-hr of total hydrocarbons.

Land: The generator set requires approximately 18.5 by 8.5 feet of space. The switchgear requires approximately an additional 4 by 10 feet (includes the clearance required for rear access).

Water: IC engines use water for cooling. Heat from the cooling water, also called jacket water, can be recovered. The G3508 is a closed loop system that should require only minimal make-up water.

Noise: IC engines are fairly noisy. Noise emissions from the Caterpillar G3508 engine are expected to be approximately 80 to 90 dBA at approximately 50 feet, which is roughly equivalent to the sound of a gas lawnmower at 100 feet, or very loud speech at the distance of three feet. Installing equipment further from receptors also will reduce perceived noise, as there is approximately a 6 dBA reduction in noise level for each doubling of distance from the noise source to the receptor. The engine as quoted is supplied with a silencer to reduce the noise from the exhaust to approximately 75-80 dBA. Mechanical noise from the engine is generally reduced by locating the equipment within an insulated building.

Aesthetic/Visual: It is not expected there would be significant visual impacts from installation of the IC engine. Equipment would be contained within the existing footprint of the facility, and although there would be a smoke stack, the equipment should have minimal visible emissions.

However, occasionally the smoke stack can produce visible emissions and in the winter can produce a visible water vapor plume that is often mistaken as dirty air emissions.

Waste By-Products: The lube oil will periodically require replacement. It is assumed that used oil will be recycled.

4.3.11 Greenhouse Gas Impacts

IC engines in this application require the combustion of methane, which emits greenhouse gases such as carbon dioxide. However, it is assumed that the methane used for the IC engine would otherwise be flared, so there is no net impact on emissions for implementation of this renewable resource technology.

However, replacing the electricity purchased from a WWTP's utility provider with electricity produced by this technology would result in a net reduction of greenhouse gas emissions. Assuming this technology could replace 80 percent of each WWTP's current electricity needs, carbon dioxide emissions would be reduced by an estimated 2,470,000 pounds per year for Gresham WWTP and 5,770,000 pounds per year for Corvallis WWRP. Calculations are shown in Appendix D.

4.3.12 Operational Impacts

Digester gas that is to be run through an internal combustion engine must be cleaned prior to use. Though the gas does not have to be cleaned to the level necessary for use in a fuel cell, the cleaner the gas, the less maintenance and air discharge issues the facility will have.

Internal combustion technology has been around for a long time. The maintenance on the units – though sometimes extensive is comparable to overhauling a car engine. In smaller facilities, the use of smaller, "disposable" engines may reduce the need for extensive maintenance experience and knowledge. A utility could utilize the engine until failure and then replace – still maintaining a net gain in energy, costs, and labor.

In addition to being coupled to a generator, the IC can also be coupled with an aeration blower. Using an IC in this fashion could reduce energy associated with aeration as well as provide supplemental heat for the digesters. Use as a supplemental and/or backup heat source for the digester (instead of the primary heat source) would minimize the impact of periodic equipment maintenance down time on digester temperature.

As previously mentioned, internal combustion engines, particularly reciprocating engines, have moderately high emissions of air pollutants, due to incomplete combustion of fuel. These emissions will impact air permitting and have an increased risk of air permit violations (especially compared to fuel cells). Operational impacts from IC Engines are summarized in Table 8.

Table 8: Operational Impacts of IC Engines

Parameter	Operational Impact

Parameter	Operational Impact
FTE / Labor	0.10 FTE increase
Maintenance Requirements	Basic engine skills required. Cleaning scrubbers can cause down time, and maintenance requirements decrease with cleaner gas. History is that IC Engines running digester gas do not have a lot of down time.
Boilers	Not needed if jackets can capture engine heat. May need backup boiler in case of engine failure.
Air Permit Compliance	Can increase risk for air permit compliance issues.
Discharge Permit Compliance	Not applicable
Need for Heat	Can be used to heat the digesters with excess used for buildings.

4.4 Micro-Hydro Turbines

4.4.1 Introduction

Wastewater treatment plants have an available renewable resource in the flow of water through the facility. Any energy from flow not required for plant operation and the energy from flow at the outfall of the plant can be used to produce renewable power. This assessment outlines using a micro-hydro turbine at a wastewater treatment plant.

4.4.2 History

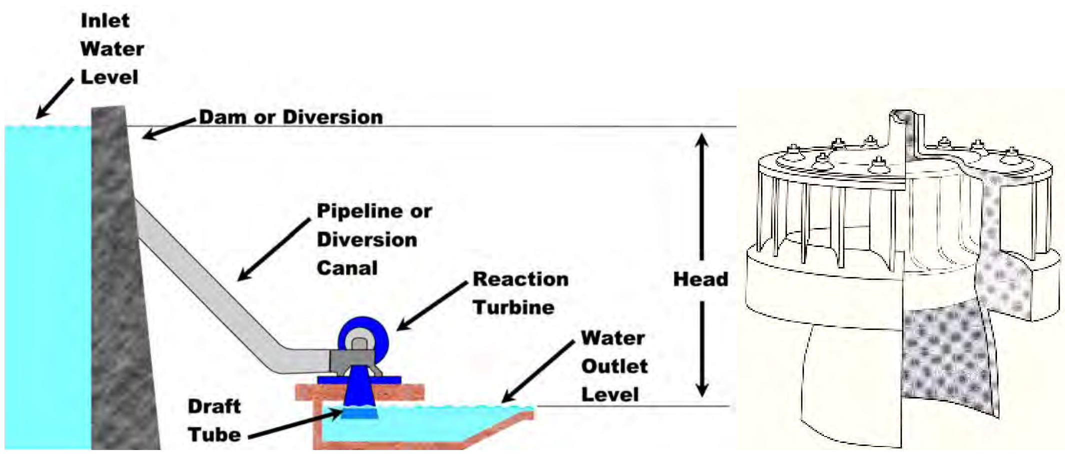
Water power has been used throughout history as a renewable resource. Hydroelectric turbines are used to provide approximately 8 percent of the electricity generated in the United States. Oregon is the third largest producer of hydroelectric power in the United States, generating 33,375 MWh of electricity in 2007, according to the Energy Information Administration. Increased interest in sustainability has caused renewed interest in the use of micro-hydro systems to produce emission free power.

4.4.3 Technical Description

Hydroelectric power is generated by converting the energy of falling or flowing water to mechanical energy. This mechanical energy can then be used to perform work, such as operating a mill or turning a generator. To determine the type of turbine to be implemented at a site, the flow and elevation change or head must be known. In addition to the change in elevation any pipeline losses must be considered when determining the effective head at a site.

There are two general categories of hydro turbines; impulse and reaction. Impulse turbines, such as Pelton and Turgo turbines, are used in situations with high head and low flow. Impulse turbines derive power from the change in momentum of the flowing water as it strikes the turbine blades. Reaction turbines, such as the Francis, Kaplan, and cross-flow turbines are used in situations with low head and high flow. Reaction turbines operate by harnessing reactive forces of the flowing water. Reaction turbines can be utilized in situations with heads as low as 2 feet but require much higher flow rates than impulse turbines. Figure 7 shows a typical reaction hydro turbine installation and a cut away picture of a hydro turbine.

Figure 7: Typical Reaction Turbine System and Cut-Away View of a Hydro Turbine



Several options are available to utilize the hydro power available at wastewater treatment plants. Most plants do not have a large elevation change inside of the plant or at the plant discharge to utilize an impulse turbine. Reaction turbines can take advantage of the relatively constant flow and the smaller head changes likely to be found in most wastewater treatment plants.

4.4.4 Vendors

Many hydro turbines are custom built to precisely match the flow and head conditions expected at the site. Canyon Industries, a micro-hydro system manufacturer based in Deming, Washington, provides custom designed systems. Other examples of manufacturers include: Dependable Turbines, located in Surrey, British Columbia and St. Onge Environmental Engineering, located in Amsterdam, New York.

There are manufacturers who produce off-the-shelf turbines which can be matched to common flow and head scenarios. These turbines are often less expensive than the custom built turbines. Cornell Pump Company produces smaller Francis turbines for heads between 30 to 700 feet and flows up to 15 cubic feet per second (cfs). Energy Systems and Design (ES&D) produces a smaller, ultra low head turbine, LH-1000, which will produce power in flow conditions between 2 to 10 feet and 450 to 1,000 gallons per minute (gpm), or 0.65 to 1.44 MGD. The data sheet for this turbine is included as Appendix I. The LH-1000 can be placed in situations with only 18 inches of water above the turbine, as long as the total drop (surface of the water above the turbine to the surface of the outlet water) is 2 to 10 feet.

4.4.5 Size and kWh Production

Since the flow rates of water are finite and limited by the design of the particular wastewater treatment plant, micro-hydro can only provide a small contribution to becoming energy independent. The Gresham facility has shown interest in implementing a turbine at the outfall of the plant to the Columbia River. The outfall of the Gresham Wastewater Treatment Plant has

22 to 31 feet of available head and a constant flow rate of 19.5 cfs (taken from “Initial Assessment of Hydroelectric Generation in Wastewater System” performed by HDR, December, 2007). With these conditions, a custom built cross-flow turbine would be an effective way to harness this power. A turbine for these conditions will produce between 25 kW and 35 kW.

The Corvallis WWRP is rated for approximately 9.7 MGD. The plant does not have a significant elevation change at its discharge; and when the Willamette River stage is high, effluent must be pumped from the plant through the outfall. At times during the year, the outfall appears to have the available 10 feet of head necessary to power an ultra low head turbine, LH-1000. The LH-1000 can produce 1 kW at 10 feet of head and 1000 gpm (1.44 MGD). At this flow rate five turbines could be utilized on the plant effluent and ensure sufficient flow for continuous operation. This turbine produces direct current (DC) power which would need to be converted and transformed to 480 V, 3 phase, 60 Hz alternating current (AC) for use in the plant. If the plant were to also consider a photovoltaic solar array or a direct current wind turbine, these systems can be combined to use a common converter to process the power they produce into usable AC power.

4.4.6 Examples of Micro-Hydro Projects

There are no known examples of micro-hydro turbines at wastewater treatment plants in Oregon, or the rest of the country. Two examples of micro-hydro turbines operating on the effluent of a wastewater treatment were found outside the country, in Germany and Taiwan.

Emmerich, Germany has a micro-hydro turbine on the effluent of the city’s wastewater treatment plant. The system operates on 12.5 feet (3.8 m) of head and 14 cfs (400 l/s) of flow and produces approximately 14 kW. This system is shown in Figure 8.

Figure 8: Emmerich, Germany Micro-Hydro Turbine

Taiwan has two micro-hydro turbines which utilize the excess flow energy of wastewater treatment plant effluent. The two facilities are located in Hsinchu and Taichung and generate

11 kW and 68 kW respectively. The equipment was supplied by Toshiba. Flow and head data were not available for these facilities. Figure 9 shows the Taichung 68 kW system.

Figure 9: Taichung, Taiwan 68 kW Micro-Hydro Turbine

4.4.7 Potential Funding Sources

There are three potential funding sources for a micro-hydro project at a wastewater treatment plant in Oregon. Oregon offers a Business Energy Tax Credit (BETC) incentive for installation of renewable energy projects equal to 50 percent of the installed cost for private developers. As a tax exempt entity, both the City of Corvallis and the City of Gresham would not be eligible for these incentives. However, tax exempt governmental entities can access the BETC through the "pass-through" mechanism that gives them 33.5 percent of the installation cost.

Another potential funding source is the Energy Trust. The Energy Trust contribution is found by determining the above market costs of the produced electricity, or the difference between the cost to produce the electricity and the value of the electricity.

The Energy Trust of Oregon (Energy Trust) may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. The table below provides an estimate of the above market cost for the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. The Energy Trust will either disburse its incentives over time or as a lump sum. We assumed the incentive was paid as a lump sum in the first year. The Energy Trust incentives can vary widely from project-to-project and the Energy Trust focuses on investing in the most cost-effective technology for the application.

In Oregon, the electric distribution utility is obligated by state law to provide a net-metering agreement for renewable energy systems with a capacity of 2 MW or less for non-residential customers, including customers of PGE and Pacific Power. Net metering is a method of metering the energy consumed and produced at a facility that has a renewable energy generator and crediting the customer with the retail value of the generated electricity. Generation of electricity using hydro power is eligible for this program. Effectively the electricity meter runs backward, causing a credit with the local power company. Net metering costs would be the deferred costs of electricity that the generating facility does not have to buy, providing the customer with the full retail value of the electricity produced. The systems must be intended primarily to offset part or all of the customer's requirements for electricity. Net excess generation (NEG) beyond that month's actual usage is carried over as a credit for a 12-month cycle, but at the end of the 12-month period, any NEG is zeroed out.

The potential funding from the three funding sources for the City of Gresham and City of Corvallis projects is provided in the Table 9.

Table 9: Potential Funding – Corvallis and Gresham

Source	Corvallis	Gresham
BETC	$209,752	$392,788
Energy Trust	$84,910	$66,591
Net Metering	$1,217	$21,001
Total	$295,879	$480,380

(Note: Available incentives from the Energy Trust of Oregon are project specific and can vary widely. The numbers provided in this report are an estimate.)

4.4.8 Cost

A custom turbine to fit the conditions at the outfall of the Gresham facility would cost approximately $175,150. The quote from Canyon Industries is included as Appendix J. This cost includes the turbine, generator, and controls package. Installation of the turbine would include adding a below grade vault and electrical improvements to sell the power back to the utility. All costs include markups to cover contractor setup, contractor overhead and profit, tax, escalation to midpoint of construction, and construction contingency. Table 10 shows the itemized cost for the Gresham 35 kW turbine.

Table 10: Gresham 35 kW Outfall Micro-Hydro Facility Estimated Costs

Item	Project Cost[a]	Gresham Utility Cost
Canyon Hydroelectric Turbine (35 kW)	$438,000	
Civil site improvements[b]	$250,000	
Electrical Improvement[c]	$250,000	
Subtotal:	$938,000	
Engineering costs (25%)	$234,500	
Total installed cost:	$1,172,500	
Starting O&M costs (3% escalation) ($/kWh)	0.50	
First year cost power (cents/kWh)	-124.77	7.21
10-Year average cost (cents/kWh)	16.62	7.82
Levelized cost (cents/kWh)	15.40	6.83

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

Notes:

(a) Project cost includes installation and bid markups (10% for contractor setup, 15% for contractor overhead and profit, 2% for cost escalation to midpoint of construction, and 40% for construction contingency).
(b) Civil site improvements include excavation and installation of a below grade vault.
(c) Electrical improvements include 350' of transmission line, transformer, and a new power pole.

The cost associated with a turbine or turbines on the outfall of the Corvallis facility is given in Table 11. To add a turbine at the outfall of the plant would require adding a utility vault to house the turbine and piping to bypass the outfall line. The markups used to this estimate are the same as listed above. This estimate includes adding five 5 kW LH-1000 turbines, charge regulators for each turbine, grid-tied inverter, transformer, piping, valves, and vault. The Corvallis facility is required to pump the effluent at certain times during the year when the Willamette River is at its higher water levels. For this evaluation, the turbines were assumed to operate 60 percent of the year, due to the necessity to pump the effluent.

With the aforementioned incentives the net capital cost of the micro-hydro would be $692,121 or $19,775 per kW.

Table 11: Corvallis 25 kW Outfall Micro-Hydro Facility Estimated Costs

Item	Project Cost[a]	Corvallis Utility Cost
LH-1000 Ultra Low Head Hydroelectric Turbine (5 kW x 5)[b]	$55,000	
Civil site improvements[c]	$408,000	
Electrical Improvement[d]	$37,900	
Subtotal:	$500,900	
Engineering costs (25%)	$125,225	
Total installed cost:	$626,125	
Starting O&M costs (3% escalation) (cents/kWh)	0.50	
First year cost power (cents/kWh)	-890.65	4.63
10-Year average cost (cents/kWh)	118.13	5.02
Levelized cost (cents/kWh)	111.76	4.39

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

Notes

(a) Project cost includes installation and bid markups (10% for contractor setup, 15% for contractor overhead and profit, 2% for cost escalation to midpoint of construction, and 40% for construction contingency).
(b) Equipment costs include the 5 turbines and all installation costs.
(c) Civil site improvements include a 30' long 10' wide and 20' deep below grade structure to house the turbines and other equipment.
(d) Electrical improvements include charge controllers for each turbine, wiring, and converter.

With the aforementioned incentives the net capital cost of the micro-hydro would be $330,246 or $13,210 per kW.

4.4.9 Political and Community Impacts

Both projects may have some impact on the community during construction. After construction, the projects, which will both be below grade, should have little to no impact on the community. State and Federal regulations encourage the use of renewable resources, and these projects could be used by both utilities to show their commitment to renewable energy.

4.4.10 Environmental Impacts

Air: Hydroelectric turbines do not have any emissions.

Land: Hydroelectric turbines require a vault or building to house the turbine. This may require the acquisition of additional land or easements to place the turbine.

Water: Hydroelectric turbines do not consume any water, nor do they create any water pollution.

Noise: Hydroelectric turbines do produce some noise, similar to any rotating equipment. If the equipment is placed in a vault there should not be any noise concerns.

Aesthetic/Visual: Both turbine projects would be placed in below ground vaults. There should be minimal aesthetic impacts.

Waste By-Product: Some hydroelectric turbines utilize grease to lubricate bearings in the generator.

4.4.11 Greenhouse Gas Impacts

Micro-hydro turbines have no emissions from their operation. However, replacing the electricity purchased from a WWTP's utility provider with electricity produced by this technology would result in a net reduction of greenhouse gas emissions. Assuming this technology could replace 290,000 kWh of each WWTP's current electricity needs, carbon dioxide emissions would be reduce by an estimated 288,000 pounds per year for Gresham WWTP, and 517,000 pounds per year for Corvallis WWRP. Calculations are shown in Appendix D.

4.4.12 Operational Impacts

The impacts on the treatment plant operations and maintenance associated with a micro-hydro turbine would be minimal. The main concern with a micro-hydro turbine would be interruption of plant flow.

Considerations must be made to ensure access to the turbine for maintenance without disruption of effluent flow. There could be concerns with biological growth in the turbine, especially if its use was periodic – though the vendor might be able to discount this concern. Due to these concerns, it would be recommended to only install the turbine in treated effluent.

The impact on labor would be minimal. Operational impacts from a micro-hydro turbine are summarized in Table 12.

Table 12: Operational Impacts of a Micro-Hydro Turbine

Parameter	Operational Impact
FTE / Labor	0 FTE increase (no increase in FTE needs)
Maintenance Requirements	Cleaning and PM. Other maintenance done by vendor.
Boilers	Not applicable
Air Permit Compliance	Not applicable
Discharge Permit Compliance	Not applicable
Need for Heat	Does not generate auxiliary heat nor offset any of the facility's heat requirements

4.5 Microturbines Using Digester Gas

4.5.1 Introduction

Wastewater treatment plants have a source of renewable energy from anaerobic digestion - digester gas. Traditionally, digester gas has been used in boilers to provide heat back to the digester and for heating of buildings. Often, excess digester gas is flared. However, digester gas may also be used to produce electricity in addition to heat. The most efficient way to utilize the energy in the digester gas is through a cogeneration system. Cogeneration is the simultaneous production of electricity and heat, both of which are used in the WWTP. This assessment provides an overview of the use of microturbines at the Corvallis facility.

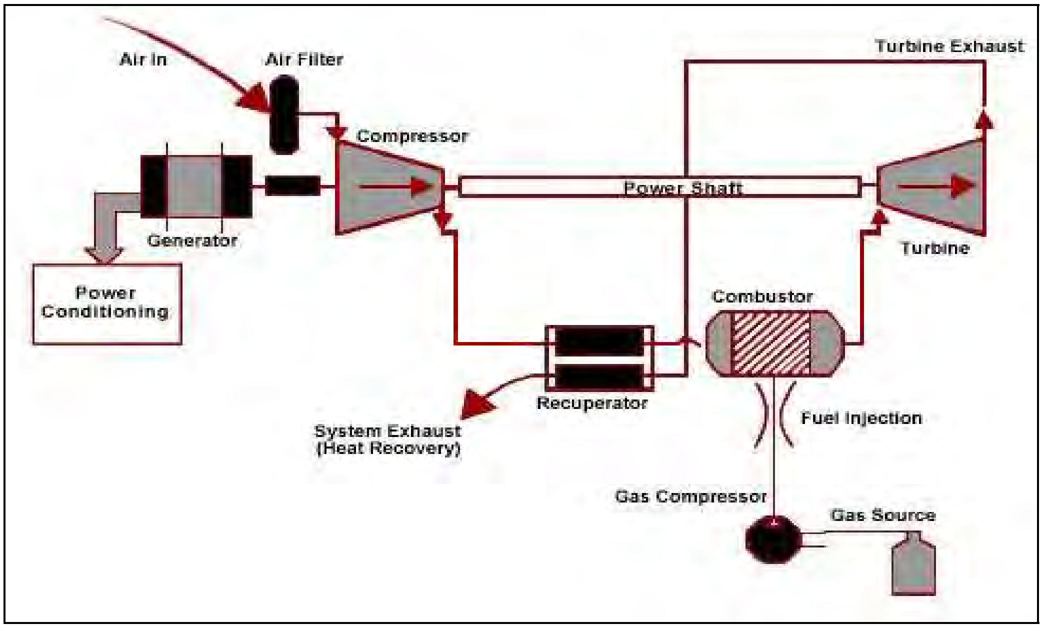
4.5.2 History

Microturbines are small combustion turbines that generally produce less than 500 kW of power. Historically, microturbines have been used since the mid-to-late 1960s as turbochargers in cars and trucks, to provide auxiliary power in aircraft and missiles, and to provide power in remote locations, particularly by the telephone industry. Microturbines used for the production of power have typically used natural gas for fuel. However, over the last several years microturbines have increasingly used feedstocks of landfill gas or other waste fuels, including digester gas to generate electricity.

4.5.3 Technical Description

Microturbines are similar to larger traditional combustion turbines, or small jet engines, but spin at much faster speeds. Pressurized fuel is supplied to the combustor, mixed with fuel, and burned. The heated combusted gases expand, powering the turbine that operates the generator and produces electricity. A recuperator can be added to the process to recover waste heat. A general schematic of the process is shown in Figure 10 (picture source: EPRI).

Figure 10: General Schematic of Microturbine



Microturbines are available in modular units rated down to approximately 30kW. Their small size (about the size of a household refrigerator) allows easy siting, typically near the point where the energy will be used, minimizing transmission losses. Using multiple smaller units allows maintenance to be performed while minimizing interruption of power generation. The efficiency of microturbines is typically between 25 and 30 percent. Greater overall efficiency (up to 70 or 80 percent) is possible when the waste heat is recovered and used.

Microturbines are more tolerant, and thus perform better, than reciprocating engines when the energy content (Btu content) of the digester gas varies over time. However, microturbines require fuels that are nearly free of impurities, such as hydrogen sulfides and siloxanes typically found in digester gas. The combustion of siloxanes leaves sand-like deposits on engine parts that can result in loss of performance or cause the turbine wheel to seize. Therefore, manufacturers usually require that the digester gas be cleaned before use in the microturbines. A typical gas treatment system, or clean-up skid, may include a chiller, compressor, activated carbon filter, and coalescing filter.

The supply of digester gas typically varies somewhat over time. Microturbine systems can be set up so that natural gas is blended with digester gas when the supply of digester gas drops temporarily. Blending in natural gas allows the microturbine to operate constantly at maximum load rather than shutting down or operating at a lower efficiency. During periods of time when the supply of digester gas was insufficient to operate the microturbine at maximum load, natural gas can be automatically blended in to supply sufficient fuel for maximum operation. This prevents digester gas from being “wasted” by diverting it to the flare. Blending of natural gas with digester gas requires additional equipment, and would likely make sense only if electricity costs were much higher than the cost of natural gas.

The use of digester gas in microturbines is relatively new. Installation of microturbines using digester gas began in the early 2000s. Because there are few moving parts, microturbines have shown high reliability, with plant availability exceeding 90 percent. Problems with initial installations generally revolved around the cleanliness of the fuel, and better fuel cleaning has resulted in improved reliability. Microturbines are designed to last between 40,000 to 80,000 hours (5 to10 years). However, since most units have not been in service that long it is not yet known exactly how long they will last.

4.5.4 Vendors

There are more than 20 companies worldwide involved in the development of microturbines. The leading manufacturers include Capstone Turbine, Elliott Microturbines, Turbec, and Ingersoll Rand Engine Systems. UTC Power, who packages Capstone microturbines and provides financing for projects, provided information about sizing and cost estimates for this resource assessment. UTC Power is a subsidiary of United Technologies Company. UTC is a Fortune 500 company with annual revenues of about $60 billion.

4.5.5 Size and kWh Production

The Corvallis facility produces an average of 65,000 cubic feet per day of digester gas with a methane content, or quality, of approximately 60 percent. The amount of digester gas available varies somewhat throughout the year. For this analysis, equipment is sized assuming 65,000 cubic feet per day of digester gas is available, with the assumption that natural gas would be used to provide a constant quality to the microturbines when dips in digester quality rates occurred.

Based on the above quality of digester gas, the facility could utilize two 65 kW microturbines, for a total of 130 kW. UTC Power's PureThermal CR65 microturbine system is provided with an integrated heat recovery module, and the recovered heat would be used for process and building heating requirements. The two units operating constantly would generate approximately 1,100,000 kWh of electricity over the course of year. During 2007, the Corvallis waste treatment plant's total energy consumption was approximately 4,000,000 kWh. Thus, the two microturbines could supply approximately 25 percent of the facility's annual demand.

In the Pacific Northwest with our large hydro-electric system, the vast majority of our energy costs come from energy rather than demand or peak. To reduce costs most of the effort in the Pacific Northwest goes to reducing energy, rather than reducing demand. To become energy independent Corvallis, provided they had sufficient digester gas which they do not, would need 7.5 microturbines at 65 kW each. However, should one chose to become completely energy independent one would also need to provide sufficient peak power from a resource option to eliminate the facility's peak electrical demand. This is typically expensive and not done in the Pacific Northwest. For Corvallis, the peak demand is approximately 1,200 kW, and it would be necessary to have nineteen 65 kW microturbines. It would likely make more sense to explore the utilization of the larger size 200 kW microturbines in this instance. The majority of the fuel supply to supply the entire facility's energy needs would be from natural gas. To judge the cost-effectiveness of microturbines using only natural gas, one would need to consider operating costs plus the cost of natural gas versus the avoided cost of purchasing electricity.

4.5.6 Examples of Microturbine Projects

In 2003, the City of Portland Columbia Boulevard Wastewater Treatment Plant installed four 30 kW Capstone microturbines operating on digester gas as part of a research and testing project. They were run briefly, then shut down for modifications, and restarted in late 2004. Most of the problems centered around the quality of the gas from the clean up equipment; and they are currently offline. Once the gas quality issue is resolved, the microturbines are expected to come back on-line and operated reliably. The cost of the installation was $2,575/kW after utilization of a tax credit of approximately 10 percent through the Oregon Building Energy Tax Credit program.

4.5.7 Potential Funding Sources

Oregon offers a Business Energy Tax Credit incentive for installation of renewable energy projects equal to 50 percent of the installed cost for private developers. A federal tax incentive is also available for installation of microturbines, after first applying the state tax incentive. The federal incentive is the smaller of $200/kW or 10 percent of the cost. The federal incentive currently is set to expire at the end of 2008, but could be extended by Congress. As a tax exempt entity, the City of Corvallis would not be eligible for these incentives. However, tax exempt governmental entities can access the BETC through the “pass-through” mechanism that gives them 33.5 percent of the installation cost which is over $318,000.

The Energy Trust of Oregon (Energy Trust) may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. The table below provides an estimate of the above market cost for the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. The Energy Trust will either disburse its incentives over time or as a lump sum. We assumed the incentive was paid as a lump sum in the first year. The Energy Trust incentives can vary widely from project-to-project and the Energy Trust focuses on investing in the most cost-effective technology for the application.

In Oregon, the electric distribution utility is obligated by state law to provide a net-metering agreement for renewable energy systems with a capacity of 2 MW or less for non-residential customers, including customers of PGE and Pacific Power. Net metering is a method of metering the energy consumed and produced at a facility that has a renewable energy generator and crediting the customer with the retail value of the generated electricity. Generation of electricity using biomass resources (i.e. – digester gas) is eligible for this program. Effectively, the electricity meter runs backward, causing a credit with the local power company. Net metering costs would be the deferred costs of electricity that the generating facility does not have to buy, providing the customer with the full retail value of the electricity produced. The systems must be intended primarily to offset part or all of the customer’s requirements for electricity. Net excess generation (NEG) beyond that month’s actual usage is carried over as a credit for a 12-month cycle, but at the end of the 12-month period, any NEG is zeroed out.

The potential funding from the three funding sources for the City of Corvallis project is provided in the Table 13.

Table 13: Potential Funding – Microturbines

Source	Incentive
BETC	$318,250
Energy Trust	$218,269
Net Metering	$50,090
Total	$586,609

(Note: Available incentives from the Energy Trust of Oregon are project specific and can vary widely. The numbers provided in this report are an estimate.)

As well, a tax exempt entity could take advantage of these incentives through a lease arrangement with UTC Power. UTC Power has a financing division that would calculate the installed cost of the microturbine system, including the cost of a service contract, would apply the tax incentives, and provide the system to the City through a lease based on these costs. UTC's lease, or Energy Services Agreement, term is typically 10 years. Leasing the equipment through UTC allows the City to gain some of the advantage of the tax incentives. UTC would be responsible for service and maintenance of the equipment during the term of the agreement. UTC would monitor the system through their 24/7 call center.

4.5.8 Cost

The rising cost of energy has made cogeneration increasingly attractive for wastewater treatment facilities. Wastewater treatment facilities have available free fuel (digester gas), use substantial amounts of on-site electricity, have a need for stand-by power (during utility power outages) for reliability, and can utilize the waste heat in the digesters. State and federal governments offer incentives to encourage “green” energy from renewable resources. These factors can make cogeneration more cost effective for smaller wastewater facilities than it has been in past years.

Microturbines cost more than reciprocating engines, but are not as expensive as fuel cells. Typically, tax incentives are higher for microturbines than for reciprocating engines. The estimated costs for two UTC Power PureThermal CR65 microturbines are presented in Table 14.

Table 14: Estimated Costs of two 35 kW Microturbines for Corvallis WWRP

Item	Project Cost	Utility Cost
PureThermal CR65 microturbine ($100,000 ea.)	$200,000	
Clean up skid (sized for 130kW)	$210,000	
Shipping, installation, commissioning	$350,000	
Subtotal:	$760,000	
Engineering costs (25%)	$190,000	
Total installed cost:	$950,000	
Starting O&M costs (3% escalation) (cents/kWh)	3.00	
First year cost power (cents/kWh)	-37.74	4.63
10-Year average cost (cents/kWh)	6.86	5.02
Levelized cost (cents/kWh)	4.88	4.39

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

First year costs are negative because of the large lump sum payment from the BETC pass-through. Design life for microturbines is estimated to be between 40,000 and 80,000 hours. UTC Power leases equipment for 10-year periods.

With the aforementioned incentives the net capital cost of the microturbines would be $363,391 or $2,795 per kW.

4.5.9 Political and Community Impacts

One of the common complaints about wastewater treatment plants by the public and regulatory agencies is odors and methane emissions. Use of a cogeneration system helps plants by minimizing methane emissions and odors, while producing both electric power and useable heat. The use of microturbines for cogeneration is more accepted by regulatory agencies than internal combustion engines because of their low nitrogen oxide emissions, and because they are substantially quieter than IC engines.

The increased cost of fuel and concern with greenhouse gas emissions has renewed interest in pursuing renewable energy alternatives. As well, state and federal policies encourage the use of renewable energy sources, and there is an increased expectation by the public for public agencies to be "green." The recently passed SB 838 Oregon Renewables Portfolio Standard (RPS) law requires electricity suppliers to purchase an increasing percentage of renewable energy over time. One growing trend since the late 1990s is for municipal governments to purchase green power for use in government buildings and infrastructure, or to set a goal requiring utilities to generate or purchase a given percentage of renewable energy. The use of a renewable energy such as digester gas with cogeneration can contribute to attainment of these local policy goals.

The City of Corvallis has a sustainability policy, and increasing use of renewable energy, such as digester gas, is an important part of the policy.

4.5.10 Environmental Impacts

Air: Air emissions from microturbines are lower than those from reciprocating engines, and are generally relatively easy to permit. The CR65 microturbine system typically has nitrogen oxide emissions of 9 ppm or less, and carbon monoxide emissions less than 120 ppm.

Land: One of the advantages of microturbines is their relatively small size. Each CR65 occupies an area of approximately 30 by 77 inches, and requires a horizontal clearance of 30 inches on the left, right, and front of the unit. A horizontal clearance of 36 inches is required at the rear of the unit. Two units located together would occupy approximately 48 square feet. Additional space is required for the equipment used to clean the digester gas. The clean-up skid occupies more area than the microturbines. The footprint of the skid is approximately 8 by 12 feet, the chiller occupies 4 by 4 feet, and the control panel occupies approximately 1 by 3 feet, for a total area of approximately 100 square feet.

Water: Microturbines use a minimal amount of water.

Noise: Microturbines are relatively quiet equipment. Noise emissions from the CR65 microturbine system is 65 dBA at 33 feet, which is roughly equivalent to the sound of an automobile traveling by at 30 mph at a distance of 50 feet, or normal conversation at the distance of three feet. An optional acoustic inlet hood kit is available to reduce noise from the microturbine by up to 5 dBA. Installing the microturbines further from receptors also will reduce perceived noise, as there is approximately a 6 dBA reduction in noise level for each doubling of distance from the noise source to the receptor.

Aesthetic/Visual: It is not expected there would be visual impacts from installation of the microturbines. Equipment would be contained within the existing footprint of the facility, and there would be no smoke stacks, visible emissions, or a water vapor plume.

Waste By-Products: The microturbines have no generation waste by-products. However, the gas cleanup equipment will generate some solid waste. The media used to remove siloxanes will periodically require replacement, and the used media can be disposed of as solid waste. Particulate filters will also require periodic replacement, and can be disposed as solid waste.

4.5.11 Greenhouse Gas Impacts

Microturbines require the combustion of methane, which emits greenhouse gases such as carbon dioxide. However, it is assumed that the methane used for the microturbines would otherwise be flared, so there is no impact on emissions for implementation of this renewable resource technology.

Replacing the electricity purchased from a WWTP's utility provider with electricity produced by this technology would result in a net reduction of greenhouse gas emissions. Assuming this technology could replace 1.1 MWh/year of each WWTP's current electricity needs, carbon dioxide emissions would be reduce by an estimated 1,090,000 pounds per year for Gresham WWTP, and 1,960,000 pounds per year for Corvallis WWRP. Calculations are shown in Appendix D.

4.5.12 Operational Impacts

Digester gas that is to be run through a microturbine must be cleaned to a high level prior to use. As with the fuel cell, this high level of cleaning means increased operational and maintenance complexity.

Microturbines are relatively new and complex equipment. Most maintenance on the microturbine itself would require additional training or an outside vendor.

Because of the high level of gas scrubbing required, there are low levels of air pollutants in the discharge. A summary of the operational impacts of microturbines is provided in Table 15.

Table 15: Operational Impacts of Microturbines

Parameter	Operational Impact
FTE / Labor	0.20 FTE increase
Maintenance Requirements	Very high level of maintenance skills required. Most high level maintenance would be performed by the vendor. Gas scrubbing equipment maintenance can be time consuming.
Boilers	May not be needed if additional heat recovery system added.
Air Permit Compliance	Discharges relatively clean air that should meet permit requirements
Discharge Permit Compliance	Not applicable
Need for Heat	Can be used to heat the digesters with excess used for buildings.

4.6 Small Wind

4.6.1 Introduction

Small wind electric systems are defined as wind turbines with no more than 100 kilowatts capacity. These small turbines are usually used for homes, telecommunications dishes, or water pumping. Because of their common residential application, small wind turbines are often referred to as “residential wind”. Small turbines are also used in connection with diesel generators, batteries, and photovoltaic systems (USDOEa, accessed online 2008). The following sections provide an assessment of small wind as a potential energy resource. Many of the sections are excerpts from government and trade organization websites for small wind, such as the United States Department of Energy (USDOE), the National Renewable Energy Laboratory (NREL), and the American Wind Energy Association (AWEA).

4.6.2 History

Wind turbines are the modern-day successors of windmills, from which people have been harnessing wind energy for hundreds of years. The use of wind turbines to generate electricity began in the late 19th and early 20th centuries, primarily on a small scale for domestic and agricultural applications. Wind turbine technology has continued to develop, and production of large scale commercial wind farms began in the 1980s (Dodge 2006).

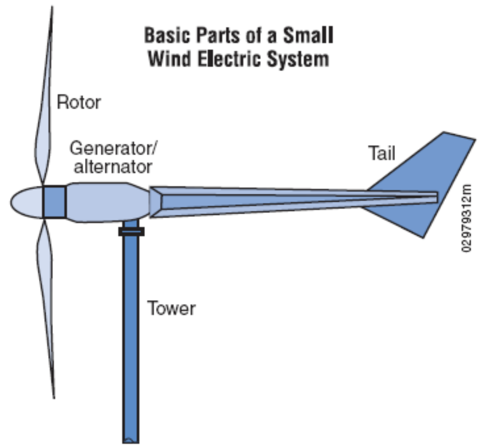
4.6.3 Technical Description

A wind turbine collects energy from the wind and converts it to electricity that is compatible with a building's electrical system. At 100 feet (30 meters) or more aboveground, they can take advantage of the faster and less turbulent wind. Turbines catch the wind's energy with their propeller-like blades. Usually, two or three blades are mounted on a shaft to form a rotor up to 25 feet in diameter. The combination of lift and drag from the wind causes the rotor to spin like a propeller, and the turning shaft spins a generator to make electricity. (NREL, accessed online 2008).

If the wind speeds are below cut-in speed (7-10 mph) – the minimum speed to spin the blades - there will be no output from the turbine. As wind speeds increase, turbine output increases. Turbine dealers can predict the wind at a potential turbine site by measuring the wind with an anemometer or by using detailed default maps to more thoroughly assess a wind resource.

There are no batteries in a modern, grid-connected small wind system. Small wind systems for remote (off-grid) applications operate somewhat differently and often charge batteries so electricity is available when the wind is not blowing (AWEA, accessed online 2008). A small wind system is shown in Figure 11.

Figure 11: Small Wind System



Source: USDOE

Permits are required before installing towers and wind turbines in Oregon. County and local government planning and construction permitting agencies need to be contacted early in the planning process to determine what land use and construction permits may be needed for a site and how long the permitting process takes.

Electrical building permits are also needed to connect the turbine generator to the building's electrical system, and the terms and conditions of connecting to the utility provider's service need to be considered. Those terms and conditions should cover both installing and connecting the turbine as well as the terms and conditions of any exchange or purchase of power from the wind resource. In Oregon, the electric distribution utility is obligated to provide a net-metering agreement for wind energy systems of 2 MWs capacity or less for non-residential customers of investor-owned utilities. The utility may value at its avoided cost the excess power generated by the customer (ODOE, accessed online 2008).

4.6.4 Vendors

As of June 2008 The Energy Trust of Oregon website http://www.energytrust.org/RR/wind/small provides a list of 11 small wind contractors supported by Energy Trust incentives who serve areas throughout the state.

In addition, small wind turbine equipment providers in the U.S. are listed by AWEA at: http://www.awea.org/smallwind/smsyslst.html. These include the following:

Manufacturer	Models (Rated Capacity)
Abundant Renewable Energy www.abundantre.com	ARE110 (2.5 kW), ARE442 (10 kW)
AeroVironment	AVX400 (0.4 kW, building-integrated)

Manufacturer	Models (Rated Capacity)
www.provenenergy.co.uk	
Bergey Windpower Co. www.bergey.com	BWC XL.1 (1 kW), BWC EXCEL (10 kW)
Distributed Energy Systems (previously known as Northern Power Systems) www.distributed-energy.com	NPS 100 (100 kW)
Energy Maintenance Service www.energyms.com	E15 (35 kW or 65 kW)
Entegrity Wind Systems www.entegritywind.com	EW15 (50 kW)
Gaia-Wind Ltd www.gaia-wind.com	11kW
Lorax Energy www.lorax-energy.com	FL 25 (25 kW), FL 30 (30 kW), FL 100 (100 kW)
Proven Energy, Ltd. www.provenenergy.co.uk	Proven 600 (0.6kW), Proven 2.5 (2.5kW), Proven 6 (6kW), Proven 15 (15kW)
Solar Wind Works www.solarwindworks.com	Proven WT600 (600 W), WT2500, (2.5 kW) WT6000 (6kW), WT15000 (15kW)
Southwest Windpower Co. www.windenergy.com	AIRX (400 W), Whisper 100 (900 W), Whisper 200 (1 kW), Whisper 500 (3 kW), Skystream 3.7(1.8 kW)
Wind Energy Solutions Canada **Error! Hyperlink reference not valid.**	WES 5 Tulipo - (5 Meter Rotor Dia. - 2.5 kW), WES 18 - (18 Meter Rotor Dia. - 80 kW), WES 30 - (30 Meter Rotor Dia. - 250 kW)
Wind Turbine Industries Corp. www.windturbine.net	23-10 Jacobs (10 kW), 31-20 Jacobs (20 kW)

4.6.5 Size and kWh Production

Small wind turbine sizes can range from 500 watts to 100 kW. A turbine manufacturer can provide the expected annual energy output of a specific turbine as a function of annual average wind speed at the site location. A generic formula developed by NREL to estimate annual energy output of a wind turbine in kWh is: Output = 0.01328 x rotor diameter (ft.) squared x average wind speed (mph) cubed. For example, if a 20-foot-diameter rotor turbine was installed at a site with average wind speeds of 12 mph, the output from the turbine would be:

$$0.01328 \times 20^2 \times 12^3 = 9{,}180 \text{ kWh}$$

According wind maps for the western states, average wind speeds throughout most of Oregon range from 0-14.3 miles per hour at 50 meters above ground, with areas surrounding Gresham and Corvallis falling at the lower end of the range (Class 1 wind, 0-12.5 mph), and areas around the Columbia River Gorge, northeast and southeast of the state falling at the higher end of that range (http://www.windpowermaps.org/windmaps/states.asp#oregon). However, wind maps give only broad estimates of wind speeds, and the wind speed on any particular site, as well as its suitability for wind turbines, is largely determined by terrain. Because the height of a small wind tower is likely to be slightly lower than 50 meters, and the wind velocity at the height of a turbine rotor will likely be slightly lower than that shown on wind maps.

According to calculators provided on the turbine manufacturer Bergey Company website, a 10 kW BWC Excel-S wind turbine with a tower height of 30 meters is estimated to produce 14,838 kWh per year with a 12.35 mile per hour average wind speed.

A 100 kW turbine available from Distributed Energy Systems called the Northwind® 100 can produce up to 70,000 kilowatts-hours of energy in a year with average wind speeds of 8.9 miles per hour (http://www.distributed-energy.com/wind_power/100kw/FAQ.html), and at higher wind speed the electricity production would increase substantially. We assumed that at a best case scenario of 12 miles per hour the 100 kW turbine would generate 175,000 kWh per year.

As a point of comparison, the Corvallis and Gresham wastewater treatment plants use approximately 3,000-4,000 MWh of energy per year. A single 100 kW wind turbine has the potential to produce 1 to 2 percent of the total energy needs of the entire plant, but may provide a significant portion of the needs for a single building or area of the plant, as demonstrated in the examples below.

The Corvallis WWRP used 4,043,448 kWh in 2007. To meet this load, it would need 23-100 kW turbines, or 272-10 kW turbines, to become energy independent with wind power. The Gresham WWTP purchased 2,560,000 kWh (after netting out the EEMs yet to be installed) in 2007. To meet this demand, it would need 15-100 kW turbines, or 173-10 kW turbines, to become energy independent from wind power.

4.6.6 Examples of Small Wind Projects

There are no small wind projects at wastewater treatment plants in Oregon, but the wastewater treatment plant in Saco, Maine has successfully installed a residential-sized windmill to power an administrative building on its site. A local newspaper highlighted the project, describing it as a 75-foot tall, 18 kW Skystream turbine with 6-foot blades that produce approximately 40 kWh per month. It is expected to pay for itself in about 10 years. The success of this wind turbine has prompted the city to consider purchasing a larger wind turbine to increase its renewable electricity generation (Harkness, 2006).

In Oregon, the City of Portland installed a small wind turbine at its Sunderland Recycling Facility in 2005. "The 10 kW turbine is a Bergey BWC Excel-S wind turbine with a GridTek 10 Power Processing Center that sits atop a 100-foot self-supporting lattice tower. Electricity generated by the wind turbine is used to power the facility's office. Additionally, solar photovoltaic panels power two red beacon lights, required by the Federal Aviation Administration (FAA) because of the tower's proximity to Portland International Airport. It cost about $63,000 to purchase and install Sunderland Recycling Facility's wind turbine. The Energy Trust of Oregon, Inc. contributed 57 percent of the project's price. The wind turbine generates an estimated 10,530 kW – about $900 worth of electricity – per year. Any power that is not utilized by the facility is returned to the grid. Some minor maintenance was performed on the beacon in 2006, but overall the wind turbine has experienced no major problems. Sunderland Recycling Facility has been pleased with the wind turbine's performance, and views this project as an opportunity to showcase the benefits of a small wind turbine and help the City of Portland achieve its renewable energy goals" (City of Portland, 2007).

4.6.7 Potential Funding Sources

The State of Oregon offers a Business Energy Tax Credit incentive for installation of renewable energy projects equal to 50 percent of the installed cost for private developers. However, tax exempt governmental entities can access the BETC through the "pass-through" mechanism that gives them 33.5 percent of the installation cost.

In addition, the Energy Trust of Oregon provides rebates for installing small wind turbines up to 50 kW. The incentive amounts to the lesser of $3,750 per meter of rotor diameter, or $4,000 per rated kilowatts of the wind turbine up to 50 kW, or $60,000. This would equal $25,125 for a 10 kW turbine with a rotor diameter of 6.7 meters. A number of restrictions apply to the qualifying projects, including a minimum tower height of 60 feet, and a project site of at least one acre with annual average wind speeds of at least 10 miles per hour. The system must be installed by a Trade Ally contractor, and the buy-down incentive is paid to the contractor and deducted from the final cost. More information is available at http://www.energytrust.org/RR/wind/small/index.html.

For 100 kW wind turbines, the Energy Trust of Oregon (Energy Trust) may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. The table below provides an estimate of the above market cost for the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. The Energy Trust will either disburse its incentives over time or as a lump sum. We assumed the incentive was paid as a lump sum in the first year. The Energy Trust incentives can vary widely from project-to-project and the Energy Trust focuses on investing in the most cost-effective technology for the application.

In Oregon, the electric distribution utility is obligated by state law to provide a net-metering agreement for renewable energy systems with a capacity of 2 MW or less for non-residential customers, including customers of PGE and Pacific Power. Net metering is a method of metering the energy consumed and produced at a facility that has a renewable energy generator and crediting the customer with the retail value of the generated electricity. Generation of electricity using wind is eligible for this program. Effectively the electricity meter runs backward, causing a credit with the local power company. Net metering costs would be the deferred costs of electricity that the generating facility does not have to buy, providing the customer with the full retail value of the electricity produced. The systems must be intended primarily to offset part or all of the customer's requirements for electricity. Net excess generation (NEG) beyond that month's actual usage is carried over as a credit for a 12-month cycle, but at the end of the 12-month period, any NEG is zeroed out.

The potential funding from the three funding sources for the Cities of Corvallis and Gresham projects is provided in the Table 16.

Table 16: Potential Funding – Small Wind

Source	Corvallis 10 kW Incentive	Corvallis 100 kW Incentive	Gresham 10 kW Incentive	Gresham 100 kW Incentive
BETC	$20,979	$167,500	$20,979	$167,500
Energy Trust	$25,125	$126,344	$25,125	$106,326
Net Metering	$687	$8,103	$1,070	$12,618
Total	$46,791	$301,947	$47,174	$286,444

(Note: Available incentives from the Energy Trust of Oregon are project specific and can vary widely. The numbers provided in this report are an estimate.)

4.6.8 Cost

As described on the AWEA website, "the cost of a wind system has two components: initial installation costs and operating expenses. Installation costs include the purchase price of the complete system (including tower, wiring, utility interconnection or battery storage equipment, power conditioning unit, etc.) plus delivery and permitting costs, installation charges, professional fees and taxes". Small wind energy systems generally cost from $3,000 to $5,000 for every kilowatt of generating capacity (AWEA, accessed online 2008). For 10 kW turbines recent examples indicate that engineering costs were approximately 50 percent of the equipment costs. For installed cost we assumed about $60,000 for a 10-kW installed system, and $500,000 for a 100-kW system. Wind energy becomes more cost-effective as the size of the turbine's rotor increases, because exponentially more electricity can be generated per foot of rotor diameter.

The estimated costs for one 10 kW BWC Excel-S wind turbine (sold by Bergey Company, http://www.bergey.com/) are presented in Table 17.

Table 17: 10 kW BWC Excel-S Wind Turbine Estimated Costs

Item	Project Cost Corvallis/Gresham	Utility Cost Corvallis/Gresham
10 kW BWC Excel-S turbine, voltage regulator, pump controller, or a line-commutated inverter	$29,500	
Tower	$12,600	

Subtotal:	$42,100	
Engineering costs (50%)	20,525	
Total installed cost:	$62,625	
Starting O&M costs (3% escalation) (cents/kWh)	1.00	
First year cost power (cents/kWh)	-249.55/-252.13	4.63/7.21
10-Year average cost (cents/kWh)	29.82/27.02	5.02/7.82
Levelized cost (cents/kWh)	19.00/16.50	4.39/6.83

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

The estimated costs for one 100 kW wind turbine are presented in Table 18, based on average costs per kW presented by AWEA (2008).

With the aforementioned incentives the net capital cost of the 10 kW wind turbine would be $15,834 or $1,583 per kW for Corvallis; and $15,451 or $1,545 per kW for Gresham.

Table 18: 100 kW Wind Turbine Estimated Costs

Item	Project Cost Corvallis/Gresham	Utility Cost Corvallis/Gresham
100 kW equipment and installation	$400,000	
Engineering costs (25%)	$100,000	
Total cost:	$500,000	
Starting O&M costs (3% escalation) (cents/kWh)	1.00	
First year cost power (cents/kWh)	-127.68/-118.82	4.63/7.21
10-Year average cost (cents/kWh)	23.17/21.52	5.02/7.82
Levelized cost (cents/kWh)	16.50/15.23	4.39/6.83

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

With the aforementioned incentives the net capital cost of the 100 kW wind turbine would be $198,053 or $1,981 per kW for Corvallis; and $211,556 or $2,116 per kW for Gresham.

4.6.9 Political and Community Impacts

The two most common public concerns regarding new wind projects are the project's effects on the viewshed, or aesthetic concerns; and concern for the safety of birds that might fly in the path of the rotor.

Given the urban setting of most wastewater treatment plants, a single small wind turbine would not have a significant impact on a viewshed in the midst of water towers, telephone poles, and other buildings.

The second concern would likely be alleviated by public education regarding studies of bird safety as it relates to wind turbines, as well as site-specific studies conducted to obtain zoning permits. Relative to other sources of death for birds (window panes, housecats, etc.), the number of deaths from wind turbines are very small. Public education on this issue should increase community acceptance of a single small wind turbine in an urban setting.

4.6.10 Environmental Impacts

Air: Wind turbines produce no emissions and emit no greenhouse or smog-causing gases.

Land: An Energy Trust requirement to qualify for financial incentives for small wind projects is an area of at least one acre. The Distributed Energy Systems Northwind® 100 turbine requires an area of between 350 and 600 sq ft. for the foundation and recommended clearance (http://www.distributed-energy.com/wind_power/100kw/FAQ.html). Generally it must be a location that is accessible by crane.

As a rule of thumb, small turbines should be mounted at least 30 feet above any structures or natural features (buildings, trees, bluffs) within 300 feet of the installation. (AWEA, accessed online 2008)

Water: Wind turbines do not consume water, nor do they cause any water pollution.

Noise: Noise from wind turbines is only slightly louder than background noise.

Aesthetic/Visual: Because a small wind turbine must be mounted on a tall tower to function effectively, the turbine itself may be visible from some distance. Similar to cell phone tower, neighbors may object to the visual impact of a wind turbine.

The Federal Aviation Administration does not generally require that towers under 200 feet be lighted. Thus, while some very large industrial-scale wind turbine towers may need to have lights (particularly if they are near an airport facility), it is unlikely that a residential-scale turbine will need to be lighted. For sites closer than two miles to an airport or runway, tower height may be restricted by FAA regulations. (AWEA, accessed online 2008)

Waste By-Products: Small wind turbines have no generation waste by-products.

4.6.11 Greenhouse Gas Impacts

Wind turbines emit no greenhouse gases, and would mitigate the impacts from greenhouse gases that would otherwise be emitted by the electricity source it replaces.

The Corvallis WWRP currently purchases approximately 4,000 MWh from PacifiCorp annually. If it were to become completely energy independent with wind resources, it would mitigate approximately 7.2 million pounds of carbon dioxide per year.

The Gresham WWRP currently purchases around 3,100 MWh from PGE annually. If it were to become completely energy independent with wind resources, it would mitigate approximately 3.1 million pounds of carbon dioxide per year.

4.6.12 Operational Impacts

The impacts on the treatment plant operations and maintenance associated with a small wind system would be minimal, and are summarized in Table 19.

Table 19: Operational Impacts of Small Wind System

Parameter	Operational Impact
FTE / Labor	0 FTE increase (no increase in FTE needs)
Maintenance Requirements	Minor PM. Other maintenance done by vendor.
Boilers	Not applicable
Air Permit Compliance	Not applicable
Discharge Permit Compliance	Not applicable
Need for Heat	Does not generate auxiliary heat nor offset any of the facility's heat requirements

4.7 Solar Photovoltaic

4.7.1 Introduction

Solar energy refers to a wide array of renewable energy sources that derive their energy from the sun. This resource assessment focuses on photovoltaic (PV) solar electric systems, in which sunlight is converted directly into electricity.

4.7.2 History

Since the 1950s, photovoltaics have been used in space technology. The energy efficiency of PV cells has increased steadily since that time, and in the 1980's the first mega-watt scale PV system went online in California. Today, there are multiple utility-scale and small-scale applications of the technology. (USDOE, accessed online May 2008).

4.7.3 Technical Description

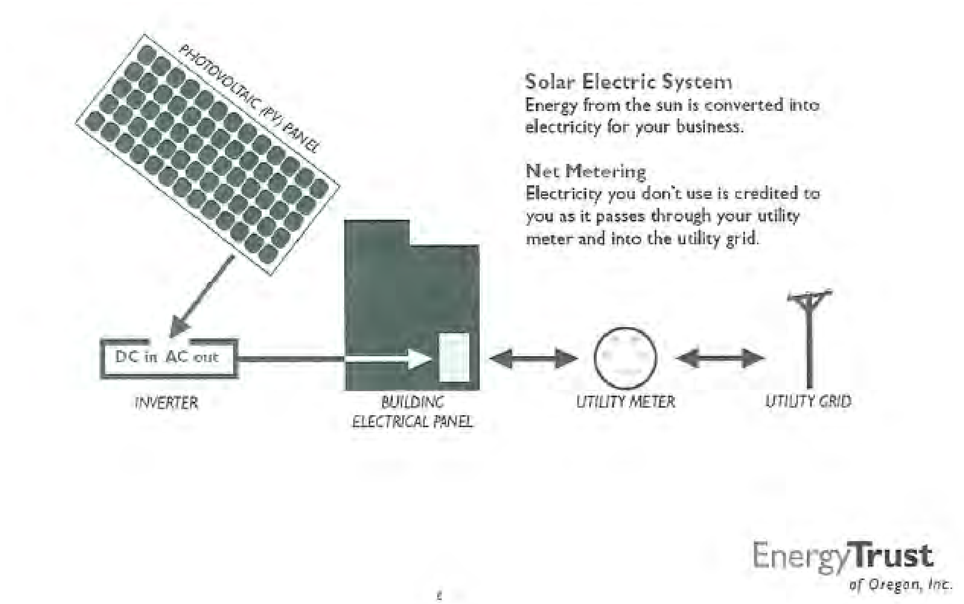
Photovoltaic devices generate electricity directly from sunlight via an electronic process that occurs naturally in certain types of material. Electrons in certain types of crystals are freed by solar energy and can be induced to travel through an electrical circuit, thereby powering any type of electronic device or load (from SEIA, accessed online May 2008).

An individual photovoltaic or solar cell is usually quite small, typically producing about 1 or 2 watts of power. To boost the power output of PV cells, larger PV units are constructed as flat-plate systems or concentrator systems. The most common array design uses flat-plate PV modules or panels. These panels can either be fixed in place or allowed to track the movement of the sun. Concentrator systems use less solar cell material and make use of relatively inexpensive materials such as plastic lenses and metal housings to capture the solar energy shining on a fairly large area, and focus that energy onto a smaller area, where the solar cell is located.

By themselves, PV units do not represent an entire PV system. The system includes support structures that point them toward the sun, and components that take the direct-current electricity produced by modules and convert it to alternate-current electricity. Most PV systems also use a storage device such as batteries to allow nighttime use of the power (from USDOE, accessed online May 2008).

Figure 12 depicts a PV system and shows how it may connect to power from an electric utility.

Figure 12: PV System



(Source: Brian Thornton, Energy Trust of Oregon, 2008.)

4.7.4 Vendors/Contractors

The Energy Trust of Oregon maintains a list of solar contractors throughout Oregon, who must be used to qualify for their incentives. The list for small commercial solar electric at the time of this report includes 64 contractors, and can be obtained via their website at: http://www.energytrust.org/solar.

4.7.5 Size and kWh Production

In general, PV systems require about 100 sq ft of unobstructed area per kilowatt, and weigh 4 to 6 lb per sq ft. (Solar Oregon, accessed online May 2008). Approximately 1000 kWh can be produce per kW. The Energy Trust of Oregon estimates the energy produced (kWh) per installed capacity (kW), or kWh or kW for different cities in Oregon as follows:

- Astoria – 1060
- Portland – 1119
- Salem – 1180
- North Bend – 1297
- Pendleton – 1347

- Medford – 1365
- Redmond – 1471.

(Source: Brian Thornton, Energy Trust of Oregon, 2008.)

A recent study performed by Doug Boleyn of Cascade Solar Consulting (2008), provides an assessment for possible sites for a PV system at the City of Gresham wastewater treatment plant. The report identifies nearly 200,000 square feet of space suitable for a PV system, which could potentially provide an estimated 3,837 kW of demand to the plant. This, in addition to its current cogeneration, would make it completely energy independent, with approximately 2,800 kW excess generation.

The Corvallis plant would require just over 1,200 kW of solar electricity generation from twelve 100 kW solar PV systems to become energy independent from PV systems. In the Pacific Northwest with our large hydro-electric system, the vast majority of our energy costs come from energy rather than demand or peak. To reduce costs most of the effort in the Pacific Northwest goes to reducing energy, rather than reducing demand. To become energy independent Corvallis, would need 38 solar PV systems at 100 kW each, and Gresham would need 24 solar PV systems.

4.7.6 Examples of Solar PV Projects

There are many examples of PV projects in Oregon. Three examples are provided below.

- Corvallis has a project in development to provide a hosted solar PV energy system of 2,000 kW. The installed solar system and associated equipment will be constructed on 15 acres of undeveloped land adjacent to the treatment plant. In operation the solar system will provide 2,300,000 kWh per year or 55% of the treatment plants annual energy requirement. The $15 million project will be designed, built, owned, and operated by a third-party; the City will purchase all of the solar power produced at a negotiated rate.

- The Nature Conservancy installed a 4 kW system of 120 PV panels at its office in Western Oregon. It was funded by PGE Enron, and installed by Mr. Sun Solar and Solar Assist of Eugene. (Solar Oregon, accessed online May 2008).
- Cleveland High School is the eighth project in the Bonneville Environmental Foundation's (BEF) Solar 4R Schools program, and one of four metro area schools to receive solar electric panels from the BEF, the Energy Trust of Oregon, and PGE during the first quarter of 2005. The system capacity is 1.1 kW, and was installed in January 2005 (http://www.b-e-f.org/renewables/cleveland.shtm).
- Kettle Foods, the natural snack food company installed a 114kW photovoltaic system at its Salem manufacturing facility. The roof-mounted system produces approximately 120,000 kWh of electricity each year. The Energy Trust Solar Trade Ally was Advanced Energy Systems, and the system began operating in September 2003. (Energy Trust, accessed online May 2008).

4.7.7 Potential Funding Sources

The State of Oregon offers a Business Energy Tax Credit incentive for installation of renewable energy projects equal to 50 percent of the installed cost for private developers. However, tax exempt governmental entities can access the BETC through the “pass-through” mechanism that gives them 33.5 percent of the installation cost, which is nearly $377,000 for a 100 kW Solar PV system.

In addition, the Energy Trust provides incentives for installing grid-tied or net metered new solar electric systems. Incentives are based on the rated power capacity of the solar array in watts, as follows:

For systems under 30,000 watts (30 kW):

- Pacific Power customers: $1.75/watt up to $150,000 (a 10 kW system would receive only $17,500)
- PGE customers: $2.00/watt up to $175,000 (a 10 kW system would receive only $20,000).

For systems over 30,000 watts (30 kW):

- Pacific Power customers: $1.50 to $1.75 /watt up to $150,000 (a 100 kW system would exceed the maximum and would receive only $150,000)
- PGE customers: $1.75 to $2.00 /watt up to $175,000 (a 100 kW system would exceed the maximum and would receive only $175,000).

Each project is unique and Energy Trust incentives are based on many factors. The Energy Trust will either disburse its incentives over time or as a lump sum. We assumed the incentive was paid as a lump sum in the first year. The Energy Trust incentives can vary widely from project-to-project and the Energy Trust focuses on investing in the most cost-effective technology for the application.

A municipal WWTP may purchase a solar electric system for net metering, forgoing federal tax incentives; or allow a third party to install, own and operate the system, and purchase the electricity from the third party, allowing federal tax incentives to be claimed (by the third party). More information is available at http://www.energytrust.org/solar/commercial/nonp_gov.php.

In Oregon, the electric distribution utility is obligated by state law to provide a net-metering agreement for renewable energy systems with a capacity of 2 MW or less for non-residential customers, including customers of PGE and Pacific Power. Net metering is a method of metering the energy consumed and produced at a facility that has a renewable energy generator and crediting the customer with the retail value of the generated electricity. Generation of electricity using solar power is eligible for this program. Effectively the electricity meter runs backward, causing a credit with the local power company. Net metering costs would be the deferred costs of electricity that the generating facility does not have to buy, providing the customer with the full retail value of the electricity produced. The systems must be intended primarily to offset part or all of the customer’s requirements for electricity. Net excess generation (NEG) beyond that month’s actual usage is carried over as a credit for a 12-month cycle, but at the end of the 12-month period, any NEG is zeroed out.

The potential funding from the three funding sources for the Cities of Corvallis and Gresham projects is provided in the Table 20.

Table 20: Potential Funding – Solar PV

Source	Corvallis Incentive	Gresham Incentive
BETC	$301,500	$301,500
Energy Trust	$150,000	$175,000
Net Metering	$4,867	$7,579
Total	$456,367	$484,079

(Note: Available incentives from the Energy Trust of Oregon are project specific and can vary widely. The numbers provided in this report are an estimate.)

4.7.8 Cost

The Energy Trust estimates the cost of PV systems to be approximately $9,000 per kW before incentives.

Given this estimate, Table 21 provides a cost summary of a 100 kW array, which is the maximum size that qualifies for Energy Trust incentives.

Table 21: 100 kW Array Cost Summary

Item	Project Cost Corvallis/Gresham	Utility Cost Corvallis/Gresham
100 kW PV system (including battery, inverter, module, charge controller)	$720,000	
Engineering costs (25%)	$180,000	
Total installed cost:	$900,000	
Starting O&M costs (3% escalation) (cents/kWh)	1.00	
First year cost power (cents/kWh)	-348.79/-375.15	4.63 / 7.21
10-Year average cost (cents/kWh)	37.49/32.32	5.02 / 7.82
Levelized cost (cents/kWh)	36.52/32.62	4.39 / 6.83

(For a detailed explanation of this table see Section 4.1 How to Read the Resource Assessments, on page 4-1)

The Corvallis WWRP had a peak demand of just over 1,200 kW in 2007. To meet this demand, it would need 13-100 kW PV arrays to become energy independent with wind power. The cost of this system would be nearly $12 million, because many of the incentives included in the cost summary above would not be available for such a large system.

The Gresham WWTP had a maximum demand of almost 1,000 kW in 2007. To meet this demand, it would need 10-100 kW PV arrays, to become energy independent from wind power. The cost of this system would be $9 million, because many of the incentives included in the cost summary above would not be available for such a large system.

In the alternative to outright purchasing the solar PV system, publicly owned treatment plants can partner with a third party that can take advantage of the tax credits that the public entity could not, and pass along some of the value of those credits. A third party with an ability to take advantage of tax credits could pay for and own the solar PV system; and take the federal tax credits, the federal accelerated depreciation, the state tax credits, and the Energy Trust or utility incentive. These incentives can add up to well over half of the project's capital cost. The third party partner could then sell the power generated by the resource to the treatment plant at an advantageous rate. In doing this the treatment plant could become energy independent, lower their power costs, and not use their scarce capital.

With the aforementioned incentives the net capital cost of the solar PV would be $443,663 or $2,207 per kW. With the aforementioned incentives the net capital cost of the 100 kW wind turbine would be $443,663 or $4,437 per kW for Corvallis; and $415,992 or $4,160 per kW for Gresham.

4.7.9 Political and Community Impacts

Community acceptance of solar electric systems is generally high, but the high cost of PV equipment and high demand on space can be limiting factors in implementing this technology. However, PV systems can provide dependable energy independence at a very low impact to the environment, which is a positive impact for both the local and regional community. Continued technological advances, a long life span for the equipment (30+ years) and tax and cash incentives have made PV more affordable at a smaller scale.

4.7.10 Environmental Impacts

Air: Solar electric systems produce no air pollution.

Water: Solar electric systems use no water, nor do they create water pollution.

Land: Solar electric systems generally require 100 square feet of unobstructed and unshaded area per kW, and weigh 4 to 6 pounds per square foot. (Solar Oregon, accessed online May 2008). A 100 kW system would therefore require 10,000 square feet, or about one quarter acre.

Noise: Solar electric systems produce no noise pollution.

Aesthetic/Visual: Installation of a PV system on an existing roof would have minimal aesthetic affects. Siting at other locations may have some visual affect.

Waste By-Products: Solar electric systems have no generation waste by-products, but the production of PV cells results in some hazardous waste (cadmium, arsenic).

4.7.11 Greenhouse Gas Impacts

PV systems emit no greenhouse gases, and would mitigate the impacts from greenhouse gases that would otherwise be emitted by the electricity source it replaces.

The Corvallis WWRP currently purchases approximately 4,000 MWh from PacifiCorp annually. If it were to become completely energy independent with PV resources, it would mitigate approximately 7.2 million pounds of carbon dioxide per year.

The Gresham WWTP currently purchases around 3,100 MWh from PGE annually. If it were to become completely energy independent with PV resources, it would mitigate approximately 3.1 million pounds of carbon dioxide per year.

4.7.12 Operational Impacts

The impacts on the treatment plant operations and maintenance associated with a solar electric system would be minimal, and are summarized in Table 22.

Table 22: Operational Impacts of Solar Electric System

Parameter	Operational Impact
FTE / Labor	0 FTE increase (no increase in FTE needs)
Maintenance Requirements	Minor PM. Other maintenance done by vendor.
Boilers	Not applicable
Air Permit Compliance	Not applicable
Discharge Permit Compliance	Not applicable
Need for Heat	Does not generate auxiliary heat nor offset any of the facility’s heat requirements

4.8 FOG and Green Waste

4.8.1 Introduction

Fats, oils, and greases (FOG) are a significant and problematic component of domestic wastewater. There is some FOG in residential wastewater; however, the main sources are commercial and industrial wastewaters. In a typical community, restaurants are generally the largest source of FOG. FOG and green waste can create additional quantities of digester gas that can be used to create electricity.

4.8.2 History

Historically, FOG has been problematic in sewer systems and it is estimated that nearly 40 percent of all sanitary sewer overflows are related to FOG that enters the sewer system. In June 2001, Barry Newman of the Wall Street Journal, wrote "America's sewers are in a bad way. Three-quarters are so bunged up that they work at half capacity, causing 40,000 illegal spews a year into open water. Local governments already spend US$ 25 billion a year to keep the sewers running."

Most communities have adopted requirements for the installation of grease traps on laterals for restaurants and other commercial and industrial establishments that have greasy waste. The traps hold much of the waste grease and prevent it from entering the collection system. However, grease traps must be periodically emptied to remove the accumulated grease or the traps will start to pass grease into the collection system.

In 1998 the National Renewable Energy Laboratory sponsored a study titled Urban Waste Grease Resource Assessment which investigated the sources and quantities of grease in 30 metropolitan areas across the United States. The communities included in the study ranged in size from a population of 83,000 to nearly 4 million. Based on the results of this study, the average annual grease production of trap grease is 13.37 pounds per person.

The same study found that food scrap waste accounts for 12.4 percent of the total municipal solid waste that is generated in the United States. This represents over 31 million tons of food scrap waste generated in 2006. Currently, only about 2.5 percent of food waste is diverted from landfills nationwide. The majority of food waste that is diverted is used for composting, which requires large amounts of land and releases volatile organic compounds into the atmosphere.

4.8.3 Technical Description

As an alternative to landfill disposal, both grease trap waste and food scrap waste are ideal for anaerobic digestion at wastewater treatment plants, assuming there is excess digester capacity. Anaerobic digestion has been successfully used for many years to stabilize a range of organic solid wastes and provide benefits of reduced demand on landfill space and a renewable energy source in the form of methane gas.

Technically, the challenging aspects to using grease trap waste and food scrap waste are related to receiving, conditioning, and feeding the waste into the anaerobic digester. Most receiving systems will have means for transferring loads from trucks used to haul the waste and an associated containment area for spillage and odor control. This is typically followed by a heavy debris separator (rock trap), grinder or chopper pump, sludge straining device, holding tank, and metering pump system. The level of processing required can vary significantly depending on the characterization of the waste stream. It is important that the waste stream be metered into the digester to prevent upset of the biological treatment process due to over feeding. Figures 13 and 14 illustrate systems that are being used successfully to receive and digest grease trap wastes and food scrap wastes.

Figure 13: Grease Trap Waste Receiving and Anaerobic Digestion Schematic

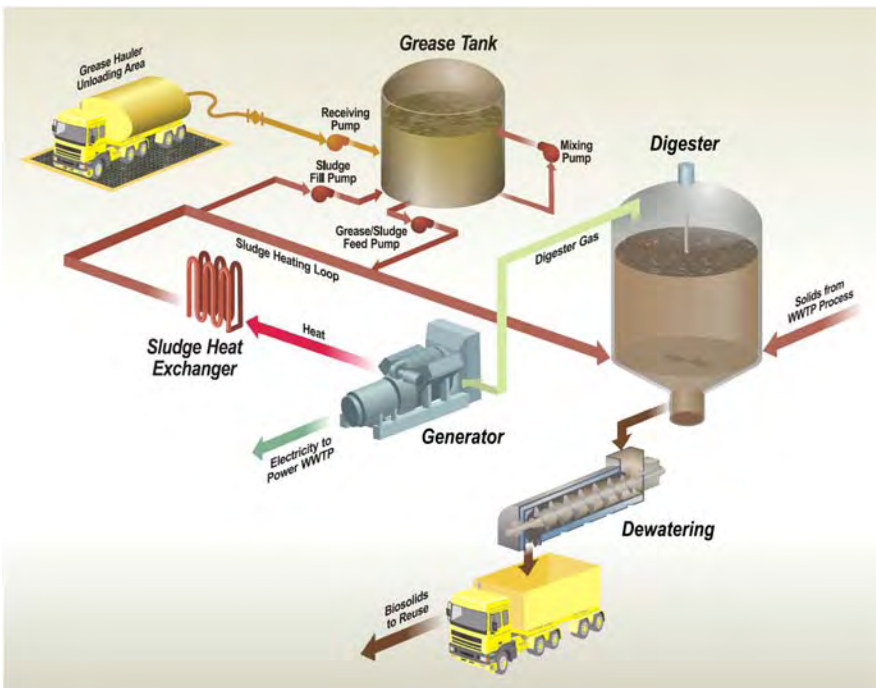
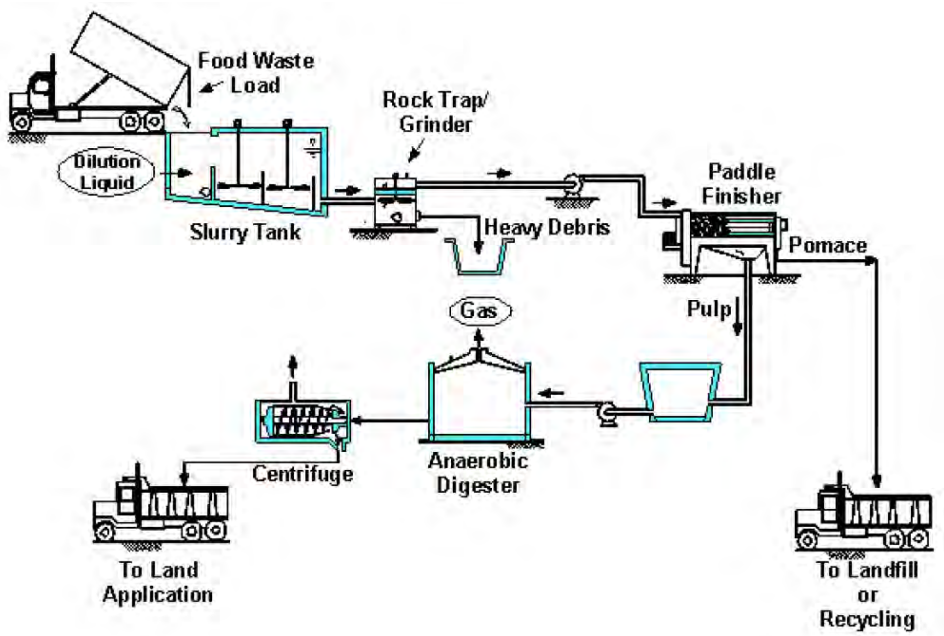


Figure 14: Food Waste Receiving and Processing Schematic



Source: March 2008 "Anaerobic Digestion of Food Waste" (EPA Funding Opportunity No. EPA-R9-WST-06-004)

4.8.4 Vendors

In general, grease trap waste and food scrap waste receiving facility designs are site specific. Land availability, waste characterization, waste hauler preferences, aesthetic concerns (visual, audible, odor related), and treatment plant configuration are some factors that are used to determine the ultimate configuration of the receiving facility.

4.8.5 Size and kWh Production

Based on operational experience at wastewater treatment plants, it is estimated that an anaerobic digester will produce roughly 13 cubic feet of digester gas for every gallon of grease trap waste received. This production estimate is made based on a grease content of 18 percent in the trap waste, 95 percent volatile content in the grease, 60 percent volatile solids destruction in the digester, and 15 cubic feet per pound of volatile solids destroyed in the digester.

Methane content in digester gas can vary, but is typically around 600 BTU per cubic foot. It is important to consider the adequacy of digester mixing before grease digestion is started since this waste stream will have a tendency to form a mat on the top of the digester if sufficient mixing energy is not available.

Based on data from a study performed by East Bay Municipal Utility District (EBMUD) titled "Anaerobic Digestion of Food Waste" dated March 2008 (EPA Funding Opportunity No. EPA-R9-WST-06-004), digester gas production from food waste can vary from 2,500 to 4,300 cubic feet of methane per wet ton of food waste. The food waste that was received at EBMUD had a total solids content of 28 percent.

It is suggested in the report that anaerobic digestion of food waste will yield more gas than municipal wastewater sludge because of higher volatile content in the food waste and higher volatile solids destruction rate associated with more biodegradable food waste. The reported volatile fraction of the food waste used in the study was 86.3 percent and the volatile destruction rate in the bench-scale digester was 73.8 percent.

A market assessment for grease trap waste and food scrap waste should be performed to determine the availability and willingness of haulers to use the facility. The market assessment typically involves a telephone survey of waste haulers in the area. In general, haulers are typically eager to use facilities at wastewater treatment plants because the treatment plants are located near to urban areas where the waste is generated. The proximity of the treatment plants to the waste sources results in less hauling time and fuel costs for the hauling companies.

As an example, assume that based on the market assessment, the wastewater treatment facility can receive one load of grease trap waste and one load of food scrap waste per day. The amount of kWh produced could be estimated as follows:

1 Grease Trap Waste Load	=	3,000 gallons		
3,000 gallons grease trap waste	x	13 CF digester gas / gallon of waste	=	39,000 CF
1 Food Scrap Waste Load	=	20 tons		
20 tons food scrap waste	x	3,400 CF / wet ton of food waste	=	68,000 CF
		Total Gas from Waste Streams	=	107,000 CF
107,000 CF Digester Gas	x	600 BTU/CF	=	642 therms
642 therms	x	29.28 kWh/therm	=	18,798 kWh
Electrical Generation Efficiency 25% (reciprocating engines)	x	18,798 kWh		4,700 kWh
Generator Availability 90%	x	4,700 kWh	=	4,230 kWh
		Daily Electrical Generation Potential	=	4,230 kWh
		Annual Electrical Generation Potential*	=	1.1 MWh

* assuming 260 working days per year

4.8.6 Potential Funding Sources

The funding incentives for installing a waste receiving facility are geared to the ultimate use of the digester gas that is produced. Energy efficiency programs could be used to help fund a digester gas driven pump or blower. Energy production incentives could be used to help fund a combined heat and power system. The improvements directly associated with waste receiving (i.e. pumps, tanks, and site improvements) are typically not eligible for incentives.

Alternative waste receiving can generate funds through tipping fees, which are charged to the haulers who use the waste receiving station. Tipping fees for grease trap waste can vary widely from $0.02 per gallon to $0.25 per gallon. Typical tipping fees for landfills that would normally take food waste range between $30 and $50 per ton. The following is an example tipping fee calculation.

1 Grease Trap Waste Load / day	=	3,000 gallons		
3,000 gallons grease trap waste / day	x	$0.10 / gallon	=	$300/day
$300 / day	x	260 days / year	=	$78,000/year
1 Food Scrap Waste Load / day	=	20 tons		
20 tons food scrap waste / day	x	$30 / ton	=	$600/day
$600 / day	x	260 days / year	=	$156,000/year
		Total Tipping Fees	=	$234,000/year

Depending on market conditions and demand for the food and grease waste, tipping fees for both grease and food waste could vary significantly.

Net metering would not apply to a FOG and Green Waste project because it does not directly generate electricity. However, the electricity created by using the digester gas created by the FOG project would be eligible.

4.8.7 Cost

Probable cost for a waste receiving station that could receive and process grease trap waste and food waste can range from $1 million to $1.5 million. In general, this would include a storage tank, metering and mixing pumps, rock-trap, food waste strainer/extruder, glass-lined ductile iron pipe, odor scrubber, waste measuring equipment, and concrete receiving area for truck unloading. The range in cost is primarily driven by above or below ground storage. Probable cost has an accuracy of plus 50 percent to minus 30 percent.

The estimated operations and maintenance cost for a waste receiving station is summarized in Table 23.

Table 23: Waste Receiving Station Estimated O&M Cost

Item	Project Cost	Utility Cost Corvallis/Gresham
Installed cost of waste receiving station	$1,000,000	
Engineering costs (10%)	$100,000	
Total installed cost:	$1,100,000	
Starting O&M costs (3% escalation) (cents/kWh)	4.00	
First year cost power (cents/kWh)	-12.07	4.63/7.21

10-Year average cost (cents/kWh)	-11.98	5.02/7.82
Levelized cost (cents/kWh)	-9.50	4.26/6.83

(For a detailed explanation of this table see Section 4.1 How To Read the Resource Assessments, on page 4-1)

Assumptions: 1 grease load (3000 gallons) and 1 food load (20 wet tons) received everyday. Cogenerator availability of 90%. Estimated O&M costs include labor power and equipment repair. Cogenerator operational costs not included here. Only costs associated with grease waste and food waste receiving are included. Project costs are based on assumption that the waste receiving tank is above ground. 20-year equipment life is assumed. Estimated tipping fees have been factored into the costs above.

With the aforementioned incentives the net capital cost after the first year of the FOG and Green Waste project cell would be $866,000.

4.8.8 Examples of FOG and Green Waste Projects

The City of Millbrae has been successfully receiving and co-digesting hauled grease waste since January of 2007. The City uses the additional digester gas to fuel a 250 kW microturbine, which can serve 80 percent of the wastewater treatment plant electrical demand. The City currently receives 3000 gallons of grease trap waste per day at their wastewater treatment plant, which has an average dry weather treatment capacity of 2 MGD.

EBMUD's main wastewater treatment plant in Emeryville, California has been successfully co-digesting food scrap waste for several years. The average annual wastewater flow to EBMUD's wastewater treatment facility is currently 80 MGD. EBMUD uses the additional digester gas to fuel their three dual-fuel engines rated at 2.15 MW each. The cogeneration plant is capable of generating 6.5 MW. During peak power production, the system can put 10 percent of the power generated back onto the utility grid. Powering the plant with biogas-generated electricity and using recovered digester heating saves EBMUD about $2,000,000 annually.

4.8.9 Political and Community Impacts

In general, FOG and food waste digestion are viewed as positive solutions to two problematic waste disposal issues. More and more communities are enacting ordinances that require restaurants and business owners to install pre-treatment devices (traps and/or interceptors) to reduce the amount of FOG that is discharged to sewers. This will result in growing demand for suitable places to dispose of the FOG waste collected by these pre-treatment devices and wastewater treatment plants are a logical receiving point for this waste.

Food waste diversion from landfills is generally viewed as a positive way to reduce volume to landfills thereby extending their lives, and recovery energy from this constant fuel supply. Collecting food waste at wastewater treatment plants also has the advantage of reducing the land that would otherwise be needed if the food waste were used for composting.

4.8.10 Environmental Impacts

Air: Impacts to air quality related to receiving and processing FOG and food waste should be minimal. The most notable impact would be potential odor emissions from the receiving area.

Both FOG and food waste can be odorous. Odor emissions can be mitigated by containing the receiving area and using equipment that minimizes the possibility of odor emissions.

Land: As compared to alternative disposal methods, receiving FOG and food waste at a wastewater treatment plant will require less land than landfill disposal or composting. Land requirement for the receiving facilities at wastewater treatment plants is relatively small (roughly 0.5 to 1.0 acre, including paved receiving area).

Water: Water usage for a waste receiving facility is typically for wash down and dilution liquid for food waste. This water can be treated effluent from the wastewater treatment plant or potable water. Impacts to surrounding surface water features should be minimal since runoff from the receiving facilities and wastewater treatment plant are typically routed back to the plant for treatment.

Noise: Noise can be a concern for the receiving station if the plant is located near to a residential community. Noise from the receiving are can be mitigated by enclosing the area or providing a sound wall. Noise on surrounding surface streets should also be considered since truck traffic will be increased. If noise on surrounding surface streets is a concern, restricted hauling times may be required.

Aesthetic/Visual: Visually the receiving area should not stand out from other industrial systems at a wastewater treatment plant. If aesthetics is an issue, equipment can be screened or enclosed.

Waste By-Products: The waste product that is generated from digestion of FOG and food waste is typically dewatered for further processing or disposal. Dewatered solids can be disposed of landfills, processed further into soil amendment, or converted into fuel (i.e. cement kiln fuel).

4.8.11 Greenhouse Gas Impacts

Adding FOG and Green Waste to digesters increases methane production, which in turn can increase electricity generation. The methane is burned, which releases greenhouse gases. Thus using FOG and Green Waste as a renewable energy source would slightly increase some greenhouse gas emissions. However, replacing the electricity purchased from a WWTP's utility provider with electricity produced by this technology would result in a reduction of greenhouse gas emissions. Assuming this technology could replace 1,100 kWh of each WWTP's current electricity needs, carbon dioxide emissions would be reduce by an estimated 1,100 pounds per year for Gresham WWTP, and 2,000 pounds per year for Corvallis WWRP. Calculations are shown in Appendix D.

4.8.12 Operational Impacts

Receiving FOG and/or green waste into the treatment plant has some operational impacts. A receiving station must be constructed and maintained. The methane gas produced must be converted into useful heat and electricity utilizing one of the methods discussed in this report. Thus the FOG/green waste option adds another process and other equipment to digester gas utilization.

The receiving station will require some maintenance and cleaning. Most have a screening system that removes large objects. The station may also have odor scrubbing equipment that will require maintenance. Additional staff labor will be required to monitor haulers, promote the FOG/green waste program, and perform periodic lab testing on samples. This labor will be in addition to that necessary for the gas to energy step. However, the added energy from the FOG and green waste most often easily offsets this extra labor. Sources of FOG and green wastes are becoming more aware of the value of this material and their options and potential revenue from this material may impact future availability to the utility – meaning more utility labor may be needed in the future to secure this material.

Managing a FOG/green waste program will require that haulers be permitted and regulated by the utility for discharge into the treatment plant. Invoicing will also add to the labor involved. There is also a risk that haulers could bring in toxic or other undesirable materials into the facility that could harm the digestion and subsequent gas making process. This risk can be mitigated either by strict manifest requirements for waste haulers and/or sampling of the waste received. Testing of the sampled waste would not be done unless there was a problem with the digester. This sampling technique has been used as an effective deterrent by other agencies that receive grease waste and septage. Samples could be held for approximately 20 days or the equivalent digester detention time, whichever is greater.

There can be odors associated with the receiving tank. Housekeeping, odor scrubbing, and consistent pumping to the digester can usually keep odors at a minimum.

Operational impacts associated with use of FOG/green waste are provided in Table 24.

Table 24: Operational Impacts of using FOG/Green Waste

Parameter	Operational Impact
FTE / Labor	0.40 FTE increase (when coupled with a gas to energy system). This assumes an automated card entry system for hauler access and monitoring.
Maintenance Requirements	Housekeeping, minor maintenance associated with screening and odor equipment.
Boilers	Not applicable with FOG /green receiving. May be required depending on gas to energy system selected.
Air Permit Compliance	Minor odor issues possible.
Discharge Permit Compliance	Not applicable
Need for Heat	May need hot water to help wash down the grease from receiving tank walls and to flush line to digester.

4.9 Resource Assessment Summary

Table 25 summarizes the detailed cost spreadsheets in Appendix H.

Table 25: Resource Assessment Summary

Resource	Unit Size (kW)	Annual kWh Production	# Units for Independence	O&M Cost (cents/kWh)	Equipment Cost ($)	Installed Total Cost ($)	1st Yr Incentive Value ($)	Net Capital Cost	1st Year Cost (cents/kWh)	10-Yr Average Cost (cents/kWh)	Levelized Cost (cents/kWh)
Fuel Cells	400	1,752,000	C=2.4 G=1.5	3.0	$1,970,000	$2,364,000	$1,481,300	$882,700	-60.84	11.06	7.87
IC Engines	385	1,349,040	C=3.0 G=1.9	3.0	$1,185,000	$1,481,250	$984,400	$496,850	-59.16	2.32	2.92
Micro-Hydro	35	291,270	n/a	0.5	$938,000	$1,172,500	$480,379	$692,121	-124.77	16.62	15.40
Micro-Hydro	5(x5)	41,610	n/a	0.5	$500,900	$626,125	$295,879	$330,246	-890.65	118.13	111.76
Microturbines	65(x2)	1,081,860	C=7.5 G=4.8	3.0	$760,000	$950,000	$586,609	$363,391	-37.74	6.86	4.88
Small Wind	10	14,838	C=272 G=173	1.0	$42,100	$62,625	$46,791	$15,834	-249.55	29.82	19.00
Small Wind	100	175,000	C=23 G=15	1.0	$400,000	$500,000	$301,947	$198,053	-127.68	23.17	16.50
Solar PV	100	105,120	C=38 G=24	1.0	$720,000	$900,000	$456,367	$443,633	-348.79	37.49	36.52
FOG & Green Waste	3000gal = 4230 kWh	1,098,504			$1,000,000	$1,100,000	$234,000	$866,000	-12.07	-11.98	-9.50
PPL									4.63	5.02	4.39
PGE									7.21	7.82	6.83

Notes: C = Corvallis, G = Gresham, Corvallis costs are reported for small wind and solar PV.

4.10 Resource Impacts Summary

The Table 25 summarizes the operational, political & community, environmental and GHG impacts of the resource options. A "+" was assigned if the resource had a positive impact with respect to a particular criterion. A "-" was assigned if the impact was negative, and a "✓" was assigned if it was neutral.

4.10.1 Environmental Impacts

The environmental impacts describe the resources impacts on the air, land, water, noise, aesthetic/visual, and if it creates waste by-products:

a. Air Impacts – the amount of air pollution created by the resource was assessed. Most options were rather benign except for the IC Engines and microturbines which directly combust the digester gas thereby creating emissions.

b. Land Impacts – the amount of land taken up by the resource was assessed. Small wind could take up a fair amount of land; and solar PV, if not confined solely to rooftops, could take up substantial amounts of land.

c. Water Impacts – the amount water consumed by the resource was assessed. Only IC Engines had a modest amount of water that was consumed.

d. Noise Impacts – how loud the resource option and its impacts on the surrounding neighbors was assessed. IC Engines were by far the loudest of all the resource options, and FOG could have noise impact from the delivery trucks.

e. Visual Aesthetic Impacts – the scale, mass, intrusion into the skyline and whether or not there was a visual emissions plume were all assessed. Small wind, because of the height of the towers could have a large visual impact. Solar PV because of the visual impact of the amount of land it would take up, and FOG because of the size of the plant and the delivery trucks had modest impacts. The water vapor plume occasionally seen from the exhaust stacks of IC Engines would also have a modest impact.

f. Waste By-product Impacts – the amount of waste by-product produced by the resource was assessed. The large amount of oil and coolant created by an IC Engines creates a modest impact. FOG of course creates a modest amount of solids after it runs through the digesters.

Table 26: Resource Impacts Summary

Resource	Ops Impacts	Political & Community Impacts	Air Impacts	Land Impacts	Water Impacts	Noise Impacts	Visual Impacts	Waste Impacts	GHG Impacts
		Environmental Impacts (✓, + -)							
Fuel Cells	✓	+	+	+	+	+	+	+	✓
IC Engines	✓	✓	-	+	✓	-	✓	✓	✓
Micro-Hydro	+	+	+	+	+	+	+	+	+
Micro-Hydro	+	+	+	+	+	+	+	+	+
Microturbines	✓	+	-	+	+	+	+	+	✓
Small Wind	+	✓	+	✓	+	+	-	+	+
Small Wind	+	✓	+	✓	+	+	-	+	+
Solar PV	+	+	+	-	+	+	✓	+	+
FOG & Green Waste	✓	+	+	+	+	✓	✓	✓	✓
PPL	+	+	✓	+	+	+	+	+	-
PGE	+	+	✓	+	+	+	+	+	-

Notes: + = positive impact, - = negative impact, ✓= neutral impact

Section 5: Recommendations

5.1 Scoring Criteria and Points

Criteria were developed in order to evaluate and compare the resources assessed in this report. The following criteria were approved by the Project Technical Advisory Committee at Meeting No. 2:

- **Cost** – How does a particular resource's cost compare to the other resource options, and to the continued purchase of utility power (i.e. – the incremental cost)?
- **Adequate Size** – How well does the per unit size of the resource option contribute to energy independence? How many units of this resource would it take to become energy independent?
- **Technological Maturity & Reliability** – has the technology been field tested to show that it is reliable, or is the technology relatively new and untested?
- **Political & Community Impacts** – How well will this resource be accepted in the political decision-making process and with the local community?
- **Environmental Impacts** – How do the air, land, water, noise, visual and waste by-products impacts of the resource compare to the other resources and continued purchase of utility power?
- **GHG Impacts** – How well do the reductions in greenhouse gases compare to the other resources and continued purchase of utility power?
- **Operational Impacts** – How does the resources' impacts on staffing, maintenance, boiler operation, air & discharge permit compliance and need for heat compare to the other resource options and continued purchase of utility power?

5.2 Scoring Matrix

Since there are seven resource assessments and seven evaluation criteria, several of which are subjective in nature, it can be difficult to do a comparison of the various options. To simplify the evaluation process the evaluation criteria were prioritized, and given a weighted score that reflects their importance to the Technical Advisory Committee as decision making criteria. The weighted scoring system assumed that there was a maximum 100 total points that each resource option could obtain. Table 27 provides the weightings for each of the evaluation criteria approved by TAC:

Table 27: Evaluation Criteria Weightings

Evaluation Criteria	Possible Points
Cost	50
Adequate Size	5
Technology Maturity & Reliability	10
Political & Community Impacts	5
Environmental Impacts	20
GHG Impacts	5
Operational Impacts	5
TOTAL =	**100**

The weighted evaluation criteria were then applied to each of the resource options; a total point score for each resource option was calculated, and each option was ranked based on their total score. Table 28 and Figure 15 represent the scoring of the seven resource options.

Even though seven renewable resource options were evaluated, the resource evaluation summary table includes nine entries. The micro-hydro and small wind renewable resources were evaluated at different sizes (5 kW vs. 35 kW for micro-hydro, and 10 kW vs.100 kW for small wind). As well, utility power from PPL and PGE were included in the analysis for purposes of comparison.

The scores for a particular evaluation criteria are based on their comparison with the other resource options. The resource option that performed the best with respect to the evaluation criterion received the maximum possible points, and the one that performed the worst received a minimum of points. For example, the costs evaluation criterion compared the levelized cost of the resource options. FOG and IC Engines had the lowest costs and therefore received the highest points (50), while micro-hydro was the most expensive and received only 10 points. The Resource Impacts Summary, Table 26, was used to assign scores to the operational, political & community, environmental and GHG impacts of the resource options. The **✓, +** and **-** were quantified by assigning weighted scores of a maximum possible points to a "+", average points for a "✓", and minimal points for a "-". For example, for criterion with a maximum of 5 points a "+" would be awarded 5 points, a "✓"3 points, and a "-"1 point. Some discretion was used to ensure scores accurately reflected relative performance of each resource. For example, it was possible to get 4 points out of 5 possible points if a resource option performance warranted that score in comparison to the other resource options.

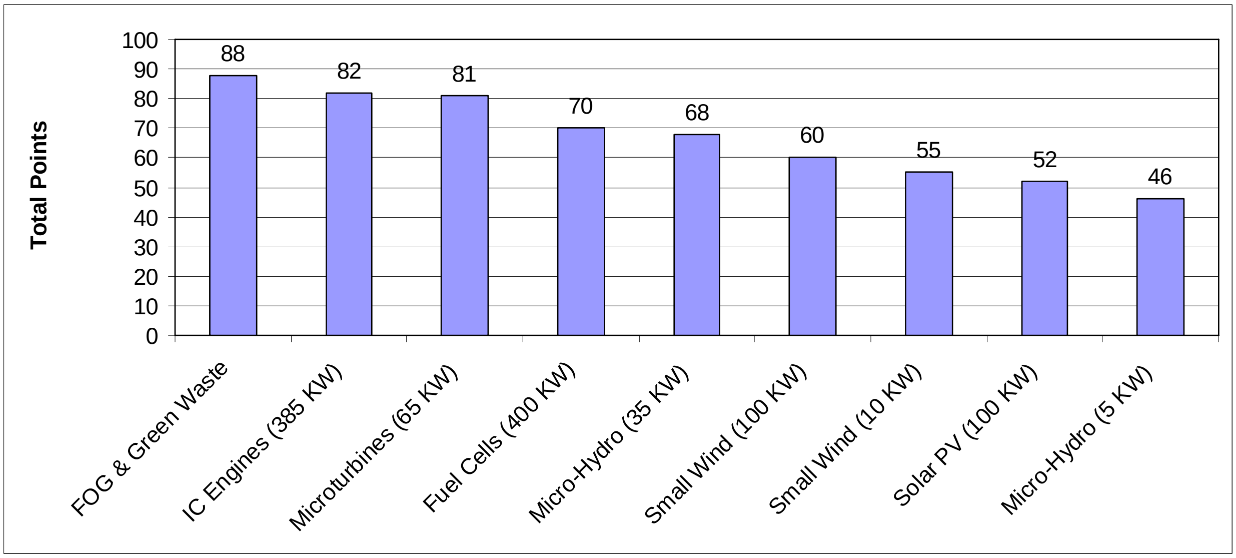
Table 28: Resource Options Ranking

Resource	Cost	Adequate Size	Tech Maturity and Reliability	Political & Community Impacts	Environmental Impacts	GHG Impacts	Operational Impacts	TOTAL	Rank
Possible Points	50	5	10	5	20	5	5	100	
Fuel Cells (400 kW)	30	4	5	5	20	3	3	70	4
IC Engines (385 kW)	50	4	9	3	10	3	3	82	2
Micro-Hydro (35 kW)	25	3	5	5	20	5	5	68	5
Micro-Hydro (5 kW)	5	1	5	5	20	5	5	46	9
Microturbines (65 kW)	45	4	6	5	15	3	3	81	3
Small Wind (10 kW)	20	3	5	3	15	5	4	55	7
Small Wind (100 kW)	25	3	5	3	15	5	4	60	6
Solar PV (100 kW)	10	3	9	5	15	5	5	52	8
FOG & Green Waste	50	4	8	5	15	3	3	88	1
PPL	45	5	10	5	18	1	5	89	
PGE	35	5	10	5	18	1	5	79	

Based on the scores shown in the Table 28, the ranking of resource options is as follows:

1. FOG & Green Waste – 88 points
2. IC Engines – 82 points
3. Microturbines – 81 points
4. Fuel Cells – 70 points
5. Micro-Hydro (35 kW) – 68 points
6. Small Wind (100 kW) – 60 points
7. Small Wind (10 kW) – 55 points
8. Solar PV – 52 points
9. Micro-Hydro (5 kW) – 46 points.

Figure 15: Graph of Resource Options Ranking



5.3 Recommendation – Gresham Wastewater Treatment Plant

Since the Gresham WWTP already uses nearly all of the available digester gas in its Caterpillar IC Engine, none of the resource options that use digester gas as a fuel (IC engines, microturbines, or fuel cells) would be available for them to become energy independent. As well, since the plant site does not appear to have a significant wind resource, small wind is also not available. To achieve energy independence the Gresham WWTP would need to rely on a combination of energy efficiency, micro-hydro and solar PV.

5.3.1 Energy Efficiency Recommendation

The first recommendation is to install the three cost-effective energy efficiency measures identified earlier in the study. The facility could also investigate the potential energy efficiency savings associated with changes to their treatment process.

5.3.2 Micro-Hydro Recommendation

Second, would be to install one of the micro-hydro 35 kW units.

5.3.3 Solar PV Recommendation

The final recommendation would be to meet the balance of the plant's energy needs (kWh) with 22 solar PV units of 100 kW each for a total of 2.2 MW, if sufficient land is available.

The summary of the renewable resource options recommended for Gresham is provided in Table 29. The estimated total net cost to become energy independent would be approximately $9.6 million.

Table 29: Gresham Recommended Renewable Resource Options

	kWh	# Units	Installed Cost $	1st Year Incentive $	Net Cost $
Gresham	3,100,800				
EEM	540,740	4	$181,425	$97,367	$84,506
Subtotal	**2,560,060**				
Micro-Hydro 35 kW	291,270	1	$1,172,500	$876,816	$295,684
Subtotal	**2,268,790**				
PV	105,120	22	$19,800,000	$10,590,074	$9,209,926
Subtotal	**-43,850**				
TOTAL					**$9,589,668**

5.4 Recommendation – Corvallis Wastewater Reclamation Plant

Since the Corvallis WWRP site does not appear to have a significant wind resource, small wind is not available to help achieve energy independence. Because of the relatively high cost of the micro-hydro option and its lowest overall score; the micro-hydro option is not recommended. The Corvallis WWRP has commendably already implemented all the cost-effective EEMs available to them. They could however, investigate potential energy efficiency savings associated with changes to their treatment process.

To achieve energy independence Corvallis WWRP would need to rely on a combination of microturbines using their existing digester gas supply and solar PV.

5.4.1 Microturbine Recommendation

The first recommendation is to install two microturbines allowing the facility to use all of the available digester gas. While IC Engines are a higher scoring and more cost-effective option; the Corvallis plant only has a limited amount of available digester gas which is insufficient to operate an IC Engine the size investigated in this report. Of the renewable options explored in this study, microturbines appear to be the most applicable for Corvallis. Two microturbines use roughly one-third the digester gas of an IC Engine, and are a better fit for Corvallis given their limited digester gas. Microturbines could be available through a lease option, such as the one offered by United Technologies Company’s subsidiary UTC Power. The advantages of such a lease would include little or no up-front cost to the city, the ability of the leasor to take advantage of tax credits and pass on some of the savings, no additional staff for O&M since that is handled by the leasor, and potentially lower costs.

As described previously, Corvallis is already operating one 43 kW demonstration Stirling engine from Stirling Biopower of Ann Arbor, Michigan. Though not included in the resource analysis for this study, the emerging Stirling engine technology appears to have promise. Stirling engines are not yet a proven technology and are in the field-testing phase of development. The performance of this demonstration unit will help determine the long-term costs and benefits of the Stirling engine compared with the full-scale renewable resource options investigated in this study. Corvallis should monitor closely the operating characteristics and cost of their demonstration unit. If it compares favorably to the microturbine, it may be a better option than the microturbine for Corvallis. Current digester gas production could operate three to four Stirling engines and provide all the hot water necessary to heat the digester and plant buildings.

The Stirling engine is an external combustion engine that burns fuel much like a boiler, common in many treatment plants. Fuel combustion occurs outside of the cylinders and the moving parts of the engine. According to the manufacturer, unlike microturbines or internal combustion engines, siloxanes do not cause catastrophic engine damage and no gas pre-treatment equipment to remove siloxane is required. Beside no pre-treatment equipment, the promise Stirling engines have is that they have fewer moving parts, low emissions, simple installation and are potentially low cost.

According to Stirling Biopower's web site: a "Stirling engine is an 'external combustion' 4-cylinder heat engine in which a fixed quantity of a gaseous working medium, such as high-pressure hydrogen, is contained and enclosed within each cylinder. A portion of the engine is maintained at a constant high temperature by burning digester gas in the combustor and transferring heat to the hydrogen via heater tubes. The other portion of the engine is maintained at a constant low temperature by circulating the hydrogen through a cooling system. The working gas is transferred back and forth between the hot and cold portions of the machine by the movement of the engine's pistons. A regenerator is used between the hot and cold portions of the engine to increase efficiency. Expansion at the hot end pushes on the top of each of the four pistons to produce power and also to compress the cold gas below each piston as part of the cycle for the adjacent cylinder. The reciprocating motion of the pistons is converted to rotary motion via a swash plate drive, which turns the generator." More information can be found at: http://www.stirlingbiopower.com/STIRLING/BASSE.swf.

5.4.2 Solar PV Recommendation

The second recommendation to allow the facility to become more energy independent would be to meet the balance of the plant's energy needs (kWh) with 28 solar PV units of 100 kW each to produce a total of 2.8 MW, if sufficient land is available. The estimated total cost to become energy independent would be approximately $12.1 million.

The summary of the renewable resource options recommended for Corvallis is provided in Table 30.

Table 30: Corvallis Recommended Renewable Resource Options

	kWh	# Units	Installed Cost $	1st Year Incentive $	Net Cost $
Corvallis	4,042,448				
Microturbine 35 kW	1,081,860	2	$950,000	$571,170	$378,830
Subtotal	**2,960,588**				
PV	105,120	28	$25,200,000	$13,478,276	$11,721,724
Subtotal	**17,228**				
TOTAL					**$12,100,554**

5.5 FOG Implementation Recommendation

This study indicates that it could be quite advantageous to a community like Gresham or Corvallis to develop a FOG and Green Waste project. Both the Corvallis and Gresham wastewater treatment plants currently have excess digester capacity for which they could use FOG and Green Waste to generate more digester gas to run one of the digester gas fueled renewable resource options (e.g., IC engines, microturbines, or fuel cells). Table 31 shows that a FOG and Green Waste project would cost about $1.1 million to process 3,000 gallons of grease and 20 tons of food scrap per day; would create approximately 107,000 CFD of digester gas, and could generate enough digester gas to run three microturbines (1.6 million kWh/year), one fuel cell at 80 percent capacity (1.4 million kWh/year), or one Caterpillar IC Engine at approximately two-thirds capacity (0.9 million kWh/year).

Serious consideration should be given to a lease option for the microturbines, such as the one offered by UTC Power. The advantages of such a lease would be no up-front cost to the city, ability of the leasor to take advantage of tax credits and pass on some of the savings, no additional staff for O&M since that is handled by the leasor, and potentially lower power costs.

Table 31: Possible Renewable Resource Options with FOG and Green Waste Project

	CFD of Digester Gas	# Units	Installed Cost $	1st Year Incentive $	Net $
FOG & GW	107,000	1	$1,100,000	$234,000	$866,000
IC Engines	162,500	0.66	$1,481,250	$984,467	$496,783
Fuel Cells	130,000	0.82	$1,481,250	$1,326,138	$155,112
Microturbines	32,500	3.29	$4,443,750	$940,234	$3,503,516

5.6 Next Steps and Future Research

This evaluation identifies great potential to meet the goal of energy independence at municipal wastewater treatment facilities. The next steps and future research elements required to approach that goal are discussed below.

5.6.1 Further Investigate Energy Use and Efficiency

During the investigation of this report it became clear that while there is sophisticated understanding about the treatment side of the wastewater business, but there is inadequate information about the energy used by wastewater treatment plants. A cooperatively funded energy use survey with potential partners from ACWA, DEQ, ODOE, and the Energy Trust could reveal the amount of energy used by Oregon facilities, how much they have already done to become more energy efficient, and how much more energy efficiency there is left to be gained from this sector. With this information a focused effort could be directed at identifying and funding energy efficiency projects at all of Oregon's wastewater treatment plants with the potential of making them more energy independent and enhancing the environment.

5.6.2 Further Investigate a FOG and Green Waste Program

This study illustrates that one of the best options available to wastewater treatment plants to become more energy independent is to institute a FOG and Green Waste program to collect unwanted waste and turn it into valuable digester gas to be used to generate electricity. An earlier study done for the Energy Trust identified at least 28 plants in Oregon that have anaerobic digesters, of which only nine currently generate electricity, meaning nineteen do not. Further investigation needs to be done on how to capture the potential energy production of a FOG program at these 28 plants. Several questions should be investigated and answered in the near-term:

- How much excess digester capacity exists?
- How could a treatment plant work cooperatively with other parts of a community to develop a community-wide FOG and Green Waste program?
- What financial and development resources would be necessary for success?
- What would be the amount of digester gas and energy that could be expected from a community-wide FOG and Green Waste program n specific communities?
- What would be the social, environmental, and financial benefits of a FOG and Green Waste program in a community?

Appendix A: Energy Efficiency Measures for Wastewater Treatment Plants

A.1 Typical Wastewater High-Use Energy Operations and Associated Potential Energy Saving Measures

High Energy Using Operations	***Energy Saving Measures***
Pumping	• Reduce load • Manage load • Water to wire efficiency • Pump selection • Motor and drive selection • Automated control
Aeration	• Fine bubble • Improved surface aerators • Premium motors • High efficiency motor drive • Blower Variable Frequency Drives (VFDs) • Automatic DO control
Dewatering	• Replace vacuum systems • Premium motors • VFDs for plant water pump
Lighting	• Motion sensors • T5 low and high bay fixtures • Pulse start metal halide • Indirect fluorescent • Super efficient T8s • Comprehensive control for large buildings
Heating, Ventilation, Air Conditioning (HVAC)	• Water source heat pumps • Energy efficient roof top units (RTUs) for heating and air conditioning • Low volume fume hood • Occupancy controls • Heat pump for generator oil sump
Compressed Air	• Fix leaks • Reduce pressure • Compressor VFD control • Refrigerated cycling dryer

(Source: Adapted from page 37 of “An Energy Management Guidebook for Wastewater and Water Utilities,” January 2008, US Environmental Protection Agency).

Below is energy savings information for typical water and wastewater equipment and systems, including motors, pumps, aeration systems, lighting, HVAC, and compressed air. (Adapted from

Appendix F of “An Energy Management Guidebook for Wastewater and Water Utilities,” January 2008, US Environmental Protection Agency).

A.2 Motors

Motors represent a major capital investment, a recurring maintenance requirement, and a significant energy demand. Proper selection and proper maintenance will help reduce energy costs and improve reliability.

Motors are often available in standard and high-efficiency models. The difference in efficiency is greater for smaller motors than for larger ones[a], although even a 1-2% difference in efficiency can make a major difference in energy cost for a large motor that is run continuously. The New England Interstate Water Pollution Control Commission recommends using high-efficiency motors in all cases except for very small motors that are used infrequently.[b] The Commission also recommends incorporating power factor correction into all designs.

The Hampton Roads Sanitation District implemented an extensive motor policy in 1996. Some of the most important elements are as follows:[c]

- Motors must meet or exceed the efficiency levels set by the Energy Policy Act of 1992;
- Efficiency is determined by test standards set by IEEE Standard 112-1984;
- Motors must be sized properly for load, with a service factor of 1.15;
- The guidelines specify 13 parameters to be noted, including horsepower, voltage, full load amps, speed, maximum starts per hour and more; and
- When deciding to repair or replace an old motor, the District will purchase a new energy-efficient motor if the simple payback period is 5 years or less, or if the cost of repair is more than 50% of the cost of a new energy efficient motor.

Proper maintenance can extend a motor’s lifetime and improve its energy efficiency. Motors should be operated as close to nameplate voltage as practical; any deviation in voltage will impair efficiency. Connections and switches on all major power-driven equipment should be checked at least once per year.[d] The major cause of motor failure is neglected maintenance of either mechanical or electrical components.

A.3 Pumps

Although aeration is typically the largest single energy demand in a WWTP, influent pumping can also be a significant demand, depending on site elevation and sewer elevation. Pumps operate nearly all the time and are often over-designed. Variable-frequency drives can improve pump efficiency.[e] Ideally, a pump would always operate at or near its Best Efficiency Point, although varying system requirements may make this impractical at times. Proper maintenance will keep a pump at or near its original design efficiency rating. Friction losses caused by piping components (such as check valves and isolation valves) can increase the energy required for pumping and have a significant impact on energy costs.[f]

A.4 Aeration Systems

Aeration is typically the largest single energy user in the treatment process,[(g)] typically ranging from 45% to 75% of the wastewater utility's total electricity consumption.[(h)] Like pumps, aeration equipment operates nearly all of the time.[(i)] Possible energy-saving measures may include any of the following:

Blowers
Variable and multiple staged single-speed blowers
Efficient, properly-sized blowers operating at or near best efficiency point
Using digester gas to fuel engine-driven blowers

Aeration System
Two-speed mechanical aerators where mechanical aeration is used
Fine bubble diffusers where diffusion aeration is used
In some cases, a combination of mechanical mixing and diffused aeration may be the most efficient

Controls
Continuous dissolved oxygen (DO) monitoring
Lowest DO concentration consistent with stable operation and treatment objectives
Automatically controlled variable air flow based on oxygen demand

The type of aeration impacts the energy demand. Energy Conservation in Wastewater Treatment Facilities, Manual of Practice No. MFD-2 from the Water Environment Federation, includes a number of case studies on fine-pore diffusers. In general, the system improves Oxygen Transfer Efficiency (OTE), and often shows a significant economic advantage. A few examples are highlighted below:

- Glastonbury, CT switched from coarse-bubble diffusers to fine-pore diffusers. OTE improved from 4-4.5% to 6.5-7%. Blower energy savings resulted in a simple payback period of approximately 2 years, although this calculation does not include increased cleaning cost.

- Hartford, CT switched from a coarse-bubble spiral roll system to a fine-pore dome diffuser system, improving OTE from 4.4% to 10%. Operating savings of $200,000 per year resulted in a simple payback period of less than 3 years.

- Ridgewood, NJ switched from a coarse-bubble aeration system to a dome fine-pore aeration system, improving OTE from 4.8% to 9.5%. The facility saw a 30% decrease in blower energy use (saving about 30 MWh per month), but increased maintenance resulted in the simple payback period being approximately 10 to 11 years.

In some cases, increased cleaning and maintenance costs extended the time required for fine-pore diffusers to repay their cost in energy savings; in other cases, cleaning costs had relatively little effect. Control systems are particularly important. An accurate aeration control system can reduce plant energy consumption by as much as 25%, for a system payback of less than three years.[j] Such a system requires accurate mass flow meters and dissolved oxygen sensors. Control systems can continuously and automatically adjust the air consumption to the optimal required amount, thereby reducing the demand on blower motors.

A.5 Lighting

Lighting is a major category of energy consumption for commercial buildings. It is not as significant for industrial facilities– and a wastewater treatment plant is essentially an industrial facility – but it remains one of the energy costs most easily addressed. Fluorescent bulb technology has continued to improve, offering higher-quality lighting at lower energy demand than previous versions; if a facility has old fluorescent lights, newer versions can improve the work environment and reduce energy costs. There exists a wealth of resources for information on energy-efficient lighting options, such as ENERGY STAR's Building Upgrade Manual.[k] Lights that are on for most of the workday are the best candidates for replacement with new energy-efficient models. For more intermittent loads, occupancy sensors may be a wise choice. These controls will switch off lights in unoccupied rooms after a period of time, automatically turning them on again if a person enters the room. Suitable areas might include warehouses, storage rooms, restrooms, small offices, lunch, copy, and utility rooms.[l]

A.6 Heating, Ventilation, and Air Conditioning

Heating, ventilation, and air conditioning (HVAC) are similar to lighting in that they are not as relatively important in energy consumption for WWTPs as they are for typical commercial facilities, but they are still a significant energy usage that can be managed effectively.

Because HVAC is such a major energy user for commercial facilities, there are many resources and many contractors able to improve the energy efficiency of a building's HVAC system. Improving insulation, sealing leaks, properly sizing the system, and selecting an energy-efficient system (such as a ground-source heat pump) can help reduce energy costs and provide a good return on investment.

A.7 Compressed Air

Compressed air for operation of diaphragm pumps, valve actuators, instrumentation, and other uses can consume significant amounts of energy for air compression and drying. To use energy efficiently in this area:

- Set the compressor control to produce air pressure no higher than needed to operate equipment requiring compressed air.
- Check air lines regularly and fix leaks immediately.
- Consider a variable speed drive for the compressor rather than throttling compressor output.

Consider a cycling air dryer, which operates only when drying is needed, rather than a dryer which runs continuously.

A.8 Notes

(a) Water Environment Federation (1997), Energy Conservation in Wastewater Treatment Facilities, Manual of Practice No. MFD-2, Alexandria, VA, 1997.

(b) New England Interstate Water Pollution Control Commission (1998), Guides for the Design of Wastewater Treatment Works, Technical Report #16.

(c) Water Environment Research Foundation (1999), Improving Wastewater Treatment Plant Operations Efficiency and Effectiveness, Project 97-CTS-1.

(d) Water Environment Federation (1997), Energy Conservation in Wastewater Treatment Facilities, Manual of Practice No. MFD-2, Alexandria, VA, 1997.

(e) Maine Department of Environmental Protection (2002), Bureau of Land & Water Quality, O&M Newsletter, February 2002.

(f) J. Oliver and C. Putnam (1997), "Energy Efficiency: Learning How to Avoid Taking a Bath on Energy Costs," WATER/Engineering and Management, July 1997.

(g) New England Interstate Water Pollution Control Commission (1998), Guides for the Design of Wastewater Treatment Works, Technical Report #16.

(h) EPRI Industrial Program (1993), "Energy-Efficient Aeration Systems for Wastewater Treatment," Environment & Energy Management, Vol. 1, No. 3; WEF's 1997 Manual of Practice cites a very similar figure of 40-70% for activated-sludge WWTP facilities.

(i) Maine Department of Environmental Protection (2002), Bureau of Land & Water Quality, O&M Newsletter, February 2002.

(j) C. Hewitt (1996), "Programmable Aeration Control System Reduces Plant Energy Costs," WATER/Engineering and Management, May 1996.

(k) U.S. Environmental Protection Agency (2004), ENERGY STAR Building Upgrade Manual, online at http://www.energystar.gov/ia/business/BUM.pdf. The section on lighting begins on page 48.

(l) J. Null and J. Hoggard.

Gresham WWTP Electricity Data [a]

Billing Month	PGE kWh used	PGE Demand, KW	On-Peak Demand, KW	kWh Produced, Cogen	kWh Total Plant	Calculated PGE Demand Charge [b]	Calculated PGE Energy Charge [b]	Calculated PGE Total Charge [b]
Jan-07	302,400	717	510	289,970	592,370	$3,672	$17,294	$21,056
Feb-07	220,800	782	769	242,249	463,049	$3,859	$12,628	$16,577
Mar-07	240,000	648	639	283,124	523,124	$3,474	$13,726	$17,289
Apr-07	220,800	739	739	273,500	494,300	$3,736	$12,628	$16,453
May-07	211,200	769	769	281,872	493,072	$3,822	$12,079	$15,991
Jun-07	249,600	981	713	218,359	467,959	$4,433	$14,275	$18,797
Jul-07	302,400	747	747	251,345	553,745	$3,759	$17,294	$21,143
Aug-07	302,400	795	795	264,099	566,499	$3,897	$17,294	$21,281
Sep-07	283,200	700	700	256,060	539,260	$3,623	$16,196	$19,909
Oct-07	278,400	747	747	264,717	543,117	$3,759	$15,922	$19,770
Nov-07	249,600	730	730	275,623	525,223	$3,710	$14,275	$18,074
Dec-07	240,000	678	670	278,095	518,095	$3,560	$13,726	$17,376
Total	3,100,800			3,179,013	6,279,813	$45,302	$177,335	$223,717

Notes:

(a) Electricity use data provided by Gresham WWTP.

(b) Electricity Costs calculated using PGE Price Summary for Schedule 83-P, effective January 17, 2007, accessed online May 2008 at http://www.portlandgeneral.com//about_pge/regulatory_affairs/pdfs/archive_price_summary/2007_Q2b/standard_service_schedules.pdf.

Basic Charge (included in total, 3-phase assumed): $90.

Demand Charge: $2.88/kW

Abbreviations:

kW = Kilowatts
kWh = Kilowatt-hours
MGD = Million gallons per day
PGE = Portland General Electric
WWTP = Wastewater treatment plant

Corvallis WWTP Electricity Data [(a)]

Billing Month	Days in Billing period	Total kWh	Max Demand kW	Max Reactive Demand kVAR	Total On-Peak Energy kWh	Max On-Peak Demand kW	Total Off-Peak Energy kWh	Max Off-Peak Demand kW	Calculated PP&L Demand Charge [(b)] $	Calculated PP&L Energy Charge [(b)] $	Calculated PP&L Total Charge [(b)] $
Jan-07	31	393,744	1064	521.6	230,111	1045	163,633	1064	$4,060	$14,019	$18,662
Feb-07	28	388,902	1203.2	558.4	227,540	1203	161,362	1099	$4,656	$13,847	$19,108
Mar-07	31	347,524	802.4	489.6	203,734	802.4	143,790	706.4	$3,105	$12,374	$16,043
Apr-07	30	327,389	701.6	477.6	183,948	658.4	143,440	701.6	$2,585	$11,649	$14,790
May-07	31	330,913	629.6	484.8	193,971	627.2	136,941	629.6	$2,429	$11,783	$14,773
Jun-07	30	312,262	600	438.4	182,257	600	130,005	479.2	$2,322	$11,118	$13,973
Jul-07	31	319,709	536	450.4	180,186	536	139,523	481.6	$2,074	$11,376	$13,991
Aug-07	31	296,725	638.4	440	177,571	546.4	119,154	638.4	$2,193	$10,569	$13,296
Sep-07	30	296,040	708.8	400	164,548	516.8	131,492	708.8	$2,163	$10,532	$13,205
Oct-07	31	305,898	1024.8	470.4	178,551	716	126,970	1025	$3,033	$10,878	$14,464
Nov-07	30	308,488	1004.8	484.8	177,461	742.4	131,027	1005	$3,096	$10,981	$14,638
Dec-07	31	414,854	1223.2	520	232,350	1223	182,504	976.8	$4,733	$14,761	$20,076
Total	365.00	4,042,448							$36,450	$143,885	$187,017

Notes:

(a) Electricity use data provided by Corvallis WWTP.

(b) Electricity Costs calculated based on actual electricity use, using Pacific Power Price Summary for Schedule 48-P, effective April 17, 2008, accessed online May 2008 at http://www.pacificpower.net/File/File49907.pdf.

Basic Charge (included in Total Charge): $270/month
Facility Capacity Charge (included in Demand Charge)**:** $0.85/kW
On-Peak Demand Charge (included in Demand Charge)**:** $3.02/kW
Energy Charge, On-Peak (included in Energy Charge)**:** $0.03602/kWh
Energy Charge, Off-Peak (included in Energy Charge)**:** $0.03502/kWh
Reactive Power (included in Total Charge): $0.60/kVar

Abbreviations:

kVAR = Kilo-volt-ampere reactive power
kW = Kilowatts
kWh = Kilowatt-hours
MGD = Million gallons per day
PP&L = Pacific Power and Light
WWTP = Wastewater treatment plant

Appendix C: Incentives and Tax Credits

The Energy Trust of Oregon, the State of Oregon, and the federal government provide financial incentives for improving energy efficiency and creating new renewable energy projects. An overview of these programs which may apply to Oregon wastewater treatment plants is provided below. In addition to these incentives, low-interest loans and grant programs may also be available to assist with the financing of projects.

C.1 Energy Trust of Oregon Incentives

The Energy Trust of Oregon is a nonprofit organization which receives funds from PGE and Pacific Power, in part to encourage energy market transformation in Oregon. Because its programs are funded by the two major utilities in Oregon, projects must typically either be inside the Oregon service territories of PGE or Pacific Power, or, if they are outside those territories, the project must deliver its power to PGE or Pacific Power for the benefit of their Oregon customers. The Energy Trust website provides details on their incentive programs: http://www.energytrust.org/index.html. The sections below are excerpts from their website describing specific programs.

The Energy Trust of Oregon (Energy Trust) may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. The table below provides an estimate of the above market cost for the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. The Energy Trust will either disburse its incentives over time or as a lump sum. We assumed the incentive was paid as a lump sum in the first year. The Energy Trust incentives can vary widely from project-to-project and the Energy Trust focuses on investing in the most cost-effective technology for the application.

Funding a project entitles the Energy Trust to a share of the project's green tags. As described on their website, "Green tags are a tradable financial instrument that represents the environmental attribute of electricity generated from renewable resources." The share of green tags belonging to the Energy Trust is contingent upon the amount of funding they provide relative to the above-market costs of the project, and the market value for green tags.

C.1.1 Lighting

The Energy Trust provides both custom and standard cash incentives for retrofit lighting projects which have a simple payback of at least one year. Custom incentives are available for $0.15 per annual kWh up to 30 percent of eligible project cost (whichever is less). Standard incentives range from $2 to $75 per lighting fixture, with a minimum incentive of $100 per project. Lighting upgrades must provide at least 25 percent energy savings compared to the existing system, and the maximum lighting incentive is $0.15 per kWh saved. More information is available at: http://www.energytrust.org/buildingefficiency/forms/BE_PI0190L.pdf.

C.1.2 Motors

The Energy Trust pays a cash incentive for motor upgrades of $10 per horsepower for NEMA premium motors of 200 hp or less. Custom incentives are also available. (http://www.energytrust.org/buildingefficiency/forms/BE_PI0191M.pdf).

C.1.3 Process Equipment

For custom wastewater process or production equipment projects, the Energy Trust will pay up to $0.32 per annual kWh saved or 50 percent of eligible project costs, whichever is less. The simple payback minimum decreased from 18 months to 12 months to be consistent with BETC and other Energy Trust programs. Projects with incentive offers signed June 1, 2008 or later and completed by December 31, 2008 have a cap of 60% of project cost. (http://www.energytrust.org/pe/water.html).

C.1.4 HVAC

The Energy Trust pays a cash incentive ranging from $120 to $495 for air conditioning upgrades (http://www.energytrust.org/buildingefficiency/forms/BE_PI0192H.pdf).

C.1.5 Other Energy Efficiency Measures

Additional energy efficiency measures my be eligible for custom incentives of up to 35 percent of the incremental cost between standard and high-efficiency equipment, not to exceed 20¢ per annual kWh saved and $1.00 per therm saved.

C.1.6 Solar

The Energy Trust provides incentives for installing grid-tied or net metered new solar electric systems. Incentives are based on the rated power capacity of the solar array in watts, as follows:

For systems under 30,000 watts (<30 kW):

- Pacific Power customers: $1.75/watt up to $150,000
- PGE customers: $2.00/watt up to $175,000.

For systems over 30,000 watts (>30 kW):

- Pacific Power customers: $1.50 to $1.75 /watt up to $150,000
- PGE customers: $1.75 to $2.00 /watt up to $175,000.

A municipal WWTP may purchase a solar electric system for net metering, forgoing federal tax incentives; or allow a third party to install, own and operate the system, and purchase the electricity from the third party, allowing federal tax incentives to be claimed (by the third party). More information is available at http://www.energytrust.org/solar/commercial/nonp_gov.php.

C.1.7 Small Wind

The Energy Trust provides rebates for installing small wind turbines up to 50 kilowatts. The incentive amounts to the lesser of $3,750 per meter of rotor diameter, or $4,000 per rated kilowatts of the wind turbine up to 50 kW, or $60,000. A number of restrictions apply to the qualifying projects, including a minimum tower height of 60 feet, and a project site of at least one acre with annual average wind speeds of at least 10 miles per hour.

The system must be installed by a Trade Ally contractor, and the buy-down incentive is paid to the contractor and deducted from the final cost. More information is available at http://www.energytrust.org/RR/wind/small/index.html.

The Wind program also provides financial support for small wind projects larger than 50 kilowatts that generate electricity for PGE or Pacific Power customers in Oregon. Energy Trust may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. More information is available at: http://www.energytrust.org/RR/wind/community/incentives.html.

C.1.8 Fuel Cells

The Energy Trust does not have an incentive program specifically for fuel cells, but fuel cells which use biogas to produce electricity, such as biogas produced from the wastewater treatment process, would fall under the Biopower incentive program described below.

C.1.9 Microturbines

The Energy Trust does not have an incentive program specifically for microturbines, but microturbines which use biogas to produce electricity, such as biogas produced from the wastewater treatment process, would fall under the Biopower incentive program described below.

C.1.10 Micro-Hydro

The Energy Trust does not have an incentive program specifically for micro-hydro technology, but micro-hydro as it is used in wastewater treatment plants may fall under the Open Solicitation incentive program described below.

C.1.11 Biopower

The Biopower program provides financial support for new biomass projects that generates electricity for PGE or Pacific Power customers in Oregon. Eligible projects use several types of organic material, including municipal wastewater digester gas. Eligible technologies may include fuel cells and microturbines.

Energy Trust may fund all or a portion of the above-market costs of a project, defined generally as the difference between wholesale or retail electricity prices, and the cost of electricity generated by the project. There is no fixed percentage for the amount of the above-market costs Energy Trust will pay. Each project is unique and incentives are based on many factors. More information is available at: http://www.energytrust.org/RR/bio/incentives.html.

C.1.12 Open Solicitation Program

The Energy Trust also provides an Open Solicitation program, which is designed to support renewable energy projects that are not eligible for other Energy Trust renewable energy programs. There is no funding cap for projects, but the projected program budget of $1.5 million is expected to fund 4-6 projects. As with other Energy Trust programs, the incentive covers above-market costs of the project, but there is no fixed percentage of these costs that are covered. More information is available at: http://www.energytrust.org/RR/os/index.html.

C.2 State of Oregon Incentives

C.2.1 Business Energy Tax Credit Program

The State of Oregon offers the Business Energy Tax Credit (BETC) for investments in energy efficiency, recycling, and renewable energy resources. The tax credit is 50 percent of the eligible costs for:

- High Efficiency Combined Heat and Power
- Renewable Energy Resource Generation
- Renewable Energy Resource Equipment Manufacturing Facilities.

For other projects BETC is 35 percent of eligible costs. The eligible costs are the incremental cost of the system of equipment that is beyond standard practice. The tax credit can cover all costs directly related to the project, including equipment cost, engineering and design fees, materials, supplies and installation costs. Loan fees and permit costs also may be claimed. For the 50 percent tax credit it is taken over five years at 10 percent per year; for the 35 percent tax credit it is taken 10 percent for the first two years and 5 percent for the remaining 3 years. Those with eligible project costs of $20,000 or less may take the tax credit in one year.

The tax credit must be applied before the project begins. The application fee is 0.6 percent of the estimated system cost up to $35,000. There is a pass-through option which allows a project owner to transfer the tax credit to a pass-through partner in return for a lump-sum cash payment upon completion of the project. When the pass-through option is used, the pass-through partner pays the project owner a lump-sum payment calculated using the pass-through rate. The pass-through rate takes into account the value of the money over time and other factors. The Oregon Department of Energy reviews and sets the pass-through rate. The pass-through rate used is the rate in effect at the time the Oregon Department of Energy receives the Pass-through Agreement. More information is available at the Oregon Department of Energy website: http://egov.oregon.gov/ENERGY/CONS/BUS/BETC.shtml.

C.2.2 Net Metering

Oregon has established a net-metering law for PGE and PacifiCorp which allows their customers to produce a portion of their own electricity and offset the electricity purchased from the utility. Net metering keeps track of both electricity consumed from the utility, and electricity produced by the facility and sent back to the grid. A customer only pays for the net amount of electricity consumed from the utility. Net metering does not exclude a facility from benefiting from other incentives, such as the Energy Trust incentives or tax credits. Eligible facilities for net metering are those producing 2 MW of electricity or less. More information is available at: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=OR03R&state=OR&CurrentPageID=1.

C.2.3 Biomass Producer or Collector Tax Credits

Producers or collectors of Oregon sourced biomass or energy crops, used for energy production in Oregon, are eligible for tax credit incentives based upon the volume of production or collection.

Credits include, but are not limited to, the following biomass sources:

- Used cooking oil or waste grease, $0.10 per gallon
- Wastewater biosolids, $10.00 per wet ton
- Yard debris and municipally generated food waste, $5.00 per wet ton.

Under these rules, both FOG and Green Waste would be eligible. Use of wastewater treatment biosolids cake or sludge as a boiler or gassifier fuel is eligible, and use in a secondary digester for either gas recovery or fuel is also eligible. Biosolids as a soil amendment is not eligible.

The applicant must be the producer or collector of the biomass in Oregon that is delivered to a bioenergy facility in Oregon for use as a energy fuel. The producer or collector also can be an Oregon non-profit organization, tribe, or public entity that partners with an Oregon business or resident who has an Oregon tax liability.

More information is available at the following Oregon Department of Energy website: http://www.oregon.gov/ENERGY/RENEW/Biomass/TaxCdt_2210.shtml

C.2.4 Renewable Energy Systems Property Tax Exemption

Renewable energy systems in Oregon qualify for a property tax exemption. The added value to any property from the installation of a qualifying renewable energy system may not be included in the assessment of the property's value for property tax purposes. Qualifying renewables include solar, geothermal, wind, water, fuel cell, or methane gas systems for the purpose of heating, cooling, or generating electricity. This exemption is intended for end users and does not apply to property owned by anyone directly or indirectly involved in the energy industry. Since municipal wastewater treatment plants do not pay property taxes they would not be eligible for this tax credit; however, should the renewables project be developed by a third-party on private property near-by that project may qualify. More information is available at: http://egov.oregon.gov/ENERGY/RENEW/Solar/Support.shtml.

C.3 Federal Incentives

Most of the Federal incentives for renewable energy and energy efficiency may not apply directly to a wastewater treatment plant, but if a third party private ownership option is chosen for new projects federal tax incentives could apply. This is common with the development of solar electric systems. The federal government does not have a pass-through-like program for tax-exempt entities like municipal wastewater treatment plants. Descriptions of the federal Incentives below are excerpts from the Database of State Incentives for Renewables and Efficiency (DSIRE), funded by the U.S. Department of Energy and accessed via the following website: http://www.dsireusa.org/.

C.3.1 Energy Efficient Commercial Buildings Tax Deduction

A tax deduction of $1.80 per square foot is available to owners of new or existing buildings who install (1) interior lighting; (2) building envelope, or (3) heating, cooling, ventilation, or hot water systems that reduce the building's total energy and power cost by 50 percent or more in comparison to a building meeting minimum requirements set by ASHRAE Standard 90.1-2001. Energy savings must be calculated using qualified computer software approved by the IRS.

Deductions of $0.60 per square foot are available to owners of buildings in which individual lighting, building envelope, or heating and cooling systems meet target levels that would reasonably contribute to an overall building savings of 50 percent if additional systems were installed. The deductions are available primarily to building owners, although tenants may be eligible if they make construction expenditures. In the case of energy efficient systems installed on or in government property, tax deductions will be given to the person primarily responsible for the systems' design. Deductions are taken in the year when construction is completed. For more information, visit the Energy Star Web site at:
http://www.energystar.gov/index.cfm?c=products.pr_tax_credits#7

C.3.2 Federal Business Energy Tax Credit

The Federal BETC contains a 30 percent tax credit designed to be taken in the tax year of system start-up. Unlike the Oregon BETC, which runs over 5 years, this is a single, one-time deduction. Also unlike the Oregon BETC, the pass-through option is not available; the credit must be used by the system owner.

For eligible equipment installed from January 1, 2006, through December 31, 2008, the credit is set at 30 percent of expenditures for solar technologies, fuel cells, and solar hybrid lighting; microturbines are eligible for a 10 percent credit during this two-year period. For equipment installed on or after January 1, 2009, the tax credit for solar energy property and solar hybrid lighting reverts to 10 percent and expires for fuel cells and microturbines. The geothermal credit remains unchanged at 10 percent.

The credit for fuel cells is capped at $500 per 0.5 kilowatt of capacity. The maximum microturbine credit is $200 per kW of capacity. No maximum is specified for the other technologies, which include Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Geothermal Electric, Solar Hybrid Lighting, and Direct Use Geothermal. More information on this tax credit can be found at:

http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US02F&State=federal&currentpageid=1&ee=1&re=1

C.3.3 Renewable Electricity Production Tax Credit

The Renewable Electricity Production Credit (PTC) is a per kilowatt-hour tax credit for electricity generated by the following qualified energy resources:

- Wind
- Closed-loop biomass
- Open-loop biomass
- Geothermal energy
- Small irrigation power (150 kW to 5 MW)
- Municipal solid waste
- Landfill gas
- Refined coal
- Hydropower
- Indian coal.

The PTC provides a tax credit of 1.5¢/kWh (in 1993 dollars and indexed for inflation) for wind, closed-loop biomass (the use of crops grown specifically for energy production), and geothermal. Currently, the PTC for these technologies is 2.0¢/kWh. Electricity from open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources, which include digester gas, and hydropower receive half that rate -- currently 1.0¢/kWh.

The duration of the credit is 10 years. However, open-loop biomass, geothermal, small irrigation hydro, landfill gas, and municipal solid waste combustion facilities placed into service after 22 October 2004, and before enactment of EPAct 2005, on 8 August 2005, are eligible for the credit for a five-year period. Owners of geothermal projects who claim the federal business energy tax credit may not also claim the PTC. More information is available at: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US13F&State=federal&currentpageid=1&ee=1&re=1

C.3.4 Accelerated Depreciation

Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. For solar, wind and geothermal property placed in service after 1986, the current MACRS property class is five years. For certain biomass property, the MACRS property class life is seven years. Eligible biomass property generally includes assets used in the conversion of biomass to heat or to a solid, liquid or gaseous fuel, and to equipment and structures used to receive, handle, collect and process biomass in a water wall (using tubes of water to control heat transfer), combustion system, or refuse-derived fuel system to create hot water, gas, steam and electricity. The federal Energy Policy Act of 2005 (EPAct 2005) classified fuel cells, microturbines, and solar hybrid lighting technologies as 5-year property as well.

The federal Economic Stimulus Act of 2008, enacted in February 2008, included a 50 percent bonus depreciation provision for eligible renewable-energy systems acquired and placed in service in 2008. To qualify for bonus depreciation, a project must satisfy these criteria:

- The property must have a recovery period of 20 years or less under normal federal tax depreciation rules;
- The original use of the property must commence with the taxpayer claiming the deduction;
- The property generally must be acquired during 2008; and
- The property must be placed in service during 2008 (or, in certain limited cases, in 2009).

If property meets these requirements, the owner is entitled to deduct 50 percent of the adjusted basis of the property in 2008. The remaining 50 percent of the adjusted basis of the property is depreciated over the ordinary depreciation schedule. The bonus depreciation rules do not override the depreciation limit applicable to projects qualifying for the federal business energy tax credit. Before calculating depreciation for such a project, including any bonus depreciation, the adjusted basis of the project must be reduced by one-half of the amount of the energy credit for which the project qualifies.

More information on the federal MACRS can be found by following the links on the following website:

http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US06F&State=federal&currentpageid=1&ee=1&re=1.

C.3.5 Renewable Energy Production Incentive (REPI)

The Federal Renewable Energy Production Incentive (REPI) provides incentive payments for electricity produced and sold by new qualifying renewable energy facilities, specifically Tribal Governments, Municipal Utilities, Rural Electric Cooperatives, and State/local governments that sell a project's electricity. The production payment applies only to the electricity sold to another entity. Qualifying systems must generate electricity using solar, wind, geothermal (with certain restrictions), biomass, landfill gas, livestock methane, or ocean (including tidal, wave, current, and thermal) generation technologies. Fuel cells using hydrogen derived from eligible biomass facilities are also eligible, but combustion of municipal solid waste is not. Qualifying systems are eligible for annual incentive payments of 1.5¢ per kilowatt-hour (in 1993 dollars and indexed for inflation) for the first 10-year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation. If there are insufficient appropriations to make full payments for electricity production from all qualified systems for a federal fiscal year, 60 percent of appropriated funds will be assigned to facilities that use solar, wind, ocean (including tidal, wave, current and thermal), geothermal or closed-loop biomass technologies; and 40 percent of appropriated funds for the fiscal year will be assigned to other projects (which includes digester gas). The current appropriation is at approximately $5 million total, with close to $100 million in application submittals, leaving a significant shortfall in funding for this incentive. More information is available at: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US33F&State=Federal&currentpageid=1.

C.3.6 Clean Renewable Energy Bonds (CREBs)

Clean Renewable Energy Bonds (CREBs) are a financing mechanism for public sector renewable energy projects. CREBs are bonds issued with a 0 percent interest rate. CREBs may be issued by electric cooperatives, government entities (states, cities, counties, territories, Indian tribal government, or any political subdivision thereof), and certain lenders. Of the $1.2 billion total of tax-credit bond volume cap allocated to fund renewable-energy projects, state and local government borrowers are limited to $750 million of the volume cap, with the rest reserved for qualified mutual or cooperative electric companies.

The borrower pays back only the principal of the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest. Tax credit funds are allocated by the U.S. Treasury Department. The tax credit rate is set daily by the U.S. Treasury Department and may be taken quarterly on a dollar-for-dollar basis to offset the tax liability of the bondholder.

CREBs differ from traditional tax-exempt bonds in that the tax credits issued through CREBs are treated as taxable income for the bondholder. The tax credit may be taken each year the bondholder has a tax liability as long as the credit amount does not exceed the limits established by EPAct 2005. More information is available at: http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=US45F&Search=TableType&type=Loan&CurrentPageID=7&EE=1&RE=0

Appendix D: GHG Emission Factors

D.1 PGE

2007 PGE Mix ($lbs\ of\ CO_2/MWh$)
995

Source: Email communication Philip H. Carver of Oregon Department of Energy, 29 May 2008.

D.2 PPL

2006 PacifiCorp Oregon Mix ($lbs\ of\ CO_2/MWh$)
1,783

Source: Email communication Philip H. Carver of Oregon Department of Energy, 29 May 2008.

Estimated 2007 Carbon Dioxide Emissions from Purchased Electricity

	Purchased Electricity (kWh)	Estimated CO2 emissions (lbs/yr)
Gresham WWTP	3,100,800	3,084,676
Corvallis WWTP	4,042,448	7,207,685

Carbon Dioxide Emissions Reductions from Implementation of Renewable Resource Technologies

	Reduction in Purchased Electricity, kWh/yr		Additional CO2 Emissions resulting from Renewable Resource Technology[(a)], lbs per year		Estimated CO2 Reduction[(b)], lbs per year	
Renewable Resource	**Gresham WWTP**	**Corvallis WWTP**	**Gresham WWTP**	**Corvallis WWTP**	**Gresham WWTP**	**Corvallis WWTP**
FOG & GREEN WASTE[c]	1,100	1,100	0	0	1,094	1,961
FUEL CELL[d]	2,635,680	3,436,081	0	0	2,621,974	6,126,532
IC ENGINE[e]	2,480,640	3,233,958	0	0	2,467,741	5,766,148
MICRO-HYDRO[f]	290,000	290,000	0	0	288,492	517,070
MICRO-TURBINE[g]	1,100,000	1,100,000	0	0	1,094,280	1,961,300
SMALL WIND[h]	3,100,800	4,042,448	0	0	3,084,676	7,207,685
SOLAR[h]	3,100,800	4,042,448	0	0	3,084,676	7,207,685

Notes:

(a) Assumes methane would be flared if it were not used as a renewable resource, so there is no net change in CO2 emissions.

(b) Gresham WWTP's electric utility is PGE; Corvallis WWTP's electric utility is Pacific Power and Light (PacifiCorp). 2007 electricity consumption data used in calculations.

Assumes PGE emissions factor of	995	lbs CO2/MWh
Assumes PacifiCorp emissions factor of	1783	lbs CO2/MWh

Emissions factors received from email communication with Philip H Carver of Oregon Department of Energy, 29 May 2008.

c) FOG resource scenario assumes 1.1 MWh/yr electricity generation.

d) Assumes Fuel Cells may replace 85% of current WWTP purchased electricity.

e) Assumes IC Engines may replace 80% of current WWTP purchased electricity. Does not incorporate non-CO2 emissions from this resource technology.

f) Micro-hydro resource scenario assumes 290,000 kWh/yr electricity generation.

g) Micro-turbine resource scenario assumes 1,100,000 kWh/yr electricity generation.

h) Small Wind and Solar assume full replacement of purchased electricity.

Appendix E: TAC Meeting No. 1

E.1 Summary

Energy Independence Project
Technical Advisory Committee
20 March 08
Salem, Oregon

Meeting Summary

Attending:

- Erin Johnston, Energy Trust of Oregon
- Elaine Prause, Energy Trust of Oregon
- Mike Nacrelli, City of Gresham
- Jim Hill, City of Medford
- Darrell McLaughlin, City of Lebanon
- Guy Graham, City of Gresham
- Alan Zelenka, Kennedy/Jenks
- Janet Gillaspie, ACWA

There were no revisions to the agenda.

Project Approach and Schedule

Zelenka reviewed the project approach and schedule.

Regarding the energy audits, Zelenka indicated that he needed all the previous energy audits completed at Corvallis and Gresham. Also, Corvallis and Gresham should provide a printout of all the equipment at the facility that uses electricity – description and model number would be useful from the inventory. Gresham and Corvallis will likely provide that information from their computerized maintenance system.

Ryan Ray will be the Kennedy/Jenks engineer completing the energy analysis. Gresham contact for conducting the energy audit will be Alan Johnston. Ryan should coordinate with Walt Mintkeski, consultant to Energy Trust of Oregon, in case he would like to join the audits.

The audits will be scheduled the week of April 2 – 4, 2008.

Kennedy/Jenks will also need copies of the energy bills for calendar year 2007 (January 1 – December 31, 2007) for the Gresham and Corvallis plants. (This can be changed if there is any reason to think that 2008 was not a normal energy year) Zelenka asked for any additional breakdown of energy use also. That information will be used to calculate energy costs, and then prepare a 10 year forecast. Graham reminded Zelenka to watch for the green power incremental costs for the Gresham facility.

Gresham and Corvallis should pull the 10 year forecast for needed treatment plant capacity from their adopted facilities plan.

Nacrelli added that he had sent to Gillaspie (who sent to Zelenka) the on-line link to the Gresham facility plan.

Identify Renewable Energy Systems

Seven renewable energy systems will be evaluated. The TAC discussed which seven should be chosen.

For each evaluation, there will be a description of the renewable energy system including:
- size and KWH,
- cost,
- incentive and funding sources,
- operational impacts,
- commission and community impacts, and
- environmental impacts (air, land, water, and greenhouse gas emissions).

Zelenka indicated that this analysis will be 2 – 3 pages per resource. Gillaspie asked that all assumptions be carefully detailed.

Johnston asked if the site requirements should be included in the descriptions (how much wind, how much land for solar, etc.). Hill suggested that shadowing for both wind and solar are needed. Erin stressed that Energy Trust funding should be included in the financing options.

Zelenka suggested these renewable resources:
1. Digester gas
2. Solar PV
3. Small wind (on site)
4. ~~Geothermal heat pumps~~
5. Fuel cells using digester gas
6. FOG and biogas includes other green waste
7. Mini-hydro (within the collection system)
8. Micro-turbines running on digester gas

The group agreed to these 7 technologies after discussion.

Graham suggested microturbines run on digester gas. McLaughlin suggested mini-hydro within the receiving stream.

Nacrelli suggested that operational efficiency is another good idea – Zelenka suggested that would be a good second phase of the project, and that it would need more funding.

Zelenka indicated that the next TAC meeting will be in mid-May. That meeting will focus on a criteria and scoring system for the renewables. Zelenka plans to use a criteria system that might include points assigned to criteria such as costs, operational impacts, reliability, environmental impacts, commission and community impacts, etc. These criteria will be used to rank the renewables and to develop recommendations.

As part of the discussion, Zelenka indicated that each technology will be evaluated as a stand-alone to provide energy independence for the POTW. Hill expressed concern about balancing all the power needs and generating too much power and being a net energy generator. You don't really want to be energy independent, said Hill.

Graham added that the inability to wheel excess power into the system is a legislative issue. Johnston added that the net metering rules are not likely to change.

The last task will be writing the report – a draft will be provided and discussed at a TAC meeting. A final report and the PowerPoint presentations (technical staff and policy makers) will be completed and the deadline is 6/30/08.

Zelenka restated the project deliverables, including:
1. Audit and ECM recommendations
2. Draft and final written reports including executive summary
3. Two PowerPoint presentations.

Zelenka provided a project schedule.

The group set the next two TAC meetings, as:
- 5/13/08 - 8:30 am to 11:00 am in Salem at the Willow Lake Treatment Plant
- 6/6/08 - 8:30 am – 11:00 am in Salem at the Willow Lake Treatment Plant

Zelenka described the information that he needed from the pilot projects including:
- one year of monthly utility data (electronic if available) – KWH and $$ and any breakdowns
- All previous audit reports and studies and ECMs installed
- All renewable resource systems studies (solar PV RFPs and proposals)

The City of Medford is working with Doug Parsons at Sun Energy – cell phone 619/548-4315.

Gillaspie will ask Bend and Redmond for information on possible PV projects.

Outreach Plan Elements

Gillaspie asked for suggestions on the outreach plan elements for the project. She indicated that the project has been included in the ACWA summer conference program.

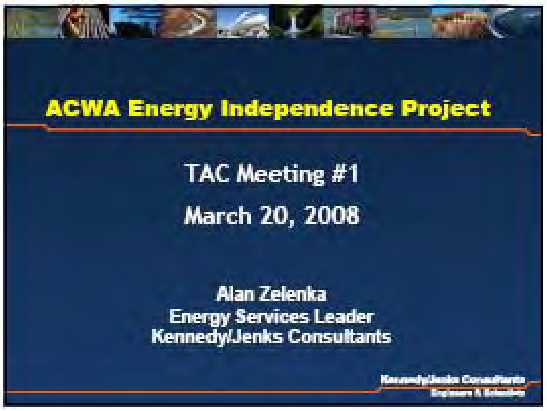
Other ideas include: League of Oregon Cities (LOC), Special Districts, and Association of Oregon Counties (AOC(annual conferences; incorporating all short school presentations; Government Finance Officers Association; city mayors of Oregon group.

Zelenka indicated that an abstract for the Pacific Northwest Clean Water Association conference had been submitted. Gillaspie added that incorporating the ideas into the DEQ facility check list and passing the information on to other groups that finance wastewater treatment plants would be useful.

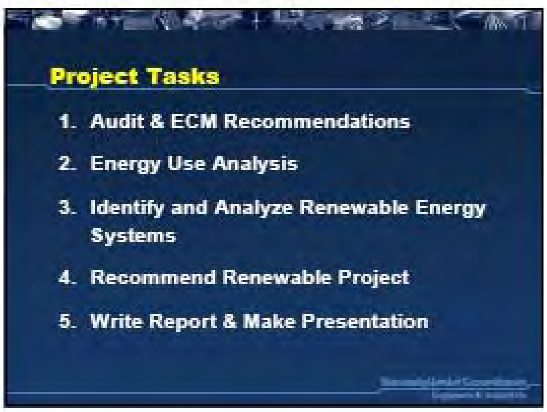
Hill suggested that a half-day training session for ACWA members and other utilities would be useful.

JAGillaspie
3/24/08

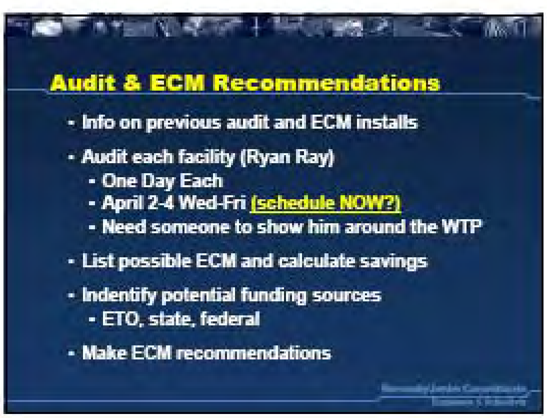
E.2 Slides



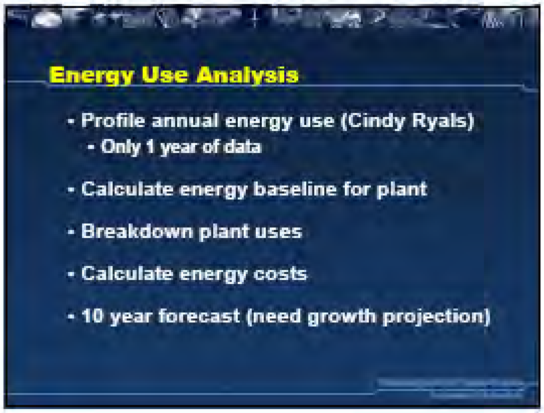
ACWA Energy Independence Project
TAC Meeting #1
March 20, 2008
Alan Zelenka
Energy Services Leader
Kennedy/Jenks Consultants

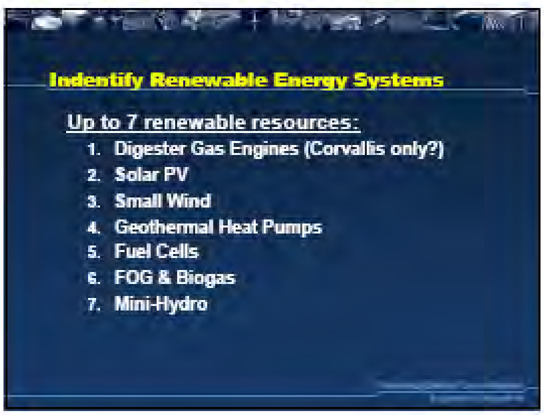


Project Tasks
1. Audit & ECM Recommendations
2. Energy Use Analysis
3. Identify and Analyze Renewable Energy Systems
4. Recommend Renewable Project
5. Write Report & Make Presentation

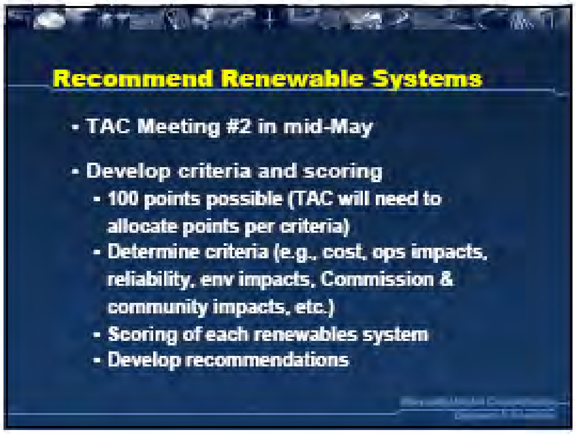


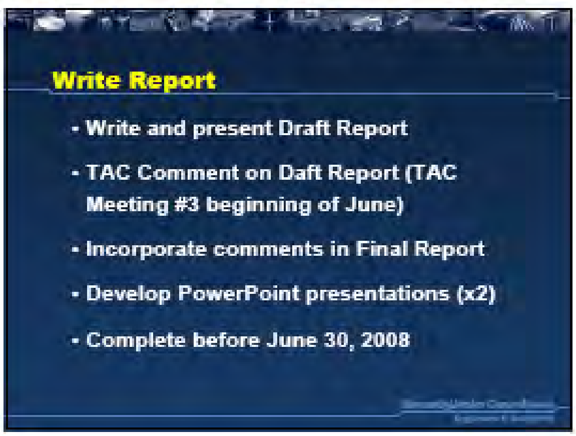
Audit & ECM Recommendations
• Info on previous audit and ECM installs
• Audit each facility (Ryan Ray)
• One Day Each
• April 2-4 Wed-Fri (schedule NOW?)
• Need someone to show him around the WTP
• List possible ECM and calculate savings
• Indentify potential funding sources
• ETO, state, federal
• Make ECM recommendations


Energy Use Analysis
• Profile annual energy use (Cindy Ryals)
• Only 1 year of data
• Calculate energy baseline for plant
• Breakdown plant uses
• Calculate energy costs
• 10 year forecast (need growth projection)


Indentify Renewable Energy Systems
Up to 7 renewable resources:
1. Digester Gas Engines (Corvallis only?)
2. Solar PV
3. Small Wind
4. Geothermal Heat Pumps
5. Fuel Cells
6. FOG & Biogas
7. Mini-Hydro


Indentify Renewable Energy Systems
• Description & size & KWH production
• (Cindy Ryals & Sherri Peterson & Greg Chung)
• Cost (capital, fuel, permits, permits, labor, O&M)
• Incentive & Funding Sources
• Operational Impacts
• Commission & Community Impacts
• Environmental Impacts (air, land, water & GHG)
• 2-3 pages total per system


Recommend Renewable Systems
• TAC Meeting #2 in mid-May
• Develop criteria and scoring
• 100 points possible (TAC will need to allocate points per criteria)
• Determine criteria (e.g., cost, ops impacts, reliability, env impacts, Commission & community impacts, etc.)
• Scoring of each renewables system
• Develop recommendations


Write Report
• Write and present Draft Report
• TAC Comment on Daft Report (TAC Meeting #3 beginning of June)
• Incorporate comments in Final Report
• Develop PowerPoint presentations (x2)
• Complete before June 30, 2008


Intermission

Project Deliverables

1. Report on Audit and ECM Recommendations
2. Draft & Final written Reports with executive summaries
3. Two PowerPoint presentation with talking points
   - technical staff and policy-maker versions

Pilot Project Information Needed

- 1 year of monthly utility data (electronic if available) – KWH and $
  - Any detailed breakdowns available?
- All previous audit reports/studies and ECMs installed
- All renewable resources systems studied (ie – solar PV RFPs & proposals)

Appendix F: TAC Meeting No. 2

F.1 Summary

Energy Independence
Technical Advisory Committee (TAC)
Salem, Oregon
13 May 08

Meeting Summary

Attending:

- Thad Roth, Energy Trust of Oregon
- Dan Hanthorn, City of Corvallis
- Walt Mintkeski, Energy Trust of Oregon
- Bob Sprick, City of Eugene
- Stephanie Eisner, City of Salem
- Alan Zelenka, Kennedy/Jenks
- Guy Graham, City of Gresham
- Alan Johnston, City of Gresham
- Mike Nacrelli, City of Gresham
- Terry Hosaka, Landau Associates
- Mark Kendall, Oregon Department of Energy (ODOE)
- Janet Gillaspie, Association of Clean Water Agencies (ACWA)

Agenda

There were no changes to the agenda.

Project Deliverables

Alan Zelenka provided an update in a PowerPoint presentation.

Zelenka reviewed the key deliverables for the project:

1. audit and energy conservation recommendations
2. energy use analysis and set baseline
3. identify and analyze renewable energy systems
4. Recommend renewable projects
5. write report and make presentations

Seven renewable energy systems will be evaluated.

Mintkeski asked if the project focus was just on renewables, not efficiency. Zelenka highlighted that the energy efficiency foundation must be set, and that is incorporated in the project scope. Mintkeski indicated that his position at Energy Trust is to assist communities like Corvallis and Gresham in installing the energy conservation measures necessary.

In the PowerPoint presentation, there is an error – the final written report is due 6/27/08 not July 27, 2008.

Energy Audits at Corvallis and Gresham
Kennedy-Jenks reviewed the existing energy conservation audits at Gresham and Corvallis along with a field audit conducted by Ryan Ray (Kennedy/Jenks) and Walt Mintkeski (Energy Trust of Oregon).

Earlier energy conservation measures at the two facilities were very good and comprehensive. There is not much more to do regarding cost-effective energy conservation for these two plants. Identified Energy Conservation Measures (ECMs) includes these categories:

- Not recommended and not implemented
- Not recommended and implemented
- Recommended and implemented
- Recommended but not yet implemented (costs included)
- Additional planned improvements
- Possible ECMs.

Zelenka reviewed the energy audit draft technical memos for Gresham and Corvallis. The group asked that regarding 'simple payback' - - add an additional sentence indicating that available incentives that would reduce the payback time.

Mike Nacrelli provided an update to the group on Gresham's solar project. The City selected Tioga Energy teamed with REC Solar for their solar installation project. An agreement has been drafted asking Gresham City Council to authorize the contract. He added that Gresham is also starting a small feasibility study on adding micro-hydro turbines to the plant effluent discharge close to the Columbia River, funded 50:50 with the Energy Trust of Oregon. It is a $50,000 project; a pre-feasibility study indicated the power output from the microturbines could be 50 KW. The project is pending in the Gresham Capital Improvement Program (CIP).

Corvallis has selected SunPower Energy and has a contract (2 MW). Hanthorn thought the contract was going to the Corvallis City Council next week. These will be ground mounted solar panels that will track in order to allow an additional 3 – 4 MW installation to be accommodated from Pacific Power. The Corvallis rate will be tied to the cost of solar panels.

Gillaspie specifically asked Hanthorn, Johnston, and Mintkeski to review the technical memorandum and respond to her and Zelenka on the draft memos by 5/20/08.

Sprick suggested for the payback calculations – show your math; that will make updating the information easier, and extend the "shelf life" of the report. Add references for all costs from earlier reports was an additional suggestion.

Renewable Energy Sources
Seven renewable energy sources will be evaluated in the project:

1. Digester Gas Engines
2. Solar PV
3. Small Wind
4. Microturbines
5. Fuel Cells
6. FOG & Biogas
7. Mini-hydro

The renewable resource assessments will include:

- Description
- Size and KHW production
- Cost
- Operational impacts
- Political and community impacts
- Environmental impacts (air, land, water)
- GHG impacts
- Potential funding sources

Zelenka provided an outline of how the renewable resource assessments will be structured - - each outline will be about 6 pages long. He also provided an example of the co-generation with microturbines using digester gas. He indicated the operational impacts and GHG sections have not been completed.

Kendall asked that applications of that technology be included - - Oregon examples. Gillaspie will ask the TAC members for existing examples of installed projects with the 7 focus technologies.

Hanthorn added a discussion about third-party power contracts; add discussion on third-party contracts and ownership options to written report, he suggested. The group agreed.

The group discussed how best to describe some of the size limitations for some of the technologies.

Sprick requested that a summary table with all seven technologies, costs, advantages, and disadvantages would be useful. Zelenka indicated that will be included in the final report.

On small wind, although the two pilot projects will not have a lot of wind potential, it will be included. Aaron Johnston at Energy Trust is a resource.

Zelenka asked if a 3% inflation factor was acceptable. He was going to use a bond sale with closing costs amortized over the life of the project. Debt service and O & M will be included – first year and average costs will be included.

He questioned the group if a lifetime, “levelized” cost should be calculated. The costs could also be shown as “net present worth”. The group liked lifecycle costs to be included. Compare to purchasing energy at present rates; add triple-bottom line elements. (don’t use the phase ‘triple bottom line’ - - remember target audience…)

Sprick suggested including a table that had the power costs over the next 20 years and then puts the technology (life costs) for each.

Gresham uses 5.75% factor for the cost of money. ODOE is loaning at 6% for bond sales. The group felt 6% was reasonable.

Evaluation Criteria

Zelenka outlined the possible criteria for evaluation:

Criteria	***Group Agreement***	
Cost of Ownership	50%	
Adequate size	5%	
Technology maturity and reliability	10%	
Political and community impacts	5%	
Environmental impacts	20%	
Greenhouse gas impacts	5%	
Operations impacts (hassle factor)	5%	
total	100%	

The group discussed the list and criteria; the group agreed with the criteria and scoring outlined by the consultant.

Gillaspie asked that the operational impacts be moved up for earlier review by the Technical Advisory Committee.

Gillaspie highlighted that meeting water quality permits must be included in a variety of places.

Mintkeski suggested that the weighting criteria might not be included to extend the shelf life of the report; Zelenka indicated that the ranking is part of the thinking process.

Outreach Plan

Gillaspie reviewed the draft outreach plan. Suggestions included:
- Strike the Pacific Northwest Clean Water Association (PNCWA) May conference and add the September 21 – 24 annual meeting in Kennewick. Mintkeski will submit an abstract
- Add PNCWA short school in August for the Umpqua section
- Add Northwest Environmental Business Association
- Add a meeting jointly organized by Energy Trust of Oregon, ODOE, and ACWA that will be held in Salem and will target interested state agencies, the Farm Bureau, PUD and municipal lobbyists, and others. Kendall and Gillaspie will organize after 8/15/08.

Gillaspie will revise the outreach plan and will submit it to Energy Trust.

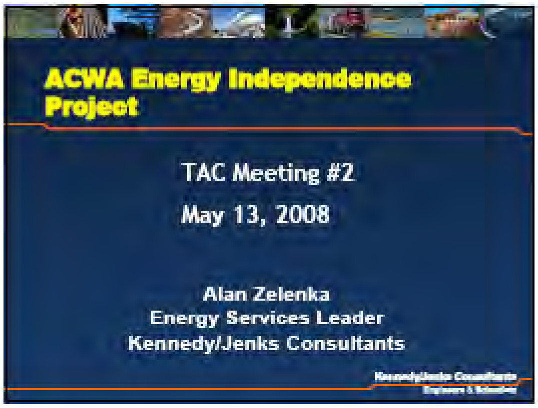
Roth added that Energy Trust could host some of the outreach meetings.

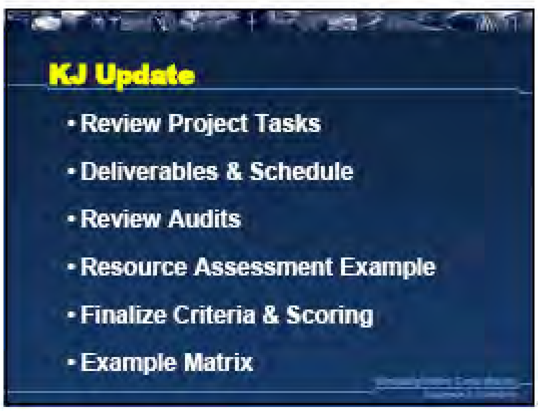
To Do:
- Gillaspie will ask the TAC group for Oregon or nearby examples of projects in the seven selected technologies
- Kendall will send Zelenka the PURPA (Public Utility Regulatory Policy Act) avoided cost reference
- Kendall will send Zelenka the Portland General Electric (PGE) and PacifiCorp cost factor

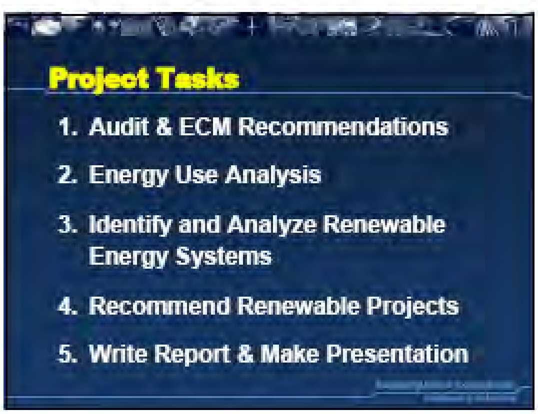
Next meeting is set for 6/6/08 at the Willow Lake Plant; the draft report will be distributed by 6/4/08.

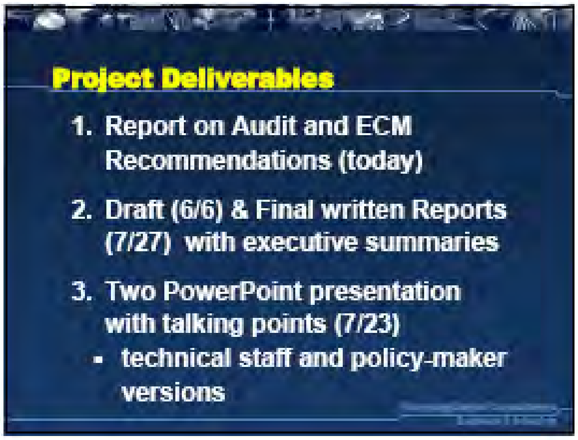
JAGillaspie
5/14/08

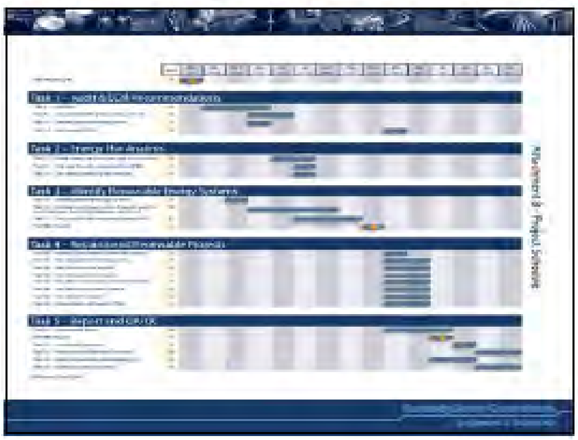
F.2 Slides

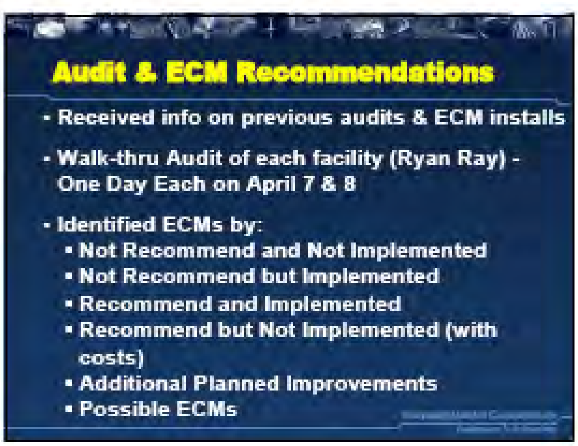

ACWA Energy Independence Project
TAC Meeting #2
May 13, 2008
Alan Zelenka
Energy Services Leader
Kennedy/Jenks Consultants


KJ Update
• Review Project Tasks
• Deliverables & Schedule
• Review Audits
• Resource Assessment Example
• Finalize Criteria & Scoring
• Example Matrix

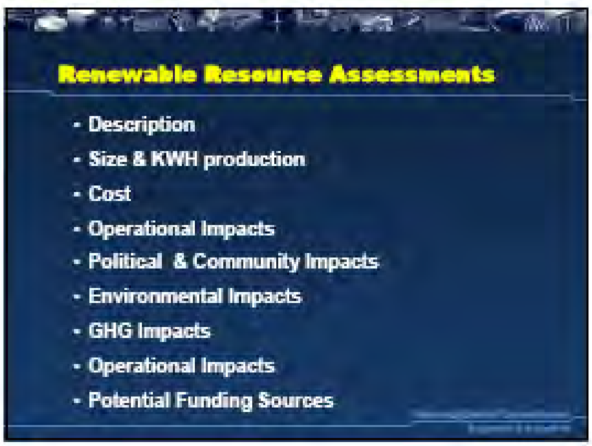

Project Tasks
1. Audit & ECM Recommendations
2. Energy Use Analysis
3. Identify and Analyze Renewable Energy Systems
4. Recommend Renewable Projects
5. Write Report & Make Presentation

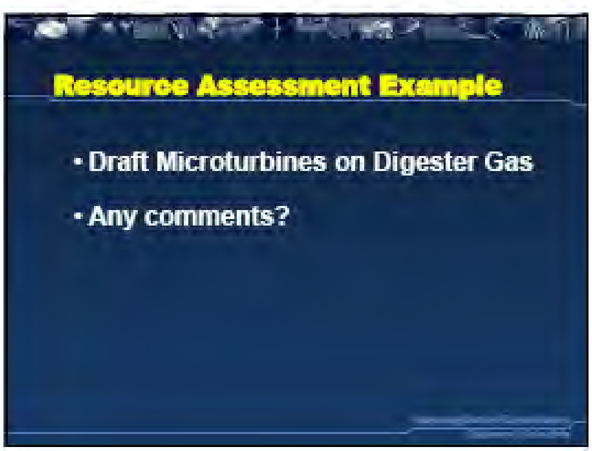

Project Deliverables
1. Report on Audit and ECM Recommendations (today)
2. Draft (6/6) & Final written Reports (7/27) with executive summaries
3. Two PowerPoint presentation with talking points (7/23)
▪ technical staff and policy-maker versions

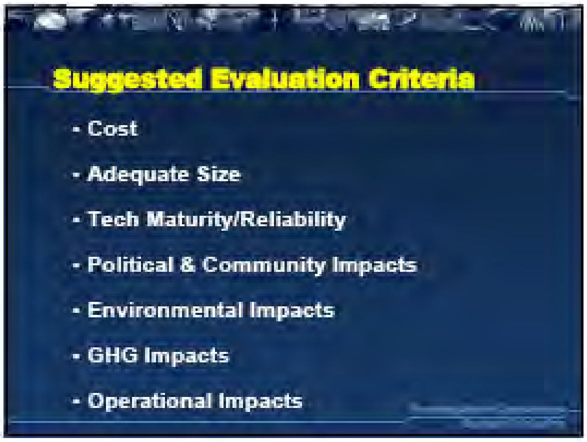


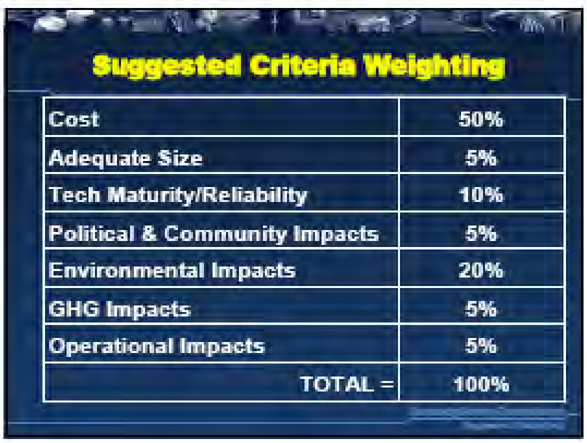

Audit & ECM Recommendations
▪ Received info on previous audits & ECM installs
▪ Walk-thru Audit of each facility (Ryan Ray) - One Day Each on April 7 & 8
▪ Identified ECMs by:
▪ Not Recommend and Not Implemented
▪ Not Recommend but Implemented
▪ Recommend and Implemented
▪ Recommend but Not Implemented (with costs)
▪ Additional Planned Improvements
▪ Possible ECMs

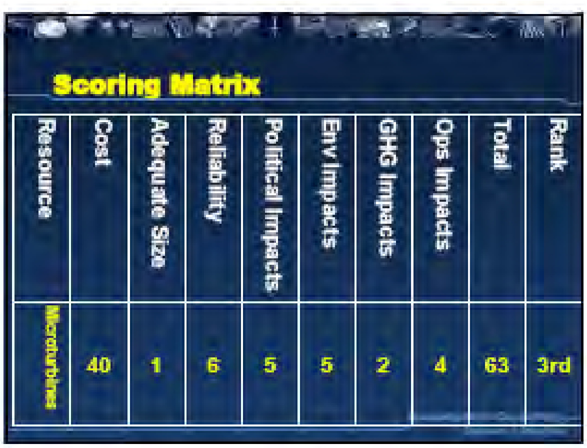

Indentify Renewable Energy Systems
7 Renewable Resources Assessments:
1. Digester Gas Engines (Corvallis)
2. Solar PV
3. Small Wind
4. Microturbines (Corvallis)
5. Fuel Cells
6. FOG & Biogas
7. Mini-Hydro


Renewable Resource Assessments
• Description
• Size & KWH production
• Cost
• Operational Impacts
• Political & Community Impacts
• Environmental Impacts
• GHG Impacts
• Operational Impacts
• Potential Funding Sources


Resource Assessment Example
• Draft Microturbines on Digester Gas
• Any comments?


Suggested Evaluation Criteria
- Cost
- Adequate Size
- Tech Maturity/Reliability
- Political & Community Impacts
- Environmental Impacts
- GHG Impacts
- Operational Impacts


Suggested Criteria Weighting
Cost 50%
Adequate Size 5%
Tech Maturity/Reliability 10%
Political & Community Impacts 5%
Environmental Impacts 20%
GHG Impacts 5%
Operational Impacts 5%
TOTAL = 100%


Scoring Matrix
Resource
Cost
Adequate Size
Reliability
Political Impacts
Env Impacts
GHG Impacts
Ops Impacts
Total
Rank
Microturbines
40
1
6
5
5
2
4
63
3rd

Appendix G: TAC Meeting No. 3

G.1 Summary

Energy Independence Project
Technical Advisory Committee
Salem, OR
13 June 08

Attending:

- Dan Hanthorn
- Guy Graham
- Bob Sprick
- Alan Zelenka
- Walt Mintkeski (by phone)
- Thad Roth (by phone)
- Erin Johnston (by phone)
- Jim Hill (by phone)
- Mike Nacrelli (by phone)
- Alan Johnston (by phone)

Project Deliverables/Schedule Update

After today's meeting, there will be additional time for comments (about a week) to Kennedy/Jenks (K/J). The final report is due to the ACWA office on 6/27/08.

The executive summary will be prepared after today's meeting and distributed to the TAC for comment, said Zelenka.

The section to extrapolate to all Oregon POTWs still needs to be completed also.

The two PowerPoint presentations will be completed in the next two weeks; they will also be provided to the TAC for comment and review.

TAC members should provide all comments to Gillaspie by close of business on Wednesday, June 18th; she will combine and align the comments, and deliver a consolidated set of final comments to K/J by Monday 6/23/08.

Gillaspie indicated that Corvallis and Gresham will have 'override' for comments related to the section discussing their facilities - - they will send their comments directly Zelenka by 6/18/08.

Comments and Suggestions

Section 1 – Introduction

- Mintkeski added additional EPA resources on conservation – please include.
- Erin Johnston would like an inventory of energy conservation measures that POTWs should be examining to be included – She will create a list of bullets for inclusion.
- Gillaspie will prepare a list of TAC members only including those that attended at least one TAC meeting.

Section 2 – Energy Conservation

Corvallis and Gresham will provide comments directly to K/J by Monday, 6/23/08. Zelenka asked what the dollar figures for installing energy incentives would be for Gresham to install the additional recommended, but not installed energy conservation measures. Mintkeski will provide the details on the calculated energy incentives, and suggested language on caveats.

Mintkeski asked about compressed air efficiency issues. POTWs use compressed air in a variety of locations including diaphragm sludge pumps, instrument air, and other uses. The conclusion was that compressed air efficiency should be added to inventory of energy conservation measurers for the Introduction.

For readability, Roth suggested putting the baseline energy use prior to the conservation measures. Zelenka responded that Section 3 includes the net energy analysis, so that is why it is staged in the report the way it is.

Section 2.3 mentions natural gas use - - is it quantified, asked Roth.

Mintkeski would like terms reworded – please use energy efficiency measures, not energy conservation measures. Delete [~~conservation~~] throughout the report.

Section 3 – Energy Profile

Roth commented on the energy use at Gresham - - is that net, yes it is responded Zelenka. The group agreed that a note or stacked bar graph showing the power that Gresham generates, and that it purchased should be added. Be clear about purchased power vs. generated power.

Executive summary – add a descriptor of the two plants. Gillaspie will draft.

- Add short paragraph from Corvallis (Dan Hanthorn) and Gresham (Alan Johnston) explaining their energy demand swings.
- Add average monthly treated in MGD flow to the graphs for Gresham and Corvallis. Include kilowatt-hours per million gallons to energy use (see 3.2).

- Add Gresham paragraph on its ability to generating power.
- Add paragraph on project scope – set fence line (Gillaspie to draft). Add that Corvallis must pump effluent into the treatment plant system, and Gresham is gravity flow. Mention that both facilities use liquid chlorine for disinfection (no UV).

Roth suggested adding information on the costs of co-generation.

Section 4 – Renewable Resource Assessments

A paragraph on the Corvallis P/V project is needed from Hanthorn.

The phrase "First year cost utility power" – is unclear. The term is explained on page 4-1. Everyone should read the explanation on page 4-1, and e-mail Zelenka with any suggestions to make clearer. In every section, the reference to the term explanations on page 4-1, and the detailed spread sheets in the appendices should be added.

Hill indicated that he thought the installation costs were low - - all of them. Zelenka responded that these are actual bids from vendors for installed systems. If they are all low they still provide a valuable comparison tool.

Erin Johnston will provide more information on small wind. She commented that she thought the readability of the report was good.

Alan Johnston indicated the IC engine cost estimates are right on for the Gresham experience.

Mintkeski indicated that he was confused by the negative number – it is due to the Oregon Business Energy Tax Credit (BETC) payment being up front – add explanation, he suggested.

Better explain funding assumptions in section 4.1. Include information that financing is anticipated to be by bonding and the interest rate assumptions.

Hill suggested that the table revised to include O & M, installed costs, first year incentives, and include **net costs**. The group thought this would be clearer.

For the environmental impacts, the "measles chart" on page 4-54, the characteristics were evaluated against each other to give (✓), (+), or (-) ratings. These factors were used to derive the values that were used in the numbers for the table in page 5-3.

The group asked for add more detail on how the (✓) (+) (-) were translated into the ratings be added to the report.

5.0 Recommendations
The group needed more time to comment.

Gillaspie asked Gresham and Corvallis to review recommendations carefully; she indicated that these communities will have veto over the text included in the report since it is their community.

Mintkeski added that on page 3-4 one energy conservation measure (aerators) for Gresham is counted twice. Zelenka will correct - - remember to reduce table 24, CO2 amounts, and recommended renewables.

Gillaspie suggested that the FOG and green waste be incorporated into the recommended analysis - - include in the executive summary and presentations.

Hill reminded the group to be careful of System Development Charges (SDCs).

Roth recommended that the FOG/green waste should be in a separate section, just as the report is drafted. The group agreed with that recommendation.

Roth added that the Energy Trust incentive numbers are estimates and are project specific. This should be emphasized in the text.

Erin Johnston – incentives are available for over 100 mw wind. In the spreadsheet, there are corrections – she will send them.

Alan Johnston indicated that Gresham is interested in exploring the FOG and green waste issue. Gillaspie suggested that Gresham examine the Oregon Economic and Community Development Department (OECDD) current call for feasibility projects related to renewable energy as a possible source of funding for such project.

Janet Gillaspie
6/13/08

ACWA Resource Assessment Cost Template

Fuel Cell

Inputs

$1,320,000	Primary Equipment Cost
1	Number of Units
$650,000	Other Equipment Costs
20%	Engineering Costs (% of Project Cost)
$394,000	Engineering Costs
$0	Fuel Costs ($/Yr)
10	Life of Units
400	kW per Unit
50%	Capacity Factor
1,752,000	Annual kWh Generation
$0.030	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator
68%	

Results

-$0.6084	First Year Cost
$0.0463	First Year Cost Utility Power
$0.1106	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
$0.0787	Real Levelized Cost
$0.0439	Real Levelized Utility Cost

Incentives	
$791,940	BETC
$608,295	ETO
$81,118	Net Metering
$1,481,352	TOTAL

Other Equipment Costs

$300,000	Clean up Skid
$350,000	Shipping, installation and Commissioning
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$650,000	TOTAL COST

Fuel Cost

	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

ETO DR = 20%

NPV = $1,759,894

NPV = $359,659

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	1,752,000	$1,970,000	$394,000	$2,364,000	$362,947	$52,560	$0	$415,507	$1,481,352	-$1,065,845	$81,118
2010	1,752,000				$362,947	$53,874	$0	$416,821	$82,578	$334,243	$82,578
2011	1,752,000				$362,947	$55,221	$0	$418,168	$84,064	$334,104	$84,064
2012	1,752,000				$362,947	$56,601	$0	$419,548	$85,577	$333,971	$85,577
2013	1,752,000				$362,947	$58,016	$0	$420,963	$87,118	$333,846	$87,118
2014	1,752,000				$362,947	$59,467	$0	$422,414	$88,686	$333,728	$88,686
2015	1,752,000				$362,947	$60,953	$0	$423,900	$90,282	$333,618	$90,282
2016	1,752,000				$362,947	$62,477	$0	$425,424	$91,907	$333,517	$91,907
2017	1,752,000				$362,947	$64,039	$0	$426,986	$93,562	$333,425	$93,562
2018	1,752,000				$362,947	$65,640	$0	$428,587	$95,246	$333,341	$95,246
2019	0				$0	$0	$0	$0	$0	$0	$0
2020	0				$0	$0	$0	$0	$0	$0	$0
2021	0				$0	$0	$0	$0	$0	$0	$0
2022	0				$0	$0	$0	$0	$0	$0	$0
2023	0				$0	$0	$0	$0	$0	$0	$0
2024	0				$0	$0	$0	$0	$0	$0	$0
2025	0				$0	$0	$0	$0	$0	$0	$0
2026	0				$0	$0	$0	$0	$0	$0	$0
2027	0				$0	$0	$0	$0	$0	$0	$0
2028	0				$0	$0	$0	$0	$0	$0	$0
2029	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.2072	$0.0300	$0.0000	$0.2372	$0.84552	-$0.6084	$0.0463	-$0.5621	-$984,728
2010	$0.2072	$0.0308	$0.0000	$0.2379	$0.04713	$0.1908	$0.0471	$0.1436	$251,665
2011	$0.2072	$0.0315	$0.0000	$0.2387	$0.04798	$0.1907	$0.0480	$0.1427	$250,039
2012	$0.2072	$0.0323	$0.0000	$0.2395	$0.04885	$0.1906	$0.0488	$0.1418	$248,394
2013	$0.2072	$0.0331	$0.0000	$0.2403	$0.04972	$0.1906	$0.0497	$0.1408	$246,728
2014	$0.2072	$0.0339	$0.0000	$0.2411	$0.05062	$0.1905	$0.0506	$0.1399	$245,042
2015	$0.2072	$0.0348	$0.0000	$0.2420	$0.05153	$0.1904	$0.0515	$0.1389	$243,336
2016	$0.2072	$0.0357	$0.0000	$0.2428	$0.05246	$0.1904	$0.0525	$0.1379	$241,610
2017	$0.2072	$0.0366	$0.0000	$0.2437	$0.05340	$0.1903	$0.0534	$0.1369	$239,863
2018	$0.2072	$0.0375	$0.0000	$0.2446	$0.05436	$0.1903	$0.0544	$0.1359	$238,096
2019	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2020	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2021	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2022	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2023	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2024	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2025	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2026	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2027	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2028	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template

IC Engines

Inputs

$975,000	Primary Equipment Cost
1	Number of Units
$210,000	Other Equipment Costs
25%	Engineering Costs (% of Project Cost)
$296,250	Engineering Costs
$0	Fuel Costs ($/Yr)
20	Life of Units
385	kW per Unit
40%	Capacity Factor
1,349,040	Annual kWh Generation
$0.030	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator

Results

-$0.5916	First Year Cost
$0.0463	First Year Cost Utility Power
$0.0232	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
$0.0292	Real Levelized Cost
$0.0426	Real Levelized Utility Cost

65,000
40%
162,500

Incentives	
$496,219	BETC
$425,788	ETO
$62,461	Net Metering
$984,467	TOTAL

Other Equipment Costs

$210,000	Clean-up Skid
	Equipment #2
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$210,000	TOTAL COST

Fuel Cost

N	USE Natural Gas (Y/N)
$ 0.76	Cost/Therm or Gallon
	Fuel Use (therms/Yr)
$0	Total Fuel Costs ($/Yr)

ETO DR = 12%

NPV = $1,443,666

NPV = $521,660

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	1,349,040	$1,185,000	$296,250	$1,481,250	$145,931	$40,471	$0	$186,402	$984,467	-$798,065	$62,461
2010	1,349,040				$145,931	$41,483	$0	$187,414	$63,585	$123,829	$63,585
2011	1,349,040				$145,931	$42,520	$0	$188,451	$64,729	$123,721	$64,729
2012	1,349,040				$145,931	$43,583	$0	$189,514	$65,894	$123,619	$65,894
2013	1,349,040				$145,931	$44,673	$0	$190,603	$67,081	$123,523	$67,081
2014	1,349,040				$145,931	$45,789	$0	$191,720	$68,288	$123,432	$68,288
2015	1,349,040				$145,931	$46,934	$0	$192,865	$69,517	$123,348	$69,517
2016	1,349,040				$145,931	$48,108	$0	$194,038	$70,769	$123,270	$70,769
2017	1,349,040				$145,931	$49,310	$0	$195,241	$72,042	$123,198	$72,042
2018	1,349,040				$145,931	$50,543	$0	$196,474	$73,339	$123,134	$73,339
2019	1,349,040				$145,931	$51,807	$0	$197,737	$74,659	$123,078	$74,659
2020	1,349,040				$145,931	$53,102	$0	$199,032	$76,003	$123,029	$76,003
2021	1,349,040				$145,931	$54,429	$0	$200,360	$77,371	$122,989	$77,371
2022	1,349,040				$145,931	$55,790	$0	$201,721	$78,764	$122,957	$78,764
2023	1,349,040				$145,931	$57,185	$0	$203,115	$80,182	$122,934	$80,182
2024	1,349,040				$145,931	$58,614	$0	$204,545	$81,625	$122,920	$81,625
2025	1,349,040				$145,931	$60,080	$0	$206,010	$83,094	$122,916	$83,094
2026	1,349,040				$145,931	$61,582	$0	$207,512	$84,590	$122,923	$84,590
2027	1,349,040				$145,931	$63,121	$0	$209,052	$86,112	$122,939	$86,112
2028	1,349,040				$145,931	$64,699	$0	$210,630	$87,662	$122,967	$87,662
2029	0				$0	$0	$0	$0	$0	$0	$0
2030	0				$0	$0	$0	$0	$0	$0	$0
2031	0				$0	$0	$0	$0	$0	$0	$0
2032	0				$0	$0	$0	$0	$0	$0	$0
2033	0				$0	$0	$0	$0	$0	$0	$0
2034	0				$0	$0	$0	$0	$0	$0	$0
2035	0				$0	$0	$0	$0	$0	$0	$0
2036	0				$0	$0	$0	$0	$0	$0	$0
2037	0				$0	$0	$0	$0	$0	$0	$0
2038	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.1082	$0.0300	$0.0000	$0.1382	$0.72975	-$0.5916	$0.0463	-$0.5453	-$735,605
2010	$0.1082	$0.0308	$0.0000	$0.1389	$0.04713	$0.0918	$0.0471	$0.0447	$60,244
2011	$0.1082	$0.0315	$0.0000	$0.1397	$0.04798	$0.0917	$0.0480	$0.0437	$58,992
2012	$0.1082	$0.0323	$0.0000	$0.1405	$0.04885	$0.0916	$0.0488	$0.0428	$57,725
2013	$0.1082	$0.0331	$0.0000	$0.1413	$0.04972	$0.0916	$0.0497	$0.0418	$56,442
2014	$0.1082	$0.0339	$0.0000	$0.1421	$0.05062	$0.0915	$0.0506	$0.0409	$55,144
2015	$0.1082	$0.0348	$0.0000	$0.1430	$0.05153	$0.0914	$0.0515	$0.0399	$53,830
2016	$0.1082	$0.0357	$0.0000	$0.1438	$0.05246	$0.0914	$0.0525	$0.0389	$52,501
2017	$0.1082	$0.0366	$0.0000	$0.1447	$0.05340	$0.0913	$0.0534	$0.0379	$51,156
2018	$0.1082	$0.0375	$0.0000	$0.1456	$0.05436	$0.0913	$0.0544	$0.0369	$49,795
2019	$0.1082	$0.0384	$0.0000	$0.1466	$0.05534	$0.0912	$0.0553	$0.0359	$48,419
2020	$0.1082	$0.0394	$0.0000	$0.1475	$0.05634	$0.0912	$0.0563	$0.0349	$47,026
2021	$0.1082	$0.0403	$0.0000	$0.1485	$0.05735	$0.0912	$0.0574	$0.0338	$45,618
2022	$0.1082	$0.0414	$0.0000	$0.1495	$0.05839	$0.0911	$0.0584	$0.0328	$44,193
2023	$0.1082	$0.0424	$0.0000	$0.1506	$0.05944	$0.0911	$0.0594	$0.0317	$42,752
2024	$0.1082	$0.0434	$0.0000	$0.1516	$0.06051	$0.0911	$0.0605	$0.0306	$41,295
2025	$0.1082	$0.0445	$0.0000	$0.1527	$0.06159	$0.0911	$0.0616	$0.0295	$39,822
2026	$0.1082	$0.0456	$0.0000	$0.1538	$0.06270	$0.0911	$0.0627	$0.0284	$38,333
2027	$0.1082	$0.0468	$0.0000	$0.1550	$0.06383	$0.0911	$0.0638	$0.0273	$36,827
2028	$0.1082	$0.0480	$0.0000	$0.1561	$0.06498	$0.0912	$0.0650	$0.0262	$35,305
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2030	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2031	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2032	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2033	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2034	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2035	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2036	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2037	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2038	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template

Micro-Hydro - Gresham

Inputs

$438,000	Primary Equipment Cost
1	Number of Units
$500,000	Other Equipment Costs
25%	Engineering Costs (% of Project Cost)
$234,500	Engineering Costs
$0	Fuel Costs ($/Yr)
20	Life of Units
35	kW per Unit
95%	Capacity Factor
291,270	Annual kWh Generation
$0.005	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0721	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator

Results

-$1.2477	First Year Cost
$0.0721	First Year Cost Utility Power
$0.1662	10 Year Average Cost
$0.0782	10 Year Average Utility Cost
$0.1540	Real Levelized Cost
$0.0664	Real Levelized Utility Cost

Incentives	
$392,788	BETC
$66,591	ETO
$21,001	Net Metering
$480,379	TOTAL

Other Equipment Costs

$250,000	Civil Site Improvements
$250,000	Electrical Improvements
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$500,000	TOTAL COST

Fuel Cost

	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

ETO DR = 20%

NPV = $570,466

NPV = $111,088

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	291,270	$938,000	$234,500	$1,172,500	$115,513	$1,456	$0	$116,969	$480,379	-$363,410	$21,001
2010	291,270				$115,513	$1,493	$0	$117,006	$21,379	$95,627	$21,379
2011	291,270				$115,513	$1,530	$0	$117,043	$21,763	$95,280	$21,763
2012	291,270				$115,513	$1,568	$0	$117,081	$22,155	$94,926	$22,155
2013	291,270				$115,513	$1,608	$0	$117,121	$22,554	$94,567	$22,554
2014	291,270				$115,513	$1,648	$0	$117,161	$22,960	$94,201	$22,960
2015	291,270				$115,513	$1,689	$0	$117,202	$23,373	$93,829	$23,373
2016	291,270				$115,513	$1,731	$0	$117,244	$23,794	$93,450	$23,794
2017	291,270				$115,513	$1,774	$0	$117,287	$24,222	$93,065	$24,222
2018	291,270				$115,513	$1,819	$0	$117,332	$24,658	$92,674	$24,658
2019	291,270				$115,513	$1,864	$0	$117,377	$25,102	$92,275	$25,102
2020	291,270				$115,513	$1,911	$0	$117,424	$25,554	$91,870	$25,554
2021	291,270				$115,513	$1,959	$0	$117,472	$26,014	$91,458	$26,014
2022	291,270				$115,513	$2,008	$0	$117,521	$26,482	$91,039	$26,482
2023	291,270				$115,513	$2,058	$0	$117,571	$26,959	$90,612	$26,959
2024	291,270				$115,513	$2,109	$0	$117,622	$27,444	$90,178	$27,444
2025	291,270				$115,513	$2,162	$0	$117,675	$27,938	$89,737	$27,938
2026	291,270				$115,513	$2,216	$0	$117,729	$28,441	$89,288	$28,441
2027	291,270				$115,513	$2,271	$0	$117,784	$28,953	$88,832	$28,953
2028	291,270				$115,513	$2,328	$0	$117,841	$29,474	$88,367	$29,474
2029	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.3966	$0.0050	$0.0000	$0.4016	$1.64926	-$1.2477	$0.0721	-$1.1756	-$342,409
2010	$0.3966	$0.0051	$0.0000	$0.4017	$0.07340	$0.3283	$0.0734	$0.2549	$74,249
2011	$0.3966	$0.0053	$0.0000	$0.4018	$0.07472	$0.3271	$0.0747	$0.2524	$73,516
2012	$0.3966	$0.0054	$0.0000	$0.4020	$0.07606	$0.3259	$0.0761	$0.2498	$72,771
2013	$0.3966	$0.0055	$0.0000	$0.4021	$0.07743	$0.3247	$0.0774	$0.2472	$72,013
2014	$0.3966	$0.0057	$0.0000	$0.4022	$0.07883	$0.3234	$0.0788	$0.2446	$71,241
2015	$0.3966	$0.0058	$0.0000	$0.4024	$0.08025	$0.3221	$0.0802	$0.2419	$70,456
2016	$0.3966	$0.0059	$0.0000	$0.4025	$0.08169	$0.3208	$0.0817	$0.2391	$69,656
2017	$0.3966	$0.0061	$0.0000	$0.4027	$0.08316	$0.3195	$0.0832	$0.2364	$68,843
2018	$0.3966	$0.0062	$0.0000	$0.4028	$0.08466	$0.3182	$0.0847	$0.2335	$68,015
2019	$0.3966	$0.0064	$0.0000	$0.4030	$0.08618	$0.3168	$0.0862	$0.2306	$67,173
2020	$0.3966	$0.0066	$0.0000	$0.4031	$0.08773	$0.3154	$0.0877	$0.2277	$66,316
2021	$0.3966	$0.0067	$0.0000	$0.4033	$0.08931	$0.3140	$0.0893	$0.2247	$65,444
2022	$0.3966	$0.0069	$0.0000	$0.4035	$0.09092	$0.3126	$0.0909	$0.2216	$64,556
2023	$0.3966	$0.0071	$0.0000	$0.4036	$0.09256	$0.3111	$0.0926	$0.2185	$63,653
2024	$0.3966	$0.0072	$0.0000	$0.4038	$0.09422	$0.3096	$0.0942	$0.2154	$62,734
2025	$0.3966	$0.0074	$0.0000	$0.4040	$0.09592	$0.3081	$0.0959	$0.2122	$61,799
2026	$0.3966	$0.0076	$0.0000	$0.4042	$0.09764	$0.3065	$0.0976	$0.2089	$60,847
2027	$0.3966	$0.0078	$0.0000	$0.4044	$0.09940	$0.3050	$0.0994	$0.2056	$59,879
2028	$0.3966	$0.0080	$0.0000	$0.4046	$0.10119	$0.3034	$0.1012	$0.2022	$58,893
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template

Micro-Hydro - LH1000 for Corvallis

Inputs

$55,000	Primary Equipment Cost
1	Number of Units
$445,900	Other Equipment Costs
25%	Engineering Costs (% of Project Cost)
$125,225	Engineering Costs
$0	Fuel Costs ($/Yr)
20	Life of Units
5	kW per Unit
60%	Capacity Factor
26,280	Annual kWh Generation
$0.005	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator

Results

-$8.9065	First Year Cost
$0.0463	First Year Cost Utility Power
$1.1813	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
$1.1176	Real Levelized Cost
$0.0426	Real Levelized Utility Cost

Incentives	
$209,752	BETC
$84,910	ETO
$1,217	Net Metering
$295,879	TOTAL

Other Equipment Costs

$408,000	Civil Site Improvements
$37,900	Electrical Improvements
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$445,900	TOTAL COST

Fuel Cost

	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

ETO DR =
20%
NPV = $301,098

NPV =
$6,436

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	26,280	$500,900	$125,225	$626,125	$61,685	$131	$0	$61,816	$295,879	-$234,063	$1,217
2010	26,280				$61,685	$135	$0	$61,820	$1,239	$60,581	$1,239
2011	26,280				$61,685	$138	$0	$61,823	$1,261	$60,562	$1,261
2012	26,280				$61,685	$142	$0	$61,826	$1,284	$60,543	$1,284
2013	26,280				$61,685	$145	$0	$61,830	$1,307	$60,523	$1,307
2014	26,280				$61,685	$149	$0	$61,834	$1,330	$60,503	$1,330
2015	26,280				$61,685	$152	$0	$61,837	$1,354	$60,483	$1,354
2016	26,280				$61,685	$156	$0	$61,841	$1,379	$60,463	$1,379
2017	26,280				$61,685	$160	$0	$61,845	$1,403	$60,442	$1,403
2018	26,280				$61,685	$164	$0	$61,849	$1,429	$60,420	$1,429
2019	26,280				$61,685	$168	$0	$61,853	$1,454	$60,399	$1,454
2020	26,280				$61,685	$172	$0	$61,857	$1,481	$60,377	$1,481
2021	26,280				$61,685	$177	$0	$61,862	$1,507	$60,354	$1,507
2022	26,280				$61,685	$181	$0	$61,866	$1,534	$60,332	$1,534
2023	26,280				$61,685	$186	$0	$61,871	$1,562	$60,309	$1,562
2024	26,280				$61,685	$190	$0	$61,875	$1,590	$60,285	$1,590
2025	26,280				$61,685	$195	$0	$61,880	$1,619	$60,261	$1,619
2026	26,280				$61,685	$200	$0	$61,885	$1,648	$60,237	$1,648
2027	26,280				$61,685	$205	$0	$61,890	$1,678	$60,212	$1,678
2028	26,280				$61,685	$210	$0	$61,895	$1,708	$60,187	$1,708
2029	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$2.3472	$0.0050	$0.0000	$2.3522	$11.25871	-$8.9065	$0.0463	-$8.8602	-$232,846
2010	$2.3472	$0.0051	$0.0000	$2.3523	$0.04713	$2.3052	$0.0471	$2.2581	$59,342
2011	$2.3472	$0.0053	$0.0000	$2.3525	$0.04798	$2.3045	$0.0480	$2.2565	$59,301
2012	$2.3472	$0.0054	$0.0000	$2.3526	$0.04885	$2.3038	$0.0488	$2.2549	$59,259
2013	$2.3472	$0.0055	$0.0000	$2.3527	$0.04972	$2.3030	$0.0497	$2.2533	$59,216
2014	$2.3472	$0.0057	$0.0000	$2.3529	$0.05062	$2.3023	$0.0506	$2.2516	$59,173
2015	$2.3472	$0.0058	$0.0000	$2.3530	$0.05153	$2.3015	$0.0515	$2.2500	$59,129
2016	$2.3472	$0.0059	$0.0000	$2.3532	$0.05246	$2.3007	$0.0525	$2.2482	$59,084
2017	$2.3472	$0.0061	$0.0000	$2.3533	$0.05340	$2.2999	$0.0534	$2.2465	$59,038
2018	$2.3472	$0.0062	$0.0000	$2.3535	$0.05436	$2.2991	$0.0544	$2.2447	$58,992
2019	$2.3472	$0.0064	$0.0000	$2.3536	$0.05534	$2.2983	$0.0553	$2.2429	$58,944
2020	$2.3472	$0.0066	$0.0000	$2.3538	$0.05634	$2.2974	$0.0563	$2.2411	$58,896
2021	$2.3472	$0.0067	$0.0000	$2.3539	$0.05735	$2.2966	$0.0574	$2.2392	$58,847
2022	$2.3472	$0.0069	$0.0000	$2.3541	$0.05839	$2.2957	$0.0584	$2.2373	$58,797
2023	$2.3472	$0.0071	$0.0000	$2.3543	$0.05944	$2.2948	$0.0594	$2.2354	$58,747
2024	$2.3472	$0.0072	$0.0000	$2.3545	$0.06051	$2.2940	$0.0605	$2.2334	$58,695
2025	$2.3472	$0.0074	$0.0000	$2.3546	$0.06159	$2.2930	$0.0616	$2.2315	$58,643
2026	$2.3472	$0.0076	$0.0000	$2.3548	$0.06270	$2.2921	$0.0627	$2.2294	$58,589
2027	$2.3472	$0.0078	$0.0000	$2.3550	$0.06383	$2.2912	$0.0638	$2.2274	$58,535
2028	$2.3472	$0.0080	$0.0000	$2.3552	$0.06498	$2.2902	$0.0650	$2.2252	$58,480
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template
Microturbines

Inputs

$100,000	Primary Equipment Cost
2	Number of Units
$560,000	Other Equipment Costs
25%	Engineering Costs (% of Project Cost)
$190,000	Engineering Costs
$0	Fuel Costs ($/Yr)
10	Life of Units
65	kW per Unit
95%	Capacity Factor
1,081,860	Annual kWh Generation
$0.030	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator

Results

-$0.3774	First Year Cost
$0.0463	First Year Cost Utility Power
$0.0686	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
$0.0488	Real Levelized Cost
$0.0439	Real Levelized Utility Cost

Incentives	
$318,250	BETC
$218,269	ETO
$50,090	Net Metering
$586,610	TOTAL

Other Equipment Costs

$210,000	Clean up Skid
$350,000	Shipping, installation and Commissioning
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$560,000	TOTAL COST

Fuel Cost

0.08	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

ETO DR =
20%
NPV = $758,609

NPV = $222,090

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	1,081,860	$760,000	$190,000	$950,000	$145,854	$32,456	$0	$178,310	$586,610	-$408,299	$50,090
2010	1,081,860				$145,854	$33,267	$0	$179,121	$50,992	$128,130	$50,992
2011	1,081,860				$145,854	$34,099	$0	$179,953	$51,910	$128,044	$51,910
2012	1,081,860				$145,854	$34,951	$0	$180,806	$52,844	$127,962	$52,844
2013	1,081,860				$145,854	$35,825	$0	$181,679	$53,795	$127,884	$53,795
2014	1,081,860				$145,854	$36,721	$0	$182,575	$54,763	$127,812	$54,763
2015	1,081,860				$145,854	$37,639	$0	$183,493	$55,749	$127,744	$55,749
2016	1,081,860				$145,854	$38,580	$0	$184,434	$56,753	$127,681	$56,753
2017	1,081,860				$145,854	$39,544	$0	$185,398	$57,774	$127,624	$57,774
2018	1,081,860				$145,854	$40,533	$0	$186,387	$58,814	$127,573	$58,814
2019	0				$0	$0	$0	$0	$0	$0	$0
2020	0				$0	$0	$0	$0	$0	$0	$0
2021	0				$0	$0	$0	$0	$0	$0	$0
2022	0				$0	$0	$0	$0	$0	$0	$0
2023	0				$0	$0	$0	$0	$0	$0	$0
2024	0				$0	$0	$0	$0	$0	$0	$0
2025	0				$0	$0	$0	$0	$0	$0	$0
2026	0				$0	$0	$0	$0	$0	$0	$0
2027	0				$0	$0	$0	$0	$0	$0	$0
2028	0				$0	$0	$0	$0	$0	$0	$0
2029	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.1348	$0.0300	$0.0000	$0.1648	$0.54222	-$0.3774	$0.0463	-$0.3311	-$358,209
2010	$0.1348	$0.0308	$0.0000	$0.1656	$0.04713	$0.1184	$0.0471	$0.0713	$77,138
2011	$0.1348	$0.0315	$0.0000	$0.1663	$0.04798	$0.1184	$0.0480	$0.0704	$76,134
2012	$0.1348	$0.0323	$0.0000	$0.1671	$0.04885	$0.1183	$0.0488	$0.0694	$75,118
2013	$0.1348	$0.0331	$0.0000	$0.1679	$0.04972	$0.1182	$0.0497	$0.0685	$74,089
2014	$0.1348	$0.0339	$0.0000	$0.1688	$0.05062	$0.1181	$0.0506	$0.0675	$73,048
2015	$0.1348	$0.0348	$0.0000	$0.1696	$0.05153	$0.1181	$0.0515	$0.0665	$71,995
2016	$0.1348	$0.0357	$0.0000	$0.1705	$0.05246	$0.1180	$0.0525	$0.0656	$70,929
2017	$0.1348	$0.0366	$0.0000	$0.1714	$0.05340	$0.1180	$0.0534	$0.0646	$69,850
2018	$0.1348	$0.0375	$0.0000	$0.1723	$0.05436	$0.1179	$0.0544	$0.0636	$68,759
2019	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2020	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2021	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2022	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2023	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2024	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2025	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2026	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2027	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2028	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template

Small Wind - 10 KW

Inputs

$29,500	Primary Equipment Cost
1	Number of Units
$12,600	Other Equipment Costs
25%	Engineering Costs (% of Project Cost)
$20,525	Engineering Costs
$0	Fuel Costs ($/Yr)
10	Life of Units
10	kW per Unit
17%	Capacity Factor
14,838	Annual kWh Generation
$0.010	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator
14,838	

49%

c

Results

-$2.4955	First Year Cost
$0.0463	First Year Cost Utility Power
$0.2982	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
$0.1901	Real Levelized Cost
$0.0439	Real Levelized Utility Cost

Incentives	
$20,979	BETC
$25,125	ETO
$687	Net Metering
$46,791	TOTAL

Other Equipment Costs

$12,600	Tower
	Equipment #2
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$12,600	TOTAL COST

Fuel Cost

	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

ETO DR = 20%

NPV = $40,983

NPV = $3,046

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	14,838	$42,100	$20,525	$62,625	$9,615	$148	$0	$9,763	$46,791	-$37,028	$687
2010	14,838				$9,615	$152	$0	$9,767	$699	$9,068	$699
2011	14,838				$9,615	$156	$0	$9,771	$712	$9,059	$712
2012	14,838				$9,615	$160	$0	$9,775	$725	$9,050	$725
2013	14,838				$9,615	$164	$0	$9,779	$738	$9,041	$738
2014	14,838				$9,615	$168	$0	$9,783	$751	$9,032	$751
2015	14,838				$9,615	$172	$0	$9,787	$765	$9,022	$765
2016	14,838				$9,615	$176	$0	$9,791	$778	$9,013	$778
2017	14,838				$9,615	$181	$0	$9,796	$792	$9,003	$792
2018	14,838				$9,615	$185	$0	$9,800	$807	$8,994	$807
2019	0				$0	$0	$0	$0	$0	$0	$0
2020	0				$0	$0	$0	$0	$0	$0	$0
2021	0				$0	$0	$0	$0	$0	$0	$0
2022	0				$0	$0	$0	$0	$0	$0	$0
2023	0				$0	$0	$0	$0	$0	$0	$0
2024	0				$0	$0	$0	$0	$0	$0	$0
2025	0				$0	$0	$0	$0	$0	$0	$0
2026	0				$0	$0	$0	$0	$0	$0	$0
2027	0				$0	$0	$0	$0	$0	$0	$0
2028	0				$0	$0	$0	$0	$0	$0	$0
2029	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.6480	$0.0100	$0.0000	$0.6580	$3.15348	-$2.4955	$0.0463	-$2.4492	-$36,341
2010	$0.6480	$0.0103	$0.0000	$0.6582	$0.04713	$0.6111	$0.0471	$0.5640	$8,368
2011	$0.6480	$0.0105	$0.0000	$0.6585	$0.04798	$0.6105	$0.0480	$0.5625	$8,347
2012	$0.6480	$0.0108	$0.0000	$0.6588	$0.04885	$0.6099	$0.0488	$0.5611	$8,325
2013	$0.6480	$0.0110	$0.0000	$0.6590	$0.04972	$0.6093	$0.0497	$0.5596	$8,303
2014	$0.6480	$0.0113	$0.0000	$0.6593	$0.05062	$0.6087	$0.0506	$0.5581	$8,281
2015	$0.6480	$0.0116	$0.0000	$0.6596	$0.05153	$0.6081	$0.0515	$0.5565	$8,258
2016	$0.6480	$0.0119	$0.0000	$0.6599	$0.05246	$0.6074	$0.0525	$0.5550	$8,234
2017	$0.6480	$0.0122	$0.0000	$0.6602	$0.05340	$0.6068	$0.0534	$0.5534	$8,211
2018	$0.6480	$0.0125	$0.0000	$0.6605	$0.05436	$0.6061	$0.0544	$0.5518	$8,187
2019	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2020	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2021	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2022	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2023	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2024	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2025	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2026	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2027	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2028	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template

Small Wind - 100 KW

Inputs

$400,000	Primary Equipment Cost
1	Number of Units
$0	Other Equipment Costs
25%	Engineering Costs (% of Project Cost)
$100,000	Engineering Costs
$0	Fuel Costs ($/Yr)
10	Life of Units
100	kW per Unit
20%	Capacity Factor
175,000	Annual kWh Generation
$0.010	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator
175,200	

c

Results

-$1.2768	First Year Cost
$0.0463	First Year Cost Utility Power
$0.2317	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
$0.1650	Real Levelized Cost
$0.0439	Real Levelized Utility Cost

Incentives	
$167,500	BETC
$126,344	ETO
$8,103	Net Metering
$301,947	TOTAL

Other Equipment Costs

	Tower
	Equipment #2
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$0	TOTAL COST

Fuel Cost

	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

ETO DR = 20%

NPV = $329,769

NPV = $35,925

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	175,000	$400,000	$100,000	$500,000	$76,765	$1,750	$0	$78,515	$301,947	-$223,432	$8,103
2010	175,000				$76,765	$1,794	$0	$78,559	$8,248	$70,311	$8,248
2011	175,000				$76,765	$1,839	$0	$78,604	$8,397	$70,207	$8,397
2012	175,000				$76,765	$1,885	$0	$78,650	$8,548	$70,102	$8,548
2013	175,000				$76,765	$1,932	$0	$78,697	$8,702	$69,995	$8,702
2014	175,000				$76,765	$1,980	$0	$78,745	$8,858	$69,887	$8,858
2015	175,000				$76,765	$2,029	$0	$78,795	$9,018	$69,777	$9,018
2016	175,000				$76,765	$2,080	$0	$78,846	$9,180	$69,665	$9,180
2017	175,000				$76,765	$2,132	$0	$78,898	$9,345	$69,552	$9,345
2018	175,000				$76,765	$2,186	$0	$78,951	$9,514	$69,437	$9,514
2019	0				$0	$0	$0	$0	$0	$0	$0
2020	0				$0	$0	$0	$0	$0	$0	$0
2021	0				$0	$0	$0	$0	$0	$0	$0
2022	0				$0	$0	$0	$0	$0	$0	$0
2023	0				$0	$0	$0	$0	$0	$0	$0
2024	0				$0	$0	$0	$0	$0	$0	$0
2025	0				$0	$0	$0	$0	$0	$0	$0
2026	0				$0	$0	$0	$0	$0	$0	$0
2027	0				$0	$0	$0	$0	$0	$0	$0
2028	0				$0	$0	$0	$0	$0	$0	$0
2029	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.4387	$0.0100	$0.0000	$0.4487	$1.72541	-$1.2768	$0.0463	-$1.2305	-$215,329
2010	$0.4387	$0.0103	$0.0000	$0.4489	$0.04713	$0.4018	$0.0471	$0.3546	$62,062
2011	$0.4387	$0.0105	$0.0000	$0.4492	$0.04798	$0.4012	$0.0480	$0.3532	$61,810
2012	$0.4387	$0.0108	$0.0000	$0.4494	$0.04885	$0.4006	$0.0488	$0.3517	$61,554
2013	$0.4387	$0.0110	$0.0000	$0.4497	$0.04972	$0.4000	$0.0497	$0.3502	$61,293
2014	$0.4387	$0.0113	$0.0000	$0.4500	$0.05062	$0.3994	$0.0506	$0.3487	$61,028
2015	$0.4387	$0.0116	$0.0000	$0.4503	$0.05153	$0.3987	$0.0515	$0.3472	$60,759
2016	$0.4387	$0.0119	$0.0000	$0.4505	$0.05246	$0.3981	$0.0525	$0.3456	$60,485
2017	$0.4387	$0.0122	$0.0000	$0.4508	$0.05340	$0.3974	$0.0534	$0.3440	$60,207
2018	$0.4387	$0.0125	$0.0000	$0.4511	$0.05436	$0.3968	$0.0544	$0.3424	$59,924
2019	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2020	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2021	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2022	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2023	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2024	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2025	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2026	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2027	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2028	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template

Solar PV System

Inputs

$720,000	Primary Equipment Cost
1	Number of Units
$0	Other Equipment Costs
25%	Engineering Costs (% of Project Cost)
$180,000	Engineering Costs
$0	Fuel Costs ($/Yr)
20	Life of Units
100	kW per Unit
12%	Capacity Factor
105,120	Annual kWh Generation
$0.010	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator

Results

-$3.4879	First Year Cost
$0.0463	First Year Cost Utility Power
$0.3749	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
$0.3652	Real Levelized Cost
$0.0426	Real Levelized Utility Cost

Incentives		
$301,500	BETC	
$150,000	ETO	PPL
$4,867	Net Metering	
$456,367	TOTAL	

$411,774
ETO DR =
20%
NPV = $437,520

NPV = $25,745

Other Equipment Costs

	Equipment #1
	Equipment #2
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$0	TOTAL COST

Fuel Cost

	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	105,120	$720,000	$180,000	$900,000	$88,667	$1,051	$0	$89,718	$456,367	-$366,649	$4,867
2010	105,120				$88,667	$1,077	$0	$89,744	$4,955	$84,790	$4,955
2011	105,120				$88,667	$1,104	$0	$89,771	$5,044	$84,727	$5,044
2012	105,120				$88,667	$1,132	$0	$89,799	$5,135	$84,664	$5,135
2013	105,120				$88,667	$1,160	$0	$89,827	$5,227	$84,600	$5,227
2014	105,120				$88,667	$1,189	$0	$89,856	$5,321	$84,535	$5,321
2015	105,120				$88,667	$1,219	$0	$89,886	$5,417	$84,469	$5,417
2016	105,120				$88,667	$1,250	$0	$89,916	$5,514	$84,402	$5,514
2017	105,120				$88,667	$1,281	$0	$89,947	$5,614	$84,334	$5,614
2018	105,120				$88,667	$1,313	$0	$89,979	$5,715	$84,265	$5,715
2019	105,120				$88,667	$1,346	$0	$90,012	$5,818	$84,195	$5,818
2020	105,120				$88,667	$1,379	$0	$90,046	$5,922	$84,124	$5,922
2021	105,120				$88,667	$1,414	$0	$90,080	$6,029	$84,052	$6,029
2022	105,120				$88,667	$1,449	$0	$90,116	$6,137	$83,978	$6,137
2023	105,120				$88,667	$1,485	$0	$90,152	$6,248	$83,904	$6,248
2024	105,120				$88,667	$1,522	$0	$90,189	$6,360	$83,829	$6,360
2025	105,120				$88,667	$1,561	$0	$90,227	$6,475	$83,752	$6,475
2026	105,120				$88,667	$1,600	$0	$90,266	$6,591	$83,675	$6,591
2027	105,120				$88,667	$1,640	$0	$90,306	$6,710	$83,596	$6,710
2028	105,120				$88,667	$1,681	$0	$90,347	$6,831	$83,516	$6,831
2029	0				$0	$0	$0	$0	$0	$0	$0
2030	0				$0	$0	$0	$0	$0	$0	$0
2031	0				$0	$0	$0	$0	$0	$0	$0
2032	0				$0	$0	$0	$0	$0	$0	$0
2033	0				$0	$0	$0	$0	$0	$0	$0
2034	0				$0	$0	$0	$0	$0	$0	$0
2035	0				$0	$0	$0	$0	$0	$0	$0
2036	0				$0	$0	$0	$0	$0	$0	$0
2037	0				$0	$0	$0	$0	$0	$0	$0
2038	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.8435	$0.0100	$0.0000	$0.8535	$4.34139	-$3.4879	$0.0463	-$3.4416	-$361,782
2010	$0.8435	$0.0103	$0.0000	$0.8537	$0.04713	$0.8066	$0.0471	$0.7595	$79,835
2011	$0.8435	$0.0105	$0.0000	$0.8540	$0.04798	$0.8060	$0.0480	$0.7580	$79,683
2012	$0.8435	$0.0108	$0.0000	$0.8542	$0.04885	$0.8054	$0.0488	$0.7566	$79,529
2013	$0.8435	$0.0110	$0.0000	$0.8545	$0.04972	$0.8048	$0.0497	$0.7551	$79,373
2014	$0.8435	$0.0113	$0.0000	$0.8548	$0.05062	$0.8042	$0.0506	$0.7536	$79,214
2015	$0.8435	$0.0116	$0.0000	$0.8551	$0.05153	$0.8035	$0.0515	$0.7520	$79,052
2016	$0.8435	$0.0119	$0.0000	$0.8554	$0.05246	$0.8029	$0.0525	$0.7505	$78,887
2017	$0.8435	$0.0122	$0.0000	$0.8557	$0.05340	$0.8023	$0.0534	$0.7489	$78,720
2018	$0.8435	$0.0125	$0.0000	$0.8560	$0.05436	$0.8016	$0.0544	$0.7472	$78,550
2019	$0.8435	$0.0128	$0.0000	$0.8563	$0.05534	$0.8009	$0.0553	$0.7456	$78,377
2020	$0.8435	$0.0131	$0.0000	$0.8566	$0.05634	$0.8003	$0.0563	$0.7439	$78,201
2021	$0.8435	$0.0134	$0.0000	$0.8569	$0.05735	$0.7996	$0.0574	$0.7422	$78,023
2022	$0.8435	$0.0138	$0.0000	$0.8573	$0.05839	$0.7989	$0.0584	$0.7405	$77,841
2023	$0.8435	$0.0141	$0.0000	$0.8576	$0.05944	$0.7982	$0.0594	$0.7387	$77,656
2024	$0.8435	$0.0145	$0.0000	$0.8580	$0.06051	$0.7975	$0.0605	$0.7370	$77,468
2025	$0.8435	$0.0148	$0.0000	$0.8583	$0.06159	$0.7967	$0.0616	$0.7351	$77,277
2026	$0.8435	$0.0152	$0.0000	$0.8587	$0.06270	$0.7960	$0.0627	$0.7333	$77,083
2027	$0.8435	$0.0156	$0.0000	$0.8591	$0.06383	$0.7952	$0.0638	$0.7314	$76,886
2028	$0.8435	$0.0160	$0.0000	$0.8595	$0.06498	$0.7945	$0.0650	$0.7295	$76,686
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2030	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2031	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2032	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2033	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2034	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2035	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2036	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2037	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0
2038	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ACWA Resource Assessment Cost Template
Grease and Food Waste Receiving

Inputs

$1,000,000	Primary Equipment Cost
1	Number of Units
$0	Other Equipment Costs
10%	Engineering Costs (% of Project Cost)
$100,000	Engineering Costs
$0	Fuel Costs ($/Yr)
20	Life of Units
132	kW per Unit
95%	Capacity Factor
1,098,504	Annual kWh Generation
$0.040	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
5.7%	Nominal Discount Rate
$0.0463	Average 2007 Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator

Results

-$0.1207	First Year Cost
$0.0463	First Year Cost Utility Power
-$0.1198	10 Year Average Cost
$0.0502	10 Year Average Utility Cost
-$0.0950	Real Levelized Cost
$0.0426	Real Levelized Utility Cost

Incentives	
$0	BETC
$0	ETO
$0	Net Metering
$0	TOTAL
$234,000	Annual Tipping Fee Estimate

Other Equipment Costs

$0	Clean up Skid
$0	Shipping, installation and Commissioning
	Equipment #3
	Equipment #4
	Equipment #5
	Equipment #6
$0	TOTAL COST

Fuel Cost

	Cost/Therm or Gallon
	Fuel Use/Yr
$0	Total Fuel Costs ($/Yr)

ETO DR =
20%
NPV = $768,073

NPV =
$269,040

Year	Annual Generation (kWh/Yr)	Equipment Cost	Engineering Cost	Total Capital Cost	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)
2009	1,098,504	$1,000,000	$100,000	$1,100,000	$108,370	$43,940	$0	$152,311	$284,861	-$132,550	$50,861
2010	1,098,504				$108,370	$45,039	$0	$153,409	$285,776	-$132,367	$51,776
2011	1,098,504				$108,370	$46,165	$0	$154,535	$286,708	-$132,173	$52,708
2012	1,098,504				$108,370	$47,319	$0	$155,689	$287,657	-$131,968	$53,657
2013	1,098,504				$108,370	$48,502	$0	$156,872	$288,623	-$131,751	$54,623
2014	1,098,504				$108,370	$49,714	$0	$158,085	$289,606	-$131,521	$55,606
2015	1,098,504				$108,370	$50,957	$0	$159,328	$290,607	-$131,279	$56,607
2016	1,098,504				$108,370	$52,231	$0	$160,601	$291,626	-$131,024	$57,626
2017	1,098,504				$108,370	$53,537	$0	$161,907	$292,663	-$130,756	$58,663
2018	1,098,504				$108,370	$54,875	$0	$163,246	$293,719	-$130,473	$59,719
2019	1,098,504				$108,370	$56,247	$0	$164,618	$294,794	-$130,176	$60,794
2020	1,098,504				$108,370	$57,653	$0	$166,024	$295,888	-$129,865	$61,888
2021	1,098,504				$108,370	$59,095	$0	$167,465	$297,002	-$129,537	$63,002
2022	1,098,504				$108,370	$60,572	$0	$168,942	$298,136	-$129,194	$64,136
2023	1,098,504				$108,370	$62,086	$0	$170,457	$299,291	-$128,834	$65,291
2024	1,098,504				$108,370	$63,638	$0	$172,009	$300,466	-$128,457	$66,466
2025	1,098,504				$108,370	$65,229	$0	$173,600	$301,662	-$128,063	$67,662
2026	1,098,504				$108,370	$66,860	$0	$175,231	$302,880	-$127,650	$68,880
2027	1,098,504				$108,370	$68,532	$0	$176,902	$304,120	-$127,218	$70,120
2028	1,098,504				$108,370	$70,245	$0	$178,615	$305,382	-$126,767	$71,382
2029	0				$0	$0	$0	$0	$0	$0	$0

Year	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)	Difference ($/kWh)	Difference ($/Yr)
2009	$0.0987	$0.0400	$0.0000	$0.1387	$0.25932	-$0.1207	$0.0463	-$0.0744	-$81,689
2010	$0.0987	$0.0410	$0.0000	$0.1397	$0.26015	-$0.1205	$0.0471	-$0.1676	-$184,143
2011	$0.0987	$0.0420	$0.0000	$0.1407	$0.26100	-$0.1203	$0.0480	-$0.1683	-$184,881
2012	$0.0987	$0.0431	$0.0000	$0.1417	$0.26186	-$0.1201	$0.0488	-$0.1690	-$185,625
2013	$0.0987	$0.0442	$0.0000	$0.1428	$0.26274	-$0.1199	$0.0497	-$0.1697	-$186,373
2014	$0.0987	$0.0453	$0.0000	$0.1439	$0.26364	-$0.1197	$0.0506	-$0.1703	-$187,127
2015	$0.0987	$0.0464	$0.0000	$0.1450	$0.26455	-$0.1195	$0.0515	-$0.1710	-$187,886
2016	$0.0987	$0.0475	$0.0000	$0.1462	$0.26548	-$0.1193	$0.0525	-$0.1717	-$188,650
2017	$0.0987	$0.0487	$0.0000	$0.1474	$0.26642	-$0.1190	$0.0534	-$0.1724	-$189,419
2018	$0.0987	$0.0500	$0.0000	$0.1486	$0.26738	-$0.1188	$0.0544	-$0.1731	-$190,192
2019	$0.0987	$0.0512	$0.0000	$0.1499	$0.26836	-$0.1185	$0.0553	-$0.1738	-$190,970
2020	$0.0987	$0.0525	$0.0000	$0.1511	$0.26936	-$0.1182	$0.0563	-$0.1746	-$191,753
2021	$0.0987	$0.0538	$0.0000	$0.1524	$0.27037	-$0.1179	$0.0574	-$0.1753	-$192,539
2022	$0.0987	$0.0551	$0.0000	$0.1538	$0.27140	-$0.1176	$0.0584	-$0.1760	-$193,330
2023	$0.0987	$0.0565	$0.0000	$0.1552	$0.27245	-$0.1173	$0.0594	-$0.1767	-$194,125
2024	$0.0987	$0.0579	$0.0000	$0.1566	$0.27352	-$0.1169	$0.0605	-$0.1774	-$194,923
2025	$0.0987	$0.0594	$0.0000	$0.1580	$0.27461	-$0.1166	$0.0616	-$0.1782	-$195,725
2026	$0.0987	$0.0609	$0.0000	$0.1595	$0.27572	-$0.1162	$0.0627	-$0.1789	-$196,530
2027	$0.0987	$0.0624	$0.0000	$0.1610	$0.27685	-$0.1158	$0.0638	-$0.1796	-$197,338
2028	$0.0987	$0.0639	$0.0000	$0.1626	$0.27800	-$0.1154	$0.0650	-$0.1804	-$198,149
2029	$0.0000	$0.0000	$0.0000	$0.0000	$0.00000	$0.0000	$0.0000	$0.0000	$0

ABS Alaskan, Inc. introduces …

The LH-1000
Hydro Turbine

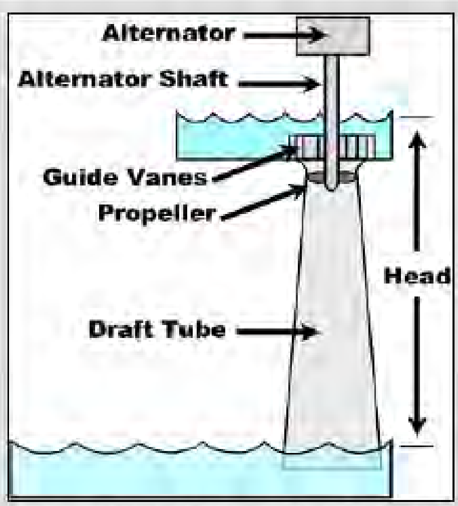
- **Produces up to 1 kW of electricity**
- **High quality turbine at a low price**
- **Ultra low head (2 ft to 10 ft)**

The LH1000 is an exciting hydro turbine that produces DC electrical power at sites with sufficient water flowing across relatively level terrain. The LH1000 uses a durable, low-head bronze propeller to produce power on a head of 2 to 10 feet. At 10 ft of head, the output from this turbine is one kilowatt, which is enough to supply the electrical requirements for an average household.

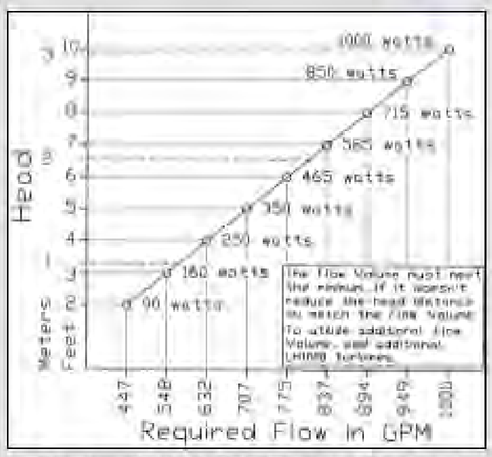
The LH1000 uses a permanent magnet alternator, which increases efficiency and performance while greatly reducing maintenance. This alternator is specifically designed for DC electrical output, eliminating the extra cost and inconvenience of an external turbine speed controller.

Water enters the LH1000 through the top guide vane assembly. As it falls through the turbine it turns the propeller, which spins the alternator, creating electricity. The water then exits the turbine through the draft tube, which is a sealed, tapered tube immersed in the tailwater. The draft tube creates a suction effect in the turbine, greatly increasing the turbine capacity.

The LH1000's light weight and small size allow for easy installation, portability, and quick removal during adverse conditions.



Basic Components of the LH1000



Optimal LH1000 Power Output
Required Water Flow Volume & Power Output in Watts for Various Head Distances.

Appendix J: Micro-Hydro Canyon Hydro Quote

Canyon Hydro

May 19, 2008
Mr. James Krumwied
Kennedy/Jenks Consultants
235-942-3438
jameskrumwied@kennedyjenks.com

Dear Mr. Krumwied,

Thank you for the opportunity to offer equipment for the WTP site you are currently evaluating.

As I understand the site, we are designing for an effective head range of 22 feet to 31 feet maintained at a relatively constant design flow rate of 19 cubic feet per second. The equipment package offered will be capable of producing outputs from 25 KW to 35 KW, under these conditions.

For your project we offer the following grid interface, power system equipment package.

> Turbine: Canyon Hydro custom Crossflow turbine. Turbine features shape machined and ground steel buckets, heat-treated and ground runner assembly, labyrinth seals, with pillow block mounted spherical roller bearings. Housing is heavy plate steel, flanged base, mounting frame integrated with generator and drive mounting frames, and intake to meet site requirements. Rotating hydraulically controlled variable flow guide vane assembly, maximum flow to 19 cfs.
> Generator: Lincoln or equivalent, 40 KW, 1200 rpm, 480 VAC, 60 Hz, three phase, brushless, induction industrial generator with complete gear drive speed increaser, couplings and drive guards.
> Control Package: Custom US manufactured switchgear/controls package to parallel the generator with the utility grid and provide protective relays per North American utility standards with hydraulic power unit to support the guide vane head adjustment and timed closure of the supplied turbine inlet valve.
>
> Budget estimate system price, as described ……………….. $175,150.00

The equipment package offered will be custom designed to meet the particular requirements of your site. As the project progresses and these requirements are determined, we would be pleased to offer a complete Preliminary Design Specifications and quotation. Budget estimates are offered for comparison purposes only but are generally within 15% of an actual quotation.

- Normal Terms 35% upon order, 35% mid-contract
- Balance due before shipping
- Normal Delivery 32-36 weeks
- Price FOB Deming, Washington

The equipment package offered is complete from your pipeline termination flange to the generator leads and will prove to be an extremely reliable power system. I look forward to learning more about this site as the project progresses. Please feel free to contact me for additional information.

Sincerely,

Eric Melander

Appendix K: ACWA RFP

Oregon Association of Clean Water Agencies

REQUEST FOR PROPOSALS
Proposals Due: 29 Feb 08

Energy Independence & Efficiency for Oregon Wastewater Treatment Plants
A Pilot Project

Project Overview

Wastewater treatment plants are one of the most energy intensive facilities managed by the public sector. Treating municipal wastewater is energy intensive – pumping water great distances, screening the wastewater, using mechanical processes to treat it, adding oxygen, and disinfecting the treated wastewater. It is estimated that Oregon's wastewater utilities are about 5% of the total electrical load in Oregon. Energy costs are generally 15% of the total wastewater treatment system budget, outspent only by personnel costs.

A combination of 'best-in-class' energy efficiency and increased renewable power production could reduce energy consumption and costs at treatment plants.

Wastewater treatment plants have the ability to generate electricity through use of their naturally occurring digester biogas. After installing an improved generator, the City of Gresham treatment plant now generates 50 – 55% of the power needed to operate its treatment plant. East Bay Municipal Utility District (EBMUD) - - serving the eastern portion of the San Francisco Bay area - - generates approximately 50% of its energy needs with biogas. The Metropolitan Wastewater Management Commission facility, serving Eugene, Springfield and portions of Lane County, generates about 57% of its power from its biogas.

Other renewable energy projects are compatible with wastewater treatment systems, including installation of solar PV panels. The City of Pacifica, California recently installed 1,800 solar PV panels to meet 10 – 15% of its treatment plant energy needs. The City of Medford is considering installing solar PV panels at its water reclamation plant.

Possible renewable power generating opportunities at a wastewater treatment plant include:

- Use of engines to generate electricity, heat recovery, or engine-driven power from biogas to fuel the treatment plant and to feed excess into the grid.
- Increasing biogas production by anaerobically digesting additional wastes including food waste from homes and restaurants, brewery and winery wastes, animal by-products, and other feedstocks.
- Using mini-hydro turbines to capture energy as it flows through the collection system or the treatment plant.
- Collecting fats, oil and grease (FOG) for biogas or biodiesel production.
- Installing solar PV systems atop large aeration basins or in the vacant areas that often surround the treatment plant.
- Installing solar PV systems atop pump stations and other equipment housing throughout the system.
- Using biosolids to grow seeds, such as canola, to produce biofuels for the plant vehicle fleet.

- Wind turbine installation at select locations.
- Tapping into geothermal energy as a heat source at select locations.
- Heat recovery from treated effluent.
- Industrial or commercial business partnerships.

Renewable energy experts may have additional ideas.

To maximize the efficiency of any renewable energy generation project, all cost-effective energy conservation measures should first be installed at each Oregon plant.

The project is being funded, in part, by the Energy Trust of Oregon. The selected contractor will agree to abide by the conditions of the letter agreement between Energy Trust of Oregon and ACWA that apply to the contractor's work.

Project Goal

The overall goal is to move Oregon wastewater treatment plants to "best-in-class" energy efficiency and 100% renewable power capacity within 10 years. This project is an element of achieving that goal.

The goal of this project is to evaluate what it would take for a typical Oregon wastewater treatment plant to maximize their use of energy efficiency and renewable power and to evaluate the economic feasibility of investing in renewable energy systems at a wastewater treatment plant. Federal and state incentives for renewable energy investments make this an excellent time for Oregon utilities to examine further investment in renewable energy systems, to meet the State of Oregon's renewable energy standard, to reduce operating costs for the utility and its ratepayers, and to reduce greenhouse gas emissions from wastewater treatment plants. This feasibility study will be used to inform and motivate Oregon cities, districts, and wastewater treatment plant managers to improve efficiency and invest in renewable power projects.

Project Approach

Two typical Oregon activated-sludge, secondary treatment systems will be selected as the pilot plants. The Technical Advisory Committee will select the pilot plants. The treatment plants must have anaerobic digesters. A medium sized (around 15 - 20 MGD) and smaller (around 1 - 5 MGD) treatment plant will be selected. Since part of the project funding is from the Energy Trust of Oregon, the selected pilot plants must be located within Portland General Electric or Pacific Power service territory.

The project consultant team will work in collaboration with a consortium of wastewater utility managers throughout the project, in addition to the staff from the two treatment plants selected. The elements of the consulting engineering firm scope of work would include: facility audit (2), energy use analysis (2), identifying renewable energy systems, recommended renewable projects and cost details, preparation of a final report, 2-page executive summary, and presentations.

Qualifications

The contractor should demonstrate these qualifications:

1. Detailed knowledge of municipal wastewater treatment secondary systems.
2. Knowledge of the Oregon electrical power system, including Oregon Renewable Portfolio Standard.

3. Knowledge of the ability of Oregon wastewater utilities to offer "green" or renewable power to customers outside of Oregon.
4. Demonstrated expertise completing energy evaluations and energy optimization analyses for secondary wastewater treatment plants.
5. Demonstrated expertise in designing renewable energy systems at industrial or wastewater treatment plant settings, included but not limited to biogas generation; mini-hydro turbines; using Fats, Oil, & Grease, animal by-products, food wastes or other wastes to generate biogas; installation of solar PV systems; biofuel products; wind turbines, or geothermal sources of power.
6. Knowledge of emerging technologies for energy conservation and sources of renewable power at a treatment plant, and emerging treatment technologies at a wastewater treatment plant.
7. Familiarity with available financing or incentives for energy efficiency or renewable energy projects at wastewater treatment plants.
8. Ability to work constructively with a wide-ranging technical advisory committee.

Preference will be shown for consultants that are associate members of ACWA.

Project Management

A group of ACWA and other technical experts will direct the project as the Technical Advisory Committee. Others joining the Technical Advisory Committee include the Energy Trust of Oregon, Oregon DEQ, League of Oregon Cities, Special Districts Association of Oregon, and possibly others. The technical advisory committee will oversee the work of the consultant.

Three or four meetings of the project technical advisory committee with the consultant team are planned. The meetings will likely be 3 to 4 hours long and will be held in Portland or Salem. At least one member of the consulting team will be required to attend each meeting. The ACWA Project Manager will be responsible for organizing the meetings, preparing meeting agendas with input from the consulting team, and preparing and distributing meeting summaries.

ACWA Executive Director Janet Gillaspie will be the project manager.

Scope of Work

All elements of the Scope of Work must be accomplished acknowledging that National Pollutant Discharge Elimination System (NPDES) and other environmental regulatory permits must be met at all times.

The Scope of Work includes:

1. Complete an energy evaluation for each of the two pilot plants. The evaluation will use any useful energy evaluation information completed for the facility to date.
   1.1. The energy evaluation for each plant shall include:
      1.1.1. Setting the current energy consumption baseline for the plant.
      1.1.2. Performing an energy optimization analysis of the wastewater treatment plants, listing all feasible energy conservation measures (including rate of return for municipal operations and a priority investment listing), any emerging energy conservation technology measures,

calculating their savings and cost-effectiveness, identifying potential funding sources, and recommending which energy conservation measures to install.

1.1.3. Calculating the plant's total electric al energy usage, system demand and power factor, and deducting the savings from the energy conservation measures to establish a new baseline energy usage.

1.1.4. Forecasting the energy demands for the plant for the next 10 years by using the adopted Facility Plan.

1.1.5. Identifying and costing-out all possible energy that could be used at the wastewater treatment plant, with an emphasis on renewable and innovative sources of power.

2. Recommend the most cost-effective and most feasible renewable energy projects that would make each wastewater treatment facility energy independent. Discuss the benefits and costs of implementing the recommendations (including but not limited to operational impacts, economic impacts, positive community and council or commission support, environmental impacts, and greenhouse gas impacts).

2.1. Summarize the energy conservation and renewable measures in a table that includes benefits and risks. Risks should include, at a minimum, NPDES permit compliance, air quality regulation compliance, safety, and other risk factors.

3. Using available data, estimate the current use of renewable power sources by municipal wastewater treatment plants in Oregon, and predict possible renewable power source usage by municipal wastewater treatment plants, if efficiency and maximum renewable projects were installed.

4. Provide a written report summarizing the information from both pilot plants, and providing useful information to other Oregon wastewater treatment plants relative to investments in efficiency and renewable power. All references and assumptions must be detailed.

4.1. Provide an Executive Summary of the full report (2 pages) that is easy to read and follow.

5. Provide a Microsoft *PowerPoint* presentation summarizing the project. Two versions of the PowerPoint presentation should be prepared.

5.1.1. Policy Maker presentation – presentation targeted to policy makers such as Council and Commission members, elected officials, senior management (10 – 20 slides)

5.1.2. Technical presentation – presentation targeted to Public Works Directors, Finance Directors, Wastewater Treatment Plant senior management (25 – 35 slides).

The project should reflect the approved wastewater facilities plan for the respective treatment plants.

ACWA, League of Oregon Cities (LOC), and Special Districts Association of Oregon (SDAO) staff and members intend to use the final report and project information to make presentations to Oregon elected officials, city managers, and wastewater treatment management staff to inform them of efficiency and renewable opportunities and to prompt them to invest in projects to increase renewable power generation at the treatment plant. The proposals should detail the availability of the consultant, if selected, to make presentations on the report and project, when completed.

Deliverables include:

1. Draft and final copies of the energy optimization study for each of the two selected pilot plants.

2. Draft and final copies of the final report that consolidates the information from the selected pilot plants and provides information, direction, and inspiration for other Oregon wastewater utilities to take action to invest in energy efficiency and renewable energy projects at their facilities.

3. Draft and final copies of an executive summary of the final report. The executive summary shall be 2-pages long, graphically pleasing, and easy-to-read.
4. Two PowerPoint presentations on the project. The PowerPoint presentations should include pictures and be graphically pleasing.
   4.1. One PowerPoint presentation should be aimed at policy makers as the target audience
   4.2. One PowerPoint presentation should be aimed at technical staff as the target audience.
      4.2.1.1. Both presentations should include speaking notes.
5. Each report will be provided in draft and final copies.
   5.1. The comments of the Technical Advisory Committee and the pilot plants will be incorporated into the final energy optimization study for each plant. A copy of each of the reports shall be provided in both a Microsoft *Word* and a PDF file format.

The consultant is encouraged to add elements to the proposed Scope of Work if it will help to improve the end product. If elements are added, please provide a cost with and without the added elements.

Schedule
The consultant will be selected around March 10, 2008. The project must be completed and the final invoice received and approved by June 30, 2008.

Budget
The project budget will not exceed $58,000.

Proposal Details
A letter proposal of no more than 6 double-sided pages (8-1/2 x 11 inches) is due at the ACWA office, 537 SE Ash, Suite 12, Portland, OR 97214 by **3:00 pm on February 29, 2008**. If mailed, sufficient time must be allowed for delivery. Postmarks do not serve as evidence of timely submittal. ACWA reserves the right to reject any or all proposals. ACWA also reserves the right to waive non-material irregularities in any proposal.

Proposers shall submit 5 paper copies of the proposal, and one electronic copy of the proposal in PDF format on CD-ROM The copies shall be submitted in a sealed package clearly marked as a *Proposal for Professional Services for Energy Independence Project.*

The proposal format should address these items, in this order:

- Cover letter (no page limit);
- Summary;
- Project Manager and Team Qualifications;
- Project Understanding and Approach;
- Scope of Services (labor hour estimate by task and schedule);
- Project schedule;
- Deliverables (draft and final, paper and electronic);
- Three project references; and
- Resumes (no page limit).

A selection committee will review and evaluate the proposals. Interviews may or may not be required, depending on the number and quality of the submittals. ACWA may choose to interview only the top rated proposers. If a proposer is asked by the selection committee to participate in an interview, the proposer will receive at least one week's notice prior to the interview to allow time for preparation.

ACWA will retain ownership of all work products produced under this contract. This is a work for hire.

For additional information, please contact Janet Gillaspie, ACWA Executive Director, by phone at (503) 236-6722, by e-mail at *gillaspie@oracwa.org.*